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August 15, 2018

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited ("Toronto Hydro")
Custom Incentive Rate-setting ("Custom IR") Application for 2020-2024 Electricity Distribution Rates and Charges
OEB File No. EB-2018-0165

With this letter, Toronto Hydro is filing its Custom IR Application for 2020-2024 electricity distribution rates and charges. The Application and supporting evidence are being filed in electronic format. This includes the live Excel versions of the appendices and models specified in the Filing Requirements. Seven physical copies will follow shortly via courier.

Toronto Hydro considers certain information contained within the Application to be confidential. Under separate cover, and in accordance with the OEB's *Rules of Practice and Procedure* and *Practice Direction on Confidential Filings*, Toronto Hydro requests confidential treatment of that information.

Please do not hesitate to contact me if you have any questions.

Yours truly,

Andrew J. Sasso
Director, Regulatory Affairs
Toronto Hydro-Electric System Limited
regulatoryaffairs@torontohydro.com

cc: Amanda Klein, Toronto Hydro
Charles Keizer, Torys LLP
Crawford Smith, Torys LLP

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August 15, 2018

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited ("Toronto Hydro")
Custom Incentive Rate-setting ("Custom IR") Application for 2020-2024 Electricity Distribution Rates and Charges – Request for Confidential Treatment
OEB File No. EB-2018-0165

Pursuant to Rule 10.01 of the OEB's *Rules of Practice and Procedure* and the OEB's *Practice Direction on Confidential Filings*, Toronto Hydro requests that certain information in the pre-filed evidence be kept confidential. Details about the particular information and the basis of the request for confidential treatment are provided below.

Descriptions of the particular information for which Toronto Hydro seeks confidential treatment and the rationale for the request, including the reasons why public disclosure would be detrimental to Toronto Hydro, are set out below. **Attachment 'A'** contains redacted versions (non-confidential) of the relevant documents. **Attachment 'B'** contains unredacted (confidential) versions of the relevant documents, each of which has been marked "confidential" and identifies all portions of the documents for which confidentiality is claimed by using highlighting. The confidential materials in Attachment 'B' are being provided to the OEB in a separate, sealed envelope that is marked "confidential" and have been excluded from the electronic version of this request. The confidentiality requests, organized by the type of information to be protected from disclosure, are as follows:

1. **Personal Information**

- Exhibit 4B, Tab 2, Schedule 3, Form T661, Part 1 and Part 2
- Exhibit 4B, Tab 2, Schedule 3, T2 Summary, Schedules 31, 550, 552 and 569

Toronto Hydro seeks confidential treatment of personal information contained in the utility's corporate income tax return. Consistent with the definition of personal information under the *Freedom of Information and Protection of Privacy Act*, RSO, 1990, CF 31, the redacted information includes: the names, phone numbers, job titles, professional designations and years of experience of employees; the names and addresses of external individuals; and the names of students and

apprentices. Toronto Hydro notes that this information has been previously held confidential by the OEB.[1]

2. **Business Numbers**
    - Exhibit 4B, Tab 2, Schedule 3, Form T661, Part 1, Part 2 and Part 9
    - Exhibit 4B, Tab 2, Schedule 3, T2 Summary, Schedules 1,2, 5-10, 23, 31, 33, 50, 53, 500, 508, 510, 511, 546, 550, 552, 568 and 569

For security and fraud protection reasons, Toronto Hydro seeks confidential treatment for any business numbers contained in the utility's corporate income tax return. Toronto Hydro submits that disclosure of this information can expose the utility and other parties to the risk of fraud, and notes that this information has previously been deemed confidential by the OEB.[2]

3. **Commercially Sensitive and Proprietary Information**
    - Exhibit 4B, Tab 2, Schedule 3, Form T661, Parts 2-8

Toronto Hydro seeks confidential treatment of commercially sensitive information contained in the utility's corporate income tax return. Specifically, the information contained in the Scientific Research and Experimental Development Expenditures Claims portion includes commercially sensitive and proprietary information that if disclosed, could affect the competitive position of Toronto Hydro and third parties.

4. **Cost Difference between Internal and External Construction Projects**
    - Exhibit 1B, Tab 2, Schedule 2, p. 22

Toronto Hydro seeks confidential treatment of the average cost differences between constructing projects internally versus using external contractors. Toronto Hydro submits that this information is commercially sensitive and that its disclosure could interfere significantly in Toronto Hydro's negotiations with construction contractors, as it may put upward pressure on contract prices. Such interference could result in a significant cost to the utility, and by extension, reduced value for ratepayers. Toronto Hydro respectfully submits that this information should be kept confidential. This information was deemed confidential by the OEB in the utility's last rebasing application.[3]

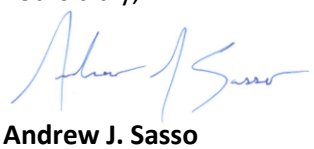
5. **Information Posing Security and Safety-Related Risks**
    - Exhibit 2B, Section E8.1, pp. 1-2, 5-9,12, 15, 17-18, 20-29, Appendix A, pp. 4, 6, 8 and Appendix B
    - Exhibit 2B, Section E8.2, pp. 1, 3, 16-18, 20, 22, 24-26

[1] See for instance, EB-2014-0116, Toronto Hydro-Electric System Decision on Confidentiality and Procedural Order No. 4 (January 7, 2015).
[2] See EB-2014-0116, Toronto Hydro-Electric System Decision on Confidentiality and Procedural Order No. 4 (January 7, 2015) at p. 4 and EB-2013-0196, 0197, 0198, Decision on Confidential Request and Procedural Order No. 5 (September 27, 2013) at pp. 7-8.
[3] EB-2014-0116, Toronto Hydro-Electric System Decision on Confidentiality and Procedural Order No. 4 (January 7, 2015) at p. 4.

Toronto Hydro seeks confidential treatment of the vulnerabilities and locations of its existing back-up and proposed Control Centre. The utility also seeks confidential treatment of the information that directly or indirectly discusses the vulnerabilities of the utility's existing security infrastructure. The disclosure of this information could adversely impact the safety and security of the distribution system. This type of information has been previously deemed confidential by the OEB.[4]

Please do not hesitate to contact me if you have any questions.

Yours truly,



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[4] See EB-2016-0160, Hydro One Networks Inc. Decision on Confidentiality Request (Revised) (September 26, 2016) at pp.3-5; and EB-2016-0152, Ontario Power Generation Inc. Decision and Order on Confidentiality (January 31, 2017) at p. 21.

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August 22, 2018

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited ("Toronto Hydro")
Custom Incentive Rate-setting ("Custom IR") Application for 2020-2024 Electricity Distribution Rates and Charges – Customer Summary Update
OEB File No. EB-2018-0165

Enclosed please find an update to the Customer Summary. In the section called "Costs of the Plan", the text was amended to clarify that, "distribution rates would increase by an average of $0.77 (1.7%) **per month,** annually from 2020 to 2024."

Please do not hesitate to contact me if you have any questions.

Yours truly,

Andrew J. Sasso
Director, Regulatory Affairs
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cc: Amanda Klein, Toronto Hydro
Charles Keizer, Torys LLP
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September 14, 2018

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited ("Toronto Hydro")
Custom Incentive Rate-setting ("Custom IR") Application for 2020-2024 Electricity Distribution Rates and Charges – Evidence Update
OEB File No. EB-2018-0165

Pursuant to Rule 11.03 of the OEB's *Rules of Practice and Procedure*, Toronto Hydro is filing an evidence update. The nature of the updates are summarized in Table 1 below. Toronto Hydro has also submitted the live Excel versions for the relevant appendices and models. Updates to the applicable evidence are marked by /C.

Table 1: List of Updates

	Topic	Update	Reference
1	Updated Table of Contents	Toronto Hydro has updated its Table of Contents as a result of the updates stated herein.	Exhibit 1, Tab 1, Schedule 1
2	Chapter 2 Appendices	Toronto Hydro submits all Chapter 2 Appendices in Excel format (that had not already been filed on August 15, 2018)	N/A
3	Appendix 2-BB	Toronto Hydro submits Appendix 2-BB and an update to the related discussion in Exhibit 4B, Tab 1, Schedule 1.	Exhibit 4B, Tab 1, Schedule 1, Appendix C *[New]*
4	Cost of Power Calculation	Toronto Hydro submits the Cost of Power calculation in Excel format.	Exhibit 2A, Tab 3, Schedule 1, Appendix A
5	Bill Impacts model	Toronto Hydro submits the Bill Impacts model in Excel format (as part of Item #2 above).	Exhibit 8, Tab 6, Schedule 1

6	OEB's Pole Attachment Workform	Toronto Hydro submits an update confirming that the utility has adopted the OEB's standard province-wide rate and therefore is not required to file a completed Pole Attachment Workform for a utility-specific rate.	Exhibit 8, Tab 2, Schedule 1
7	Accounting Order from EB-2014-0116	Toronto Hydro submits the Accounting Order from EB-2014-0116.	Exhibit 9, Tab 1, Schedule 1, Appendix B *[New]*
8	Cost Allocation Model	Toronto Hydro has corrected reference errors and resubmits the model in Excel format. Toronto Hydro confirms that the identified errors had no effect on the outputs of the model.	Exhibit 7, Tab 1, Schedule 3
9	2023 Revenue Requirement Workform	Toronto Hydro has corrected a summation error and resubmits the model. Toronto Hydro confirms that there is no effect on bill impacts from the summation error identified above.	Exhibit 6, Tab 1, Schedule 5
10	Group 2 Deferral and Variance accounts	Toronto Hydro has updated its evidence to include a request and rationale to continue certain Group 2 accounts. Toronto Hydro submits that the request and rationale to continue the Capital Related Revenue Requirement, Externally driven Capital and Derecognition variance accounts was already included in the original filing.	Exhibit 9, Tab 1, Schedule 1
11	Anticipated Evidence Updates	Toronto Hydro submits a table summarizing updates to the Application anticipated at this time.	Exhibit 1A, Tab 3, Schedule 1, Appendix B *[New]*
12	Earnings Sharing Mechanism	Toronto Hydro submits an update describing the ESM approach and methodology that the utility proposes to continue in 2020-2024 and was approved by the OEB in EB-2014-0116.	Exhibit 1B, Tab 4, Schedule 1
13	Explanations for Differing Disposition Amounts stated in (i) Summary of Proposed Dispositions; (ii) Continuity Schedule; and (iii) Rate Riders	Toronto Hydro provides an update to the Rate Rider table providing an explanation of the differing amounts presented in other related areas of the Application.	Exhibit 9, Tab 3, Schedule 1, p. 1 ["Rate Riders Table"]

14	CVs and Acknowledgement of Expert's Duty (Form A) for Authors of PSE's Total Cost Benchmarking report	Toronto Hydro has updated its evidence to include the CVs and Form A for Erik Sonju and Steve Fenrick.	Exhibit 1B, Tab 4, Schedule 2, Appendix A *[New]*
15	Power System Engineering Inc.'s Dataset and Models	Toronto Hydro will provide this material in the same manner as was shared with OEB Staff in the utility's last application.	Exhibit 1B, tab 4, Schedule 2

Please do not hesitate to contact me if you have any questions.

Yours truly,



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September 28, 2018

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited ("Toronto Hydro")
Custom Incentive Rate-setting ("Custom IR") Application for 2020-2024 Electricity Distribution Rates and Charges – Request for Confidential Treatment of Power Systems Engineering Inc.'s Dataset and Models
OEB File No. EB-2018-0165

On August 28, 2018, Toronto Hydro received a request from OEB Staff to provide the dataset and models underlying Power Systems Engineering Inc.'s ("PSE") Econometric Benchmarking Report. Pursuant to Rule 10.01 of the OEB's *Rules of Practice and Procedure* and the OEB's *Practice Direction on Confidential Filings*, Toronto Hydro requests that the information relating to PSE's cost and reliability benchmarking models be kept confidential.

Descriptions of the particular information for which Toronto Hydro seeks confidential treatment and the rationale for the request are set out below. This information is of the type specifically contemplated by Appendix A to the OEB's *Practice Direction on Confidential Filings* and has been treated as confidential in other proceedings.[1]

On behalf of PSE, Toronto Hydro seeks confidential treatment of the following information relating to PSE's cost and reliability benchmarking models:

a. Data used in the respective study, in the form of a Microsoft Excel spreadsheet or other files;
b. Microsoft Excel or other files that made use of the source data and produced measures that were used, directly or indirectly, by the respective benchmarking models;
c. Microsoft Excel or other files used to produce the Tables and Figures in the PSE benchmarking report;
d. The computer code used to generate results for the respective benchmarking models; and
e. Electronic GIS files used to define utility service territories and PSE defined urban congested areas.

[1] See EB-2014-0116 and EB-2017-0049.

The above noted information consists of proprietary, technical, and commercially sensitive dataset and models that represents significant work undertaken by PSE. In addition, this information holds considerable commercial value. Toronto Hydro submits that PSE's dataset and models should be kept confidential as public disclosure would result in financial and competitive harm to PSE.

Please find enclosed with this letter a USB key which includes copies of PSE's dataset and models. The files in their entirety are being filed on a confidential basis and therefore are not being submitted in a redacted and un-redacted form.

Please do not hesitate to contact me if you have any questions.

Yours truly,



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November 13, 2018

Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited ("Toronto Hydro")
Custom Incentive Rate-setting Application for 2020-2024 Electricity Distribution Rates and Charges – Response to Submissions Received on Confidentiality Request
Ontario Energy Board ("OEB") File No. EB-2018-0165

The purpose of this letter is to reply:

1. to the submissions made in respect of Toronto Hydro's request for confidential treatment of certain information (the "Confidentiality Request"); and,

2. to the PWU's letter dated November 8, 2018, written in response to Toronto Hydro's letter dated November 5, 2018.

Confidentiality Request

Toronto Hydro received submissions from: (i) Energy Probe Research Foundation ("Energy Probe") by letter dated October 28, 2018; (ii) the Building Owners and Managers Association, Greater Toronto ("BOMA") by letter dated October 30, 2018; and (iii) OEB Staff by letter dated October 31, 2018.

For the reasons set out in the Confidentiality Request and below, Toronto Hydro maintains that confidential treatment should be afforded to the information requested, with the exception of certain information contained in the 2016 tax return (discussed in section 4, below), pursuant to the OEB's *Rules of Practice and Procedure* and the *Practice Direction on Confidential Filings*.

1. The dataset and models relating to Power Systems Engineering Inc.'s ("PSE") Econometric Benchmarking Report contain proprietary technical information

BOMA and Energy Probe object to Toronto Hydro's request for confidential treatment of the

dataset and models underlying PSE's Econometric Benchmarking Report.[1]

BOMA's states that this type of information is not specifically enumerated in Appendix B to the *Practice Direction on Confidential Filings*, and that Toronto Hydro has not shown how disclosure will result in substantial loss to PSE.[2]

PSE's dataset and models have been processed, derived, and calculated using significant investment and time. The resulting technical proprietary information has considerable commercial value to PSE. Public disclosure of this information would cause significant financial and competitive harm to PSE.

In previous proceedings (including Toronto Hydro's 2015-2019 Rate Application) the OEB has routinely accorded confidential treatment to the same type of proprietary technical information, on the basis that disclosure would likely adversely affect PSE's competitive position and cause significant loss.[3] This precedent has been recently applied by the OEB in its November 6, 2018 decision in respect of the confidentiality request for PSE data and models in Hydro One Sault Ste. Marie LP's 2019 transmission revenue requirement proceeding:

> … the OEB finds that the technical material and the aggregated form of data contained in the Working Papers such as models, calculations, and source codes, represent significant intellectual property. The public disclosure of this information could reasonably be expected to cause potential commercial and financial harm to PSE and SNL [*being the third party data provider in that case*].[4]

Energy Probe's submissions on this issue contains several inaccuracies. First, Energy Probe argues that a confidentiality request was not made for the same materials in the utility's last Application (EB-2014-0116).[5] To the contrary, in correspondence dated December 19, 2014, Toronto Hydro expressly sought confidential treatment of "information relating to PSE's costs and reliability benchmarking models."[6] In other words, the PSE dataset and models underlying the current Confidentiality Request are identical to the request made in the 2015-2019 proceeding.

Second, Energy Probe appears to assume that Toronto Hydro is seeking confidential treatment

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[1] PSE's Econometric Benchmarking Report is found at Exhibit 4B, Tab 4, Schedule 2.

[2] BOMA Submissions (October 30, 2018) ["**BOMA Submissions**"], p. 2.

[3] Also see: (i) Hydro One Networks Inc.'s 2018-2022 distribution rates proceeding (EB-2017-0049), Decision on Confidentiality (April 12, 2018); and (ii) Hydro One Sault Ste. Marie LP's 2019 transmission revenue requirement proceeding (EB-2018-0218), Decision on Confidentiality and Procedural Order No. 2 (November 6, 2018) ["**EB-2018-0218 PO #2**"].

[4] EB-2018-0218 PO #2, p. 2.

[5] Energy Probe Submissions (October 28, 2018) ["**Energy Probe Submissions**"], p. 2.

[6] See: Toronto Hydro's Confidentiality Request re PSE September 2014 Data (December 19, 2014).

of "the whole [PSE] Report".[7] This is wrong. The request applies only to the datasets and models underlying the PSE report. The PSE report, in its entirety is publicly available at Exhibit 1B, Tab 4, Schedule 2 of the 2020 Rate Application.

Energy Probe further argues that the 2018 PSE report does not contain the same disclaimer (i.e., prohibiting the unauthorized use of proprietary information) that was found in the PSE report filed in the 2015-2019 Rate Application.[8] Respectfully, the absence of this disclaimer has no bearing on the issue of confidentiality. The presence or absence of such a disclaimer does not change the fact that the underlying datasets and models are proprietary technical information that represent considerable commercial value for PSE.

Finally, Energy Probe asserts that PSE has not provided the same level of disclosure and descriptions in this report as compared to the report included in the 2015-2019 Rate Application. This assertion is equally wrong but has nothing to do with the issue of confidentiality. To the extent the two reports may align or differ in some aspects of their presentation, it has no bearing on the fact that the underlying datasets and models remain proprietary and confidential to PSE.

2. Disclosure of the cost difference between internal and external construction projects would place upward pressure on Toronto Hydro's costs

BOMA objects to confidential treatment of the cost difference between internal and external construction projects. BOMA argues that the average cost difference is not likely to affect proposals from third party contractors, since Toronto Hydro is not obliged to accept any bids that it considers too high.[9]

Toronto Hydro respectfully submits that BOMA's position fails to recognize the reality and complexities of Toronto Hydro's negotiations with construction contractors and unions, and that disclosure of this information would likely prejudice Toronto Hydro's competitive position and place upward pressure on Toronto Hydro's costs. The OEB recognized these concerns and afforded confidential treatment of the same information in Toronto Hydro's 2015-2019 Rate Application.[10]

3. Disclosure of security and safety-related information could adversely impact Toronto Hydro's infrastructure

Toronto Hydro received objection from one intervenor, BOMA, on the issue of confidential treatment of the information posing a security or safety-related concern. In its submissions,

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[7] Energy Probe Submissions, p. 3.

[8] Energy Probe Submissions, p. 2.

[9] BOMA Submissions, p. 3.

[10] See: EB-2014-0116 (i) Toronto Hydro letter re Confidential IRs (November 11, 2014), and (ii) OEB Decision on Confidentiality and Procedural Order No. 4 (January 7, 2015) at p. 4.

BOMA argues that the proposed confidentiality redactions are excessive and ought to be narrowed in scope.[11]

Toronto Hydro has reviewed the information and maintains its position that the information warrants confidential treatment. Disclosure of this information would have an adverse impact on the security and safety of Toronto Hydro's infrastructure. Toronto Hydro has carefully only redacted information that contains the vulnerabilities of the utility's safety and security systems, and also any information that, when viewed in aggregate, could indirectly reveal or allow inferences to be drawn regarding the potential existence and nature of such vulnerabilities. As noted in our Confidentiality Request, this type of information has been previously granted confidential treatment by the OEB.[12]

4. Scientific Research and Experimental Development schedule (redacted from the 2016 corporate tax return) will be filed on the public record

BOMA and OEB Staff object with respect to the Scientific Research and Experimental Development ("SR&ED") schedule (Form T661) filed on a confidential basis as part of Toronto Hydro's 2016 tax return at Exhibit 4B, Tab 2, Schedule 3.

Toronto Hydro has carefully considered these submissions and is prepared to file the SR&ED schedule on the public record and consequently withdraws its request for confidential treatment in relation to this information.[13] Toronto hydro will be updating its application accordingly and placing this information on the public record. For clarity, Toronto Hydro's business numbers and any personal information remains redacted from this schedule.

Reply to Power Workers Union

In its November 5, 2018 letter, Toronto Hydro asked that should the cost difference between internal and external construction projects (item #2 above) be afforded confidential treatment, it not be made available to the PWU including where its representatives have signed the OEB Declaration and Undertaking.

The PWU letter appears to acknowledge the reasonableness of Toronto Hydro's request as it relates to certain representatives but argues that access should be given to its counsel. Toronto Hydro disagrees.

Toronto Hydro's disagreement has nothing to do with the creditworthiness of counsel's undertaking. The issue relates to the difference between the purpose of this proceeding and

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[11] BOMA Submissions, pp. 3-4.

[12] See: EB-2016-0160, Hydro One Networks Inc. Decision on Confidentiality Request (Revised) (September 26, 2016) at pp.3-5; and EB-2016-0152, Ontario Power Generation Inc. Decision and Order on Confidentiality (January 31, 2017) at p. 21.

[13] Being information found at Exhibit 4B, Tab 2, Schedule 3, Form T661, Parts 2-8.

collective bargaining. Here, the OEB is charged with setting just and reasonable rates for the distribution of electricity in Toronto. A number of intervenor groups have been granted status by the OEB expressly to advance the interests of consumers of that electricity. Why the PWU requires the information to advance its interests in the proceeding – however those are defined – is unstated. The application is not intended to enable or facilitate collective bargaining. That however appears to be the genesis of PWU's position. In the most recent round of bargaining the parties agreed in writing that Toronto Hydro would not be obliged to share the information with the PWU. Toronto Hydro's obvious concern now is that the PWU is effectively trying to achieve indirectly a result it could not achieve directly in bargaining. It is inviting the OEB to circumvent the agreement reached by the parties in bargaining. That is not the proper purpose of a rate proceeding and does nothing to advance the objectives of the OEB.

Moreover, even if the PWU's request were related to a genuine need for the information in this case, Toronto Hydro submits that the prejudice to its competitive position outweighs that interest, particularly where, as set out above, the interest of consumers is already represented.

In the event the OEB however is inclined to agree with the PWU that its counsel should be granted access to the information, Toronto Hydro asks that two further restrictions be granted. First, that such individuals be external to and at arms-length from the PWU. Second, that they not be involved in <u>any</u> future collective bargaining-related activities on its behalf.

In its letter, the PWU argues that the Board-mandated Declaration and Undertaking should suffice to protect Toronto Hydro's interest. This argument has twice been made by the PWU and rejected by the OEB. In both OPG's most recent payment amounts proceeding (EB-2016-0152) and the Alectra-Guelph MAADs (EB-2018-0014) case, the OEB required PWU representatives (including counsel) to provide a Declaration and Undertaking as well as an affidavit affirming the satisfaction of certain requirements comparable to the two conditions. In doing so, the OEB indicated its intention to "give ratepayers the highest degree of confidence in the OEB's processes and treatment of highly sensitive information", and not to question "[PWU counsel's] integrity or to suggest that [he has] not complied with previous undertakings".[14]

Please do not hesitate to contact me if you have any questions.

[14] EB-2016-0152, OEB Letter re: Power workers' Union objections regarding filing of affidavit (January 31, 2017), p. 5.

Yours truly,



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cc: Charles Keizer, Torys LLP
Crawford Smith, Torys LLP
Intervenors of Record for EB-2018-0165

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April 30, 2019

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: EB File No. EB-2018-0165, Toronto Hydro-Electric System Limited ("Toronto Hydro") Custom Incentive Rate-setting ("Custom IR") Application for 2020-2024 Electricity Distribution Rates and Charges – Evidence Updates and Corrections

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Further to Procedural Order No. 4, enclosed with this letter is a copy of Toronto Hydro's Application Update (Exhibit U). The primary purpose of this update is to provide 2018 financial information. The Application Update is being filed in electronic format, including the live Excel versions of the updated appendices and models specified in the Filing Requirements. Physical copies will follow via courier.

Toronto Hydro is also filing a number of corrections to previously filed evidence, as summarized in the enclosed table of revisions (Appendix A). Pursuant to the OEB's *Rules of Practice and Procedure*, the revised documents are provided in blue paper, and marked by /C to indicate the parts revised.

In advance of the Oral Hearing, Toronto Hydro will file electronic copies of consolidated versions of the Application and Evidence and Interrogatory Responses.

Please contact me directly if you have any questions or concerns.

Respectfully,

Andrew J. Sasso
Director, Regulatory Affairs
Toronto Hydro-Electric System Limited

cc: Lawrie Gluck, OEB Case Manager
Michael Miller, OEB Counsel
Parties of Record
Amanda Klein, Toronto Hydro
Daliana Coban, Toronto Hydro
Charles Keizer, Torys LLP

Appendix A: Table of Revisions (April 30, 2019), Toronto Hydro 2020-2024 Custom IR Application, OEB File No. EB-2018-0165

Original Evidence (as originally filed or subsequently updated)	Revised Evidence (filed April 30, 2019)	Numerical Differences
Electricity Distributor Scorecard and 2015-2019 Distribution System Plan Performance Measures **(Exhibit 1B, Tab 2, Schedule 2)**	Revised the Serious Electrical Incident Index measure of Rate of incidents per 1,000 km of line.	"Toronto Hydro has surpassed the distributor targets, with only one reporting incident in the three years, which results in a ratio of ~~0.070~~ 0.035 incidents per 1,000 km of line for 2017."
Letters of Comment Responses **(Exhibit 1B, Tab 3, Schedule 5)**	Revised to include letters of comment filed with the OEB and Toronto Hydro's responses.	N/A
Rate Base Overview **(Exhibit 2A, Tab 1, Schedule 1)**	Revised the Gross and Net Property, Plant and Equipment ("PP&E"), the Fixed Asset Continuity Schedules, the Gross Assets Breakdown by USoA, and the Summary of Depreciation Expense to show Customer Specific Energy Storage Systems as being recovered under Contributions and Grants, consistent with Toronto Hydro response to undertaking JTC3.1.	The numerical differences cannot be summarized in this table. Please refer to the updated schedules.
OEB Appendix 2-BA: Fixed Asset Continuity Schedule – MIFRS **(Exhibit 2A, Tab 1, Schedule 2)**		
Gross Assets Breakdown by Major Plant Account **(Exhibit 2A, Tab 2, Schedule 1, Appendix A)**		
Summary of Depreciation Expense **(Exhibit 4B, Tab 1, Schedule 1, Appendix A)**		

<table>
<tr><th>Original Evidence (as originally filed or subsequently updated)</th><th>Revised Evidence (filed April 30, 2019)</th><th>Numerical Differences</th></tr>
<tr><td>Capital Expenditure Summary
(Exhibit 2B, Section E4)</td><td>Revised Table 2, Costs and Gains Associated with the OCCP Program, to correct a drafting error and align with the information in Exhibit 9, Tab 1, Schedule 1.</td><td>Table 2: Costs and Gains Associated with the OCCP Program
<table><tr><th></th><th>Planned</th><th>Actual</th><th>Variance</th></tr><tr><td>Net gain from Sale</td><td>$72.5M</td><td><s>$133.9</s>M
$142.2M</td><td><s>$61.4M</s>
$69.7M</td></tr></table></td></tr>
<tr><td>Underground System Renewal – Downtown
(Exhibit 2B, Section E6.3)</td><td>Revised the forecast volumes of lead based cables to be replaced over the 2020-2024 period.</td><td>Due to the size of the information, the numerical differences cannot be summarized for the purposes of this table. Please refer to the updated schedule.</td></tr>
<tr><td>Stations Expansion
(Exhibit 2B, Section E7.4)</td><td>Revised sentence re Toronto Hydro’s capital contribution to Hydro One for the Horner TS Expansion to correct a drafting error.</td><td>“Toronto Hydro plans to make a capital contribution to Hydro One of <s>$41</s> $34.4 million over the 2020-2024 period for a large-scale expansion project at Horner TS.”</td></tr>
<tr><td>OEB Appendix 2-C: Depreciation and Amortization Expense
(Exhibit 4B, Tab 1, Schedule 1, Appendix B)</td><td>Revised the Depreciation and Amortization Expense tables to correct errors related to ICM asset transfers and derecognition.</td><td>Due to the size of the Depreciation and Amortization Expense tables, the numerical differences cannot be summarized for the purposes of this table. Please refer to the updated schedule.</td></tr>
<tr><td>Response to Association of Major Power Consumers in Ontario Interrogatories
(1B-AMPCO-2(a))</td><td>Revised the number of customer outages in 2018.</td><td>Table 1: Number of outages 2006-2018
<table><tr><th>Year</th><th>Customer Interruptions (Excl. LoS, MEDs)</th></tr><tr><td>2018</td><td><s>1,247,848</s> 869,713</td></tr></table></td></tr>
<tr><td>Response to School Energy Coalition Interrogatories
(2B-SEC-56, Table 2)</td><td>Revised the number of wholesale meters to be replaced in 2022.</td><td>Updated the number of wholesale meters in 2022 from 70 to 0.</td></tr>
</table>

Exhibit List / Table of Contents

Exhibit	Tab	Schedule	Appendix		
1A ADMINISTRATION					
1	Table of Contents				
	1	Table of Contents			
2	Legal Application				
	1	Legal Application			
3	Filing Requirements				
	1	Administration			
			A OEB Appendix 2A: List of Requested Approvals	+ excel	/C
			B Planned Evidence Updates		/C
	2	Filing Requirements Checklist			
	3	Certification of Evidence			
	4	Glossary			
	5	Disclaimer			
1B REQUESTS AND RATIONALE					
1	Executive Summary				
	1	Executive Summary and Business Plan Overview			
			A Summary of Total Bill Impacts and Updated Tariff Charges		
2	Outcomes and Performance Management				
	1	Outcomes and Performance Management			
			A Annually Reported Measures		
			B UMS Unit Cost Benchmarking Study		
			C OEB Appendix 5-A: Metrics		
	2	Electricity Distributor Scorecard and 2015-2019 Distribution System Plan Performance Measures			
	3	Service Quality Performance			
	4	Reliability Performance			
	5	OEB Appendix 2-G: Service Reliability Indicators		+ excel	/C
3	Customer Engagement and Stakeholdering				
	1	Customer Engagement			
			A Customer Engagement Report, prepared by Innovative Research Group		
			B OEB Appendix 2-AC: Customer Engagement Activities	+ excel	/C
	2	Stakeholder Consultations			
			A Toronto Hydro 2020 CIR Stakeholder Consultation Report		
	3	Customer Summary			
	4	Community Meetings			
	5	Letters of Comment Responses			
4	Rate Framework and Benchmarking				
	1	Rate Framework			
	2	Econometric Benchmarking Report, prepared by PSE			
			A Curricula Vitae and Form A		/C
	3	PEG Forecast Benchmarking Results			
5	Application Summary				
	1	Application Summary			
1C CORPORATE INFORMATION					
1	Operating Environment				
	1	Operating Environment			
	2	Toronto Hydro Service Area Map			
2	Corporate Structure and Governance				
	1	Corporate Structure and Governance			

3 Financial Information
- 1 Financial Information Overview
- 2 Accounting Standards
- 3 Audited Financial Statements
  - A 2015 Financial Statements and Notes
  - B 2016 Financial Statements and Notes
  - C 2017 Financial Statements and Notes
- 4 Reconciliations
  - A 2015 RRR Reconciliation
  - B 2016 RRR Reconciliation
  - C 2017 RRR Reconciliation
- 5 THC 2016 and 2017 Management Discussion and Analysis
- 6 THC 2017 Annual Information Form
- 7 Public Debt Offering
  - A Base Shelf Prospectus, 2017
  - B 11th Supplemental Trust Indenture, Sep 2014
  - C 12th Supplemental Trust Indenture, Mar 2015
  - D 13th Supplemental Trust Indenture, Jun 2016
  - E 14th Supplemental Trust Indenture, Nov 2017
- 8 Rating Agency Reports
  - A Standard and Poor's, 30 April 2018
  - B DBRS, 27 April 2018
- 9 Existing Accounting Orders and Departures from USoA
- 10 THC 2017 Annual Report

2A RATE BASE

1 Rate Base
- 1 Rate Base Overview
- 2 OEB Appendix 2-BA: Fixed Asset Continuity Schedules **+ excel**

2 Gross Assets
- 1 Gross Assets
  - A Gross Assets by USoA Account

3 Working Capital Allowance
- 1 Working Capital Allowance
  - A Cost of Power **+ excel** **/C**
- 2 Working Capital Requirements Study, prepared by Navigant Consulting

4 Capital Expenditures
- 1 Capital Expenditures
- 2 OEB Appendix 2-AA: Capital Projects Summary **+ excel** **/C**
- 3 OEB Appendix 2-AB: Capital Expenditures Summary **+ excel**

5 Capitalization
- 1 Capitalization Policy
  - A Toronto Hydro Capitalization Policy
- 2 Overhead Costs
  - A OEB Appendix 2-D: Overhead Costs **+ excel** **/C**

6 Eligible Renewable Generation Investments

1 Cost of Eligible Investments for the Connection of Qualifying Generation Facilities

2	OEB Appendix 2-FA: Renewable Generation Connection Investment Summary (Energy Storage)	**+ excel**	**/C**
3	OEB Appendix 2-FB: Calculation of Renewable Generation Connection Direct Benefits (Energy Storage)	**+ excel**	**/C**
4	OEB Appendix 2-FA: Renewable Generation Connection Investment Summary (GPMC)	**+ excel**	**/C**
5	OEB Appendix 2-FB: Calculation of Renewable Generation Connection Direct Benefits (GPMC)	**+ excel**	**/C**

Exhibit	Section/Appendix
2B	**DISTRIBUTION SYSTEM PLAN**
	Title Page and Table of Contents
A	*Distribution System Plan Overview*
A1	Introduction
A2	Key Elements of Distribution System Plan
A3	Asset Management Process
A4	Coordinated Planning with Third Parties
A5	Grid Modernization
B	*Coordinated Planning with Third Parties*
B1	Overview of Coordinated Planning Approach
B2	Regional Planning Process
B3	IESO Comments on Renewable Energy Generation
	Appendix A - Needs Assessment Report (Toronto)
	Appendix B - Needs Assessment Report (GTA North)
	Appendix C - Regional Infrastructure Plan (Metro Toronto)
	Appendix D - Regional Infrastructure Plan (GTA North)
	Appendix E - Integrated Regional Resource Plan (Central Toronto)
	Appendix F - IESO Letter of Comment
C	*Performance Measurement for Continuous Improvement*
C1	Customer Preferences and the Outcomes Framework
C2	Toronto Hydro's 2020-2024 Custom Performance Measures
D	*Asset Management Process*
D1	Asset Management Process Overview
D2	Overview of Distribution Assets
D3	Asset Lifecycle Optimization
D4	Facilities Asset Management Strategy
D5	Information Technology Asset Management Strategy
	Appendix A - DSP Asset Management Review, prepared by UMS
	Appendix B - Standards Review 2018 Update, prepared by PSE
	Appendix C - Toronto Hydro Asset Condition Assessment Methodology
	Appendix D - Climate Change Vulnerability Assessment
E	*Capital Expenditure Plan*
E1	Capital Expenditure Plan Introduction
E2	Capital Expenditure Planning Process Overview
E3	System Capability Assessment for Renewable Energy and Conventional Generation
E4	Capital Expenditure Summary
E5	System Access Investments
	E5.1 Customer Connections
	E5.2 Externally Initiated Plant Relocations and Expansion
	E5.3 Load Demand
	E5.4 Metering
	E5.5 Generation Protection, Monitoring, and Control

E6 System Renewal Investments
- E6.1 Area Conversions
- E6.2 Underground System Renewal - Horseshoe
- E6.3 Underground System Renewal - Downtown
- E6.4 Network System Renewal
- E6.5 Overhead System Renewal
- E6.6 Stations Renewal
- E6.7 Reactive and Corrective Capital

E7 System Service Investments
- E7.1 System Enhancements
- E7.2 Energy Storage Systems
- E7.3 Network Condition Monitoring and Control
- E7.4 Stations Expansion

E8 General Plant Investments
- E8.1 Control Operations Reinforcement
  - A Jurisdictional review and economic case for a dual distribution control center in Toronto Hydro territory, prepared by London Economics
  - B List of Emergency Critical Functions
- E8.2 Facilities, Management and Security
- E8.3 Fleet and Equipment Services
- E8.4 Information Technology and Operational Technology Systems
  - A IT Budget Assessment Report, prepared by Gartner Consulting

Exhibit	Tab	Schedule	Appendix		
3	**OPERATING REVENUE**				
	1	Load, Customers, and Revenue			
		1	Load, Customers, and Revenue		
			A1 Model - Input Data	+ excel	
			A2 Model - Statistical Results	+ excel	
			B Alternative HDD CDD Forecast	+ excel	
			C CDM Load Forecast to LRAM Reconciliation	+ excel	
		2	OEB Appendix 2-IB: Customer, Connections, Load Forecast and Revenues Data and Analysis	+ excel	/C
	2	Revenue Offsets			
		1	Other Revenue		
		2	OEB Appendix 2H: Other Operating Revenues	+ excel	/C
4A	**OPERATING COSTS: OM&A**				
	1	OM&A Overview			
		1	Overview of OM&A Expenditures		
		2	OEB Appendix 2-JA: Summary of Recoverable OM&A Expenses	+ excel	/C
		3	OEB Appendix 2-JB: Recoverable OM&A Cost Driver Table	+ excel	/C
		4	OEB Appendix 2-JC: OM&A Programs Table	+ excel	/C
		5	OEB Appendix 2-L: Recoverable OM&A Cost per Customer and per FTE	+ excel	/C
	2	OM&A Programs			
		1	Preventative and Predictive Overhead Line Maintenance		
		2	Preventative and Predictive Underground Line Maintenance		
		3	Preventative and Predictive Station Maintenance		
		4	Corrective Maintenance		
		5	Emergency Response		
		6	Disaster Preparedness Management		
		7	Control Centre Operations		
		8	Customer-Driven Work		
		9	Asset and Program Management		

		10	Work Program Execution		
		11	Fleet and Equipment Services		
		12	Facilities Management		
		13	Supply Chain Services		
		14	Customer Care		
		15	Human Resources and Safety		
		16	Finance		
		17	Information Technology		
		18	Legal and Regulatory		
			A OEB Appendix 2-M: Regulatory Costs Schedule	+ excel	/C
		19	Charitable Donations and LEAP		
		20	Common Costs and Adjustments		
		21	Allocations and Recoveries		
	3	Non-Affiliate Services			
		1	Purchases of Non-Affiliate Services		
			A Procurement Policy, October 2016		
			B Engagements Not Originating from a Competitive Procurement Process		
	4	Workforce Staffing and Compensation			
		1	Workforce Staffing and Compensation - Executive Summary		
		2	OEB Appendix 2-K: Employee Costs / Compensation Table	+ excel	/C
		3	Workforce Staffing Plan and Strategy		
		4	Compensation Strategy and Workforce Governance		
		5	Non-Executive Compensation and Benefits Review, prepared by Mercer		
		6	Post-Employment Benefits for Employees of Toronto Hydro, prepared by Willis		
	5	Shared Services			
		1	Shared Services and Corporate Cost Allocations		
		2	OEB Appendix 2-N: Shared Services and Corporate Cost Allocation	+ excel	/C
4B	**OPERATING COSTS: DEPRECIATION AND PILs**				
	1	Depreciation			
		1	Depreciation and Amortization		/C
			A Summary of Depreciation Expense		
			B OEB Appendix 2-C: Depreciation and Amortization Expense	+ excel	/C
			C OEB Appendix 2-BB: Service Life Comparison	+ excel	/C
		2	Derecognition of Assets		
	2	Taxes and PILs			
		1	Corporate Taxes (PILs)		
		2	PILs Model	+ excel	
		3	Tax Information for 2016		
5	**COST OF CAPITAL**				
	1	Capital Structure			
		1	Cost of Capital		
		2	OEB Appendix 2-OA: Capital Structure and Cost of Capital		
		3	OEB Appendix 2-OB: Debt Instruments		
6	**REVENUE REQUIREMENT**				
	1	Revenue Requirement			
		1	Revenue Requirement and Sufficiency / Deficiency		
			A Modifications to the OEB's 2018 RRWF		
		2	Revenue Requirement Workform Model 2020	+ excel	
		3	Revenue Requirement Workform Model 2021	+ excel	
		4	Revenue Requirement Workform Model 2022	+ excel	
		5	Revenue Requirement Workform Model 2023	+ excel	
		6	Revenue Requirement Workform Model 2024	+ excel	

7 COST ALLOCATION

1 Cost Allocation
- 1 Cost Allocation
- 2 Sample Methodology - Demand Data for Cost Allocation Model
- 3 Cost Allocation Model **+ excel**

8 RATE DESIGN

1 Rate Design
- 1 Rate Design
- 2 Allocation between Fixed and Variable Rates

2 Specific Service Charges
- 1 Specific Service Charges

3 Rate Schedules
- 1 Current Tariff Sheet
- 2 Proposed Tariff Sheet

4 Loss Adjustment
- 1 OEB Appendix 2-R: Loss Factors **+ excel** **/C**
- 2 Large User Loss Study, prepared by Navigant Consulting

5 Retail Transmission Service Rates
- 1 Retail Transmission Service Rates Workform 2020 **+ excel**

6 Bill Impacts Table
- 1 OEB Appendix 2-W: Bill Impacts **+ excel** **/C**

9 DEFERRAL AND VARIANCE ACCOUNTS

1 Deferral and Variance Accounts
- 1 Deferral and Variance Accounts
  - A Draft Accounting Orders
  - B 2015CIR - Accounting Draft **/C**

2 Continuity Schedules
- 1 Deferral and Variance Accounts **+ excel**
- 2 Energy Sales and Cost of Power Expenses

3 Rate Riders
- 1 Rate Riders Development

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, Schedule B to the *Energy Competition Act, 1998*, S.O. 1998, c.15;

AND IN THE MATTER OF an Application by Toronto Hydro-Electric System Limited for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective January 1, 2020 to December 31, 2024.

The Applicant, Toronto Hydro-Electric System Limited (the "Applicant, "Toronto Hydro", "THESL", the "Company" or the "Utility"), is a corporation incorporated under the Business Corporations Act, (Ontario), and is licensed by the Ontario Energy Board (the "OEB") under licence number ED-2002-0497 to distribute electricity in the City of Toronto.

Toronto Hydro hereby applies to the OEB pursuant to section 78 of the Ontario Energy Board Act, 1998 (the "OEB Act") as amended, for approval of its proposed:

1) Electricity distribution rates and other charges effective January 1, 2020; and
2) Custom Price Cap Index ("Custom PCI") framework to set distribution rates effective for the period January 1, 2021 to December 31, 2024.

This Application is prepared in accordance with the OEB's:

1) Filing Requirements for Electricity Distribution Rate Applications, issued July 12, 2018 (the "Filing Requirements");
2) Renewed Regulatory Framework, established through a Report of the Board on October 18, 2012 under file numbers EB-2010-0377, EB-2010-0378, EB-

2010-0379, EB-2011-0043 and EB-2011-0004 and further developed through additional reports issued under those file numbers; and,

3) Handbook for Utility Rate Applications, issued October 13, 2016.

This application is supported by pre-filed written evidence, which may be amended from time to time.

I. FORM OF HEARING REQUESTED

Toronto Hydro requests that this application be disposed of by way of an oral hearing.

II. PROPOSED EFFECTIVE DATE

The applicant requests that the OEB make its Rate Order effective January 1, 2020. In the alternative, the Applicant requests an interim Order making the Applicant's current distribution rates and charges effective on an interim basis as of January 1, 2020 and establishing an account to recover any differences between the interim rates and the actual rates effective January 1, 2020 based on the OEB's Decision and Order.

III. PROPOSED DISTRIBUTION RATES AND OTHER CHARGES

The Tariff of Rates and Charges proposed in this application is identified in Exhibit 8, Tab 3, Schedule 2. In addition to the evidence in support of those rates and charges for the 2020 test year, Toronto Hydro is filing evidence in support of its Custom Incentive Rate-Setting ("Custom IR" or "CIR") framework and the rates resulting from it for 2021-2024.

IV. PROPOSED DISTRIBUTION RATES ARE JUST AND REASONABLE

For all the reason set out in this application. Toronto Hydro submits that the proposed distribution rates and other charges are just and reasonable.

V. SPECIFIC RELIEF REQUESTED

With this application, Toronto Hydro requests:

1) Approval of 2020 base revenue requirement as proposed in Exhibit 6, Tab 1.
2) Approval of 2020 electricity distribution rates and charges as proposed in Exhibit 8, including a number of credits to customers. In particular:
    a) Base distribution rates as set out in Exhibit 8, Tab 1, Schedule 1;
    b) Specific Service Charges as set out in Exhibit 8, Tab 2, Schedule 1; and
    c) Rate riders as set out in Exhibit 9, Tab 3, Schedule 1.
3) Approvals related to deferral and variance accounts as proposed in Exhibit 9. In particular:
    a) To dispose of balances in existing deferral and variance accounts as detailed in Exhibit 9, Tab 1, Schedule 1;
    b) Approval of the continuation of existing deferral and variance accounts, as set out in Exhibit 9, Tab 1, Schedule 1; and
    c) Approval of new deferral and variance account as proposed in Exhibit 9, Tab 1, Schedule 1:
        i) A variance account in respect of excess expansion deposits; and
        ii) Three variance accounts in respect of Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges.
4) Approval of the rate-setting formula and related elements, as proposed in Exhibit 1B, Tab 4, Schedule 1.
5) Approval of annual reporting as proposed in Exhibit 1B, Tab 2, Schedule 1.

6) Other items or amounts that may be requested by the Applicant in the course of the proceeding, and such other relief or entitlements as the OEB may grant.

DATED at Toronto, Ontario, this 15th day of August, 2018.

Applicant: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

14 Carlton Street
Toronto, Ontario
M5B 1K5

Signed by:

Andrew J. Sasso, Director, Regulatory Affairs

ADMINISTRATION

This Schedule provides information relating to the administration of the Application.[1]

1. PRIMARY CONTACT FOR THE APPLICATION

Andrew J. Sasso
Director, Regulatory Affairs
14 Carlton Street
Toronto, Ontario M5B 1K5
Phone: (416) 542-7834
Fax: (416) 542-2683
Email: RegulatoryAffairs@TorontoHydro.com

2. LEGAL REPRESENTATION FOR THE APPLICATION

Charles Keizer – ckeizer@torys.com
Crawford Smith – csmith@torys.com
Torys LLP
79 Wellington Street West
Toronto, Ontario M5K 1N2

3. INTERNET ADDRESS

Toronto Hydro's main webpage:
www.torontohydro.com

[1] Section 2.1.4 of the Chapter 2 Cost of Service Filing Requirements.

Regulatory documents will be available under the Regulatory Affairs tab:

http://www.torontohydro.com/sites/electricsystem/Pages/RegulatoryAffairs.aspx

4. MEDIA ACCOUNTS

Twitter – twitter.com/torontohydro

Facebook – facebook.com/torontohydro

Instagram – Instagram.com/torontohydro

YouTube – youtube.com/torontohydro

LinkedIn –linkedin.com/company/toronto-hydro/

5. CHANGES WITH MATERIAL IMPACT TO CUSTOMERS

There are no changes in the Application that result in bill impacts that exceed the 10% bill impact threshold, and any variances or proposals that result in an impact that exceeds Toronto Hydro's general $1 million revenue requirement materiality threshold have been explained throughout the evidence.

Overall, as a result of Toronto Hydro's application proposals, rates will change for all customers, including the final year of transition to fully fixed rates for Residential and CSMUR customers.

6. NOTICE OF HEARING PUBLICATION

Toronto Hydro recommends that the Notice of Hearing for its Application be published in the Toronto Star and L'Express newspapers, both of which are paid publications, as well as on the utility's website www.torontohydro.com. L'Express is a weekly French language newspaper serving Toronto and the Greater Toronto Area, which has a circulation of approximately 22,000 readers per week. The Toronto Star is a daily

newspaper serving Toronto and the surrounding area, has a total average daily circulation of approximately 360,000 readers.

7. LIST OF POTENTIAL VENUES FOR COMMUNITY MEETINGS

As described in Exhibit 1B, Tab 3, Schedule 4, Toronto Hydro proposes four community meetings. Toronto Hydro recommends that one meeting be held in each of the following locations: Scarborough, North York, Etobicoke, and downtown, in order to reflect the geographic diversity of the service area. Toronto Hydro further recommends that one of these community meetings be webcast. There are many suitable venues in Toronto for these community meetings, including civic/community centres, schools and libraries.

Toronto Hydro will work with the OEB to finalize locations, venues, dates and times for the community meetings, and to produce bill inserts and other materials, as may be stipulated by the OEB.

8. BILL IMPACTS

Table 1, below, provides a summary of the distribution-only bill impacts (per sub-total A of Appendix 2-W, which is filed at Exhibit 8, Tab 7) to be used for the Notice of Application for a typical residential customer using 750 kWh per month and for a General Service <50 kW customer using 2,000 kWh per month.

Table 1: Summary of Bill Impacts (Distribution Only)

Residential (750 kWh)						
Distribution Bill	**2020**	**2021**	**2022**	**2023**	**2024**	**Average**
Subtotal A $	-2.32	1.37	1.07	1.89	1.83	0.77
Subtotal A %	-5.3	3.3	2.5	4.3	4.0	1.7
GS < 50 kW (2000 kWh)						
Distribution Bill	**2020**	**2021**	**2022**	**2023**	**2024**	**Average**
Subtotal A $	-4.62	3.45	2.68	4.74	4.59	2.17
Subtotal A %	-4.3	3.3	2.5	4.3	4.0	1.9

9. FORM OF HEARING REQUESTED

Toronto Hydro requests an oral hearing.

10. EFFECTIVE REQUESTED DATE

Toronto Hydro requests new rates to be effective January 1, 2020.

11. DEVIATIONS FROM FILING REQUIREMENTS

Toronto Hydro is filing a Custom Incentive Rate-setting ("Custom IR") Application. In preparing this Application, Toronto Hydro has followed Chapters 1, 2, and 5 of the OEB's Filing Requirements for Electricity Distribution Rate Applications issued July 12, 2018 (the "Filing Requirements"). Any departures from the Filing Requirements are noted in the Checklist filed at Exhibit 1A, Tab 3, Schedule 2.

12. METHODOLOGY CHANGES

Since Toronto Hydro's 2015-2019 Rate Application,[2] the utility has made the following methodology changes:

[2] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015).

- Toronto Hydro has transitioned from the Asset Condition Assessment ("ACA") methodology, originally adopted in 2008, to an ACA model that provides more accurate and comprehensive condition-based analytics, and that better supports expenditure planning over longer time horizons (the Common Network Asset Indices Methodology). For more information on Toronto Hydro's ACA methodology transition, please see Exhibit 2B, Section D1.
- Toronto Hydro has made adjustments to its CPCI formula by incorporating those components (growth, and stretch on capital) ordered by the OEB in its Decision and Order[3] and has proposed a custom stretch factor supported by expert econometric evidence prepared by Power System Engineering Inc.[4]
- Toronto Hydro has used the most recent version of the Cost Allocation Model issued by the OEB.

13. PREVIOUS OEB DIRECTIONS

The four OEB Directions identified below are from the 2015-2019 OEB Decision.[5]

[3] EB-2014-0116, Toronto Hydro-Electric System Limited Decision and Order (December 29, 2015).
[4] For more information, please see Exhibit 2A, Tab 1, Schedule 1.
[5] *Supra* note 3.

Table 2: OEB Directions

	Direction	How the Direction was Addressed in this Application
1	**Customer Engagement:** ***"****The OEB finds that Toronto Hydro's customer engagement efforts undertaken as part of the Application are reasonable as the first such effort in the context of the RRFE. However, there are some deficiencies which the OEB expects Toronto Hydro to address by the time it files its next full cost of service or Custom IR rate application. […] The OEB agrees with intervenors and OEB staff that Toronto Hydro did not provide its customers with sufficient information on the context of the proposed Application such as its existing benchmarking ranking and its relative levels of productivity and efficiency. Toronto Hydro did not develop its plan in conjunction with its customer engagement activities. It sought input to confirm the plan it had already prepared rather than engaging its customers to ascertain their preferred options in the context of Toronto Hydro's current cost and reliability situations.*[6]	Toronto Hydro has addressed the OEB's direction. For specific details, please see Exhibit 1B, Tab 3, Schedule 1.
2	**Line Losses:** ***"****The OEB expects Toronto Hydro to incorporate the results of the OEB audit into its distribution rates as well as to update its loss factors at its next full cost of service or Custom IR rate application."*[7]	Toronto Hydro has addressed the OEB's direction. For specific details, please see Exhibit 8, Tab 1, Schedule 1 for details on how the utility updated its loss factors.

[6] Ibid at pp. 7-8.
[7] *Supra* note 3 at p.46.

	Direction	How the Direction was Addressed in this Application
3	**Monitoring and Reporting:** *"The OEB, however, will expect Toronto Hydro to develop better performance metrics as part of its ongoing customer engagement efforts with the objective of achieving greater conformity with the general intent of the RRFE"*[8]	Toronto Hydro has addressed the OEB's direction. For specific details, please see: • Exhibit 1B, Tab 2, Schedule 1 for details on Toronto Hydro's Outcomes Framework; and • Exhibit 2B, Section C for details on Toronto Hydro's performance measures.
4	**Disposition of Deferral Accounts:** ***"****The OEB approves Toronto Hydro's proposed disposition of accounts and its request to defer the disposition of the RSVA accounts. Upon conclusion of the OEB audit, the OEB expects Toronto Hydro to request disposition of all the RSVA balances in its next rate application."*[9]	Toronto Hydro has addressed the OEB's direction. For specific details, please see: • EB-2016-0254, Toronto Hydro-Electric System Limited Application to Finalize 2017 Electricity Distribution Rates and Charges (August 23, 2017), Tab 2, Schedule 1 at p.4.

14. CONDITIONS OF SERVICE

Toronto Hydro's current Conditions of Service, along with revision history for any changes made from the utility's last Application, can be found at the following link:

http://www.torontohydro.com/sites/electricsystem/business/ConditionsofService/Pages/default.aspx

At this time, Toronto Hydro does not expect any of the proposals in this Application to result in a material change to its Conditions of Service.

[8] *Supra* note 3 at p. 47.
[9] *Supra* note 3 at p. 53.

Toronto Hydro has identified three charges listed in the Conditions of Service that are not on its Tariff of Rates and Charges. Consistent with other similar charges that are recovered through capital contributions, they are not recorded as a Specific Service Charge in Toronto Hydro's OEB-approved tariff sheet. For more details, please see Exhibit 8, Tab 2, Schedule 1.

15. CORPORATE AND UTILITY ORGANIZATIONAL STRUCUTRE

Toronto Hydro's organizational chart is provided in Figure 1, below.

A corporate entities relationship chart showing the extent to which the parent company is represented on the utility's Board of Directors and a description of the reporting relationships between utility and parent company is provided in Exhibit 1C, Tab 2, Schedule 1.

There are no planned changes in corporate or operational structure.

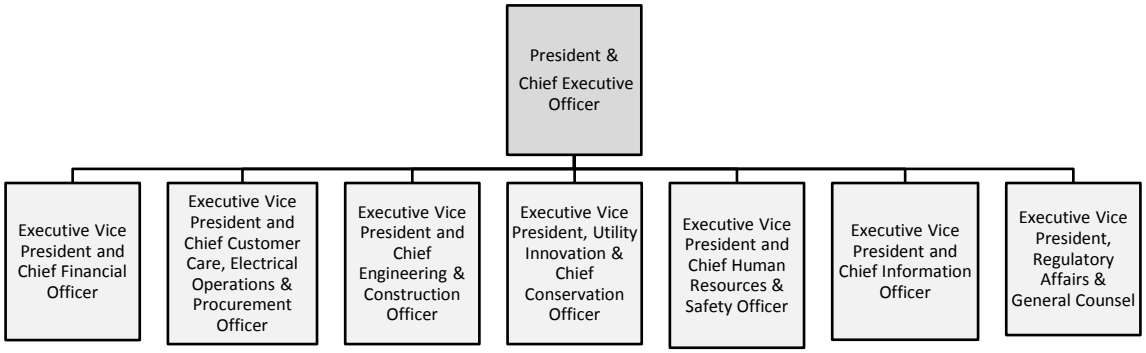


Figure 1: Toronto Hydro's Organizational Chart

16. LIST OF APPROVALS REQUESTED

The list of specific approvals requested as part of this Application are provided at Exhibit 1A, Tab 2, Schedule 1, and Appendix 2-A, reproduced below:

Pursuant to section 78 of the *Ontario Energy Board Act, 1998*,[10] Toronto Hydro seeks the following approvals:

With this application, Toronto Hydro requests:

1) Approval of 2020 base revenue requirement as proposed in Exhibit 6, Tab 1.
2) Approval of 2020 electricity distribution rates and charges as proposed in Exhibit 8, including a number of credits to customers. In particular:
   a) Base distribution rates as set out in Exhibit 8, Tab 1, Schedule 1;
   b) Specific Service Charges as set out in Exhibit 8, Tab 2, Schedule 1; and
   c) Rate riders as set out in Exhibit 9, Tab 3, Schedule 1.
3) Approvals related to deferral and variance accounts as proposed in Exhibit 9. In particular:
   a) To dispose of balances in existing deferral and variance accounts as detailed in Exhibit 9, Tab 1, Schedule 1;
   b) Approval of the continuation of existing deferral and variance accounts, as set out in Exhibit 9, Tab 1, Schedule 1; and
   c) Approval of new deferral and variance account as proposed in Exhibit 9, Tab 1, Schedule 1:
      i) A variance account in respect of excess expansion deposits; and
      ii) Three variance accounts in respect of Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges.

[10] *Ontario Energy Board Act, 1998*, SO 1998, c 15, Sched. B.

4) Approval of the rate-setting formula and related elements, as proposed in Exhibit 1B, Tab 4, Schedule 1.
5) Approval of annual reporting as proposed in Exhibit 1B, Tab 2, Schedule 1.
6) Other items or amounts that may be requested by the Applicant in the course of the proceeding, and such other relief or entitlements as the OEB may grant.

OEB Appendix 2-A
List of Requested Approvals

The distributor must fill out the following sheet with the complete list of specific approvals requested and relevant section(s) of the legislation must be provided. All approvals, including accounting orders (deferral and variance accounts) new rate classes, revised specific service charges or retail service charges which the applicant is seeking, must be separately identified, as well being clearly documented in the appropriate sections of the application.

Additional requests may be added by copying and pasting blank input rows, as needed.

If additional requests arise, or requested approvals are removed, during the processing of the application, the distributor should update this list.

1		Approval of 2020 base revenue requirement as proposed in Exhibit 6, Tab 1.
2		Approval of 2020 electricity distribution rates and charges as proposed in Exhibit 8, including a number of credits to customers. In particular: a) Base distribution rates as set out in Exhibit 8, Tab 1, Schedule 1; b) Specific Service Charges as set out in Exhibit 8, Tab 2, Schedule 1; and c) Rate riders as set out in Exhibit 9, Tab 3, Schedule 1.
3		Approvals related to deferral and variance accounts as proposed in Exhibit 9. In particular: a) To dispose of balances in existing deferral and variance accounts as detailed in Exhibit 9, Tab 1, Schedule 1; b) Approval of the continuation of existing deferral and variance accounts, as set out in Exhibit 9, Tab 1, Schedule 1; and c) Approval of new deferral and variance account as proposed in Exhibit 9, Tab 1, Schedule 1: i) A variance account in respect of excess expansion deposits; and ii) Three variance accounts in respect of Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges.
4		Approval of the rate-setting formula and related elements, as proposed in Exhibit 1B, Tab 4, Schedule 1.
5		Approval of annual reporting as proposed in Exhibit 1B, Tab 2, Schedule 1.
6		Other items or amounts that may be requested by the Applicant in the course of the proceeding, and such other relief or entitlements as the OEB may grant.

PLANNED EVIDENCE UPDATES

Table 1, below, provides information relating to updates Toronto Hydro anticipates at this time. The utility reserves the right to add to this list as new information becomes available.

Table 1: Planned Updates Anticipated as of Sep 14, 2018

	Topic	Reference	Details
1	Rate Framework	Exhibit 1B, Tab 4, Schedule 1	Toronto Hydro proposes to use the OEB's I-factor in its CPCI. As the value for I-factor is updated annually, Toronto Hydro will incorporate the updated value into its CPCI, once released, to appropriately adjust base distribution rates for the following year.
2	Income Tax/PILs Workform	Exhibit 4B, Tab 2 Schedule 2	Toronto Hydro plans to update the PILS workforms once its 2018 tax return is filed in June 2019.
3	Rate Design	Exhibit 8, Tab 1, Schedule 1	Toronto Hydro's proposed Retail Transmission Service Rates in the model reflect the projected 2020 billing units, applied to the current Uniform Transmission Rates ("UTRs"). Toronto Hydro will update the calculated rates prior to the 2020 rate implementation based on OEB approved UTRs at that time.
4	Wireline Pole Attachment Rate	Exhibit 8, Tab 2, Schedule 1	Toronto Hydro plans to update the escalation percentage for the wireline attachment rate once the OEB releases the final inflation factor for 2020.

	Topic	Reference	Details
5	Deferral and Variance Accounts- Retail Settlement Variance Accounts	Exhibit 9, Tab 1, Schedule 1	Toronto Hydro will update the evidence and propose to clear the Retail Settlement Variance Accounts balances for the 2018 period when the 2018 balances are finalized.
6	Deferral and Variance Accounts- Lost Revenue Adjustment Mechanism Variance Account	Exhibit 9, Tab 1, Schedule 1	Toronto Hydro will update the evidence and propose to clear the Lost Revenue Adjustment Mechanism Variance Account amount for the 2018 period when the 2018 Final CDM Annual Report and Persistence Savings Report is available from the IESO.
7	Carrying Charges	Exhibit 9, Tab 1, Schedule 1	Carrying charges have been applied to specific accounts using the OEB's Prescribed Interest Rate. For the periods up to 2018 Q3, the rates are as determined by the OEB. For the periods 2018 Q4 through 2019 Q4, the 2018 Q3 has been applied as a forecast. Toronto Hydro proposes to update these rates for the actual approved rates at the time of clearance of these accounts.
8	Earning Sharing Mechanism ("ESM")- 2018 Calculation	Exhibit 1B, Tab 4, Schedule 1	Toronto Hydro will update its 2018 ESM calculation when 2018 year-end financial results become available. Toronto Hydro will clear any applicable amounts as part of this Application.
9	ESM- 2019 Calculation	Exhibit 1B, Tab 4, Schedule 1	Toronto Hydro will update its 2019 ESM calculation and clear any applicable amounts as part of its 2021 annual rate application.
10	2018 Financial Figures	N/A	Toronto Hydro plans to update 2018 financial figures in April 2019.

2019 Cost of Service Checklist

Toronto Hydro-Electric System Limited

EB-2018-0165

Filing Requirement Page # Reference

Date: August 15, 2018

		Yes/No/N/A	Evidence Reference, Notes
GENERAL REQUIREMENTS			
Ch 1, Pg. 2	Certification by a senior officer that the evidence filed is accurate, consistent and complete	**Yes**	Exhibit 1A, Tab 3, Schedule 3
Ch 1, Pg. 3	Confidential Information - Practice Direction has been followed	**Yes**	Confidential filing letter and confidential filing
Ch 2, Pg. 1	Statement identifying all deviations from Filing Requirements	**Yes**	Described in the Notes boxes in this check list
2	Chapter 2 appendices in live Microsoft Excel format; PDF and Excel copy of current tariff sheet	**Yes**	Filed with Application
3	If applicable, late applications filed after the commencement of the rate year for which the application is intended to set rates is converted to the following rate year.	**N/A**	
3	Aligning rate year with fiscal year - request for proposed alignment	**N/A**	
5	Text searchable and bookmarked PDF documents	**Yes**	
5	Links within Excel models not broken and models names so that they can be identified (e.g. RRWF instead of Attachment A)	**Yes**	
5	Materiality threshold; additional details beyond the threshold if necessary	**Yes**	Exhibit 1A, Tab 3, Schedule 1
16	Proposal for disposition of any balances in existing DVAs for renewable generation and smart grid development, if applicable	**Yes**	Exhibit 9, Tab 1, Schedule 1
6	State accounting standard(s) used in historical, bridge and test years. Provide a summary of changes to its accounting policies made since the applicant's last cost of service filing. Identify all material changes or confirm no material changes in the adoption of IFRS. Appendix 2-Y	**Yes**	Exhibit 1C, Tab 3, Schedule 2
RESS Guideline	Two hardcopies of application sent to OEB the same day as electronic filing (p10 of RESS Guideline)	**Yes**	Due to the size and complexity of application and number of requested sets, hard copies will be sent shortly after electronic filing
EXHIBIT 1 - ADMINISTRATIVE DOCUMENTS			
Table of Contents			
6	Table of Contents listing major sections and subsections of the application. Electronic version of application appropriately bookmarked to provide direct access to each section	**Yes**	Exhibit 1A, Tab 1, Schedule 1
Executive Summary			
6	Summary identifying key elements of the proposals and the Business Plan underpinning application, as guided by the Rate Handbook including plain language information about its goals	**Yes**	Exhibit 1B, Tab 1, Schedule 1
Administration			
6	Brief but complete summary of the application that will be posted as a stand-alone document on the OEB's website for review by the general public and be made available to customers of the applicant	**Yes**	Exhibit 1B, Tab 3, Schedule 3
6 & 7	Primary contact information (name, address, phone, fax, email)	**Yes**	Exhibit 1A, Tab 3, Schedule 1
7	Identification of legal (or other) representation	**Yes**	Exhibit 1A, Tab 3, Schedule 1
7	Applicant's internet address for viewing of application and any social media accounts used by the applicant to communicate with customers	**Yes**	Exhibit 1A, Tab 3, Schedule 1
7	Statement identifying customers materially affected by the application including any change to any rate or charge and specific statement of what individual customer or customer groups would be affected by the proposed change	**Yes**	Exhibit 1A, Tab 3, Schedule 1
7	Statement identifying where notice should be published and why	**Yes**	Exhibit 1A, Tab 3, Schedule 1
7	A list of one ore more accessible community-based venues for each non-contiguous area that the utility serves	**Yes**	Exhibit 1B, Tab 3, Schedule 4
7	Bill impacts - distribution only impacts for 750 kWh residential and 2000 kWh GS<50 (sub-total A of Tariff Schedule and Bill Impact Spreadsheet Model) to be used for notice; proposed bill impacts based on alternative consumption profiles and customer groups as appropriate given consumption patterns of a distributors customers	**Yes**	Exhibit 1A, Tab 3, Schedule 1
7	Form of hearing requested and why	**Yes**	Exhibit 1A, Tab 3, Schedule 1
7	Requested effective date	**Yes**	Exhibit 1A, Tab 3, Schedule 1
7	Statement identifying and describing any changes to methodologies used vs previous applications	**Yes**	Exhibit 1A, Tab 3, Schedule 1
8	Identification of OEB directions from any previous OEB Decisions and/or Orders. The applicant must clearly indicate how these are being addressed in the current application (e.g., filing of a study as directed in a previous decision)	**Yes**	Exhibit 1A, Tab 3, Schedule 1
8	Reference to Conditions of Service - LDC does not need to file Conditions of Service, but must provide reference to website and confirm version is current; identify if there are changes to Conditions of Service (a) since last CoS application or (b) as a result of the current application. Confirmation that there are no rates and charges linked in the Conditions of Service that are not in the distributor's Tariff of Rates and Charges must be provided	**Yes**	Exhibit 1A, Tab 3, Schedule 1
8	Description of the corporate and utility organizational structure, showing the main units and executive and senior management positions within the utility. Include a corporate entities relationship chart, showing the extent to which the parent company is represented on the utility company's Board of Directors and a description of the reporting relationships between utility and parent company management. Also include any planned changes in corporate or operational structure, including any changes in legal organization and control	**Yes**	Exhibit 1C, Tab 2, Schedule 1
8	List of approvals requested (and relevant section of legislation), including accounting orders - a PDF copy of Appendix 2-A should be provided in this section	**Yes**	Exhibit 1A, Tab 3, Schedule 1, Appendix A
Distribution System Overview			
8	Description of Service Area (including map, communities served)	**Yes**	Exhibit 1C, Tab 1, Schedule 2
8 & 9	Description of whether the distributor is a host distributor and/or embedded distributor. Identification of embedded and/or host distributors; if partially embedded provide %load from host distributor. If the distributor is a host, the applicant should identify whether there is a separate Embedded Distributor customer class or if any embedded distributors are included in other customer classes such as GS > 50 kW	**Yes**	Exhibit 1C, Tab 1, Schedule 1
9	Statement as to whether or not the distributor has had any transmission or high voltage assets deemed by the OEB as distribution assets and whether or not there are any such assets the distributor is seeking approval for in this application	**Yes**	Exhibit 1C, Tab 1, Schedule 1
Application Summary			
At a minimum, the items below must be provided. Applicants must also identify all proposed changes that will have a material impact on customers.			
9	Revenue Requirement - service RR, increase/decrease ($ and %) from change from previously approved and main drivers	**Yes**	Exhibit 1B, Tab 5, Schedule 1
9	Budgeting and Accounting Assumptions - economic overview and identification of accounting standard used for test year and brief explanation of impacts arising from any change in standards	**Yes**	Exhibit 1B, Tab 5, Schedule 1
9	Load Forecast Summary - load and customer growth, % change in kWh/kW and customer numbers, description of forecasting method(s) used for customer/connection and consumption/demand	**Yes**	Exhibit 1B, Tab 5, Schedule 1
9 & 10	Rate Base and DSP - major drivers of DSP, rate base for test year, change in rate base from last approved ($ and %), capital expenditures requested for the test year, change in capital expenditures from last approved ($ and %), summary of costs requested for renewable energy connections/expansions, smart grid, and regional planning initiatives, any O.Reg 339/09 planned recovery	**Yes**	Exhibit 1B, Tab 5, Schedule 1
10	OM&A Expense - OM&A for test year and change from last approved ($ and %), summary of drivers, inflation assumed, total compensation for test year and change from last approved ($ and %).	**Yes**	Exhibit 1B, Tab 5, Schedule 1

2019 Cost of Service Checklist

Toronto Hydro-Electric System Limited

EB-2018-0165

Date: August 15, 2018

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
10	Cost of Capital - summary table showing proposed capital structure and cost of capital parameters used in WACC. Statement regarding use of OEB's cost of capital parameters; summary of any deviations	Yes	Exhibit 1B, Tab 5, Schedule 1
10	Cost Allocation & Rate Design - summary of any deviations from OEB methodologies, significant changes proposed to revenue-to-cost ratios and fixed/variable splits and summary of proposed mitigation plans	Yes	Exhibit 1B, Tab 5, Schedule 1
10	Deferral and Variance Accounts - total disposition (RPP and non-RPP), disposition period, new accounts requested	Yes	Exhibit 1B, Tab 5, Schedule 1
10	Bill Impacts - total impacts ($ and %) for all classes for typical customers	Yes	Exhibit 1B, Tab 5, Schedule 1
Customer Engagement			
10	Discussion on how customers were informed of the proposals being considered for inclusion in the application and the value of those proposals to customers i.e. costs, benefits, and the impact on rates	Yes	Exhibit 1B, Tab 3, Schedule 1
10	Discussion of any feedback provided by customers and how the feedback shaped the final application	Yes	Exhibit 1B, Tab 3, Schedule 1
11	Reference to any other communication sent to customers about the application i.e. bill inserts, town hall meetings or other forms of out reach and the feedback received from customers through these engagement activities	Yes	Exhibit 1B, Tab 3, Schedule 1
11	Complete Appendix 2-AC Customer Engagement Activities Summary - explicit identification of the outcomes of customer engagement in terms of the impacts on the distributor's plans, and how that information has shaped the application	Yes	Exhibit 1B, Tab 3, Schedule 3
11	All responses to matters raised in letters of comment filed with the OEB	Yes	Exhibit 1B, Tab 3, Schedule 5
11	Impact of customer engagement activities on the development of the capital plan are to be filed as part of the capital plan requirements in Chapter 5	Yes	Exhibit 2B, Section E2.3
11	Provide relevant customer and local knowledge for (community) meeting planning purposes, preparing presentation and other materials as may be required, attending the meeting and having one or more executives of the distributor available to present the distributor's rate application information and answer customer questions	Yes	Exhibit 1B, Tab 3, Schedule 4
11	Required to advertise the OEB's community meeting(s) on a bill insert developed by the OEB in the next available billing cycle following the filing of the application or sooner. The OEB may require the distributor to advertise the meeting(s) through other channels	Yes	Exhibit 1B, Tab 3, Schedule 4
Performance Measurement			
12	Discussion of performance for each of the distributor's scorecard measures over the last five years; drivers for its performance, plans for continuous improvement, identify performance improvement targets, forecast of efficiency assessment using the PEG forecasting model for the test year, discussion on how the results obtained from the PEG model has informed the business plan and application	Yes	Exhibit 1B, Tab 2, Schedule 2 and Exhibit 1B, Tab 4,Schedule 3
Financial Information			
12	Non-consolidated Audited Financial Statements for 2 most recent years (i.e. 3 years of historical actuals)	Yes	Exhibit 1C, Tab 3, Schedule 3, Appendix A, B and C
12	Detailed reconciliation of AFS with regulatory financial results filed in the application, with identification of any deviations that are being proposed	Yes	Exhibit 1C, Tab 3, Schedule 4
13	Annual Report and MD&A for most recent year of distributor and parent company, if applicable	Yes	Exhibit 1C, Tab 3, Schedule 5
13	Rating Agency Reports, if available; Prospectuses, etc. for recent and planned public issuances	Yes	Exhibit 1C, Tab 3, Schedule 7 and 8
13	Any change in tax status	Yes	Exhibit 4B, Tab 2, Schedule 1
13	Existing accounting orders and departures from the accounting orders and USoA	Yes	Exhibit 1C, Tab 3, Schedule 9
13	Accounting Standards used for financial statements and when adopted	Yes	Exhibit 1C, Tab 3, Schedule 2
13	Confirmation that accounting treatment of any non-utility business has segregated activities from rate regulated activities	Yes	Exhibit 1C, Tab 3, Schedule 2
Distributor Consolidation			
13	If a distributor has acquired or amalgamated with another distributor, identify any incentives that formed part of the acquisition or amalgamation transaction if the incentive represents costs that are being proposed to remain or enter rate base and/or revenue requirement. A distributor must specify whether any commitments made to shareholders are to be funded through rates	N/A	
13	Description of actual savings as a result of consolidation compared to what was in the approved consolidation application and explanation of how savings are sustainable and the efficacy of any rate plan approved as part of the MAADs application	N/A	
13	Identify approved ACM or ICM from a previous Price Cap IR application it proposes be incorporated into rate base.	N/A	
EXHIBIT 2 - RATE BASE			
Overview			
14	Completed Fixed Asset Continuity Schedule (Appendix 2-BA) - in Application and Excel format	Yes	Exhibit 2A, Tab 1, Schedule 2
14	Opening and closing balances, average of opening and closing balances for gross assets and accumulated depreciation (discussion of methodology if applicant uses an alternative method); working capital allowance (historical actuals, bridge and test year forecast)	Yes	Exhibit 2A, Tab 1, Schedule 1
14 & 15	Continuity statements (year end balance, including interest during construction and overheads). Explanation for any restatement (e.g. due to change in accounting standards) Year over year variance analysis; explanation where variance greater than materiality threshold Hist. OEB-Approved vs Hist. Actual Hist. Act. vs. preceding Hist. Act. Hist. Act. vs. Bridge Bridge vs. Test	Yes	Exhibit 2A, Tab 1, Schedule 1
15	Opening and closing balances of gross assets and accumulated depreciation must correspond to fixed asset continuity statements. If not, an explanation must be provided (e.g. CWIP, ARO). Reconciliation must be between net book value balances reported on Appendix 2-BA and balances included in rate base calculation	Yes	Exhibit 2A, Tab 1, Schedule 1
Gross Assets - PP&E and Accumulated Depreciation			
15	Breakdown by function and by major plant account; description of major plant items for test year	Yes	Exhibit 2A, Tab 2, Schedule 1
15 & 16	Summary of approved and actual costs for any ICM(s) and/ or ACM approved in previous IRM applications	N/A	
16	Continuity statements must reconcile to calculated depreciation expenses and presented by asset account	Yes	Exhibit 2A, Tab 1, Schedule 1 and Exhibit 4B, Tab 1, Schedule 1
16	All asset disposals clearly identified in the Chapter 2 Appendices for all historical, bridge and test years and if any amounts related to gains or losses on disposals have been included in Account 1575 IFRS - CGAAP Transitional PP&E Amount	Yes	Exhibit 2A, Tab 1, Schedule 2
Allowance for Working Capital			
16	Working Capital - 7.5% allowance or Lead/Lag Study or Previous OEB Direction	Yes	Exhibit 2A, Tab 3, Schedule 1 and 2
16	Lead/Lag Study - leads and lags measured in days, dollar-weighted	Yes	Exhibit 2A, Tab 3, Schedule 2
16 & 17	Cost of Power must be determined by split between RPP and non-RPP Class A and Class B customers based on actual data, use most current RPP (TOU) price, use current UTR. Calculation must fully consider all other impacts resulting from the Ontario Fair Hydro Plan Act, 2017. Distributors must complete Appendix 2-Z - Commodity Expense.	Yes	Toronto Hydro-specific Cost of Power calculation in place of Appendix 2-Z at Exhibit 2A, Tab 3, Schedule 1
17	In consideration of the impact of the Fair Hydro Plan, actual data must be split between Class A and Class B customers (RPP and non-RPP).	Yes	Toronto Hydro-specific Cost of Power calculation in place of Appendix 2-Z at Exhibit 2A, Tab 3, Schedule 1
17	Non-RPP Class B consumption data must be further split between customers eligible for the Global Adjustment (GA) modifier vs. non-eligible. The GA modifier must be applied to eligible customers and a weighted average commodity price must be determined by the split between RPP, eligible non-RPP and non-eligible Non-RPP customers.	Yes	Toronto Hydro-specific Cost of Power calculation in place of Appendix 2-Z at Exhibit 2A, Tab 3, Schedule 1
17	For customer classes that include Class A customers, distributor must incorporate Class A GA cost by completing the relevant section in Appendix 2-Z	Yes	Toronto Hydro-specific Cost of Power calculation in place of Appendix 2-Z at Exhibit 2A, Tab 3, Schedule 1

2019 Cost of Service Checklist

Toronto Hydro-Electric System Limited

EB-2018-0165

Filing Requirement Page # Reference

Date: August 15, 2018

		Yes/No/N/A	Evidence Reference, Notes
17	If a distributor expects test year consumption data to vary significantly, a distributor may provide a forecast of the expected split between Class A and Class B and the expected split between RPP, non-RPP eligible for modifier and non-RPP non eligible for modifier consumption data and provide brief explanation of the forecast	**Yes**	Toronto Hydro-specific Cost of Power calculation in place of Appendix 2-Z at Exhibit 2A, Tab 3, Schedule 1
Capital Expenditures			
17	DSP filed as a stand-alone document; a discrete element within Exhibit 2	**Yes**	Exhibit 2B
18	Complete Appendix 2-AB - four historical years must be actuals, forecasts for the bridge and test years; at a minimum, for historical years, applicants must provide actual totals for each DSP category. If no previous plan has been filed, applicants are only required to enter their planned total capital budget in the "plan" column for each historical year and for the bridge year including the OEB-approved amount for the last rebasing year	**Yes**	Appendix 2-AB (Exhibit 2A, Tab 4, Schedule 3) includes three historical years and two bridge years, which corresponds with the 2015-2019 DSP
19	Distributor that has an approved ACM or ICM from a previous Price Cap IR application must file a schedule of the ACM/ICM capital asset amounts (ie PP&E and associated accumulated depreciation) it proposes be incorporated into rate base. Distributor must provide a comparison of actual capital spending with the OEB-approved amount and provide explanation for variances.	**N/A**	
Policy Options for the Funding of Capital			
18	Distributor may propose ACM capital project coming into service during Price Cap IR (a discrete project documented in DSP). Provide cost and materiality calculations to demonstrate ACM qualification	**N/A**	
18	Distributor must establish need for and prudence of these projects based on DSP information; identification that distributor is proposing ACM treatment for these future projects, preliminary cost information	**N/A**	
18	Complete Capital Module Applicable to ACM and ICM	**N/A**	
Addition of Previously Approved ACM and ICM Project Assets to Rate Base			
19	Distributor with previously approved ACM(s) and/or ICM(s) - schedule of ACM/ICM amounts proposed to be incorporated into rate base. The distributors must compare actual capital spending with OEB-approved amount and provide an explanation for variances	**N/A**	
19 & 20	Balances in Account 1508 sub-accounts, reconciliation with proposed rate base amounts; recalculated revenue requirement should be compared with rate rider revenue	**N/A**	
Capitalization Policy and Capitalization			
20	Changes to capitalization policy since its last rebasing application as a result of the OEB's letter dated July 17, 2012 or for any other reasons, the applicant must identify the changes and the causes of the changes.	**Yes**	Exhibit 2A, Tab 5, Schedule 1
20	Appendix 2-D complete; identification of burden rates and burden rates prior to changes, if any	**Yes**	Exhibit 2A, Tab 5, Schedule 2, Appendix A
Costs of Eligible Investments for the Connection of Qualifying Generation Facilities			
21 & 22	Generation Facilities - If applicable, proposal to divide the costs of eligible investments between the distributor's ratepayers and all Ontario ratepayers per O.Reg. 330/09. Request for rate protection exceeds the materiality threshold in section 2.0.8 of the Filing Requirements - Appendices 2-FA through 2-FC identifying all eligible investments for recovery	**Yes**	Exhibit 2A, Tab 6, Schedules 2-5. Please note Appendix 2-FC is n/a (no Renewable Expansion Investments).
Service Quality and Reliability Performance			
22	5 historical years of ESQRs, explanation for any under-performance vs standard and actions taken	**Yes**	Exhibit 1B, Tab 2, Schedule 3
22	5 historical years of SAIDI and SAIFI - for all interruptions, all interruptions excluding loss of supply, and all interruptions excluding major events. The applicant should also provide a summary of major events that occurred since last rebasing. For each interruption set out in section 2.1.4.2.5 of the RRR, for the last 5 years, a distributor must report on the following data: name of the Cause of Interruption, number of interruptions that occurred as a result of the Cause of Interruption, Number of Customer Interruptions that occurred as a result of the Cause of Interruption, and the Number of customer-hours of Interruptions that occurred as a result of the Cause of Interruption	**Yes**	Exhibit 1B, Tab 2, Schedule 4
22	Explanation for any under-performance vs 5 year average and actions taken	**Yes**	Exhibit 2A, Tab 7, Schedule 1 and 2
22	Distributors may propose SAIDI and SAIFI benchmarks different than 5 year average; provide rationale	**Yes**	Exhibit 1B, Tab 2, Schedule 2
22	Completed Appendix 2-G	**Yes**	Exhibit 1B, Tab 2, Schedule 5
Ch 5 p6	Where applicable, explanation for section headings other than Chapter 5 headings; cross reference table	**Yes**	Exhibit 2B, Section A2
Ch 5 p7-8	Distribution System Plan Overview - key elements, sources of cost savings, period covered, vintage of information on investment drivers, changes to asset management process since last DSP filing, dependencies	**Yes**	Exhibit 2B, Section A
Ch 5 p8-9	Coordinated Planning with 3rd parties - description of consultations - deliverables of the Regional Planning Process, or status of deliverables - IESO letter in relation to REG investments (Ch 5 p9) and Dx response letter	**Yes**	Exhibit 2B, Section B
Ch 5 p9-11	Performance Measurement - identify and define methods and measures used to monitor DSP performance - summary of performance and trends over historical period. Must include SAIFI and SAIDI for all interruptions and all interruptions excluding loss of supply - explain how information has affected DSP	**Yes**	Exhibit 1B, Tab 2, Schedule 4 and Exhibit 2B, Section C
Ch 5 p11	Realized efficiencies due to smart meters -documented capital and operating efficiencies realized as a result of the deployment and operationalization of smart meters and related technologies. Both qualitative and quantitative descriptions should be provided	**Yes**	Exhibit 2B, Section E5.4
Ch5 p12	Asset Management Process Overview - description of AM objectives/corporate goals and how Dx ranks objectives for prioritizing investments	**Yes**	Exhibit 2B, Sections D1 and D3
Ch5 p12	Inputs/Outputs of the AM process and information flow for investments; flowchart recommended	**Yes**	Exhibit 2B, Sections D1 and D3
Ch 5 p13	Overview of Assets Managed - description of service area (including evolution of features in forecast period affecting DSP), - description of system configuration - service profile and condition by asset type (tables and/or figures) - date data compiled - assessment of degree the capacity of system assets is utilized	**Yes**	Exhibit 2B, Section D2
Ch 5 p13-14	Asset Lifecycle Optimization - description of asset lifecycle optimization policies and practices, including asset replacement and refurbishment, maintenance planning criteria and assumptions - description of asset life cycle risk management policies and practices, assessment methods and approaches to mitigation	**Yes**	Exhibit 2B, Section D3
Ch 5 p14-15	System Capability Assessment for REG - REG applications > 10 kW, number and MW of REG connections for forecast period, capacity of Dx to connect REG, connection constraints	**Yes**	Exhibit 2B, Section E3
Ch 5 p15	Capital Expenditure Plan Summary for significant projects and activities to be undertaken - capability to connect new load or Gx customers, total annual capex over forecast period by investment category, description of how AMP and Capex planning have affected capital expenditures for each category - list, description and total capital cost of material capital expenditures sorted by category (table recommended) - information related to Regional Planning Process (Needs Assessment Report, Regional Planning Status Letter, Regional Infrastructure Plan - as appropriate) - description of customer engagement - Dx expectations of system development over next 5 years - list, description and total capital cost of projects planned in response to customer preferences, to take advantage of technology based opportunities, to study innovative processes (table recommended)	**Yes**	Exhibit 2B, Sections E1 and E2

2019 Cost of Service Checklist

Toronto Hydro-Electric System Limited

EB-2018-0165

Date: August 15, 2018

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
Ch 5 p16-17	Capital Expenditure Planning Process Overview - description of capex planning objectives/criteria/ assumptions, relationship with AM objectives, policy on consideration of non-distribution alternatives, processes used to identify projects in each investment category, customer feedback and impact on plan, method and criteria used to priorities REG investments	**Yes**	Exhibit 2B, Section E2
Ch 5 p17	Rate-Funded Activities to Defer Distribution Infrastructure -CDM programs that target distributor-specific peak demand reductions to address a local constraint of the distribution system -demand response programs to reduce peak demand in order to defer capital investment -programs to improve the efficiency of the distribution system and reduce distribution losses -energy storage programs whose primary purpose is to defer specific capital spending for the distribution system	**Yes**	Exhibit 4A, Tab 2, Schedule 9 and Exhibit 2B, Section E7.4
Ch 5 p18-19	Capital Expenditure Summary by Investment Category - completed Table 2 of Ch 5 for historical and forecast period, explanation of markedly different variances plan vs actual, explanation of markedly different variances year over year Table 2 of Ch 5 is provided in Excel format in Appendix 2-AB (must provide actual totals for historical years, as a minimum) - Must also complete Chapter 2 Appendix 2-AA, along with explanations of variances by project or category, the proposed accounting treatments, a statement should be provided that there are no expenditures for non-distribution activities in the applicant's budget	**Yes**	Exhibit 2B, Section E4 and Exhibit 2A, Tab 4, Schedules 2 and 3
Ch 5 p19	Justifying Capital Expenditures -filings must enable OEB to assess whether and how a distributor's DSP delivers value to customers, including by controlling costs in relation to its proposed investments through appropriate optimization, prioritization, and pacing of capital-related expenditures -distributors should also keep pace with technological changes and integrate cost-effective innovative projects and traditional planning needs such as load growth, asset condition and reliability	**Yes**	Exhibit 2B, Sections E2 and E5-E8
Ch5 p19-20	Overall Plan - comparative expenditures by category over historical period, forecast impact of system investment on O&M, drivers of investments by category, information related to Dx system capability assessment	**Yes**	Exhibit 2B, Sections A and E
Ch 5 p20-27	Material Investments - For each project that meets materiality threshold set in Ch 2 p5 - general information - total capital, customer attachments, dates, risks, variances, REG investments - evaluation criteria - may include: efficiency, customer value, reliability, etc. - category specific requirements for each project - system access, system renewal, system service, general plant (as applicable)	**Yes**	Exhibit 2B, Section E5-E8
EXHIBIT 3 - OPERATING REVENUE			
Load and Revenue Forecasts			
22	Explanation of causes, assumptions and adjustments for volume forecast. Economic assumptions and data sources for customer and load forecasts	**Yes**	Exhibit 3, Tab 1, Schedule 1 and Appendices
22	Explanation of weather normalization methodology	**Yes**	Exhibit 3, Tab 1, Schedule 1
22	Quantification of any impacts arising from the persistence of historical CDM programs as well as the forecasted impacts arising from new programs in the bridge and test years through the current 6-year CDM framework by customer class	**Yes**	Exhibit 3, Tab 1, Schedule 1
23	Completed Appendix 2-IB; the customer and load forecast for the test year must be entered on RRWF, Tab 10	**Yes**	Exhibit 3, Tab 1, Schedule 2
23 & 24	Multivariate Regression Model - rationale for choice, regression statistics, explanation of weather normalization methodology, sources of data for endogenous and exogenous variables, any binary variables used to either account for individual data points or to account for seasonal or cyclical trends or for discontinuities in the historical data, explanation of any specific adjustments made; data used in load forecast must be provided in Excel format, including derivation of constructed variables	**Yes**	Exhibit 3, Tab 1, Schedule 1 and Appendices
24	NAC Model - rationale for choice, data supporting NAC variables, description of accounting for CDM including licence conditions, discussion of weather normalization considerations	**N/A**	
24 & 25	CDM Adjustment - account for CDM in 2019 load forecast. Consider impact of persistence of historical CDM and impact of new programs. Adjustments may be required for IESO reported results which are full year impacts	**Yes**	Exhibit 3, Tab 1, Schedule 1
25	CDM savings for 2019 LRAMVA balance and adjustment to 2019 load forecast; data by customer class and for both kWh and, as applicable, kW. Provide rationale for level of CDM reductions in 2019 load forecast	**Yes**	Exhibit 3, Tab 1, Schedule 1
25	Completed Appendix 2-I	**Yes**	Toronto Hydro-specific CDM/LRAM calculation in place of Appendix 2-I at Exhibit 3, Tab 1, Schedule 1
Accuracy of Load Forecast and Variance Analyses			
25	Completed Appendix 2-IB	**Yes**	Exhibit 3, Tab 1, Schedule 1
25	For customer/connection counts - identification as to whether customer/connection count is shown in year end or average format, year-over-year variances in changes of customer/connection counts with explanation of major changes, explanations of bridge and test year forecasts by rate class, for last rebasing variance analysis between last OEB-approved and actuals with explanations for material differences	**Yes**	Exhibit 3, Tab 1, Schedule 1
25 & 26	For consumption and demand - explanation to support how kWh are converted to kW for applicable demand-billed classes, year-over-year variances in kWh and kW by rate class and for system consumption overall (kWh) with explanations for material changes in the definition of or major changes over time (should be done for both historical actuals against each other and historical weather-normalized actuals over time), explanations of the bridge and test year forecasts by rate class, variance analysis between the last OEB-approved and the actual and weather-normalized actual results	**Yes**	Exhibit 3, Tab 1, Schedule 1
26	For revenues - calculation of bridge year forecast of revenues at existing rates, calculation of test year forecasted revenues at existing and proposed rates, year-over-year variances in revenues comparing historical actuals and bridge and test year forecasts	**Yes**	Exhibit 3, Tab 1, Schedule 1
26	With respect to average consumption, for each rate class, distributors are to provide weather-actual and weather-normalized average annual consumption or demand per customer as applicable for the rate class for last OEB approved and historical, weather normalized average annual consumption or demand per customer for the bridge and test years, explanation of the net change in average consumption from last OEB-approved and actuals from historical, bridge and test years based on year-over-year variances and any apparent trends in data	**Yes**	Exhibit 3, Tab 1, Schedule 1
Other Revenue			
26 & 27	Completed Appendix 2-H	**Yes**	Exhibit 3, Tab 2, Schedule 2
27	Variance analysis - year over year, historical, bridge and test	**Yes**	Exhibit 3, Tab 2, Schedule 1
27	Any new proposed specific service charges, or proposed changes to rates or application of existing specific service charges	**Yes**	Exhibit 8, Tab 2, Schedule 1
27	Revenue from affiliate transactions, shared services, corporate cost allocation. For each affiliate transaction, identification of the service, the nature of the service provided to affiliate entities, accounts used to record the revenue and associated costs (Appendix 2-N)	**Yes**	Exhibit 4A, Tab 5, Schedule 2
28	Distributors must identify any discrete customer groups that may be materially impacted by changes to other rates and charges	**N/A**	
EXHIBIT 4 - OPERATING COSTS			
Overview			
28 & 29	Brief explanation of test year OM&A levels, cost drivers, significant changes, trends, inflation rate assumed, business environment changes	**Yes**	Exhibit 4A, Tab 1, Schedule 1 and Exhibit 4A, Tab 2
Summary and Cost Driver Tables			
29	Summary of recoverable OM&A expenses; Appendix 2-JA	**Yes**	Exhibit 4A, Tab 1, Schedule 2
29	Recoverable OM&A cost drivers; Appendix 2-JB	**Yes**	Exhibit 4A, Tab 1, Schedule 3
29	OM&A programs table; Appendix 2 JC	**Yes**	Exhibit 4A, Tab 1, Schedule 4
29	Recoverable OM&A Cost per customer and per FTE; Appendix 2-L	**Yes**	Exhibit 4A, Tab 1, Schedule 5

2019 Cost of Service Checklist

Toronto Hydro-Electric System Limited

EB-2018-0165

Date: August 15, 2018

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
29	Identification of change in OM&A in test year in relation to change in capitalized overhead.	Yes	Exhibit 4A, Tab 1, Schedule 1 and Appendix 2-D at Exhibit 2A, Tab 5, Schedule 2
29	OM&A variance analysis for test year with respect to bridge and historical years; Appendix 2-D	Yes	Exhibit 4A, Tab 1, Schedule 1; Appendix 2-D at Exhibit 2A, Tab 5, Schedule 2; and Exhibit 4A, Tab 2
Program Delivery Costs with Variance Analysis			
29 & 30	Completed Appendix 2-JC OM&A Programs Table - completed by program or major functions; include variance analysis limited to variances that are outliers, between test year and last OEB approved and most recent actuals, including an explanation for each significant change whether the change was within or outside the applicant's control and explanation of why	Yes	Exhibit 4A, Tab 1, Schedule 4 and Exhibit 4A, Tab 2
30	For each significant change within the applicant's control describe business decision that was made to manage the cost increase/decrease and the alternatives	Yes	Exhibit 4A, Tab 2
Workforce Planning and Employee Compensation			
30	Employee Compensation - completed Appendix 2-K	Yes	Exhibit 4A, Tab 4, Schedule 2
30	Description of previous and proposed workforce plans, including compensation strategy	Yes	Exhibit 4A, Tab 4, Schedules 3 and 4
30	Discussion of the outcomes of previous plans and how those outcomes have impacted their proposed plans including an explanation of the reasons for all material changes to headcount and compensation. Explanation for all years includes: - year over year variances - basis for performance pay, eligible employee groups, goals, measures, and review process for pay-for-performance plans, - relevant studies (e.g. compensation benchmarking)	Yes	Exhibit 4A, Tab 4, Schedules 3 to 6
30 & 31	Details of employee benefit programs including pensions for last OEB approved, historical, bridge and test; must agree with tax section	Yes	Exhibit 4A, Tab 4, Schedules 4 and 6
31	Most recent actuarial report on employee benefits, pension and OPEBs	Yes	Exhibit 4A, Tab 4, Schedule 6
31	Accounting method for pension and OPEBs; if cash method, sufficient supporting rationale. If proposing to change the basis in which pension and OPEB costs included in OM&A, quantification of impact of transition	Yes	Exhibit 4A, Tab 2, Schedule 20
Shared Services and Corporate Cost Allocation			
31	Identification of all shared services among affiliates and parent company; identification of the extent to which the applicant is a "virtual utility"	Yes	Exhibt 4A, Tab 5, Schedule 1
31 & 32	Allocation methodology for corporate and shared services, list of costs and allocators, including any third party review	Yes	Exhibt 4A, Tab 5, Schedule 1
32	Completed Appendix 2-N for service provided or received for historical, bridge and test; including reconciliation with revenue included in Other Revenue	Yes	Exhibt 4A, Tab 5, Schedule 2
32	Shared Service and Corporate Cost Variance analysis - test year vs last OEB approved and most recent actual	Yes	Exhibt 4A, Tab 5, Schedule 1
32	Identification of any Board of Director costs for affiliates included in LDC costs	Yes	Exhibt 4A, Tab 5, Schedule 1
Non-Affiliate Services, One-Time Costs, Regulatory Costs			
32	Purchased Non-Affiliated Services - file a copy of procurement policy (signing authority, tendering process, non-affiliate service purchase compliance)	Yes	Exhibt 4A, Tab 3, Schedule 1
32	For material transactions that are not in compliance with procurement policy, or that were undertaken pursuant to exceptions contemplated within the policy, an explanation as to why as well as a summary of the nature and cost of the product, and a description of the specific methodology used for selecting the vendor	Yes	Exhibt 4A, Tab 3, Schedule 1
32 & 33	Identification of one-time costs in historical, bridge, test; explanation of cost recovery in test (or future years). If no recovery of one-time costs is being proposed in the test year and subsequent IRM term, an explanation must be provided	Yes	Exhibit 4A, Tab 2, Schedule 20 addresses that there are no one-time costs, other than regulatory costs (below)
33	Regulatory costs - breakdown of actual and forecast, supporting information related to CoS application (e.g. legal fees, consultant fees), proposed recovery (i.e. amortized?) Completed Appendix 2-M	Yes	Exhibit 4A, Tab 2, Schedule 18, Appendix A
LEAP, Charitable and Political Donations			
33	LEAP - the greater of 0.12% of forecasted service revenue requirement or $2,000 should be included in OM&A and recovered from all rate classes	Yes	Exhibit 4A, Tab 2, Schedule 19
33	Detailed information for all contributions that are claimed for recovery	Yes	Exhibit 4A, Tab 2, Schedule 19
33	Charitable Donations - the applicant must confirm that no political contributions have been included for recovery	Yes	Exhibit 4A, Tab 2, Schedule 19
Depreciation, Amortization and Depletion			
34	Explanations for any useful lives of an asset that are proposed that are not within the ranges contained in the Kinectrics Report	Yes	Exhibit 4B, Tab 1, Schedule 1
34	Depreciation, Amortization and Depletion details by asset group for historical, bridge and test years. Include asset amount and rate of depreciation/amortization. Must complete Appendix 2-C which must agree to accumulated depreciation in Appendix 2-BA under rate base	Yes	Exhibit 4B, Tab 1, Schedule 1
34	Identification of any Asset Retirement Obligations and associated depreciation, accretion expense	Yes	Exhibit 4B, Tab 1, Schedule 1
34	Identification of historical depreciation practice and proposal for test year. Variances from half year rule must be documented and supporting rationale provided	Yes	Exhibit 4B, Tab 1, Schedule 1
34 & 35	Copy of depreciation/amortization policy, or equivalent written description; summary of changes to depreciation/amortization policy since last CoS	Yes	Exhibit 4B, Tab 1, Schedule 1
35	Explanation of any deviations from the practice of depreciating significant parts or components of PP&E separately	Yes	Exhibit 4B, Tab 1, Schedule 1
35	For any depreciation expense policy or asset service lives changes since its last rebasing application: - identification of the changes and detailed explanation for the causes of the changes, including any changes subsequent to those made by January 1, 2013 -use of Kinectrics study or another study to justify changes in useful life - list detailing all asset service lives tied to USoA, detail differences in TUL from Kinectrics and explain differences outside of minimum and maximum TUL range from Kinectrics; Appendix 2-BB	Yes	Exhibit 4B, Tab 1, Schedule 1
PILs and Property Taxes			
36	Completed version of the PILs model (PDF and Excel); derivation of adjustments for historical, bridge, test years	Yes	Exhibit 4B, Tab 2, Schedule 2 . Adjustments to OEB models documented in evidence
36	Supporting schedules and calculations identifying reconciling items	Yes	Exhibit 4B, Tab 2, Schedule 1 and 2
36	Most recent federal and provincial tax returns	Yes	Exhibit 4B, Tab 2, Schedule 3
36	Financial Statements included with tax returns if different from those filed with application	Yes	Exhibit 1C, Tab 4, Schedule 2
36	Calculation of Tax Credits; redact where required (filing of unredacted versions is not required)	Yes	Exhibit 4B, Tab 2, Schedule 1 and 2
36	Supporting schedules, calculations and explanations for other additions and deductions	Yes	Exhibit 4B, Tab 2, Schedule 2
36	Completion of the integrity checks in the PILs Model	Yes	Exhibit 4B, Tab 2, Schedule 1
36	Explanation of how taxes other than income taxes or PILS (e.g. property taxes) are derived	Yes	Exhibit 4B, Tab 2, Schedule 1
Non-recoverable and Disallowed Expenses			
36	Exclude from regulatory tax calculation any non-recoverable or disallowed expenses	N/A	
Conservation and Demand Management			

2019 Cost of Service Checklist

Toronto Hydro-Electric System Limited

EB-2018-0165

Date: August 15, 2018

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
37, 38 & 39	LRAMVA - disposition of balance. Distributors must provide new LRAMVA Work Form in a working Excel file and provide the following: - statement identifying the year(s) of new lost revenues and prior year savings persistence claimed in the LRAMVA disposition - statement confirming LRAMVA based on verified savings results supported by the distributors final CDM Report and Persistence Savings Report (both filed in Excel format) and a statement indicating use of most recent input assumptions when calculating lost revenue - summary table with principal and carrying charges by rate class and resulting rate riders - statement providing the disposition period; rationale provided for disposing the balance in the LRAMVA if one or more classes do not generate significant rate riders - statement confirming LRAMVA reference amounts, rationale for the distributors circumstances if LRAMVA threshold not used - rationale confirming how rate class allocations for actual CDM savings were determined by class and program (Tab 3-A of LRAMVA Work Form) - statement confirming whether additional documentation was provided in support of projects that were not included in distributors final CDM Annual Report (Tab 8 of LRAMVA Work Form as applicable) - for OEB-approved programs prior to 2014, a submission of a third party report that provides a review and verification of the LRAM calculation including: confirmation of use of correct input assumptions and lost revenue calculations, participation amounts, net and gross impacts of each program (kW and kWh) by class by year, and verification of any carrying charges requested	N/A	
EXHIBIT 5 - COST OF CAPITAL AND CAPITAL STRUCTURE			
Capital Structure			
40	Statement that LDC adopts OEB's guidelines for cost of capital and confirms that updates will be done. Alternatively - utility specific cost of capital with supporting evidence	Yes	Exhibit 5, Tab 1, Schedule 1
40	Completed Appendix 2-OA for last OEB approved and test year	Yes	Exhibit 5, Tab 1, Schedule 2
40	Completed Appendix 2-OB for historical, bridge and test years	Yes	Exhibit 5, Tab 1, Schedule 3
40	Explanation for any changes in capital structure	N/A	
Cost of Capital (Return on Equity and Cost of Debt)			
40	Calculation of cost for each capital component	Yes	Exhibit 5, Tab 1, Schedule 1
40	Profit or loss on redemption of debt	N/A	
40	Copies of promissory notes or other debt arrangements with affiliates	Yes	Exhibit 1C, Tab 4, Schedule 6
40	Explanation of debt rate for each existing debt instrument	Yes	Exhibit 5, Tab 1, Schedule 1
40	Forecast of new debt in bridge and test year - details including estimate of rate	Yes	Exhibit 5, Tab 1, Schedule 1
40	If proposing any rate that is different from the OEB guidelines, a justification of the proposed rate(s), including key assumptions	Yes	Exhibit 5, Tab 1, Schedule 1
41	Notional Debt - difference between actual debt thickness and deemed debt thickness attracts the weighted average cost of actual long-term debt rate (unless 100% equity financed)	N/A	
Not-for-Profit Corporations			
41	Not for Profit Corporations - evidence that excess revenue is used to build up operating and capital reserves	N/A	
41	Detailed calculation for test year revenue requirement based on its Reserve Requirement	N/A	
41	The proposed reserves and rationale for the need to establish each reserve, the time period of building up the reserves, and the procedure and policy of each reserve	N/A	
42	Description of the governance of the not-for-profit corporation	N/A	
42	If there are approved reserves from previous OEB decisions provide the following: -the limits of any capital and/or operating reserves as approved by the OEB, and identifying the decisions establishing these reserve accounts and their limits -the current balances of any established capital and/or operating reserves	N/A	
EXHIBIT 6 - REVENUE DEFICIENCY/SUFFICIENCY			
42	Calculation of delivery-related Revenue Deficiency/Sufficiency (excluding cost of power and associated costs): net utility income, rate base, actual return on rate base, indicated rate of return, requested rate of return, deficiency/sufficiency, gross deficiency/sufficiency. Deficiency/sufficiency must also be net of other costs (e.g. LV costs, RSVAs, smart meter or MIST meter expenditures/revenues and other DVA balances).	Yes	Exhibit 6, Tab 1, Schedule 1
42 & 43	Summary of drivers for test year deficiency/sufficiency, how much each driver contributes; references in application evidence mapped to drivers	Yes	Exhibit 6, Tab 1, Schedule 1
43	Impacts of any changes in methodologies to deficiency/sufficiency	N/A	
Revenue Requirement Work Form			
43	RRWF - in PDF and Excel. Revenue requirement, def/sufficiency, data entered in RRWF must correspond with other exhibits	Yes	Exhibit 6, Tab 1, Schedule 2. Adjustments to OEB models documented in evidence.
43	If the enhanced RRWF cannot reflect a distributor's proposed rates accurately, the distributor must file its rate generator model	N/A	
43	Completed Appendices 2-JA, 2-JB, and 2-JC	Yes	Exhibit 4A, Tab 1, Schedules 2, 3, 4
EXHIBIT 7 - COST ALLOCATION			
Cost Allocation Study Requirements			
44	Completed cost allocation study using the OEB-approved methodology or a comparable model must be filed reflecting future loads and costs and be supported by appropriate explanations and live Excel spreadsheets. Sheets 11 and 12 of the RRWF must also be completed. Live Excel version of 2017 cost allocation model will be filed (updated load profiles or scaled version of HONI CAIF). Model must be consistent with test year load forecast, changes to customer classes and load profiles.	Yes	Exhibit 7, Tab 1
44	Explanation provided if a distributor is unable to update its load profiles and confirm that it intends to put plans in place to update its load profiles the next time a cost allocation model is filed	N/A	
45	Description of weighting factors, and rationale for use of default values (if applicable)	Yes	Exhibit 7, Tab 1
45	Hard copy of sheets I-6, I-8, O-1 and O-2 (first page)	Yes	Exhibit 7, Tab 2
45 & 46	Host Distributor only - evidence of consultation with embedded Dx - statement regarding embedded Dx support for approach to allocation of costs - if embedded Dx is separate class - class in cost allocation study and RRWF, Sheet 11 - if new embedded Dx class - rationale and supporting evidence (cost of serving, load served, asset ownership information, distribution charges); include in cost allocation study and RRWF, Sheet 11 - if embedded Dx billed as GS customer - , include with the GS class in cost allocation model and Appendix 2-P. Provide cost of serving, load served, asset ownership information, distribution charges, appropriateness of rate class. File Appendix 2-Q.	N/A	
46	Unmetered Loads (including Street Lighting) - Confirmation of communication with unmetered load customers when proposing changes to the level of the rates and charges or the introduction of new rates and charges	Yes	Exhibit 7, Tab 1, Schedule 1
46 & 47	microFIT - if the applicant believes that it has unique circumstances which would justify a certain rate, appropriate documentation must be provided	N/A	
47	Standby Rates - if seeking approval on final basis, provide evidence that affected customers have been advised. If seeking changes to standby charges, provide rationale and evidence that affected customer have been advised.	N/A	
47	New customer class or eliminated customer class - rationale and restatement of revenue requirement from previous CoS	N/A	
Class Revenue Requirements			

2019 Cost of Service Checklist

Toronto Hydro-Electric System Limited

EB-2018-0165

Filing Requirement Page # Reference

Date: August 15, 2018

		Yes/No/N/A	Evidence Reference, Notes
48	To support a proposal to rebalance rates, the distributor must provide information on the revenue by class that would apply if all rates were changed by a uniform percentage. Ratios must be compared with the ratios that will result from the rates being proposed by the distributor.	N/A	
Revenue to Cost Ratios			
48	If R:C ratios outside deadband based on model - distributors must include cost allocation proposal to bring them within the OEB-approved ranges. In making any such adjustments, distributors should address potential mitigation measures if the impact of the adjustments on the rates of any particular class or classes is significant.	N/A	
49	If Cost Allocation Model other than OEB model used - exclude LV, exclude DVA such as smart meters	N/A	
EXHIBIT 8 - RATE DESIGN			
50	Monthly fixed charges - 2 decimal places; variable charges - 4 decimal places	Yes	Toronto Hydro uses 2 decimal places for fixed charges, 4 decimal places for kVA based charges, and 5 decimal places for kWh based charges
Fixed Variable Proportion			
50	The following is to be provided in relation to the fixed/variable proportion of proposed rates: -Current F/V with supporting info -Proposed F/V proportion with explanation for any changes (billing determinants from proposed load forecast) -Comparison between current and proposed monthly fixed charges with the floor and ceiling as in cost allocation study Analysis must be net of rate adders, funding adders, and rate riders	Yes	Exhibit 8, Tab 1, Schedule 1
Rate Design Policy			
50 & 51	LDCs must propose changes to residential rates consistent with policy to transition to fully fixed monthly distribution service charge.	Yes	Exhibit 8, Tab 1, Schedule 1
51	Proposal follows approach set out in Tab 12 of RRWF	Yes	Exhibit 8, Tab 1, Schedule 1
51	If applicable, distributor with seasonal residential class must propose identical rate design treatment for such a class	N/A	
RTSRs			
51	Retail Transmission Service Rate Work Form - PDF and Excel	Yes	Exhibit 8, Tab 5, Schedule 1 with adjustments to OEB models documented in this evidence.
51	RTSR information must be consistent with working capital allowance calculation	Yes	Exhibit 8, Tab 5, Schedule 1
Retail Service Charges			
51 & 52	If proposing changes to Retail Service Charges or introduction of new rates and charges - evidence of consultation and notice	N/A	
Regulatory Charges			
52	Wholesale Market Service Rate - reflect current approved rate in application or justify otherwise	Yes	Exhibit 8,Tab 1 and 3
Specific Service Charges			
52 & 53	Specific Service Charge description/purpose/reason for new and revised SSC; calculations to support charges	Yes	Exhibit 8, Tab 2, Schedule 1
53	Identification in the Application Summary all proposed changes that will have a material impact on customers, including charges that may affect a discrete group.	Yes	Exhibit 1B, Tab 5, Schedule 1
53	Identification of any rates and charges in Conditions of Service that do not appear on tariff sheet. Explain nature of costs, provide schedule outlining revenues or capital contributions 2012-2015, bridge and test years. Whether these charges should be included on tariff sheet	Yes	Exhibit 8, Tab 2, Schedule 1
53	Ensure revenue from SSCs corresponds with Operating Revenue evidence	Yes	Exhibit 8, Tab 2 and Exhibit 3, Tab 2
Wireline Pole Attachment Charge			
53	LDC without a distributor-specific charge will charge the province-wide pole attachment charge of $28.09 from September 1, 2018 to December 31, 2018. This charge will increase to $43.63 effective January 1, 2019.	Yes	Exhibit 8, Tab 2, Schedule 1 addresses Toronto Hydro's adoption of the new province-wide pole attachment charge
54	Record the excess incremental revenue as of September 1, 2018 until the effective date of its rebased rates in a new variance account related to pole attachment charge	N/A	
54 & 55	If an LDC chooses to apply for a custom charge, it must file a completed version of the OEB's Wireline Pole Attachment Work Form, and include the following information as part of their application: statement confirming the proposed distributor-specific wireline pole attachment charge; statement discussing the main cost drivers, including rationale; a table summarizing key inputs in the rate calculation, and a statement confirming the RRR data and pre-tax weighted cost of capital are consistent; confirmation of the total number of poles and joint use poles in the rate calculation, and a table outlining the rate of pole replacements and percentage of poles depreciated over the past 5 years; confirmation of the number of attaches that are specific to the distributor's service territory, a description of the types of poles and discussion of contractual arrangements with other entities that affect the number of attachments, including overlashing attachments; explanation of changes to the power deduction factor, must complete Tab 4-A and explain methodology, LDCs should provide supporting data and analysis, as applicable; explanation of changes to the hybrid equal sharing allocation rate; explanation of changes to the allocation factor of pole maintenance, Table 8 in Tab 4 must be completed; description of activities performed by the distributor to directly accommodate third party attaches, should include discussion of methodology, costs and data sources to calculate each component of direct costs, detailed calculations of total administration and LOP costs, including staff time and labour rates, as applicable	N/A	
Low Voltage Service Rates			
55	Forecast of LV cost, sum of host distributors charges	N/A	
55	Low Voltage Cost (historical, bridge, test), variances and explanations for substantive changes	N/A	
55	Support for forecast LV, e.g. Hydro One Sub-Transmission charges	N/A	
55	Allocation of LV cost to customer classes (typically proportional to Tx connection revenue)	N/A	
55	Proposed LV rates by customer class	N/A	
Smart Meter Entity Charge			
55	Distributor must follow accounting guidance provided on March 23, 2018	Yes	Exhibit 8, Tab 1, Schedule 1
Loss Factors			
55	Proposed SFLF and Total Loss Factor for test year	Yes	Exhibit 8, Tab 1, Schedule 1
56	Statement as to whether LDC is embedded including whether fully or partially	Yes	Exhibit 8, Tab 1, Schedule 1
56	Study of losses if required by previous decision	Yes	Exhibit 8, Tab 4, Schedule 2
56	3-5 years of historical loss factor data - Completed Appendix 2-R	Yes	Exhibit 8, Tab 4, Schedule 1
56	If proposed loss factor >5%, explanation and action plan to reduce losses going forward	N/A	
56	Explanation of SFLF if not standard	N/A	
Tariff of Rates and Charges			
56	Current and proposed Tariff of Rates and Charges filed in the Tariff Schedule/Bill Impacts Model - each change must be explained and supported in the appropriate section of the application	Yes	Exhibit 8, Tab 3, Schedule 1 and 2
56	Explanation of changes to terms and conditions of service if changes affect application of rates	N/A	
Revenue Reconciliation			
56	Calculations of revenue per class under current and proposed rates; reconciliation of rate class revenue and other revenue to total revenue requirement (i.e. breakout volumes, rates and revenues by rate component etc.)	Yes	Exhibit 6, Tab 2, Schedule 2
56 & 57	Completed RRWF - Sheet 13 - rates and charges entered on this sheet should be rounded to the same decimal places as tariff	Yes	Exhibit 6, Tab 2, Schedule 2

2019 Cost of Service Checklist

Toronto Hydro-Electric System Limited

EB-2018-0165

Filing Requirement Page # Reference

Date: August 15, 2018

		Yes/No/N/A	Evidence Reference, Notes
Bill Impact Information			
57	Completed Tariff Schedule and Bill Impacts Model. Bill impacts must identify existing rates, proposed changes to rates, and detailed bill impacts (including % change in distribution excluding pass through costs - Sub-Total A, % change in distribution - Sub-Total B, % change in delivery - Sub-Total C, and $ change in total bill)	Yes	Exhibit 8, Tabs 3 and 6
57	Impact of changes resulting from the as-filed application on representative samples of end-users (i.e. volume, % rate change and revenue). Commodity and regulatory charges held constant	Yes	Exhibit 8, Tab 6, Schedule 1
57	Rates and charges input in the tariff schedule and Bill Impacts Model rounded to the decimal places as shown on the existing tariff	Yes	Exhibit 8, Tab 6, Schedule 3 and 6
57	Bill impacts provided for typical customers and consumption levels. Must provide residential 750 kWh, residential at the lowest 10th percentile and GS<50 2,000 kWh. Bill impacts must be provided for a range of consumption levels relevant to the service territory.	Yes	Exhibit 8, Tab 6, Schedule 1
57	If applicable, for certain classes where one or more customers have unique consumption and demand patterns, the distributor must show a typical impact and provide an explanation	Yes	Exhibit 8, Tab 6, Schedule 1
Rate Mitigation			
58	Evidence showing that the monthly service charge would not rise by more than $4 per year due only to the rate design change, and that the total bill impact, reflecting all proposed changes in the application, will not exceed 10%. If either of these criteria is not met, some form of mitigation may be required (i.e. extending transition period).	Yes	Exhibit 8, Tab 1, Schedule 1 and Exhibit 6, Tab 1, Schedule 2
58	Evaluation of bill impact for residential customer at 10th consumption percentile. Describe methodology for determination of 10th consumption percentile. File mitigation plan for whole residential class if impact >10% for these customers.	Yes	Exhibit 8, Tab 1, Schedule 1 and Exhibit 6, Tab 1, Schedule 2
59	Mitigation plan if total bill increase for any customer class is >10% including: specification of class and magnitude of increase, description of mitigation measures, justification, revised impact calculation. The Tariff Schedule and Bill Impacts Model must reflect any mitigation plan proposed.	N/A	
59	Rate Harmonization Plans, if applicable - including impact analysis	N/A	
EXHIBIT 9 - DEFERRAL AND VARIANCE ACCOUNTS			
60	List of all outstanding DVA and sub-accounts; provide description of DVAs that were used differently than as described in the APH	Yes	Exhibit 9, Tab 1, Schedule 1
60	Completed DVA continuity schedule for period following last disposition to present - live Excel format	Yes	Exhibit 9, Tab 2, Schedule 1
60	Confirm use of interest rates established by the OEB by month or by quarter for each year	Yes	Exhibit 9, Tab 1, Schedule 1
60	Explanation if account balances in continuity schedule differs from trial balance in RRR and AFS	Yes	Exhibit 9, Tab 2, Schedule 1
60	Identification of Group 2 accounts that will continue/discontinue going forward, with explanation	Yes	Exhibit 9, Tab 1, Schedule 1
60	Statement as to any new accounts, and justification.	Yes	Exhibit 9, Tab 1, Schedule 1
60 & 61	Statement whether any adjustments made to DVA balances previously approved by OEB on final basis; explanation, amount of adjustment and supporting documents	N/A	
61	Breakdown of energy sales and cost of power by USoA - as reported in AFS mapped and reconciled to USoA. Provide explanation if making a profit or loss on commodity.	Yes	Exhibit 9, Tab 2, Schedule 2
61	Statement confirming that IESO GA charge is pro-rated into RPP and non-RPP; provide explanation if not pro-rated.	Yes	Exhibit 9, Tab 1, Schedule 1
Account 1575, IFRS-CGAAP Transitional PP&E Amounts			
61	1575 IFRS-CGAAP PP&E account - Account 1575 and 1576 can't be used interchangeably - breakdown of balance, including explanation for each accounting change; Appendix 2-EA - listing and quantification of drivers - volumetric rate rider to clear 1575; separate rider must be on a fixed basis for the residential class; - rate of return component is to be applied to 1575 but not recorded in 1575 - statement confirming no carrying charges applied to 1575 - explanation for the basis of the proposed disposition period to clear Account 1575 rate rider - show the balance in DVA continuity schedule	N/A	
Retail Service Charges			
61 & 62	Retail Service Charges - material balance in 1518 or 1548 - confirm variances are incremental costs of providing retail services; identify drivers for balances - provide schedule identifying all revenues and expenses listed by USoA for 2013, actual/forecast for bridge and test year - state whether Article 490 of APH has been followed; explanation if not followed	N/A	
62	Retail Service Charges - zero balance in 1518 or 1548 - state whether Article 490 of APH has been followed; explanation if not followed	N/A	
Disposition of Deferral and Variance Accounts			
62	Identify all accounts for which LDC is seeking disposition; identify DVA for which LDC is not proposing disposition and the reasons why	Yes	Exhibit 9, Tab 1, Schedule 1
62	Statement whether DVA balances before forecasted interest match the last AFS; explain any variances	Yes	Exhibit 9, Tab 1, Schedule 1
62	Provide an explanation of variance > 5% between amounts proposed for disposition and amounts reported in RRR for each account.	N/A	
62	Provide explanations if variances are < 5% threshold if the variances in question relate to: (1) matters of principle (i.e. conformance with the APH or prior OEB decisions, and prior period adjustments); and/or, (2) the cumulative effect of immaterial differences over several accounts total to a material difference between what is proposed for disposition in total before forecasted interest and what is recorded in the RRR filings	N/A	
62	For any utility specific accounts requested for disposition, supporting evidence showing how balance is derived and relevant accounting order	Yes	Exhibit 9, Tab 1, Schedule 1
62	Disposition of residual balances for vintage Account 1595 are only done once - distributors expected to seek disposition of the balance a year after a rate rider's sunset date has expired. No further dispositions of these accounts are generally expected unless justified by the distributor	Yes	Exhibit 9, Tab 1, Schedule 1
62	Proposed mechanisms for disposition with all relevant calculations: allocation of each account (including rationale), billing determinants for recovery purposes in accordance with Rate Design Policy	Yes	Exhibit 9, Tab 1, Schedule 1
62	Rate riders where volumetric rider is $0.0000 for one or more classes not included in the tariff for those classes	N/A	
63	Propose rate riders for recovery or refund of balances that are proposed for disposition. The default disposition period is one year; if the applicant is proposing an alternative recovery period must provide explanation.	Yes	Exhibit 9, Tab 1, Schedule 1
63	Establish separate rate riders to recover balances in the RSVA's from Market Participants who must not be allocated the RSVA balances related to charges for which the MP's settle directly with the IESO.	N/A	
63 & 64	Proposed disposition of Account 1580 sub-account CBR Class B in accordance with the CBR Accounting Guidance. - embedded distributors who are not charged CBR (therefore no balance in sub-account CBR Class B) must indicate this is the case for them - In the DVA continuity schedule, applicants must indicate whether they serve any Class A customers during the period where Account 1580 CBR Class B sub-account balance accumulated. - Account 1580 sub-account CBR Class A is not to be disposed through rates proceedings but rather follow the OEB's accounting guidance. - The DVA continuity schedule will allocation the portion of Account 1580 sub-account CBR Class B allocated to customers who transitioned between Class A and Class B based on consumption levels	N/A	

2019 Cost of Service Checklist

Toronto Hydro-Electric System Limited

EB-2018-0165

Filing Requirement Page # Reference

Date: August 15, 2018

		Yes/No/N/A	Evidence Reference, Notes
Global Adjustment			
64	Establishment of a separate rate rider included in the delivery component of the bill that would apply prospectively to Non-RPP Class B customers when clearing balances from the GA Variance Account	N/A	
65	GA Analysis Workform in live Excel format- complete GA Analysis Workform; explain discrepancies	N/A	
65 & 66	Description of settlement process with IESO or host distributor, specify GA rate used for each rate class, itemize process for providing estimates and describe true-up process, details of method for estimating RPP and non-RPP consumption, treatment of embedded generation/distribution. If distributor uses the actual GA rate to bill non-RPP Class B customers, a proposal must be made to exclude these customer classes from the allocations of the balance of Account 1589 and the calculation of the resulting rate riders	N/A	
66	RPP Settlement True-Up - distributors to follow guidance in May 23, 2017 letter pertaining to the period that is being requested for disposition for Accounts 1588 and 1589	N/A	
66 & 67	Certification by the CEO, CFO or equivalent that distributor has robust processes and internal controls in place for the preparation, review, verification and oversight of account balances being proposed for disposition	N/A	
Establishment of New Deferral and Variance Accounts			
67	New DVA - information provided which addresses that the requested DVA meets the following criteria: causation, materiality, prudence; include draft accounting order.	Yes	Exhibit 9, Tab 1, Schedule 1

TOTAL "NO" **0**

CERTIFICATION OF EVIDENCE

I, Amanda Klein, Executive Vice-President, Regulatory Affairs and General Counsel of Toronto Hydro-Electric System Limited ("Toronto Hydro"), hereby certify that the evidence filed in support of Toronto Hydro's 2020-2024 Custom Incentive Rate-setting Application (EB-2018-0165) is accurate, consistent and complete to the best of my knowledge.

This certification is given pursuant to the Ontario Energy Board's *Filing Requirements for Electricity Distribution Rate Applications* (issued July 12, 2018).

DATED this **15th** day of **August, 2018.**



Amanda Klein

Executive Vice President, Regulatory Affairs and General Counsel

GLOSSARY

"ACA" refers to Toronto Hydro's asset condition assessment.

"Affiliate Relationships Code" or "**ARC**" refers to the OEB's Affiliate Relationships Code for Electricity Distributors and Transmitters.

"**AFS**" refers to Toronto Hydro's audited financial statements.

"AFUDC" refers to Allowance For Funds Used During Construction.

"AILC" refers to Asbestos-Insulated Lead-Covered (cable).

"AM" refers to Asset Management.

"**APH**" refers to the OEB's Accounting Procedures Handbook.

"APUL" refers to Assets Past Useful Life.

"**ARO**" refers to Asset Retirement Obligation.

"ATS" refers to Automatic Transfer Switches.

"AWG" refers to aluminum conductor steel reinforced assets.

"BCE" refers to business case evaluation.

"BOMA" refers to the Building Owners and Managers Association.

"C&I" refers to Commercial and Institutional customers.

"CAF" refers to Customer Action Form, a notice issued to a customer when any deficiencies are found on customer-owned equipment or structures.

"CAIDI" refers to the Customer Average Interruption Duration Index and is a measure (in hours) of the average duration of interruptions experienced by customers, not including MED. CAIDI represents the quotient obtained by dividing SAIDI by SAIFI.

"Capital Expenditures" or **"Capex"** refers to expenditures relating to property, plant and equipment and intangible assets.

"CC&B" refers to the Customer Care & Billing system, Toronto Hydro's main customer care interface used for billing and customer information.

"CDM" refers to conservation and demand management.

"**CGAAP**" refers to Canadian Generally Accepted Accounting Principles.

"CHI" refers to Customer Hours Interrupted.

"CHP" refers to Combined Heat and Power generation.

"CI" refers to Customer Interruptions.

"CIR" or **"Custom IR"** refers to Custom Incentive Rate-setting.

"CIS" refers to customer information system. Toronto Hydro's current CIS is the CC&B.

"**City**" refers to the City of Toronto.

"CNAIM" refers to the Common Network Asset Indices Methodology adopted by Toronto Hydro for asset condition assessment.

"CPCI" or **"Custom PCI"** refers to Custom Price Cap Index.

"CPCP" refers to a Certified Power Cable Person.

"CPLP" refers to a Certified Power Line Person

"CRD" refers to Compact Radial Distribution assets.

"CSMUR" refers to the Competitive Sector Multi-Unit Residential rate class.

"CUPE One" or "CUPE" refers to the Canadian Union of Public Employees, Local One

"CWIP" refers to Construction Work In Progress.

"DG" refers to distributed generation.

"Distribution System Code" or "**DSC**" refers to the OEB's Distribution System Code.

"**DMS**" refers to Toronto Hydro's Distribution Management System.

"DR" refers to Demand Response.

"DSP" refers to Distribution System Plan.

"DST" refers to Distribution System Technologist.

"DVA" refers to Deferral and Variance Accounts.

"EDS" refers to the OEB's Electricity Distributor Scorecard.

"**EHS**" refers to Environment, Health, and Safety.

"**EHSMS**" refers to the Environmental, Health, and Safety Management System.

"Electricity Act" refers to the *Electricity Act, 1998,* S.O. 1998, c. 15, Sched. A (Ontario), as amended.

"EMS" refers to emergency management services (i.e. police, fire, and ambulance).

"ERM" refers to Enterprise Risk Management.

"**ERP**" refers to an Enterprise Resource Planning system.

"ESA" refers to the Electrical Safety Authority.

"ESQR" refers to Electricity Service Quality Requirements as mandated by the OEB's Distribution System Code.

"EUSR" refers to the Electrical Utilities Safety Rules.

"EV" refers to Electric Vehicle.

"FESI" refers to Feeders Experiencing Sustained Interruptions.

"**Filing Requirements**" refers to Chapters 1, 2 and 5 of the OEB Filing Requirements for Electricity Distribution Rate Applications issued July 12, 2018.

"**FIM**" refers to Toronto Hydro's Feeder Investment Model.

"FTE" refers to full-time equivalent.

"**GEA**" or "**Green Energy Act**" refers to the *Green Energy and Green Economy Act, 2009*, S.O. 2009, C. 12 (Ontario), as amended.

"GEAR" refers to the Geospatially Enabled Asset Registry, a geospatial information system used by Toronto Hydro that provides a graphic representation of distribution assets and their relationship to other assets within Toronto Hydro's network.

"GIS" refers to the Geographical Information System.

"GWh" refers to a gigawatt-hour, a standard unit for measuring electrical energy produced or consumed over time. One GWh is the amount of electricity consumed by one million kWh.

"HR" refers to Human Resources.

"**HST**" refers to Harmonized Sales Tax.

"HV" refers to High Voltage.

"HVAC" refers to Heating, Ventilation, and Air-Conditioning.

"Hydro One" or **"HONI"** refers to Hydro One Networks Inc.

"HI" refers to Health Index.

"IAS" refers to International Accounting Standards.

"IEEE" refers to the Institute of Electrical and Electronic Engineers Inc.

"IESO" refers to the Independent Electricity System Operator.

"IFRS" refers to the International Financial Reporting Standards.

"IPPR" refers to Toronto Hydro's Investment Planning and Portfolio Reporting (process).

"IRRP" refers to the Integrated Regional Resource Plan.

"ISA" refers to an in-service addition of assets to the utility's rate base.

"**IT**" refers to Information Technology.

"ITIS" refers to the Interruption Tracking Information System.

"**IVR**" refers to the Interactive Voice Response technology that assists customers with their account management enquiries by providing updated account balances, payment option information, bill amount predictors and other related tools.

"Key Accounts" refers to large customers with average peak loads over 1 MW.

"kW" refers to a kilowatt, a common measure of electrical power equal to 1,000 Watts.

"kWh" refers to a kilowatt-hour, a standard unit for measuring electrical energy produced or consumed over time. One kWh is the amount of electricity consumed by ten 100 Watt light bulbs burning for one hour.

"LCA" refers to a Life Cycle Analysis.

"LDC" refers to Local Distribution Company.

"LEAP" refers to the financial assistance portion of the OEB's Low-Income Energy Assistance Program.

"LoS" refers to Loss of Supply.

"LRAM" refers to the Lost Revenue Adjustment Mechanism.

"LRAMVA" refers to the Lost Revenue Adjustment Mechanism Variance Account.

"LRT" refers to Light Rail Transit.

"LTEP" refers to the Ontario Long-Term Energy Plan.

"LV" refers to Low Voltage.

"MAIFI" refers to the Momentary Average Interruption Frequency Index.

"**MCR**" refers to the City of Toronto's Municipal Consent Requirements for the Installation of Plant Within City of Toronto Streets.

"MED" refers to major event days as defined by Institute of Electrical & Electronic Engineers Inc. specification 1366.

"**mIFRS**" or "**MIFRS**" refers to Modified IFRS.

"MS" refers to Municipal Station, a station within the distribution system which is supplied by feeders at 27.6 kV or 13.8 kV and steps down voltage to 13.8 kV or 4.16 kV.

"MW" refers to megawatt, a common measure of electrical power equal to one million watts.

"**NBV**" refers to Net Book Value.

"NERC" refers to the North American Electric Reliability Corporation.

"**OCCP**" refers to the Operational Centers Consolidation Program.

"OEB" refers to the Ontario Energy Board.

"OEM" refers to the Original Equipment Manufacturer.

"OHSA" refers to the *Occupational Health and Safety Act*, R.S.O. 1990, c. O.1.

"OM&A" refers to Operations, Maintenance, and Administration.

"OMERS" refers to the Ontario Municipal Employees Retirement System, a multi-employer, contributory, defined benefit pension plan established in 1962 by the Province for employees of municipalities, local boards and school boards in Ontario.

"**OMS**" refers to Toronto Hydro's Outage Management System.

"OPA" refers to the Ontario Power Authority.

"OPEBs" refers to Other Post-Employment Benefits.

"**OSC**" refers to the Ontario Securities Commission.

"OTO" refers to Orders to Operate.

"PCB" refers to polychlorinated bi-phenyl.

"**PILC**" refers to Paper-Insulated Lead-Covered (cable).

"PILs" refers to the Payment In Lieu of Corporate Taxes.

"**PP&E**" refers to Property, Plant, and Equipment.

"PPE" refers to Personal Protective Equipment.

"PSC" refers to Power System Controller.

"PSE" refers to Power System Engineering Inc.

"PWU" refers to Power Workers' Union.

"RCM" refers to Reliability Centered Maintenance.

"REI" refers to Renewable Improvements.

"**REG**" refers to Renewable Energy Generation.

"RFP" refers to Request for Proposal.

"RIP" refers to a Regional Infrastructure Plan.

"ROE" refers to Return on Equity.

"RPB" refers to Reverse Power Breaker.

"RRF" or **"RRFE"** refers to the OEB's policy for a Renewed Regulatory Framework for Electricity Distributors.

"RRR" refers to the OEB's Reporting & Record Keeping Requirements.

"RTU" refers to a Remote Terminal Unit.

"SAIDI" refers to the System Average Interruption Duration Index and is a measure (in hours) of the annual system average interruption duration for customers served, not including MED. SAIDI represents the quotient obtained by dividing the total customer hours of interruptions longer than one minute by the number of customers served.

"SAIFI" refers to the System Average Interruption Frequency Index and is a measure of the frequency of service interruptions for customers served, not including MED. SAIFI represents the quotient obtained by dividing the total number of customer interruptions longer than one minute by the number of customers served.

"SCADA" refers to Supervisory Control and Data Acquisition.

"Society" refers to the Society of Professional Engineers.

"**SSS**" refers to the OEB Standard Supply Service Code for Electricity Distributors.

"Toronto Hydro" refers to Toronto Hydro-Electric System Limited.

"**TOU**" refers to Time of Use billing practices

"TRIF" refers to Total Recordable Injury Frequency.

"TS" refers to Transformer Station, a point of power supply from the Hydro One transmission system that steps down supply voltage from 230 kV or 115 kV to 27.6 kV or 13.8 kV.

"TTC" refers to Toronto Transit Commission.

"URD" refers to Underground Residential Distribution.

"USGAAP" refers to United States Generally Accepted Accounting Principles.

"**USL**" refers to the Unmetered Scattered Load rate class.

"USofA" refers to the Uniform System of Accounts set out in the Accounting Procedures Handbook.

"Watt" or **"W"** refers to a common measure of electrical power. One Watt equals the power used when one ampere of current flows through an electrical circuit with a potential of one volt.

"WCA" refers to the Working Capital Allowance.

"**WMS**" refers to the Warehouse Management System.

"**WSIB**" refers to the Workplace Safety and Insurance Board.

"XLPE" refers to Cross-Linked Polyethylene

DISCLAIMER

The information in these materials is provided to the OEB for the purposes of Toronto Hydro's electricity distribution rates application pursuant to the OEB's Custom Incentive Rate-Setting framework (the "Application"). Toronto Hydro does not warrant the accuracy, reliability, completeness, or timeliness of the information and undertakes no obligation to revise or update these materials, except as required for purposes of providing new information that represents a material change to the evidentiary record in the Application before the OEB. Toronto Hydro (including its directors, officers, employees, agents, and subcontractors) hereby waives any and all liability for damages of whatever kind and nature which may occur or be suffered as a result of the use of these materials or reliance on the information therein.

These materials may also contain forward-looking information within the meaning of applicable securities laws in Canada ("Forward-Looking Information"). The purpose of the Forward-Looking Information is to provide Toronto Hydro's expectations and future operational, capital and revenue requirements for 2020 through 2024, and may not be appropriate for other purposes. All Forward-Looking Information is given pursuant to the "safe harbour" provisions of applicable Canadian securities legislation. All information, other than statements of historical fact, which address activities, events or developments that we expect or anticipate may or will occur in the future, are Forward-Looking Information. The words "aims", "anticipates", "believes", "budgets", "commits", "can", "could", "estimates", "expects", "focus", "forecasts", "future", "intends", "may", "might", "plans", "propose", "projects", "schedule", "seek", "should", "strives", "trend", "will", "would" , "objective", "outlook" or the negative or other variations of these words or other similar words or expressions are often intended to

identify Forward-Looking Information, although not all Forward-Looking Information contains these identifying words.

The Forward-Looking Information reflects the current beliefs of, and is based on information currently available to, Toronto Hydro's management. The Forward-Looking Information in these materials includes, but is not limited to, statements regarding Toronto Hydro's future results and performance, as well as expected nature, timing and cost of capital and operational programs. The statements that make up the Forward-Looking Information are based on estimates and assumptions made by the utility's management in light of past experience and perception of historical trends, current conditions and expected future developments, as well as other factors that management believes to be reasonable in the circumstances, including, but not limited to, expected load and customer growth, externally driven plant relocation requests, changes in funding requirements, no unforeseen delays and costs in capital projects, no unforeseen changes in the legislative and operating framework for electricity distribution in Ontario, the receipt of applicable regulatory approvals and requested rate orders, no unexpected delays in obtaining required approvals, the receipt of applicable IESO approvals, the ability of the utility to obtain and retain qualified staff, equipment and services in a timely and cost efficient manner, no unfavourable changes in government regulation, the level of interest rates and Toronto Hydro's ability to borrow, and all other assumptions regarding general business and economic conditions.

The Forward-Looking Information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the Forward-Looking Information. The factors which could cause results or events to differ from current expectations include, but are not limited to, risks

associated with the rate of deterioration of Toronto Hydro's assets; risks associated with execution of Toronto Hydro's capital and maintenance programs necessary to maintain the performance of our aging distribution assets and make required infrastructure improvements; risks associated with capital projects; risks associated with electricity industry regulatory developments and other governmental policy changes; risks associated with the timing and results of regulatory decisions regarding Toronto Hydro's revenue requirements, cost recovery and rates; risks associated with information system security and with maintaining complex information technology systems; risks associated with the possibility that advances in technology may compete with Toronto Hydro by affecting energy consumption levels and, as a result, customer demand for Toronto Hydro's services, risk to Toronto Hydro's facilities and operations posed by unexpected weather conditions caused by climate change and other factors, terrorism and pandemics; risks related to Toronto Hydro's work force demographic and its potential inability to attract, train and retain skilled employees; risks associated with possible labour disputes and Toronto Hydro's ability to negotiate appropriate collective agreements; unexpected increases or decreases in load and customer growth, and legislative, judicial or regulatory developments that could affect Toronto Hydro's ability to meet the goals set out in this application. Toronto Hydro cautions that this list of factors is not exclusive.

All Forward-Looking Information in these materials is qualified in its entirety by the above cautionary statements, except as required by law, or by the OEB for the purposes of the Application.

2020-2024 Custom Incentive Rate-Setting Application

EXECUTIVE SUMMARY AND BUSINESS PLAN OVERVIEW



1. OVERVIEW

Toronto Hydro Electric-System Limited ("Toronto Hydro" or the "utility") distributes electricity in the City of Toronto. The utility and its predecessors have met the electricity needs of the residents, businesses, and institutions of the municipality (and its predecessors) for over 100 years, performing a critical role in the community. In planning and carrying out its work, the utility is guided by the needs, preferences, and priorities of its customers and other stakeholders. Meeting Toronto's electricity requirements remains central to Toronto Hydro's purpose.

This Application covers the 2020-2024 period. The proposed rates are necessary to fund the utility's business plan for that period. For a residential customer, the utility's 5-year proposal would result in an average annual increase of $0.77 (1.7 percent) on Toronto Hydro's distribution portion of the bill, or a $0.56 (0.4 percent) increase on the overall electricity bill. For the first year of the plan, 2020, residential customers will experience a decrease of $3.10 on the overall electricity bill.[1]

Toronto Hydro's plan was developed in consultation with its customers, having regard to how the utility's costs and performance compare with its peers (i.e. benchmarking), and with the objective of producing outcomes that customers value. These external inputs were combined with Toronto Hydro's knowledge and experience of the state of its distribution system infrastructure, and the other considerations that inform good utility practice and long-term performance. As part of its due diligence, and recognizing the

[1] All figures in this paragraph are for the monthly bill of a customer in the Residential rate class who uses 750 kWh of electricity. Bill impacts for other Residential customer profiles and other customer classes, and the only tariff (Wireline Attachment Rate) being updated in this Application, are explained in detail at Exhibit 1B, Tab 5, Schedule 1; and Exhibit 8, Tab 1, Schedule 1, and for quick reference, are included in a summary chart as Appendix "A" to this Exhibit.

value of third party perspective, Toronto Hydro engaged external experts to review significant parts of the plan and is filing their work product as part of the Application.

This is the second five-year plan filed by Toronto Hydro. The plan largely continues the methodology approved by the OEB for the 2015-2019 period. As with the 2015-2019 plan, the 2020-2024 plan reflects a Custom Incentive Rate-setting ("CIR") methodology that is aligned with OEB policy guidance.

This plan continues the utility's effort to renew a significant backlog of deteriorated and obsolete assets at risk of failure, and to adapt to the continuously evolving challenge of serving, and operating within a dense, mature, and growing major city. Efforts to date have resulted in gradual improvements to reliability, the overall age of the system, and other performance indicators.

Despite these indicators of progress, investing in the short-term performance and long-term viability of an aged, deteriorated, and highly utilized system remains an urgent priority for the utility (see Figure 1, below). Recent extreme weather events, accompanied by growing evidence of the impact of climate change on weather patterns in Toronto, have amplified this need, underscoring the challenge to build a resilient system for the long-term. At the same time, technology and innovation are driving a more dynamic system that is transitioning away from the usual patterns of supply and demand, adding additional complexity and urgency to the challenge of modernizing the grid, which in turn is driving investment needs in information technology and cyber security solutions.



Figure 1: Toronto Hydro at Work

The evidence that supports the Application is the utility's business plan. Organized according and in response to the OEB's Filing Requirements, Toronto Hydro's plan for 2020-2024 is the result of thorough business planning in which customers' needs and preferences were integrated from start to finish. The plan is expected to produce performance outcomes that customers value and are willing to financially support through their distribution rates. With the funding that these rates would provide, Toronto Hydro expects to continue to meet the needs of its customers.

Toronto Hydro is continuing the commitments made in its last application, while remaining responsive to challenges inherent in its operating environment. This performance-based plan is about ensuring Toronto Hydro is able to meet the needs and preferences of its customers today and in the future, including maintaining overall system performance and addressing specific areas requiring improvement.

2. ABOUT TORONTO HYDRO

Toronto Hydro is licensed by the OEB to serve the City of Toronto.[2] See Figure 2, below, for a map of Toronto Hydro's service territory. Toronto Hydro is the successor to the six former hydro-electric commissions of the municipalities which amalgamated on January 1, 1998 to form the City of Toronto. The utility is a wholly-owned subsidiary of Toronto Hydro Corporation, whose sole shareholder is the City of Toronto.[3]



Figure 2: Toronto Hydro's Service Territory

As of 2020, Toronto Hydro forecasts distributing electricity to 784,330 customers who are forecasted to consume over 24 TWh[4] of power that year.[5] Toronto Hydro serves them using approximately 30,000 kilometres of wire and cable, 180,000 poles, and over

[2] Electricity Distribution Licence ED-2002-0497.
[3] To learn more about Toronto Hydro's Corporate Structure and Governance, please refer to Exhibit 1C, Tab 2, Schedule 1.
[4] 24 TWh (terawatt hours) is equal to 24,000,000,000,000 watt hours of electricity. It is the equivalent of running 1 million 60 watt light bulbs non-stop for over 45 years.
[5] For more information about Toronto Hydro's load forecast, please refer to Exhibit 3, Tab 1, Schedule 1.

200 stations and substations. This is a 4.9 percent increase in customer count but a 4.0 percent decrease in power consumption over 2015.[6]

Toronto Hydro's customers range from residential consumers in single family dwellings and multi-unit buildings to large industrial and commercial businesses. These include the country's largest banks, stock exchanges and other large customers that are sensitive to service interruptions. The utility powers non-residential customers from a wide variety of sectors, including: dozens of accounts for hospitals and healthcare and long-term care facilities; hundreds of accounts for schools, colleges, and universities; data centres; and large industrial and manufacturing facilities. Toronto Hydro also supplies electricity to Ontario's Provincial Legislature and Ministries, as well as Toronto's municipal government. The utility also serves thousands of multi-unit residential condominium and apartment buildings, each of which can have dozens or hundreds of units.[7]

3. CUSTOMER ENGAGEMENT AND THE BUSINESS PLAN

Toronto Hydro began the process of developing its business plan by engaging its customers. Feedback from customers was that price, reliability, and safety were their top three priorities. Their other priorities related to customer service, environment, and public policy.[8] Considering this feedback and other inputs (as discussed below), Toronto Hydro established the following strategic parameters for its business plan:

1) **Price Limit:** Toronto Hydro set an upper limit of 3.5 percent as a cap on the average annual increase to base distribution rates.[9]

[6] For more information about Toronto Hydro's distribution system, please refer to Exhibit 1C, Tab 1, Schedules 1 and 2; and Exhibit 2B, Section D2.
[7] To learn more about the breadth and diversity of Toronto Hydro's customer base, please refer to Exhibit 1B, Tab 3.
[8] Please see Customer Engagement evidence at Exhibit 1B, Tab 3, Schedule 1.
[9] As calculated for the monthly bill of a Residential customer using 750 kWh.

2) **Budget Limits**: Toronto Hydro set upper limits of approximately $560 million for the average annual capital plan budget and $277 million for the 2020 operational plan budget, which corresponded with capping infrastructure and operations spending predominantly at sustainment levels.
3) **Performance:** Toronto Hydro developed an Outcomes Framework that established a lens through which the utility could express its plans and performance in terms that demonstrate value for customers, and are meaningful to its operations.

Toronto Hydro's business plan and this Application are aligned with these strategic parameters:

- The average annual increase to base distribution rates associated with Toronto Hydro's plan is approximately 3.0 percent;[10]
- Toronto Hydro's capital and operational budgets that underlie the plan are consistent with the caps the utility established; and
- Toronto Hydro's Outcomes Framework reflects customer priorities, Toronto Hydro's operational pillars, and the OEB's performance categories, and includes 44 measures to track its performance.[11]

Customer preferences and priorities informed Toronto Hydro's development of its business plan throughout the preparation of the utility's capital and operational plans. For example, Toronto Hydro eliminated approximately $75 million per year from its capital plan in response to the price limit noted above.

[10] As calculated for the monthly bill of a Residential customer using 750 kWh. When rate riders are included, the impact drops to 1.7 percent.
[11] For more information on Toronto Hydro's Outcomes Framework, please see Exhibit 1B, Tab 2, Schedule 1.

Prior to filing this Application, Toronto Hydro returned to customers with the key details of its penultimate plan and asked customers for their feedback. Customers were also provided with options of supporting more or less investment, including with respect to the plans for specific types of work, such as Rear-Lot Conversions, Underground Network Transformers, and Microgrids. See Figure 3, below, for an example of the type of work addressed as part of Rear-Lot Conversions.

After making their own preliminary choices, customers were provided with the total price implications of those choices and invited to change their selections.



Figure 3: Legacy Rear Lot Supply Conversion

Through this interactive, iterative customer engagement process, Toronto Hydro obtained valuable insights about the plan at the aggregate and detailed levels. A majority of customers in all customer classes supported the plan or an accelerated

version of it, including the associated price increase.[12] Many customers were willing to pay for an accelerated plan with a higher price impact. However, certain parts of the plan, such as Microgrids, did not receive strong customer support.[13] This customer feedback assisted Toronto Hydro in further refining and finalizing its plan: the result is this business plan and Application.[14]

4. MAJOR CHALLENGES

Toronto Hydro faces a number of significant and urgent challenges in building and operating its distribution system, and responding to the outcomes that customers prioritized. In order to ensure that overall system performance is maintained and specific areas requiring improvement are addressed in 2020 to 2024 and beyond, Toronto Hydro has developed capital and operating plans focused on managing a number of challenges and associated risks.[15] In developing its 2020-2024 business plan, the utility took into account a large number of operating considerations and investment drivers, which are discussed within each of the programs.[16] There are also a number of significant macro challenges that affect the broader business plan. These include deteriorating infrastructure, the growing city, extreme weather, workforce retirements, and technology advancements (including cyber threats), which are discussed in turn below.

[12] Telephone survey results for the plan received 71 percent Residential, 55 percent Small Business and 73 percent Mid-Market customer support. The majority of Key Account customers interviewed (25 out of 37) supported the utility's plan. See Exhibit 1B, Tab 3, Schedule 1, Appendix A.
[13] Phase 1 feedback from customers indicated that microgrids had a degree of customer support. Through Phase 2, Toronto Hydro tested the statistical significance of that support.
[14] Details of Toronto Hydro's customer engagement process and the ways in which it integrated its results into its business plan and this Application can be found throughout the evidence (especially Exhibit 1B, Tab 3, Schedule 1; and Exhibit 2B, Section E2).
[15] For a comprehensive overview of Toronto Hydro's 2020-2024 Distribution System Plan and the key elements driving the level and mix of capital expenditures, please refer to Exhibit 2B, Section A.
[16] To learn more about Toronto Hydro's challenges and cost drivers, please refer to Exhibit 2B, Sections D2 and E; and Exhibit 4A, Tab 2.

4.1 Deteriorating Infrastructure

Toronto Hydro operates in a mature, congested urban environment, which presents significant cost and operating challenges. For instance, Figure 4, below, provides an example of aging box construction feeders from the pre-amalgamation City of Toronto.

In undertaking its capital and operational work, the utility contends with complexities including:

- The intensification of development (such as condominium complexes, transit extensions, and community redevelopments);
- Limited space for utility equipment installation, over a century of construction by various agencies in the public right-of-way and on private properties, often with missing or inaccurate historical records;
- Coordination with other City and utility reconstruction programs; and
- A densely populated downtown core, served by a complex arrangement of equipment that is unique in its span and configuration in Ontario's distribution sector.



Figure 4: Box Construction in a Backyard with Leaking Equipment

Toronto Hydro's distribution system faces a number of significant and evolving challenges that drive the need for the proposed level of investment. As seen in Figure 5, below, approximately a quarter of the utility's asset base continues to operate beyond useful life, and an estimated 9 percent will reach that point by 2025, indicating that a significant, proactive renewal program is necessary to prevent the investment backlog from increasing. Toronto Hydro anticipates that an increase in the backlog of assets past useful life would result in a deterioration in reliability, safety, and other outcomes driven by asset failure. Defective equipment continues to be, by far, the largest contributor to the frequency (36 percent), and duration (44 percent) of outages.

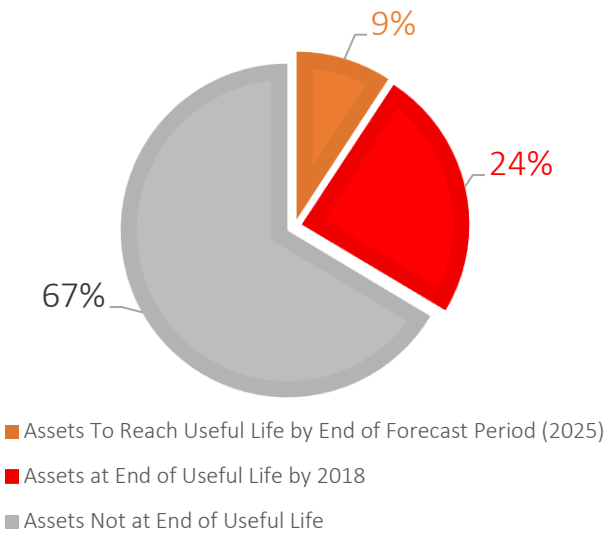


Figure 5: Percentage of Assets Past Useful Life

Asset Condition Assessment demographic results also indicate substantial asset investment needs for a number of critical asset classes over the plan period. Among the subset of asset classes that Toronto Hydro analyzed, major civil assets like poles and vaults, and major stations electrical assets are showing the greatest signs of material

deterioration. These types of assets are the backbone of a safe and viable distribution system, and tend to have a high reliability effect on the system.

4.2 Growing City

By 2020, Toronto Hydro expects to be distributing 24 TWh of electricity to approximately 784,000 customers. This continues a steady trajectory of customer growth and it is expected to continue. Further, Toronto continues to experience concentrated load growth in certain areas of the City, primarily due to the high number of large condominium developments. This concentrated growth is mainly observed in the downtown area, but also along major transit corridors such as Yonge Street and Sheppard Avenue (and in the near future other corridors, such as Eglinton Avenue and Finch Avenue). This growth is pushing certain distribution equipment to capacity. Infrastructure renewal and upgrades are urgently required to support that growth while maintaining reliability and safety outcomes.

Toronto's concentrated load growth is due in part to the high number of large condominium developments in certain parts of the city. Figure 6, below, illustrates that Toronto has more buildings under construction than most North American cities, and a number of high-rise and mid-rise buildings under construction at a rate comparable to New York.

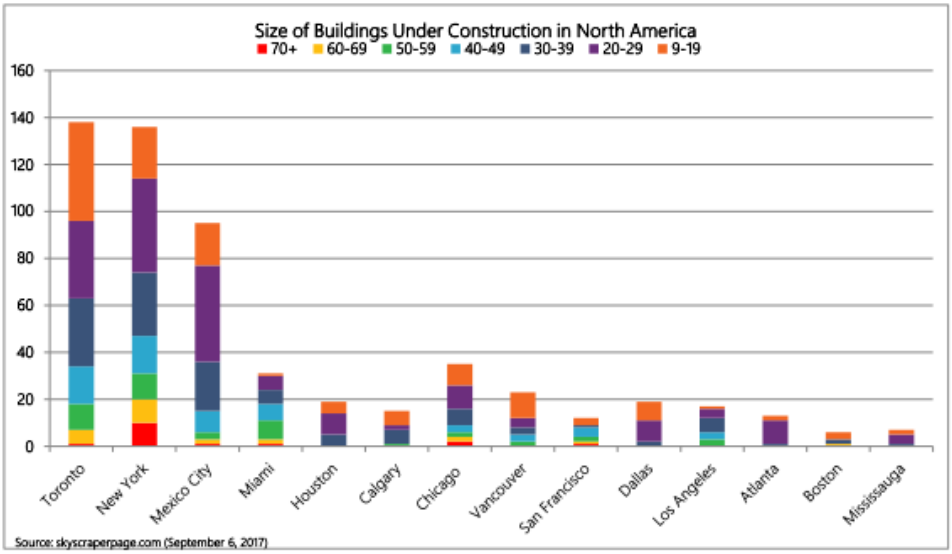


Figure 6: Number of Floors in High-Rise & Mid-Rise Buildings under Construction[17]

4.3 Extreme Weather

Distributing electricity to a city of Toronto's size and complexity is operationally challenging. When extreme weather is factored in, this challenge is amplified. As evidenced by recent events, extreme weather is no longer an infrequent experience; it has become a regular condition of operating a distribution system. It necessarily changes how the utility must plan its infrastructure, execute its plans, and respond to emergencies.

Recent extreme weather events such as wind and ice storms outlined in Table 1, below, have repeatedly and pervasively affected Toronto Hydro's customers.

[17] Toronto Economic Bulletin (September 26, 2017), available at: <https://www.toronto.ca/legdocs/mmis/2017/ed/bgrd/backgroundfile-107204.pdf>.

Table 1: 18 Months of Extreme Weather (January 2017 through June 2018)

Event	Description
Freezing Rain (February 2017)	• Approximately 2-6 mm of freezing rain followed by additional heavy rain. • Estimated 9,200 customers out at peak; all customers restored within 24 hours of the start of the freezing rain event.
High-water/flooding (May - June 2017)	• Heavy rainfall in southern Ontario exceeded the yearly average for an entire summer. • Numerous incidents of high-water/flooding reported across Toronto. • No customers were directly impacted during this 55-day incident due to the utility's proactive damage assessment and DPM mitigation measures, including flood mitigation efforts.
Wind Storm (October 2017)	• Strong wind gusts approaching 100 km/h in some areas and lasting approximately 3 hours. • Estimated 43,000 customers out at peak. • 90 percent of customers restored within 11 hours of event; all customers restored within 48 hours of the end of the event.
Wind storm (April 2018)	• Sustained 65 km/h winds, with gusts approaching 90 km/h. • Estimated 24,000 customers out at peak; all customers restored within 48 hours of the end of the event.
Ice Storm (April 2018)	• Approximately 10-20 mm of freezing rain, 20-25 mm rain, sustained winds of 70 km/h with gusts up to 110 km/h. • Estimated 51,000 customers out at peak. • 99 percent of customers restored within first two days of response; all impacted customers restored within 5 days of the start of the event.
Wind Storm (May 2018)	• High winds reported throughout service territory with gusts reaching approximately 120 km/h. • Estimated 68,000 customers out at peak. • 96 percent of customers restored within 48 hours of the start of the event.
Flash Storm (June 2018)	• High winds reported throughout service territory with gusts reaching approximately 90-100 km/h. • Estimated 16,500 customers out at peak. • 86 percent of customers restored within the first 12 hours and 97 percent of customers restored within the first 24 hours of the event.

Extreme weather events in 2017 resulted in a 72 percent increase in the number of customer interruptions attributed to tree contacts compared to the average of the previous five years. Similarly, in 2018, Toronto Hydro experienced four extreme storms during the first half of the year, leaving nearly 160,000 customers without electricity.



Figure 7: Damage due to Weather Events

Climate change affects different parts of the distribution system in different ways. The overhead system is susceptible to extreme winds, freezing rain and wet snow resulting in damage and outages. Broken trees and the weight of ice and snow accretions can bring lines, poles and associated equipment to the ground. Figure 7, above, are some examples of line damage caused by the recent weather-related events in the City of Toronto. The underground system is vulnerable to flooding from extreme rainfall. For instance, extreme rainfall in April and May of 2017 caused a number of Toronto Hydro's vaults and cable chambers in the underground system to flood. One particular network vault in Toronto's downtown core experienced severe flooding, causing a network protector to fail. This resulted in a lengthy outage in the financial district with significant disruption to customers, a closure of a busy arterial road during afternoon rush hour, and significant public and media attention.

In addition to extreme weather events, Toronto experiences a wide range of weather conditions that may not be classified as extreme, but nevertheless have the potential to adversely affect the distribution system at various times during the year. Heat, high winds, heavy rainfall, freezing rain, and heavy snowfall cause major system damage. They also make restoration more challenging, and prolong outages.

4.4 Workforce Retirements

Toronto Hydro employees are essential in executing planned and reactive work programs that are necessary to maintain the distribution system's integrity, mitigate unacceptable risks in the areas of reliability and safety, and operate the system. Toronto Hydro is in the midst of a significant renewal of its workforce, with approximately 23 percent of its workforce (or approximately 340 FTEs) forecasted to retire between 2020 and 2024. Of that number, approximately 80 percent are from the utility's staffing categories that directly maintain and operate the distribution system (e.g. certified and skilled trades, designated and technical professionals, and supervisory positions). These personnel are critical to maintaining and operating the distribution system in a safe and efficient manner, and filling these roles can be especially challenging and can take up to six years to train. Recruitment and retention are particularly challenging in Toronto's competitive job market and with quickly escalating costs of living in the City and neighbouring communities.

4.5 Technology Advancements

Technology advancements are a major challenge in the electricity distribution sector globally, and is in many ways greater for distributors in major urban centres. A prominent example of that challenge is the complexity of integrating distributed energy

resources on heavily loaded feeders in dense areas that serve customers sensitive to power quality. A dangerous example of that challenge is cyber threats.[18]

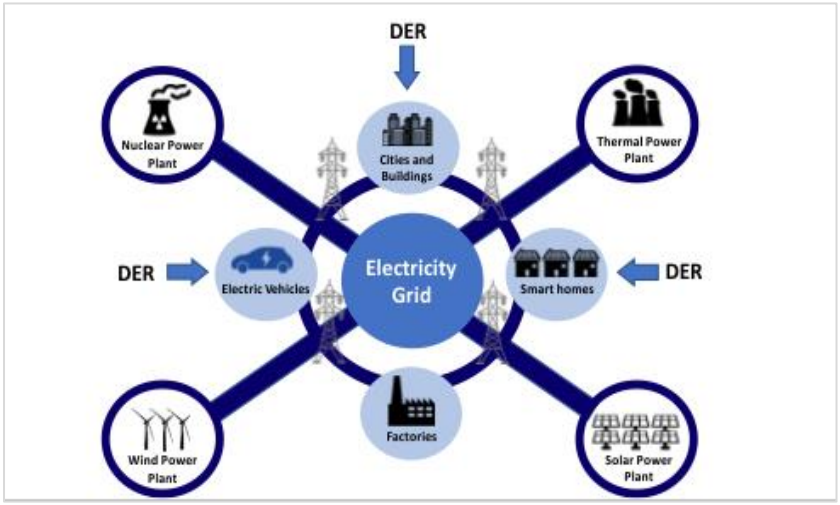


Figure 8: Distributed Energy Resources Interacting with the Electricity Grid[19]

Technology and innovation are driving a more dynamic system that is transitioning away from usual patterns of supply and demand towards more complex interactions and inputs in electricity generated and consumed (Figure 8, above). The role of the utility continues to evolve to support the new smart grid ecosystem, comprising renewable and other distributed energy resources, microgrids, electric vehicles, and growing interest in energy storage for power quality, off-peak storage, and grid resilience. See Figure 9, below, for an example of Toronto Hydro crews installing a pole-mounted

[18] Toronto Hydro works closely with the OEB on regulatory policy with respect to these challenges. In particular, on the OEB Chair's Advisory Committee on Innovation:
< https://www.oeb.ca/sites/default/files/Advisory-Committee-on-Innovation-terms-of-reference.pdf> and the OEB Policy Steering Committee that helped develop the Ontario Cyber Security Framework (December 6, 2017): <https://www.oeb.ca/sites/default/files/Ontario-Cyber-Security-Framework-20171206.pdf>.
[19] Exhibit 2B, Section 8.1, Appendix A.

energy storage system. This dynamic introduces new variables that the utility proposes to address through its business plan.



Figure 9: Installation of Pole-Mounted Energy Storage Systems

Interest in generation projects within Toronto Hydro's service territory has steadily increased in recent years, and Toronto Hydro expects it to continue into the future: the utility has connected approximately 1,800 distributed generation connections. Toronto Hydro is regularly approached by its customers to discuss utility options for or capacity to facilitate net metering and battery energy storage. Inquiries regarding conventional generators have also increased as micro-turbine based installations become more economically viable and commercial and industrial customers attempt to increase site reliability and operational cost savings. These developments require Toronto Hydro to take on functions historically managed by transmission utilities.[20]

[20] Discussed further in Exhibit 2B, Section E8.1, Appendix A.

Another type of technological advancement challenge is protecting the utility and its customers from cyber threats, which has emerged in recent years as an urgent challenge for Toronto Hydro.[21] While smart grid systems, infrastructure automation, and other technological advancements by Toronto Hydro and its customers offer significant opportunities, they also increase the exposure of the grid and those connected to it to greater risk of attack by hostile actors. This global challenge is particularly acute in major economic centres, such as Toronto. Electric utilities are targets for security breaches because of the critical role they play in enabling essential service providers (e.g. hospitals, public transit, water treatment systems, communications, and traffic management) and the vast databases of confidential customer information they possess.[22]

5. PERFORMANCE AND CONTINUOUS IMPROVEMENT

Toronto Hydro has created a customer-focused outcomes framework (the "Outcomes Framework") for the 2020-2024 period that facilitates continuous improvement and measures the effectiveness of the utility's plans through the implementation of 15 custom performance measures for a total of 44 unique measures to be reported to the OEB annually (see discussion below). These outcomes are expressions of the utility's goals and objectives. As set out in Figure 10, the Outcomes Framework links customer priorities with the programs that constitute the capital and operational plans.

[21] For more information on Toronto Hydro's proposed investments to assist with cyber security, please refer to Exhibit 2B, Section E8.2; Exhibit 2B Section E8.4; and Exhibit 4A, Tab 2, Schedule 17.
[22] The OEB recently issued a regulatory response through its Cyber Security Framework (December 6, 2017) : <https://www.oeb.ca/sites/default/files/Ontario-Cyber-Security-Framework-20171206.pdf>.

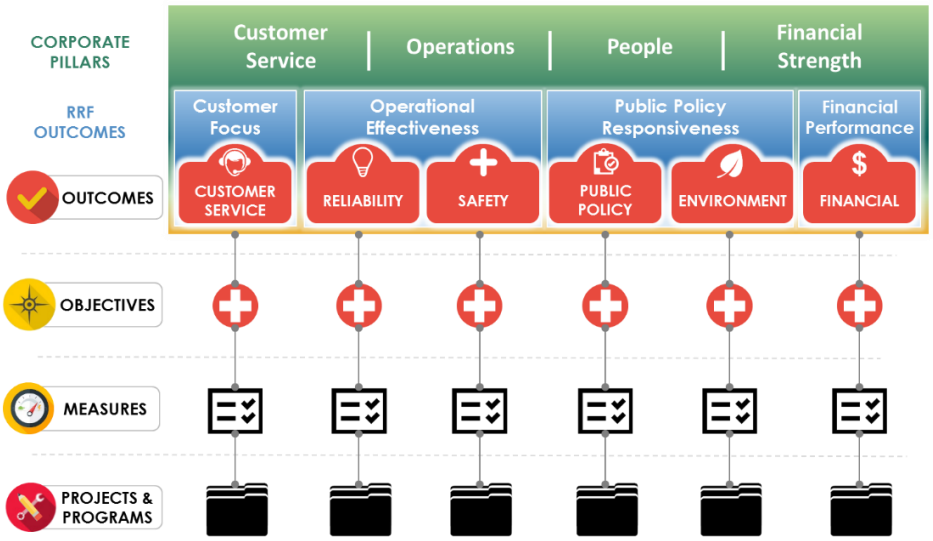


Figure 10: Outcomes Framework

This framework and its associated measures provides customers, the OEB and other stakeholders, both qualitative and quantitative assessment tools for Toronto Hydro's performance during this plan period (2020 to 2024), as well as quantitative insight into Toronto Hydro's strong performance during the last plan period (2015 to 2019).

5.1 Performance-Based Plan

To remain responsive to customer needs and preferences and demonstrate continuous improvement in performance setting and tracking, Toronto Hydro has proposed 15 custom measures within its Outcomes Framework that are incremental to measures tracked and assessed by the OEB, for a total of 44 measures to be reported annually. Table 2, below, shows the number of performance measures within each Outcomes categories. Toronto Hydro's proposed custom measures reflect a thorough understanding of customer priorities and provide assurance that value for money will be achieved through the utility's capital and operational plans.

Table 2: Outcomes and Performance Measures

Toronto Hydro Outcome	OEB Reporting Category	Performance Measures
Customer Service	Service Quality	9
	Customer Satisfaction	5
Safety	Safety	7
Reliability	System Reliability	6
	Asset Management	4
Financial	Cost Control	5
	Financial Ratios	3
Public Policy	Conservation and Demand Management	1
	Connecting Renewable Generation	2
Environment	Environment	2
Total Performance Measures		44

Toronto Hydro has proposed a ratemaking framework for this Application that provides incentives for the utility to seek out further productivity and efficiency improvements over the 2020-2024 period. This framework also requires the utility to share the benefits of these improvements with its customers.

As discussed above, Toronto Hydro structured the business plan around the Outcomes Framework. The capital and operational plans, aligned with that framework, are focused on advancing objectives for the outcome categories, as assessed using performance measures.

5.2 Performance Measurement and Management

Toronto Hydro is an efficient organization that strives to continue its history of performance, productivity, and customer cost savings, including its commitment to a strong performance management culture. Inherent in its focus on outputs and value is

an emphasis on measuring and tracking performance, using internal and external benchmarking.

The OEB established performance metrics for electricity distributors through its Electricity Distributor Scorecard ("EDS") to assess utility performance over time and to compare performance across utilities. Toronto Hydro's performance on the EDS has been strong, including improvements in customer first contact resolution, telephone calls answered on time, new residential and small business services completed on time, and billing accuracy. Table 3, below, provides a snapshot of Toronto Hydro's strong performance, indicating that the utility has met or exceeded OEB standards over the last five years.

Table 3: Snapshot of Toronto Hydro's Strong Performance in the Last Five Years

Performance Categories	Measures	2013	2014	2015	2016	2017	Industry
Service Quality	New Residential/Small Business Services Connected on Time	94.2%	91.5%	96.9%	97.0%	**98.3%**	90.0%
	Scheduled Appointments Met On Time	99.6%	99.8%	99.9%	99.5%	**99.4%**	90.0%
	Telephone Calls Answered On Time	82.0%	71.9%	76.8%	64.7%	**77.9%**	65.0%
Customer Satisfaction	Billing Accuracy	-	96.6%	97.5%	98.8%	**99.2%**	98.0%

In addition, from 2013-2017, Toronto Hydro achieved or exceeded the OEB's Electricity Service Quality Requirements ("ESQR") standards 85 percent of the time. In 2017, for instance, the utility met or surpassed the OEB's standards for 11 out of the 12 measures (92 percent). In respect of outages, Toronto Hydro's has slightly improved its number and frequency of customer interruptions in the last five years, and its performance has been equal to or better than the distributor target from 2013-2017. This achievement is attributable to the investments the utility has made in the system.

Further, in addition to its performance on scorecard and service quality measures, Toronto Hydro's framework of current and future productivity processes and initiatives emphasize increasingly sophisticated performance measurement tools, including new efficiency opportunities such as reducing manual, labour-intensive processes through streamlining and technological improvements. Most recently, Toronto Hydro has improved its processes and provided demonstrable cost savings in areas such as safety, facilities management, fleet size, feeder scheduling, and eBilling.[23]

5.3 Completing Major Capital Programs

For several years, Toronto Hydro has focussed on delivering a significant and ongoing capital plan to improve the safety and reliability of the distribution system and deliver service levels aligned with the needs and preferences of its customers. By the end of 2019, a number of the utility's initiatives are on-track to be substantially complete, including:[24]

- The Operating Cost Centre Consolidation Program ("OCCP"), which involved the consolidation of Toronto Hydro's operating centres to optimize the utility's use of space and decrease property costs, as well as return net gains on sales to ratepayers. [25]
- Paper-Insulated Lead-Covered ("PILC") Cable Leakers and Piece-Outs Program, which involved replacing and repairing aging and defective PILC cables, reducing reliability, safety, and environmental risks.[26]

[23] For further details, please see Exhibit 2B, Sections E8.2 and 8.3; and Exhibit 4A, Tab 2, Schedule 1-3, 11-15.
[24] For a complete list of programs to be completed during 2015-2019, please see Exhibit 2B, Section E4.
[25] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 5, 2016), Exhibit 2B, Section E8.3.
[26] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 5, 2016), Exhibit 2B, Section E6.2.

- Overhead Infrastructure Relocation Program, which involved replacing feeders that were in difficult to access locations or high-risk location (e.g. ravines and overhead highway crossings), reducing system reliability and safety risks. [27]
- Copeland Station, an underground transformer station (see Figure 11, below) that will add capacity equivalent to 70 skyscrapers to the downtown core, helping to ensure that Toronto continues to receive safe and reliable electricity in the face of growth and pressures on system capacity.[28]



Figure 11: Copeland TS

[27] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 5, 2016), Exhibit 2B, Section E6.5.
[28] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 5, 2016), Exhibit 2B, Section E7.9.

5.4 System Stewardship

To assess the age demographics of its distribution system, Toronto Hydro examines the proportion of assets past useful life ("APUL"). In 2015, Toronto Hydro's percentage of APUL was 26 percent, with an additional 7 percent forecasted to reach the end of their expected useful life by 2020. As a result of Toronto Hydro's ongoing renewal programs, the APUL measure is no longer deteriorating as it did prior to 2014. A continued decline in APUL would have led to a corresponding deterioration in reliability, safety risk, reactive replacement costs, and other outcomes driven by asset failure.

The decrease in APUL has also strengthened the reliability of the system, which is one of the top three priorities of customers. Since the mid-2000s, reliability had been deteriorating. However, through investments in these assets, reliability has stabilized. As shown in Figures 12 and 13, below, the frequency and duration of outages have essentially plateaued, with slight improvements in the last five years.

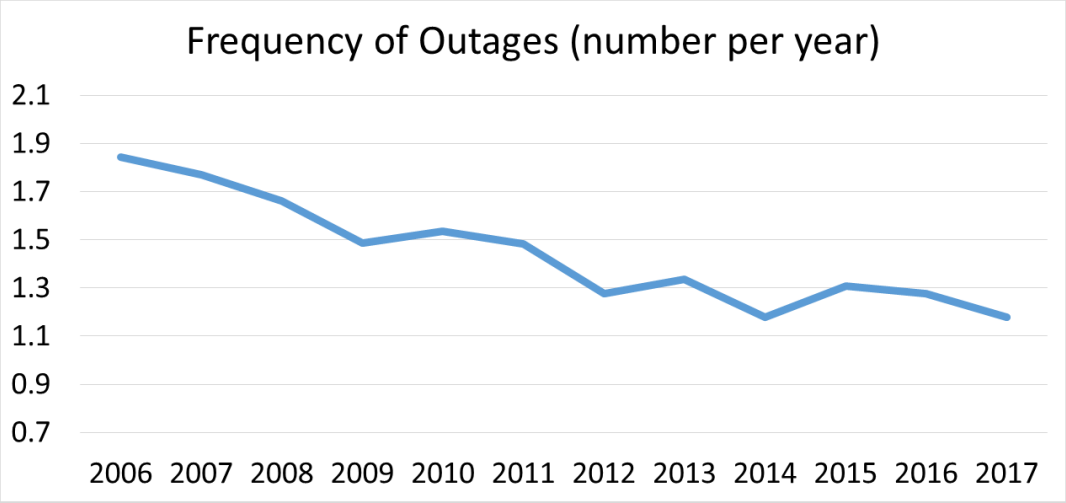


Figure 12: Historical SAIFI[29]

[29] Excluding MEDs and Loss of Supply.

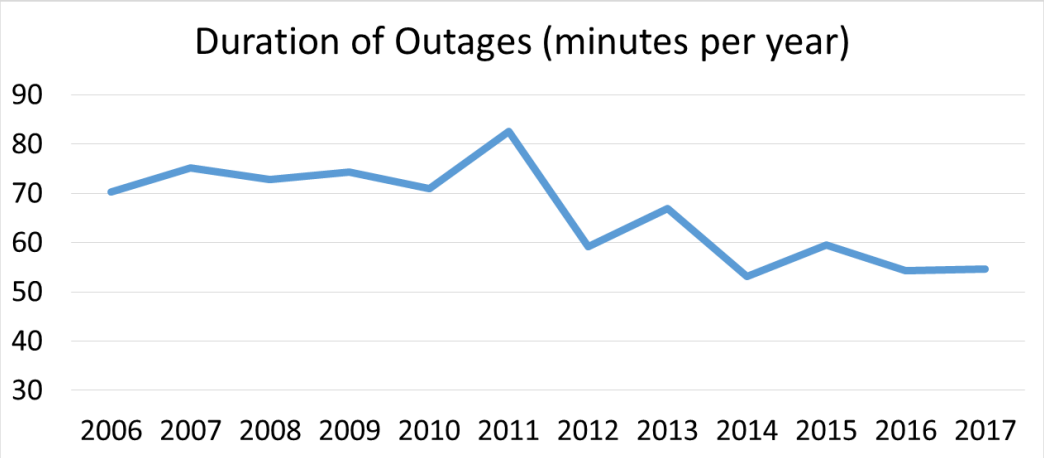


Figure 13: Historical SAIDI[30]

There is still a large population of assets past their useful life. Continued investment is required to ensure there is no deterioration in recently stabilized system performance.

5.5 Analytic Tools

Toronto Hydro also took a significant step forward in further establishing the link between its capital plans, operational plans, and asset condition by adopting a best in class methodology which has helped improve the sophistication of Toronto Hydro's plans, consistent with the utility's drive for continuous improvement. It is also responsive to guidance received from the OEB that such deeper analysis would be helpful to understanding and supporting Toronto Hydro's large, complex capital plan.[31]

6. OVERVIEW OF THE 2020 TO 2024 CAPITAL AND OPERATIONAL PLANS

The plans for Toronto Hydro's capital and operational programs included in this Application are central elements of the utility's business plan. Capital plans address

[30] Excluding MEDs and Loss of Supply.
[31] For a detailed discussion on Toronto Hydro's ACA methodology (the Common Network Assets Indices Methodology), please see Exhibit 2B, Section D, Appendix C.

investments in distribution system infrastructure as well as other investments in supporting facilities and equipment, such as system control centres, fleet vehicles (see Figure 14, below), and data management software.[32] Operational plans address day-to-day activities, such as emergency response to outages, system infrastructure inspections, and employee training.[33]



Figure 14: Example of Toronto Hydro's Fleet Vehicles

The 2020-2024 plan strikes a balance between these pressing needs and customer preferences for: (i) keeping prices as low as possible; (ii) maintaining average reliability; (iii) improving reliability for customers experiencing below-average service; and (iv) balancing other priorities (e.g. customer service) with the need to contain rate increases. The resulting five-year plan represents the minimum level of investment

[32] See Exhibit 2B, Section E.
[33] See Exhibit 4A, Tab 2.

needed to ensure this balance is achieved, while avoiding the accumulation of risk and associated declines in performance over the long-term.

These plans are driven by urgent needs that, if not adequately addressed, will create significant risks to Toronto Hydro's ability to meet customer-valued outcomes, including maintaining the safety and reliability of the distribution system. In some cases, these risks will materialize in the near term, such as lack of capacity to connect new customers or accommodate urban intensification. However, in many cases, the risks will materialize in the medium or long term, such as more outages that are more frequent, longer, and more expensive to resolve. If its plans are not completed, Toronto Hydro could fall out of compliance with new or existing legislative and regulatory obligations.

6.1 Price Constrained Plans

Toronto Hydro developed and refined its capital and operational plans having regard to customer feedback that limiting price increases was a paramount concern, to the degree that doing so would not adversely affect service performance, and that performance would improve in certain areas.

Accordingly, Toronto Hydro's plans do not include all the reasonable funding requests that it would propose as appropriate given the needs of the system. For example, Toronto Hydro has constrained its capital plan that underlies its proposed rate increase to an annual average of $562 million average per year, even though a higher level is preferable from an asset management perspective to better manage certain elevated asset risks such as those associated with rear lot plant and direct-buried cable.[34]

[34] To learn more about the details of Toronto Hydro's approach to business and financial planning, as well as its specific approaches to building the capital and OM&A proposals contained within this application, please see Exhibit 2B; and Exhibit 4A.

Reducing these risks sooner would support lower total asset lifecycle costs over the longer-term by mitigating higher reactive replacement costs and the avoidable costs associated with repeatedly visiting project areas to repair assets that could be rebuilt more economically on a planned basis.

Nevertheless, Toronto Hydro has calibrated a plan that strikes an appropriate balance: the plans propose the minimum level of investment needed to ensure this balance, while managing the major challenges facing the utility and achieving long-term performance. Customers agreed: majority of residential, small business, mid-market and large (i.e. key account) customers supported the plan, or one that does even more.

6.2 Capital Plan

Toronto Hydro's capital plan is set out in the Distribution System Plan ("DSP").[35] This part of its business plan is organized into 20 programs, each of which is driven by similar urgent system needs and customer priorities. These programs address direct distribution needs such as ensuring that customers can connect to the distribution system (i.e. system access),[36] continuing the needed repairs and replacements of deteriorating infrastructure (i.e. system renewal),[37] and enhancing the functionality of the system, such as by increasing what it can receive from the transmission system and through better monitoring equipment (i.e. system service).[38] Figure 15, below, provides an example of a vault with Network Condition Monitoring and Control equipment installed.

[35] See Exhibit 2B.
[36] See Exhibit 2B, Section E5.
[37] See Exhibit 2B, Section E6.
[38] See Exhibit 2B, Section E7.

These programs also address supportive distribution needs such as investments in fleet vehicles, data management systems, and other assets that indirectly support the distribution system (i.e. general plant).[39] All these programs are necessary to safely and reliability power the City of Toronto and to be responsive to other customer needs, preferences, and priorities.

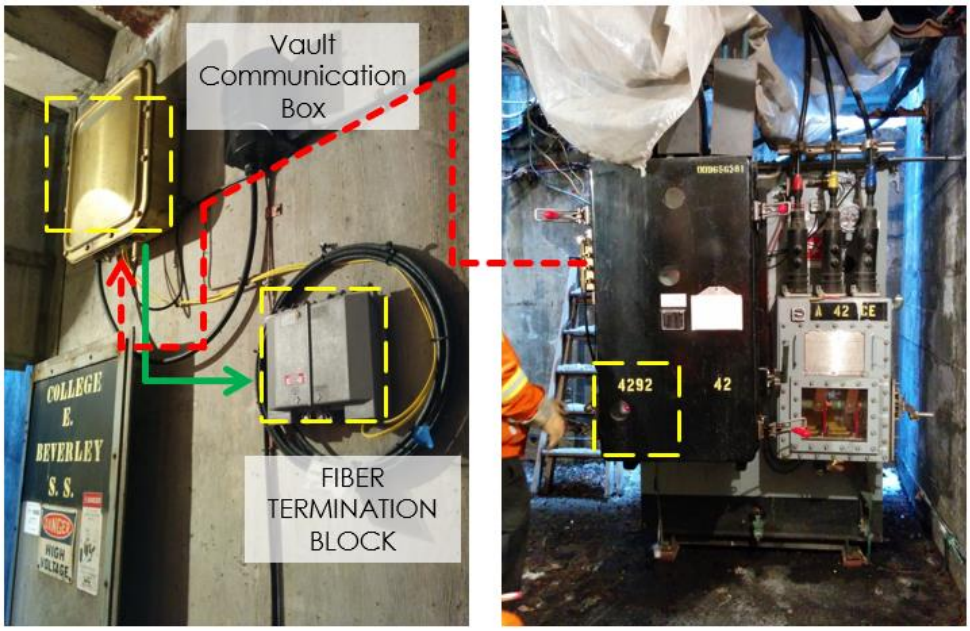


Figure 15: Vault Layout with Network Condition Monitoring and Control Equipment Installed

The 2020-2024 capital plan continues the utility's effort to renew a significant backlog of deteriorated and obsolete assets at risk of failure, adapt the system to handle a growing and intensifying major city, and harden the system to make it more resilient when extreme weather hits and expedite restoration capabilities when outages do occur. This plan will enable the utility to keep pace with technological advancements, and enable

[39] See Exhibit 2B, Section E8.

the security investments proportionate to the risks of cyber-attack. The proposed pace for this plan is expected to sustain current age and condition, which will help to maintain system performance over the 2020-2024 period and mitigate the risks of it worsening during this period and in the future.[40]

Despite the success of Toronto Hydro's 2015-2019 plan, its distribution system's need for continued and increased capital investment as proposed in this plan, remains urgent in the 2020-2024 period. In light of the risks of age, condition, and obsolete infrastructure, Toronto Hydro concluded that taking a more reactive approach to infrastructure renewal (i.e. allowing more assets to run to failure) would reduce reliability over the near and long-terms. See Figure 16, below, for examples of the types of reactive work Toronto Hydro completes. In addition to hurting performance, a reactive renewal approach would also increase costs.



Figure 16: Examples of Reactive Work: Pole Fire Caused by Tracking (left), Exposed and Rusted Rebar in Network Vault (right)

[40] For instance, in 2017, 14 percent of pole top transformers had reached or exceeded their expected useful life. Without this plan, that will increase to approximately 40 percent by 2024. Similarly, the percentage of underground transformers and cable chambers at reached or exceeding estimated useful life will increase from approximately 20 percent to 35 percent and 30 percent respectively by 2024.

The risk to the utility's deteriorating infrastructure is compounded by increases in the frequency and magnitude of extreme weather. Toronto Hydro continues to emphasize plans and programs that facilitate and improve its system resiliency, and ability to respond to these events.[41]

With more than 1,800 distributed energy resources connected to Toronto Hydro's system,[42] reducing risks to the grid requires Toronto Hydro to enhance its visibility of them and put in appropriate safety equipment and protocols. To this end, the utility plan includes a number of investments to assist in managing evolving system requirements and technological landscape.[43]

6.3 Operating, Maintenance & Administration ("OM&A" or "Operational") Plan

Toronto Hydro's operational plan is organized into 21 programs, each of which advances similar outcomes in similar ways. Some programs work directly with the distribution system, such as preventative maintenance, emergency response, and the control centre.[44] Other programs provide support to operations and customers, such as fleet, facilities, and supply chain,[45] customer service and support,[46] human resources, finance, and information technology.[47] All these programs are necessary to safely and reliably

[41] These programs include the Control Operations Reinforcement program (Exhibit 2B, Section E8.1), Area Conversions (Exhibit 2B, E6.1), System Enhancements (Exhibit 2B, E7.1), and Overhead System Renewal (Exhibit 2B, Section E6.5).
[42] There are likely dozens, perhaps even hundreds more of these micro-generation, storage, and other devices that are installed without notice to Toronto Hydro, the operation of which by the customer can affect the distribution system and other customers connected to it (e.g. power quality fluctuations, back-flow of power, spikes up and down in demand).
[43] See Exhibit 2B, Section E7.1 (System Enhancements); Exhibit 2B, Section E7.2 (Energy Storage Systems); Exhibit 2B, Section E7.3 (Network Condition Monitoring and Control); and Exhibit 2B, Section E8.1 (Control Operations Reinforcement program).
[44] See Exhibit 4A, Tab 2, Schedules 1-10.
[45] See Exhibit 4A, Tab 2, Schedules 11-13.
[46] See Exhibit 4A, Tab 2, Schedules 14 and 19.
[47] See Exhibit 4A, Tab 2, Schedules 15-18, 20-21.

power the City of Toronto and be responsive to other customer needs, preferences, and priorities.

Toronto Hydro's operational plan largely continues its 2015-2019 programs. These programs provide functions that address relatively consistent needs over time, such as supporting the safe and reliable operation of the distribution system, delivering customer-facing services that respond to customer expectations and improve ratepayer value, and providing critical corporate functions that allow the utility to operate in a financially responsible and policy-responsive manner.

This plan continues the utility's effort to extract the full value out of distribution equipment through programs that perform preventative, predictive, and corrective maintenance on the deteriorating infrastructure.[48] The Customer-Driven Work Program is at the centre of responding to Toronto's growth and intensification.[49] The utility readies itself for extreme weather through the Disaster Preparedness Management Program and deals with those challenging events through the Emergency Response Program.[50] Keeping pace with external technological advancements and using those advancements to better meet customer needs and protect the utility and customers from cyber threats are major concerns of multiple programs.[51]

6.4 Third Party Input and Review

As part of its business plan, Toronto Hydro retained external experts to conduct assessments of its current performance, including benchmarking with respect to

[48] See Exhibit 4A, Tab 2, Schedules 1-4.
[49] See Exhibit 4A, Tab 2, Schedule 8.
[50] See Exhibit 4A, Tab 2, Schedules 5-6.
[51] For example, see Exhibit 4A, Tab 2, Schedules 7 (Control Centre Operations), 14 (Customer Care), and 17 (Information Technology).

productivity, reliability, and unit/cost efficiency. The results of those studies, filed with this Application, determined that Toronto Hydro's performance is comparable to that of its peers, and in some cases out-performs its peers.

In this Application, the utility has also filed third party assessments of its plans, including a review of its asset management, benchmarking the IT function against peers, and an analysis of the proposal underlying the Control Operations Reinforcement Program. These studies provided Toronto Hydro with important insights and the reports are filed with the Application as commentary and support for the associated plans.

APPENDIX A: SUMMARY OF TOTAL BILL IMPACTS AND UPDATED TARIFF CHARGES

	Change in bill	2020 Proposed	2021 Proposed	2022 Proposed	2023 Proposed	2024 Proposed
Residential	$/30 days	-3.10	1.44	1.12	1.40	1.92
	%	-2.4	1.1	0.9	1.1	1.5
Competitive Sector Multi-Unit Residential	$/30 days	-1.19	1.14	0.89	0.99	1.52
	%	-1.7	1.7	1.3	1.4	2.1
General Service <50 kW	$/30 days	-6.60	3.62	2.81	4.39	4.82
	%	-2.0	1.1	0.9	1.3	1.4
General Service 50-999 kW	$/30 days	-156.17	63.57	49.55	87.48	84.52
	%	-1.1	0.5	0.4	0.6	0.6
General Service 1,000-4,999 kW	$/30 days	-1,452.01	521.66	406.45	717.98	693.76
	%	-0.9	0.3	0.3	0.5	0.5
Large Use	$/30 days	-3,187.65	2,692.82	2,098.05	3,704.72	3,579.26
	%	-0.5	0.4	0.3	0.5	0.5
Street Lighting	$/30 days	-0.15	0.28	0.22	0.39	0.38
	%	-0.8	1.5	1.2	2.1	2.0
Unmetered Scattered Load	$/30 days	-1.23	1.19	0.93	1.62	1.57
	%	-1.9	1.9	1.4	2.5	2.3

Specific charge for access to the power poles	per pole/year	44.15
(wireline attachments)	%	5.1

OUTCOMES AND PERFORMANCE MANAGEMENT

In developing its approach to outcomes and performance management, Toronto Hydro considered the policy guidance from the OEB, including the *Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach* (the "RRF").[1] A key theme of the OEB's guidance is that emphasizing results rather than activities is more responsive to customer preferences, enhanced distributor productivity, and promoting innovation.[2]

Toronto Hydro has a long-standing productivity culture, which has evolved over time while remaining responsive to the utility's operating challenges and regulatory landscape. Since amalgamation in 1998, the utility has been working on streamlining and rationalizing legacy tools, eliminating unnecessary processes, and optimizing assets and workforce. Toronto Hydro's systems and processes are structured around this culture of performance and outcomes, and include a suite of tools to sustain or improve performance as required.

As detailed in the utility's 2015-2019 Application, as the utility has matured, its productivity efforts have resulted in significant savings for customers.[3] This has involved streamlining and rationalizing legacy tools, processes, assets and workforce, as well as enhancing utility capabilities such as the asset management and resourcing practices and tools to plan and deliver a significant and sustained capital plan. This has also included the introduction of efficiency-driving tools such as its outage management

[1] Ontario Energy Board, Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach (October 18, 2012).
[2] *Ibid* at p. 2.
[3] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015), Exhibit 1B, Tab 2, Schedule 5, Appendix A.

system, and distribution management system, adoption of reliability-centered maintenance, job harmonization, and performance and attendance management programs.

Toronto Hydro's commitment to performance management is reflected throughout this Application. For instance, the utility relies on performance governance tools to drive performance and continuous improvement. Specifically, the Management Control and Reporting System ("MCRS") and the Plan-Do-Check-Act ("PDCA") management control cycle, consistent with ISO 14001 and OHSAS 18001 standards.[4] Toronto Hydro uses these tools to manage processes, provide timely data, and enable decision-making.

Similarly, Toronto Hydro utilizes another performance governance process, Lean (i.e. Kaizen), an operational efficiency methodology that focuses on eliminating eight types of waste,[5] and streamlining business processes. Collaboration with front line staff, who are most familiar with processes and wastes, results in optimizing how work is completed – thereby saving resources (labour, time, materials, space). By targeting waste reduction in areas such as inventory, waiting time, space, and staff utilization, a direct impact to customer value can be realized as costs to operate are streamlined.

Toronto Hydro has also developed a customer-focused outcomes framework (the "Outcomes Framework") for the 2020-2024 plan period that facilitates continuous improvement and measures the effectiveness of the utility's plans. These outcomes are expressions of the utility's goals and objectives.

[4] Toronto Hydro is registered with ISO 14001:2015 and OHSAS 18001:2007, both internationally recognized standards in environment, health, and safety. Together, they establish a framework that incorporates effective risk management, emphasizes continual improvement, and achieves operational efficiencies.
[5] Defects, Overproduction, Waiting, Non-Utilized Talent, Transportation, Inventory, Motion, Extra-Processing.

Leveraging this foundation, the utility expects its custom measures, reported under the Outcomes Framework, and the OEB reporting measures (Electricity Distributor Scorecard and Electricity Service Quality Requirements) will provide the OEB, stakeholders and most importantly, customers, quantitative assessment tools for the utility's planning and execution activities. This framework and associated measures also provide quantitative insight into Toronto Hydro's strong performance during the last plan period (2015 through 2019), and enables performance measurement during the period of this plan (2020 through 2024).

Lastly, as detailed in Toronto Hydro's rate-setting framework, Exhibit 1B, Tab 4, Schedule 1, the utility has included productivity gains as part of the rate adjustment mechanism, constraining operational funding increases going forward at less than the rate of inflation, and reconciling a price-cap formula with funding requirements to address Toronto Hydro's significant, multi-year investment needs over the 2020 to 2024 period. It has also included, throughout the Application, detailed descriptions of how the utility is managing costs and improving outputs.[6]

This Exhibit is separated into two sections. A discussion of Toronto Hydro's Outcomes Framework, including its development, inputs, and proposed custom measures, is followed by a comprehensive performance management overview incorporating its productivity and cost efficiency initiatives including benchmarking results. Productivity initiatives, such as those discussed in Section 2, are directed to achieve savings, reductions, or efficiencies. Since productivity consists of inputs and outputs, changes to inputs are influenced in an ongoing, continuous improvement cycle. Inputs include cost management, but also more subtle contributors such as increased capacity and process

[6] Please see Exhibit 2B, Section A and Exhibit 4A, Tab 2, Schedules 1-18, specifically the "Cost Control" sections.

improvement. Overall, this Exhibit provides a centralized discussion on how Toronto Hydro ensures customer value by using results from cost trends and assessments, benchmarking studies as well as customer engagement activities to shape its proposed plans.

1. TORONTO HYDRO'S OUTCOMES FRAMEWORK

Toronto Hydro has organized its application around outcomes to ensure that value for customers is achieved via a utility's selection of investments and pacing. This outcomes or results-based focus is not new to Toronto Hydro. The utility has a long and established corporate performance framework with a focus on continuous improvement.

Toronto Hydro's 2020-2024 Outcomes Framework was derived from six customer priorities identified through the utility's customer engagement activities, the utility's corporate pillars as well as the OEB's RRF outcomes.

Toronto Hydro's customers identified six categories of priorities related to: Price, Reliability, Safety, Customer Service, Public Policy, and Environment.[7] The OEB RRF outcomes are: Customer Focus, Operational Effectiveness, Public Policy Responsiveness, and Financial Performance.[8] Toronto Hydro's corporate pillars are: Customer Service, Operations, People, and Financial Strength.

[7] See Exhibit 1B, Tab 3, Schedule 1
[8] EB-2010-0379, Ontario Energy Board Report of the Board: Performance Measurement for Electricity Distributors: A Scorecard Approach (March 5, 2014).

The resulting framework, depicted in Figure 1, is informed by the six priorities identified in the Phase I low-volume customer focus groups, in addition to Toronto Hydro's corporate pillars and the OEB's RRF outcomes. The Outcomes Framework is focused on six key outcomes: Customer Service, Reliability, Safety, Environment, Public Policy,[9] and Financial.[10] This Framework transitioned into the lens through which Toronto Hydro articulated and implemented its strategic vision throughout business planning. This vision is reflected in the investment decisions made by the utility.

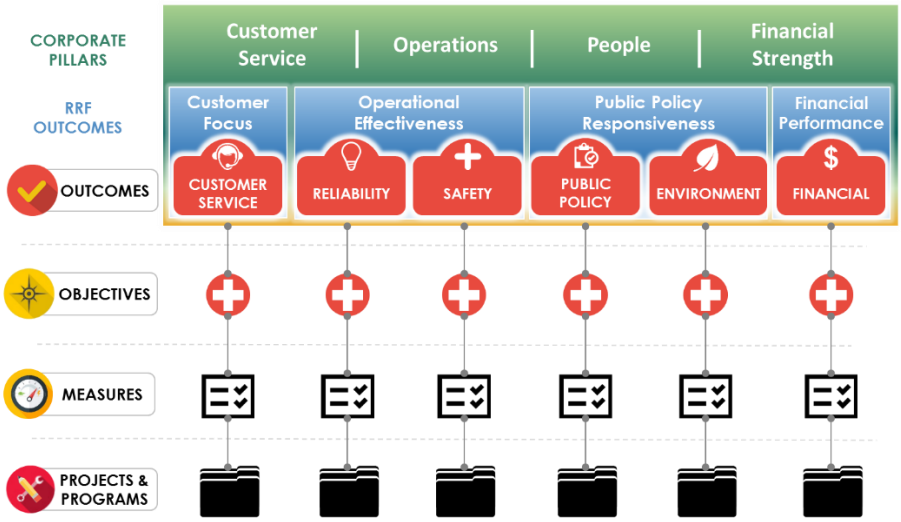


Figure 1: Toronto Hydro's Customer-Focused Outcomes Framework[11]

Overall, Toronto Hydro intends to continue using its Outcomes Framework to assess and communicate the effectiveness of its plans in delivering value that aligns with evolving customer preferences over time. Please see Exhibit 2B, Section E2, for a discussion of

[9] Which includes enabling the system to support in the reduction of greenhouse gases.
[10] Which includes delivering reasonable electricity prices.
[11] The RRF Outcomes are aligned alongside Toronto Hydro's Outcomes based on the definitions provided by the OEB in the Utility Rate Handbook. It should be noted that Toronto Hydro's Financial outcome includes cost-related components that the OEB would classify within the Operational Effectiveness outcome.

how the utility has identified specific outcomes valued by its customers and how its plans and proposed expenditures deliver those outcomes.

1.1 Toronto Hydro's 2020-2024 Custom Performance Measures

To remain responsive to customer needs and preferences and demonstrate continuous improvement in performance setting and tracking, Toronto Hydro has proposed 15 custom measures within its Outcomes Framework that are incremental to measures tracked and assessed by the OEB, for a total of 44 unique measures to be reported annually.[12] See Appendix A for a full list of measures to be reported annually to the OEB. For a comprehensive discussion of Toronto Hydro's custom measures for the 2020-2024 plan period, please refer to Exhibit 2B, Section C2. Toronto Hydro's proposed custom measures reflect a thorough understanding of customer priorities and provide assurance that value for money will be achieved through the utility's 2020-2024 Distribution System Plan.

Table 1: 2020-2024 Custom Performance Scorecard Measures

Toronto Hydro Outcome	OEB Reporting Category	Toronto Hydro's Custom Measures	Target
Customer Service	Customer Satisfaction	Customers on eBills	Improve
Safety	Safety	Total Recorded Injury Frequency	Maintain
		Box Construction Conversion	Improve
		Network Units Modernization	Improve
Reliability	System Reliability	SAIDI - Defective Equipment	Maintain
		SAIFI - Defective Equipment	Maintain
		FESI 7 System	Improve
		FESI-6 Large Customers	Maintain
	Asset Management	System Capacity	Maintain
		System Health (Asset Condition) – Wood Poles	Monitor
		Direct Buried Cable Replacement	Improve

[12] These proposed measures will monitor distribution system planning process performance.

Toronto Hydro Outcome	OEB Reporting Category	Toronto Hydro's Custom Measures	Target
Financial	**Cost Control**	Average Wood Pole Replacement Cost	Monitor
		Vegetation Management Cost per km	Monitor
Environment	**Environment**	Oil Spills Containing PCBs	Improve
		Waste Diversion Rate	Monitor

Toronto Hydro's custom performance measures, and the targets related to all measures in general (including the Electricity Distributor Scorecard and the Electricity Service Quality Requirements), have been developed on the basis of the proposals, plans, and associated rates contained in this Application. To the extent that Toronto Hydro's approvals differ from those it seeks in this Application, then the utility would need to reforecast and re-assess its forecasted attainable performance for the period. Further, there are risks outside of Toronto Hydro's control which may also affect its ability to achieve performance targets.

2. PERFORMANCE MANAGEMENT

Toronto Hydro is an efficient organization that strives to promote its history of productivity and customer cost savings. Inherent in its focus on outputs and value is the emphasis on measuring and tracking performance, using internal and external benchmarking.

This section centralizes the utility's discussion of productivity and includes summaries of benchmarking studies relating to Toronto Hydro's performance relative to its peers. The activities captured within the following discussions are testament to the utility's commitment to ensure continuous improvement in the efficiency of key operational tasks that ultimately contribute to value-for-money for customers.

2.1 Productivity

Toronto Hydro's framework of current and future productivity processes and initiatives emphasize increasingly sophisticated performance measurement tools, identification for new efficiency opportunities, and reducing manual, labour-intensive processes through streamlining and technological improvements. The discussion below provide examples of sources of productivity improvements.

2.1.1 Health and Safety

Lost working time negatively affects productivity. Therefore, Toronto Hydro has applied extensive efforts in health and safety, which has decreased costs, reduced absenteeism and improved employee health and safety. In 2015 and 2016, the Canadian Electricity Association recognized Toronto Hydro as the best in its peer group for its superior performance in occupational health and safety. Table 2, below, compares Workplace Safety Insurance Board ("WSIB") accident costs averaged over the 2014-2016 period.

Table 2: Average WSIB Accident Costs[13]

	Toronto Hydro	Hydro One Networks	Alectra Utilities	Hydro Ottawa	London Hydro	Enwin Utilities
Average WSIB Accident Costs 2014 - 2016	$21,922	$1,361,519	$69,694	$200,719	$60,158	$28,128
Average WSIB Accident Costs per Employee 2014 -2016	$13.70	$247.54 [a] $180.59 [b]	$43.56	$286.74	$191.59	$85.49

[a] Based on 5,500 full time employees

[b] Based on 5,500 full time employees plus 2,045 part time employees

[13] Workplace Safety Insurance Board Ontario, Compass, available at: <https://compass.wsib.on.ca>.

This recognition is based on Toronto Hydro's significant and sustained improvement, between 2011 and 2016, with notable improvements with respect to the following safety indicators:

- A 68 percent decrease in total recordable injury frequency ("TRIF") (Figure 2, below);
- A 96 percent decrease in lost time injury severity;
- A 63 percent decrease in lost time injury frequency;
- A 87 percent decrease in restricted work days (Figure 2, below); and
- A 57 percent decrease (86 to 37) in the number of WSIB claims.

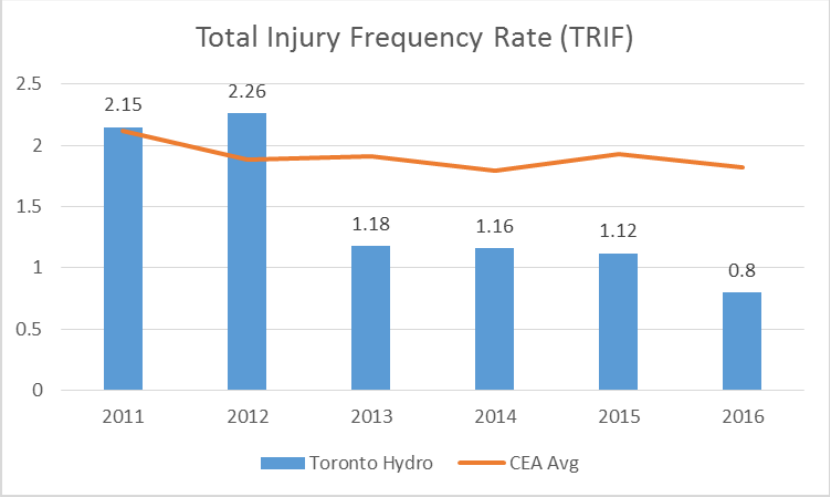


Figure 2: Total Recordable Injury Frequency

Over the past ten years, Toronto Hydro improved its safety performance as measured by Total Recordable Injury Frequency ("TRIF") by 82.6 percent. More recently, Toronto Hydro spent over 5 million hours without a lost-time injury from December 17, 2014 to August 10, 2016. The total lifetime cost to an employer associated with a lost-time

injury may be over $165,000.[14] The avoidance of these costs creates savings for the utility and its customers.

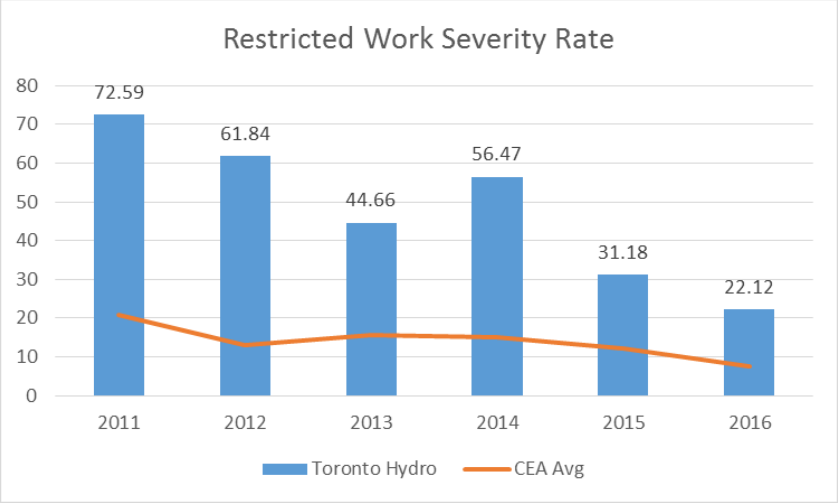


Figure 3: Restricted Work Days

As seen in Figure 3, above, from 2011 to 2016, Toronto Hydro also achieved and sustained an 87 percent reduction in restricted work days. A restricted work day is the number of calendar days to a maximum of 180 days during which an employee is subject to restricted work, based on the recommendation of a physician or licensed health care professional, for an individual case.[15] Restricted work days impacts a utility's performance by reducing the contribution an employee is physically able to make often resulting in additional costs related to finding replacement or supplementary labour.

[14] Workplace Safety and Insurance Board (Ontario) Fact Sheet: High Impact Claims, available at: <http://www.wsib.on.ca/cs/idcplg?IdcService=GET_FILE&dDocName=WSIB011540&RevisionSelectionMethod=LatestReleased>

[15] When an employee is medically determined to be unable to perform one or more routine functions or unable to work the normal time period of their pre-injury/illness work day, they are working in a "restricted" capacity. Routine functions are the work activities that the employee regularly performs at least once a week.

Further, between 2011 and 2017, Toronto Hydro's employee attendance number improved by 50 percent, with employees averaging 4.74 number of sick days per year. Comparatively, the average number of sick days per employee (in all industries) in Canada during this same period was 9.21, and for employees in the utility industry, the average number of sick days was 9.06. From a productivity standpoint, this means that Toronto Hydro employees had 4.5 fewer sick days than employees in other industries in Canada during this time period, and 4.3 fewer days than employees in other utilities in Canada. Currently, Toronto Hydro's absentee rate of 3.54 days is well below that of the national, provincial, and municipal average of 9.6 days, 8.6 days, and 7.2 days respectively.[16] This translates to more than $2 million in cost savings relative to the utility industry benchmark, on average, during this time period.[17]

Toronto Hydro's superior safety performance has resulted in significant cost savings resulting from a reduction in WSIB annual premiums and an increase in WSIB rebates. WSIB is funded solely through premium revenue.[18] Premiums are based on a number of factors, including: new claims, administration expenses, and past claim costs. In addition, between 2011 and 2016, the utility lowered its WSIB New Experimental Experience Rating ("NEER") costs by approximately 82 percent, see Figure 4, while WSIB performance index improved by 80 percent over the same time frame. NEER is a mandatory program administered by the WSIB to track and anticipate costs for WSIB claims. Each year, the WSIB establishes an expected annual cost based on industry claim history and the size of organization, and compares the employers' performance against this expected cost (calculated as the performance index). If WSIB actual costs

[16] Work absence of full-time employees, Statistics Canada, available at: <https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1410019001>
[17] These estimated cost savings are conservative values based on wages alone.
[18] About Us, Workplace Safety Insurance Board, available at: <http://www.wsib.on.ca>.

are below the expected cost, the employer receives a rebate of the difference between the actual and expected costs. On the other hand, if the WSIB actual costs exceed the expected cost, the employer must pay a surcharge up to three times the expected cost. Through its strong focus on safety, Toronto Hydro has received substantial WSIB rebates.

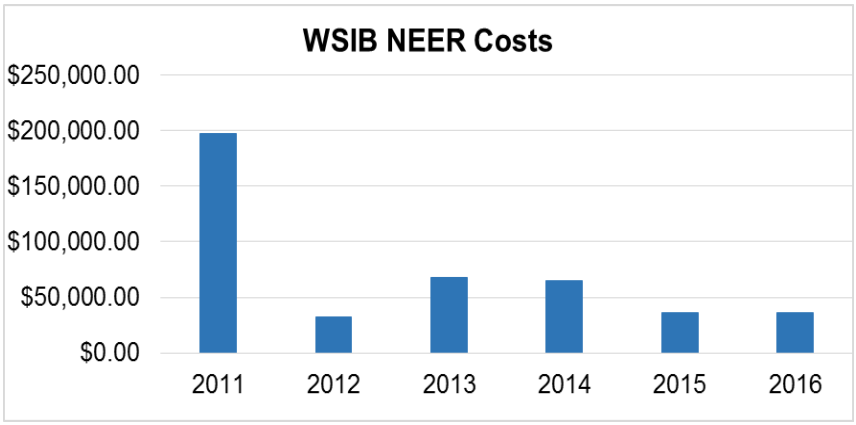


Figure 4: WSIB NEER Costs

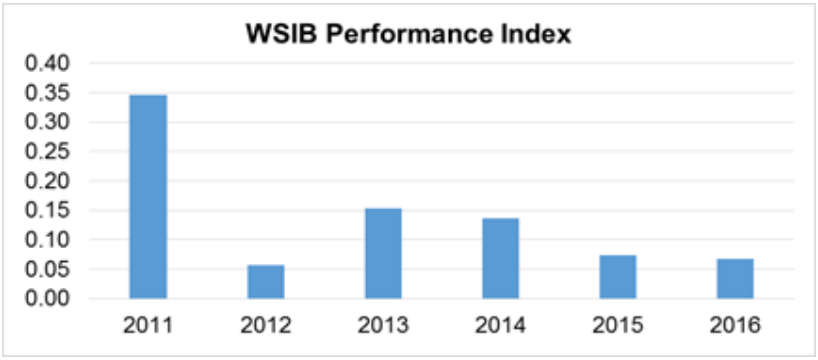


Figure 5: WSIB Performance Index[19]

[19] The WSIB is in the process of transitioning to a new methodology in 2020 for calculating premiums that will eliminate the NEER program. For more info see: *http://www.wsib.on.ca.*

Toronto Hydro's strong safety performance is intrinsically linked to its comprehensive and cost-effective internal training programs. The utility develops and provides key internal training, leveraging internal resources and equipment to complete testing, audits, completion of applications, and authoring of reports, saving the utility significant external consultant and vendor costs. For instance, in 2007, the Government of Ontario recognized Toronto Hydro's curriculum for the Certified Power Line Person ("CPLP") as equivalent to the in-school requirements for Power Line Technician Trade. Given Toronto Hydro's unique distribution system, in 2008, Toronto Hydro obtained Training Delivery Agent Status from the Province for its Power Line Technician Program to train its own apprentices. In 2017, the average delivery costs to provide the CPLP accreditation internally was approximately $16,000. By comparison, the average cost of external CPLP accreditation is approximately $25,000-$31,000.

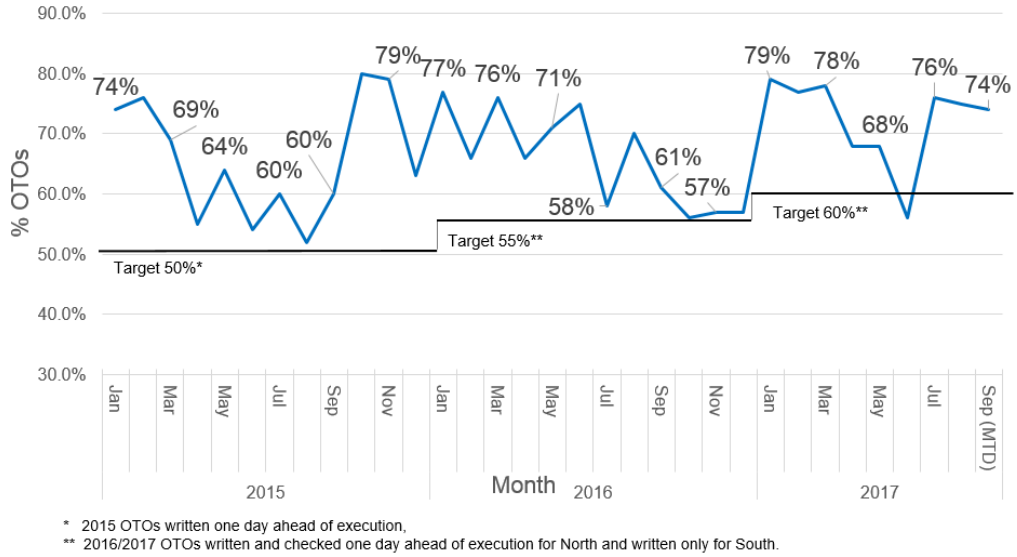
2.1.2 Process Improvements

Increasing Wrench Time for Crews

Toronto Hydro's Control Centre is responsible for the safe and efficient operation of the distribution system. This includes directly opening and closing remotely operable switches to redirect the flow of electricity and directing/instructing field crews in the execution of work. The Control Centre is responsible for switching steps (Orders to Operate) and the issuance of "Hold Offs."

An Order to Operate is comprised of a list of switching instructions that enable operations crews to safely transfer customer load and establish suitable work protection over a specified range of system devices. Over the last few years, Toronto Hydro's Control Centre has been working on steadily increasing the percentage of planned

Orders to Operate completed prior to work execution. This has contributed to a reduction in last minute work volume and allows field work to commence without delay.



* 2015 OTOs written one day ahead of execution,
** 2016/2017 OTOs written and checked one day ahead of execution for North and written only for South.

Figure 6: Percentage of Orders to Operate Completed Ahead of Work Execution

Toronto Hydro has also made improvements to Hold Off times experienced by its crews. Hold Offs are special conditions that prevent certain automatic equipment operations for the duration of time that a field crew is working in proximity to Toronto Hydro's infrastructure. The application of Hold Offs for certain activities are a requirement of Toronto Hydro's work procedures, and if not applied, can result in equipment damage and create extended outages should an incident occur in the physical or electrical proximity to the work site.

Since 2016, Toronto Hydro's Control Centre analyzed Hold Off volume data and used this to spread the peak demand across a longer time frame by staggering call-in times. As shown in Figure 7, this has directly contributed to a significant reduction in the average time crews spent waiting for Hold Offs.

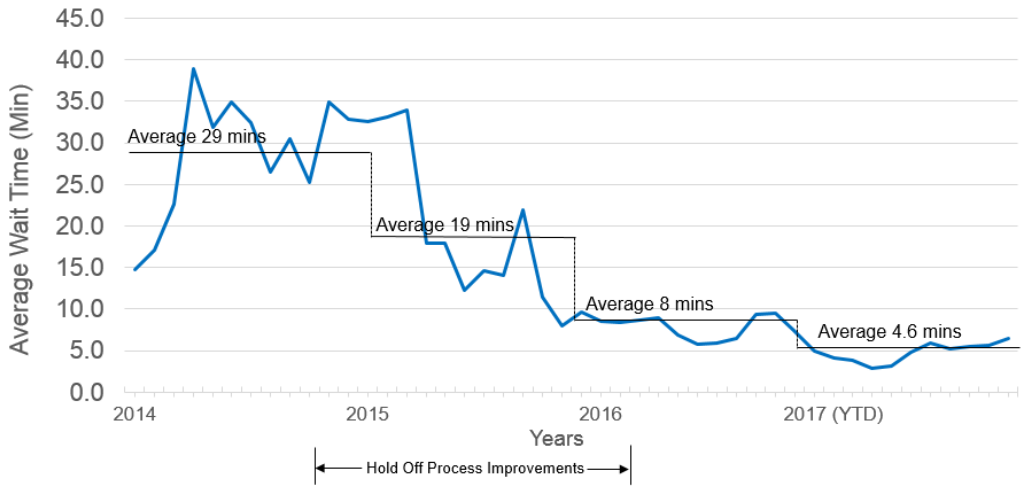


Figure 7: Average Crew Wait Times for Hold Offs

For more information on the Control Centre's process improvements driving productivity, please refer to Exhibit 4A, Tab 2, Schedule 7.

In addition, since 2015, to aid in the efficient execution of work, Toronto Hydro implemented processes to ensure feeder scheduling occurs in an optimized manner. Much of the work performed on Toronto Hydro's system (e.g. maintenance, capital construction, urgent reactive or emergency work, customer maintenance, or new connections) requires feeders to be taken out of service in order to create a safe work zone. Every time a feeder is taken out of service in the downtown core, crews are required to visit the site and manually move the switch handles. Toronto Hydro has been working on maximizing the amount of work that is completed during each feeder outage. This is accomplished through strong coordination and planning, specifically, weekly switching and system restoration schedules.

For a complete list of benefits resulting from this process, please refer to the Preventative and Predictive maintenance programs at Exhibit 4A, Tab 2, Schedules 1-3.

Facilities Asset Management Improvements

Toronto Hydro maintains a complex portfolio of facilities, including critical operational sites (e.g. stations and control centres), in support of the reliable and efficient operation of the utility's distribution system. The effective maintenance of these facilities is required in order to ensure adequate protection for electrical grid equipment, secure access for employees and security of designated areas, and appropriate work conditions to support employee productivity. Since 2015, Toronto Hydro has created a robust facilities management system that records assessments and maintenance plans for all assets located in Toronto Hydro's work centres and stations. This repository system identifies the condition of all facilities-related assets (e.g. poor, fair, good) owned by Toronto Hydro, thereby ensuring that the utility efficiently performs the necessary maintenance work where required.

These changes have facilitated the development of a robust Facilities Asset Management Strategy, filed at Exhibit 2B, Section D4. The Strategy ensures that when planning and executing projects, the utility makes strategic decisions based on a number of factors, including detailed asset condition assessments, the criticality of the asset, industry standards, and past experience. These process improvements facilitated the results of a third-party assessment, which ranks these processes above average in facilities asset management competence (see Asset Management Practices discussion, below). For more information on Toronto Hydro's Facilities programs, please refer to Exhibit 2B, Section E8.2 and Exhibit 4A, Tab 2, Schedule 12.

Reduction in Manual Processes

Toronto Hydro's Customer Care program invests in a number of automation processes that eliminates the need for manual work. This leads to cost savings. For instance, through various initiatives, the utility encourages the use of customer self-service features on Toronto Hydro's website to provide easier customer access to information and to reduce the need for customer contact. This decreases the volume of customer contact for the call centres and allows optimization of the use of lower cost outsourced labour. For instance, since call-centre business hours were expanded to 8:00 p.m., Toronto Hydro's third-party service provider has been used exclusively to provide lower cost call handling resources and customer service.

In addition, the utility has also reduced its paper, printing, and postage costs by increasing the adoption of customer electronic billing to 224,420, as at end of 2017, which saves approximately $9.52 per electronically billed customer a year. For a full list of Customer Care process improvements, please refer to Exhibit 4A, Tab 2, Schedule 14.

Lastly, through investments in the Metering program, specifically in meters that have a more effective transmitter that increases the range of the meter signal, the utility decreases the number of manual reads required and retrieves faster customer level outage information. Similarly, through the introduction of meters with remote disconnection capabilities, Toronto Hydro is able to decrease the number of physical visits to a customer's property. For a complete list of metering related improvements driving customer service and efficiency gains, please refer to Exhibit 2B, Section E5.4.

2.1.3 Program-Level Efficiencies

As part of planning, Toronto Hydro employs a variety of tools, processes, and approaches to facilitate a culture of continuous improvement and further efficiency and productivity gains for the benefit of customers. The five examples below are provided as a means of summarizing the type of initiatives and processes utilized by the utility to improve execution efficiency and reduce costs.

- **Facilities Management** (Exhibit 4A, Tab 2, Schedule 12): Toronto Hydro's real-estate management approach has been driving cost savings for customers. Specifically, as part of the Operating Centres Consolidation Program ("OCCP"),[20] the utility sold two of its facilities and returned the after-tax gains on the sale and related tax savings to customers through a rate-rider. The termination of a lease at two other facilities allowed for a reduction in maintenance costs, as explained in Exhibit 4A, Tab 2, Schedule 12.[21] In addition, in 2018, Toronto Hydro sold an additional property (60 Eglinton), allowing for: (i) allocation of net after-tax gains and related tax savings on the sale of this property; (ii) eliminating otherwise ongoing property-related costs associated with the property; (iii) increasing the utilization of remaining properties; and (iv) returning the gains to ratepayers. For details on the cost savings achieved through Toronto Hydro's facilities management, please refer to Exhibit 4A, Tab 2, Schedule 12. For a comprehensive variance analysis on the OCCP, please refer to Exhibit 2B, E4.
- **Disaster Preparedness Management** (Exhibit 4A, Tab 2, Schedule 6): Due to significant efforts to build and retain internal disaster planning expertise, the program continues to reduce reliance on external consultants for program

[20] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015), Exhibit 2B, Section E8.3.
[21] For a comprehensive discussion of the results of OCCP, please refer to Exhibit 2B, Section E4.

guidance and development, leading to cost savings. In addition, the program facilitates efficient use of internal resources with a view to controlling external labour costs. In addition, in partnering with other utilities via Mutual Assistance Agreements, Toronto Hydro has access to "at cost" crews, equipment, supplies and expertise following a disaster event (weather related or otherwise).

- **Corrective Maintenance** (Exhibit 4A, Tab 2, Schedule 4): Toronto Hydro actively works on correcting cable chamber nomenclature deficiencies as the need is identified. This eliminates the need to create a separate work request and additional travel time for repair, resulting in savings of approximately $400,000 per year.
- **Fleet and Equipment Services** (Exhibit 2B, Section E8.3): Through extensive efforts to rationalize the size of its vehicle fleet, Toronto Hydro has decreased its number of fleet vehicles from 660 in 2013 to 588 in 2017, which reduces maintenance, fuel, repair, licensing and administrative costs. The utility plans on maintaining this reduced fleet size in the 2020-2024 plan period.
- **Area Conversions** (Exhibit 2B, Section E6.1): The Area Conversions program funds the replacement of functionally obsolete 4.16 kV distribution system designs with updated standard 13.8 kV and 27.6 kV lines, Improving the speed and cost-efficiency of customer grid access (including generation and electric vehicle access) in high-growth areas of downtown Toronto by converting approximately 2,600 poles (containing approximately 100 kilometres of low capacity and low clearance box construction feeders) to more efficient and flexible higher voltage standards. This improves the efficiency with which we can connect or upgrade customers with any associated savings directed back to the connecting/upgrading customer.

For additional information on how Toronto Hydro's work is facilitating efficiencies and a reduction in operating and maintenance costs, please refer to Exhibit 2B, Section D and Exhibit 4A, Tab 2, Schedules 1-18. Lastly, for a discussion on program-level cost-savings expected to be carried forward to the 2020-2024 plan period, please refer to Exhibit 2B, Section A.

2.2 Scorecard Performance & Internal Benchmarking

The OEB has established a set of performance metrics for electricity distributors through its Performance Scorecard, the Electricity Distributor Scorecard ("EDS"), to assess utility performance over time and to compare performance across utilities. For the last several years, Toronto Hydro's performance on the EDS has been strong, with observable improvements in several key areas such as customer first contact resolution, telephone calls answered on time, new residential and small business services completed on time and billing accuracy. In addition, over the 2013-2017 period, Toronto Hydro achieved or exceeded the Electricity Service Quality Requirements ("ESQR") standards 85 percent of the time. In 2017, for instance, the utility met or surpassed the OEB's standards for 11 out of the 12 measures (92 percent). In respect of outages, Toronto Hydro's number and frequency of customer interruptions have been equal to or better than the distributor target for the 2013-2017 period. This achievement is attributable to the investments the utility has made in the system. For a comprehensive review of the utility's reliability improvements, please refer to Exhibit 2B, Section E2.

For further information on Toronto Hydro's internal benchmarking including historical performance on the EDS and 2015-2019 DSP measures, ESQR and reliability, please see

Exhibit 1B, Tab 2, Schedules 2, 3, 4, and 5.[22] Please refer to Exhibit 2B, Section C for a discussion on how the utility will continue to use internal benchmarking to set baseline targets for the proposed custom performance measures, and Exhibit 2B, Section E2 for a discussion on the utility's internal benchmarking results on reliability.

2.3 External Benchmarking

Since its 2015-2019 Application, Toronto Hydro has used a variety of benchmarking studies to assess its proposed plans, including those set out in Table 3, below.

Table 3: Benchmarking Reports Filed in this Application

Benchmarking Review	Evidence Reference
Econometric Benchmarking of Historical and Projected Total Cost and Reliability Levels – Power System Engineering Inc.	Exhibit 1B, Tab 4, Schedule 2
Unit Costs Benchmarking Study – UMS Group	Exhibit 1B, Tab 2, Schedule 1, Appendix B
IT Budget Assessment- Gartner Consulting	Exhibit 2B, Section E8.4, Appendix A
Compensation Benchmarking – Mercer Canada	Exhibit 4A, Tab 4, Schedule 5
Dual Distribution Control Centre – London Economics Inc.	Exhibit 2B, Section E8.1, Appendix A

The results allow for the identification of continuous improvement opportunities. The discussion below summarizes Toronto Hydro's benchmarking studies and provides the conclusions reached by several third party assessors on the utility's performance and costs in relation to its peers. Collectively, these results identify Toronto Hydro as a strong performer in a variety of areas.

[22] This includes a completed OEB Appendix 2-G (filed at Exhibit 1B, Tab 2, Schedule 5), documenting both the Service Quality and Service Reliability indicators, as per s. 2.2.2.8 of the Chapter 2 Filing Requirements. The utility confirms that the data is consistent with its scorecard.

2.3.1 Econometric Total Costs

In the course of preparing for its current Application, Toronto Hydro retained Power System Engineering Inc. ("PSE") to apply econometric modelling to benchmark the utility's historical and projected costs and reliability.[23] The purpose of this review was to assess the reasonableness of Toronto Hydro's revenue forecasts and inform the appropriate stretch factor in the utility's Application.[24]

PSE compared Toronto Hydro's historical and projected total costs against its benchmark costs i.e. Toronto Hydro's expected costs in any given year based on the econometric model.[25] PSE's results indicated that (i) the historical average total costs for the utility, from 2015 to 2017, are 18.6 percent below benchmark expectations.[26] Specifically, Toronto Hydro's total annual costs were approximately $157 million below benchmark values in 2017;[27] and (ii) the projected total cost levels during the 2020-2024 period are 6.0 percent below benchmark expectations.[28] Toronto Hydro's total annual costs are expected to be approximately $32 million below benchmark values in 2024.[29]

[23] Power System Engineering Inc., Econometric Benchmarking of Historical and Projected Total Cost and Reliability (July 18, 2018), filed at Exhibit 1B, Tab 4, Schedule 2. As discussed in Exhibit 1B, Tab 4, Schedule 1, Toronto Hydro's plan is prepared based on a forecasting model, as envisioned in section 2.1.8 of the Filing Requirements. A custom element of this Application is using a PSE forecasting model in place of a PEG forecasting model.
[24] *Ibid* at p. 2.
[25] *Supra* note 23 at p. 4.
[26] *Supra* note 23 at p. 30.
[27] *Ibid*.
[28] *Ibid*.
[29] I*bid*.

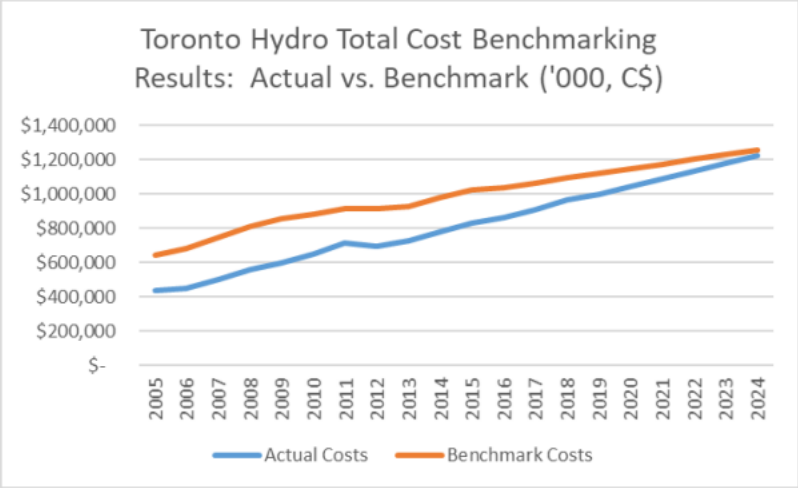


Figure 8: Toronto Hydro's Cost Performance 2005-2024[30]

Based on their findings, PSE states that Toronto Hydro is not a poor total cost performer and recommends a stretch factor of 0.3 percent.[31] For more information on this report, as well as details on Toronto Hydro's ratemaking framework, please refer to Exhibit 1B, Tab 4, Schedule 1.

2.3.2 Unit Costs

To assess the actual efficiency with which Toronto Hydro executes its system investment and maintenance programs, the utility retained UMS Group ("UMS") to perform a capital and maintenance unit cost benchmarking exercise.[32] The utility provided UMS with actual, all-in capitalized unit costs for major asset classes for the 2014-2016 period. UMS assessed these asset classes to be reflective of the utility's operating performance. UMS performed a normalized comparison of these results to those of peer utilities

[30] *Supra* note 23 at p. 7.
[31] *Supra* note 23 at p. 49.
[32] UMS Group, Toronto Hydro-Electric System Limited Unit Costs Benchmarking Study, filed at Appendix B to Exhibit 1B, Tab 2, Schedule 1.

across North America. These peer utilities were of comparable size and complexity. The results of this analysis are provided in Table 4 below.

Table 4: Results of UMS Group's Unit Cost Benchmarking Study[33]

Category/Program	Quartile			
	Top	2nd	3rd	Bottom
Wood Pole		X		
UG Cable (XLPE)		X		
OH Switches (Manual and Remote/Motor-Operated		X		
Pole Top Transformer			X	
Padmount/UG Transformer		X		
Network Transformer/Protector		X		
Breaker (SF_6, Oil, and Vacuum)		X		
Vegetation Management		X		
Pole Test and Treat		X		
Overhead Line Patrol		X		
Vault Inspection		X		

As Table 4, above, illustrates, Toronto Hydro faired strongly in comparison with its peers for the majority of the asset categories. UMS reports that the methods currently in place to report and manage unit costs conform to industry standards.

These results provide an indication that the utility has delivered its large capital program cost-effectively through rigorous project development, program management, assessment, and execution practices. UMS further reports that the utility's attempts to improve the collection and maintenance of unit cost information is expected to further assist in managing costs and productivity.[34] For more information on the Unit Cost

[33] *Ibid* at p.7.
[34] *Supra* note 32 at p.8.

Benchmarking report, as well OEB Appendix 5-A (Unit Cost Metrics), please refer to Exhibit 1B, Tab 2, Schedule 1, Appendix B and Appendix C, respectively.

2.3.3 Information Technology ("IT") Costs

As part of its IT cost planning and assessment, Toronto Hydro retained Gartner Consulting ("Gartner") to provide a peer benchmark review of its IT budget.[35] The review included a comprehensive comparison of IT metrics, spending and staff distributions to provide the utility with a view on how its IT spending aligns against its peers. Toronto Hydro was benchmarked against 15 peer utilities based on industry and revenue, all serving major urban locations.[36] Gartner concluded that for 2017, Toronto Hydro's IT spending, expressed as a percentage of revenue and operational expense, is lower than the peer group.[37] Specifically, 2.2 percent versus 2.5 percent and 2.4 percent versus 3.1 percent, respectively.[38] Further, infrastructure support costs are approximately $4 million less than what other peer organizations would spend to support the same workload.[39] Gartner made similar findings in respect to the utility's 2020 forecast.[40] For more information on this review and Toronto Hydro's IT program, please see Exhibit 2B, Schedule E8.4.

Table 5: IT Costs Benchmarking for 2017 (Actuals) and 2020 (Forecast)

	Toronto Hydro 2017 Costs	Toronto Hydro 2020 Costs	Peer Average
Revenue ($ Millions)	4,016.9	4,042.5	4,477.8
Operational Expense ($ Millions)	3,572.7	3,447.5	3,659.8

[35] Gartner Consulting, IT Budget Assessment- Final Report (March 16, 2018), filed at Exhibit 2B, Schedule E8.4, Appendix A.
[36] *Ibid* at p. 8.
[37] *Supra* note 35 at pp. 10-11.
[38] *Supra* note 35 at p.12.
[39] *Supra* note 35 at p. 13.
[40] *Supra* note 35 at pp.23-32.

	Toronto Hydro 2017 Costs	Toronto Hydro 2020 Costs	Peer Average
Organizational Employees	1,390	1,467	4,730
Organizational Users	3,430	N/A	N/A
IT FTEs	214	200	305
IT Capital and Operating Expenses ($ Millions)	87.1	92.9	110.4
Customers	758,193	784,095	1,233,000

2.3.4 Compensation Costs

In 2018, Toronto Hydro retained Mercer Canada Limited ("Mercer") to undertake a market review of the utility's compensation and benefits program competitiveness for its non-executive management, non-union professionals, and unionized employees.[41] The peer group was selected amongst energy and general industry sectors the utility competes against for talent.[42] Toronto Hydro worked with Mercer to identify a variety of positions to use as its benchmark, including positions that represent 56 percent of the employees at the utility.[43]

Overall, Mercer concluded that total remuneration, including value of all cash compensation, benefit and pension plans are positioned within a market competitive range[44] relative to the 50th percentile of the energy market, and are below the general industry market.[45] For more information, please refer to the full review, filed as part of Toronto Hydro's compensation evidence at Exhibit 4A, Tab 4, Schedules 4-5.

[41] Mercer Canada Limited, Toronto Hydro-Electric System Limited Non-Executive Compensation and Benefits Review (January 2018), filed at Exhibit 4A, Tab 4, Schedule 5.
[42] *Ibid* at p.2.
[43] *Ibid*.
[44] Mercer considers "competitive range" to include compensation levels that fall within 10 percent of the target market position on a position-by-position basis and 5 percent on an overall organization basis (where you have a larger sample size and smaller variability in observations) when compared to target positioning (e.g. the 50th percentile).
[45] Supra note 41 at p. 5.

2.3.5 Asset Management Practices

Toronto Hydro's vast and complicated assets require the utilization of various asset management ("AM") processes to provide the architecture for its long-term, short-term, and maintenance planning functions, found at Exhibit 4A, Tab 2, Schedules 1-5, and the framework underpinning the development of its 2020-2024 Capital Expenditure Plan, described in Section E of the DSP. Toronto Hydro's AM process aims to realize sustainable value from the utility's assets for the benefit of its customers and stakeholders.

In the course of preparing its 2020-2024 DSP, Toronto Hydro engaged UMS Group ("UMS") to perform a review and evaluation of the utility's asset management practices.[46] UMS is strongly qualified to assess utility asset management practices and has adopted its assessment methodologies to align with emerging industry standards.[47] UMS assessed Toronto Hydro's AM practices against the industry standard for asset maturity (ISO 55001) using a variety of methods, including conducting interviews with several Toronto Hydro key departments, reviewing relevant sections of the utility's 2020-2024 DSP, and benchmarking against a peer utility group.

UMS concluded, among other findings, that the utility has a number of key AM processes that substantiate the DSP as a means to "deliver value to stakeholders by optimizing decisions from an asset lifecycle perspective and balancing risk with cost performance."[48] In addition, UMS found that Toronto Hydro's use of lifecycle planning, trade-offs analysis, risk assessments and use of failure forecasting all exceeded the

[46] UMS Group, Toronto Hydro-Electric System Limited Distribution System Plan Asset Management Review, filed at Exhibit 2B, Section D, Appendix A.
[47] *Ibid* at p.3.
[48] *Supra* note 46 at pp. 15-16.

typical utility asset management process.[49] Outside programs addressing assets strictly serving the distribution system, Toronto Hydro's IT programs'[50] use of risk analysis and lifecycle assessments exceeds industry standard practice, while the Facilities programs'[51] use of asset condition assessments rank it above the average utility in facilities asset management competence.[52] For more information on this review as well as Toronto Hydro's AM practices, including how the utility plans, prioritizes, and optimizes expenditures based on this information, please refer to Exhibit 2B, Section D.

2.3.6 Dual Distribution Control Centre

Toronto Hydro engaged London Economics International LLC ("LEI") to conduct a two-part analysis to evaluate the reasonableness of the utility's proposal for a dual Control Centre.[53] First, LEI was tasked with undertaking a review of comparator utilities with one or more fully functional Control Centres. As part of this undertaking, LEI compared Toronto Hydro's forecast dual Control Centre construction costs to those expended by other utilities. Second, LEI assessed, from an economic perspective (using the concept of Value of Lost Load), the utility's proposal for a dual Control Centre.[54]

In respect to its review of comparator utilities, LEI assessed four other large U.S. and Canadian utilities with more than one fully functional Control Centre. These utilities cite a myriad of factors, similar to those outlined in Toronto Hydro's Control Operations Reinforcement program, for utilizing more than one fully functional Control Centre,

[49] *Ibid*.
[50] See Exhibit 2B, Section E8.4 and Exhibit 4A, Tab 2, Schedule 17 for more information.
[51] See Exhibit 2B, Section E8.2 and Exhibit 4A, Tab 2, Schedule 12 for more information.
[52] *Supra* note 46 at pp. 16.
[53] London Economics International LLC, Jurisdictional Review and Economic Case for a Dual Distribution Control Centre in Toronto Hydro Territory (June 22, 2018), filed at Exhibit 2B, Section E8.1, Appendix A.
[54] *Ibid* at p.4.

including supporting resiliency, increasing reliability, assisting with the increase in distributed generation resources, and ensuring quick recovery from natural disasters and terrorist threats.[55] LEI concluded that there was a precedent for North American utilities to build one or more fully functioning Control Centre.[56] Further, when assessed against other utilities for Control Centre construction costs, in the last five years, Toronto Hydro was in line (and slightly lower than) the identified utilities.[57]

Second, LEI used an economic analysis based on the Value of Lost Load methodology to conclude that outages of relatively short durations will cost as much as Toronto Hydro's forecast construction costs for the dual Control Centre.[58] Therefore, if the utility's proposed dual Control Centre could reduce the duration of potential outages or allow for a fully functional alternative in the event that the primary Control Centre is non-functional, the avoided outage costs would mean that the dual Control Centre would pay for itself.[59]

For more information on this review as well as Toronto Hydro's proposed dual Control Centre in the Control Operations Reinforcement program, please refer to Exhibit 2B, Section E8.1

[55] *Ibid* at pp. 5-14.
[56] *Supra* note 53 at p. 27.
[57] *Ibid.*
[58] *Ibid*.
[59] *Supra* note 53 at p. 26.

Appendix A: Annually Reported Measures

Outcomes	OEB Reporting Category	Electricity Distributor Scorecard Measures	Electricity Service Quality Requirement Measures	Custom Performance Measures[1]
Customer Service	Service Quality	▪ New Residential/Small Business Services Connected on Time ▪ Scheduled Appointments Met on Time ▪ Tel. Calls Answered on Time	▪ Connection of New Services (LV)[2] ▪ Connection of New Services (HV)[3] ▪ Appointments Met ▪ Telephone Accessibility ▪ Appointment Scheduling ▪ Rescheduling a Missed Appt. ▪ Telephone Call Abandon Rate ▪ Emergency Response - Urban ▪ Reconnection Performance Standards	
	Customer Satisfaction	▪ First Contact Resolution ▪ Billing Accuracy ▪ Customer Survey Satisfaction Results	▪ Billing Accuracy ▪ Written Responses to Enquiries	▪ Customers on eBills
Safety	Safety	▪ Level of Public Awareness ▪ Compliance with Ontario Reg. 22/04 ▪ Number of General Public Incidents ▪ Rate per 10, 100, 1000 Km of Line		▪ Total Recorded Injury Frequency ▪ Box Construction Conversion ▪ Network Units Modernization

[1] See Exhibit 2B, Section C2 for a detailed discussion of Toronto Hydro's Custom Performance Measures.
[2] Low Voltage ("LV")
[3] High Voltage ("HV")

Outcomes	OEB Reporting Category	Electricity Distributor Scorecard Measures	Electricity Service Quality Requirement Measures	Custom Performance Measures[1]
Reliability	System Reliability	▪ Average Number of Hours that Power to a Customer is Interrupted (SAIDI) ▪ Average Number of Times that Power to a Customer is Interrupted (SAIFI)		▪ SAIDI - Defective Equipment ▪ SAIFI - Defective Equipment ▪ FESI-7 ▪ FESI-6 - Large Customers
	Asset Management	▪ DSP Implementation Progress		▪ System Capacity ▪ System Health (Asset Condition) – Wood Poles ▪ Direct Buried Cable Replacement
Financial	Cost Control	▪ Efficiency Assessment ▪ Total Cost per Customer ▪ Total Cost per Km of Line		▪ Average Wood Pole Replacement Cost ▪ Vegetation Management Cost per Km
	Financial Ratios	▪ Liquidity: Current Ratio ▪ Leverage: Total Debt to Equity Ratio ▪ Regulated ROE - Deemed vs. Achieved		
Public Policy	Conservation & Demand Management	▪ Net Cumulative Energy Savings		
	Connection or Renewable Generation	▪ Renewable Gen. Connection Impact Assessments Completed on Time ▪ Micro-embedded Gen. Fac. Connected on Time	▪ Micro Gen. Fac. Connected on Time	
Environment	Environment			▪ Oil Spills Containing PCBs ▪ Waste Diversion Rate

Toronto Hydro-Electric System Limited
EB-2018-0165
Exhibit 1B
Tab 2
Schedule 1
Appendix B
ORIGINAL
(61 pages)

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED ("THESL")

UNIT COSTS BENCHMARKING STUDY

SECTION I - INTRODUCTION

Torys LLP ("Torys"), acting on behalf of Toronto Hydro-Electric System Limited ("THESL" or "the Company"), engaged UMS Group to conduct a third party independent review of the Company's methodology for deriving unit costs and perform benchmarking comparisons of a pre-selected set of asset categories and maintenance programs; namely:

Asset Categories

- Wood Pole Replacement
- UG Cable (XLPE)
- OH Switches (Manual and Remote / Motor Operated)
- Pole Top Transformer Replacement
- Padmount / UG Transformer Replacement
- Network Transformer / Protector Replacement
- Breaker Replacement (SF6, Oil and Vacuum)

Maintenance Programs

- Vegetation Management
- Pole Test and Treat
- Overhead Line Patrol
- Vault Inspection

Establishing Context

In establishing context for the analyses and conclusions contained within this report, UMS Group:

- Reviewed relevant reports, procedures and system performance data provided by the Company, (***see Appendix A***);
- Was provided complete access to the Company's technical and management staff in the form of conference calls and on-site workshops (e.g.; Design and Construction, Planning and Standards, Enterprise Project Management and Development, Engineering and Regulatory and Finance); and
- Formed a Peer Group Panel, comprised of 17 electric utilities with system and customer demographics like those of THESL, each dealing with the unique cost drivers that are prevalent in large urban settings (***see Appendix B***).

Comparative Analysis

The actual Peer Group comparisons of unit costs accounted for the fact that though there are similarities among the electric utilities selected, there are also differences to be reconciled, including:

- Regional costs,
- Practices in reporting costs,
- System demographics (i.e.; population density and underground utility congestion), and
- Other external factors (i.e.; mandates and constraints regarding performance of work, weather, and vegetation).

Thus, we developed normalization factors (***see Appendix C***), assuring the completeness and relevance of our benchmarks. In addition, with respect to our assessment of the Company's unit costing practices, we adopted an industry-wide perspective (*i.e.;* not constrained by those of the Peer Group Panel).

UMS Group Qualifications

UMS Group, headquartered at 300 Interpace Parkway, Parsippany, NJ, 07054, was retained as an independent expert. With over 28 years of experience conducting comparative performance assessments for the global utilities industry, UMS Group has supported multiple assessments and global benchmarking programs on six continents working with state and province public utility commissions as well as more than 300 electric, gas and water utilities. UMS Group has augmented its analytical capabilities with a team of industry experts who are knowledgeable in best productivity and service-level performance practices to (1) ascertain an electric utility's efficiency and effectiveness in comparison to a qualified peer group, and (2) collaboratively develop aggressive, yet achievable performance improvement plans. Among other qualifications, UMS Group leads several Global Learning and Benchmarking consortia, which together with our portfolio of ongoing client engagements facilitates our ability to maintain "real-time" proprietary cost and operational performance data, correlated to industry "best practices," all supported by an analytical framework built on the premise that industry "best performers" can be both efficient and effective. Appendix D provides additional details regarding UMS Group's qualifications and those of the individuals assigned to this effort.

The UMS Group-assigned expert for this effort, Mr. Jeffrey W. Cummings, fully acknowledges his duties as an expert in accordance with Rule 13 and Form A of the Ontario Energy Board's ("OEB" or "Board") Rules of Practice and Procedure. In so doing, he acknowledges that it is his duty to provide evidence in relation to this report as follows:

- To provide opinion evidence that is fair, objective and non-partisan;
- To provide opinion evidence that related only to matters that are within his area of expertise; and

- To provide such additional assistance that the Board may reasonably require, to determine a matter in issue.

He acknowledges that the duty referred to above prevails over any obligation, which he may owe either Torys or THESL.

Structure of the Report

The ensuing discussion is divided into three sections:

- Section II – Executive Summary: A summarization of our conclusions on the Company's methodology for deriving unit costs and the benchmarking comparisons with the Peer Group Panel,
- Section III – Project Approach: A description of and rationale for the approaches, methodologies, criteria and frameworks adopted to accomplish THESL's stated objectives, and
- Section IV – Summary of Results: An expanded discussion of findings, conclusions and recommendations around the topic of unit costs.

We have provided additional appendices to supplement the information provided in Sections II through IV in the form of comparative charts, graphs and tables, as well as more in-depth explanations of the bases for our evaluations and supporting analytics.

SECTION II – EXECUTIVE SUMMARY

Overview of THESL's Unit Cost Initiative

UMS Group was retained to conduct a review of THESL's methodology for determining the unit costs underlying its distribution system capital and maintenance programs and perform a utility benchmarking study to compare THESL's unit costs with those of a Peer Group Panel. In accomplishing these objectives, UMS Group:

- Conducted a series of workshops / interviews with several THESL stakeholder organizations (e.g.; Design and Construction, Planning and Standards, Enterprise Project Management and Development, Engineering, and Regulatory and Finance),
- Reviewed a myriad of requested reports, procedures and system performance data (***see Appendix A***).
- Established a Peer Group Panel of 17 electric utilities, largely based on demographics (customer density, vegetation, and weather / climate), and factors that add complexity to field execution (e.g.; technical, legislative, regulatory and Bargaining Unit constraints / mandates),
- Designed and administered a survey, seeking fully-loaded unit cost comparators and key accounting and local factors to conduct full-scale normalization (i.e.; accounting for elements beyond currency conversion rates and regional cost adjustments), and
- Analyzed the results of the survey, resulting in the benchmark of seven asset categories and four maintenance programs and a comparison of THESL's unit cost methodology with that of representative sampling of industry peers.

The results of this effort summarized below and expanded upon in Section IV, "Summary of Results," yielded insights from both industry and THESL – specific perspectives.

Industry Perspective Regarding Unit Cost Methodology

Unit costing is a simple concept to grasp. However, the reporting of unit costs for productivity measurement or benchmarking across electric utilities is complex:

- *Asset Categories*: Most utilities map burdened labor (i.e.; vacations, holidays and training less corporate A&G), and material and equipment costs to asset classes based on some form of work order time sheets, and then allocate design, engineering, permitting, warehousing and AFUDC to arrive at a total cost. One can then infer a unit cost by dividing this "fully-loaded" cost by the number of units installed within the same year. Though seemingly straight forward, electric utilities need to account for the (1) carryover of costs from the previous fiscal year, (2) lagging costs applied to uninstalled assets, and (3) different reporting regimens for work performed in-house vs. by a third party.
- *Maintenance Programs*: The industry is consistent in not applying overheads to maintenance costs (only salary burdened by statutory costs and benefits). However, there

are inconsistencies regarding the extent to which maintenance activities are actually "unitized" (often they are managed as "buckets" with budgets based on historical spending patterns with little, if any visibility on units inspected, tested or maintained). Therefore, the fact that 50 percent of the utilities responding to the survey could not provide unit costs for three of the four maintenance programs was not a surprise.

In spite of the industry shortfalls described above, electric utilities have typically used unit costs to provide order-of-magnitude estimates, define staffing levels, create resource-loaded schedules, and/or support financial reporting requirements. Therefore, the above-described methodology has proven adequate. However, as the focus shifts to measuring and comparing performance, inconsistencies in the burdening of capital labor costs, challenges in disaggregating the components of unit costs to arrive at a direct labor unit cost, and lack of transparency into the number of units installed will:

- Preclude effective Performance Management (e.g.; use of fully-loaded unit costs potentially masks productivity improvement or degradation, the inability to unitize maintenance programs limits the monitoring of productivity to budget management, and inconsistencies in the burdening of capital labor costs results in the need for more rigorous "normalization" routines when comparing unit costs across electric utilities),
- Adversely affect management's ability to assess the effectiveness of material procurement policies, and
- Limit insights regarding the trade-offs in using in-house vs. hiring outside contractor resources.

As we surveyed the industry, THESL was among a small percentage of electric utilities that are addressing these issues.

THESL – Specific Perspective Regarding Unit Cost Methodology

THESL has taken some initial steps to bridge the gap between unit cost and performance management by implementing a new "Asset Assembly Unit Structure" ("AAU") for tracking unit costs for in-house capital projects as a complement to "Unit Pricing Contract Management System" ("UPCMS") used for work performed by outside contractors. This change allows for the (1) collection of labor and material cost information at the asset level (in contrast to the project or work order level), (2) comparison of actual and budgeted unit costs on an on-going basis, and (3) disaggregation of the components of unit cost to expand THESL's view of performance. In other words, THESL is disaggregating the components of unit cost to expand its view of performance by separating labor from material, and removing financial loaders on labor to establish a direct labor unit cost.

With respect to the four Maintenance Programs that comprised the scope of this effort, THESL derived cost and unitized information from the vendor invoices, thus reflecting an accurate depiction of unit cost. For maintenance work performed by THESL in-house staff, THESL comports to the industry standard of not applying overheads to maintenance costs (only salary burdened by statutory costs and benefits).

Unit Cost Benchmarks

In reviewing the actual benchmarks, relative to a Peer Group Panel of 17 electric utilities spanning the North American continent (***see Section III and Appendix B***), fully "normalized" comparisons place THESL in the second quartile in all but one asset category. Even without "normalizing" for differences in regional costs, accounting practices, and a myriad of difficulty factors - ***see Section III and Appendix C*** - THESL's position is still fairly strong: Two Asset Categories: Wood Pole and Breaker, and One Maintenance Program: Pole Test and Treat slip slightly into the 3rd quartile.

Table II-1: Fully Normalized Benchmark Comparisons

		Quartile			
Category / Program	**THESL Unit Cost 3-YR Weighted Average**	**Top**	**2nd**	**3rd**	**Bottom**
Wood Pole	$7,434		**X**		
UG Cable (XLPE)	$96		**X**		
OH Switches (Manual and Remote / Motor-Operated	$21,062		**X**		
Pole Top Transformer	$11,761			**X**	
Padmount / UG Transformer	$21,454		**X**		
Network Transformer / Protector	$88,943		**X**		
Breaker (SF6, Oil, and Vacuum)	$85,242		**X**		
Vegetation Management	$2,111		**X**		
Pole Test and Treat	$18		**X**		
Overhead Line Patrol	$44		**X**		
Vault Inspection	$253		**X**		

The seven asset categories represent approximately 60 percent of the maintenance capital budget over the 2014 through 2016 period, and THESL spends approximately 50 percent of all preventative and predictive maintenance costs on the four maintenance programs that comprised this study.

Summary

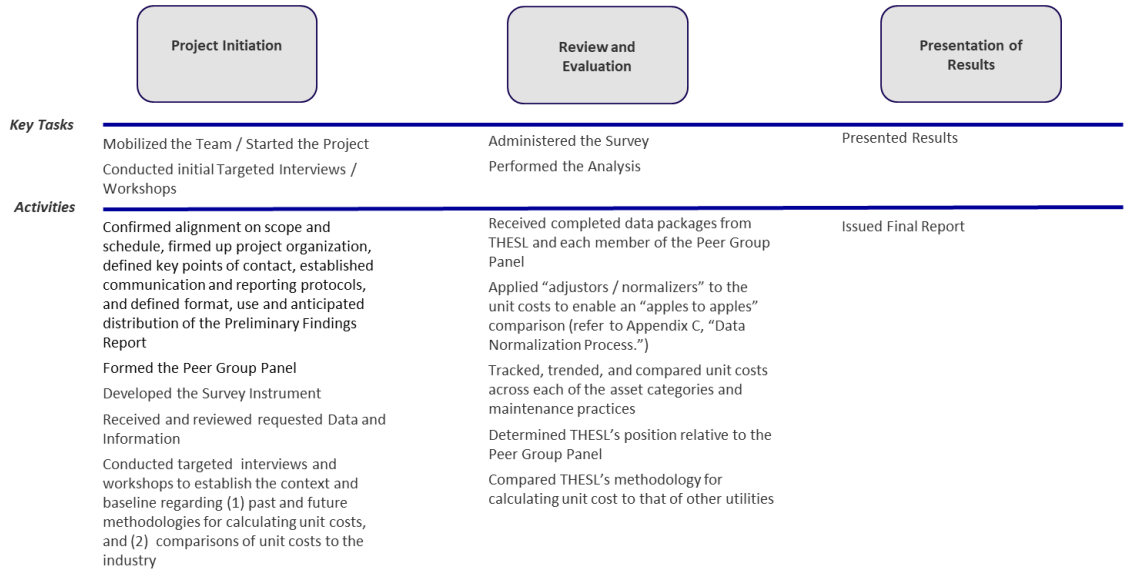
THESL is operating from a position of strength with respect to Unit Costs:

- Fully normalized benchmark comparisons place THESL in a strong position (2nd quartile in all but one of the asset categories / maintenance programs reviewed as part of this project),
- Recent changes in the structures used by THESL to collect and maintain capital unit cost information (i.e.; AAU) opens the door for improving the quality of estimates and the managing of productivity, and
- Methods currently in place to report and manage unit costs related to maintenance programs comport to industry standards.

SECTION III – PROJECT APPROACH

In order to assess the Company's methodology for deriving unit costs and perform benchmarking comparisons of a pre-selected set of asset categories and maintenance programs, UMS Group developed and executed the following work plan:

Figure III-1: Unit Cost Performance Assessment Overview



From Project Initiation to the Presentation of Results, UMS Group applied several elements of its proprietary and time-tested benchmarking and practices assessment methodology to independently assess THESL's approach in deriving unit costs; and benchmark the fully loaded unit costs of a representative cross-section of asset categories and maintenance programs. The following discussion will expound on those aspects of our approach that contributed to our achieving the level of objectivity and relevance committed to in our original proposal.

Peer Group Panel

The Peer Group Panel used for this study consisted of 17 electric utilities; namely:

- AES-IPL (Indianapolis, IN)
- AES-DPL (Dayton, OH)
- Ameren UE (St. Louis, MO)
- Baltimore Gas and Electric (Baltimore, MD)
- Detroit Edison (Detroit, MI)
- Dominion – VP (Richmond, VA)
- ENMAX (Edmonton, AB)
- FirstEnergy CEI (Cleveland, OH)
- Lansing Board of Water and Light (Lansing, MI)

- Pacific Gas and Electric (San Francisco, CA)
- Portland General Electric (Portland, OR)
- Philadelphia Electric Company (Philadelphia, PA)
- SMUD (Sacramento, CA)
- SaskPower (Regina, Saskatchewan)
- Seattle City Light (Seattle, WA)
- Southern California Edison (Southern California including Los Angeles suburbs)
- Xcel Energy – MN (Minneapolis, MN)

In selecting the utilities that comprise this group, our goal was to provide comparisons that would be relevant to an electric utility of THESL's size and complexity (and where there were inconsistencies, apply industry-accepted normalization processes). Table III-1 illustrates THESL's relative position across the myriad of factors considered in conducting like-for-like unit cost comparisons. Though no two electric distribution systems / organizations are identical, THESL is among the highest percentages within this Peer Group Panel in four of five factors that can influence comparisons of fully loaded unit costs.

Table III-1: Distribution of Peer Group Panel across Difficulty Factors (including THESL)

Vegetation		
Low	Medium	High
9	**7**	2
UG Utility Congestion		
Low	Medium	High
1	6	**11**
Population Density (Customers per Square KM)		
Low (<25)	Medium (25 to 100)	High (>100)
2	4	**12**
External Factors		
Low	Medium	High
2	7	9
Weather / Climate		
Mild	Moderate	Harsh
4	**11**	3

NOTES: The area shaded in red reflects the categorization of THESL in each category.

There are several instances where a utility has a large urban center and even larger rural areas (e.g.; Xcel Energy, Ameren UE, and SaskPower). In these cases, we were able to collect data on those districts that serve the larger population centers (i.e.; more closely approximating THESL's demographics).

In considering other Province of Ontario electric distribution systems / organizations, notwithstanding the recently formed Alectra Utilities,[1] THESL stands unique. Toronto city ordinances, a higher cost of living, the amount of underground construction, greater volatility in customer movements, amount of electric distribution assets, and population density, taken in totality, suggested a more appropriate peer group for comparing unit costs, one that consists of electric utilities operating in other regulatory environments / under other jurisdictions.

See Appendix B for more detail regarding the categorization of utilities in Table III-1.

Asset Categories and Maintenance Programs

As stated in Section I – Introduction, the study addressed unit costs for replacing seven categories of assets and conducting four maintenance programs, based initially on a list prepared by THESL, and then modified based on the availability of relevant unit cost information from the Peer Group Panel:

Asset Categories

- Wood Pole Replacement
- UG Cable (XLPE)
- OH Switches (Manual and Remote / Motor Operated)
- Pole Top Transformer Replacement
- Padmount / UG Transformer Replacement
- Network Transformer / Protector Replacement
- Breaker Replacement (SF6, Oil and Vacuum)

Maintenance Programs

- Vegetation Management
- Pole Test and Treat
- Overhead Line Patrol
- Vault Inspection

In assessing the viability of these asset categories / maintenance programs to serve as a proxy for THESL's effectiveness and efficiency in performing work, UMS Group considered two perspectives:

- *Contribution to Capital Expenditures and Maintenance Spending*: The seven asset categories represent approximately 60 percent of the maintenance capital budget over the 2014 through 2016 period; and THESL spends approximately 50 percent of all preventative and predictive maintenance costs in each year on the four maintenance programs that comprised this study.

[1] **It may be appropriate to invite Alectra Utilities to join the Peer Group Panel in future benchmark studies, but only after the organizations around which this organization has formed fully integrate their business practices and accounting processes. Given that the merger was not compete until January 31st, 2017, the time frame for this study (2014-2016), and our view that a 3 to 5-year time frame to complete these types of transformations is reasonable, we felt it appropriate to hold off on including Alectra Utilities in this effort.**

- *Impact on Reliability*: UMS Group has conducted several reliability-related assessments over the past 10 years (ranging from reviewing system performance to adjudging response during major storm events, ***see Appendix E***). In conducting these assessments, the primary areas of concern include vegetation management, equipment failures, underground facilities, and the overall conduct of inspection, test and maintenance programs, all of which the seven asset categories and four maintenance programs that comprised this study are covered.

It is therefore our view that any conclusions around performance resulting from benchmarking or trending the unit costs of these seven asset categories and four maintenance programs are reflective of THESL's operating performance.

Survey Instrument

UMS Group originally identified 20 electric utilities for inclusion in the Peer Group Panel, requiring 12 to assure a valid sample size on which to make meaningful comparisons. We were successful in soliciting the participation of 17, thus enhancing the veracity of the results. The Survey Instrument itself (***see Appendix F***) consisted of three tabs:

- *Unit Costs* for years 2014 through 2016, requesting the fully loaded installation, test, and inspection costs and number of assets installed / test and inspections conducted for each asset category and maintenance program. We averaged the responses were across the three-year period (weighted by number of replacements, inspections and / or tests each year) to "smooth out" the year-to-year fluctuations that are likely to occur in the course of executing an annual capital investment and the maintenance-spending portfolio.
- *Accounting*, requesting (1) brief descriptions of each electric utility's method for determining unit costs, (2) listings of costs (in addition to direct labor and material) that were included in the reporting of costs (in-house work), (3) listings of costs included for contracted work, and (4) the bases for the accounting of these costs (i.e.; GAAP or IFRS). This information was then used to inform the "Pre-Analysis Adjustors" phase of the normalization process (i.e.; account for the different methods used to apply indirect and overhead costs to capital projects), briefly described below and further expanded upon in ***Appendix C***.
- *Local Factors*, providing a listing of any technical, legislative, regulatory and bargaining unit constraints / mandates (referred to as "external factors") that dictate specific practices to be employed in performing work that could have cost ramifications. This information informed the "Full-Scale" phase of the normalization process briefly described below and further expanded upon in ***Appendix C***.

THESL first reviewed and tested the survey instrument, after which UMS Group issued it to each of the electric utilities that agreed to participate in this study. As the completed surveys were returned, UMS Group reviewed the responses and reached out to the respondents as necessary to resolve any apparent outliers and/or address areas where there appeared to be confusion.

Practices Assessment

UMS Group met with several organizations within THESL (e.g.; Design and Construction, Planning and Standards, Enterprise Project Management and Development, Engineering, and Regulatory and Finance) to gain insights and perspective regarding its practices (past, current and future state) to derive unit costs. We used a variety of sources to compare this input with practices in use across the industry (summarized in Section IV-Summary of Results); namely:

- Insights gleaned from the Peer Group responses in the Accounting Tab of the Survey Instrument, augmented by follow up conversations to clarify / lend context to expressed points-of-view,
- Feedback from electric utilities that are part of our Global Learning Consortia (the focus of which includes benchmarking and the sharing of practices to improve performance and reduce costs), most notably the International Distribution Asset Management Study (IDAMS), International Transmission Operations and Maintenance Study (ITOMS), and International Distribution Benchmark Consortium (IDBC), and
- UMS Group knowledge gleaned from routinely working with over 40 to 50 electric utility organizations on an annual basis.

Benchmarking

UMS Group applied its methodology and a tailored work plan to meet THESL's specific objective to benchmark unit costs across seven asset categories and four maintenance programs. Data provided by the previously described Peer Group Panel (***see Appendix B***) established THESL's position with respect to efficiency (cost); and we conducted practices interviews to lend context to these comparisons. In so doing, we were able to ascertain THESL's position relative to the Peer Group Panel, and further inform our views regarding THESL's methodology to calculate unit costs.

The benchmarking process itself consisted of three steps:

- Data Collection and Analysis: As each electric utility indicated its willingness to participate in the Peer Group Panel for this effort, UMS Group transmitted the survey instrument, configured to ensure consistent responses (i.e.; the questions were tightly structured) and support the "normalization" process (allow for valid comparison of fully-loaded unit costs). In concert with sending the survey instrument, UMS Group provided "real time" instruction, and over time, conducted follow-up sessions to track progress, provide clarification and address any questions that might arise. THESL was the initial recipient of the Survey Tool, enabling the identification and remediation of any unanticipated areas of confusion / ambiguity / difficulty in completing the data package; and thus, increasing the likelihood of a valid comparison with the Peer Group Panel. As the surveys were completed, UMS Group performed a validation check for data quality, thus increasing the overall credence of the results. As UMS Group detected instances of potential misinformation, omissions, or anomalies it contacted the respondent and resolved any underlying issues.

- Assure an "Apples-to-Apples" Comparison: The initial formation of a Peer Group Panel represents the first step in assuring valid unit cost comparisons. Table III-1 provides a view of this group relative to five areas that can affect performance (i.e.; Vegetation, UG Utility Congestion, Population Density, External Factors and Weather Climate). There was not a perfect fit for the 17 electric utilities across all five areas, though each member of the peer group panel was "compatible" with THESL in several of these areas (but, none in all of them). UMS Group developed data normalization routines to account for any remaining gaps, enabling valid comparisons of fully loaded unit costs (acknowledging that directional accuracy rather than precision is the acceptable standard in conducting such comparisons). Unique to this project was the use of a phased approach to data normalization. We started with raw comparisons (accounting for the conversion from imperial to metric units and US to Canadian dollars), then applied pre-analysis adjustors (accounting for regional cost factors and the different methods used by electric utilities in burdening unit costs with indirect and overhead costs), and ended with full scale normalization (adjusting for the difficulty factors presented in Table III-1). Addressed in more detail in ***Appendix C***, this staged approach provides transparency to the process of data normalization, deemed appropriate given the wide range of factors that can affect these comparisons.
- Present the Results: UMS Group presented THESL's position relative to the Peer Group Panel median at each of the three phases of normalization (refer to Table IV-1). Recognizing that some might prefer more delineation in the ranking, we also provided a more expansive presentation of THESL's position relative to each member of the Peer Group Panel for the fully normalized scenario in ***Appendix G***.

SECTION IV – SUMMARY OF RESULTS

The following discussion summarizes the results of an approach that

- Utilized UMS Group's proprietary and time-tested benchmarking and practices assessment methodology,
- Drew upon our extensive cost and service level database and best practices library,
- Analyzed input from a survey instrument administered to the Peer Group Panel, and
- Captured insights and perspectives from key management staff within the THESL organization.

Assessment of THESL's Unit Cost Methodology

As a precursor to assessing THESL's Unit Cost Methodology it is important to reemphasize that though a simple concept to grasp, there is enough evidence to suggest that the reporting of unit costs for benchmarking across electric utilities is complex:

- Past applications of unit costs have not necessarily been part of a performance management / improvement process; rather used to provide order-of-magnitude estimates (with no feedback loop to actual execution), and/or support some form of financial reporting (not necessarily linked to managing worker productivity or project / program execution). Further, current data collection processes for cost are heavily biased towards supporting basic finance and accounting functions, and are generally not conducive to providing the necessary granularity (from an operations perspective) to manage costs at the project or program level. The results of the Peer Group Panel Survey validated this point, as only half of the respondents were able to differentiate among the different types of UG cable and breakers, or separate UG network transformers from network protectors (some utilities even encountered challenges in integrating units installed with dollars spent).
- Practices regarding the burdening of capital labor costs are inconsistent across the industry (e.g.; the industry treats training, meetings, conferences, and A&G, and AFUDC / CWIP costs differently), rendering use of publicly available information to conduct such comparisons, marginally useful.
- Maintenance program costs are not always unitized or traceable back to actual installations. Rather, electric utilities often manage them as programs with budgets based on historical spending patterns with little, if any visibility on units inspected, tested or maintained.

Therefore, any industry comparisons of unit costs across electric utilities will require some degree of normalization. However, internal trending through application of a consistent methodology can be an integral part of any electric utility's internal performance management program by tracking changes in performance related to project / program execution.

In assessing THESL's approach to unit costing, it is our view that THESL is in line with the industry, noting the following as the bases for this statement:

- *Asset Categories*: THESL is transitioning from an approach that mirrors (in concept) that which is in effect across the industry to one that will provide even more granularity and transparency in measuring performance. In responding to the survey that drove this effort, THESL aggregated fully loaded unit costs for each asset class within a project (referred to as a "data point"). It then removed outliers (i.e.; those data points that fell within the lower decile and upper decile of the full range of data points), and calculated the average value of all remaining data points (reflecting a combination of in-house and outside contractor costs). This approach was necessary for the following reasons:
    - The structure used to track and maintain unit cost estimates (referred to as the "LU / MU" structure where "LU" signifies "Labor Units" and "MU" signifies "Material Units") lacks sufficient granularity to facilitate traceability of actual costs charged against specific types of assets and repetitive activities during project execution. THESL has since implemented a revised work breakdown structure complete with an "Asset Assembly Unit" structure ("AAU") to capture average costs incurred on repetitive activities. This effort will include specific type of assets that, for internally executed planned capital work, will (1) facilitate an improved feedback loop between budgeted and actual costs for estimated units, and (2) isolate the wrench time component in an activity to better analyze the controllable drivers of field productivity.
    - The "Unit Pricing Contractor Management System" ("UPCMS") used to estimate, track and invoice work performed by outside contractors does not facilitate a view of the actual direct labor costs for completed units of work. .
- *Maintenance Programs*: For work performed by external contractors, THESL extracted unit costs directly from the vendor invoices. Consistent with established industry practices, any in-house labor costs assigned to maintenance programs are not burdened by overheads (i.e.; only statutory costs and benefits are applied).

Benchmarking of THESL's Unit Costs

In accordance with the approach outlined in the previous section, UMS Group benchmarked THESL's Unit Costs at each of the pre-established checkpoints:

- Raw Comparisons ("Median" in Table IV-1), reflecting the conversions from imperial to metric units and US to Canadian dollars, and a few adjustments to the original asset categories / maintenance programs to facilitate Peer Group comparisons (e.g.; combining Network Transformers with Network Protectors),
- Pre-Analysis Adjustors ("Median 1" in Table IV-1), adjusting for regional cost variances and accounting for the different methods used by electric utilities in applying indirect and overhead costs to unit costs, and

- Full-Scaled Normalization ("Median 2" in Table IV-1), incorporating commonly incurred "difficulty factors" (e.g.; Population Density, UG Utility Congestion, External Factors, Weather/Climate, and Vegetation) to further refine the benchmarking process.

Table IV-1 provides an encapsulated summary of THESL's unit costs (reflecting a three-year average through 2016), as compared to the Peer Group median at each of these checkpoints. The red shading reflects the one asset category with unit costs significantly higher than the Peer Group Median, and the yellow shading highlights two asset classes (Wood Pole Replacement and Breaker Replacement) and one maintenance program (Pole Test and Treat) where THESL's unit costs are marginally higher (within 10 percent) than that of the Peer Group Median. So, on balance, THESL compares favorably with the Peer Group Panel.

Table IV-1: THESL and Peer Group Panel Comparisons

	Units	THESL	Median	Median 1	Median 2
Asset Categories					
Wood Pole Replacement	Each	$ 7,434	$ 7,372	$ 7,438	$ 7,665
UG Cable Replacement-XLPE	per Meter	$ 96	$ 96	$ 96	$ 98
OH Switches Replacement	Each	$ 21,062	$ 21,590	$ 22,269	$ 23,451
Pole Top Transformer Replacement	Each	$ 11,761	$ 8,652	$ 9,301	$ 10,514
Padmount / UG Transformer Replacement	Each	$ 21,454	$ 21,491	$ 21,645	$ 23,479
Network Transformer / Protector Replacement	Each	$ 88,943	$ 89,254	$ 87,991	$ 95,369
Breaker Replacement	Each	$ 85,242	$ 85,228	$ 85,128	$ 92,938
Switchgear Replacement	Each	$ 1,529,625	Note 1	Note 1	Note 1
Maintenance Practices					
Vegetation Management	per Line KM	$ 2,111	$ 3,739	$ 3,792	$ 3,965
Pole Test and Treat	Each	$ 18	$ 17	$ 19	$ 19
Overhead Line Patrol	per Line KM	$ 44	$ 44	$ 47	$ 47
Vault Inspection	Each	$ 253	$ 253	$ 261	$ 272

We provide a more detailed presentation of these results in ***Appendix G***.

Implications of the Study

In reviewing our assessment of THESL's Unit Cost methodology, the subsequent benchmarking across seven asset categories and four maintenance programs, and taking stock of industry practices, additional assertions apply:

- The asset categories and maintenance programs selected by THESL represent a valid proxy for trending its performance.
- Within these asset categories and maintenance programs, continued refinement is called for in the reporting, collecting and synthesizing of cost and installation data, particularly as the industry drives to adopt unit costing as a means for trending and comparing performance.

- The industry (particularly in North America and certainly in the US) has not matured to the point where (1) common methodologies exist in deriving unit rates, or (2) managing unit rates is a conscious part of any performance improvement programs.
- Benchmarking is directionally accurate in identifying opportunities for improvement and/or validating current cost and service levels. In applying this methodology to unit costs, absent detailed specifications regarding their calculation (which were developed for this study but not practical when conducting less rigorous comparisons of publicly available data), there are a wide array of variables to consider such an effort difficult.

Appendix A – Supporting Material

UMS Group used the following THESL provided information and data to support the study:

- Unit Cost Survey – THESL September 5, 2017 (THESL Response to Unit Cost and Accounting Tabs on the Survey Form)
- 2-AMPCO-3 Table of Costs
- 2015-2019 Programs to Asset Category Mapping_V2_20170801 (Capital Program Tracker)
- Capital UC Methodology (Capital Unit Cost Methodology-Power Point Presentation)
- Interrogatory Response-AMPCO (1-AMPCO-3 filed May 27, 2016)
- Maintenance Practice
- SAIFI SAIDI 2012-2016 (2012-2016 SAIFI SAIDI by Cause Code with and without MED for Lines and Stations)
- SAP Asset Class Mapping Extract 08082017)Master Spreadsheet of Distribution Assets)
- THESL-Reply Argument (EB-2014-0116 pages 66 through 68 13398-2009 19208026.4)
- THESL LTR Affidavit of A. Rouse 20150116 (THESL Custom Incentive Rate Application (EB-2014-0116 dated January 16, 2015)
- THESL Response AMPCO Motion Settlement 20170121 (THESL Custom Incentive Rate Application (EB-2014-0116 dated January 21, 2015)
- THESL SUB AMPCO Affidavit of M. Walker dated January 13, 2015 (THESL Responses to motions filed by Energy Probe and AMPCO on December 22nd and 31st, 2014)
- UMS Info Request Response 2017-09-15 (Estimated Labor % per Unit by Asset Class – Capital / Regulated Safety Training, and Employee Fringes)
- Unit Cost Local Factors (THESL Response to Local Factors Tab on the Survey Form)
- Unit Costs for Benchmarking Study – Maintenance (VM, Pole Testing, OH Line Patrol and IR Screening, OH Switch Maintenance, and UG Vault Inspection 2014 through 2019)
- Whitepaper Adoption of IAS16 PPE Engineering and Admin Reclassification 2010-04-03 (“EAR” Version V5.7-Final dated July 30, 2010)

Appendix B – Peer Group

The Peer Group Panel used for this study consisted of 17 electric utilities; namely:

- AES-IPL (Indianapolis, IN)
- AES-DPL (Dayton, OH)
- Ameren UE (St. Louis, MO)
- Baltimore Gas and Electric (Baltimore, MD)
- Detroit Edison (Detroit, MI)
- Dominion – VP (Richmond, VA)
- ENMAX (Edmonton, AB)
- FirstEnergy CEI (Cleveland, OH)
- Lansing Board of Water and Light (Lansing, MI)
- Pacific Gas and Electric (San Francisco, CA)
- Portland General Electric (Portland, OR)
- Philadelphia Electric Company (Philadelphia, PA)
- SMUD (Sacramento, CA)
- SaskPower (Regina, Saskatchewan)
- Seattle City Light (Seattle, WA)
- Southern California Edison (Southern California including Los Angeles suburbs)
- Xcel Energy – MN (Minneapolis, MN)

In selecting the utilities that comprise this group, we strove to provide results based on comparisons that would be relevant to an electric utility of THESL's size and complexity (and where there are inconsistencies, apply industry-accepted normalization processes – ***see*** Appendix C). Table B-1 illustrates THESL's relative position across the myriad factors that need to be considered in conducting like-for-like unit cost comparisons of Electric Distribution Companies; and though no two Electric Distribution Systems / Organizations are identical, THESL is among the highest percentages within this peer group for four of five factors that can influence comparisons to unit costs.

Table B-1: Distribution of Peer Group Panel across Difficulty Factors (including THESL)

Vegetation		
Low	**Medium**	**High**
9	**7**	2
UG Utility Congestion		
Low	**Medium**	**High**
1	6	**11**
Population Density (Customers per Square KM)		
Low (<25)	**Medium (25 to 100)**	**High (>100)**
2	4	**12**
External Factors		
Low	**Medium**	**High**
2	7	9
Weather / Climate		
Mild	**Moderate**	**Harsh**
4	**11**	3

NOTE: The area shaded in red reflects the categorization of THESL in each category.

The following extracts were used to categorize the Peer Group utilities in terms of **Vegetation**:

Figure B-1: US Vegetation Density

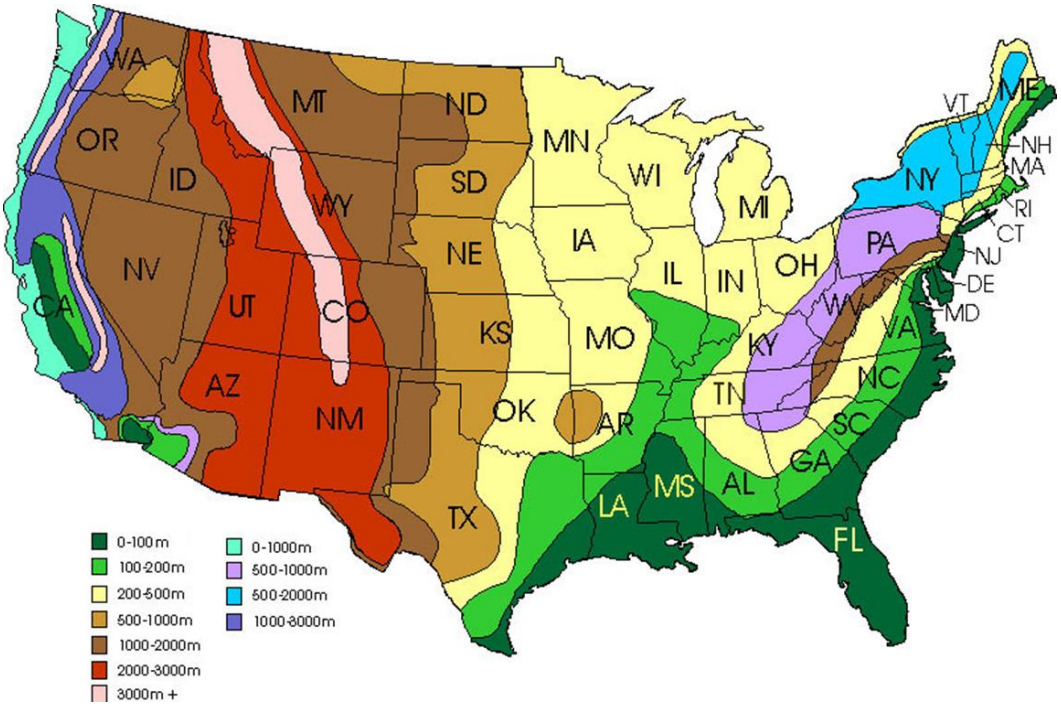
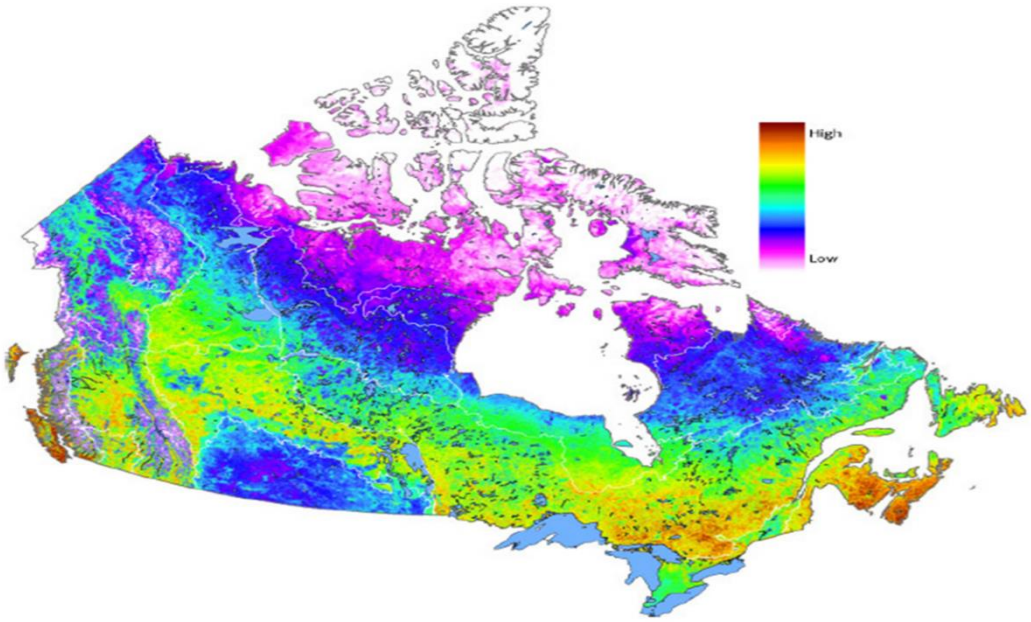
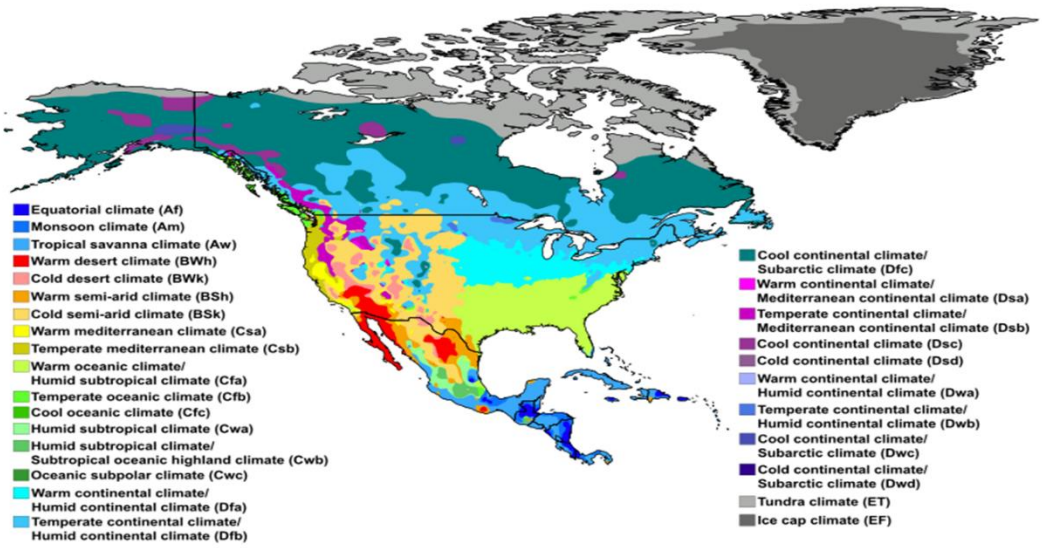


Figure B-2: Canadian Vegetation Density



In addition, with respect to **Weather / Climate**:

Figure B-3: North American Climate Map



The **External Factors** rating reflected responses to our queries regarding applicability of an array of factors that have an adverse effect on field productivity. Based on the responses, an assessment of the level of difficulty confronting each utility was made (high, medium or low).

Table B-2: Summary of External Factors Ratings

Cost Impact Category	THESL	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
Excessive Travel Time	X		X	X	X	X	X	X			X	X	X	X	X	X	X	X
Road restrictions which limit working hours	X	X	X	X	X	X	X	X		X	X	X		X	X	X	X	X
High water table	X	X					X	X		X		X		X	X			
Working next to energized lines (requiring dedicated observer, gloves, etc.)	X	X	X	X	X	X	X	X	X	X	X	X		X	X	X	X	X
Requirements to perform work off hours (i.e., night/weekend)	X		X	X	X	X	X	X		X	X	X	X	X	X	X	X	X
Changed standards requiring rebuilds rather than like-for-like (i.e., clearances)	X	X	X	X		X		X	X			X	X	X				
Excessive switching requirements (i.e., to isolate on dual radial construction)	X	X	X	X				X	X	X			X		X			
Shoring requirements for UG work	X											X		X		X	X	X
Limitations on tree trimming (e.g.; unusually tight clearances)	X	X				X	X			X	X	X		X	X	X	X	X
Prior use of lead cables	X	X							X				X				X	
High fault currents (impacting equipment sourcing)	X	X								X	X	X	X	X	X	X	X	X
Paid duty for police presence on public roads	X	X	X	X	X	X	X			X		X	X	X	X	X	X	X
Extensive use of submersible transformers	X	X						X										X
Environmental regulations	X	X				X	X	X		X		X		X	X	X		X
Insufficient IT Enablement									X								X	
Union Work Rules										X		X		X				
City consent requirements (i.e., customer notification, restoration, progressive clean-up, etc.)	X	X	X	X	X	X	X		X	X	X	X	X	X	X	X	X	X
Level of Difficulty	**High**	**High**	**Medium**	**Medium**	**Low**	**Medium**	**Medium**	**Medium**	**Low**	**High**	**Medium**	**High**	**Medium**	**High**	**High**	**High**	**High**	**High**

NOTE: The "alpha" designations are applied to mask the identity of any specific utility in the Peer Group Panel (a commitment that must be adhered to throughout the process, as guarantees of confidentiality were required to garner their participation in the study).

In addition, the following table substantiates the groupings (High, Medium and Low) of the Peer Group Panel based on **Population Density**.

Table B-3: Peer Group Panel Population Density

Peer Group Panel	Number of Customers	Service Territory (Sq. KM)	Population Density
AES-IPL	480,000	1,368	**351.0**
AES-DPL	520,000	6,000	**86.7**
Ameren UE	1,200,000	113,183	**10.6**
Baltimore Gas and Electric	1,250,000	5,957	**209.8**
Detroit Edison	2,200,000	20,000	**110.0**
Dominion VP	2,600,000	77,700	**33.5**
ENMAX	850,000	1,087	**782.0**
FirstEnergy CEI	700,000	4,403	**159.0**
Lansing Board of Water and Light	100,000	130	**769.2**
Pacific Gas and Electric	16,000,000	181,300	**88.3**
Portland General Electric	862,000	10,360	**83.2**
Philadelphia Electric Company	1,600,000	5,439	**294.2**
Sacramento Municipal Utility District	625,000	1,431	**436.8**
SaskPower	522,000	651,000	**0.8**
Seattle City Light	425,000	342	**1,243.1**
Southern California Edison	15000000	130000	**115.4**
Toronto Hydro	761,000	630	**1,207.9**
Xcel Energy	2,500,000	17,066	**146.5**

NOTE: Though the normalization process is designed to account for differences in key variables (of which Population Density is one), a review of Table B-3 identifies three utilities whose population density is excessively low (SaskPower, Ameren UE and Dominion VP) in comparison to the Peer Group Panel. Removing them from the sample does not change Toronto Hydro's position within the respective quartiles.

The categorization of **UG Utility Congestion** (High, Medium and Low) was based on each utility's response to a direct inquiry from UMS Group.

Other Utilities Serving the Province of Ontario

In establishing the Peer Group Panel, there is rationale for defining a peer group outside of the other utilities that serve the Province of Ontario (as the peer group determines the comparative position with respect to unit costs). First, from purely a demographic perspective, the City of Toronto ranks among the more urban in North America, and as with all predominantly urban electric utilities, they deal with several unique cost drivers, including:

- City ordinances that impact the conduct of work (e.g., restrictions on work hours and additional police/traffic control), logistics that limit access of vehicles and work teams to

the work site (e.g.; traffic flow considerations and congestion), and system design (e.g. fully enclosed substations with due regard to external appearances and limits on use of overhead construction)

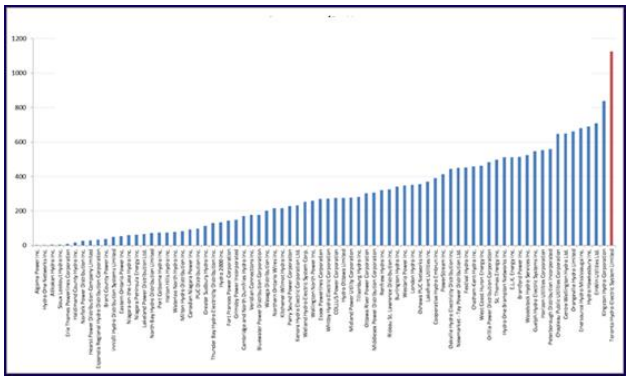
- Higher cost of living which leads to higher wage structures and a noted increase in overheads (offices and other facilities)
- Complex underground construction related to secondary networks (e.g.; limited access, possible interference with other underground utilities, underground cable through concrete duct banks, increased number of feeder ties and back-feed capability, and increased need for technology to provide more automation).
- More volatility in customer movements causing a higher number of turn-on/turn-offs.

Consistent with these factors, notwithstanding the recently formed Alectra Utilities, THESL stands unique among the other Ontario LDCs. The following charts illustrate THESL's relative standing to other Ontario utilities, looking at customer density, amount of installed assets, and comparison to other predominantly urban electric distribution companies.

Population Density

At a customer density of 1,208 customers per square kilometer (as compared to the Ontario utility average of 293), THESL's unit costs are impacted by the requirements for larger and more complex service points, and the sheer volume of traffic and congestion related to high density areas.

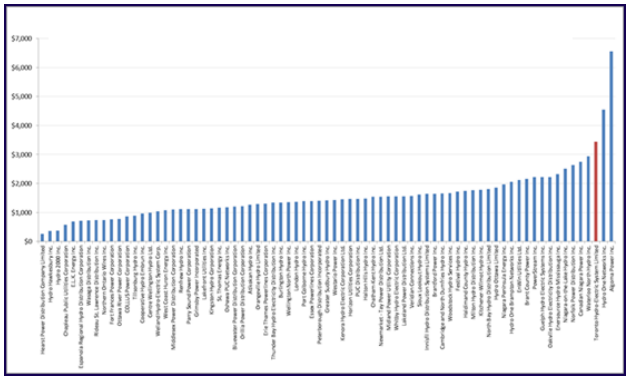
Figure B-4: Customer per KM^2 (Comparison with other Ontario LDCs)



Installed Distribution Assets

As THESL serves a significantly larger number of customers (10 times that of the Provincial average), they are among the top 3 in terms of fixed assets per customer (i.e.; more assets to maintain and ultimately replace on a per customer basis).

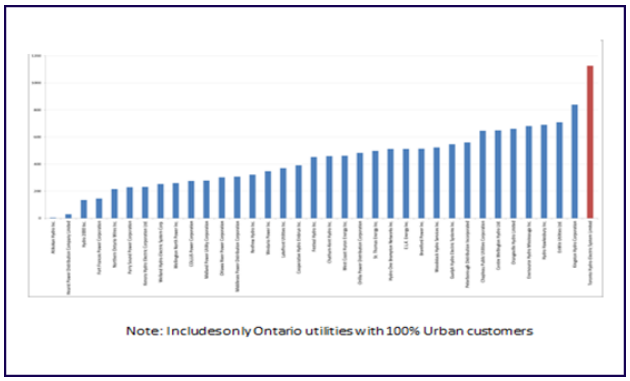
Figure B-5: Installed Distribution Assets (Comparison with Ontario LDCs)



Urban Population Density

Narrowing the view to Electric Distribution Companies serving only urban customers, THESL is at the far end of the scale; and is the second largest in total number of customers.

Figure B-6: Customers per Urban KM^2



The uniqueness among LDCs is always an issue when conducting comparative analyses (i.e.; the need for normalizing the inputs). However, in this instance, the sheer magnitude and scope of the differences in customer density, system configuration, and number of installed assets, combined with the external factors that are typically intensified in large urban areas, presents THESL as an outlier relative to all the other Ontario LDCs. Therefore, we have established a peer group that presents a more compatible view of these differentiating factors, thus facilitating a more valid comparison of unit costs.

Appendix C – Unit Cost Benchmarking Normalization

Prior to conducting comparative analyses with the Panel Group Panel (***see*** Appendix B), it was necessary to "normalize" the unit cost performance across all participating electric utilities. The selection of the panel accounted for key criteria to facilitate proper comparisons (*e.g.;* mix of urban and rural centers, cross-section of public and investor-owned utilities, with minor exceptions climate and number of customer served, existence of an underground network, and externally imposed mandates / constraints that affect productivity). Yet no two electric utilities or the specific factors that affect their costs are ever identical - thus, the need to "normalize."

Defining the "Normalizing" Variables

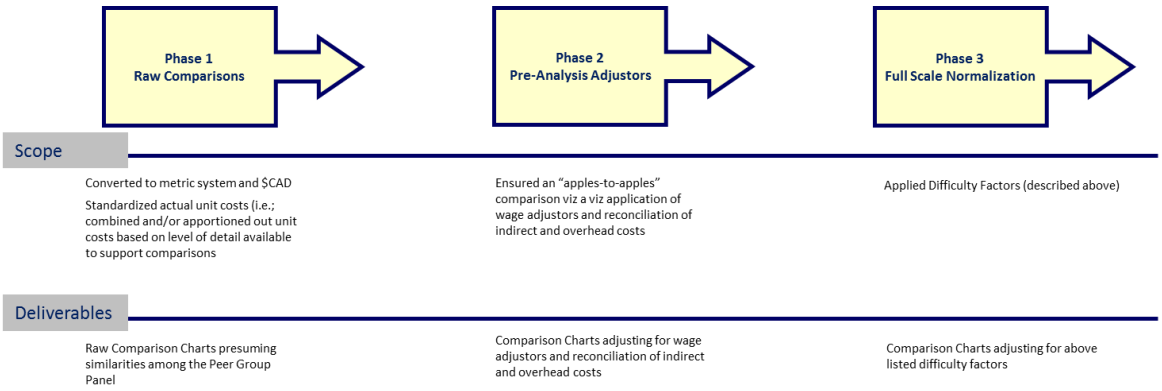
For this study, we established two categories of variables:

- Cost-Related Variables:
  - *Regional Cost Differences* (applying regional cost adjustors based on average wages in each of the major cities that comprise the Peer Group Panel)
  - *Accounting Practices* (relating to the handling of indirect costs and overhead allocations viz a viz unit costs for asset replacements and / or the conduct of maintenance practices.
- Difficulty Factors, acknowledging that system and city-specific demographics play a role in worker productivity:
  - *Population Density* (potentially impacts accessibility, increases awareness of public safety, and creates added distractions during the performance of work),
  - *Underground Utility Congestion* (increases the propensity for third-party damage and accounts for the impact of tight spaces, both factors that can contribute to the slowdown of work),
  - *External Factors* (accounts for varying degrees of technical, legislative, regulatory and bargaining unit constraints / mandates that dictate the specific practices to be employed in performing work, many of which inhibit the flow of work),
  - *Weather*, (accounts for the differences between harsh and temperate climates and their impact on productivity), and
  - *Vegetation* (besides the direct correlation to one of the maintenance programs being benchmarked, accounts for the challenges that increased vegetation might pose in gaining access to critical assets).

Applying the "Normalizing" Variables

In applying these variables, we instituted a three-phased approach, thereby availing the reader total transparency to the comparisons at three major junctures of the process.

Figure C-1: Three-Phased Data Normalization Process



- **Raw Comparisons (Phase 1)** involved, where appropriate, the conversion from imperial to metric units and US to Canadian dollars. As we opted to adopt a three-year average (2014 through 2016), the conversion rate of $US to $CDN at the end of each year was applied (accounting for the ever-changing conversion rate over the three-year period).

- **Pre-Analysis Adjustors (Phase 2)** involved the application of regional cost adjustors and accounting for the different methods used by electric utilities to apply indirect and overhead costs to unit costs.

  Table C-1 illustrates the derivation of regional cost adjustors, sources for which include the Board of US Labor Statistics and, for Canada, individual governmental provincial websites. Using "average wage" as a proxy, we decreased the unit costs at electric utilities with regional costs higher than THESL (i.e.; ENMAX, Pacific Gas and Electric and Southern California Edison) and increased all others (except Seattle City Light, which is on a par with THESL), these changes all proportionate to their variance from the average wage for Toronto.

Table C-1: Regional Cost Adjustors

Peer Group Panel	Average Wage	Factor	Adjustment
AES-IPL	$ 58,082	0.74	1.35
AES-DPL	$ 58,627	0.75	1.34
Ameren UE	$ 59,818	0.76	1.31
Baltimore Gas and Electric	$ 68,101	0.87	1.15
Detroit Edison	$ 63,860	0.82	1.23
Dominion VP	$ 60,896	0.78	1.29
ENMAX	$ 104,410	1.33	0.75
FirstEnergy CEI	$ 59,830	0.76	1.31
Lansing Board of Water and Light	$ 58,962	0.75	1.33
Pacific Gas and Electric	$ 94,438	1.21	0.83
Portland General Electric	$ 66,910	0.85	1.17
Philadelphia Electric Company	$ 66,452	0.85	1.18
Sacramento Municipal Utility District	$ 67,816	0.87	1.15
SaskPower	$ 89,431	1.14	0.88
Seattle City Light	$ 78,492	1.00	1.00
Southern California Edison	$ 102,400	1.31	0.76
Toronto Hydro	**$ 78,280**	**1.00**	**1.00**
Xcel Energy	$ 68,212	0.87	1.15
	Average Adjustment		**1.13**

NOTE: We made adjustment indicated in Table C-1 to the labor component of Unit Cost, assuming the following split between labor and non-labor costs

Table C-2 Labor and Non-Labor Cost Split

Asset Category / Maintenance Program	Labor Costs	Non-Labor Costs
Wood Pole Replacement	60%	40%
UG Cable Replacement	50%	50%
OH Switches Replacement	40%	60%
Pole Top Transformer Replacement	50%	50%
Padmount / UG Transformer Replacement	50%	50%
Network Transformer / Protector Replacement	40%	60%
Breaker Replacement	40%	60%
Vegetation Management	70%	30%
Pole Test and Treat	70%	30%
Overhead Line Patrol	70%	30%
Vault Inspection	70$	30%

In further adjusting for the differences in Accounting Practices, we queried each of the electric utilities as to what non-direct labor and material were and were not included in the unit costs, distinguishing between utility and outside contractor-performed work. Table C-3 illustrates the differences across the Peer Group Panel.

Table C-3: Composition of Unit Costs
(In addition to Direct Labor and Material)

Category	THESL	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
Design and Permitting Costs	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Project Management / Supervisory Costs	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Other Project-Related Costs (e.g.; Fleet and Warehousing)	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Other Labor-Related Costs (e.g.; Training, Meetings and Conferences)	X	X	X	X	X	X	X	X	X	X	X	X		X	X	X	X	
Employee-Related Costs (Benefits, Pensions and Bonuses)	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Divisional Administrative and General Costs			X	X				X	X	X		X			X	X		X
AFUDC / CWIP	X		X	X	X			X	X	X			X	X	X	X		X
Adjustment Factor	1.0	1.02	0.95	0.95	1.0	1.02	1.02	0.95	0.95	0.95	1.02	1.0	1.02	1.0	0.95	0.95	1.02	1.0

The adjustment factors, ranging between 0.95 and 1.02, reflect comparisons with THESL (i.e.; those with more categories in their Unit Costs calculation than THESL were reduced by five percent; and those with fewer categories in their Unit Costs calculation than THESL were increased by two percent). There was no noted difference in applying loaders to work performed by outside contractors.

- **Full-Scale Normalization (Phase 3)** applied the above described difficulty factors in further normalizing unit costs across all 18 participating electric utilities. Table C-4 provides the bases for these adjustments.

Table C-4: Full Scale Normalization

Utility	Population Density	UG Utility Congestion	External Factors	Weather / Climate	Vegetation
Impact	High / Medium/ Low	High / Moderate / Low	High / Medium / Low	Mild / Moderate / Harsh	High / Medium / Low
Source of Impact Assessment	Table B-3	Peer Group Survey	Table B-2	Figure B-3	Figures B-1 and B-2
AES-IPL	High	High	Medium	Moderate	Low
AES-DPL	Medium	Low	Medium	Moderate	Low
Ameren UE	Low	Moderate	Low	Moderate	Low
Baltimore Gas and Electric	High	High	High	Moderate	Medium
Detroit Edison	High	Moderate	Medium	Moderate	Low
Dominion-VP	Medium	Moderate	Medium	Mild	High
ENMAX	High	Moderate	Medium	Harsh	Low
FirstEnergy-CEI	High	High	High	Moderate	Medium
Lansing Board of Water and Light	High	Moderate	Low	Moderate	Low
Pacific Gas and Electric	High	High	High	Mild	Medium
Portland General Electric	Medium	High	High	Moderate	Medium
Philadelphia Electric Company	High	High	Medium	Moderate	High
Sacramento Municipal Utility District	High	High	High	Mild	Medium
SaskPower	Low	Moderate	Medium	Harsh	Low
Seattle City Light	High	High	High	Moderate	Medium
Southern California Edison	High	High	High	Mild	Low
Toronto Hydro	High	High	High	Moderate	Medium
Xcel Energy	High	High	High	Harsh	Low

In addition, Table C-5 outlines the framework used in applying these normalizing factors.

Table C-5: Difficulty Factor Scoring Criteria

Domain	Weighting	Metric	Source	Ordinal Ranking Assignment
Population Density	20%	Customers per KM^2 translated to High / Medium Low	Table B-3	High: 6 Medium: 5 Low: 4
UG Utility Congestion	20%	High / Moderate / Low	Peer Group Survey	High: 6 Medium: 5 Low: 4
External Factors	20%	High / Medium /Low	Table B-2	High: 6 Medium: 5 Low: 4
Weather / Climate	20%	Harsh / Moderate / Mild	Figure B-3	High: 6 Medium: 5 Low: 4
Vegetation	20%	High / Medium / Low	Figures B-1 and B-2	High: 6 Medium: 5 Low: 4

In applying the domain rankings to specific Asset Categories and Maintenance Programs, it is important to note that depending on the operating environment for each category / program, not all the domains in Table C-5 applied. Tables C-6 and C-7 account for this further refinement to the normalization process.

Table C-6: Domain Applicability Matrix by Asset Category / Maintenance Program

Operating Environment	Asset Category / Maintenance Program	Domain				
		Population Density	UG Utility Congestion	External Factors	Weather / Climate	Vegetation
Overhead (OH)	Wood Pole OH Switch Pole Top Transformers Breaker Pole Test and Treat OH Line Patrol	**X**		**X**	**X**	**X**
Underground (UG)	UG Cable Padmount / UG Transformer Network Transformer / Protector Vault Inspection	**X**	**X**	**X**	**X**	
Vegetation Management	Vegetation Management			**X**	**X**	**X**

Table C-7: Full-Scale Normalization Factors (by Domain and Operating Environment)

Peer Group Panel	Population Density	UG Utility Congestion	External Factors	Weather / Climate	Vegetation	OH Adjustment		UG Adjustment		VM Adjustment	
						Score	Factor	Score	Factor	Score	Factor
AES-IPL	6	6	5	5	4	20	**1.09**	22	**1.04**	14	**1.13**
AES-DPL	5	5	5	5	4	19	**1.14**	20	**1.13**	14	**1.13**
Ameren UE	4	5	4	5	4	17	**1.23**	18	**1.22**	13	**1.19**
Baltimore Gas and Electric	6	6	6	5	5	22	**1.00**	23	**1.00**	16	**1.00**
Detroit Edison	6	5	5	5	4	20	**1.09**	21	**1.09**	14	**1.13**
Dominion VP	5	5	5	4	6	20	**1.09**	19	**1.17**	15	**1.06**
ENMAX	6	5	5	6	4	21	**1.05**	22	**1.04**	15	**1.06**
FirstEnergy CEI	6	6	6	5	5	22	**1.00**	23	**1.00**	16	**1.00**
Lansing Board of Water and Light	6	5	4	5	4	19	**1.14**	20	**1.13**	13	**1.19**
Pacific Gas and Electric	6	6	6	4	5	21	**1.05**	22	**1.04**	15	**1.06**
Portland General Electric	5	6	6	5	5	21	**1.05**	22	**1.04**	16	**1.00**
Philadelphia Electric Company	6	6	5	5	6	22	**1.00**	22	**1.04**	16	**1.00**
Sacramento Municipal Utility District	6	6	6	4	5	21	**1.05**	22	**1.04**	15	**1.06**
SaskPower	4	5	5	6	4	19	**1.14**	20	**1.13**	15	**1.06**
Seattle City Light	6	6	6	5	5	22	**1.00**	23	**1.00**	16	**1.00**
Southern California Edison	6	6	6	4	4	20	**1.09**	22	**1.04**	14	**1.13**
Toronto Hydro	6	6	6	5	5	22	**1.00**	23	**1.00**	16	**1.00**
Xcel Energy	6	6	6	6	4	22	**1.00**	24	**0.96**	16	**1.00**
					Average Adjustment		**1.07**		**1.07**		**1.07**

Tables C-8 through C-10 present the outputs of the three-phased approach to normalization across the seven asset categories and four maintenance programs, noting that the Peer Group Panel is intentionally masked to comply with our commitment regarding the confidential handling of this information.

Table C-8: Raw Comparisons – Phase 1
(Metric and Canadian Dollar Conversion)

Asset Category	Unit	THESL	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	Median
Wood Pole Replacement	Each	$ 7,434	$ 6,190	$ 5,552	$ 5,957	$ 5,229	$ 4,801	$ 7,567	$ 7,533	$ 5,174	$ 7,452	$ 7,233	$ 7,286	$ 7,964	$ 7,848	$ 7,457	$ 7,762	$ 7,310	$ 7,548	$ 7,372
UG Cable Replacement (XLPE)	Meter	$ 96	$ 72	$ 79	$ 84	$ 77	$ 99	$ 92	$ 96	$ 95	$ 101	$ 93	$ 90	$ 99	$ 96	$ 98	$ 97	$ 88	$ 100	$ 96
OH Switch Replacement	Each	$ 21,062	$ 27,456	$ 21,086	$ 19,095	$ 18,282	$ 21,574	$ 21,786	$ 23,278	$ 21,605	$ 16,813	$ 17,762	$ 20,755	$ 23,795	$ 26,310	$ 22,300	$ 22,433	$ 18,929	$ 24,154	$ 21,590
Pole Top Transformer Replacement	Each	$ 11,761	$ 7,006	$ 8,090	$ 7,412	$ 8,093	$ 8,157	$ 9,300	$ 12,576	$ 7,491	$ 10,166	$ 12,043	$ 7,285	$ 12,435	$ 13,683	$ 8,527	$ 8,326	$ 10,358	$ 8,777	$ 8,652
Padmount / UG Transformer Replacement	Each	$ 21,454	$ 19,684	$ 18,239	$ 18,938	$ 18,612	$ 19,475	$ 19,309	$ 22,375	$ 18,689	$ 21,691	$ 21,855	$ 21,738	$ 23,025	$ 24,610	$ 21,670	$ 17,452	$ 21,529	$ 21,910	$ 21,491
Network Transformer / Protector Replacement	Each	$ 88,943	$ 81,811	$ 80,099	$ 79,766	$ 72,128	$ 81,871	$ 73,024	$ 92,465	$ 72,905	$ 91,423	$ 86,034	$ 89,565	$ 90,700	$ 94,052	$ 94,811	$ 92,043	$ 91,030	$ 90,472	$ 89,254
Breaker Replacement	Each	$ 85,242	$ 74,373	$ 78,582	$ 74,057	$ 71,214	$ 81,570	$ 79,773	$ 89,565	$ 78,571	$ 88,328	$ 85,214	$ 86,356	$ 87,765	$ 88,240	$ 88,316	$ 82,809	$ 88,139	$ 87,093	$ 85,228
Maintenance Practice																				
Vegetation Management	Line KM	$ 2,111	$ 4,071	$ 2,403	$ 2,697	$ 3,786	$ 3,713	$ 3,683	$ 3,436	$ 4,369	$ 3,312	$ 4,264	$ 4,030	$ 3,765	$ 3,600	$ 4,134	$ 4,564	$ 3,115	$ 4,534	$ 3,739
Pole Test and Treat	Each	$ 18	$ 15	$ 16	$ 17		$ 17		$ 19			$ 15				$ 15		$ 18		$ 17
Overhead Line Patrol	Line KM	$ 44	$ 40	$ 44	$ 45		$ 46		$ 46			$ 41				$ 44		$ 42		$ 44
Vault Inspection	Each	$ 253	$ 214	$ 221	$ 215		$ 229		$ 275			$ 257				$ 283		$ 256		$ 253

Table C-9: Pre-Analysis Adjustors - Phase 2
(Regional Cost Adjustments and Accounting Practices)

Asset Category	Unit	THESL	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	Median 1
Wood Pole Replacement	Each	$ 7,434	$ 7,481	$ 6,375	$ 6,798	$ 6,197	$ 5,560	$ 9,040	$ 6,082	$ 5,882	$ 7,802	$ 8,166	$ 7,960	$ 7,442	$ 7,835	$ 6,083	$ 8,027	$ 8,124	$ 6,773	$ 7,438
UG Cable Replacement (XLPE)	Meter	$ 96	$ 85	$ 88	$ 93	$ 89	$ 112	$ 108	$ 80	$ 105	$ 104	$ 104	$ 96	$ 94	$ 96	$ 82	$ 99	$ 96	$ 91	$ 96
OH Switch Replacement	Each	$ 21,062	$ 31,460	$ 22,818	$ 20,573	$ 20,539	$ 23,993	$ 24,759	$ 19,900	$ 23,214	$ 17,058	$ 19,407	$ 22,036	$ 22,834	$ 26,281	$ 19,189	$ 22,570	$ 20,461	$ 22,501	$ 22,269
Pole Top Transformer Replacement	Each	$ 11,761	$ 8,248	$ 9,022	$ 8,222	$ 9,342	$ 9,260	$ 10,840	$ 10,452	$ 8,283	$ 10,478	$ 13,377	$ 7,847	$ 11,776	$ 13,664	$ 7,146	$ 8,493	$ 11,355	$ 8,026	$ 9,301
Padmount / UG Transformer Replacement	Each	$ 21,454	$ 23,173	$ 20,340	$ 21,007	$ 21,485	$ 22,108	$ 22,506	$ 18,596	$ 20,663	$ 22,358	$ 24,276	$ 23,415	$ 21,805	$ 24,576	$ 18,162	$ 17,803	$ 23,600	$ 20,035	$ 21,645
Network Transformer / Protector Replacement	Each	$ 88,943	$ 93,741	$ 86,679	$ 85,938	$ 81,032	$ 91,052	$ 82,989	$ 79,048	$ 78,336	$ 92,755	$ 94,003	$ 95,093	$ 87,038	$ 93,951	$ 81,584	$ 92,603	$ 98,403	$ 84,280	$ 87,991
Breaker Replacement	Each	$ 85,242	$ 85,218	$ 85,037	$ 79,788	$ 80,006	$ 90,717	$ 90,660	$ 76,569	$ 84,425	$ 89,615	$ 93,107	$ 91,686	$ 84,222	$ 88,145	$ 75,995	$ 83,312	$ 95,277	$ 81,133	$ 85,128
Maintenance Practice																				
Vegetation Management	Line KM	$ 2,111	$ 5,049	$ 2,838	$ 3,164	$ 4,604	$ 4,386	$ 4,507	$ 2,692	$ 5,102	$ 3,521	$ 4,891	$ 4,465	$ 3,471	$ 3,593	$ 3,280	$ 4,784	$ 3,510	$ 3,991	$ 3,792
Pole Test and Treat	Each	$ 18	$ 19	$ 19	$ 20		$ 20		$ 15			$ 17				$ 12		$ 20		$ 19
Overhead Line Patrol	Line KM	$ 44	$ 50	$ 52	$ 53		$ 54		$ 36			$ 47				$ 35		$ 47		$ 47
Vault Inspection	Each	$ 253	$ 266	$ 261	$ 252		$ 270		$ 215			$ 295				$ 224		$ 289		$ 261

Table C-10 Full-Scale Normalization – Phase 3
(Difficulty Factors)

Asset Category	Unit	THESL	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	Median 2
Wood Pole Replacement	Each	$ 7,434	$ 7,481	$ 6,955	$ 7,724	$ 7,605	$ 6,066	$ 9,862	$ 6,358	$ 6,684	$ 8,156	$ 8,166	$ 8,322	$ 8,457	$ 7,835	$ 6,636	$ 8,027	$ 8,124	$ 7,081	$ 7,665
UG Cable Replacement (XLPE)	Meter	$ 96	$ 85	$ 92	$ 105	$ 108	$ 122	$ 126	$ 83	$ 119	$ 109	$ 108	$ 101	$ 106	$ 96	$ 86	$ 95	$ 96	$ 95	$ 98
OH Switch Replacement	Each	$ 21,062	$ 31,460	$ 24,892	$ 23,378	$ 25,207	$ 26,175	$ 27,010	$ 20,805	$ 26,380	$ 17,834	$ 19,407	$ 23,038	$ 25,948	$ 26,281	$ 20,933	$ 22,570	$ 20,461	$ 23,524	$ 23,451
Pole Top Transformer Replacement	Each	$ 11,761	$ 8,248	$ 9,843	$ 9,343	$ 11,466	$ 10,101	$ 11,825	$ 10,927	$ 9,412	$ 10,954	$ 13,377	$ 8,203	$ 13,382	$ 13,664	$ 7,796	$ 8,493	$ 11,355	$ 8,391	$ 10,514
Padmount / UG Transformer Replacement	Each	$ 21,454	$ 23,173	$ 21,224	$ 23,747	$ 26,155	$ 24,030	$ 26,420	$ 19,405	$ 23,358	$ 23,330	$ 25,332	$ 24,433	$ 24,650	$ 24,576	$ 18,951	$ 17,029	$ 23,600	$ 20,906	$ 23,479
Network Transformer / Protector Replacement	Each	$ 88,943	$ 93,741	$ 90,448	$ 97,147	$ 98,648	$ 98,969	$ 97,422	$ 82,485	$ 88,554	$ 96,788	$ 98,090	$ 99,227	$ 98,391	$ 93,951	$ 85,132	$ 88,577	$ 98,403	$ 87,945	$ 95,369
Breaker Replacement	Each	$ 85,242	$ 85,218	$ 92,768	$ 90,668	$ 98,189	$ 98,964	$ 98,902	$ 80,050	$ 95,938	$ 93,688	$ 93,107	$ 95,854	$ 95,706	$ 88,145	$ 82,904	$ 83,312	$ 95,277	$ 84,821	$ 92,938
Maintenance Practice																				
Vegetation Management	Line KM	$ 2,111	$ 5,049	$ 3,193	$ 3,559	$ 5,467	$ 4,935	$ 4,789	$ 2,861	$ 6,059	$ 3,521	$ 4,891	$ 4,744	$ 3,688	$ 3,593	$ 3,690	$ 4,784	$ 3,510	$ 4,241	$ 3,965
Pole Test and Treat	Each	$ 18	$ 19	$ 21	$ 23		$ 22		$ 16			$ 17				$ 13		$ 20		$ 19
Overhead Line Patrol	Line KM	$ 44	$ 50	$ 56	$ 60		$ 59		$ 38			$ 47				$ 38		$ 47		$ 47
Vault Inspection	Each	$ 253	$ 266	$ 272	$ 285		$ 293		$ 225			$ 308				$ 234		$ 289		$ 272

Appendix D – UMS Group and Project Team Qualifications

UMS Group is an International Utility Management Consulting firm founded in 1989 to serve the global utility industry. We specialize in enterprise-level value creation, performance management solutions, and utility asset management. We are a private employee-owned company incorporated in New Jersey with headquarters in Parsippany, New Jersey, and major branch offices in Australia, The Netherlands, and The Philippines. This project was managed out of UMS Group's Headquarters Office, located at Morris Corporate Center 1, 300 Interpace Parkway, Suite C380, Parsippany, NJ 07054.

We bring to our clients a unique knowledge of global industry best practices, an advanced library of diagnostic methodologies and performance benchmarking data, and a strong base of utility strategic and operational expertise. We combine experienced utility consultants and seasoned industry professionals with world class tools and intellectual capital to assist our clients in diagnosing problems, designing solutions, and implementing change.

We offer:

- A team of senior consultants who have "been there and done that" in implementing change in difficult cultural, political, and labor environments.
- Strong insights into key trends and directions across the global utility industry and comprehensive understanding of the underlying drivers and emerging technology and strategies for creating competitive advantage.
- Time-tested and accepted methodologies for conducting current state assessments in four core areas which we believe are the key to achieving best practices or best-in-class performance: Operating (and Accountability) Model, Business Processes and Practices, Competencies, and Technology, Data and Information Management.
- A comprehensive set of tools and approaches that quickly and effectively build on performance insights gained from assessments, to create actionable improvement strategies and plans.
- Experience in the successful development and implementation management of projects and initiatives that drive improvements in the performance of operations, business and financial, customer service, and asset management.

Our specific product and service offerings fall under the categories of **Performance** or **Asset Management**.

Performance Management

- Performance diagnostics (i.e. *comparative analyses*) to identify areas in which to improve operational efficiencies (cost level) while increasing operational effectiveness (service level).

- Enterprise-wide and function-specific *benchmarking* to substantiate rate case filings, identify reliability improvement initiatives including service interruption mitigation and restoration, and support Capital and O&M budget submittals to external stakeholders.
- Development of *operational dashboards* to provide line-of-sight performance tracking between corporate strategy and specific investment and spending programs.

Asset Management

- Asset Management Business Architecture, Strategy and Planning: Major *Strategic Asset Management Transformations* facilitated by UMS Group, have achieved significant cost reductions/productivity improvements, process efficiency and effectiveness improvements, system reliability and customer satisfaction improvements and OPEX and CAPEX optimization. This practice competency has given rise to many decision support tools and a corporate performance dashboard design and implementation practice.
- Life-Cycle Investment Decision-Making and Optimization: Services range from improving practices and methodologies related to *aging infrastructure* to refining existing tools / installing new tools to aid in *Capital Investment and O&M Program Portfolio Optimization* supporting the notion of maximizing value enterprise-wide (comprehensive accounting of benefits aligned to corporate strategy) while operating within a pre-established budget and risk profile.
- Assess Management Program Assessments: As an *endorsed Assessor by the Institute of Asset Management*, UMS Group has conducted a significant number of PAS 55 / ISO55000 assessments, comparing utilities' compliance with basic asset management policies and practices. We view this standard as a lens in ensuring all asset management activities within a utility support the achievement of its business plan, at optimal cost and on a sustainable basis.

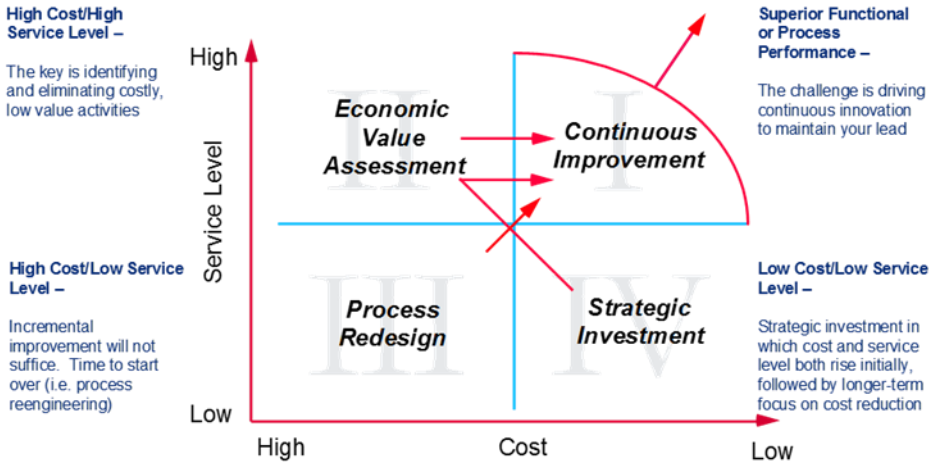
UMS Group Competencies and Skills

UMS Group has consistently demonstrated the following key competencies and skills required to complete a unit cost measurement and benchmarking effort in the utility industry:

- *Operational Knowledge of the Industry*: The ability to effectively converse with the utility Subject Matter Experts (critical to discovering the information under the numbers) requires a certain level of conversance with the factors that drive unit costs. The core team of four consultants that contributed to this effort combine for over 120 years of experience, three of whom have worked (either as full-time staff or in a consulting capacity) within utility organizations.
- *Development of a Performance Management Framework*: UMS Group has perfected the use of a 2-dimensional view of performance, calling for the simultaneous measurement of cost and service level in conducting performance diagnostic and comparative analyses.

Though this effort was largely cost-oriented, one still had to factor for the reality that maintaining an acceptable level of service (*e.g.;* reliability, power quality and customer service) is vital; and therefore, any comparisons to a Peer Group Panel had to factor for varying levels of customer expectations.

Figure D-1: UMS Group Performance Management Framework



- *Data Normalization*: Comparative Analysis (*i.e.;* Benchmarking), performed correctly, is directionally accurate in that it points towards areas where well-targeted intervention can result in improved performance (in this case reduced unit costs), and provides a point for real-time performance comparisons. However, normalization for factors such as customer density, amount and accessibility of vegetation, and weather need to be accounted for in presenting any comparisons (in the form of adjustments and / or mitigating statements). Specifically, about unit costs, there are issues with the peer data that need to be addressed / adjusted for to ensure an "apples-to-apples" comparison including the use of burdened vs unburdened rates, inclusion of equipment costs, whether work is performed energized or de-energized, comparability of work performed, etc. In forming the Peer Group Panel, these types of variances can be reduced, but never eliminated. Being able to assess the extent to which these factors negate exact comparisons and draw on years of benchmarking experience was critical to managing the presentation and interpretation of these results.
- *Communication*: The ability to frame the conversation in a manner that proactively dismisses the false impressions that benchmarking can reveal, yet pose paradigms that are grounded and lead to constructive discussion are critical to any project's success. The previously presented competencies played a key role in conveying the correct message; but so was operating discipline of thoroughly vetting a developing narrative before issuing any final documentation. Our views were substantiated by the data and information we requested and received and answers to the questions we posed, but may not have, at the first pass, represented the full story. Therefore, the ability to listen, interpret and modify views (requiring evidence of any bases to change them) was at least as important as the

technical elements around industry knowledge, performance management and data normalization.

We have accomplished similar projects with clients in various markets around the world. The following table summarizes the successful completion of relevant projects,

Table D-1: Recent UMS Group Comparative Analyses / Benchmarking Efforts

Client / Project	Relevant Analyses
ATCO Electric PBR Rate Filing Support	• Capital Additions • Investment levels for Asset Replacement/ End of Life, Clearance and Safety, and Reliability • System Performance Risk Mitigation • Transmission Construction Costs and Practices
ATCO Electric T&D Performance Diagnostics	• T& D Capital Maintenance Program Frequency • Distribution Projects Efficiency and Budget Adherence • Vegetation Management Spending Levels and Performance • O&M Productivity (internal comparison and external benchmarks)
Dayton Power and Light (AES) Generation and T&D Performance Diagnostics T&D System Refurbishment and Replacement Risk Assessment	• Capital Investment Levels • O&M Spending Levels • System Reliability Performance • Maintenance Performance • Workforce Productivity (Unit Costs) • Aging Infrastructure Trends and Comparisons • Reliability and Equipment Failure • Adequacy of Capital Investment and O&M Spending Levels
FirstEnergy (JCP&L) Investment, O&M Spending and Performance Comparison Study	• Capital Investment Levels • O&M Spending Levels • Reliability Performance • Aging Infrastructure Analysis
Indianapolis Power and Light Company (AES) Generation and T&D Benchmarking	• Generation Plant Performance Gap Assessment • Generation Asset Management Gap Analysis and Transformation Plan • T&D Asset Management Maturity • T&D Staffing Productivity (Unit Costs)
Lansing Board of Water and Light Power Production and Energy Delivery High Level Performance Diagnostic	• Cost and Service Level Comparison • Infrastructure Renewal Analysis • System Maintenance Performance • Aging Workforce Analysis • Worker Productivity (Unit Costs) • Organizational Effectiveness
Nova Scotia Power Enterprise-wide Performance Diagnostic	• O&M Spending Comparison • Capital Investment Levels Comparison • Investment Renewal Comparison • Asset Recovery Comparison • Reliability and Availability Comparison • Practices Assessment • Work Planning and Execution • Maintenance Program Effectiveness • Workforce Productivity (Unit Costs) • Aging Workforce Analysis
PSE&G-NJ and PSE&G-LI O&M Reduction Program Support Efficiency Improvement and Cost Reallocation Project	• O&M Spending Assessment • Workforce Management Assessment • Overtime Analysis / Comparisons • Organizational Effectiveness Review • Workforce Productivity (Unit Costs) • Aging Workforce Comparisons
PSE&G-LI Efficiency Improvement and Cost Reallocation Project	• Organization Redesign • Work Management • Asset Management • O&M Cost Reduction • Aging Workforce / Succession Planning

SaskPower Business Renewal Initiative: Capital Efficiency and O&M Spending Assessments (Generation, T&D and Customer Service)	• Capital Investment Levels • O&M Spending Levels • System Reliability Performance • Worker Productivity (Unit Costs) • Maintenance Performance • Aging Infrastructure Trends and Comparisons • Aging Workforce Comparisons

Experience Summaries of UMS Group Core Team

Representing over 120 years of electric utility experience, the individuals provided by UMS Group are knowledgeable in unit costing practices, and conversant with the analytics necessary to perform the comparative analyses required to support an objective, independent third-party assessment. The following table provides a high-level view of their qualifications, followed immediately by their resumes.

Table D-2: UMS Group Core Team

Name	Project Role	Years of Experience	Relevant Areas of Expertise
Jeffrey Cummings	Project Manager and Expert Witness	37	• Regulatory Support • Comparative Analysis / Benchmarking • Strategic and Operational Planning • T&D Grid Resiliency and Revitalization • Electric Distribution Reliability • Capital Investment and O&M Program Planning and Prioritization • Asset Lifecycle Planning • Maintenance Program Optimization • Repair vs. Replacement Criteria • Labor Relations
Steven Morris	SME-Operational Analytics	29	• Cost and Service Level Comparative Assessments • O&M Program Spending • Staffing Level Analyses and Benchmarking • Capitalization Practices related to Major Maintenance • Substation Maintenance and Construction • Distribution Construction Unit Cost Benchmarking • Economic Modeling for Asset Replacement and Maintenance Decision Support
Thomas Myers	SME-Inspection, Test and Maintenance	32	• Technology Selection and Implementation • Enterprise Analytics • Asset Lifecycle Planning • Capital Investment and O&M Program Planning • Service Restoration • Inspection, Test and Maintenance Program Optimization • GIS Implementation and Operation • Work Planning and Execution
Brett Shaw	SME-Electric Distribution Operations	30	• Comparative Assessments (Benchmarking Diagnostics) • Energy Delivery • Industry Learning Consortia • Asset Management Transformations • Asset Risk and Performance Diagnostics • Work Planning and Execution • Work Productivity Assessments • Overtime Root Cause Analysis • Contract Administration

Jeffrey W. Cummings

SUMMARY AND BACKGROUND

Mr. Cummings is a Senior Vice President and Managing Director for the Americas of UMS Group. He has 37 years of professional consulting experience, with an extensive background in both engineering and strategic and operational planning for the large investor-owned utilities and municipalities in North America and Australia; most recently AES-Indianapolis Power and Light Company, FirstEnergy (Ohio, West Virginia, Maryland, New Jersey and Pennsylvania), Westar Energy, ATCO Electric, Lansing Board of Water and Light, Saskatchewan Power, BC Hydro, Ameren (Illinois and Missouri), Ergon Energy and Public Service Electric and Gas Company. He supports these clients in addressing key strategic and operational challenges, focusing on T&D network modernization, distribution reliability, energy efficiency, and fleet optimization, capital investment planning and prioritization, asset strategy and plan development, organizational transformation, and regulatory strategy; and when called upon, has offered expert testimony, most recently to one Canadian Provincial Utility Commission (PBR Rate Filing) and two U.S. State Regulators (Financial and Reliability Performance Assessments).

Prior to joining UMS Group, Mr. Cummings operated an independent consulting practice for nearly a decade where he supported utilities in the areas of strategic and operational planning, organizational development, technical and commercial management, and merger and acquisition assessment and implementation. Earlier in his career he held a series of engineering leadership positions at Vectra Technologies (formerly Pacific Nuclear and a publicly traded nuclear services company) and ultimately became Vice President of Nuclear Engineering. In that capacity, he served as the profit/loss manager for over 425 professional engineers across 5 regional offices in the U.S. In performing this role, he actively engaged in formulating strategies for customer development, product/service expansion, business consolidation, and oversaw the management of over 500 projects annually for approximately 75 percent of the U.S. nuclear utilities. And, prior to his tenure with Vectra Technologies, Mr. Cummings was employed by Stone and Webster Engineering Corporation where he assumed increasing levels of responsibility in the management of large Lignite and Nuclear Power engineering and construction projects.

Mr. Cummings holds an M.S. degree in Operations Research from the U.S. Naval Postgraduate School and a B.S. degree from the U.S. Naval Academy at Annapolis, Maryland

HIGHLIGHTS OF EXPERIENCE

Spearheaded efforts to provide third party assessments of a mid-Atlantic electric utility's capital investment, O&M spending levels and service level performance in support of a base rate filing; and later assessed the prudence of decisions made in the events leading up and during three extraordinary storm events during the 2011 - 2012-time frame. In both instances, written direct testimony was provided and Mr. Cummings was called upon to provide oral testimony during cross-examination.

Assisted a mid-western electric utility in developing a Grid Revitalization Program for submittal to its Board of Directors and State Regulator. The proposed plan provided profiles of projected

capital and O&M cash flows, the capture of utility and customer benefits, and an industry context around which to justify such a program.

Assisted a Canadian electric utility in offering an independent third-party assessment of a recent PBR filing performing high-level comparative analyses of proposed growth and infrastructure renewal capital investments over a 5-year period; and assessing the risk of returning to previously established lower capital investment plans. This effort included providing testimony as part of a formal hearing with the Provincial Utility Commission.

Served as Project Director for a full-scale business renewal effort, establishing a plan to improve the efficiency of capital investments, and decrease O&M spending by as much as $50 million a year without any noted decrease in system performance. Conducted across Power Production, Transmission and Distribution and Customer Service, this effort launched a series of initiatives that over 10 years will decrease spending levels by a cumulative $500 million, and set the stage for adopting the relevant aspects of PAS55. Areas of focus included comparative cost and service level analyses, work planning and execution, performance dashboards, transmission and distribution reliability, capital portfolio optimization, and business value/risk tolerance frameworks.

Served as Project Director of four comprehensive assessments for separate Transmission and Distribution operating companies of a large US-based electric holding company. Three involved a review of practices and processes related to electric system reliability as measured by SAIFI, CAIDI and SAIDI with a thorough review of historical results (as reported in their outage management systems) and supporting reliability programs. Specifically, these assessments analyzed service interruptions, service restoration, organization and staffing, and capital/operating spending patterns with the objective immediately and sustainably improving performance; and included formal presentations to Commission staff across 2 regulatory jurisdictions. The fourth assessment involved a thorough review of the electric distribution infrastructure from both an asset health and condition and energy efficiency viewpoint, resulting in a long-term strategy and plan to transform the network to 21st century standard. This involved identification of key technical and financial legacy issues, incorporation of several constraints and factors (e.g. financial, technology and social equity), and a holistic portrayal of costs and benefits from both a portfolio and individual circuit/substations perspectives; and the articulation of the plan tailored for each external stakeholder (e.g. commission staff/regulator, legislators, environmentalists, shareholders and customers).

Assisted a large Northeastern utility in identifying over $80 million of O&M cost reduction initiatives without impacting service level (e.g. customer service, system reliability or safety). Areas of focus included electric transmission and distribution, customer operations, gas distribution and asset management. The outcome has been incorporated into a long-range plan to improve earnings despite an unfavorable outcome is a recent rate case filing.

Performed a capital and O&M spending diagnostic for a mid-level Midwest utility in support of an overall business case to infuse more capital into its transmission and distribution infrastructure. The case was compelling enough to present to the Board of Directors and the Commission State and will be a cornerstone for subsequent strategic planning and future rate filings.

Supported a mid-level Midwest utility in its energy efficiency/demand response filing with the state regulatory and governing entities. Applied industry comparative analyses in demonstrating value

capture for all stakeholders (investors, customers and utility), and validated that the proposed program met the intent and letter of the legislative mandate.

Conducted an enterprise-wide capital efficiency assessment for a Canadian Utility spanning electric transmission and distribution and power generation. In reviewing their planned capital expenditures over a 10-year period, Mr. Cummings developed a plan to (1) reduce the current plan by 25 percent and (2) optimize the allocation of capital over the 10-year capital planning horizon.

Strategic advisor for a major transformation effort within a U.S. Midwest municipality, that included conducting performance diagnostics of its engineering and production divisions, development of a work planning and outage management program (and support processes), and several initiatives focused on achieving organizational alignment.

Assisted a large Australian electricity distribution utility in optimizing the size and mix of its fleet of vehicles and attached equipment, factoring in financial constraints, environmental requirements, and the aligning of work level, staffing and specific task descriptions. The process of arriving at a plan to reduce capital investments by as much as $20.0 million and operating expenses by $1.2 to $2.0 million involved the active participation of the company's internal customers (i.e. users of the fleet assets), resulting in organizational acceptance of the outcome. Mr. Cummings extended this effort to a large Western U.S. electric municipality, developing a strategy and plan to achieve comparative results.

Led the implementation of a process (and supporting software) to optimize the capital spending profile across three operating companies within a large US-based electric and gas company (electric transmission and distribution, gas transmission, distribution and storage, fleet, and electric generation); as well as one of the largest gas utilities in the US Midwest. In performing these projects, Mr. Cummings facilitated the linkage of a proposed investment's value and its contribution to overall corporate strategy as well as the risk should a specific investment be deferred; and equally important, implemented the process in a manner that garnered organizational support for change.

Oversaw the implementation of an industry forum to identify trends and perform causal analyses on the failure of critical transmission equipment and components. In pooling industry equipment/component performance data, the goal was to apply statistically relevant data to accurately predict failure patterns establish optimum replacement vs. refurbishment criteria. In parallel with the initial formation of this forum, Mr. Cummings also performed the following:

- Comprehensive performance diagnostic across all functions of one of the largest electric municipalities within the US Southwest. In so doing, he provided a plan of action to maintain service levels yet reduce operating costs by as much as 25 percent. The recommendations were adopted and integrated with the municipality's five-year operating plan.
- Development of a preventive and corrective fleet (vehicle and attached equipment) maintenance program, adopting may of the best practices from the petroleum and U.S. Naval programs, and tailoring them to application in a gas municipality environment. The project team, led by Mr. Cummings, provided a detailed process manual (with supporting

process maps), an implementation plan (i.e. process/procedure changes and additions, technology enhancements and organization adjustments), and a series of key measures to assist the utility in adopting the recommendations. The program was embraced by both the municipality and city government officials.

Participated in a task force and subsequently joined the implementation team in developing and executing a five-year plan to revamp the electric transmission and distribution infrastructure for the Chicago business district. This effort involved the translation of highly technical specifications and detailed budgeting information into terms easily understood by commission staff, city government, and the utility's customers. The resulting plan was adopted by the Board of Directors, accepted by the City of Chicago, and supported by the commission staff and state regulator.

While supporting implementation, Mr. Cummings developed the strategies and plans for initially routing, certifying, designing, and installing 135kV and 345kV transmission to meet projected load growth and system reliability requirements. He played a key role in shortening the certification period by as much as 50 percent. This required effective liaison and communication with the Illinois Commerce Commission and Army Corps of Engineers as well as coordination of Commonwealth Edison's engineering and construction organizations and their assigned "contractors of choice."

Provided consulting services to several technology-based enterprises including gas and electric utilities, engineering and architectural firms and manufacturers of electric components. The projects included:

- Strategic and Operational Planning and Integration (Linkage of Business Vision, Core Values, Financial Goals and Core Business Processes, maintaining a balance between long-range sustainability of the business and short-range stakeholder expectations).
- Organizational Development (Competency-based Performance Management System Development and Implementation, Business Culture Assessments, Employee 360-degree Evaluations, Leadership Development, Recruiting and Employee Selection).
- Marketing and Sales Support (Branding Strategy Development, Customer Satisfaction Surveys, Product/Service Positioning and Pricing Strategies, and Sales Training).
- Technical and Commercial Management (Ensuring a proper balance between achieving profit/loss targets and meeting the quality standards as specified by the customer)
- Merger and Acquisition Assessment and Implementation

Worked in a variety of capacities for a nuclear engineering consulting company, serving initially as a Project Manager and ultimately as the Vice President of Nuclear Engineering. Over this 11-year period he played a major role in growing annual revenues from $5.0 million to $50.0 million while increasing market penetration to approximately 75 percent of the US nuclear utilities. Many of the skills and competencies used by Mr. Cummings in his roles as management consultant (summarized above) were developed through hands-on experience in managing over 425 engineering professionals and overseeing the management of over 500 projects annually.

Worked in a variety of capacities for Stone and Webster Corporation, primarily assigned to major nuclear power plant design and construction projects. Specific assignments included:

- Assignment to the Beaver Valley Power Station project, establishing a projects control process and system within the Duquesne Light Company to manage the installation of Three Mile Island modifications in support the second refueling outage, improving actual performance in terms of work performed and schedule duration from the initial refueling outage by a factor of three. Following this effort, Mr. Cummings shifted his focus to the unit under construction (unit no. 2) where he installed a process to facilitate the final turnover of the systems (and accompanying documentation) to plant operations over an 18-months period.
- Assignment to Clinton Power Station, where he acted as Project Controls Manager for the contractor, facilitating the lifting of 12 Nuclear Regulatory Commission (NRC) imposed stop work orders and subsequent construction and turnover of the plant to the Illinois Power Company (IPC). Key activities over a two-year period included a successful Fuel Load Caseload presentation to the NRC, support to IPC in preparing and presenting rate cases to the Illinois Commerce Commission (ICC) for cost recovery, installing an information system to track the turnover of all systems, and instituting an integrated cost and schedule process and system to support weekly and monthly reporting to project and IPC executive management. His role in integrating the construction and system turnover schedules (and subsequent development of computerized detailed system turnover punch lists) served as a primary catalyst for successful completion of the Clinton Power Station project.

Served in the U.S. Navy in increasingly responsible roles culminating as a Weapons Officer on a destroyer, USS Robert E. Peary (FF-1073). In this capacity, he managed and led three divisions totaling 100 sailors, responsible for the maintenance and operation of all weapon and detection systems, the major equipment necessary to support basic seamanship evolutions, and daily consumables for the entire ship's force.

He left the U.S. Navy in 1980, having earned the **Navy Achievement Medal** for his efforts during two extended deployments and extraordinary performance in the areas of Anti-Submarine Warfare and Naval Gunfire Support.

RECENT ARTICLES AND SPEECHES

- "*Driving Reliability Improvements-Regulatory Oversight",* presentation given to the EEI Transmission, Distribution and Metering Conference, New Orleans, LA, April 7, 2009.
- *"A Paradox of Thrift: Economic Barriers to T&D Network Modernization",* an article written in January 2009.
- *"Grid Modernization: A Roadmap to Tomorrow's Infrastructure…Don't Get Lost on the Way to AMI,"* a white paper written in April 2009.

Steven J. Morris

SUMMARY AND BACKGROUND

Mr. Morris is a Principal of UMS Group. He has 29 years of consulting and management experience with the last 20 years spent in the electric and gas utility industries. He has significant expertise in performance management, asset management, strategic planning, financial analysis, and benchmarking and has written/edited dozens of analytical reports on utility industry topics.

He is currently responsible for leading the firm's client-sponsored benchmarking and best practices study projects in which ad hoc groups of utilities are brought together to perform targeted, deep dive studies into issues of industry concern.

Prior to joining UMS, Mr. Morris worked for both Andersen Consulting and Navigant Consulting. He also founded Research Reports International, a business focused on providing data and information on key issues facing electric and gas industry executives. Mr. Morris holds a B.A. in Economics and an M.B.A. both from Cornell University.

HIGHLIGHTS OF EXPERIENCE

Developed and implemented a process and analytical tools to support decisions related to the health of a West Coast utility's station assets. Identified the customized functionality necessary for existing AHI tool to provide the decision support capabilities required. Developed algorithms for determining effective age and identified the sources of input data needed for the model. Defined failure modes and assessed impact of failure. Defined and map the processes needed to make optimum use of the tool.

Led the effort for a major West Coast combination utility to develop skills and competencies in Asset Management for Transmission and Distribution. Performed 2-day Asset Management Workshop for 30 client managers and engineers. Developed template and process for creating Asset Life-cycle Strategies and supported client Asset Strategists in creating the first two strategies, Distribution Wood Poles and Substation Transformers.

Performed an external assessment of a Northeastern Utility's Asset Management processes and underlying practices (UMS had performed similar assessment 4 years ago). The objective of this review was to evaluate the effectiveness of Asset Management in performing its responsibilities, as well as review cross-functional processes to identify opportunities for improvement.

Conducted several studies of utility accounting of plant investments to assist clients in optimizing their allocation of expenditures for major maintenance among capital and O&M accounts. Performed industry surveys of property accounting policies for coal-fired and hydro power generation, as well as for natural gas compression and storage. Identified the factors considered in determining if a cost is capitalized, the specific criteria used (e.g., length, % replacement, etc.), and the approach and strategies for managing the decision to capitalize spending. Identified opportunities for clients to revise their property accounting methodology based upon how others are addressing similar work.

Assisted a large Northeastern electric utility in identifying opportunities to reduce its total O&M budget by 10-15% on an ongoing basis. Managed project team assessing all areas of the business (i.e., Power Markets, T&D, Customer Ops, and Corporate Services) to identify opportunities for achieving $110 million in annual savings. Team performed benchmarking and analyses, conducted interviews and observations, and reviewed processes and practices to identify opportunities for reducing costs through change in maintenance frequencies, reduction in staff, appropriate allocation of costs between O&M and capital, process improvement, leveraging technology, and outsourcing.

Developed a business strategy for a Midwestern gas utility to expand its competitive meter services business. Evaluated the existing business to identify weaknesses and limitations; developed and evaluated alternatives for growing the business; and developed a plan to reposition the business and drive growth through acquisitions. Also evaluated acquisition and partnership candidates and recommended targets. Identified the capabilities required to succeed in implementing the new business strategy.

Evaluated the ability of a Midwestern gas utility to successfully manage and operate a newly purchased water utility. Evaluated personnel skill sets and technology/assets available to support the water business; identified key areas of management and operational concern; and developed recommendations on improving management and operations to alleviate concerns.

Performed several Staffing Analyses for generation companies. Benchmarked staffing levels across major functions, evaluated spans of control, and analyzed organizational designs. Developed innovative model to forecast appropriate staffing levels for maintenance, operations, engineering, and supervision based on plant technology, size, and function. Recommended staffing changes, contracting strategies, and organizational realignment to reduce headcount without impacting performance.

Conducted multiple projects for a major West Coast combination utility to optimize substation maintenance and inspection practices. Project included designing and executing a multi-company comparative study to identify inspection/maintenance tasks performed, the scope and frequency of these tasks, the resource mix, and the productivity/efficiency of maintenance. Based on Study results, organized and facilitated three conferences with utilities to share their practices in substation inspection maintenance.

Identified best practices in Customer Facilities Extension for a Canadian utility. Conducted survey with North American utilities to determine standard and best practice in estimating process, pricing strategy, deposit/payment policy, investment levels, rebates, and risk mitigation strategies. Assessed impact of regulatory environment on policy direction. Interviewed key account customers to understand their view on company's current policies and practices. Provided recommendations on modifying policies and practices to support client's desired objectives.

Restructured Western utility's resource planning and performance management organizations for its Transmission Line, Substation, and System Operations business units. Interviewed key personnel on both the service provider and internal customer sides to understand work performed, value received, and gaps in services. Analyzed staffing levels and resources per function. Identified opportunities for consolidating some functions, shifting some functions to other

organizations, and achieving efficiencies in existing functions. Recommended restructuring of groups resulting a 20% headcount reduction with no reduction in performance.

Performed a SWOT analysis of a Western Municipal Utility's Field Operations group. Assessed and benchmarked lines and stations maintenance and construction functions to identify strengths and weaknesses. Assessment included cross-functional processes and enabling technology. Developed 3, 5 and 10-year views of federal, state, and local opportunities and threats. Recommended strategic direction to leverage strengths and opportunities. Developed recommendations to close gaps around weaknesses.

Performed an assessment of a Midwestern electric utility's Distribution and Transmission practices, processes, and performance. Analyzed overtime, outages, asset age, OPEX/CAPEX, etc. to identify gaps against best practices. Developed recommendations for improving performance / reducing business risk and quantified impact, difficulty, and relative cost to implement.

Provided independent assessment of a Northeastern utility's outage restoration capabilities, staffing levels, and asset replacement in support of a rate case filing. Performed analyses to determine utility's performance in relation to regional peers and in support of filed testimony. Developed a framework for evaluating and comparing mobilization efforts and restoration time frames across several companies, region-wide and assessing their performance based on impact of storms and amount of damage.

Assisted a European State-owned Transmission System Operator in developing an innovation management process to ensure state-of-the-art technology adoption and operation in their grid. Performed benchmark of key transmission grid technologies to identify current and future market penetration. Surveyed and interviewed top performing utilities to identify best practices in technology monitoring, assessment, and selection, R&D outsourcing, technology commercialization, and innovation management. Developed recommendations on changes to culture, processes, systems, and business orientation required to implement a more innovation business structure.

Conducted a study to help a major U.S. combination utility understand industry best practices for improving its inventory control and accuracy tools and processes. Designed and implemented survey of utility industry practices regarding inventory segmentation and cycles, counting and reconciliation, training and technology, and controls and key performance indicators. Interviewed Study participants to identify common and best industry practices. Study included a dozen U.S. utilities and identified both common and best industry practices in these areas, as well as benchmarked KPIs.

Thomas Myers

SUMMARY AND BACKGROUND

Mr. Myers is a Principal at UMS Group with over 32 years of experience providing management consulting services to the utilities industry. He has extensive worldwide experience developing business plans, achieving improvements in business processes, and implementing technology to reduce costs and improve operating results. Tom's extensive worldwide experience and thought leadership has provided him with a unique understanding of the technical, operational, and business challenges related to grid modernization. His involvement on more than 60 consulting projects at over 40 utilities in seven countries has provided him with a track record of successful engagements. Tom is a frequent speaker and writer on industry issues and recognized thought leader in the industry.

Prior to joining UMS, Mr. Myers held leadership positions at IBM, KEMA, Scott Madden, Arthur Andersen and Andersen Consulting.

Mr. Myers is a Certified Public Accountant (CPA), Project Management Professional (PMP), and held a professional engineer's license in Arizona. He has a Bachelor's Degree in Engineering from the University of Illinois and a Master of Accountancy from Arizona State University.

HIGHLIGHTS OF EXPERIENCE

Conducted an after-action review of a Northwest energy company's performance during a significant weather event and compared against a previous assessment performed four years earlier.

Conducted a leading practice survey related to damage assessment for a Northwest energy company to improve storm response effectiveness and support improvements in training, organization, staffing and management of storm-related work activities.

Developed a facilities strategy for a Pacific utility to address current vulnerabilities and future requirements related to their operations in emergency situations, such as after a tsunami.

Assessed the emergency response function of a Northwest municipal utility to define needed improvements and establish parameters and facility requirements that could be used to develop a capital improvement project.

Managed a project for a large west coast energy company to develop an Enterprise Analytics Strategy and Roadmap that defined capabilities, technologies and initiatives to support a strategic direction for the use of analytics for asset management and operations. The Roadmap defined the functional and technical architectures to support these analytical capabilities.

Managed a project for an energy company in Brazil to identify and implement global leading practices that utilized emerging technology to support asset lifecycle optimization for construction and maintenance processes.

Managed a project for a Pacific energy company to launch their asset management function and develop strategies for major categories of transmission and distribution assets. The strategies

were used to establish performance, capital investment and maintenance plans, and supported regulatory proceedings to gain cost recovery through the rate base.

Conducted a global research project for a Canadian regulatory agency into the use of asset management standards by regulators in the review and assessment of energy company investment plans.

Managed a project for a large east coast energy company to optimize asset performance and develop capital plans to address aging assets and projected performance issues.

Managed a project for a Midwest transmission company to improve asset performance and develop action plans for reducing the number and duration of interruptions.

Managed a project for a Midwest transmission company to build out asset management functions, processes and capabilities. He developed process flows and procedures for the new asset owner.

Managed a project for a global energy company to support a long-term asset performance improvement project to reduce costs and improve the operating performance of the company's overall portfolio of plants.

Managed an asset management and geographic information system implementation project for a U.K. water company to support their strategy to be a leader in the industry through the exploitation of technology for asset management decision-making.

Managed a project for a large Midwest energy company to develop the business model for asset management, including the organization structure, business processes, performance measures and technology architecture**.** This model was to become the template to be applied to each newly acquired company in support of the company's acquisition strategy.

Managed a project for a large west coast energy company to assess the capabilities of their geographic information system, and to develop an investment strategy to support future asset management strategies.

Managed a project for a large Southwest pipeline company to implement a geographic information system to support engineering and operating departments in their performance of asset management functions.

RELEVANT ARTICLES AND PRESENTATIONS

"*Asset Management*" – presented in March 2012 at the Power Systems Conference at Clemson University in South Carolina.

"*Approach to Managing Critical Transformers*" – presented in January 2012 at the DistribuTECH conference in San Antonio, Texas

"*Optimizing Investments in Vegetation Management*" – Presented in February 2011 at the DistribuTECH Conference in San Diego, California

Brett Shaw

SUMMARY AND BACKGROUND

Mr. Shaw is a Senior Associate of UMS Group. He has over 30 years of experience in and with the electric utility industry and is responsible for the delivery of the firm's asset and risk management assessments, diagnostic benchmarking, process improvement and performance measurement and management systems, with specific emphasis on the Electric Transmission, Distribution, and Customer Operations, and Demand Side Management business areas.

Prior to joining UMS Group, Mr. Shaw served in various senior management capacities at Southern Company (Gulf Power), and most recently as Vice President of Engineering and Operations at CHELCO, a large electric cooperative serving a large portion of Florida's Panhandle.

Mr. Shaw is a graduate of the University of West Florida, with a B.S. degree in Industrial Technology, and currently serves in a variety of executive roles in the Florida's business & civic community. Mr. Shaw is also a graduate of the National Rural Electric Cooperative Association (NRECA) MIP executive leadership program, as well as various Southern Company leadership training programs.

HIGHLIGHTS OF EXPERIENCE

Leads onsite member delivery of the ITOMS Consortium, a custom transmission operation and maintenance diagnostic program, and manages new member program orientation and training. This program is performed every other year and has participants from North and South America, Europe, Middle East, Africa, Asia, and Australia. All programs are comprehensive; they analyze existing policy effectiveness and unit cost per activity and assess the processes and practices in place. Assessments are performed by leveraging information gathered from senior staff interviews and diagnostics are performed by collecting performance data from the participant records. Performance gaps are identified, and improvement strategies and tactics explored.

Led several large-scale asset management transformation projects and PAS 55 assessments for many major electric utility companies around the globe. These efforts have involved detailed process assessments leading to redesign of activities in the Risks and Asset Management frameworks. Key focus areas have included Asset Strategy and Investment Planning, Design Construct & Refurbish, Operate Maintain & Restore, and Performance Management activities.

Led and played an integral role in conducting risks and diagnostic assessments for multiple global clients. These studies included extensive analysis of performance in functional areas like Transmission Lines, Substations, Distribution and Vegetation Management. In addition to analytical diagnostics, global best practices were also evaluated for applicability for each client.

Led and performed multiple performance assessments of US electric utility's Electric Transmission and Delivery organizations. Benchmarked cost and service level performance against peer utilities to identify potential areas of concern. Conducted practices interviews with representatives from all major functions and across the hierarchy to identify work and

management practices that were contributing to performance issues. Developed recommendations for improving business performance that included changes in culture, management philosophy, work practices, and processes. Identified and recommended key performance indicators to monitor implementation of recommendations and track actual performance improvement

Performed assessments of multiple US and Canadian electric utility's Distribution and Transmission practices, processes, and performance. Analyzed overtime, outages, asset age, OPEX/CAPEX, etc. to identify gaps against best practices. Developed asset management recommendations for improving performance / reducing business risk and quantified impact, difficulty, and relative cost to implement.

Performed an assessment of a Midwestern electric utility's Distribution and Transmission practices, processes, and performance. Analyzed overtime, outages, asset age, OPEX/CAPEX, etc. to identify gaps against best practices. Developed recommendations for improving performance / reducing business risk and quantified impact, difficulty, and relative cost to implement.

Participated in a Grid Modernization study for a prominent Northeastern Investor-Owned Utility, Mr. Shaw conducted in depth reviews of existing infrastructure and the relevance of aging "legacy" material and construction standards on the client's ability and ease to implement modernization strategies.

Led the integration of UMS' Investment Optimization tool set in to the Asset Management process at a large Southwestern utility. The implementation involved working with the client's asset management and energy delivery management teams to develop and implement the Optimizer to effectively manage the client's large portfolio of both Capital and O&M expenditures.

Led integrated organizations consisting of customer service, engineering, construction/ operations/ maintenance of electric transmission & distribution infrastructure, and marketing across all major customer segments. As a member of the Executive staff, participated in and provided leadership at Board of Directors meetings for the cooperative. Led territorial negotiations with a neighboring utility.

Reengineered contract administration function, generating significant cost savings through review of existing contracts. Negotiated and successfully administered contracts with major municipalities, military installations, and service providers. Established strategic plans and goals at enterprise and functional levels within his organizations as well as in cooperation with partner organizations such as Alabama Electric Cooperative (now PowerSouth Energy Cooperative). Revamped transformer and equipment production/repair facility and moved facility to positive earnings and cash flow. Managed major National Account program including the leadership of company wide sales force.

Participated in a statewide risks assessment and comment process, through the Florida Electric Cooperative Association, of the "storm-hardening" rule for electric distribution proposed by the Florida Public Service Commission. Was actively involved in regulatory negotiations, achieving positive win-win outcomes while ensuring regulatory compliance.

Corporate Senior Management experience included leading and empowering engineering and operations organizations to design, construct and maintain electric transmission and distribution systems. Provided key leadership in successful labor agreement negotiations. Also provided management leadership to other customer operation organizations including customer service and marketing.

Major project leadership includes providing leadership throughout a $140 million restoration effort following a major hurricane event and serving as the corporate lead in formulating and managing a major Y2K transition plan.

Led Total Quality Management (TQM) teams in achievement of Florida's Sterling Award for Quality. Facilitated process improvements toward the achievement of 25% efficiency gains and directed downstream implementation activities.

Appendix E – UMS Group Reliability Performance Assessments

UMS Group has established credentials in electric distribution reliability, as illustrated by the following more recent engagements:

- *Pacific Gas and Electric:* UMS Group conducted a third-party expert review of Pacific Gas and Electric's distribution reliability to determine what had happened in the areas of *Equipment Failure* and *3rd Party Damage*, and what, if anything, could be done to help mitigate the reliability target shortfalls for the current year. As a result of our review of reliability results (reviewing restoration performance, weather effects, "Blue Sky" SAIFI trends, outage causes, equipment failure-caused outages, metrics – number of outages, customer interruptions, and customer minutes, worst performing circuits and wires down drivers) over a three-year time frame, key findings and recommendations were presented in the areas of Equipment Failure (OH Conductor, Transformers and UG Cable), and Third Party Damage (Vehicles and Metallic Balloons).

- *Public Service Electric and Gas – Long Island:* UMS Group was retained by Public Service Electric and Gas – Long Island (PSE&G-LI) to review its reliability in the context of pre-established performance targets and changes during the year preceding the project. The primary objective was to determine the underlying cause of an apparent deterioration of performance over a three-year period, with specific focus on those factors that resulted in PSEG LI approaching (and in the case of SAIFI exceeding) the minimum performance level specified in its contract with LIPA; and recommend specific actions that could be taken to reverse the trend and return to previous stronger levels of performance. Specific recommendations revolved around vegetation management (danger tree removal and use of herbicides), UG cable replacement, animal guarding, vehicle caused outages, and creating an asset management information repository.

- *Israel Electric Company:* UMS Group provided an expert opinion regarding Israel Electric Company's (IEC's) restoration performance during a major storm event in October 2015. Filed with the Israeli courts, his opinion addressed IEC's comparable position in restoration time, restoration rate, immediate response, restoration practices deployed, and overall prudence of its decisions in the events leading up and during the storm. He not only provided incontrovertible proof of prudence, but through comparisons with other major storm events in North America and Europe, he presented a compelling argument that IEC excelled in its performance.

- *FirstEnergy Pennsylvania Operating Companies:* The FirstEnergy Pennsylvania Operating Companies engaged UMS Group to conduct an independent review and assessment of its internal and external mutual assistance activities, including a review of the mutual assistance provided to and received from other electric distribution companies (EDCs) during 2011 and 2012. An initial list of 26 outages covering 13 storm events was

developed, based on number of customers impacted (minimum of 5 percent), with due regard to including all four Operating Companies within Pennsylvania. We applied our standard multi-tiered diagnostic framework to:

- Compare the FE PA OPCOs practices relating to Mutual Assistance with those in use at comparable electric distribution organizations, and
- Assess execution of these practices, initially at a high level to address issues of equity in their application across the FE PA OPCOs' service territories and electric utility industry, and then on a storm-by-storm / outage-by-outage basis to identify specific opportunities for improvement, either programmatic or event driven.

In order to establish context for the analyses and comparisons required to support the specific assessments and conclusions contained within this report, UMS Group reviewed (1) FirstEnergy's most current E-Plan, (2) specific service restoration information for the 26 outages contained within FirstEnergy's Outage Management System (OMS), and (3) all previously filed Major Event Reports (MERs) for these specific outages / storm events, and was afforded complete access to the Company's technical and management staff. UMS Group concluded that notwithstanding a number of opportunities to fine-tune / improve its practices that at the highest level, the FE PA OPCOs' use of Mutual Assistance fell well within an industry-based range of reasonableness. Our review confirmed that plans were reasonably conceived, for the most part actions were properly executed (some exceptions were noted in the final report), and the results were generally appropriate (although with the benefit of hindsight, we did acknowledge that marginal improvement opportunities may have been possible). As with the above mentioned Focused Reliability Audits, all findings and recommendations were accepted as presented by the respective Commission Staffs and FirstEnergy.

- *Jersey Central Power and Light:* In support of a 2011 Base Rate Case Filing, UMS Group was hired to provide an independent, third-party assessment of FirstEnergy's JCP&L Operating Company's investment and spending levels and reliability performance as compared against the other FirstEnergy electric utilities, other New Jersey electric utilities, and other peer group utilities. Our efforts objectively demonstrated that JCP&L's reported reliability had shown consistent improvement since 2004 and that its performance ranged between top quartile and median relative to two comparable peer groups. We were also successful in showing JCP&L's effectiveness in implementing asset management-related initiatives, and industry-leading service restoration processes; appropriately bridging the gap between reported reliability and the customer experience related to two extraordinary storm events in 2011 (Hurricane Irene and the October 31st Snow Storm). Further, his analyses illustrated that the capital investment and O&M spending levels were appropriate for the level of service required by the Regulator (BPU). In conjunction with filing written direct testimony, Mr. Cummings provided direct and rebuttal testimony at rate hearings conducted in October 2013 and supported JCP&L's outside counsel in the preparation of final briefs. Related to this effort, he prepared a written report adjudging the prudence of

decisions made during the 2011 extraordinary storm events and Super Storm Sandy, from which the utility received a favorable outcome.

- *Met-Ed, Cleveland Electric Illuminating, and Penelec:* UMS Group has also performed several detailed reliability assessments for other FirstEnergy Operating Companies (Met-Ed, CEI and Penelec). This work was conducted for FirstEnergy with the approval / concurrence of respective State Regulators to address concerns around reliability and included extensive interaction with commission staffs. In each of these efforts, UMS Group assessed actual reliability performance, relevant O&M practices, spending and investment levels, and overall approaches to Asset Management against industry "best practices," and provided recommendations that were accepted by each utility and their respective Commission Staffs. The final deliverables included a comprehensive report and a formal presentation to the PA and OH Commission Staffs.

Appendix F – Peer Group Panel Survey

Unit Costs Tab

Category	Unit of Measurement	2014		2015		2016		Comments
		Number of Units (if known)	Unit Costs (2016)	Number of Units (if known)	Unit Costs (2015)	Number of Units (if known)	Unit Costs (2014)	
Wooden Pole Replacement	each							
UG XLPE Replacement	meter							
UG PILC Replacement	meter							
Vegetation Management - Tree Trimming	kilometer							
Vegetation Management - Herbicide	acre							
Pole Test and Treat	each							
Overhead Line Patrol	circuit							
Vault Inspection	each							
OH Manual Switches	each							
OH Remote/Motor Operated Switches	each							
Overhead (Poletop) Transformer Replacement	each							
Padmount Transformer Replacement	each							
Underground (submersible and vault) Transformer Replacement	each							
Network Transformer Replacement	each							
Network Protector Replacement	each							
Oil Breaker Replacement	each							
SF6 Breaker Replacement	each							
Vacuum Breaker Replacement	each							
Station Switchgear (Air) Replacement	each							
Station Switchgear (GIS) Replacement	each							

Accounting Tab

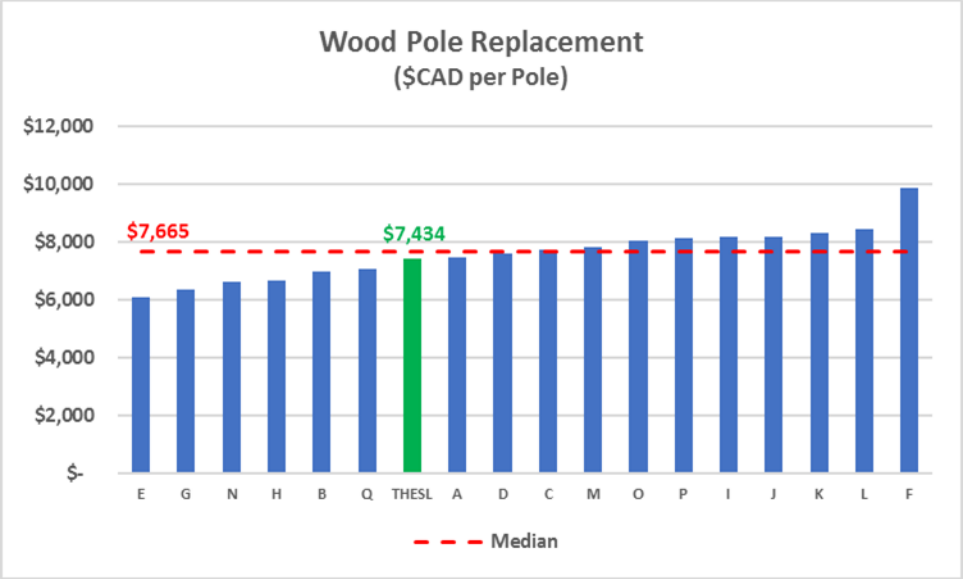
	Accounting Related Questions	Response	Comments
1	Which of the following methods do you use to determine unit rates for your distribution programs (e.g., pole replacement, UG cable replacement, veg mgmt, etc.)?		
	Divide total spent by number of units		
	Average individual costs of separate work orders		
	Other (please describe)		
2	In addition to Direct Labor and Material, which of the following costs are included in your unit costs for **In-House work**?	**Response (Please indicate "Y" or "N")**	**Comments**
	Design and Permitting costs		
	Project Management and Supervisory costs		
	Other project-related costs (e.g.; Fleet and Warehouse)		
	Other labor-related costs (e.g.; training, conferences, and meetings)		
	Employee-related costs (e.g.; vacation, sick time, insurances and pension)		
	Administrative and General costs		
	AFUDC / CWIP		
	Other (please describe)		
3	In addition to Contractor's cost, which of the following costs are included in your unit costs for **Contracted work**?	**Response (Please indicate "Y" or "N")**	**Comments**
	Contractor Management/Supervision costs (please indicate in comments if these costs include overheads per question 2)		
	Permitting and Design Costs		
	Other (please describe)		
4	Do you "net out" customer contributions from your unit costs?		
5	Do you use GAAP or IFRS accounting? (please specify which in Comments)		

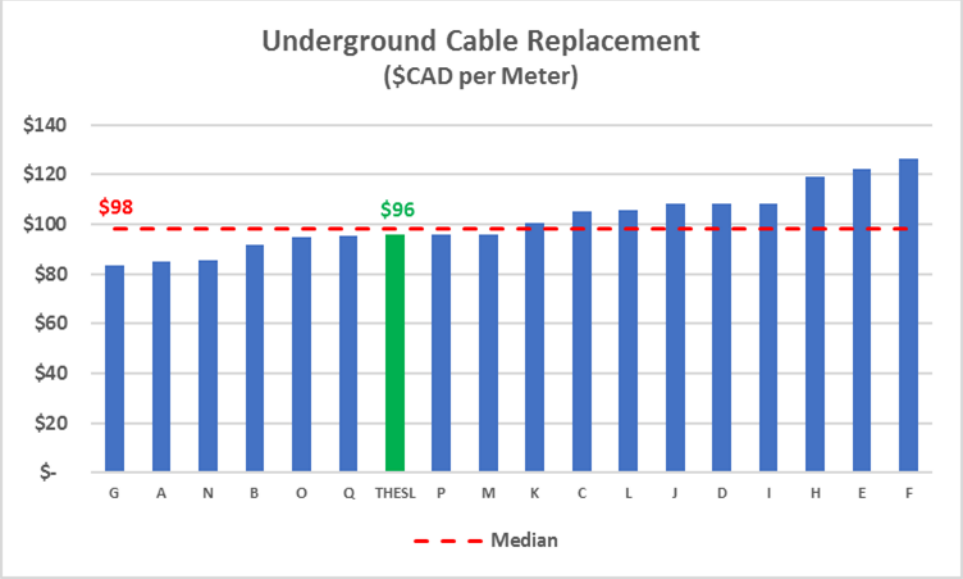
Local Factors Tab

	Local Factors	"X" to those that apply	Comments
1	Which of the following factors impact the cost of you performing inspections and replacement work?		
	Excessive travel time (over 30 mins.)		
	Road restrictions which limit working hours		
	High water table		
	Working next to energized lines (requiring dedicated observer, gloves, etc.)		
	Requirements to perform work off hours (i.e., night/weekend)		
	Changed standards requiring rebuilds rather than like-for-like (i.e., clearances)		
	Excessive switching requirements (i.e., to isolate on dual radial construction)		
	Shoring requirements for UG work		
	Limitations on tree trimming (e.g.; unusually tight clearances)		
	Box Construction		
	Prior use of lead cables		
	High fault currents (impacting equipment sourcing)		
	Paid duty for police presence on public roads		
	Extensive use of submersible transformers		
	Environmental regulations		
	City consent requirements (i.e., customer notification, restoration, progressive clean-up, etc.)		
	Other (please specify in Comments)		

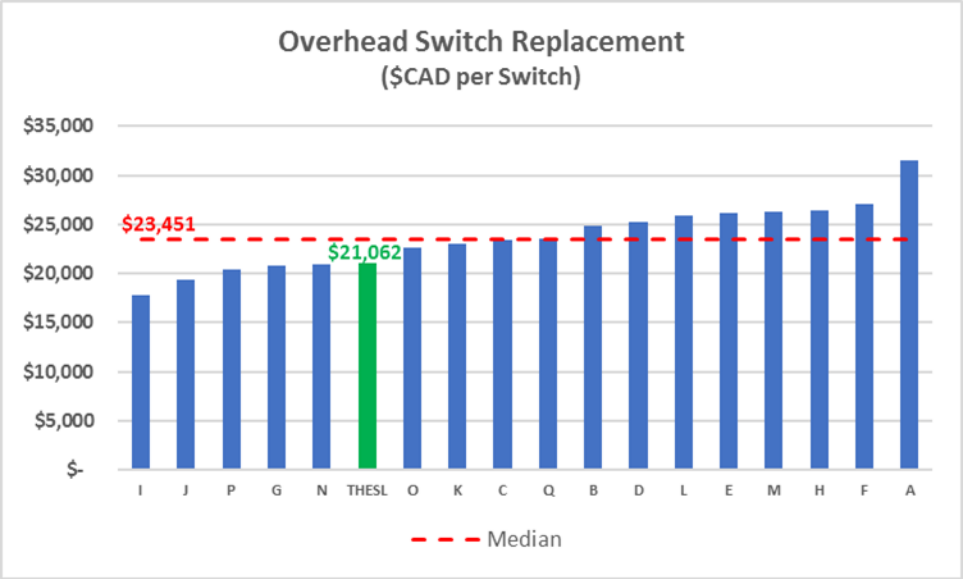
Appendix G – Detailed Benchmarking Results

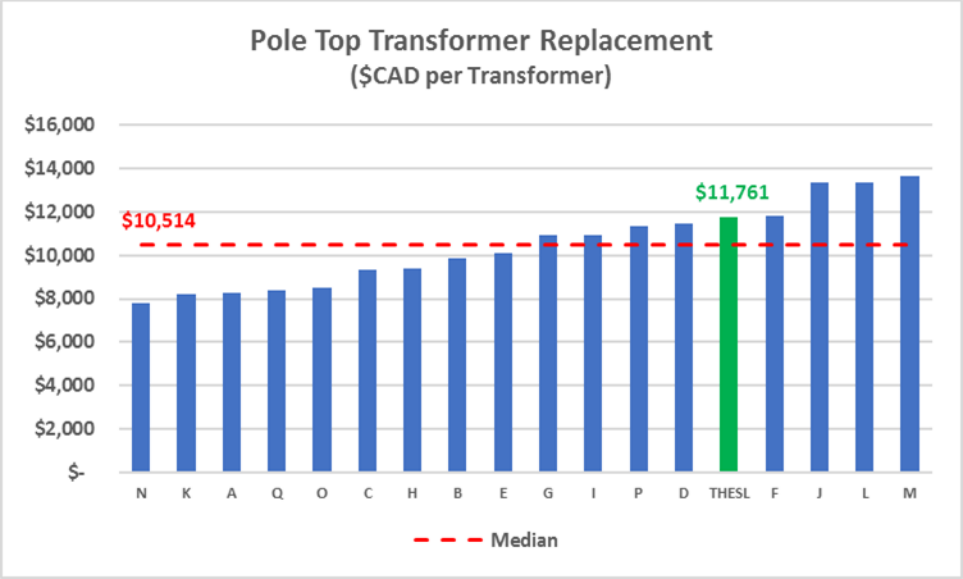
The following charts are provided, presenting the unit costs for each of the utilities (in ascending order), showing THESL's (Green) position relative to each of the electric utilities and the Peer Group Panel full-scaled "normalized" median value (Red). Tables that detailed tables each step of the "normalization" process are presented in Appendix C (Tables C-8, C-9 and C-10).





NOTE: The use of a letter designation for each member of the Peer Group Panel provides the confidentiality assured in soliciting participation for this study.





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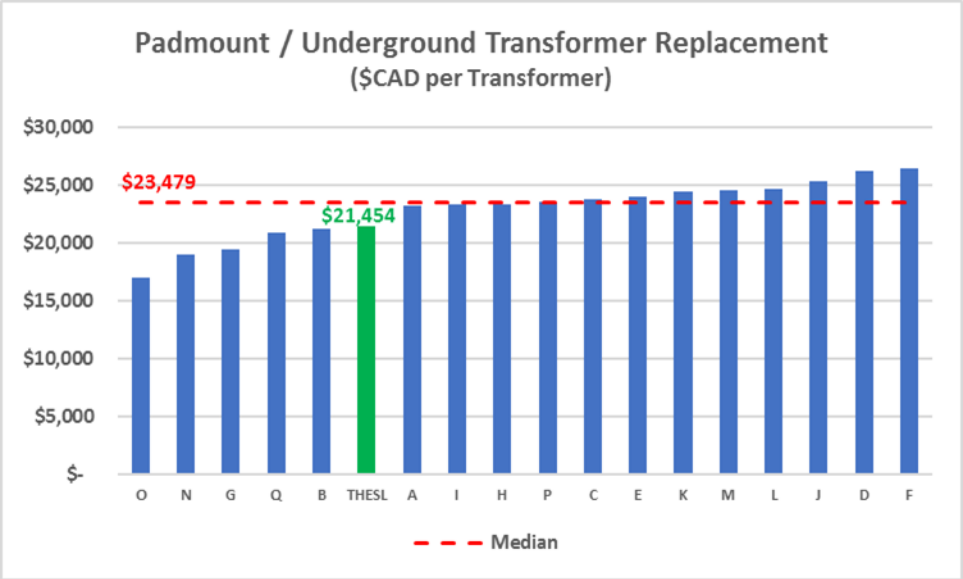

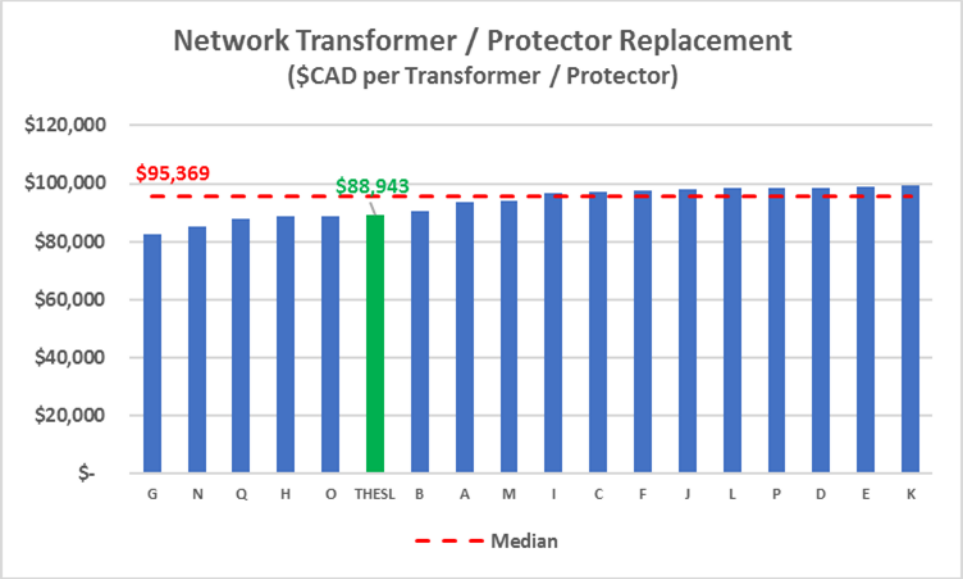

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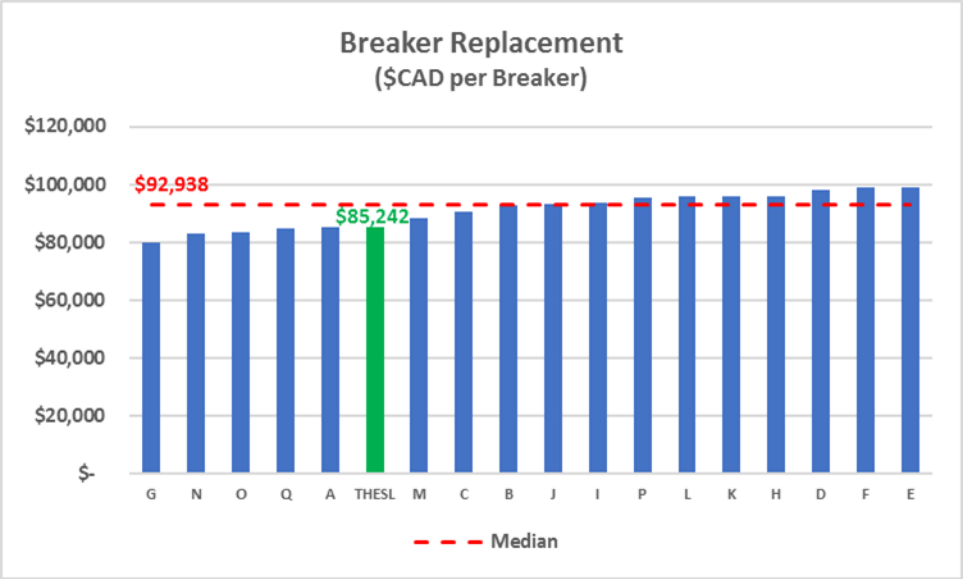

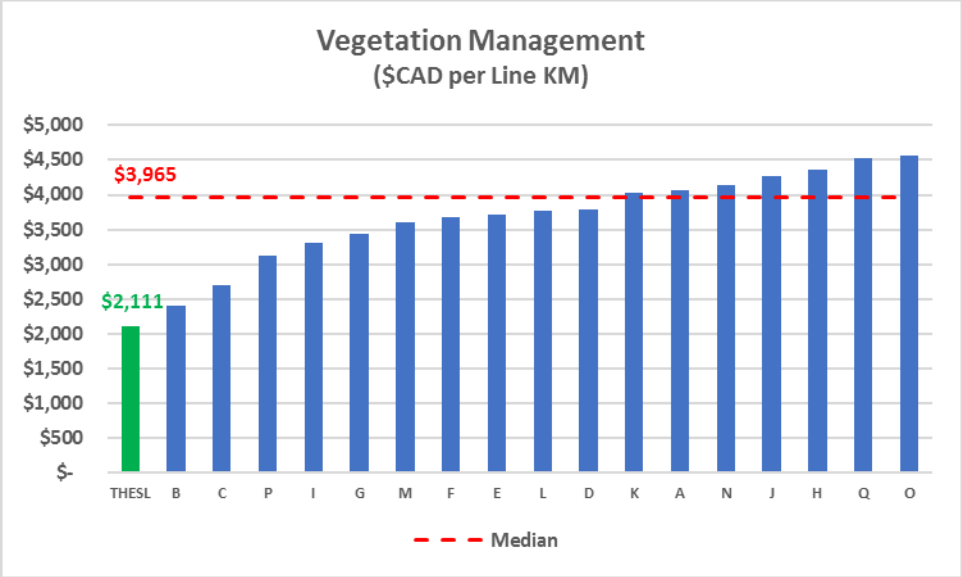

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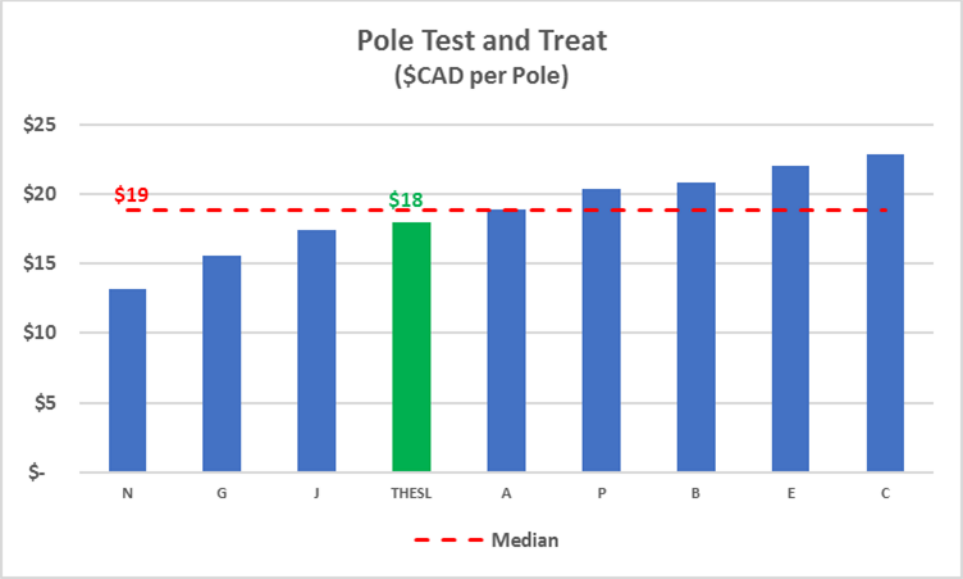

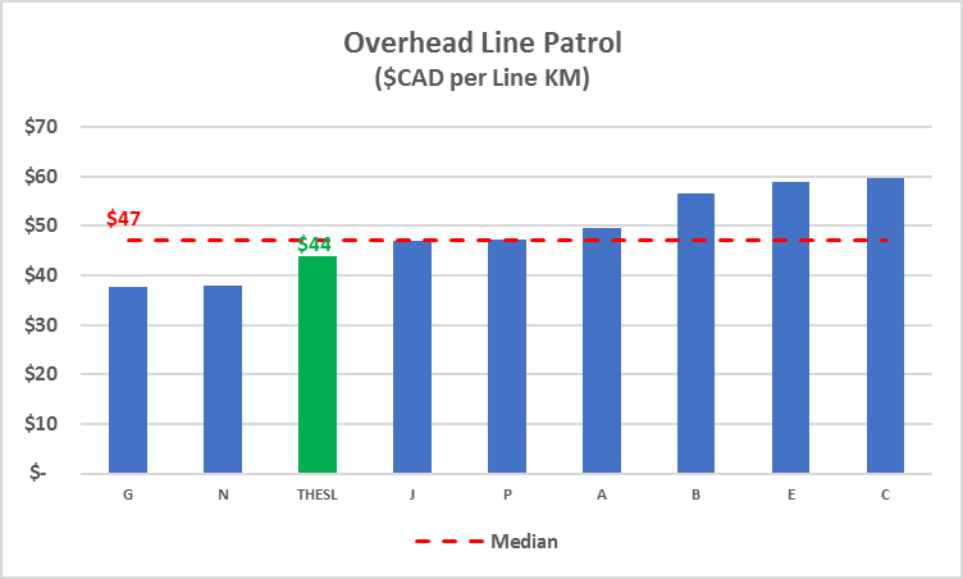

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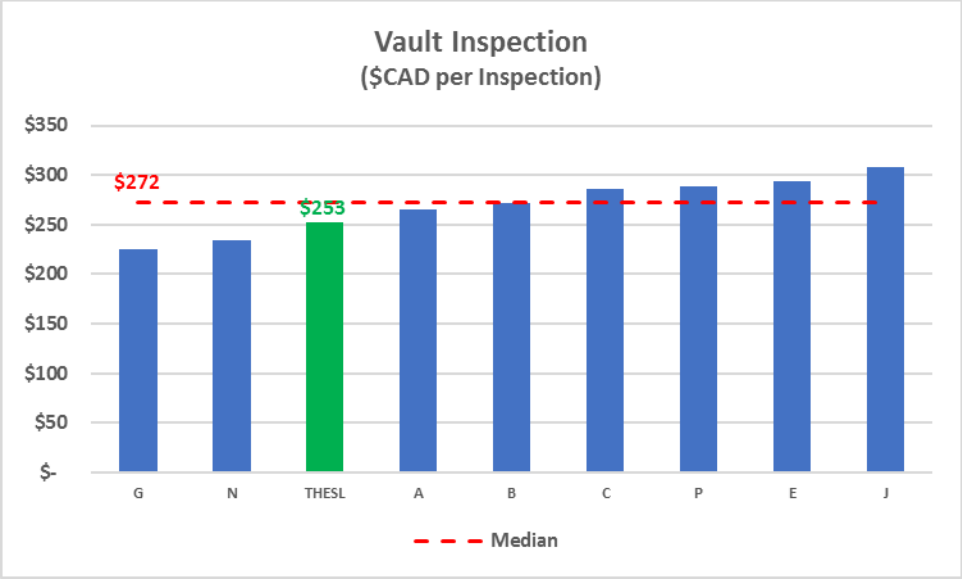

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OEB Appendix 5-A
Metrics

Metric Category	Metric	Measures	
		2017 (1 Year)	2013-2017 (5 Year) Average
Cost	Total Cost per Customer[1]	870	815
	Total Cost per km of Line[2]	23,234	42,438
	Total Cost per MW[3]	157,364	137,824
CAPEX	Total CAPEX[4] per Customer	715	657
	Total CAPEX[4] per km of Line	19,086	33,837
O&M	Total O&M per Customer	155	158
	Total O&M per km of Line	4,148	8,602

Notes to the Table:

1 Total Cost per Customer is the sum of a distributor's capital and O&M expenditures divided by the total number of customers that the distributor serves. The expenditure and customer amounts are as presented in the Yearbooks.
2 Total Cost per km of Line is the sum of a distributor's capital and O&M expenditures divided by the total number of kilometres of line that the distributor operates to serve its customers. The expenditure and kilometre amounts are as presented in the Yearbooks.
3 The Total Cost per MW is the sum of the distributor's capital and O&M expenditures divided by the total peak MW that the distributor serves. The expenditure and peak demand amounts are as presented in the Yearbooks.
4 Annual CapEx amounts are as presented in Yearbooks.

Explanatory Notes on Adverse Deviations (complete only if applicable)

Metric Name: Total Cost per Customer

The increase of $55 is primarily due to increased investment in the distribution system as described in Exhibit 2B, Section E.

Metric Name: Total Cost per MW

The increase of $19,540 is primarily due to increased investment in the distribution system (see Exhibit 2B, Section E) and lower than average peak demand.

Metric Name: Capital Addition for the Year per Customer

The increase of $57 is primarily due to increased investment in the distribution system (see Exhibit 2B, Section E).

ELECTRICITY DISTRIBUTOR SCORECARD AND 2015-2019 DISTRIBUTION SYSTEM PLAN PERFORMANCE MEASURES

In accordance with the OEB's *Renewed Regulatory Framework for Electricity Distributors* (the "RRF"), Toronto Hydro reports annually on its progress against measures aligned with the following core objectives: Customer Focus, Operational Effectiveness, Public Policy Responsiveness, and Financial Performance.[1] These results are reported as part of the OEB's Electricity Distributor Scorecard (the "EDS") and used to assess utility performance over time and in comparison to other utilities.

The first section of this Schedule discusses Toronto Hydro's performance for each of the EDS measures[2] for the last five years, i.e. 2013-2017, and is consistent with the approach Toronto Hydro undertakes in its annual reporting.[3] The second section of this Schedule discusses historical performance relating to the 12 Distribution System Plan ("DSP") measures introduced as part of the utility's 2015-2019 Rate Application.[4]

1. EDS PERFORMANCE

As illustrated in Table 1, Toronto Hydro's performance on the EDS has been strong over the 2013-2017 period, including notable improvements in Customer First Contact Resolution, Telephone Calls Answered on Time, New Residential and Small Business Services Completed on Time and Billing Accuracy. The following sections provide

[1] Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach (October 18, 2012).
[2] The definitions of each of these performance measures is available at: <https://www.oeb.ca/sites/default/files/uploads/Scorecard_Performance_Measure_Descriptions.pdf>
[3] Toronto Hydro's Electricity Distributor Scorecard for 2016 is available at: <https://www.torontohydro.com/sites/electricsystem/residential/customercare/Documents/Scorecard%20-%20Toronto%20Hydro-Electric%20System%20Limited.pdf>
[4] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015), Exhibit 2B, Section C.

additional detail on Toronto Hydro's EDS historical performance and targets, for each measure.

Table 1: Toronto Hydro EDS Performance 2013-2017

Performance Outcomes	Performance Categories	Measures		2013	2014	2015	2016	2017[a,b]	Target: Industry	Target: Distributor	Average
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		94.20%	91.50%	96.90%	97.70%	98.32%	90.00%		95.72%
		Scheduled Appointments Met On Time		99.60%	99.80%	99.90%	99.50%	99.37%	90.00%		99.63%
		Telephone Calls Answered On Time		82.00%	71.90%	76.80%	64.70%	77.92%	65.00%		74.66%
	Customer Satisfaction	First Contact Resolution		77%	81%	84%	86%	88%			83%
		Billing Accuracy			96.62%	97.54%	98.86%	99.24%	98.00%		98.07%
		Customer Satisfaction Survey Results			91%	91%	83%	83%			N/A
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness				71.00%	71.00%	69.00%			70.33%
		Level of Compliance with Ontario Regulation 22/04		C	C	C	C	C		C	N/A
		Serious Electrical Incident Index	Number of General Public Incidents	2	3	0	0	1		2	1.2
			Rate per 10, 100, 1000 km of line	0.202	0.295	0	0	0.070		0.083	0.113
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted		1.11	0.89	0.99	0.91	0.91		1.11	0.96
		Average Number of Times that Power to a Customer is Interrupted		1.34	1.18	1.31	1.28	1.18		1.36	1.26
	Asset Management	Distribution System Plan Implementation Progress [c]		105%	147%	100%	101%	99%			N/A
	Cost Control	Efficiency Assessment		5	5	5	5				5
		Total Cost per Customer		$924	$967	$1,000	$1,044				$984
		Total Cost per Km of Line		$66,793	$70,688	$73,309	$27,819				$59,652
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g. in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings				12.51%	34.58%	62.30%		1,576.05 GWh	N/A
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		100.00%	97.12%	100.00%	100.00%	81.08%			95.64%
		New Micro-embedded Generation Facilities Connected On Time		100.00%	100.00%	100.00%	100.00%	92.41%	90.00%		98.48%
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.80	0.68	0.67	0.61	0.64			0.68
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.34	1.65	1.57	1.45	1.34			1.47
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.58%	9.58%	9.30%	9.30%	9.30%			9.41%
			Achieved	7.10%	7.41%	10.71%	12.18%	9.08%			9.30%

a. Results to be finalized and submitted to the OEB via the annual Scorecard MD&A process
b. Certain results are issued by the OEB and were not available at the time of preperation.
c. The amount previously reported for 2016 has been adjusted from 113% to 101%

1.1 Service Quality: New Residential/Small Business Services Connected on Time

Toronto Hydro connected an average of 95.7 percent of new residential and small business services (i.e. new connections less than 750 volts) on time over the 2013-2017 period, exceeding the industry target of 90 percent. In 2017, Toronto Hydro achieved its best result to date, connecting 98.3 percent of the 2,621 new residential and small business connections on time.

Serving one of the fastest growing cities in North America, Toronto Hydro receives high volumes of connections and upgrades requests for residential and commercial developments each year. To meet these challenges, the utility continues to look for ways to improve the connection needs of its customers. For instance, in 2017, Toronto Hydro consolidated its connection design teams to enable the allocation and distribution of work across design team members in a more effective and efficient manner. In addition, Toronto Hydro provided electronic means for customers to complete their connections inquiries. These process improvements enable customer inquiries to be handled efficiently and expeditiously.

For the 2020-2024 period, Toronto Hydro aims to meet or exceed the current OEB standard for this measure. The utility's performance under this measure is enabled by a number of programs including Customer Connections (Exhibit 2B, Section E5.1) and Customer-Driven Work (Exhibit 4A, Tab 2, Schedule 8).

1.2 Service Quality: Scheduled Appointments Met On Time

Toronto Hydro met an average of 99.6 percent of all requested appointments on time over the 2013-2017 period, exceeding the performance standard set by OEB of 90 percent.

Serving one of the fastest growing cities in North America, Toronto Hydro receives high volumes of appointments requests every year. For the 2020-2024 period, Toronto Hydro aims to meet or exceed the current OEB standard for this measure. The utility's performance under this measure is enabled by a number of programs including Customer Connections (Exhibit 2B, Section E5.1) and Customer-Driven Work (Exhibit 4A, Tab 2, Schedule 8).

1.3 Service Quality: Telephone Calls Answered On Time

Toronto Hydro answered an average of 74.7 percent of telephone calls on time over the 2013-2017 period, exceeding the industry target of 65 percent.

Toronto Hydro met the standard each year from 2013-2017 with the exception of 2016, where the performance was at 64.7 percent, just slightly below the OEB standard. The was due to a number of factors including a 10 percent call volume increase, when compared to 2015, due to an increase in calls resulting from rate changes.

In 2017, Toronto Hydro extended its Call Centre weekday business hours from 8:00 a.m. to 4:30 p.m. to 8:00 a.m. to 8:00 p.m. The extended Call Centre hours has resulted in more manageable call volumes, contributing to improving results. While some year-over-year volatility is to be expected, for the 2020-2024 period, Toronto Hydro aims to meet or exceed the current OEB standard for this measure. The utility's performance under this measure is enabled primarily by the utility's Customer Care program (Exhibit 4A, Tab 2, Schedule 14).

1.4 Customer Satisfaction: First Contact Resolution

First Contact Resolution tracks the successful resolution of a customer's concern or needs in the first instance they contact the utility. This measure reflects the proportion

of telephone enquiries related to a residential or commercial account where the issue was resolved in the first call. Toronto Hydro has averaged 83.2 percent in this measure over the 2013-2017 period. The utility continues to explore effective ways to promote the consumer-utility interaction such as enabling self-service tools for specific issues.

Toronto Hydro's First Call Resolution performance has consistently improved from 77 percent in 2013 to 88 percent in 2017. In addition, the promotion of customer self-service features on Toronto Hydro's website has contributed to a reduction in the potential need for customers to contact the utility. Toronto Hydro remains committed to performing well in this measure. The utility's performance under this measure is enabled primarily by the utility's Customer Care program (Exhibit 4A, Tab 2, Schedule 14).

1.5 Customer Satisfaction: Billing Accuracy

Toronto Hydro issued an accurate bill 98.1 percent of the time on average over the 2014-2017 period, meeting the industry target of 98 percent.

Billing inaccuracies may be caused by a variety of factors including incomplete or inaccurate meter data, incorrect account or move-in/move-out information, or misapplication of rates.

Toronto Hydro's performance was slightly below the industry target in 2014 and 2015. The steady improvements since 2014 resulted from focused attention by the utility on process improvements and hardware enhancements. Since 2015, Toronto Hydro has invested extensively on process improvements and hardware enhancements driving the billing accuracy performance back to the OEB standard, and in fact slightly exceeding it in 2016 and 2017.

Process improvements include streamlining the meter to cash process, implementation of preventative measures to monitor and reduce billing errors and exceptions, improvements to training and standard operating procedure documents, and the proactive integration of relevant controls in new projects. Replacements of defective meters, enhanced engagement with vendors, enhancements to field service and metering data exception management processes, and investments in metering and meter data collection technologies also contributed to reductions in billing inaccuracies.

Over the 2020-2024 period, Toronto Hydro intends to begin an upgrade of its residential and small commercial meters (for more information please refer to the Metering Program – Exhibit 2B, Section E5.4). These new meters allow for improved data transmission to collectors, resulting in fewer errors and less manual meter reads. They also contain larger storage capacity, resulting in lower data loss, and an enhanced meter signal range, resulting in cost reduction from fewer personnel required to conduct manual meter reads. These investments are expected to allow Toronto Hydro to achieve superior Billing Accuracy results.

For the 2020-2024 period, Toronto Hydro intends to meet or exceed the OEB standard for this measure. The utility's performance under the measure is enabled by a number of programs including Toronto Hydro's Customer Care program (Exhibit 4A, Tab 2, Schedule 14) and the Metering program (Exhibit 2B, Section E5.4).

1.6 Customer Satisfaction: Customer Satisfaction Survey Results

Toronto Hydro first reported this measure in 2014 and surveyed customer satisfaction in the following key areas: (a) power quality and reliability; (b) price; (c) billing and payment; (d) communications; and (e) the customer service experience.

In 2016, Toronto Hydro adopted a survey methodology used by Innovative Research Group and the Electricity Distributors Association. Based on the survey activities undertaken in December 2016, Toronto Hydro achieved an overall score of 83 percent, which surpassed the provincial average of 79 percent. It is not possible to compare the 2016 and 2014 survey results because the two surveys are based on different methodologies, including differences in scoring scales, structure of questions and overall scoring index versus a single score.

Toronto Hydro intends to continue to engage with customers via a customer satisfaction survey every two years, at a minimum, through the 2020-2024 period, and will aim to maintain or improve customer satisfaction. The utility's performance under the measure is enabled by a number of Toronto Hydro programs including Customer Care (Exhibit 4A, Tab 2, Schedule 14) and Customer Connections (Exhibit 2B, Section E5.1).

1.7 Safety: Level of Public Awareness of Electrical Safety

This measure was introduced in 2015. The overall Public Safety Awareness Index across various areas of the utility, as reported for 2015 and 2016, was 71 percent and the 2017 survey results were 69 percent. The results remain stable and are within the 4 percent margin of error, given the sample size of 600 customers.

Toronto Hydro values safety and proactively ensures awareness and importance of safety in the vicinity of its distribution equipment. These activities include proactive contact voltage scans on street-level assets, taking prompt corrective action where potential safety issues are identified, and fostering a robust corporate safety culture including comprehensive internal safety course work.

Distributors are required to report the results of a standard safety awareness survey of the general public residing within their service territory, who may or may not be direct customers, at least once every two years. The survey, as designed by the Electrical Safety Authority ("ESA") and tests the respondents' electrical safety awareness across several topics, including power line clearance distances, emergency procedures related to vehicular collisions with utility equipment and safety precautions related to excavation work.

For the 2020-2024 period, Toronto Hydro intends to continue to monitor the level of public safety awareness relating to the distribution system as well as continuing to meet or exceed all current OEB EDS targets relating to public safety. The utility's performance under this measure is impacted by Toronto Hydro's ongoing communications messaging as part of the Customer Care program (Exhibit 4A, Tab 2, Schedule 14).

1.8 Safety: Compliance with Ontario Regulation 22/04

The ESA deemed Toronto Hydro to be compliant with the requirements of Ontario *Regulation 22/04 – Electrical Distribution Safety* for 2013 through 2017. These results were achieved through successful due diligence inspections, resolution of public safety concerns, compliance investigations, and annual compliance audits conducted by the ESA and a declaration of compliance.

Ontario *Regulation 22/04 – Electrical Distribution Safety* establishes the requirements for electrical distribution safety related to the design, construction, and maintenance of electrical distribution assets owned by the utility. This includes making sure appropriate procedures are in place to prevent accidents or incidents, keeping the system in safe working condition, etc. The utility must demonstrate how well it met the standards by providing declarations, audit results, inspection reports, and other documentation.

Toronto Hydro intends to remain in compliance with *Ontario Regulation 22/04* through the 2020-2024 period. The utility's performance under the measure is enabled through a number of programs included in Exhibit 2B, Sections E5-E8, and Exhibit 4A, Tab 2.

1.9 Safety: Serious Electrical Incident Index

Toronto Hydro has surpassed the distributor targets, with only one reporting incident in the three years, which results in a ratio of 0.035 incidents per 1,000 km of line for 2017. /C

For the 2020-2024 period, Toronto Hydro intends to meet or exceed the relevant distributor target for this measure. The mitigation of public safety risk is enabled by a number of programs included in Exhibit 2B, Section E5 and E6 and Exhibit 4A, Tab 2.

1.10 System Reliability: SAIDI / SAIFI

Toronto Hydro's average SAIDI performance for the 2013-2017 period was 0.96 while the average SAIFI performance for the period was 1.26. The utility's annual SAIDI and SAIFI results have met or exceeded the OEB's distributor target during this period. Please see Exhibit 1B, Tab 2, Schedule 4 for a comprehensive discussion on the underlying causes of system interruptions captured by SAIDI and SAIFI.

For the 2020-2024 period, Toronto Hydro intends to continue its strong performance and maintain system reliability performance at the 2013-2017 average.[5] The utility's performance under the measure is enabled through a number of programs including Area Conversions (Exhibit 2B, Section E6.1), Network System Renewal (Exhibit 2B, Section E6.4), and the Underground and Overhead System Renewal programs (Exhibit 2B, Section E6.2, E6.3, and E6.5).

[5] Toronto Hydro will be using performance results from 2013-2017, which is the most current five-year average, as opposed to the fixed five-year (2010-2014) average distributor specific target.

1.11 Asset Management: Distribution System Plan ("DSP") Implementation Progress

For 2017, the DSP implementation progress was 99 percent. Toronto Hydro has adjusted planned spending in 2018 and 2019 to closely adhere to the approved five-year cumulative amount. See Exhibit 2B, Section E4 for details on the implementation of the utility's DSP.

The DSP Implementation Progress measure reflects the effectiveness of the utility in implementing its DSP. This measure is intended to track the ratio of the actual cumulative capital expenditures to the aggregate approved five-year capital expenditure amount. Toronto Hydro has hundreds of individual capital projects each year, and the selection and timing of those projects varies with dynamic customer and system needs, as well as weather, field conditions, permitting, site access, third party co-ordination, and other factors. A regular part of Toronto Hydro's operation is rebalancing the mix and timing of capital projects to adjust for these factors.

For the 2020-2024 period, Toronto Hydro will continue to report the progress of its DSP implementation based on the approved amount.

1.12 Efficiency Assessment

Efficiency is determined using an econometric benchmarking model that compares each actual total costs to average total costs predicted by the model, which benchmarks against Ontario-based utilities. Utilities' total costs are evaluated to produce a single efficiency ranking. This is divided into five groups based on the magnitude of the difference between each utility's actual and predicted costs. For the period 2013-2016, Toronto Hydro maintained its efficiency ranking of 5.[6]

[6] The 2017 OEB Benchmarking results were not available at the time of filing.

While Toronto Hydro endorses the importance of a sophisticated quantitative assessment of distributor efficiency, the methodology underlying the reported results for this measure do not adequately assess the efficiency performance of a utility of Toronto Hydro's size, density, and asset base.

Toronto Hydro's PSE Benchmarking Report– *Econometric Benchmarking of Historical and Projected Total Cost and Reliability Levels* – is a better indicator of the utility's performance and is included in Exhibit 1B, Tab 4, Schedule 2.

For the 2020-2024 period, Toronto Hydro will continue to report under this measure, as defined by the OEB.

1.13 Total Cost per Customer and Total Cost per km of Line

For the 2013-2016 period, Toronto Hydro's average total cost per customer was $984 and average cost per kilometre was $59,652. This amount is then divided by the total number of Toronto Hydro customers served and the total the number of kilometres of line of distribution line operated by the utility.

In 2016, the utility adjusted its methodology for the Total Cost per km of Line measure to align with the OEB's definition by accounting for the utility's significant secondary (lower-voltage) distribution network. This is reflected in the significant (62 percent) decrease in results from 2015 to 2016.

Toronto Hydro's Total Cost per Customer is increasing primarily due to increased capital costs paired with modestly increasing OM&A costs. This increase is consistent with Toronto Hydro's ongoing efforts to find operational efficiencies while undertaking

capital work to replace aging and deteriorating assets and meet the growing demand on its distribution system.

For the 2020-2024 period, Toronto Hydro will continue to report under this measure, as defined by the OEB.

1.14 Net Cumulative Energy Savings

In 2017, Toronto Hydro achieved 333 GWh of net incremental energy savings persisting to 2020. At the halfway point of implementation, the utility has achieved 62 percent of the 1,576 GWh target for net cumulative energy savings for the 2015 to 2020 period.

Under the Conservation First Framework, the IESO allocates energy savings to be achieved by each utility in the province. Each LDC is then responsible for achieving its allocated 2015-2020 CDM Plan Target. Toronto Hydro works closely with the IESO and other LDCs to continually develop and improve provincial offerings, while at the same time creating local programs that target specific opportunities unique to Toronto. In 2017, Toronto Hydro achieved the highest annual energy savings Toronto Hydro has ever reported, driving new standards of performance across all customer segments.

Most of the utility's Conservation and Demand Management programs are not funded via rates. However, Toronto Hydro's Stations Expansion program (Exhibit 2B, Section E7.4) includes rates-funded demand response activities to defer distribution infrastructure, which supports the Conservation First objectives.

Going forward, Toronto Hydro aims to fulfill the target within the time-frame allotted.

1.15 Connection of Renewable Generation: Renewable and Micro-Embedded Generation Connections

The utility averaged 96.5 percent for Renewable Generation Connection Impact Assessments ("CIAs") Completed on Time and 98.5 percent for New Micro-embedded Generation Facilities Connected on Time over the 2013-2017 period.

As of the end of 2017, Toronto Hydro had responded to over 8,000 inquiries from customers and developers seeking to connect generation under various programs such as the IESO programs,[7] Net-Metering, Energy Storage, Combined Heat and Power ("CHP"), Closed Transition, and Load Displacement. A wide range of proponents have submitted project applications, including many schools, housing managers, large grocery stores, condominium corporations, and department stores. As of the end of 2017, Toronto Hydro had connected nearly 1,800 distributed generation projects of various sizes totalling 225.7 MW in capacity.

In 2017, Toronto Hydro's connection process changed such that the execution of the Connection Agreement and collection of connection costs would occur prior to meter installation. Due to uncertainty about some of the provincially-supported programs, customers began to exhibit a reluctance in paying the connection costs after the project was connected to the grid. As a result, more time and effort was required by Toronto Hydro to deal with the increased volume of non-payment collections. The change in process is expected to minimize this matter and contribute to increased efficiencies in relation to the connection process.

[7] Including Feed-in-Tariff ("FIT"), microFIT, Process and Systems Upgrade Initiative ("PSUI"), and Renewable Energy Standard Offer Program ("RESOP").

Toronto Hydro intends to improve its performance of the CIA measure and to continue to exceed or maintain the industry target for micro embedded through the 2020-2024 period. The utility's performance under this measure is enabled by the Customer Connections (Exhibit 2B, Section E5.1), Generation Protection, Monitoring, and Control (Exhibit 2B, Section E5.5), and Energy Storage Systems (Exhibit 2B, Section E7.2).

1.16 Financial Ratios: Liquidity: Current Ratio (Current Assets/Current Liabilities)

Toronto Hydro's "Current Assets" and "Current Liabilities" are determined in accordance with the requirements of the OEB's Electricity Reporting and Record Keeping Requirements for Electricity Distributors ("RRR") and the Accounting Procedures Handbook ("APH"), and not by reference to IFRS. As a result, the "Liquidity Ratio" expressed in the EDS may differ from similarly-termed financial ratios or information presented in documents that the utility's parent company, Toronto Hydro Corporation, is required to file under securities laws, and which are available on System Electronic Document Analysis and Retrieval ("SEDAR").

For an analysis on the financial performance of Toronto Hydro Corporation and its affiliates, including the utility, please refer to the financial reports available on Toronto Hydro's website[8] and SEDAR.[9]

1.17 Financial Ratios: Leverage: Total Debt to Equity Ratio

Toronto Hydro's "Total Debt" and "Equity" are determined in accordance with the requirements of the OEB's RRR and APH, and not by reference to IFRS. As a result, the "Leverage Ratio" expressed in the Scorecard and this Scorecard MD&A may differ from

[8] Toronto Hydro Financial Reports <http://www.torontohydro.com/sites/corporate/InvestorRelations/FinancialReports/Pages/FinancialReports.aspx>
[9] <https://www.sedar.com/>

similarly-termed financial ratios or information presented in documents that Toronto Hydro is required to file under securities laws and which are available on SEDAR.

For an analysis on the financial performance of Toronto Hydro Corporation and its affiliates, including the utility, please refer to the financial reports available on Toronto Hydro's website[10] and SEDAR.[11]

1.18 Financial Ratios: Leverage: Profitability: Regulatory Return on Equity – Deemed (included in rates) and Achieved

The Regulatory Return on Equity ("ROE") is calculated on the same basis as the methodology used to establish Toronto Hydro's base rates for a year, which is prescribed by the OEB. The Regulatory ROE is not determined in accordance with IFRS. As such, the Scorecard's "Profitability" performance measures ("Deemed" and "Achieved" Regulatory ROE) may differ from similarly-termed expressions of profitability and return on equity presented in documents that Toronto Hydro Corporation, the utility's parent company, is required to file under securities laws and which are available on SEDAR.

For analysis of the financial performance of Toronto Hydro Corporation and its affiliates, including the utility, please refer to its Corporate MD&A available on Toronto Hydro's website[12] and SEDAR.

[10] Toronto Hydro Financial Reports <http://www.torontohydro.com/sites/corporate/InvestorRelations/FinancialReports/Pages/FinancialReports.aspx>
[11] <https://www.sedar.com/>
[12] *Supra* note 10.

2. 2015-2019 DSP PERFORMANCE MEASURES

This section provides the results of Toronto Hydro's historical performance on the 12 DSP measures proposed as part of its 2015-2019 Rate Application.[13] In an effort to reduce duplication, performance results for measures already discussed in the previous section or in Exhibit 1B, Tab 2, Schedules 3 and 4 and Exhibit 2B, Section C are not included here.

3. CUSTOMER AVERAGE INTERRUPTION DURATION INDEX ("CAIDI")

CAIDI measures the outage duration experienced by an average Toronto Hydro customer. The utility's performance for CAIDI has been consistent with overall reliability improvements exhibited in recent years. Figure 1, below, shows the utility's performance for this measure over the 2013-2017 period. Toronto Hydro's reliability improvements are attributable to the utility's distribution system investments.

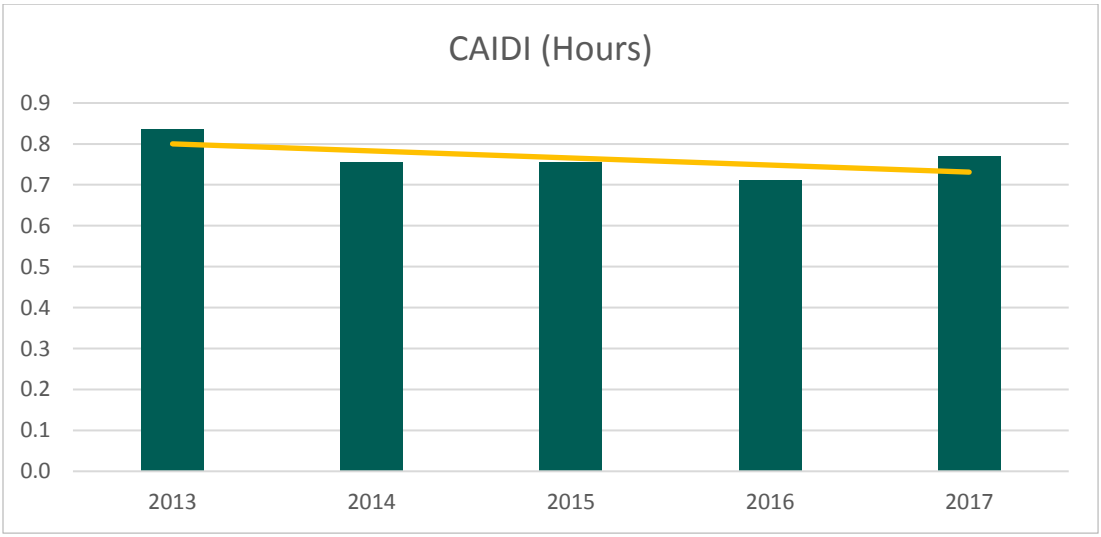


Figure 1: CAIDI Performance from 2013-2017

[13] *Supra* note 4. Note that in place of some of these measures, Toronto Hydro has proposed 15 Custom Performance Measures for the 2020-2024 plan period in the current Application. Please see Exhibit 2B, Section C for more information.

4. MOMENTARY AVERAGE INTERRUPTION FREQUENCY INDEX ("MAIFI")

MAIFI measures the average frequency of momentary interruptions (i.e. less than one minute) that affect Toronto Hydro's customers. Figure 2, below, shows the utility's performance for this measure over the 2013-2017 period. The five-year annual frequency value for the period 2013 to 2017 is 2.56 compared to the corresponding value of 2.74 reported in the utility's last Rate Application (for the period 2009 to 2013). For 2017, MAIFI was 2.52. This result represents a marginal improvement from the prior year and is generally consistent with recent historical results.

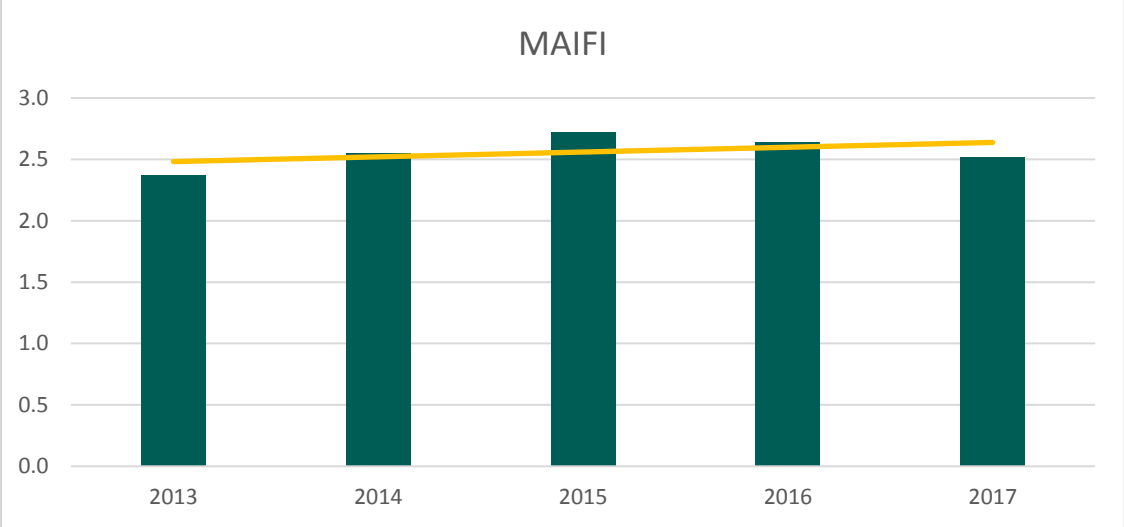


Figure 2: MAIFI Performance from 2013-2017

5. OUTAGES CAUSED BY DEFECTIVE EQUIPMENT

The Number of Outages Caused by Defective Equipment tracks the total number of sustained customer interruptions attributable to defective equipment, which may result from causes such as equipment failures due to deterioration from age or maintenance deficiencies and indicates the health of the system.

Figure 3, below, shows the utility's performance in this measure over the 2013-2017 period. In 2017, Toronto Hydro recorded 484 outages caused by defective equipment, the lowest number in recent history. The overall declining trend as shown in Figure 3, below, aligns with Toronto Hydro's general expectations and is consistent with its implementation of its capital renewal programs.

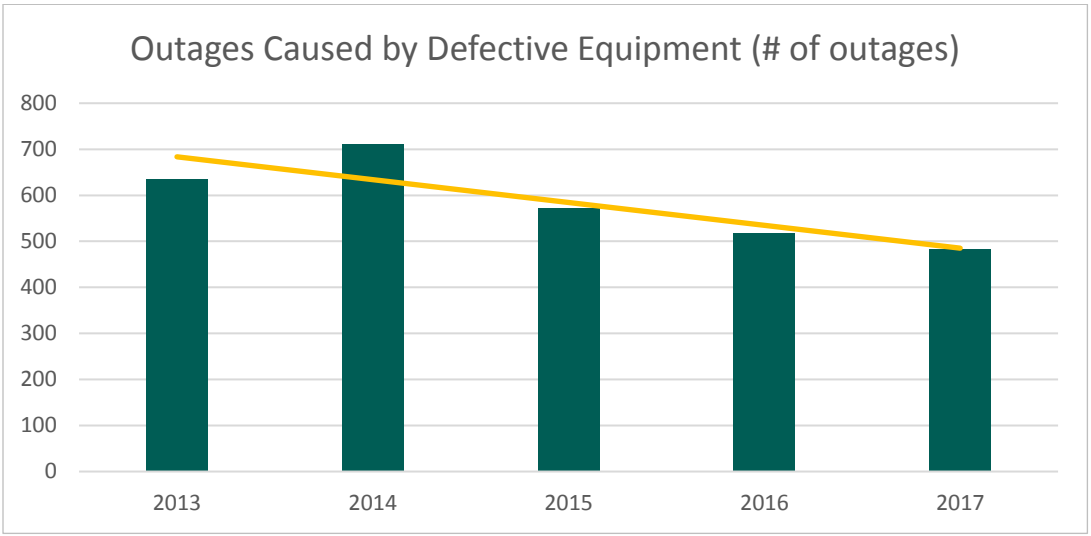


Figure 3: Outages by Defective Equipment Performance from 2013-2017

6. STATIONS CAPACITY AVAILABILITY

The Stations Capacity Availability tracks the number of Transformer Stations where station demand is forecasted to exceed 90 percent of the station's firm capacity within the next five years. Figure 4 shows the utility's performance in this measure over the 2013-2017 period. The number of stations with demand forecasted to exceed the 90 percent threshold within five years remained at one station in 2016 and 2017. The measure has remained consistent, since system peak load in 2017 was similar to 2016. Figure 4, below, also shows a declining trend for the past five-year period illustrating that Toronto Hydro has managed stations capacity and load transferring successfully.

Distribution system load across the system decreased slightly from 2014 to 2017, driving the measure down to zero. Two stations currently are forecasted to become loaded beyond 90 percent in the coming years.

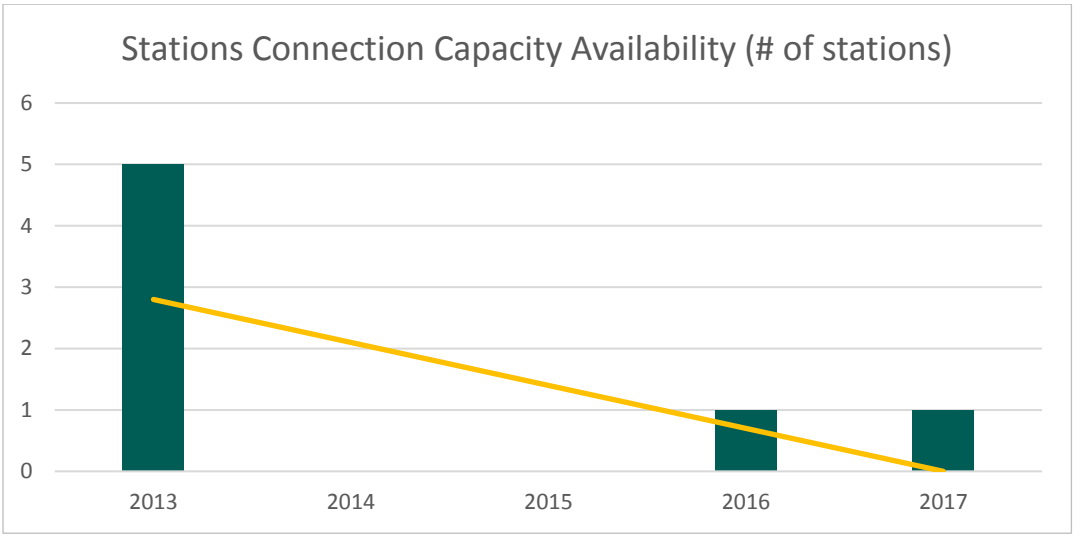


Figure 4: Stations Capacity Available Progress Performance for 2013-2017

7. PLANNING EFFICIENCY - ENGINEERING AND SUPPORT COSTS

This measure monitors the proportion of indirect labour costs being charged to capital projects. Figure 5 shows the utility's performance in this measure over the 2013-2017 period. Factors that have impacted this measure include year-to-year variations in overall capital spending, design requirements for future spending, and increases in Control Centre activities to manage increasing demands for outage management on the distribution system. Demands have also increased in the System Access category, which requires increased Control Centre engagement. These demands include staffing requirements which resulted in higher labour costs, and increased cost attributable to this category.

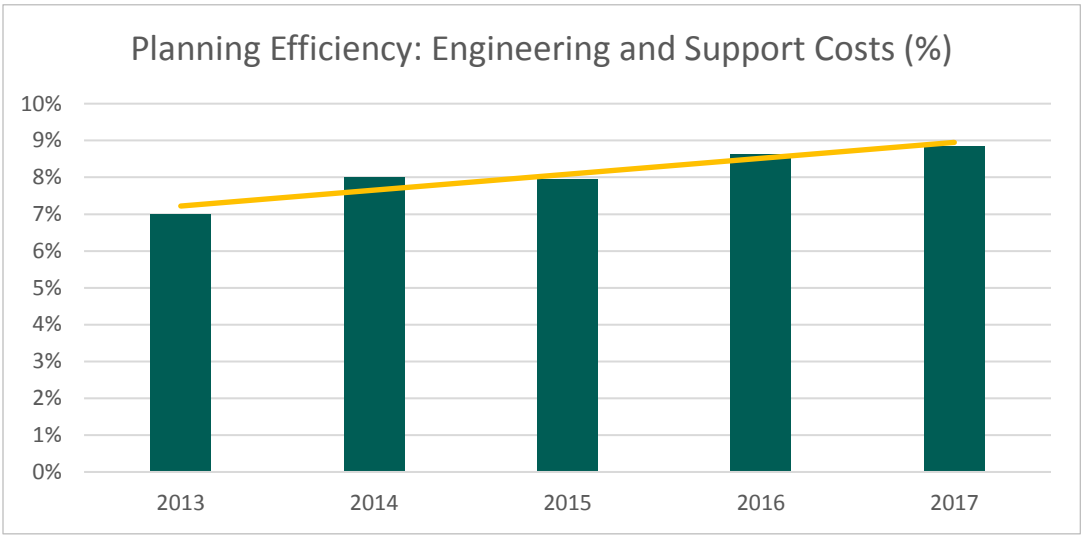


Figure 5: Engineering and Support Costs (%) Performance from 2013-2017

8. SUPPLY CHAIN EFFICIENCY: MATERIALS HANDLING ON-COST

In accordance with the applicable accounting framework, Toronto Hydro adds the eligible portion of its supply chain and warehousing activities costs directly to the capital projects and programs that these activities support. The supply chain and warehousing costs are added to the total costs of capital projects through the service charge referred to as "On-Cost", which is applied as a percentage of the project's total costs.

As shown in Figure 6, actual on-cost rate decreased between 2013 and 2017, with the general stability over the five-year historical period.

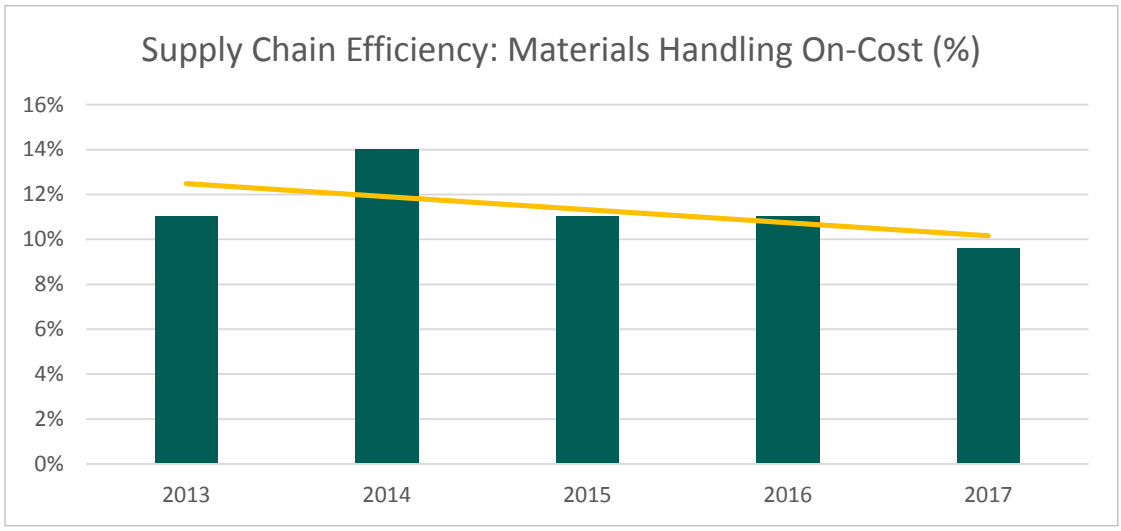


Figure 6: Materials Handling On-Cost Performance from 2013-2017

9. CONSTRUCTION EFFICIENCY: INTERNAL VS CONTRACTOR COST BENCHMARKING

To track the costs of capital construction projects completed by the utility's internal construction crews, Toronto Hydro compared the cost of select projects constructed internally to the unit prices charged for similar work performed by external contractor crews.

Internal project construction costs were on average [redacted] than the costs of the same projects had they been constructed externally using up to seven design and construction contractors over the 2013 to 2016 period.[14] This value was calculated using the weighted average of individual estimate variances equal to the portion of contractor work performed by each of the six or seven contractors in a reference year. Year-over-year results were affected by the selected sample project which comprised of different units of work.

[14] The results for 2017 are not available at this time.

10. CONSTRUCTION EFFICIENCY: STANDARD ASSET ASSEMBLY LABOUR INPUT

The Standard Asset Assembly Labour Input is related to the development of a comprehensive framework for tracking the total number of labour hours required to stage, install, and energize a fully assembled unit corresponding to each major asset class of the utility's electricity distribution plant (e.g. transformers, switchgear etc.).

In 2016, Toronto Hydro successfully implemented Asset Assembly Units for estimating internal construction activities and leveraged this new approach to develop a construction scheduling and dashboard tool to manage construction projects during their lifecycle. The asset assembly project was launched in 2017, and Toronto Hydro is in the very early stages of data collection. Given the amount of electrical planned capital project work that is executed by internal Toronto Hydro staff, obtaining a statistically significant data set is expected to take at least 12-24 months.

The envisioned end-state scope includes about 25 discrete estimates of total labour and "non-wrench" hours (e.g. driving, set-up/take-down, breaks) required to fully complete a single installation of a major asset class unit. The estimates of total hours will be developed based on system averages derived through analysis of past results, pilot time studies, and other activities determined as necessary during the project stages. Toronto Hydro continues work on developing and assessing the feasibility of this measure.

SERVICE QUALITY PERFORMANCE

1. OVERVIEW

Toronto Hydro monitors and reports its performance results for the Electricity Service Quality Requirements ("ESQRs") in accordance with the OEB's Reporting and Record-keeping Requirements ("RRR").[1] This section provides the reported Service Quality Requirements for the last five years (2013-2017). A completed Appendix 2-G, documenting both Service Quality and Service Reliability Indicators, is provided in Exhibit 1B, Tab 2, Schedule 5. Toronto Hydro confirms that the data included in this evidence is consistent with the scorecard.[2]

As illustrated in Table 1, Toronto Hydro's Service Quality performance has been steady in most areas over the last five years, meeting or exceeding the ESQR standards 85 percent of the time, with noteworthy improvements in Emergency Response and Connections of New Services (Low Voltage) measures. A detailed explanation as well as a remediation plan for those measures below the OEB standard are provided below.

[1] See OEB Distribution System Code, Chapter 7 Service Quality Requirements, and RRR section 2.1.4.
[2] This section is filed in accordance with section 2.2.2.8 [Service Quality] of the Chapter 2 Cost of Service Filing Requirements.

Table 1: Summary of Toronto Hydro's ESQR Performance

ESQR	OEB Standard	Hist. 5 Year Avg.	2013	2014	2015	2016	2017
Connection of New Services-Low Voltage ("LV")	90	95.7	94.2	91.5	96.9	97.7	98.3
Connection of New Service-High Voltage ("HV")	90	99.7	100.0	100.0	100.0	100.0	98.4
Micro Embedded Generation Facilities	90	98.5	100.0	100.0	100.0	100.0	92.4
Appointment Scheduling	90	87.7	96.6	96.2	89.0	72.0	81.8
Appointment Met	90	99.6	99.6	99.8	99.9	99.5	99.4
Rescheduling a Missed Appointment	100	98.6	98.4	94.6	100.0	100.0	100.0
Telephone Accessibility	65	74.7	82.0	71.9	76.8	64.7	77.9
Telephone Call Abandon Rate	10	1.9	1.2	1.7	1.6	3.1	1.9
Written Response to Enquires	80	94.9	98.9	85.8	97.5	93.1	99.0
Billing Accuracy	98	98.1	NA	96.6	97.5	98.9	99.2
Emergency Response (Urban)	80	87.8	74.4	92.0	87.2	91.8	93.6
Reconnection Performance Standard	85	99.8	100.0	100.0	100.0	99.7	99.4

2. CONNECTION OF NEW SERVICES – LOW VOLTAGE

Over the 2013-2017 period, on average, Toronto Hydro has exceeded the OEB standard for this measure. Specifically, Toronto Hydro connected an average of 95.7 percent of new low voltage connections (i.e. new connections below 750 volts) on time over the 2013-2017 period, exceeding the OEB standard of 90 percent. Further details on the utility's performance in this measure can be found under "New Residential/Small Business Services Connected on Time"[3] in Exhibit 1B, Tab 2, Schedule 2.

[3] OEB EDS Measure Descriptions are available at: <https://www.oeb.ca/sites/default/files/uploads/Scorecard_Performance_Measure_Descriptions.pdf>

3. CONNECTION OF NEW SERVICES – HIGH VOLTAGE

Over the 2013-2017 period, on average, Toronto Hydro has exceeded the OEB standard for this measure. Specifically, Toronto Hydro connected an average of 99.7 percent of new high voltage connections (i.e. new connections greater than 750 volts) on time over the 2013-2017 period, exceeding the OEB standard of 90 percent.

Toronto Hydro's services one of the fastest growing cities in North America, requiring the utility to respond to high volumes of connections and upgrades requests for residential and commercial developments each year. To meet these challenges, the utility continues to look for ways to improve how it responds to the connection needs of its customers. For instance, in 2017, Toronto Hydro consolidated its connection design teams to enable the allocation and distribution of work across design team members in a more effective and efficient manner. In addition, Toronto Hydro introduced an online method of allowing customers to complete their connections inquiries. This has enabled customer inquiries to be dealt with efficiently and expeditiously.

For the 2020-2024 period, Toronto Hydro intends to continue to meet or exceed the current OEB standard for this measure. Toronto Hydro's performance under this measure is enabled by programs including the low voltage connections work discussed in Toronto Hydro's Customer Connections program (Exhibit 2B, Section E5.1).

4. MICRO-EMBEDDED GENERATION FACILITIES

Over the 2013-2017 period, on average, Toronto Hydro has exceeded the OEB standard for this measure. Specifically, Toronto Hydro connected an average of 98.5 percent of micro-embedded generation facilities over the 2013-2017 period, exceeding the OEB standard of 90 percent. Further details on the utility's performance in this measure can

be found under "New Micro-Embedded Generation Facilities Connected on Time" in Exhibit 1B, Tab 2, Schedule 2.

5. APPOINTMENTS SCHEDULING

Over the 2013-2017 period, on average, Toronto Hydro has performed below the OEB standard for this measure. Specifically, on average, Toronto Hydro scheduled 87.7 percent of appointments within five business days over the 2013-2017 period, falling slightly below the OEB standard of 90 percent.

Toronto Hydro has made several process improvements in an effort to increase performance in this measure. Some of these improvement initiatives include:

- Optimizing the number and use of contractors to address appointments for cable locates;
- Establishing self-locating agreements that enable qualified excavators to perform locates safely, without engaging Toronto Hydro;
- Establishing alternate locate agreements allowing excavations to be performed under pre-established conditions without a field locate;
- Increased training of locate service providers enabling them to complete pre-screening; and
- Expanding the use of remote pre-screening to identify locations where no underground infrastructure exists, thus eliminating the need for a site visit (and an appointment).[4]

[4] Self-locating agreements enable excavators to provide their own locates on Toronto Hydro's behalf and alternate locate agreements allow excavations under set conditions without a field locate.

These efforts have led to a 10 percent increase in the reported performance from 2016 to 2017. Specifically, in 2017, Toronto Hydro scheduled 81.8 percent of all appointments within five business days, improving on its 2016 performance of 72.0 percent. Going forward, the utility will continue to work on its performance. The utility's performance under this measure is enabled by such programs as Customer-Driven Work (Exhibit 4A, Tab 2, Schedule 8).

6. APPOINTMENTS MET

Over the 2013-2017 period, on average, Toronto Hydro has exceeded the OEB standard for this measure. Specifically, Toronto Hydro has arrived on time for an appointment 99.6 percent of the time over the 2013-2017 period, exceeding the OEB standard of 90 percent. Toronto Hydro's performance under this measure is discussed in Exhibit 1B, Tab 2, Schedule 2 under "Scheduled Appointments Met n Time."

7. RESCHEDULING A MISSED APPOINTMENT

Over the 2013-2017 period, on average, Toronto Hydro has performed below the OEB standard for this measure. Specifically, on average, Toronto Hydro rescheduled a missed appointment 98.6 percent of the time over the 2013-2017 period, falling slightly below the OEB standard of 100 percent. However, performance under this measure has been at the OEB standard of 100 percent for the last three years (i.e. 2015, 2016, and 2017).

Toronto Hydro strives to meet all its appointments, with very few missed on an annual basis. When one of these few missed appointments is subsequently not rescheduled in accordance with the OEB's standard, it results in a relatively significant impact in percentage terms. For instance, in 2014, out of a total of number of 16,727 customer

appointments only 37 were missed, of which only two were rescheduled in accordance with the OEB's standard.

For the 2020-2024 period, Toronto Hydro intends to perform at the current OEB standard of 100 percent. The utility's performance under this measure is enabled by such programs as Customer-Driven Work (Exhibit 4A, Tab 2, Schedule 8).

8. TELEPHONE ACCESSIBILITY

Over the 2013-2017 period, on average, Toronto Hydro has exceeded the OEB standard for this measure. Specifically, Toronto Hydro responded within a 30-second time period 74.7 percent of the time over the 2013-2017 period, exceeding the OEB standard of 65 percent. Toronto Hydro's performance under this measure is discussed in Exhibit 1B, Tab 2, Schedule 2 under "Telephone Calls Answered on Time." The utility's performance under this measure is enabled by such programs as Customer Care (Exhibit 4A, Tab 2, Schedule 14).

9. TELEPHONE CALL ABANDON RATE

Over the 2013-2017 period, on average, Toronto Hydro has exceeded the OEB standard for this measure. Specifically, Toronto Hydro has a call abandonment rate of 1.9 percent, on average, compared to the OEB standard of 10 percent.

The Toronto Hydro's Contact Centre receives and responds to approximately 93,000 written inquiries and 527,000 telephone calls per year. Customers engage with the Contact Centre to inquire about Toronto Hydro's business practices, including, but not limited to, payment options, electricity consumption, and collections.

In 2017, Toronto Hydro extended its Call Centre weekday business hours from 8:00 a.m. to 4:30 p.m. to 8:00 am to 8:00 p.m. These extended hours have resulted in more manageable call volumes.

For the 2020-2024 period, Toronto Hydro intends to meet or exceed the OEB standard for this measure. The utility's performance under this measure is enabled by such programs as Customer Care (Exhibit 4A, Tab 2, Schedule 14).

10. WRITTEN RESPONSE TO ENQUIRIES

Over the 2013-2017 period, on average, Toronto Hydro has exceeded the OEB standard for this measure. Specifically, Toronto Hydro has responded to written enquiries within ten business days 94.9 percent of the time over the 2013-2017 period, exceeding the OEB standard of 80 percent.

For the 2020-2024 period, Toronto Hydro intends to meet or exceed the OEB standard for this measure. The utility's performance under this measure is enabled by such programs as Customer Care (Exhibit 4A, Tab 2, Schedule 14).

11. BILLING ACCURACY

Over the 2013-2017 period, on average, Toronto Hydro has met the OEB standard for this measure. Specifically, Toronto Hydro has issued an accurate bill 98.1 percent of the time, on average, over the 2013-2017 period, meeting the OEB standard of 98 percent. Toronto Hydro's performance under this measure is discussed in Exhibit 1B, Tab 2, Schedule 2 under "Billing Accuracy." The utility's performance under this measure is enabled by such programs as Metering (Exhibit 2B, Section E5.4) and Customer Care (Exhibit 4A, Tab 2, Schedule 14).

12. EMERGENCY RESPONSE

Over the 2013-2017 period, on average, Toronto Hydro has exceeded the OEB standard for this measure. Specifically, Toronto Hydro responded to emergency calls within 60 minutes 87.8 percent of the time over the 2013-2017 period, exceeding the OEB standard of 80 percent for urban areas.

The utility's performance below the OEB standard in 2013 was explained in Toronto Hydro's 2015-2019 Application as resulting from the timing and severity of Major Event Days ("MEDs") – typically storms – which may not allow for a timely response to all (often simultaneous) emergency calls. Since then, Toronto Hydro's 2014 to 2017 performance has substantially improved and has resulted in an overall five-year average of 87.8 percent – exceeding the OEB standard of 80 percent.

In 2017, Toronto Hydro successfully responded to 93.6 percent of emergency calls within 60 minutes. Toronto Hydro continues to assess and optimize the number of crews on shift to maximize resources and prioritize events to increase the number of events responded to per crew shift.

For the 2020-2024 period, Toronto Hydro intends to meet or exceed the current OEB standard for this measure. The utility's performance under this measure is enabled by such programs as Emergency Response (Exhibit 4A, Tab 2, Schedule 5).

13. RECONNECTION PERFORMANCE STANDARD

Over the 2013-2017 period, on average, Toronto Hydro has exceeded the OEB standard for this measure. Specifically, Toronto Hydro reconnected an average of 99.8 percent of customers on time for the 2013-2017 period, exceeding the OEB standard of 85 percent.

Toronto Hydro has made investments to its metering system to allow remote reconnection for certain customers. This was part of a pilot project started in 2017 to improve the efficiency and timeliness of the reconnection process. Toronto Hydro is gradually upgrading its meters to have remote-control capabilities and as of the end of 2017 had over 48,000 meters with such capabilities in service. These new meters can be remotely disconnected, reconnected, or operated intermittently to interrupt load on a pre-set schedule, without the need for a site visit.

As these meters become more commonplace, performance under this measure is expected to further improve, as the utility will increase its capability to remotely reconnect customers nearly instantaneously after a customer makes payment or enters into an arears payment plan.

For the 2020-2024 period, Toronto Hydro intends to meet or exceed the current OEB standard for this measure. Toronto Hydro's performance under this measure is enabled by work including that in the Metering (Exhibit 2B, Section E5.4) and Customer Care program (Exhibit 4A, Tab 2, Schedule 14).

RELIABILITY PERFORMANCE

Toronto Hydro tracks reliability performance indicators System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI") in several ways:[1]

1) All events;
2) Excluding events relating to Loss of Supply ("LoS");
3) Excluding events relating to Major Event Days ("MEDs");
4) Excluding MEDs and LoS; and
5) Excluding MEDs, LoS, and scheduled outages.

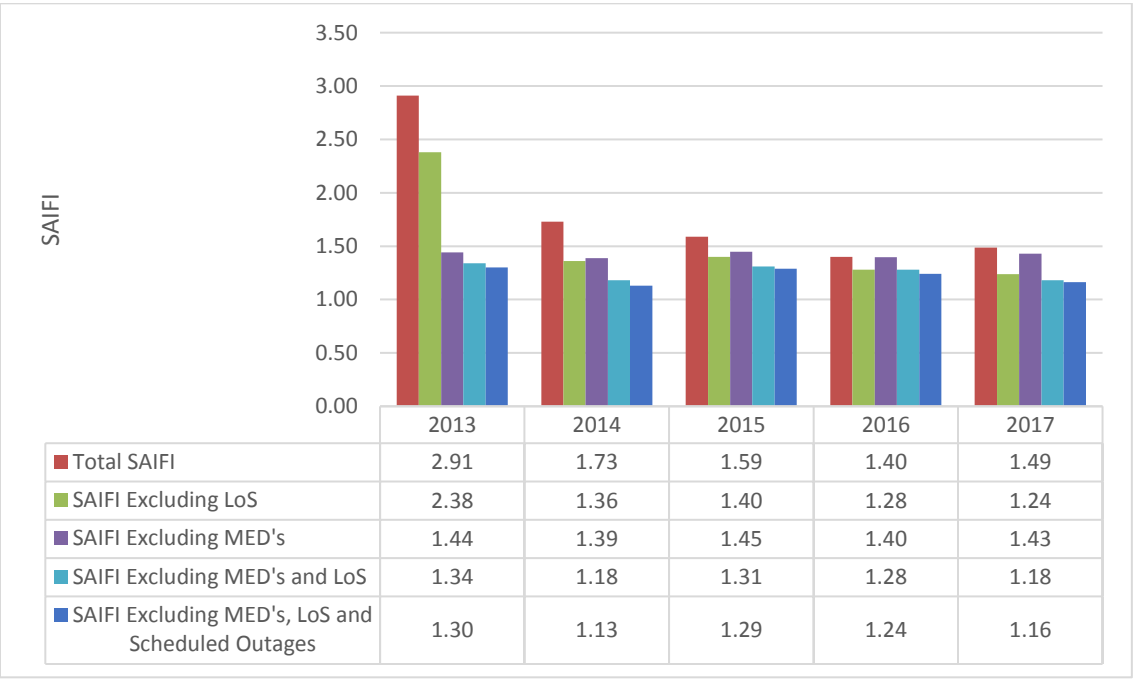
Scenarios 1, 2, and 3 provide SAIFI and SAIDI in the manner required by the OEB's prescribed Appendix 2-G, filed at Exhibit 1B, Tab 2, Schedule 5. Scenarios 4 and 5 provide SAIFI and SAIDI excluding: (i) outages related to MEDs and LoS (consistent with the OEB Electricity Distributor Scorecard and MD&A) discussed in Exhibit 1B, Tab 2, Schedule 2; and (ii) MEDs, LoS and scheduled outages, respectively, as a more normalized reflection of total system reliability performance. Each scenario provides valuable information as to the causes, duration, and frequency of outages within Toronto Hydro's distribution system.

1. SYSTEM OVERVIEW

Figures 1 and 2 below show the system's total SAIFI and SAIDI between 2013 and 2017, respectively, under each of the five scenarios. The notably higher SAIFI and SAIDI in 2013 under Scenarios 1 and 2 can be attributed to the flooding of Manby TS in July and

[1] During the 2020-2024 plan period, Toronto Hydro will be tracking performance under FESI-7 (System) and FESI-6 (Large Customers) as part of its custom performance measures, please see Exhibit 2B, Section C for more information.

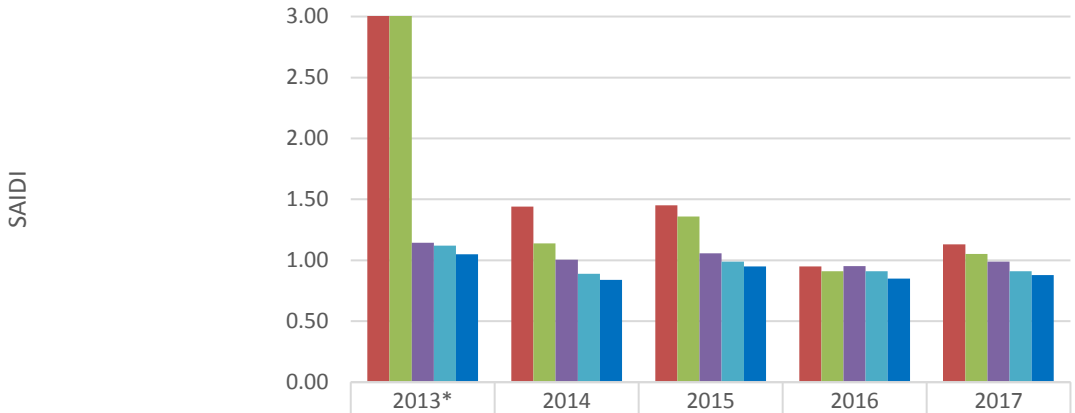
the ice storm in December of that year. Both of these occurrences were outside the utility's control and met the definition of MEDs as set out in the OEB's Electricity Reporting and Record Keeping Requirements ("RRR").[2] These MEDs caused the year-over-year fluctuations to be more drastic. In contrast, Scenarios 3 (excluding MEDs), Scenario 4 (excluding MEDs and LoS), and Scenario 5 (excluding MEDs, LoS, and scheduled outages) illustrate more normalized SAIFI and SAIDI values with less fluctuations. Toronto Hydro considers these latter scenarios to offer greater insight into system reliability as they provide a better indication of the performance trend of the system and the impact of recent investments, and are the more commonly used indicators across the industry for benchmarking against distribution system performance.



	2013	2014	2015	2016	2017
Total SAIFI	2.91	1.73	1.59	1.40	1.49
SAIFI Excluding LoS	2.38	1.36	1.40	1.28	1.24
SAIFI Excluding MED's	1.44	1.39	1.45	1.40	1.43
SAIFI Excluding MED's and LoS	1.34	1.18	1.31	1.28	1.18
SAIFI Excluding MED's, LoS and Scheduled Outages	1.30	1.13	1.29	1.24	1.16

Figure 1: System Level SAIFI

[2] OEB, Electricity Reporting and Record Keeping Requirements ("RRR"), Section 2.1.4.2(7).



	2013*	2014	2015	2016	2017
Total SAIDI	21.07	1.44	1.45	0.95	1.13
SAIDI Excluding LoS	17.70	1.14	1.36	0.91	1.05
SAIDI Excluding MED's	1.14	1.00	1.06	0.95	0.99
SAIDI Excluding MED's and LoS	1.12	0.89	0.99	0.91	0.91
SAIDI Excluding MED's, LoS and Scheduled Outages	1.05	0.84	0.95	0.85	0.88

*2013 Values cut off above the chart due to the high SAIFI and SAIDI values prior to excluding MEDs.

Figure 2: System Level SAIDI

2. LOSS OF SUPPLY

Loss of Supply ("LoS") events have a significant impact on the overall reliability of Toronto Hydro's distribution system, and being external to Toronto Hydro's operations and control, are generally excluded from a system reliability analysis. On a system level, LoS events can contribute up to 22 percent of SAIFI and 20 percent of SAIDI (based on system reliability analysis beginning in 2013), although significant variations can occur year to year. There are also significant variations between individual LoS events, which makes it difficult to perform trend analyses and forecast future reliability performance. For instance, 23 LoS events occurred in 2015, whereas 20 LoS events occurred in 2017. Nevertheless, the fewer events in 2017 affected SAIFI and SAIDI to a greater extent due to the higher impacts of individual events in that year. Figures 3 and 4 below show the SAIFI and SAIDI system impact due to LoS.

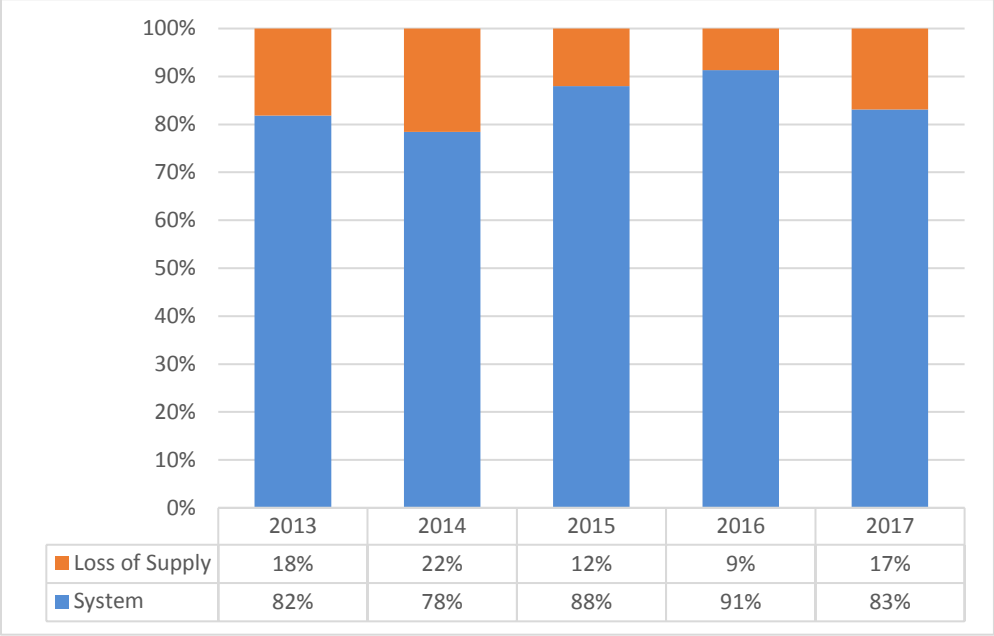


Figure 3: Loss of Supply Impact on Total SAIFI

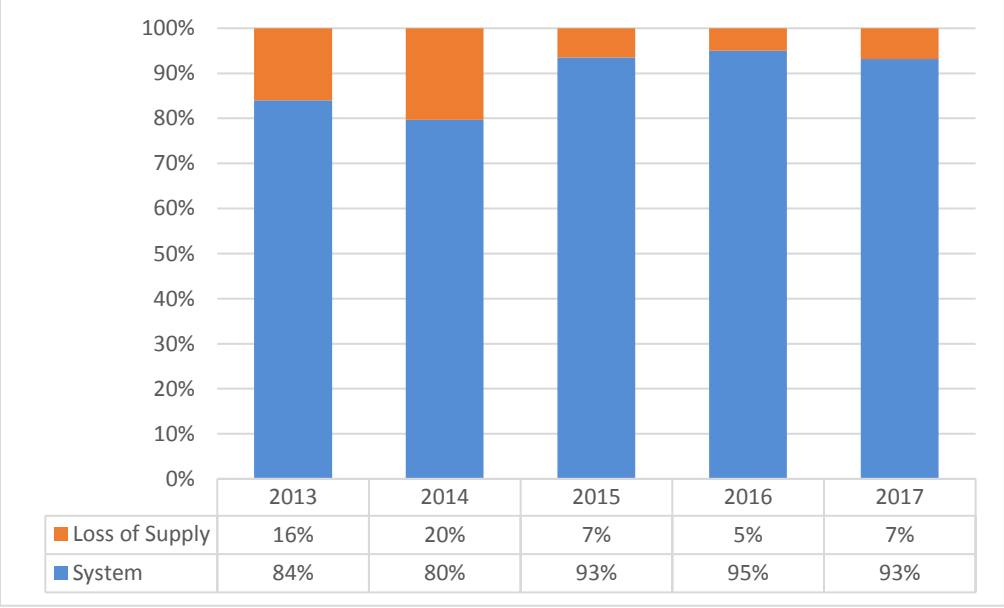


Figure 4: Loss of Supply Impact on Total SAIDI

3. MAJOR EVENT DAYS

Major Event Days ("MEDs") are defined by the Institute of Electrical and Electronics Engineers ("IEEE") as "events that are beyond the design and/or operational limits of a utility."[3] Major Events are similarly defined by the OEB's RRR as "an event that is beyond the control of the distributor and is: unforeseeable, unpredictable, unpreventable, or unavoidable."[4] Similar to LoS events, MEDs are external to routine utility operation, and in addition, are highly volatile from year to year. The exclusion of MEDs and LoS events allows a utility to normalize its reliability data, making it possible to establish meaningful reliability performance trends and associated targets. MEDs experienced by Toronto Hydro since 2003 are shown in Table 1, below.

Table 1: Major Event Days

Dates	Description	Number of Outages	Total Customers Interrupted	Total Customer Hours Interrupted
July 8, 2013	Major Storm (Thunderstorm)	56	324,672	2,377,913
July 9, 2013	Major Storm (Thunderstorm)	44	41,502	91,646
December 21, 2013	Freezing Rain Ice Storm	42	175,928	3,204,481
December 22, 2013	Freezing Rain Ice Storm	208	441,547	8,295,093
December 23, 2013	Freezing Rain Ice Storm	25	29,530	196,633
December 24, 2013	Freezing Rain Ice Storm	23	13,983	149,337
December 25, 2013	Freezing Rain Ice Storm	18	20,225	92,924
December 26, 2013	Freezing Rain Ice Storm	20	19,147	91,458
April 15, 2014	Loss of Supply to Manby TS	27	113,035	129,479
June 17, 2014	Major Thunderstorm	38	55,442	88,496
November 24, 2014	Wind Storm	46	82,053	99,027
March 3, 2015	Freezing Rain	49	107,242	291,672
October 15, 2017	Wind Storm	31	43,175	107,846

[3] IEEE 1366-2012 – IEEE Guide for Electric Power Distribution Reliability Indices.
[4] Ontario Energy Board, Electricity Reporting & Record Keeping Requirements (March 15, 2018) at p. 10.

Figures 5 and 6, below, demonstrate the SAIFI and SAIDI system impacts resulting from MEDs.

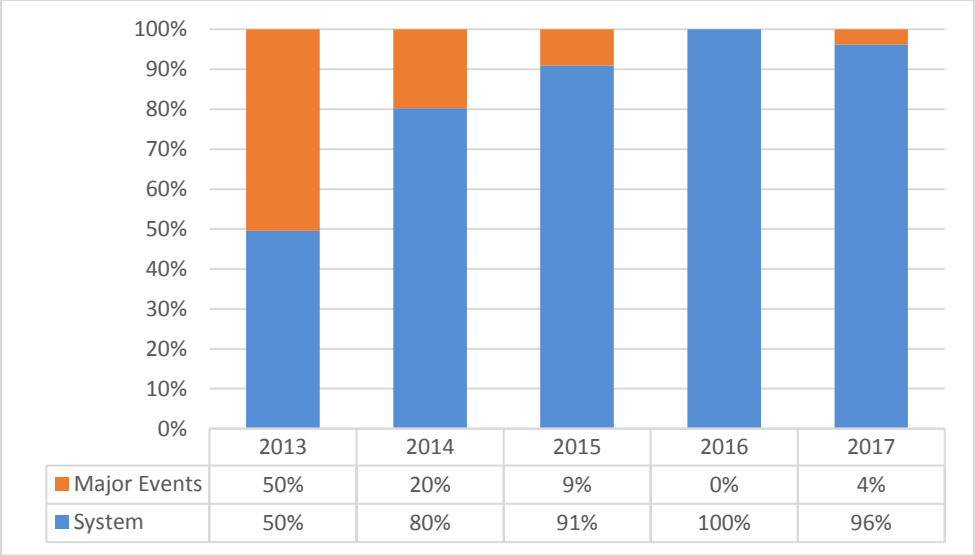


Figure 5: Major Event Days Impact on Total SAIFI

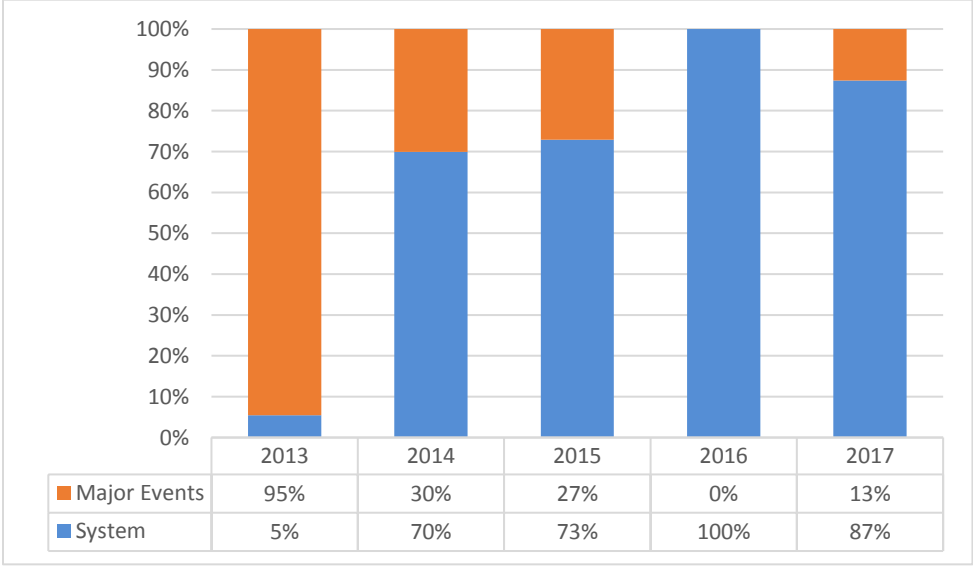
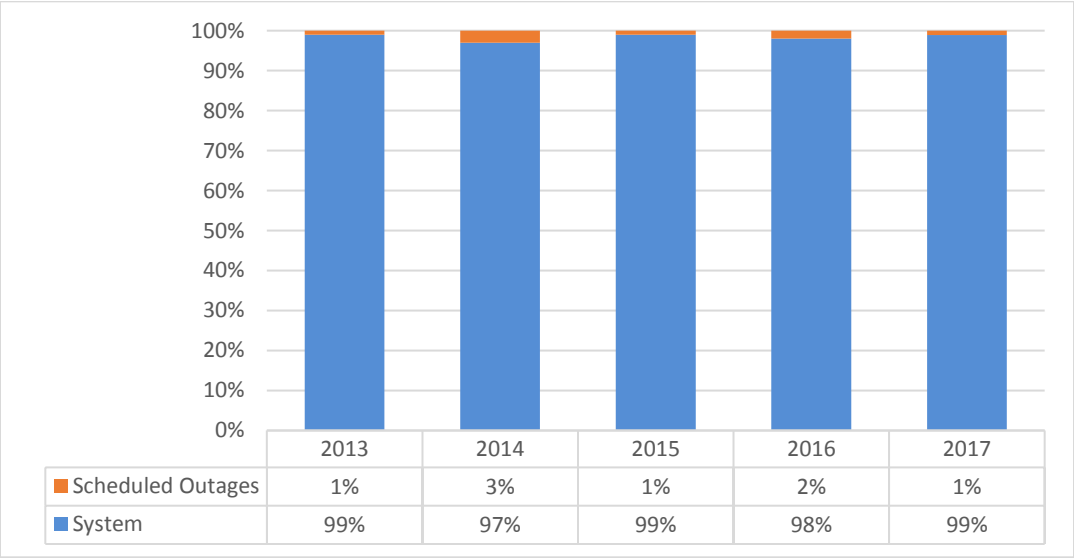


Figure 6: Major Event Days Impact on Total SAIDI

4. SCHEDULED OUTAGES

Scheduled outages are associated with construction and preventative maintenance activities. Assets that are at risk of failing in the near future may be taken out of service to be repaired or replaced. While this can lead to lengthy outages, the duration of the outage would generally be much shorter than those caused by the asset failing while in-service. These planned replacements are also often required to mitigate safety risks to Toronto Hydro's employees. Toronto Hydro provides customers advanced notification of any impeding work prior to engaging the project, which gives them the opportunity to plan their activities around the repair work. As planned outages do not reflect the inherent reliability performance of the distribution system, they are typically excluded from reliability analyses.



	2013	2014	2015	2016	2017
Scheduled Outages	1%	3%	1%	2%	1%
System	99%	97%	99%	98%	99%

Figure 7: Scheduled Outages Impact on Total SAIFI

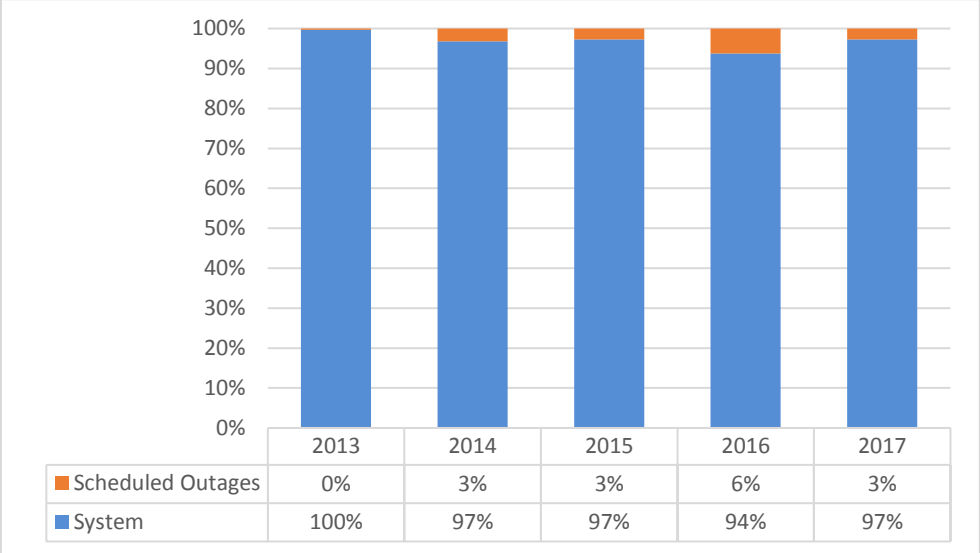


Figure 8: Scheduled Outages Impact on Total SAIDI

5. SYSTEM RELIABILITY EXCLUDING LOSS OF SUPPLY, MAJOR EVENT DAYS AND SCHEDULED OUTAGES

As noted above, MEDs and LoSs are outside the utility's control. As a result, these factors are typically excluded from analysis of the overall system performance. In addition, scheduled outages are required to allow certain work to be completed on the distribution system such as replacing assets that are at their end of life or in deteriorated condition to prevent a future outage. The inclusion of scheduled outages in reliability analysis would not provide a true reflection of distribution system performance. Figures 9 and 10, below, show the adjusted SAIFI and SAIDI (excluding LoS, MEDs, and scheduled outages).

The year-over-year adjusted values show that SAIFI and SAIDI have been generally stable, with a slight downward trend. A breakdown of system interruption causes is shown by the cause codes in Figures 11 and 12. The cumulative weather reliability impacts on the system are highlighted in Figures 13 and 14. SAIDI shows a steady

improvement over the 2013-2017 period. This is in part a reflection of the utility's continued work to improve restoration times through the installation of remotely operated switches, which allow faster restoration of customers as well as reconfigurations to reduce assets in rear lot locations that typically have longer outage durations.

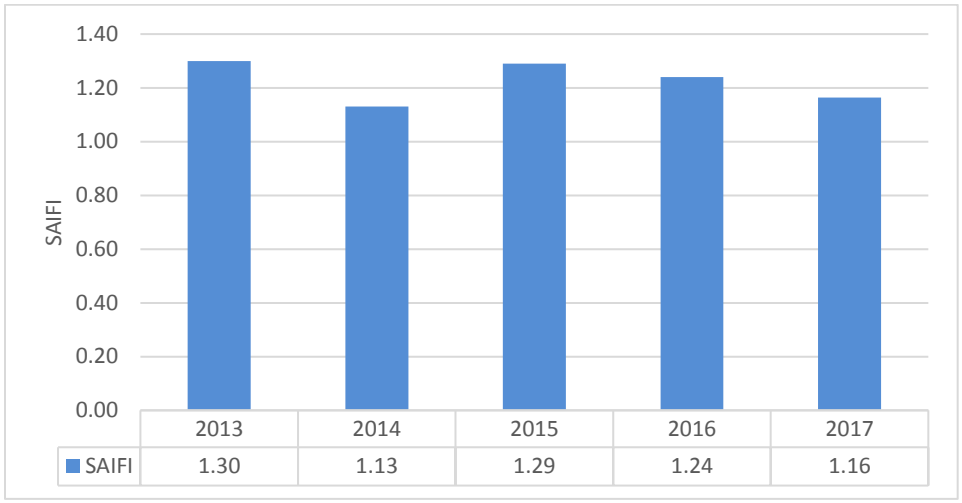


Figure 9: System SAIFI Excluding MEDs, Loss of Supply and Scheduled Outages

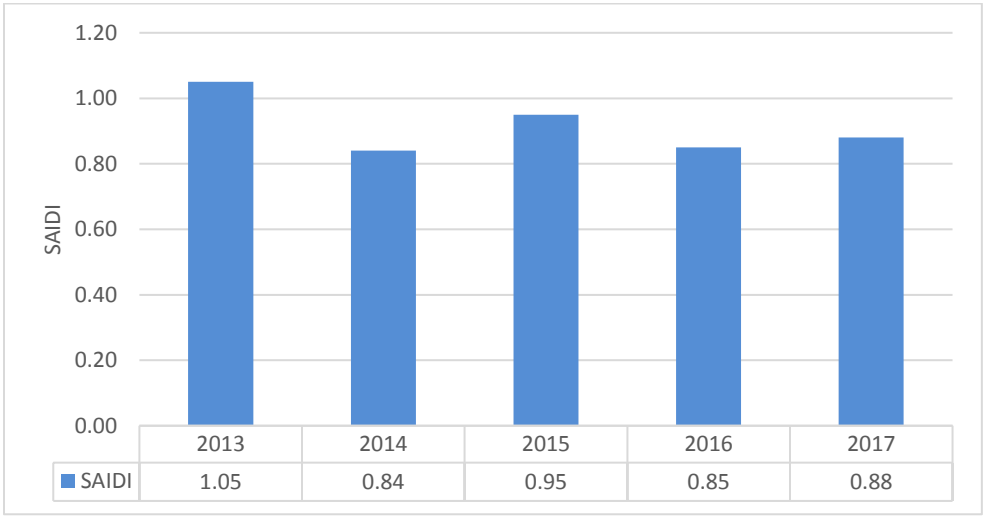
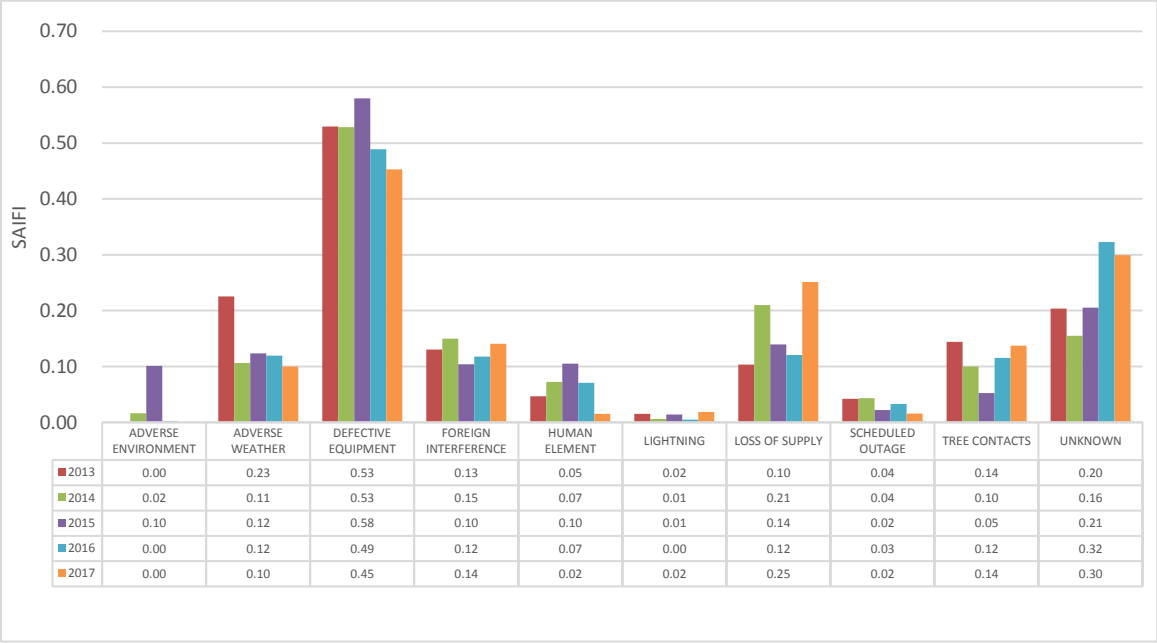


Figure 10: System SAIDI Excluding MEDs, Loss of Supply and Scheduled Outages

6. CAUSE CODE ANALYSIS

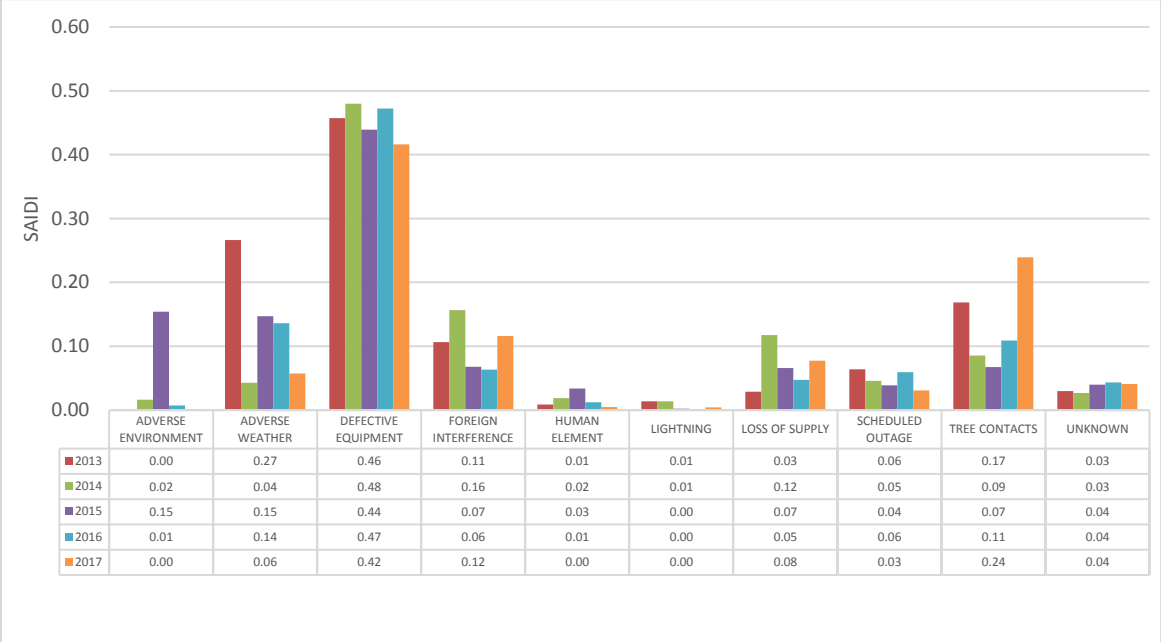
Toronto Hydro tracks causes of service interruptions using the ten primary cause codes as specified in the OEB's RRR.[5] Figures 11 and 12, below, show the utility's 2013-2017 SAIFI and SAIDI performance by cause code. Table 2, below, shows the percentage contribution of each cause code to overall system SAIFI and SAIDI.



	ADVERSE ENVIRONMENT	ADVERSE WEATHER	DEFECTIVE EQUIPMENT	FOREIGN INTERFERENCE	HUMAN ELEMENT	LIGHTNING	LOSS OF SUPPLY	SCHEDULED OUTAGE	TREE CONTACTS	UNKNOWN
2013	0.00	0.23	0.53	0.13	0.05	0.02	0.10	0.04	0.14	0.20
2014	0.02	0.11	0.53	0.15	0.07	0.01	0.21	0.04	0.10	0.16
2015	0.10	0.12	0.58	0.10	0.10	0.01	0.14	0.02	0.05	0.21
2016	0.00	0.12	0.49	0.12	0.07	0.00	0.12	0.03	0.12	0.32
2017	0.00	0.10	0.45	0.14	0.02	0.02	0.25	0.02	0.14	0.30

Figure 11: SAIFI Cause Code Breakdown (Excluding MEDs)

[5] RRR, Section 2.1.4.2.5 - Reporting Cause Codes.



	ADVERSE ENVIRONMENT	ADVERSE WEATHER	DEFECTIVE EQUIPMENT	FOREIGN INTERFERENCE	HUMAN ELEMENT	LIGHTNING	LOSS OF SUPPLY	SCHEDULED OUTAGE	TREE CONTACTS	UNKNOWN
2013	0.00	0.27	0.46	0.11	0.01	0.01	0.03	0.06	0.17	0.03
2014	0.02	0.04	0.48	0.16	0.02	0.01	0.12	0.05	0.09	0.03
2015	0.15	0.15	0.44	0.07	0.03	0.00	0.07	0.04	0.07	0.04
2016	0.01	0.14	0.47	0.06	0.01	0.00	0.05	0.06	0.11	0.04
2017	0.00	0.06	0.42	0.12	0.00	0.00	0.08	0.03	0.24	0.04

Figure 12: SAIDI Cause Code Breakdown (Excluding MEDs)

Table 2: Five-Year Average SAIFI and SAIDI Contribution by Cause Code

Cause Code	Contribution % to SAIFI	Contribution % to SAIDI
Defective Equipment	36.3	44.0
Unknown	16.7	3.5
Loss of Supply*	11.6	6.5
Foreign Interference	9.0	9.9
Adverse Weather	9.5	12.6
Tree Contacts	7.7	13.0
Human Element	4.4	1.5
Scheduled Outage*	2.2	4.6
Adverse Environment	1.7	3.5
Lightning	0.8	0.7

* Excluded from typical system analysis when evaluating Toronto Hydro's system reliability performance

Between 2013 and 2017, defective equipment was the main contributor to SAIFI and SAIDI, at 36.3 percent and 44.0 percent respectively. As shown in Figures 11 and 12,

above, the majority of improvement in 2017 SAIFI and SAIDI results relative to prior years was in respect to Defective Equipment and Adverse Weather. Toronto Hydro views the Defective Equipment cause code as a primary indicator of the condition of its distribution system and tracks the cost code as a measure of continuous improvement in the execution of its capital expenditure and maintenance plans. To this end, Toronto Hydro has proposed two custom performance measures, SAIDI – Defective Equipment and SAIFI – Defective Equipment for the 2020-2024 plan period. Please refer to Exhibit 2B, Section C for more information. Additional analysis of certain cause codes is provided below.

7. WEATHER IMPACTS

The following three cause codes can generally be combined to provide a more accurate reflection of weather impacts on the system:

1) Adverse Weather,
2) Lightning, and
3) Tree Contacts.

Figures 13 and 14, below, illustrate the cumulative weather reliability impacts on the system.

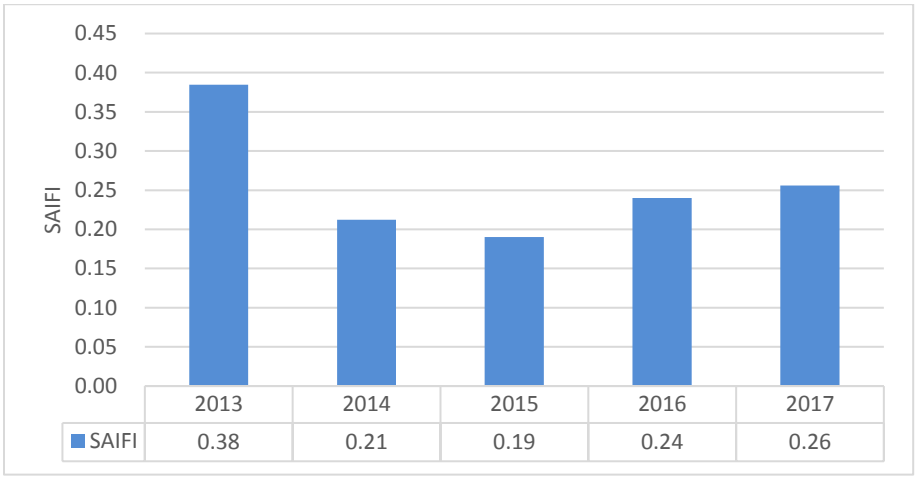


Figure 13: Weather Impacts to SAIFI

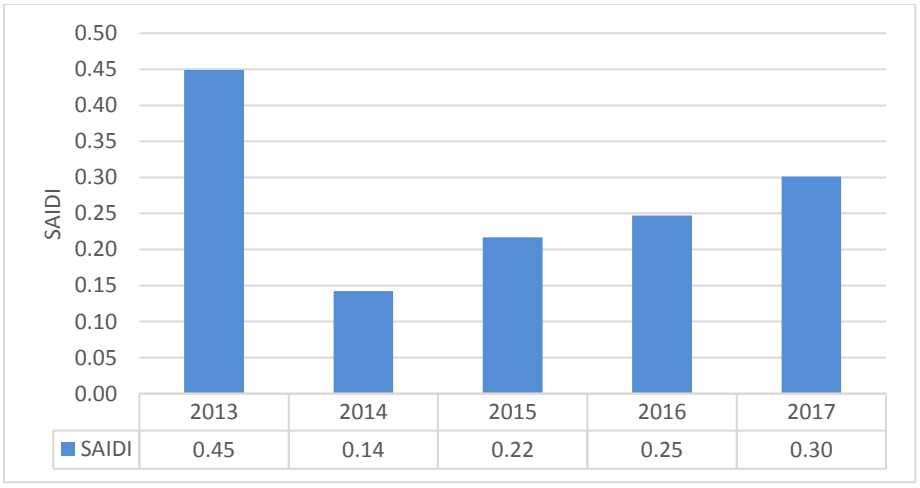
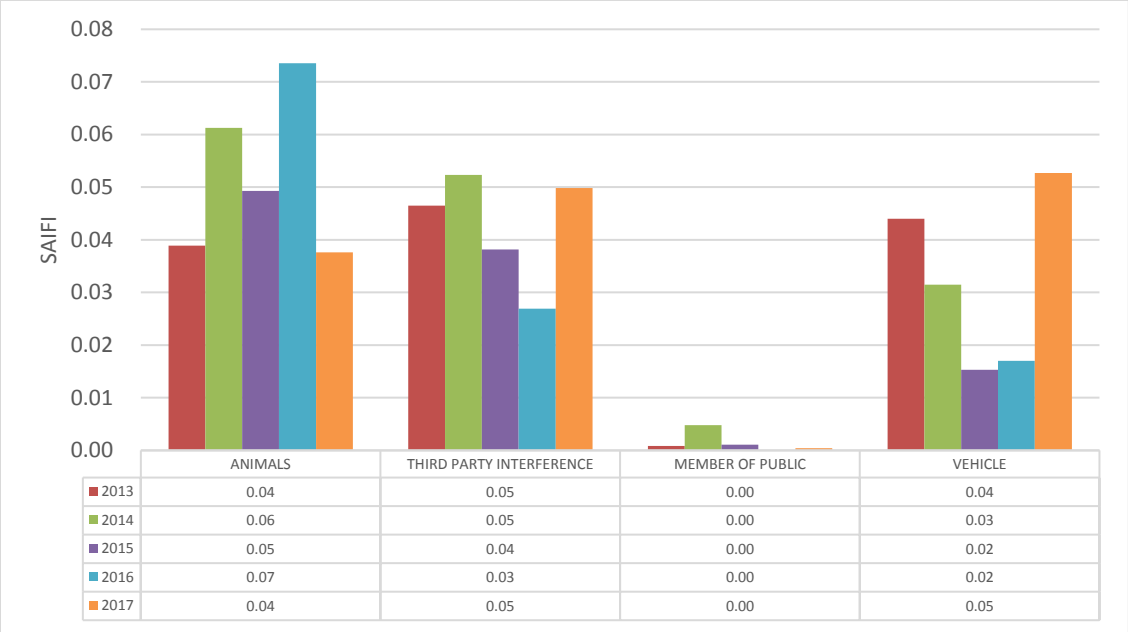


Figure 14: Weather Impacts to SAIDI

Weather impacts on the distribution system account for a significant portion of total system SAIFI and SAIDI. In 2017, weather related causes contributed 18 percent of the annual SAIFI and 30 percent of the annual SAIDI results. Figures 13 and 14, above, demonstrate that a large portion of the SAIFI and SAIDI improvements in 2014 can be attributed to relatively favorable weather conditions that year.

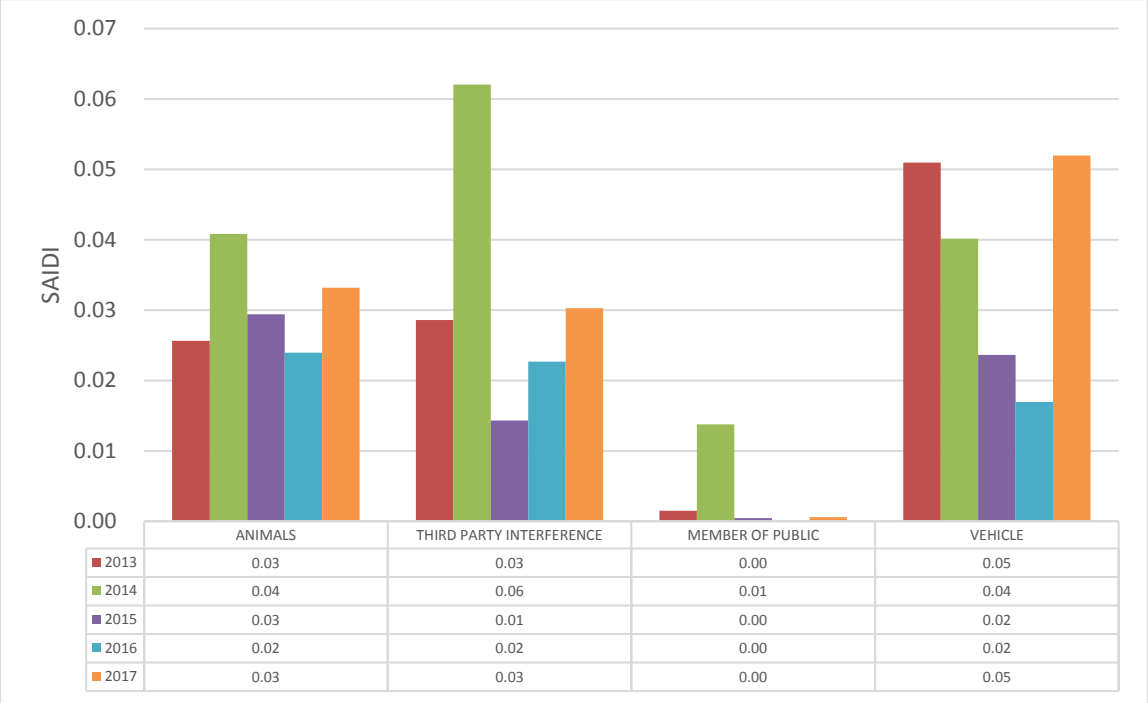
8. FOREIGN INTERFERENCE IMPACTS

Foreign interference consists of outages caused by animal contact, dig-ins, vehicles, and other foreign objects. Though there are different ways to mitigate foreign interference, such as installing animal guards or moving assets to more secure locations, yearly performance is generally volatile and largely attributable to single isolated events. Figures 15 and 16, below, show the impacts of foreign interference on Toronto Hydro's distribution system.



	ANIMALS	THIRD PARTY INTERFERENCE	MEMBER OF PUBLIC	VEHICLE
2013	0.04	0.05	0.00	0.04
2014	0.06	0.05	0.00	0.03
2015	0.05	0.04	0.00	0.02
2016	0.07	0.03	0.00	0.02
2017	0.04	0.05	0.00	0.05

Figure 15: Foreign Interference – Root Cause SAIFI



	ANIMALS	THIRD PARTY INTERFERENCE	MEMBER OF PUBLIC	VEHICLE
2013	0.03	0.03	0.00	0.05
2014	0.04	0.06	0.01	0.04
2015	0.03	0.01	0.00	0.02
2016	0.02	0.02	0.00	0.02
2017	0.03	0.03	0.00	0.05

Figure 16: Foreign Interference – Root Cause SAIDI

Of the four sub-categories of foreign interference shown in Figures 15 and 16, above, animal contact is one of the more "controllable" factors, in that Toronto Hydro is able to install reasonable measures to effectively mitigate this risk. More specifically, Toronto Hydro's capital programs include installing new standard animal guards as part of overhead renewal programs (see the Overhead System Renewal program, Exhibit 2B, Section E6.5), and spot mitigation activity as part of the Worst Performing Feeder program (see the Reactive and Corrective Capital program Exhibit 2B, Section E6.7). These new standard animal guards eliminate a physical point of contact with live equipment and insulate all critical components.

The Third Party Interference category and dig-ins (where third parties such as other utilities have dug into the ground and interfered with Toronto Hydro's equipment,

causing a fault) have continued to decline due to the removal of direct buried cables from the system. However, this improvement was offset in 2017 by increased foreign interference from contractors and other utilities. In general, the above-noted Foreign Interference categories are volatile and generally beyond Toronto Hydro's control. For instance, 3 percent of SAIFI and 10 percent of SAIDI in 2017 were due to a single vehicle incident on April 3, 2017.

9. UNKNOWN IMPACTS

Unknown Impacts consist of outages that have no apparent cause, where power is restored by simply closing the breaker or replacing a fuse. As shown by Figures 17 and 18, below, Unknown Impacts show some similarities to the trend of Weather Impacts over the past few years. However, as this category can encompass many different possible causes, there are unexplained variations as well. Although Toronto Hydro makes best efforts to investigate these events, it is not always possible to pinpoint the exact cause.

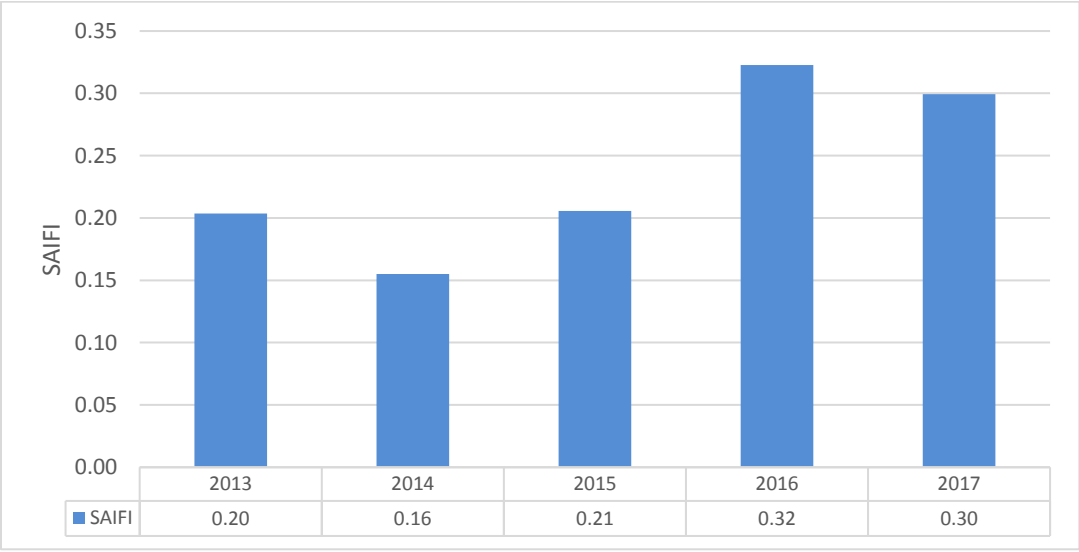


Figure 17: Unknown Impacts to SAIFI

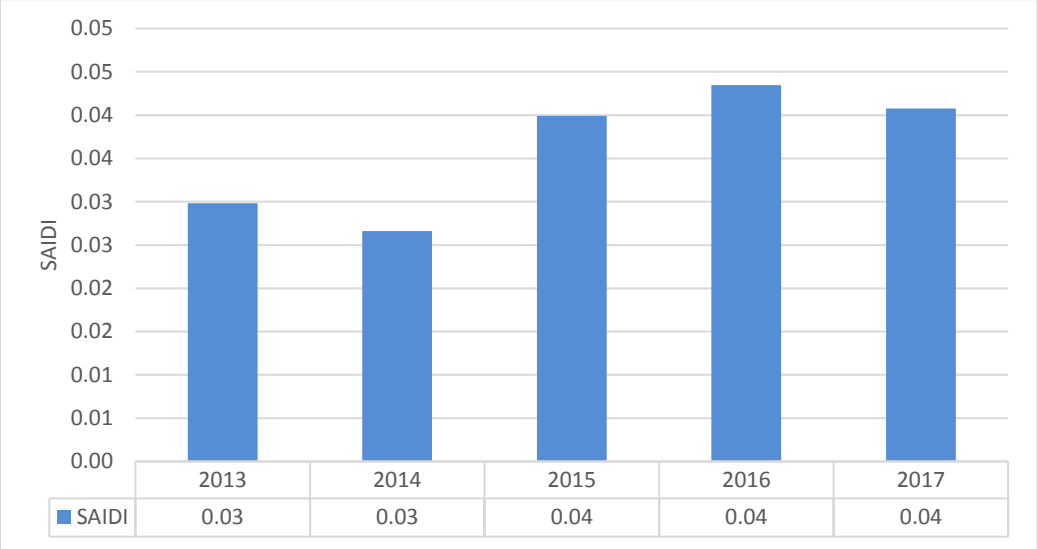
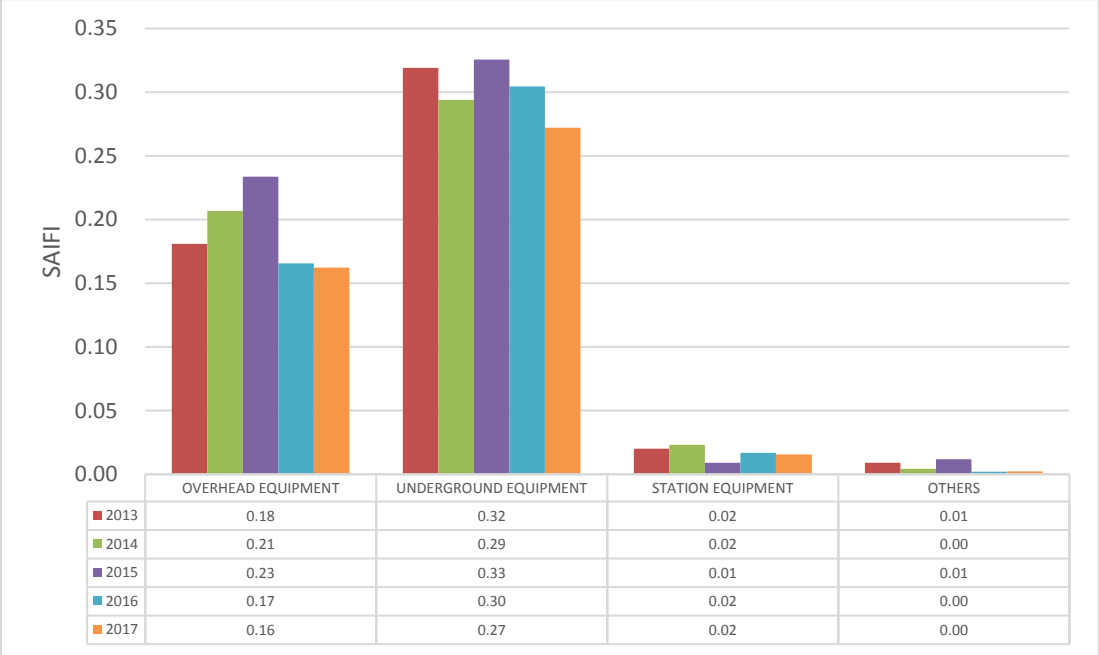


Figure 18: Unknown Impacts to SAIDI

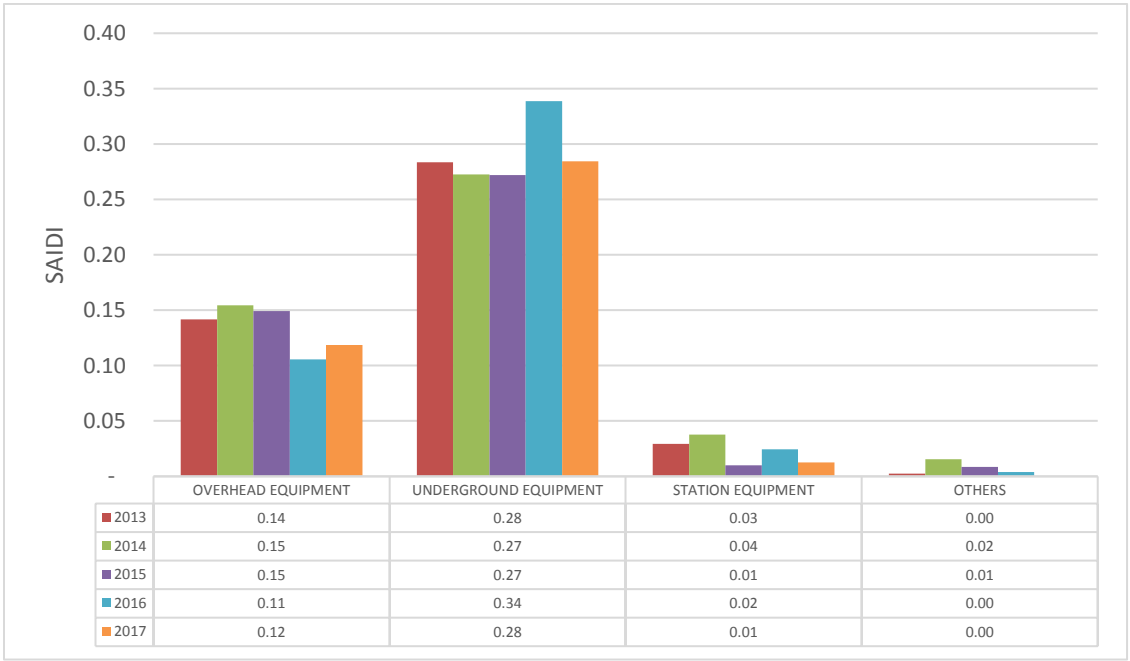
9.1 Defective Equipment Impacts

As shown in Figures 19 and 20, below, since 2013, the contribution of defective equipment to Toronto Hydro's SAIFI and SAIDI has shown a slight improvement overall in all categories.



	OVERHEAD EQUIPMENT	UNDERGROUND EQUIPMENT	STATION EQUIPMENT	OTHERS
2013	0.18	0.32	0.02	0.01
2014	0.21	0.29	0.02	0.00
2015	0.23	0.33	0.01	0.01
2016	0.17	0.30	0.02	0.00
2017	0.16	0.27	0.02	0.00

Figure 19: Defective Equipment SAIFI



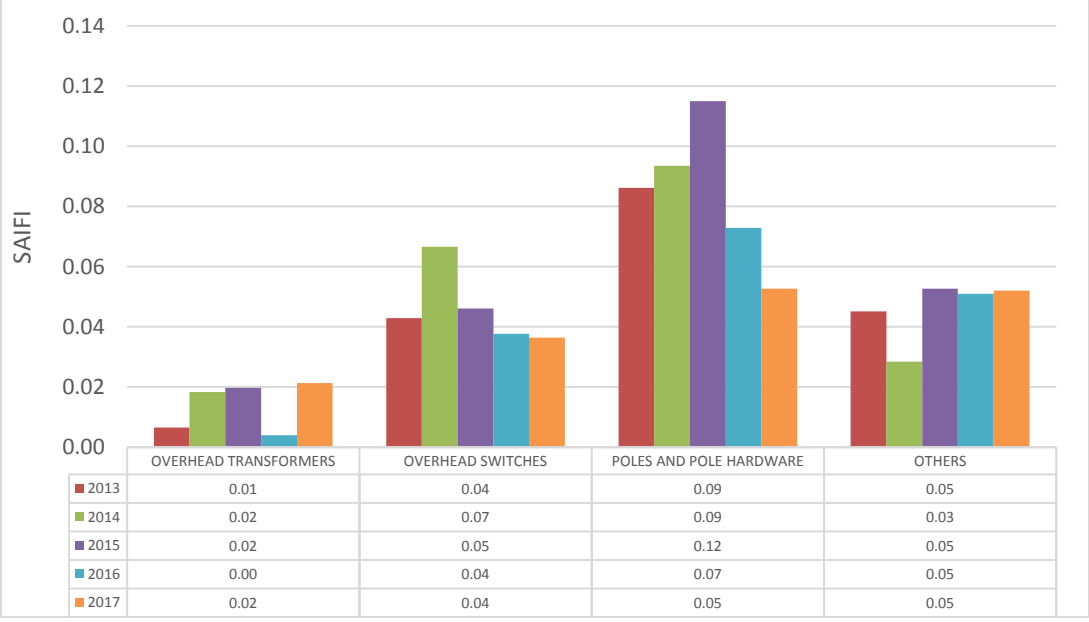
	OVERHEAD EQUIPMENT	UNDERGROUND EQUIPMENT	STATION EQUIPMENT	OTHERS
2013	0.14	0.28	0.03	0.00
2014	0.15	0.27	0.04	0.02
2015	0.15	0.27	0.01	0.01
2016	0.11	0.34	0.02	0.00
2017	0.12	0.28	0.01	0.00

Figure 20: Defective Equipment SAIDI

9.2 Overhead Defective Equipment

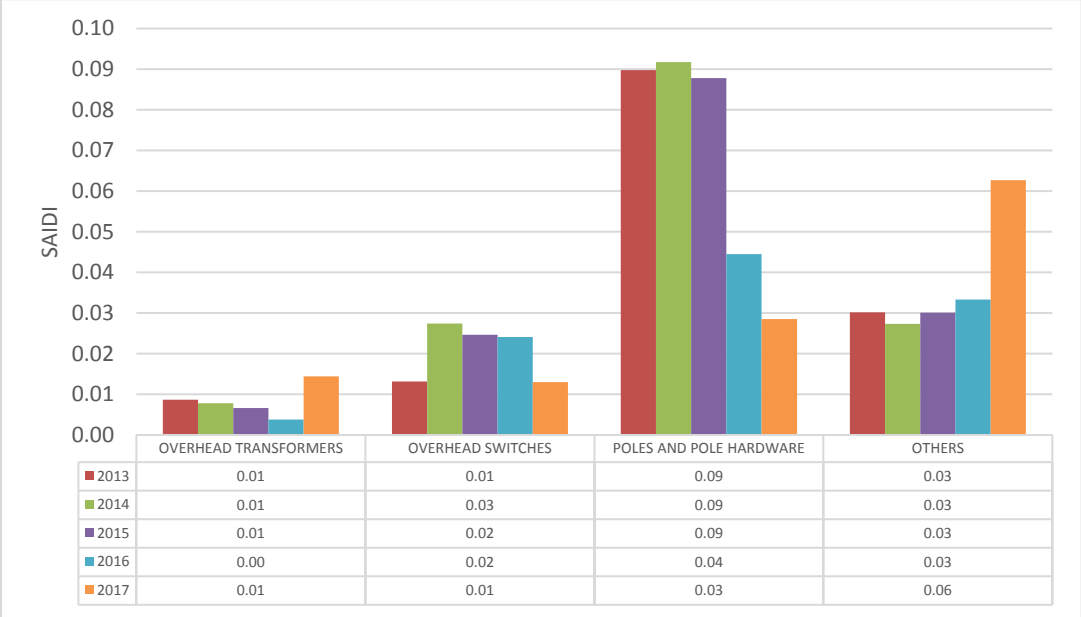
As shown by the Overhead Defective Equipment cause codes in Figures 21 and 22, below, the most significant SAIDI and SAIFI impacts since 2013 are attributable to pole and pole hardware failures as well as overhead switches. This is mainly due to the magnitude of these types of failures, which often disable large numbers of feeders.

Overall, Toronto Hydro has experienced a stable or improving trend across most sub-categories under Overhead Defective Equipment. This is attributable to the investment work Toronto Hydro has undertaken in respect to overhead rebuilds and porcelain insulator replacements. Other programs such as Area Conversions (see Exhibit 2B, Section E6.1), which also renews and relocates overhead assets, have also contributed to the improvement of reliability performance on the overhead system. To sustain this trend, Toronto Hydro plans to continue this replacement program through the 2020-2024 plan period.



	OVERHEAD TRANSFORMERS	OVERHEAD SWITCHES	POLES AND POLE HARDWARE	OTHERS
2013	0.01	0.04	0.09	0.05
2014	0.02	0.07	0.09	0.03
2015	0.02	0.05	0.12	0.05
2016	0.00	0.04	0.07	0.05
2017	0.02	0.04	0.05	0.05

Figure 21: Defective Equipment SAIFI – Overhead

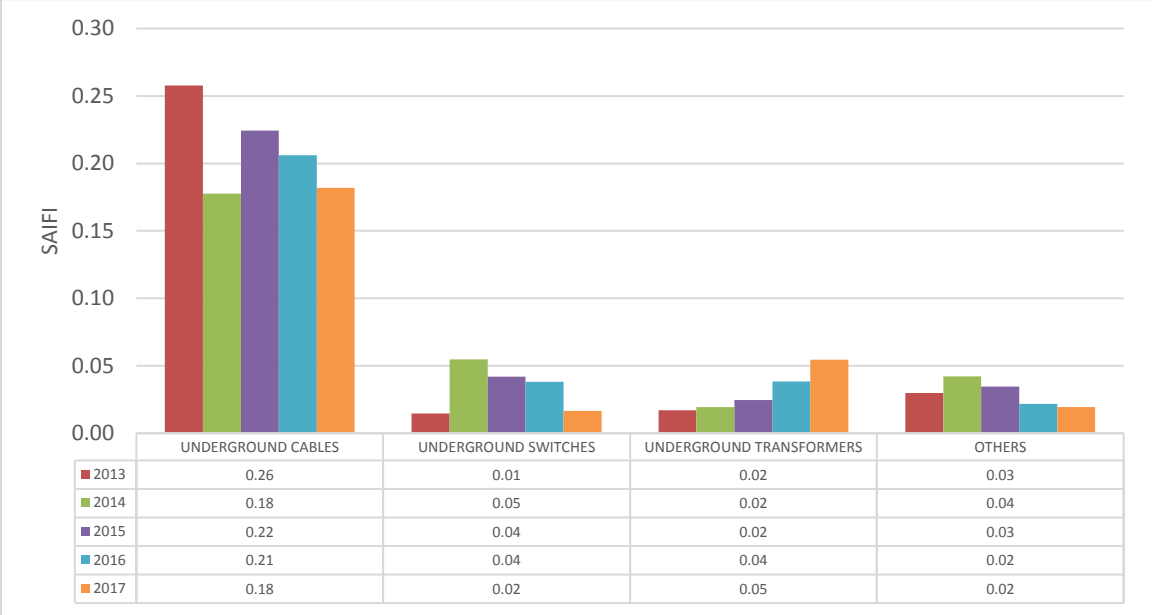


	OVERHEAD TRANSFORMERS	OVERHEAD SWITCHES	POLES AND POLE HARDWARE	OTHERS
2013	0.01	0.01	0.09	0.03
2014	0.01	0.03	0.09	0.03
2015	0.01	0.02	0.09	0.03
2016	0.00	0.02	0.04	0.03
2017	0.01	0.01	0.03	0.06

Figure 22: Defective Equipment SAIDI – Overhead

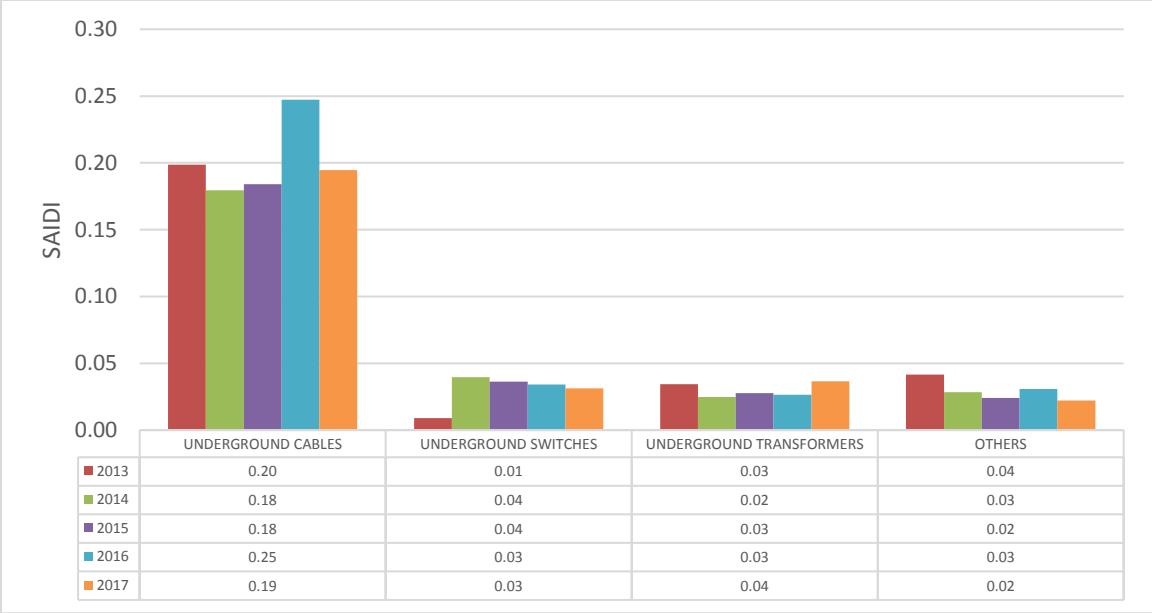
10. UNDERGROUND DEFECTIVE EQUIPMENT

As shown by the Underground Defective Equipment cause codes in Figures 23 and 24, below, underground cable faults dominate both the SAIFI and SAIDI indices and are the biggest equipment-related causes of interruptions in Toronto Hydro's system. The majority of these failures have been due to direct buried cables. Given the emphasis on replacing direct buried cables over the past few years, there has been a reduction in failures caused by these cables. Nevertheless, despite these efforts, the continued aging of the remaining direct buried cables and of other types of cables that are reaching end of life are offsetting improvements and resulting in a marginal improvement to overall underground cable failures and an overall stable trend to underground defective equipment. This supports the need to continue investment in replacing cables that are past useful life, as detailed in Underground System Renewal – Horseshoe program Exhibit 2B, Section E6.2.



	UNDERGROUND CABLES	UNDERGROUND SWITCHES	UNDERGROUND TRANSFORMERS	OTHERS
2013	0.26	0.01	0.02	0.03
2014	0.18	0.05	0.02	0.04
2015	0.22	0.04	0.02	0.03
2016	0.21	0.04	0.04	0.02
2017	0.18	0.02	0.05	0.02

Figure 23: Defective Equipment SAIFI – Underground



	UNDERGROUND CABLES	UNDERGROUND SWITCHES	UNDERGROUND TRANSFORMERS	OTHERS
2013	0.20	0.01	0.03	0.04
2014	0.18	0.04	0.02	0.03
2015	0.18	0.04	0.03	0.02
2016	0.25	0.03	0.03	0.03
2017	0.19	0.03	0.04	0.02

Figure 24: Defective Equipment SAIDI – Underground

OEB Appendix 2-G
Service Reliability Indicators
2013 - 2017

Index	SAIDI					SAIFI				
	2013	2014	2015	2016	2017	2013	2014	2015	2016	2017
Including all events	21.07	1.44	1.45	0.95	1.13	2.91	1.73	1.59	1.40	1.49
Excl. LoS	17.70	1.14	1.36	0.91	1.05	2.38	1.36	1.40	1.28	1.24
Excl. MED's	1.14	1.00	1.06	0.95	0.99	1.44	1.39	1.45	1.40	1.43
Excl. LoS and MED's	1.12	0.89	0.99	0.91	0.91	1.34	1.18	1.31	1.28	1.18
Excl. LoS, MED's & Sch. Outages	1.05	0.84	0.95	0.85	0.88	1.30	1.13	1.29	1.24	1.16

	5 Year Historical Average SAIDI	5 Year Historical Average SAIFI
Including all events (1)	5.21	1.82
Excl. LoS (2)	4.43	1.53
Excl. MED's (3)	1.03	1.42
Excl. LoS and MED's (4)	0.96	1.26
Excl. LoS, MED's & Sch. Outages (5)	0.91	1.22

SAIDI = System Average Interruption Duration Index

SAIFI = System Average Interruption Frequency Index

(1) including all events

(2) excluding events related to Loss of Supply ("LoS")

(3) excluding events related to Major Event Days (MEDs)

(4) excluding Major Event Days ("MEDs") and LoS

(5) excluding MEDs, Loss of Supply, and Scheduled Outages

Indicator	OEB Minimum Standard	2013	2014	2015	2016	2017
Low Voltage Connections	90%	94.2	91.5	96.9	97.7	98.3
High Voltage Connections	90%	100.0	100.0	100.0	100.0	98.4
Micro-Embedded Generation Facilities	90%	100.0	100.0	100.0	100.0	92.4
Appointment Scheduling	90%	96.6	96.2	89.0	72.0	81.8
Appointments Met	90%	99.6	99.8	99.9	99.5	99.4
Rescheduling a Missed Appointment	100%	98.4	94.6	100.0	100.0	100.0
Telephone Accessibility	65%	82.0	71.9	76.8	64.7	77.9
Telephone Call Abandon Rate	10%	1.2	1.7	1.6	3.1	1.9
Written Response to Enquires	80%	98.9	85.8	97.5	93.1	99.0
Billing Accuracy	98%	n/a	96.6	97.5	98.9	99.2
Emergency Urban Response	80%	74.4	92.0	87.2	91.8	93.6
Emergency Rural Response	80%	n/a	n/a	n/a	n/a	n/a
Reconnection Performance Standard	85%	100.0	100.0	100.0	99.7	99.4

CUSTOMER ENGAGEMENT

1. OVERVIEW

Toronto Hydro undertook extensive Customer Engagement in connection with and as part of the development of this CIR Application. Following the OEB's policy guidance, Toronto Hydro developed a genuine understanding of its customers' needs and preferences and analyzed and used the results of Engagement to inform its plans. Toronto Hydro relies on both "Planning-specific" and "Ongoing" Customer Engagement activities, as detailed in this Schedule.

2. CUSTOMER ENGAGEMENT: POLICY GUIDANCE

In conducting Customer Engagement, Toronto Hydro considered the Renewed Regulatory Framework for Electricity Distributors ("RRF"), Chapter 5 of the Filing Requirements for Electricity Distribution Rate Applications ("Filing Requirements"), the Handbook for Utility Rate Applications, the EB-2014-0116 decision in respect of Toronto Hydro's 2015-2019 rate application, and OEB decisions in other utilities' rate applications.[1] A key theme of the OEB's guidance is that a utility's business plan be informed by and responsive to customer needs and preferences. This requires an expectation that the utility develop a genuine understanding of its customers' needs and preferences, and is able to demonstrate how the development of its business plan was informed by the results of Customer Engagement.

3. PLANNING-SPECIFIC CUSTOMER ENGAGEMENT

Toronto Hydro's Planning-specific Customer Engagement process was a multi-phased, iterative process that equipped the utility with a genuine understanding of its

[1] For example, EB-2017-0024, Decision and Order.

customers' needs, preferences, and priorities so as to inform the utility's business plan. The process spanned over 18 months, between late 2016 and mid-2018, and involved over 10,000 Toronto Hydro customers of all sizes.

Toronto Hydro engaged Innovative Research Group ("Innovative"), a national consulting firm with expertise in public opinion research (and experience in energy policy in particular), to execute the utility's Planning-specific Customer Engagement. The resulting final report (the "Innovative Report") can be found in Appendix A to this Schedule.

Innovative executed the Planning-specific Customer Engagement in two phases. Phase 1 provided input into the development of the business plan, including the penultimate Distribution System Plan ("DSP"). Phase 2 helped to refine the business plan, including the final DSP.

3.1 Phase 1

Phase 1 of the Planning-specific Customer Engagement focused on assessing customer needs and preferences in relation to outcomes relevant to Toronto Hydro's programs and services. Phase 1 was conducted to generate a comprehensive view of customers' priorities as a front-end input into Toronto Hydro's business plan.

Innovative used a range of techniques to assess customers' needs and preferences. Quantitative methods provided statistically valid results (e.g. surveys directed at residential and small business customers). Qualitative methods provided constructive context to supplement the statistical results (e.g. focus groups directed at residential, small business and mid-market customers).

The Innovative Report discusses in detail the Phase 1 process and results. For example, initial focus group engagement identified six key customer priorities:

1) Delivering reasonable electricity prices;
2) Ensuring reliable electrical service;
3) Ensuring the safety of electrical infrastructure;
4) Providing quality customer service;
5) Helping customers with electricity conservation and efficient usage;
6) Enabling the electrical system to support the reduction of greenhouse gases.

In the follow-up telephone survey, a majority of customers replied that each of these six priorities were either "important" or "extremely important." When asked to rank them, low-volume customers prioritized "delivering reasonable electricity prices" first, followed by "ensuring reliable electrical service." By comparison, large customers with average peak loads over 1 MW ("Key Accounts") prioritized "ensuring electrical service", ahead of "delivering reasonable electricity prices".[2]

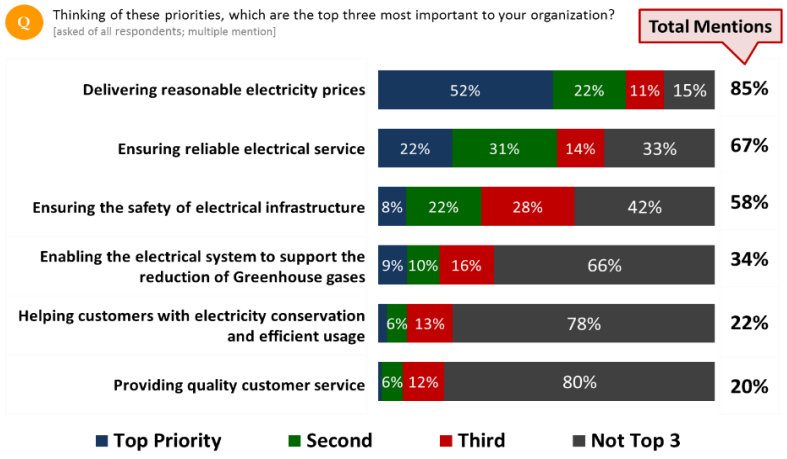


Figure 1: Low-volume Customer Priority Rankings, Phase 1.

[2] Innovative Report, Exhibit 1B, Tab 3, Schedule 1, Appendix A, Executive Summary pg. 11.

Considering the entirety of the Phase 1 results, Innovative concluded that "customer and stakeholder feedback from Phase 1 can be summarized by the following key points:

1) Keeping distribution price increases as low as possible;
2) Maintaining long-term performance for customers experiencing average or better service;
3) Improve service levels for customers experiencing below average service or who have special reliability needs (e.g. hospitals); and
4) Balancing other customer priorities (e.g. customer service) with the need to contain rate increases."[3]

The timing of Phase 1 allowed Toronto Hydro to leverage the results in a number of ways. It informed the development of the Outcomes Framework (see Exhibit 1B, Tab 2, Schedule 1), which became the lens through which the utility assessed the value to customers of its program expenditure proposals. It informed the strategic parameters established for the business plan, which included an upper limit of 3.5 percent as a cap on the average annual increase to base distribution rates (see Exhibit 1B, Tab 1, Schedule 1). Consequently, Phase 1 results informed the development of the penultimate business plan that was taken back to customers during Phase 2 (see Exhibit 1B, Tab 1, Schedule 1; Exhibit 2B, Section E2).

Innovative developed a high-level, two-page "Placemat" summary of the findings of its work in support of Toronto Hydro's Phase 1 Customer Engagement activities. The Customer Engagement Placemat provided an easily accessible version of the key results of Phase 1 Customer Engagement.

[3] Ibid., pg. 5

3.2 Phase 2

Phase 2 provided additional insight about customers' needs and preferences prior to the completion of the business plan. The purpose of Phase 2 was threefold:

- To confirm customer needs, preferences, and priorities identified in Phase 1;
- To solicit customer feedback on the content of Toronto Hydro's proposed plans and the subsequent rate impact including customer preferences toward particular capital programs where trade-offs on pacing existed; and
- To solicit customer feedback on Toronto Hydro's planning development process, including the customer engagement process.

The Phase 2 approach involved two different methods: a workbook and surveys. Innovative developed an online workbook to gather input from any interested residential, small business, or mid-market customer. Toronto Hydro took a number of steps to increase the visibility of the workbook, including: emailing over 200,000 residential and small business customers notifying them about the workbook; advertising the workbook in the utility's electronic newsletter delivered to nearly 200,000 customers; and promoting the workbook through social media posts, which made over 40,000 impressions (Twitter and Facebook).

Innovative developed surveys based on the feedback from the online workbook. A randomly recruited telephone survey was executed for residential, small business and mid-market customers, and an online survey was done to gather input from Key Account customers. All Key Account customers were notified by email about the survey and reminder emails were sent to encourage its completion. Details about both surveys are provided in the Innovative Report.

Based on the results, Innovative concluded that customers' needs and preferences identified in Phase 1 were consistent with customer feedback received in Phase 2. Customers were also strongly supportive of the customer engagement process used to collect and use customer needs and preferences.

Innovative further concluded that customers generally supported Toronto Hydro's proposed plan, and that "majorities of residential, small business, mid-mark and key account customers say [the utility] should stick with its proposed plan or do more."[4] Innovative also found a range of customer support for the various investment pacing trade-offs presented to customers. For example, a majority of customers favoured a more limited involvement by Toronto Hydro in support of microgrids, in contrast to strong support for increasing the pace of investments in monitoring and control equipment and network units.

In response to the conclusion that customers generally supported the plan, Toronto Hydro made only modest refinements to its plan. Given the particularly strong support across customer classes for programs that address the risk of network vault floods and fires (i.e. Network Unit Renewal and Network Condition Monitoring & Control), Toronto made minor adjustments to the pace of these programs to address these issues at an accelerated pace over the 2020-2024 period. Exhibit 2B, Section E2.3 discusses in detail how Customer Engagement results are reflected in the 2020-2024 Capital Expenditure Plan, including the final adjustments made in response to Phase 2 results.

[4] Ibid. pg. 3.

3.2.1 Continuous Improvement

The Planning-specific Customer Engagement described in this evidence represents an evolution in the process used in connection with Toronto Hydro's 2015 CIR Application in a number of important ways. Phase 1 was introduced as an entirely new process and purposefully sequenced to inform the development of the business plan.

The Phase 2 process was changed in a number of ways. Customers were provided specific information about Toronto Hydro's planning process, how it solicited feedback from customers, and information about Toronto Hydro's cost benchmarking performance. The results of the Phase 1 engagement were summarized and customers were again asked to rank priorities to evaluate if the needs and preferences that informed the business plan had changed. Program-specific information, including activities, outcomes, and bill impacts were shared in respect of trade-offs where customer input was sought. And customers participating in the online workbook were shown the estimated net bill impact of their trade-off choices and allowed to change their responses if desired.

3.2.2 Ongoing Customer Engagement

Ongoing Customer Engagement occurs and informs decision-making at Toronto Hydro through the range of interactions that are primarily intended to deliver valued customer services.

Toronto Hydro's customer services, outlined in the Customer Care program (Exhibit 4A, Tab 2, Schedule 14), respond to the needs of the utility's wide array of customers. The utility serves a large and diverse base of approximately 768,000 customers, ranging from individual residential consumers to large industrial and commercial businesses. Toronto

is home to Canada's largest banks, stock exchange, major manufacturers, and other large organizations sensitive to service interruptions. There are dozens of hospital, healthcare and long-term care facilities and hundreds of schools, colleges, and universities. Toronto Hydro also delivers electricity to the Provincial Legislature, City Hall and a range of government offices and work centres. It also serves thousands of high-rise multi-residential condominium and apartment buildings, which serve many more customers behind a Toronto Hydro "bulk meter."

Over time, interactions with all customers through various channels inform the utility's plans in a number of ways including the continuous improvement of its customer services, as well as the development of its capital programs and execution of capital work.

3.2.3 Customer Services

Toronto Hydro's customer services continue to evolve with customer expectations, as detailed in the following examples.

As noted in the Customer Care Program (see Exhibit 4A, Tab 2, Schedule 14), an increasingly popular method of engagement continues to be Toronto Hydro's customized self-service portal (known as "MyTorontoHydro"). It offers automated move-in/move-out capability, eBill and pre-authorized payment enrolment, and the ability to view bill and payment histories. In addition, through the Independent Electricity System Operator's ("IESO") residential conservation program, Toronto Hydro expanded the functionality of its PowerLens portal to include a variety of electricity management tools and educational information such as usage breakdowns, kWh reduction goal setting, consumption and cost alerts, disaggregation charts, home

assessments, and customized tips and recommendations to reduce consumption. The portal is available online or via mobile devices, further enhancing customer experience. Additional offerings will continue to be incorporated based on customer research and feedback to identify opportunities to bolster usage of the self-service portal. This includes offering MyTorontoHydro account management services to commercial customers, as well as expanding capabilities on PowerLens for electric vehicle usage.

Toronto Hydro's Contact Centre handles about 93,000 written inquiries and 527,000 telephone calls per year pertaining to inquiries about payment options, electricity consumptions, collections, and a range of other topics. The Contact Centre is responsible for many activities whose performance is tracked by the OEB in the Service Quality Requirements (see Exhibit 1B, Tab 2, Schedule 3).

Toronto Hydro's Customer Experience function manages research and work that provide insights to customers' views on current services, processes and communications, and opportunities for continuous improvement.

Escalations and Special Investigations resolves customer concerns that require more complex or lengthy analysis, and is closely connected to the Contact Centre, which initiates over 320 requests. Over 300 other requests are commenced through the Office of the President and the OEB. In 2017, Escalations and Special Investigations successfully resolved 98 percent of escalated customer inquiries within ten business days.

Communications and Public Relations is responsible for direct-to-customer and digital communications, such as bill inserts, website and social media, and corporate

communications, such as news releases and reporting. Media are important conduits between Toronto Hydro and its customers that purvey accurate and timely information about power outages, electrical safety, consumer issues, and local investments. Media relations play a particularly critical role during emergency outage situations when customers are most likely to be looking for this information.

3.2.4 Individual Capital Projects

Feedback from customers received through Toronto Hydro's customer services can also influence individual capital projects within a given DSP program, as detailed in the following examples.

Through Community Relations and Customer Operations Communications ("COC"), Toronto Hydro maintains a comprehensive approach for communicating information to customers concerning planned capital work and planned outages, in order to provide a better understanding around the capital project and prepare customers for work at or near their properties. This engagement commonly takes the form of one-on-one contact with customers, community town hall meetings, special information sessions, and a variety of online content. A customer inquiry line and escalation process is available to customers and, when needed, staff are dispatched on-site to liaise directly with customers.

Engagement with Toronto Hydro customers is also a regular occurrence when work has the potential to disrupt local neighbourhoods and property. Typically, there are three rounds of notifications:[5]

[5] Toronto Hydro's Key Accounts function works directly with Key Account customers to minimize disruptions to large businesses and institutional customers.

- General notification of construction work is given to all residents in an affected area;
- Letters are provided to all customers that will have equipment, such as poles or transformers, located on or adjacent to their property; and
- A pre-construction letter is issued approximately one week prior to work commencing.

COC is responsible for providing these notifications and for addressing or escalating customer concerns. For example, if customers are not satisfied with the scope or nature of planned work, COC may investigate new design options or engage customers in-person or at Toronto Hydro-initiated community meetings.

More intensive and incremental engagement is used in relation to rear-lot projects, which can require significant work on Toronto Hydro's part to relocate electrical infrastructure and remove legacy assets from private property. Before work begins, Toronto Hydro proactively initiates an Open House in the community where work is expected to take place. At that forum, Toronto Hydro provides an overview of the scope and timelines of the work, an explanation of why the work is taking place and contact information for customers who wish to follow up for more information. The three-round notification process is then implemented. For more information about Toronto Hydro's rear-lot investments, see the Area Conversions program in the DSP (Exhibit 2B, Section E6.1).

In addition to COC, the Key Accounts function works proactively with large business and institutional customers on matters such as planned outage notification and coordination, Global Adjustment settlement notification, load profile and rates analysis

and power quality and energy management. It also responds to issues raised by Key Account customers and acts as a liaison to expedite workable solutions. Municipal Government Relations and the Office of the President handle over 1,500 issues per year in response to City councillor requests on citizens inquiries, most commonly regarding street lighting, capital projects and power outage-related issues, and routinely meet with City councillors and staff on ongoing and emerging issues.

3.2.5 Capital Programs

Ongoing customer engagement can also influence Toronto Hydro's capital investment plans. Toronto Hydro's Worst Performing Feeder investment is an example of capital work that emerged from a customer-centric analysis of the utility's reliability performance that provided a better understanding of the customer experience as it relates to reliability.[6] This work is proposed to continue in 2020 to 2024 as part of the Reactive and Corrective Capital Program. More information on Worst Performing Feeders can be found in the DSP (Exhibit 2B, Sections D3, and E6.7).

Toronto Hydro's participation in Regional Planning is another channel of ongoing engagement that informs the development of the capital plan. The Regional Planning Process includes the Local Advisory Committee ("LAC"), led by the IESO. The IESO invited the City of Toronto, First Nations, and Metis communities, stakeholders, community groups, and the general public to provide input on the development of the Regional Plan. In all, the Toronto LAC has 18 members. For more information about the Regional Planning Process, see Section B of the DSP (Exhibit 2B). For more information about how Regional Planning considerations influence Toronto Hydro's plans, see Section E2.2.3.3 of the DSP.

[6] EB-2011-0144. Exhibit D1, Tab 10, Schedule 3. p. 1.

Finally, Toronto Hydro's plans are responsive to the priorities of local government. An example is *TransformTO*, which identifies how the City of Toronto plans to reduce greenhouse gas emission and improve health, grow the economy and improve social equity. Toronto Hydro plans to partner with the Toronto Transit Commission ("TTC") to make improvements and additions to nearby distribution plant to support the conversion of the TTC's bus fleet from diesel hybrid to electric. For more information on Toronto Hydro's engagements with the City of Toronto, see Section D2.1 of the DSP.

INNOVATIVE RESEARCH GROUP

CUSTOMER ENGAGEMENT

2020 CIR Application

June 15, 2018

Prepared for:

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TORONTO HYDRO®

Customer Engagement

2020 CIR Application

June 15, 2018

Confidentiality

This Report and all of the information and data contained within it may not be released, shared or otherwise disclosed to any other party, without the prior, written consent of Toronto Hydro Electric-System Ltd. (THESL).

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for THESL. The conclusions drawn and opinions expressed are those of the authors.

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Table of Contents

1. Introduction 1

2. Executive Summary 3

2.1 Phase I Customer Engagement 4

2.1.1 Understanding Customer Needs and Preferred Outcomes 4

2.1.2 Customer Outcomes Priorities by Rate Class 7

2.2 Phase II Customer Engagement 13

2.2.1 Customer Needs 13

2.2.2 Re-confirming Customer Outcome Priorities 14

2.2.3 Planning Principles and Rate Impacts 15

2.2.4 Addressing Safety and Reliability 16

2.2.5 Innovation and Planning for the Future 17

2.2.6 Opinion of Toronto Hydro's Proposed Plan 17

2.2.7 Key Account Online Survey 19

3. About this Consultation 21

3.1 Ontario Electricity in Context 21

3.2 Approach to Meaningful Consultation 21

3.3 Responding to OEB Direction 22

3.4 Enhanced Customer Engagement 23

3.4.1 Policy Evolution 23

3.4.2 Gathering and Responding to Customer Feedback 23

3.4.3 Consultation Process Overview 24

Table of Appendices

Appendix 1.0 - Phase 1 Appendices

Appendix 1.1 - Low Volume Customer Focus Group Report

Appendix 1.2 - Mid-Market Customer Focus Group Report

Appendix 1.3 - Low-Volume Customer Needs & Preferences Survey Report

Appendix 1.4 - Key Account Needs & Preferences Survey Report

Appendix 1.5 – Stakeholder In-depth Interview Report

Appendix 1.6 – Customer Priorities Summary (Placemat)

Appendix 2.0 - Phase 2 Appendices

Appendix 2.1 - Online Customer Feedback Portal Report

Appendix 2.2 - Residential Telephone Survey Report

Appendix 2.3 - Small Business Telephone Survey Report

Appendix 2.4 - Mid-Market Telephone Survey Report

Appendix 2.5 - Key Account Online Survey Report

Appendix 3.0 – Consultation Materials

Appendix 3.1 - Online Customer Feedback Portal Content (Print Version)

Appendix 3.2.1 - Residential Telephone Questionnaire

Appendix 3.2.2 - Small Business Telephone Questionnaire

Appendix 3.2.3 - Mid-Market Telephone Questionnaire

Appendix 3.2.4 - Key Account Online Questionnaire

1. Introduction

Innovative Research Group Inc. (INNOVATIVE) was engaged by Toronto Hydro Electric-System Ltd. (Toronto Hydro or THESL) to help it design, execute and document the results of THESL's customer engagement process as part of the development of its Financial and Business Planning process and its 2020 to 2024 Custom Incentive Rate (CIR) Application, including its Distribution System Plan.

The Ontario Energy Board's (OEB) "consumer-centric" approach to rate applications contained in the *Renewed Regulatory Framework for Electricity (RRFE)* requires Local Distribution Companies (LDCs) to demonstrate that their services are provided in a manner that responds to identified customer needs and preferences.[1] LDCs are required to provide an overview of customer engagement activities that they have undertaken with respect to their plans and how customer needs and preferences have been reflected in the LDCs' application. The Handbook for Utility Rate Applications notes the following: *"The OEB expects a utility's rate application to provide an overview of customer needs, preferences and expectations learned through the utility's customer engagement activities."*[2] These requirements have the effect of bringing customers feedback data and actionable intelligence to bear on utility planning.

The OEB does not specify how customer engagement should be conducted or how customer feedback should be received. However, it has encouraged utilities to use *"both existing and new processes."*[3] THESL's customer engagement was designed with this in mind, where customer feedback was collected using multiple methodologies, including: an online customer feedback portal, focus groups, one-on-one interviews, telephone surveys and online surveys.

New customer engagement elements in this consultation included:

- Collecting customer input prior to Toronto Hydro's planning process for the CIR Application as well as in the final decision-making stage.
- Allowing customers participating in the online workbook to review the bill impact of their responses and to change those responses if desired.
- A more extensive effort to increase participation in the online exercise resulting in over 10,000 completed workbooks.
- Using examples of specific projects to identify customer preferences between bill impacts and customer-facing outcomes in a transparent fashion.
- The use of incentives in the phone survey to allow for a longer survey that might otherwise have been possible.

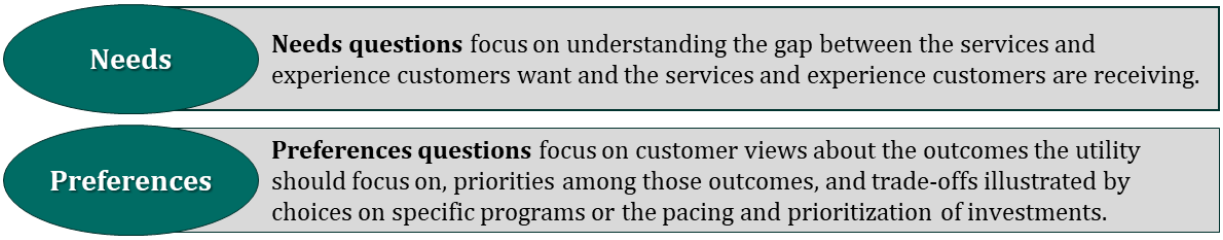
Other efforts to respond to comments regarding previous engagements are addressed later in this report.

[1] OEB Renewed Regulatory Framework for Electricity Sections 2.4.2, 5.0, and 5.0.4.

[2] Handbook for Utility Rate Applications, p. 12 (October 13, 2016)

[3] Handbook for Utility Rate Applications (October 13, 2016)

Based on a review of the OEB handbook and previous decisions, the engagement focused on two types of questions: **needs** and **preferences.**



As noted on the previous page, customer feedback related to THESL's proposed rate application was collected in two phases.

- **Phase I (2016-2017)** set out to identify customer needs and preferences as they relate to the outcomes that the utility should focus on and prioritize. While THESL has ongoing feedback on customer needs from its customer satisfaction work and had extensive input from customers on general trade-offs from both its IRRP and previous rate application consultations, it did not have any specific customer feedback on preferences related to outcomes. Given the priority placed on identifying customer preferences in the Handbook, the key priority for the first round was to develop a list of customer outcomes and to identify customer priorities among those outcomes for the THESL planning process. Customer feedback obtained in this phase helped inform Toronto Hydro's business planning, including the penultimate DSP.
- **Phase II (2017-18)** re-engaged with customers to confirm customer needs and preferences as they relate to outcomes in Phase I. With THESL planning now well advanced, this round of engagement was able to solicit customer feedback on THESL's proposed plans, and explore trade-offs in relation to specific programs and the associated bill impacts, as well as the pacing and prioritization of investments. Customers were able to look at the cumulative bill impact of their choices and adjust them as needed.

This report summarizes the findings from THESL's iterative CIR customer engagement program conducted over a two year period, between 2016 and 2018.

2. Executive Summary

The customer engagement as part of this Application took a two phased approach to identify customer needs and preferences. The first phase focused on identifying the outcomes THESL customer value and priorities among those outcomes. The second phase focused on generating feedback on Toronto Hydro's proposed plans.

While customer engagement continues to be an ongoing process, the engagement as part of this Application found the following:

Toronto Hydro is generally seen to be meeting the needs of most customers effectively.

THESL customers are generally satisfied with the services they receive. When customers are asked how THESL can improve its service, most customers either have no suggestions or are looking for lower rates.

Price and reliability dominate as customers' top outcome priorities.

Customers consistently, across rate classes value price and reliability above other priorities, with price constantly at the top priority for non-large use customers.

Customers generally support THESL's propose plan.

After reviewing the key choices in THESL's plan, majorities of residential, small business, mid-market and key account customers say THESL should stick with its proposed plan or do more. Even the most economically vulnerable customers support the plan.

While customers began reviewing Toronto Hydro's plan skeptically, they were strongly supportive of programs aimed to improve parts of the system experiencing below average performance or where spending more now can avoid greater disruption and higher costs in the future.

Customers are less supportive of innovation. They support investments in control equipment that would improve performance but do not support paying more for increased storage and microgrids.

2.1 Phase I Customer Engagement

The first phase of THESL's customer engagement dedicated to this application took place at the beginning of the planning process. The goal of this phase was to provide THESL with input on customer needs and preferences at the start of the planning process.

At that time, the OEB had just released the *Handbook for Utility Rate Applications* with a clear focus on outcomes. THESL's existing work had explored needs and a wide variety of trade-offs but had not explicitly addressed outcomes. Phase I focused on filling that gap by developing a list of outcomes important to customers and then establishing customer priorities among those outcomes. As part of that exercise, information on customer needs was also updated.

2.1.1 Understanding Customer Needs and Preferred Outcomes

To identify customer needs and preferences, INNOVATIVE conducted a series of customer engagements, designed to help uncover priorities for the utility that customers' value and their relative importance against each other.

Before engaging directly with THESL customers, INNOVATIVE and THESL discussed existing research related to customer needs, preferences and outcomes to understand the potential issues THESL customer care about and what they want and need from their utility.

Building on previous research, INNOVATIVE conducted exploratory focus groups to better understand and identify the outcomes that THESL customers' value, and the criteria they use to measure successful delivery of these outcomes. The focus groups included mapping the customer journey, expectations of THESL today and in the future as a way of uncovering outcomes and measurement criteria.

Based on customer feedback from the focus groups, a series of outcomes were developed and evaluated through a representative low-volume customer survey. The survey was designed to assess the importance of identified outcomes and rank them by relative importance.

In addition to a low-volume customer survey, INNOVATIVE also surveyed Key Account customers to better understand how THESL could deliver valued services and set outcomes among competing priorities.

This section of the report details the iterative research process of identifying and ultimately quantifying the THESL outcomes as valued and prioritized by its customers.

Phase I Customer Engagement Summary

	Methodology	Dates	Quantity	
Qualitative Research				
Residential	Focus Groups	Dec. 5 & 6, 2016	2 groups	
Small Business (GS < 50 kW)	Focus Groups	Dec. 5 & 6, 2016	2 groups	
Mid-Market (GS > 50 kW)	Focus Groups	Feb. 28 – Mar. 1, 2017	4 groups	
Stakeholders (NGOs, Industry Associations)	In-depth Interviews	June 12-30, 2017	10 interviews	
	Methodology	**Field Dates**	**Targeted Sample Size**	**Final Completes**
Low-Volume Telephone Survey				
Residential	Telephone	Dec. 7-14, 2016	n=400	n=416
Small Business (GS < 50 kW)			n=200	n=211
Total Low-Volume Customer Completes			n=600	n=627
Key Accounts				
Large Use Customers (2MW+)	Online	Feb. 23 – Mar. 24, 2017	N/A	**n=63**

Summary of Customer Priorities

Priorities	Residential*	GS < 50 kW*	GS > 50 kW**	Key Accounts$^{\beta}$
1st	Prices	Prices	Price	Reliability
2nd	Reliability	Reliability	Reliability	Price
3rd	Safety	Safety	ETOR / Communications	Environmental Risk Mitigation (Reliability)

* Feedback from **residential** and **GS < 50 kW** customers obtained through both focus groups and telephone surveys.

** Feedback from **GS > 50 kW** customers obtained through focus groups.

$^{\beta}$ Feedback from **Key Account** customers obtained through an online survey.

Customer and stakeholder feedback from Phase I can be summarized by the following key points:

1. Keeping distribution price increases as low as possible;
2. Maintaining long-term performance for customers experiencing average or better service;
3. Improve service levels for customers experiencing below average service or who have special reliability needs (e.g. hospitals); and,
4. Balancing other customer priorities (e.g. customer service) with the need to contain rate increases.

Phase I customer feedback informed THESL's business planning, including the penultimate DSP. THESL's plans were later refined based on feedback from the Phase II customer engagement.

An overview of customer priorities can be found below in the ***Phase I: Toronto Hydro Customer Priorities*** table. At the conclusion of Phase I, INNOVATIVE provided a two-page summary with the overview table and the key results of the low volume and Key Accounts surveys for reference

Phase I: Toronto Hydro Customer Priorities

PRIORITIES	Residential & GS <50 KW	GS >50 KW	Key Accounts (Large Users)
Price	**HIGH (1st Priority)** • Containing price increases is the top priority for most residential and small business customers. • Increasing rates must be justified (i.e. there is a clear need and ratepayers dollars will be spent efficiently).	**HIGH (1st Priority)** • Containing price and providing short-term rate predictability is the top priority.	**HIGH (2nd Priority)** • Prioritizing reliability over price is of high importance (i.e. cost of power interruptions outweighs the cost of rate increases).
Reliability	**HIGH (2nd Priority)** • Maintaining current "good" level of reliability is a key priority.	**HIGH (2nd Priority)** • Maintaining current level of reliability is a key priority for this group of customers. • Providing outage communications and responsive service is valued more highly among this rate class (than others).	**HIGH (1st and 3rd Priority)** • #1 Maintaining reliability (including power quality) is the top priority. • #3 Implementing strategies to mitigate outages caused by extreme weather is a top 3 priority.
Safety	**HIGH (3rd Priority)** • Setting public safety as a top priority is assumed and expected.	• Setting public safety as a top priority is assumed and expected.	• Setting public safety as a top priority is expected.
Customer Service	• Provide accurate ETOR, proactive information on CDM programs and energy management. • Provide tools to make billing, account management, and usage information easily accessible.	**HIGH (3rd Priority)** • Providing accurate ETOR and proactive communications is a key priority. • Enhance customer service to match emerging technological capabilities and needs (e.g. allow customers to get bills by emails, create master accounts to manage multiple bills).	• Maintaining current "very good" levels is expected. • Helping customers take advantage of CDM programs is seen as a valued priority.
Public Policy Response	• Incentivize adoption of innovative technologies that enable conservation and consumption management.	• Pursue value-for-money investments where long-term cost savings can be realized (e.g. spend now to save later). • Avoid premature investments in unproven or untested technologies that impact customer rates.	• Investing in technology that helps customers save money is valued.
Environmental	• Make programs combatting climate change known to customers. • Show customers how such programs impact their bills.	• Maintain equipment and infrastructure in adverse weather.	• Actualize other priorities, before focusing on environmental concerns.
Methodology ▸▸	Quantitative and Qualitative	Qualitative	Quantitative

Stakeholder Groups (Key Issues)	
Housing & Social Services	• Reliability outweighs cost • Quality and consistency of power is a key need • Incentive programs need to be more accessible and may not be targeted at greatest returns • Conservation efforts constrained by bulk meter buildings • Building renewal and retrofitting are priorities
Large Commercial	• Reliability is needed 24/7 • Reliability is a competitive advantage • System resilience is a concern • Cybersecurity is a priority • Behind the meter innovation is a need • Cost is not a significant factor
Small Commercial	• Reliability is needed 24/7 • Customer service is the key need – lampposts, local development, outages • Cost is primarily a concern among local, micro businesses
Small / Mid-sized Manufacturing	• Cost is a significant factor • Reliability seen as less of a concern • ICI program ineligible • Global adjustment is a friction point, impairs budgeting
Methodology ▸▸	Qualitative

Source: **Innovative Research Group** (Customer Research - December 2016, March 2017, June 2017)

2.1.2 Customer Outcomes Priorities by Rate Class

Low-Volume Customer Priorities

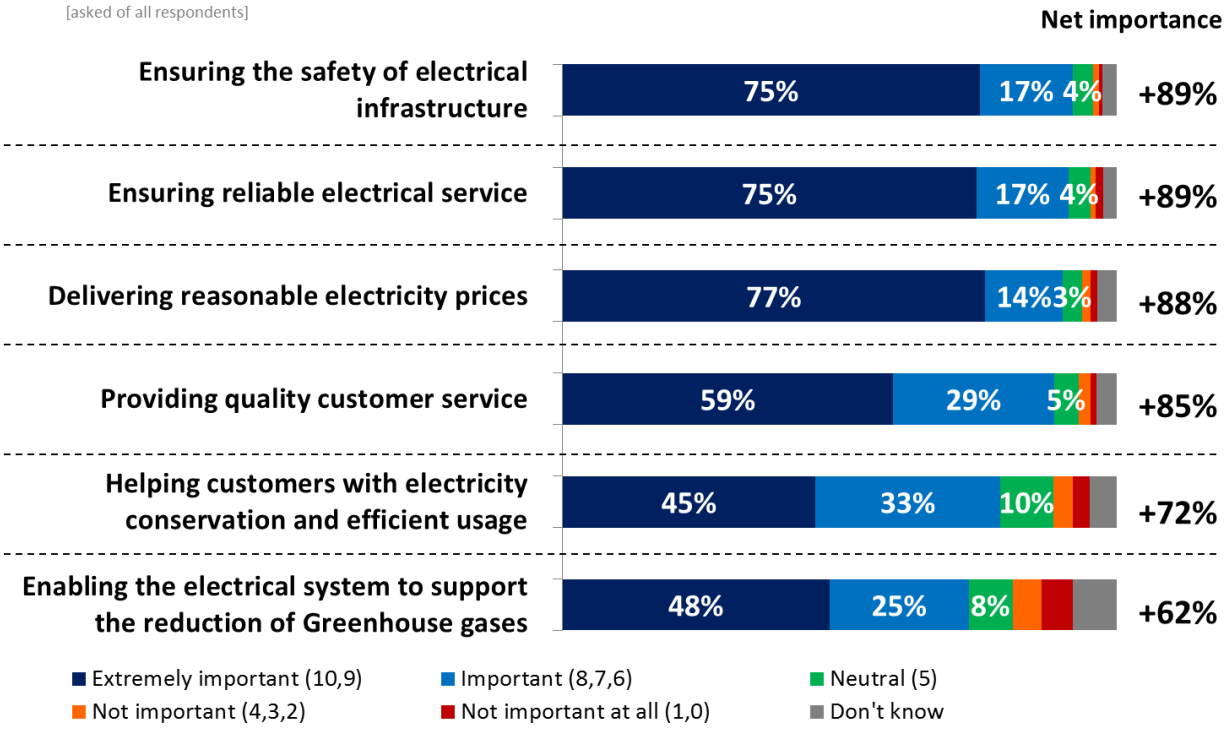
Through the focus groups with residential and GS < 50kW customers conducted on December 5 and 6, 2016, a list of six key customer outcomes were identified:

1. Delivering reasonable electricity prices
2. Ensuring reliable electrical service
3. Ensuring the safety of electrical infrastructure
4. Providing quality customer service
5. Helping customers with electricity conservation and efficient usage
6. Enabling the electrical system to support the reduction of Greenhouse gases

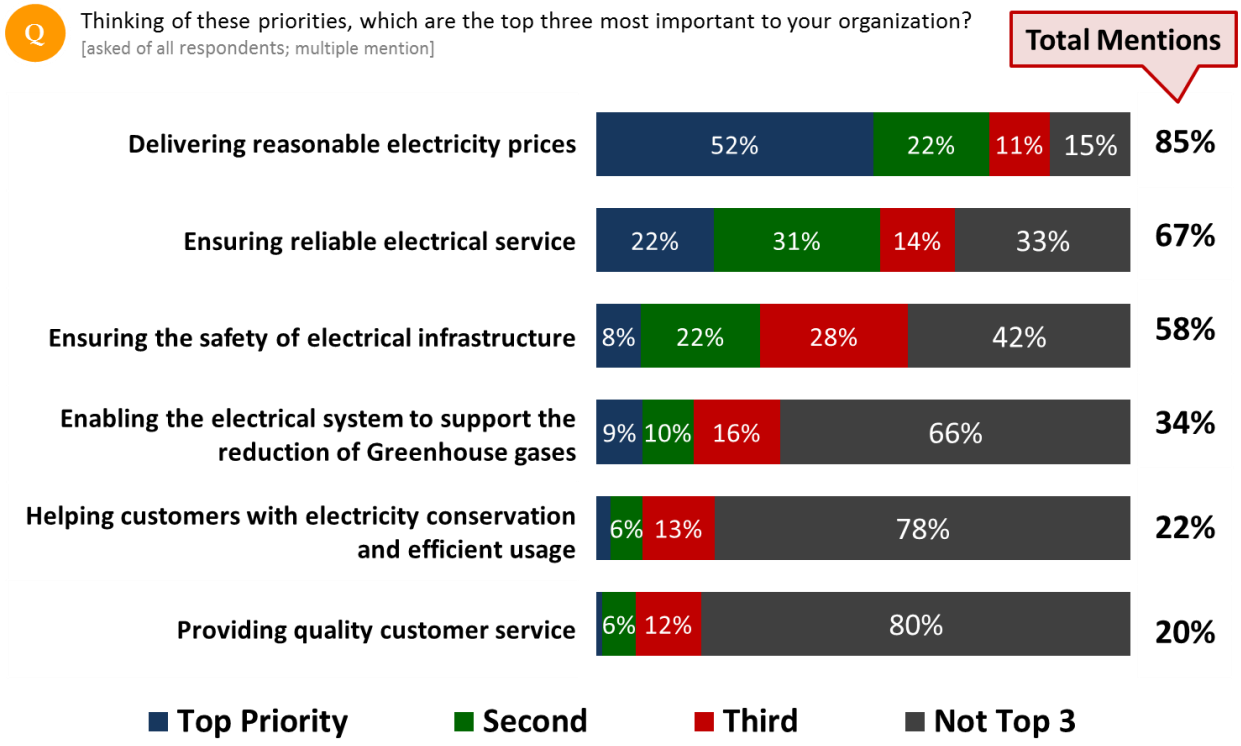
In a follow-up telephone survey of n=627 low-volume THESL customers (conducted December 7-14, 2016), respondents were asked to assess the importance of each priority.

Similar to what was observed in the previous focus group research, *safety*, *reliability,* and *price* are seen as equally important to low-volume customers.

Q Using a scale from 0 to 10, where 0 means not important at all and 10 means extremely important, please tell me how important each of the following Toronto Hydro priorities are to you as a customer?
[asked of all respondents]



Customers were then asked to rank outcomes in order to help THESL understand which of the most important outcomes to give priority to when those outcomes conflict. *Delivering reasonable electricity price* clearly emerges as the top priority valued by low-volume customers, followed by *reliability*, and then *safety.*



Mid-Market Customer Outcome Priorities

INNOVATIVE conducted a total of four focus groups over two nights, among GS > 50 kW customers on February 28 and March 1, 2017. All focus groups were held in North York. Respondents were randomly recruited from a THESL provided list of approximately 6,000 GS > 50 kW customers.

From the focus groups, the following common priorities were identified:

1. **Customer Service**: Overall, customer service is seen as excellent with the exception to specific incidents where base observations are noted. Generally, maintaining the current level of customer services was seen as a priority for THESL.
2. **Reliability and Outage Communications**: Power reliability is seen as good, but more importantly Toronto Hydro's responsiveness and communications were seen as key business needs. Maintaining the current level of reliability appears to be a priority among this rate class.
3. **Bill Impact**: Cost was an overarching concern, but not specifically directed at Toronto Hydro. The more participants learned about Toronto Hydro, its plans and its place in the electricity system, the less concern participants appeared to be regarding Toronto Hydro's impact on their bill.
4. **Future Rates**: While learning more about Toronto Hydro reduced concern about price, participants still give high priority to cost containment and short-term rate predictability. Even

with that concern about bill impacts, this rate class appears to be willing to accept "reasonable" rate increases based on a value proposition that included the following definitions:

a) Maintaining current reliability (not necessarily enhancing reliability);

b) Investing prudently, where long-term cost savings are realized (spend more now to save even more later);

c) No premature investing in unproven or untested technologies;

d) Enhanced customer service to match emerging technological capabilities and needs (e.g. allow customers to get bills by emails, create master accounts to manage multiple bills, live assistance chat features); and

e) Investing in education and promotion of CDM as a means for individual cost savings and also as a route to mitigating future demand and reliability challenges.

Key Account Customer Outcome Priorities

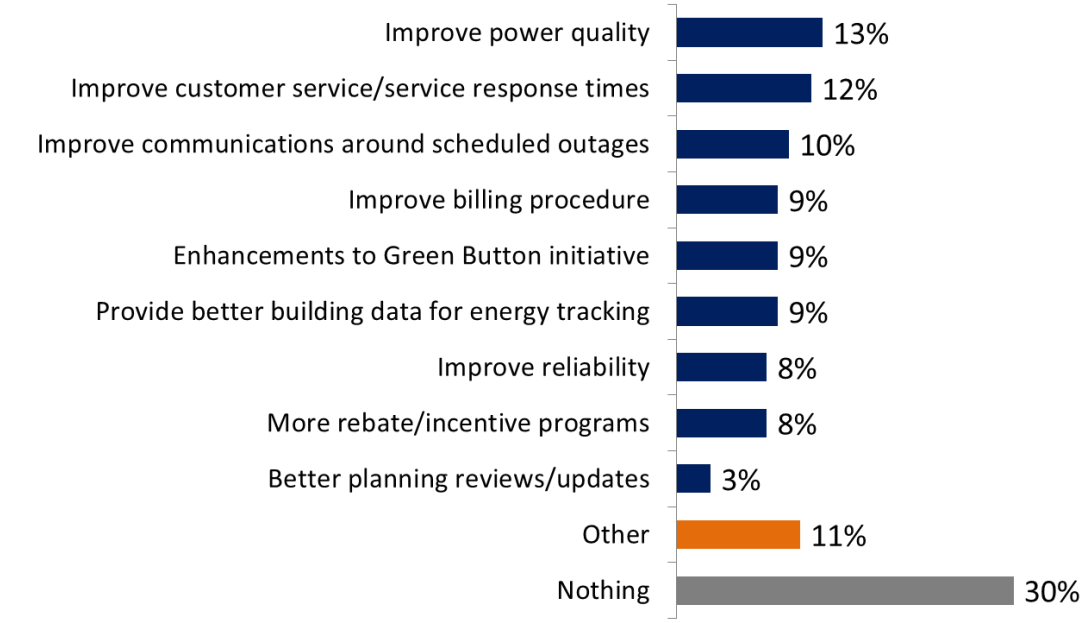
These are the findings from an INNOVATIVE online survey conducted among Key Account customers between February 23 and March 24, 2017.

Toronto Hydro provided INNOVATIVE with an email contact list consisting of the prime contact for each of its 275 Key Account customers. INNOVATIVE provided each Key Account contact with a unique URL via an email invitation so that only customers identified by Toronto Hydro were able to complete the survey and complete the survey only once.

The analysis of this survey is based on 63 eligible responses from Toronto Hydro's Key Account customers.

When asked what THESL could do to improve service, a plurality (30%) suggested nothing; followed by power quality and improved service response times.

Q Is there anything in particular that **Toronto Hydro** can do to improve its services to your organization?
[OPEN-ENDED; multiple mention, asked of all respondents; n=63]



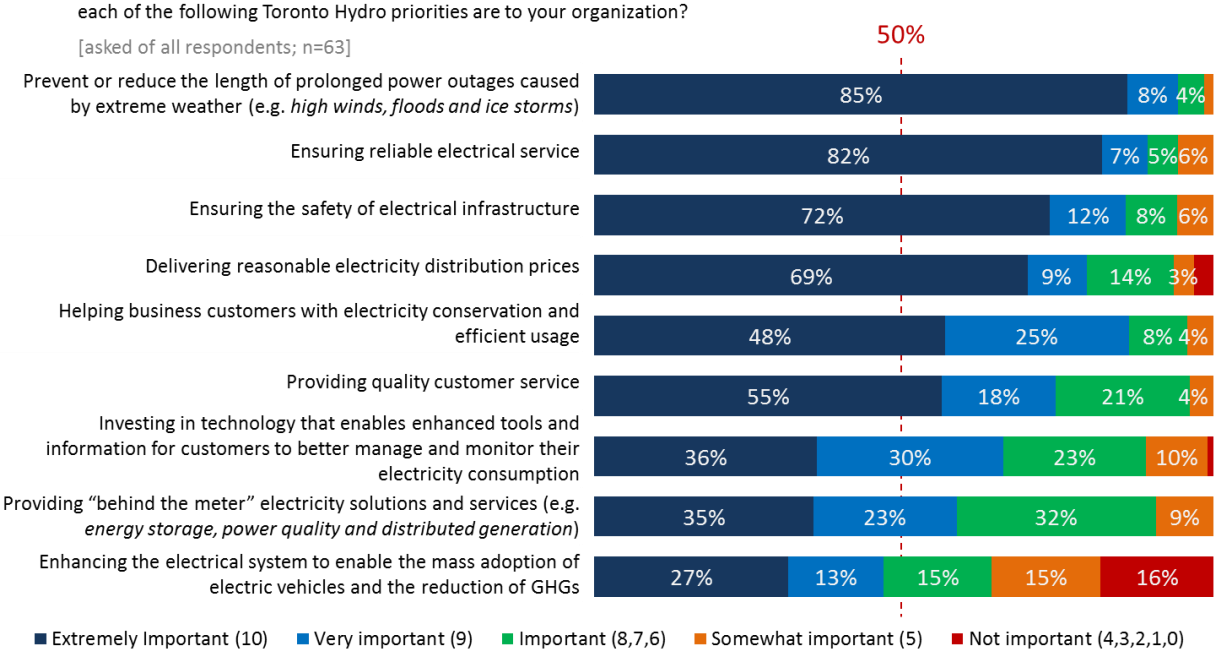
As with lower volume customers, Key Accounts were asked to rate and rank a list of outcomes. Several categories were added to the Key Account list based on an initial review of previous Key Account engagements with THESL staff.

Similar to other rate classes, *safety*, *reliability,* and *price* are most important to customers. System hardening, an additional category unique to this survey, is the topped ranked priorities among Key Accounts (this priority did not come up in qualitative discussions with other rate classes).

Q Toronto Hydro regularly holds discussions with its customers to better understand how it should set spending priorities with ratepayer dollars. In recent conversations with customers, a number of company goals were identified as priorities for Toronto Hydro.

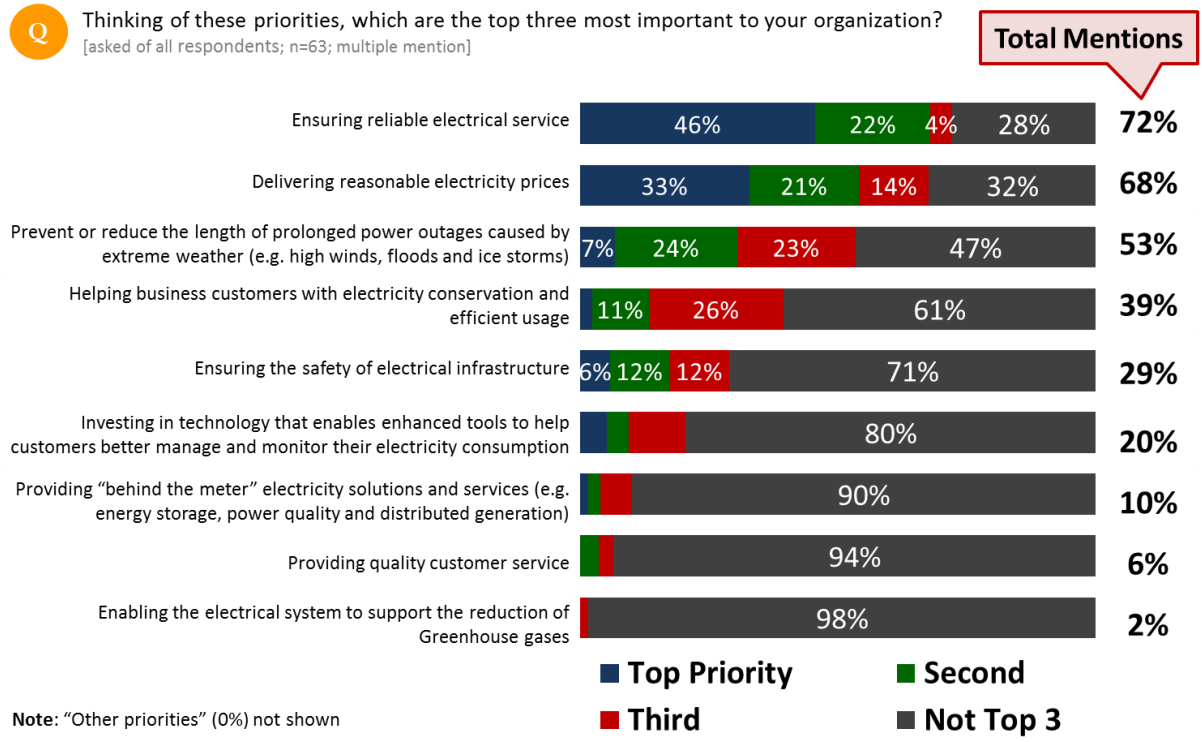
Using a scale from 0 to 10, where 0 means not important at all and 10 means extremely important, please indicate how important each of the following Toronto Hydro priorities are to your organization?

[asked of all respondents; n=63]



Looking at the top priority (first mention), *reliability* appears to be more important than *price* to this rate class (although price is a close second in priority rankings).

Q Thinking of these priorities, which are the top three most important to your organization?
[asked of all respondents; n=63; multiple mention]



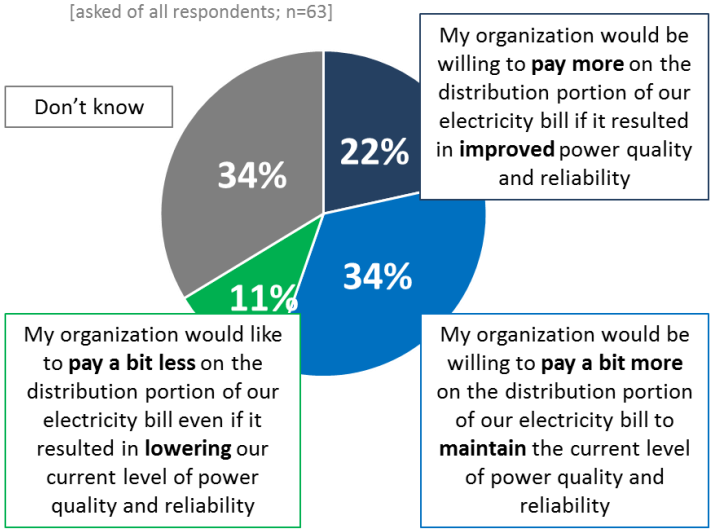
Note: "Other priorities" (0%) not shown

A majority of Key Account customers (56%) say they are willing to pay more to maintain or improve system reliability.

Q Despite best efforts, no electrical distribution system can deliver perfectly reliable electricity. As a general rule, the more reliable the system, the more expensive the system is to build and maintain.

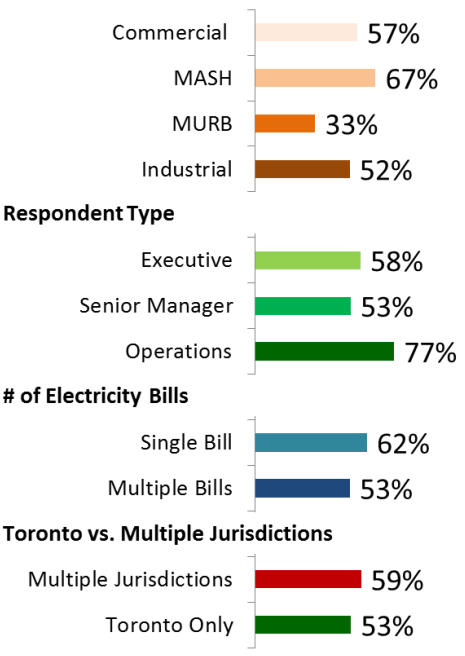
Thinking about the trade-offs between reliability and the cost of your electricity bill, which of the following statements best represents your general point of view?

[asked of all respondents; n=63]



Segmentation

*"Pay More" to either **improve** or **maintain**:*



Stakeholder Outcomes Preferences

INNOVATIVE conducted nine in-depth interviews with industry and social stakeholders between June 12 and 30, 2017. Interviews and dyads were semi-structured based around key themes. Specific and topical probes were employed throughout. All interviews and dyads were held at participant organization offices across Toronto.

The in-depth stakeholder interviews revealed a number of common themes.

1) **Reliability**: Industry associations held reliability, by far, their overreaching top priority.
2) **Social Outcomes**: Social organizations also held reliability as top priority, but also held social outcomes as a key priority (e.g. community renewal, sustainable living).
3) **Price**: Mid-sized manufacturing association held price above all else, far above reliability. Specifically, this stakeholder was seeking a price reductions as opposed to price stabilization.
4) **Price Predictability**: Most industry and social organizations favour price stabilization and predictability over absolute reductions (e.g. reasonable price increase are accepted by this group of stakeholders). The biggest concern with the price of electricity is not distribution rates, but rather the global adjustment that has been unpredictable over the past decade.
5) **Risk Mitigation**: Resilience of infrastructure – defined as an ability of withstand adverse events which may be physical or virtual – appears to be a key priority for almost all stakeholder groups.
6) **Socio-economic Outcomes**: Every group, in varying ways, cited socio-economic outcomes as an increasing priority (e.g. impact poverty, employment, cost of living, quality of life, economic competitiveness, etc.).
7) **Incentive Programs**: Better target incentives where there is the greatest long-term benefits. Make it easier to access incentives.
8) **Other**: Specific one-off instances of interaction points of service friction with Toronto Hydro (e.g. vaults, sub-metering, inconsistent power quality, collaboration and communications on development projects, lampposts).

2.2 Phase II Customer Engagement

In 2017, THESL planners used customer and stakeholder feedback, collected throughout the Phase I customer engagement program, to help align the 2020 CIR DSP and operational programs with customer expectations.

Phase II of the engagement took place in the spring of 2018 and focused on three goals:

- confirming the customer needs, preferences and priorities identified in Phase I;
- soliciting customer feedback on the content of its proposed plans and subsequent rate impact including customer preferences towards particular capital projects where trade-offs on pacing exist,
- soliciting customer feedback on THESL's planning development process, including the customer engagement process.

INNOVATIVE worked with THESL staff to translate the penultimate business plan and DSP into consultation materials that a typical customer could understand. Consultation materials were designed to provide meaningful feedback.

The following section summarizes customer feedback from an online feedback portal among low-volume customers, telephone surveys among low-volume and mid-market customers, and an online survey among Key Account customers.

Phase II Customer Engagement Summary

	Methodology	Field Dates	Targeted Sample Size	Final Completes
Online Feedback Portal				
Residential	Online	April 26 – May 28, 2018	N/A	n=10,165
Small Business (GS < 50 kW)			N/A	n=181
Total Online Feedback Portal Completes			N/A	n=10,346
Surveys				
Residential	Telephone	May 1 – 10, 2018	n=600	n=600
Small Business (GS < 50 kW)	Telephone	May 2 – 14, 2018	n=200	n=215
Mid-Market (GS > 50 kW)	Telephone	May 3 – 11, 2018	n=200	n=202
Key Accounts	Online	June 7 – 15, 2018	N/A	n=XX

2.2.1 Customer Needs

A strong majority of Toronto Hydro customers are both familiar with the utility and satisfied with the services they receive. When asked if there is anything in particular that Toronto Hydro could do to improve services, customers respond with either "*nothing*" or "*reduce the price*" – this is consistent with all rate classes.

Customer Needs	Telephone Surveys		
	Residential	Small Business	Mid-Market
Familiarity with Toronto Hydro			
Familiar	**84%**	**81%**	**87%**
Not familiar	11%	13%	10%
Satisfaction with Services			
Satisfied	**74%**	**79%**	**78%**
Dissatisfied	12%	8%	7%
Suggestions for Improved Services			
None	**34%**	**41%**	28%
"Reduce the price"	32%	31%	**30%**

A key part of the engagement is to ensure all participants have a basic understanding of key facts about Toronto Hydro and its role in Ontario's electricity system. Following that background information, INNOVATIVE asked customers about familiarity with both the amount of their bill that is remitted to Toronto Hydro, as well as the OEB. Familiarity with both measures is quite low, and it is observed that a majority of customers have no level of awareness regarding the OEB.

Familiarity with Electricity System	Telephone Surveys		
	Residential	Small Business	Mid-Market
Familiarity with Amount of Bill Retained by Toronto Hydro			
Familiar	**35%**	**26%**	**30%**
Not familiar	62%	64%	63%
Familiarity with Ontario Energy Board			
Familiar	**45%**	**33%**	**43%**
Not familiar	54%	62%	54%

2.2.2 Re-confirming Customer Outcome Priorities

Using the customer priorities identified in Phase 1 of the consultation, in Phase 2, customers were again asked to rank which priority was most important to them personally, or their organization. Consistent with Phase 1, it was found that customers prioritize price and reliability above all else. Ensuring the safety of electricity infrastructure was also consistently seen as an important priority that Toronto Hydro should focus on.

Customer Priorities	Residential		Small Business		Mid-Market	
	Phase 1 (July 2017)	Phase 2 (May 2018)	Phase 1 (July 2017)	Phase 2 (May 2018)	Phase 1 (July 2017)†	Phase 2 (May 2018)
1st	Prices	**Prices***	Prices	**Prices***	Prices	**Prices***
2nd	Reliability	**Reliability****	Reliability	**Reliability****	Reliability	**Reliability****
3rd	Safety	**Safety*****	Safety	**Safety*****	ETOR / Communications	**Safety*****

* Delivering reasonable electricity prices

** Ensuring reliable electricity service

*** Ensuring the safety of electricity infrastructure

† In Phase 1, Mid-Market customer views were gathered through qualitative focus group research.

Beyond the six customer priority outcomes identified in Phase 1 and further probed in Phase 2, a strong majority of customers did not identify any missing outcomes that Toronto Hydro should be focusing on. Furthermore, when asked if Toronto Hydro's Customer Engagement process seemed like a good way or poor way of bringing customer needs and preferences into the Plan, a clear majority feel that it is the *right way*.

Feedback on Customer Engagement Process	Telephone Surveys		
	Residential	Small Business	Mid-Market
Does this Customer Engagement process seem like a good way or a poor way to bring customer needs and preferences into Toronto Hydro's plan?			
Good way	**73%**	**74%**	**85%**
Poor way	20%	15%	11%
Don't know	6%	12%	4%

2.2.3 Planning Principles and Rate Impacts

Before exploring individual programs and their potential customer benefits and outcomes, customers were asked to respond to Toronto Hydro's general approach.

In the telephone surveys, customers received the preamble below, which had customized rate impacts based on rate class. The following reflects the residential rate class preamble.

> *"Based, in part, on the initial customer input, Toronto Hydro has drafted a plan totaling approximately $4.3B over five years.*
>
> *Toronto Hydro's proposed plan focuses on delivering current levels of reliability and customer service for most customers and targeted improvements for customers experiencing below average service or who have special reliability needs, like hospitals.*
>
> *This proposed plan translates into an average 3.4% increase in your distribution rates each year from 2020 to 2024. The distribution charges on the monthly bill would increase to $49 by 2024 for a typical residential customer."*

Rate Class	*Proposed Annual Rate Increase (2020 to 2024)*
Residential	3.4%
Small Business	4.4%
Mid-Market	3.9%

Proposed 2020 – 2024 Rate Impacts (%)

In the absence of a discussion of specific benefits for customers, a plurality of participants felt this general approach to be the *wrong approach.*

Approach to Planning for the Next Five Years	Telephone Surveys		
	Residential	Small Business	Mid-Market
Do you feel that this is definitely the right approach, probably the right approach, probably the wrong approach or definitely the wrong approach to Toronto Hydro's planning for the next five years or would you say you don't know?			
Right Approach	**37%**	**28%**	**31%**
Wrong Approach	44%	46%	37%
Don't know	19%	26%	32%

While this is the only trade-off question where respondents appear to place price concerns above the maintenance of reliability and targeted improvements, it highlights the general concern about delivering reasonable electricity prices seen in the outcome section. As customers became more engaged in discussing more detailed trade-offs, their responses favoured the other outcomes over bill impacts.

2.2.4 Addressing Safety and Reliability

Customers were asked to provide feedback on the pacing and prioritization of six specific programs that are being proposed as part of the investment bucket *"Addressing Safety and Reliability"*. A majority of customers in each rate class support either the current proposed pace of investments or an accelerated approach and associated outcomes for all six programs, including *rear-lot, direct buried cable* and *PILC cable* replacement.

	Online Feedback Portal		Telephone Surveys		
	Residential	Small Business	Residential	Small Business	Mid-Market
Addressing Safety and Reliability | Rear-Lot Replacement Program					
Stick with the proposed pace of investment	23% 68%	24% 56%	33% 70%	43% 65%	40% 71%
Pay more to remove rear-lot sooner	44%	32%	38%	22%	31%
Slow down this program	21%	29%	26%	29%	28%
Don't know	11%	15%	4%	6%	1%
Addressing Safety and Reliability | Direct Buried Cable Replacement Program					
Stick with the proposed pace of investment	28% 67%	29% 56%	39% 70%	36% 63%	56% 73%
Pay more to remove high risk direct buried cable sooner	39%	27%	31%	27%	16%
Slow down this program	21%	30%	27%	27%	27%
Don't know	12%	14%	3%	9%	1%
Addressing Safety and Reliability | Paper Insulated Lead Covered (PILC) Cable Replacement Program					
Stick with the proposed pace of investment	25% 67%	24% 55%	28% 72%	20% 56%	44% 75%
Pay more to accelerate PILC replacement	42%	30%	45%	36%	31%
Slow down this program	20%	26%	24%	36%	24%
Don't know	13%	19%	4%	8%	1%

	Online Feedback Portal		Telephone Surveys		
	Residential	Small Business	Residential	Small Business	Mid-Market
Addressing Safety and Reliability | Network Unit Replacement Program					
Stick with the proposed pace of investment	27% 68%	24% 53%	33% 72%	32% 62%	40% 75%
Pay more to replace transformers sooner	40%	29%	39%	30%	35%
Slow down this program	19%	28%	25%	33%	23%
Don't know	13%	19%	3%	6%	2%
Addressing Safety and Reliability | Cable Chamber Renewal Program					
Stick with the proposed pace of investment	25% 68%	24% 57%	32% 71%	26% 55%	43% 69%
Pay more to replace deteriorating cable chambers faster	43%	33%	39%	29%	26%
Reconstruct reactively, lowering rates now	18%	25%	25%	36%	30%
Don't know	14%	18%	4%	9%	1%
Addressing Safety and Reliability | System Restoration Improvements					
Spend more to improve restoration times during outages	44%	29%	49%	41%	37%
Stick with what's already planned	48%	58%	49%	55%	63%
Don't know	8%	13%	2%	4%	1%

2.2.5 Innovation and Planning for the Future

With regards to investments in *"Innovation and Planning for the Future"*, customers were asked to provide feedback on three types of programs, including *energy storage*, *monitoring and control equipment* and *microgrids*. Customers are largely supportive in investments in monitoring and control equipment – in fact more customers believe that Toronto Hydro should be spending more on these investments, rather than reducing the current pace.

Knowing that energy storage investments are not required to maintain current levels of reliability, a majority of customers in all rate classes do not want to pay more for Toronto Hydro to do more energy storage projects. Likewise, a majority of customers only feel that Toronto Hydro should support *microgrids* only when those in the grid pay the full costs – again, knowing that these investments are not necessary to maintain reliability.

	Online Feedback Portal		Telephone Surveys		
	Residential	Small Business	Residential	Small Business	Mid-Market
Innovation and Planning for the Future | Investments in Energy Storage Projects					
Spend more to partner on storage projects	40%	29%	37%	37%	26%
Don't spend more on storage projects	49%	58%	60%	55%	74%
Don't know	10%	13%	5%	8%	1%
Innovation and Planning for the Future | Investments in Monitoring and Control Equipment					
Spend more on monitoring and control equipment	**27%** (67%)	**18%** (52%)	**31%** (79%)	26% (66%)	47% (86%)
Maintain current pace of investment	**40%**	**34%**	**48%**	40%	39%
Reduce spending on monitoring and control equipment	20%	29%	19%	26%	12%
Don't know	13%	18%	2%	8%	2%
Innovation and Planning for the Future | Investments in Microgrids					
Spend more on supporting development of microgrids	35%	20%	36%	31%	37%
Support microgrids, **if benefiting customers pay**	46%	55%	56%	54%	59%
Don't know	19%	25%	8%	14%	4%

2.2.6 Opinion of Toronto Hydro's Proposed Plan

Overall, Toronto Hydro customers are supportive of the utility's current proposed plan, or a plan that improves services, including investments that focus on improving reliability and safety or innovation and planning for the future.

	Online Feedback Portal		Telephone Surveys		
	Residential	Small Business	Residential	Small Business	Mid-Market
Improve Service *Toronto Hydro should improve service, as discussed on the previous pages, even if that means an annual increase that exceeds [Residential: 3.4%; Small Business: 4.4%, Mid-Market: 3.9%]*	26%	22%	23%	18%	18%
	63%	52%	71%	55%	73%
Stick with Proposed Plan *Toronto Hydro should stick with a [Residential: 3.4%; Small Business: 4.4%, Mid-Market: 3.9%] annual increase to deliver current levels of reliability and customer service for most customers and targeted improvement for customers experiencing below average service or who have special reliability needs.*	37%	30%	48%	37%	55%
Scale Back Proposed Plan *Toronto Hydro should keep increases below [Residential: 3.4%; Small Business: 4.4%, Mid-Market: 3.9%] annually, even if that could mean reductions in service.*	21%	27%	24%	34%	23%
Other	6%	6%	2%	3%	2%
Don't know	10%	15%	3%	7%	2%

When highlighting more vulnerable customers, the table below illustrates that a majority (50%) of customers who say their electricity bill has a major impact on their finances support Toronto Hydro's current plan or an increase that exceeds the current proposal to improve services.

Opinion of Toronto Hydro's Proposed Plan Residential Customers	*The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.*			***Total***
	Sig. Impact [n=139]	**Impact** [n=143]	**No Impact** [n=303]	
Improve services, increase above 3.4%	10%	14%	31%	**23%**
	50%	70%	81%	
Stick with current plan at 3.4%	40%	56%	50%	**48%**
Keep increases below 3.4%	42%	24%	15%	**24%**

Small business customers whose electricity bill has a significant impact on their organization's bottom line are less likely to support Toronto Hydro's proposed plan.

Opinion of Toronto Hydro's Proposed Plan Small Business Customers	*The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being delayed.*			***Total***
	Sig. Impact [n=61]	**Impact** [n=59]	**No Impact** [n=64]	
Improve services, increase above 4.4%	13%	20%	23%	**18%**
	40%	67%	62%	
Stick with current plan at 4.4%	27%	47%	40%	**37%**
Keep increases below 4.4%	47%	31%	27%	**34%**

A majority of Mid-Market customers whose bill has a significant impact on their bottom line are supportive of Toronto Hydro's current proposed plan or, again, one that improves services beyond a 3.9% annual increase.

Opinion of Toronto Hydro's Proposed Plan Mid-Market Business Customers	*The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being delayed.*			*Total*
	Sig. Impact [n=84]	**Impact** [n=71]	**No Impact** [n=38]	
Improve services, increase above 3.9%	12%	18%	33%	**18%**
	62%	79%	89%	
Stick with current plan at 3.9%	49%	61%	56%	**55%**
Keep increases below 3.9%	32%	19%	11%	**23%**

2.2.7 Key Account Online Survey

As part of Phase II of this customer engagement, an online survey was conducted among 37 Toronto Hydro Key Accounts between June 7 and 18, 2018. The purpose of this survey was to build on the findings from Phase I; gathering general feedback on needs and priorities, THESL's engagement process, the utility's planning principles, as well as the rate impacts of the proposed plan.

General Satisfaction and Customer Needs

- 29 of 37 Key Account customers interviewed are satisfied with the services they receive from Toronto Hydro, with five neither satisfied nor dissatisfied and the remaining three somewhat dissatisfied.
- Areas for service improvements include; improved communications, quicker service response times, improved reliability and support with understanding or reducing impacts of Global Adjustment charges.

Toronto Hydro's Customer Engagement Process

- 32 of 37 Key Account customers interviews feel that Toronto Hydro's customer engagement process seems like a good way to bring customer needs and preferences into the utility's plan.

Re-Affirming Key Account Customer Priorities

- Confirming the findings from Phase I of the customer engagement, 33 of 37 Key Account customers feel that the following priorities are aligned with what they expect the utility to focus on:
    - Ensuring reliable electrical service;
    - Delivering reasonable electricity prices, and;
    - Preventing or reducing the length of prolonged power outages caused by extreme weather (e.g. high winds, floods and ice storms).

Power Quality Trade-Offs

- 24 of 37 Key Account customers interviewed express that their organization would be willing to pay more on the distribution portion of their bill in order to improve (10 of 37) or maintain (14 of 37) the current level of power quality.

Planning Principles

- 35 of 37 Key Account customers interviewed feel that Toronto Hydro's proposed plan that is responsive to the principles outlined below seems like the *right approach* to planning.



1. Legal requirements by continuing to meet its obligations, including safety;

2. Customer feedback by:
   a) Keeping distribution price increases as low as possible;
   b) Maintaining long-term performance for customers experiencing average or better service;
   c) Improve service levels for customers experiencing below average service or who have special reliability needs (e.g. hospitals); and,
   d) Balancing other customer priorities (e.g. customer service) with the need to contain rate increases.

3. Business input by relying on expert analysis and professional judgment to develop construction and operations programs that address technical and operational requirements.

Opinion of Toronto Hydro's Proposed Plan

- 29 of 37 Key Account customers interviewed feel that Toronto Hydro should either exceed the current plan to improve services beyond what is being proposed (4 of 37) or stick with the current plan and its expressed outcomes (25 of 37). Two customers feel that increases should be below what it currently proposed, and the remaining six either provided an alternative response or don't know.

3. About this Consultation

3.1 Ontario Electricity in Context

THESL's initial round of engagement occurred before the introduction of the Fair Hydro Plan and the second round occurred in the lead up to the 2018 Provincial Election campaign. Both of these periods saw considerable public discussion of electricity, particularly surrounding price.

While this environment was challenging and participants certainly expressed view that were consistent with the political environment, they were still able to provide meaningful input into the planning issues facing Toronto Hydro.

3.2 Approach to Meaningful Consultation

Engaging customers in meaningful consultation on electricity can be a challenge.

Often customers feel they do not know enough to contribute to a consultation because of their limited familiarity with the distribution system; including how it is funded, regulated and the nature of its challenges. Others fear the combative nature of some public processes or prefer not to risk offending friends and neighbours by taking positions on issues that are sometimes controversial. Moreover, many customers simply do not pay attention and remain unaware of particular consultations that they would participate in had they been aware.

Considering both the challenge of engaging a representative group of customers and the challenge of lack of knowledge, INNOVATIVE developed a process built on five key principles:

1. Create open voluntary processes that allow anyone who wants to be heard an opportunity to express themselves.
2. Use random-sampling research elements to ensure a representative sample of customers are engaged.
3. Provide customers with the context they require to make informed decisions in a transparent manner that are articulated in real terms.
4. Create an opportunity for customers to learn the basics of the distribution system so they can provide a more informed point of view.
5. Focus on fundamental value choices. Look for questions that ask people to choose between key outcomes rather than focus on the technical questions of how to reach those outcomes.
6. Give THESL customers an opportunity to "colour outside the lines" through qualitative feedback.

As part of this engagement, more than 10,000 customers completed THESL's online feedback portal, compared to 209 as part of the utility's 2013 engagement. This increase in participation demonstrates clear progress in ensuring that customers who wish to express their views have the opportunity to do so.

One of the foundations of this customer engagement process was to provide customers the opportunity to "colour outside the lines" and raise issues that were not covered by the survey questions. The open-ended elements of the workbook and the discussion groups allowed customers this opportunity.

Finally, a specific effort was made to collect participant comments on the process itself to provide an opportunity for future improvements.

3.3 Responding to OEB Direction

In Toronto Hydro's 2015 CIR Decision, to OEB found that "Toronto Hydro's customer engagement efforts undertaken as part of the Application are reasonable as the first such effort in the context of the RRFE" but made several suggestions for improvement in the future.

It was noted that the utility had not provided sufficient context, including "*its existing benchmarking ranking and its relative levels of productivity and efficiency."* (Toronto Hydro, Decision and Order, December 29, 2015, p. 7.) In response, additional information was provided to customers in both the online feedback portal and telephone surveys. An excerpt from Toronto Hydro's *Customer Feedback Portal* is as follows:

> *Toronto Hydro's total spending is benchmarked by the OEB against other utilities in Ontario. In the last year of publicly available data collected by the OEB, Toronto Hydro's total cost per customer of $1,044 is higher than the average Ontario utility cost of $798. Those total costs are a combination of Toronto Hydro's operating and capital costs.*
>
> *Toronto Hydro's operating costs of $305 per customer are close to the Ontario average of $304 dollars per customer. The choices in the operating budget are primarily driven by technical analysis and expert assessments of best practices.*

In the same 2015 CIR Decision, the OEB commented on the timing of the utility's engagement, noting "…the results were too late to have any meaningful influence on the capital and operating plans." (Toronto Hydro, Decision and Order, December 29, 2015, p. 8.) As such, Toronto Hydro conducted this engagement in two rounds. The first round was used to provide input to THESL planners at the beginning of the planning process. This phase focused on identify needs and outcomes and establishing preferences among those outcomes.

The initial phase began in **December 2016**, roughly two months after the OEB released the Handbook for Utility Rate Applications. This timing allowed for the consultation to reflect both the 2015 CIR Decision as well as the 2016 Handbook.

This most recent engagement, which spanned approximately 18 months, is, in part, a response to the Handbook which notes, "*Planning is an ongoing utility activity, not just something that is done in preparation for a rate application. Likewise, customer engagement to inform utility planning must also be an ongoing activity* (Handbook to Utility Rate Applications, p. 12.)

Additionally, in its 2015 CIR Decision, the OEB noted of Toronto Hydro's engagement that *"…customers had not been provided with enough information to understand the impact of proposed levels of work on their rates…"* (Toronto Hydro, Decision and Order, December 29, 2015, p. 7.). In the customer engagement as part of this Application, additional effort was made to provide relevant

background information regarding investment trade-offs, including utility benchmarking, system performance and program-specific investment decisions.

Finally, Toronto Hydro implemented a new approach in the *Customer Feedback Portal* which allowed customers to not only view their customized bill impact based on their responses, but also featured a dynamic tool that allowed them to re-calculated their potential bill impact until they reached the best balance for them. This allowed for more customer control and was intended to provide additional context on the impact of proposed investments on rates.

3.4 Enhanced Customer Engagement

3.4.1 Policy Evolution

In 2012, the OEB released its "**consumer-centric**" *Renewed Regulatory Framework* (RRFE), which began a fundamental shift in the way utilities operate; moving from a focus on ***utility cost*** to ***value to customers***.

Since THESL's 2015 CIR application filing the OEB issued its *Handbook for Utility Rate Applications,* which provides additional guidance to utilities on OEB expectations the role customer engagement should play in rate application development.

A key component of the rate application process includes documenting the **active engagement** between utilities and their customers.

- Utilities should engage customers in the development of their business plans in a way that addresses identified **outcomes that are valued by customers**.
- Utilities should then engage customers on the investment plan proposed to deliver on the business plan by identifying **preferences** and **needs**.
- Utilities must demonstrate services are provided in a manner that responds to identified customer **preferences** and **needs**.

3.4.2 Gathering and Responding to Customer Feedback

To address OEB requirements set out in the *RRFE* and *Handbook* – and direction set by OEB rate decisions – THESL and INNOVATIVE developed an iterative, multi-year approach to gathering and responding to customer feedback.

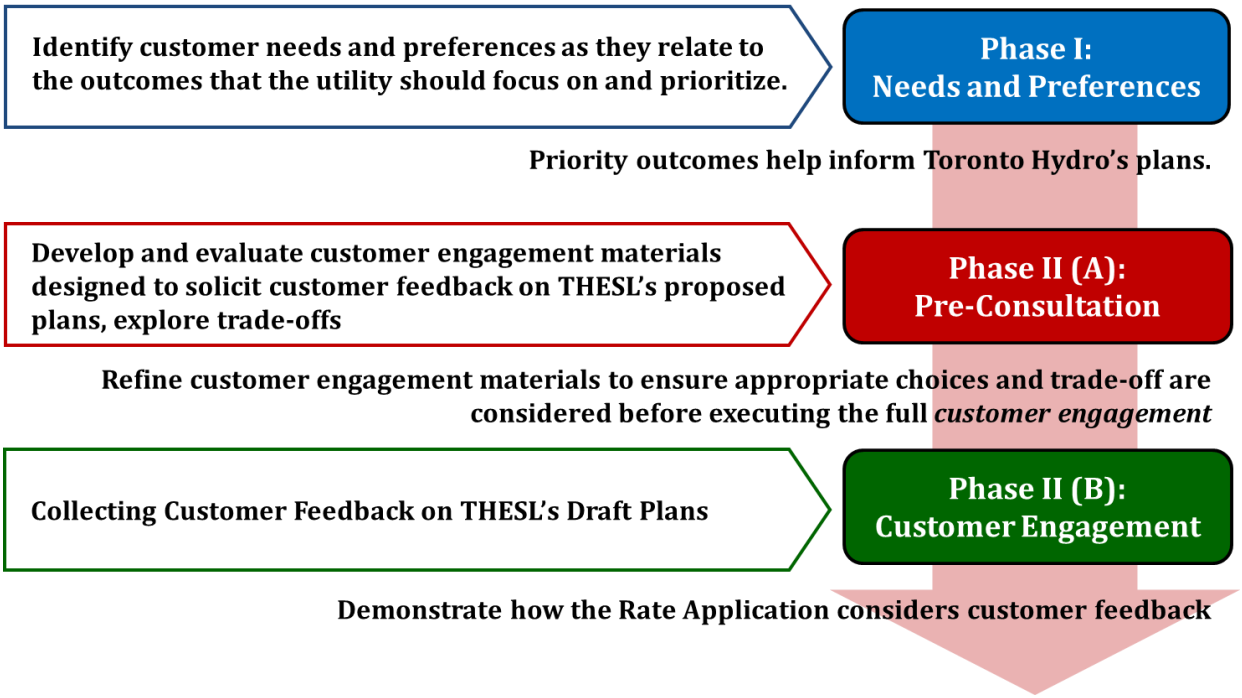
1. **Identifying Customer Priorities**: In 2016 and 2017, INNOVATIVE executed **Phase I** of THESL's customer engagement, where customers from all rate classes were consulted to develop a detailed understanding of their preferences as they relate to the outcomes that the utility should focus on and prioritize.
2. **Using Customer Feedback to Guide the Development of Plans**: In 2017, THESL used the **Phase I** customer engagement feedback to help inform Toronto Hydro's business planning, including the penultimate DSP.
3. **Collecting Customer Feedback on THESL's Penultimate Plans**: In 2017 and 2018, INNOVATIVE executed **Phase II** of THESL's customer engagement program, where it re-engaged with customers to confirm customer needs and preferences as they relate to outcomes in **Phase I**. This round of engagement was able to solicit customer feedback on

THESL's proposed plans, and explore trade-offs in relation to specific programs and the associated bill impacts, as well as the pacing and prioritization of investments.

4. **Re-Examining the Business Plan and DSP**: In 2018, THESL revised the utility's business plan and DSP in response to **Phase II** customer engagement feedback as part of their OEB requirement to demonstrate how customer feedback has been considered in the development of their **2020 CIR Application** before filing with the OEB.

3.4.3 Consultation Process Overview

The diagram below provides an overview of INNOVATIVE's multi-phased customer engagement process, designed to support the consultation requirements of THESL's 2020 CIR application. This customer engagement program was designed as an iterative process where each subsequent phase of the consultation built on learnings from previous phases and the components within.



1. **Phase I (2016-2017)** set out to identify customer needs and preferences as they relate to the outcomes that the utility should focus on and prioritize. This was executed using a combination of both qualitative and quantitative research methodologies. In addition to engaging low-volume, mid-market and large use customers, INNOVATIVE also conducted a series of in-depth interviews with stakeholders who represent a cross-section of views from various customer groups.

   This first phase of the customer engagement provided THESL's information to help inform Toronto Hydro's business planning, including the penultimate DSP.

2. **Phase II (A) – Consultation Materials Design and Evaluation.** The next phase of this process was to develop and evaluate customer engagement materials designed to solicit customer feedback on THESL's proposed plans, and explore trade-offs in relation to specific programs and the associated bill impacts, as well as the pacing and prioritization of investments.

   Following the development of THESL's penultimate DSP, INNOVATIVE began the process of translating detailed financial and technical documents into customer-facing consultation materials. The developed customer consultation materials took the form of an online customer feedback portal.

   Customer testing focus groups were conducted before the launch of the online customer feedback portal. These focus groups were intended to ensure the portal used language that was accessible to customers and that it provided an appropriate amount and substance of information, in order for customers to provide an informed opinions on THESL's proposed plan.

3. **Phase II (B) - Customer Engagement**. The next phase of the customer engagement integrated research-based consultation tools, with traditional voluntary-based tools. The online customer feedback portal provided an opportunity for customers who wished to participate in the consultation to have their say. This process also provided a clear understanding of needs and preferences across the broader customer base. This final phase of the customer engagement was divided into two components:

   - **Qualitative Component**: An online workbook allowed us to determine the range of views held by THESL customers regarding the plan and trade-offs.
   - **Quantitative Component**: Randomly recruited telephone surveys of residential, small commercial (GS < 50 kW), and mid-market (GS > 50 kW) customers and an online survey of large use (Key Account) customers was the final step in the consultation process. Randomly recruited surveys allow for generalizable conclusions that can be applied to the broader population of THESL customers. The surveys were developed based on the feedback from the online customer feedback portal. Incentives were used to allow for a longer survey which allowed more topics to be covered.

APPENDIX 1.1

Low-Volume Customer Focus Groups

March 17, 2017

Prepared for:

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Low-Volume Customer Focus Groups

Following our iterative research process, the low-volume focus groups were designed based on feedback collected from internal staff interviews and the literature review of previous customer satisfaction research.

Objective: Using an exploratory research methodology, our objective was first to understand the customer journey, from initial contact (typically account initiation or transfer) through to the various other touchpoints customers typically encounter.

Our second objective was to obtain insights into what customers expect of Toronto Hydro, particularly in terms of what represents value to customers and what customer priorities for Toronto Hydro are, both in context of valued outcomes and choices impacting customers.

1.1 Methodology

Four focus groups were conducted on December 5 and 6, 2016, in Downtown Toronto at Consumer Vision (5th) and at the Westin Hotel North York (6th), recruited by Innovative Research Group. Respondents received a cash incentive for participation. On both nights, the first group was of low volume business customers and the second of residential customers. In the business groups, a mix of ages, genders and business types was obtained. In the residential groups, an even mix of ages and incomes, as well as an even split between house and condo dwellers, was obtained. In general, for the Downtown groups respondents were recruited from south of Eglinton, and for North York groups respondents were recruited from north of Eglinton and east of Yonge, extending north of the 401 and east into Scarborough.

We deployed a detailed *Discussion Guide*, used to moderate all four focus groups. In group 2, a verbal primer was employed early in the session to give basic contextual information on Toronto Hydro and the electrical system overall. In groups 3 and 4 a printed primer was employed to give more formal and consistent contextual information.

The show rate was high, averaging 6 to 8 respondents in each group.

This memo summarizes key findings, and offers observations and potential strategic avenues based on these groups and past research. We are pleased to discuss these findings in greater detail, if desired. *Respondent verbatim responses are in italics.* In general, our approach in reporting is to allow the respondents to be heard as much as possible, utilizing representative verbatim comments, offering interpretation and comment where necessary. Where a respondent comment is specific to an ethnicity or gender, it is so noted. Overall, there were few differences between respondents or groups, so we have chosen not to identify verbatim by group, customer type or gender, so that interpretation is not unduly biased.

Please Note: Qualitative research does not hold the statistical reliability or representativeness of quantitative research. It is an exploratory research technique that should be used for strategic direction only.

A note on interpreting focus groups findings: In focus group research, the value of the findings lies in the *depth* and *range* of information provided by the participants, rather than in the *number* of individuals holding each view. References in this report such as “most” or “some” participants

cannot be projected to the full population. Only a large sample, quantitative survey would be accurately projectable to the full population.

1.2 Customer Journey

1.2.1 Initial Point of Contact

For both business and residential customers, the initial point of contact on the customer journey was at the connection point to initiate an account. In almost every case, this was to transfer an existing account or change billing name on an account being taken over. In general, this happened by telephone, although for many, the contact was not direct as a landlord or lawyer may have handled the account transfer, so the true initial point of contact was receiving the first bill.

Other points of contact cited by respondents included:

- Information inserted in the billing
- Representative entering residence or business to read meter
- Service technician on site for electrical system upgrade
- Safety issue – phone contact or field contact
- Security issue – billing scam, phishing scam
- Usage/conservation inquiry
- Closing account
- Subcontractor issue - inspection
- Payment issue – billing anomaly or disconnect issue
- Online contact – for information, or account activity

Verbatim customer quotes included:

> *"When I joined the company it was already connected."*
>
> *"It was 22 years ago, so I would have started by opening an account in person."*
>
> *"They reached out to me about a tenant default,"*
>
> *"About a power outage."*
>
> *"Disconnect and reconnect in a system upgrade."*
>
> *"Somebody contacted me about unpaid bills, it was a scam, so I contacted (Toronto Hydro) and they confirmed it was a scam."*
>
> *"They contacted a few years ago to come in and install high efficiency bulbs."*
>
> *"A call to hydro to set up the account."*
>
> *"I live in an apartment building, so my landlord set it up."*
>
> *"I called them to set up account details, it was uneventful."*
>
> *"I haven't had any contact other than the bills."*
>
> *"I came back from vacation and forgot to pay my bill, so they had disconnected me."*
>
> *"They gave me some information on using my cooker at night to save money."*

1.2.2 Customer Expectations

Frequently cited expectations of customers fall into the following broad descriptors:

- Human contact
- Acknowledgement
- Friendly customer contact
- Information
- Swift service, reasonable service standard (timely response)
- Ease of access, alternatives for access
- Proactive information, information actionable to the customer
- Reliable, organized, clean onsite service

In general, for most, Toronto Hydro met their service expectations at every point of contact. Toronto Hydro was felt to be very professional in customer service. Customer verbatim included:

> *"They pretty much met my expectations"*
>
> *"They broke down the bill and rates quite well, they explained it well and gave me good advice"*
>
> *"I have no problems; their service has been fine."*
>
> *"I think they are pretty good."*
>
> *"My contact has been very professional."*

Where there were perceptions of expectations not being met, two factors emerged: first, that the misalignment of expectations and service outcome was situational and circumstantial, and second, that the perception may have been fueled by anger over electricity bills that was not necessarily focused on Toronto Hydro, but the electrical system overall, and was largely due to a desire, rather than an expectation, for which no outcome at that point of contact was possible. Further, lack of understanding had significant impact on those perceptions.

> *"My expectations depend on the circumstances."*

1.2.3 Outages

Outages were the top point of discussion. There was significant distinction made between outages which are broader and event related, such as the' 2012 ice storm', and those which are what respondents considered 'system' related – outages due to infrastructure failures or random, yet commonly occurring events – such as a tree falling down. Respondents considered ice storm level events 'Acts of God' and had more communications expectations than restoration expectations, or were inclined to be more forgiving with these events.

However, respondents frequently noted that not all weather related events fall into this category, with many falling under 'day to day, common' event categories – where the expectation is that Toronto Hydro should be well prepared for such events, or even that infrastructure should be robust enough that such outages rarely occur.

Overall, outages were seen as a very significant issue to business owners, citing the impact on their revenues and costs. The expectation, however, was less on reduction of outages than it was on giving businesses more ability to take appropriate actions when an outage occurs. The base expectation is that Toronto Hydro is aware of the outage and is taking action. Business owners were looking for a reliable *estimated time of response* (ETOR), so that they can make decisions on their

own resources - sending staff home, closing for the day, avoiding spoilage, or taking any other possible actions. None had an expectation of absolute certainty or a very specific time or length – they simply wanted information at a level where they could make business decisions. To an extent this was also true of residential respondents, a number of whom work from home. Outages for residential customers also had impact on child care and care of elderly residents.

Respondents often brought up a distinction between what they felt were 'planned outages' and unplanned, 'event driven' outages. The former they saw as outages that were scheduled by Toronto Hydro for maintenance, upgrades or other reasons – and were known in advance, and likely had known durations. In these cases, respondents felt that advance notice is an expectation and a firm ETOR as well.

> *"In my business, I am looking to know they are acting on it (power outage)".*
>
> *"I need to know a time frame in a power outage, a range, so I can make decisions right away."*
>
> *"Looking to know local, at a granular level."*
>
> *"I expect that customers will be compensated for any outage."*
>
> *"If there is a default based on the system rather than a weather event it should be compensated."*
>
> *"I want acknowledgement and an expected time frame, so we don't keep employees around for nothing."*
>
> *"I expect that they know about it and are fast."*

A few respondents in each group brought up an expectation of compensation for outages. Others dismissed that notion as impractical, but regardless, the notion expressed was primarily based on an expectation of acknowledgement and empathy more than tangible consideration.

Whether the outage is local, defined typically as their home or workplace and adjoining buildings; or their street, or broader based significantly affected expectations on information. If it is very local, respondents tended to have expectations that were also very local – based on their own interests, but when the outage is broader or extends out of the local area, respondents tended to have less personal expectations and looked at the outage in broader social terms.

> *"I just want to know (in an outage) what to do next – will it be 5 minutes, 5 hours or 5 days?"*
>
> *"Just want a window."*
>
> *"Because I work at home, an outage can be very disruptive. I need to manage my day."*

There was some mention of contacting Toronto Hydro during an outage. For most, there was an understanding that such situation often overload customer service. But for some, what was missing was a human element. Most, however, were simply looking for enhanced tools – mostly online – to allow them to manage their own expectations and take any necessary actions.

> *"Anytime I had contact about an outage I got a busy service, there was no human contact."*
>
> *"Want to be able to go online for outages by postal code."*
>
> *"Can we get an email or text message about an outage, especially when I am out of town."*

In the North York groups, both business and residential respondents cited more frequent, short term outages than did downtown respondents. In both downtown and North York groups, some respondents, based on personal experiences either first or second hand, felt that some areas of the

City received favorable treatment in terms of priority in a widespread outage. At the same time, many respondents identified that restoring power as quickly as possible to the greatest number of customers should be the priority.

> *"In my area (Don Mills) we have regular power outages. They should figure out why we have so many outages."*
>
> *"With outages, it is just managing expectations."*

1.2.4 Billing

Respondents had clear expectations on billings and the account process. They desired a reasonable service standard in terms of phone response time, which they generally felt was met; easy to understand billings, which they felt was not met (but not entirely a fault of Toronto Hydro); and many were starting to look to migrating account activities online, where their expectation was of a very simple process that respected their time and provided information on what the next steps were for a customer in terms of payment and confirmation.

Most desired more information on the items being billed. Few, if any, respondents understood their bills are many focused on the delivery charge as a main element where understanding was lacking.

Overall, what respondents wanted in terms of information on billing could be described as twofold – information that could be used to identify the root causes of perceived high electricity bills, and proactive information tools that allowed them to – or gave a feeling of – being able to act on their electricity costs. One frequently mentioned suggestion was to break out electricity bills by component company.

In terms of customer contact with Toronto Hydro, most felt the phone contact was friendly and professional. Many felt that, in their contact with Toronto Hydro, they received useful and relevant advice. The few who cited negative experiences or perceptions largely formed these from situations of non-payment or a billing conflict. Their expectation in these cases could be best described as looking for more empathy or understanding of their situation.

> *"I can get my personal bill by email but not my business bill."* (A misconception but a perception held by several business customers)
>
> *"The bills are not in layman's terms, I don't understand them. The bills are not approachable."*
>
> *"I have to learn about this by word of mouth"*
>
> *"When I was away, I came back expecting the bill to be zero, but it had spiked on one day, and they couldn't explain it to me. They kept trying to convince me someone must have been in my house. They wouldn't take me at my word, but I understand that is a big ask."*
>
> *"A small gesture would have created a lot of good will,"*
>
> *"A breakdown of that delivery charge would be appreciated. I know there is Hydro One in there and other people getting a piece."*
>
> *"These rate increases might not even be Toronto Hydro, it could be these other people."*
>
> *"It would be better to get information from Toronto Hydro on where money goes than from the newspapers."*
>
> *"Even billing, spreading out over 12 months would be helpful, like Enbridge."*

"I want information on what the process is, what my next step is in terms of paying, and what the business responsibilities are."

"I should be able to do all the setup and information entry online, and there should be a confirmation process in return."

"The website has to be very easy to follow. Small businesses don't have time to sit in front of a computer."

"I want to be able to call in, and get someone quickly. If there are one or two steps, fine, but more, it is too much."

"I want to be able to call and they have the business history quickly available."

"They should rename the delivery charge." "I don't understand the delivery fees."

1.2.5 Information/Conservation

Across all groups, there was a frequently expressed desire for more 'tools', primarily seen as online or mobile, to enable customers to better manage their consumption and costs. Behind what was commonly expressed was a desire for Toronto Hydro to enable and empower customers with actionable information, at a day and time usage level.

Customers generally felt that they had no options on electricity provider, or in many cases – particularly businesses – on usage. Providing proactive information that empowers customers could mitigate this significantly.

Items that are proactive – daily usage tools, alerts for anomalous usage or spikes – were often mentioned across groups.

"I need more tools to manage my costs"

"I don't have time to look into conservation. The business doesn't have any options (on usage) as it is all peak time."

"I would be really interested in finding out daily usage. I didn't know you could get it online; that would make me sign up online."

"Having unusual usage alerts would be good."

"I would want more tips, but not just for homeowners, for renters too."

1.2.6 Service/Field Interactions

Expectations on service calls and field interactions were primarily functional in terms of being clean, timely and accountable for their work. While there were few respondents who had service technician or other field interaction, most were noted as being positive. The expectations were where the customer felt that their problem was not resolved and Toronto Hydro was seen as not taking responsibility for resolution.

Some business customers noted instances where Toronto Hydro attended their workplace to install energy saving fixtures or upgrades. These were viewed positively, as Toronto Hydro being proactive.

"I expect them to show up on time, be organized, clean up after themselves, and do the job quickly. I can't say they didn't meet my expectations."

"I expect them to take accountability for their mistakes and not blame the customer for any problems."

"But I do appreciate them coming in and showing me ways to save money. Guidance."

"Warnings on old systems and upgrades, improving service from internal systems to reduce downtime."

1.2.7 Customer Choices

In every group, there was mention of Toronto Hydro being a monopoly and the customer having no choices in supplier. This came up as a perception that affected many respondents' attitudes on customer service, as those inclined to have weaker service perceptions also tended to express emotions related to lack of choice. There were no specific incidents or encounters that formed this perception, however, indicating that the true need expressed was again to obtain some empathy and acknowledgement on what they saw as burdensome electricity costs. Customers who held this view were voicing a sense of not having an outlet for their feelings, rather than a concrete desire for any structural change to the electricity market.

"There are no choices, so they don't have to be more customer friendly."

"They are just like the TTC, you don't have any options so they just don't care."

"Maybe they should have an ombudsman to take care of any concerns."

"I just want to be treated as a person."

1.3 Emerging Issues and Priorities

Frequently identified issues and associated priorities were consistent across all groups, and can be described as:

- Price increases
- Infrastructure – upgrading, preplanning
- Demand – population growth, lifestyle changes, technology, electrification of transit
- Climate change
- Capacity
- Disruption due to technology – storage
- Alternative power – solar, wind
- Social shifts – lifestyles, employment, business
- Economic impacts of pricing and investments

Over-arching and coloring attitudes and perceptions of future issues and expectations in electricity, and perceived value and priorities, was concern about future costs. Overall, across all groups, respondents placed choices through a lens of what would impact future prices, and in relation to other issues and shifts they saw on the horizon – in how they live; and socially and technologically.

Some were immediate impacts such as an imminent carbon tax. Other were demand based on the horizon – electrification of transit, increased household demand through increased adoption of technology, and population growth demands.

Electrification of transit was seen as threatened by electricity rates. Technology adoption was seen as a source of higher electricity use, and higher bills purely from usage. Growth was seen as both a source of higher costs, as more infrastructure and replacement of older infrastructure would add to rates, but also a reliability issue and an issue of innovation.

"How can they ensure with carbon tax coming in that people can even afford hydro?"

"With a coming jobs crisis what are they doing to get rates down?"

"Electric cars will be a big new demand but the price is (making them) unaffordable."

"With electric cars coming in, we are really going to be in trouble."

"We can't have electricity so high that we have people who can't afford electricity."

"There has to be a break point in what they invest in where rates don't go up higher."

Although perceived high rates and fear of future rate increase was predominant across all groups, when individual written 'intervention' exercises were introduced, the consideration set expanded considerably and price was not necessarily the top consideration. Most were open to accepting some level of cost increase, with conditions. The prime consideration was broadly cost effectiveness, seen as ensuring – or providing some level of validation – that Toronto Hydro is, itself, operating to be cost effective operationally, and that cost increases go towards the areas that customers are most concerned with.

"I am willing to accept higher rates for investments if they result in lower rates in a few years."

"I understand rates will keep going up. It is a question of whether those increases are going to investments, in reliability, renewables and so on, or not."

1.3.1 Reliability

Reliability – reducing outages, which to some was eliminating outages altogether – was seen to be a required core value. However, on probing, most identified this as an infrastructure issue primarily driven by perceptions of aging equipment and growth in demand. To most, reliability overall trumped cost, electricity being seen as a necessity of life and business. However, there was low value placed on achieving higher reliability for most – as in general, with the exception of some North York customers, reliability was seen as quite high, and the infrequent minor inconvenience was not seen as less important than keeping costs low. At the same time, respondents distinguished between those minor, infrequent outages and outages from infrastructure deficiencies, which they felt needed to be addressed as they were seen as having broader ramifications.

"The infrastructure is weak, resiliency of the network is weak."

"Electricity is something we can't do without. We have to minimize downtime."

"Minimize downtime, but don't raise my bill."

"The priority is to spend more of the part that goes to Toronto Hydro on infrastructure and reliability and not raise costs."

"Concerns about the durability of the grid."

"High reliability at minimum cost to customers – reliable and affordable."

"It doesn't matter if we provide a cheap source of electricity if it isn't reliable."

"You can have a very low price but it doesn't matter if there is no reliability."

"Elimination is ideal, but reduce it so it doesn't happen from old equipment but from specific events."

"Investing in reducing outages should result in savings that trickle down to me."

"I don't have a problem with outages so that doesn't create value for me."

"They have been doing the infrastructure, but look at internal costs like salaries."

"There are only two points to this. One is better, bigger, faster, The other is costs, costs, costs."

1.3.2 Value for Money and Balancing Trade-Offs

Overall, across all groups, "value" was seen as achieving balance between investments that might have short term rate impact but would yield longer term cost containment. Customers, both business and residential, often felt that growth in demand came primarily from the pace of condo development, and were inclined to believe that this demand was being forced on them as ratepayers, without the developers paying what was perceived as their 'fair share'.

Respondents also felt they did not have sufficient information on the sources of rate pressures. This was typically seen partly as being able to assign 'blame', but also as fulfilling or alleviating an unformed perception on internal spending.

Yet respondents generally took a long term view of value, feeling that making reasonable investments over the short term may raise costs to ratepayers, but may bring longer term benefits that include either reducing rates or mitigating future increases.

However, it was also seen that Toronto Hydro had limitations on its ability to be more efficient.

"Value for money has also to do with the balance between paying high wages and spending on infrastructure. All our concerns have to do with infrastructure and distribution, but value also has to do with how they spend money internally."

"The priorities should be the ones that have the most direct impact on costs."

"I need to know where the source of the cost increases is coming from, like OPG not Toronto Hydro, so I can put that where it deserves."

"The reason we pay so much isn't Toronto Hydro, it's OPG and Hydro One."

"Find ways to make condo developers pay more for infrastructure."

"How much do these condos pay to fund capital investment?"

"The customer bears a lot of costs, as does Toronto Hydro, for someone else or someone forcing it on them."

"I don't think industrial or condo developers are paying for the system upgrades they cause."

"Toronto Hydro openly admit they can't fill the new demand from all these new downtown condos. But the condo developers should pay, not regular customers."

"Long term, modernizing infrastructure will pay for itself."

"I would like to see them look within the company on how they can save money."

"We pay a lot of money. Yes, we have to invest. But we just can't keep increasing the rates."

"We don't know if costs are too much because don't know where the money goes. "

"Presumable if infrastructure expands that should bring the costs down eventually."

"The 10 year goal should be to invest in ways that reduce bills."

"Being Toronto only, there is no ability to gain economies of scale that would benefit the customer."

Balancing reliability and cost was consistent across groups. Reliability was viewed as an asset management issue – balancing new investment to meet future demand and replacement of aging equipment to increase reliability. While 100% reliability was seen as an ideal, most felt that the cost of achieving that was not a priority.

"Reliability is an asset management problem – the balance between investing for new demand and increasing reliability on existing lines."

"Sometimes in business there is nothing you can do to manage usage, so reliability is most important."

"You can do all these things if you throw a lot of money at them, but you can't make the costs so high that nobody can afford them. So, value for money might not be the latest technology."

"Meeting demand that is coming up is most important to me, with less power outages."

"Reliability is good right now. Whatever happens on other fronts, reliability can't go down. It is low on the priority list, particularly in terms of costs."

"I think the current level of redundancy is fine and I wouldn't expect them to spend to increase it."

"A 2% increase in reliability isn't worth any cost increase."

"If we are at, say, 95% reliability now, it is a question of how much it would cost to get to 99%."

1.3.3 Demand and Growth

Respondents uniformly saw increased demand placing pressures on the electrical system from three primary sources:

(1) lifestyle, from increased use of technology,
(2) climate change, from increased need for air conditioning as well as increasing climate related events, and
(3) population growth.

Respondents did not place personal value on these challenges, other than expecting Toronto Hydro to have a plan in place and appropriate support systems to ensure this demand is met.

"In our ecosystem, climate change is causing increased demands."

"There are more devices using electricity so the demand is always going up."

"Is there a system in place to support all the new development?"

"Need to support future growth."

"There should be a framework in place for major events to be ready."

1.3.4 Environmental

'Clean energy' and environmental concerns did not come up unaided from respondents, itself indicative of lower concern. In part this was because respondents did not view this as an area completely under Toronto Hydro's control or mandate. However, when prompted, respondents identified green energy and clean energy sources as an emerging issue, albeit without clear needs from Toronto Hydro.

> *"Environmental – ratio of clean to dirty power."*
>
> *"I put environmental last on my list as I felt it is more an OPG issue than Toronto Hydro, so I felt other issues are more important."*
>
> *"Focus more on green energy alternatives."*

1.3.5 Innovation

Respondents identified the emergence of alternative energy sources as both an opportunity and threat. The threat identified was in perceived future ability of businesses and residential customers, through solar power, to generate their own electricity – and by doing so, disrupt the current electrical system by having less 'system generated' electricity to spread infrastructure and utility costs over. The opportunity was seen as alternative energy sources giving customers the ability to control their costs.

Many respondents also cited the need for innovation to match how the nature of employment and business is changing. Many business respondents saw the notion of peak usage becoming outmoded, as employment patterns shift from traditional models to more flexible, remote or other models.

> "Decentralization of power sources will be disruptive to their business model."
>
> "What's going to happen when more people go to solar – and demand decreases? Will rates go up even more?"
>
> "Peak use changing as the way businesses operate change."

1.4 Identified Outcomes

Across all groups, respondents identified a similar set of desired outcomes from Toronto Hydro. Their ranking of those outcomes in terms of importance was also very consistent, and in order of importance cab be described as:

- Reducing prices
- Enhancing reliability
- Ensuring safety – for both employees and the public
- Responsiveness to customer concerns, ease of access
- Tools to enable consumption management
- Community partner

1.4.1 Inter-related, programmatic

Overall, respondents across all groups had similar priorities for Toronto Hydro. Overall, safety was the top priority, seen as an over-arching value that took precedence over any other factors. Safety was largely seen as table stakes in this context, which respondents assumed was always a core outcome.

Price was a secondary, over-arching priority. Respondents across all groups felt that price impact must be top of mind in every activity Toronto Hydro proposes or undertakes. However, price concerns did not restrict the consideration set – respondents had priorities that ranked ahead of price, but with the condition that price impacts must be minimized or justified adequately.

So the priorities were all seen as inter-related and forming part of an overall program that had safety and price as over-riding considerations or table stakes that had to be satisfied, but were otherwise strongly related to one another.

> *"All these points you listed are inter-related."*
>
> *"I don't think we should have to choose. They are accountable for all this."*
>
> *"We should invest in green energy, but we can't do that without proper infrastructure in place."*
>
> *"If we say that catastrophes are more important than day to day outages, we will see a decrease in service on day to day."*
>
> *"The consumer simply can't pay a single penny more."*
>
> "*Increasing costs to businesses hurts the consumers more because I just pass that on by raising product prices."*
>
> *"First priority is reliability and second is price."*
>
> *"First is reliability, second price, third environmentally sensitive."*
>
> *"Cleaner and more reliable are the priorities."*

Power quality was not seen as an issue or priority among low-volume customers.

> *"I would be surprised if anyone notices any [power] quality differences. It's not an issue anymore."*

1.4.2 Safety

Respondents placed high value on safety, seen as safety of Toronto Hydro employees and safety of customers, both within their homes and workplaces and externally, on the streets or in public.

> *"Safety is the top priority. Not just about me, more broad, socially."*
>
> *"Safety is expected as a bare minimum. If they can't manage their equipment safely, they have no business running the system."*
>
> *"If you are reliable then you should already be safe."*

Safety was seen by all groups as the top, over-arching priority. It was viewed as both a core value and a pre-condition – safety was something seen as an attribute that permeates every other aspect. Respondents were unanimous across groups in expressing that safety comes before everything else, even price.

1.4.3 Innovation

Respondents identified investment in innovative technologies as a high priority. This was seen as having short tern rate impacts that were justified by longer teem benefits to customers, both in terms of enabling them to obtain lower cost energy, and in terms of conservation and environmental benefits.

The integration of renewables with traditional sources was identified across groups as a high priority. Investing in storage technology was seen as having significant long term benefits and as having the potential to meet increased demand while both lowering costs and possibly alleviating part of the infrastructure challenges.

Respondents believed that Toronto Hydro had a role in incentivizing adoption of innovative technologies that enable conservation and better customer usage management.

> *"It would be interesting if they were looking at storage with solar and wind."*
>
> *"Something some companies are doing is getting into stored power. Toronto Hydro should look at innovations to meet demand peaks."*
>
> *"Invest in innovative infrastructure."*
>
> *"Incentives for conservation innovations, like solar shingles."*
>
> *"Integration of off grid sources & renewables."*

1.4.4 Customer empowerment

Empowerment adds value and significantly abates rate founded emotions. Enabling usage management was identified as a priority that created significant value for both business and residential customers. This was seen as providing tools, online and mobile, that enabled real time, granular level usage information – even longer term, usage at an individual appliance or source level. Many residential customers suggested pro-active tools – mobile alerts for usage anomalies and outages, for example.

All saw value in creating tools that empowered customers to manage their own usage, and saw these as cost savers with a benefit in excess of any added costs to implement.

> *"Look at more online ways to help me monitor my usage and costs."*
>
> *"I can do my banking on my phone, I should have something like that for electricity on my phone."*
>
> *"They could have proactive tools like alerts that tell me when I am doing something costly or inefficient."*
>
> *"Continual education reminds me to do things that save money."*
>
> *"Tools for conservation, like online tools, are needed."*
>
> *"There should be more detailed, day and time information."*
>
> *"They provide more information on usage to household than businesses."*
>
> *"There should be an incentive like programs to save."*

A few residential customers were aware of tools online in their customer account that provide daily usage information. Business users were not aware of such tools, and felt that there was more focus

on information to residential than to business customers. Some residential customers suggested creating programs that provide some incentive to reduce consumption.

In terms of the billing and account process, respondents also saw these as communications and empowerment issues – they valued ease of access, particularly through online tools, that gave them easy and quick access to their accounts, to setup an account or make changes, and to obtain responses from Toronto Hydro on outages, billing concerns and conservation tips.

1.4.5 Communication is key

Enhancing communications, particularly with ETOR but also pro-actively with usage and monitoring tools, was seen across all groups as a priority and creating value. Communications was seen as a key and over-arching service element. It touched on every aspect of the customer experience, and in fact formed perceptions on reliability and largely mitigated potential sources of dissatisfaction.

Respondents expected Toronto Hydro to operate through the customer lens, and this was seen throughout as a matter of having empathy for the customer and looking at service, as well as investment priorities, in terms of the pressures and changes customers are experiencing in their lives and businesses.

> *"Service is parts of everything – reliability, communications, improving infrastructure is dependability, but also the price."*
>
> *"People will pay more…slightly more…for improved service, communications."*
>
> *"Communications is ahead of reliability."*
>
> *"It comes back to what the mission of Toronto Hydro is."*
>
> *"Maybe they have a CEO mindset but they need to look at priorities through the customer mindset."*

Respondents across groups saw customer service as communications. Overall, as there were few gaps identified in customer service other than specific, isolated instances, what respondents prioritized in customer service along with 'empowerment' tools was responsiveness and having a sense that customer service is at the forefront. For example, most respondents saw being more responsive to communicating with customers on outages as a higher priority than reducing them. Similarly, most saw enhancing communications on conservation and usages as a higher priority than simply reducing costs or maintaining current rates.

> *"Being a community partner means being responsive to customer concerns."*
>
> *"Being responsive to customer concerns is actually a reliability issue."*
>
> *"It is a customer service industry so customer service comes first. Proactive response not reactive."*

1.5 Measuring Outcome Success

While customers have strong opinions on how they want Toronto Hydro to focus its efforts in terms of customer outcomes, few have concrete suggestions on how Toronto Hydro should measure successful delivery of such outcome.

Overall, measuring success was seen by customers to be reflected on their bills – keeping cost increases at a minimum.

More broadly, respondents saw a strong measure of social responsibility in Toronto Hydro's mandate and an opportunity to lead. Social responsibility was typically defined as both how Toronto Hydro treats customers with difficulty paying their bills, for which there was more of a need for empathy than for abatement, and at a higher level, in Toronto Hydro being seen as having a significant city building mandate.

> *"The measure of reliability is avoiding stories about major outages in the media."*
>
> *"Measure of success is on the bills."*
>
> *"Faster and more coherent response to outages, better communication, showing what that 25% is doing."*
>
> *"Successful is in how the public feels about Toronto Hydro, whether people feel they are being listened to."*
>
> *"It shouldn't be about a business, it should be about improving our city."*
>
> *"There is a social responsibility embedded in Toronto Hydro, they should be a model for other companies."*

1.6 Preferred Customer Engagement

Overall, both business and residential customers identified a need for simple information that enabled them to have a better understanding of how the electrical system works and on where money is spent to make a meaningful contribution to a consultation.

More specifically, respondents wanted cost breakdowns, and information on the costing and cost impacts of the elements of Toronto Hydro's plans.

While many stated that the preferred vehicle for a consultation is online, probing revealed that, in fact, customers preferred a format where they could be given information, perhaps in a video format, and survey type questions they could respond to once they have suitable information.

No one preferred public meetings.

Some residential customers were cynical about the consultation process, feeling that it would have no impact. This was not, however, a majority view. In fact, many respondents wanted to ensure that a broad cross section of views were collected, including low income customers.

> *"Do a survey."*
>
> *"I need to know how many low-income customers they have, we need to look at whether they are consulted."*
>
> *"Public meetings are a terrible way to get feedback."*

"I like a workshop online, with information and questions."

"Need financial information, like budgets and cost breakdowns."

"Need to know why this and not something else, why they need this plan and not some other plan."

"I don't think anything would change their plans."

"What are my options?"

"Need to know the whole chain of how they operate, every aspect and the costs."

"I need to know how they propose to address alternate energy, increased demand, price increases and so on."

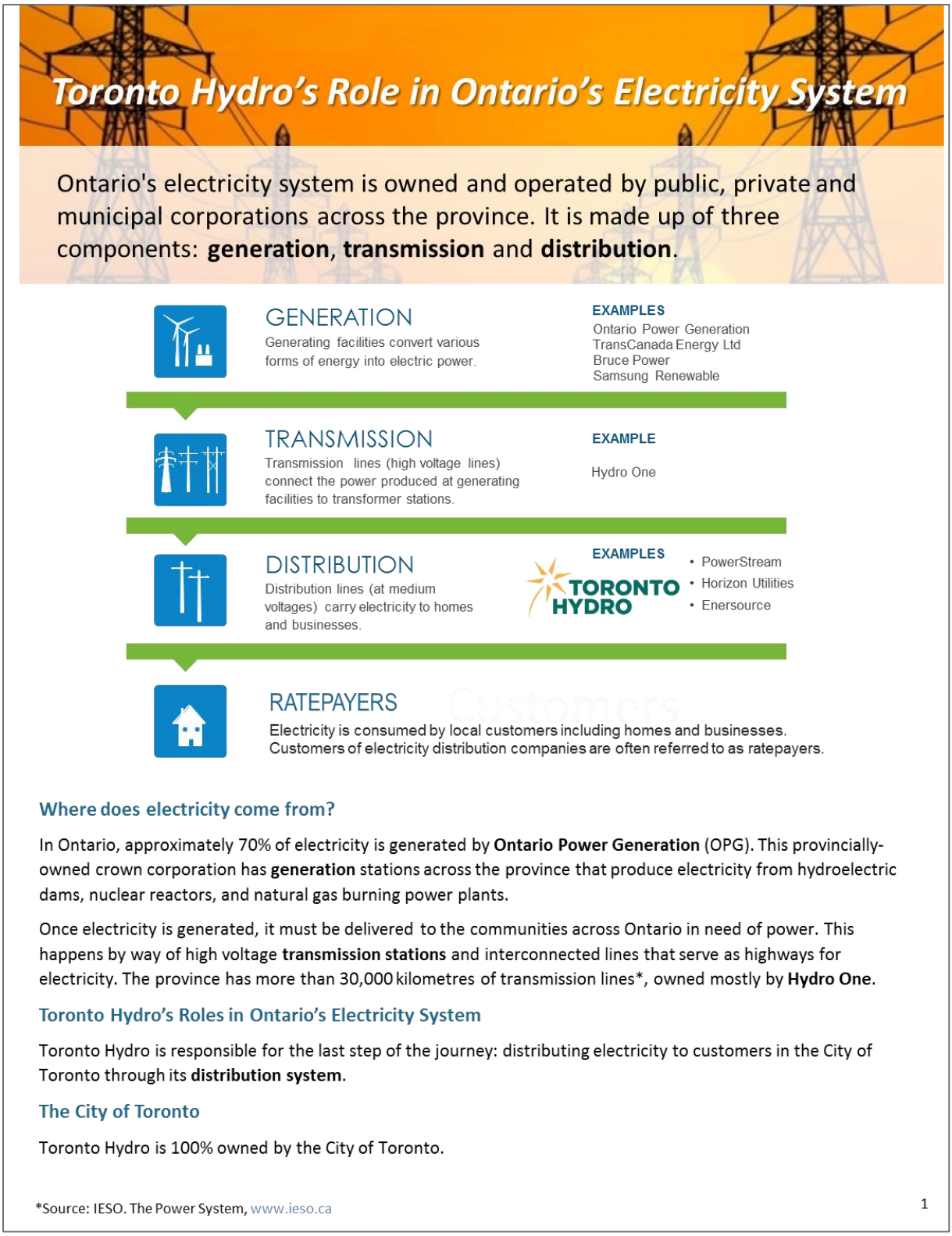
"I would like a video on how Toronto Hydro operates."

"Give some information like this in the bills, and then I could go online for more information on each topic."

"I need to know what the options are on each priority and the impacts on costs and longer term impacts."

1.7 Focus Group Appendix

The following two-page background primer was used in the second night of THESL's residential customer focus group in North York. A similar version of the primer was used with GS customer in North York as well.



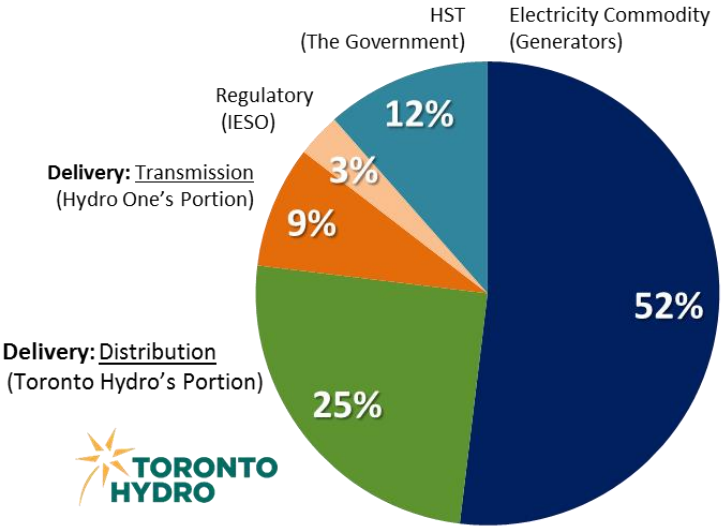


Electricity Bills:
Understanding where your money goes

Your Electricity Bill: Every item and charge on your bill is mandated by the provincial government or regulated by the OEB. There are two distinct cost areas that make up the "Delivery " charge on your bill: ***distribution*** and ***transmission***. While Toronto Hydro collects both, the transmission charge is remitted to Hydro One. The distribution charges include the portion of your bill that Toronto Hydro keeps, as well as some other "pass through" charges, most of which are remitted to the IESO. The distribution charges which Toronto Hydro keeps make up about 25% of the typical residential customer's (750 kWh per month) total electricity bill.

Toronto Hydro's distribution rates are subject to the review and approval of the OEB. The distribution fees collected from customers cover Toronto Hydro's capital investments and operating expenses.

About 25% of the average residential electricity bill goes to Toronto Hydro. The rest of the bill goes to power generation companies, transmission companies, the government, and regulatory agencies.



SAMPLE RESIDENTIAL MONTHLY BILL
Toronto Hydro-Electric System Ltd.

Account Number:
000 000 000 000 0000

Meter Number:
00000000

Your Electricity Charges

Electricity	
Off-Peak @ 8.700 ¢/kWh	42.41
Mid-Peak @ 13.200 ¢/kWh	16.83
On-Peak @ 18.000 ¢/kWh	24.30
Delivery (Toronto Hydro $40.23)	53.94
Regulatory Charges	4.92
Debt Retirement Charge	0.00
Debt Retirement Charge exemption saved you $X.XX	
Total Electricity Charges	**$142.40**
HST	$18.51
Total Amount	**$160.91**

How are electricity rates determined in Ontario?

The electricity industry in Ontario is regulated by the **Ontario Energy Board** (OEB). One of the OEB's roles is to review the distribution plans of all electricity distributors and set the rates that they can charge customers.

Toronto Hydro is funded by the distribution rates paid by its customers. Periodically, Toronto Hydro is required to file an application with the OEB to determine the funding available to operate and maintain the distribution system. Toronto Hydro must submit evidence to justify the amount of funding it needs to safely and reliably distribute electricity to its customers.

2

APPENDIX 1.2

Mid-Market Customer Focus Groups

March 17, 2017

Prepared for:

Toronto Hydro

14 Carlton Street

Toronto, Ontario M5B 1K5

Mid-Market Focus Groups

Following our iterative research process, the mid-market (GS > 50 kW) focus groups were designed based on feedback collected from internal staff interviews and the literature review of previous customer satisfaction research.

Objective: Using an exploratory research methodology, our objective was to obtain insights into what customers expect of Toronto Hydro, particularly in terms of what represents value to customers and what customer priorities for Toronto Hydro are, both in context of valued outcomes and choices impacting customers.

1.1 Methodology

Four mid-market focus groups were conducted on February 28 and March 1, 2017, in North York at Head Research.

February 28, 2017:

- Industrial Customers (6 participants)
- Mash & Other Customer Types (6 participants)

March 1, 2017:

- Commercial Customers (6 participants)
- Commercial Customers (6 participants)

Participants received a $150 cash incentive as compensation for their time. Participants were recruited from across Toronto and qualified if they either paid their organization's electricity bill or had oversight on electricity management decisions.

We deployed a detailed *Discussion Guide*, used to moderate all four focus groups. In all four focus groups a printed primer was shared with participants in the early part of the session to provide consistent contextual information on Toronto Hydro and the role it plays within Ontario's electricity system, and bill impact.

This report summarizes key findings, and offers observations and potential strategic avenues based on these groups and past research. *Respondent verbatim responses are in italics.* In general, our approach in reporting is to allow the respondents to be heard as much as possible, utilizing representative verbatim comments, offering interpretation and comment where necessary.

Please Note: Qualitative research does not hold the statistical reliability or representativeness of quantitative research. It is an exploratory research technique that should be used for strategic direction only.

A note on interpreting focus groups findings: In focus group research, the value of the findings lies in the *depth* and *range* of information provided by the participants, rather than in the *number* of individuals holding each view. References in this report such as "most" or "some" participants cannot be projected to the full population. Only a large sample, quantitative survey would be accurately projectable to the full population.

1.2 General Overview

1.2.1 Knowledge and Familiarity:

Across all four groups, respondents were asked first a series of introductory questions to establish baseline context and direct the discussion to Toronto Hydro's role as the local distributor. Virtually all respondents identify Toronto Hydro as their supplier of electricity, and, unaided, a strong majority identify Toronto Hydro as the distributor in some form. When provided a description in a handout, most are surprised to learn that Toronto Hydro only represents 10% of their bill. Ownership of Toronto Hydro was less clear. Although some identify it as city owned, many are not clear.

1.2.2 Touchpoints

For all respondents, there was no 'customer journey' initially. Virtually all grandfathered in some way (e.g. THESL account predated participant involvement with their organization). Common customer service touchpoints included:

- Billing inquiries
- Internal service work
- Metering inquiries online
- Outages
- Service of Toronto Hydro equipment
- Online app – service interruptions
- Scheduled maintenance – internal
- CDM program participation

Overall **electricity rates** came up early and unaided.

1.2.3 Mid-Market Customer Priorities

1. **Customer Service**: Overall, customer service is seen as excellent with the exception to specific incidents where base observation are noted.
2. **Reliability and ETOR**: Power reliability is seen as good, but more importantly Toronto Hydro's responsiveness and communications were seen as meeting business needs.
    - Maintaining the current level of reliability appears to be a priority among this rate class.
3. **Bill Impact**: Cost was an overarching concern, but not specifically directed at Toronto Hydro. Becoming aware of Toronto Hydro's place in the electricity system significantly abated "rate rage" directed toward Toronto Hydro.

- Increasing transparency and education about THESL's role and future plans further abated concerns on rates and significantly expanded consideration of Toronto Hydro's priorities and challenges (e.g. to know Toronto Hydro, is to like Toronto Hydro).

4. **Future Rates**: While knowing more about Toronto Hydro decreases "rate rage", there was an observed desire for cost containment and short-term rate predictability. That said, for the most part, this rate class appears to be willing to accept "reasonable" rate increases based on a value proposition that included the following definitions:

   a) maintaining current reliability (not necessarily enhancing or decline);

   b) investing prudently, where long-term cost saving are realized (spend more now to save more later);

   c) no premature investing in unproven or untested technologies;

   d) enhanced customer service to match emerging technological capabilities and needs (e.g. allow customers to get bills by emails, create master accounts to manage multiple bills, live assistance chat features); and

   e) investing in education and promotion of CDM as a means for individual cost savings and also as a route to mitigating future demand and reliability challenges.

1.3 Industrial

Group 1 consisted of manufacturers.

> *"Dealing with Hydro I have had no issues."*

Overall, respondents were happy with Toronto Hydro's service, although there were two 'outliers' who had long standing issues with their electrical service – one who operated a business with apparently antiquated equipment that was sensitive to power fluctuations, and another who operated a small manufacturing business which had a unique electrical issue.

> *"We are in a strange area where we having a floating ground, so there can be extreme voltage swings, like 134 volts down to 20. "*

These respondents had two areas of focus that dominated their views – **reliability and costs**. To those with older manufacturing equipment, outages were a concern, although with one exception that was likely not strictly a reliability issue all had general satisfaction with reliability.

In terms of reliability, which for these participants' experience is defined as infrequent, spontaneous outages, the expectation is similar to other groups – ability to make a reasonably informed business decisions, without expressly holding Toronto Hydro to a precise time frame. Many make their own estimation based on available facts; others were active in connecting online. One noted that Twitter information is more precise than Toronto Hydro's website. In general, respondents felt that Toronto Hydro met their expectations in communicating what they need to know in an outage.

> *"Look to see if a wider area is out, or what the issue is, which tells me how long it might be and I can act accordingly."*

> *"I don't always get the answer I need on an outage as quickly as I want, but I understand the issue at their end."*

"I just want to know they are aware of it, and about how long they think it will take."

"Their website has gotten better on service interruptions. Updating is much better."

"I just want to know if I should get people to sweep the floors or send them home."

"My expectations were met."

"They handed out flyers about a planned interruption two days in advance, they finished two hours early, can't ask for more than that."

"There was a broad power outage in Scarborough recently. I looked on the website, saw the scope of the outage, made the decision to send everyone home based on that, it came back on 90 minutes later and we lost a half day of production. If there were tools that gave a bit more information about the nature of the fault we might have been able to make a better decision."

"It would be nice to have a fixed estimate. Nobody is going to hold them to it."

"They do that on their twitter feed but not on their website."

The nature of this respondent group was such that conservation did not come up as an issue, expectation or something they had actively looked in to. Their businesses were such that they were likely operating on older equipment or older buildings operating on low capital budgets. Hence, their focus was on costs, not cost savings through active means. To the manufacturers, this was a competitive issue.

"Electricity is a main ingredient in our business. I can change all the lightbulbs in the world and it won't make a blip in our costs."

"We need electricity to produce, but we can't be competitive, even with Quebec."

"My business can't survive."

"They increase prices 16% a year. No business I know of increases prices that much every year. My infrastructure is aging too. I can't pass on those costs to customers."

"Now we are trading with the rest of the world, so our competitiveness is at risk, particularly with what we are headed towards."

Respondents could not find a satisfactory explanation of why rates continue to rise, and while some had made superficial inquiries, they had little knowledge of the components of their electrical bills or the system overall.

"When I make inquiries about increases the answer is usually that the OEB allows it."

"The terminology on the bills like global adjustment is not well explained. It would be good to see that on the bill."

"As far as I know Toronto Hydro is not making any profit off the commodity. The problem reaches beyond Hydro."

"They can't really tell you why rates keep going up. They only give a stock answer."

"I expect [Toronto Hydro] to behave like every other business, to not just pass along every cost increase because the OEB approves it."

This last comment was a typical sentiment – a misalignment with the market and economy their businesses operate in.

In terms of issues facing Toronto Hydro and the electricity system overall, respondents identified a limited, but consistent range of challenges: increased demand from new technologies, such as transit electrification, population growth, climate change and aging infrastructure. None cited environmental concerns more broadly that the impact of climate change on reliability as it affects their businesses.

Conservation was not explicitly mentioned, although several had investigated the possibility of solar energy for their business.

> *"Today solar panels just aren't efficient enough yet."*

Although none saw solar energy as a short term solution for their business, many saw *"democratization of the grid"* with what they saw as the eventual adoption of solar energy and local storage as a long term eventuality.

> *"In 150 years we don't need Toronto Hydro, we will have solar heating and storage batteries."*

In the near term, respondents saw reliability as the top priority, defined as maintaining the current reliability level at the lowest cost, while new technologies mature and become cost-effective.

> *"They have to focus on the core of the business – reliability."*
>
> *"Making the infrastructure reliable, at least at today's level, would be the top priority."*
>
> *"They should allocate funds towards maintaining the reliability levels we have now."*
>
> *"There are many technologies coming on line, but with the cost problem, they can't be investing while they are cutting corners to save on rates. They should only invest where there is a positive rate impact."*
>
> *"Don't expect too much unless the bill goes up."*
>
> *"We don't face too many overages. If the costs of hydro go up much more, we don't have to worry about infrastructure or long term issues, we will be out of business."*
>
> *"I don't see any industry that operates at 100% efficiency, what we are just trying to get better repair time. We are not suggesting increasing reliability is where to invest more money."*

Respondents felt that the current reliability is reasonable, and although one who had a specific voltage swing issue cited quality as a priority, this was seen as a result of his own individual issue rather than a systemic issue affecting more customers.

> *"The quality of the commodity needs to be looked at, as a reliability issue."*

There was no feeling that enhancing reliability at higher cost created value for their businesses. However, many felt that a longer term view towards investing with pay-back over a longer period, by investing in technologies that may reduce costs and/or dependency later, is valuable, even at a short term cost.

> *"Investing in renewable energy sources will pay off by getting us off the high cost contracts."*
>
> *"Transitioning to renewables is the priority, even if it raises rates during the transition."*

In Group 1, none really felt they had a fully formed solution. All recognized that the challenges they identified were tangible and had cost impacts. Their overall view was that Toronto Hydro needs to take cost-effective measures to maintain the infrastructure in place now, but not be purely reactive

to events. This was seen as a need for a 'plan' to minimize event-driven disruptions while investing effectively in the future.

> *"There is no magic solution here. You need to increase reliability or maintain it with these challenges coming that have cost implications. I don't have the answer."*

> *"Patchwork infrastructure replacement is not very cost effective. They need an efficient plan that minimizes reactions to one-time events."*

Many respondents recognized technologies being developed that may bring cost savings, but expressed a caution in investing too quickly in unproven technologies or what they saw as 'interim' technologies. The sentiment expressed was that early adoption may bring early obsolescence.

> *"Don't spend too much money on technology."*

> *"In terms of technology I would rather wait. We cannot imagine today what might emerge, so anything we invest in today is probably obsolete right away. We are already way behind Asia and Europe. If we spend to catch up, we will still be behind."*

To some, their view of Toronto Hydro investing in emerging technologies was clouded by their view on Smart Meters.

> *"I'm not sure they are using the best technology. The Smart Meters is how I judge that."*

> *"Toronto Hydro must be squirrelling away money from these increases to put towards investments."*

> *"I prefer the status quo."*

> *"Reliability has to be the top. When the power goes out in our business bad things happen. Consistency is the standard."*

Overall, the consensus was to invest, with acceptance of the rate implications, with a view to lowering longer term rates and enhancing business profitability.

> *"If manufacturers get a break in their cost they can produce more and bring back economic benefits."*

1.4 MASH & Other Customers

Group 2 consisted of a range of business customers: landlords, property developers, an event company, the electricity manager for a major school board, and the Vice-President in charge of electricity at Toronto Community Housing. This dynamic, with two highly engaged a knowledgeable respondents and some smaller, but still highly engaged but less knowledgeable participants, was very effective in elevating the range of consideration for all.

Overall, respondents were very happy with Toronto Hydro service. Most had experienced power outages of a minor nature, or of a longer period attributed to weather related issue or other unpredictable event. All felt that Toronto Hydro's performance in outages is excellent.

> *"I find them very helpful and accommodating."*
>
> *"In power outages, they are great."*
>
> *"24/7 in power outages."*
>
> *"They are operating within a highly regulated framework, but with us they really do step up to tailor programs to help our tenants."*
>
> *"Power interruptions are so few and far between it really is very impressive."*
>
> *"I am downtown, that system is really old."*
>
> *"It never takes more than an hour to get the power back on."*
>
> *"I come from Mexico, if there is a slight wind the power goes out, here it is just great."*

Overall, expectations surrounding power outages were purely communications related. Most felt that Toronto Hydro does a good job at this, whether a planned service interruption or a spontaneous outage. Some, whose businesses were highly dependent on absence of even minor outages, felt they had some personal responsibility to provide 100% continuity, and that it was not entirely reasonable to expect Toronto Hydro to achieve complete elimination of any outages.

Communications was defined by all as simply the information they need to make a business decision, which is an estimated length of outage. Some felt that when they know the area or extent of the outage, and factor in the weather conditions, they can make an estimate themselves.

> *"I just expect that they communicate about the length they expect."*
>
> *"We just need 24 hours' notice of any planned work in the area, which they usually do."*
>
> *"I just need an idea of when it is coming back on, so I can tell my tenants."*
>
> *"The last thing I need to hear is 'I don't know'."*
>
> *"If you need power to be absolutely running 100% of the time without exception, you have to get a backup generator."*

All respondents felt strongly that Toronto Hydro understands their business concerns with regards to reliability.

However, most had only made superficial inquiries or research into available incentives or conservation programs that would help reduce their costs. Conservation as a means to enable cost savings was a major focus and expectation of all respondents.

Respondents identified that they had primary responsibility in conservation. However, they felt that Toronto Hydro could assist them by making access to conservation information more easily accessible. Some felt that Toronto Hydro programs were tailored, or at least more accessible, to customers larger than they are. Many felt that the application process for programs was very labor intensive and complex.

> *"The large customers probably have the knowledge but the smaller ones don't."*

Some noted that Toronto Hydro works well with other utilities and felt that they could collaborate for incentive and conservation programs more. Other suggested 'bundling' programs together to make them more accessible and less daunting.

Accessibility was primarily defined as website access in as few clicks as possible. It was also defined as promoting available programs more heavily to prompt customers such as them to inquire.

Accessibility to conservation information and programs, which respondents expected Toronto Hydro to provide, had some impact on overall rate viewpoints. Being pro-active in promoting and simplifying programs and incentives was highly valued, as respondents, faced with continued rate increases, recognized that their most direct route to mitigating rate increases is conservation.

> *"I haven't spent enough time looking into incentives and resources to reduce my consumption."*
>
> *"They are very vague with conservation programs."*
>
> *"They are not territorial; they work with other energy suppliers to help us."*
>
> *"When we replaced lighting with LEDs they had an incentive."*
>
> *"I think they need a more user friendly website. The phone process is too slow."*
>
> *"Toronto Hydro should bundle incentives together based on volume to help smaller customers."*
>
> *"Customers need to have a pretty sophisticated team on the ground to be able to access things. The processes (applications) need to be streamlined."*
>
> *"As rates keep going up ultimately we have to make program decisions and customer decisions. Either we cut our programs or raise prices."*
>
> *"They have to find a way to cut the rates. They have 11% projected annual increases. I understand where they come from, but they have to find a way."*

Although respondents recognized that Toronto Hydro is only a relatively small part of their overall electricity bill, they felt that Toronto Hydro 'owned' some responsibility for being the first touchpoint in helping mitigate rate increases – as Toronto Hydro sends the bill for all related components; respondents felt they had primary responsibility for helping reduce impact for all components.

> *"When I get a bill, it says Toronto Hydro on it … that is where their image problem is. I assume it is all going to them."*

Respondents were primarily concerned with the rising costs impeding their profitability, or being passed on to customers where possible and competitively feasible. Even more than the quantum of rates, predictability of rate changes was very important to business planning. In this sense, consistency and predictability were valued above the absolute amount of the rates.

"Electricity is an essential service. When the amount we can save through conservation is exceeded by the rates increases, that just gets passed on to customers or shareholders."

"We need budget predictability over several years."

Respondents identified consistent range of challenges facing Toronto Hydro, and the electrical distribution system, on the horizon.

"Increased demand will bring reliability issues."

"Environmental challenges – producing electricity that produces environmental challenges, such as carbon footprint."

"Power shortages through over-usage will increase, that goes with climate change."

"Climate change, global warming, we need electricity but the costs of green energy are unsustainable."

"Toronto Hydro has infrastructure issues that will only get worse with sharing of the grid."

"A lot of Toronto Hydro's distribution is above the ground and that will be a huge issue with increasingly extreme weather."

In this group only, due to the unique mix of respondents, we were able to probe on whether an internal plan and specific actions were undertaken:

"We have a plan to deal with these things. The first step is in occupant behaviour."

Landlords, as well as the school board, recognized that changing the behavior of occupants/individual locations was part of the solution. Others agreed with this, and felt that aside from rate concerns, behavioral change was simply good corporate citizenship. The larger respondents were aware that Toronto Hydro has plans to address these issues, others were not. Being aware that there is a plan caused some attitudinal change in the unaware. Their view turned to transparency as being made aware, particularly in terms of impact on rates, as being aware of the identified challenges and the existence of plans to address them (none identified a need to be made deeply aware of the actual plans) significantly abated any entrenched opposition to any rate increase. This also helped mid-level respondents obtain buy-in on rate increases from upper management.

"We have discussed it at our green committee, but no real plan."

Smaller businesses are aware but may have no plan. The two larger organizations represented did.

"We have a five year plan that has a target of 4% reduction every year."

"We looked at what the carbon footprint is of all our buildings and looked at what a realistic reduction target could be. We have identified the capital cost of achieving a 34% reduction by 2024, but we need funding to support that plan."

"Our plan is simply to reduce costs. So far that is changing to LED lighting."

"Cost is the driver but it is also part of being a good global citizen."

"Resiliency is part of the plan – bringing in resources to deal with systemic challenges. Toronto Hydro is working with us on a pilot project bringing in new technology."

"My employer is always interested in the costs, so that is the point where Toronto Hydro can help me get buy-in on any programs they have. Increasing awareness is important to that."

Respondents uniformly consider Toronto Hydro's main responsibility is to keep the power on. Overall, respondents all felt Toronto Hydro does a good job of it. Respondents were very aware that a key issue is aging infrastructure, which, combined with population growth and demand increases from new uses, are going to intersect in the near future.

Respondents were willing to accept short term increases that maintain current reliability. At the same time, there was a consistent view that Toronto Hydro's priority should be threefold:

1. Adopting new technologies that will reduce dependency and costs in the future
2. Enhancing incentives for conservation and increasing awareness of conservation programs
3. Be future oriented – maintain reliability at current levels and invest for long term gains

"Toronto Hydro's main responsibility is to provide electricity to my buildings."

"If you build awareness of programs and provide incentives that will help with the aging infrastructure. Every dollar spent on conservation yield many more dollars saved on infrastructure."

"Lessening dependency on the grid is key to keeping rates down."

"Establishing local generation through co-gen should be ramped up."

"Make local generation easier. Take a nodal approach."

"Short term costs increases for longer term payoffs is a good investment."

"There is no sense in paying money for more reliability, that only means paying for more crews on the road, which is short term at best and doesn't pay down the line with the demands accelerating. The investments need to be very future oriented to reduce dependency."

"Right now rates are just increasing without any long term sustainable solutions."

"If you educate you will have less usage and that will bring less outages and strain on the grid."

Respondents felt that there is a highly politicized environment around electricity now, and this is an impediment to their understanding, and to a conversation about longer term, sustainable solutions. Increased transparency was seen as the solution, as many of the issues and possible routes to resolution were not seen as likely to be highly visible as Toronto Hydro's plans are implemented.

"Political issues. Politicization of electricity."

"More transparency will help de-politicize."

"Our concern is about transparency, we don't know why they are increasing the rates so much. There is no difference in the service."

"It needs to be clear where they are investing so it doesn't become a political football."

"Toronto Hydro has to obtain public concurrence in addressing the problem. They have to be very transparent in obtaining that concurrence. The first step is making sure that everyone understands why rates keep going up."

"They need to show they are shaping a path for future generations. They need to shift the conversation away from justifying increases to the bigger picture."

As to how to increase understanding and awareness, respondents felt that the traditional 'insert in the bills' is not effective, and Toronto Hydro has to take a more active approach.

> *"It can't just be in an insert in the bills. We don't see those."*
>
> *"Nowhere on the bills does it say 'for more information on rates call this number'."*
>
> *"Their website is not user friendly in getting this information."*
>
> *"Toronto Hydro should show the consumer where they are going with electricity quality, wholesale price, and technology solutions…"*
>
> *"I get a lot of pamphlets in the bill that I don't read. It needs to be more interactive, inserts are very old school."*
>
> *"I didn't even know I could see my metering information online until I called them."*

Many respondents, particularly in condo or property management, were very low-tech.

> *"Toronto Hydro needs to go global and go big in their thinking."*

Respondents, particularly the two representatives of larger organizations, came away from the discussion encouraged and enthusiastic.

> *"I've been writing down things tonight that are great ideas I never knew before."*
>
> *"I am very heartened by this conversation tonight. Everyone around this table wants to know more and be part of the solution. Toronto Hydro has the right instincts in doing this."*

1.5 Commercial Customers (Senior Managers)

Group 3 was a mix of commercial and residential property managers as well as a church pastor. These respondents were knowledgeable about Toronto Hydro being a local distributor, but had low knowledge of the electrical system overall and limited knowledge and understanding of their bills. There was some confusion at the outset about debt retirement and global adjustment, as well as ownership of Toronto Hydro.

> *"The debt retirement charge is gone now, it's the global adjustment."*
>
> *"The facts I didn't know, like 30,000 km, and I thought Toronto Hydro got a bigger part of the pie."*
>
> *"I didn't know the City of Toronto owned it. So the City should manage it, not the provincial government."*

Overall, with one exception due to a billing issue, respondents were highly satisfied with Toronto Hydro's customer service. Touchpoints with Toronto Hydro were the same as in other groups, with some in Group 3 having had contact for retrofits and energy audits.

> *"I am in the Save On Energy program, I have a representative at Toronto Hydro who helps me a lot."*
>
> *"Customer service is good, they are very accommodating and forthcoming."*
>
> *"Same thing, they came out and went through the building very thoroughly and gave me good advice."*

The respondent with a specific experience was not representative of others, and his negative view was formed by an expectation that Toronto Hydro, who as he saw it was in possession of knowledge he was not, should have been pro-active when his meter, which he feels is Toronto Hydro's responsibility, was out of service.

> *"Had a poor experience. A meter was offline for 6 months. It was a smart meter, so they would know immediately it was out. They were estimating my usage. They would not adjust the bill."*

Now, he does not say that the estimate was different than actual might have been. He was simply angry that no one told him that the meter was offline.

> *"I only found out when I called to ask why my bill had gone up, it was way higher than I expected."*

It is possible that this customer felt he had an opportunity to achieve an unexpected windfall and was denied.

Another suggested returning to early payment discounts, but other respondents were not in favor, believing that the discounts either come from other customers or are in effect not a discount but an increase to those who cannot pay in a relatively short period.

> *"I would like then to consider a discount again on early payments."*

There were no other specific service related comments. Respondents overall felt that Toronto Hydro provided a high level of service and was responsive.

There was less discussion of outages and reliability than in other groups.

Group 3 identified a range of issues consistent with other groups:

- externally caused demand increase impacting reliability – population growth, technology
- climate change impacting reliability
- price increases of a systemic nature, outside Toronto Hydro's control
- aging infrastructure
- safety – due to infrastructure aging, climate change
- alternative energy sources becoming a larger supply source, concerns about reliability and ability to meet demand
- need for behavioral change among electricity users, both residential and business

> *"Everything runs on electricity today, more and more. This will increase demand a lot, going to EVs, other electrification."*
>
> *"Climate change will start knocking down lines more often."*
>
> *"Increasing population will bring a lot of people who can't afford power."*
>
> *"The infrastructure has to be rebuilt and that is going to cost a lot. Even in nuclear safety."*
>
> *"I have no confidence in alternative energy resources over the near term."*
>
> *"In terms of conservation there has to be a mentality change."*

Although there was great consistency with other groups in expectations of Toronto Hydro in meeting these challenges, Group 3 had an expanded consideration set and different priorities.

Group 3 was asked to perform an individual, written exercise intended to prompt respondents to expand their consideration set and think more broadly of trade-offs between cost and addressing the issues identified, by specifically identifying what creates value for their businesses. Groups 1 and 2 were given similar written exercises as well, but Group 3 was asked in terms of creating value, which Groups 1 and 2 were not. As a result, respondents were prompted to think less of their individual business concerns but to broader social and economic value.

Group 3 had a top focus on rates. However, they saw rates not purely in terms of their own bills, but more broadly – in terms of efficiency and more broadly than simply cutting costs. Their expectation was that Toronto Hydro makes smart, efficient choices when impacting rates. They identified that "*economic impacts*" be the key parameter involved in those choices, rather than simply 'costs'.

However, having established economic impact as the over-arching expectation, Group 3 went on to identify 3 key expectations that related to rate impact which create value:

1. improving access to conservation programs and incentives, as a quality of service priority, streamlining program supplication processes
2. improving client education – information and incentives, but also by providing penalties for usages that do not conform to some normative conservation behavior
3. maintaining, but not enhancing, current reliability levels, upgrading and replacing on an "*incremental basis*" in a way that increases efficiency of distribution longer term

> *"They should do more to promote conservation with the public."*
>
> *"Focus on client education. As a landlord, we are the ones to suffer from the behaviour of the tenants."*
>
> *"The problem is in Canada we have had the freedom to use as much energy as we want for so long, so changing the attitude is hard."*
>
> *"Toronto Hydro's job is getting it to us reliably."*
>
> *"Before the roof falls down you need to maintain it."*
>
> *"The focus has to be on maintaining infrastructure. If your roof is leaking, you have no choice. You can't just patch it, which just puts it off and makes it worse."*
>
> *"Incremental increases are reasonable increases."*
>
> *"Maintain what you have."*

Respondents advised caution on adopting new, unproven technologies.

> *"I expect what I have now. I expect they should not be spending money on new and untried things. McGuinty did that and look what happened."*
>
> *"I'm happy with service right now. "*
>
> *"On the subject of tradeoffs – quality of service vs. incremental increases. I am willing to pay more for a quality service. All aspects of service."*

The overall trade-off between cost increases and service was uniformly seen as "*Dependability over cost".*

Respondents in Group 3 saw electricity as an essential service that must be reliable, at the current levels. They saw investing in 'soft' aspects of service, particularly those that promoted conservation and behavioral change, as having high value both short and longer term, easing some of the pressures facing the distribution system as new technologies and sources become proven, reliable and cost effective.

> *"Canada is a cold country. We need reliable electricity, it is not a luxury. This is not the Caribbean."*
>
> *"You can't get cheap and high end reliability at the same time. I favor dependability over cost."*
>
> *"There are no tradeoffs. Electricity is an essential service."*

In terms of how to communicate with customers to promote conservation, respondents were vague but cited advertising and educational campaigns. They were specific, though, in stating that flyers inserted in bills may have limited reach.

> *"The information on flyers only gets to the bill payers, not the tenants."*

1.6 Commercial Customers (Finance and Accounting Staff)

Group 4 was composed largely of mid to junior level respondents, primarily in residential landlord companies, who might be best characterized as accounts payable staff. As a result, they had little knowledge of electricity or Toronto Hydro beyond their narrow role in processing monthly invoices, or in some cases making basic inquiries on any billing anomaly or missing bill.

We chose to probe more deeply on functional aspects of their billing interactions, particularly the issues or concerns related to billing. In the later phase of the group, we elected to create a spontaneous paired dyad exercise to push respondents to collaborate on broader future issues beyond their limited job scope.

Overall, contact points with Toronto Hydro were more limited than in other groups – primarily occasional billing inquiries, which generally were about a missing bill or a perceived anomaly on the billing. The consideration set towards Toronto Hydro in this group was very limited, centering on aspects of processing bills.

> *"Just about the billing."*
>
> *"I get the bills and I pay them."*
>
> *"Calling about a missing bill."*

Few had other contact points with Toronto Hydro, but *some* noted vaguely that they had inquired about conservation programs, usually promoted by receiving a higher than expected billing. There had also been contact about tenants moving, where the landlord paid hydro directly. One had contacted Toronto Hydro about an electricity reseller who solicited at his office.

> *"They have some conservation programs I have asked about."*
>
> *"Calling about tenant move in and move out."*
>
> *"I have called them about people coming to the door offering discount rates. I tell my department to call Toronto Hydro to ask if they are legit."*

"We have had no issues with Ontario Hydro calling in."

In general, respondents were satisfied with Toronto Hydro's service, which to this group, was generally driven by phone contact. One respondent had a specific issue causing him to have a negative view.

"We had our plaza shut off because of an unpaid missing bill."

Probing this issue showed that the respondent likely had an internal issue where notices of the overdue bill apparently were not followed up on. Upon reduction through probing, the sole issue was that the respondent felt that Toronto Hydro should have recognized his business as a long-standing customer and contacted directly by phone before disconnecting. However, he was uncertain as to whether there had, in fact, been any phone notification.

Another specific issue was raised by a respondent who was an accountant who worked previously in bankruptcy, who felt that as a trustee Toronto Hydro did not consistently apply Bankruptcy Act rules around reconnection, and that when contacting Toronto Hydro, he would receive different responses from different representatives. However, his time acting as a trustee may not be very recent.

"I have found (in trustee situations) that they don't know or apply the rules consistently."

Focusing on aspects of billing interactions with those whose jobs involved clerical processing of invoices, most comments involved modernization of billing practices, particularly online access to billings, and flexibility in setting umbrella or 'master' accounts for landlords with multiple properties.

"They won't send me a missing bill by email, and they charge $15 every time."

"We need the bills in paper."

"We tried to get e-bills, they could only do it by individual property, which is not how our company is set up."

"Other utilities make it way easier to set up e-billing."

In situations where there has been an omission or oversight on the customer's part and disconnection has been threatened, respondents noted that, as corporations, Toronto Hydro's requirements on payment do not fit with many corporation's practices. This was of particular concern to landlords holding multiple properties and/or units, and was related to the identified issue of ability to set up 'master' accounts.

"Corporations can't pay by credit card."

"One issue we have is paying a hydro deposit for each property we own, instead of a global corporate deposit. That money could better be used towards retrofits and other things."

In terms of phone contact, respondents at this level simply wanted reduced hold time. It was noted that many of the 'accounts payable' type respondents were relatively 'low-tech' in their jobs, which may be common among smaller industrial and property management customers.

"I hesitate to call them because I'm afraid I will be on hold for 15 minutes."

"They have actually gotten better at that."

"They could utilize email better, modernize how they send bills."

"Answer my questions in a timely manner."

"The more efficient in their responses they are, the more efficient we can be in our jobs."

"I get the bills from Toronto Hydro so that's who I ask about anything."

In common with other groups, Group 4 perceived Toronto Hydro as their point of contact for everything electricity related. They had a broad expectation of Toronto Hydro as an arbiter and focal point for advising them on how to mitigate rising costs on the overall bill, regardless of where responsibility lies.

In that perceived role, respondents expected Toronto Hydro to show empathy and flexibility – the latter defined as being able to react to their unique operating circumstances.

"Business advisory – help with mitigating the rising costs."

"Consistency, compassion, efficiency, compatibility."

"Flexibility."

The industrial respondents cited competitive concerns with rising costs, and some noted that Quebec competitors are taking advantage of the disparity in electricity costs.

"We have a hard time explaining to customers in Quebec why electricity for machinery is so much higher here, we are losing market share."

Respondents in this range felt that they were not of sufficient scale to invest in energy saving retrofits, and that available rebate programs are not sufficient. Some noted that the application process is too cumbersome for businesses of their size.

"The bottom line is that the costs to retrofit are too high. We have units on baseboard heaters and we have proposed a small rebate on our own."

"The rebate programs are not enough of an inducement."

Group 3 hade a limited range of future issues they could identify, and struggled to identify and issues beyond expected increases in demand. None had any concrete view on reliability and none had experienced any significant outages, and for many, who simply processed invoices, outages were not in their consideration set. For those who had limited experience of outages, there was a view that increasing demand was a driving factor, and an expectation that communications to provide the ability to make business decisions, rather than reducing occasional outages, was the priority.

"I wonder if hydro can continue to meet the demand."

"I expect 100% answer, not necessarily 100% no outages."

Respondents had limited knowledge or experience with conservation programs, and expected Toronto Hydro to be more pro-active in getting this information to them.

"They aren't getting any information to me on what (conservation programs) are available. For businesses just putting an insert in an envelope isn't good enough."

"They should offer rebates for people who want to get into solar power."

Paired Dyad Exercise – Priorities:

For the last phase of the group, given the limited field of view towards electricity the respondents demonstrated and relatively limited business view stemming from many respondents being in 'invoice processing' positions, we elected to create an exercise where respondents were split into

pairs, and asked to work together in those pairs to identify key issues that the electrical system is facing and where Toronto Hydro should invest as priorities. The pairs were asked to identify investment priorities based on where value is created for their businesses. By pairing respondents in dyads, the goal was for the interaction to elevate the consideration set and prompt broader consideration.

From this exercise, respondents identified a range of issues similar to other groups:

- Demand increases due to population growth and technology
- Reliability pressures due to aging infrastructure and increased demand
- Climate change impacting reliability
- Economic changes, in the nature of work and economic mix shifting demand patterns
- Customer service needs changing due to shifts in work patterns and technology

In all these issues, respondent pairs saw cost as an over-arching concern, and saw investing in conservation programs – particularly promoting conservation, and making access to information easier – as creating value that had impact on reliability and demand challenges.

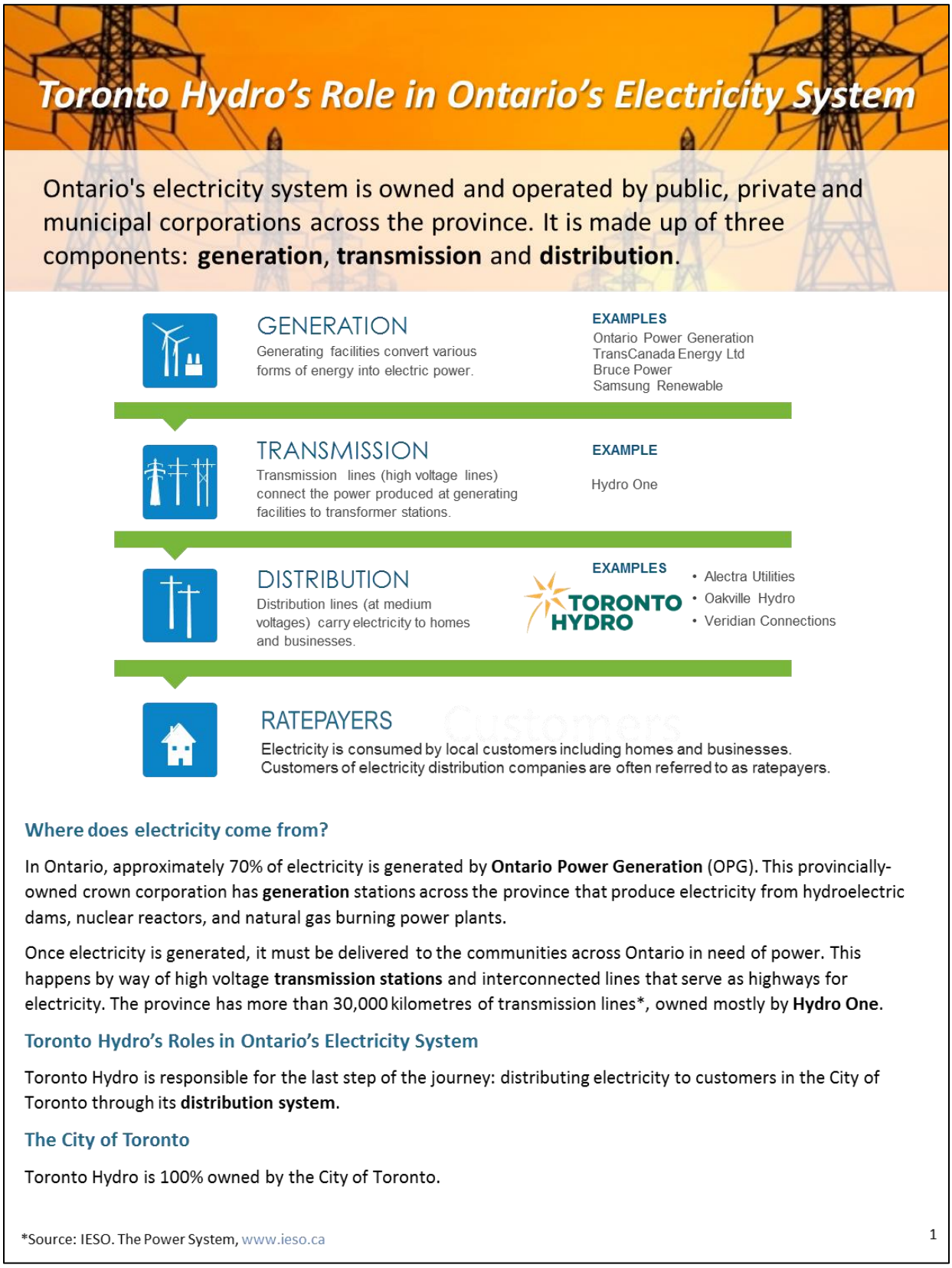
From their vantage point, investing in customer service – modernizing tools and increasing efficiency of contact resolution – as being of high value.

> *"Reliability so they can meet demand, but don't raise the cost beyond what it needs to be – maintain stability and reliability while keeping cost increases as low as possible."*
>
> *"Managing demand is part of reliability – push the programs to reduce consumption, which in turn helps keep the need for infrastructure upgrades to a minimum."*
>
> *"Upgrade their email and online customer service to make navigating easier for customers. Something like a chat feature on their website. They need to step up their ball-game."*
>
> *"Implement a 'chat' feature on their website to speed up service."*
>
> *"Reduce demand keeps reliability high."*
>
> *"We would accept extra costs for easier access to customer service."*
>
> *"We are looking for out of the box solutions that enable more efficient use of electricity and better reliability, and would pay more if they could demonstrate the value proposition."*
>
> *"We are not looking for Cadillac service or reliability, to us value is better and quicker service and communications."*

Overall, respondents through this exercise arrived at a similar position to other groups – maintain reliability at current levels, invest in solutions that maintain that reliability accepting that, in the short term, rates will go up, but with a payback longer term. In the short term, create value by streamlining customer service, adding online tools that make their jobs easier and more efficient.

1.7 Focus Group Appendix

The following two-page background primer was used in all four mid-market focus groups.



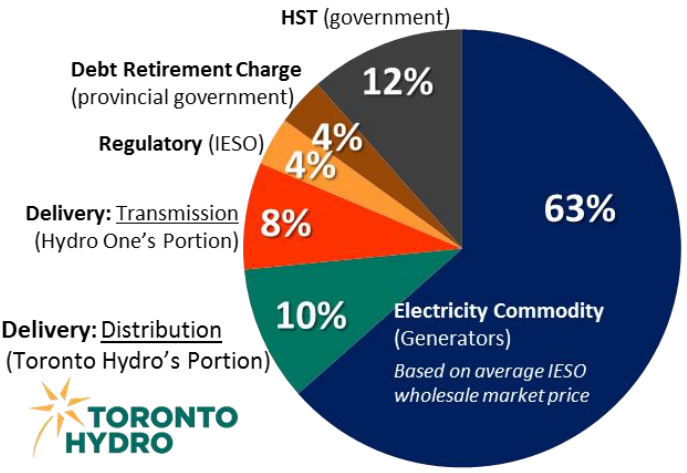


Your Electricity Bill: Every item and charge on your bill is mandated by the provincial government or regulated by the OEB. There are two distinct cost areas that make up the "Delivery " charge on your bill: ***distribution*** and ***transmission***. While Toronto Hydro collects both, the transmission charge is remitted to Hydro One. The distribution charges include the portion of your bill that Toronto Hydro keeps, as well as some other "pass through" charges, most of which are remitted to the IESO.

The distribution charges which Toronto Hydro keeps make up about 10% of the typical electricity bill for general service customers with a monthly demand of 170 kW. The amount your organization pays varies depending on your peak demand.

The distribution fees collected from customers cover Toronto Hydro's capital investments and operating expenses.

About 10% of the average mid-sized business' electricity bill goes to Toronto Hydro. The rest of the bill goes to power generation companies, transmission companies, the government, and regulatory agencies.



SAMPLE GENERAL SERVICE > 50 kW MONTHLY BILL
Toronto Hydro-Electric System Ltd.

Account Number:
000 000 000 000 0000

Meter Number:
00000000

Your Electricity Charges

Electricity Commodity*	$9,402.72
*Commodity based on average IESO wholesale market price	
Delivery (Toronto Hydro's portion: $1,479.09)	$2,651.31
Regulatory Charges (IESO)	$529.43
Debt Retirement Charge	$525.00
Total Electricity Charges	**$13,108.46**
HST	$1,704.10
Total Amount	**$14,812.56**

How are electricity rates determined in Ontario?

The electricity industry in Ontario is regulated by the **Ontario Energy Board** (OEB). One of the OEB's roles is to review the distribution plans of all electricity distributors and set the rates that they can charge customers.

Toronto Hydro is funded by the distribution rates paid by its customers. Periodically, Toronto Hydro is required to file an application with the OEB to determine the funding available to operate and maintain the distribution system. Toronto Hydro must submit evidence to justify the amount of funding it needs to safely and reliably distribute electricity to its customers.

APPENDIX 1.3

Low-Volume Customer Needs & Preferences Survey

March 17, 2017

Prepared for:

Toronto Hydro

14 Carlton Street

Toronto, Ontario M5B 1K5

Low-Volume Customer Needs & Preferences

Building on the findings from the previous research phases, INNOVATIVE developed a survey instrument to determine THESL customer priorities and trade-offs between outcomes.

1.1 Methodology

INNOVATIVE conducted two customer surveys by telephone for THESL. In total, 627 low-volume THESL customers were surveyed between December 7th and 14th, 2016.

- A residential customer survey was conducted among 416 respondents.
- A general service customer survey was conducted among 211 respondents.

1.1.1 Sample Design

Survey respondents were randomly selected from customer lists provided by Toronto Hydro.

Respondents were only able to complete the survey if they were either responsible for managing or overseeing their organizations electricity bill or are primarily or have shared responsibility for paying their household electricity bill.

The sample was weighted downed to n=400 to represent the actual distribution of Toronto Hydro customers by rate class, region and consumption levels.

Since the online survey was not a random probability based sample, a margin of error cannot be calculated. The Marketing Research and Intelligence Association prohibits statements about margins of sampling error or population estimates with regard to most online panels. However, a random probability based sample of n=627 would have an estimated margin of error of ±3.9%, 19 times out of 20. The estimated margin of error would be larger within each sub-grouping of the sample.

Unweighted Sample

Region	Rate Class	Low	Medium-Low	Medium-High	High	Total
Toronto/ East York	GS	27	27	26	27	107
	Residential	38	37	39	37	151
Etobicoke/ York	GS	9	9	9	10	37
	Residential	21	22	22	21	86
North York	GS	10	10	11	10	41
	Residential	22	22	23	22	89
Scarborough	GS	6	6	6	8	26
	Residential	23	22	22	23	90
Total	GS	52	52	52	55	211
	Residential	104	103	106	103	416
Total		**156**	**155**	**158**	**158**	**627**

Weighted Sample

Region	Rate Class	Low	Medium-Low	Medium-High	High	Total
Toronto/ East York	GS	8	8	8	8	32
	Residential	31	31	31	31	124
Etobicoke/ York	GS	3	3	3	3	12
	Residential	17	17	17	17	68
North York	GS	3	3	3	3	12
	Residential	18	18	18	18	72
Scarborough	GS	2	2	2	2	8
	Residential	18	18	18	18	72
Total	GS	16	16	16	16	64
	Residential	84	84	84	84	336
Total		100	100	100	100	400

1.1.2 Survey Design

The survey questions asked of low-volume THESL customers were designed based on input from the previous phases of research. The questions were designed to assess importance of identified outcomes and then rank their relative importance.

The question wording was as follows:

> *Toronto Hydro regularly holds discussions with its customers to better understand how it should set spending priorities with ratepayer dollars.*
>
> *In recent conversions with customers, a number of company goals were identified as priorities for Toronto Hydro.*
>
> *Using a scale from 0 to 10, where 0 means not important at all and 10 means extremely important, please tell me how important each of the following Toronto Hydro priorities are to you as a customer?*

Code	Response	
00	Not important at all	
01		
02		
03		
04		
05	Somewhat important	
06		
07		
08		
09		
10	Extremely important	
98	Don't know (**DNR)**	
99	Refused (**DNR**)	

Randomize

1. *Delivering reasonable electricity prices*
2. *Ensuring reliable electrical service*
3. *Ensuring the safety of electrical infrastructure*
4. *Providing quality customer service*
5. *Helping customers with electricity conservation and efficient usage*
6. *Enabling the electrical system to support the reduction of Greenhouse gases*

End Battery

Thinking of the priorities we just discussed, which is most important to you as a Toronto Hydro customer?

[**Read list in same order as previous battery of questions**]

Code	Response	
01	Delivering reasonable electricity prices	
02	Ensuring reliable electrical service	
03	Ensuring the safety of electrical infrastructure	
04	Providing quality customer service	
05	Helping customers with electricity conservation and efficient usage	
06	Enabling the electrical system to support the reduction of Greenhouse gases	
98	Don't know (**DNR)**	
99	Refused (**DNR**)	

7. *What is your top priority for Toronto Hydro?*
8. *What is the next most important priority?*
   [remove answer from previous question, if asked to read again]
9. *And what do you consider the third most important priority?*
   [remove answer from previous two questions, if asked to read again]

1.2 Outcome Importance and Rankings

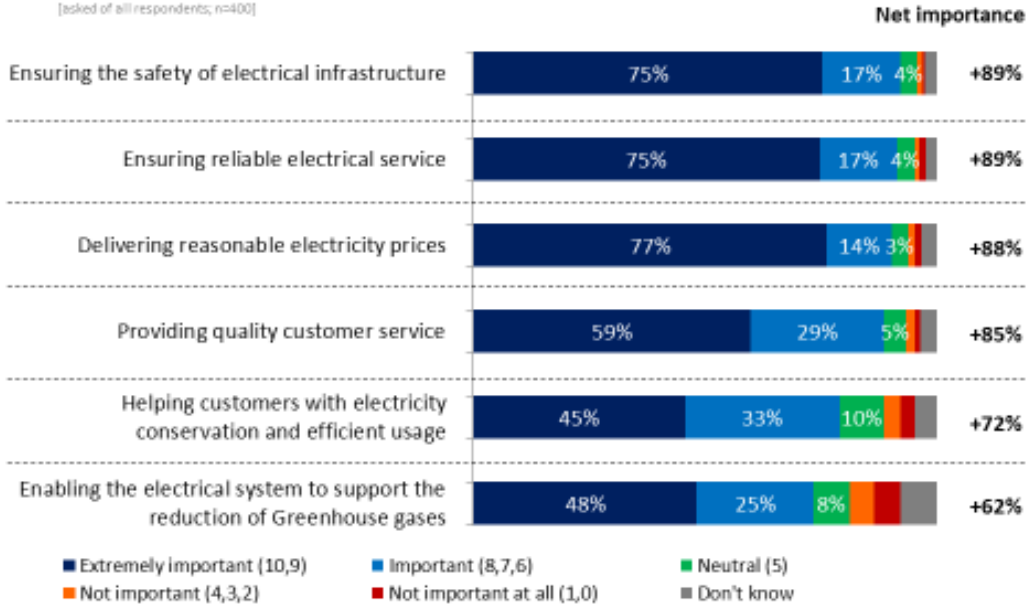
In terms of relative importance, *safety*, *reliability*, and *price* seen as the most important priorities valued by THESL customers.

However, when asked to rank the top priority, among a provided list of outcomes, that Toronto Hydro should focus its efforts, "*delivering reasonable electricity prices*" is the clear priority for customers. In terms of rankings, *reliability* ranks second and *safety* ranks third, among a list of six priorities.

Relative Importance: *Safety*, *reliability*, and *price* seen as the most important priorities valued by THESL customers

Q Using a scale from 0 to 10, where 0 means not important at all and 10 means extremely important, please tell me how important each of the following Toronto Hydro priorities are to you as a customer?

[asked of all respondents; n=400]

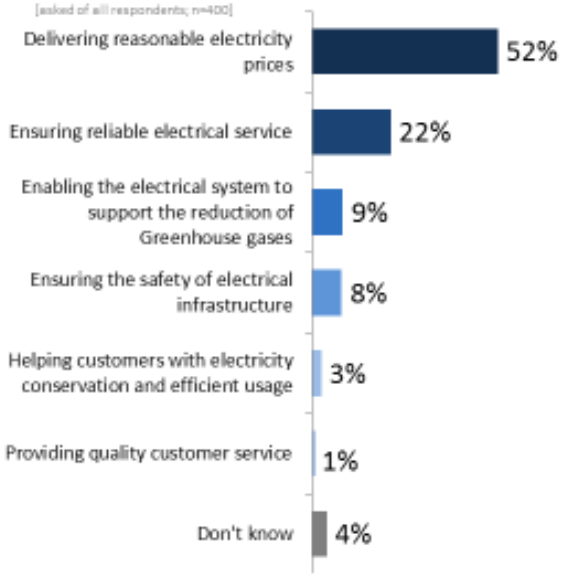


Ranking Outcomes: Over half (52%) identified *price* as their top priority, among multiple THESL outcomes

Q Thinking of the priorities we just discussed, which is most important to you as a Toronto Hydro customer?

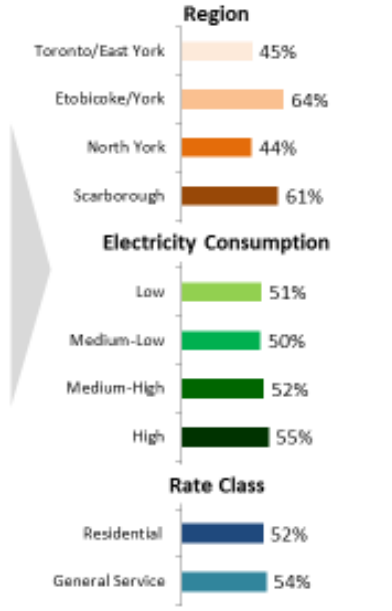
What is your top priority for Toronto Hydro?

[asked of all respondents; n=400]



Segmentation

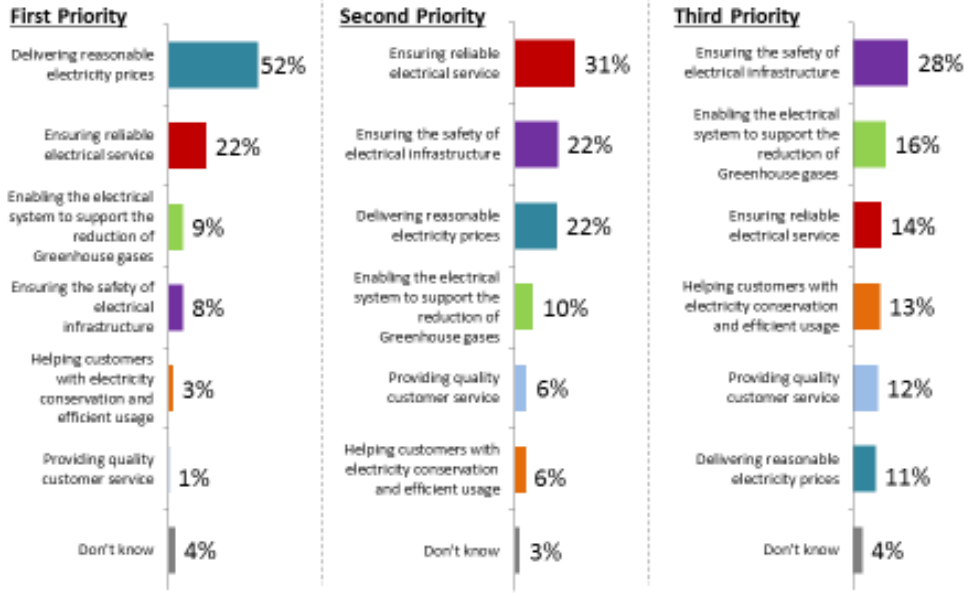
Respondents who say "Reasonable Electricity Prices":



Ranking Outcomes: When asked to rank top three priorities; 1st *price*, 2nd reliability, and 3rd safety

Q Thinking of the priorities we just discussed, which is most important to you as a Toronto Hydro customer? What is your top priority for Toronto Hydro? Next most important? Third most important?

[asked of all respondents; n=400]



Multiple Mentions: *Price*, *Reliability*, and *Safety* top three identified priorities for Toronto Hydro customer outcomes

Q Thinking of the priorities we just discussed, which is most important to you as a Toronto Hydro customer? What is your top priority for Toronto Hydro? Next most important? Third most important?

[asked of all respondents; top three outcomes, columns will not equal 100%]

		Regional Breakdown				Rate Class	
Total Mentions	Total	Toronto/ East York	Etobicoke/ York	Scarborough	North York	General Service	Residential
Delivering reasonable electricity prices	**83%**	81%	85%	86%	81%	85%	82%
Ensuring reliable electrical service	**64%**	62%	69%	64%	65%	67%	64%
Ensuring the safety of electrical infrastructure	**55%**	56%	54%	49%	59%	50%	56%
Enabling the electrical system to support the reduction of Greenhouse gases	**32%**	38%	26%	26%	35%	27%	34%
Helping customers with electricity conservation and efficient usage	**21%**	19%	21%	27%	16%	18%	21%
Providing quality customer service	**18%**	20%	20%	17%	14%	23%	17%
Don't know	**11%**	10%	11%	11%	12%	12%	11%



Appendix 1.4
Key Account Needs & Preferences Survey

This report and all of the information and data contained within it may NOT be released, shared or otherwise disclosed to any other party, without the prior, written consent of Toronto Hydro-Electric Services Ltd.

April 6, 2017 | **Report**

Strictly Privileged and Confidential

Key Findings

General Satisfaction

In line with Key Accounts' high level of familiarity with Ontario's electricity system, satisfaction with the service their organizations receive is high.

- Familiarity with the various parts of Ontario's electricity system is high among Key Accounts. Nine-in-ten (92%) report being familiar; 22% of those are *very familiar and can explain the details to others.* MURB Key Accounts (40%) are approximately twice as likely than other customer types to report being *very familiar*.
- Four-in-five (82%) report being satisfied with the service their organization receives, with the plurality (42%) *very satisfied.* Satisfactions level vary according to customer type – Commercial: 78%; MASH: 95%; MURB: 100%; Industrial: 73%.
- Regarding Toronto Hydro's efforts to engage with management, the majority of Executive Management (67%) and Senior Managers (62%) feel they should maintain the current level of engagement, while 51% of Operations and Engineering feel Toronto Hydro should be doing more.

Corporate Attributes

Evaluations of all of Toronto Hydro's corporate attributes are net positive with more than half scoring a net agreement of more than +50%.

- Toronto Hydro's strongest attribute is providing its Key Accounts with quality advice and guidance (+75%). Areas to improve are providing good value for money (+43%) and being more than an just electricity distributor, but a business partner (+37%).

Priorities and Outcomes

Priorities regarding reliability and power quality are most important among Key Accounts.

- Rated *extremely* or *very important*, the top mentioned priorities are ensuring reliable service (93%), preventing or reducing length of outages caused by weather (89%), and ensuring safety of infrastructure (84%).
- Nine-in-ten (88%) have no additional priorities to suggest.
- The top ranked priorities are ensuring reliability, delivering reasonable prices, and system hardening.

Key Findings [2]

Power Quality and Reliability

Given the attributed importance of these capacities, Toronto Hydro is doing a good job managing power quality and reliability, however there remains room for improvement.

- The majority of Key Accounts are satisfied with the quality of power delivered to their organization (71%), and the reliability of their service (67%). A smaller majority is satisfied with the amount of time it takes to restore power (50%).

Price and Bill Impact

While a majority of Key Accounts find the portion of their bill allotted to Toronto Hydro to be reasonable, the impact of the total bill on their bottom line is significant for many.

- Three-in-five (60%) report familiarity with the breakdown of their bill, with MURB and MASH customers reporting the highest level of familiarity.
- Further, just over half (53%) find this breakdown to be reasonable, while only 10% find it unreasonable. The remaining 38% don't know enough to say.
- 78% agree that their bill has a major impact on the bottom line of their organization and results in some important spending priorities and investments being put off.

Regulated and Unregulated Services

Few Key Accounts suggest going beyond the status quo when it comes to extra and existing services, but there are common themes among those who do.

- Only 14% of Key Accounts say there are additional services they want from Toronto Hydro to which they're will to pay for. These services, management seminars, training and coaching regarding energy management and assistance with filing application.
- Modifications to existing services involve better access to meter interval data was most common among the 19% who had suggestions.

Key Findings [3]

Conservation and Demand Management

While the majority of Key Accounts feel Toronto Hydro does a good job of promoting CDM programs, alternative means of communication were suggested.

- CDM program participation varies among customer type. While more than half of Commercial (61%), MASH (74%), and Industrial (73%) Key Accounts have participated, this is the case for only 20% of MURB Key Accounts.
- That said, three-quarters (76%) say that Toronto Hydro does a good job of promoting CDM programs, including 80% of MURB Key Accounts.
- Providing concise and regular communications regarding energy management in the form of emails or newsletters is a common suggestion when asked how Toronto Hydro can better share information. Some also suggested webinars and joint forums with other utilities (e.g. gas and water).

Trade-off Between Reliability and Price

Throughout, power quality and reliability has proven to be a key priority among Key Accounts. However, there is a definite division in where they stand on the trade-off between reliability and price. This division appears to be anchored in customer type.

- 34% would be willing to **pay a bit more** to **maintain** the current level of power quality and reliability, while 22% would **pay more** to **improve.**
  - Separated by customer type, 57% Commercial, 67% MASH, 33% MURB, and 52% Industrial Key Accounts would pay more to either maintain or improve service.
- Only 11% prioritize **paying less** if this **resulted in lower** power quality and reliability.
- Finally, 34% of Key Accounts don't know enough to say.

Information Needs and Sources

Toronto Hydro provides valued management services, and has proven to be the number one source of information on electricity issues.

- Overall, the majority (67%) of Key Accounts are satisfied with Toronto Hydro's management services; the others (21%) are neither satisfied nor dissatisfied, or don't know enough to say (11%).
- All value statements pertaining to information needs and sources reflect positive outcomes. Most agree that they would like more information on how to manage costs (net +72%), and that better management of electricity costs will make their organization more competitive (net +70%).
- Toronto Hydro (75%) itself is the most common source of advice and information on electricity issues. The IESO (41%), BOMA (29%) and the Ministry of Energy (26%) are also top mentions.

Methodology

These are the findings of an **Innovative Research Group** (INNOVATIVE) online survey conducted among key account customers between February 23 and March 13, 2017.

Toronto Hydro provided INNOVATIVE with an email contact list consisting of the prime contact for each of its **275 key account customers**. INNOVATIVE provided each key account contact with a unique URL via an email invitation so that only customers identified by Toronto Hydro were able to complete the survey and complete the survey only once.

Customers were sent three reminder emails to encourage survey participation. In addition, Toronto Hydro staff followed up with customers by telephone to encourage survey participation.

The analysis of this survey is based on **63** eligible responses from Toronto Hydro's key account customers. The response rate of **22.9%** falls within the expected range for a survey of this nature.

Individual key account responses were anonymous and no identifiable respondent information was shared with Toronto Hydro. Responses were combined to protect the confidentiality of individual key account customers.

Category	Distribution		Survey Sample		Diff.	Weighted Sample	
	#	%	#	%	%	#	%
Commercial	102	37%	23	37%	--	23	37%
MASH	49	18%	19	30%	+12%	11	18%
MURB	27	10%	5	8%	-2%	6	10%
Industrial	94	34%	15	24%	-10%	22	34%
Other	3	1%	1	2%	--	1	1%
Total	**275**	**100%**	**63**	**100%**	--	**63**	**100%**

As illustrated in the adjacent table, the survey over-samples MASH customers and under-samples industrial customers. To correct for this skew in the data and better represent the views of the boarder rate-class, the sample has been weighted by the actual distribution of business categories.

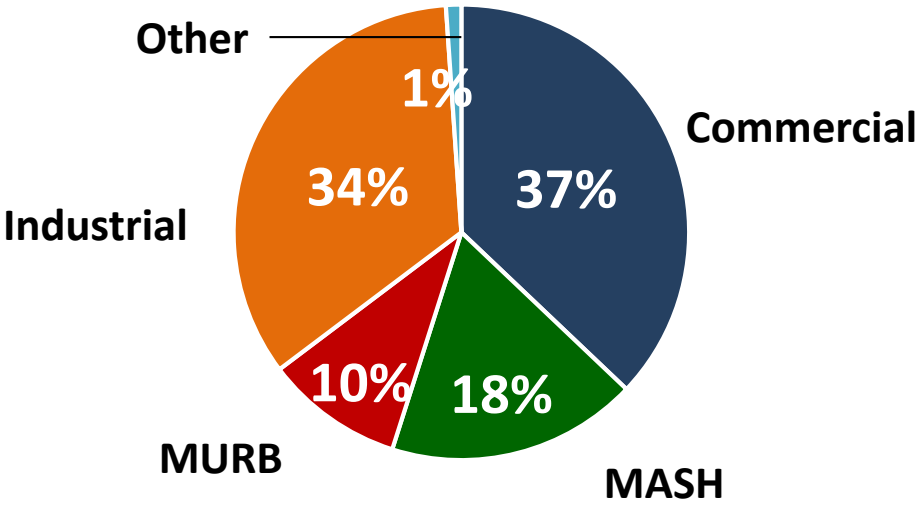
The estimated *Margin of Error* for a finite sample of this size is **±10.9%**, 19 times out of 20. The margin of error would be larger within each sub-grouping of the sample.

NOTES: References throughout this report such as "most" or "some" respondents cannot be projected to the full population of Toronto Hydro key account customers. Only a large sample, quantitative survey would be accurately projectable to the full population. In most cases, the findings from this small sample quantitative study should be interpreted as directional only.

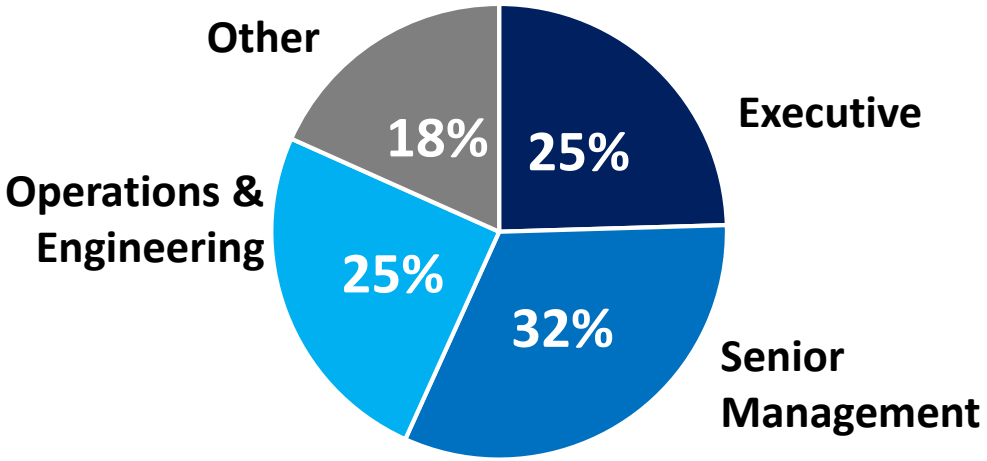
Graphs may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers.

Respondent Firmographic Profile

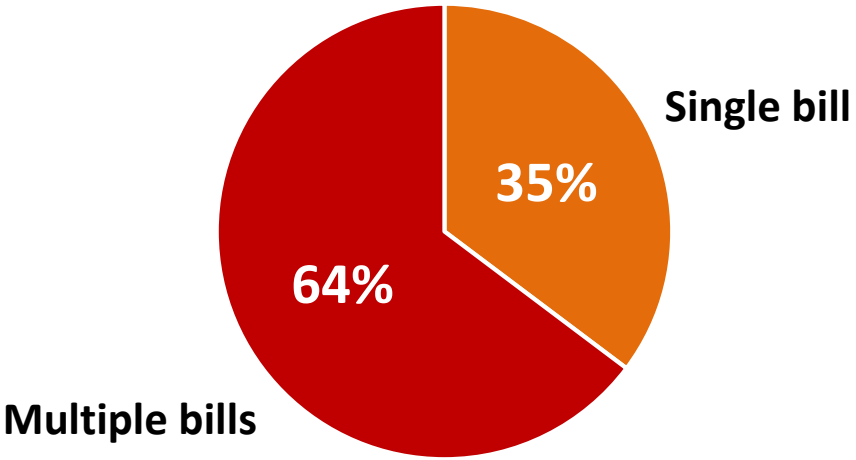
Customer Type



Respondent Occupation

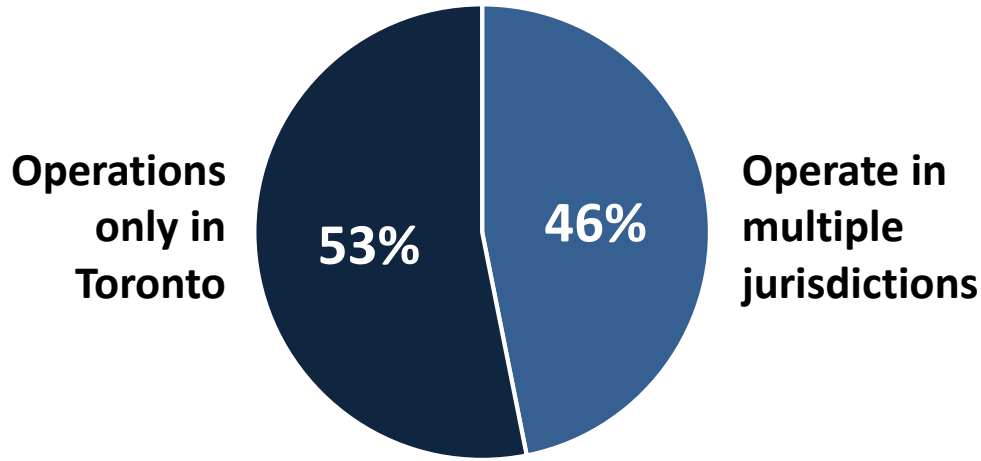


of Electricity Bills from THESL



Note: "Don't know" (1%) not shown

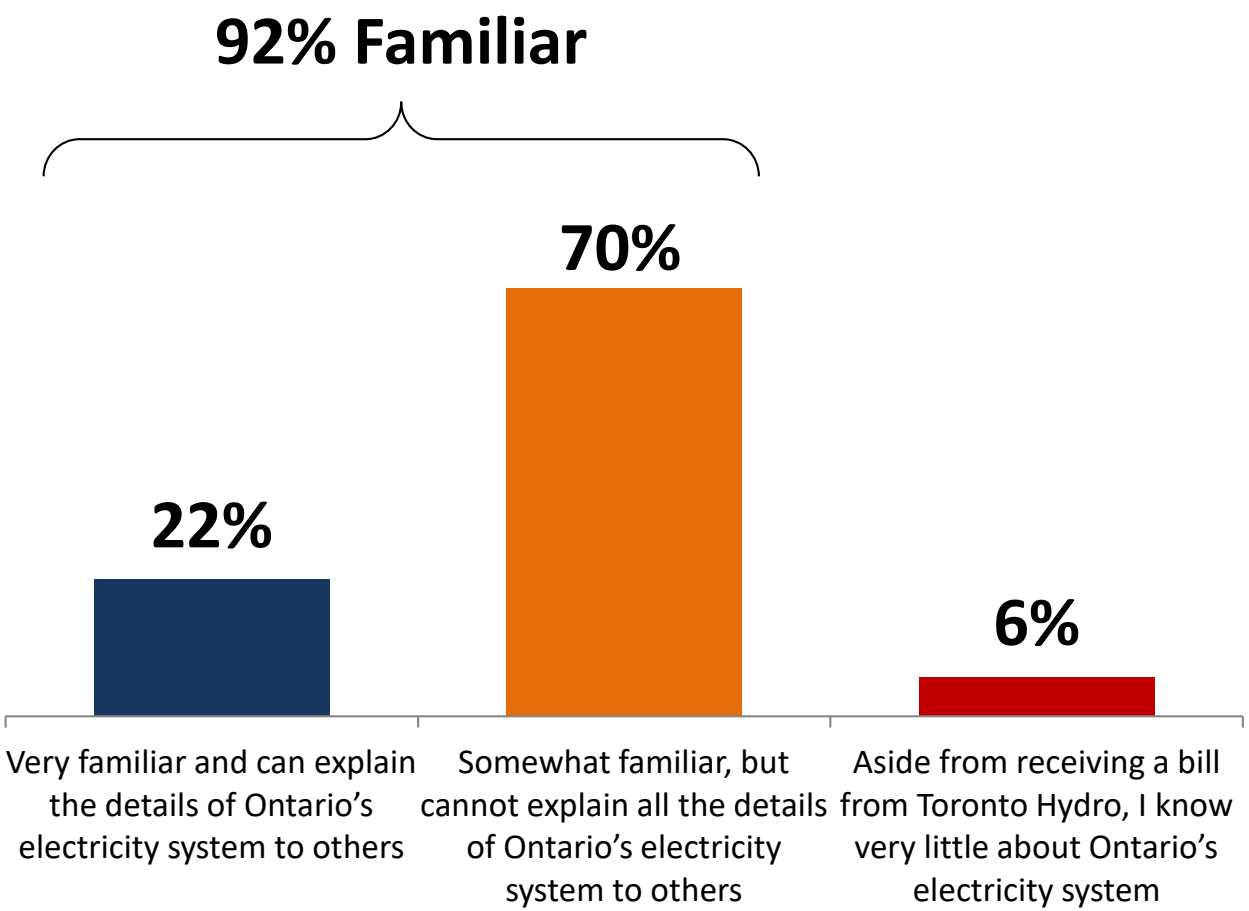
Jurisdictional Operations



Note: "Don't know" (1%) not shown

Familiarity: Nine-in-10 (92%) are familiar with Ontario's electricity system; 22% are *very familiar*

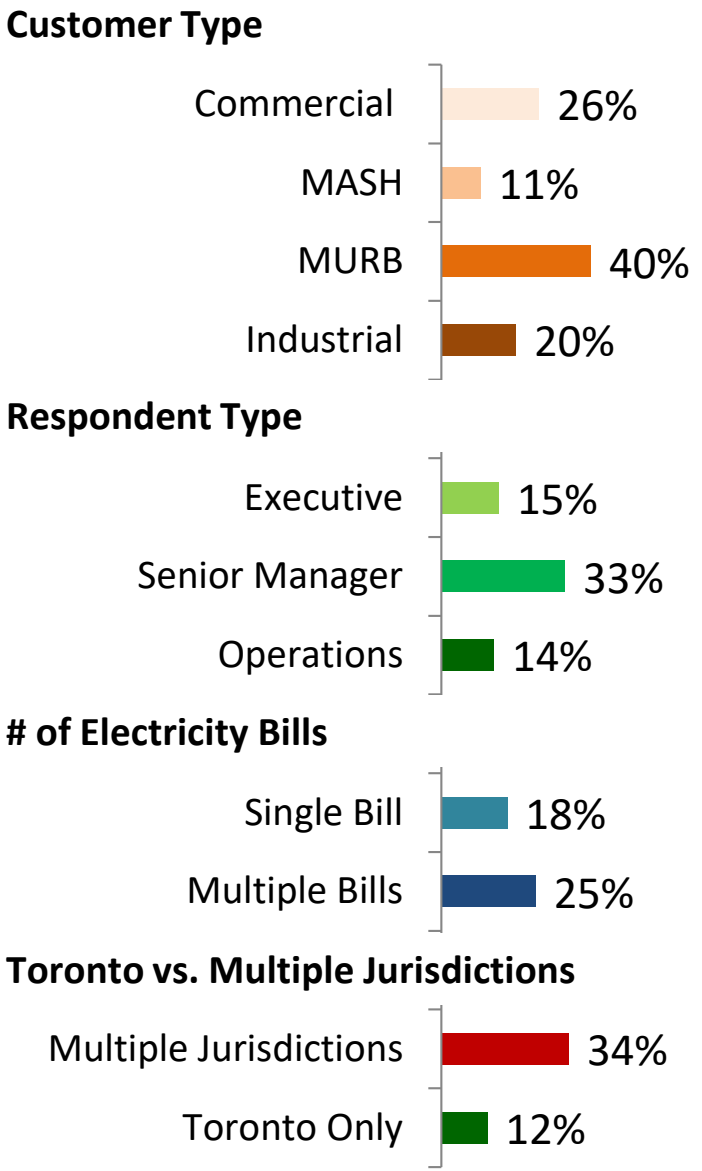
Q How familiar are you with the various parts of Ontario's electricity system, how they work together and which parts Toronto Hydro is responsible for?
[asked of all respondents; n=63]



Note: "Don't know" (2%) not shown

Segmentation ▸▸

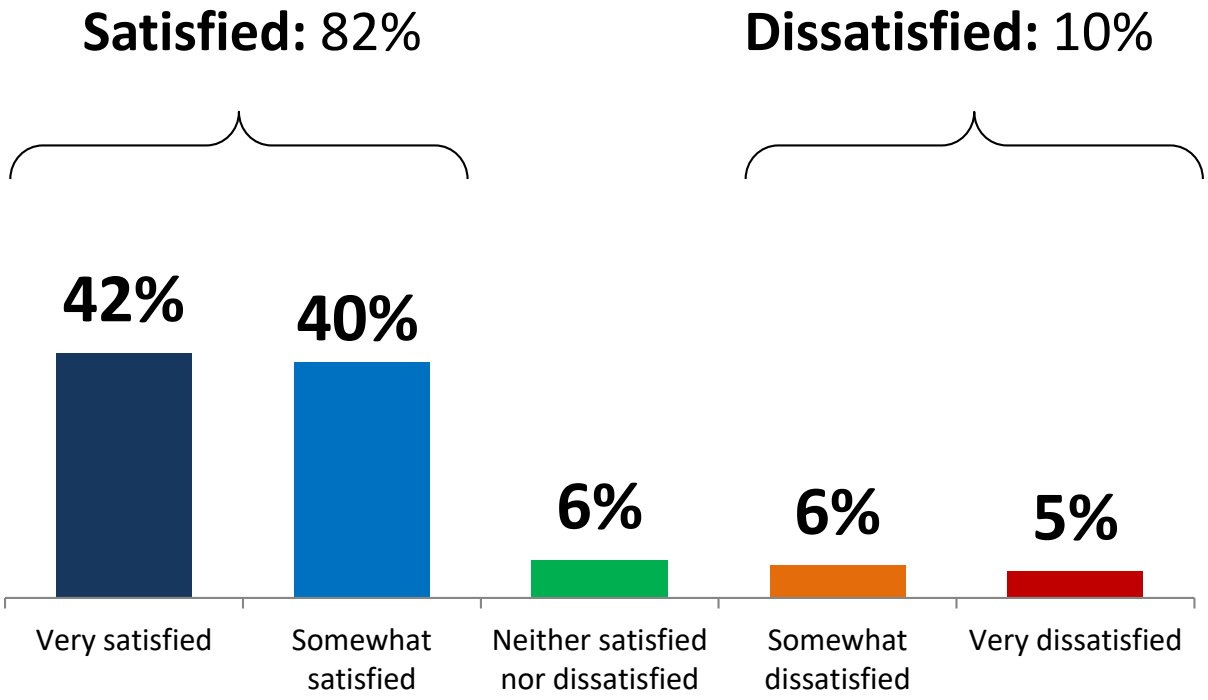
Respondents who say "Very Familiar":



Overall Satisfaction: 82% satisfied with service; plurality (42%) *somewhat satisfied*

Q As you may know, **Toronto Hydro** operates and maintains the local electricity distribution system, reads meters, calculates your charges, answers your calls, responds during outages and clears trees and brush from power lines. **Toronto Hydro** does not set the commodity price of electricity or the Global Adjustment charge.

Generally, how satisfied are you with the service your organization receives from **Toronto Hydro**?
[asked of all respondents; n=63]

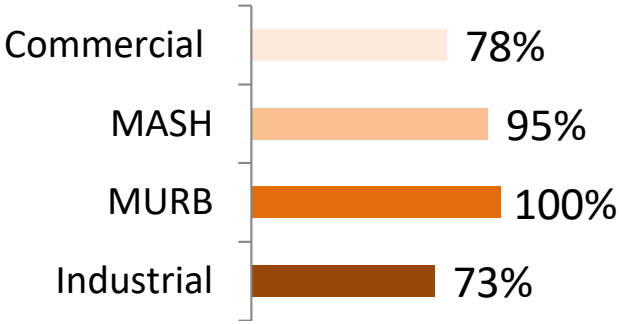


Note: "Don't know" (2%) not shown

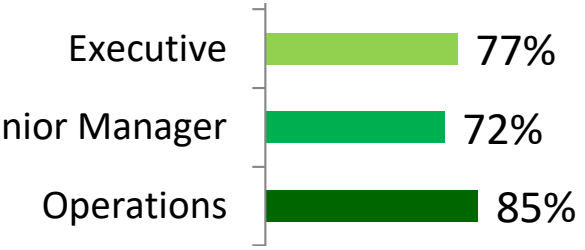
Segmentation ▶▶

Respondents who are "Satisfied":

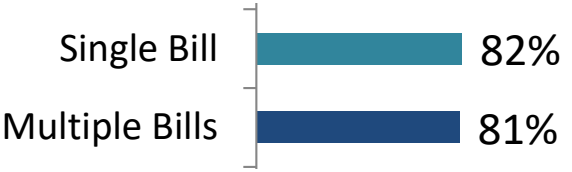
Customer Type



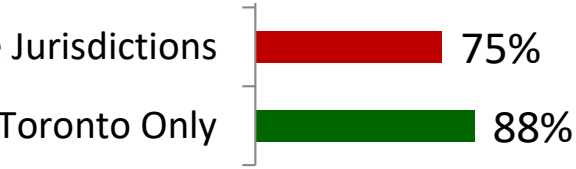
Respondent Type



# of Electricity Bills

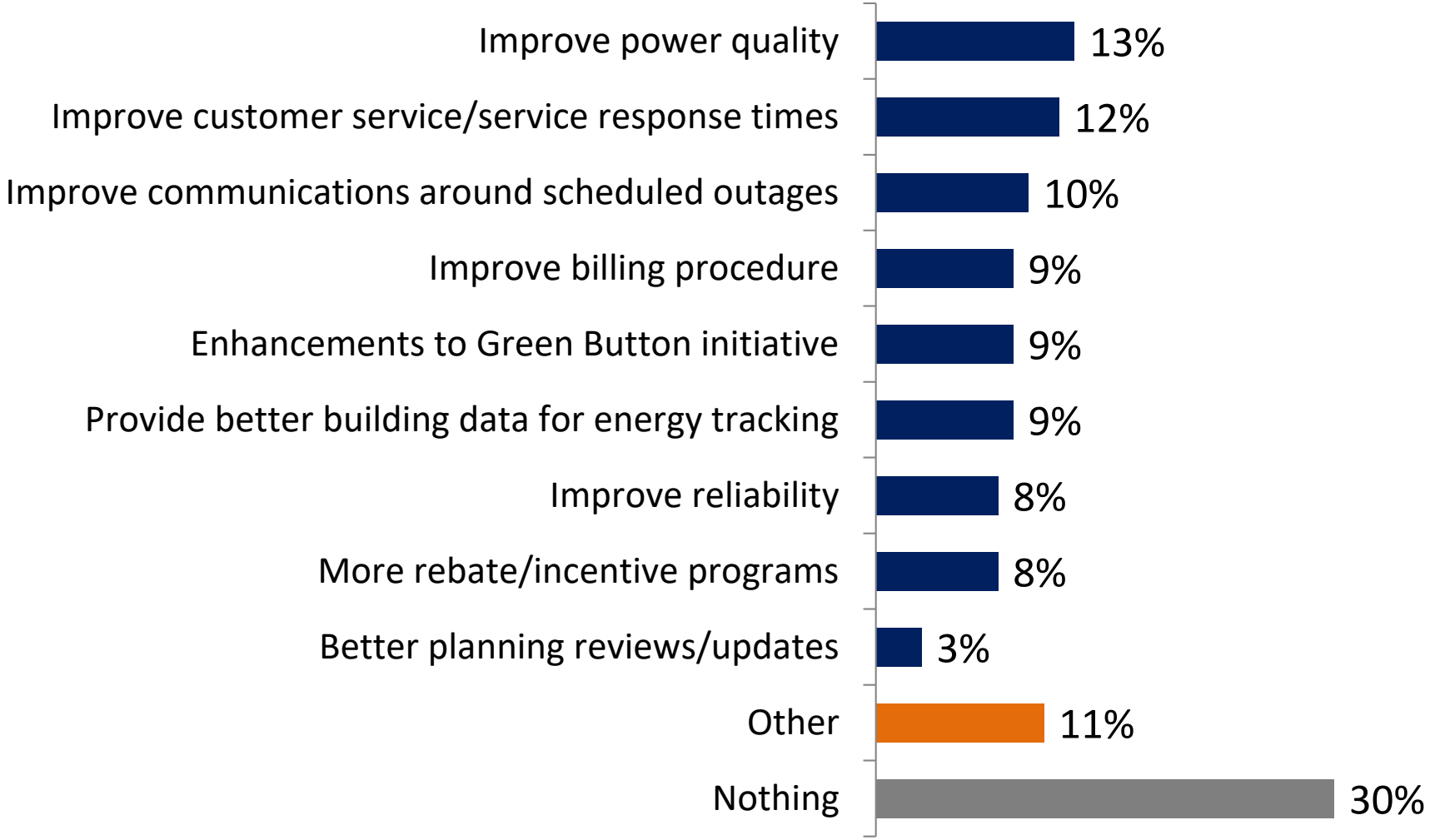


Toronto vs. Multiple Jurisdictions



Improvement: Plurality (30%) suggest nothing; power quality and response time next most commonly mentioned

Q Is there anything in particular that **Toronto Hydro** can do to improve its services to your organization?
[OPEN-ENDED; multiple mention, asked of all respondents; n=63]

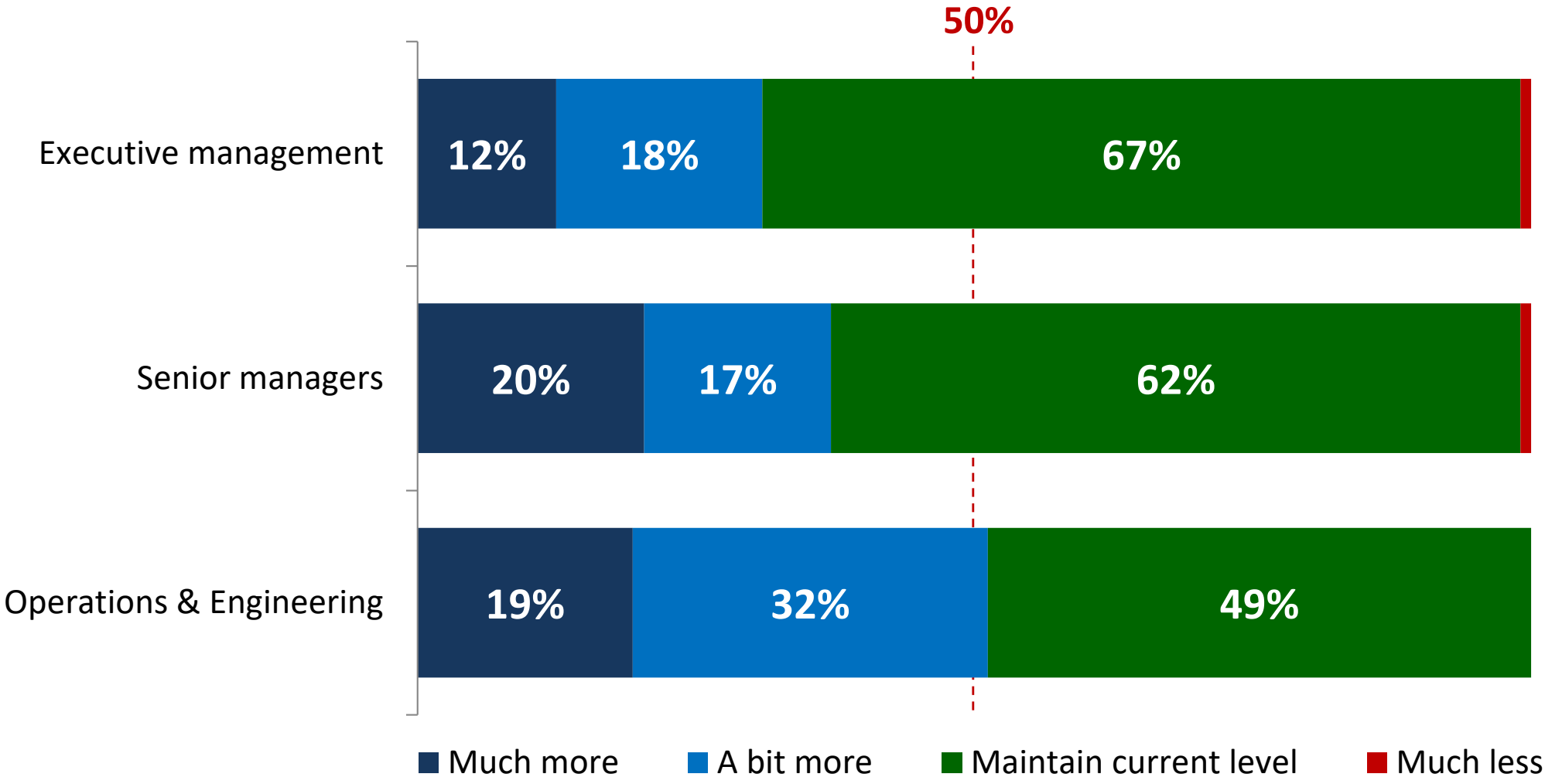


INNOVATIVE RESEARCH GROUP

Engagement: for the most part, *maintain current level of staff engagement;* but greater effort required with O&E

Q Do you think **Toronto Hydro** should be making more or less efforts to engage with the following levels of management at your organization?

[asked of all respondents; n=63]

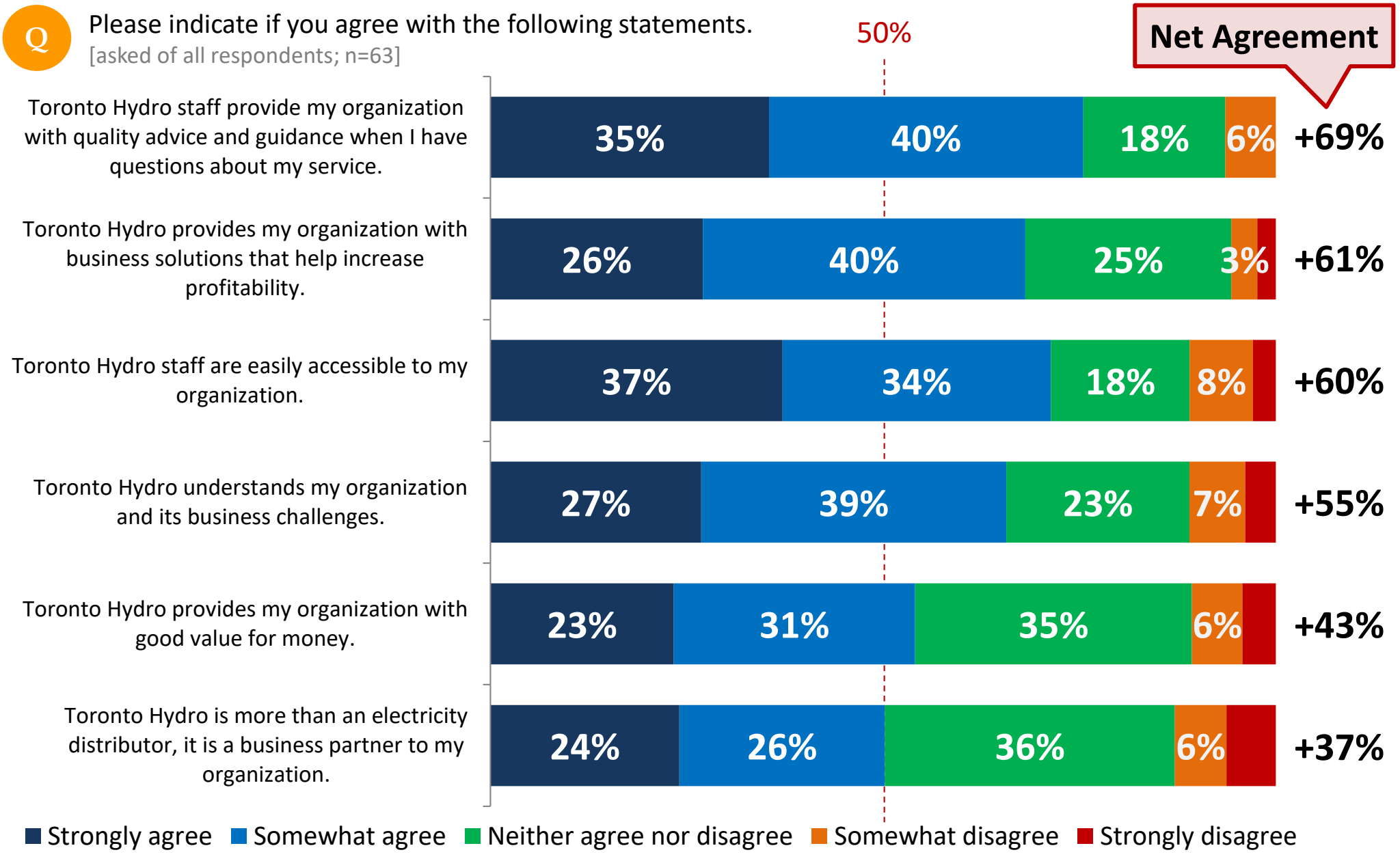


Note: Don't know (1% Executive management; 0% other levels of management) not shown

INNOVATIVE RESEARCH GROUP

Corporate Attributes: Strong agreement on all tested attributes – particularly with **advice, solutions,** and **access**

Q Please indicate if you agree with the following statements.
[asked of all respondents; n=63]



Note: "Don't know" not shown.

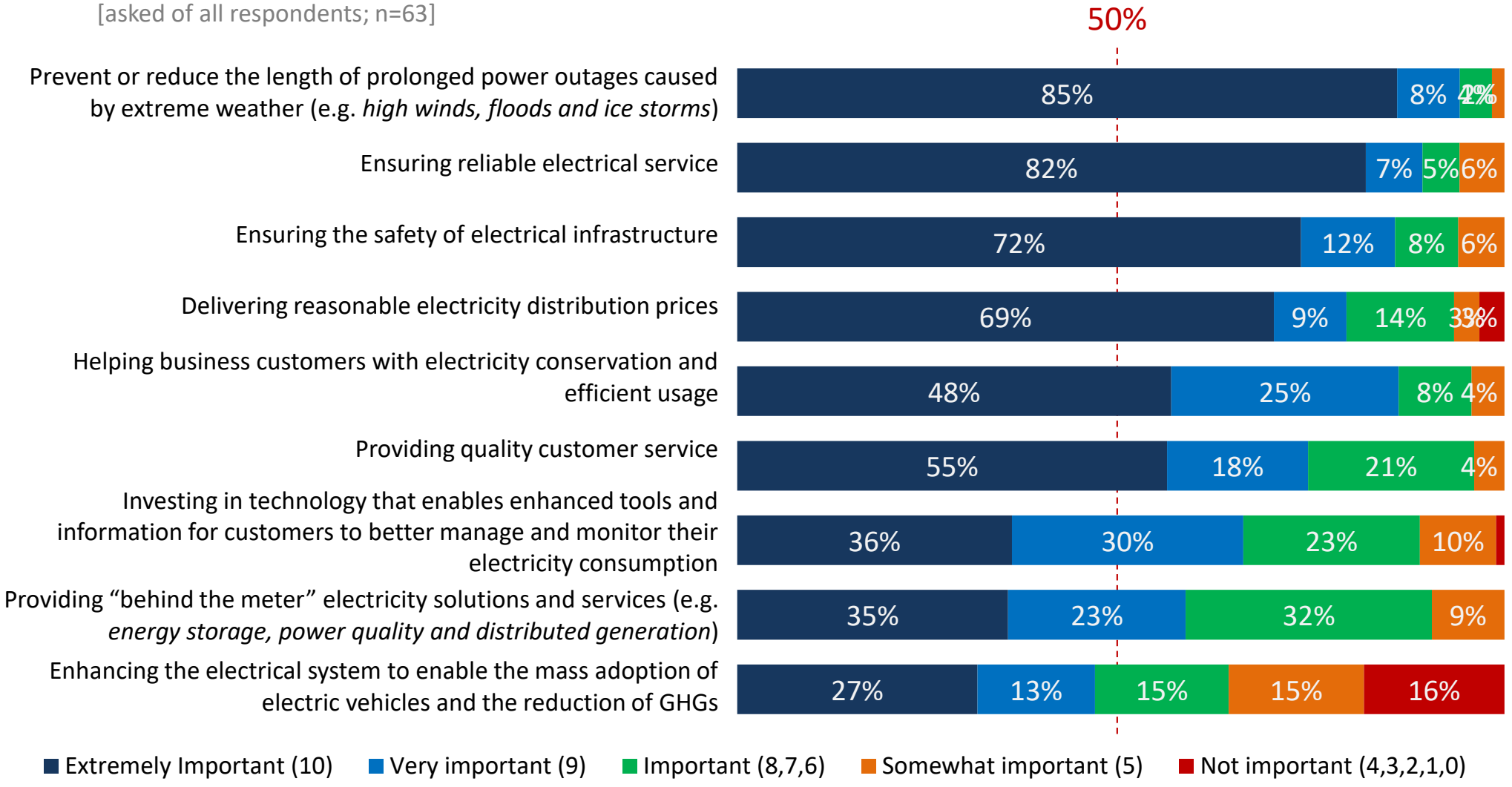
Priority Importance: Resuming service following an outage, reliability and safety are most important priorities

Q

Toronto Hydro regularly holds discussions with its customers to better understand how it should set spending priorities with ratepayer dollars. In recent conversations with customers, a number of company goals were identified as priorities for Toronto Hydro.

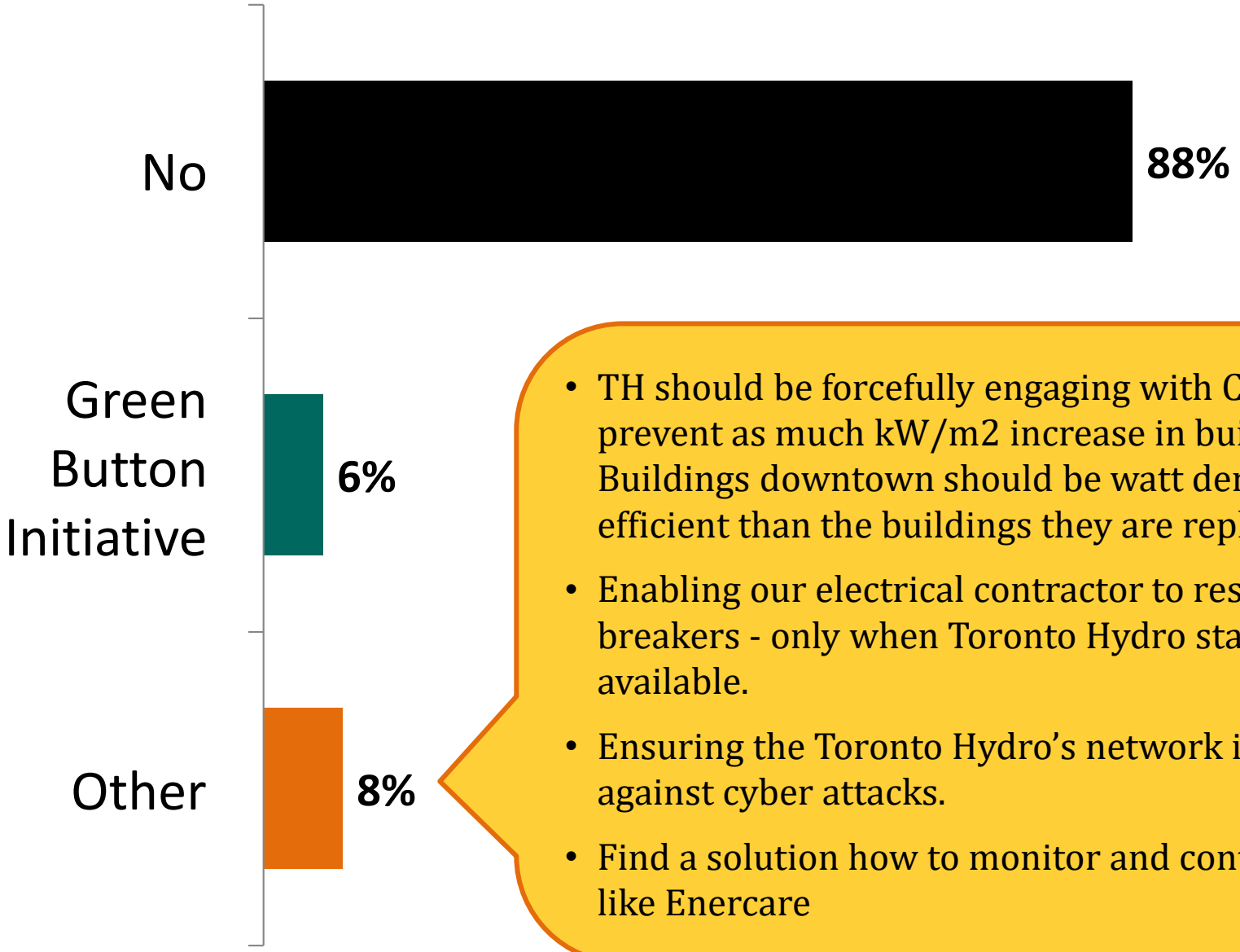
Using a scale from 0 to 10, where 0 means not important at all and 10 means extremely important, please indicate how important each of the following Toronto Hydro priorities are to your organization?

[asked of all respondents; n=63]



Additional Priorities: Majority (88%) suggest no additional priorities for Toronto Hydro

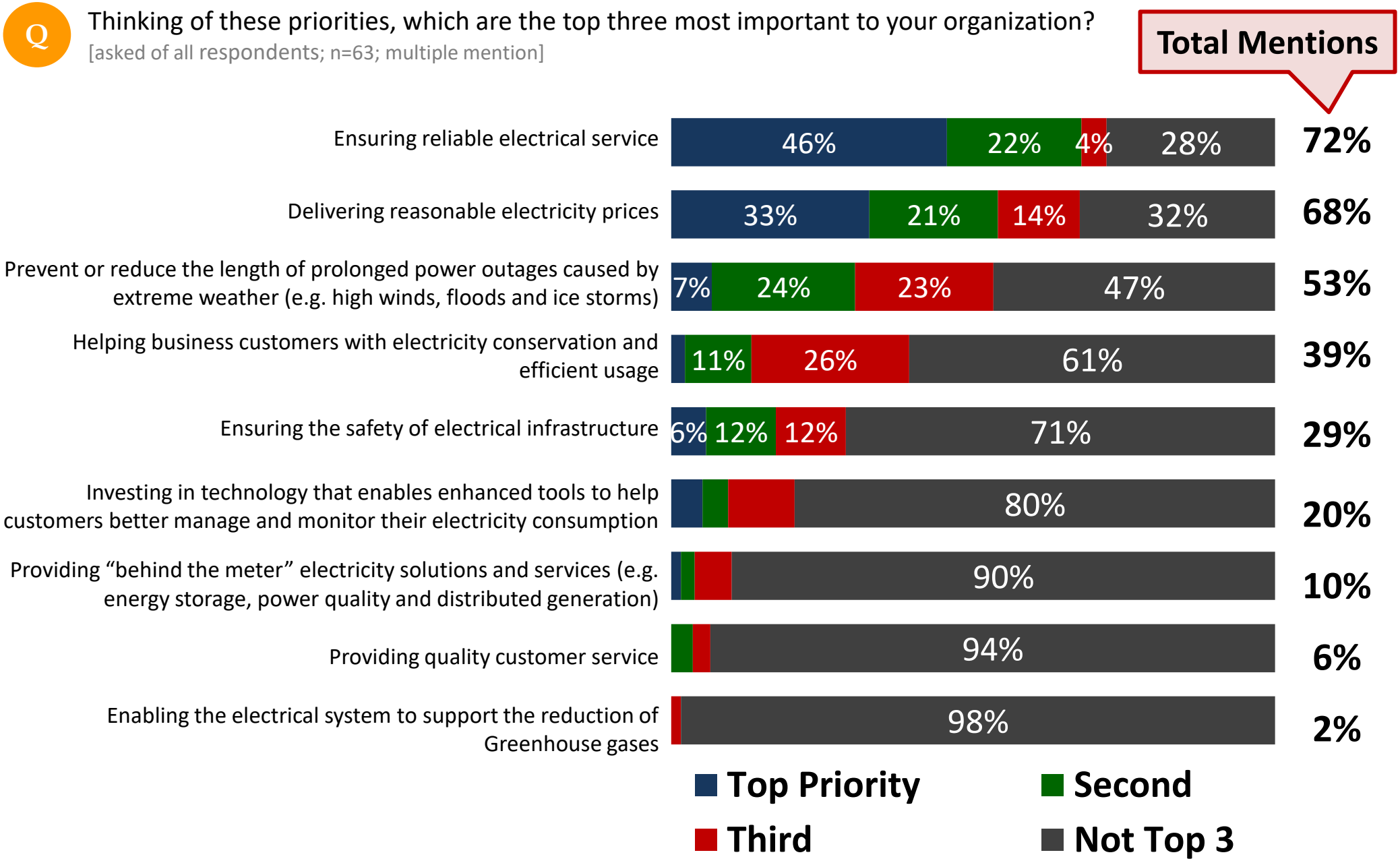
Q Are there any other important priorities that **Toronto Hydro** should be focusing on, not mentioned above.
[OPEN-ENDED; asked of all respondents; n=63]



- TH should be forcefully engaging with City planning to prevent as much kW/m2 increase in buildings in the core. Buildings downtown should be watt density neutral or MORE efficient than the buildings they are replacing.
- Enabling our electrical contractor to reset tripped main breakers - only when Toronto Hydro staff/contractors are not available.
- Ensuring the Toronto Hydro's network is fully protected against cyber attacks.
- Find a solution how to monitor and control the subcontractor like Enercare

Priority Rankings: Top priorities include reliability, price, and system hardening

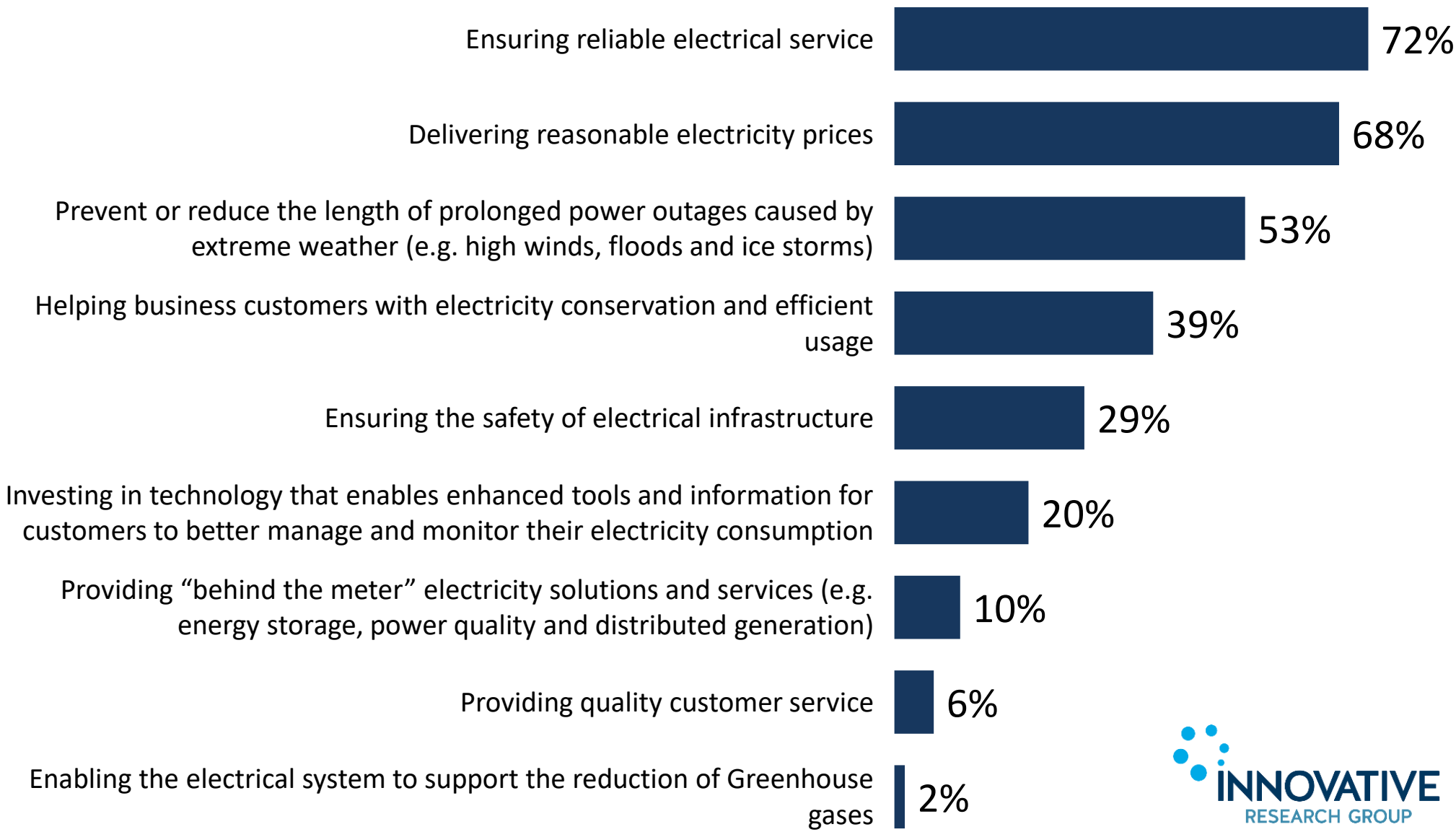
Q Thinking of these priorities, which are the top three most important to your organization?
[asked of all respondents; n=63; multiple mention]



Note: "Other priorities" (0%) not shown

Top 3 Priority Rankings: Majority ranked reliability, price, and system hardening as top priorities

Q Thinking of these priorities, which are the top three most important to your organization?
[asked of all respondents; n=63; multiple mention]

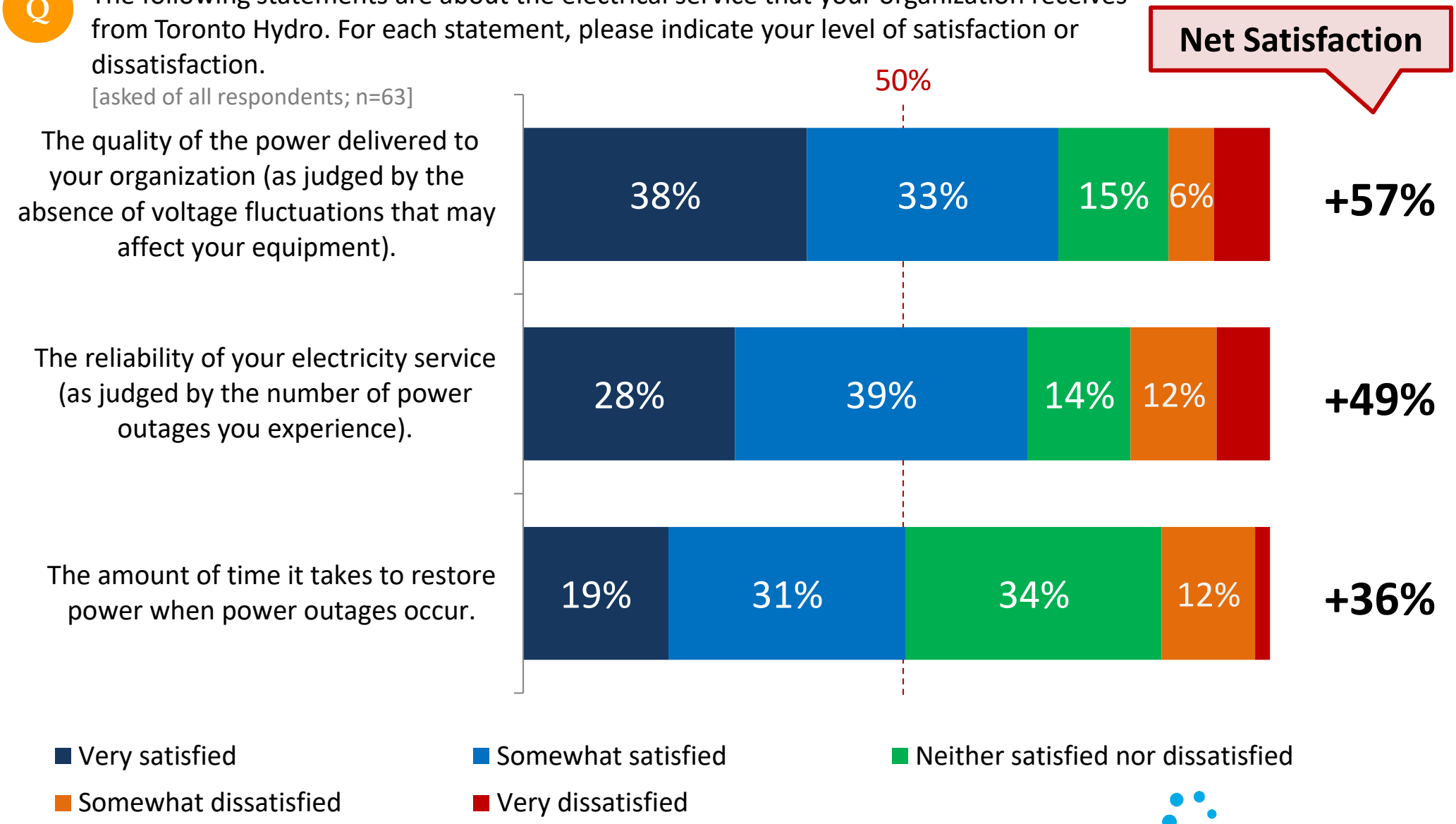


INNOVATIVE RESEARCH GROUP

Power Quality and Reliability: 57% net satisfaction for power quality, 49% for reliability, 36% for restoration time

Q The following statements are about the electrical service that your organization receives from Toronto Hydro. For each statement, please indicate your level of satisfaction or dissatisfaction.

[asked of all respondents; n=63]



Note: "Don't know" not shown

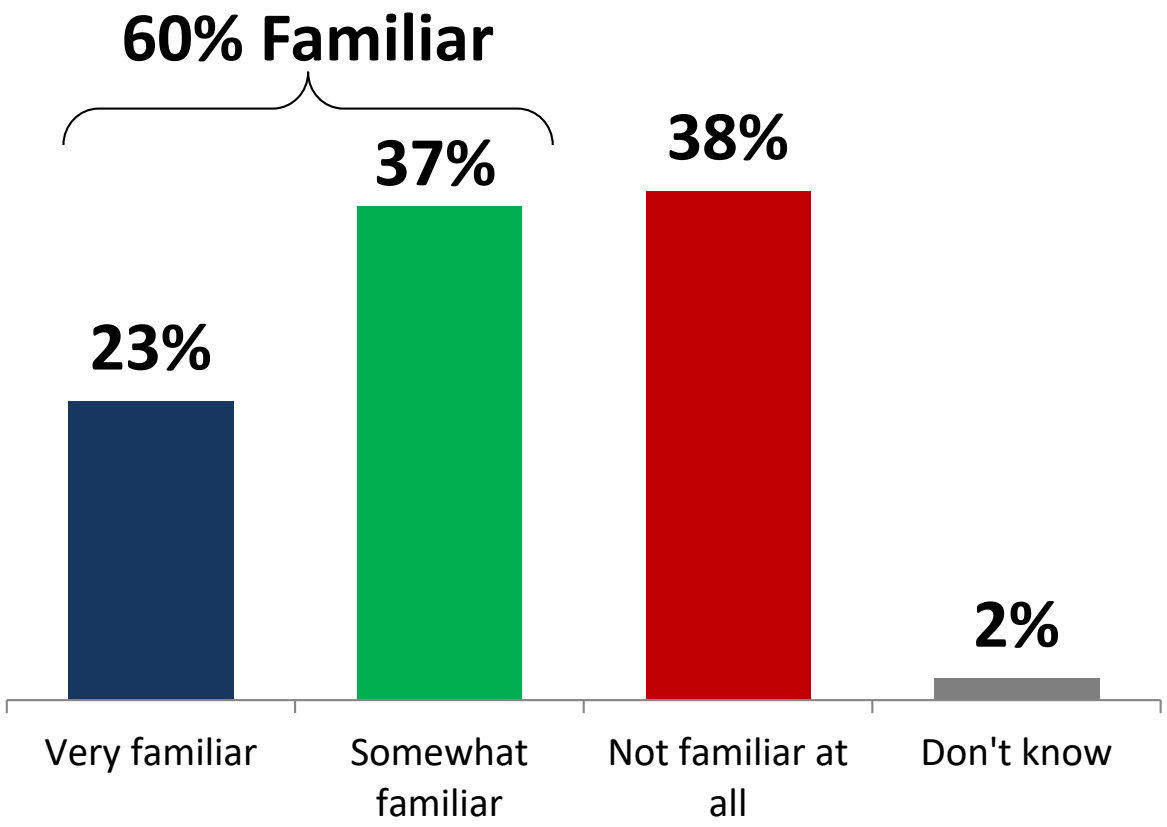
INNOVATIVE RESEARCH GROUP

Familiarity with Portion of Bill: 60% are familiar with 23% *very familiar*; MASH (68%) and MURB (80%) most familiar

Q While **Toronto Hydro** is responsible for collecting payment for the entire electricity bill, they retain only **about 8%** of the average key account's bill. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.

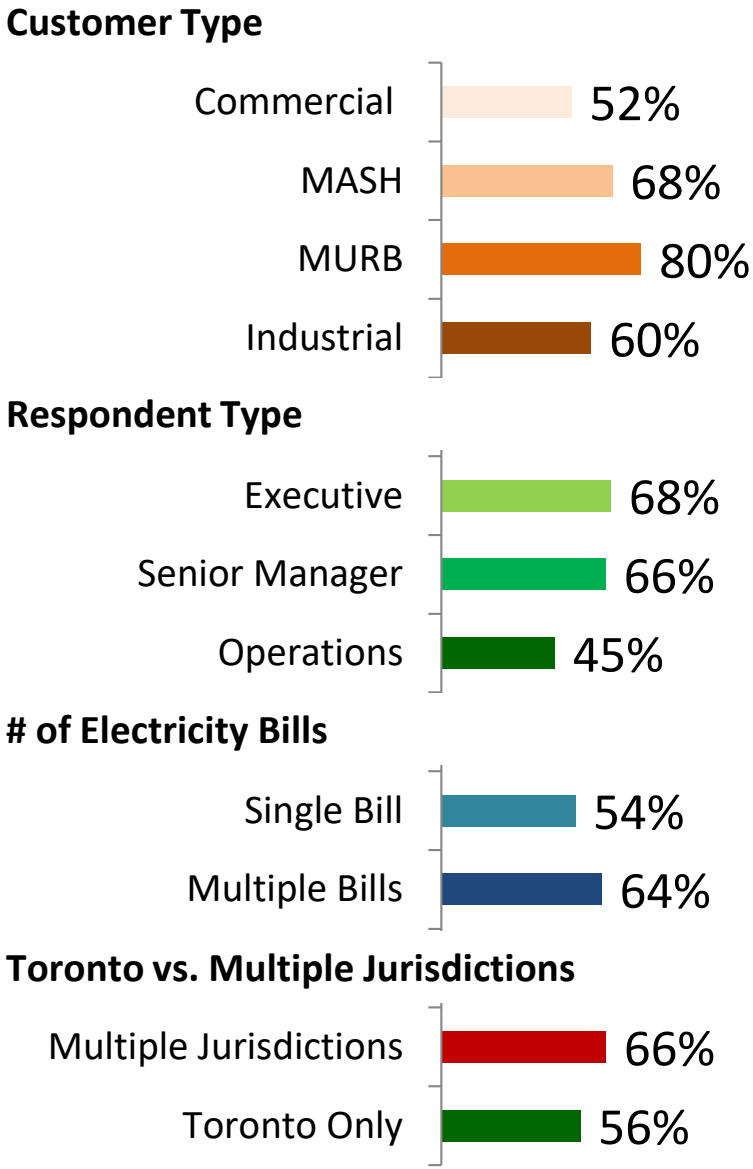
Before this survey, how familiar were you with the percentage of your organization's electricity bill that went to Toronto Hydro?

[asked of all respondents; n=63]



Segmentation ▸▸

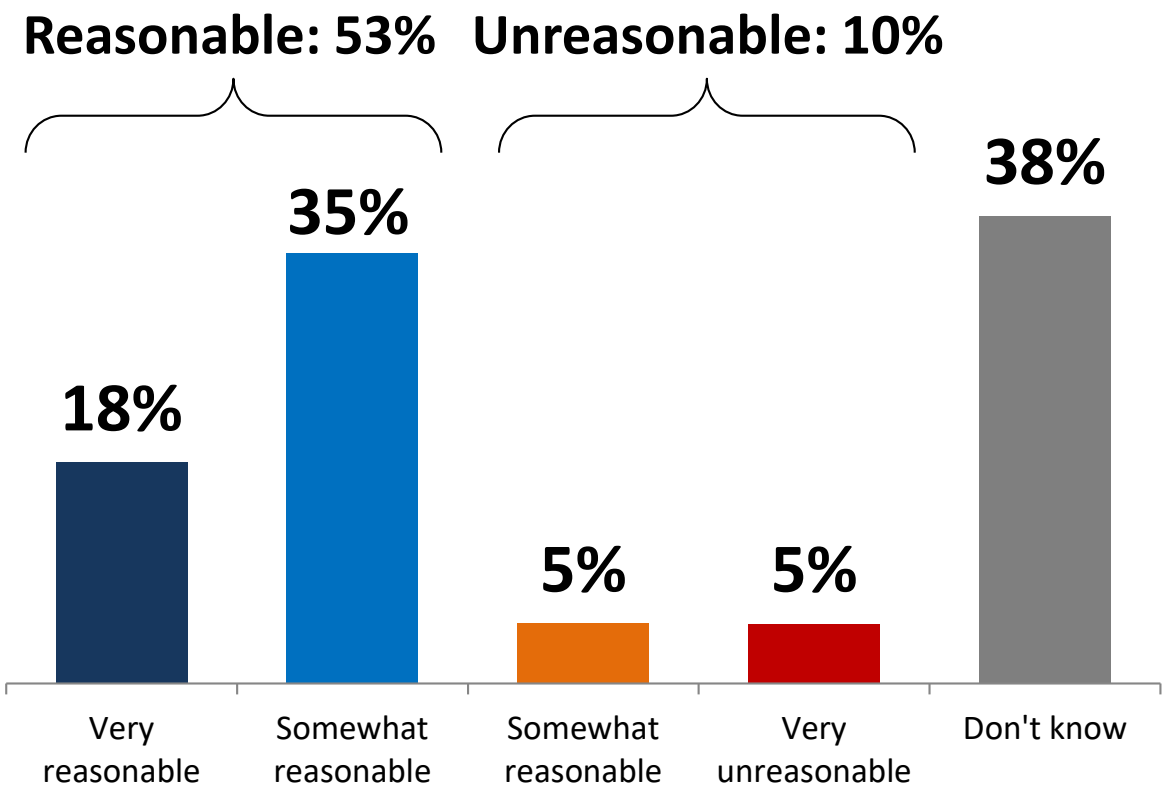
Respondents who say "Familiar":



Reasonability of Bill: Majority (53%) feel bill is reasonable; plurality (38%) don't know enough to say

Q Do you feel that the **8% of your organization's total electricity bill** that you pay to **Toronto Hydro** for the services they provide is reasonable, unreasonable or would you say you don't know enough to say?

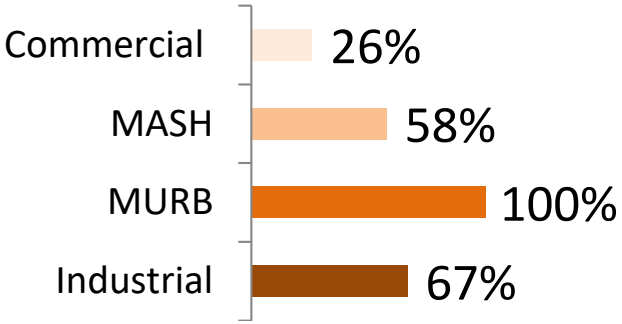
[asked of all respondents; n=63]



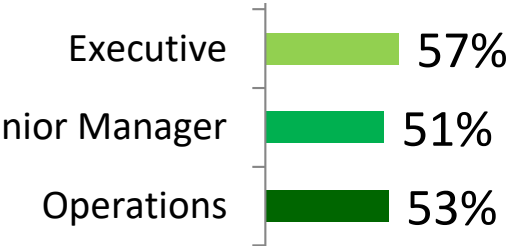
Segmentation

Respondents who say "Reasonable":

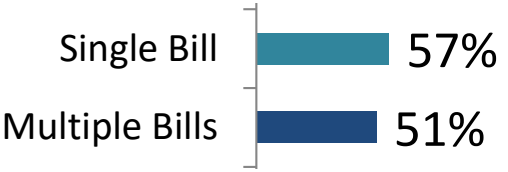
Customer Type



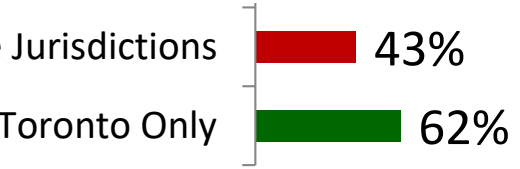
Respondent Type



# of Electricity Bills



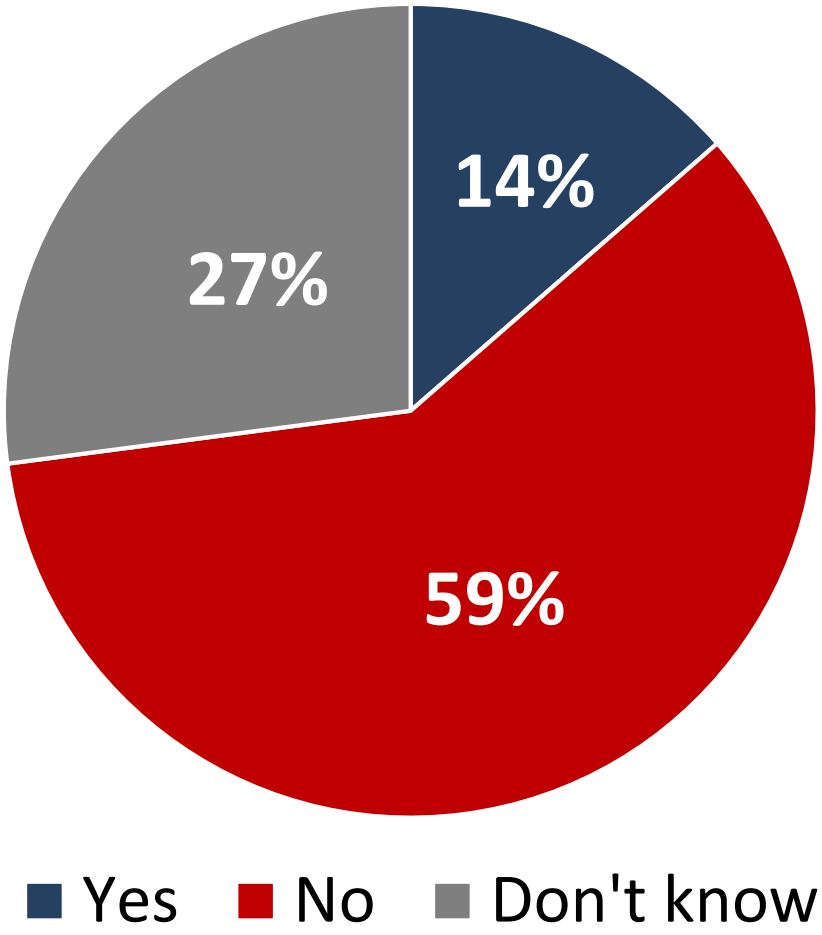
Toronto vs. Multiple Jurisdictions



Additional Services: Majority (59%) say there are no additional services they would be willing to pay for

Q

Are there any additional services that you would look to **Toronto Hydro** to provide and would be willing to pay for?
[asked of all respondents; n=63]



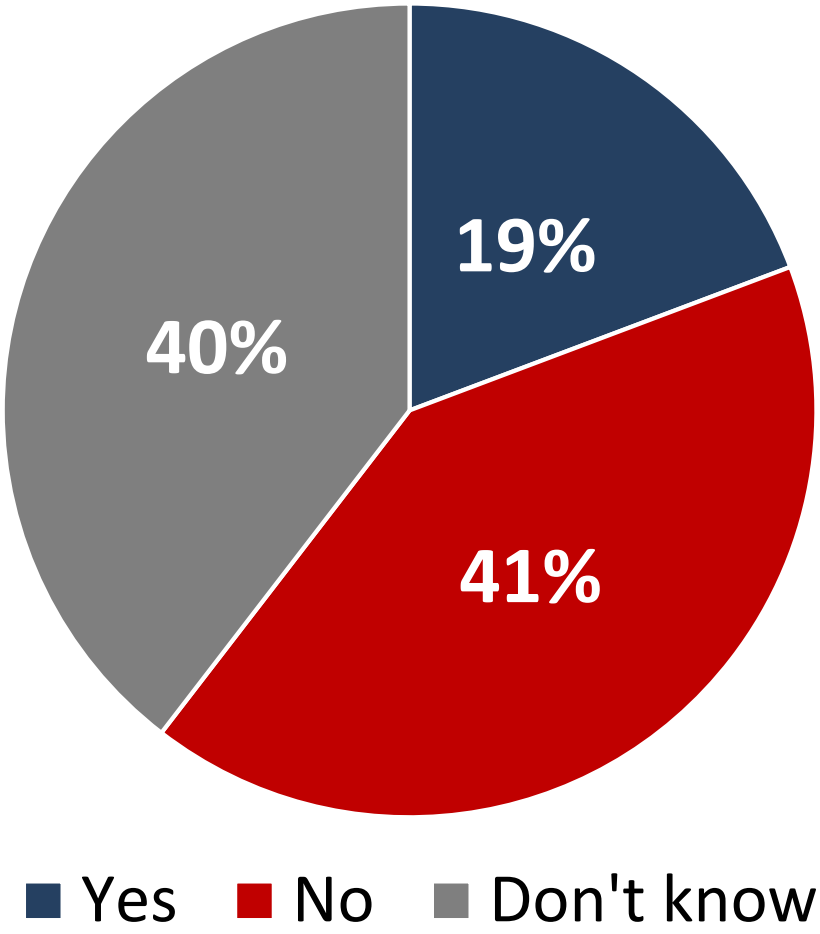
Additional Services Verbatim

- Additional seminar/training sessions for managers, executives and operations staff. Additional administrative assistance for filing applications, etc.
- Annual audits of energy usage on a per equipment/system basis.
- Electronic billing.
- Energy efficiency projects/solar.
- Energy management coaching. Energy storage implementation. Onsite distributed generation.
- Ensure system installed by Enercare is providing accurate data.
- Residential and commercial sub-metering.
- Seminar/updates on future and current projects, trends, etc.

Modified Services: One-in-five (19%) suggest modification to existing services; plurality (41%) *don't know*

Q Are there services that are currently offered by **Toronto Hydro** that could be done differently to better fit your needs?

[asked of all respondents; n=63]



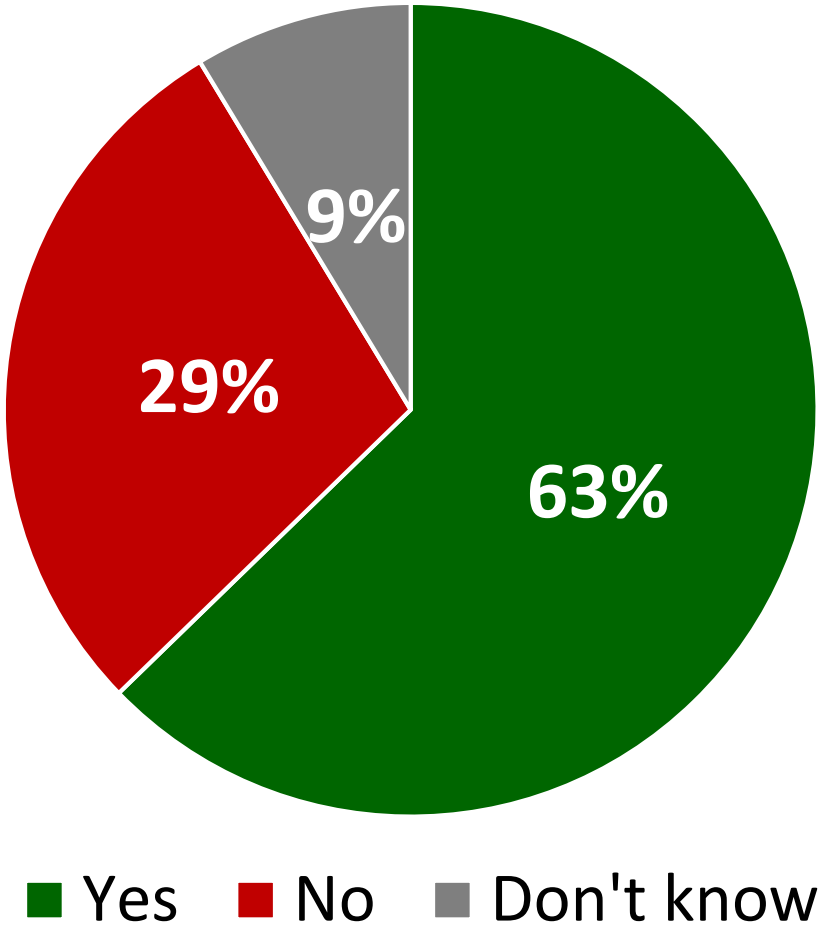
Modified Services Verbatim

- Better incentive explanation/support.
- Dedicated crews available for maintenance lock out.
- Demand side management program is very complicated and hard to use.
- Easy access for owner-managers to main meter interval data in a green button format via website or open API.
- Educate on trends in Global Adjustment and how to reduce it.
- Increased visibility into system studies so that we are able to expedite request that flow through that unit.
- Provide easier to read hourly and daily consumption in an electronic format that can be imported into our energy management software.
- Provide more access to ION interval meter capability to help diagnose power quality issues.
- Reviewing and approving drawings for hydro services takes too long.
- The incentive program can be difficult at times to modify the application, but thanks to T.H. representative the difficulties are dealt with in a timely manner.

Conservation Demand Management: Majority (63%) have participated in a CDM program

Q Has your organization ever participated in a **Toronto Hydro** conservation demand management (CDM) program?

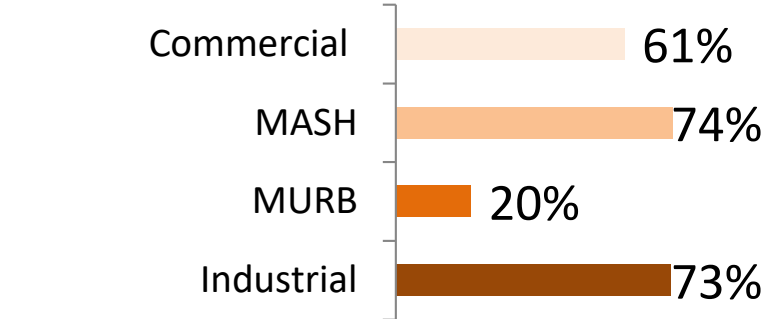
[asked of all respondents; n=63]



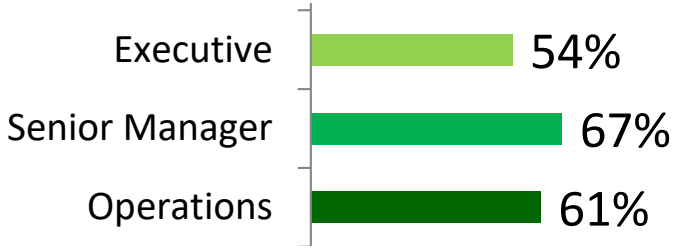
Segmentation

Participated in a THESL CDM program:

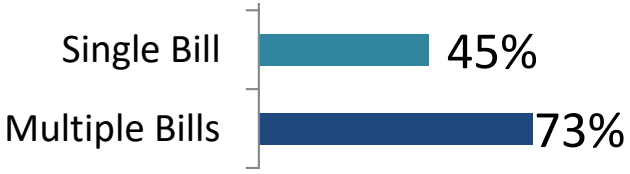
Customer Type



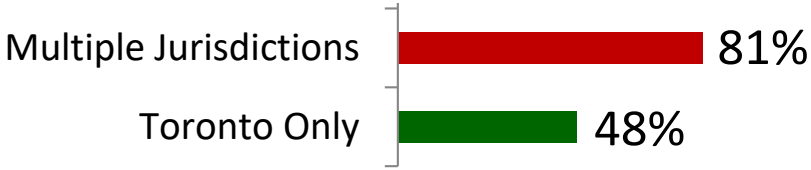
Respondent Type



# of Electricity Bills



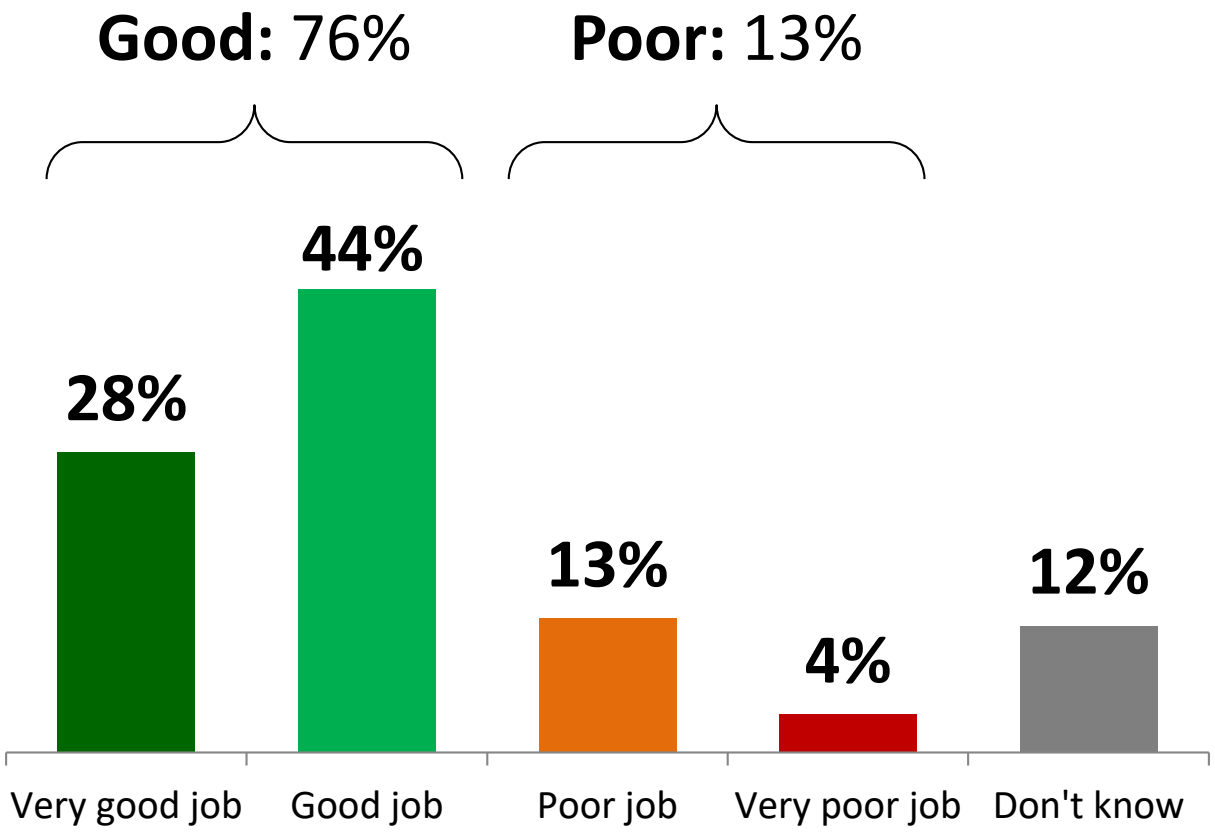
Toronto vs. Multiple Jurisdictions



Promoting CDM: 7-in-10 (72%) say Toronto Hydro does a good job of promoting CDM

Q How good or poor a job does **Toronto Hydro** do at providing your organization with information on available CDM tools and programs that can help you manage your organization's electricity bill?

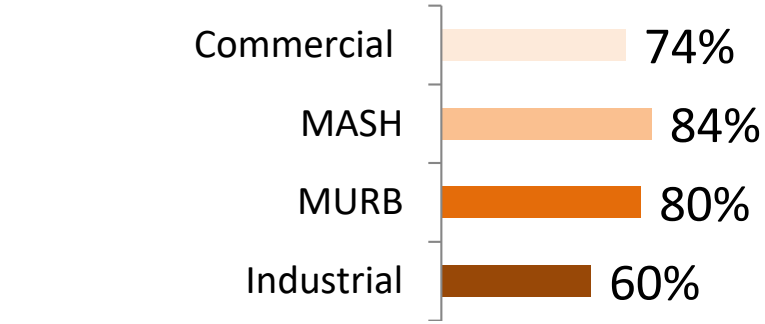
[asked of all respondents; n=63]



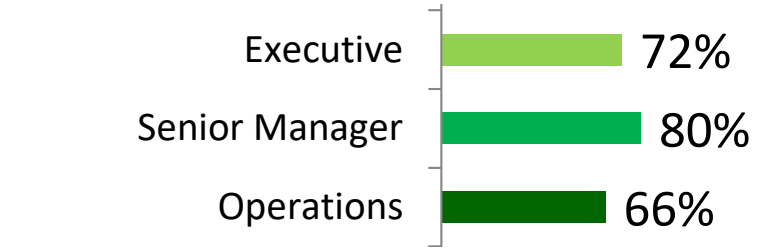
Segmentation

Respondents who say "Good Job":

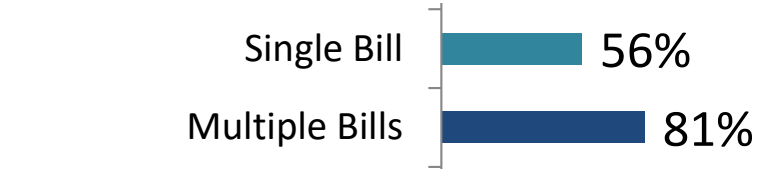
Customer Type



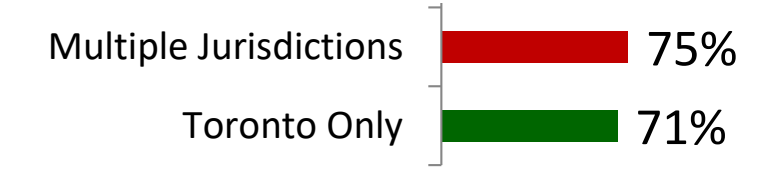
Respondent Type



# of Electricity Bills



Toronto vs. Multiple Jurisdictions



Improving the Promotion of CDM: More communication and opportunity for interaction a common theme

Q Is there anything that **Toronto Hydro** can do to improve how it shares information on available saving tools and programs with your organization?

[OPEN-ENDED; asked of all respondents; n=63]

Promoting CDM Verbatim

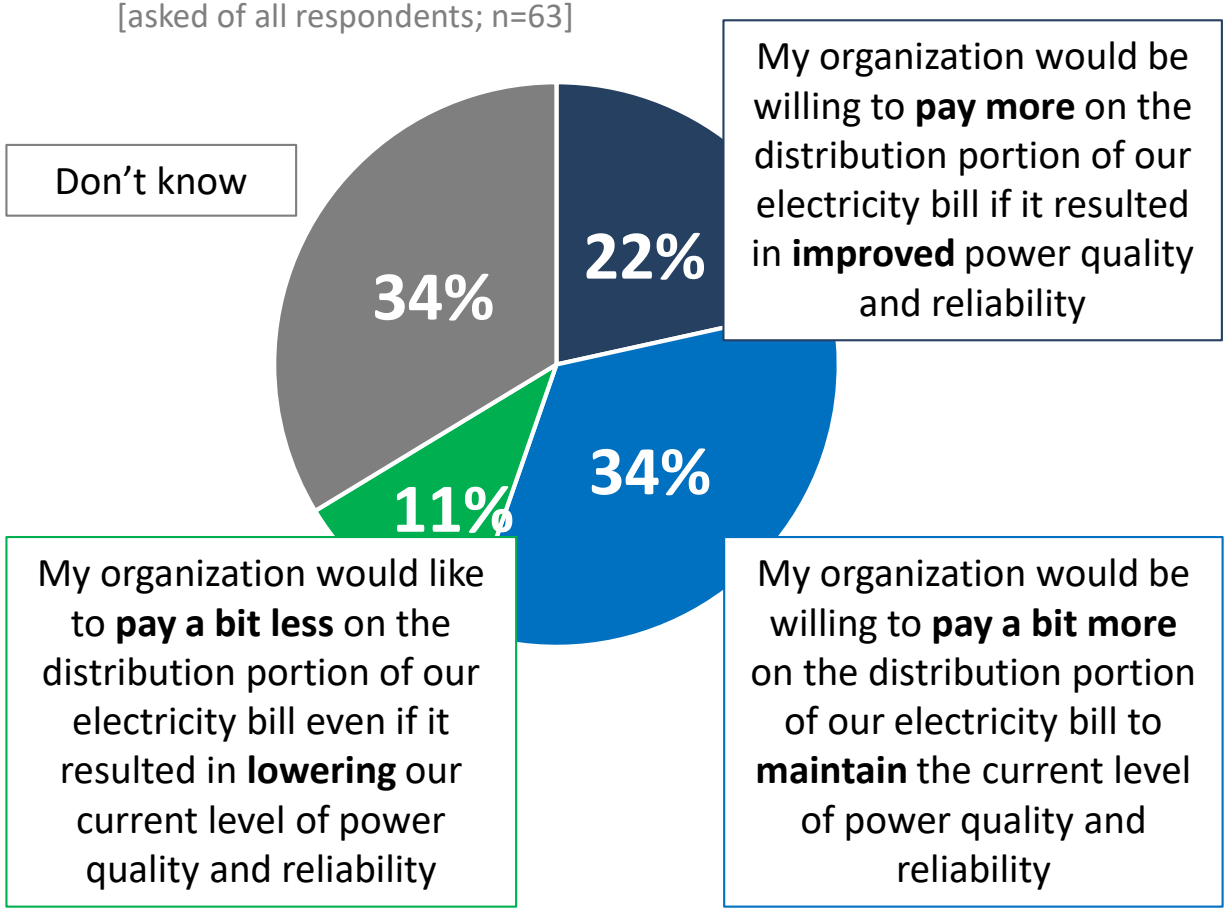
- A regular newsletter.
- Communication of available tools is important, there is always ways to improve.
- Energy into Action type forums should be run more often AND with other Utility stakeholders such as Enbridge gas distribution and TO Water. As each utility can offer COMPLEMENTARY energy management opportunities that when displayed in a vacuum don't make as viable an economic case.
- Find ways to help reduce consumption.
- Having easy-to-read one-pagers available that can be circulated to property management teams that outline all available IESO incentives (and steps to access them). Provide and annual meeting/webinar with all property managers to present/review Toronto Hydro services on offer, incentive application process, etc.
- I don't know what is available even though we have regular meetings with the Toronto Hydro representative.
- I will be attending my first Toronto Hydro meeting next week to discuss Global Adjustment. More of these opportunities should be scheduled.
- Improve the SaveOn Energy website and keep it current. It is not as user friendly as it can be and the applications are not being updated as they change. There are still several dated applications on the website that do not apply anymore.
- More email notifications.
- More information.
- Please provide us with the rate changes information, so we can budget our expenses.
- Provide more seminars for the commercial and industrial buildings.
- Providing data on a regular and shareable basis. I must point out however, that the Hydro staff have been extremely helpful in trying to bridge this gap and they should be commended for their great efforts - very much appreciated.
- Support on incentive applications - Intelligent incentives which Provide value
- Unsure. Sometimes receive the information, but most of the time other staff receive it before management.
- Updating by email to customers.
- We have a great relationship with Toronto Hydro, a roving Energy Mgr, and good personal contacts to ask questions of. No problems in this area.
- Workshops, webinars, emails.

Reliability and Price Trade-Off: Majority (56%) willing to pay more for improved or maintained reliability

Q Despite best efforts, no electrical distribution system can deliver perfectly reliable electricity. As a general rule, the more reliable the system, the more expensive the system is to build and maintain.

Thinking about the trade-offs between reliability and the cost of your electricity bill, which of the following statements best represents your general point of view?

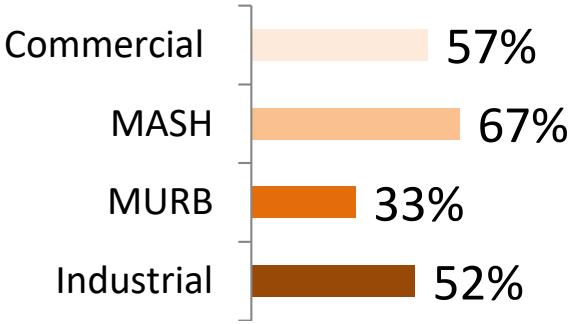
[asked of all respondents; n=63]



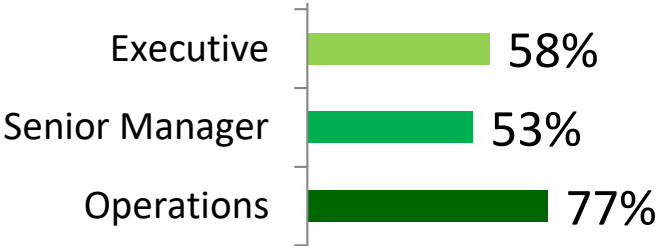
Segmentation ▸▸

*"Pay More" to either **improve** or **maintain**:*

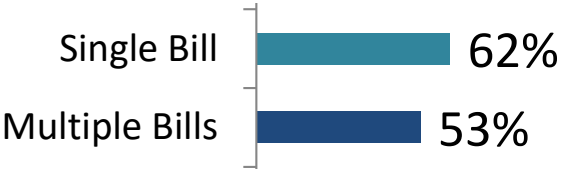
Customer Type



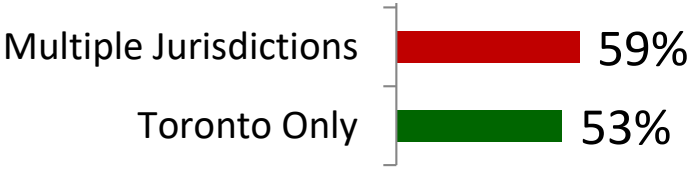
Respondent Type



# of Electricity Bills



Toronto vs. Multiple Jurisdictions



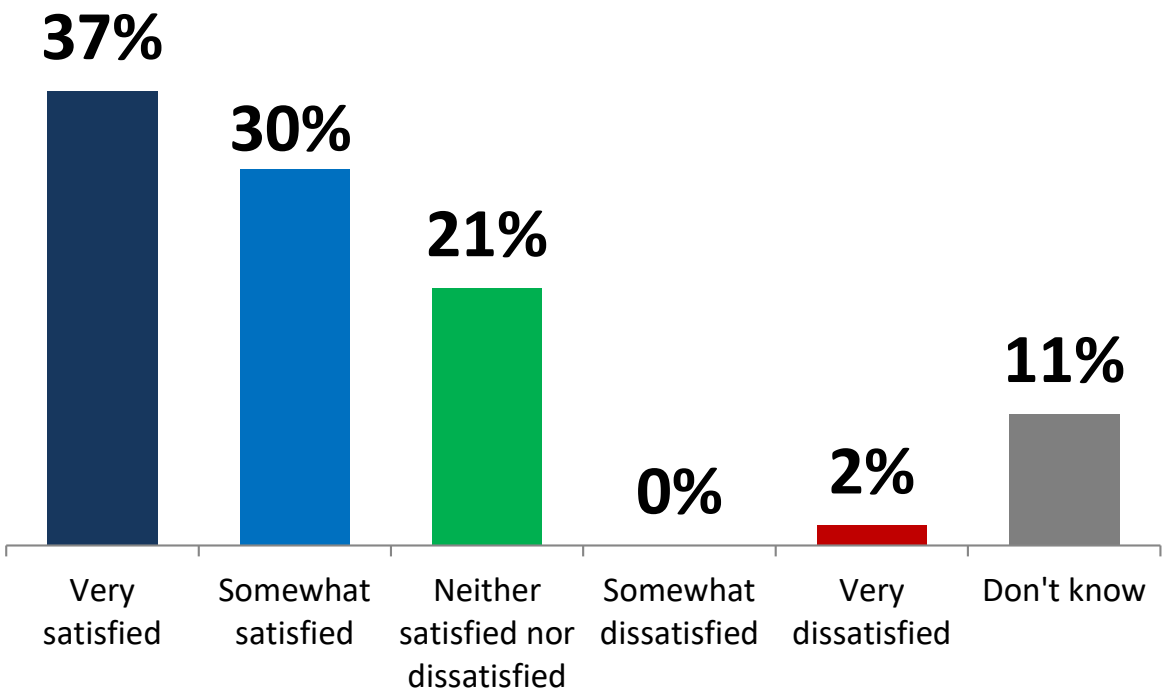
Satisfaction w/ KA service: Two-thirds (67%) satisfied with key account management; only 2% dissatisfied

Q How satisfied are you with **Toronto Hydro's** key account management services including after-hours information service and call number?

[asked of all respondents; n=63]

Satisfied: 67%

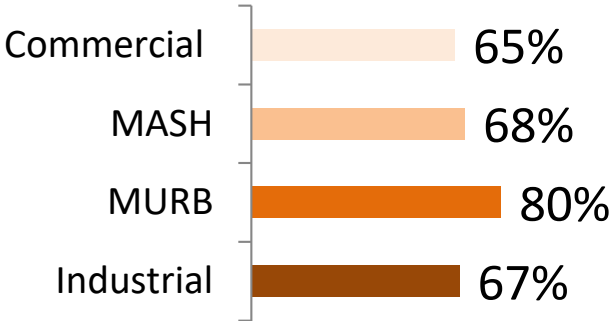
Dissatisfied: 2%



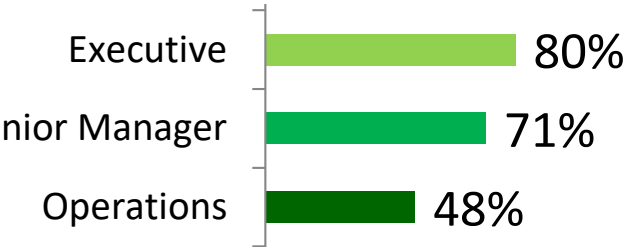
Segmentation ▸▸

Respondents who say "Satisfied":

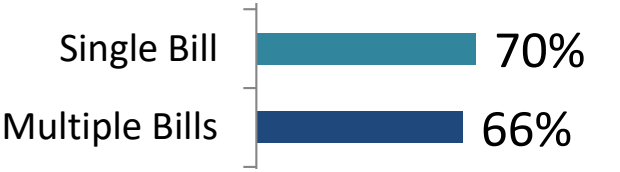
Customer Type



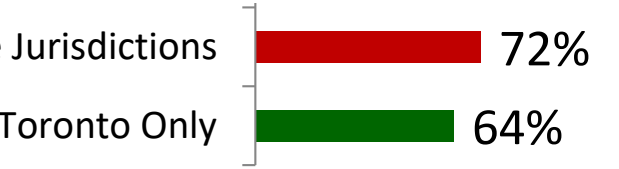
Respondent Type



# of Electricity Bills



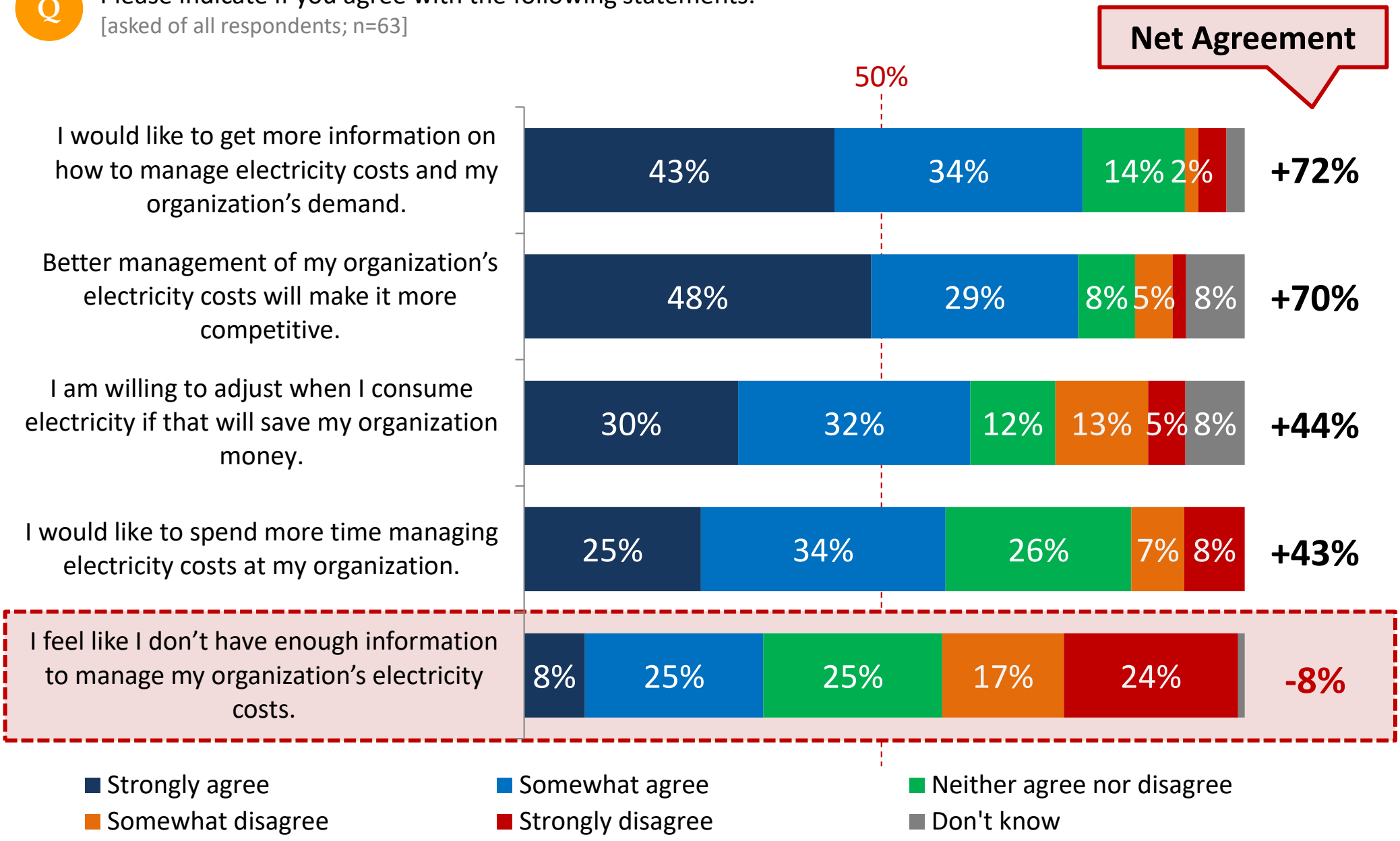
Toronto vs. Multiple Jurisdictions



Information Needs and Sources:

All measures reflect positive outcomes

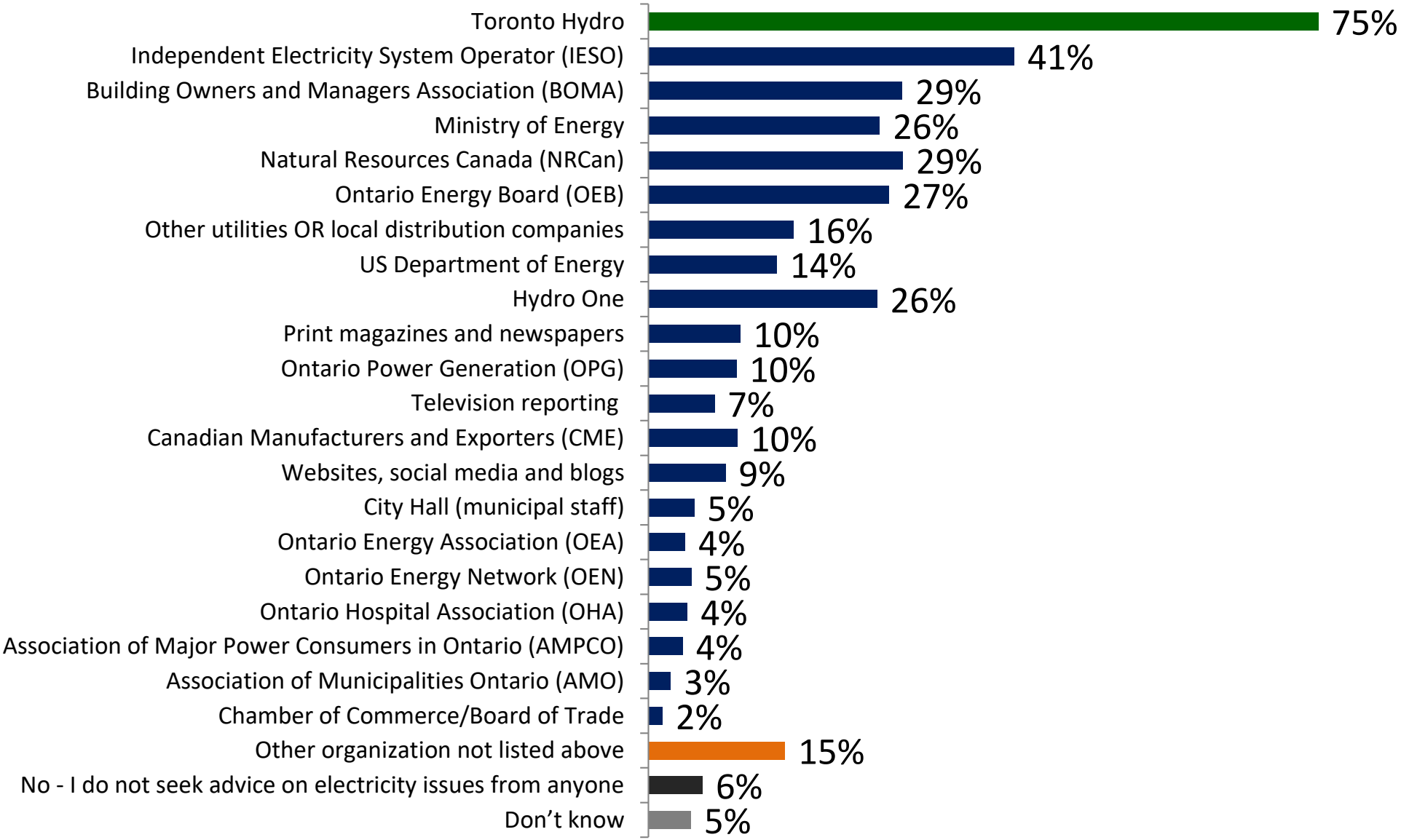
Q Please indicate if you agree with the following statements.
[asked of all respondents; n=63]



Electricity Info Sources: Toronto Hydro (73%) top mention, followed by IESO (38%) and BOMA (33%)

Q Do you seek advice and information on electricity issues from any of the following organizations or sources? If so, which ones?

[SELECT ALL THAT APPLY; asked of all respondents; n=63]



Organizations as Resources

Q Respondents were asked to further specify organizations or choices from the previous question.
[OPEN-ENDED; asked of all respondents; n=63]

Print Magazines and Newspapers

- Toronto Star
- Globe and Mail
- National Post
- Facility Manager Magazine
- Sales brochures and newsletters
- Plant Magazine

Television Reporting

- CBC
- City TV
- Global
- All networks

Websites, Social Media and Blogs

- US Energy Star

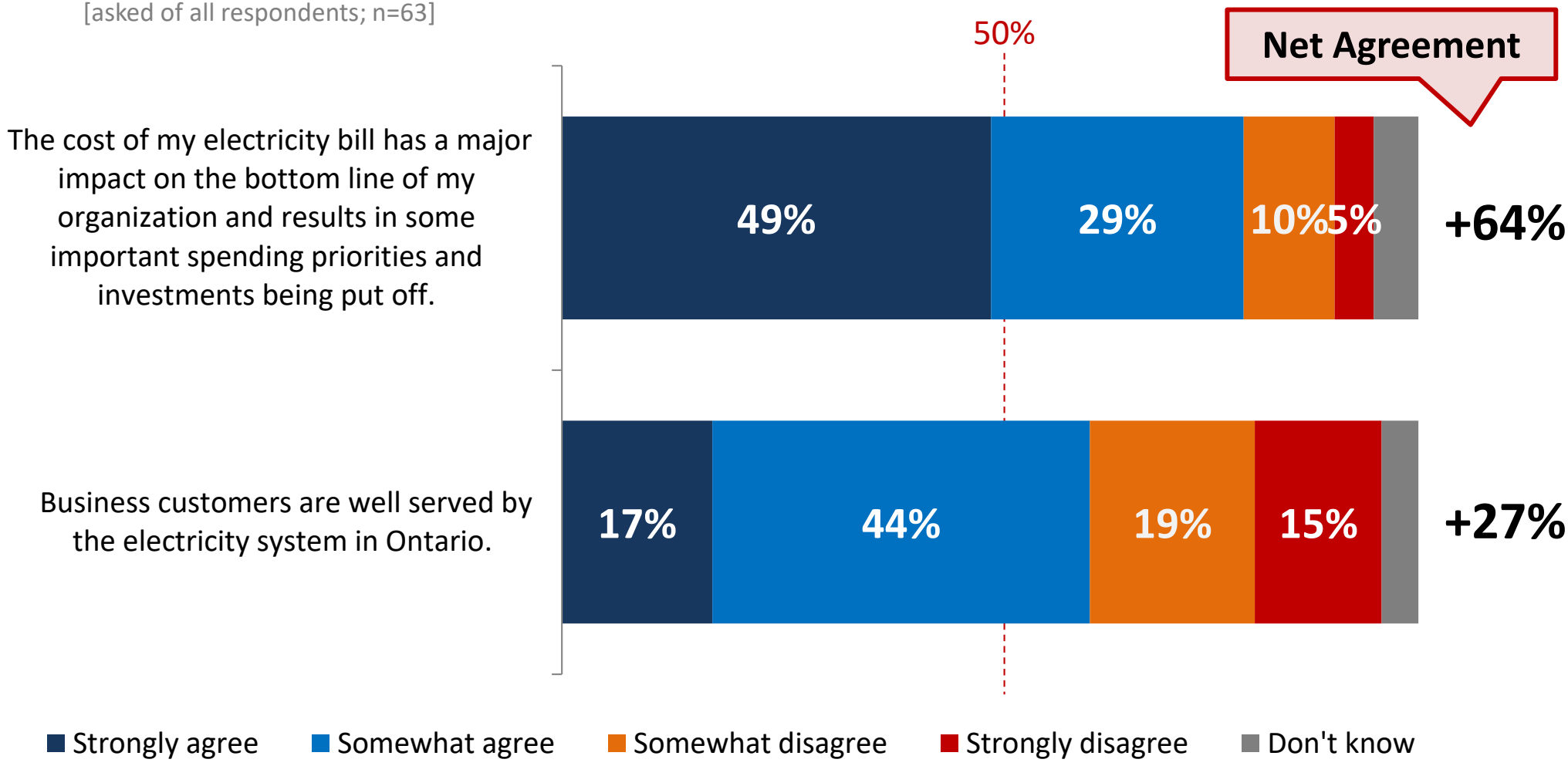
Other Organizations

- Bruce Power
- CaGBC
- Canadian Hospital Engineering Society
- Energy Profiles Ltd.
- Greening Healthcare and FM service provider
- Green Team
- HEADS UP Energy Efficiency
- Other LDCs across Ontario and nationally
- REALPAC
- Vendors

Environmental Controls: 79% agree that their bill has a major impact; 61% agree that customers are well served

Q For each statement, indicate to what extent you agree or disagree. If you don't know enough to say or don't have an opinion, please indicate below.

[asked of all respondents; n=63]



INNOVATIVE RESEARCH GROUP

Final Comments

Q Do you have any additional comments or feedback?
[OPEN-ENDED; asked of all respondents; n=63]

Final Comments Verbatim

- Global A opt-in is a disaster about to unfold. Between battery systems, gas gen sets and other GA busting being a Global B participant will be an ongoing disincentive to invest CapEx in the province.
- I have found working directly with some of your staff in helping us with energy saving incentives and initiatives to be highly motivated and extremely approachable professional who have provided very useful information to help us find the right solutions to save energy.
- Compliments to our Toronto Hydro Account Executive. He provides us with a one-stop shopping approach to energy savings and incentives support.
- I just received a letter in the mail this week from the Buffalo NY Bus development group soliciting our business transfer there to save money on taxes, incentives to move, lower electricity, labour training incentives... Clearly some business have already moved. We must get Hydro pricing in line to remain competitive and get me off the list with my Accounting people at my USA head offices who compare my Toronto plant with Kansas, Iowa, Ohio, and Kentucky.
- I know Toronto Hydro has nothing to with the Global Adjustment however, I believe money should be invested to find different sources of power. The GA has done nothing to help organizations like us.
- Improving Toronto Hydro's website to provide more customer related info. e.g planned outages, incentive programs, would be helpful. Improving MVWeb is essential.
- Rates are an issue.
- Reliable power and power quality is very important to our business. Outages, brownouts, sags and surges impact equipment reliability and ongoing business operations.
- Toronto Hydro needs a stronger voice on development in Toronto. Existing customers cannot have their power supplies diminished in quality in order to provide new services for new development. Costs should be the burden of the developers and no approvals given until it is determined by an independent third party that existing supplies can handle more intensity. If the service needs to be upgraded, the developer pays.
- Victor and Team are excellent.
- Waste less, and charge us less.

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APPENDIX 1.5

Stakeholder In-depth Interviews

June 30, 2017

Prepared for:

Toronto Hydro

14 Carlton Street

Toronto, Ontario M5B 1K5

Table of Contents

1. Stakeholder In-depth Interviews 2

1.1 Methodology 2

1.2 Key Findings 3

1.2.1 Toronto Hydro's fit with organizational mandates 3
1.2.2 Expectations of Toronto Hydro 3
1.2.3 Future electricity challenges 4
1.2.4 How should Toronto meet perceived challenges 4
1.2.5 What the balance between costs and meeting challenges 4

1.3 Participant Profile 4

1.4 Stakeholder Priorities 5

1.5 Detailed Findings 6

1.5.1 FRPO/GTAA 7
1.5.2 Association of Condominium Managers of Ontario 9
1.5.3 Housing Services Corporation/Toronto Community Housing Corporation 10
1.5.4 United Way of Toronto and York Region 12
1.5.5 Bloor-Yorkville Business Improvement Area 13
1.5.6 Metropolitan Toronto and Region Conservation Authority 14
1.5.7 Toronto Financial Services Alliance 16
1.5.8 Coalition of Concerned Manufacturers 18
1.5.9 Leslieville Business Improvement Area 19

1. Stakeholder In-depth Interviews

Following our iterative research process, the key influencer/stakeholder in-depth interviews were designed based on feedback collected from prior qualitative research steps.

1.1 Methodology

Objective

Using an exploratory research methodology, our objective was to obtain insights into what customers expect of Toronto Hydro, particularly in terms of what represents value to customers and what customer priorities for Toronto Hydro are, from key influencers – associations, charities and municipal agencies whose members have significant interaction with, impacts from activities of and social and/or commercial stakes in the outcomes of Toronto Hydro.

These stakeholder groups represent the views of specific cohorts or categories, and while some of those cohorts or categories have been participants in other research feedback as individual members, the objective in this phase was to obtain a higher level, industry or cohort view, that represents the consensus views of each group.

Approach

Nine on-site in depth interviews were conducted between June 12 and June 30, 2017, all at the respondent organization's offices.

Participants were selected and initially contacted by Toronto Hydro, from their list of key impacted or influencer groups. In particular, participants were selected to represent those who may not have direct contact with Toronto Hydro's Key Account team, or who were determined to have views and input of relevance that may not be otherwise collected or considered.

We deployed a detailed *Discussion Guide*, used to moderate all sessions. No materials were shared with participants before or during the sessions, although those who asked were provided with an outline of topics to be covered in advance.

The sessions were moderated by INNOVATIVE Vice-President Robert Hutton. Toronto Hydro representatives accompanied to every session. Their role was twofold – to assist the facilitator should technical questions or matters came up beyond his limited technical expertise, and to listen as observers.

This report summarizes key findings, and offers observations and potential strategic avenues based on these groups and past research. *Respondent verbatim responses are in italics.* In general, our approach in reporting is to allow the respondents to be heard as much as possible, utilizing notes taken during the sessions and summaries from observers, and representative verbatim comments, offering interpretation and comment where necessary.

Please Note: Qualitative research does not hold the statistical reliability or representativeness of quantitative research. It is an exploratory research technique that should be used for strategic direction only.

A note on interpreting focus groups findings: In focus group research, the value of the findings lies in the *depth* and *range* of information provided by the participants, rather than in the *number* of individuals holding each view. References in this report such as "most" or "some" participants cannot be projected to the full population. Only a large sample, quantitative survey would be accurately projectable to the full population.

Interview Structure

The interviews were semi-structured based around five themes:

1. Where Toronto Hydro fits with the organization's mandate?
2. What are the key expectations of Toronto Hydro among stakeholders?
3. What are the issues or challenges in electricity distribution seen emerging over the next decade?
4. What are the expectations of Toronto Hydro in response to these challenges?
5. What is the balance between costs and investment to meet those challenges?

Specific probes were deployed throughout on safety, reliability, demand/capacity, quality and customer service.

Topical probes deployed were on price, efficiency, technology, social impacts and environmental impacts. Not all probes applied to each stakeholder, so probes were adapted to suit each context.

1.2 Key Findings

1.2.1 Toronto Hydro's fit with organizational mandates

- Distribution fit with all mandates
- Key aspects in common: reliability, cost, infrastructure renewal
- All have differing, but significant, interruption costs and impacts
- All see Toronto Hydro as a key collaborator and as a natural integrator with other system elements
- All had elements of social outcomes that fit with Toronto Hydro's mandate

1.2.2 Expectations of Toronto Hydro

- Reliability is the primary expectation and is 'table stakes'
- Cost is an expectation, but less reduction than containment, and does not trump reliability or higher level and longer term social outcomes
- Resilience of infrastructure, not only physical, but virtual
- Collaboration is a common expectation – increased engagement, coordination
- Easier access to incentives, particularly retrofits, is a need
- Focus incentives on better returns and consumption/waste reduction
- Systems approach – be an integrator and information hub
- Increase focus on, and visibility in, social outcomes

1.2.3 Future electricity challenges

- Maintain reliability
- Building renewal
- Behaviour modification is limited by lack of unit metering and other government policy
- Grid renewal, community renewal
- Development growth
- Cybersecurity

1.2.4 How should Toronto meet perceived challenges

- Electricity literacy is low, misinformation is common – increase outreach and communication, at street level
- More strongly advocate with provincial government

1.2.5 What the balance between costs and meeting challenges

- Reliability far outweighs cost considerations
- Cost increases must be tempered with cost containment
- Target investment to greatest long tern returns
- Include social outcomes in evaluation criteria

1.3 Participant Profile

Federation of Rental Housing Providers/Greater Toronto Apartment Association

- **Mandate**: Advocacy, government relations
- **Constituents**: Property managers and building owners
- **Key Issues**: Sub metering, building renewal, energy retrofit incentives, vaults, energy costs

Association of Condominium Managers

- **Mandate**: Advocacy, government relations
- **Constituents**: Condominium managers and corporations
- **Key Issues**: Energy costs, time of use, unit metering, inconsistent power, energy retrofit and conservation programs

Housing Services Corporation/Toronto Community Housing

- **Mandate**: Advocacy, government relations
- **Constituents**: Low income and not for profit housing providers
- **Key Issues**: Energy affordability, housing stock retrofits, sustainable occupancy, targeted incentives

United Way

- **Mandate**: Poverty reduction
- **Constituents**: Member agencies, vulnerable populations

- **Key Issues**: Energy costs, tower renewal, access to incentives, energy retrofit and conservation programs

Bloor-Yorkville BIA

- **Mandate**: Advocacy, government relations
- **Constituents**: Local businesses
- **Key Issues**: Lampposts, local development, customer service

Metropolitan Toronto and Region Conservation Authority

- **Mandate**: Greenhouse gas reduction
- **Constituents**: Commercial building owners
- **Key Issues**: Energy waste, incentive programs, retro-commissioning, grid planning

Toronto Financial Services Alliance

- **Mandate**: Advocacy, promotion
- **Constituents**: Financial services sector
- **Key Issues**: Reliability, continuity, stability, cybersecurity

Coalition of Concerned Manufacturers

- **Mandate**: Advocacy
- **Constituents**: Small to mid-sized manufacturers
- **Key Issues**: Energy costs, ICI, global adjustment, combined heat/hydro solutions

Leslieville BIA

- **Mandate**: Advocacy, government relations
- **Constituents**: Local independent businesses
- **Key Issues**: Energy costs, reliability, sponsorship, customer service, local development

1.4 Stakeholder Priorities

Reliability: Industry associations held reliability as by far, their overreaching top priority.

Social Outcomes: social organizations also held reliability as top priority, but also held social outcomes as a key priority (e.g. community renewal, sustainable living).

Price: Manufacturing association held price above all else, far above reliability. Specifically, this stakeholder was seeking a price reductions as opposed to price stabilization.

Price Predictability: Both industry and social organizations favour price stabilization and predictability over absolute reductions (e.g. reasonable price increase are accepted by this group of stakeholders).

Biggest concern with the price of electricity is not distribution rates, but rather the global adjustment that has been unpredictable over the past decade.

Risk Mitigation: Resilience of infrastructure – defined as an ability of withstand adverse events which may be physical or virtual – appears to be a key priority for almost all stakeholder groups.

Socio-economic Outcomes: Every group, in varying ways, cited socio-economic outcomes as an increasing priority (e.g. impact poverty, employment, cost of living, quality of life, economic competitiveness, etc.).

Incentive Programs: Better target incentives where there is the greatest long-term benefits. Make it easier to access incentives.

Other: Specific points of service friction with Toronto Hydro (e.g. vaults, sub-metering, inconsistent power quality, collaboration and communications on development projects, lampposts).

Summary of Priorities by Stakeholder Group

Housing & Social Services	Large Commercial
• Reliability far outweighs cost • Sub-metering is a key constraint • Conservation efforts constrained by lack of sub metering and time of use • Building renewal and retrofitting are priorities • Quality and consistency of power is a key need • Incentive programs need to be more accessible and may not be targeted at greatest returns • Social outcomes need to be considered	• 24/7 reliability is table stakes • Cybersecurity is a priority • System resilience is a concern • Behind the meter innovation is a need • Cost is not a significant factor • Reliability is a competitive advantage
Small Commercial	**Small / Mid-sized Manufacturing**
• Reliability is 24/7 • Customer service is the key need – lampposts, local development, outages • Cost is primarily a concern among local, micro businesses	• Cost is a significant survivability factor • Reliability not a concern • ICI fairness is a need • Global adjustment is a friction point, impairs budgeting

1.5 Detailed Findings

Across all participant groups, respondents were asked first a series of introductory questions to establish baseline context and direct the discussion to Toronto Hydro's role as the local distributor. A key opening topic was to establish the cohort or constituency the participant was representing, to establish whose views were being represented.

Participants were asked if they wished for their input to be provided in confidence, with the usual confidentiality disclaimers of qualitative research, or, recognizing many have a mandate to provide advocacy and input on topics affecting their members or representative cohort, they wished to respond 'on the record 'on behalf of their organization, with identity attribution.

With one exception, and in that case only because the participants did not have authority, confidentiality was waived and attribution requested.

1.5.1 FRPO/GTAA

Group 1 was a dyad, with the Greater Toronto Apartment Association (GTAA) and the Federation of Rental Housing Providers of Ontario (FRPO).

FRPO members tend to be larger property owners and managers "*as the industry has become a lot more professional*". These include OMERS, many REIT's, insurance companies as well as some members who supply the industry. FRPO's focus is on advocacy and government relations. A key area of advocacy is in improvements in rental housing stock, where energy efficiency is a key focus. FRPO represents over 50,000 rental housing units across the province. It offers a certification program and a designation for buildings incorporating over 50 standards including green energy.

GTAA membership overlaps significantly with FRPO, but only within Toronto. Its members represent over 150,000 rental units across the GTA, all-purpose built housing, representing about 60% of the total rental housing stock. All its members are landlords in the primary rental market.

Neither FRPO nor GTAA may be fully representative of smaller landlords.

Sub-metering was seen as a key conservation strategy, but blocked by provincial regulation for electrical heat. This defeats attempts to modify resident behavior and effectively blocks the main route to developing a conservation consciousness among tenants.

> *"Sub-metering is a big issue – it is highly regulated. 10 to 15% of old buildings are heated with electricity. It is illegal to sub-meter electrical heat, then there is a socio-economic issue."*
>
> *"Changing people's habits is the biggest impediment to conservation. As there is no sub-metering, residents don't change habits as a result of billing."*
>
> *"There tends to be more people living in a unit than before."*
>
> *"It would be helpful if Toronto Hydro came out advocating for sub-metering. Push government to (allow) sub-metering."*

Provincial rent control regulations were seen to block landlord ability to invest in energy conservation, as well as being in conflict with policy goals to maintain current stock and build new affordable rental supply. Both felt that the $400mm provincial green investment fund is focused on emerging technologies, rather than practical solutions their members could take advantage of – an example was retrofitting windows, a main source of energy loss.

> *"The province has a $400mm program for conversion which is not very helpful."*
>
> *"The 50% bumpup will not have much uptake as few are sub-metered."*
>
> *"The province has embarked on energy benchmarking. A lot is done in a vacuum – to create incentives that work needs to be done in collaboration."*
>
> *"No longer being allowed to apply for above guideline increases for utilities."*

Landlords have difficulty navigating the available incentives and it would be useful to aggregate into an easily accessed form. Also, the application process was seen as deterring uptake of incentive programs.

There should be something on the (Toronto Hydro) website that is a one-stop shop for programs that are available."

Citing overall widely varying and overall minimal energy literacy among property owners and managers, may struggle with assessing energy consultants who approach them and in selecting technical solutions or equipment.

"Pre-qualify consultants who approach buildings offering energy conservation solutions or equipment."

Vaults were identified as a friction point. Prioritizing upgrades of vaults in older buildings is a priority, and moving them outside buildings where they can be more easily accessed and less of a risk is also seen as important. As electrical vehicles become more of an issue with landlords, vault location will become more or a critical factor, in being able to install charging stations often underground, under one or more floors of concrete. Disclosure of vault inspection findings was also seen as helpful.

"Toronto Hydro vaults in buildings is a sore spot. When something happens, the landlord takes the blame. Toronto Hydro doesn't share info or history on vault inspections. Most are in older buildings and) need an upgrade program or have them moved out of buildings.

"Prioritize infrastructure upgrades on older buildings and areas."

There was confusion over the implementation of the Fair Hydro Plan. The Fair Hydro Plan was seen as acting together with new rent control legislation to create a significant risk to landlords if, after the plan expires, rates skyrocket.

"Different utilities are dealing with the 17% reduction in different ways."

"Fair Hydro Plan – what will happen after the next election?"

"Do we start to create a reserve fund for 10 years down the line when costs jump up massively?"

"There is a big inequity in terms of applying the reduction in debt retirement charge, those with sub-metering companies have a big advantage."

Overall both saw reliability as very good, but note that when an interruption occurs, the impacts on tenants can be severe, particularly in winter months

"There are increasing failures of hardware – Toronto is working to make backup generation mandatory."

"For reliability (interruptions) the tenants and the media blame the landlord."

FRPO in particular was interested in collaborating with Toronto Hydro to act as a central hub for landlords to access resources such as incentive programs, rate plan information and conservation information.

Both felt that more regular stakeholder engagement would be beneficial, and asked that Toronto Hydro step up advocacy particularly when political decisions have broader ramifications on landlords, and tenants.

"Have annual meetings like this, maybe (together) with other LDCs"

"Speak up when politicians do something not in the interests of citizens."

1.5.2 Association of Condominium Managers of Ontario

Group 2 was an in-depth interview with the Association of Condominium Managers of Ontario (ACMO).

ACMO represents over 1,000 condominium managers and 6 to 7,000 condominium corporations. In turn, these members represent over 700,000 condominium homeowners across Ontario, out of the 1.1mm people living in condos in the province. The bulk of those condominiums are in the GTA.

A major issue the industry faces is that "*there are not enough condo managers to go around*" and as a result energy literacy and technical ability vary widely. However, the new Condominium Act will bring rapid 'professionalization' to the industry, which will be an opportunity for Toronto Hydro to step up CDM collaboration and education.

With respect to Toronto Hydro, this impacts ability to manage rising costs and implement cost saving technologies, but also has more practical implications in being unable to budget hydro costs reasonably.

> *"The major issue is dealing with the costs that are ever escalating." "Helping our stakeholders keep costs in check is a constant battle."*
>
> *"The uncertainty – trying to get budgets done without really knowing where rates are going."*
>
> *"We fight time of use constantly – we can't do much with individual unit owners, but we still have to pass on those costs."*
>
> *"Individually metered units vs. bulk metered units is a challenge."*

A major issue is inconsistent power – providing a consistent 60Hz cycle. Power surges are damaging variable frequency drives and other sensitive equipment, as well as resident equipment. Toronto Hydro could assist by providing a conduit that property managers could coordinate with in logging and identifying sources of spikes.

> *"The other problem is inconsistent power – particularly buildings with centralized systems – there are a tremendous number of spikes."*
>
> *"We need Toronto Hydro to provide a cleaner feed."*
>
> *"Variable frequency drives are being installed – VFD's do not like spikes – members lost 9 VFD's in 6 months. We can't get a consistent cycle rate."*
>
> *"Toronto Hydro can help document that – ACMO can get a notice out to members to start tracking & logging spikes – we need a conduit through Toronto Hydro."*

ACMO is generally supportive of incentive programs, particularly energy retrofit incentives, but questions whether the amount of the incentives is proportionally fair with respect to the benefit Toronto Hydro is seen as receiving.

> *"We need retrofit programs and better conservation programs."*
>
> *"With the amount of the rebate, we are helping Toronto Hydro more than they are helping our members."*

The practice of estimating bills creates problems for the industry:

> *"Estimated bills is another problem – considering the technology available, there is no reason still to do this, it creates havoc with our budgetary process."*

"Accuracy of the metering is not a problem."

The issue of rates rising faster than inflation was brought up, in context of perceptions that Ontario is selling off excess energy at lower rates while infrastructure has been deterioration. This was seen as a lack of information and knowledge creating a vacuum in which negative perceptions can be formed, and ACMO noted that media reports on perceived excessive executive compensation tend to paint all LDC's with the same brush. Education on the global adjustment, distribution vs. transmission and understanding bill components could assist in this regard.

"For smaller buildings, the distribution cost seems out of proportion in relation to the commodity cost. (Toronto Hydro) needs to explain distribution costs better."

In terms of future issues, the major challenge was seen to be infrastructure supporting vehicle electrification. The industry faces significant barriers, both in the requirement under the Condominium Act for Board approval for substantial changes and in absorbing costs. The industry is looking to Toronto Hydro to ensure capacity is sufficient to enable EV charging and to provide financial incentives to help defray costs.

Overall, ACMO was looking for Toronto Hydro to engage the development community earlier and more often on energy upgrades to buildings.

"Reach out to developers to intervene (earlier) as part of the conversion process when upgrading buildings."

1.5.3 Housing Services Corporation/Toronto Community Housing Corporation

Group 3 was a dyad with Housing Services Corporation (HSC) and Toronto Community Housing Corporation (TCHC).

HSC is a not for profit under the Ontario Social Housing Act, serving the housing sector since 2002, including municipally owned, not for profit and co-op housing, all of which are subsidized to varying degrees. TCHC is the largest landlord in Canada, so can be considered a major subset of the sector HSC serves.

Both have a "*vested interest in energy utilities*". HSC is part of an Energy Stakeholder Advisory Group, of which TCHC is a major stakeholder. Energy utilities are not subsidized to TCHC in any way, so they have a strong mandate to reduce energy costs.

HSC advocates for continuation of energy incentives, program flexibility and a holistic approach to gas & electricity programming.

Affordability is a major focus for HSC – particularly for tenants on individual meters, but also for landlords in the low income housing sector. However, in public housing as well as private low income housing suite metering is not common. Loss of federal subsidies and rising costs are impacting both, requiring support for tenants who fall into arrears.

Reliability is seen as very good, with some 'pockets' within the city experiencing more frequent outages which contain significant low-income populations, and significant outages impact the low income tenant severely as they have no options to relocate temporarily. TCHC faces these same challenges, as it has no options to evacuate and needs to enable residents to stay in place during an outage. TCHC is concerned about the end of incentives for CHP. TCHC operates on a "sustained occupancy model" through behind the meter generation. TCHC would like to see incentives for AC

upgrades as they have over 20,000 units requiring replacement, noting that all are old, highly inefficient units, typically poorly and unsafely installed.

HSC's benchmarking data indicates that newer buildings with more efficient systems and central cooling have higher energy demand. Larger family sizes in some buildings also drives up demand. Individual suite metering is a lower priority in capital backlogs.

Two key challenges in achieving both mandates are tenant behaviours and building operator knowledge and ability.

> *"Hard to get tenants to understand their impact."*
>
> *"It is a challenge to educate building operations – site staff – as they have varying levels of knowledge and are mostly focused on building maintenance."*
>
> *"The problem is having one person leaving a building to obtain training – we need an intensive training program."*
>
> *"Building operators are resisting technology & upgrades because they don't have the knowledge. Some even disconnect upgrade technology."*

HSC cites "*incentive fatigue*" caused by frustration in accessing and understanding IESO's web site. Involvement of the IESO in CDM programs was seen as adding unnecessary complexity. Both feel that "*strong incentive programs*" are needed. With respect to OECB, "*the onus was on the customer to apply*" which was seen as ineffective due to low level of knowledge and understanding. Both felt Toronto Hydro could be more pro-active in this respect. SHARP (Social Housing Apartment Retrofit Program) is seen as a small start but not necessarily well conceived or directed. Both felt that Toronto Hydro could add significant value by being pro-active with government at the point of program inception.

> *"Utility companies were nowhere to be seen when these programs were developed."*
>
> *"Be more actively engaged with Ministries when these funding programs are created."*

An IESO funded 'Energy Manager' for the sector was seen as being very beneficial.

HSC noted that Toronto Hydro's public facing materials make no mention of how social housing fits into Toronto Hydro's plans. Information aimed at the sector on bill components, Fair Hydro Plan, RPP vs. Non-RPP and targeted conservation information was seen as being of great value. Both respondents felt that the sector as a whole is a unique cohort that Toronto Hydro can collaborate with, offering a unique opportunity to be a test bed for pilot programs or collaborative initiatives in "*sustainable occupancy*".

> *"Social housing providers are inherently marginalized. Look at social housing as a unique cohort, take advantage of the sector for pilot programs and cooperative programs."*

Both respondents were organizationally concerned about price increases after the Fair Hydro Plan expires, noting the next 4 years as a "*temporary pause*" before price increases hit. Their expectation was that Toronto Hydro use this period as an opportunity to assist the sector in "*getting ahead of the price increases*" before they impact.

1.5.4 United Way of Toronto and York Region

Group 4 was composed of representatives of the United Way of Toronto and York Region (United Way). The United Way's mandate is to alleviate or prevent poverty generally and with a focus on priority neighborhoods. They are an 'anchor agency' to provide funding to a wide range of subsidiary agencies, but also to residents, to enable them to make changes, particularly vulnerable youth and employment.

Agencies funded by United Way deal with pocketbook issues as a major concern among their clients.

Those agencies, receiving a small part of their funding from United Way, are also facing challenges – since government grants no longer fund operating expenses, their funding has reduced, leaving less to support their clients.

> *"In Toronto, 80% of low income housing is private, 20% public – TCHC"*
>
> *"The cost of delivering service is always increasing, funding is reducing, keeping the lights on is a challenge."*
>
> *"There are people the agencies serve who are finding it increasingly difficult to make ends meet."*

Electricity cost is a greater issue where quality of housing is poor. Quality of life is a key advocacy point for United Way.

> *"Most low income stock are highly inefficient buildings built in the 50's and 60's – there needs to be a tower renewal program. The challenge is to find a program that incentivizes private owners to upgrade their stock, making buildings more energy efficient and as a result more livable."*

Tower renewal is a major concern, which United Way looks to Toronto Hydro to take a role in. Many privately owned low income housing units are highly energy-inefficient, and it is a challenge to attract investment. As a result, United Way feels that access to incentives is the main route to achieving energy upgrades to existing stock, with ancillary benefits to quality of life and overall in maintaining current stock.

United Way cite a need for a systemic approach to incentives, even involving other utilities; increasing ability to access incentives given the often low literacy and technical capability of potential applicants and flexibility for LDC's to deliver incentives directed to where they do the most good.

> *"Problem is how to get people access to incentives and programs."*
>
> *"We need a systems response to this."*
>
> *"Landlords get incentives for upgrades but don't pass them (the cost savings) on to tenants. The problem is that it is public money (they are receiving)."*
>
> *"Incentives around Hydro can be very effective individually but less so in a system sense in tower renewal. Incentives need to leverage each other to provide stronger overall incentives – a better business case results – including social outcomes."*

United Way suggest that a "systems view" needs to be adopted, not only in the sense of integration of programs offered by multiple utilities and governments – which they feel Toronto Hydro is the

best poised to be the natural integrator – but a view that takes in social outcomes, housing policy outcomes as well as renewal.

> *"Non-english people don't understand their bills."*

United Way cite a higher incidence of non-english speakers in low income housing, creating a further barrier to understanding bills and obtaining information to enable greater control of their energy costs, and suggest bills and information be made available in a range of languages to meet this need.

Overall, United Way has not been hearing quality or reliability complaints from member agencies, but perceives that Toronto Hydro is not differentiated from other aspects of infrastructure.

In terms of investment – the next dollar spent – United Way feels that upgrading existing stock is inherently and quantitatively more valuable than building out new supply. Investment in transforming existing stock is therefore seen as the investment priority.

> *"United Way focuses on the public good – the expectation/priority for Toronto Hydro is to consider the broader public good in the investment plan."*

> *"Toronto Hydro needs to get the story out about how important they are to the social fabric of the City."*

> *"Toronto Hydro should have a customer advisory panel of low to medium income customers."*

United Way would like future meetings on a regular basis with Toronto Hydro and suggested high value in creating an advisory panel of low to mid income residents for consultation and advocacy on an ongoing basis.

1.5.5 Bloor-Yorkville Business Improvement Area

Group 5 was with the Bloor Yorkville Business Improvement Area (BIA).

The BIA represents the business community in the Bloor–Yorkville area, from Avenue Road north to Scollard and south to Charles, east to St.Paul Square. – over 1,400 businesses: store owners, property owners, office tenants and other businesses, funded by a 2% levy on property taxes businesses pay.

Of particular relevance to Toronto Hydro are the 240 lampposts the BIA own and pay monthly fees to Toronto Hydro to service. These are functional, as well as decorative lamppost intended to convey the unique positioning of the area.

> *"Our biggest issue has to do with lampposts. Related to development, when a lamppost is turned off or stored during construction. The area will continue to have major construction for the next 10 years."*

> *"At Yonge & Hayden, we moved a lamppost that Toronto Hydro said was not working to Yorkville, where it worked beautifully. Our frustration with Toronto Hydro is that nobody there knows what to do."*

The respondent mentioned that they had for many years been dealing with a Toronto Hydro representative who provided excellent, knowledgeable service but has since retired. Subsequent to his departure, the level of service and knowledge seems to have declined.

> *"We are not getting to the people in the vaults who know what they are doing."*

Many of the representative businesses, particularly low rise buildings and small, owner operated stores, are struggling financially, not solely due to rising hydro costs:

> *"Hydro has become too expensive, on top of recent property tax assessments."*

Many smaller businesses in the area were recently reassessed due to 'best and highest use assessment' practices. In the retail stores, hydro use is a critical component of the marketing mix – lighting is necessary to display and sell, and to create a retail experience. For many storefronts, lighting is 24/7. Hydro increases are coming on top of much steeper increases in property taxes.

> *"Moving from bi-monthly to monthly billing has added costs to small business owners because they have to pay a bookkeeper, particularly onerous on property owners."*

As responsible for the 240 lampposts, the BIA cites inefficiencies that add to their costs unnecessarily:

> *"There is duplication in cost in marking out Toronto Hydro owned conduits."*
>
> *"The list of lampposts on each vault is out of date – some are billed to the City, some to the BIA, some are shared conduits."*

Probing on reliability, safety, outage response and quality, overall, the BIA felt the businesses they represent are well served, noting that most infrastructure in the area is underground.

> *"Not aware of outright power reliability issues. Not aware of brownouts or blackouts affecting the area – most infrastructure is underground."*
>
> *"Being able to turn on the lights and operate equipment is critical. Not aware of any issues."*
>
> *"Hopefully we are building much smarter than ever before, particularly in new buildings, where they are using better modern technologies"*
>
> *"There has been a disconnect between Hydro and the City on Bloor St. redevelopment … the BIA has been caught in the middle."*

This last comment refers to an issue on the Bloor redevelopment 10 years ago, where there was a delay in issuing a purchase order from the city that delayed the project over a year, but this was noted as not being the fault of Toronto Hydro.

1.5.6 Metropolitan Toronto and Region Conservation Authority

Group 6 was with the Metropolitan Toronto and Region Conservation Authority (MTRCA). The MTRCA is a unique stakeholder in that it is both an advocate as well as a major customer. As one of 36 regional conservation authorities established by provincial legislation in Ontario, it is a major land owner, owning 16 facilities across the GTA – office buildings, 2 campgrounds, a museum, conservation areas and education centres, with over 50,000 acres of land. The MTRCA Board is composed of politicians from Peel, York, Dufferin and Toronto.

MTRCA is also unique in that this advocacy work has extended into paid 'product' – it has "*partnered with a private firm to create a benchmarking program which audits and sets up comparative energy targets for buildings*". MTRCA "*pulls together funding and makes partnerships*" to promote that program.

Intertwined with the energy benchmarking program is a point of view towards energy conservation that MTRCA advocates – "*a huge shift – trying to change how people look at their energy costs, shifting*

from capital equipment expenditures with an energy reduction payback to operational savings through reducing energy waste".

At another level, Toronto Hydro is a sponsor of MTRCA in the Mayor's Megawatt program, and interacts with Toronto Hydro on permit applications for events and activities.

MTRCA characterizes itself as an environmental agency. Their principal point of advocacy is in reducing greenhouse emissions. Energy is seen as key element of that mandate, but more as an entry point for advocacy:

> *"We push for greenhouse reductions."*
>
> *"The audience for greenhouse gas reductions is maybe 25%, to get more of an audience for environmental concerns, the way is not through behavioral change, it is through cost savings."*

In this context, price is not in of itself a primary concern.

> *"Price is almost academic. Everyone should be reducing their costs."*

MTRCA's singular view, in a sense their unique selling proposition, is that emphasis on reducing cost through most equipment replacement is "*wrong*", that is a point of view pushed by those who benefit financially, but that the most effective way to reduce costs is to benchmark against comparators and establish a target to bring energy consumption in line with the top quadrant of the comparator set. This, in the view of MTRCA, is best accomplished by identifying the greatest sources of energy waste, not by taking incremental steps through costly equipment upgrades that bring increments of energy efficiency.

Taken in this context, MTRCA has singular views on the effectiveness of many incentive programs, informed by their investiture in their benchmarking program.

> *"CDM is investing dollars in incentives that reduce demand, to generate savings."*

The implication made is that this is primarily directed to either behavioral change or equipment upgrades – not identifying and correcting the greatest sources of waste.

> *"SNAP – Sustainable Neighborhoods – is an engagement program that is successful, but it doesn't fit with the typical funding programs."*
>
> *"Toronto Hydro's Upsaver program is cutting edge."*
>
> *"MOECC is not interested in what we are doing, they don't see the value."*
>
> *"ECDM programs and the data (benchmarking, sources of energy waste) don't align – most of the incentives are going to where there are no savings."*

Hence TRCA's position on incentives is that they do not align with their programs:

> "*When we identify savings, they look to Toronto Hydro for incentives (which are typically attached to equipment expenditures, not reductions in consumption.)*"

Relations with Toronto Hydro were seen as good.

> *"The only point of frictions is permitting – for example, at BlackCreek Village there is deteriorating underground wiring – Toronto Hydro has been slow to respond, citing a backlog – we are using backup generators that use oil – very expensive and environmentally damaging."*

Another program the TRCA is involved in is 'Greening Healthcare' – "*half of hospitals in the GTA and part of the program.*"

> "*Many have gone to hardware smoothing solutions as quality of power is variable in the city, predominantly outside the core– Scarborough is a problem*."

TRCA also interacts with Toronto Hydro as it manages all flood remediation, modelling flows along rivers, where Toronto Hydro equipment might be at risk.

As TRCA advocates less on behalf of any cohort or stakeholder group than for conceptual positions – "*we don't advocate on an individual level, we don't care about homeowners*" – their views on issues emerging in the future takes a more over-arching, conceptual form.

> *"The future is not on the larger grid, it is at the community level. IESO thinks big grid infrastructure, but this is not the future."*
>
> *"Focus on retro-commissioning – achieving operational savings by pointing to waste."*
>
> *"Work under the auspices of energy savings to bring in climate change, demand shifts, population growth to create sustainable eco-zones. Historical data doesn't work any more on any parameter."*
>
> *"Need to devolve grid planning to the municipal LDC level."*
>
> *"Invest where there are synergies, that help the greatest number of companies. Each building is an ecosystem that can help each other (energy transference). Take a bigger role in community planning. Ask what other roles Toronto Hydro can play with their assets."*

1.5.7 Toronto Financial Services Alliance

Group 7 was an in-depth interview with representatives of the Toronto Financial Services Alliance (TFSA). The TFSA is a public-private partnership whose mandate is to act as a facilitator and catalyst of opportunities within the financial services sector to attract new investment, assist in growth and market Toronto's value proposition as a global financial center. The TFSA's role is advocacy, but not in the sense of a typical industry trade association, as TFSA "*rarely takes public positions*" and "*tends to work behind the scenes*", lobbying "*less for members than for the region overall*".

The TFSA has 3 pillars of advocacy – growth, reputation and competitiveness. Increasingly, the financial sector members are global players, who happen to be located in Toronto but operate often more outside the country.

> *"Toronto Hydro fits with competitiveness and infrastructure in a big way."*

The sector relies on uninterrupted, reliable power 24/7, noting that today financial firms are highly systems dependent, conducting high level transaction feeds across multiple time zones simultaneously, and operate continually. TFSA also noted that the financial sector in Toronto is constantly competing globally for investment, talent and transactions – and electricity supply and reliability are part of the competitive framework of the region.

> *"Not so much a price issue – for most members, it's a rounding error."*

TFSA notes that this, in context, is simply a matter of reliability and consistency trumping price by a wide margin, even though the sector incurs substantial electricity costs.

> *"Continuity, quality, stability."*

TFSA notes that these are the 3 over-arching expectations of the sector. These are summed by TFSA as:

> *"Anything that interferes with their (the sector) ability to operate their systems is a major issue."*

Of note is the reference to "systems", not to 'keeping the lights on' or enabling employees to work uninterrupted – the focus is on the systems that the financial system depends on almost exclusively to generate revenues.

> *"Stability and reliability is part of the value proposition of the financial sector."*
>
> *"Stability means – don't have to worry about it when they are doing their technology or security plans."*
>
> *"The value proposition (of the sector) is in the back office, not the retail side."*
>
> *"Half of new investors are in fin-tech."*

Cybersecurity with respect to the electrical distribution system was a major concern, and expectation of Toronto Hydro.

> *"We worry about the resilience of the system to cyberattacks."*

In this sense, resilience was not only a physical expectation and priority, resilience to a cyberattack was even more of a priority.

Overall, TFSA saw reliability as high – *"We don't hear anything about brownouts or outages from members."*

Compared to other major financial cities the TFSA competes with, the electrical reliability in Toronto is considered a competitive advantage. There is a trend to locating data centers outside Toronto, but this is primarily to build redundancy and due to office space and talent access considerations.

However, continued reliability is a priority. There is concern that there are only two points of supply into the city, and loss of one would put the sector at risk.

> *"The interruption cost is huge."*
>
> *"The price vs. reliability equation is heavily weighted towards reliability."*
>
> *"Things like the vault fire are scary."*
>
> *"The east and west trunks are over 40 years old."*
>
> *"In reliability, predictability is important, firms don't want to have small event contingency plans. For larger occurrences, most have contingency plans in place."*

TFSA's priority for Toronto Hydro is preventative investment to ensure continued reliability and build resiliency and security. They would be supportive of greater flexibility in utility investment 'behind the meter' particularly in alternatives to conventional grid solutions which address power quality and reliability issues.

> *"Go to major clients to see if there are new technologies that Toronto Hydro could take advantage of."*

TFSA offered to provide letters of support for investments, particularly behind the meter, as well as to facilitate further engagement through round tables. TFSA suggested meeting with Toronto Global as a next step in the consultation process.

1.5.8 Coalition of Concerned Manufacturers

Group 8 is a recently formed group of 5 manufacturing related associations and a number of small to mid-sized manufacturers called the Coalition of Concerned Manufacturers (COCM). This coalition was created in November 2016 by Automatic Coating, a mid-sized manufacturer, solely in response to energy rates. COCM has since adopted advocacy positions on cap & trade and recently announced changes to employment standards. Automatic Coating (ACL) leads this coalition, and is the primary spokesperson. As a result, the views of COCM are formed by, and indistinguishable from those of ACL, and the COCM spokesperson moved freely between expressing views that represent the coalition and those that represent ACL. In effect the interview should be considered to represent ACL as a customer primarily.

The Coalition's overall goal is to "*ensure Ontario has the right policies to help & grow small to medium manufacturing businesses*." The Coalition sees energy prices as central to this and more recently, the implementation of cap & trade as a key obstacle to manufacturer survival and growth.

The Coalition feels that "*cap & trade has been set up to help large businesses but harm small to mid-sized ones*" by "*not giving us any credits but making us pay*."

The Coalition claims that many small to mid-sized business have taken steps to minimize their carbon footprints – "*we (ACL) have invested in technologies to reduce greenhouse emissions but do not receive credits, while paying extra for cap & trade on energy*."

The Coaliton states that "*we only really started to pay attention to our energy bills two years ago*" and claim that cap & trade has been the key driver of their increased concern with energy costs.

A further point of concern was the global adjustment, which was characterized as "*outrageous – it makes it impossible to budget*" due to unpredictability.

> *"The more people get off the grid, the higher the global adjustment will be."*

Another issue was that many manufacturers – those with 50 employees or less – don't qualify for ICI, and "*for many who do qualify, ICI raises their rates*."

> *"We need an industrial rate, like in most states (in the U.S.)"*

Comparisons to the United States on the 3 main advocacy points – energy costs, minimum wages and cap & trade – were frequently brought up.

> "*Companies who are not relocating (to the United States) are relocating their growth, others are selling out to international conglomerates who will then relocate*."

However, the discussion was short on concrete solutions – "*just lower the damn rates*" and some misinformation was seen – "*stop giving excess power away at a loss to subsidize our competitors in the U.S., excess energy should be sent to (Ontario) manufacturers*."

When probed, the representative acknowledged that their primary source of information is media reports, noting they have a significant Facebook following.

All these factors formed an overall position that rates, seen as being driven by government policy, were squeezing small manufacturers to a point where they are being forced to make decisions to re-acquire competitiveness with other jurisdictions:

> *"Manufacturers have 4 potential options now:*
>
> 1. *Many have and will close and go bankrupt*
> 2. *Some will close and go to the U.S.*
> 3. *Some will stay, but will establish their growth (expansion) in the U.S.*
> 4. *Some will sell to an international conglomerate, who will then move the business to a more favorable jurisdiction."*

The primary outcome of any of these options was "*loss of all those jobs*", "*loss of that economic activity*" and "*Toronto Hydro is losing customers*."

Again largely formed by media reporting, there were perceptions raised about "people at Hydro getting paid 5 times what everyone else gets paid" and "CEO's getting paid outrageous salaries" that fed the overall position:

> "*Don't ask manufacturers for a single penny more until you get your costs in order*."

In terms of reliability, the representative noted that "*most small manufacturers have backup generators*", however this may be based on ACL having a backup generator. The participant noted that generally reliability and quality are good.

> "*I hear more about reliability issues outside of Toronto that inside."*

While not noting any specific problems, the representative noted that small manufacturers have "*a high threshold for quality*."

The only specific issue identified was that "*planned outages are a problem*", identifying a need for more advance notice and coordination.

In terms of conservation and investment in technologies:

> "*Manufacturers don't know a lot about combined heat/hydro solutions – Toronto Hydro could do more by giving some advice on this. We get realtors selling CHP units on the side and desperate manufacturers may make bad decisions."*

1.5.9 Leslieville Business Improvement Area

The Leslieville B.I.A. represents around 225 independent businesses along Queen St. East between Vancouver Avenue and Empire Avenue. The businesses represented are largely independent and locally owned, ranging from galleries, restaurants, retail, arts & culture to "*next level services*" – digital and marketing agencies. Stakeholders are residents and visitors, but primarily businesses who pay the B.I.A. levy.

The BIA itself has several points of interaction with Toronto Hydro:

- *"sponsorship of a community event", "banners on hydro poles"*
- *"engaged Hydro over the Jones & Queen mural to cover wires"*
- *"generally looking for cooperation and support"*

- *"some members may contact the BIA first about a Toronto Hydro issue"*

In general the BIA "*has never heard anything about Hydro*" from members.

The only point of friction noted was an issue arising from a Toronto Hydro contractor a member experienced stemming from an incentivized lighting conversion, which was satisfactorily resolved, and the BIA ascribes to "*miscommunication*."

However, that issue was significant to the BIA as the member business took to Facebook to be critical of Toronto Hydro, rather than contacting them first to ask for assistance, noting that "*social media can be an opportunity (for members) to spread the good and the bad*".

The BIA characterizes electricity, to its members as "*an essential service, and Toronto Hydro is the only game in town.*"

> "*Businesses struggle to balance costs*."
>
> "*There is a perception that businesses pay too much – not just hydro, in property taxes and other costs*."

The importance of electricity, to businesses, was ranked "*on a scale of 1 to 10, probably a 10*."

Consequently, the key expectations are on reliability of service and billing accuracy:

> "*Reliability has to be 24/7."*
>
> "*No wastage – don't charge when you don't have to."*
>
> "*An alarm system that is out for 20 minutes can be a serious issue*."

Reliability is seen as good, and a key expectation is on communication."

> "*Hydro on Twitter has been highly responsive, even late at night*."

The BIA would like to have more engagement with Toronto Hydro, on several fronts:

> *"Would like to be able to alter businesses in advance (to planned outages)"*
>
> *"Available programs, incentives, proactive issues."*

Two particular areas of collaboration were identified: Given "*lots of development in Leslieville*" bringing "*sudden construction that can take away parking*", with immediate impact on local retail businesses, not only is "*getting notice in advance*" of assistance, but having a contact the BIA can coordinate with onsite – "*the Site Manager's number*" – would allow the BIA to act as a central point of coordination with Toronto Hydro.

An imminent issue is street-scaping along Queen East:

> "*At some point Toronto Hydro will come into play – we will probably need Toronto Hydro to come in and give clear guidelines and hope that Hydro has fed into the City on this."*

The need identified is to better coordinate with the City, seen by the BIA as more difficult to interact with than Toronto Hydro:

> *"Leslie Barn is an example of a project where all the components worked together – better coordination."*
>
> *"Coordinate better with contractors"*

An upcoming issue might be vehicle electrification – street charging stations.

> *"We would want to work with Toronto Hydro on vehicle electrification."*

Conservation was not seen as a priority for members due to "*focus on making the day's sales*" – businesses would like more information, but were not seen as actively seeking out conservation information as it is not part of their immediate focus. The BIA felt they could be a point of collaboration on this:

> *"Could work through the BIA to reach members – Toronto Hydro being part of our new member introduction would be a small dunk – for existing members at the AGM or a stand-alone event."*

In terms of investment priorities, the BIA recognizes that costs are a continuing challenge for members, yet reliability is also a priority –

> *"Members would accept incurring a cost now but there would have to be a longer term benefit, not just economically but socially as well."*

Appendix 1.6 - Toronto Hydro Customer Priorities (Phase I)

PRIORITIES	Residential & GS <50 KW	GS >50 KW	Key Accounts (Large Users)
Price	**HIGH (1st Priority)** • Containing price increases is the top priority for most residential and small business customers. • Increasing rates must be justified (i.e. there is a clear need and ratepayers dollars will be spent efficiently).	**HIGH (1st Priority)** • Containing price and providing short-term rate predictability is the top priority.	**HIGH (2nd Priority)** • Prioritizing reliability over price is of high importance (i.e. cost of power interruptions outweighs the cost of rate increases).
Reliability	**HIGH (2nd Priority)** • Maintaining current "good" level of reliability is a key priority.	**HIGH (2nd Priority)** • Maintaining current level of reliability is a key priority for this group of customers. • Providing outage communications and responsive service is valued more highly among this rate class (than others).	**HIGH (1st and 3rd Priority)** • #1 Maintaining reliability (including power quality) is the top priority. • #3 Implementing strategies to mitigate outages caused by extreme weather is a top 3 priority.
Safety	**HIGH (3rd Priority)** • Setting public safety as a top priority is assumed and expected.	• Setting public safety as a top priority is assumed and expected.	• Setting public safety as a top priority is expected.
Customer Service	• Provide accurate ETOR, proactive information on CDM programs and energy management. • Provide tools to make billing, account management, and usage information easily accessible.	**HIGH (3rd Priority)** • Providing accurate ETOR and proactive communications is a key priority. • Enhance customer service to match emerging technological capabilities and needs (e.g. allow customers to get bills by emails, create master accounts to manage multiple bills).	• Maintaining current "very good" levels is expected. • Helping customers take advantage of CDM programs is seen as a valued priority.
Public Policy Response	• Incentivize adoption of innovative technologies that enable conservation and consumption management.	• Pursue value-for-money investments where long-term cost savings can be realized (e.g. spend now to save later). • Avoid premature investments in unproven or untested technologies that impact customer rates.	• Investing in technology that helps customers save money is valued.
Environmental	• Make programs combatting climate change known to customers. • Show customers how such programs impact their bills.	• Maintain equipment and infrastructure in adverse weather.	• Actualize other priorities, before focusing on environmental concerns.
Methodology ▸▸	Quantitative and Qualitative	Qualitative	Quantitative

Stakeholder Groups (Key Issues)

Housing & Social Services

- Reliability outweighs cost
- Quality and consistency of power is a key need
- Incentive programs need to be more accessible and may not be targeted at greatest returns
- Conservation efforts constrained by bulk meter buildings
- Building renewal and retrofitting are priorities

Large Commercial

- Reliability is needed 24/7
- Reliability is a competitive advantage
- System resilience is a concern
- Cybersecurity is a priority
- Behind the meter innovation is a need
- Cost is <u>not</u> a significant factor

Small Commercial

- Reliability is needed 24/7
- Customer service is the key need – lampposts, local development, outages
- Cost is primarily a concern among local, micro businesses

Small / Mid-sized Manufacturing

- Cost is a significant factor
- Reliability seen as less of a concern
- ICI program ineligible
- Global adjustment is a friction point, impairs budgeting

Qualitative

Source: **Innovative Research Group** (Customer Research - December 2016, March 2017, June 2017)

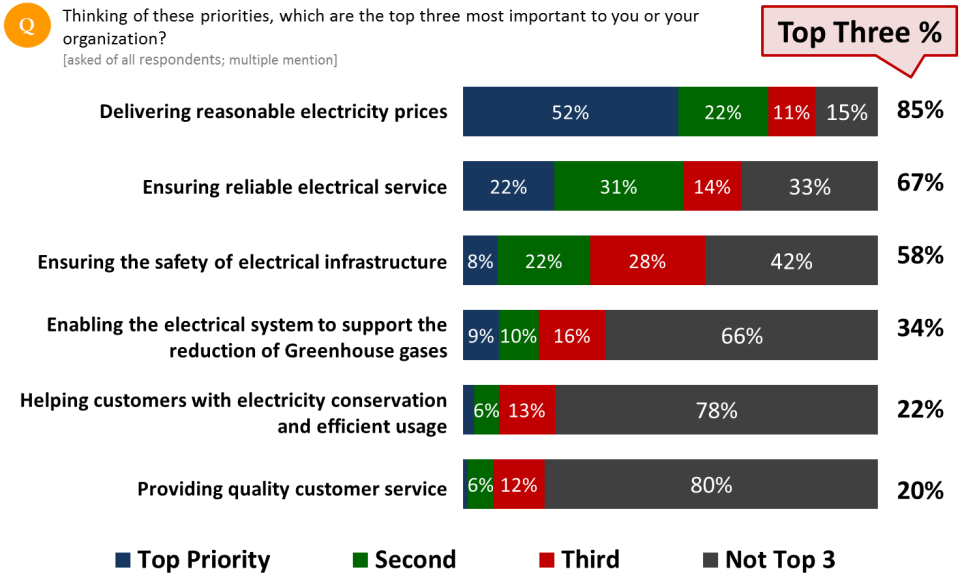
Toronto Hydro Customer Priorities

Low-Volume Customers (Residential and GS < 50 kW)

A series of questions were developed to identify Toronto Hydro customer priorities. The questions below were designed to rank their relative importance.

Ranking Priorities: When asked to rank top three priorities; 1st *price*, 2nd *reliability*, and 3rd *safety*.

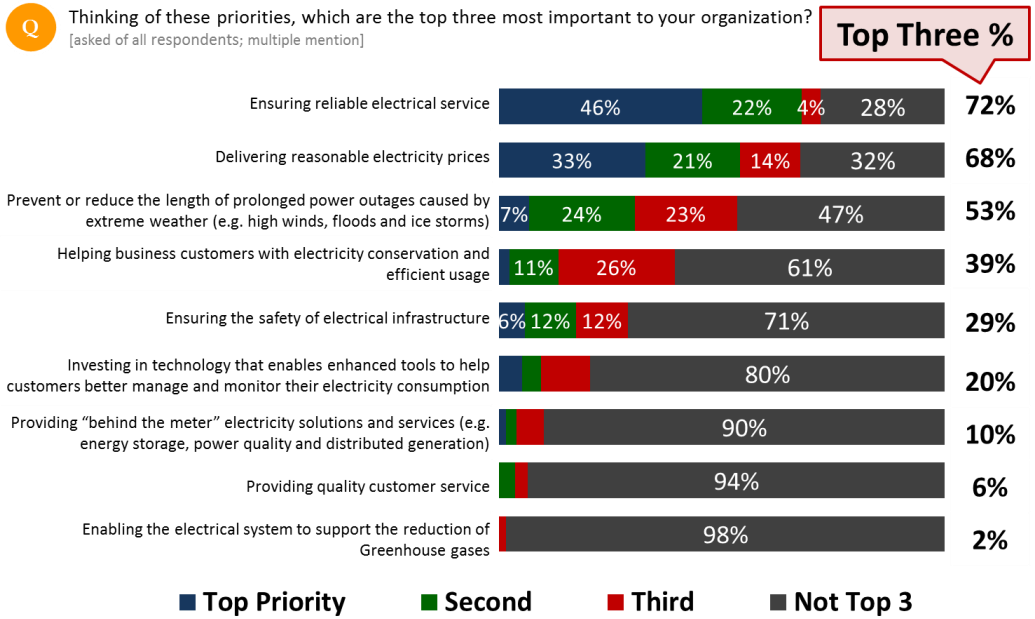
Q Thinking of these priorities, which are the top three most important to you or your organization?
[asked of all respondents; multiple mention]



Key Account Customers (Large Users)

Ranking Priorities: Top priorities include reliability, price, and environmental risk mitigation.

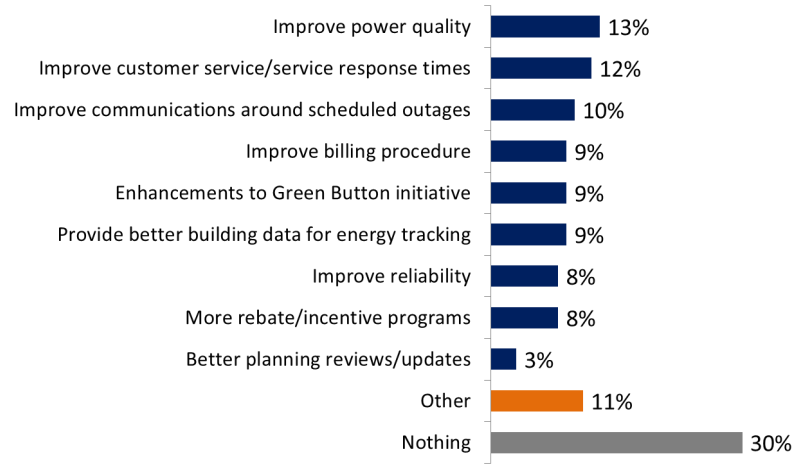
Q Thinking of these priorities, which are the top three most important to your organization?
[asked of all respondents; multiple mention]



The following open-ended question was asked of key account customers to identify where Toronto Hydro can improve services to their businesses.

Areas for Improvements: Plurality (30%) suggest nothing; power quality and response time next most commonly mentioned.

Q Is there anything in particular that **Toronto Hydro** can do to improve its services to your organization?
[OPEN-ENDED; multiple mention, asked of all respondents]



For more information on using this document or customer engagement results, please contact:

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Appendix 2.1

Toronto Hydro 2018 Customer Engagement

Customer Feedback Portal Report

STRICTLY PRIVILEGED AND CONFIDENTIAL

Survey Methodologies



Toronto Hydro commissioned INNOVATIVE to develop an online customer feedback portal to provide all customers an opportunity to learn more about Toronto Hydro and provide an opportunity to tell the utility how best they can serve them moving forward.

Field Dates

The Online Portal was accessible to Toronto Hydro customers from April 26th to May 28th, 2018.

Promoting the Online Portal

Promoting the online customer feedback portal included a combination of digital approaches:

- Toronto Hydro corporate web site promotions;
- Social media promotion (Twitter and Facebook); and
- E-blast promotions.

Publishing the Portal Online

INNOVATIVE hosted the online portal at the following URL: TorontoHydroFeedback.com

The website prevented customers from completing questions repeatedly and saved their progress as they answered each question. Upon completion, the site was no longer accessible at the web address given.

Validating Consumer Responses

Customers who filled out the online portal were tagged with an identification number based on their postal code and their response as a residential or business consumer of Toronto Hydro. Postal codes were checked against lists provided by Toronto Hydro for validity and those deemed invalid were removed from the final sample.

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

INNOVATIVE RESEARCH GROUP

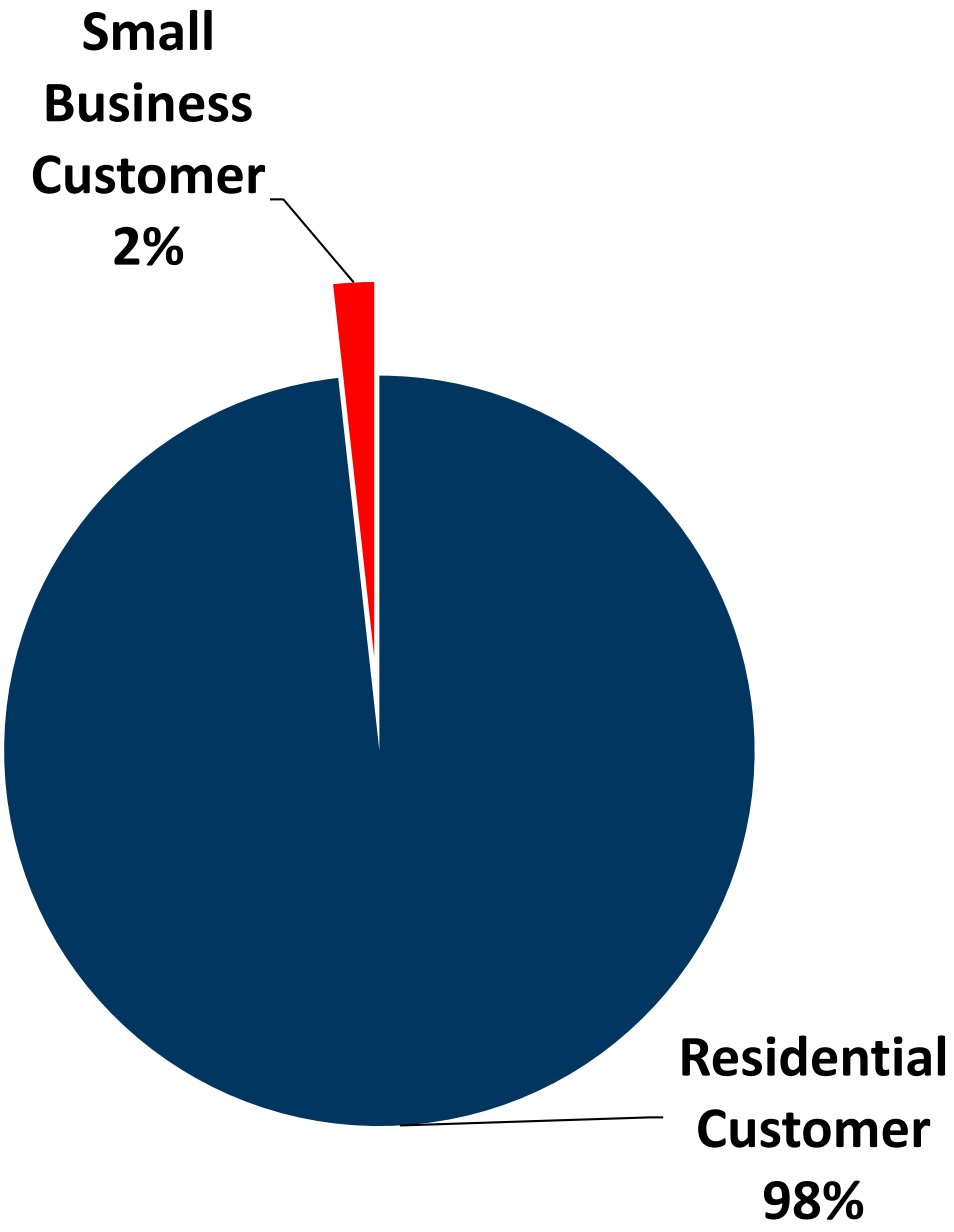
Segmentation and Demographics



Demographics

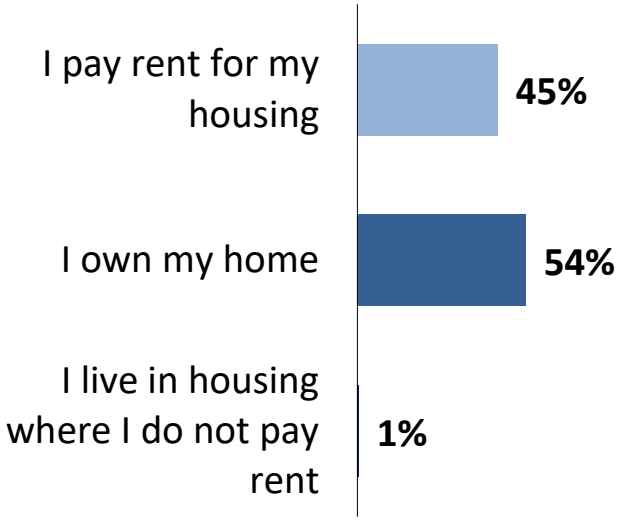
Respondents were shown different values in the survey based on whether they were residential or small business customers.

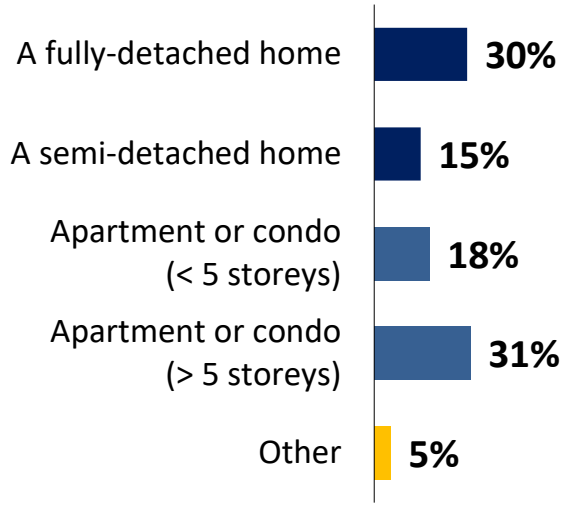
Residential n=10,165
Small business n=181



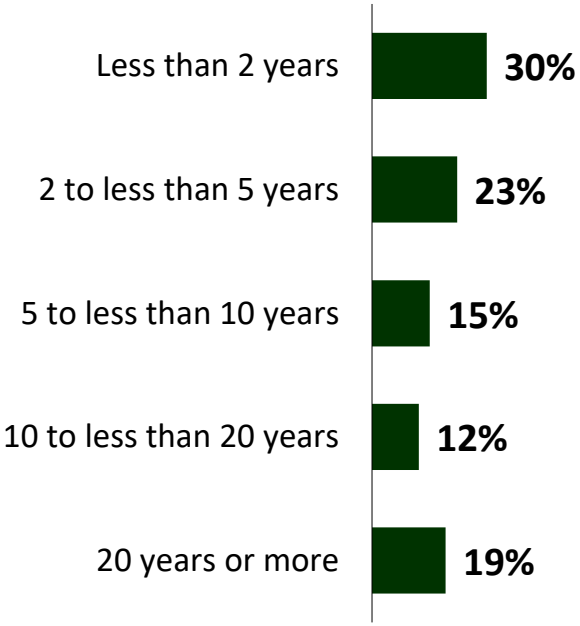
Demographics – *Residential*

Primary Residence

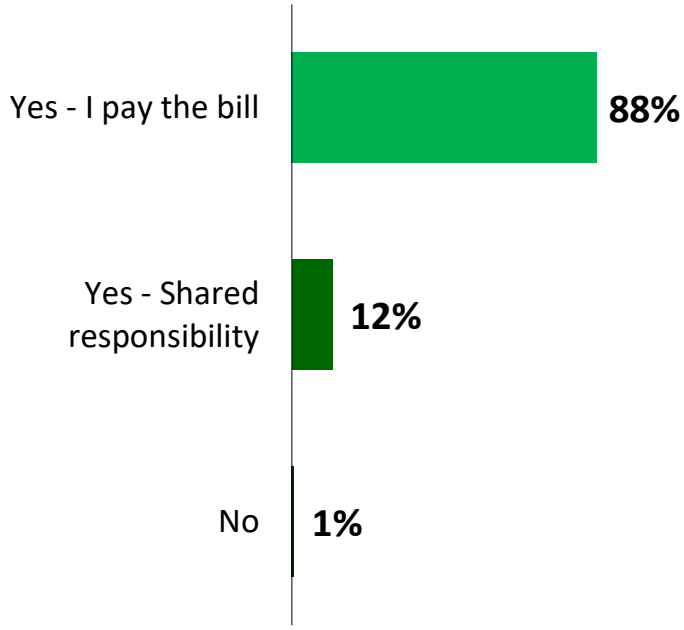




Length as a Toronto Hydro Customer

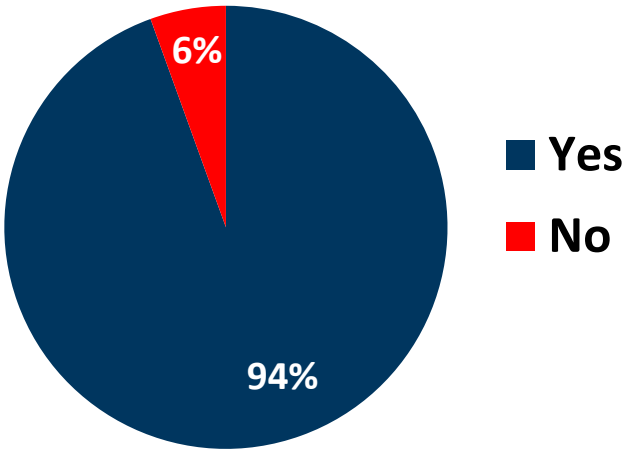


Bill Payment

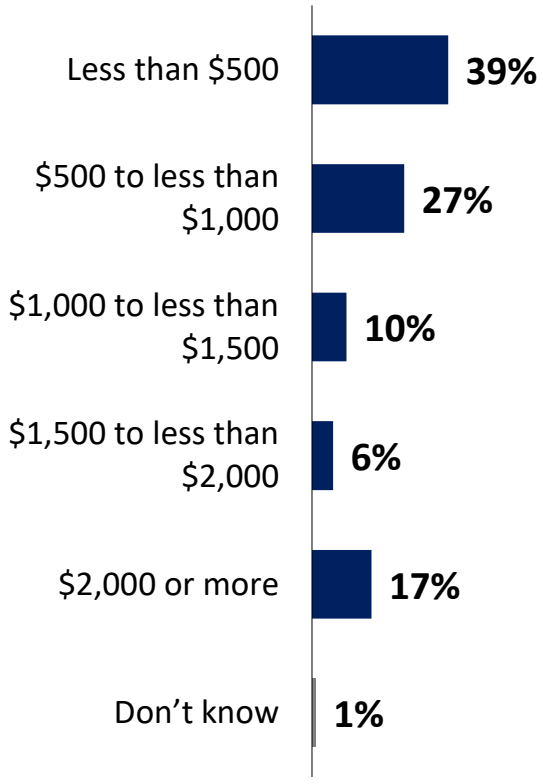


Demographics – *Small Business*

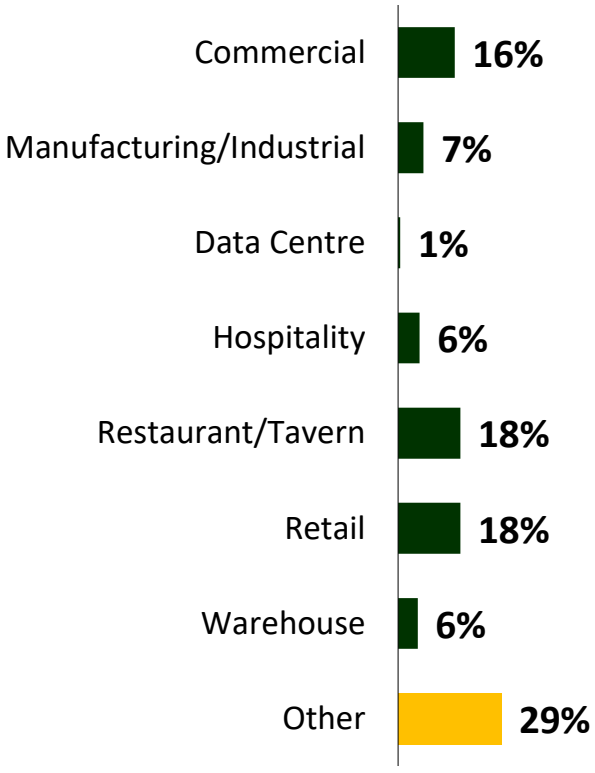
Q As part of your job, do you make decisions or influence decisions about electricity management?



Estimated Monthly Hydro Expenses



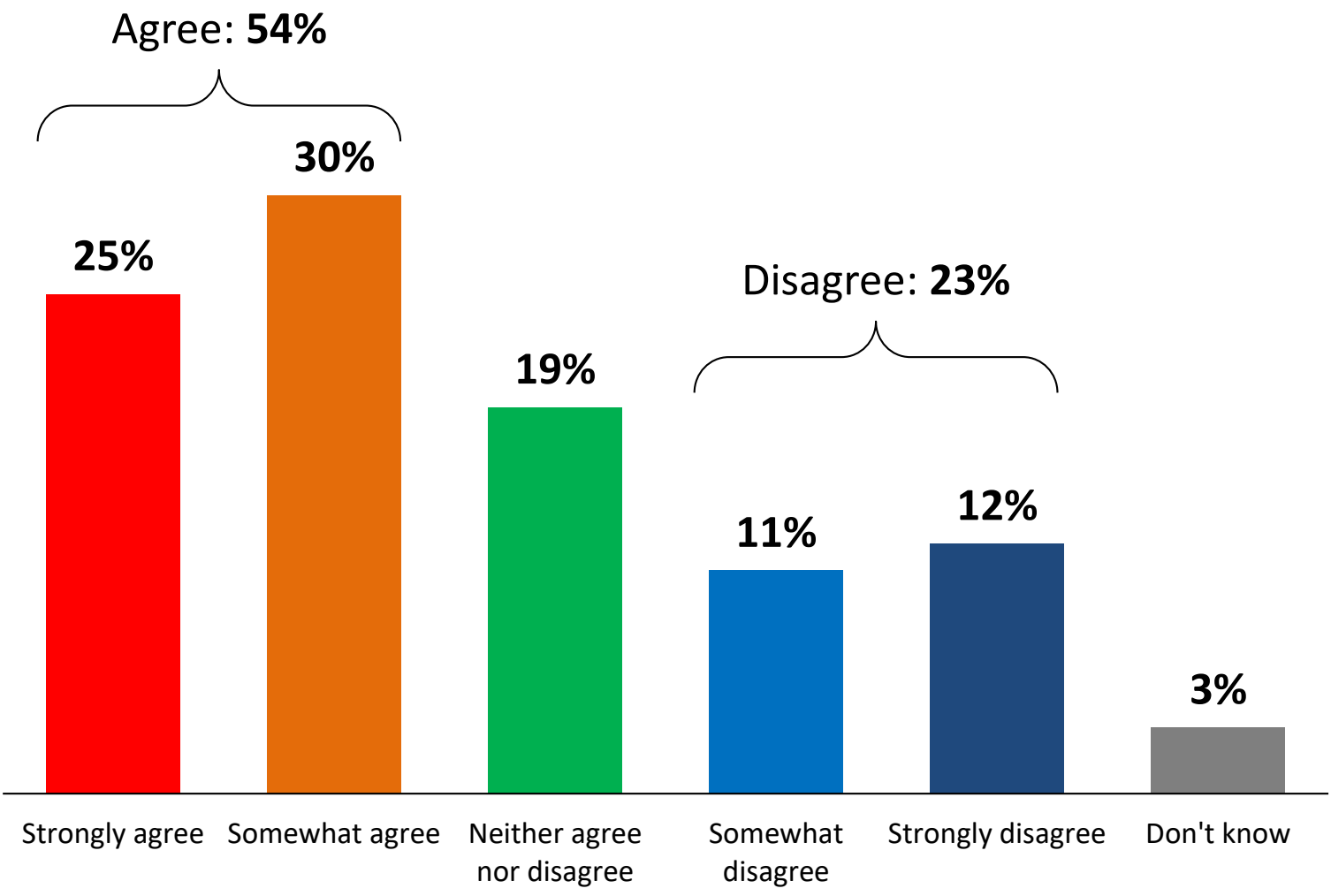
Sector



Segmentation & Demographics

Q Please indicate the extent to which you agree or disagree with the following statement: The cost of my electricity bill has a major impact on my household finances and requires I do without some other important priorities.

[asked all respondents, n=10,346]



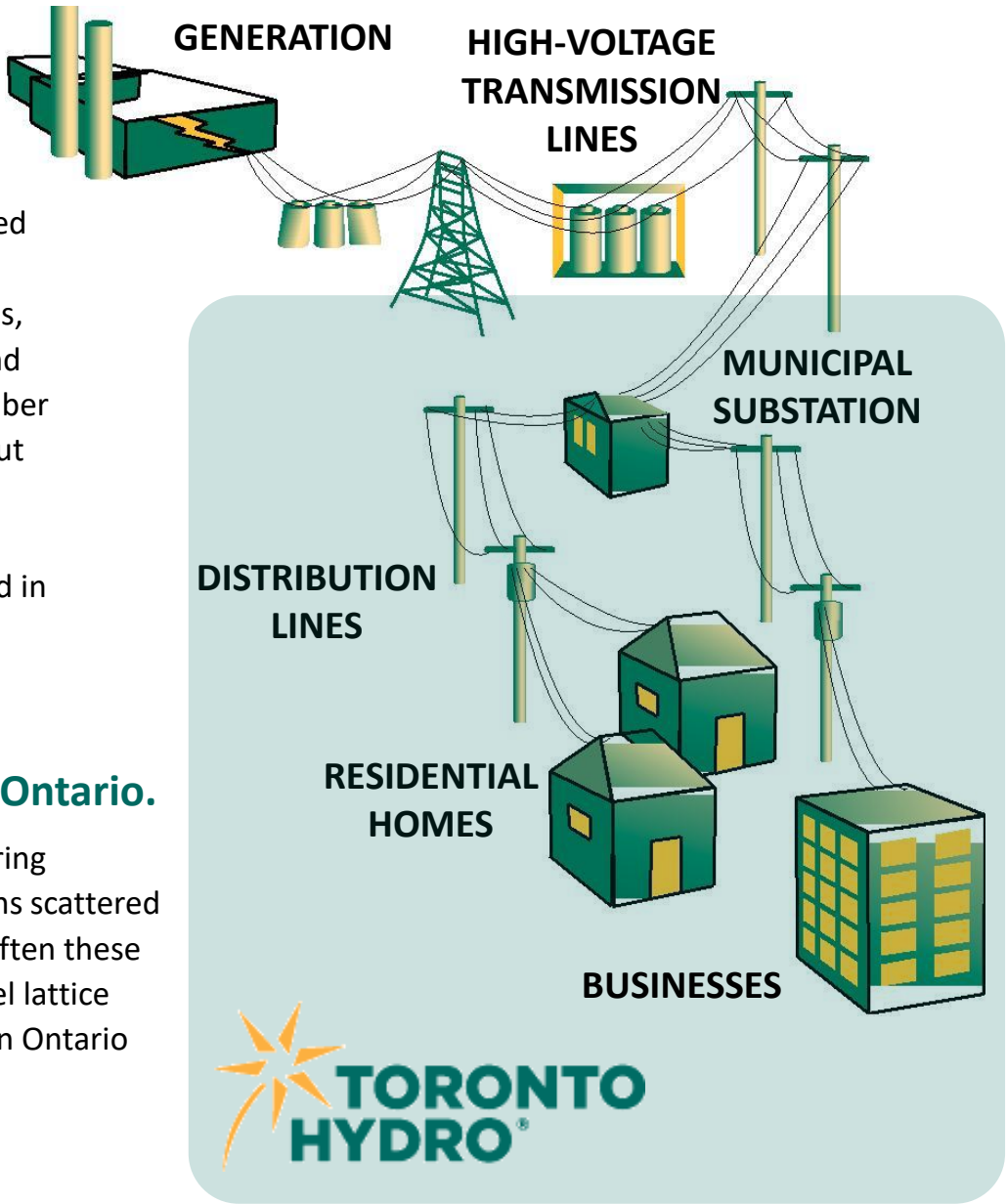
Where does Toronto Hydro fit within the electricity system?

There are three main parts to Ontario's electricity system:

1) Generation

Where electricity comes from.

The electricity you use is generated from a mix of nuclear generation stations, water power installations, natural gas generating plants, wind turbines, and solar panels. A number of companies own these plants but Ontario Power Generation, a provincial crown corporation, generates most of the power used in Ontario.



2) Transmission

Electricity travels across Ontario.

High voltage transmission lines bring electricity from generating stations scattered across the province to Toronto. Often these lines are suspended on large, steel lattice towers. Almost all of these lines in Ontario are owned by Hydro One.

3) Local Distribution

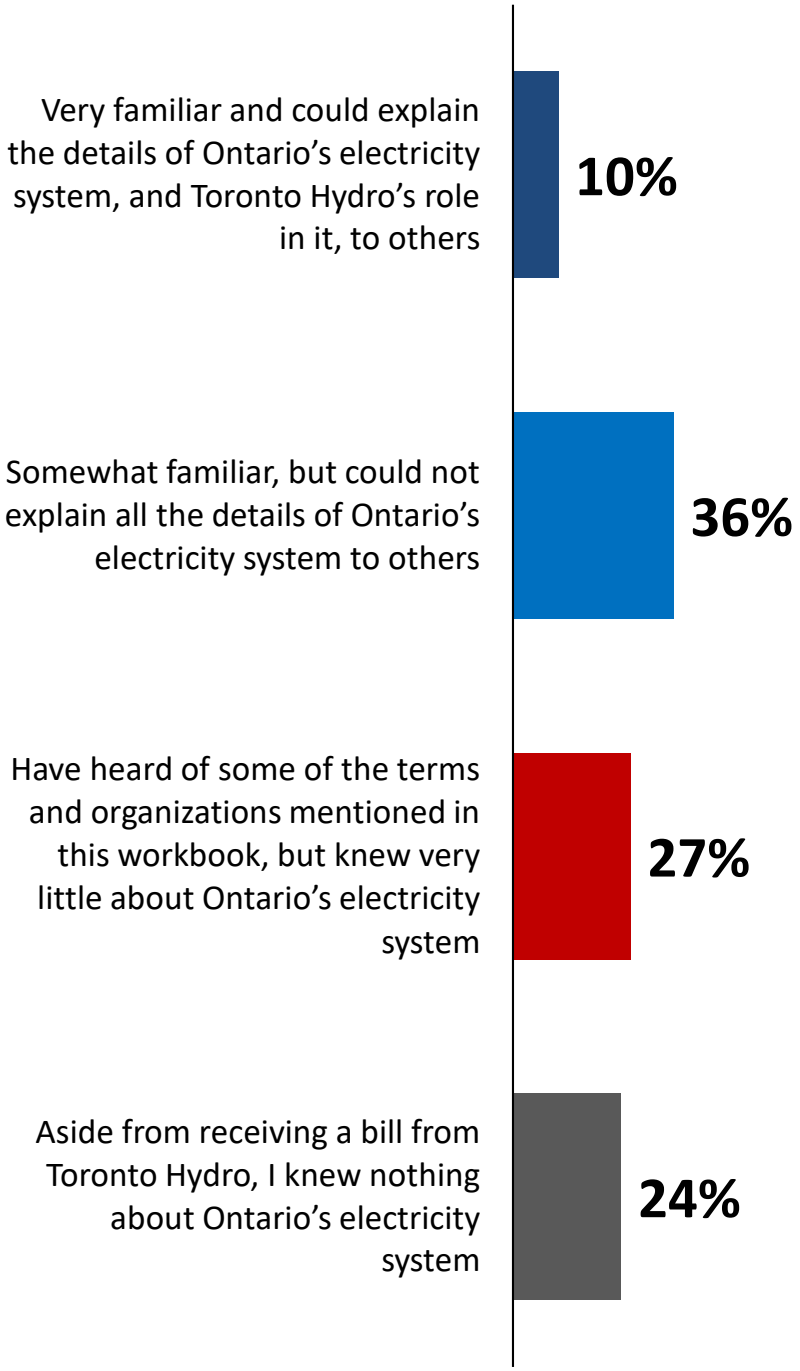
Delivering power to homes and businesses in your community.

Toronto Hydro runs the part of the electricity system that directly serves you. Distribution stations receive and convert electricity to safer voltages. Distribution poles, wires, and underground cables deliver it to your home or business. Toronto Hydro builds and operates this distribution system, reads meters, calculates and collects bills for all parts of the electricity system, answers customer calls, and delivers conservation programs. Toronto Hydro is owned by the City of Toronto. Its activities are funded by rates set by the OEB, not by government tax dollars.

Familiarity with Toronto Hydro

Q Before this consultation, how familiar were you with the various parts of the electricity system, how they work together, and for which services Toronto Hydro is responsible?

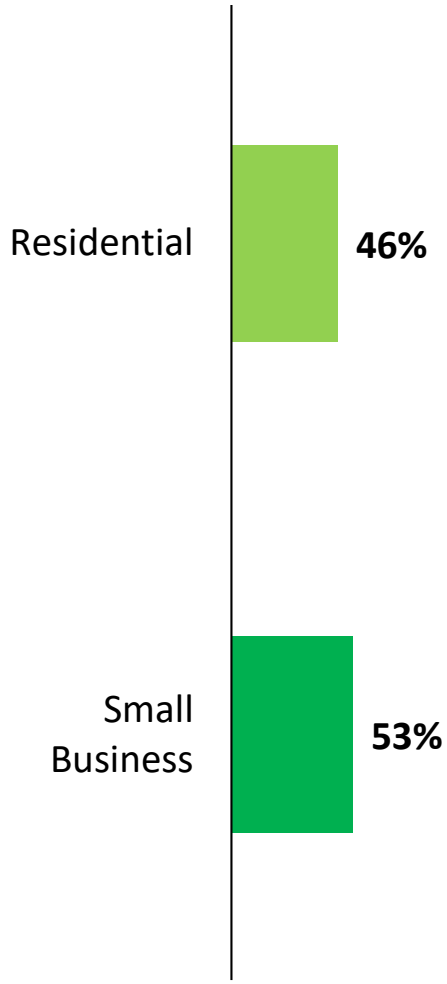
[asked all respondents, n=10,346]



Segmentation

*Those who say "**Familiar**":*

Rate Class



Note: "Don't know" (2%) not shown.

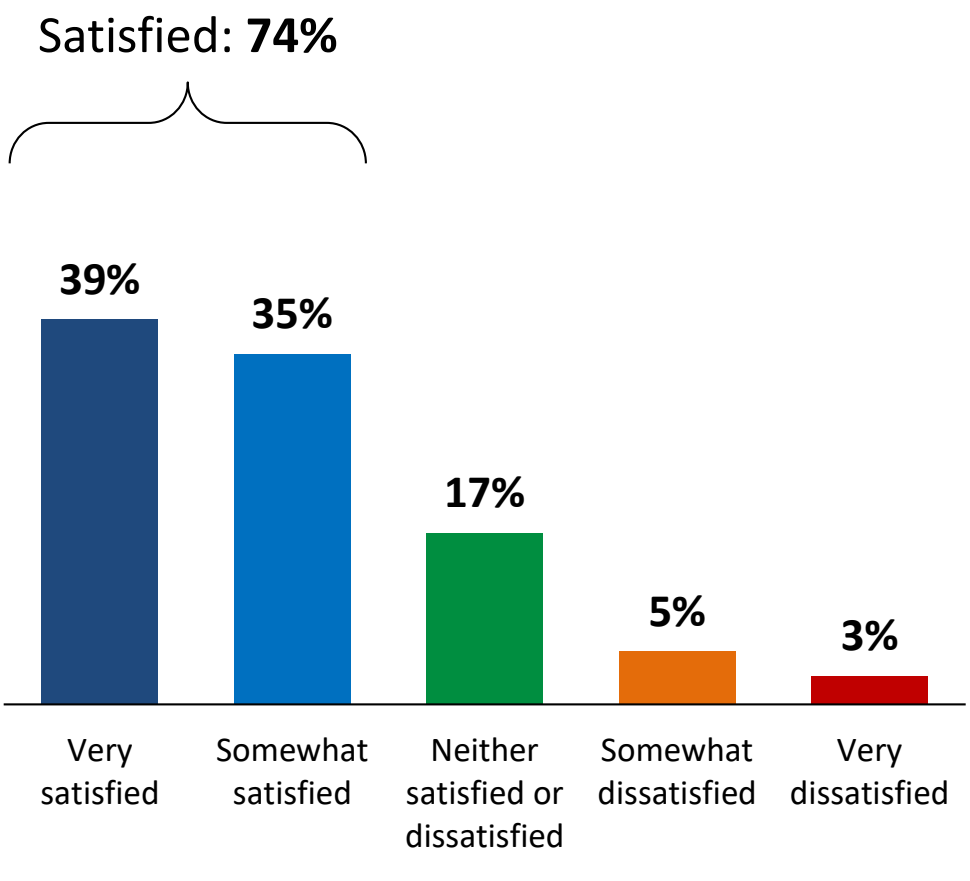
Satisfaction with Services

Q

Toronto Hydro operates and maintains the local electricity distribution system, delivers electricity throughout the community, reads meters, calculates and collects customer electricity bills, answers customer calls, responds during outages, clears trees and brush from power lines, and delivers conservation and demand programs.

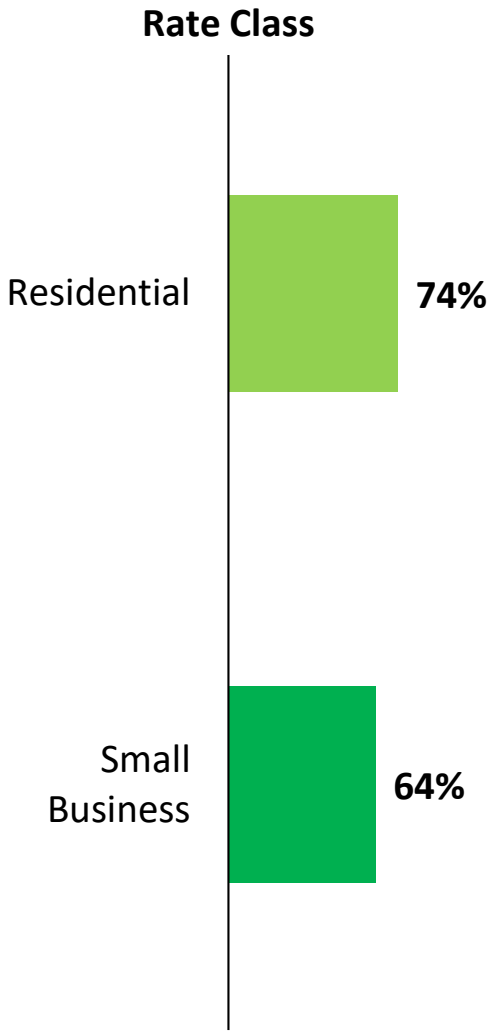
Generally, how satisfied or dissatisfied are you with the services you receive from Toronto Hydro?

[asked all respondents, n=10,346]



Segmentation

*Those who say "**Satisfied**":*

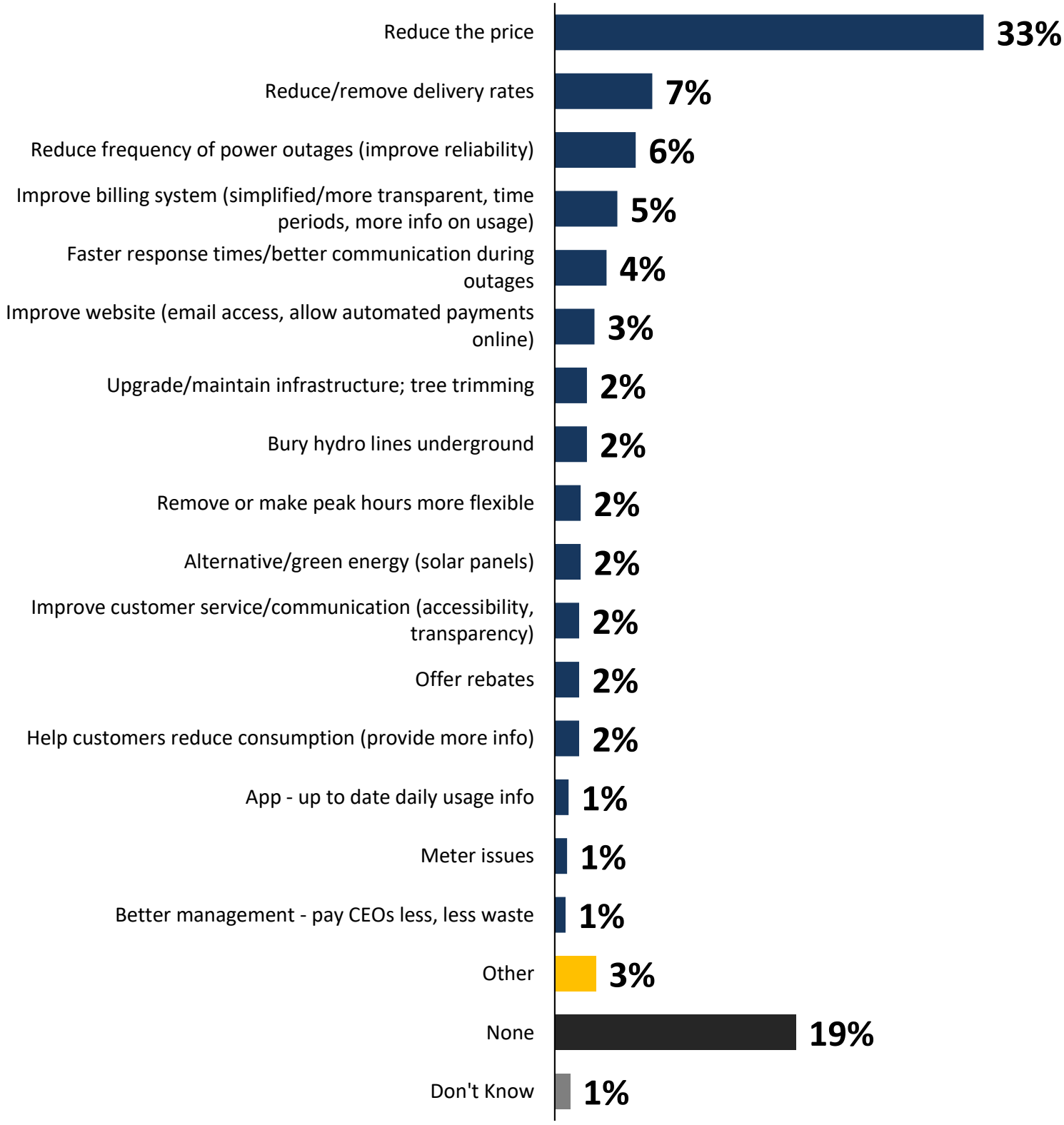


Note: "Don't know" (1%) not shown.

Suggestions for Improved Services

Q Is there anything in particular that **Toronto Hydro** can do to improve its services to you?

[asked all respondents, n=854]

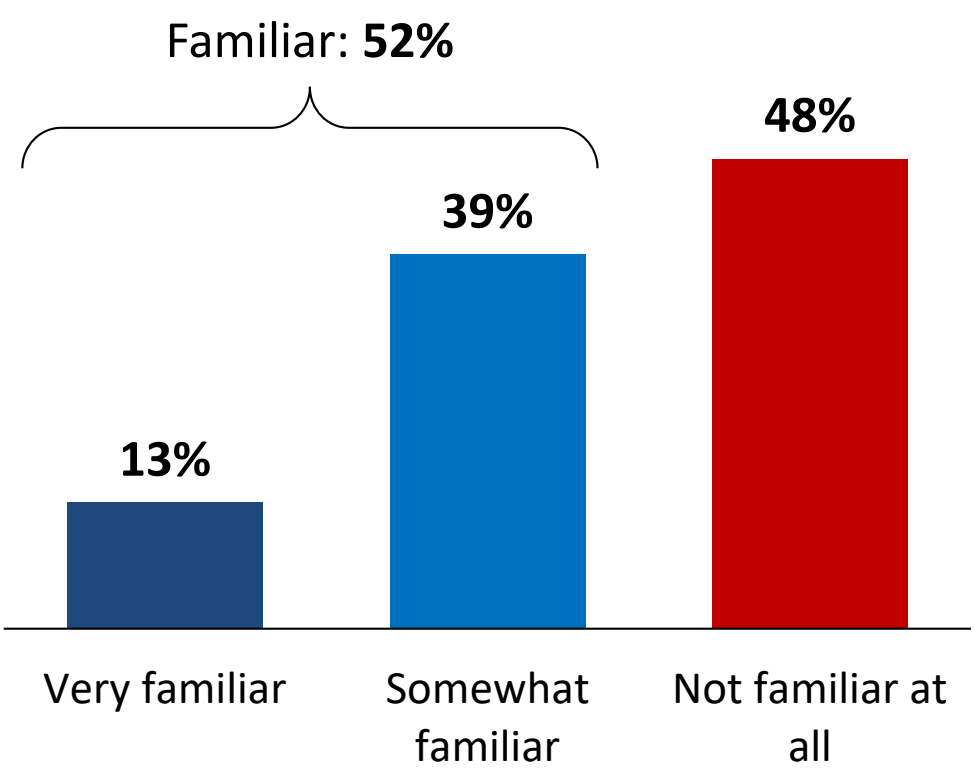


Note: "Refused" (1%) not shown.

Amount of Bill Retained by Toronto Hydro

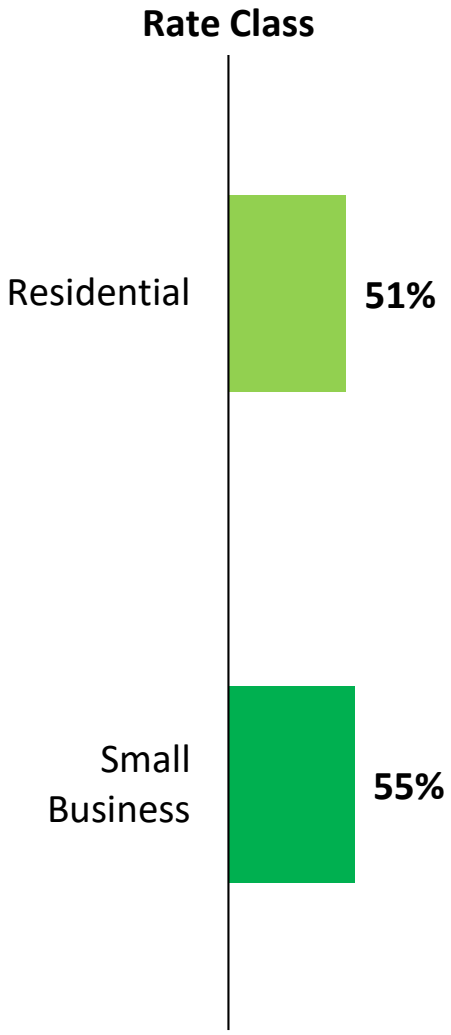
Q Before this engagement, how familiar were you with the percentage of your electricity bill that is retained by Toronto Hydro?

[asked all respondents, n=10,346]



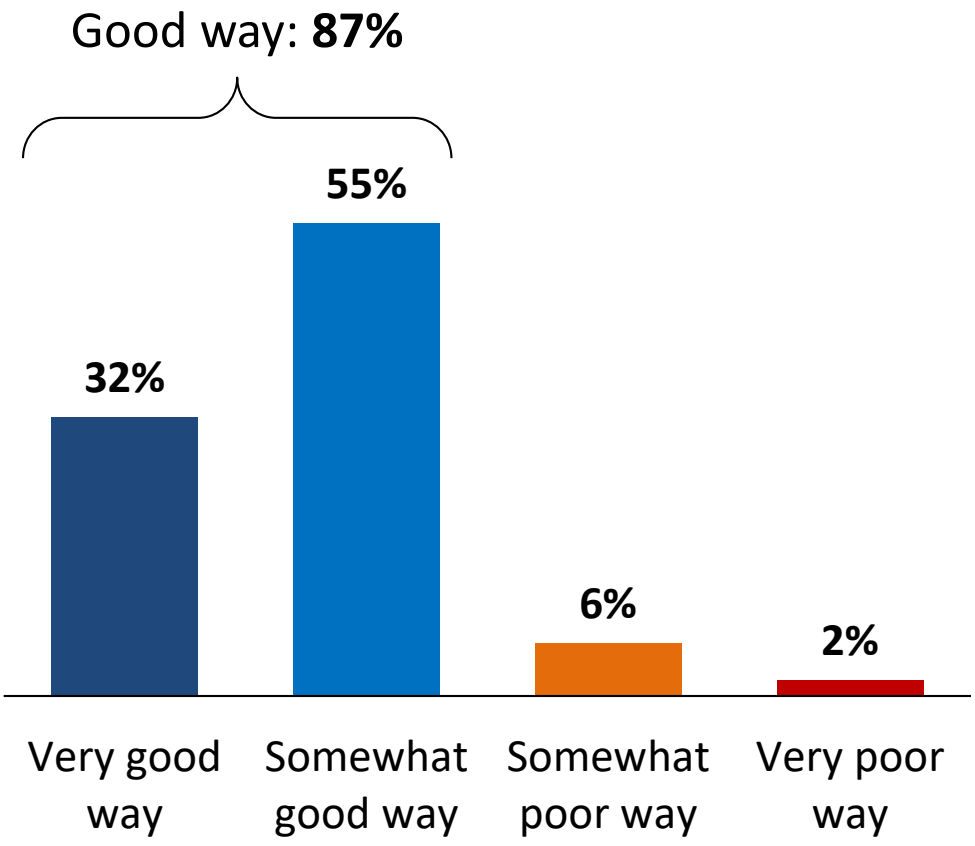
Segmentation

*Those who say "**Familiar**":*

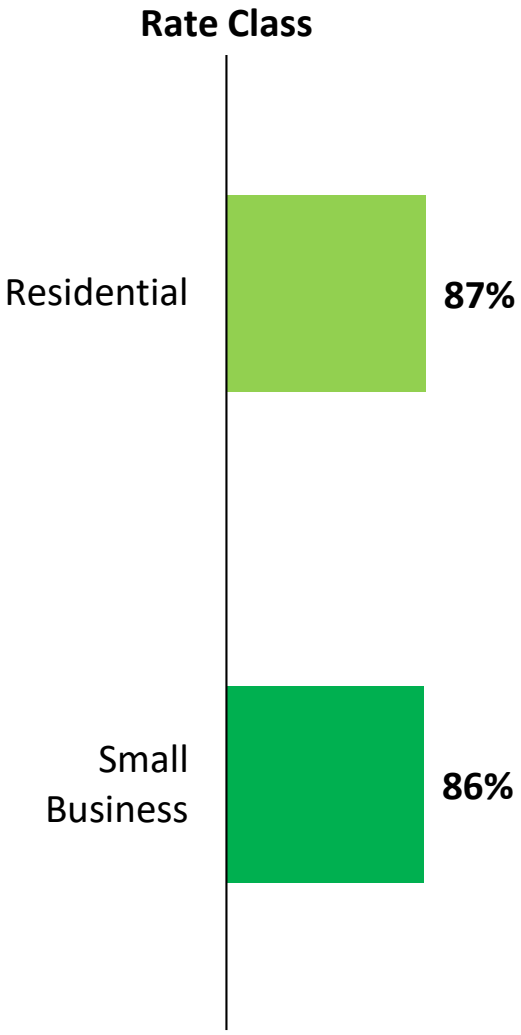


Feedback on Customer Engagement Process

Q Does this Customer Engagement process seem like a good way or a poor way to bring customer needs and preferences into **Toronto Hydro's** plan?
[asked all respondents, n=10,346]



Segmentation
*Those who say "**Good Way**":*



Note: "Don't Know" (5%) not shown.

Customer Priorities That Don't Belong

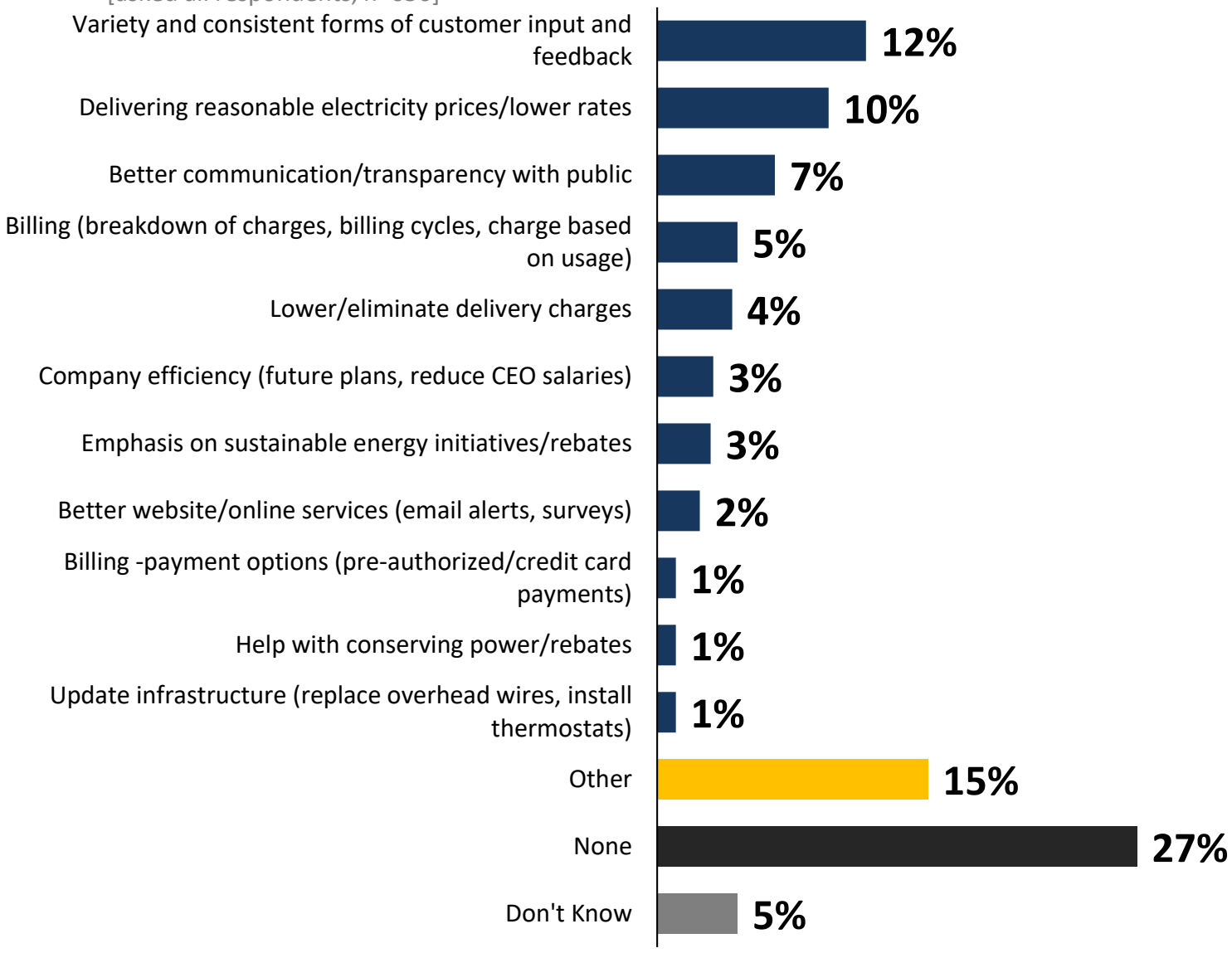
Q

In the initial customer engagement, residential and small business customers identified six core priorities which they believe should be a focus for Toronto Hydro. They are:

- *Delivering reasonable electricity prices*
- *Ensuring reliable electricity service*
- *Ensuring the safety of electricity infrastructure*
- *Enabling the electricity system to support the reduction of greenhouse gases*
- *Helping customers with conservation and efficiency*
- *Providing quality customer service*

Are there any priorities on the list above that you feel don't belong? If so, please specify.

[asked all respondents, n=656]



Note: "Refused" (4%) not shown.

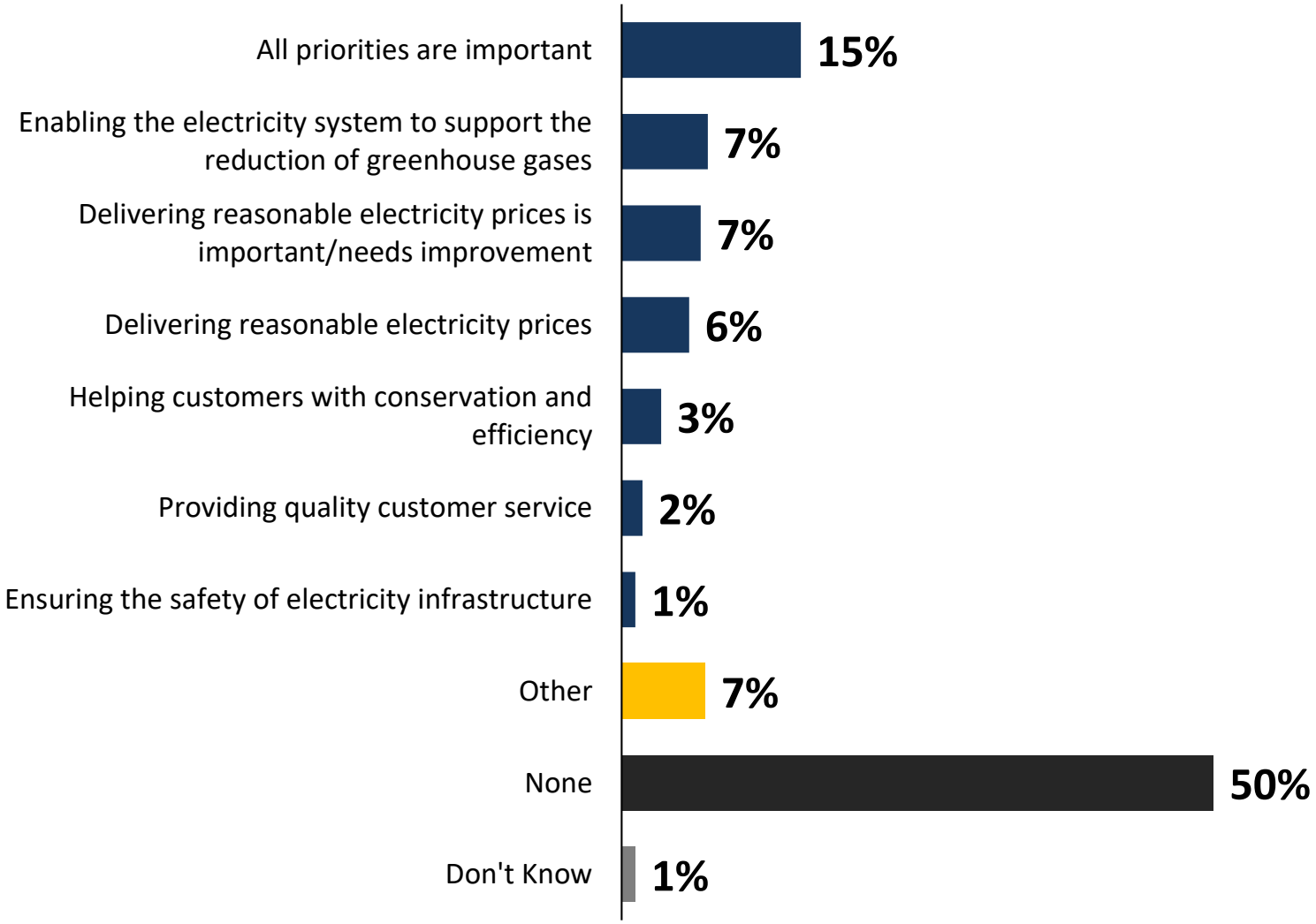
Additional Customer Priorities

In the initial customer engagement, residential and small business customers identified six core priorities which they believe should be a focus for Toronto Hydro. They are:

- *Delivering reasonable electricity prices*
- *Ensuring reliable electricity service*
- *Ensuring the safety of electricity infrastructure*
- *Enabling the electricity system to support the reduction of greenhouse gases*
- *Helping customers with conservation and efficiency*
- *Providing quality customer service*

Are there any priorities that you would add to the list above? If so, please specify which priorities you would add.

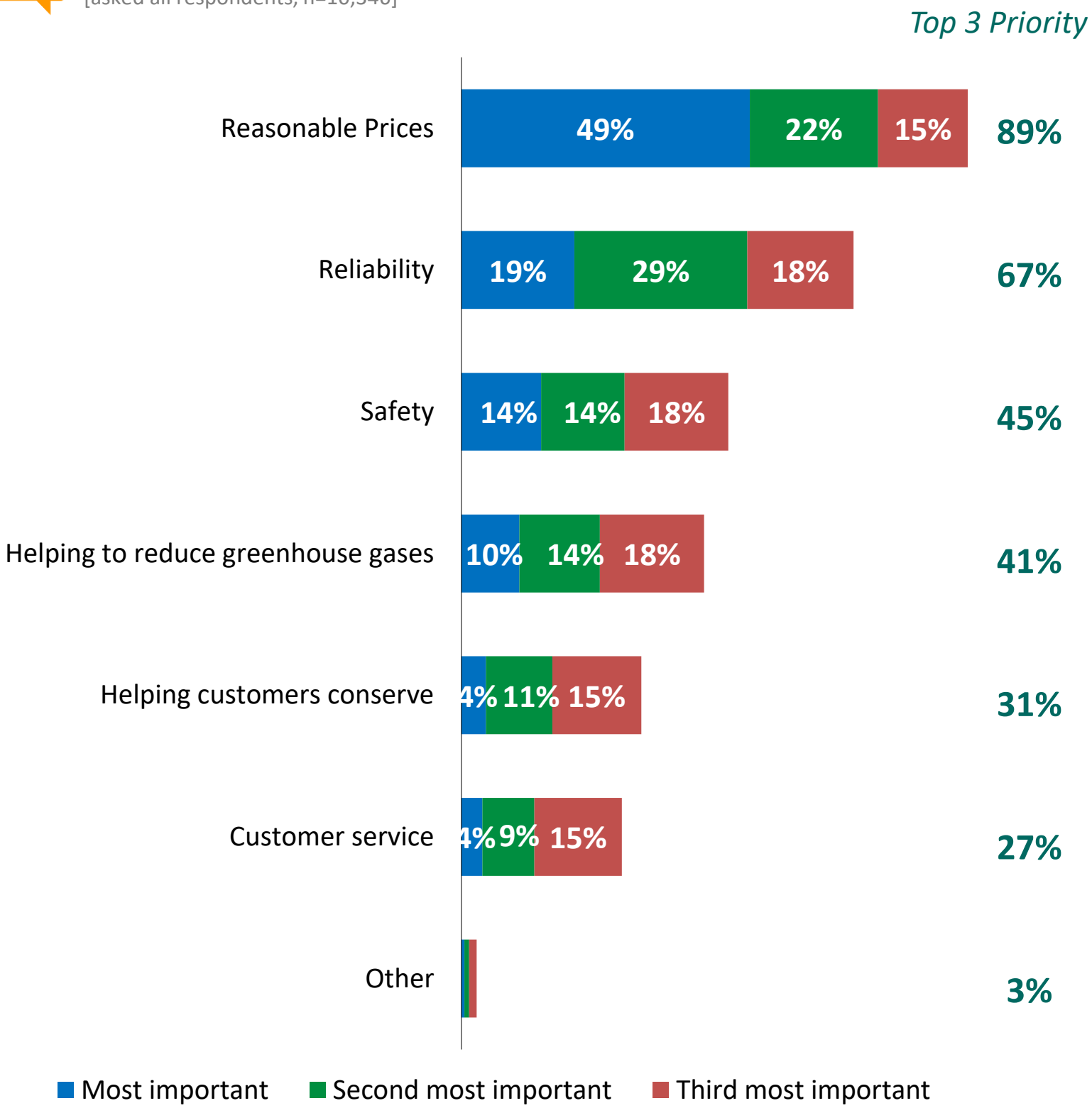
[asked all respondents, n=511]



Note: "Refused" (1%) not shown.

Customer Priorities

Please rank your Top 3 priorities from the list below.
[asked all respondents, n=10,346]



Building Toronto Hydro's Plan

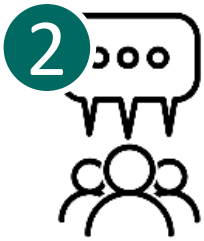
With this customer feedback in mind, Toronto Hydro is proposing a Plan that is responsive to:



1. Legal requirements by continuing to meet its obligations, including safety;



2. Customer feedback by:
    a) Keeping distribution price increases as low as possible;
    b) Maintaining long-term performance for customers experiencing average or better service;
    c) Improve service levels for customers experiencing below average service or who have special reliability needs (e.g. hospitals); and,
    d) Balancing other customer priorities (e.g. customer service) with the need to contain rate increases.





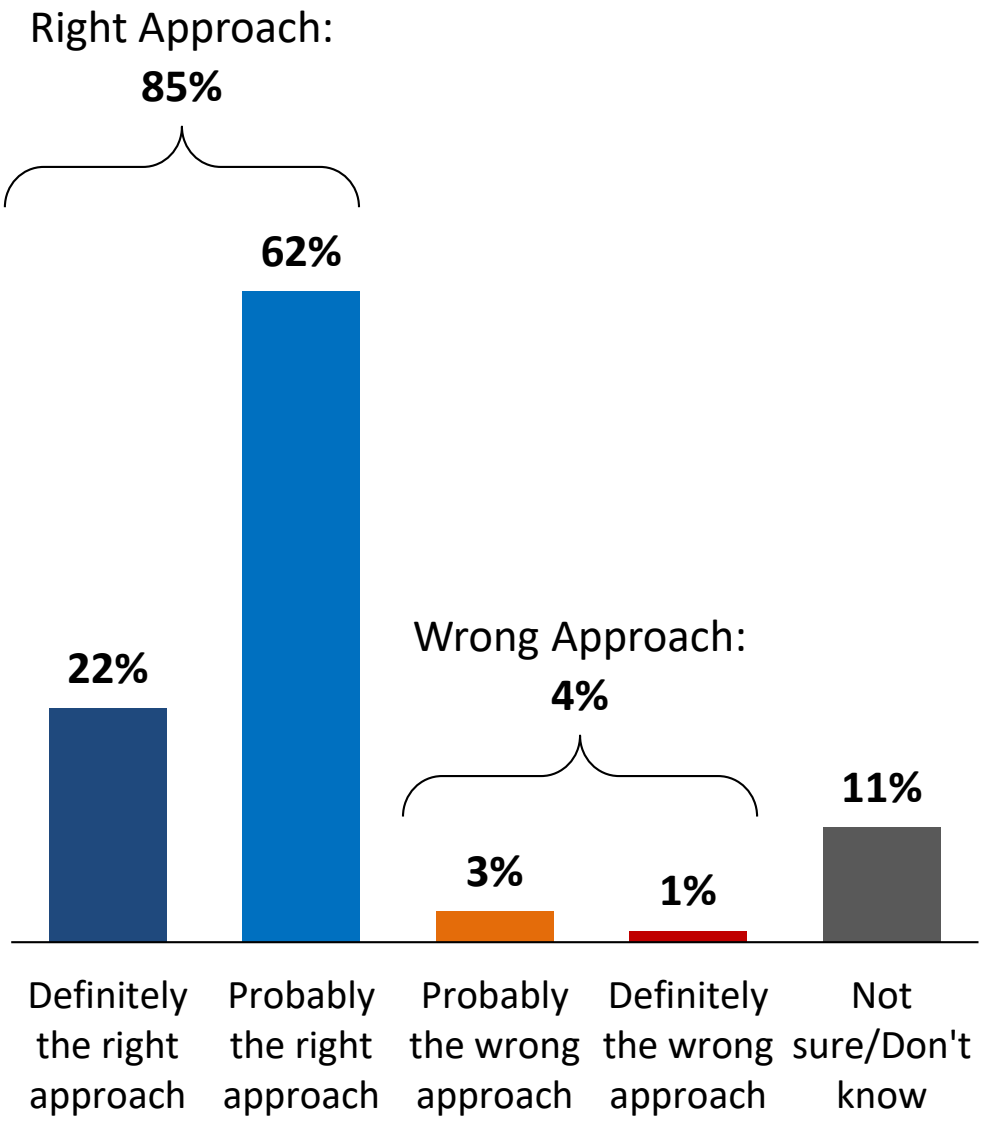


3. Business input by relying on expert analysis and professional judgment to develop construction and operations programs that address technical and operational requirements.

More information on Toronto Hydro's planning process here.

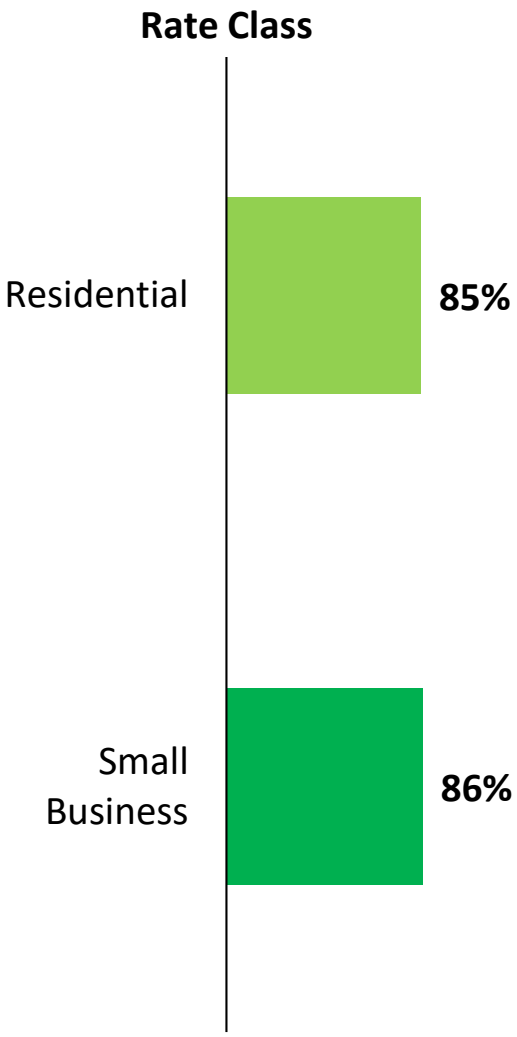
Approach to Planning for the Next Five Years

Q Does this seem like the right approach or the wrong approach?
[asked all respondents, n=10,346]



Segmentation

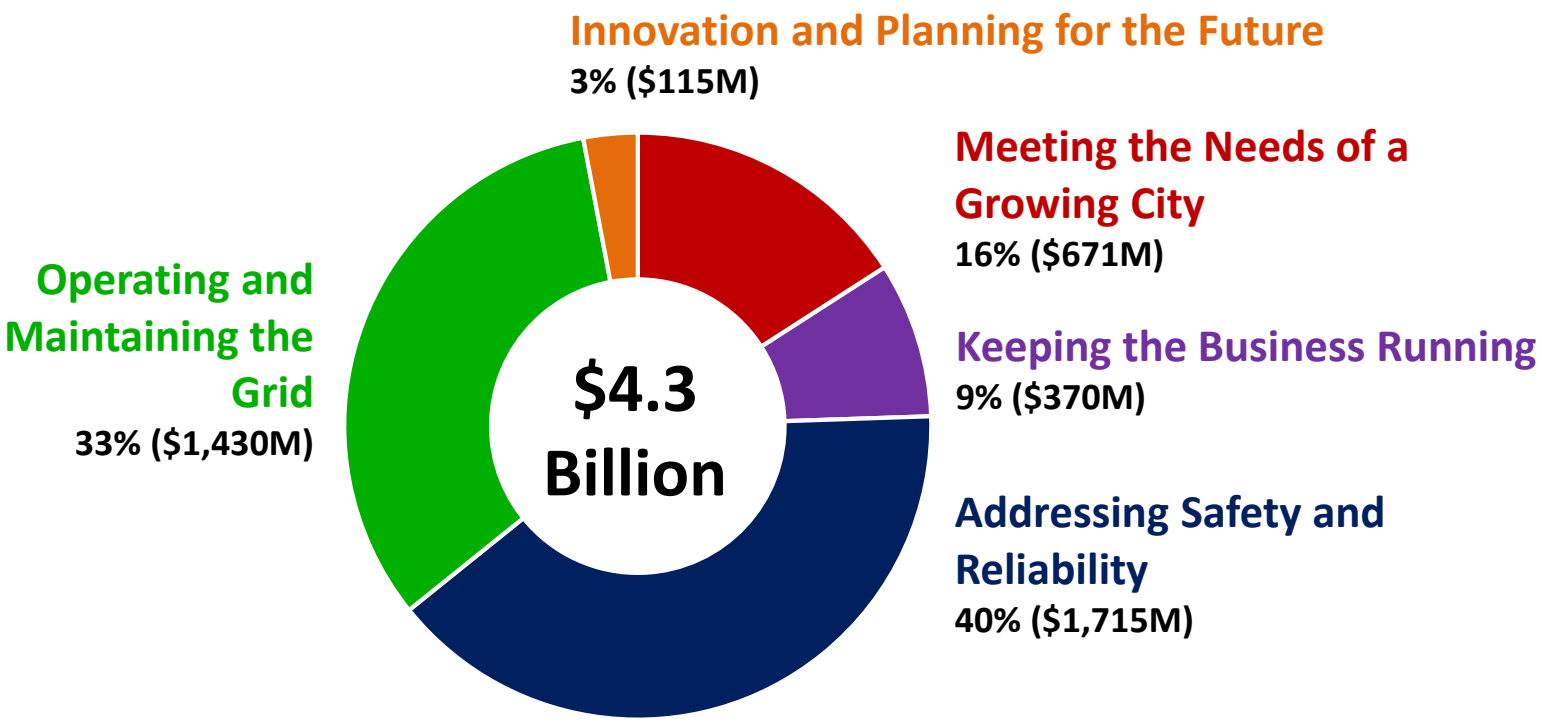
*Those who say "**Right Approach**":*



The Current Plan and Your Rates

Based on the initial customer input and the approach outlined on the previous page, Toronto Hydro has developed a plan totalling approximately $4.3B over five years. **There are five key budget categories.**

To learn more about each category, simply hover over the title.



That translates into an average 3.4% (4.4%) increase in your (organization's) distribution rates in each of the five years of the plan. This compares to an average increase of 5.8% (6.8%) per year in Toronto Hydro's current plan for 2015 to 2019,



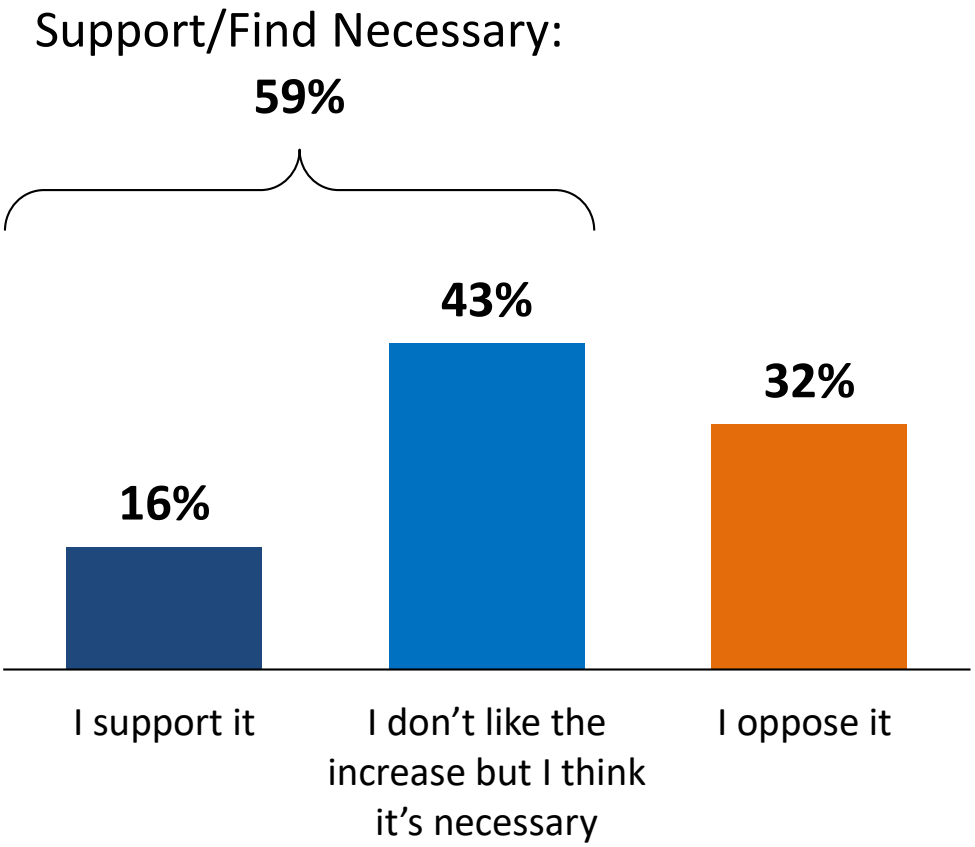
- In dollars and cents, that means an **average increase to the monthly bill of $1.51 ($4.86) each year** for the typical residential (small business) customer.
- Over the course of the proposed 5-year plan, the typical residential (small business) customer will see the distribution portion of their electricity bill **increase by $7.57 ($24.32).**
- As a result, the distribution charges on the monthly bill would increase from a proposed amount of **$41.60 ($101.98) in 2019** to **$49.17 ($126.30) by 2024.**

The next section of this workbook will explore some of the choices Toronto Hydro needs to make to finalize this plan. However, before that discussion, we would like to get your initial feedback on the cost of the current version of the plan.

Initial Feedback on Proposed Plan

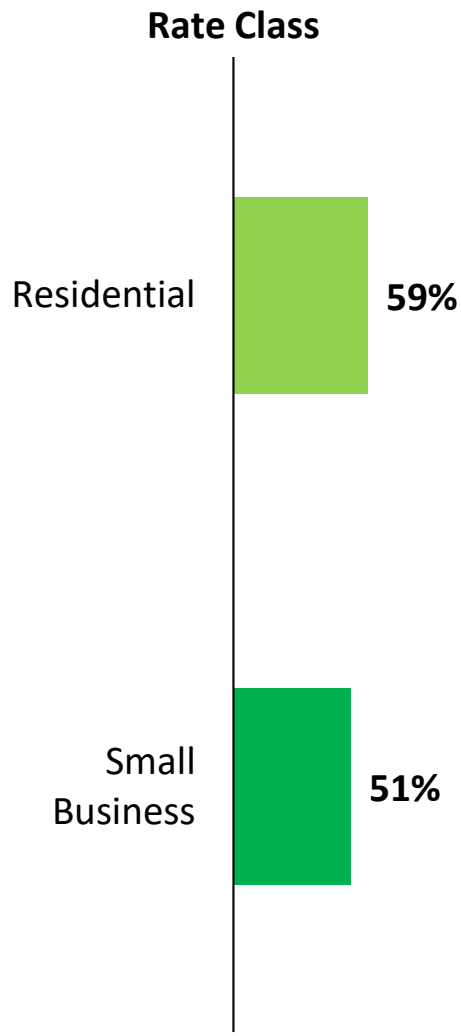
Q Which of the following statements best represents your view about a 3.4% (4.4%) annual increase to deliver current levels of reliability and customer service for most customers and targeted improvements for customers experiencing below average service or who have special reliability needs?

[asked all respondents, n=10,346]



Segmentation

*Those who say "**Support/Find Necessary**":*

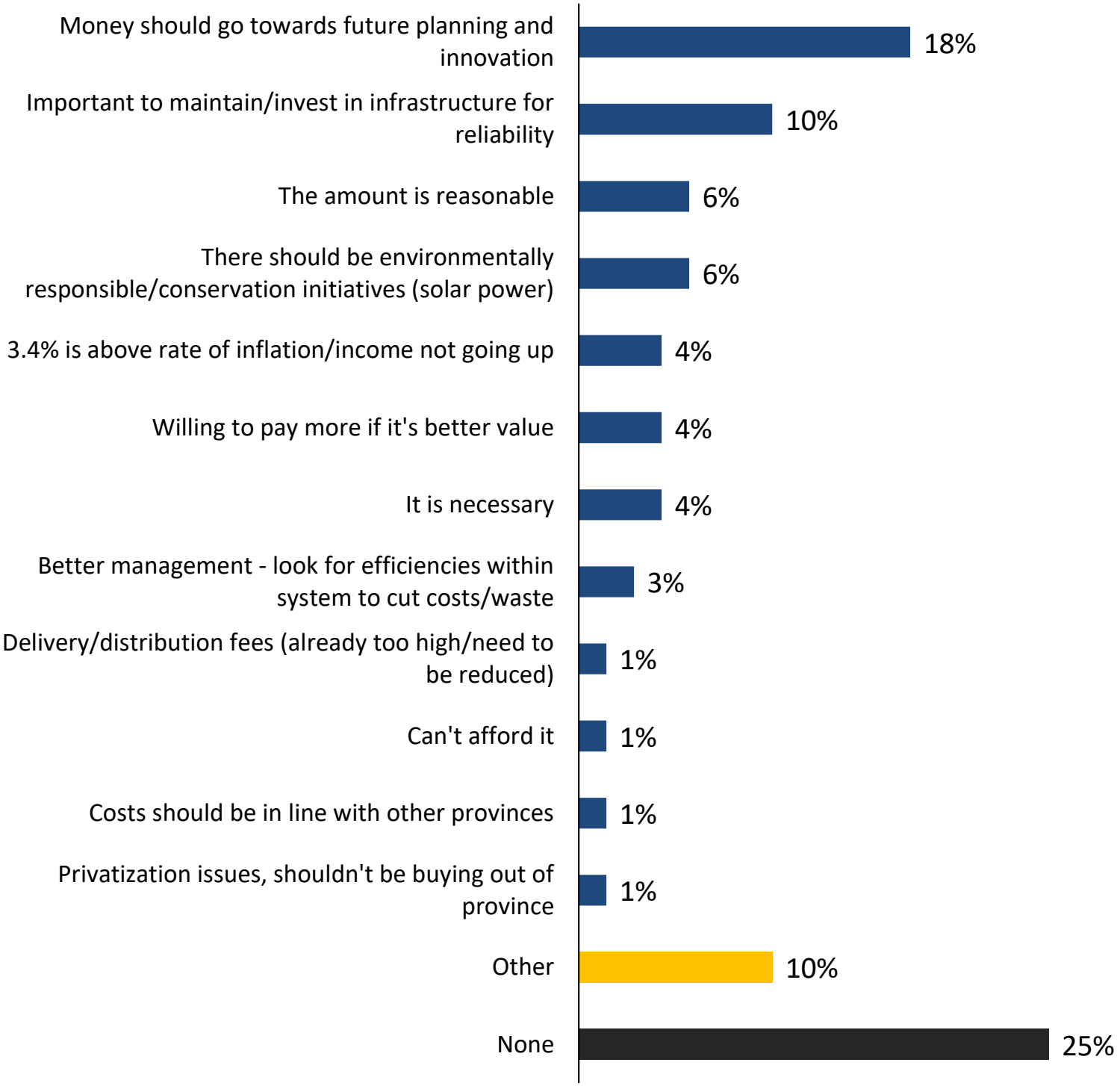


Note: "Don't Know" (9%) not shown.

Initial Feedback on Proposed Plan
Additional Comments

Q Do you have any comments you wish to add?
[asked all respondents, n=67]

*Those who say "**I support it**":*



Note: "Refused" (1%) not shown.

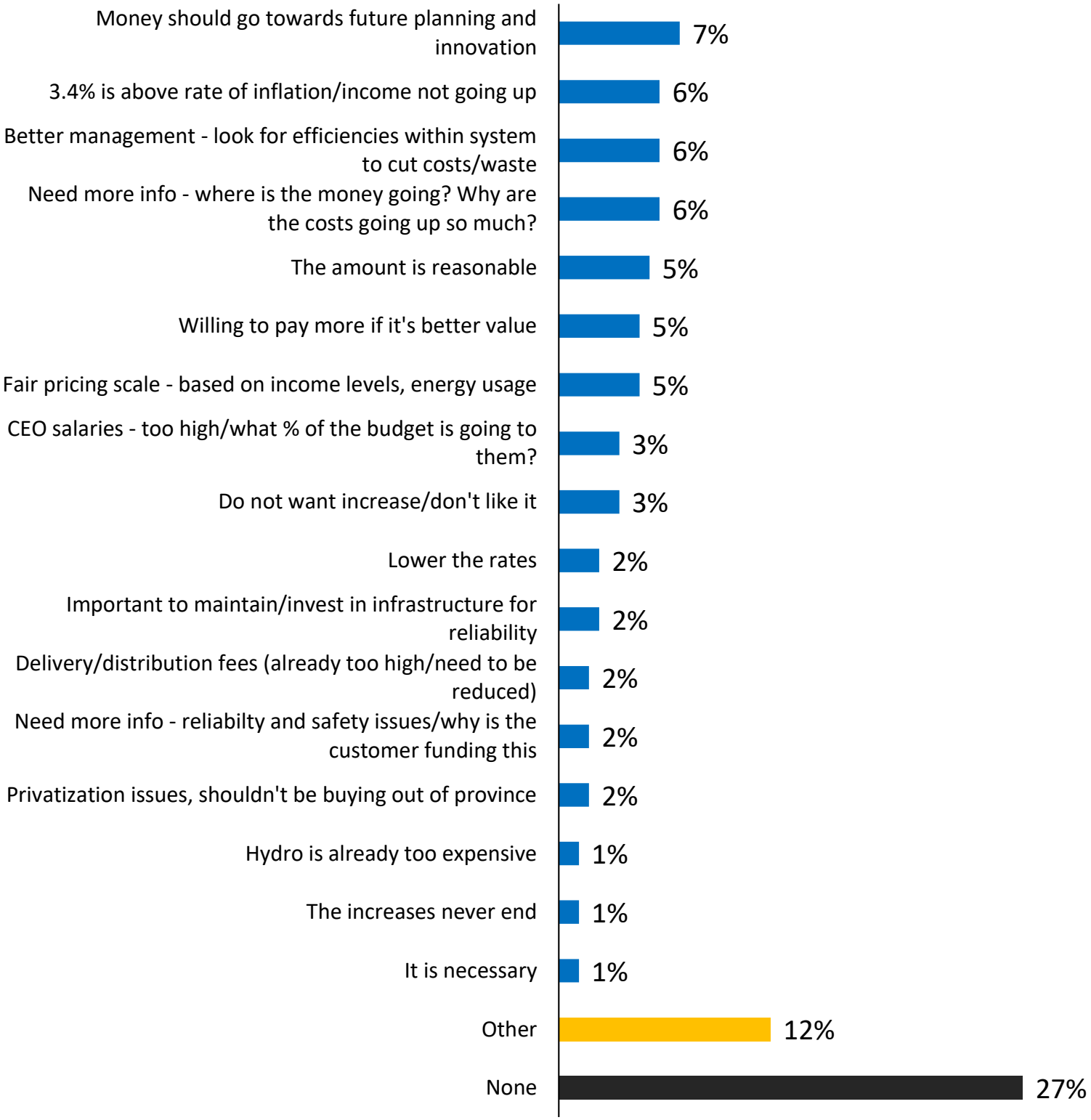
Initial Feedback on Proposed Plan

Additional Comments

Q Do you have any comments you wish to add?

[asked all respondents, n=173]

*Those who say "**I don't like the increase by I think it's necessary**":*



Note: "Refused" (2%) not shown.

Initial Feedback on Proposed Plan

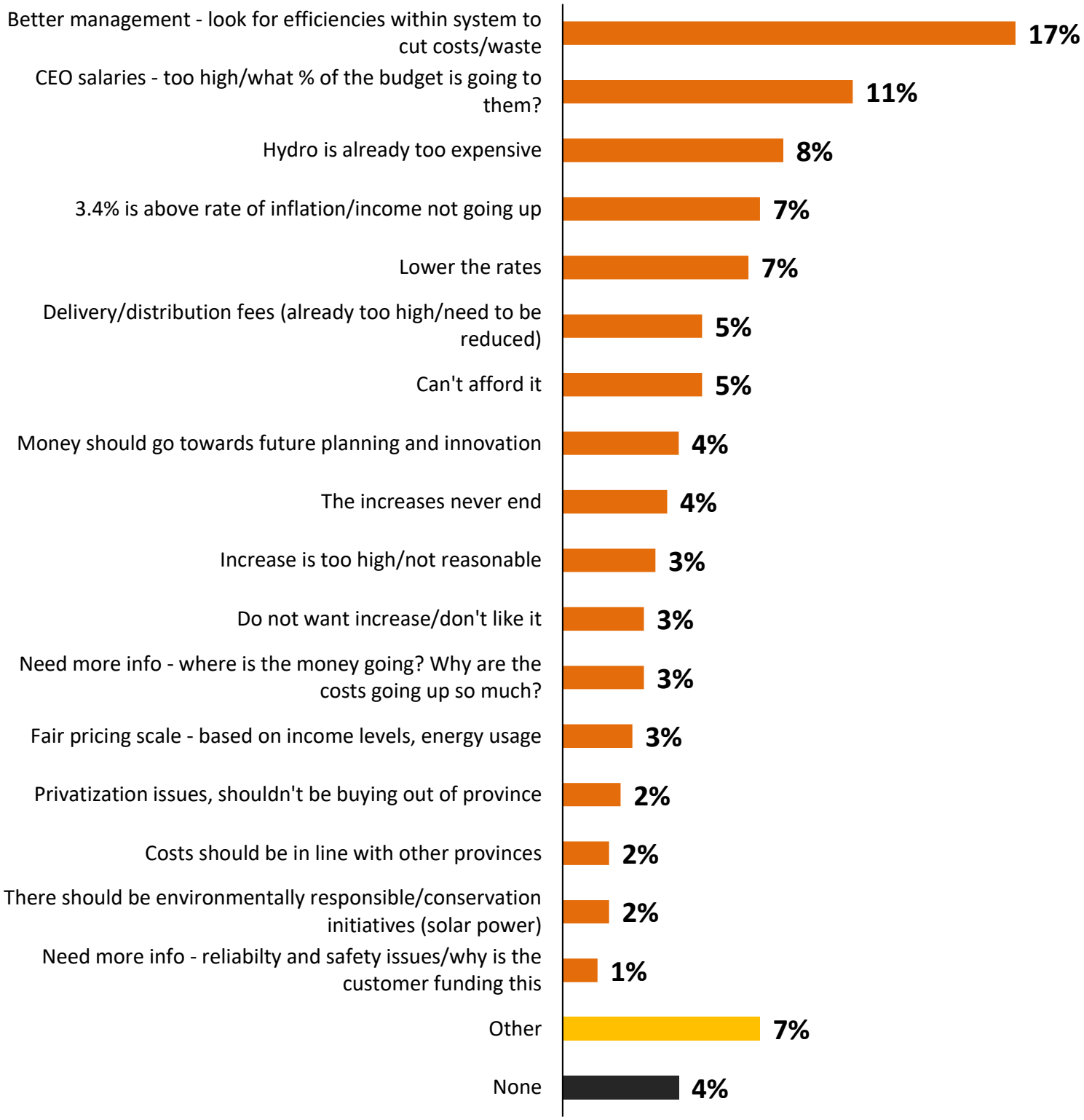
Additional Comments

Q

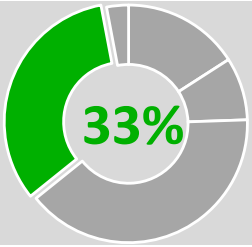
Do you have any comments you wish to add?

[asked all respondents, n=233]

*Those who say "**I oppose it**":*



Note: "Refused" (1%) not shown.

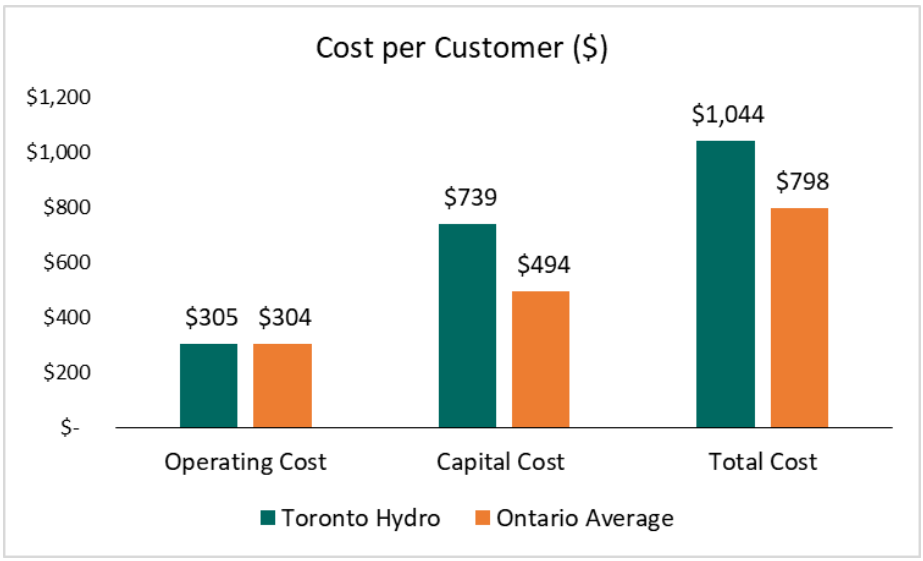


Making Choices

The following sections will ask about some key choices that could impact your rates.

Toronto Hydro's total spending is benchmarked by the OEB against other utilities in Ontario. In the last year of publicly available data collected by the OEB, Toronto Hydro's total cost per customer of $1,044 is higher than the average Ontario utility cost of $798. Those total costs are a combination of Toronto Hydro's operating and capital costs.

Toronto Hydro's **operating costs** of $305 per customer are close to the Ontario average of $304 dollars per customer. The choices in the operating budget are primarily driven by technical analysis and expert assessments of best practices.



As promised earlier, this customer feedback portal does not ask questions that expect you to be an electricity expert.

The OEB runs an open and transparent review process where experts from the OEB and intervenor groups review and challenge the Toronto Hydro's analyses and assessments. You are welcome to participate in the OEB process if you are interested in those issues. Details can be found here.

This consultation is focused on capital investments. Toronto Hydro's capital costs are $739 per customer compared to an Ontario average of $494 per customer. Some of this spending is required by the standards that apply to all electricity distributors, or technical analysis of requirements. In other cases, the final amount Toronto Hydro spends is based on choices on the appropriate balance between cost and other outcomes that matter to customers. Since you as a customer are the best judge of which outcomes are most important to you, the remaining questions in this workbook ask for your feedback on those choices.

Again, the following sections will ask about some key choices that could impact your rates.

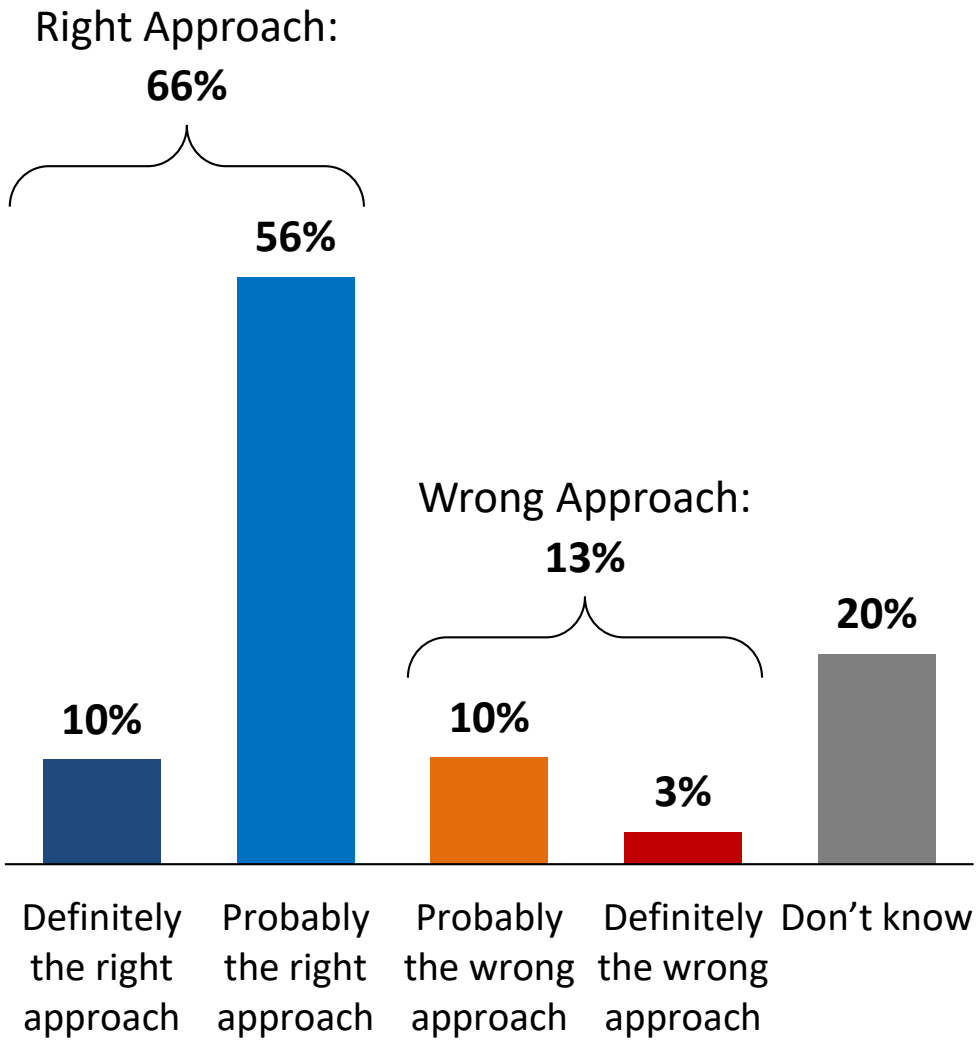
At the end of the portal, you will have an opportunity to review your responses and their impact on your bill. You will then be able to adjust your choices to provide what you feel is the best balance.

Making Choices

Q

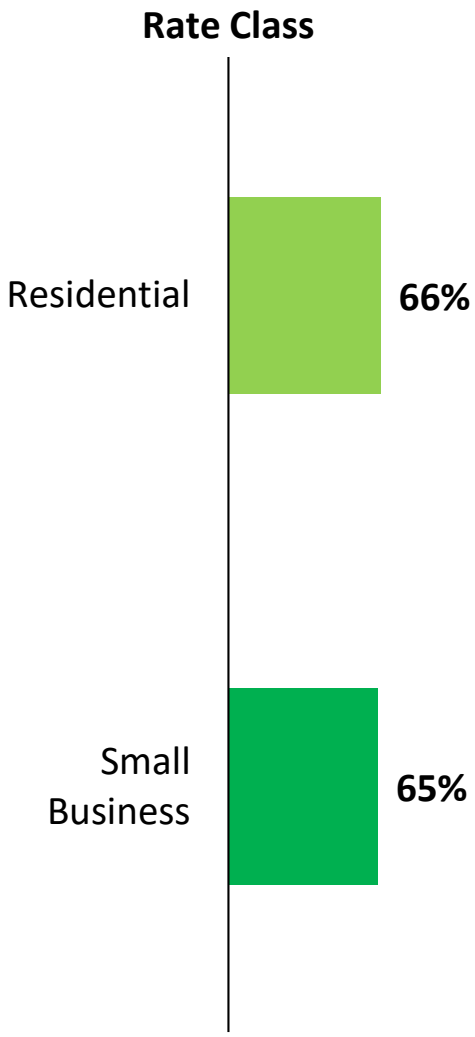
This workbook leaves detailed discussion of Toronto Hydro's operating budget to experts from the OEB and intervenors in the formal OEB review; the workbook focuses on collecting your view on competing trade-offs in infrastructure investments. Does this seem like the right approach or the wrong approach to you?

[asked all respondents, n=10,346]



Segmentation

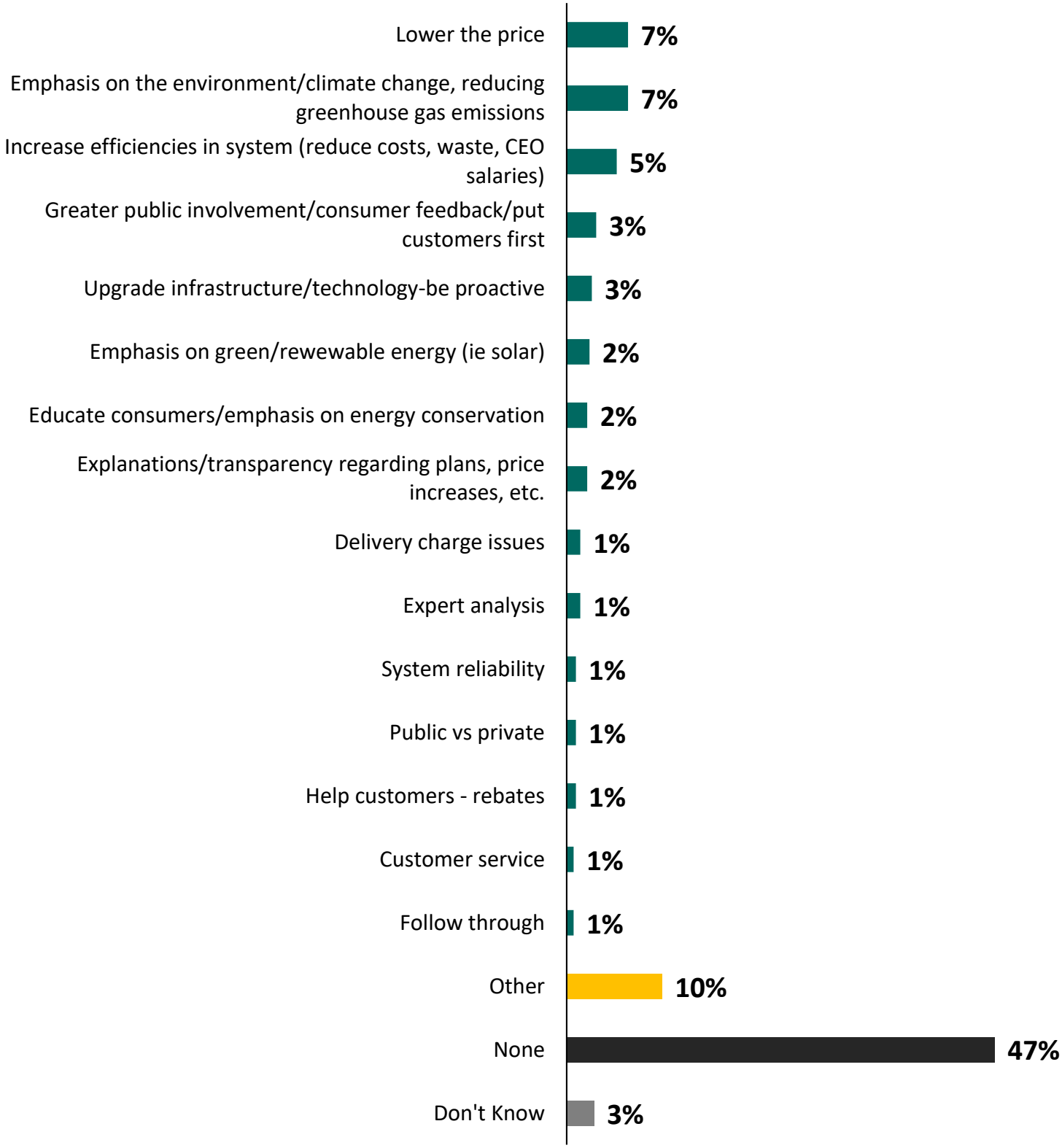
*Those who say "**Right Approach**":*

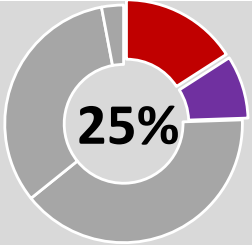


Making Choices
Additional Comments

Q Is there is anything in particular you would change about this approach or any other comments you would like to make?

[asked all respondents, n=401]





Investing in the Basics

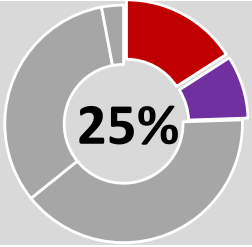
Meeting the Needs of a Growing City

Toronto is Growing. Toronto Hydro has an obligation to serve it.

You just have to drive around Toronto to see how quickly this community of over 2.9 million people is growing. New condos, office buildings, and transit projects are creating increasing demands on the electricity grid. Toronto Hydro is required to connect new customers to the grid and move infrastructure at the request of government, including for transit projects or road widening.



Beyond this, Toronto Hydro's efforts to meet the needs of a growing city include making investments that meet new demands on the grid in ways that at least maintain current reliability.



Investing in the Basics

Keeping the Business Running



In addition to maintaining the distribution grid, Toronto Hydro has to ensure that it invests in tools required to keep up with the needs of customers and the grid. The types of tools in this category are:

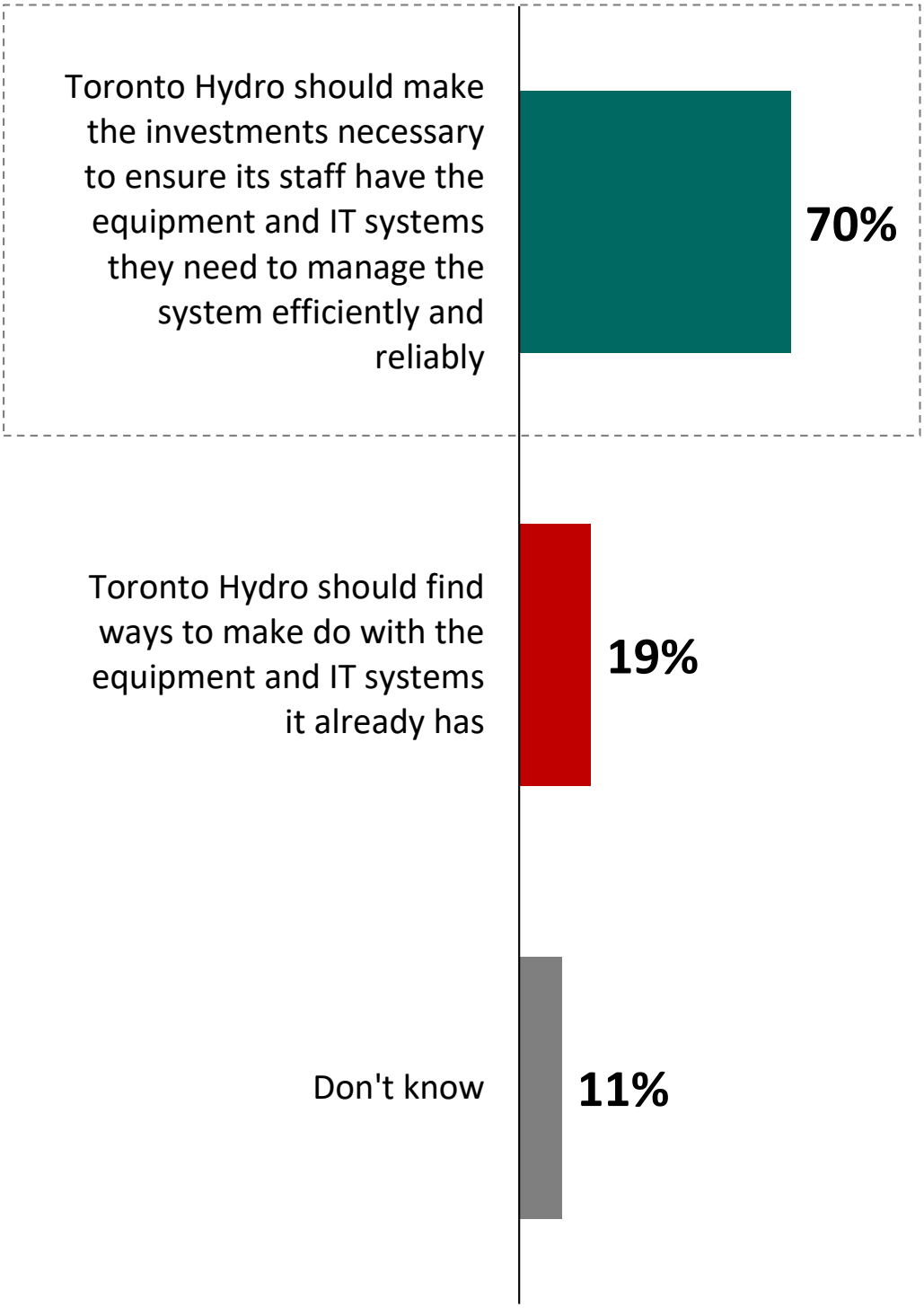
- **Information Technology**: systems required to securely operate the distribution system, manage customer information and privacy, and keep personnel working effectively and efficiently
- **Vehicles**: bucket trucks and other vehicles used to move personnel and supplies around the city to support the safe and reliable operation of the grid
- **Facilities:** offices and operations centers that house the people, vehicles, and equipment needed to serve customers

When deciding whether to continue to maintain existing tools or replace them, Toronto Hydro considers whether the risks and costs of continuing to use them outweighs the benefits of waiting longer to replace them. For example, Toronto Hydro intends to replace its system used for customer service and billing: the old version has reached the end of its useful life, no longer has full vendor support, and efforts to keep it going are becoming expensive and increasing the risks that Toronto Hydro cannot get accurate bills to customers on time.

Investing in the Basics

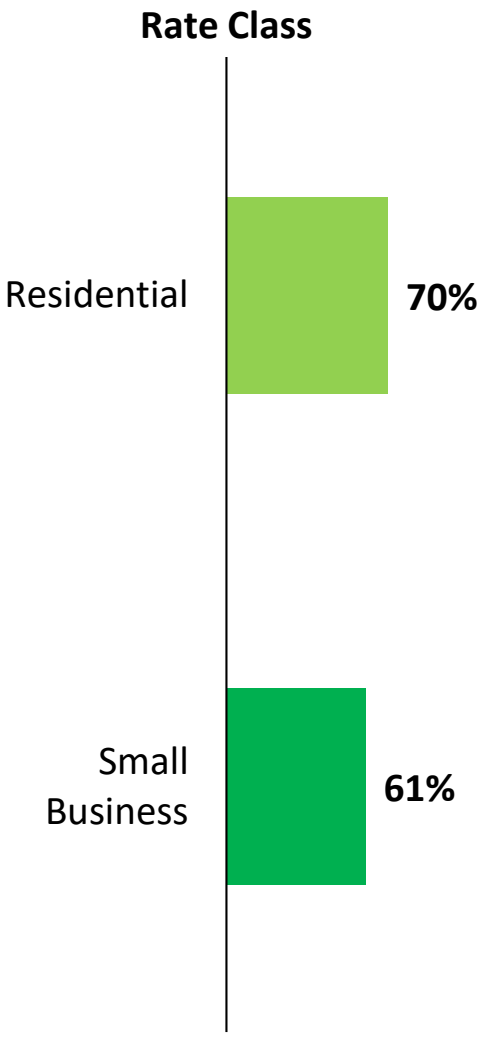
As a company, Toronto Hydro needs vehicles and tools to service the power lines and IT systems to manage the system and customer information. Which of the following statements best represents your point of view?

[asked all respondents, n=10,346]



Segmentation

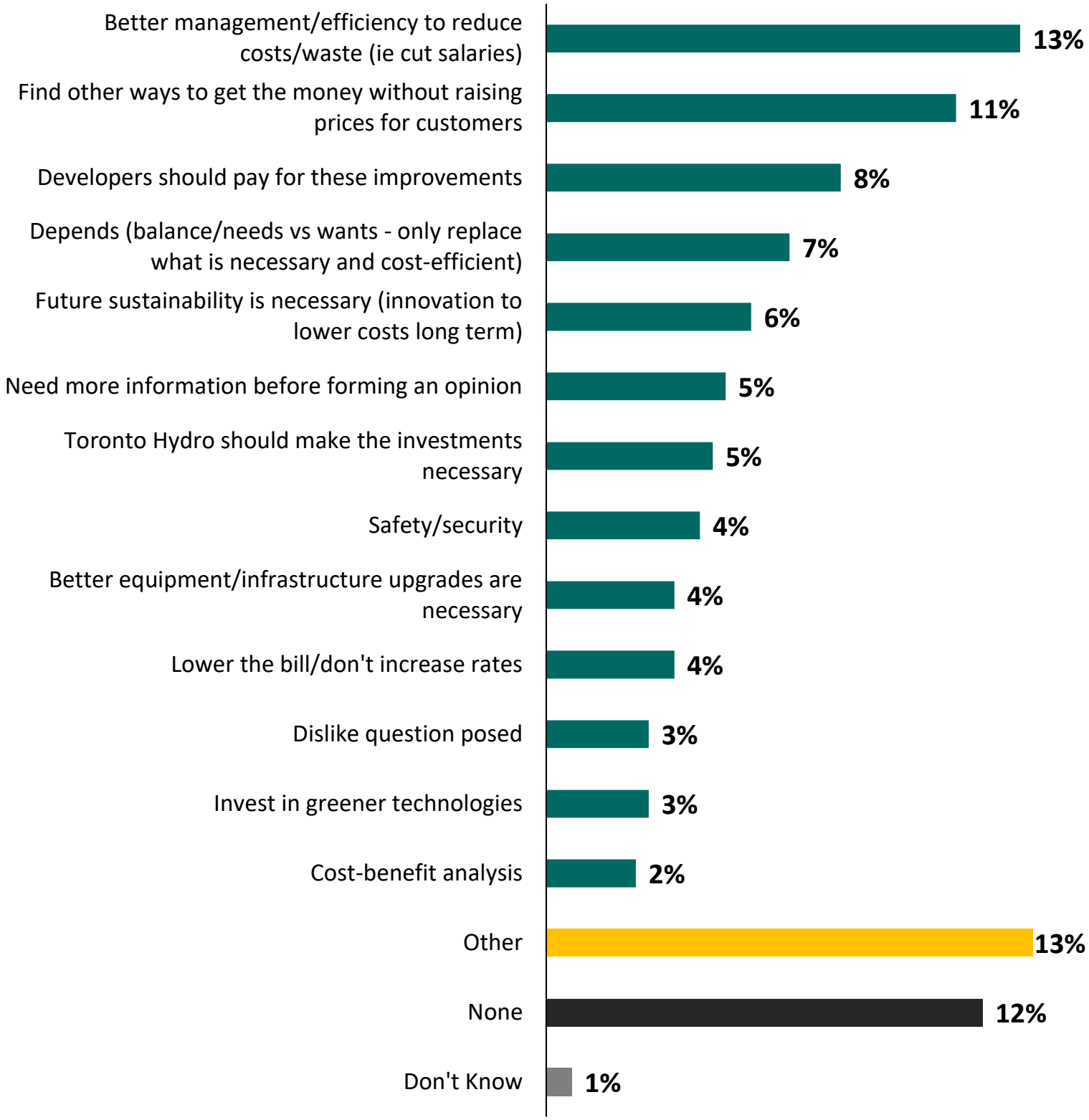
*Those who say "**make the investments necessary**":*

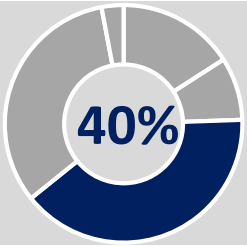


Investing in the Basics
Additional Feedback

Q

Additional Feedback
[asked all respondents, n=284]





Addressing Safety and Reliability

What's in this category?

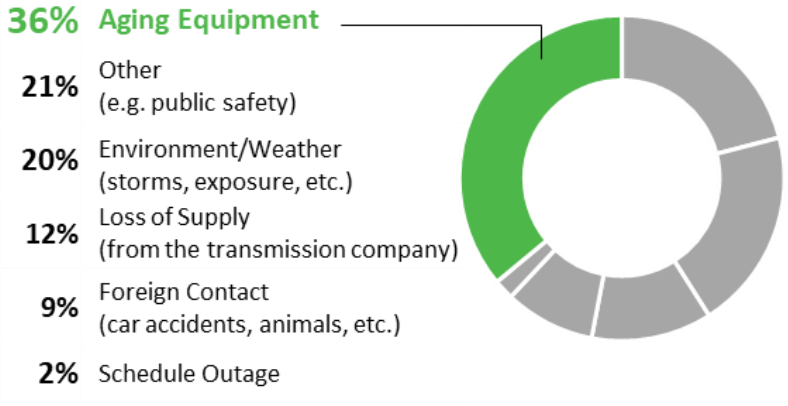
40% of Toronto Hydro's proposed budget will go towards ensuring safety and reliability is maintained and service improvements are made for customers experiencing below average reliability or who have special reliability needs (e.g. hospitals).

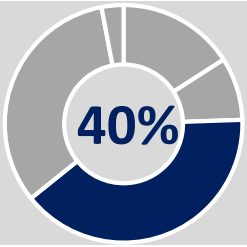
There are many reasons for poorer reliability (e.g. outages). In any given year, reliability can increase or decrease in response to unusual weather events. In fact, roughly 20% of all outages are caused by ice storms, severe winds, extreme rainfall, and other environmental events. However, the largest number of outages, roughly 36% of them, can be attributed to aging equipment.

Toronto Hydro measures both how many interruptions customers experience and how long those outages last. Over the past five years, excluding major events like ice storms, the average customer has experienced:

- Average of **1.4** outages per year.
- Between **60** and **70** minutes without power per year.

Aging equipment is responsible for approximately 36% of Outages



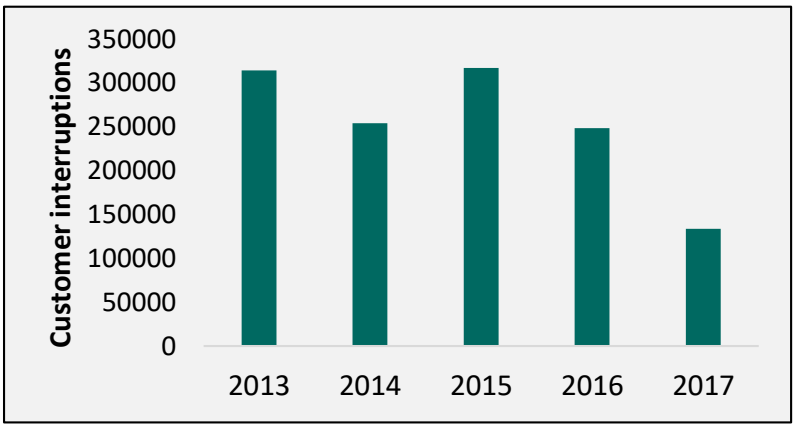


Addressing Safety and Reliability

Approximately one-third of Toronto Hydro's distribution assets are beyond their expected useful lives or will reach their expected end of useful life within the next five years. Toronto Hydro takes a stewardship approach to that challenge: investing in infrastructure that benefits today's customers and future generations of customers.

Toronto Hydro's current five year plan (2015-2019) ramped up investment in replacing old equipment **and the average number and length of outages has been declining.** The chart below illustrates this improvement for people who were having the worst experiences.

In the new plan, Toronto Hydro's general approach is to spend just enough on the grid so that most customers can expect a similar level of reliability over the next five years as they are experiencing today, and to provide improved service for those customers whose reliability is poorer or who have special reliability needs (e.g. hospitals).

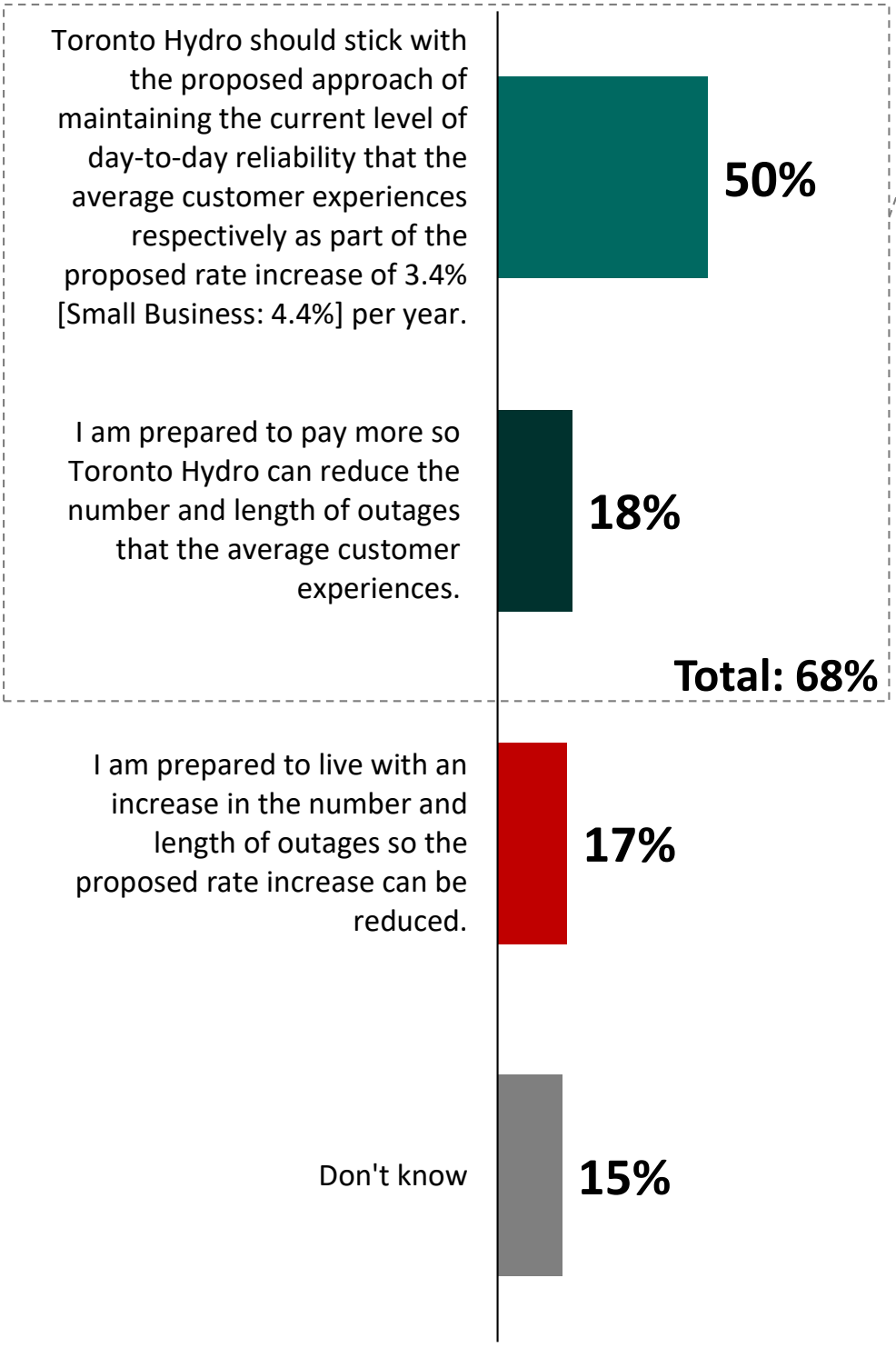


# of Customer Interruptions on Poor Performing Circuits

Addressing Safety and Reliability

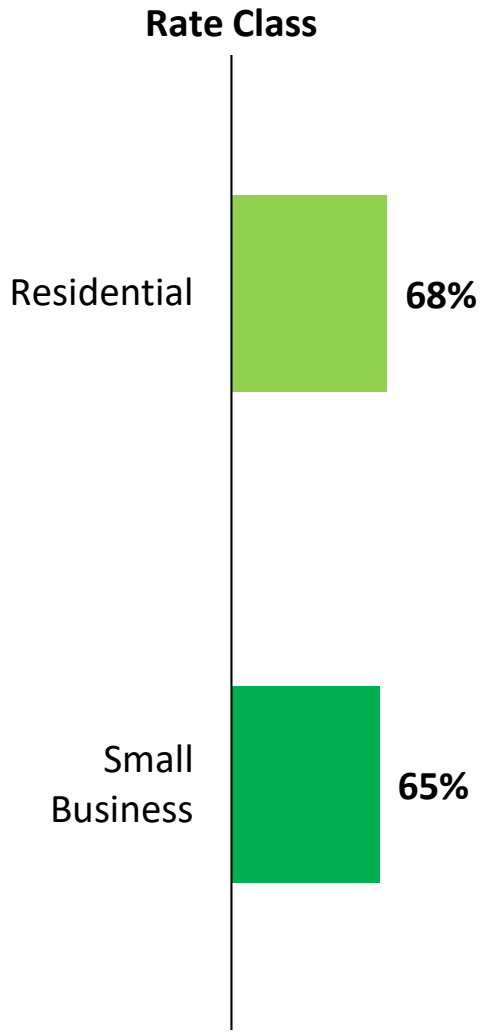
Q Which of the following is closest to your point of view regarding Toronto Hydro's stewardship approach to addressing reliability?

[asked all respondents, n=10,346]



Segmentation

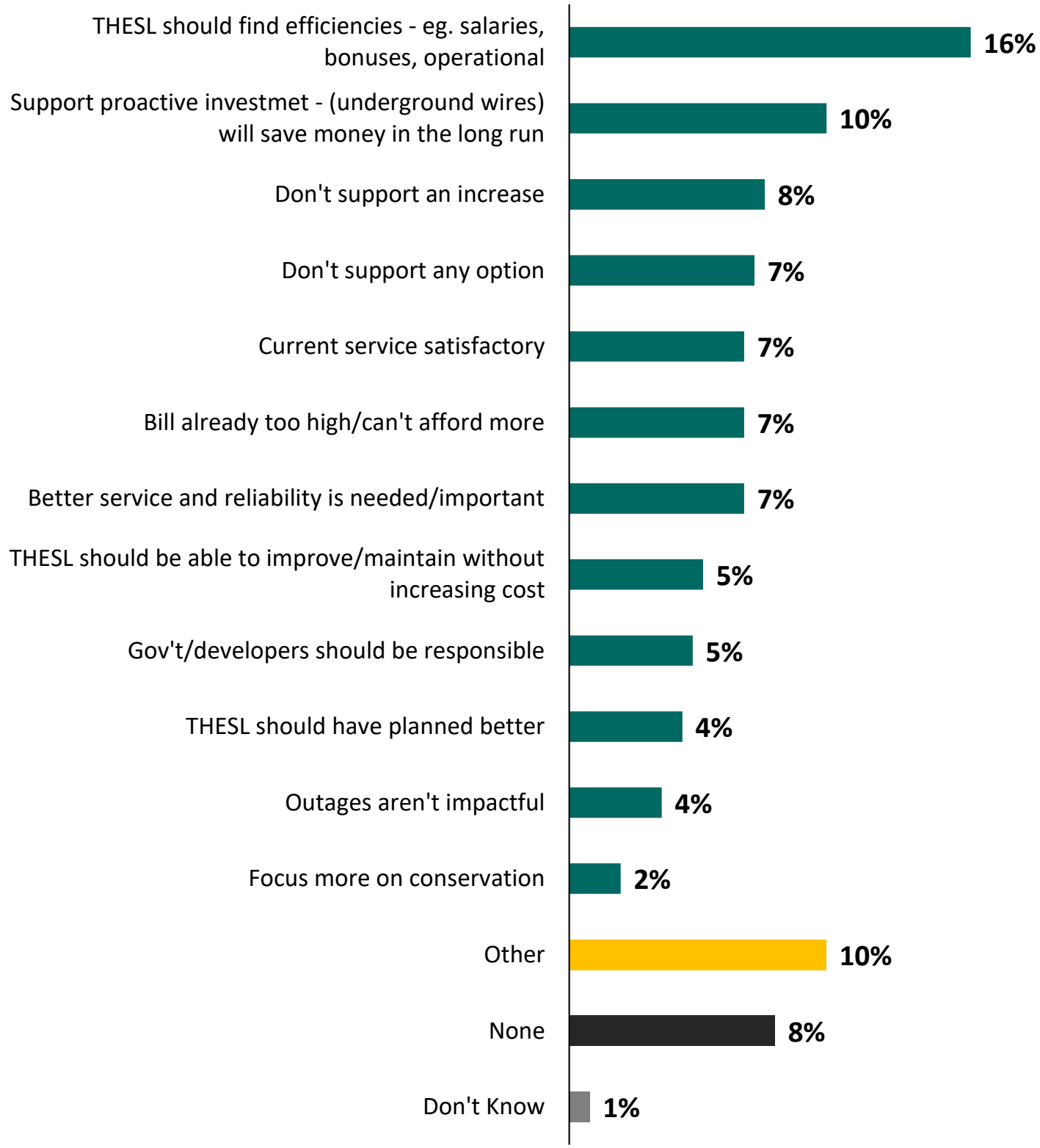
*Those who say "**prepared to pay more**" or "**stick with the proposed approach**":*

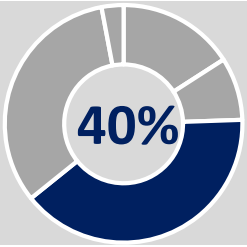


Addressing Safety and Reliability
Additional Feedback

Q

Additional Feedback
[asked all respondents, n=249]





Dealing with types of lines that fail more often with more problems

Should we spend more to replace lines that cause more complicated problems more often?



While this is a general question, there are two particular types of neighbourhood power lines where there is a pressing issue - Rear-Lot Feeders and Direct Buried Cable. These are old technologies that have been in use for more than 50 years. While initially they served Toronto Hydro customers well, they now pose reliability and safety concerns. Customers served by these lines are more likely to experience power outages, and when they do those outages are more likely to last longer and be more expensive to fix.

- **Rear-Lot** refers to a type of overhead construction installed in residential backyards during the 1950s and 1960s. Because rear-lot lines are in customers' backyards, they are often difficult for crews to reach and have more exposure to risks such as falling trees and branches. Working on these lines often causes additional disruption and inconvenience to customers. Outages on rear-lot lines are about 1.3 hours longer on average as compared to outages on other power lines.

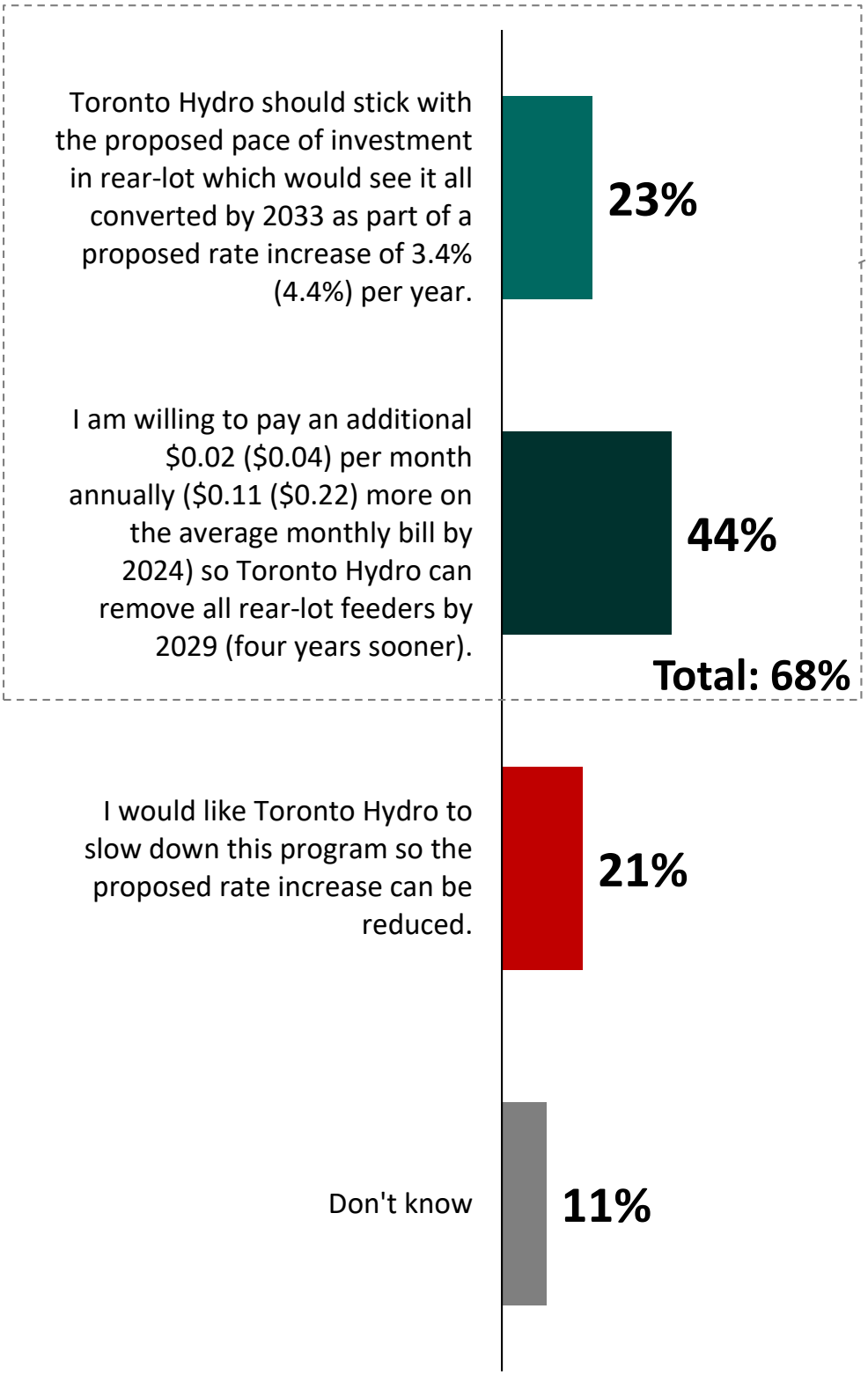
- **Direct Buried Cable** refers to a legacy type of underground construction where cables are laid directly in underground trenches without a protective barrier. While equipment failure causes 36% of outages across the system, cable failure accounts for 70% of all outages on the underground system. Once these cables start to fail, they tend to experience a rash of failures. On average 800 customers are affected by each buried cable failure and the outages last longer than average (between 4 and 24 hours).

Toronto Hydro's initial plan will phase out rear-lot feeders by 2033 and a quarter of the highest risk direct buried cable by 2024. Converting these lines faster will improve reliability for customers served by this type of equipment.

Rear-lot Replacement Programs

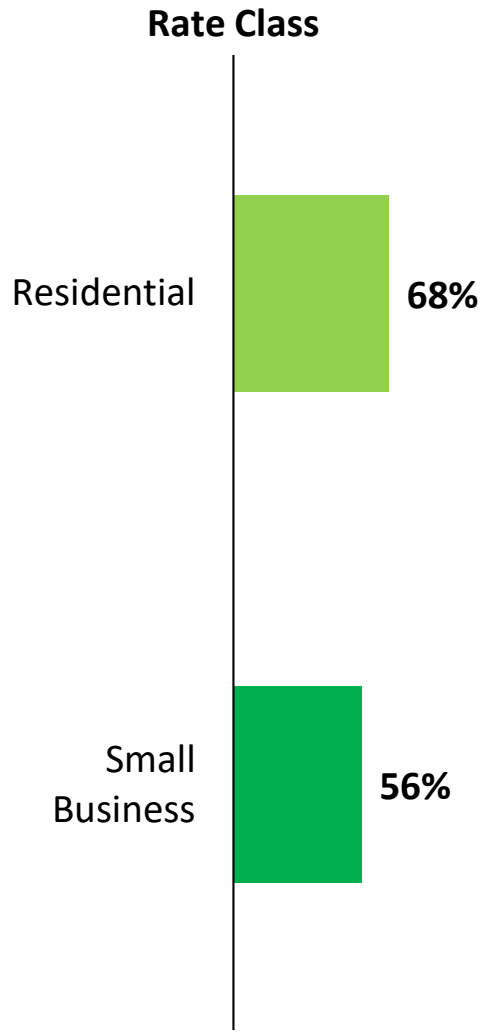
Q Which of the following is closest to your point of view regarding Toronto Hydro's rear-lot replacement programs?

[asked all respondents, n=10,346]



Segmentation

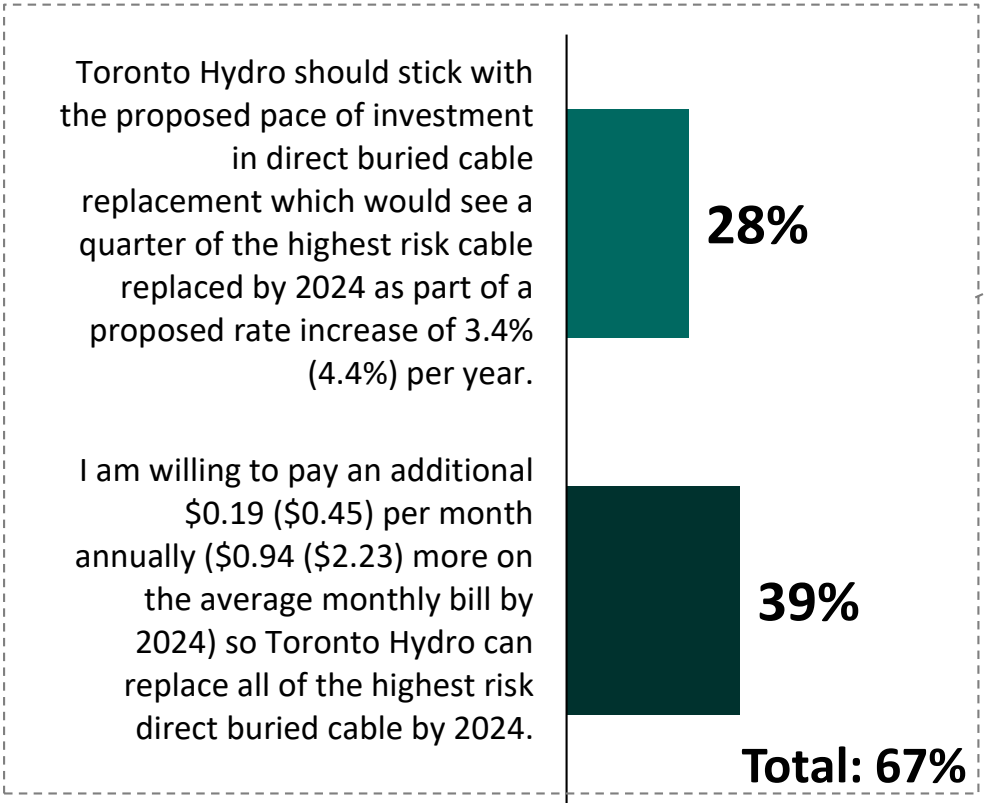
*Those who say "**willing to pay an additional fee**" or "**stick with the proposed pace**":*



Direct Buried Cable Replacement Program

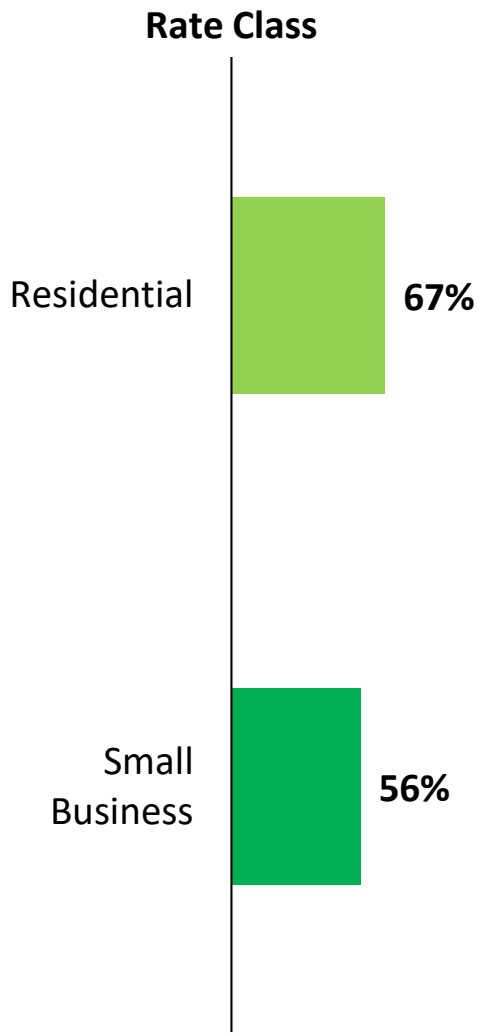
Which of the following is closest to your point of view regarding Toronto Hydro's direct buried cable replacement programs?

[asked all respondents, n=10,346]



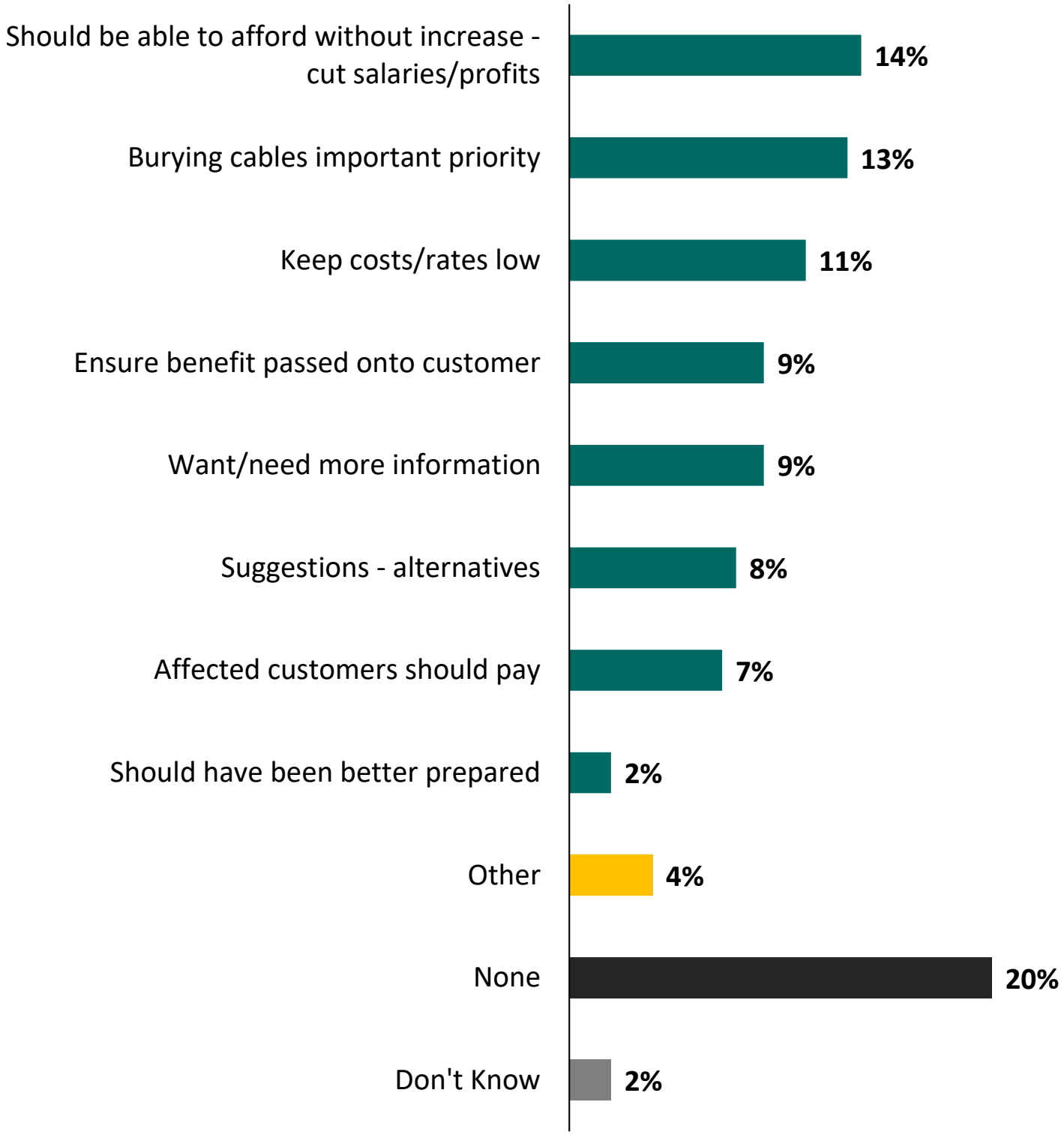
Segmentation

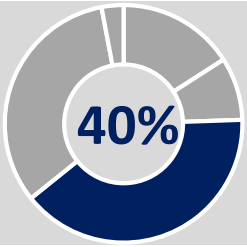
*Those who say "**willing to pay an additional fee**" or "**stick with the proposed pace**":*



Dealing with types of lines that fail more often with more problems

Q Additional Feedback
[asked all respondents, n=152]





Dealing with complicated projects in built up areas

Should we spend more now to avoid increased cost and disruption later?

In order to keep rate increases down, Toronto Hydro has focused its spending on dealing with more urgent and immediate needs. However, with the current pace of growth in Toronto, there are a number of locations where Toronto Hydro knows that it will need to conduct work within a few years and where planned and current development will make those projects more expensive and more disruptive if Toronto Hydro waits.





Paper Insulated Lead Covered (PILC) Cable

One major example of this is PILC cable. PILC cable was the first type of underground cable installed as part of Toronto Hydro's grid and a lot of it is still providing electricity to the downtown core.

While this is a resilient type of equipment, all of these cables were installed more than 20 years ago. As these cables begin to age, the outer lead covers can begin to crack and leak oil.

Environmental regulations have changed, making it more costly and difficult to remove and replace these cables. As workers who first installed these types of cables continue to retire, fewer trades people have the expertise to deal with this equipment.

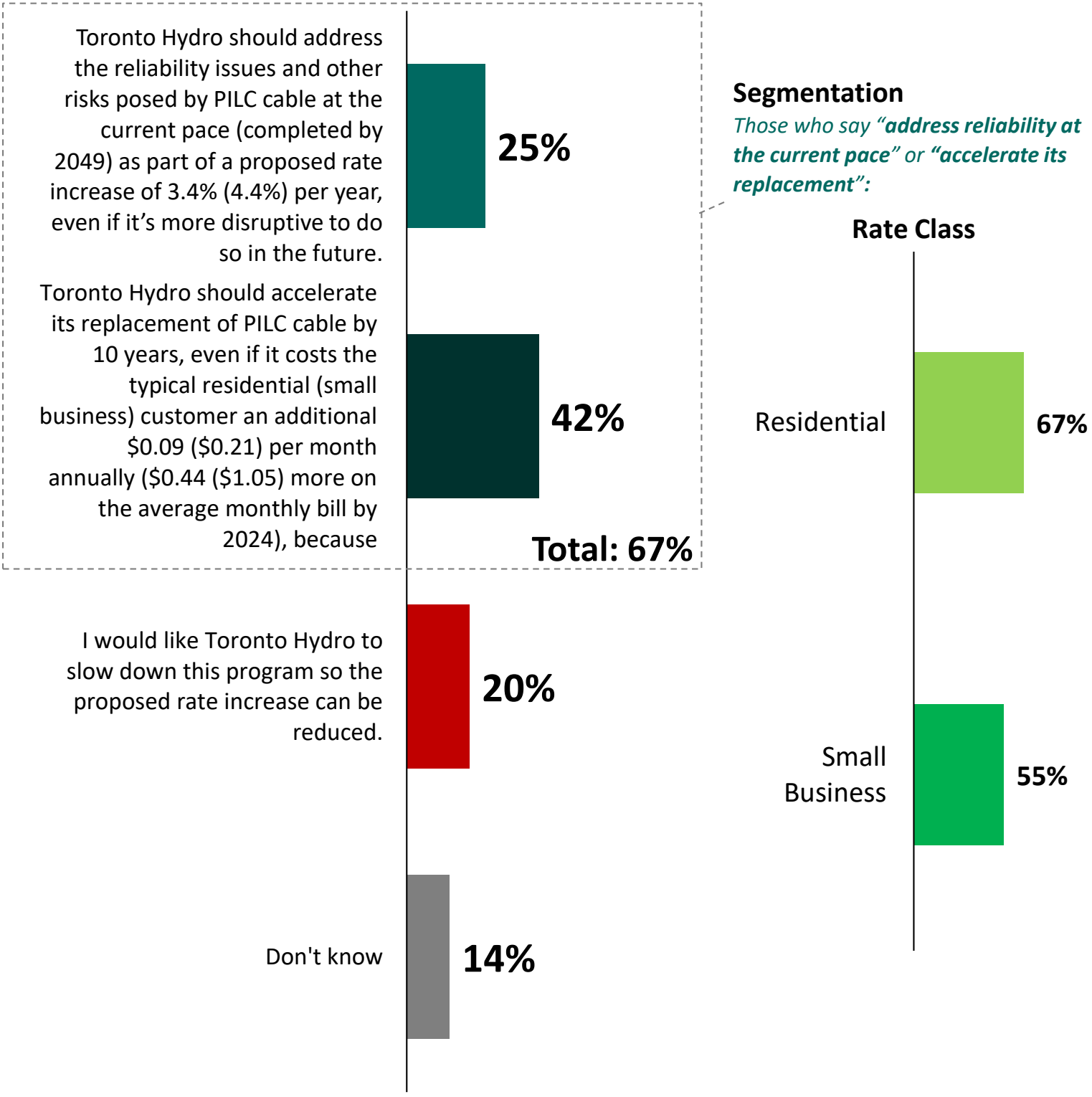
Toronto Hydro has a long-term plan to remove and replace PILC cable by 2049 while still meeting legal, safety, and regulatory obligations. However, as the downtown core becomes more densely populated, it becomes increasingly more difficult, complex, and expensive to complete this type of work.

Toronto Hydro has identified an opportunity to replace all of this cable by 2039 by replacing these assets proactively, instead of relying solely on maintenance, refurbishment, and reactive replacement. This will improve reliability, reduce risks to the public, and avoid additional expense and disruption in the future.

PILC Cable Replacement Program

Q Which of the following is closest to your point of view regarding Toronto Hydro's PILC Cable replacement program?

[asked all respondents, n=10,346]

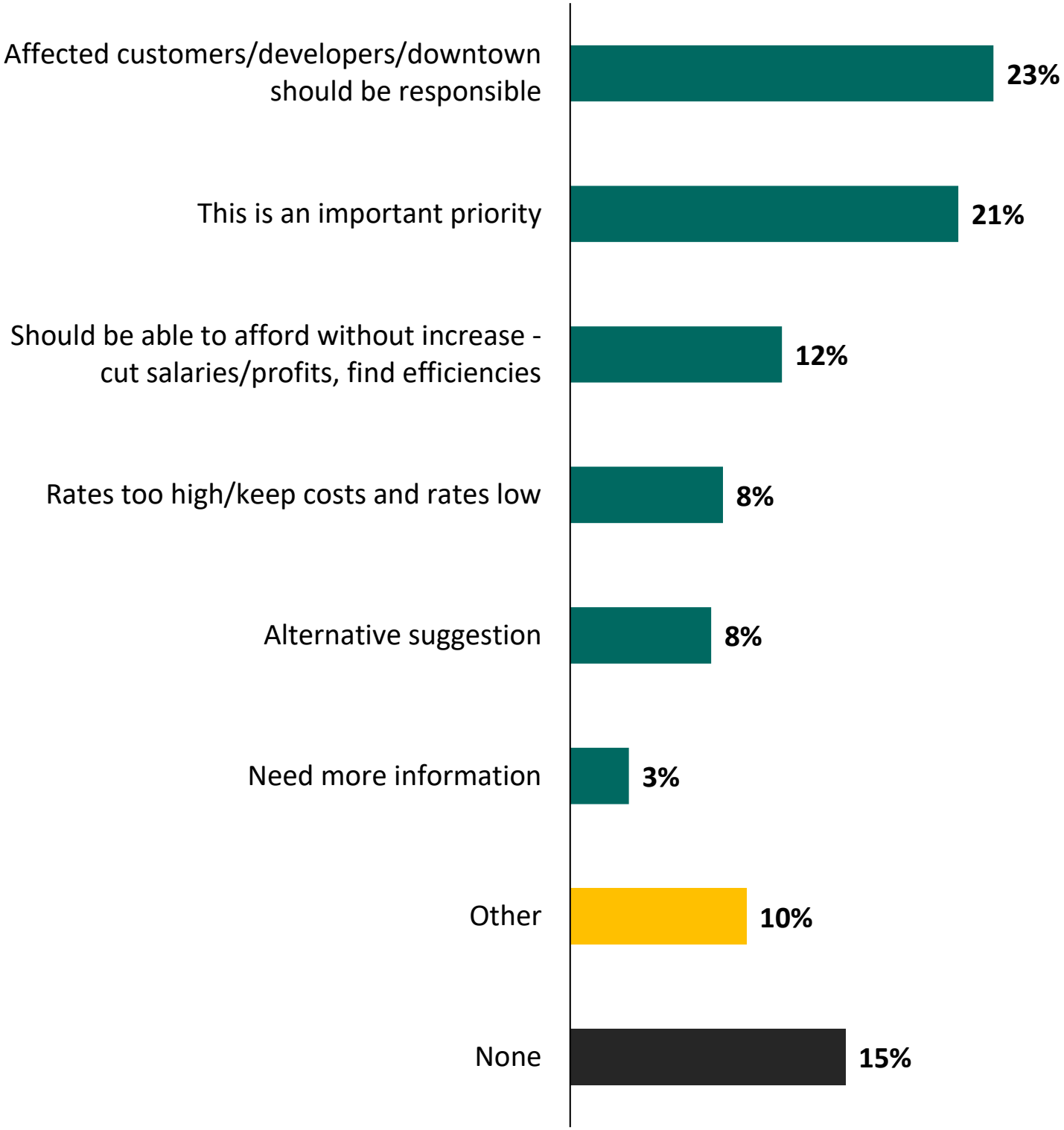


PILC Cable Replacement Program

Q

Additional Feedback

[asked all respondents, n=156]



Underground Network Transformers

Underground Network Transformers

Other underground infrastructure in the downtown core also faces some of the same challenges as PILC cable. Underground network transformers, units whose old design makes them prone to flooding, are located in areas that have been growing in terms of density and congestion. It is more difficult to do this work as time goes on.

Toronto Hydro's current plan (2015-2019) is dealing with the most pressing of these units that pose safety and reliability concerns. In the plan for 2020 to 2024, the focus is to replace just enough of these units so that outages, due to equipment failure, don't get any worse.

However the new units are significantly superior to the existing infrastructure. Much of the old infrastructure is not designed for the flooding that has become increasingly common and which can cause equipment failure and public safety hazards. The new network units are submersible and equipped with sensors to monitor transformer, protector, and vault conditions, resulting in the cost-effective reduction of reliability, environmental, and safety risks.

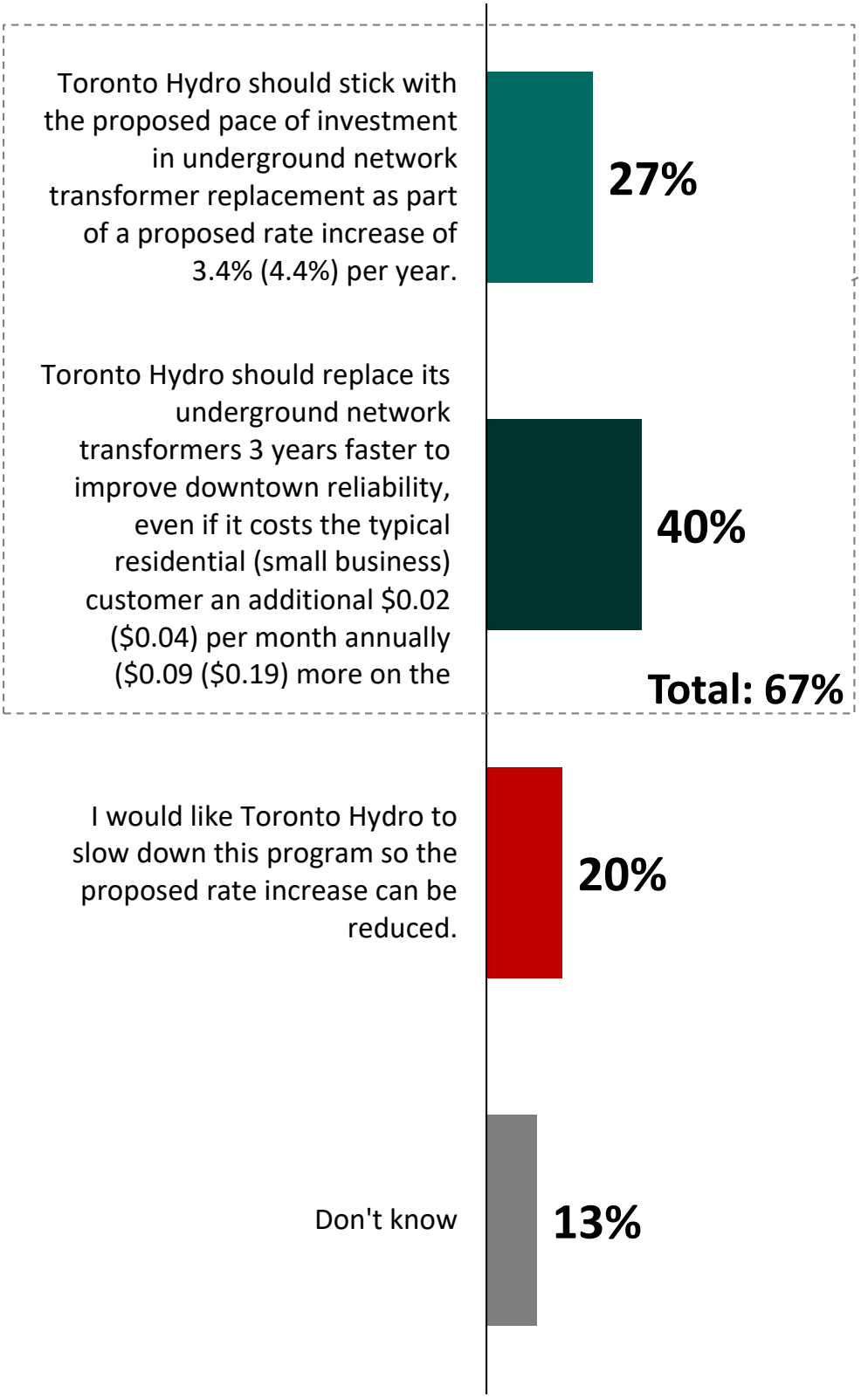


While the proposed plan would replace all the unit by 2031, the process could be advanced by three years to replace all these units by 2028.

Underground Network Transformers

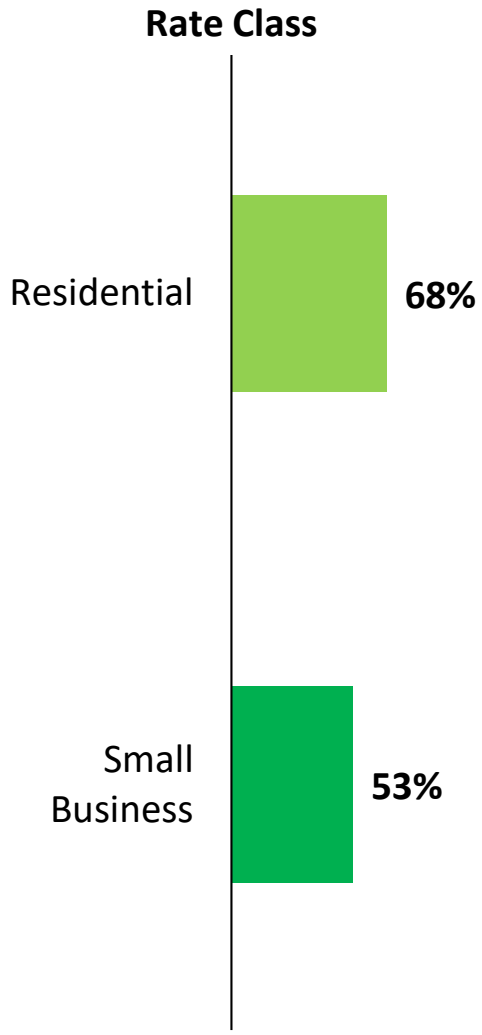
Q Which of the following is closest to your point of view regarding Toronto Hydro's Network Unit replacement program?

[asked all respondents, n=10,346]



Segmentation

*Those who say "**stick with the proposed pace**" or "**improve reliability**":*

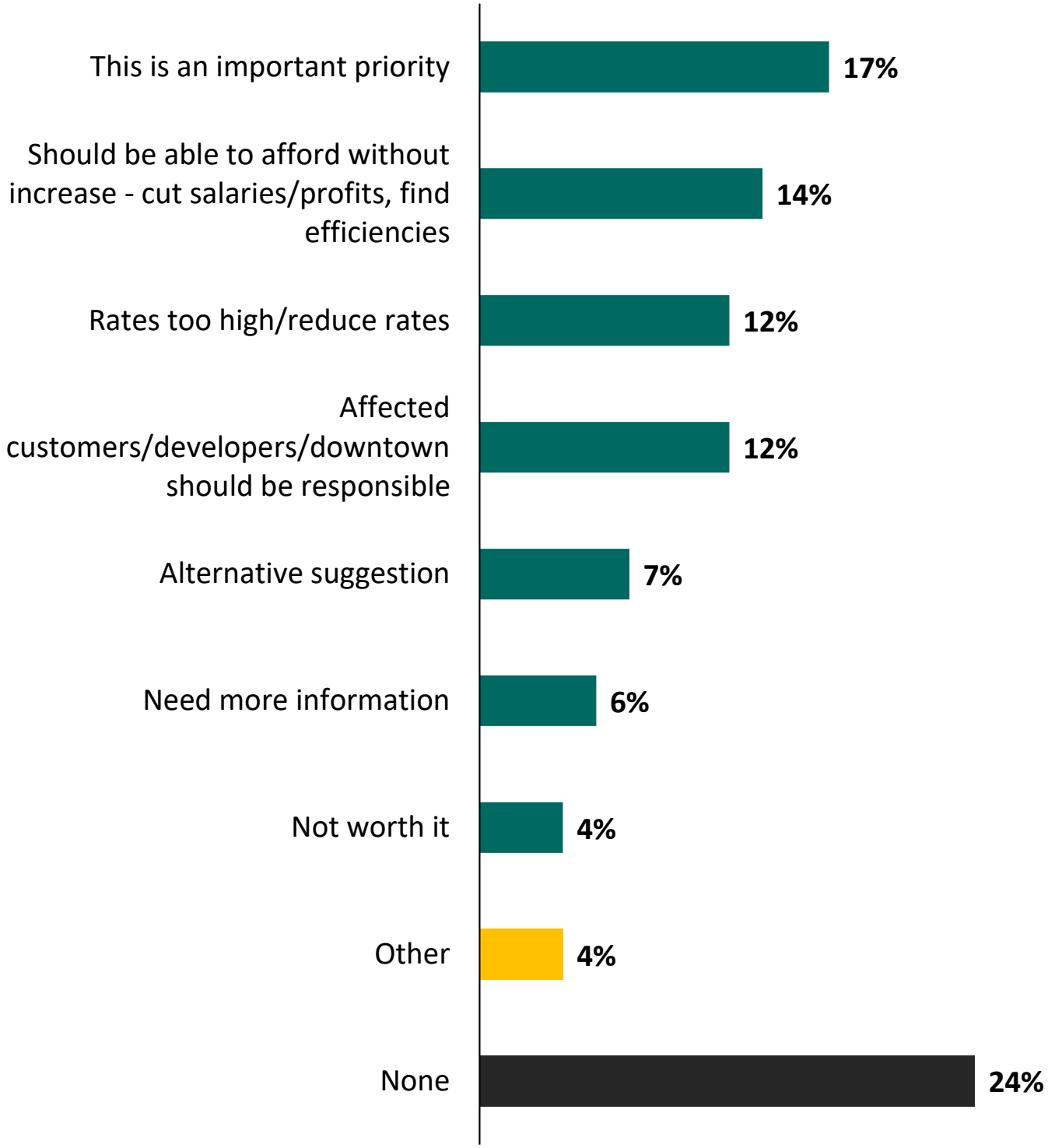


Underground Network Transformers

Q

Additional Feedback

[asked all respondents, n=124]



Cable Chambers

Cable Chambers

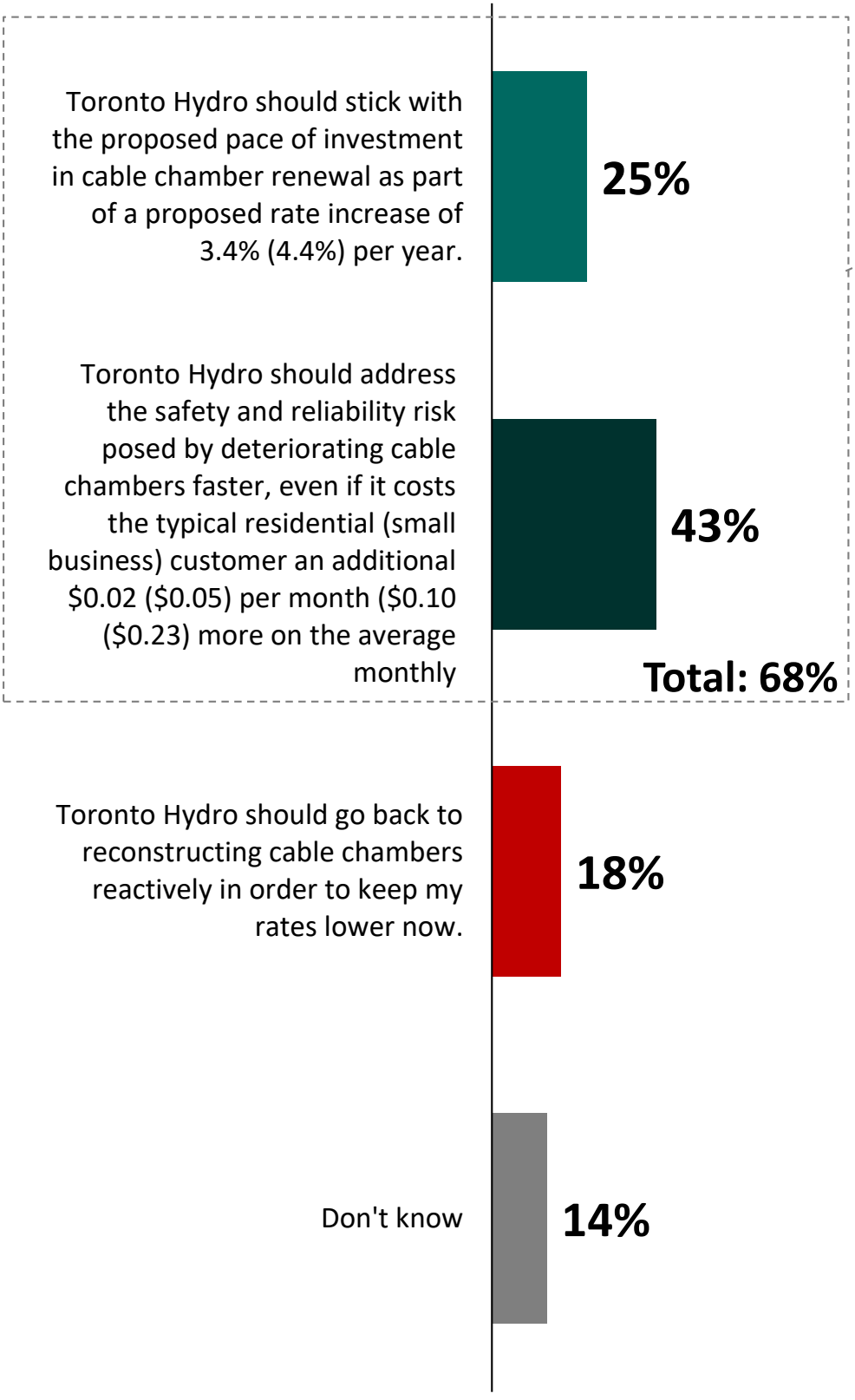
Cable chambers are a third example of equipment that will become more costly and disruptive to fix over time. Cable chambers house, protect, and provide access to underground electrical equipment across the city. There are over 10,000 in Toronto, but many of them – including the majority of the roughly 500 that are in the most urgent need of attention – are downtown where they are subject to increased foot traffic. When they deteriorate or break, they can pose anything from a tripping hazard to something much more serious in the case of a collapsed chamber. Such instances can also cause long outages, either by damaging equipment or requiring the power to be turned off to the cables in the chamber so repairs can be made.

As part of its plan, Toronto Hydro is now taking a proactive approach to rebuilding hundreds of cable chambers at risk of failing. At the current pace, it would take approximately 30 years to address the chambers in the worst condition. Accelerating the work could halve that period, at an additional cost now.

Cable Chambers

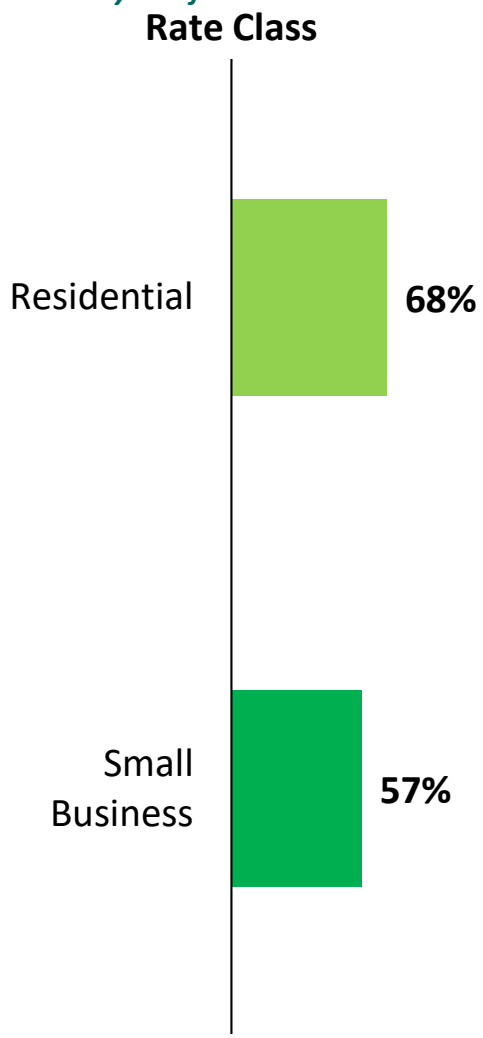
Q Which of the following is closest to your point of view regarding Toronto Hydro's Cable Chamber renewal program?

[asked all respondents, n=10,346]



Segmentation

*Those who say "**stick with the proposed pace**" or "**address the reliability risk faster**":*

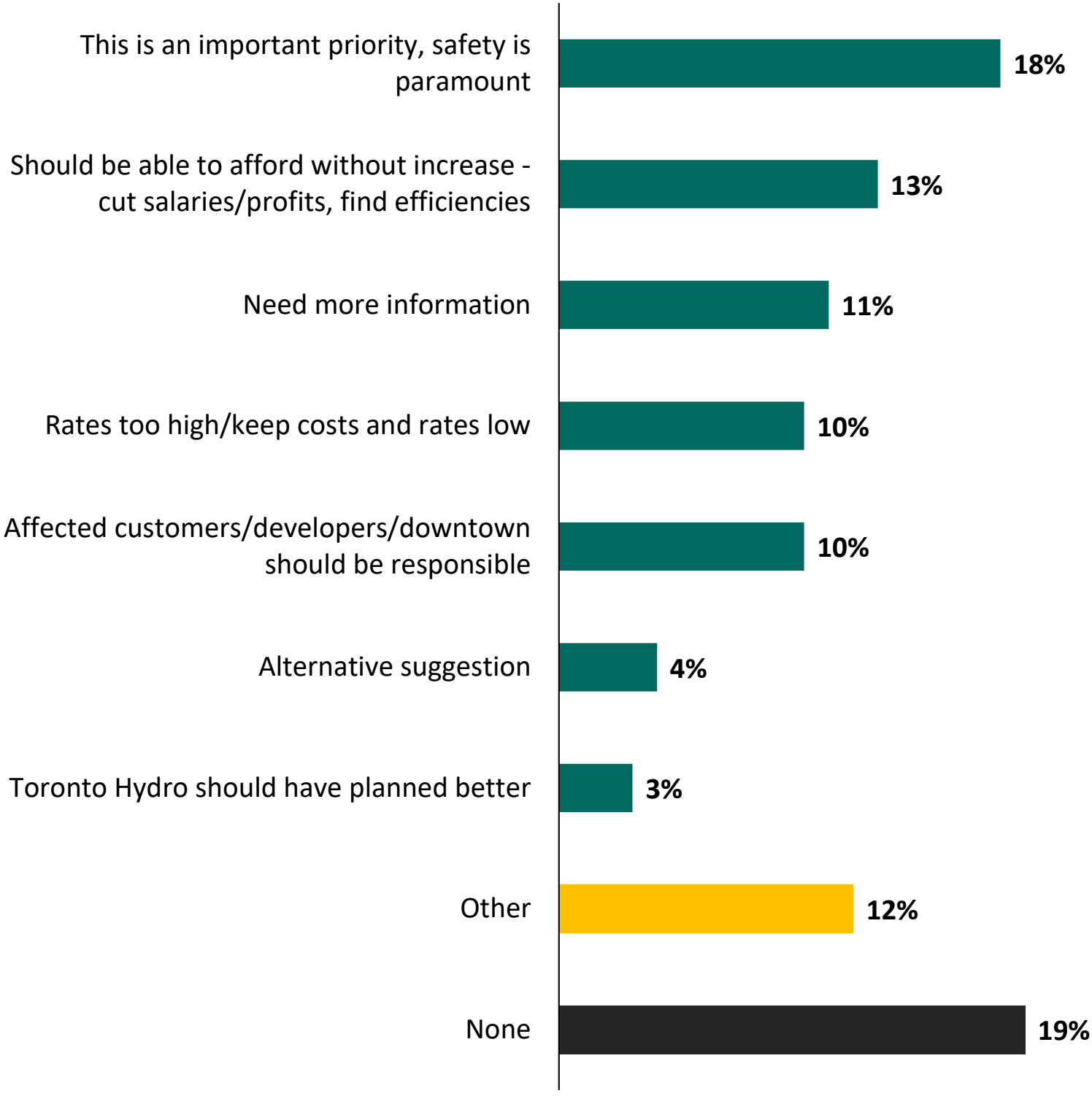


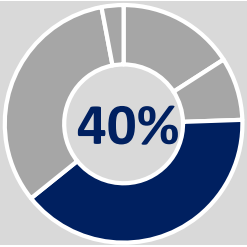
Cable Chambers

Q

Additional Feedback

[asked all respondents, n=100]





Dealing with more frequent extreme weather events

Should we spend more to make the distribution system more resilient to the effects of major storms?



Toronto Hydro's distribution system is exposed to the elements: strong winds, freezing rain, and severe flooding have all caused at least one wide-spread outage in Toronto in recent years. While it may be impossible or impractical to completely guard against extreme weather, steps can be taken to "harden" the distribution system. Toronto Hydro is proposing a variety of enhancements to continue to build resiliency. Toronto Hydro is looking for your opinion on whether it should do more in one area in particular: the overhead system outside of the downtown core.

System Restoration Improvements

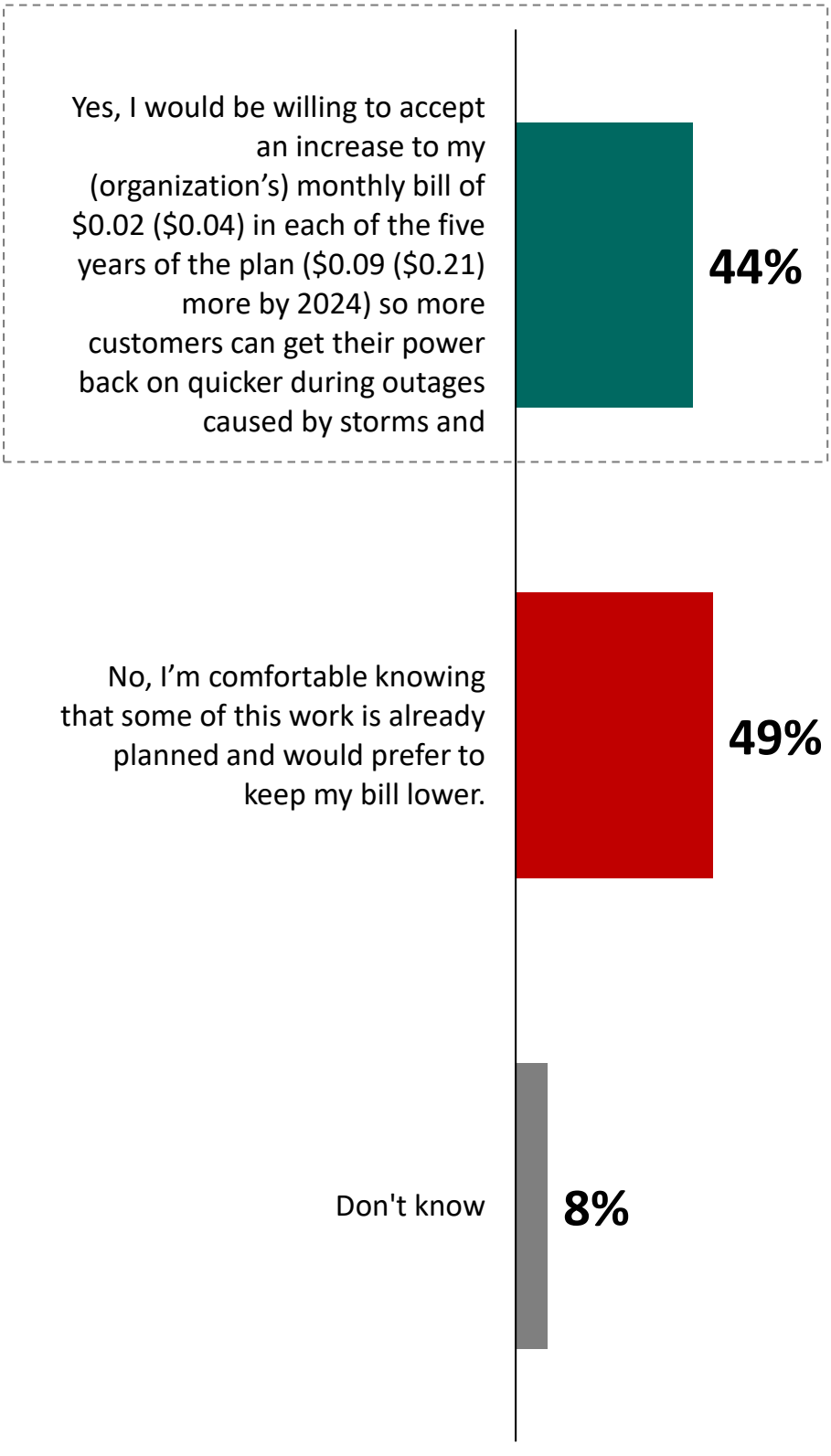
This type of work makes it easier for Toronto Hydro to restore power customers outside of the downtown following an outage. By adding remotely-operated technology, more back-up links within the grid, and other improvements, Toronto Hydro can better isolate the problem and get more customers' power back on faster.

Given customer desires to keep rate increases down, Toronto Hydro is currently proposing to reduce spending in this category. Improvements have already been made to some parts of the City and the reliability of this part of the overhead system has shown improvement in recent years. It is possible for Toronto Hydro to address more areas during 2020 to 2024 not yet benefiting from these improvements.

Dealing with more frequent extreme weather events

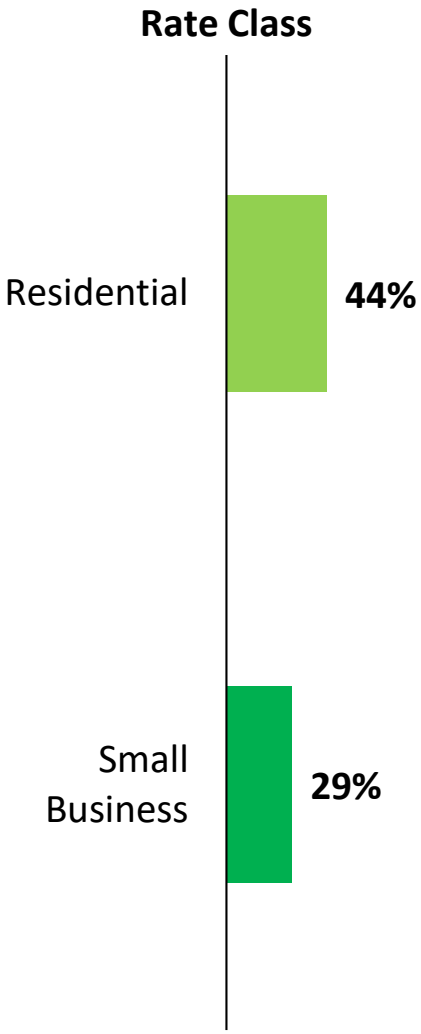
Q Should Toronto Hydro spend more now to speed up the pace of reducing outage times by up to 50% in neighbourhoods outside of downtown?

[asked all respondents, n=10,346]



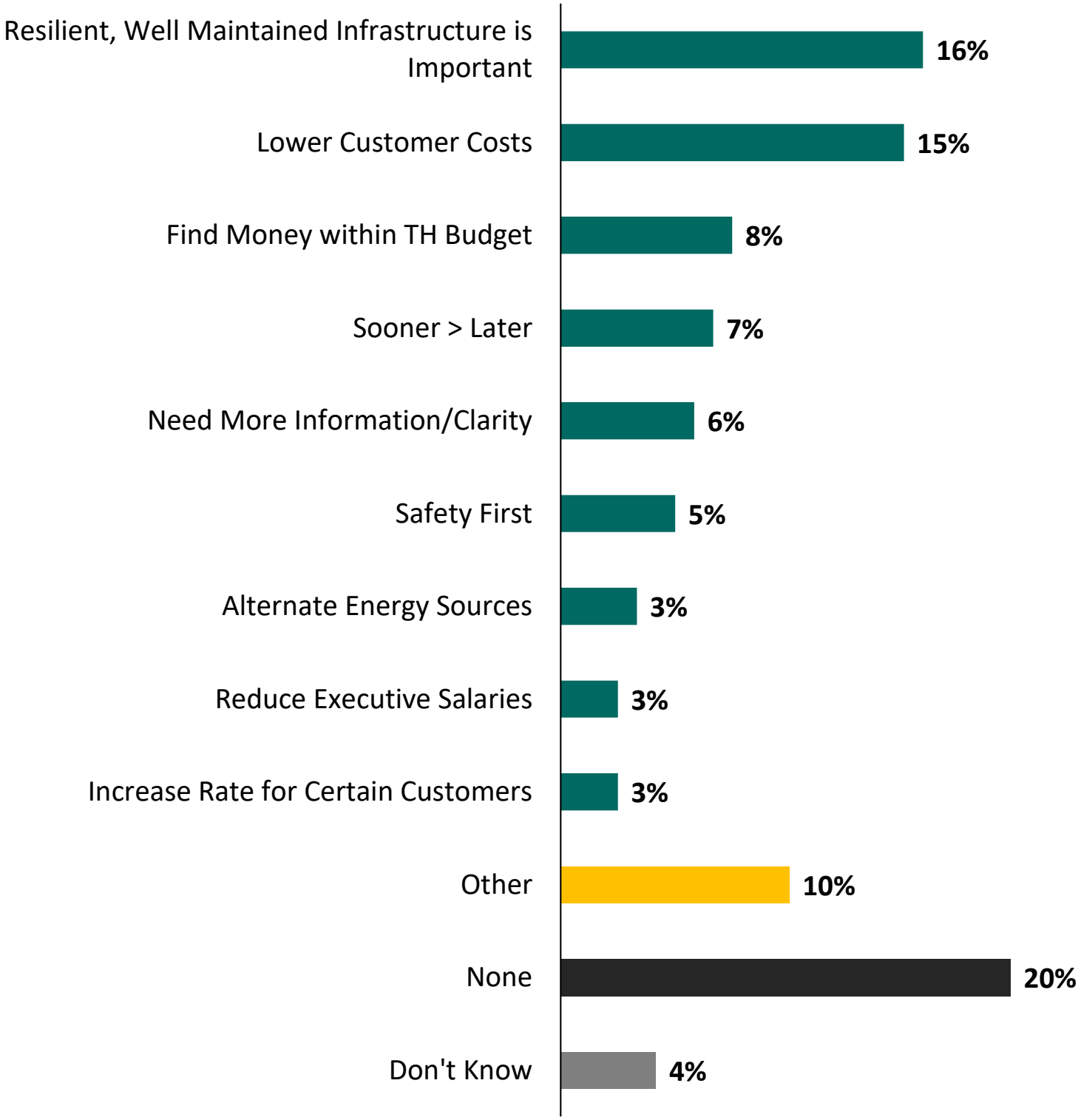
Segmentation

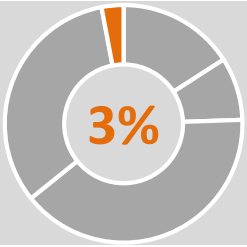
*Those who say **"Willing to accept an increase":***



Dealing with more frequent extreme weather events

Q Additional Feedback
[asked all respondents, n=118]





Innovation and Planning for the Future

Bring New Technology into the Toronto Hydro System

Technology is changing how people use electricity and the demands on the grid. Customers are not just taking power from the grid, they are also using technology like solar panels to produce their own power and send any extra back to the grid. Toronto Hydro is currently implementing new technologies in a limited manner and could increase the pace of that investment.

Energy Storage

Toronto Hydro has already begun to integrate large-scale electricity storage into the system. Storage provides a number of benefits to customers:

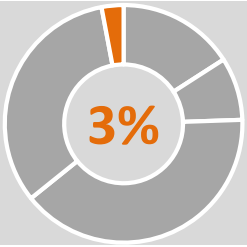
- It supports reliability by providing electricity when the connection to generators is interrupted
- It can allow low cost electricity generated in off-peak hours to be available during peak demands.
- It helps intermittent renewable sources such as wind and solar integrate into the system, thereby increasing the availability of clean energy and reducing greenhouse gases (GHGs).



Crosstown Battery Storage (3D rendering of Phase 1)

- It helps to enable the integration of electric vehicles into the system without requiring major increases in more traditional wires and transformers to deal with electric vehicle charging needs.

Storage also provides a number of benefits that are invisible to customers but critical to the stability of the grid including power quality, load following, and frequency regulation.



Innovation and Planning for the Future

Right now Toronto Hydro is primarily using energy storage where there is an immediate benefit to the system. For example, at one of Toronto Hydro's most congested downtown stations (Cecil TS), battery storage and conservation solutions are being used to delay a necessary upgrade for approximately five to six years. This approach is expected to reduce the total overall cost to ratepayers by approximately $6 million.



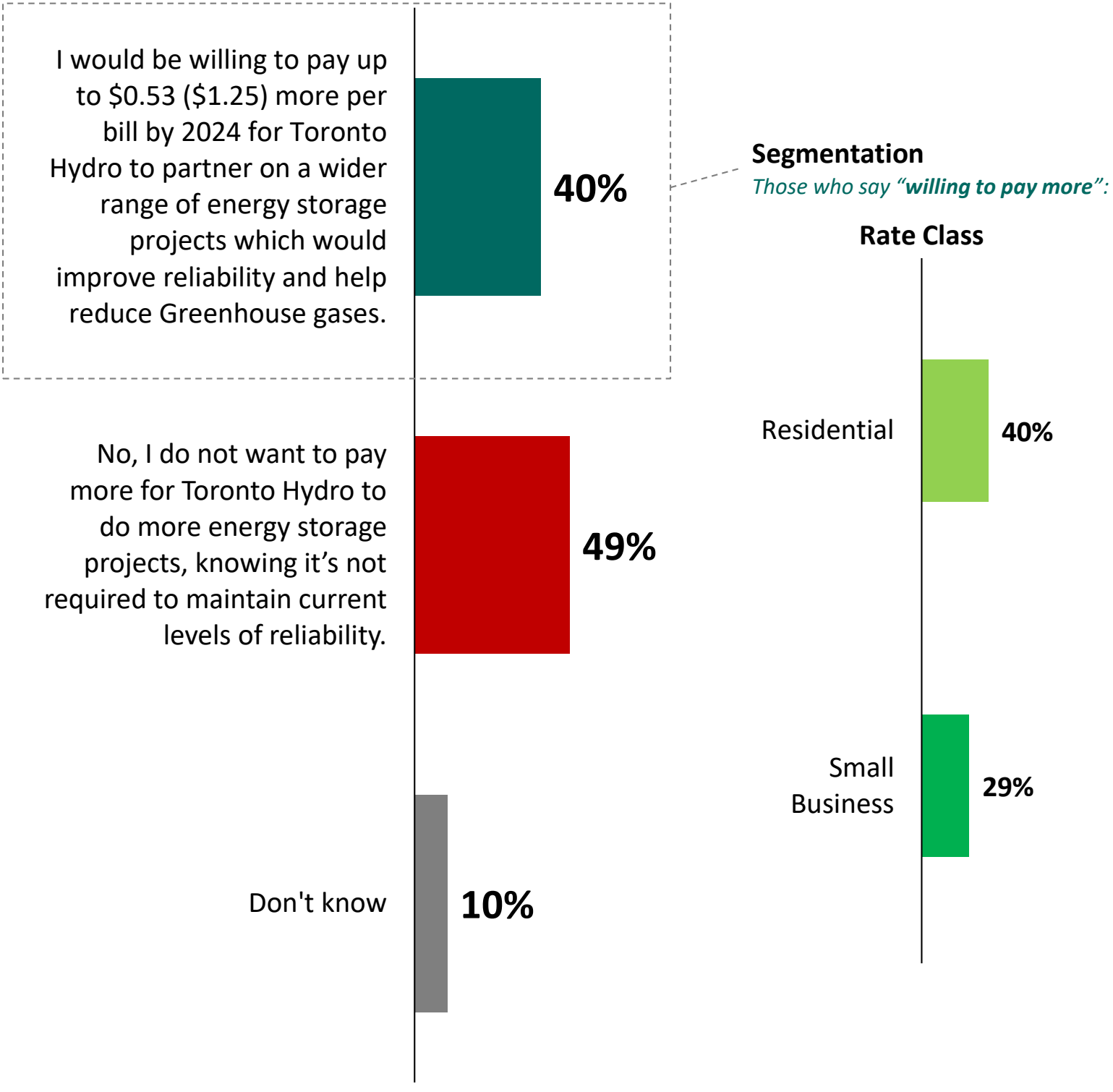
Poletop Energy Storage Unit

Toronto Hydro has identified a number of additional energy storage-related projects with critical large-scale public and private sector customers with a defined project need. These batteries would be located at host sites and provide benefits locally and to the distribution system. The host would pay most of the costs. Customers like you would pay for the portion that relates to the benefit they receive (e.g. area reliability).

These projects would improve reliability and help reduce GHGs but are not required to maintain current reliability. Pursuing these projects would increase the average annual bill impact of the plan by up to $0.11 per month or a total of $0.53 by 2024.

Innovation and Planning for the Future

Q Which of the following is closest to your point of view?
[asked all respondents, n=10,346]

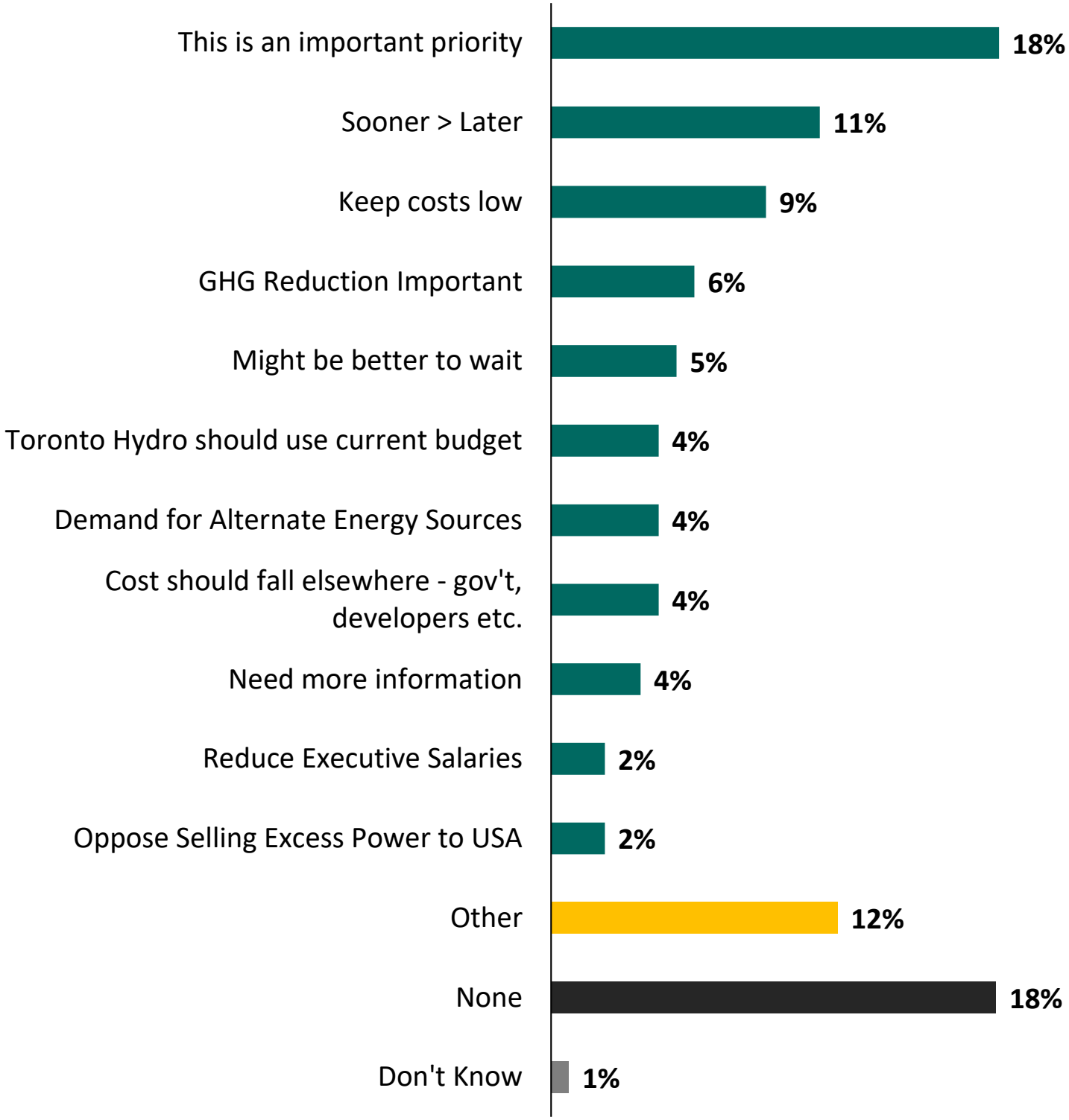


Innovation and Planning for the Future

Q

Additional Feedback

[asked all respondents, n=138]



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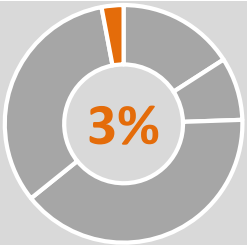


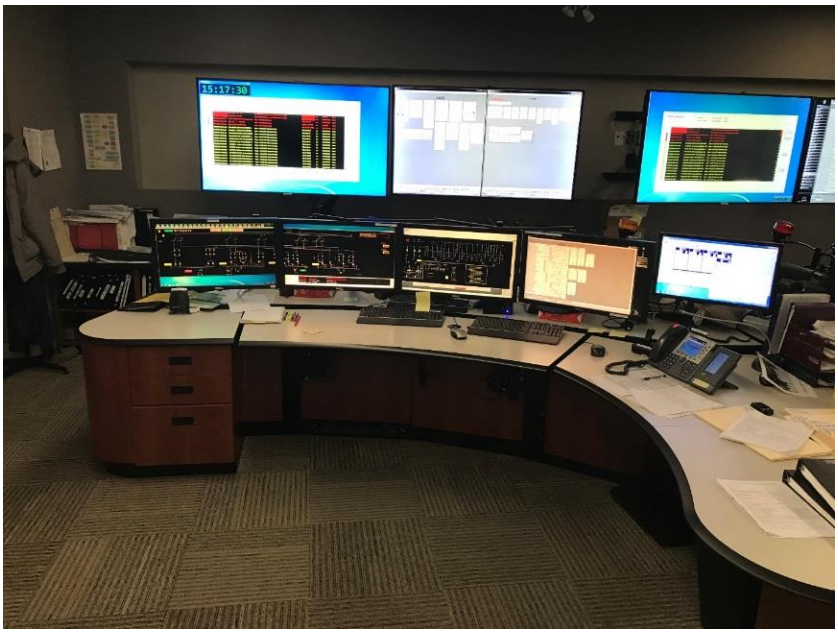
Innovation and Planning for the Future

Monitoring and Control Equipment

New communication technology has revolutionised the way the grid can be managed. New remote switches allow a Toronto Hydro system manager to restore power to many customers by flicking a switch in a control room before the line crew even leaves to repair the break. Remote monitors allow system managers to pinpoint where the break occurred instead of sending crews out in trucks visually inspecting the line. Environmental monitors at critical equipment facilities such as major transformers can identify changing conditions that threaten equipment before the equipment fails so preventative action can be taken to avoid an outage in the first place.

Within the base budget covered by the 3.4% (4.4%) annual increase, Toronto Hydro's new construction takes advantage of these new technologies wherever clear benefits can be established.

However, Toronto Hydro can improve the reliability of its grid by adding these devices to lines and transformers. In particular, installing devices in the downtown underground network that detect fire, floods or other risks can be completed more quickly.



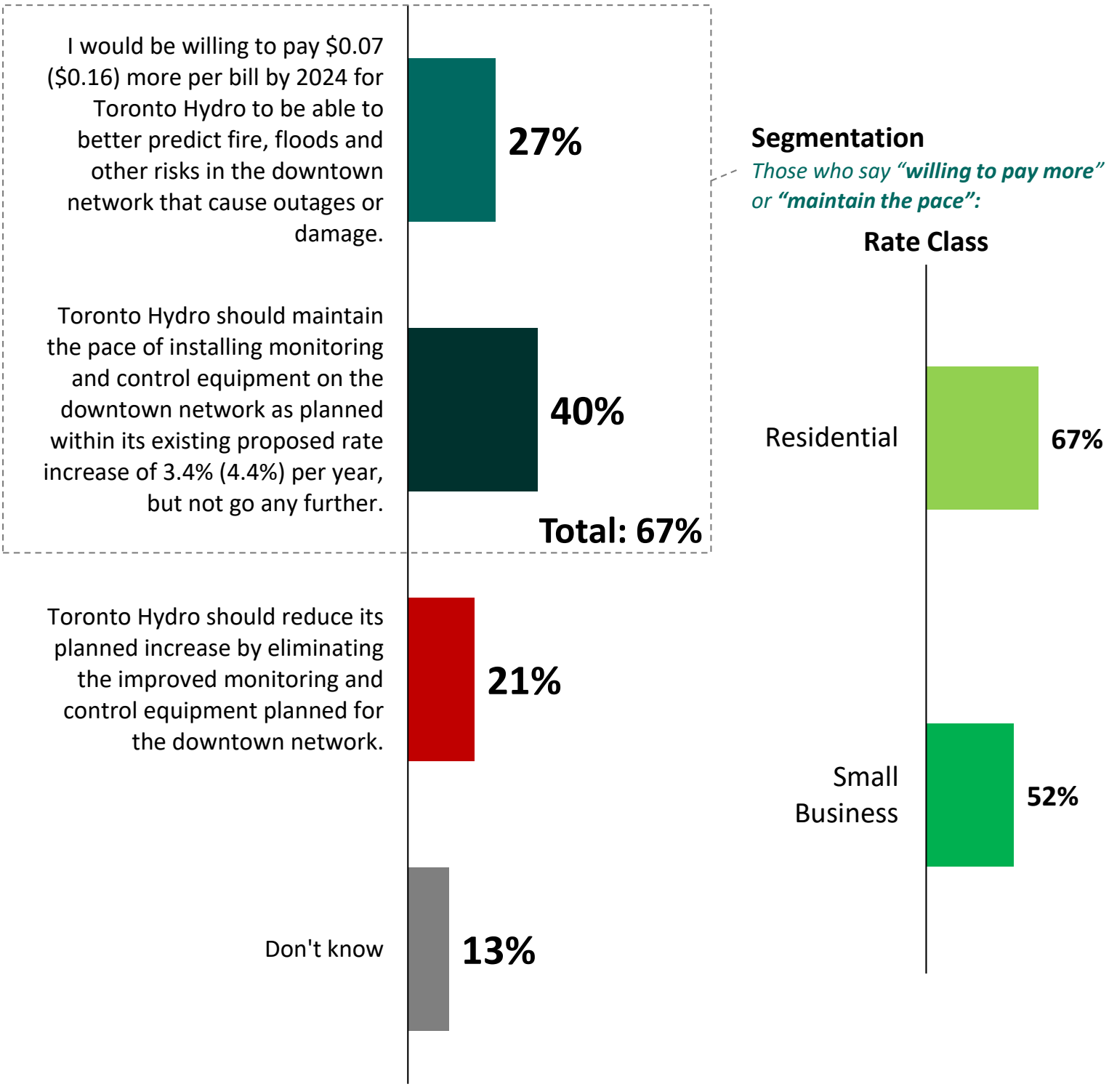
Toronto Hydro Control Room

Innovation and Planning for the Future

Q

Which of the following is closest to your point of view?

[asked all respondents, n=10,346]

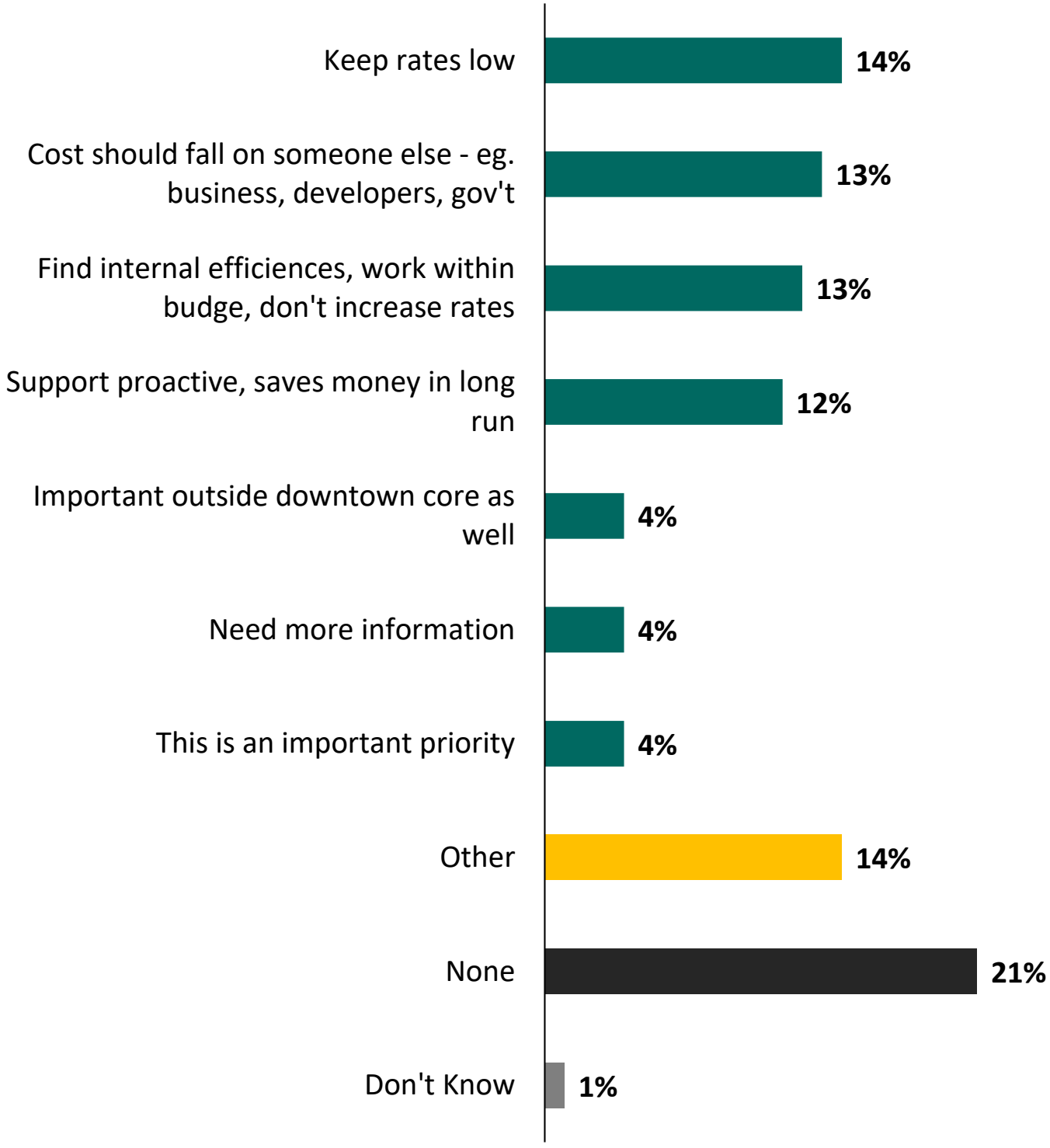


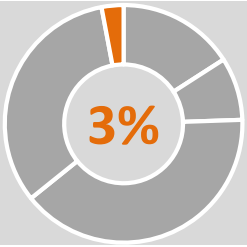
Innovation and Planning for the Future

Q

Additional Feedback

[asked all respondents, n=104]





Innovation and Planning for the Future

Microgrids

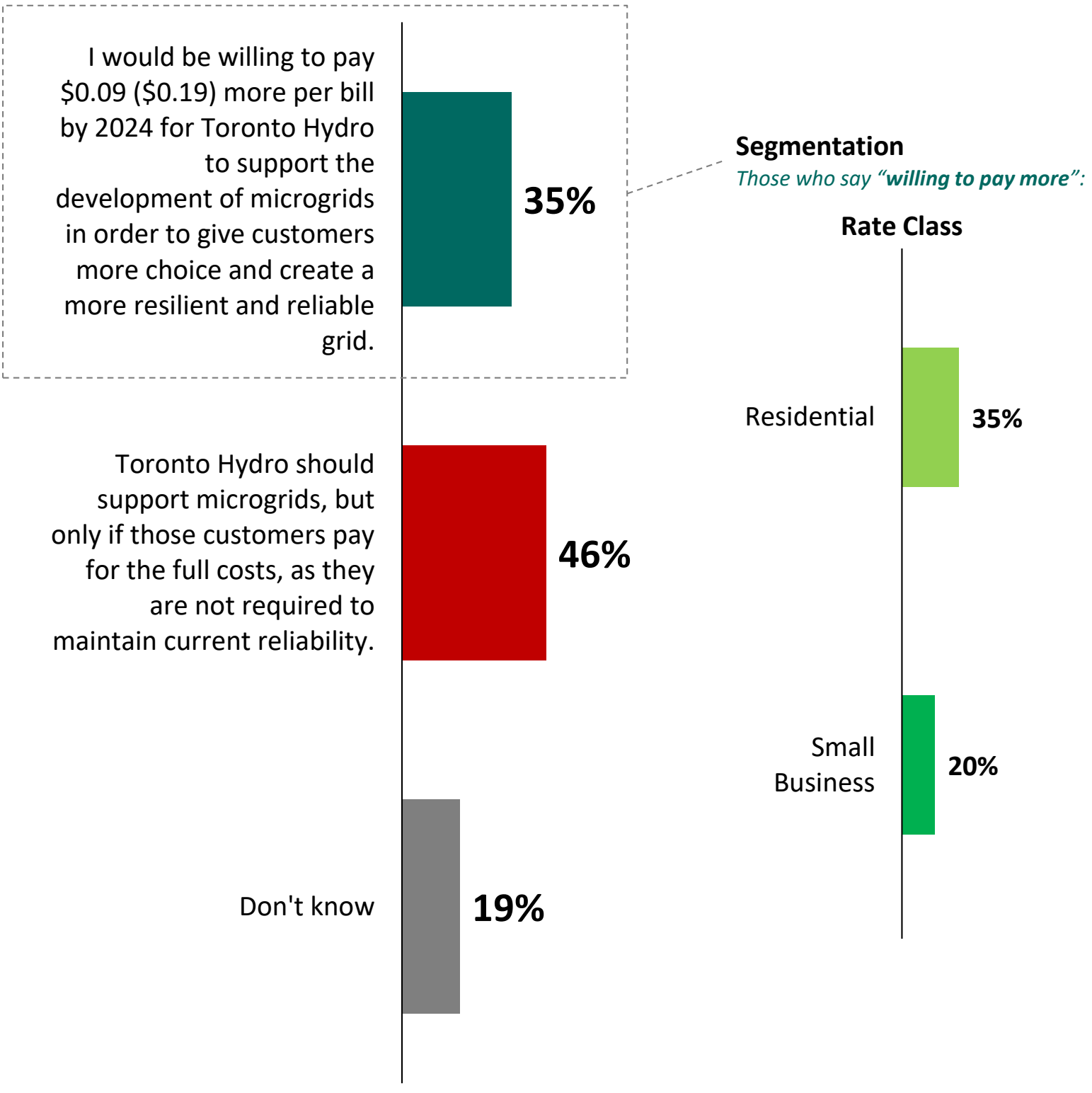
New types of generation (often renewable), storage, and supporting systems are making it possible for communities, institutions or other large customers to develop “microgrids”. These are a local electricity network linking smaller sources of electricity with nearby uses such as homes, businesses and institutions. In the event of a failure of the larger network, a microgrid can seal itself off and continue to provide power locally. These offer customers increased choice for power supply, cost management, and improved resilience.



Microgrids would give customers more choices, while creating a more resilient and reliable grid. While spending on microgrids does benefit customers who are not on microgrids, those benefits are not required to maintain current reliability.

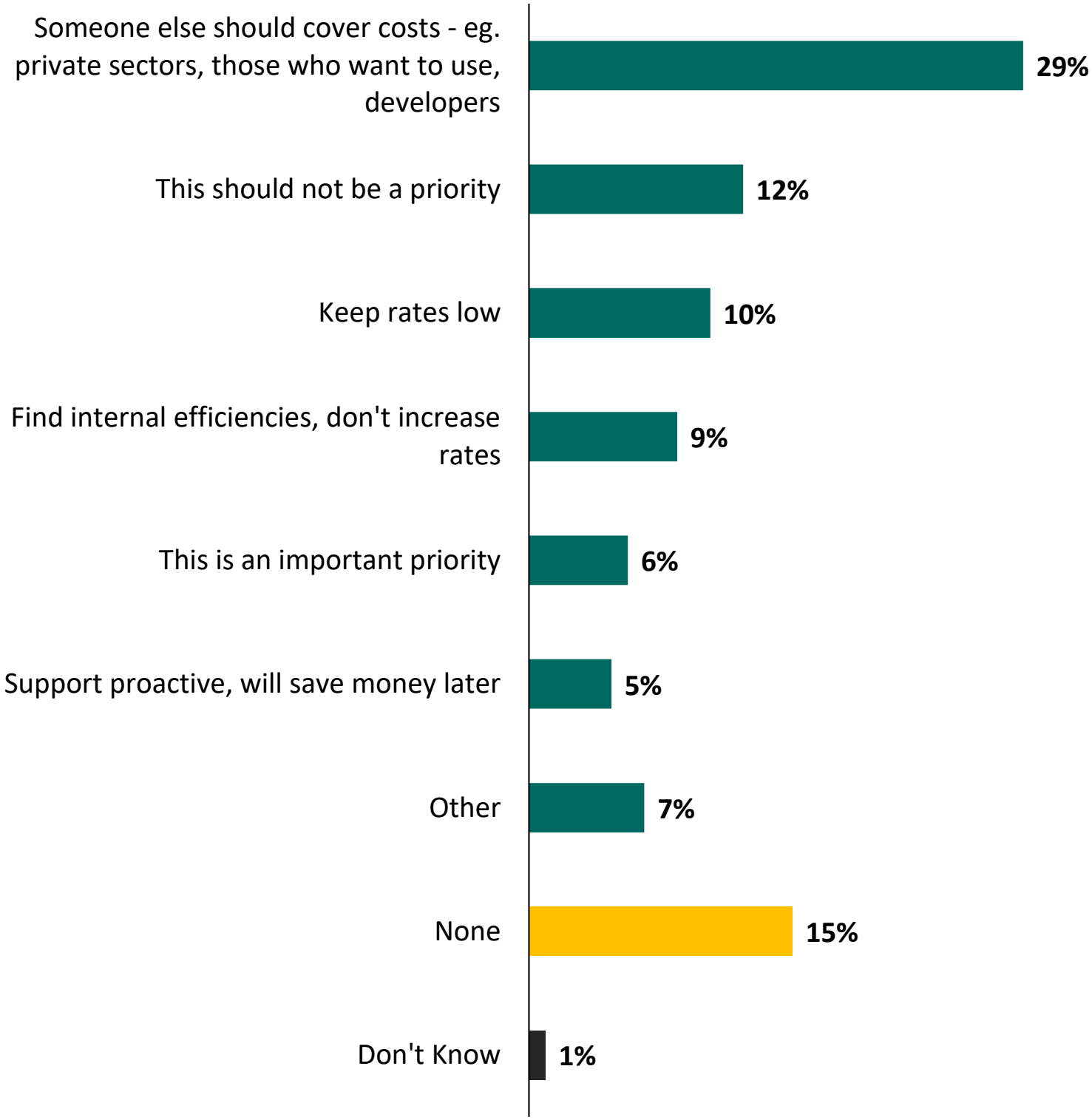
Innovation and Planning for the Future

Q Which of the following is closest to your point of view?
[asked all respondents, n=10,346]



Innovation and Planning for the Future

Q Additional Feedback
[asked all respondents, n=104]



Note: "Refused" (7%) not shown.

Investment Alternatives Summary

Throughout this portal, you have been asked about some key choices that could impact your rates.

First a quick reminder:

- Toronto Hydro's current proposed plan would result in a monthly **bill increase of $1.51 each year** for the typical residential customer.
- Over the course of the proposed 5-year plan, the typical residential customer will see the distribution portion of their electricity bill **increase by $7.57**.
- As a result, the distribution charges on the monthly bill would increase from a proposed amount of **$41.60 in 2019** to **$49.17 by 2024.**

Below are your answers to questions that could impact your rates. At the bottom of this page you will find the total bill impact of all the answers you gave that would result in a bill increase.

Having seen the total bill impact, please review your answers and change your responses if you desire. Your potential rate impact will be re-calculated and you will be have the opportunity to adjust your answers again until you feel you've reached the best balance for you.

Addressing Safety & Reliability: Rear-lot replacement program

- ✓ Toronto Hydro should stick with the proposed pace of investment in rear-lot which would see it all converted by 2033 as part of a proposed rate increase of 3.4% per year.
- □ I am willing to pay an additional $0.02 per month annually ($0.11 more on the average monthly bill by 2024) so Toronto Hydro can remove all rear-lot feeders by 2029 (four years sooner).
- □ I would like Toronto Hydro to slow down this program so the proposed rate increase can be reduced.
- □ Don't know

Addressing Safety & Reliability : Direct buried cable replacement program

- ✓ Toronto Hydro should stick with the proposed pace of investment in direct buried cable replacement which would see a quarter of the highest risk cable replaced by 2024 as part of a proposed rate increase of 3.4% per year.
- □ I am willing to pay an additional $0.19 per month annually ($0.94 more on the average monthly bill by 2024) so Toronto Hydro can replace all of the highest risk direct buried cable by 2024.
- □ I would like Toronto Hydro to slow down this program so the proposed rate increase can be reduced.
- □ Don't know

Investment Alternatives Summary

Addressing Safety & Reliability : Paper Insulated Lead Covered (PILC) cable replacement program

- ☑ Toronto Hydro should address the reliability issues and other risks posed by PILC cable at the current pace (completed by 2049) as part of a proposed rate increase of 3.4% per year, even if it's more disruptive to do so in the future.
- ☐ Toronto Hydro should accelerate its replacement of PILC cable by 10 years, even if it costs the typical residential customer an additional $0.09 per month annually ($0.44 more on the average monthly bill by 2024), because it's less disruptive to do it now than in the future.
- ☐ I would like Toronto Hydro to slow down this program so the proposed rate increase can be reduced
- ☐ Don't know

Addressing Safety & Reliability : Network Unit replacement program

- ☑ Toronto Hydro should stick with the proposed pace of investment in underground network transformer replacement as part of a proposed rate increase of 3.4% per year.
- ☐ Toronto Hydro should replace its underground network transformers 3 years faster to improve downtown reliability, even if it costs the typical residential customer an additional $0.02 per month annually ($0.09 more on the average monthly bill by 2024).
- ☐ I would like Toronto Hydro to slow down this program so the proposed rate increase can be reduced
- ☐ Don't know

Addressing Safety & Reliability : Cable chamber renewal program

- ☑ Toronto Hydro should stick with the proposed pace of investment in cable chamber renewal as part of a proposed rate increase of 3.4% per year.
- ☐ Toronto Hydro should address the safety and reliability risk posed by deteriorating cable chambers faster, even if it costs the typical residential customer an additional $0.02 per month ($0.10 more on the average monthly bill by 2024).
- ☐ Toronto Hydro should go back to reconstructing cable chambers reactively in order to keep my rates lower now.
- ☐ Don't know

Addressing Safety & Reliability : System Restoration Improvements

- ☑ Yes, I would be willing to accept an increase to my monthly bill of $0.02 in each of the five years of the plan ($0.09 more by 2024) so more customers can get their power back on quicker during outages caused by storms and other events.
- ☐ No, I'm comfortable knowing that some of this work is already planned and would prefer to keep my bill lower.
- ☐ Don't know

Investment Alternatives Summary

Innovation & Planning for the Future: Investments in energy storage projects

- ☑ I would be willing to pay up to $0.53 more per bill by 2024 for Toronto Hydro to partner on a wider range of energy storage projects which would improve reliability and help reduce Greenhouse gases.
- ☐ No, I do not want to pay more for Toronto Hydro to do more energy storage projects, knowing it's not required to maintain current levels of reliability.
- ☐ Don't know

Innovation & Planning for the Future: Investments in monitoring and control equipment

- ☑ I would be willing to pay $0.07 more per bill by 2024 for Toronto Hydro to be able to better predict fire, floods and other risks in the downtown network that cause outages or damage.
- ☐ Toronto Hydro should maintain the pace of installing monitoring and control equipment on the downtown network as planned within its existing proposed rate increase of 3.4% per year, but not go any further.
- ☐ Toronto Hydro should reduce its planned increase by eliminating the improved monitoring and control equipment planned for the downtown network.
- ☐ Don't know

Innovation & Planning for the Future: Investments in microgrids

- ☑ I would be willing to pay $0.09 more per bill by 2024 for Toronto Hydro to support the development of microgrids in order to give customers more choice and create a more resilient and reliable grid.
- ☐ Toronto Hydro should support microgrids, but only if those customers pay for the full costs, as they are not required to maintain current reliability.
- ☐ Don't know

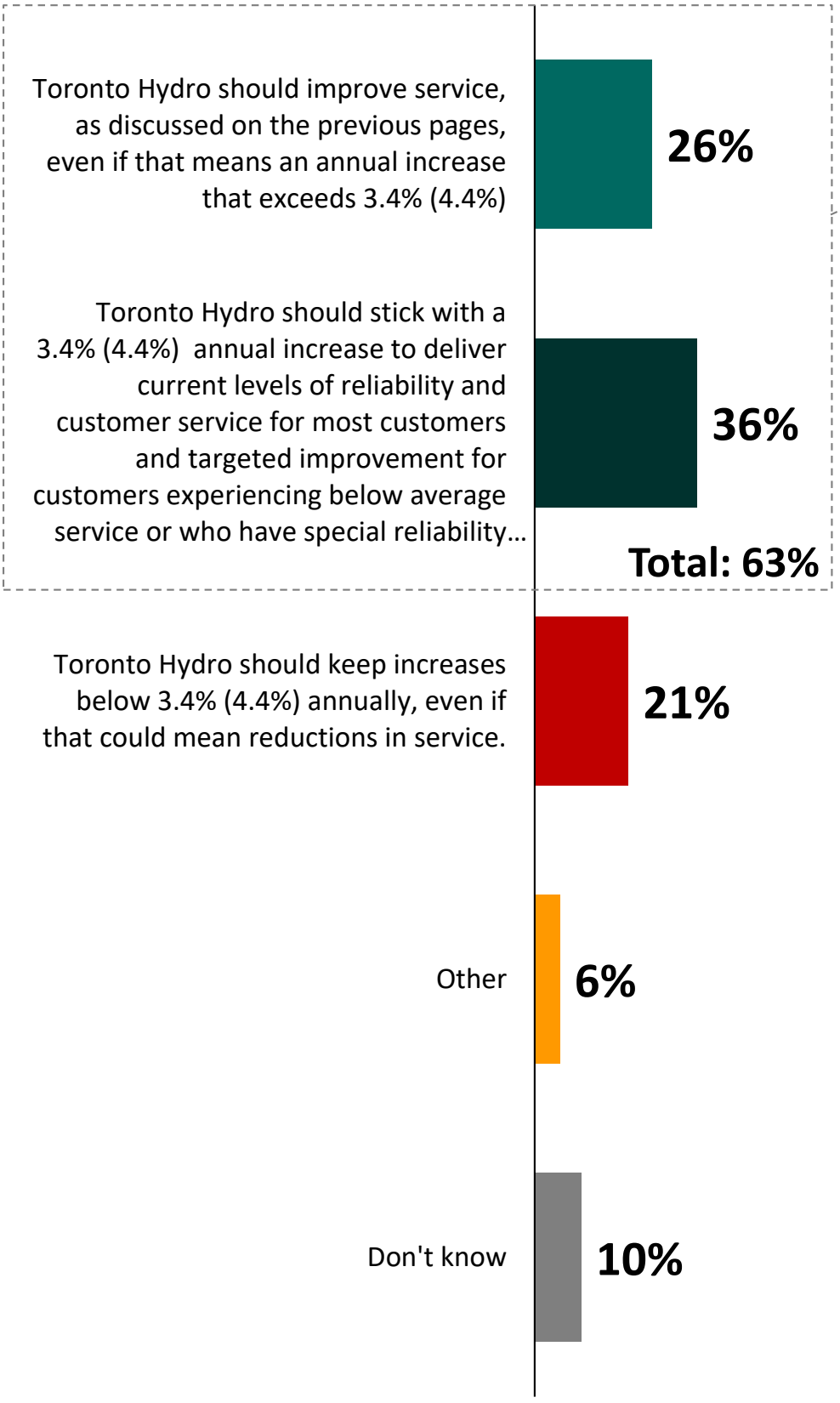
Based on your responses above, by 2024, the incremental bill impact of your choices would result in:

+$X.XX per month

in addition to the estimated $49.17 in distribution charges on the average residential customer's electricity bill.

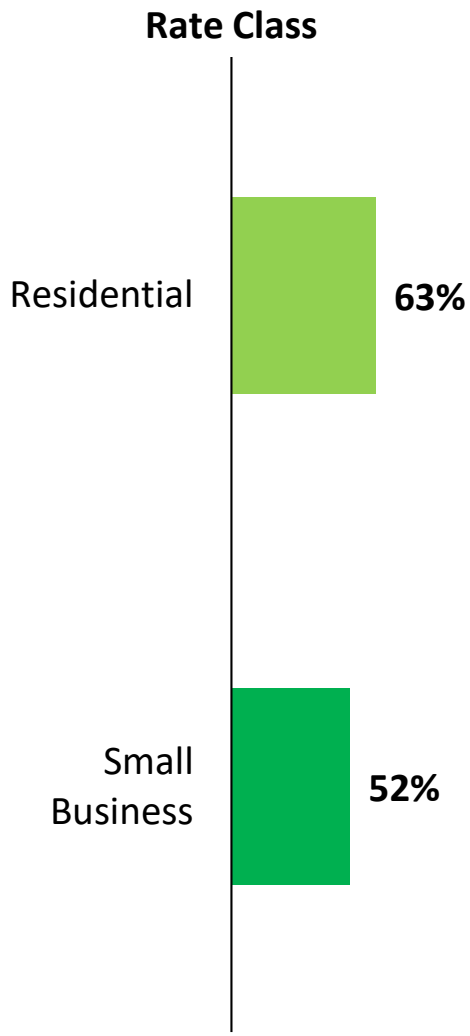
Customer Feedback:
Investment Alternatives

With regards to Toronto Hydro's proposed plan, which of the following statements best represents you view?
[asked all respondents, n=10,346]



Segmentation

*Those who say "**Stick with current pace of investment or increase to improve services**":*

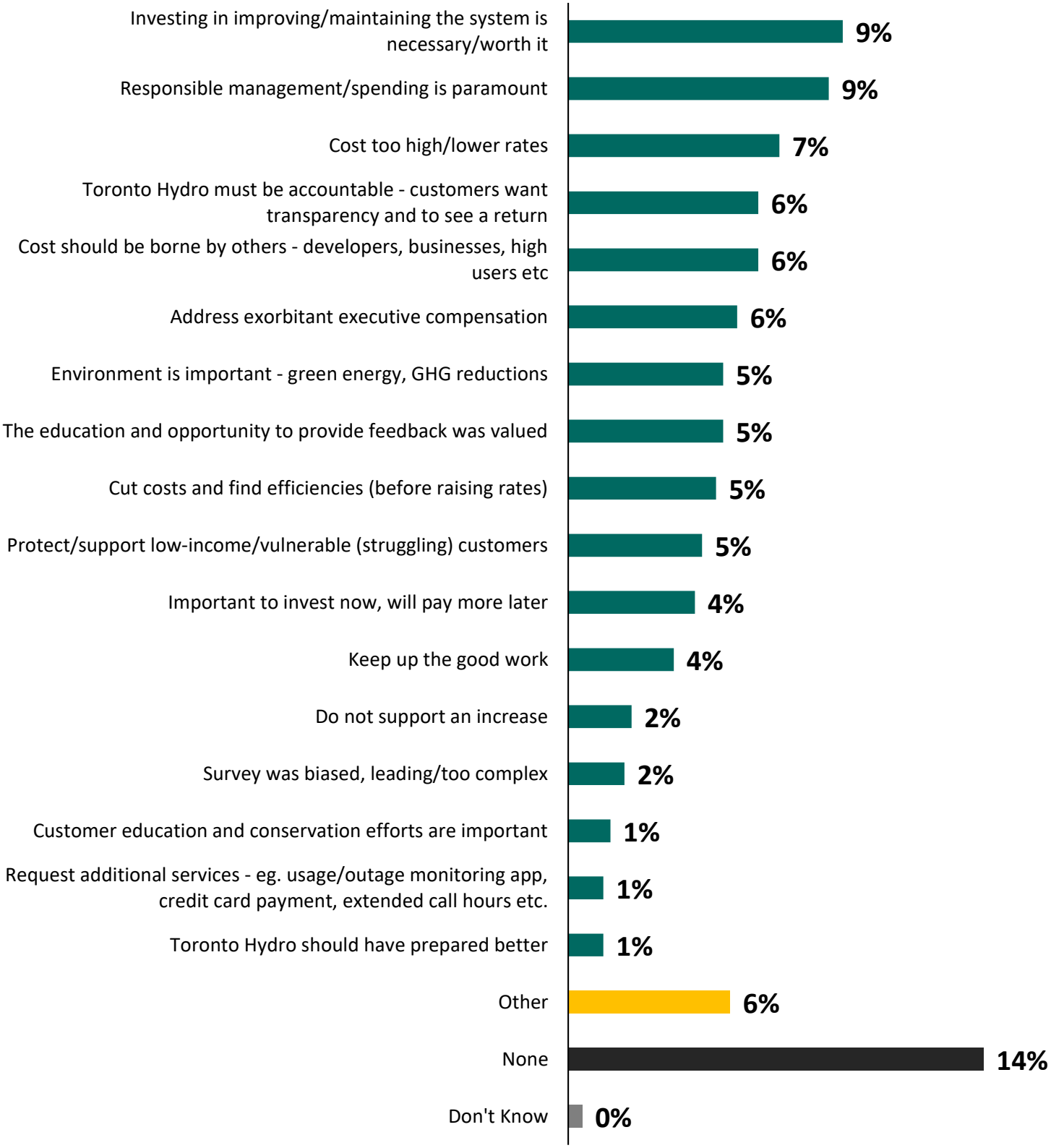


Final Comments

Q

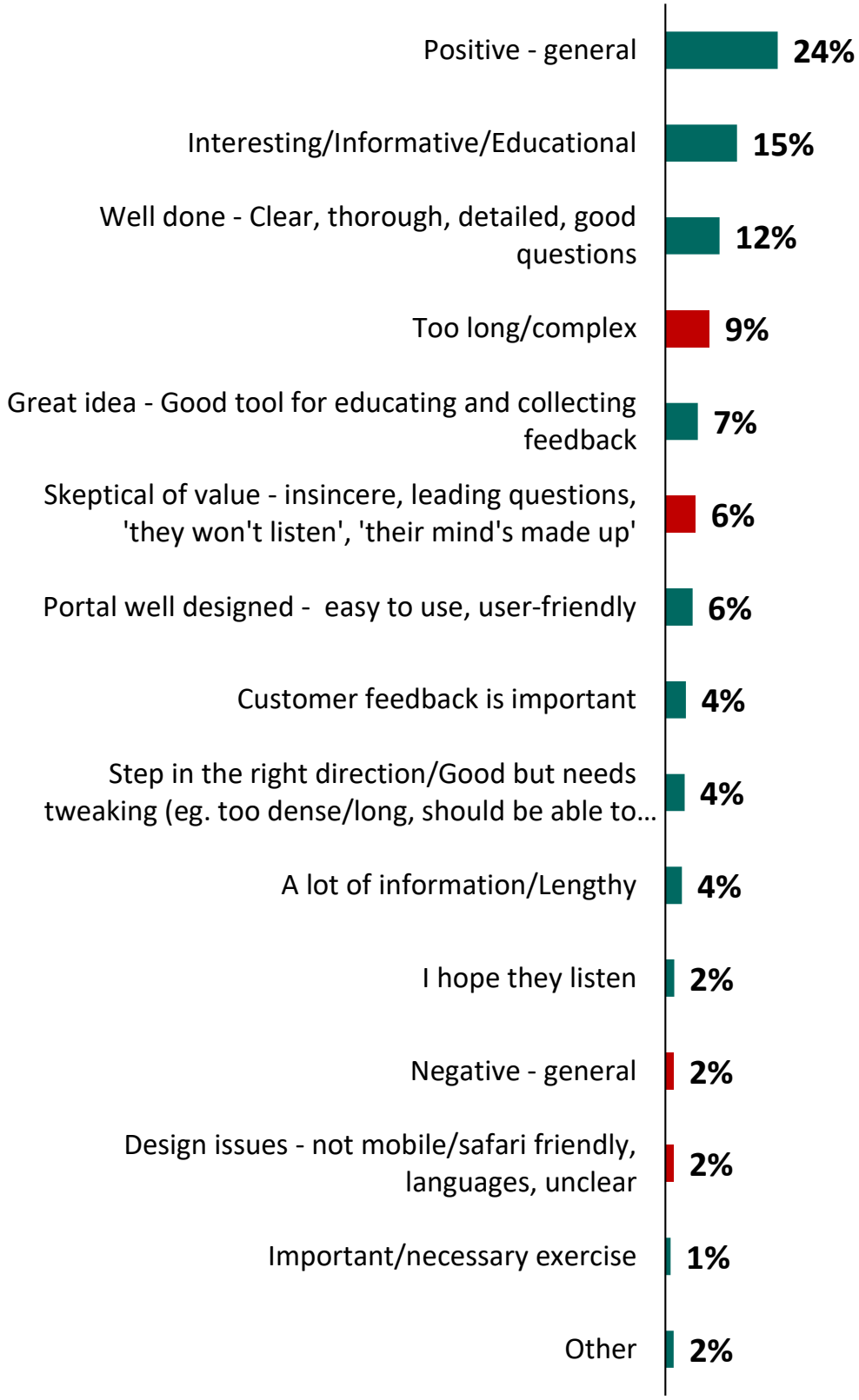
Now that you have considered the various choices Toronto has to make and the cost implications of those choices, do you have any final comments for Toronto Hydro?

[asked all respondents, n=418]



Overall Impression

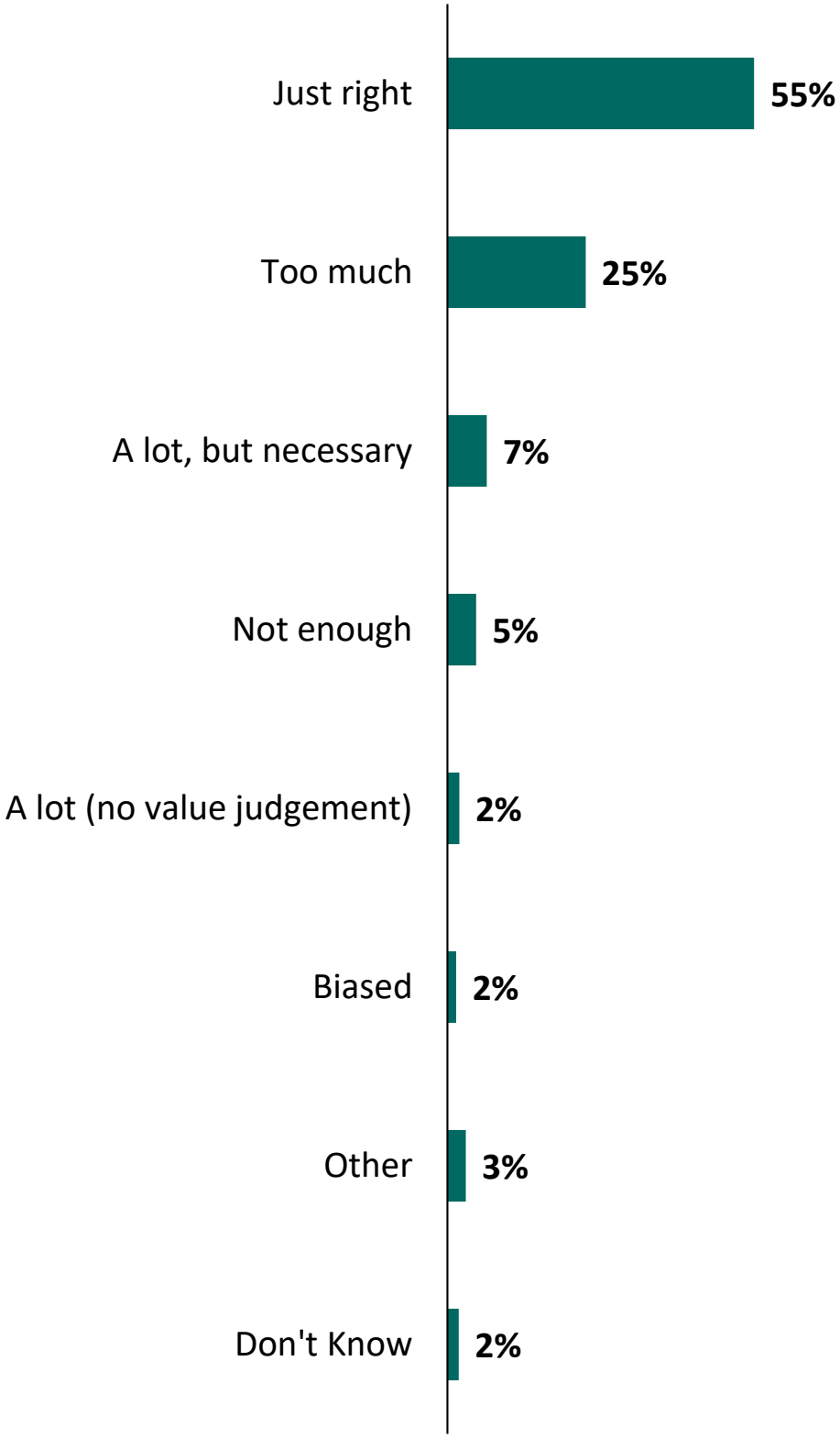
Q What did you think about the customer feedback portal?
[asked all respondents, n=1,078]



Volume of Information

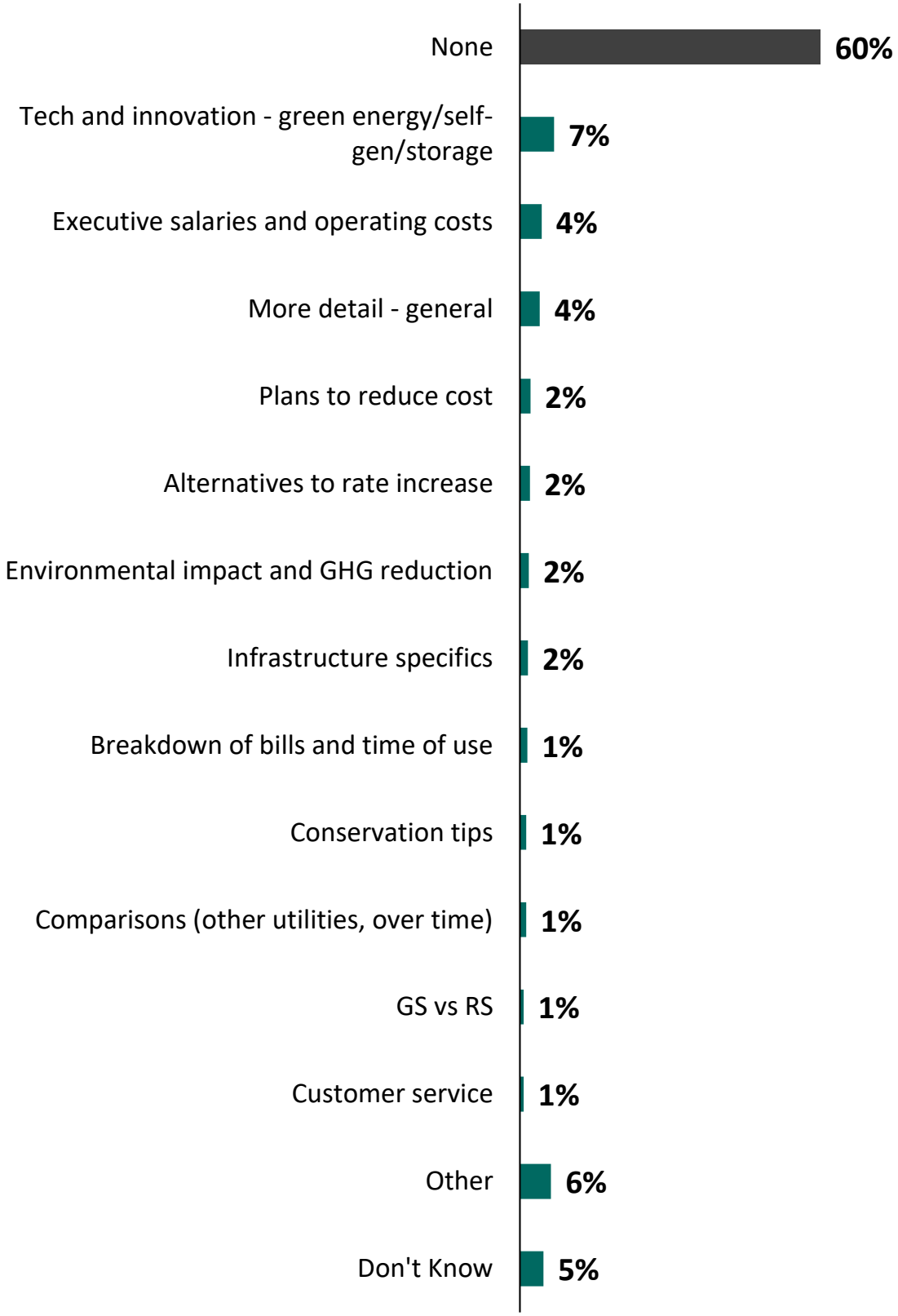
Q Did Toronto Hydro provide too much information, not enough, or just the right amount?

[asked all respondents, n=1,104]



Content Covered

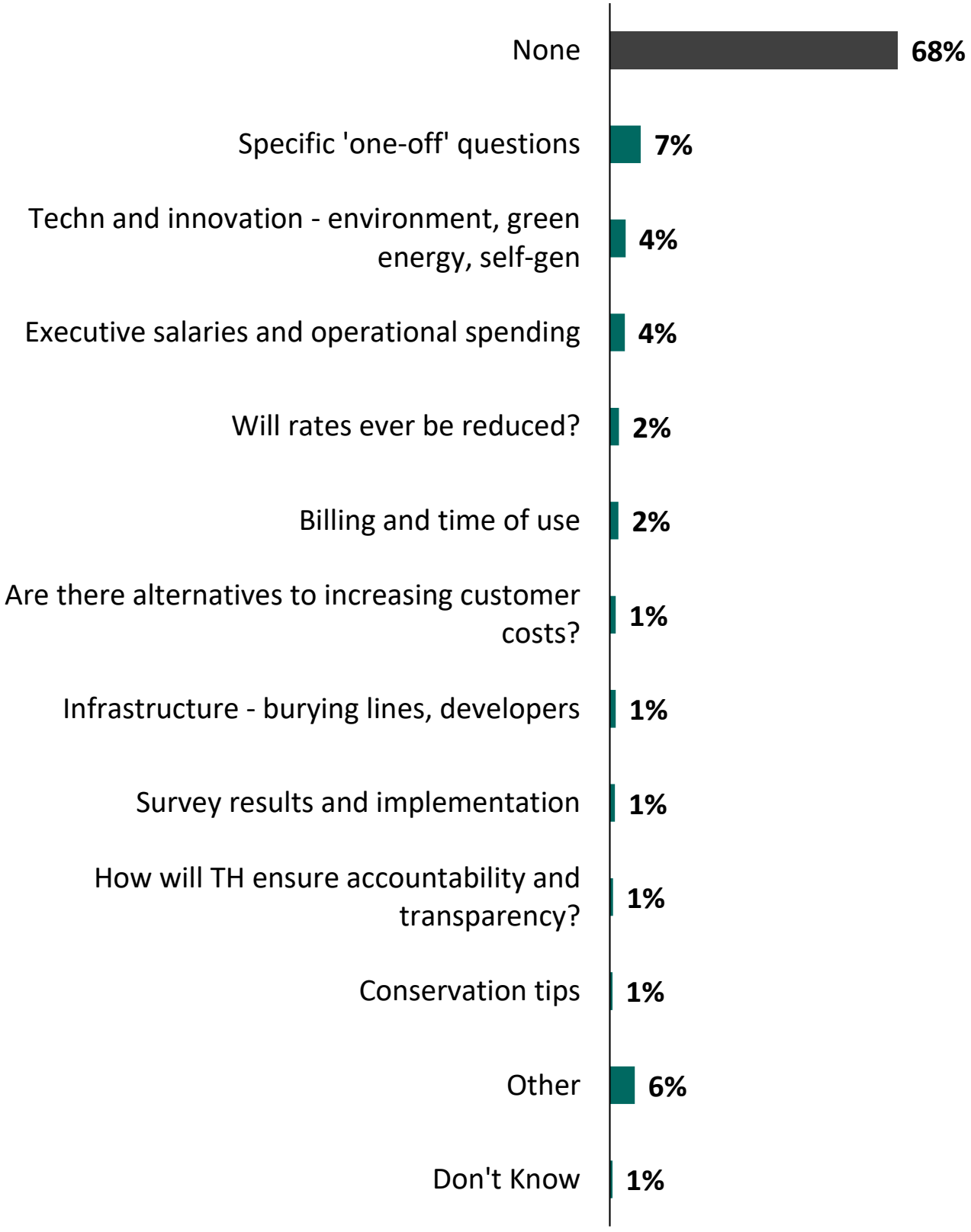
Q Was there any content missing that you would have liked to have seen included?
[asked all respondents, n=807]



Outstanding Questions

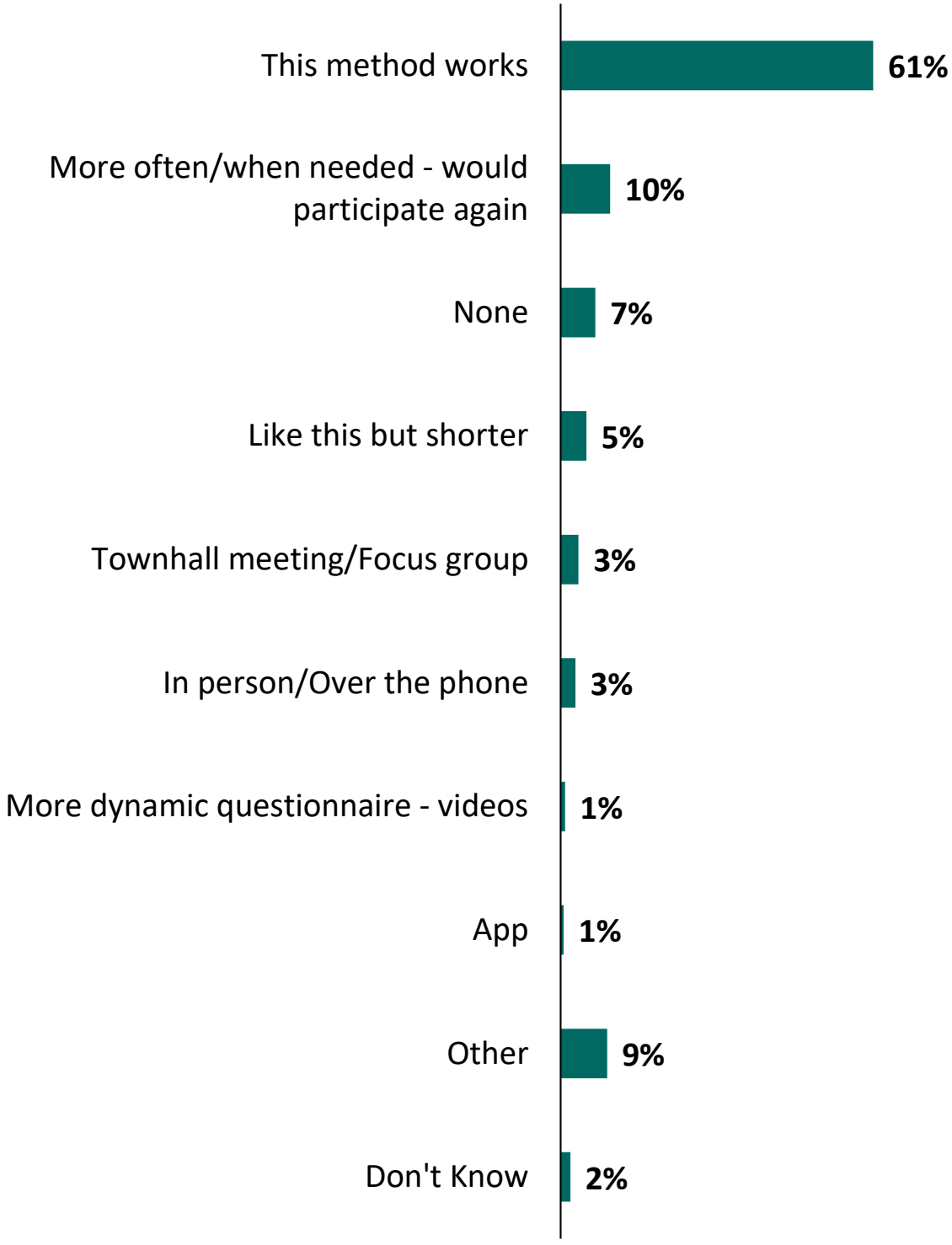
Q

Is there anything that you would still like answered?
[asked all respondents, n=642]



Suggestions for Future Consultations

Q How would you prefer to participate in these consultations?
[asked all respondents, n=701]



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Appendix 2.2

Toronto Hydro 2018 Customer Engagement

Residential Telephone Survey Report

Residential Report

June 2018

STRICTLY PRIVILEGED AND CONFIDENTIAL

Survey Methodologies



Field and Design

These are the findings of an Innovative Research Group (INNOVATIVE) telephone survey conducted among **n=600** Toronto Hydro **residential customers** between **May 1 and 10, 2018.**

The margin of error for a sample of n=600 is approximately +/-4.0%. 19 times out of 20.

Quotas were set by electricity consumption levels and geographic considerations from within the Toronto Hydro service territory in order to obtain a representative customer sample.

Residential customers were divided into quartiles based on annual electricity usage to ensure the sample had a proportionate mix of customers from low, medium-low, medium-high, and high electricity usage households.

For the purposes of executing the customer surveys, Toronto Hydro provided INNOVATIVE with a confidential list of customers' contact information.

The contact list included only customers with telephone contact information on file and who had been a customer of Toronto Hydro for at least one year. The information contained in the contact list included customer name, telephone number(s), postal code and total annual electricity consumption.

Only one customer per household was eligible to complete the survey. Respondents were screened to certify that only customers responsible for paying or overseeing their electricity bill were interviewed. This step was taken to ensure that survey respondents represented the most qualified person within a household to answer questions.

Customers were offered a $10 Amazon Gift Card in appreciation for completing the survey.

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

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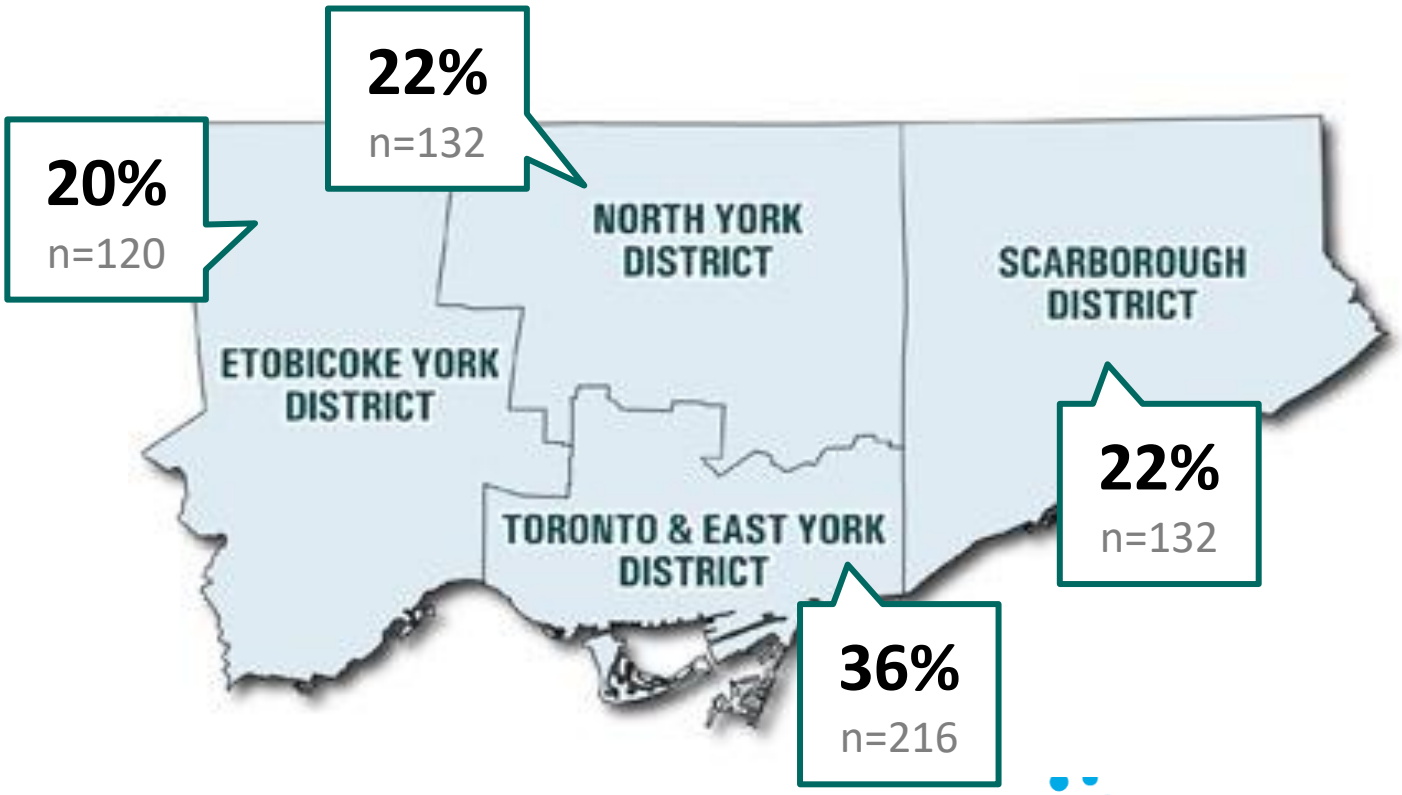
Consumption Quartiles

The tables below illustrate the strata divisions for each rate class, based on consumption quartiles.

Dividing customer sample into quartiles based on known characteristics, including region and annual consumption, was used to develop accurate quotas to ensure the sample was representative of Toronto Hydro's customer base.

	Consumption Quartiles				Total
	Low	Medium-Low	Medium-High	High	
Toronto & East York	54	54	54	54	**216**
Etobicoke & York	30	30	30	30	**120**
North York	33	33	33	33	**132**
Scarborough	33	33	33	33	**132**
Total	**150**	**150**	**150**	**150**	**600**



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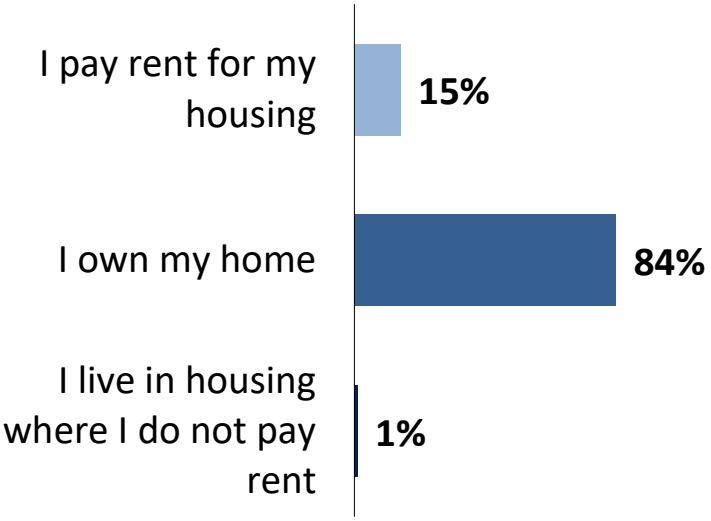
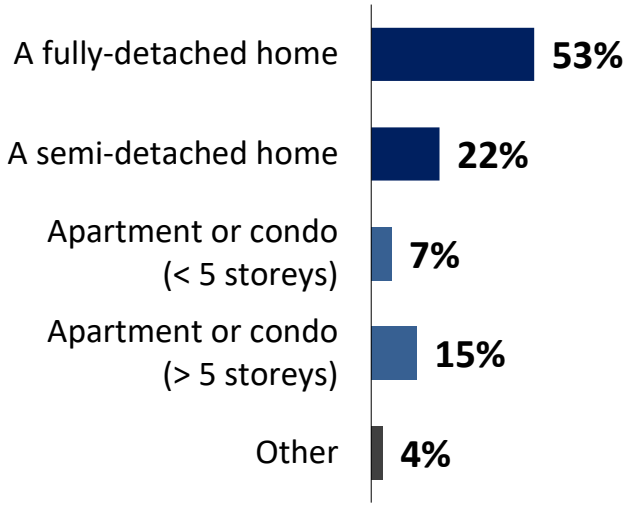
Segmentation and Demographics



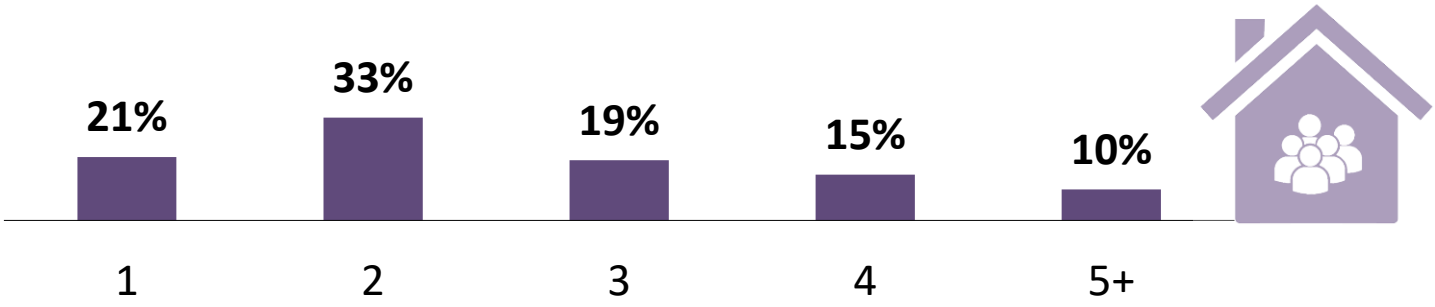
Segmentation & Demographics

Primary Residence



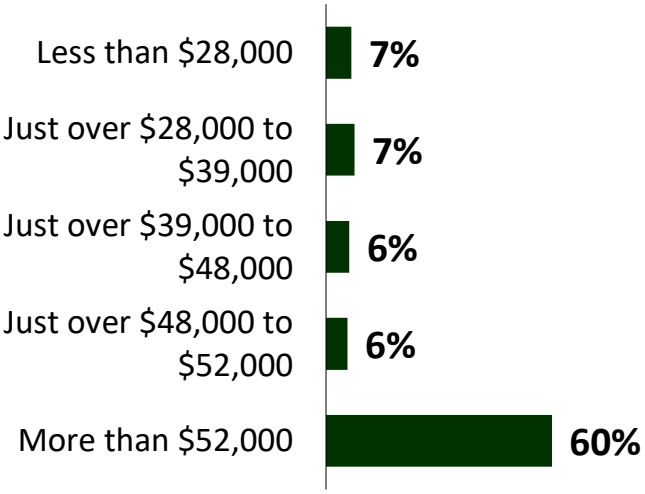


Household Size



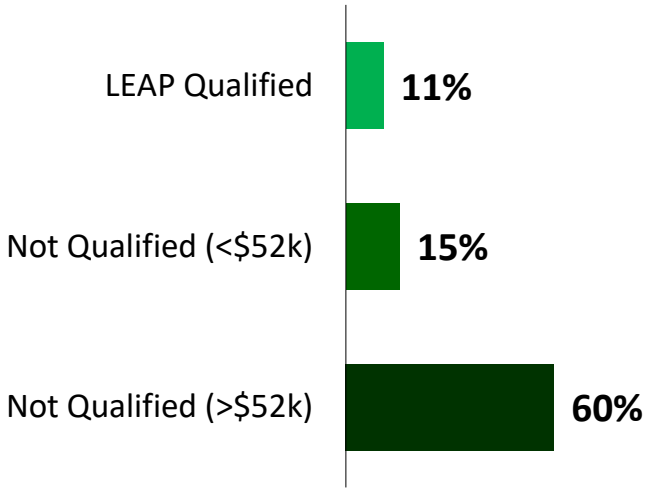
Note: 'Don't know' (2%) not shown.

Household Income After Tax



Note: 'Refused' (12%), 'Not sure' (2%) not shown.

LEAP Qualification

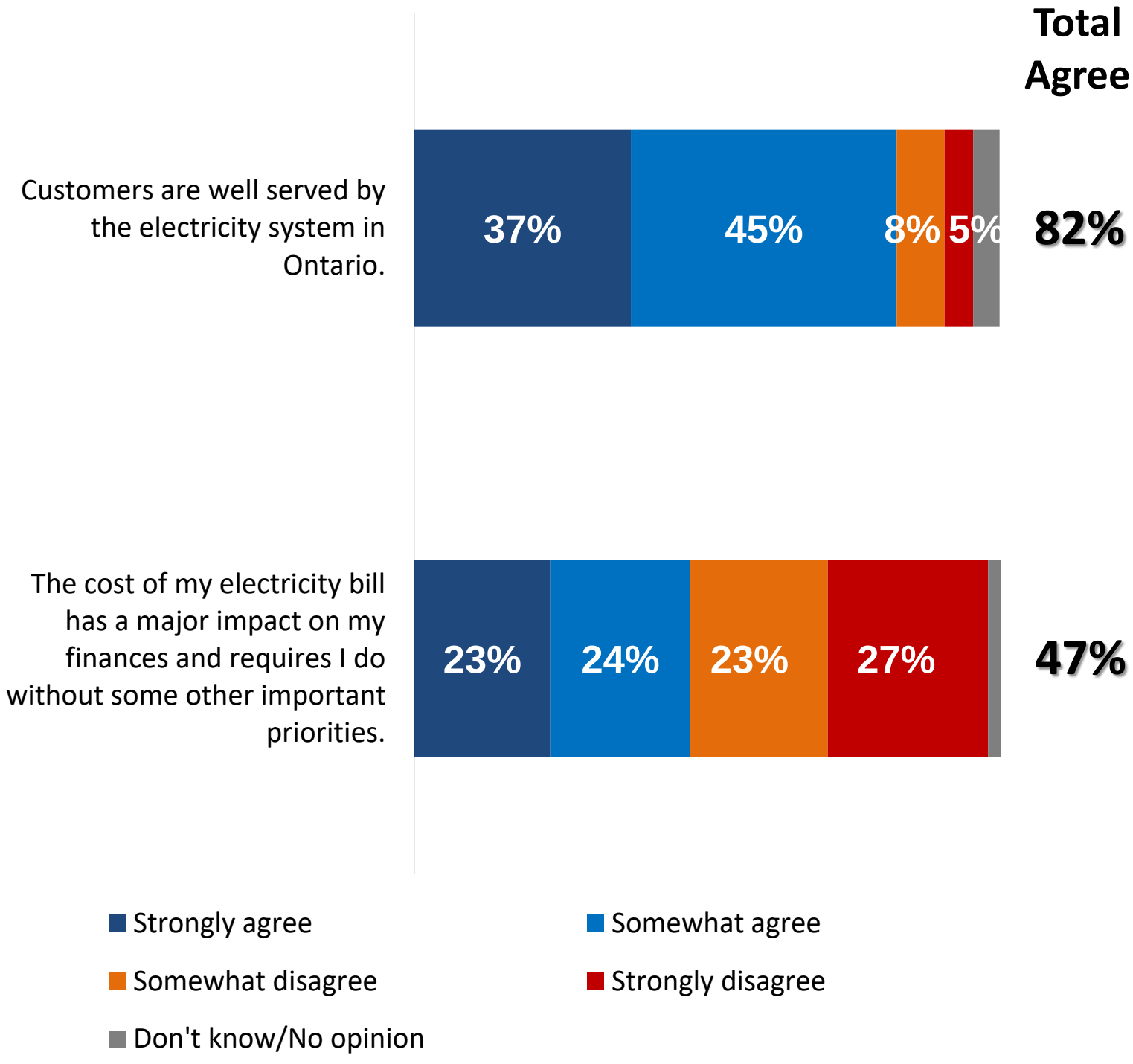


Note: 'Refused' (22%), 'Not sure' (2%) not shown.

Segmentation & Demographics

Q For each statement please tell me if you would strongly agree, somewhat agree, somewhat disagree or strongly disagree. If you don't know enough to say or don't have an opinion just let me know.

[asked all respondents, n=600]



Familiarity Preamble

To start, I'd like to ask you a few questions about the electricity system …

As you may know, Ontario's electricity system has three key components: ***generation***, ***transmission*** *and* ***distribution****.*

- ***Generating stations*** *convert various forms of energy into electric power;*
- ***Transmission lines*** *connect the power produced at generating stations to where it is needed across the province; and*
- ***Distribution lines*** *carry electricity to the homes and businesses in our communities.*

Today we're going to talk about your ***local distribution system*** *which is maintained and operated by Toronto Hydro.*

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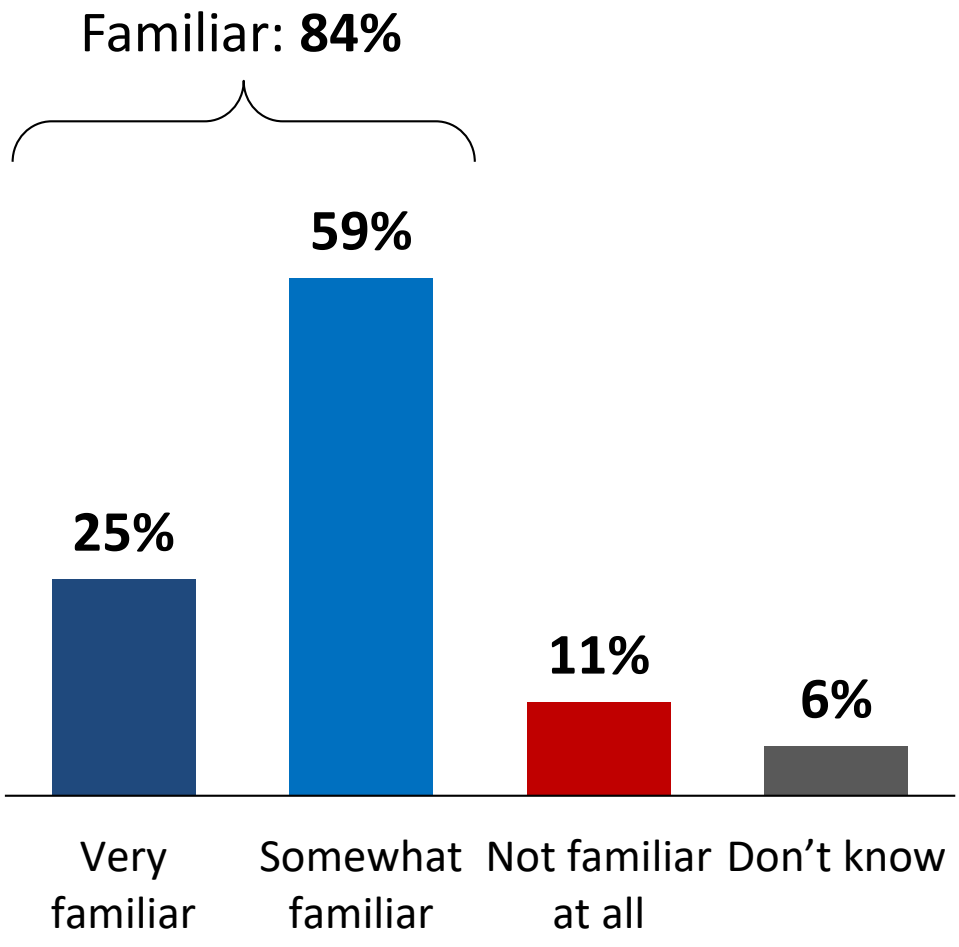
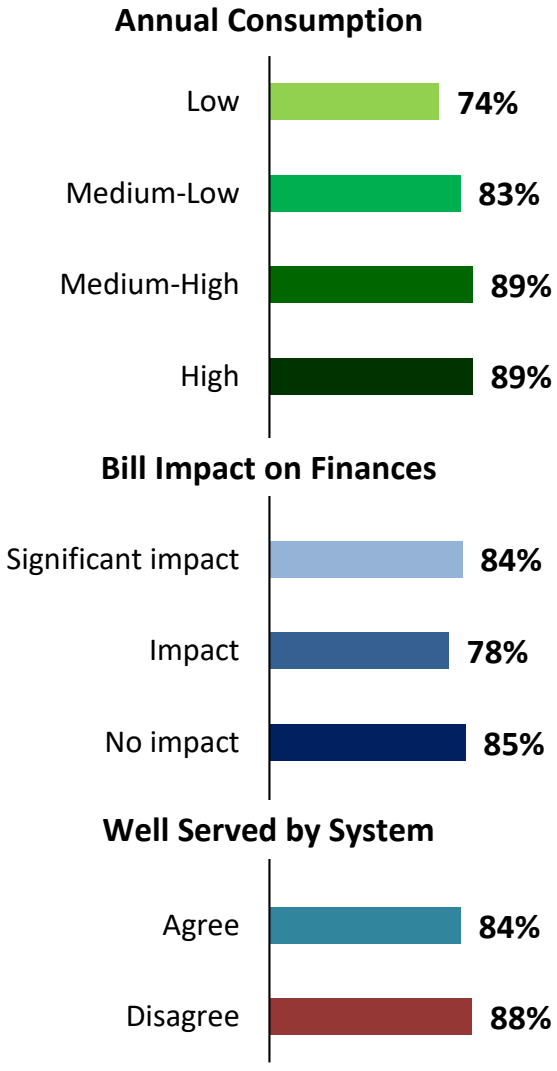
Familiarity with Toronto Hydro

How familiar are you with **Toronto Hydro**?
[asked all respondents, n=600]



Segmentation

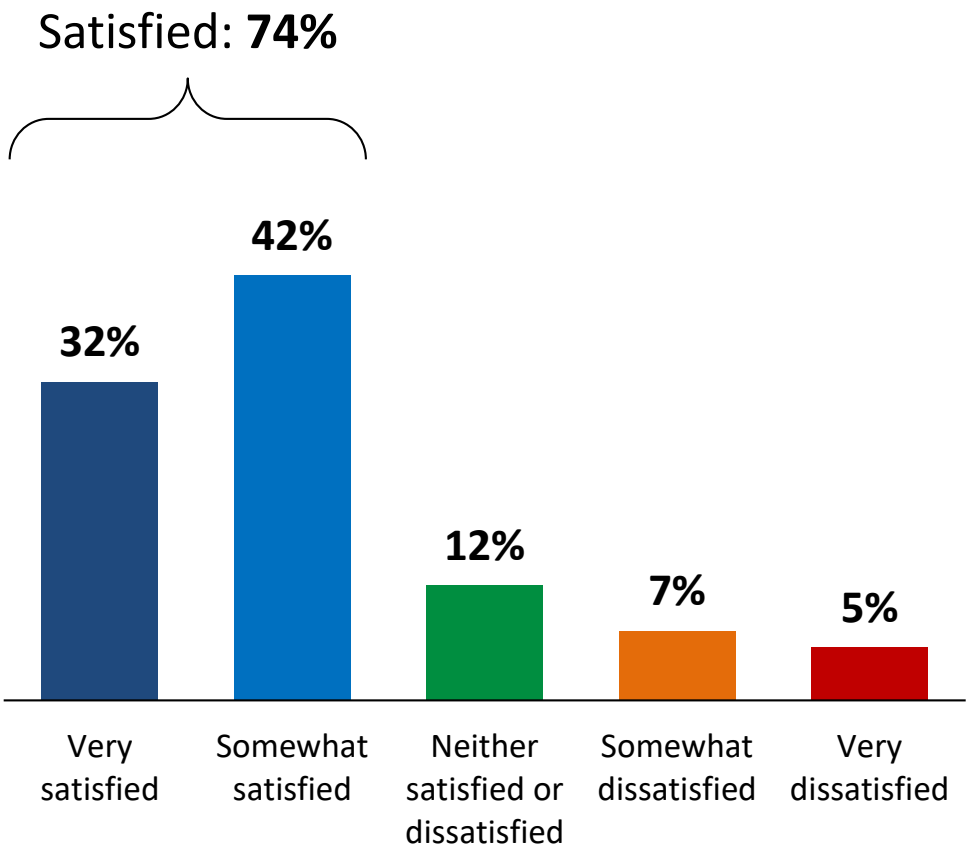
*Those who say "**Familiar**":*



Satisfaction with Services

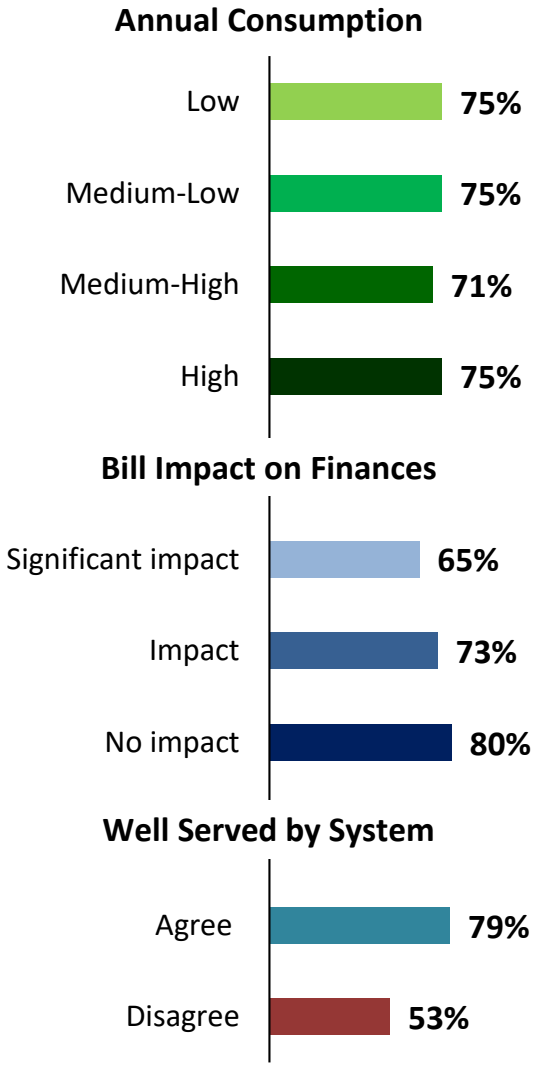
In general, how satisfied or dissatisfied are you with the services you receive from **Toronto Hydro**?

[asked all respondents, n=600]



Segmentation

*Those who say "**Satisfied**":*

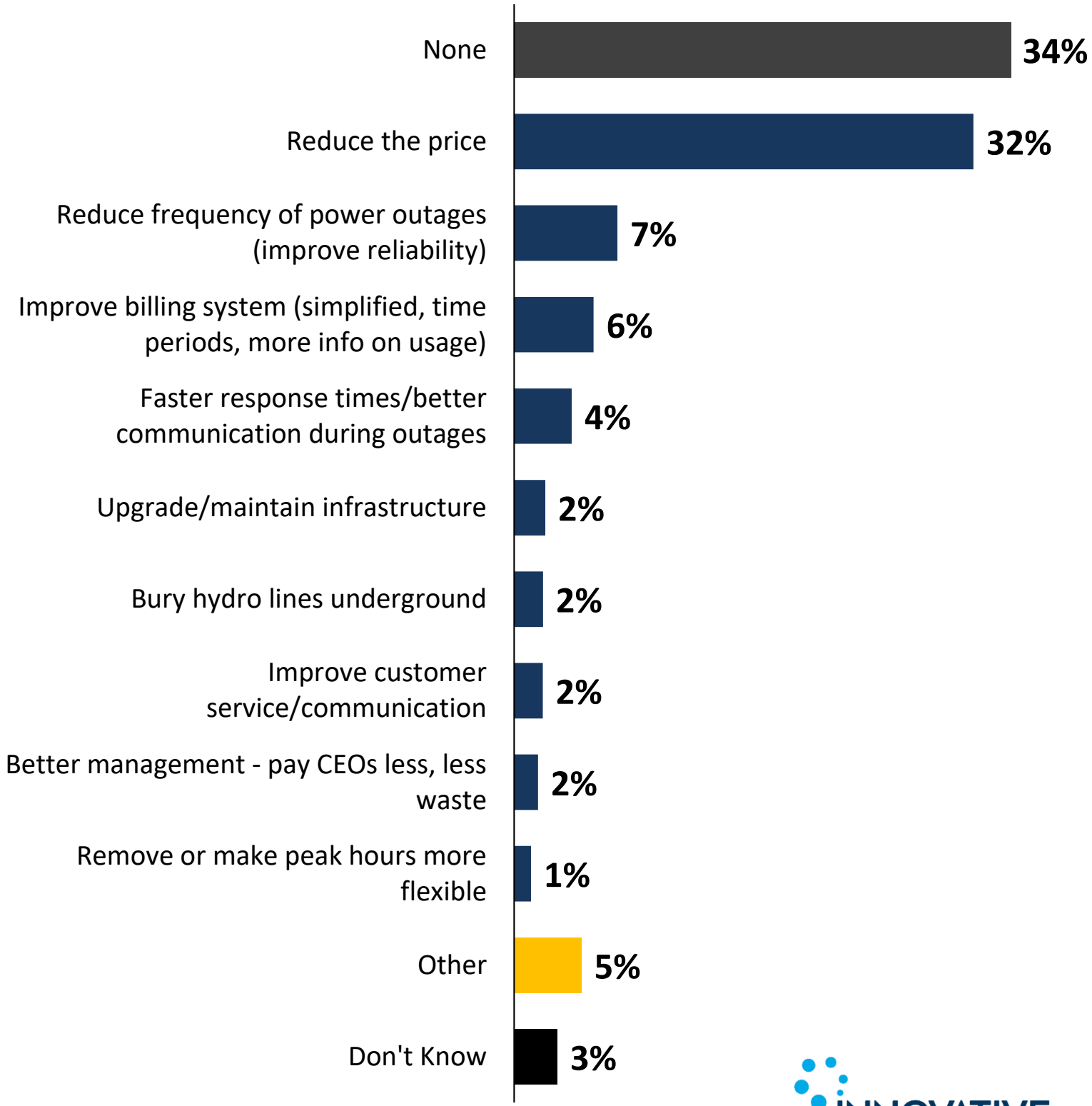


Note: "Don't know" (2%) not shown.

Suggestions for Improved Services

Q Is there anything in particular that **Toronto Hydro** can do to improve its services to you?

[asked all respondents, n=600]



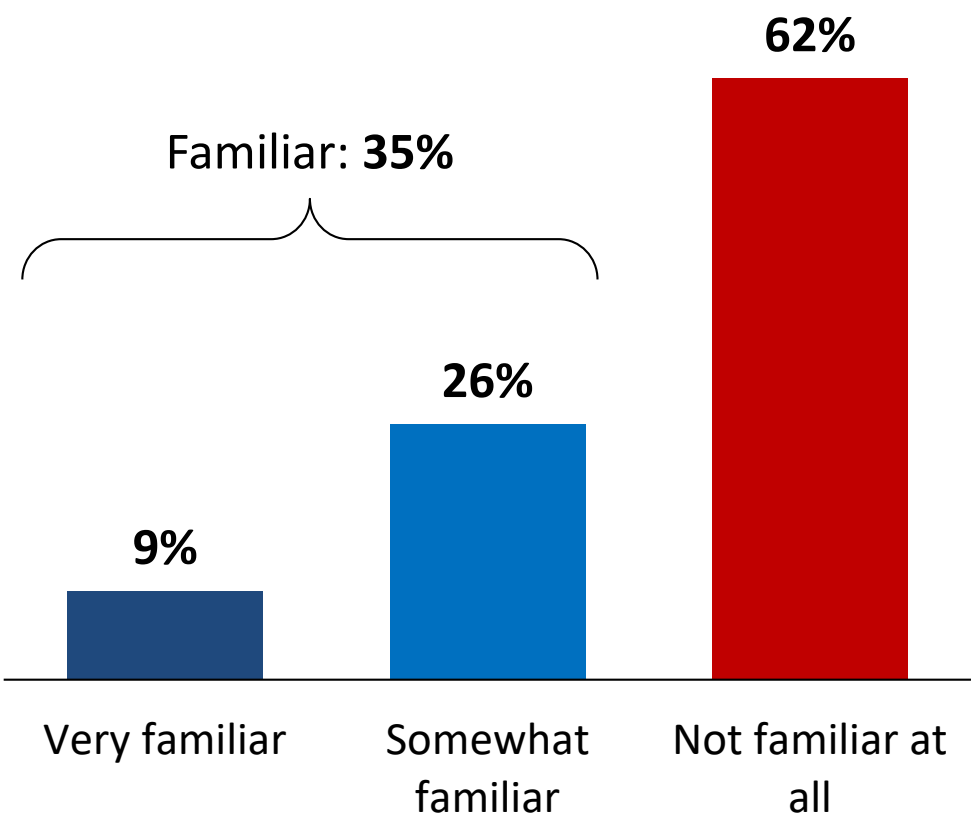
Note: "Refused" (1%) not shown.

Amount of Bill Retained by Toronto Hydro

While **Toronto Hydro** is responsible for collecting payment for the entire electricity bill, they retain about **32%** of the typical residential customer's bill. This is about **$39** on an average **$123** monthly residential electricity bill. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.

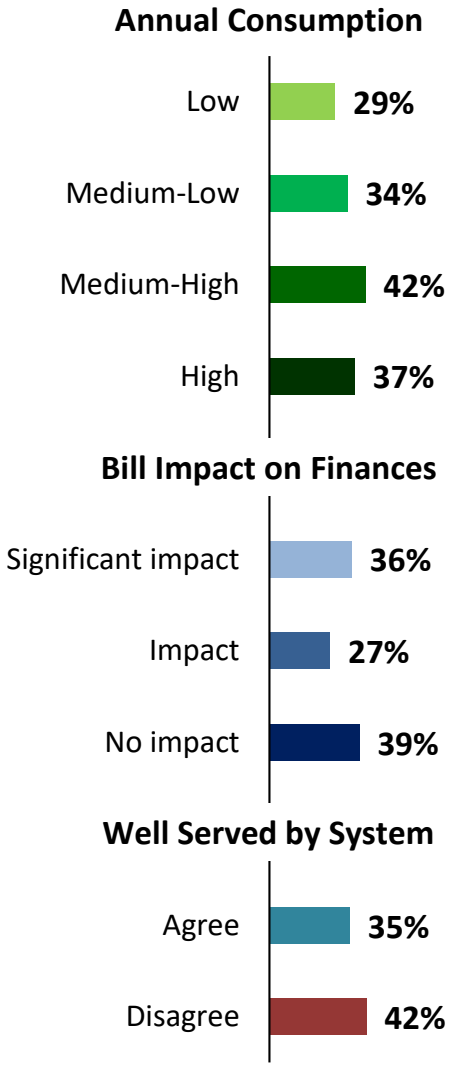
Before this survey, how familiar were you with the percentage of your electricity bill that is retained by **Toronto Hydro**?

[asked all respondents, n=600]



Segmentation

*Those who say "**Familiar**":*



Note: "Don't Know" (2%) not shown.

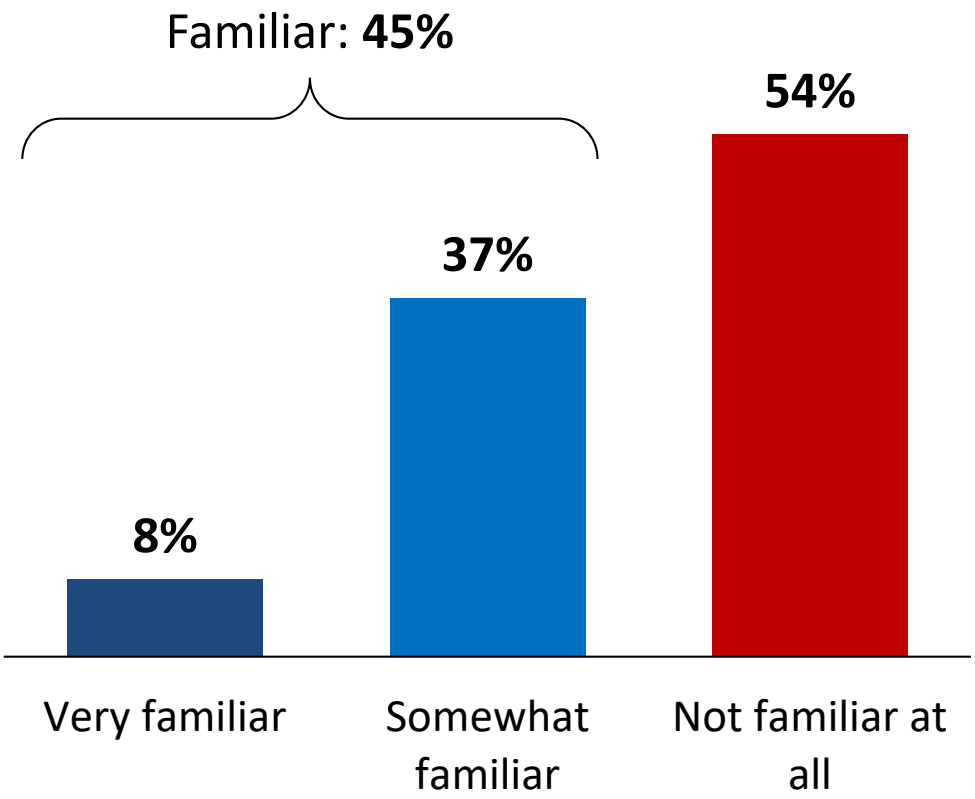
Familiarity with Ontario Energy Board

Q

Electricity distributors are required to file a rate application with the Ontario Energy Board (OEB) to request a change in distribution rates based on their plans for capital and operating spending. Toronto Hydro is now consulting on its plans for 2020 to 2024.

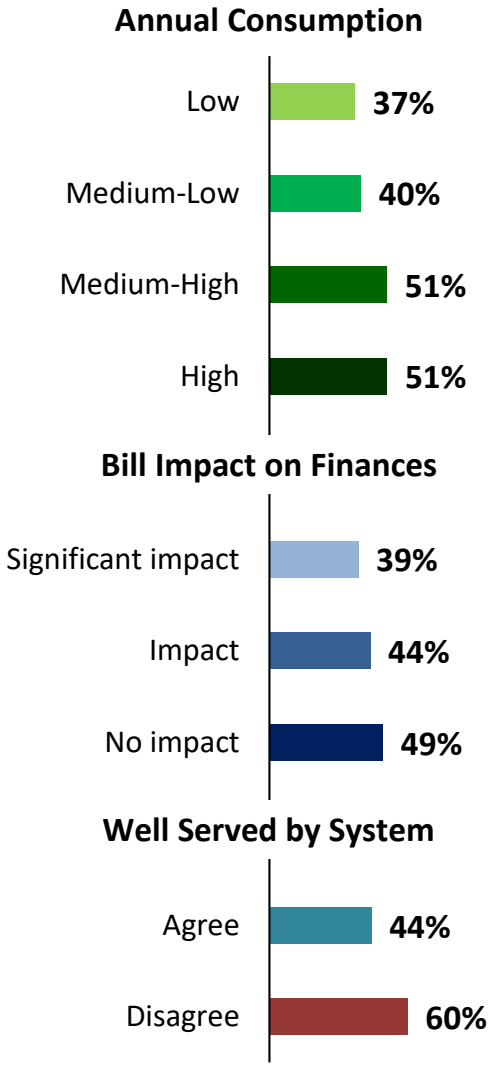
The OEB is mandated to protect consumers with respect to prices and the reliability and quality of electricity service.

How familiar would you say you are with the Ontario Energy Board or "OEB"?
[asked all respondents, n=600]



Segmentation

*Those who say "**Familiar**":*



Note: "Don't Know" (1%) not shown.

Customer Engagement Process Preamble

As part of **Toronto Hydro's** consultation, it has developed a five-phase approach to gathering and responding to customer feedback.

- First, **Toronto Hydro** identified customer priorities through a series of surveys and focus groups;
- Then, used this customer feedback to guide development of its Draft Plan;
- Now, **Toronto Hydro** is in the process of collecting customer feedback on its Draft Plan;
- The next phases will include re-examining its Draft Plan based on customer feedback and preparing a submission to the OEB.

This survey is part of the third stage of **collecting customer feedback on the Draft Plan.**

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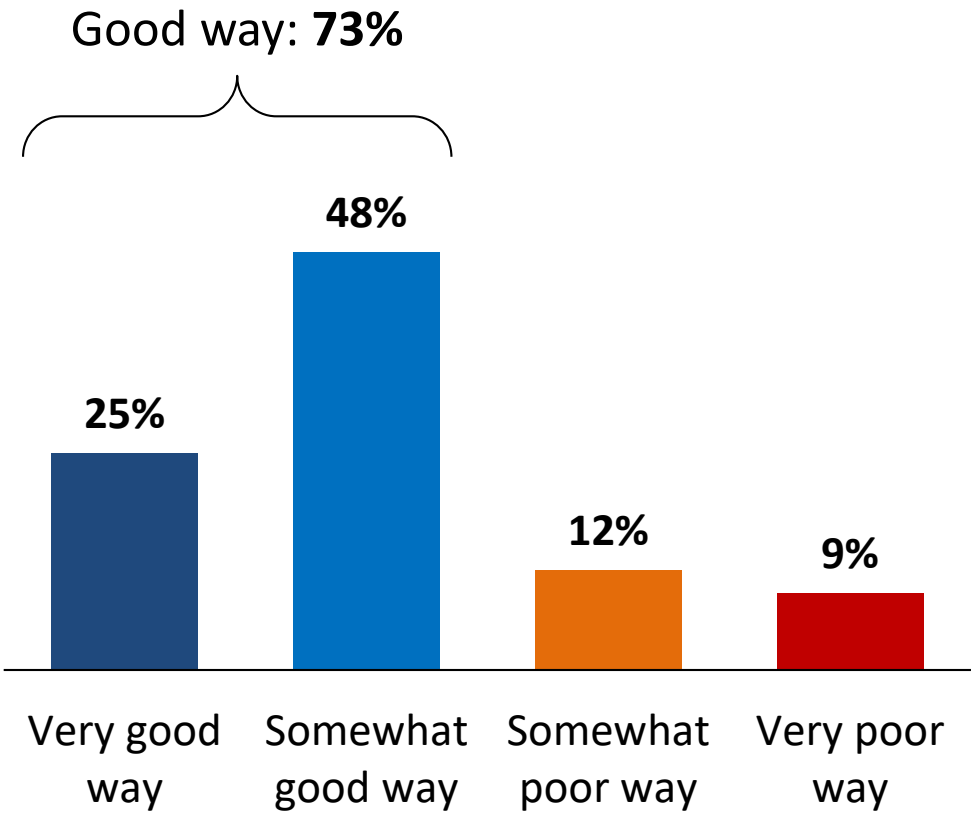
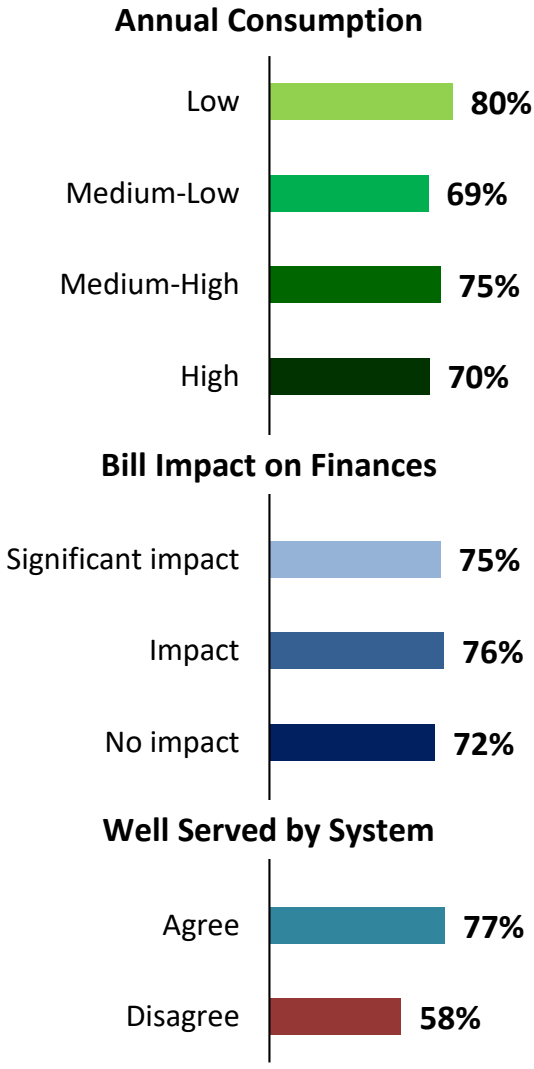
Feedback on Customer Engagement Process

Q Does this Customer Engagement process seem like a good way or a poor way to bring customer needs and preferences into **Toronto Hydro's** plan?
[asked all respondents, n=600]



Segmentation

*Those who say "**Good Way**":*



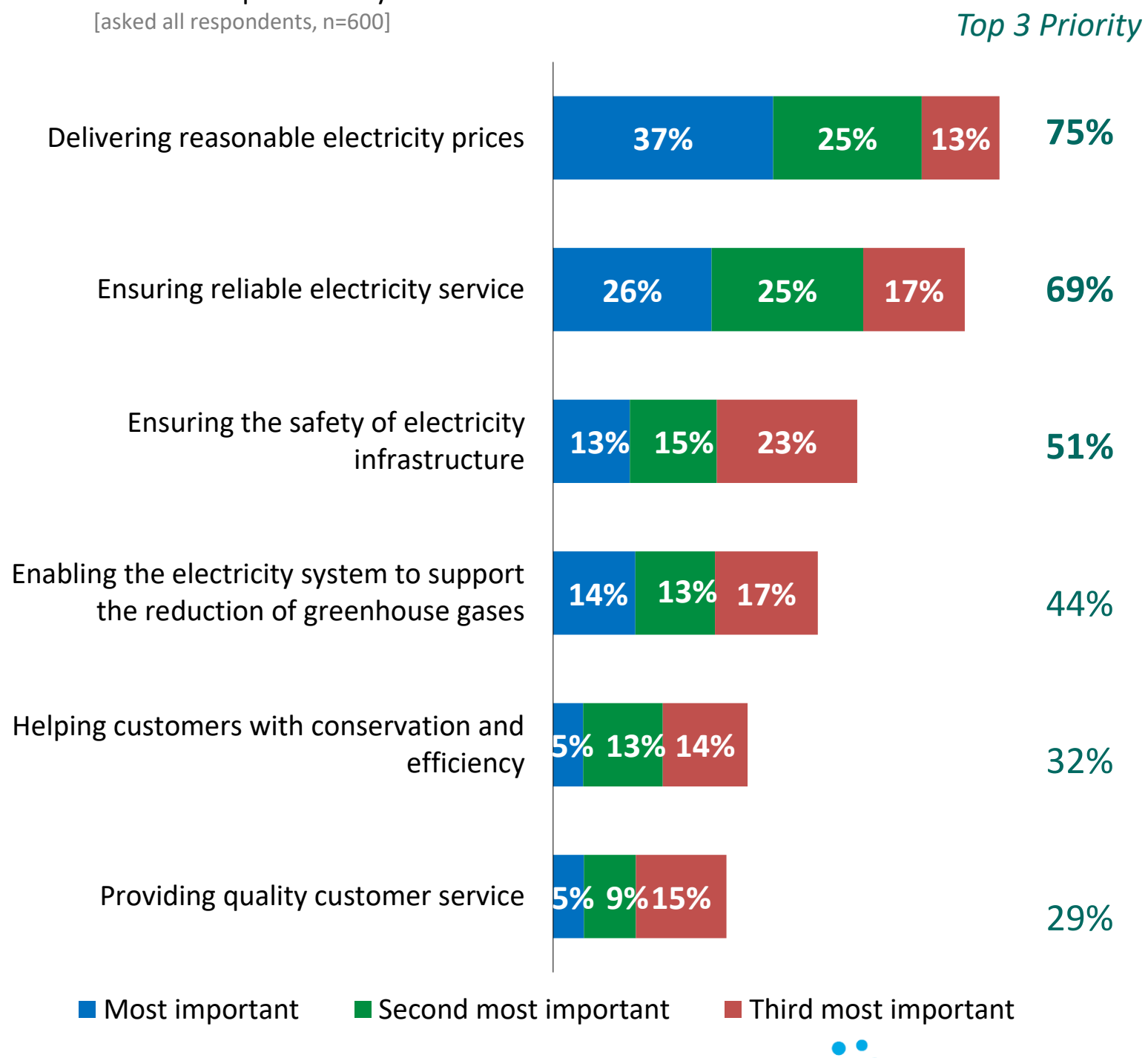
Note: "Don't Know" (6%) not shown.

Customer Priorities

Toronto Hydro wants to better understand customer priorities. In the first phase of customer engagement, residential and small business customers identified six core priorities which they believe should be a focus for **Toronto Hydro**.

Among the following customer identified priorities, please tell me which one is the most important to you.

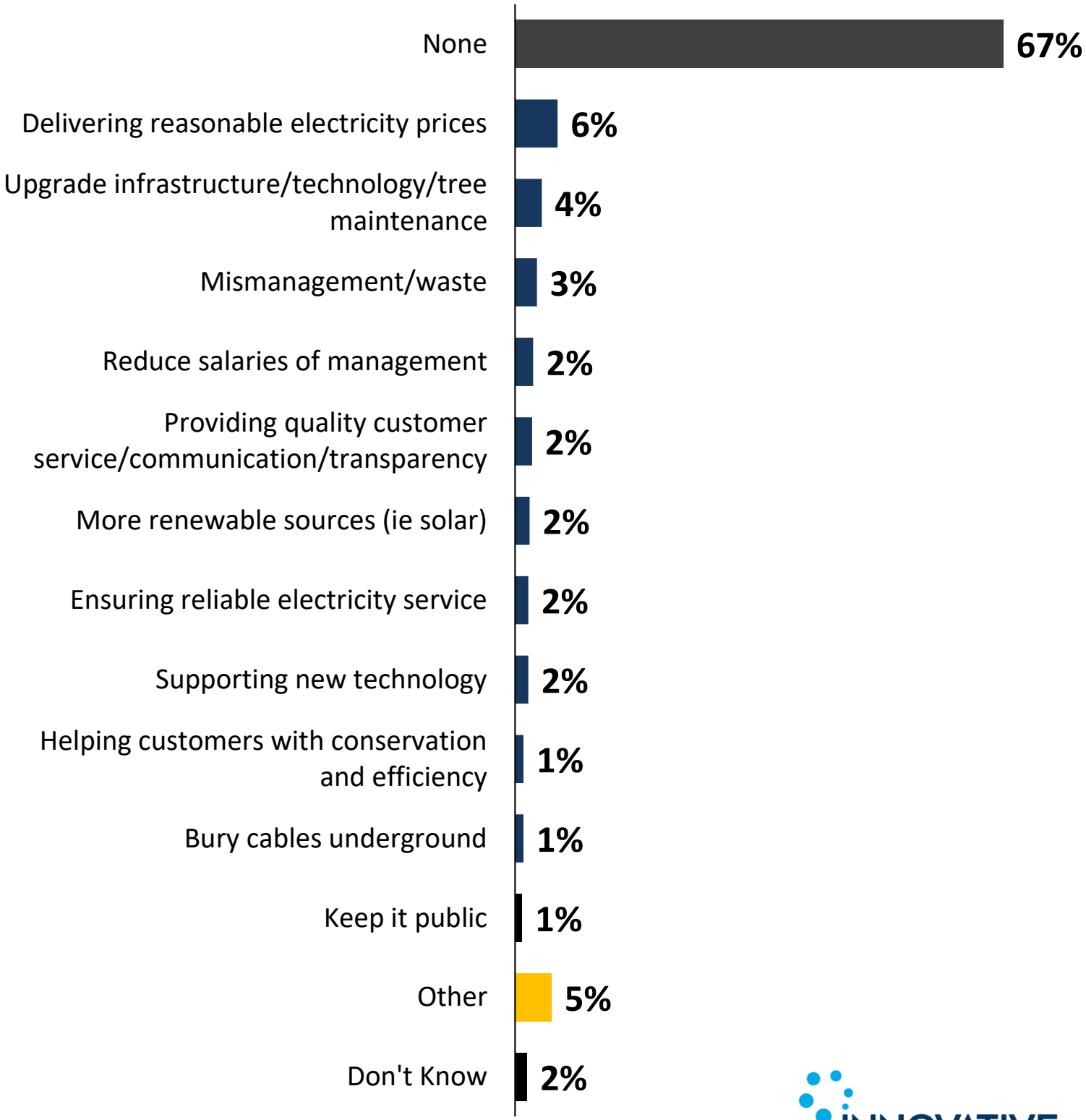
[asked all respondents, n=600]



Additional Customer Priorities

Q Are there any other important priorities that **Toronto Hydro** should be focusing on that weren't included in the previous list I read to you?

[asked all respondents, n=600]



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Planning Principles and Rate Impact Preamble

Based, in part, on the initial customer input, **Toronto Hydro** has drafted a plan totaling approximately $4.3B over five years.

Toronto Hydro's proposed plan focuses on delivering current levels of reliability and customer service for most customers and targeted improvements for customers experiencing below average service or who have special reliability needs, like hospitals.

This proposed plan translates into an average 3.4% increase in your distribution rates each year from 2020 to 2024. The distribution charges on the monthly bill would increase to $49 by 2024 for a typical residential customer.

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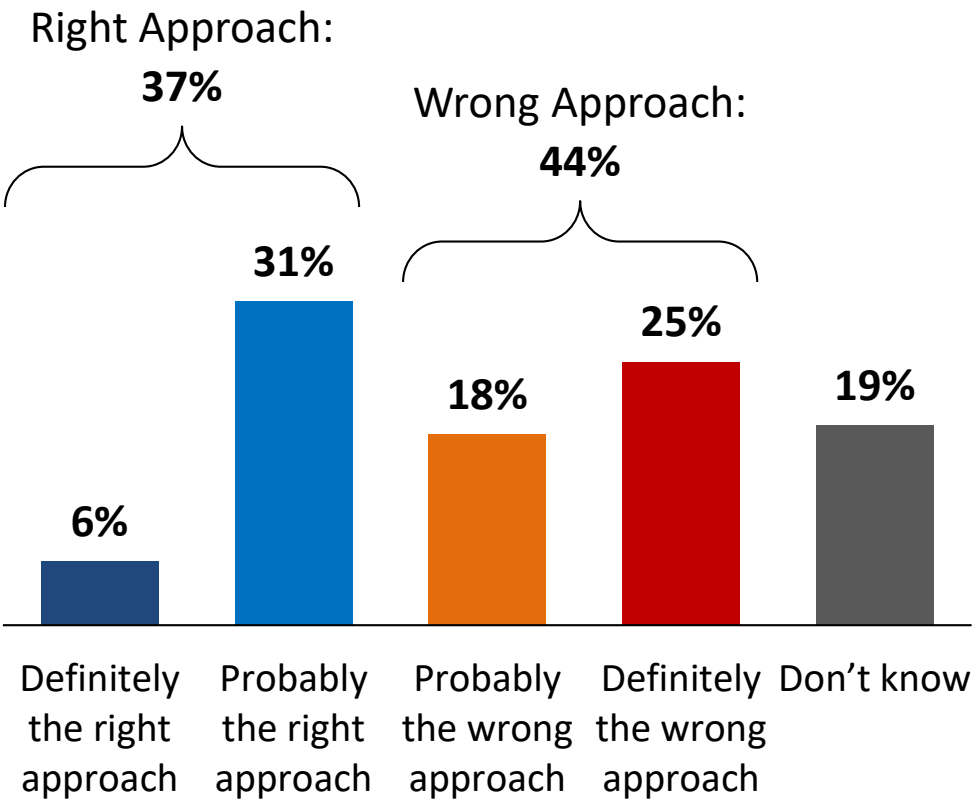
Approach to Planning for the Next Five Years

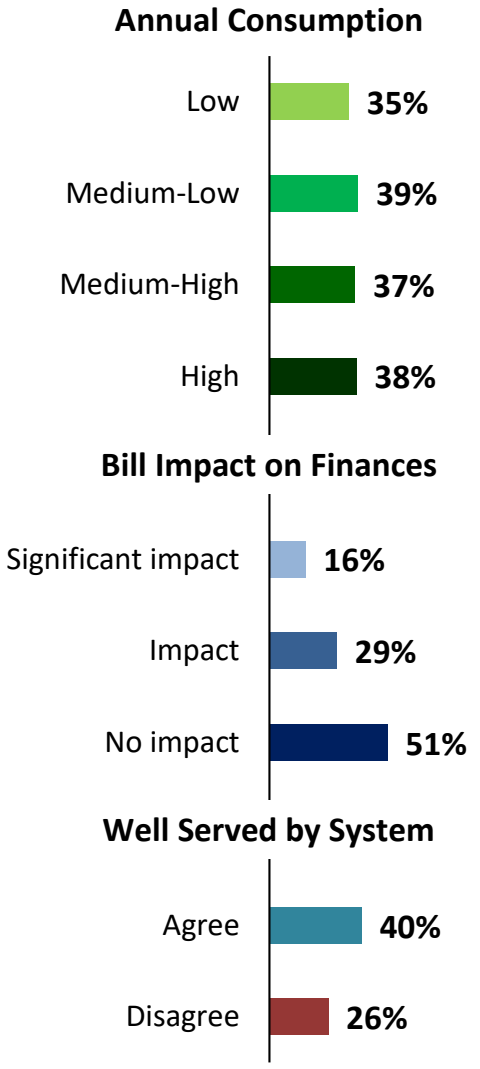
Q Do you feel that this is definitely the right approach, probably the right approach, probably the wrong approach or definitely the wrong approach to **Toronto Hydro's** planning for the next five years or would you say you don't know?

[asked all respondents, n=600]



Segmentation

*Those who say "**Right Approach**":*



Gathering Feedback on Capital Investment Decisions

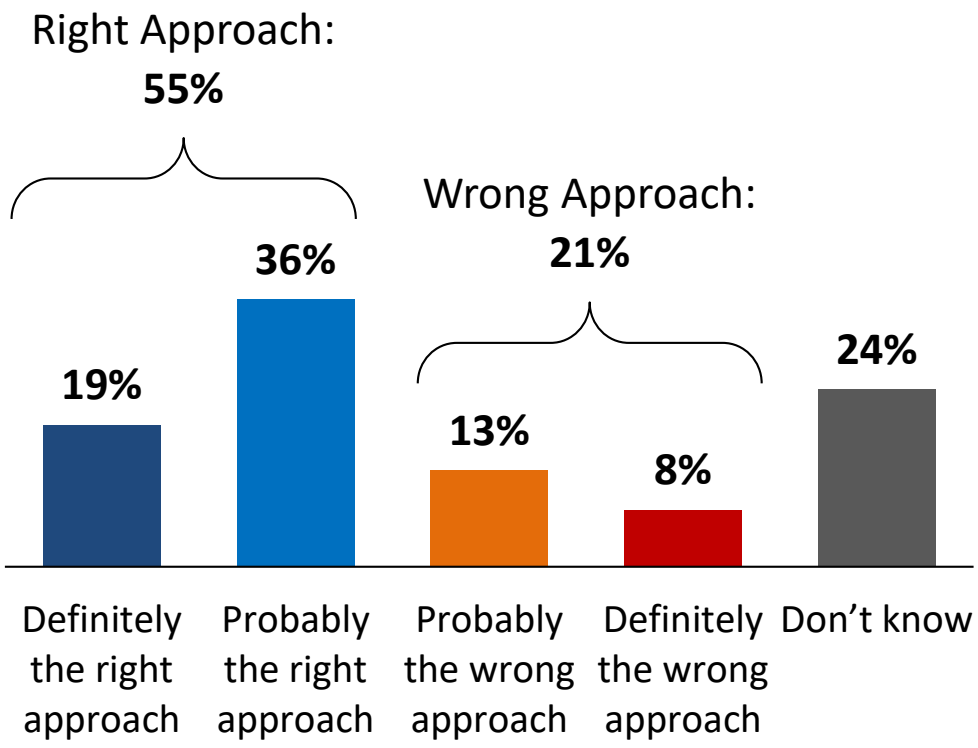
Toronto Hydro's total spending is benchmarked by the OEB against other utilities in Ontario. Toronto Hydro's operating costs of $305 per customer are within $1 of the provincial average.

However **Toronto Hydro's** capital investment costs are $739 per customer which are $245 more than the provincial average.

Since a number of capital investment decisions are based trade-offs between costs and customer outcomes – like services and reliability levels – the remaining questions in this survey ask for your feedback on those choices.

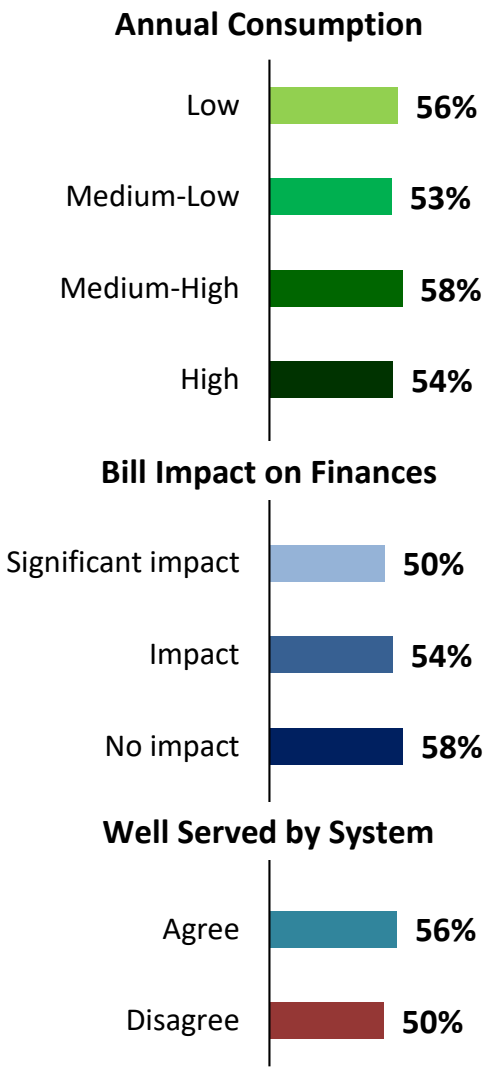
Do you feel that gathering feedback on capital investment decisions is *definitely the right approach, probably the right approach, probably the wrong approach, definitely the wrong approach or would you say you don't know*?

[asked all respondents, n=600]



Segmentation

*Those who say "**Right Approach**":*



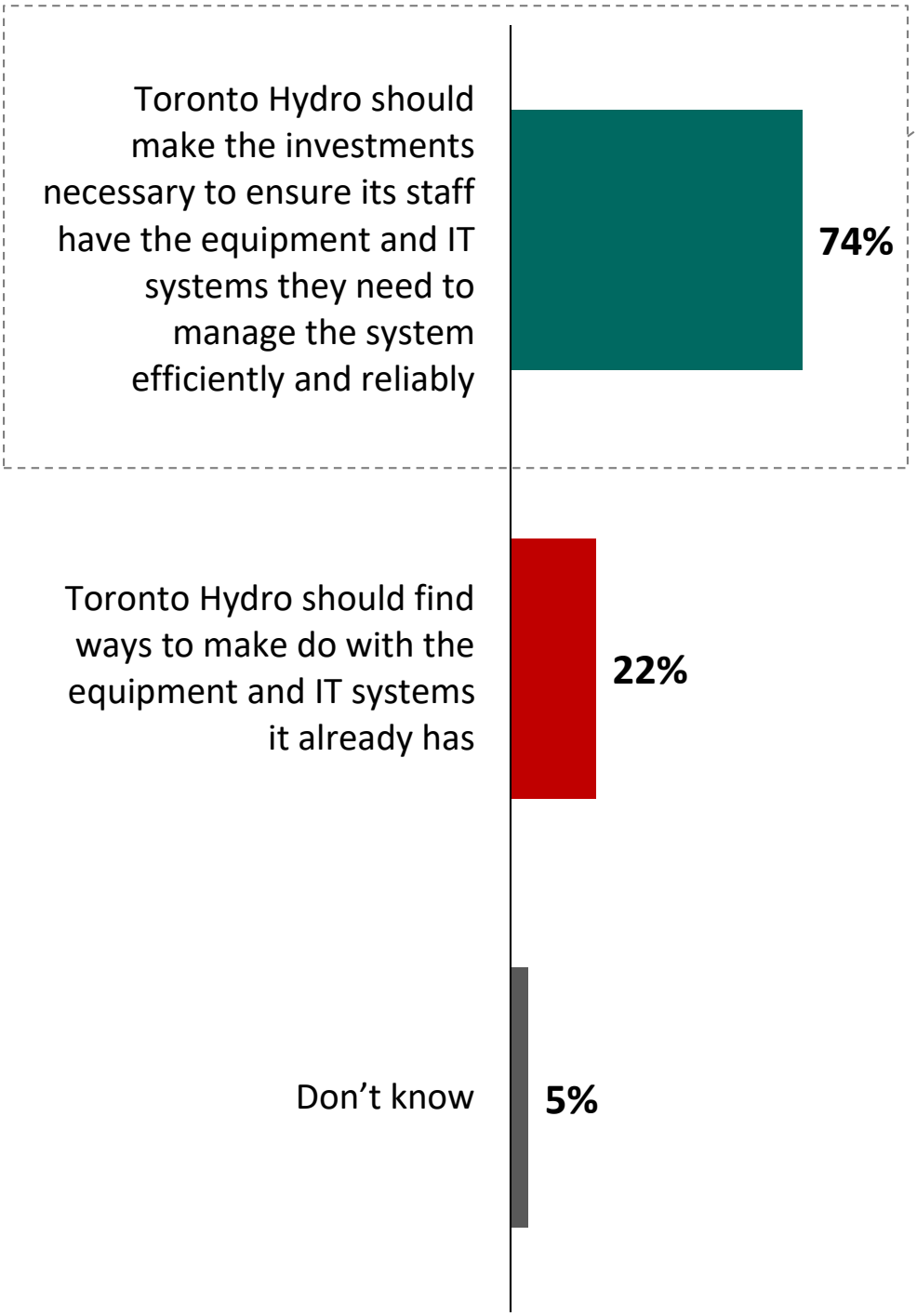
Investing in the Basics

Q

As a company, **Toronto Hydro** needs vehicles and tools to service the power lines and IT systems to manage the system and customer information.

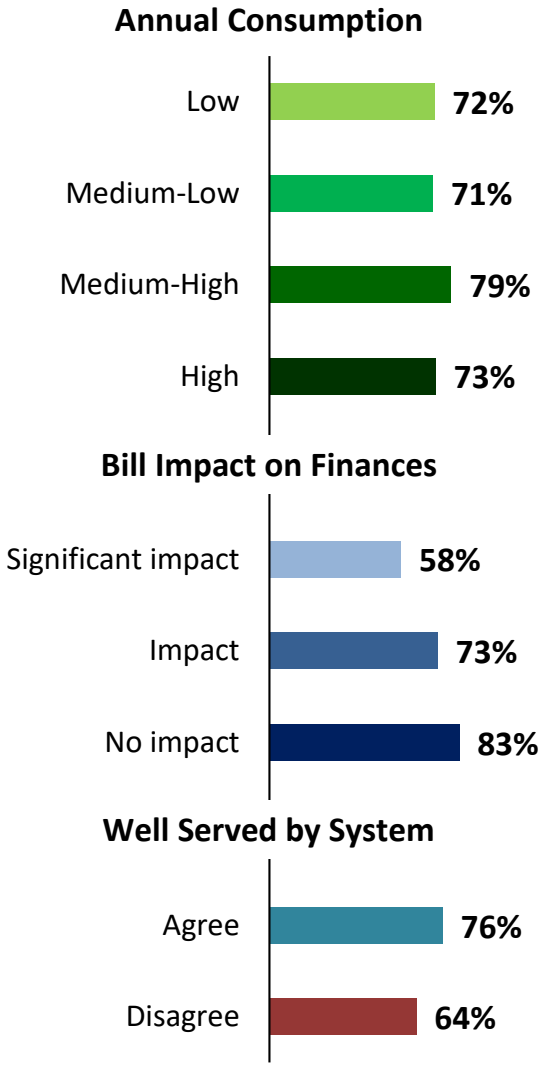
Which of the following statements best represents your point of view?

[asked all respondents, n=600]



Segmentation

*Those who say "**Make necessary investments**":*



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Addressing Safety and Reliability



Addressing Safety and Reliability Preamble

Toronto Hydro has identified areas where it could accelerate investments. These accelerated projects could increase the **typical customer's bill by $2.46 per month by 2024**. These projects are in addition to the 3.4% increase that is currently being proposed.

Toronto Hydro wants to get your feedback on particular projects before deciding whether or not to accelerate its investment plan in certain specific areas.

Right now, the typical **Toronto Hydro** customer averages 1.4 outages per year with an average of between 60 and 70 minutes without power over the year. While many of those outages are caused by events outside of **Toronto Hydro's** control, roughly 36% are caused by the failure of aging equipment.

In this proposed plan, **Toronto Hydro's** general approach is to spend just enough on replacing equipment so that most customers can expect a similar level of reliability over the next five years as they are experiencing today, and to provide improved service for those customers whose reliability is poorer or who have special reliability needs such as hospitals.

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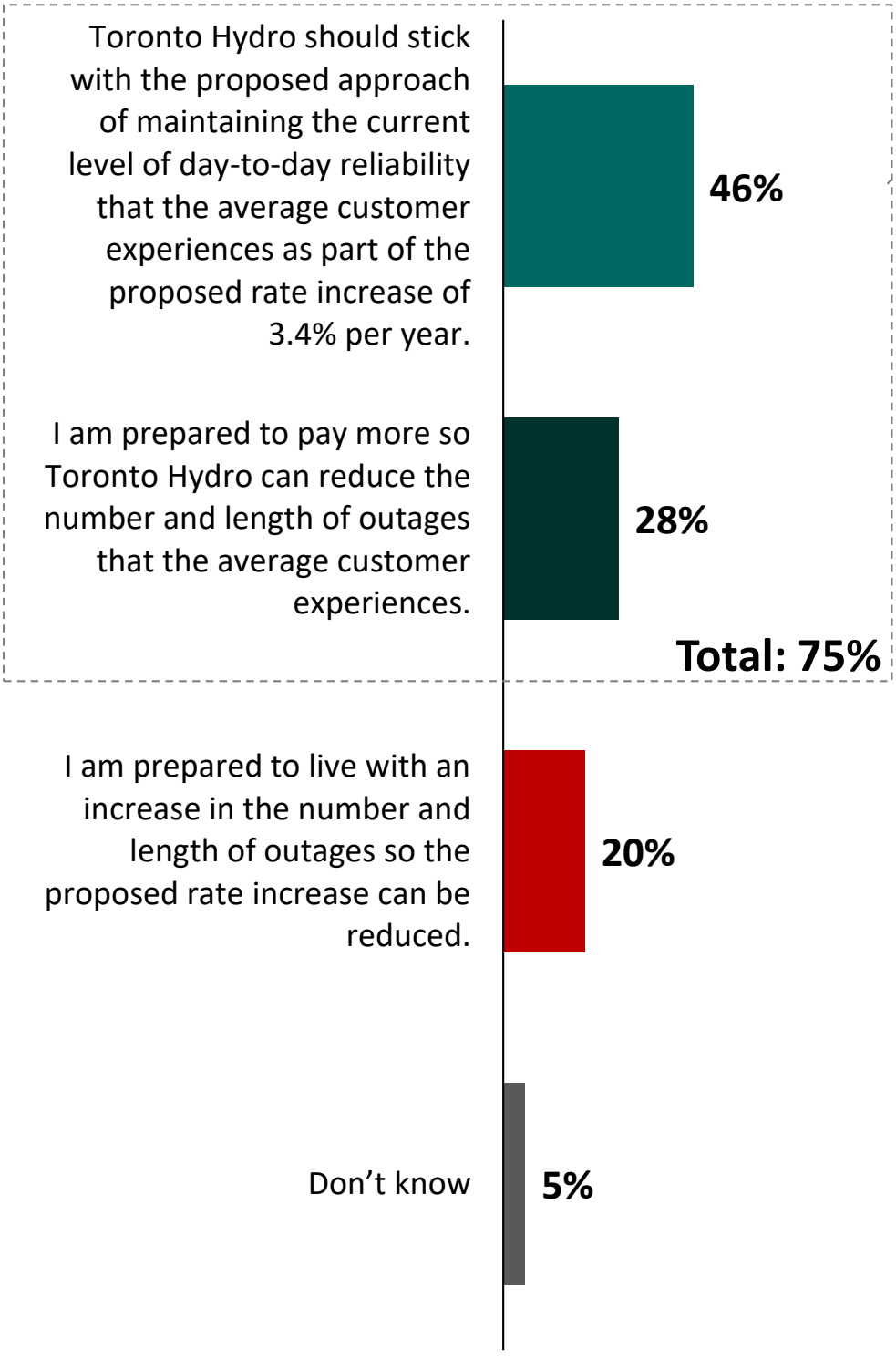
Approach to Addressing Reliability

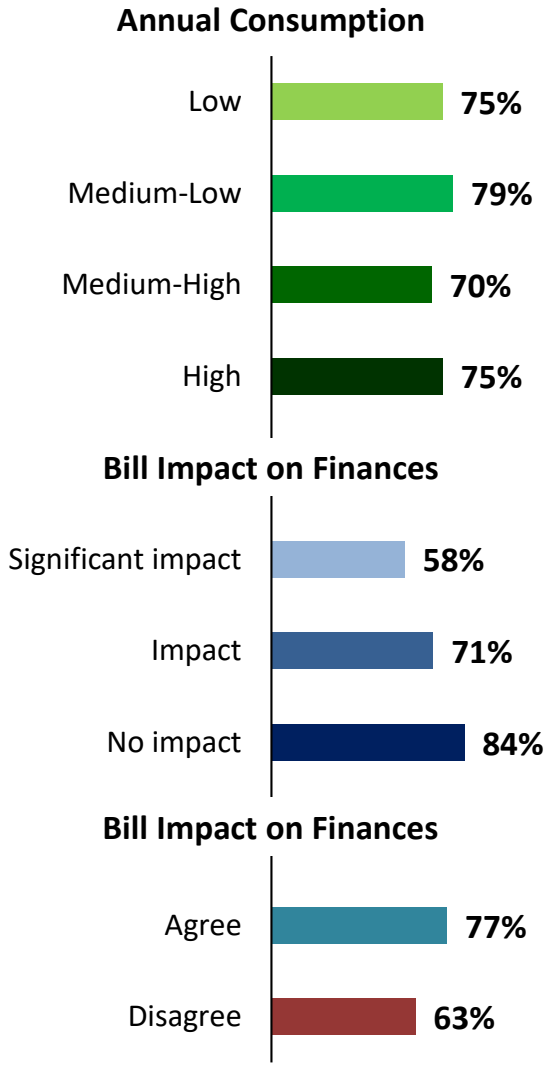
Q Which of the following is closest to your point of view regarding **Toronto Hydro's approach to addressing reliability?**

[asked all respondents, n=600]



Segmentation

*Those who say "**Stick with proposed approach or spend more**":*



Rear-Lot Replacement

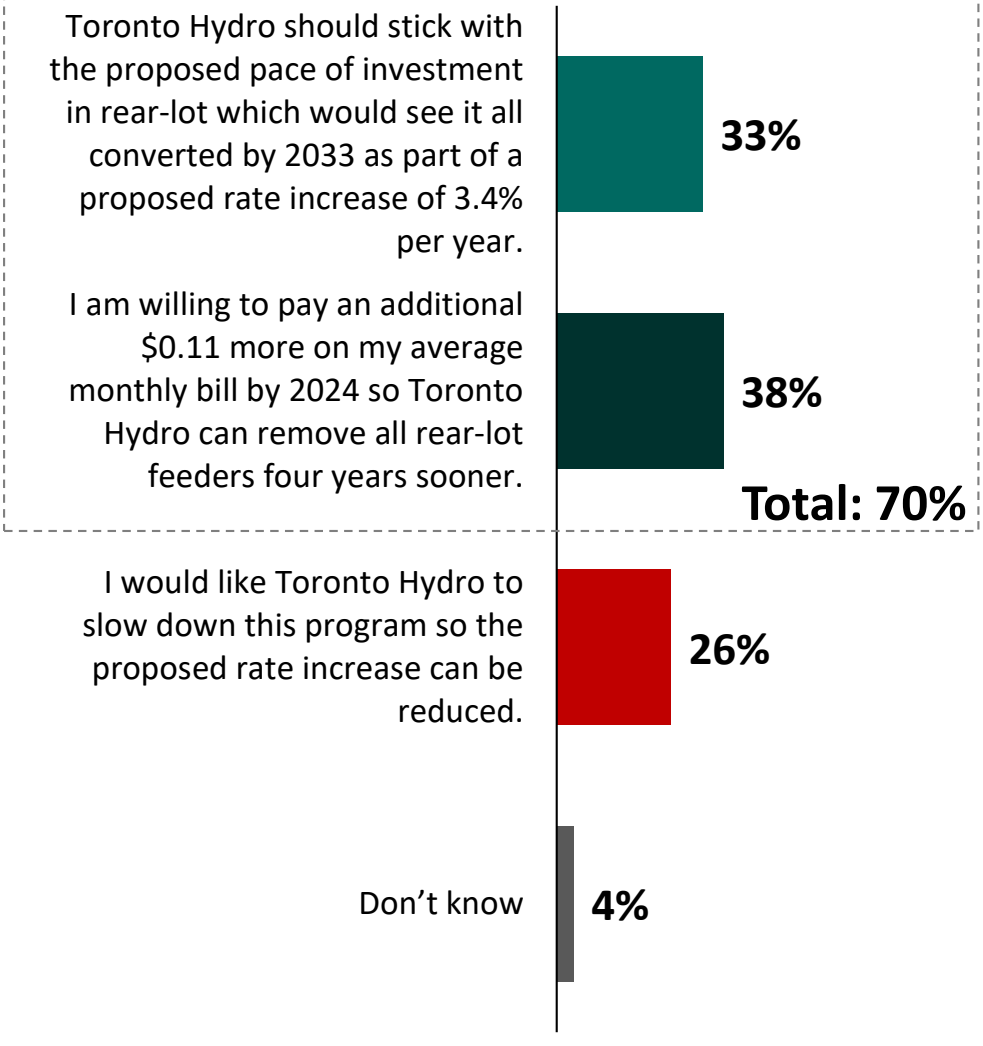
Some customers are served by older types of lines that are more likely to fail, causing more frequent, and longer lasting power outages. These customers are more likely to experience poorer reliability over time than most Toronto Hydro customers. The proposed plan will replace those lines over time but the work could be done faster.

I would like to ask you about two types of lines.

One example is **rear-lot lines**. They go through residential backyards and are often more difficult to service and more exposed to falling branches. The proposed plan will replace all existing rear-lot lines by 2033. **Toronto Hydro** could replace those lines 4 years sooner for an additional cost.

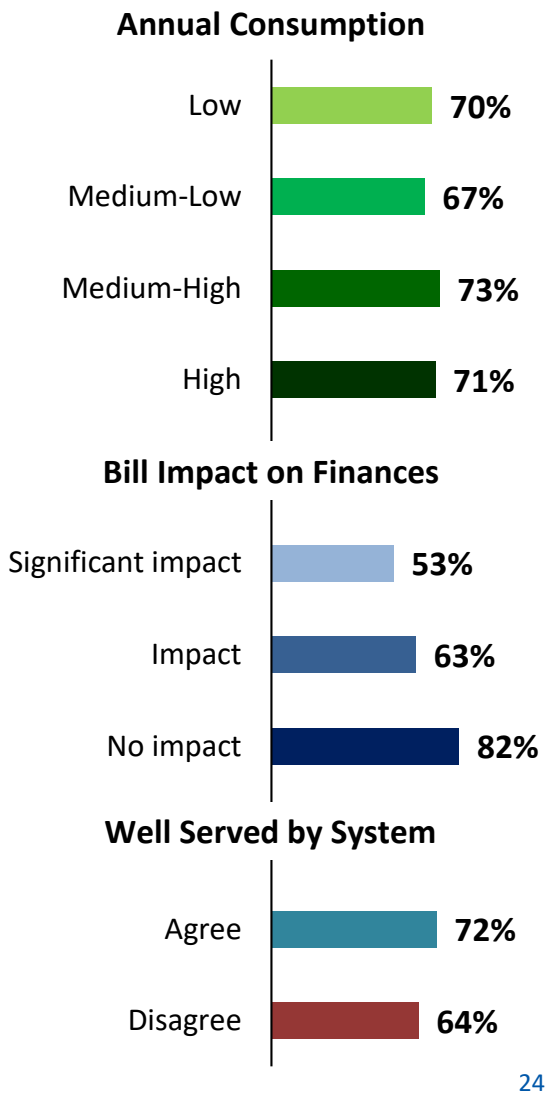
Which of the following statements is closest to your view?

[asked all respondents, n=600]



Segmentation

*Those who say "**Stick with proposed approach or spend more**":*



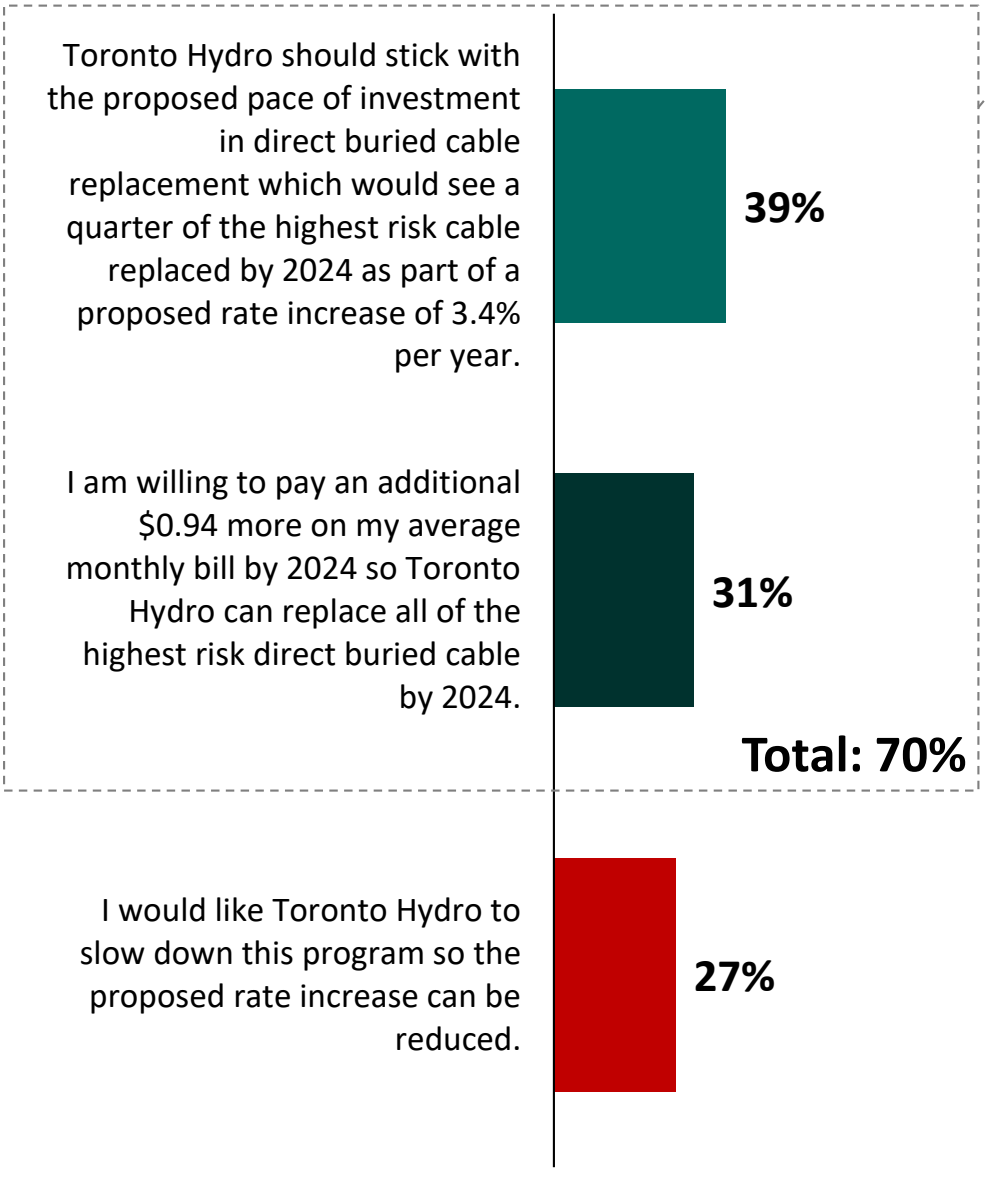
Direct Buried Cable Replacement

Another example is **direct buried cable** where cables are laid directly in underground trenches without a protective barrier. While equipment failure causes 36% of outages across the system, cable failure accounts for 70% of all outages on the underground system.

Once these cables start to fail, they tend to experience a rash of failures. The proposed plan will replace a quarter of the highest risk direct buried cable by 2024. **Toronto Hydro** could replace all of the highest risk direct buried cable by 2024 for an additional cost.

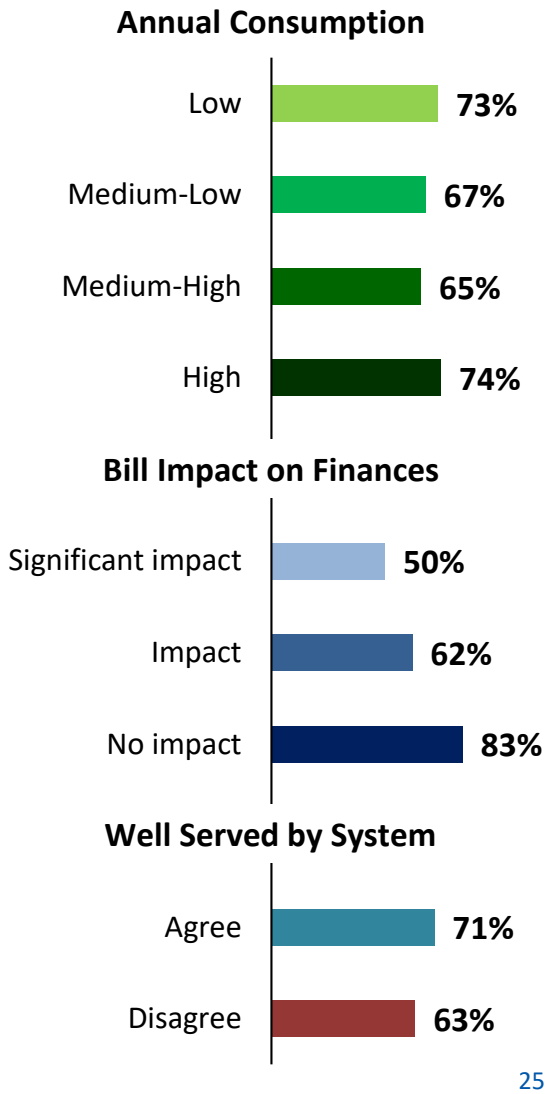
Which of the following statements is closest to your view?

[asked all respondents, n=600]



Segmentation

*Those who say "**Stick with proposed approach or spend more**":*



Note: "Don't Know" (3%) not shown.

Paper Insulated Lead Covered (PILC) Preamble

Toronto Hydro has identified three equipment upgrades that are needed within the next few years. If **Toronto Hydro** waits, those upgrades will be more expensive and disruptive as Toronto continues to grow.

Firstly, Paper Insulated Lead Covered (PILC) cable. PILC cable was an old type of underground cable that stopped being installed on **Toronto Hydro's** grid 20 years ago. While the equipment is resilient and is still providing electricity to the downtown core, the outer lead covers can begin to crack and leak oil. Replacing these cables is becoming increasingly difficult and expensive to resource and complete.

Toronto Hydro has a long-term plan to remove and replace PILC cable by 2049. But **Toronto Hydro** can replace all of this cable ten years earlier by 2039, at an additional cost now. This will improve reliability, reduce risks to the public, and avoid additional expense and disruption in the future.

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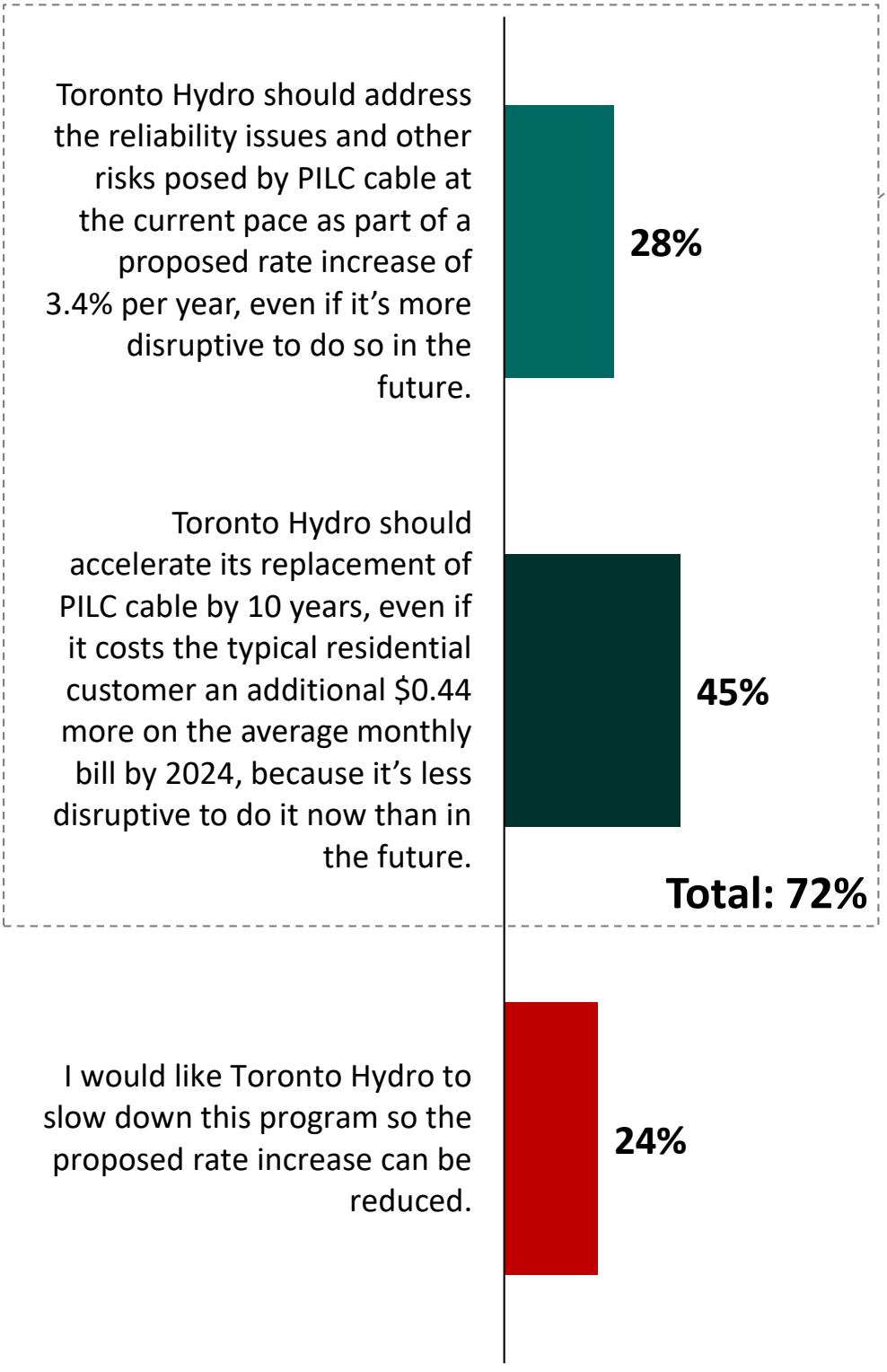
PILC Cable Replacement Program

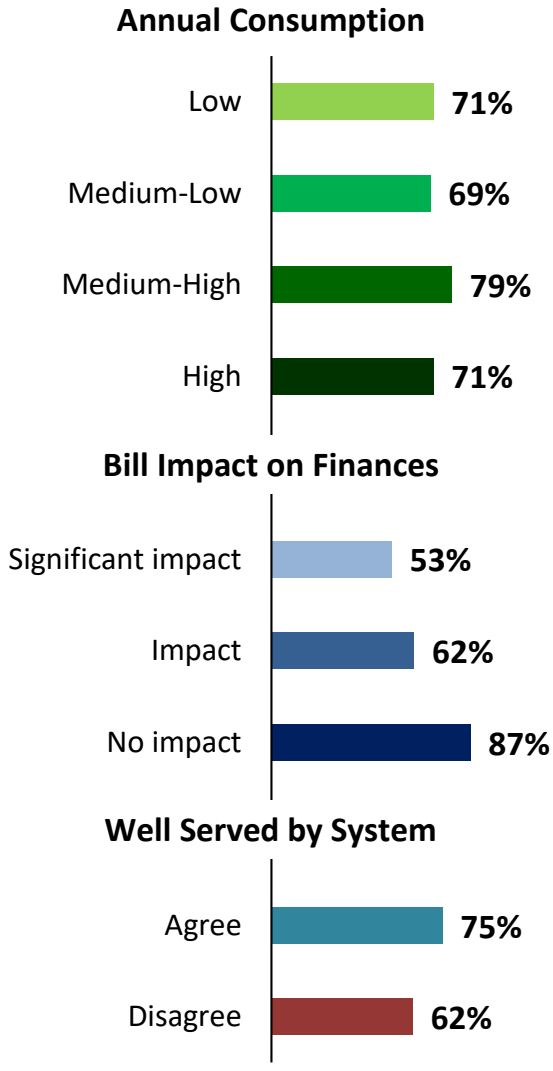
Q Which of the following is closest to your point of view regarding **Toronto Hydro's** PILC Cable replacement program?

[asked all respondents, n=600]



Segmentation

*Those who say "**Stick with proposed approach or spend more**":*



Note: "Don't Know" (4%) not shown.

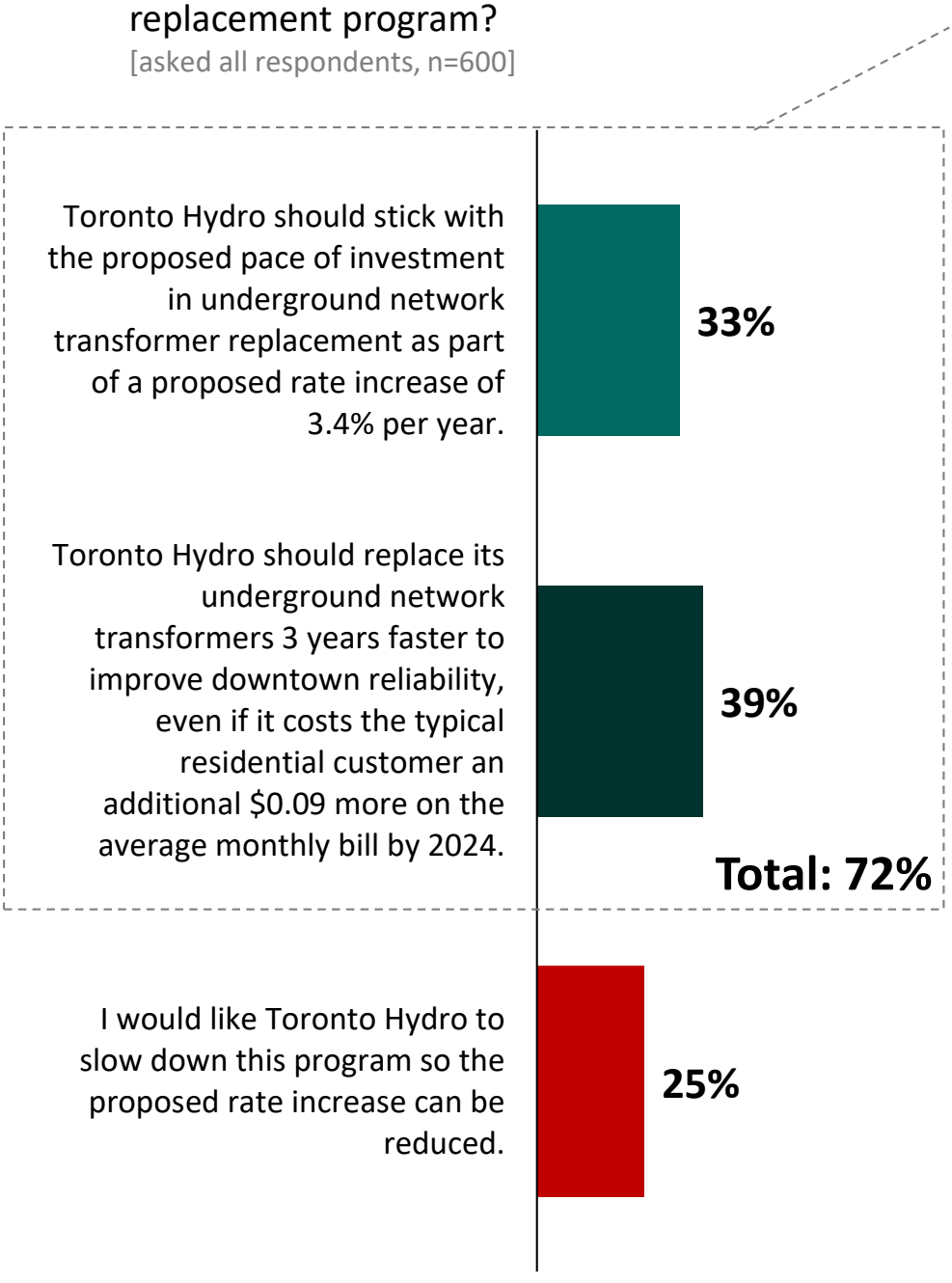
Network Unit Replacement Program

The second upgrade project identified is *Underground Network Transformers*. The key problem with these units is their older design which makes them prone to flooding.

Toronto Hydro plans to replace just enough of these units by 2031 so that outages, due to equipment failure, don't get any worse. But the process could be advanced by three years to replace all these units by 2028.

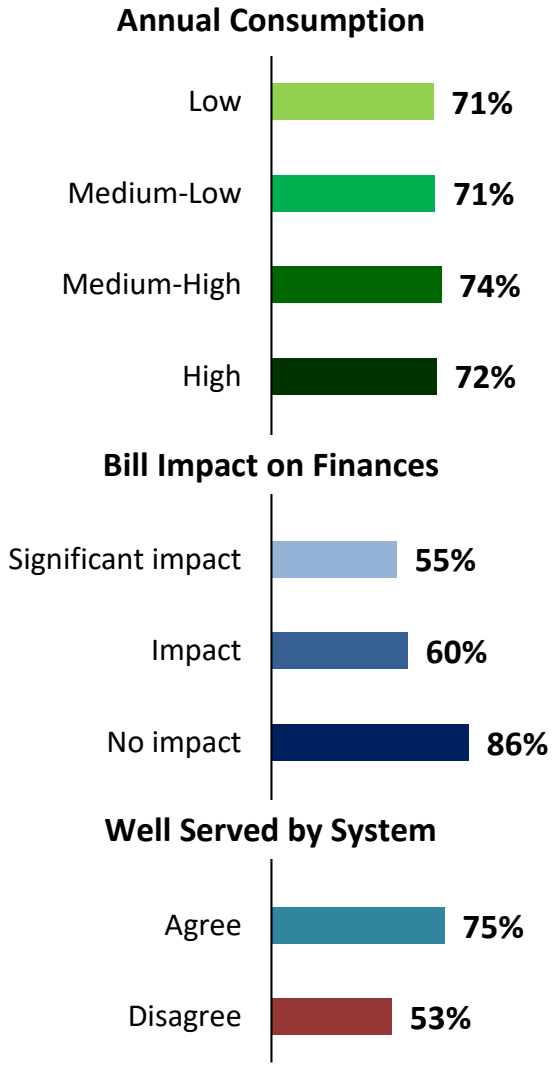
Which of the following is closest to your point of view regarding **Toronto Hydro's** Network Unit replacement program?

[asked all respondents, n=600]



Segmentation

*Those who say "**Stick with proposed approach or spend more**":*



Note: "Don't Know" (3%) not shown.

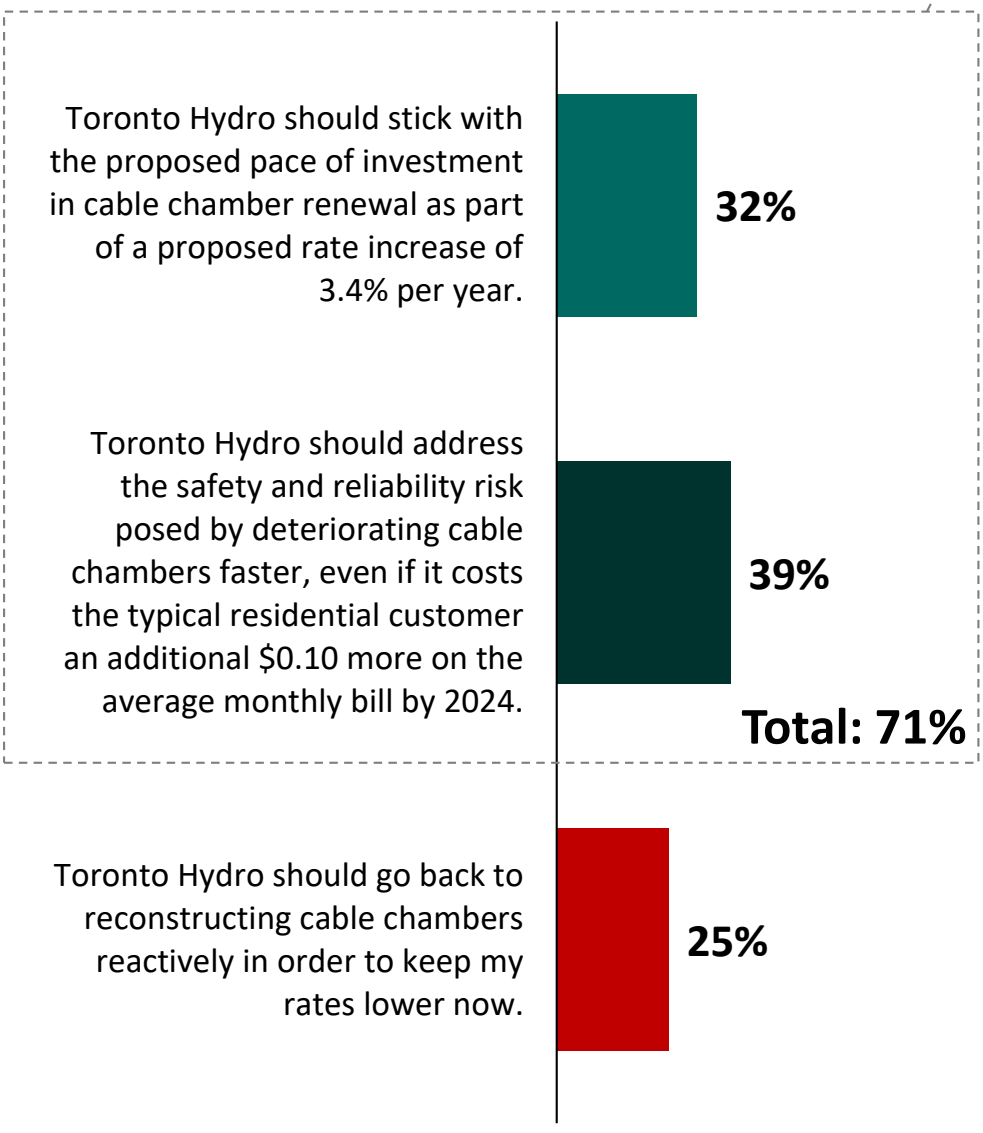
Cable Chamber Renewal Program

The third upgrade project identified is *Cable Chamber replacement*. Cable Chambers house, protect, and provide access to underground electrical equipment across the city. When they deteriorate or break, this equipment can cause outages and pose anything from a tripping hazard to something more serious like a collapsed chamber.

Toronto Hydro plans to take approximately 30 years to address the chambers in the worst condition. But accelerating the work could halve that period, at an additional cost now.

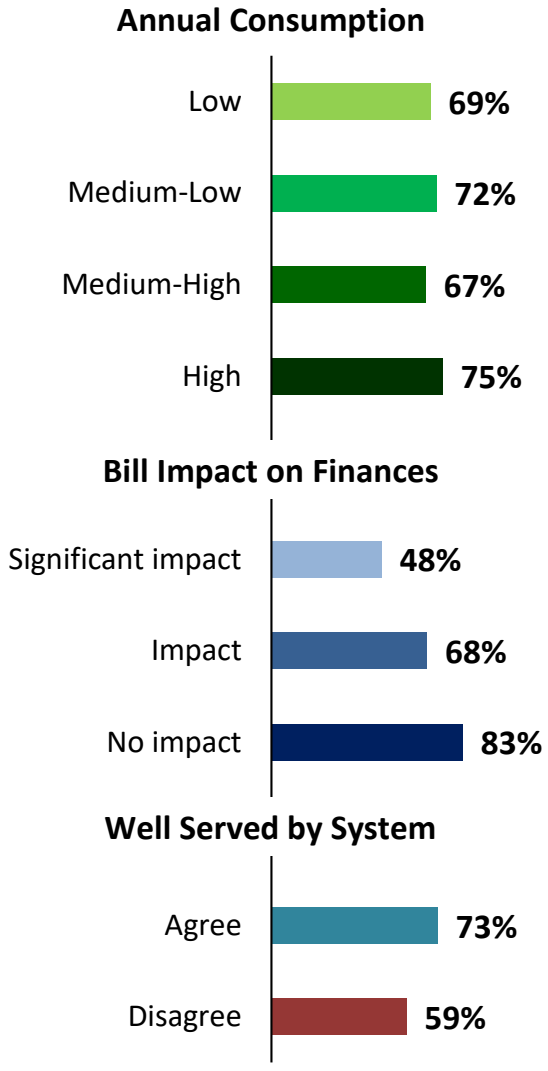
Which of the following is closest to your point of view regarding **Toronto Hydro's** Cable Chamber renewal program?

[asked all respondents, n=600]



Segmentation

*Those who say "**Stick with proposed approach or spend more**":*



Note: "Don't Know" (4%) not shown.

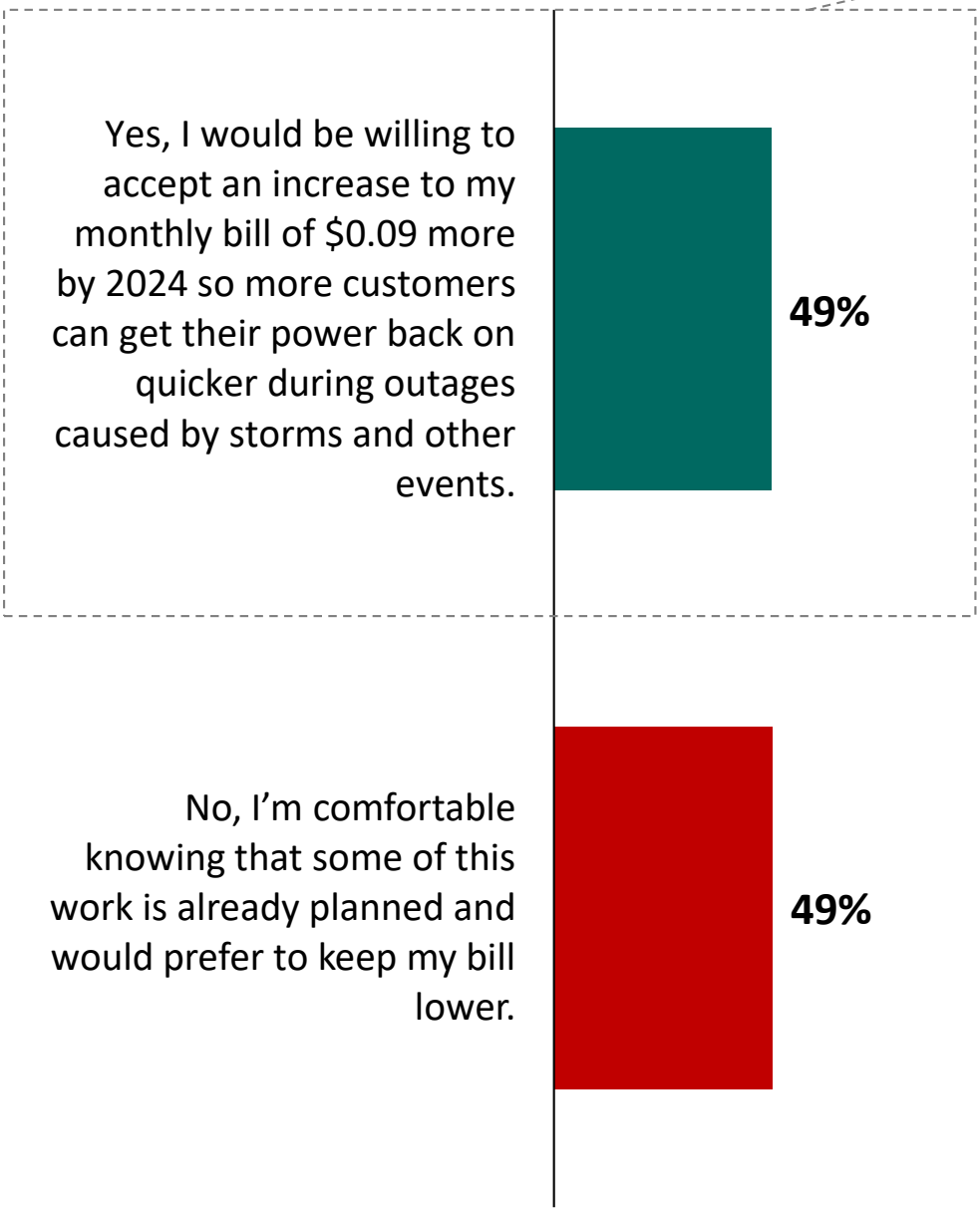
Dealing with More Frequent Extreme Weather Events

As **Toronto Hydro's** distribution system is exposed to strong winds, freezing rain, and severe flooding, they are proposing a variety of enhancements to improve the resiliency of the distribution system against extreme weather events.

Toronto Hydro could enhance the system further in neighbourhoods outside of downtown. The improvements include adding remotely-operated technology and more back-up links within the grid. This will help **Toronto Hydro** to better isolate the problem and reduce outage times by as much as 50% in these areas.

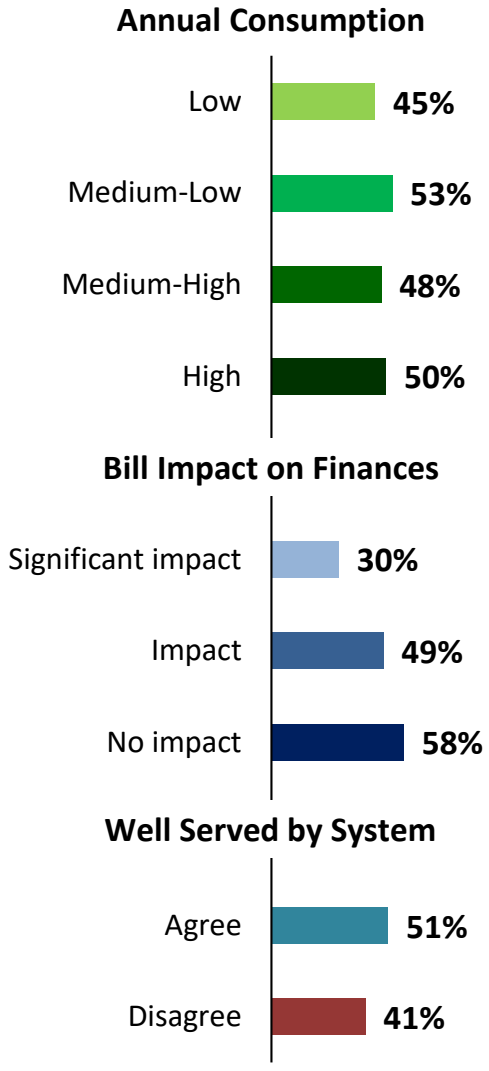
Which of the following statements best represents your point of view?

[asked all respondents, n=600]



Segmentation

*Those who say "**Restore power more quickly during outages**":*



Note: "Don't Know" (2%) not shown.

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Innovation and Planning for the Future



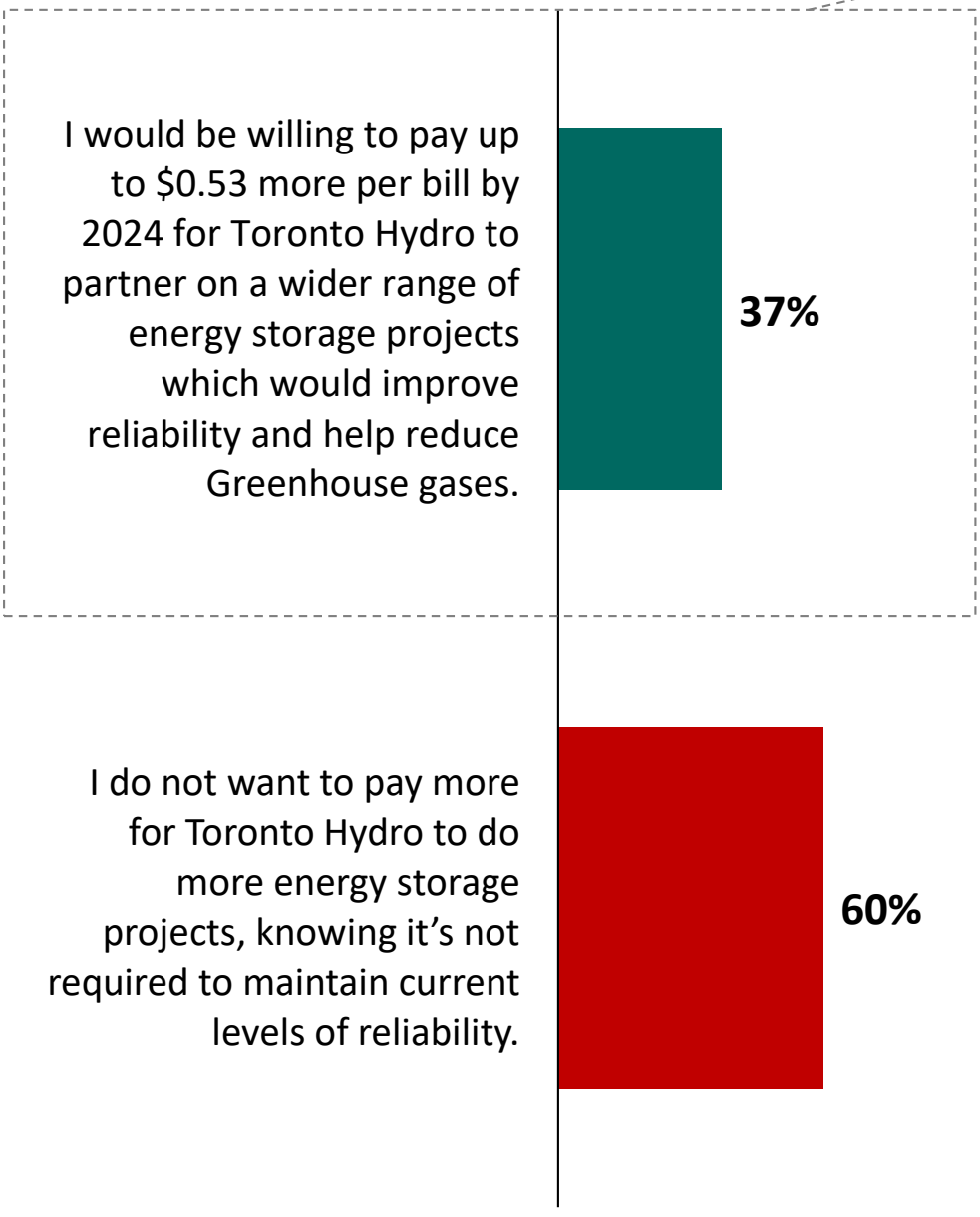
Investments in Energy Storage

3% of the proposed budget would be spent on innovation and planning for the future. The following questions are about this aspect of the budget.

Toronto Hydro has already begun to integrate large-scale battery electricity storage into the system. They have now identified more opportunities to partner on a wider range of energy storage projects. Integrating storage into the system can improve reliability and help reduce greenhouse gases, but it is not required to maintain current levels of reliability.

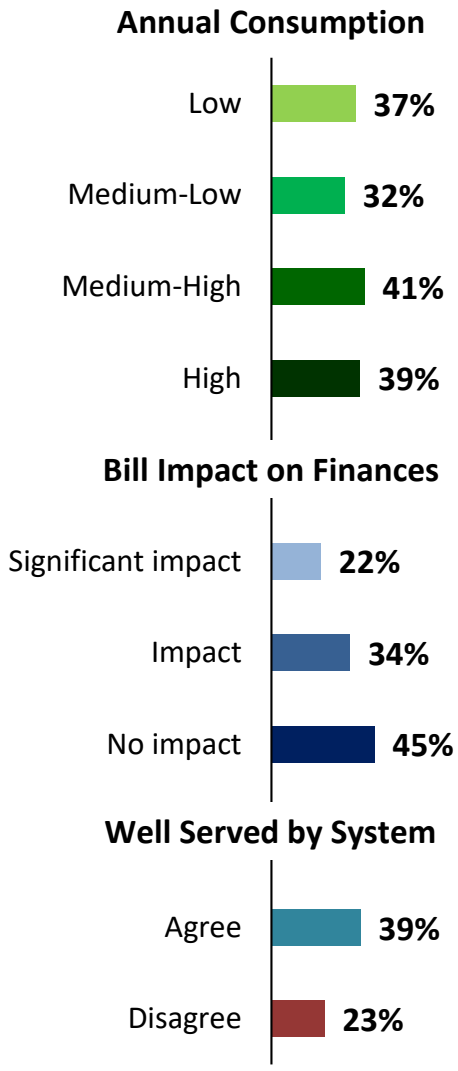
Which of the following is closest to your point of view?

[asked all respondents, n=600]



Segmentation

*Those who say "**Pay more to partner on energy storage projects**":*



Note: "Don't Know" (3%) not shown.

Monitoring and Control Equipment

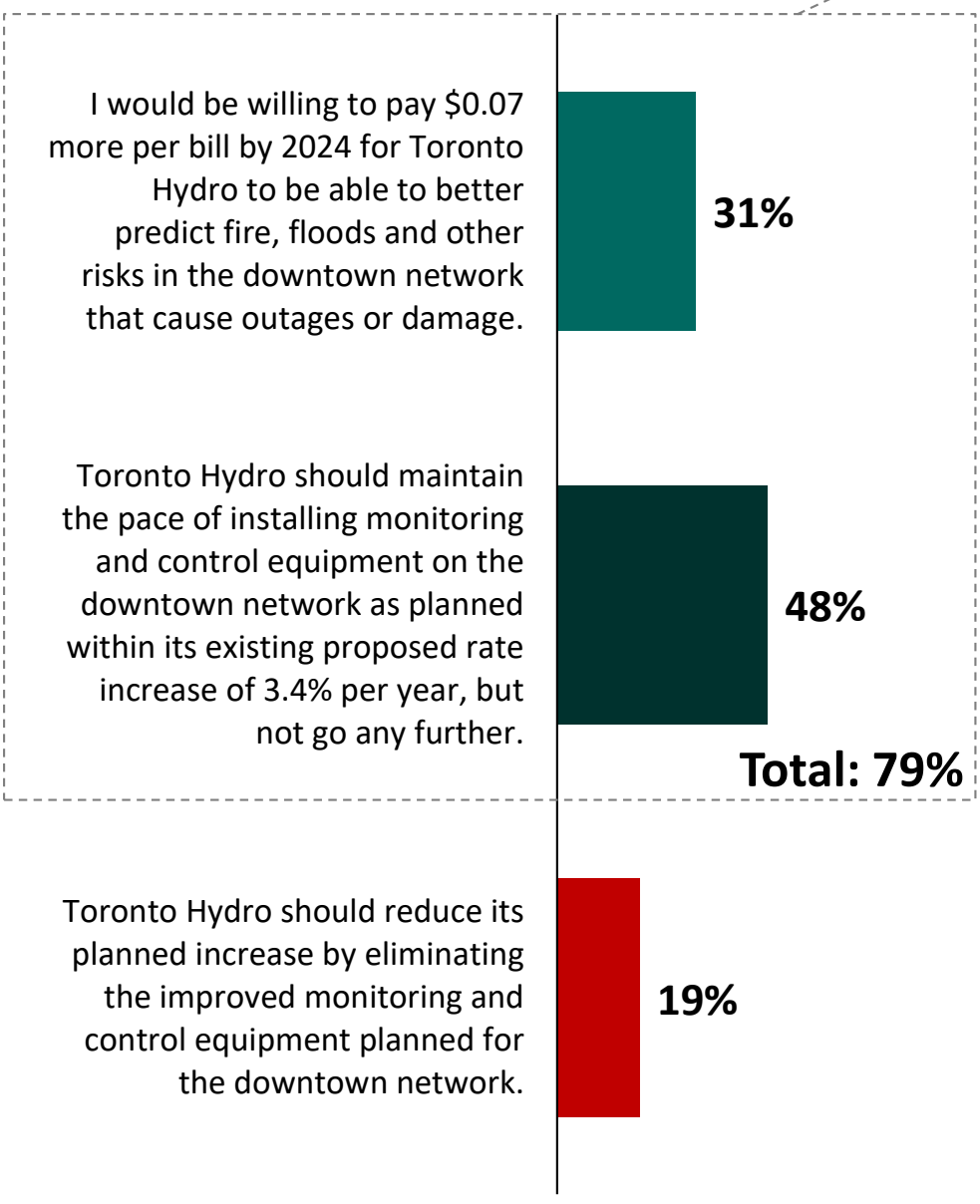
New communication technology has revolutionised the way the grid can be managed.

Toronto Hydro plans to take advantage of various new technologies wherever clear benefits can be established.

However, **Toronto Hydro** can improve the reliability of its grid further by installing communication devices in the downtown underground network that detect fire, floods or other risks more quickly.

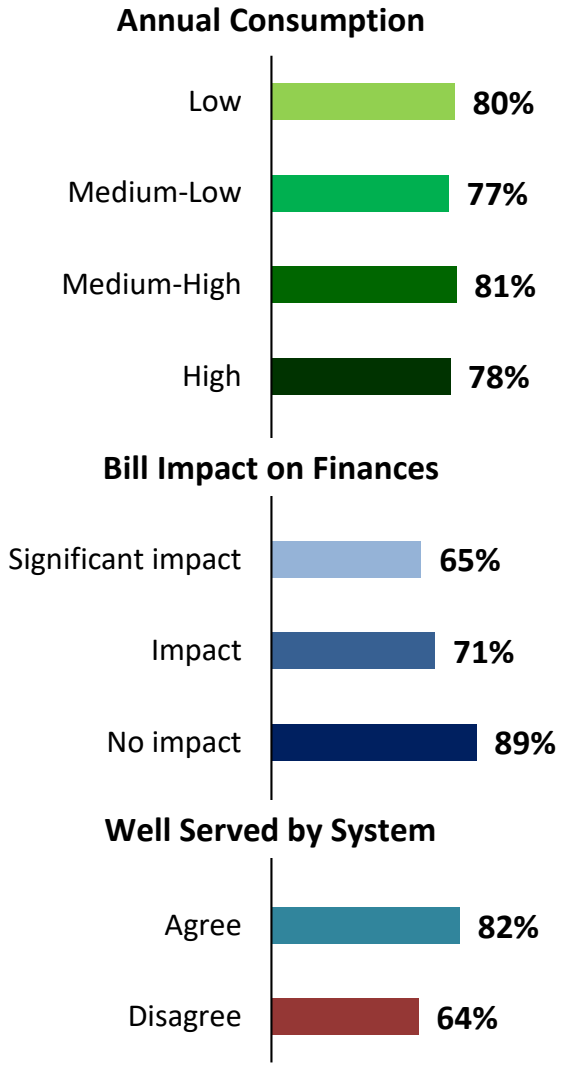
Which of the following is closest to your point of view?

[asked all respondents, n=600]



Segmentation

*Those who say "**Stick with proposed approach or spend more**":*



Note: "Don't Know" (2%) not shown.

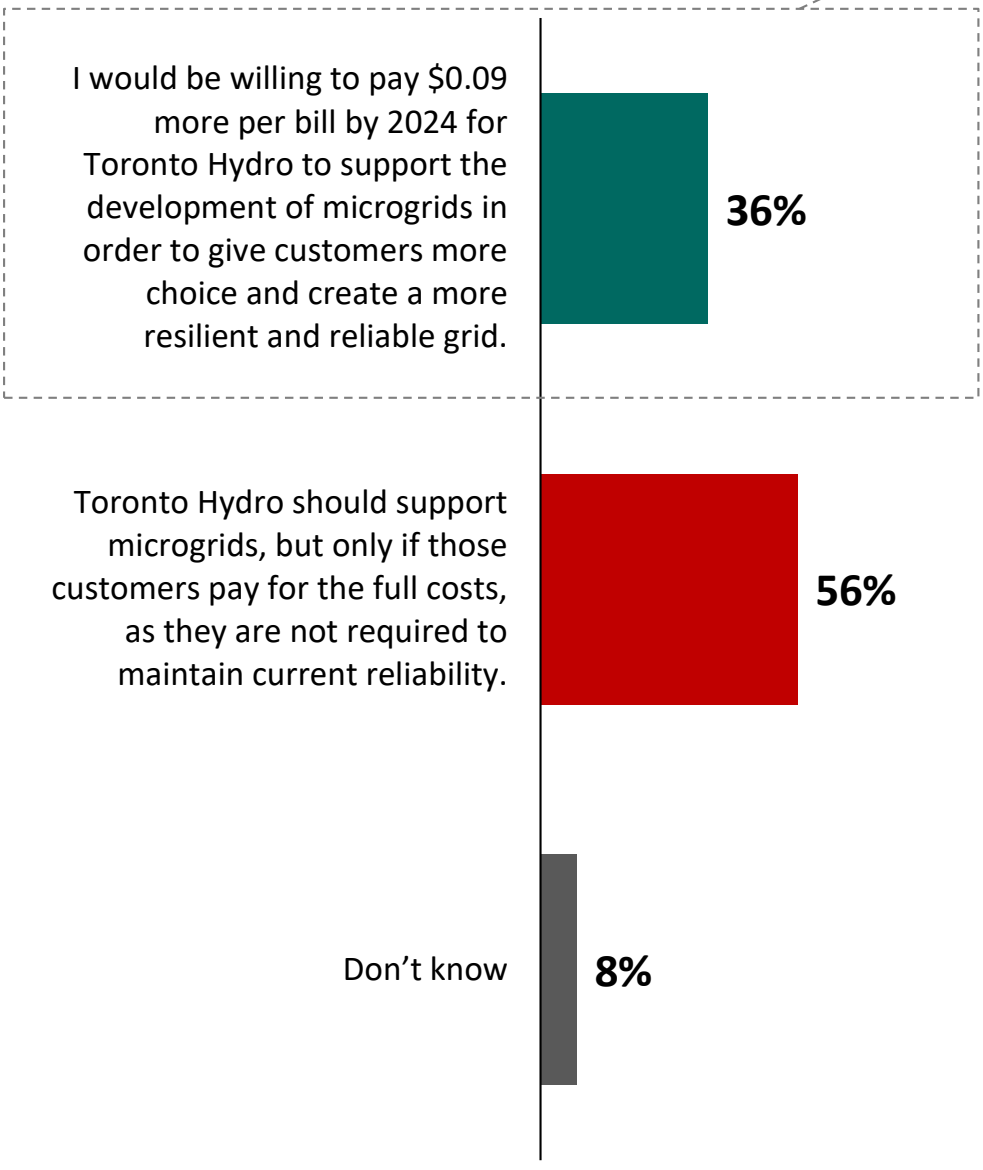
Supporting Microgrids

New types of generation (often renewable), storage, and supporting systems are making it possible for communities, institutions or other large customers to develop “microgrids”. They are a local electricity network linking smaller sources of electricity with nearby uses such as homes, businesses and institutions. In the event of a failure of the larger network, a microgrid can seal itself off and continue to provide power locally.

Microgrids would give customers more choices, while creating a more resilient and reliable grid. However, they are not required to maintain current reliability.

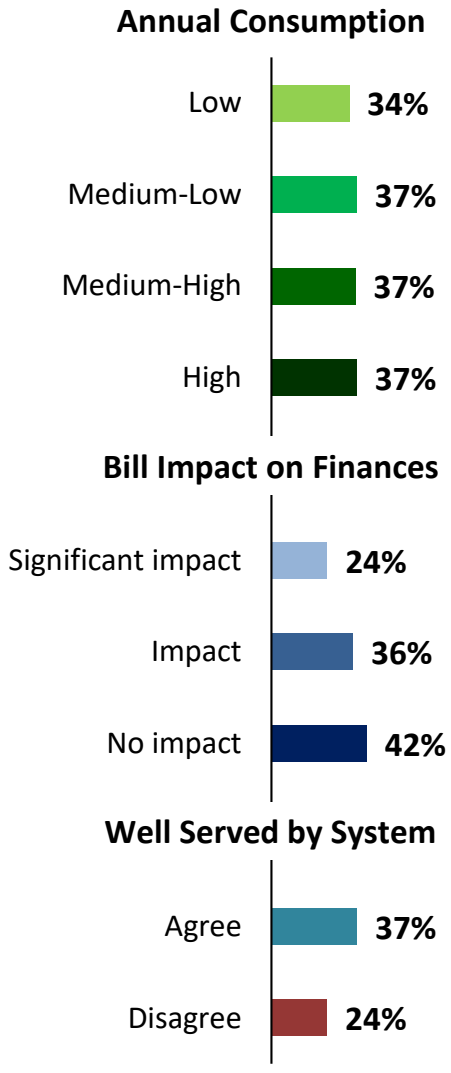
Which of the following is closest to your point of view?

[asked all respondents, n=600]



Segmentation

*Those who say “**Pay more to support microgrids**”:*



Investment Alternatives Summary Preamble

Toronto Hydro's current proposed plan, which translates into an average 3.4% annual increase, focuses on delivering current levels of reliability and customer service for most customers and targeted improvements for customers experiencing below average service or who have special reliability needs, like hospitals.

In dollars and cents, that means an average increase to the monthly bill of $**1.51 each year** for the typical residential customer.

Over the course of the proposed 5-year plan, the typical residential customer will see the distribution portion of their electricity bill **increase by $7.57.**

As a result, the distribution charges on the monthly bill would increase from a proposed amount of **$42 in 2019** to **$49 by 2024**.

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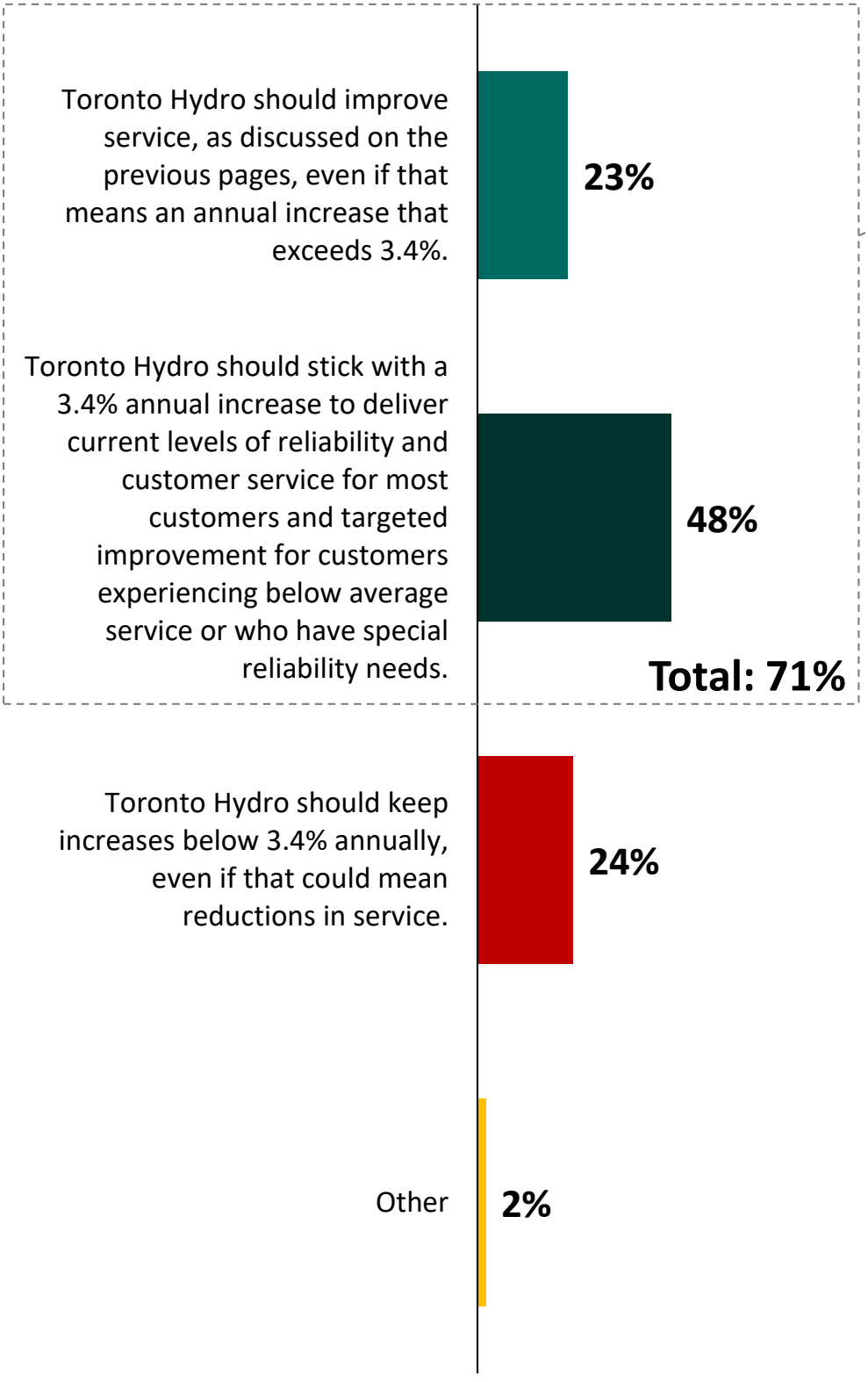
Opinion of Toronto Hydro's Proposed Plan

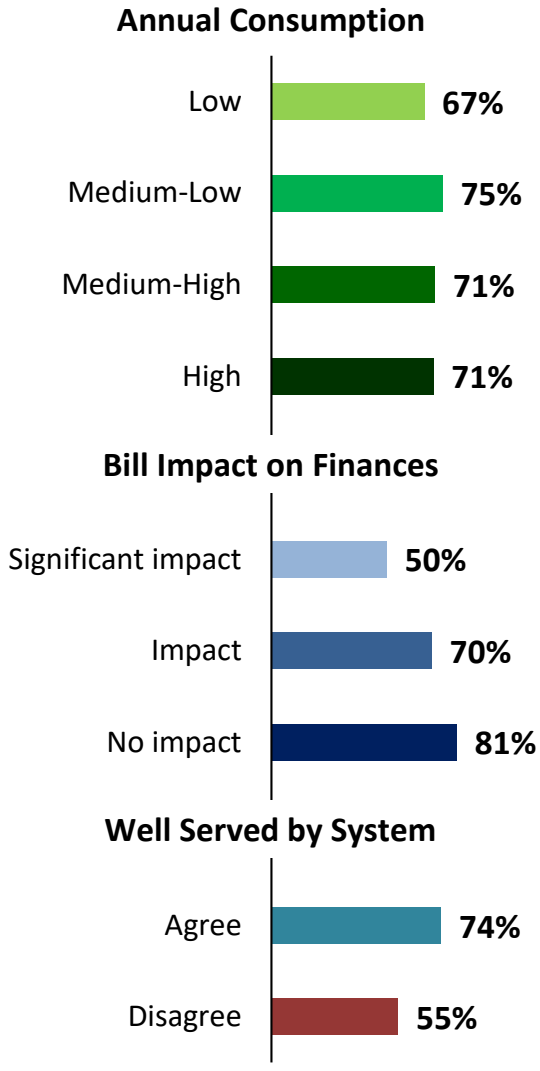
With regards to **Toronto Hydro's** proposed plan, which of the following statements best represents your view?

[asked all respondents, n=600]



Segmentation

*Those who say "**Stick with current pace of investment or increase to improve services**":*



Note: "Don't Know" (3%) not shown.

Opinion of Toronto Hydro's Proposed Plan by Demographics

Q With regards to **Toronto Hydro's** proposed plan, which of the following statements best represents your view?
[asked all respondents, n=600]

Bill Impact on Finances

Opinion of Toronto Hydro's Proposed Plan	*The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.*			*Total*
	Sig. Impact [n=139]	**Impact** [n=143]	**No Impact** [n=303]	
Improve services, increase above 3.4%	10%	14%	31%	**23%**
	50%	70%	81%	
Stick with current plan at 3.4%	40%	56%	50%	**48%**
Keep increases below 3.4%	42%	24%	15%	**24%**

Low-income Energy Assistance Program (LEAP) Qualification

Opinion of Toronto Hydro's Proposed Plan	*LEAP Qualification*			*Total*
	LEAP Qualified [n=64]	**Not Qualified (<$52k)** [n=392]	**Not Qualified (>$52k)** [n=359]	
Improve services, increase above 3.4%	16%	19%	27%	**23%**
	72%	64%	74%	
Stick with current plan at 3.4%	56%	46%	47%	**48%**
Keep increases below 3.4%	23%	30%	22%	**24%**

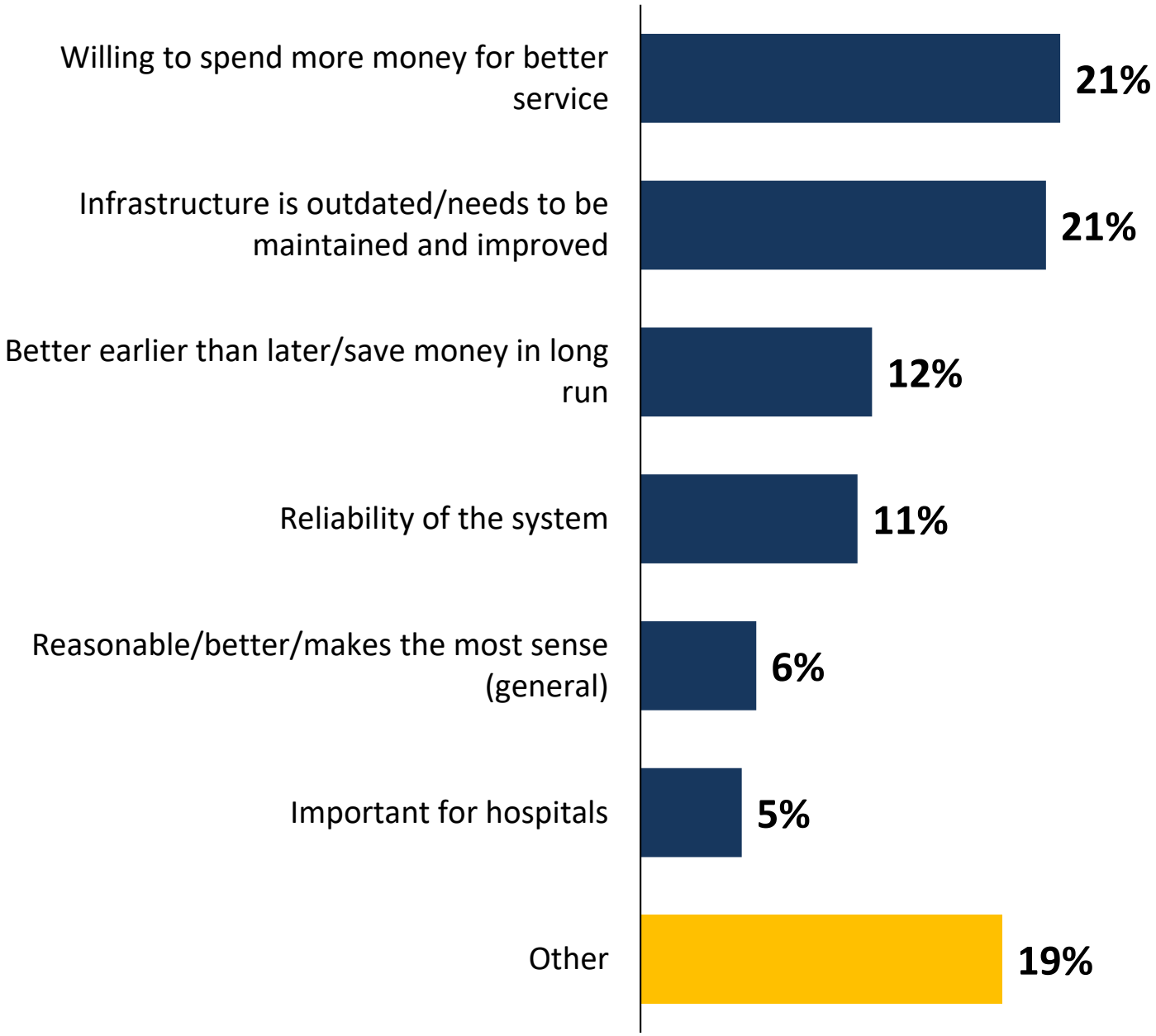
Note: "Other", "Don't Know", "Refused" not shown.

Opinion of Toronto Hydro's Proposed Plan

Q And why do you say that?

[asked of those who say Toronto Hydro should improve service, n=135]

For those who answered: Toronto Hydro should improve service, as discussed on the previous pages, even if that means an annual increase that exceeds 3.4%. (n=135)



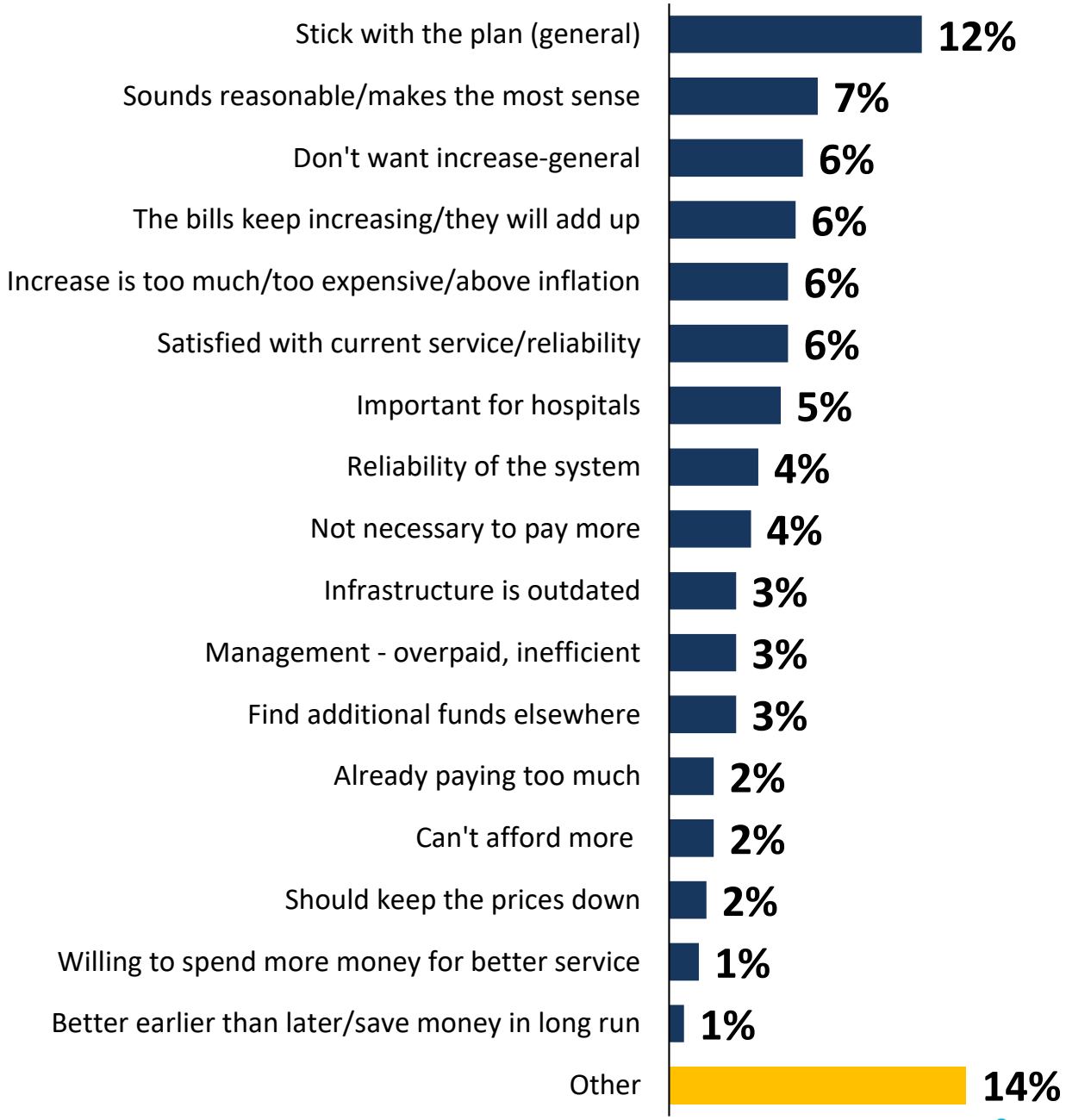
Note: "None" (1%), "Don't know" (4%), "Refused" (1%) not shown.

Opinion of Toronto Hydro's Proposed Plan

Q And why do you say that?

[asked of those who say Toronto Hydro should stick with proposed plan, n=290]

For those who answered: Toronto Hydro should stick with a 3.4% annual increase to deliver current levels of reliability and customer service for most customers and targeted improvement for customers experiencing below average service or who have special reliability needs. (n=290)



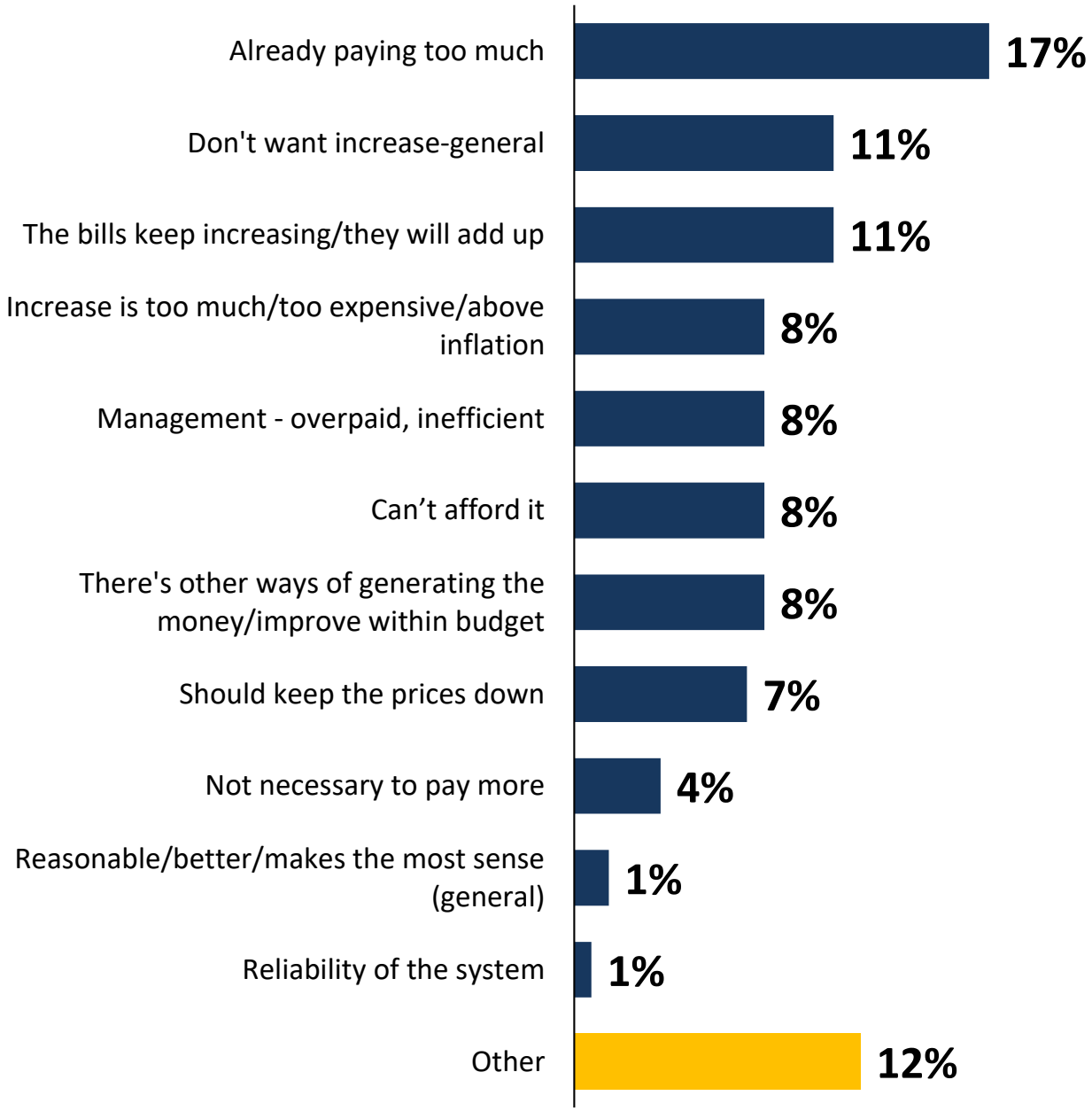
Note: "None" (6%), "Don't know" (6%), "Refused" (2%) not shown.

Opinion of Toronto Hydro's Proposed Plan

Q And why do you say that?

[asked of those who say Toronto Hydro should keep increases below 3.4%, n=143]

For those who answered: Toronto Hydro should keep increases below 3.4% annually, even if that could mean reductions in service. (n=143)



Note: "None" (2%), "Don't know" (1%), "Refused" (1%) not shown.

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Appendix 2.3

Toronto Hydro 2018 Customer Engagement

Small Business Telephone Survey Report

Small Business Report

June 2018

STRICTLY PRIVILEGED AND CONFIDENTIAL

Survey Methodologies



Field and Design

These are the findings of an Innovative Research Group (INNOVATIVE) telephone survey conducted among **n=215** Toronto Hydro **small business customers** between **May 2 and 14, 2018.**

Quotas were set by electricity consumption levels and geographic considerations from within the Toronto Hydro service territory in order to obtain a representative customer sample.

Small business customers were divided into quartiles based on annual electricity usage to ensure the sample had a proportionate mix of customers from low, medium-low, medium-high, and high electricity usage groups.

The sample has been weighted to n=200 by the quartiles and region to reflect the actual composition of small business customers within the service area.

The margin of error for a sample of n=200 is approximately +/-6.9%. 19 times out of 20.

For the purposes of executing the customer surveys, Toronto Hydro provided INNOVATIVE with a confidential list of customers' contact information. The contact list included only customers with telephone contact information on file and who had been a customer of Toronto Hydro for at least one year. The information contained in the contact list included customer name, telephone number(s), postal code and total annual electricity consumption.

Only one customer per organization was eligible to complete the survey. Respondents were screened to certify that only the personnel responsible for managing or overseeing their electricity bill were interviewed. This step was taken to ensure that survey respondents represented the most qualified person within an organization to answer questions.

Customers were offered a $20 Amazon Gift Card in appreciation for completing the survey.

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Consumption Quartiles

The tables below illustrate the strata divisions for each rate class, based on consumption quartiles.

Dividing customer sample into quartiles based on known characteristics, including region and annual consumption, was used to develop accurate quotas to ensure the sample was representative of Toronto Hydro's customer base. The tables below show the unweighted and weighted distributions.

	Consumption Quartiles (Unweighted n)				Total
	Low	Medium-Low	Medium-High	High	
Toronto & East York	15	22	18	26	**81**
Etobicoke & York	13	13	11	10	**47**
North York	12	4	14	14	**44**
Scarborough	12	11	9	11	**43**
Total	**52**	**50**	**52**	**61**	**215**

	Consumption Quartiles (Weighted n)				Total
	Low	Medium-Low	Medium-High	High	
Toronto & East York	20	20	20	20	**81**
Etobicoke & York	8	8	8	8	**33**
North York	11	11	11	11	**44**
Scarborough	10	10	10	10	**42**
Total	**50**	**50**	**50**	**50**	**200**

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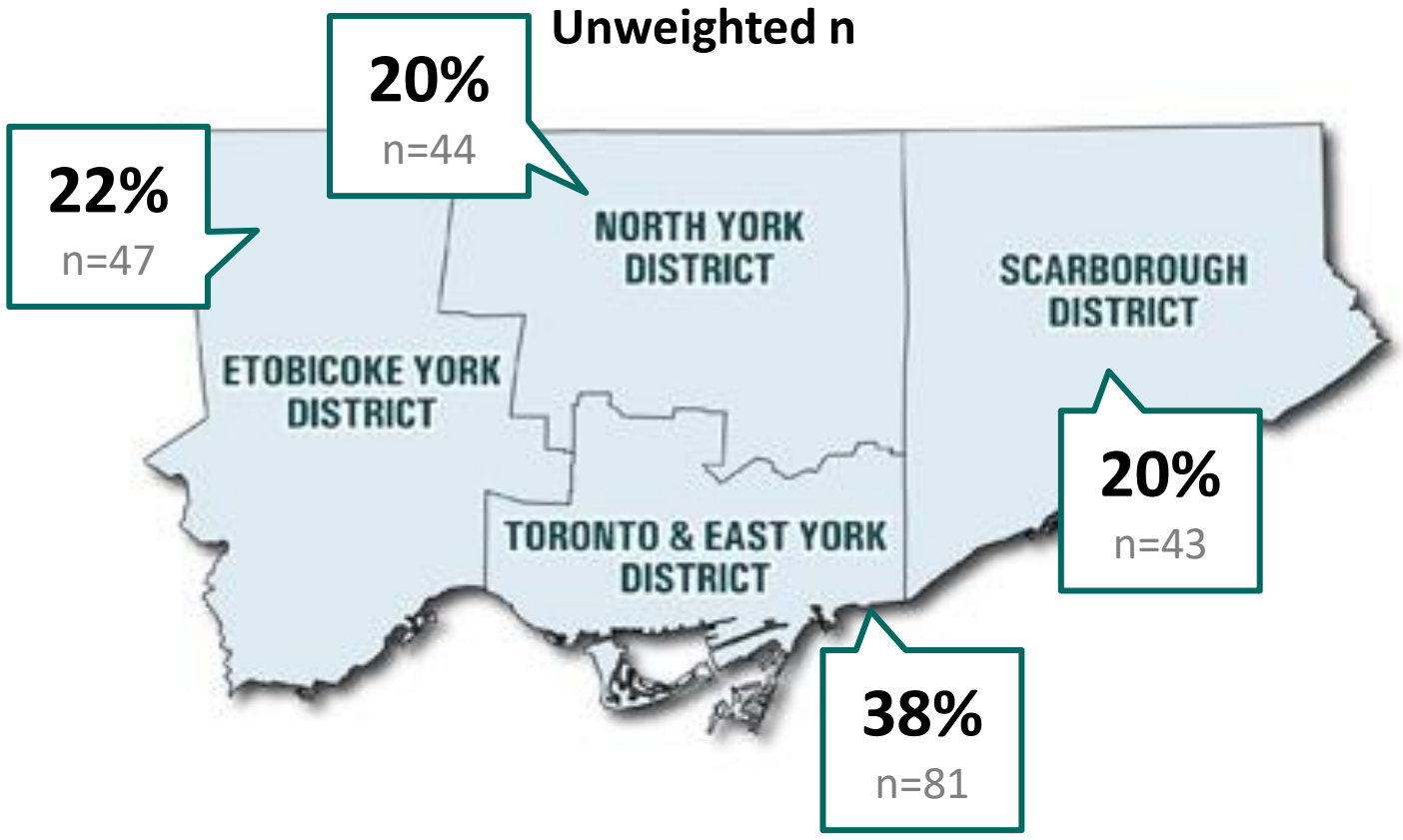
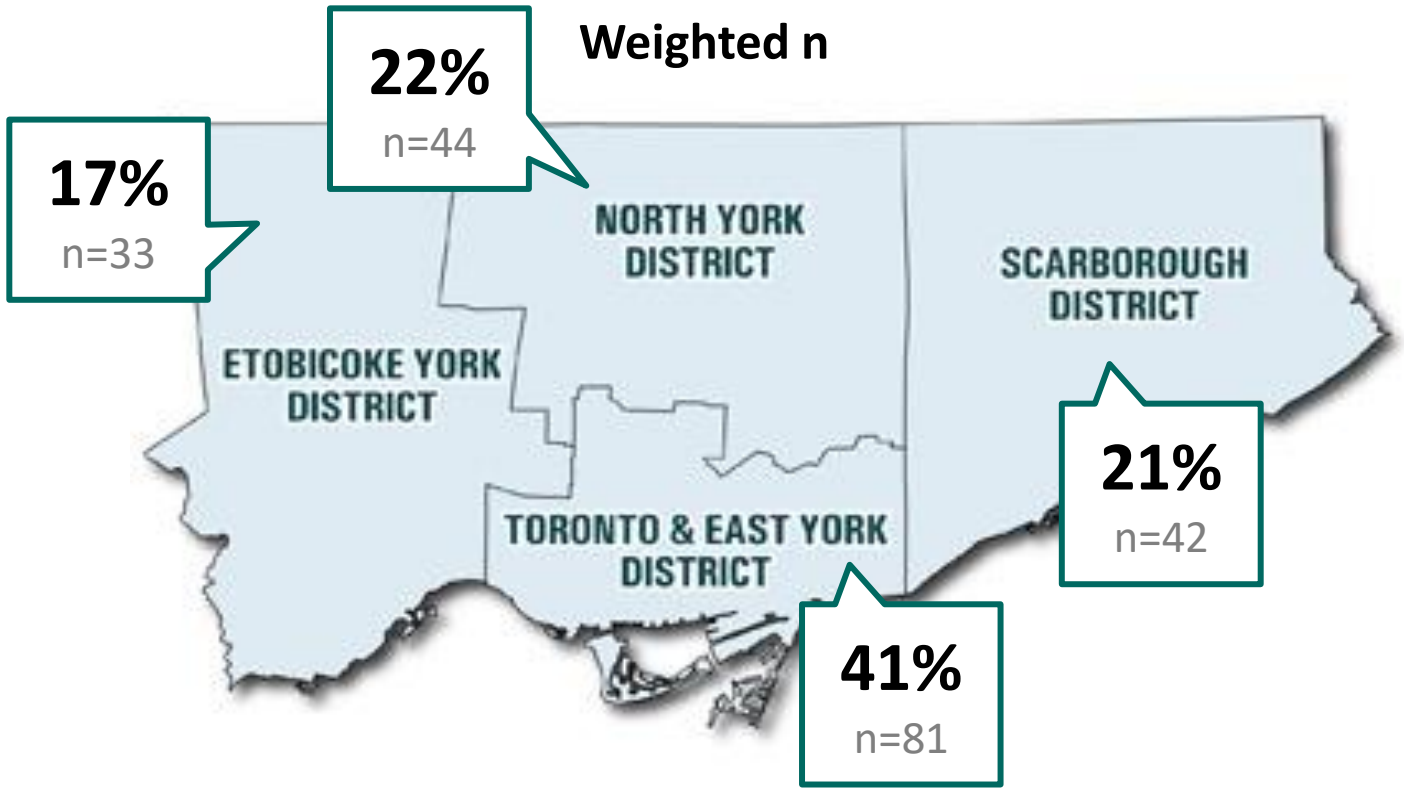
Regions

The chart below illustrate the overall regional distribution.

The charts below show the unweighted and weighted distributions.





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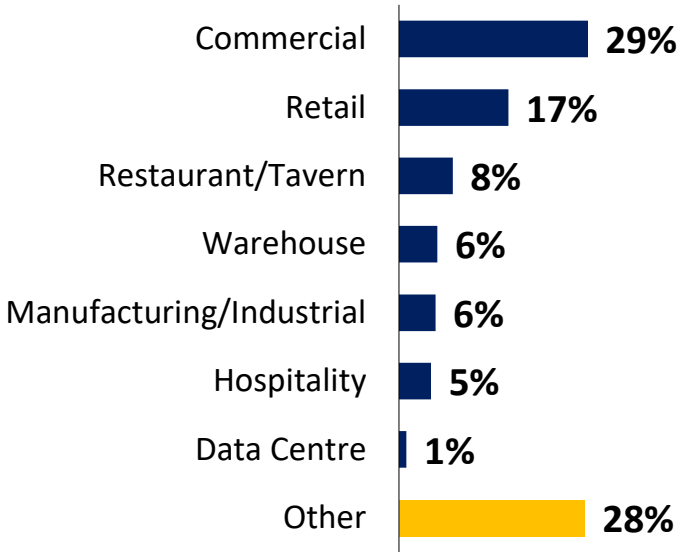
Segmentation and Demographics



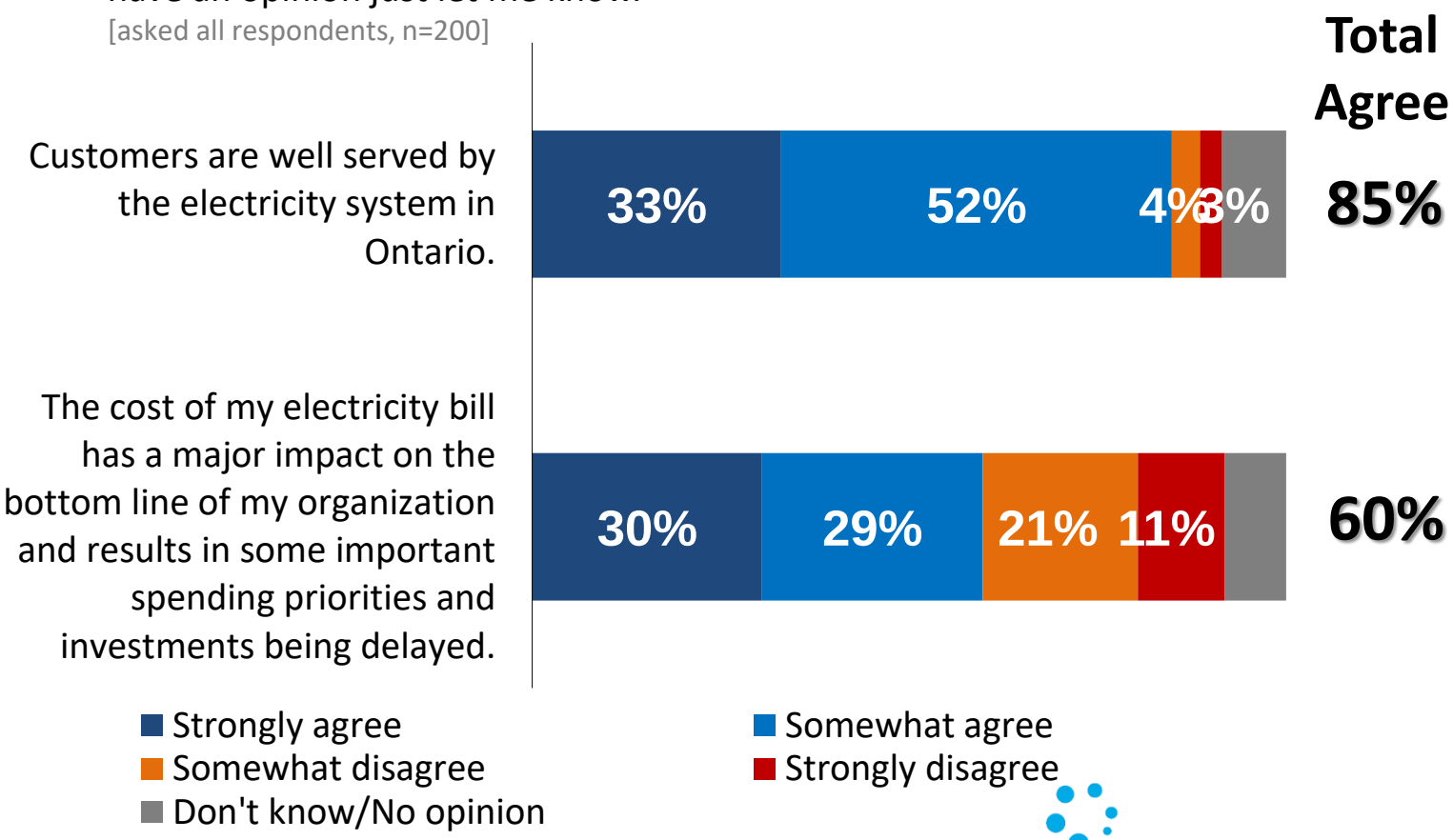
Segmentation & Demographics

Business Sector



Q For each statement please tell me if you would strongly agree, somewhat agree, somewhat disagree or strongly disagree. If you don't know enough to say or don't have an opinion just let me know.

[asked all respondents, n=200]



Familiarity Preamble

To start, I'd like to ask you a few questions about the electricity system …

As you may know, Ontario's electricity system has three key components: ***generation***, ***transmission*** *and* ***distribution****.*

- ***Generating stations*** *convert various forms of energy into electric power;*
- ***Transmission lines*** *connect the power produced at generating stations to where it is needed across the province; and*
- ***Distribution lines*** *carry electricity to the homes and businesses in our communities.*

Today we're going to talk about your ***local distribution system*** *which is maintained and operated by Toronto Hydro.*

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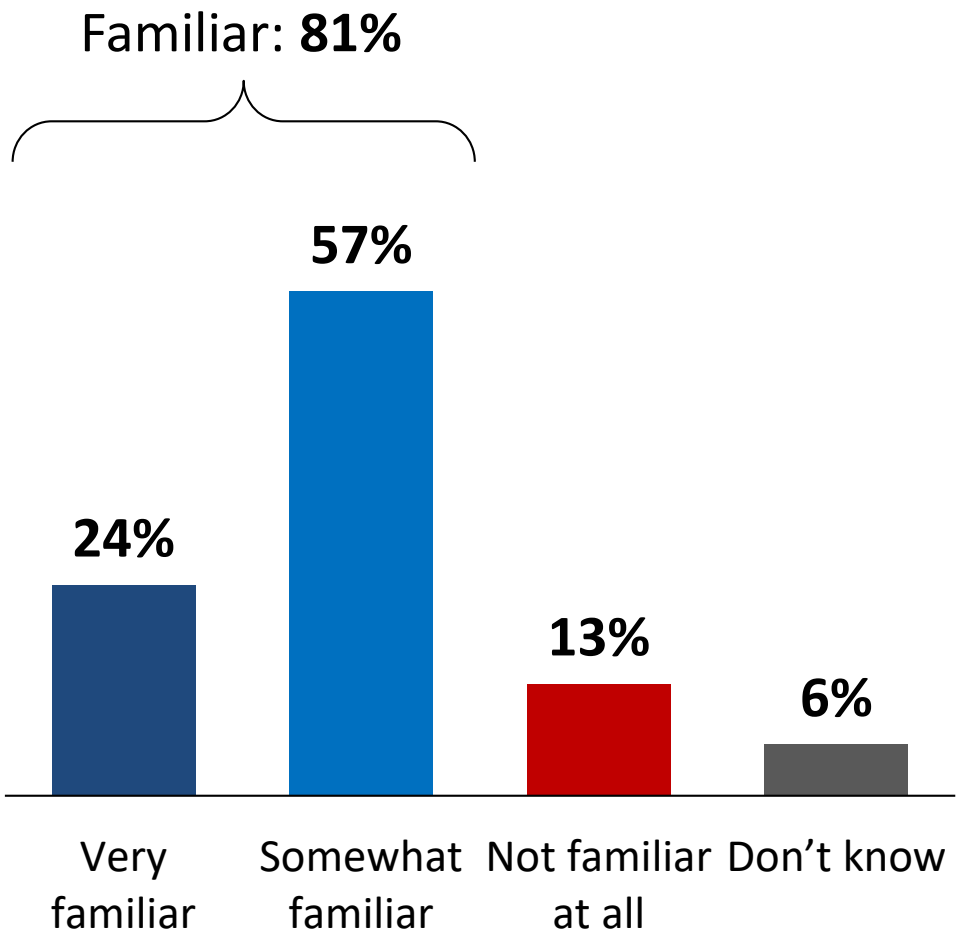
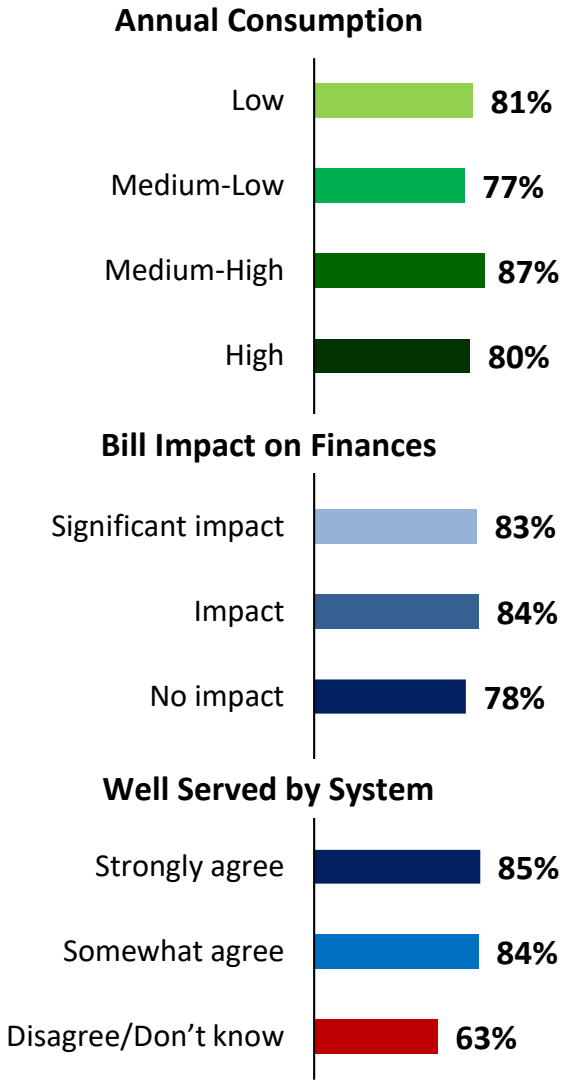
Familiarity with Toronto Hydro

How familiar are you with **Toronto Hydro**?
[asked all respondents, n=200]



Segmentation

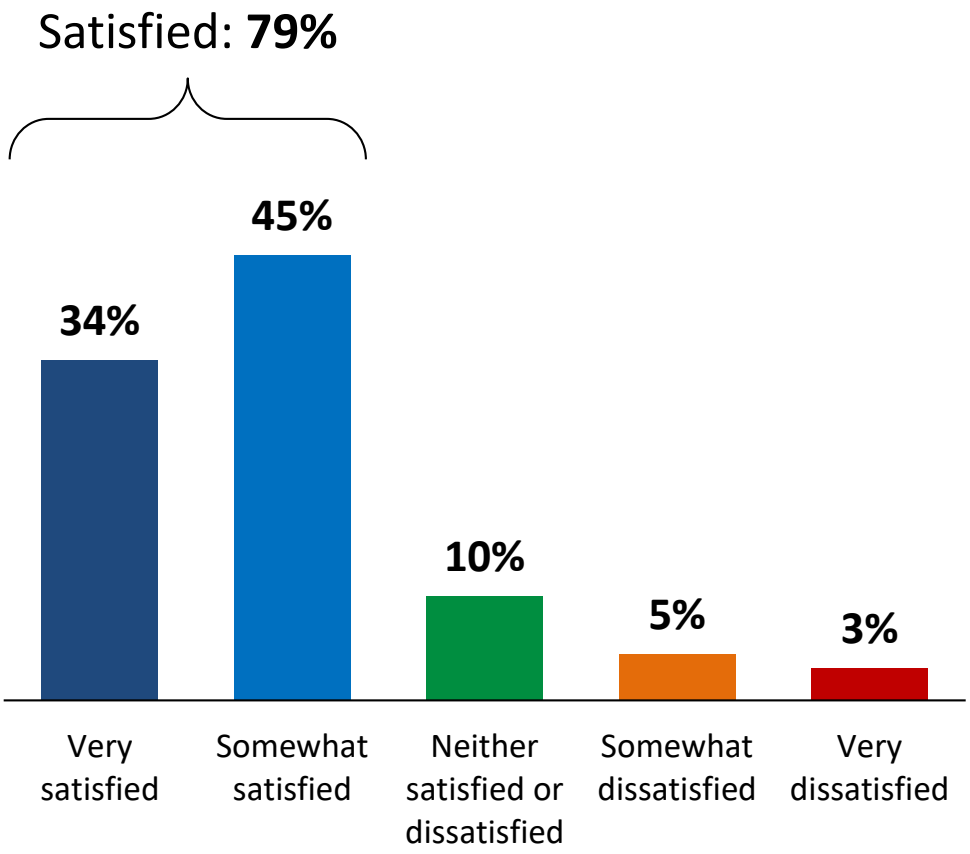
*Those who say "**Familiar**":*



Satisfaction with Services

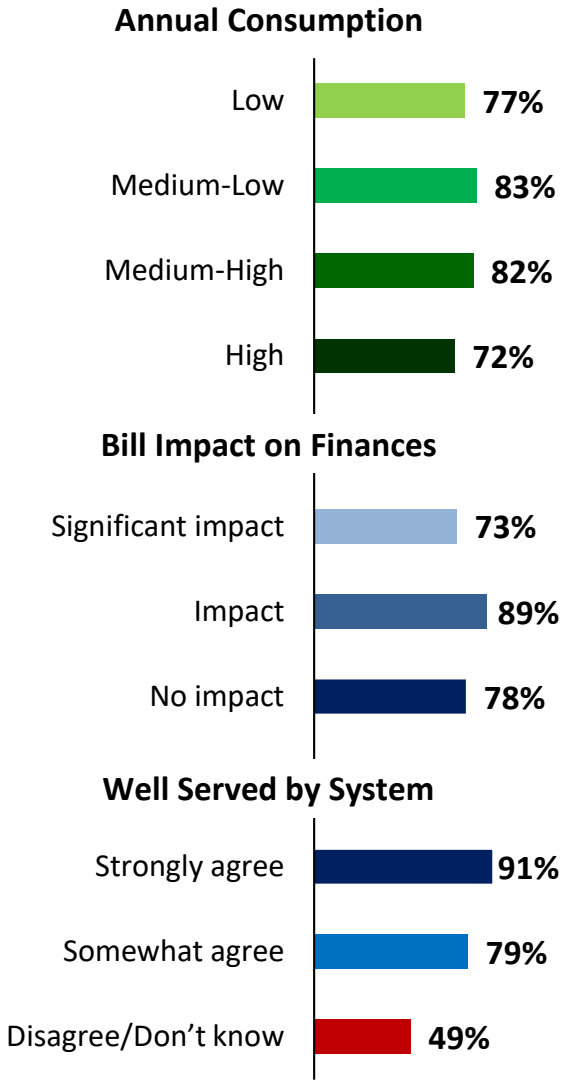
Q In general, how satisfied or dissatisfied are you with the services your organization receives from **Toronto Hydro**?

[asked all respondents, n=200]



Segmentation

*Those who say "**Satisfied**":*

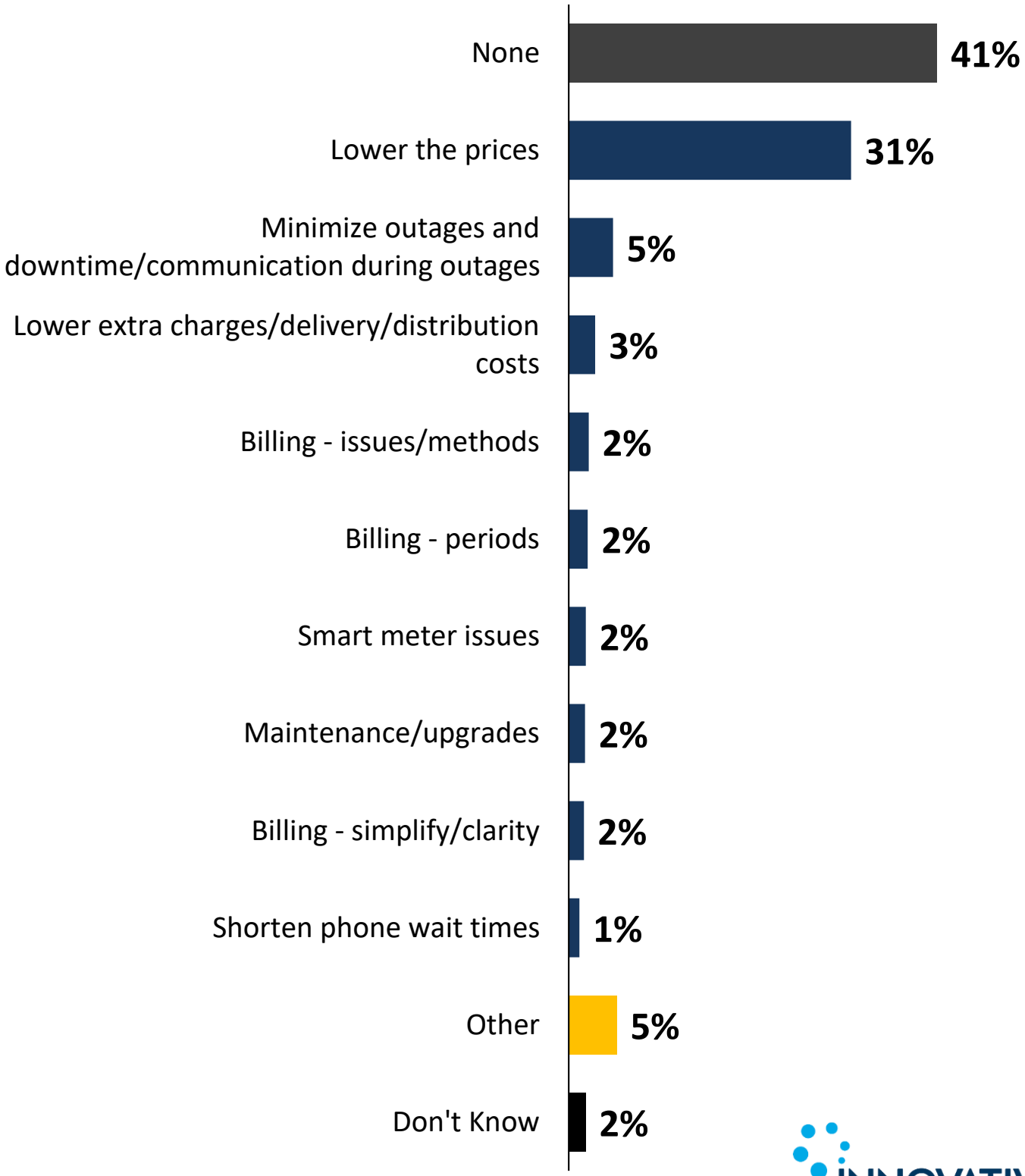


Note: "Don't know" (3%) not shown.

Suggestions for Improved Services

Q Is there anything in particular that **Toronto Hydro** can do to improve its services to your organization?

[asked all respondents, n=200]



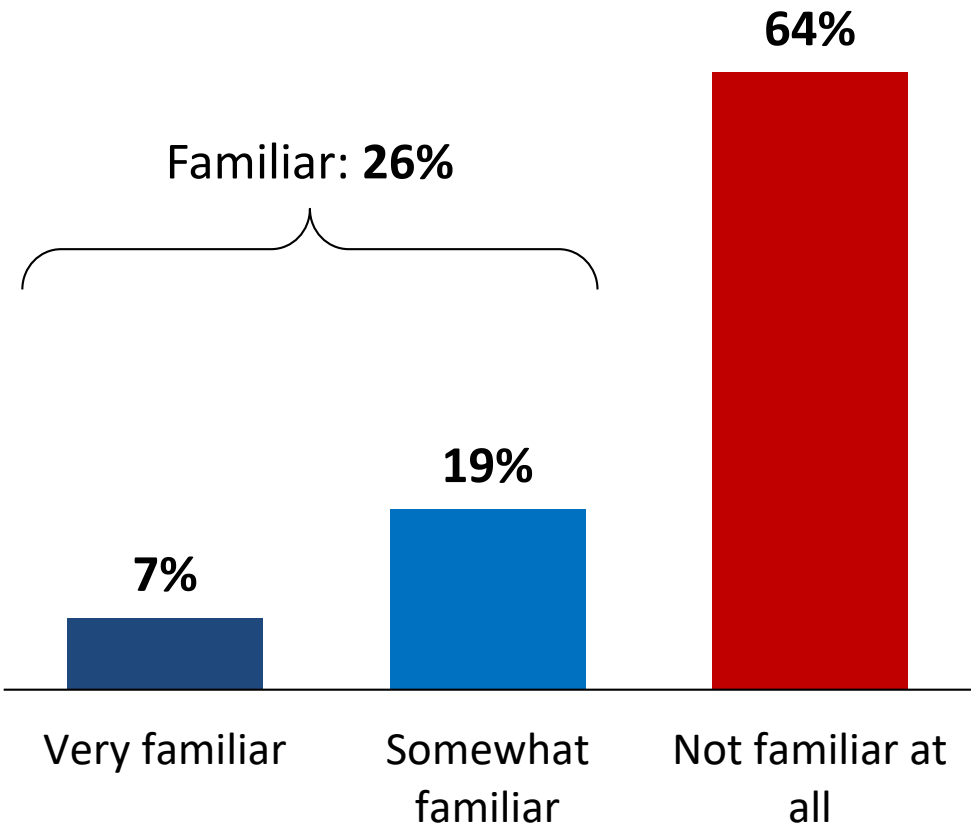
Note: "Refused" (2%) not shown.

Amount of Bill Retained by Toronto Hydro

While **Toronto Hydro** is responsible for collecting payment for the entire electricity bill, they retain about **30%** of the typical small business customer's bill. This is about **$94** on an average **$314** monthly small business electricity bill. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.

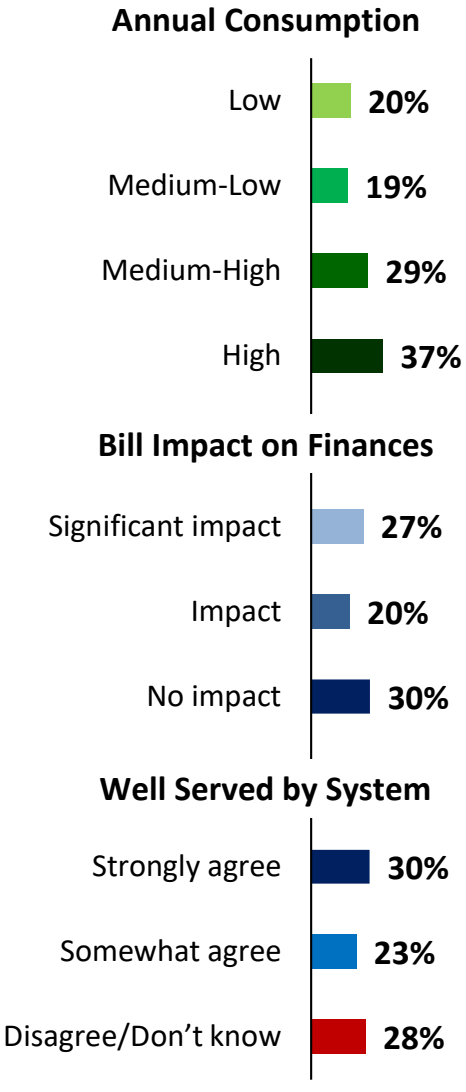
Before this survey, how familiar were you with the percentage of your organization's electricity bill that is retained by **Toronto Hydro**?

[asked all respondents, n=200]



Segmentation

*Those who say "**Familiar**":*



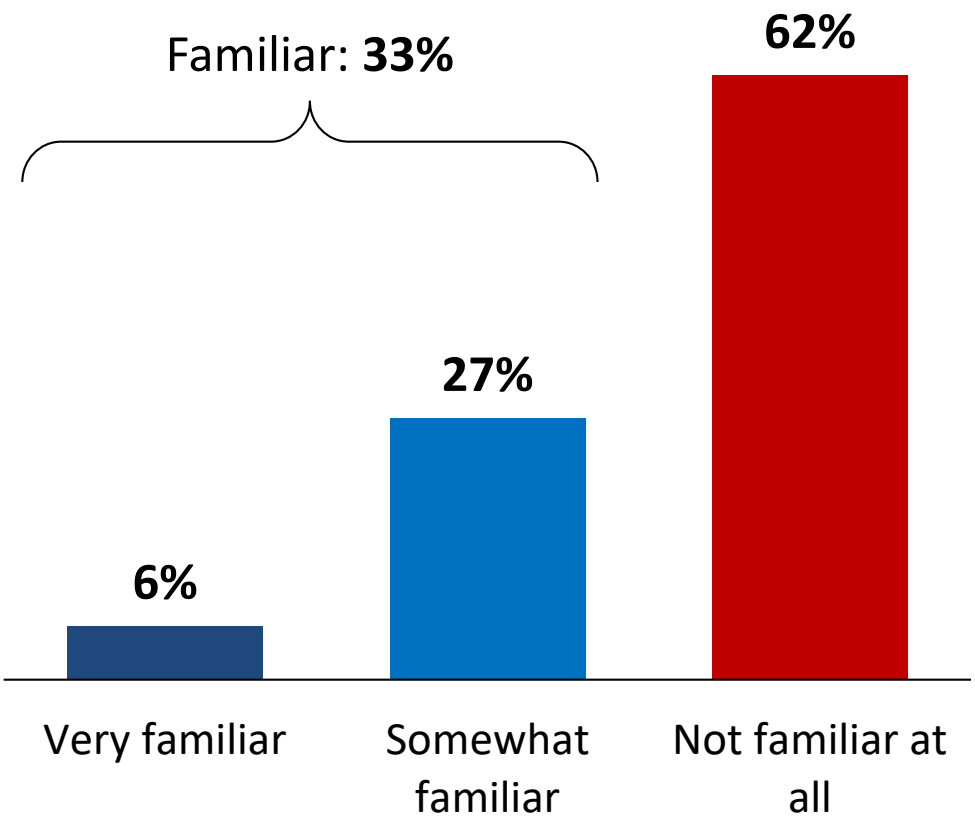
Note: "Don't Know" (10%) not shown.

Familiarity with Ontario Energy Board

Electricity distributors are required to file a rate application with the Ontario Energy Board (OEB) to request a change in distribution rates based on their plans for capital and operating spending. Toronto Hydro is now consulting on its plans for 2020 to 2024.

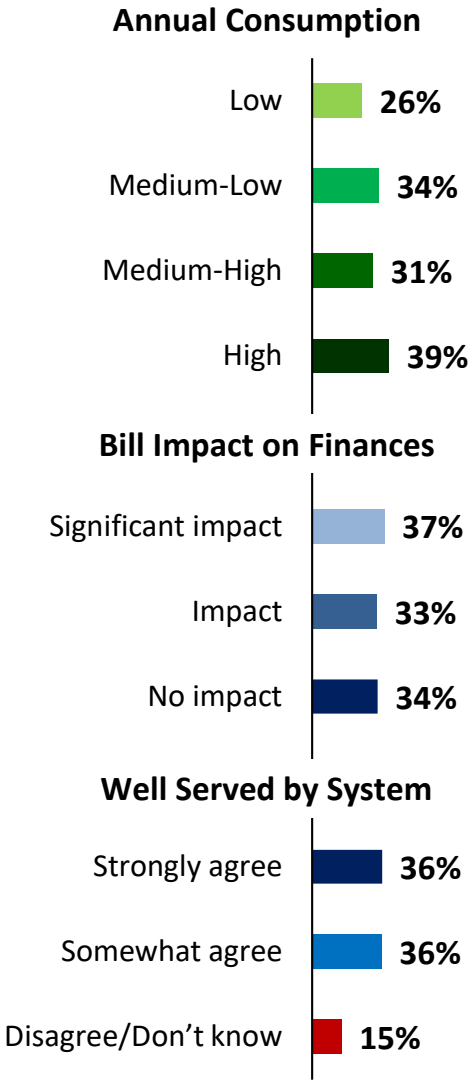
The OEB is mandated to protect consumers with respect to prices and the reliability and quality of electricity service.

How familiar would you say you are with the Ontario Energy Board or "OEB"?
[asked all respondents, n=200]



Segmentation

*Those who say "**Familiar**":*



Note: "Don't Know" (5%) not shown.

Customer Engagement Process Preamble

As part of **Toronto Hydro's** consultation, it has developed a five-phase approach to gathering and responding to customer feedback.

- First, **Toronto Hydro** identified customer priorities through a series of surveys and focus groups;
- Then, used this customer feedback to guide development of its Draft Plan;
- Now, **Toronto Hydro** is in the process of collecting customer feedback on its Draft Plan;
- The next phases will include re-examining its Draft Plan based on customer feedback and preparing a submission to the OEB.

This survey is part of the third stage of **collecting customer feedback on the Draft Plan.**

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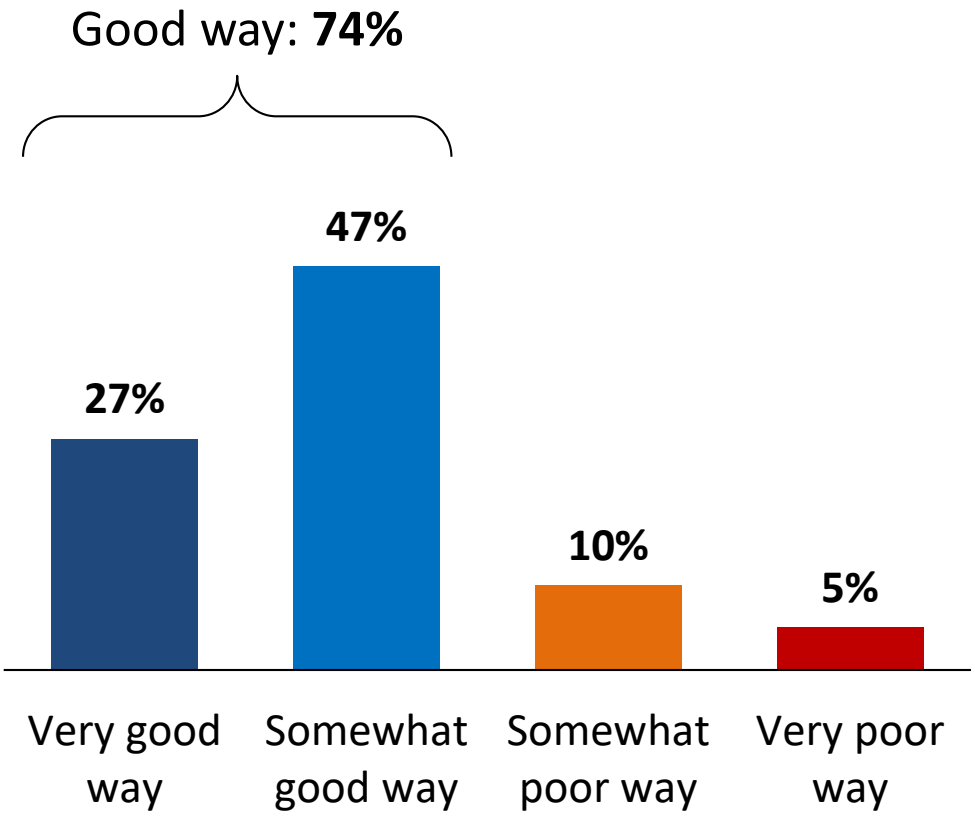
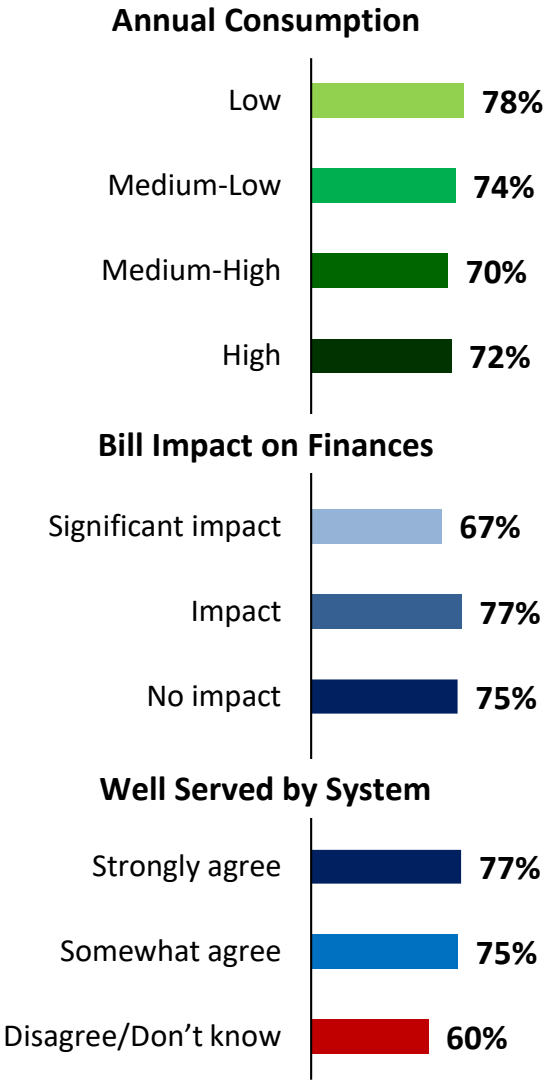
Feedback on Customer Engagement Process

Q Does this Customer Engagement process seem like a good way or a poor way to bring customer needs and preferences into **Toronto Hydro's** plan?
[asked all respondents, n=200]



Segmentation

*Those who say "**Good Way**":*



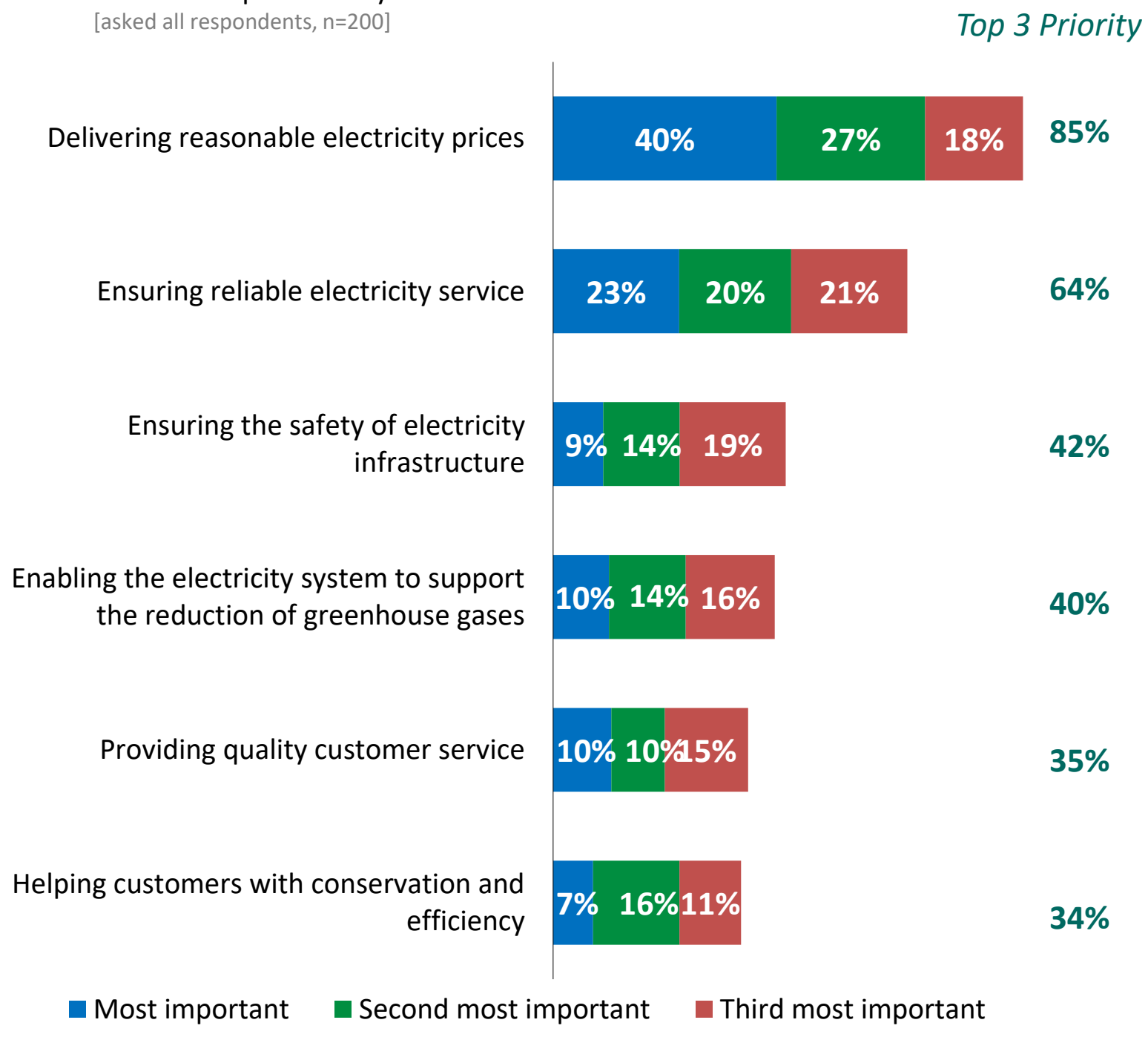
Note: "Don't Know" (12%) not shown.

Customer Priorities

Toronto Hydro wants to better understand customer priorities. In the first phase of customer engagement, residential and small business customers identified six core priorities which they believe should be a focus for **Toronto Hydro**.

Among the following customer identified priorities, please tell me which one is the most important to you.

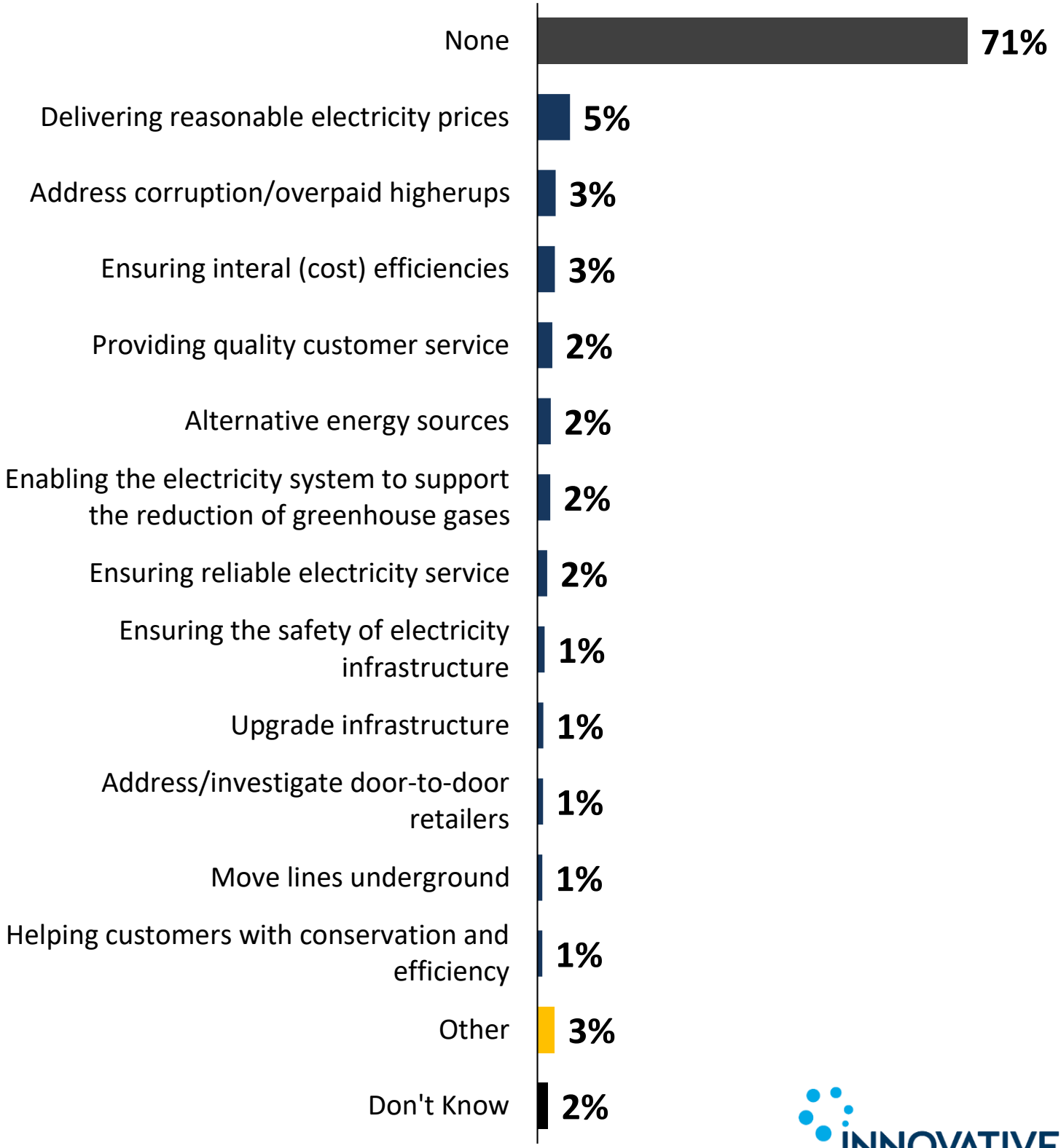
[asked all respondents, n=200]



Additional Customer Priorities

Q Are there any other important priorities that **Toronto Hydro** should be focusing on that weren't included in the previous list I read to you?

[asked all respondents, n=200]



Note: "Refused" (1%) not shown.

Planning Principles and Rate Impact Preamble

Based, in part, on the initial customer input, **Toronto Hydro** has drafted a plan totaling approximately $4.3B over five years.

Toronto Hydro's proposed plan focuses on delivering current levels of reliability and customer service for most customers and targeted improvements for customers experiencing below average service or who have special reliability needs, like hospitals.

This proposed plan translates into an average 4.4% increase in your organization's distribution rates each year from 2020 to 2024. The distribution charges on the monthly bill would increase to $126 by 2024 for a typical small business customer.

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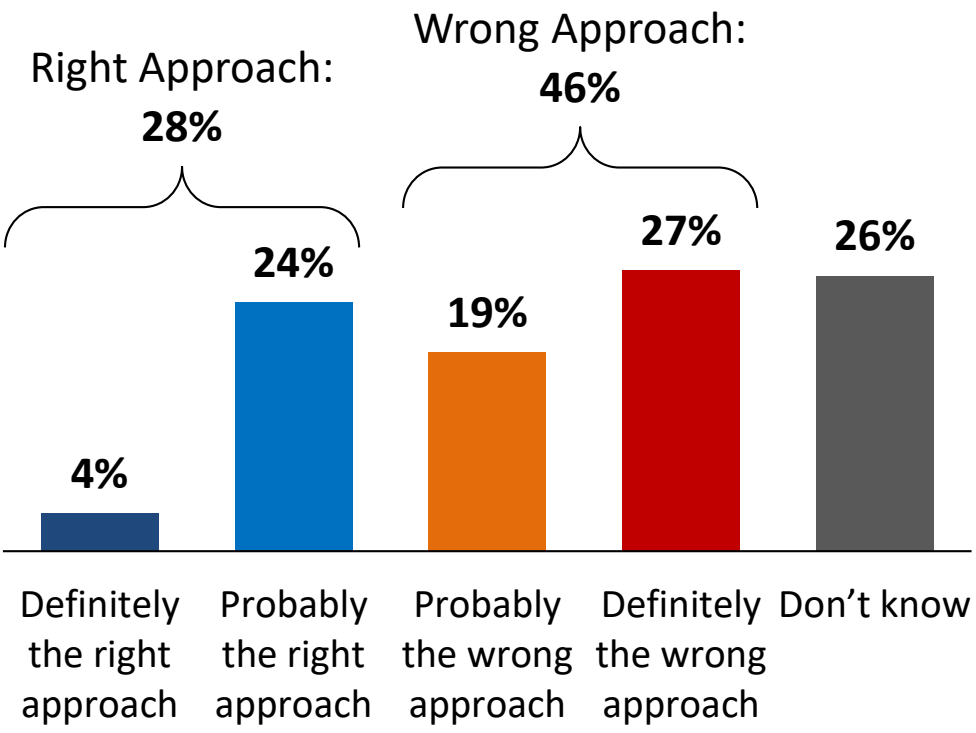
Approach to Planning for the Next Five Years

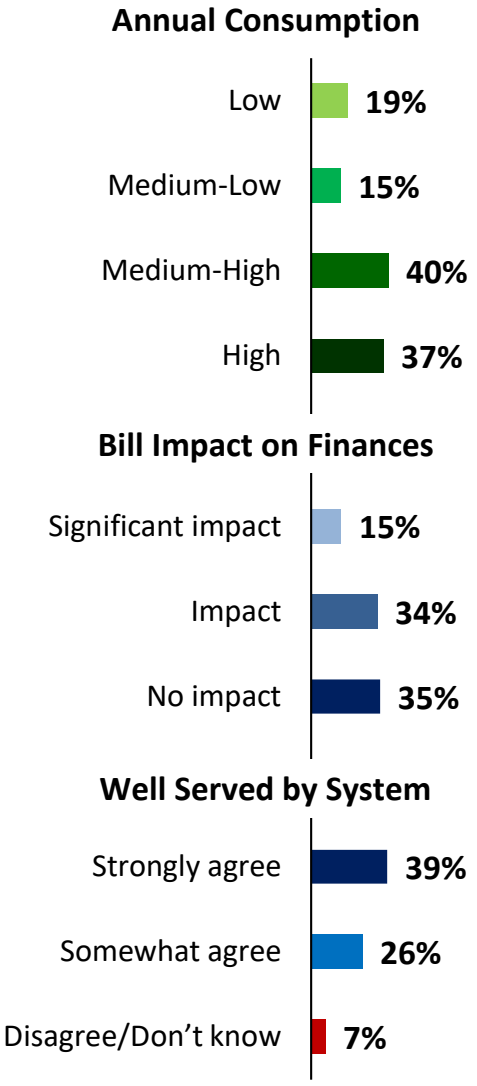
Q Do you feel that this is definitely the right approach, probably the right approach, probably the wrong approach or definitely the wrong approach to **Toronto Hydro's** planning for the next five years or would you say you don't know?

[asked all respondents, n=200]



Segmentation

*Those who say "**Right Approach**":*



Gathering Feedback on Capital Investment Decisions

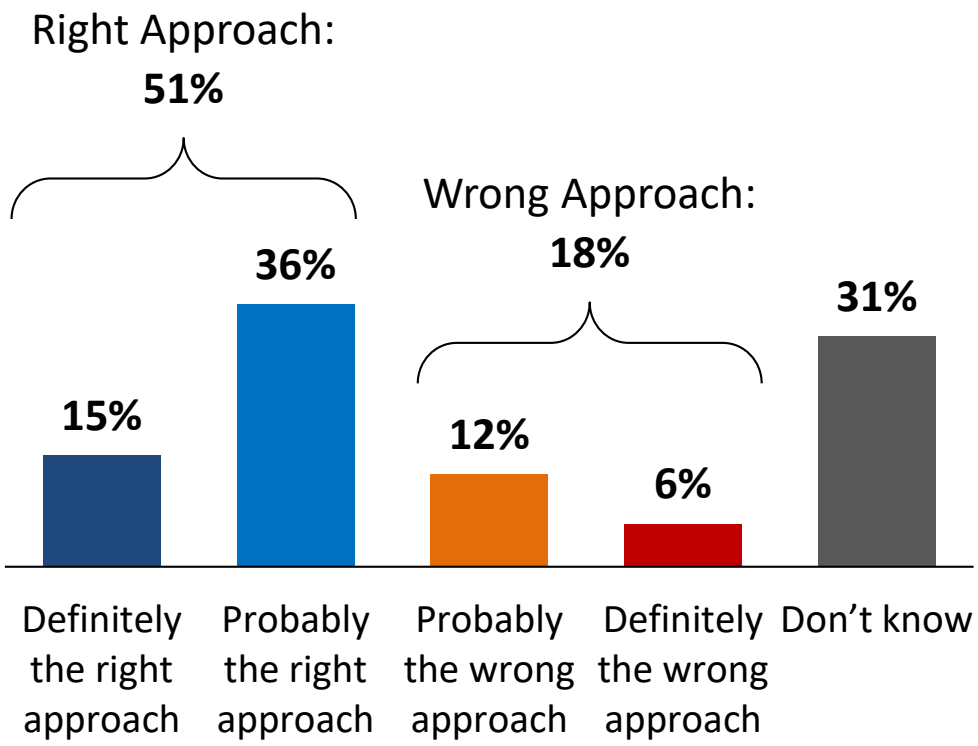
Toronto Hydro's total spending is benchmarked by the OEB against other utilities in Ontario. Toronto Hydro's operating costs of $305 per customer are within $1 of the provincial average.

However **Toronto Hydro's** capital investment costs are $739 per customer which are $245 more than the provincial average.

Since a number of capital investment decisions are based trade-offs between costs and customer outcomes – like services and reliability levels – the remaining questions in this survey ask for your feedback on those choices.

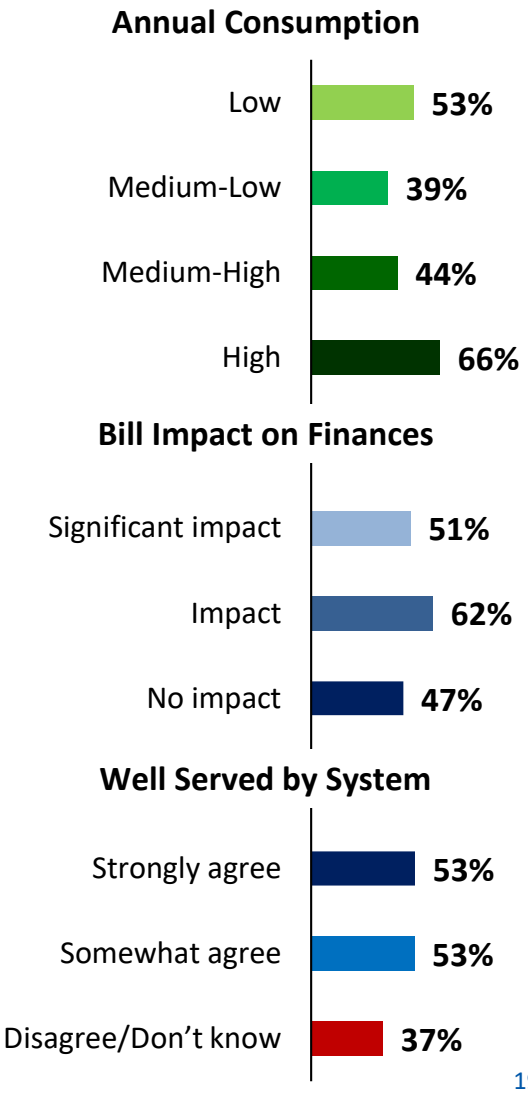
Do you feel that gathering feedback on capital investment decisions is *definitely the right approach, probably the right approach, probably the wrong approach, definitely the wrong approach or would you say you don't know*?

[asked all respondents, n=200]



Segmentation

*Those who say "**Right Approach**":*

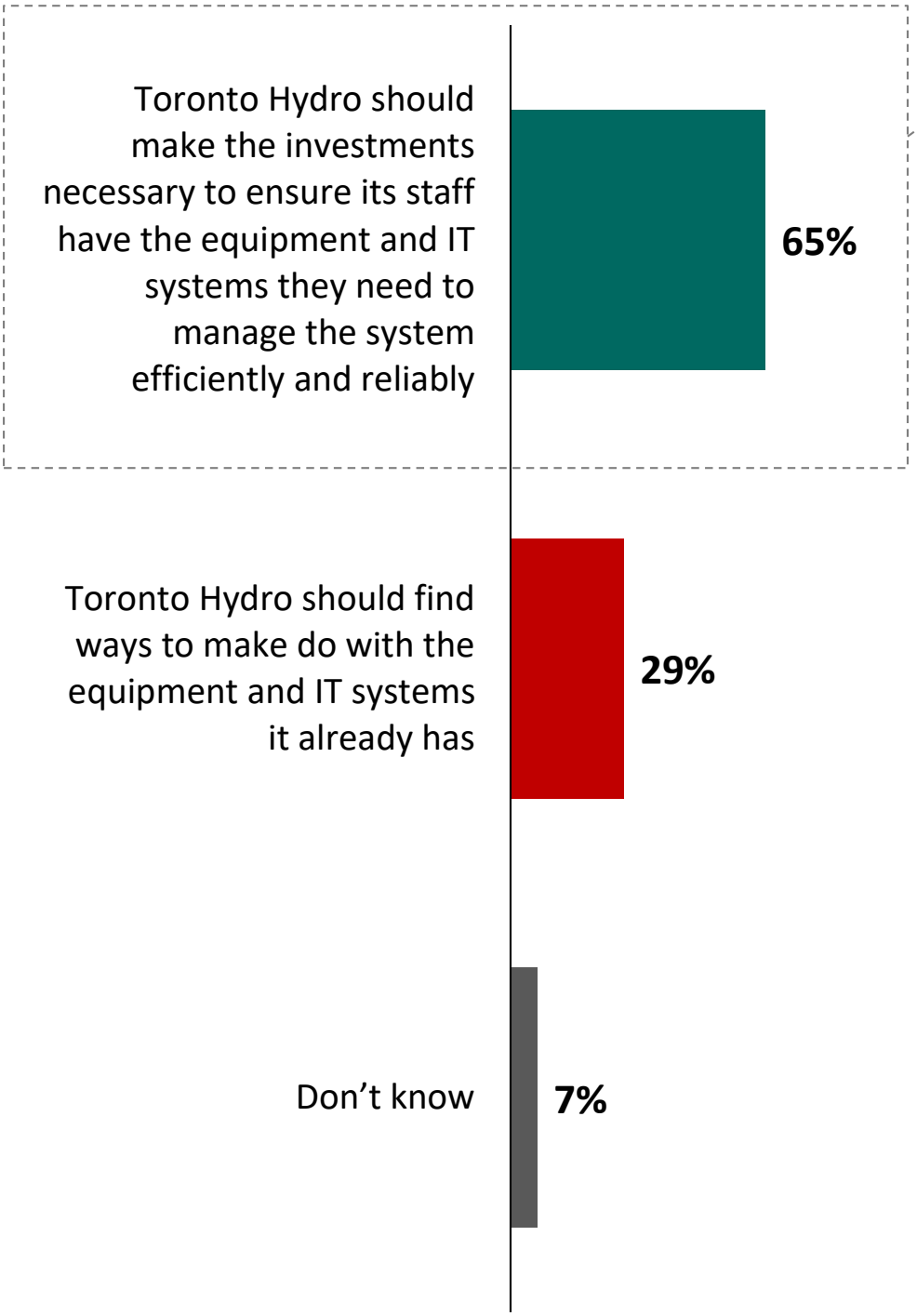


Investing in the Basics

As a company, **Toronto Hydro** needs vehicles and tools to service the power lines and IT systems to manage the system and customer information.

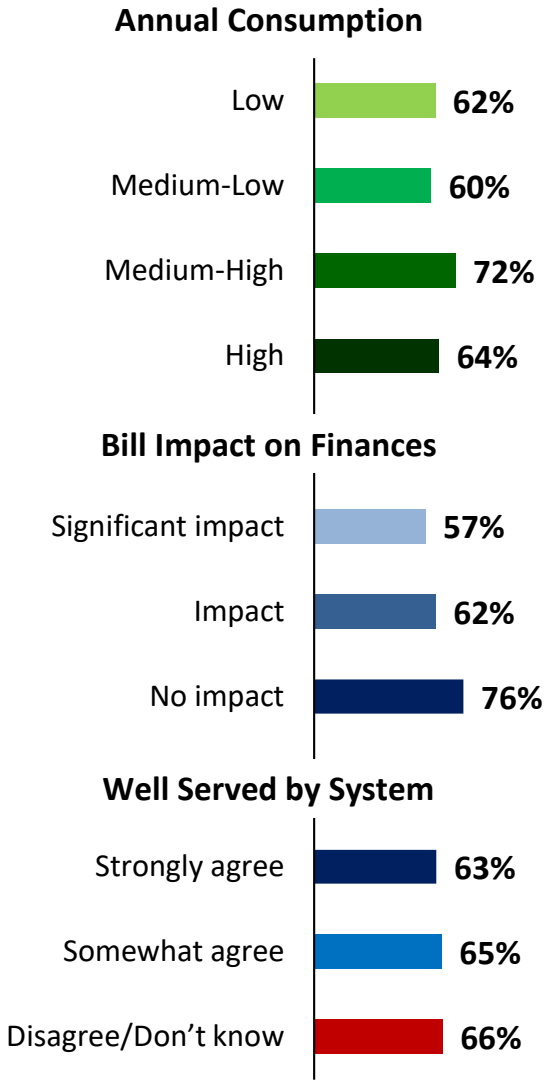
Which of the following statements best represents your point of view?

[asked all respondents, n=200]



Segmentation

*Those who say "**Make necessary investments**":*



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Addressing Safety and Reliability



Addressing Safety and Reliability Preamble

Toronto Hydro has identified areas where it could accelerate investments. These accelerated projects could increase the **typical customer's bill by $5.73 per month by 2024**. These projects are in addition to the 4.4% increase that is currently being proposed.

Toronto Hydro wants to get your feedback on particular projects before deciding whether or not to accelerate its investment plan in certain specific areas.

Right now, the typical **Toronto Hydro** customer averages 1.4 outages per year with an average of between 60 and 70 minutes without power over the year. While many of those outages are caused by events outside of **Toronto Hydro's** control, roughly 36% are caused by the failure of aging equipment.

In this proposed plan, **Toronto Hydro's** general approach is to spend just enough on replacing equipment so that most customers can expect a similar level of reliability over the next five years as they are experiencing today, and to provide improved service for those customers whose reliability is poorer or who have special reliability needs such as hospitals.

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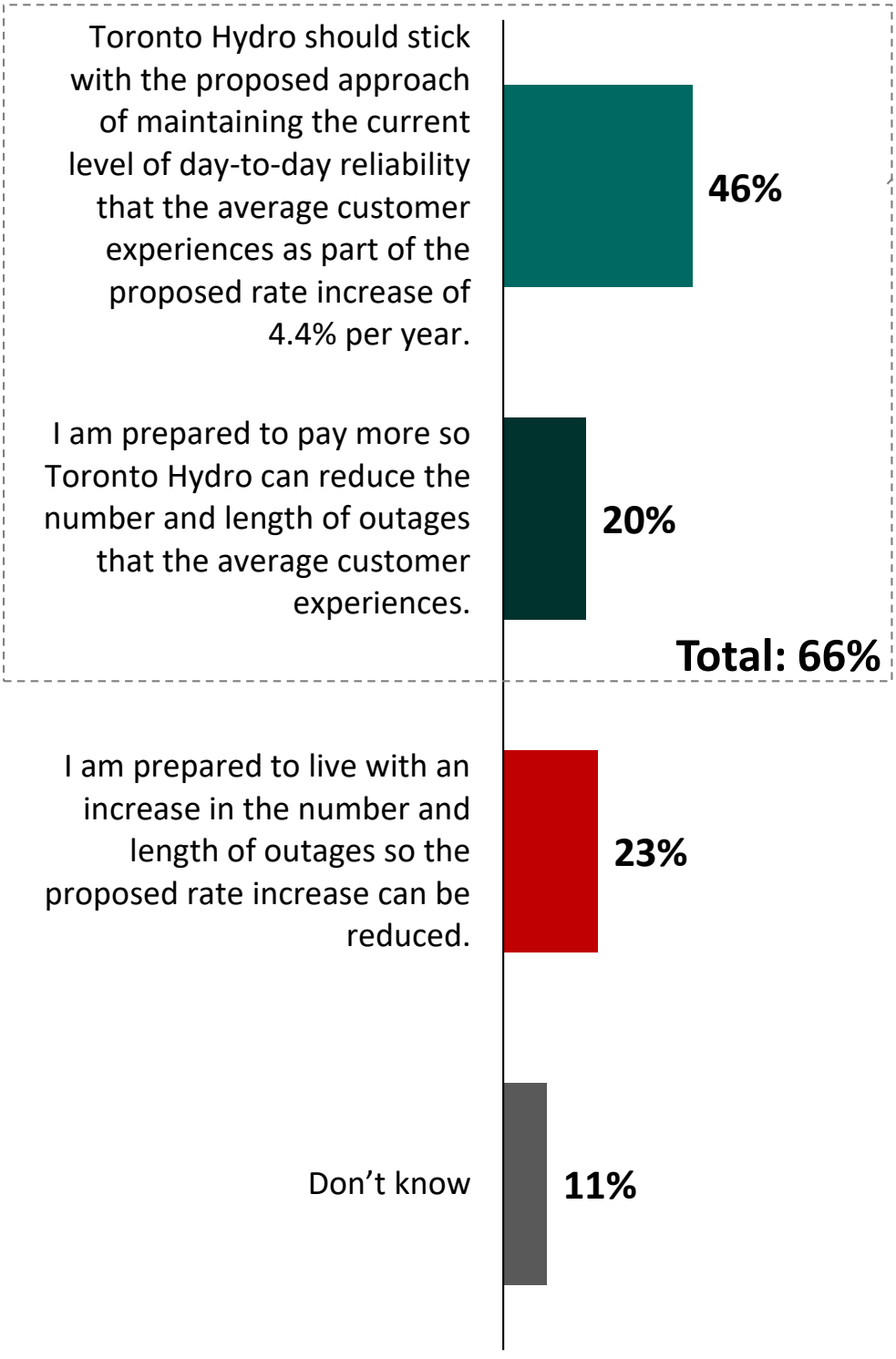
Approach to Addressing Reliability

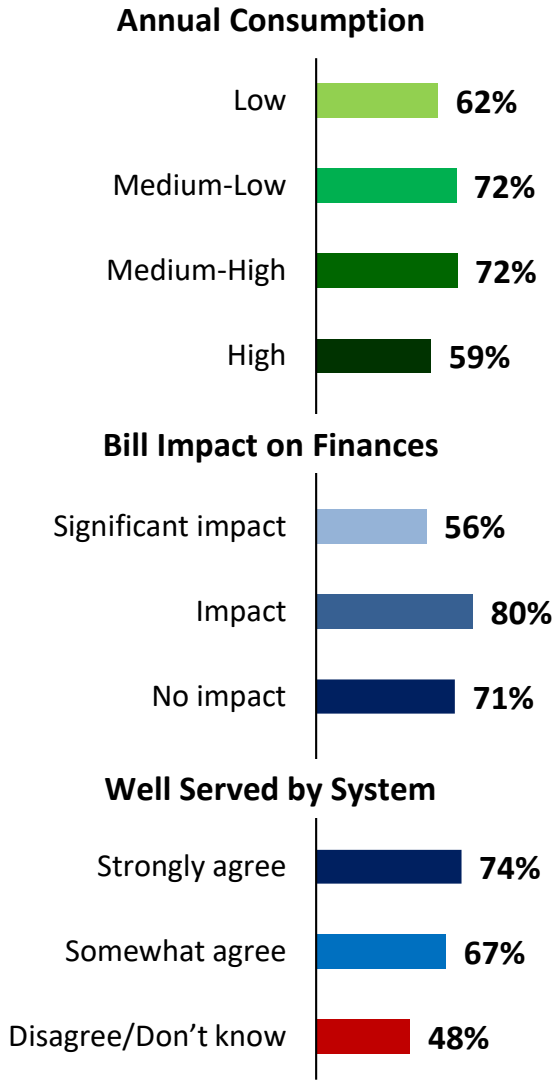
Q Which of the following is closest to your point of view regarding **Toronto Hydro's approach to addressing reliability?**

[asked all respondents, n=200]



Segmentation

*Those who say "**Stick with proposed approach or spend more**":*



Rear-Lot Replacement

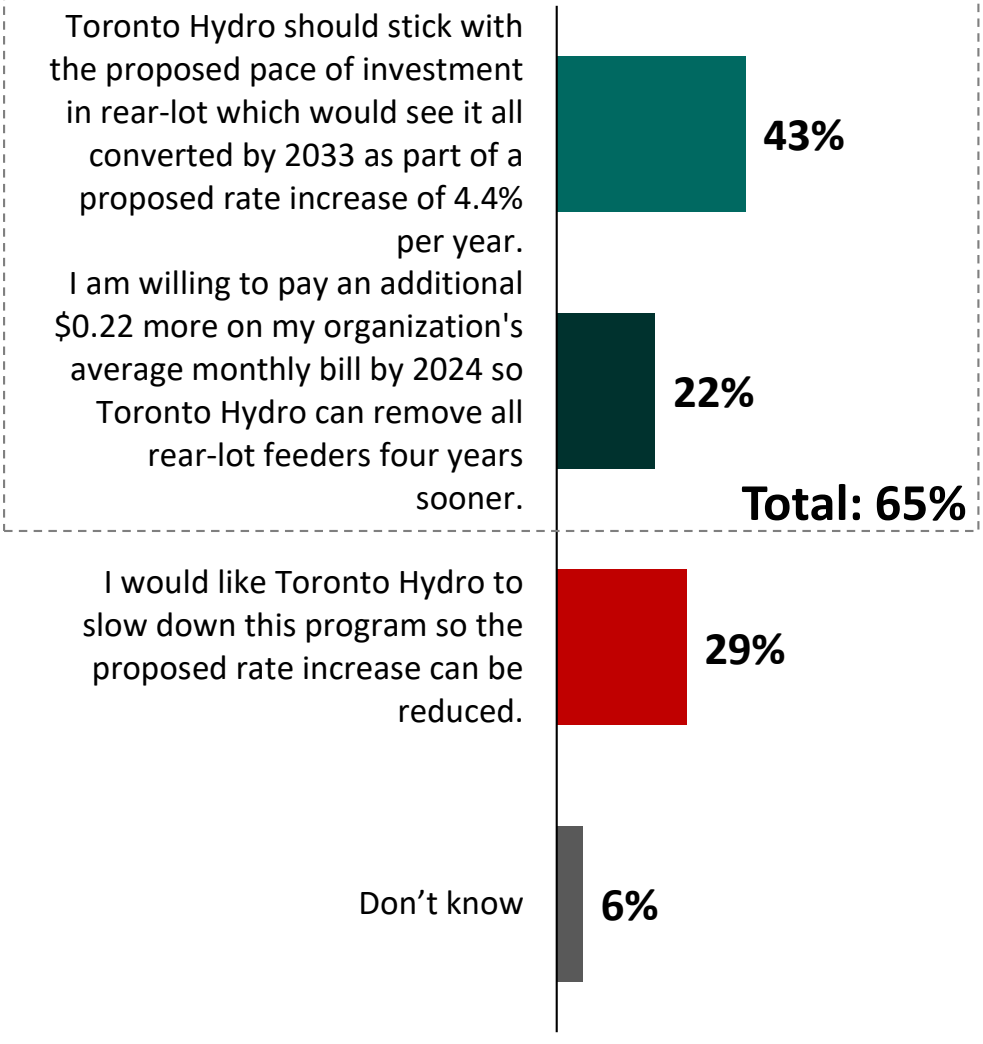
Some customers are served by older types of lines that are more likely to fail, causing more frequent, and longer lasting power outages. These customers are more likely to experience poorer reliability over time than most Toronto Hydro customers. The proposed plan will replace those lines over time but the work could be done faster.

I would like to ask you about two types of lines.

One example is **rear-lot lines**. They go through residential backyards and are often more difficult to service and more exposed to falling branches. The proposed plan will replace all existing rear-lot lines by 2033. **Toronto Hydro** could replace those lines 4 years sooner for an additional cost.

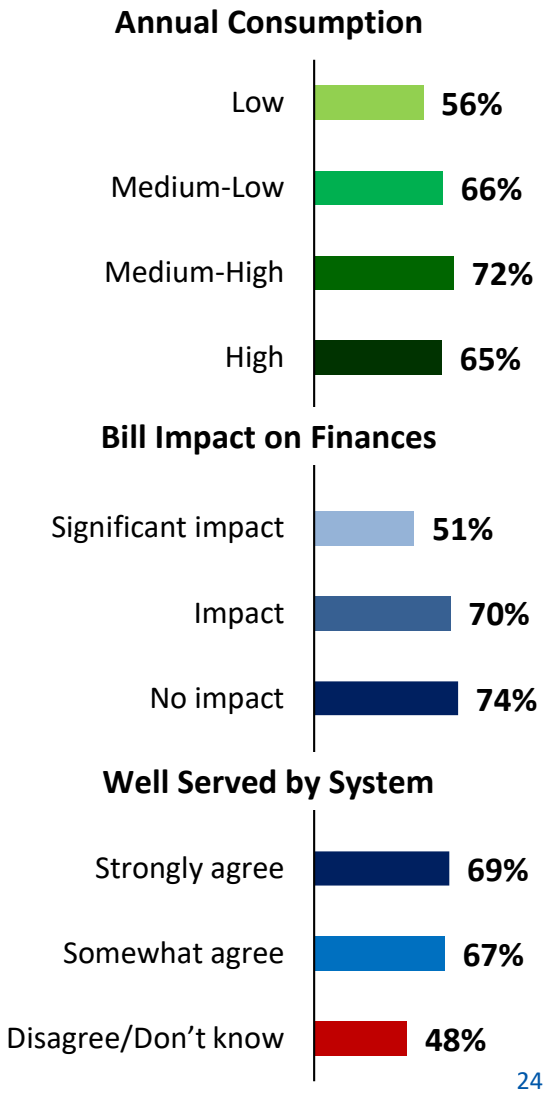
Which of the following statements is closest to your view?

[asked all respondents, n=200]



Segmentation

*Those who say "**Stick with proposed approach or spend more**":*



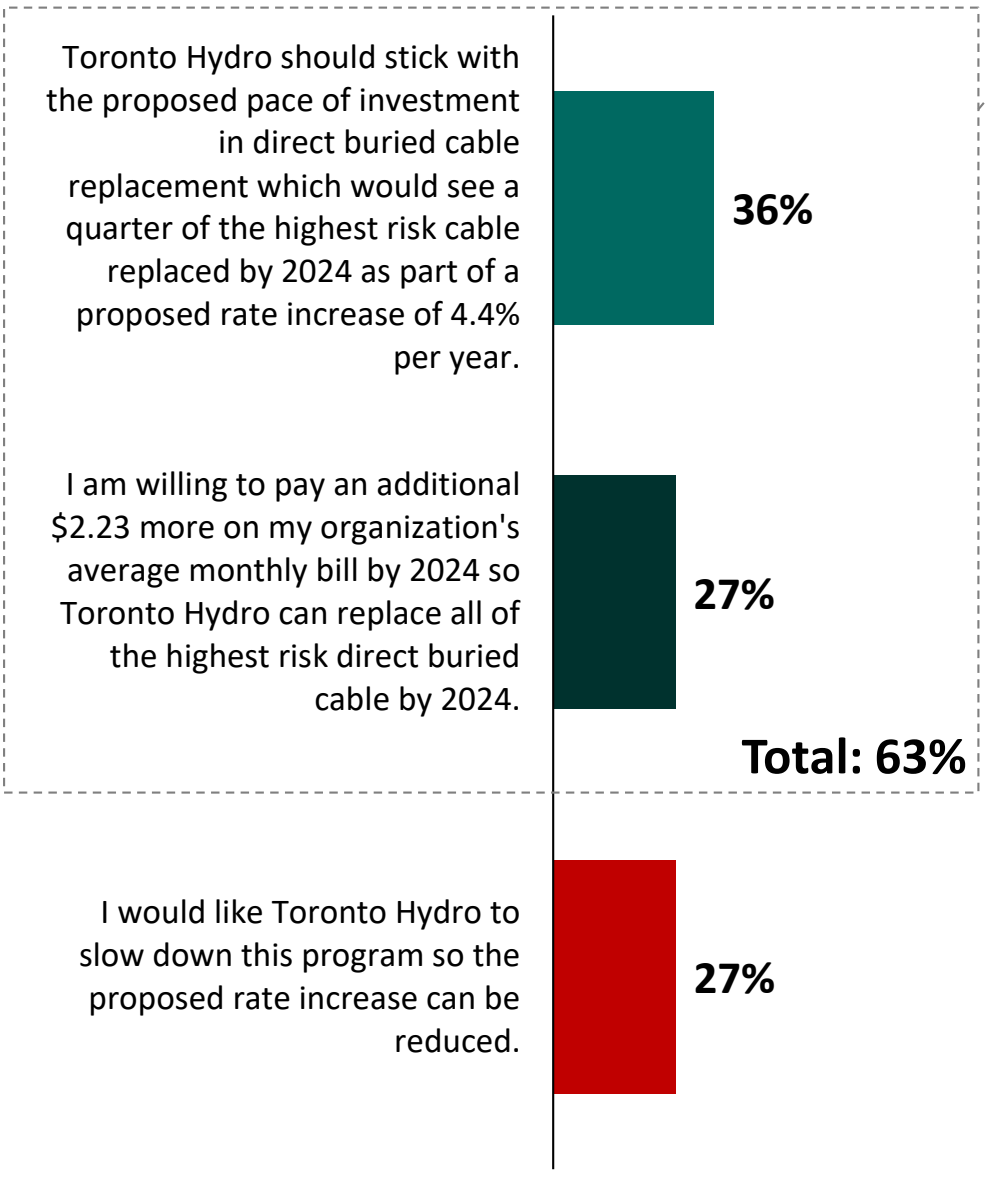
Direct Buried Cable Replacement

Another example is **direct buried cable** where cables are laid directly in underground trenches without a protective barrier. While equipment failure causes 36% of outages across the system, cable failure accounts for 70% of all outages on the underground system.

Once these cables start to fail, they tend to experience a rash of failures. The proposed plan will replace a quarter of the highest risk direct buried cable by 2024. **Toronto Hydro** could replace all of the highest risk direct buried cable by 2024 for an additional cost.

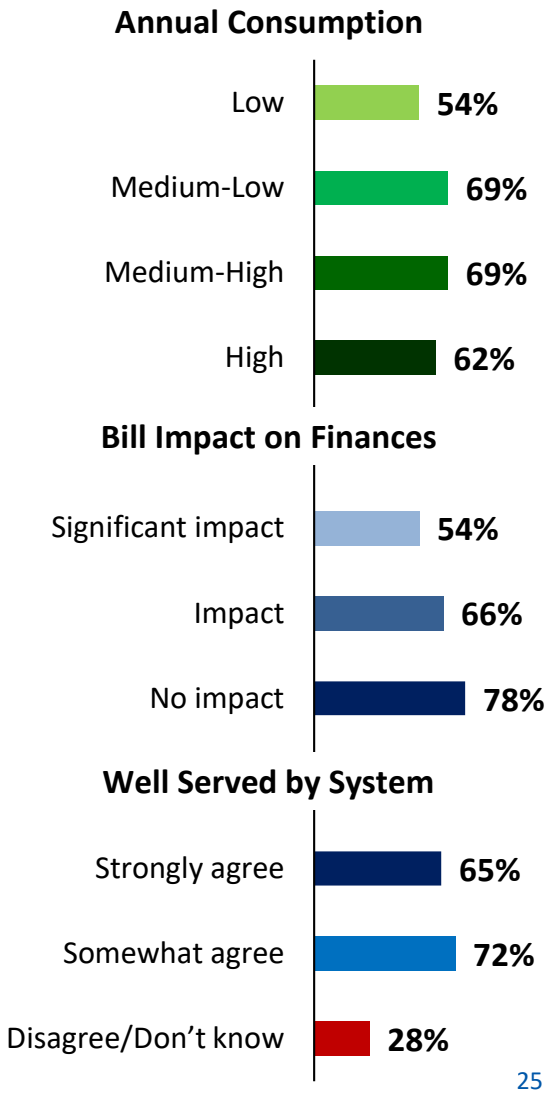
Which of the following statements is closest to your view?

[asked all respondents, n=200]



Segmentation

*Those who say "**Stick with proposed approach or spend more**":*



Note: "Don't Know" (9%) not shown.

Paper Insulated Lead Covered (PILC) Preamble

Toronto Hydro has identified three equipment upgrades that are needed within the next few years. If **Toronto Hydro** waits, those upgrades will be more expensive and disruptive as Toronto continues to grow.

Firstly, Paper Insulated Lead Covered (PILC) cable. PILC cable was an old type of underground cable that stopped being installed on **Toronto Hydro's** grid 20 years ago. While the equipment is resilient and is still providing electricity to the downtown core, the outer lead covers can begin to crack and leak oil. Replacing these cables is becoming increasingly difficult and expensive to resource and complete.

Toronto Hydro has a long-term plan to remove and replace PILC cable by 2049. But **Toronto Hydro** can replace all of this cable ten years earlier by 2039, at an additional cost now. This will improve reliability, reduce risks to the public, and avoid additional expense and disruption in the future.

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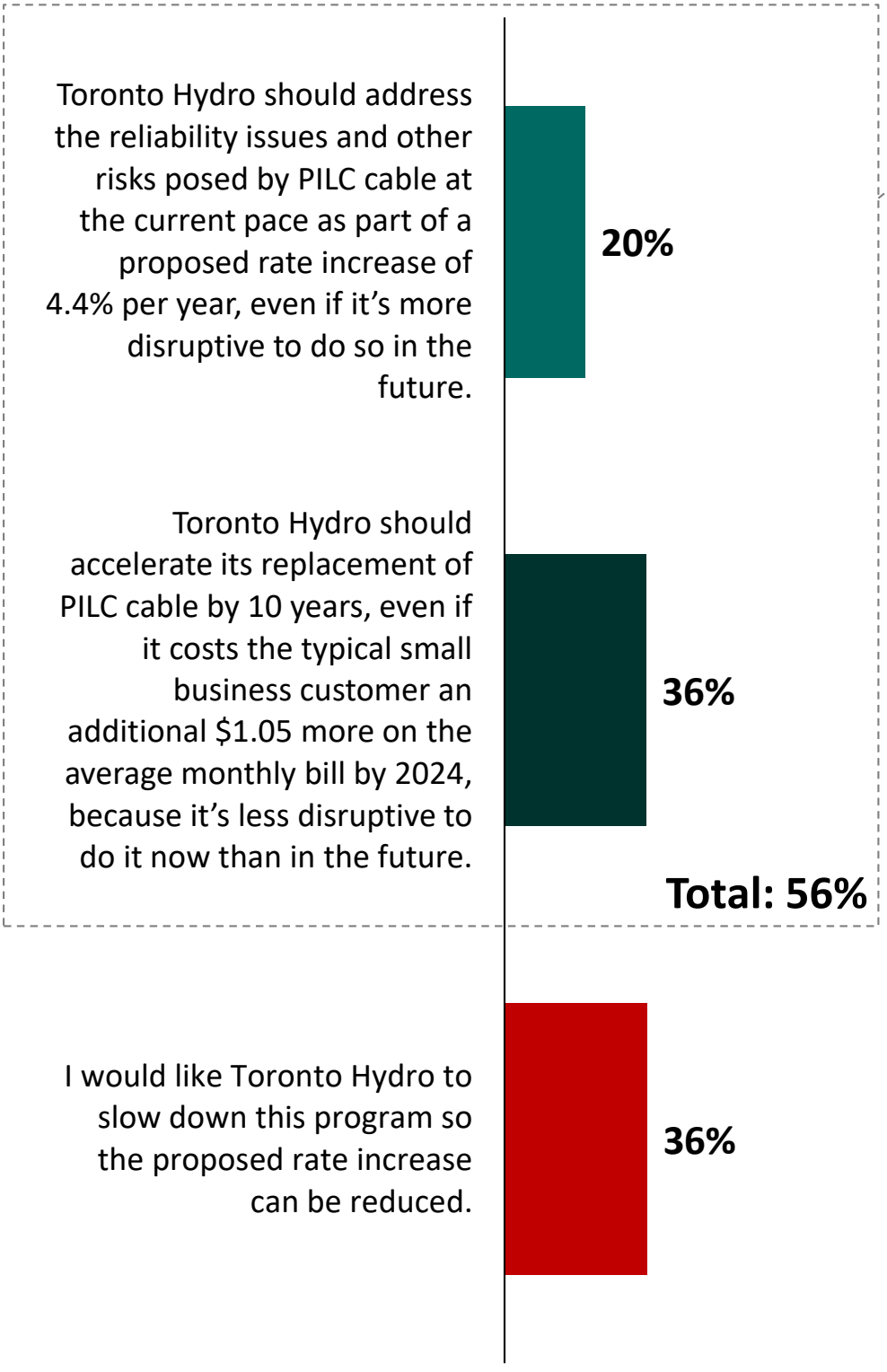
PILC Cable Replacement Program

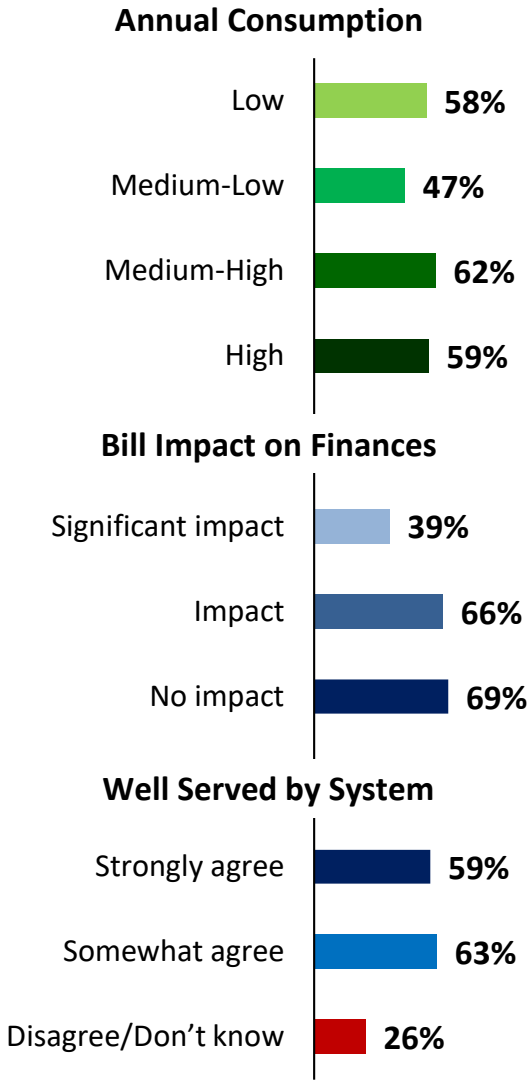
Q Which of the following is closest to your point of view regarding **Toronto Hydro's** PILC Cable replacement program?

[asked all respondents, n=200]



Segmentation

*Those who say "**Stick with proposed approach or spend more**":*



Note: "Don't Know" (8%) not shown.

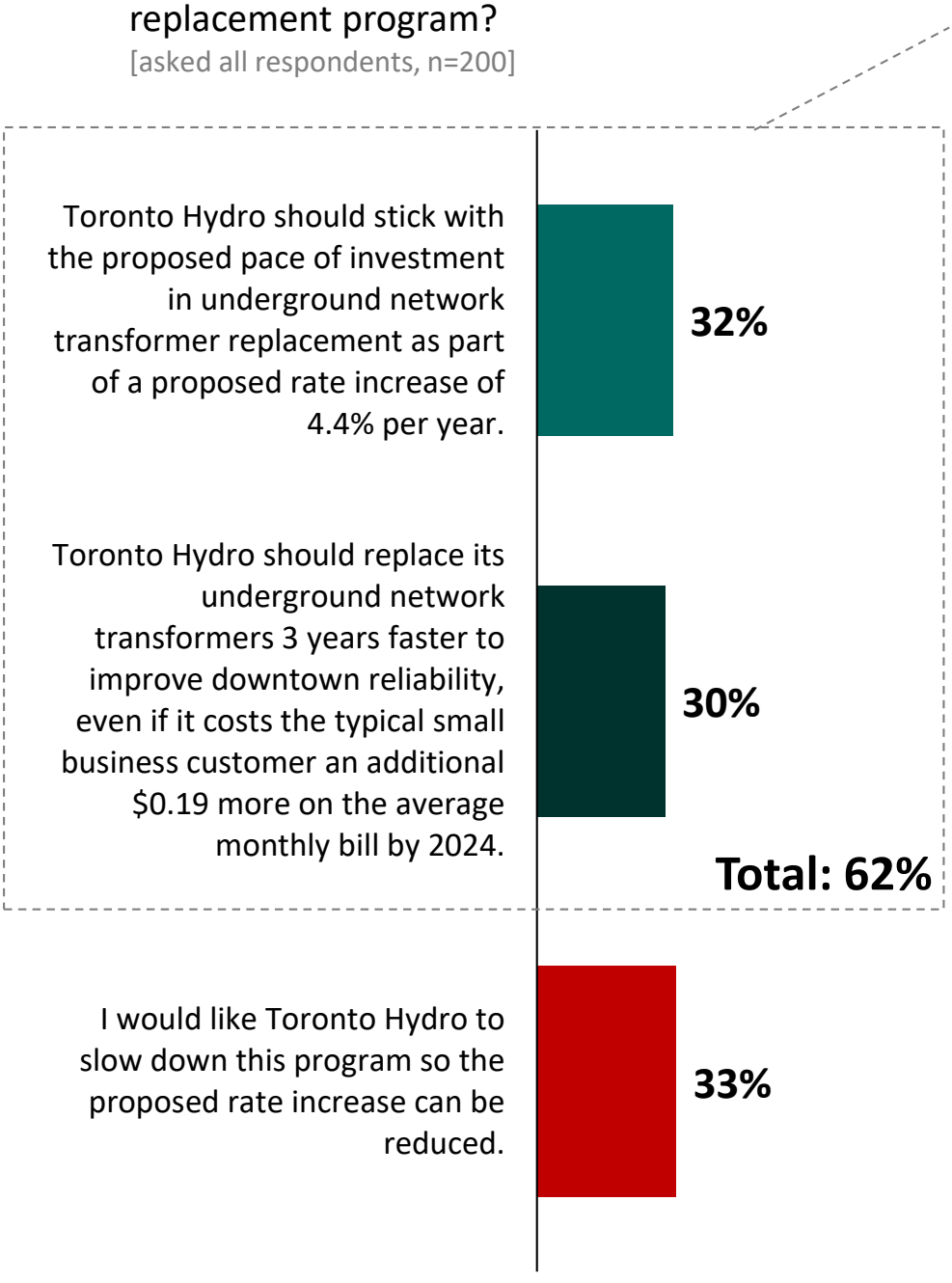
Network Unit Replacement Program

The second upgrade project identified is *Underground Network Transformers*. The key problem with these units is their older design which makes them prone to flooding.

Toronto Hydro plans to replace just enough of these units by 2031 so that outages, due to equipment failure, don't get any worse. But the process could be advanced by three years to replace all these units by 2028.

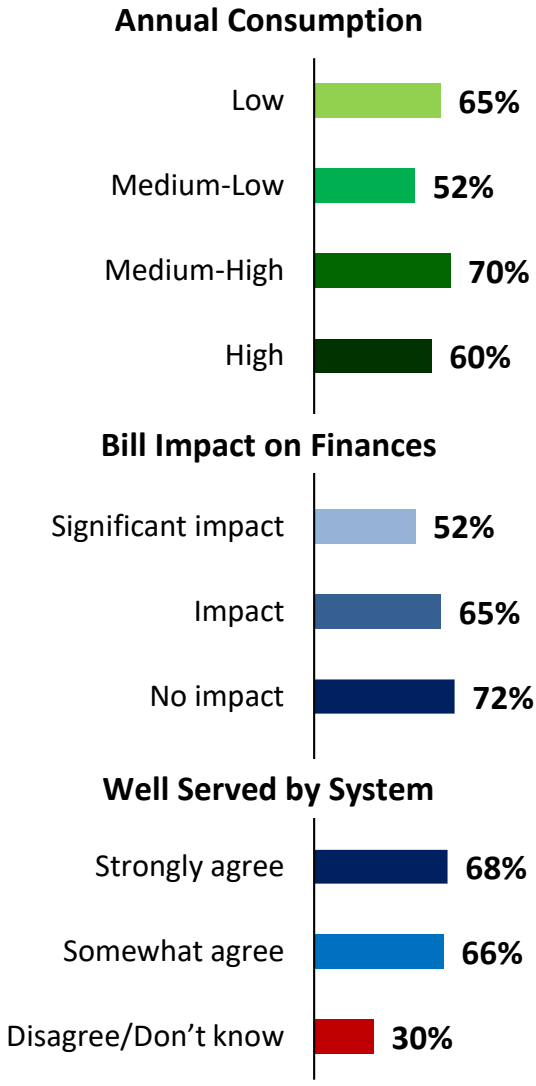
Which of the following is closest to your point of view regarding **Toronto Hydro's** Network Unit replacement program?

[asked all respondents, n=200]



Segmentation

*Those who say "**Stick with proposed approach or spend more**":*



Note: "Don't Know" (6%) not shown.

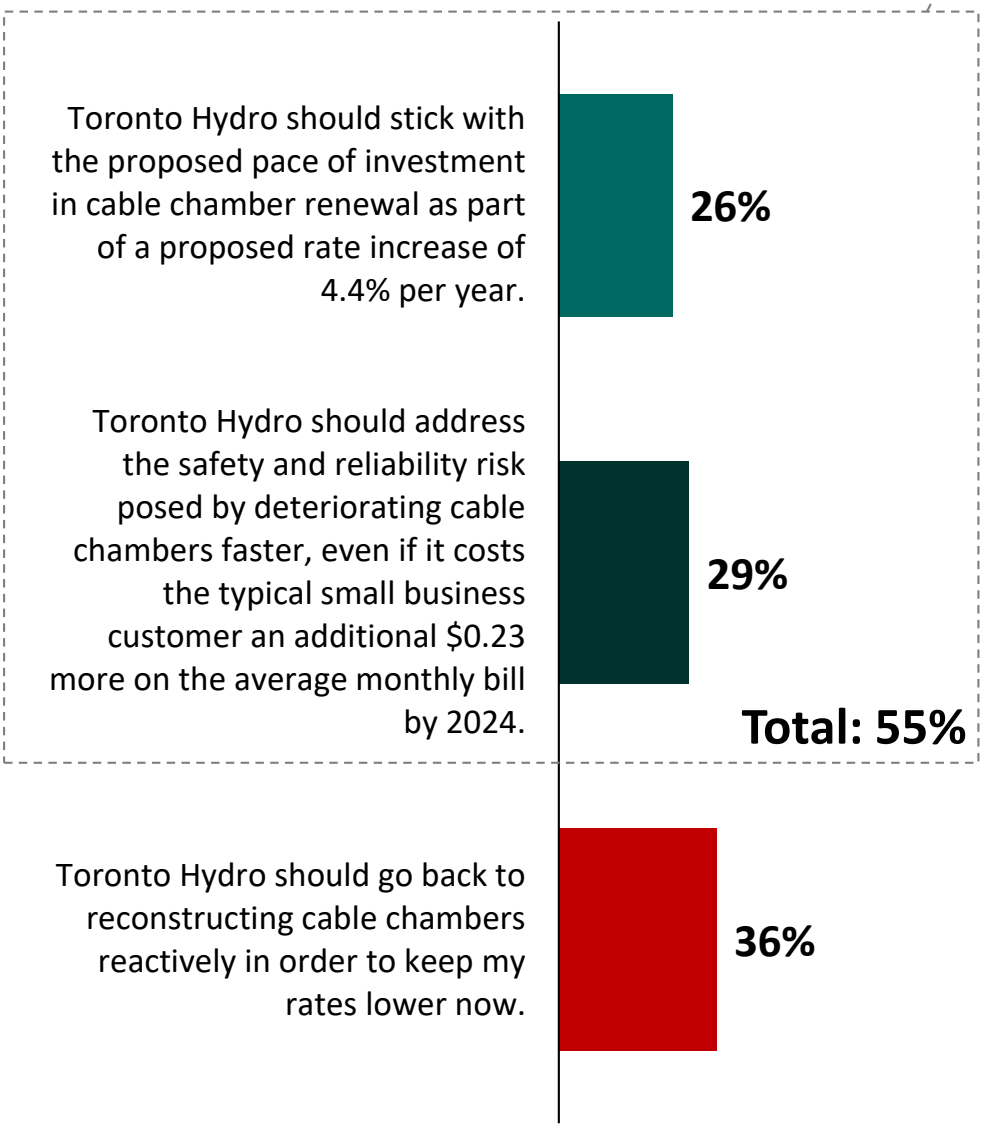
Cable Chamber Renewal Program

The third upgrade project identified is *Cable Chamber replacement*. Cable Chambers house, protect, and provide access to underground electrical equipment across the city. When they deteriorate or break, this equipment can cause outages and pose anything from a tripping hazard to something more serious like a collapsed chamber.

Toronto Hydro plans to take approximately 30 years to address the chambers in the worst condition. But accelerating the work could halve that period, at an additional cost now.

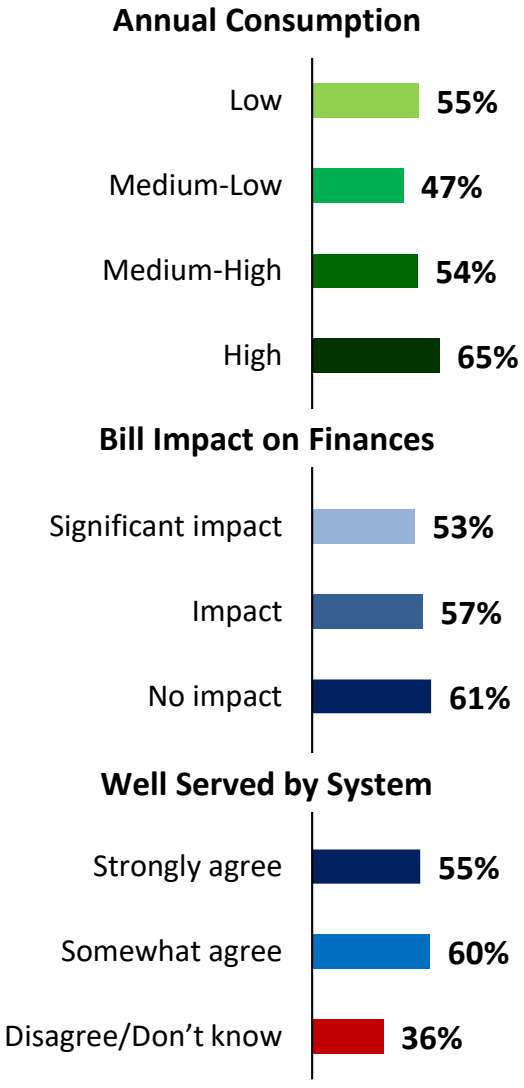
Which of the following is closest to your point of view regarding **Toronto Hydro's** Cable Chamber renewal program?

[asked all respondents, n=200]



Segmentation

*Those who say "**Stick with proposed approach or spend more**":*



Note: "Don't Know" (9%) not shown.

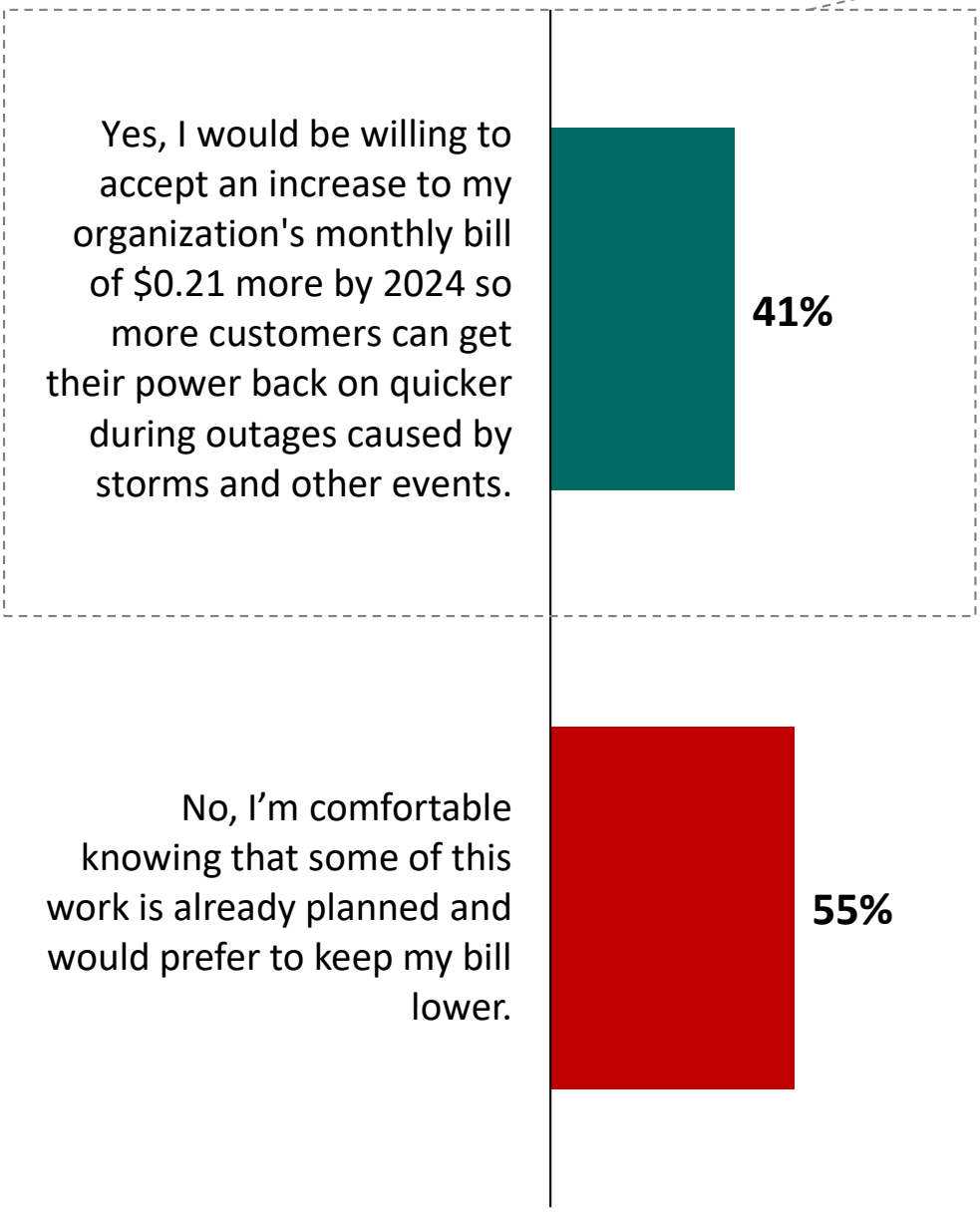
Dealing with More Frequent Extreme Weather Events

As **Toronto Hydro's** distribution system is exposed to strong winds, freezing rain, and severe flooding, they are proposing a variety of enhancements to improve the resiliency of the distribution system against extreme weather events.

Toronto Hydro could enhance the system further in neighbourhoods outside of downtown. The improvements include adding remotely-operated technology and more back-up links within the grid. This will help **Toronto Hydro** to better isolate the problem and reduce outage times by as much as 50% in these areas.

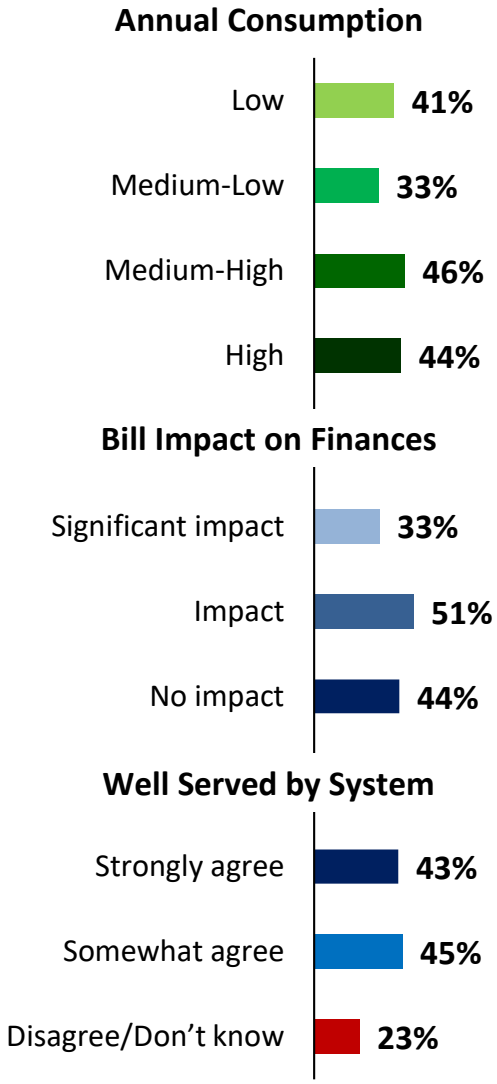
Which of the following statements best represents your point of view?

[asked all respondents, n=200]



Segmentation

*Those who say "**Restore power more quickly during outages**":*



Note: "Don't Know" (4%) not shown.

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Innovation and Planning for the Future



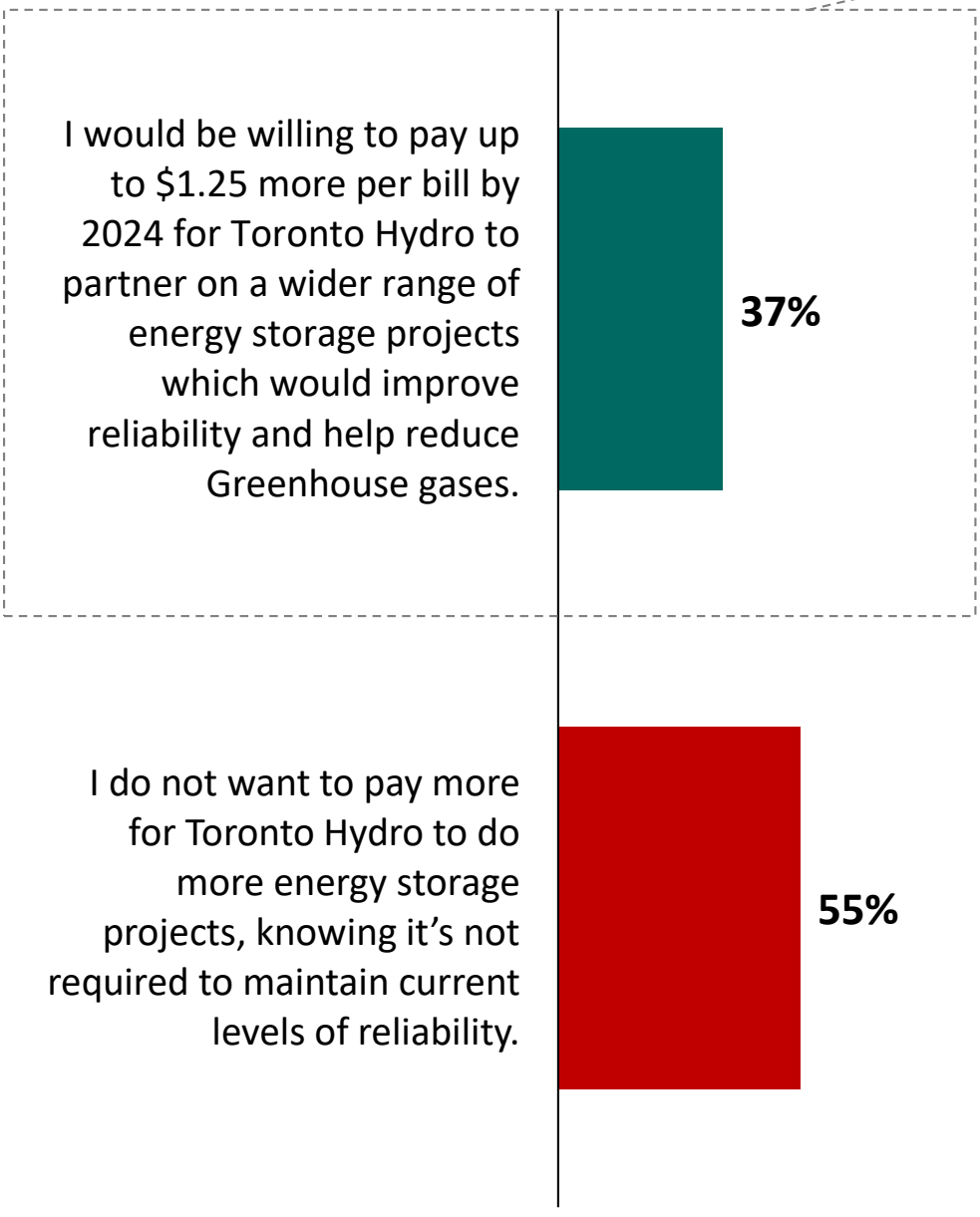
Investments in Energy Storage

3% of the proposed budget would be spent on innovation and planning for the future. The following questions are about this aspect of the budget.

Toronto Hydro has already begun to integrate large-scale battery electricity storage into the system. They have now identified more opportunities to partner on a wider range of energy storage projects. Integrating storage into the system can improve reliability and help reduce greenhouse gases, but it is not required to maintain current levels of reliability.

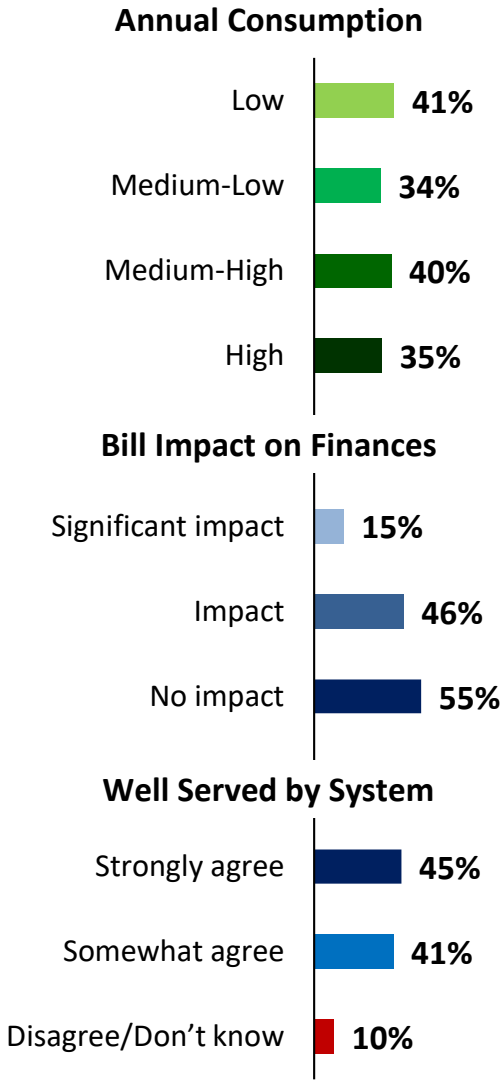
Which of the following is closest to your point of view?

[asked all respondents, n=200]



Segmentation

*Those who say "**Pay more to partner on energy storage projects**":*



Note: "Don't Know" (8%) not shown.

Monitoring and Control Equipment

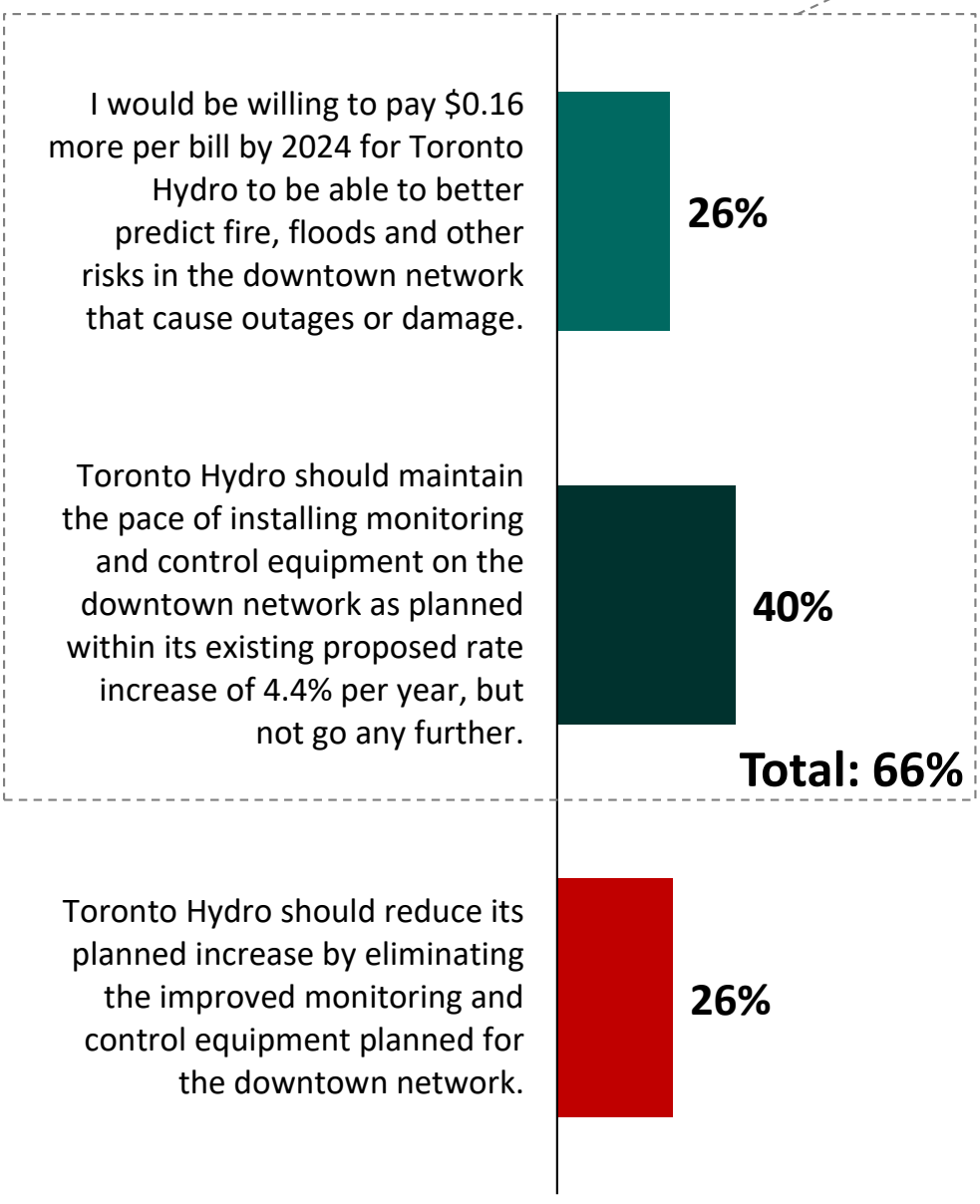
New communication technology has revolutionised the way the grid can be managed.

Toronto Hydro plans to take advantage of various new technologies wherever clear benefits can be established.

However, **Toronto Hydro** can improve the reliability of its grid further by installing communication devices in the downtown underground network that detect fire, floods or other risks more quickly.

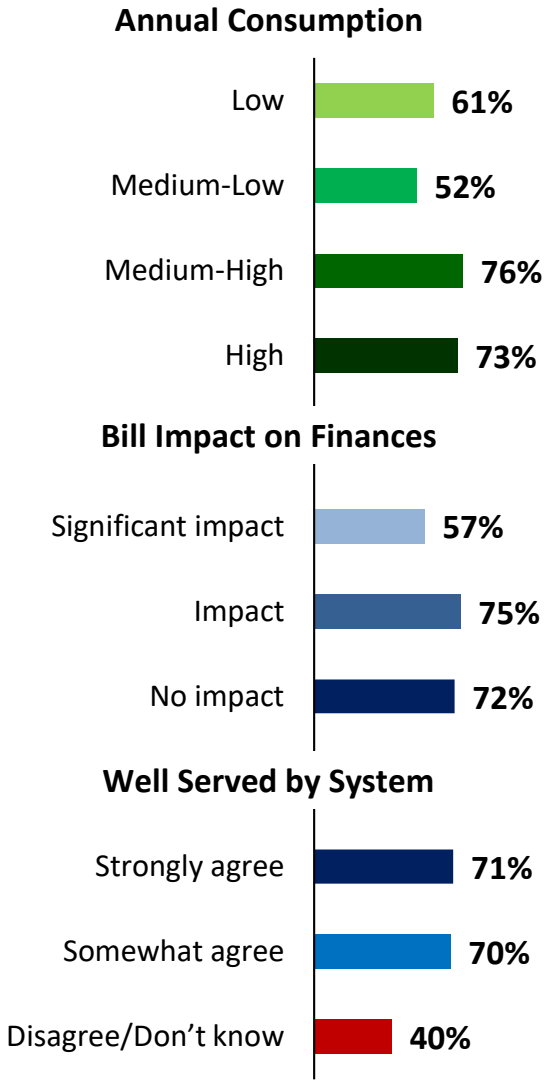
Which of the following is closest to your point of view?

[asked all respondents, n=200]



Segmentation

*Those who say "**Stick with proposed approach or spend more**":*



Note: "Don't Know" (8%) not shown.

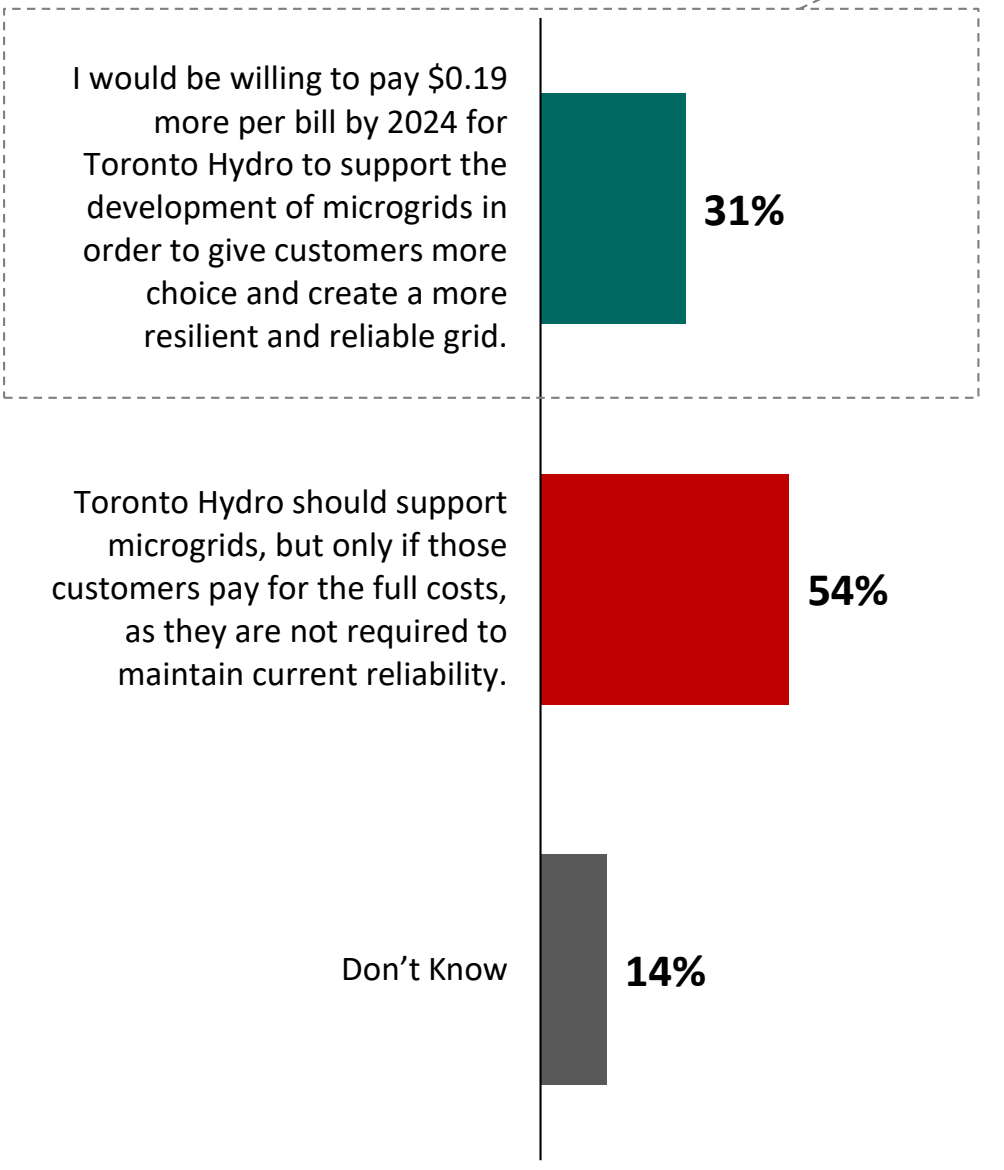
Supporting Microgrids

New types of generation (often renewable), storage, and supporting systems are making it possible for communities, institutions or other large customers to develop “microgrids”. They are a local electricity network linking smaller sources of electricity with nearby uses such as homes, businesses and institutions. In the event of a failure of the larger network, a microgrid can seal itself off and continue to provide power locally.

Microgrids would give customers more choices, while creating a more resilient and reliable grid. However, they are not required to maintain current reliability.

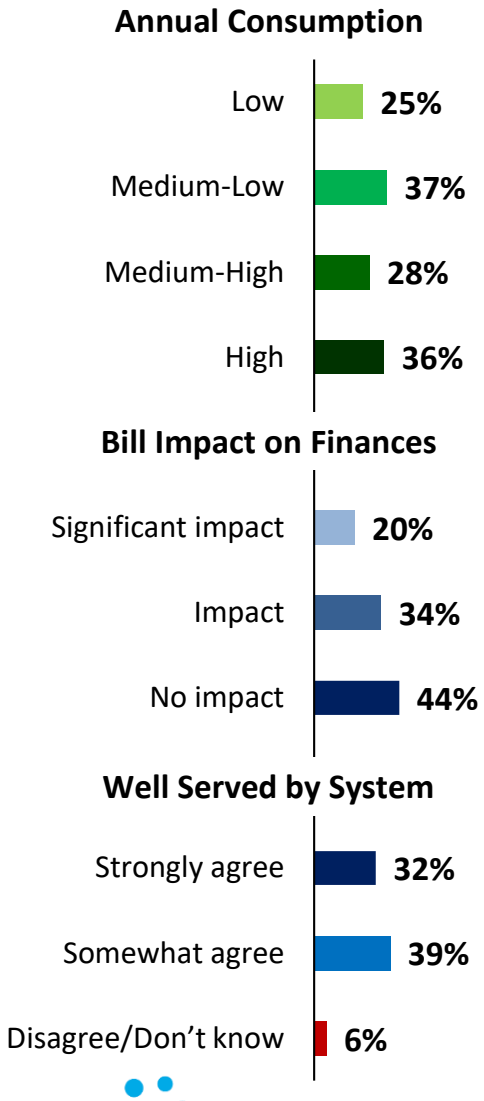
Which of the following is closest to your point of view?

[asked all respondents, n=200]



Segmentation

*Those who say “**Pay more to support microgrids**”:*



Investment Alternatives Summary Preamble

Toronto Hydro's current proposed plan, which translates into an average 4.4% annual increase, focuses on delivering current levels of reliability and customer service for most customers and targeted improvements for customers experiencing below average service or who have special reliability needs, like hospitals.

In dollars and cents, that means an average increase to the monthly bill of **$4.86 each year** for the typical small business customer.

Over the course of the proposed 5-year plan, the typical small business customer will see the distribution portion of their electricity bill **increase by $24.32.**

As a result, the distribution charges on the monthly bill would increase from a proposed amount of **$102 in 2019** to **$126 by 2024**.

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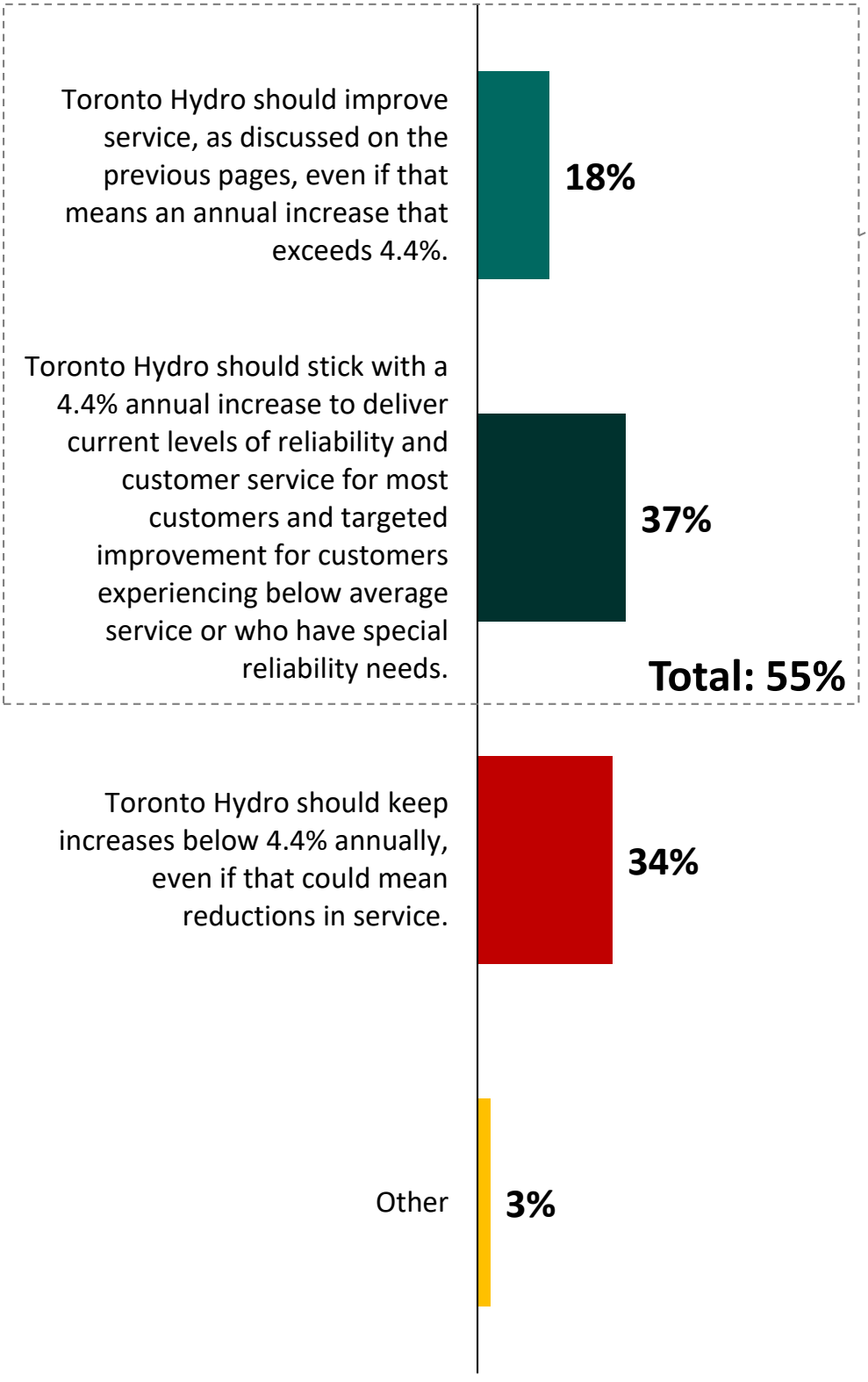
Opinion of Toronto Hydro's Proposed Plan

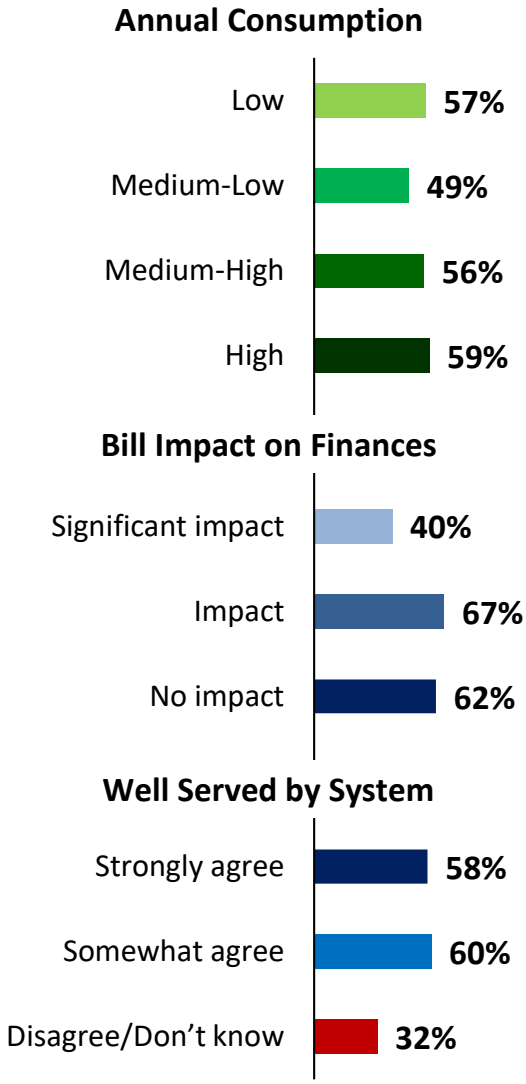
Q With regards to **Toronto Hydro's** proposed plan, which of the following statements best represents your view?

[asked all respondents, n=200]



Segmentation

*Those who say "**Stick with current pace of investment or increase to improve services**":*



Note: "Don't Know" (7%) not shown.

Opinion of Toronto Hydro's Proposed Plan by Segmentations

Q With regards to **Toronto Hydro's** proposed plan, which of the following statements best represents your view?
[asked all respondents, n=200]

Bill Impact on Finances

Opinion of Toronto Hydro's Proposed Plan	*The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being delayed.*			*Total*
	Sig. Impact [n=61]	**Impact** [n=59]	**No Impact** [n=64]	
Improve services, increase above 4.4%	13%	20%	23%	**18%**
	40%	67%	62%	
Stick with current plan at 4.4%	27%	47%	40%	**37%**
Keep increases below 4.4%	47%	31%	27%	**34%**

Well Served by System

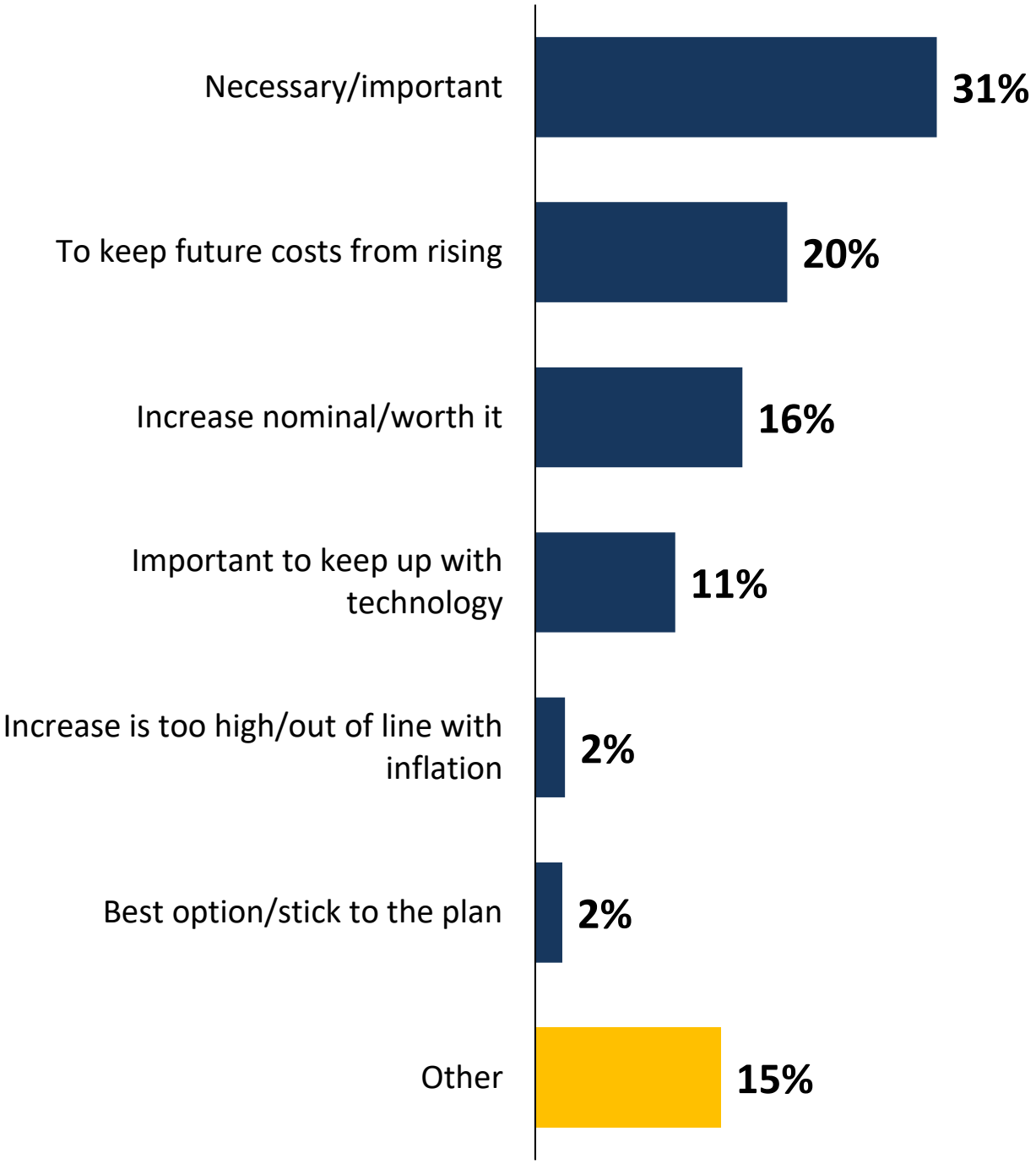
Opinion of Toronto Hydro's Proposed Plan	*Customers are well served by the electricity system in Ontario.*			*Total*
	Strongly agree [n=66]	**Somewhat agree** [n=104]	**Disagree/ Don't know** [n=30]	
Improve services, increase above 4.4%	22%	20%	3%	**18%**
	58%	60%	32%	
Stick with current plan at 4.4%	36%	40%	29%	**37%**
Keep increases below 4.4%	35%	34%	32%	**34%**

Note: "Other" and "Don't Know" not shown.

Opinion of Toronto Hydro's Proposed Plan

Q And why do you say that?
[asked of those who say Toronto Hydro should improve service, n=36]

For those who answered: Toronto Hydro should improve service, as discussed on the previous pages, even if that means an annual increase that exceeds 4.4%. (n=36)



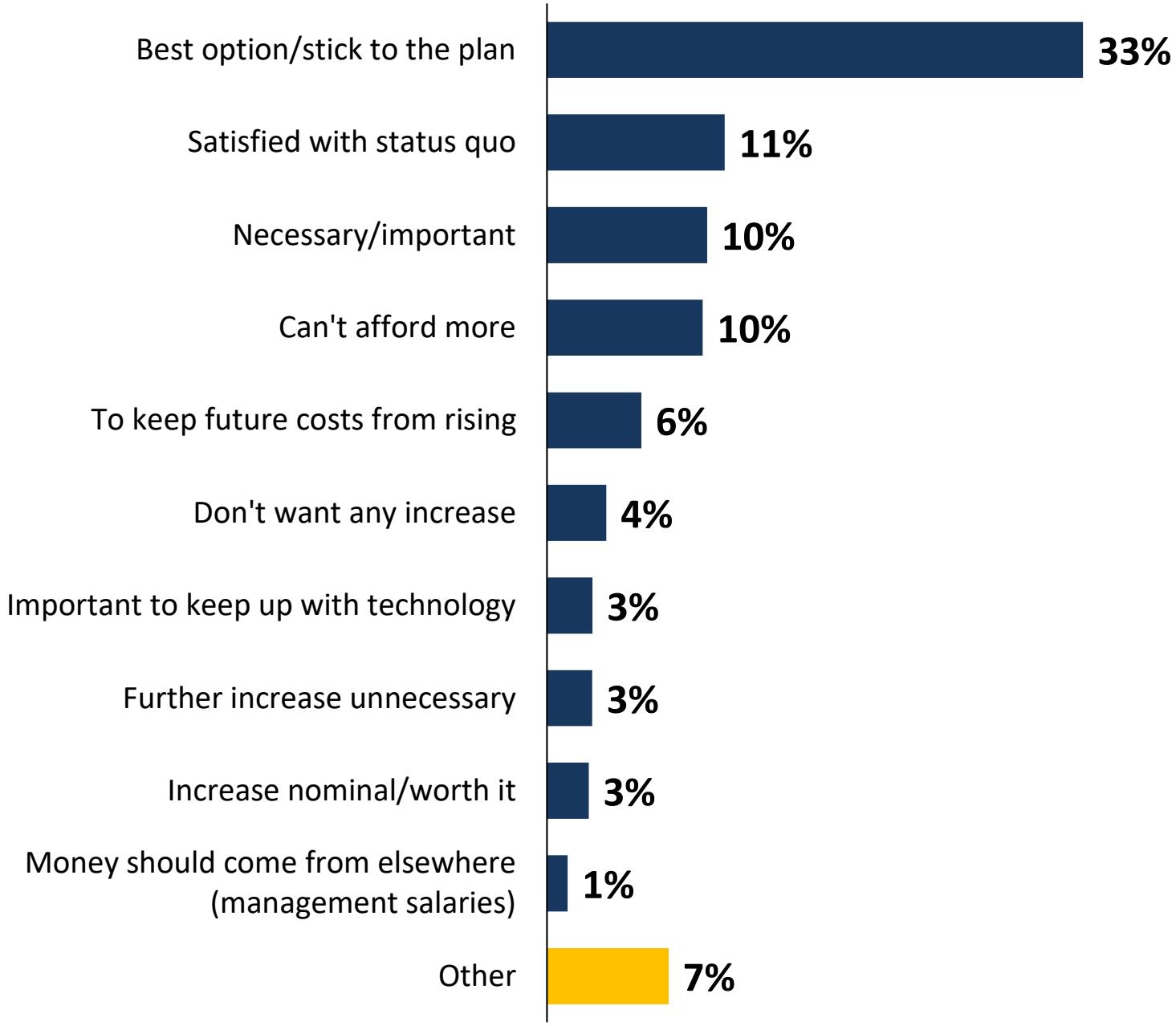
Note: "Refused" (3%) not shown.

Opinion of Toronto Hydro's Proposed Plan

Q And why do you say that?

[asked of those who say Toronto Hydro should stick with proposed plan, n=74]

For those who answered: Toronto Hydro should stick with a 4.4% annual increase to deliver current levels of reliability and customer service for most customers and targeted improvement for customers experiencing below average service or who have special reliability needs. (n=74)



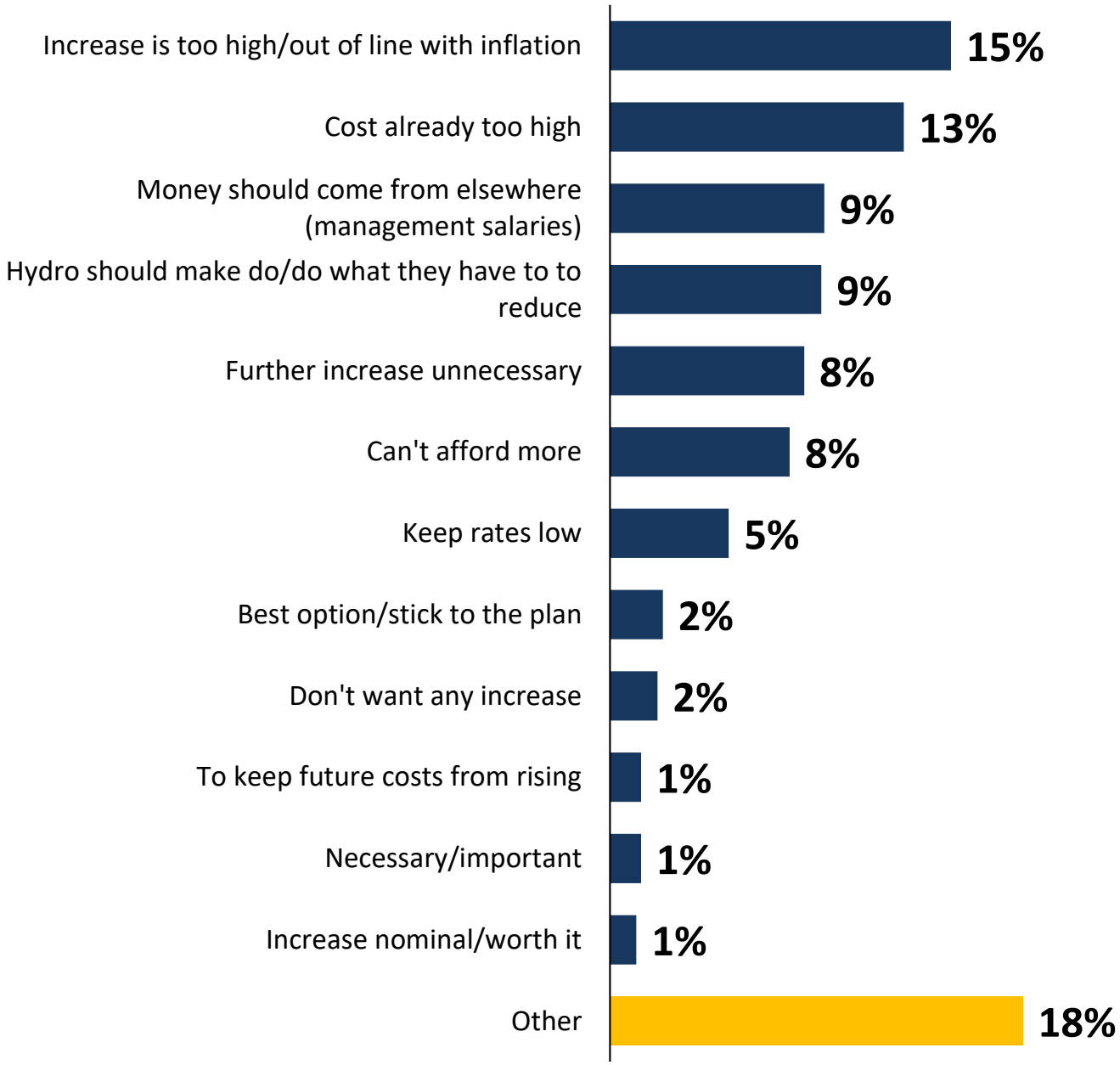
Note: "None" (6%), "Don't Know" (3%), "Refused" (1%) not shown.

Opinion of Toronto Hydro's Proposed Plan

Q And why do you say that?

[asked of those who say Toronto Hydro should keep increases below 4.4%, n=67]

For those who answered: Toronto Hydro should keep increases below 4.4% annually, even if that could mean reductions in service. (n=67)



Note: "Don't Know" (3%) and "Refused" (3%) not shown.

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Personalized research to connect you and your audiences.

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Appendix 2.4

Toronto Hydro 2018 Customer Engagement

Mid-Market Telephone Survey Report

Mid-Market Report

June 2018

STRICTLY PRIVILEGED AND CONFIDENTIAL

Survey Methodologies



Field and Design

These are the findings of an Innovative Research Group (INNOVATIVE) telephone survey conducted among **n=202** Toronto Hydro **mid-sized business customers** between **May 2 and 14, 2018.**

Quotas were set by electricity consumption levels and geographic considerations from within the Toronto Hydro service territory in order to obtain a representative customer sample.

Mid-sized business customers were divided into quartiles based on annual electricity usage to ensure the sample had a proportionate mix of customers from low, medium-low, medium-high, and high electricity usage groups.

The sample has been weighted to n=200 by the quartiles and region to reflect the actual composition of mid-sized business customers within the service area.

The margin of error for a sample of n=200 is approximately +/-6.9%. 19 times out of 20.

For the purposes of executing the customer surveys, Toronto Hydro provided INNOVATIVE with a confidential list of customers' contact information. The contact list included only customers with telephone contact information on file and who had been a customer of Toronto Hydro for at least one year. The information contained in the contact list included customer name, telephone number(s), postal code and total annual electricity consumption.

Only one customer per organization was eligible to complete the survey. Respondents were screened to certify that only the personnel responsible for managing or overseeing their electricity bill were interviewed. This step was taken to ensure that survey respondents represented the most qualified person within an organization to answer questions.

Customers were offered a $20 Amazon Gift Card in appreciation for completing the survey.

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Consumption Quartiles

The tables below illustrate the strata divisions for each rate class, based on consumption quartiles.

Dividing customer sample into quartiles based on known characteristics, including region and annual consumption, was used to develop accurate quotas to ensure the sample was representative of Toronto Hydro's customer base. The tables below show the unweighted and weighted distributions.

	Consumption Quartiles (Unweighted n)				Total
	Low	Medium-Low	Medium-High	High	
Toronto & East York	13	21	21	18	**73**
Etobicoke & York	13	9	8	6	**36**
North York	19	13	12	18	**62**
Scarborough	5	9	9	8	**31**
Total	**50**	**52**	**50**	**50**	**202**

	Consumption Quartiles (Weighted n)				Total
	Low	Medium-Low	Medium-High	High	
Toronto & East York	17	17	17	17	**68**
Etobicoke & York	10	10	10	10	**39**
North York	14	14	14	14	**54**
Scarborough	10	10	10	10	**39**
Total	**50**	**50**	**50**	**50**	**200**

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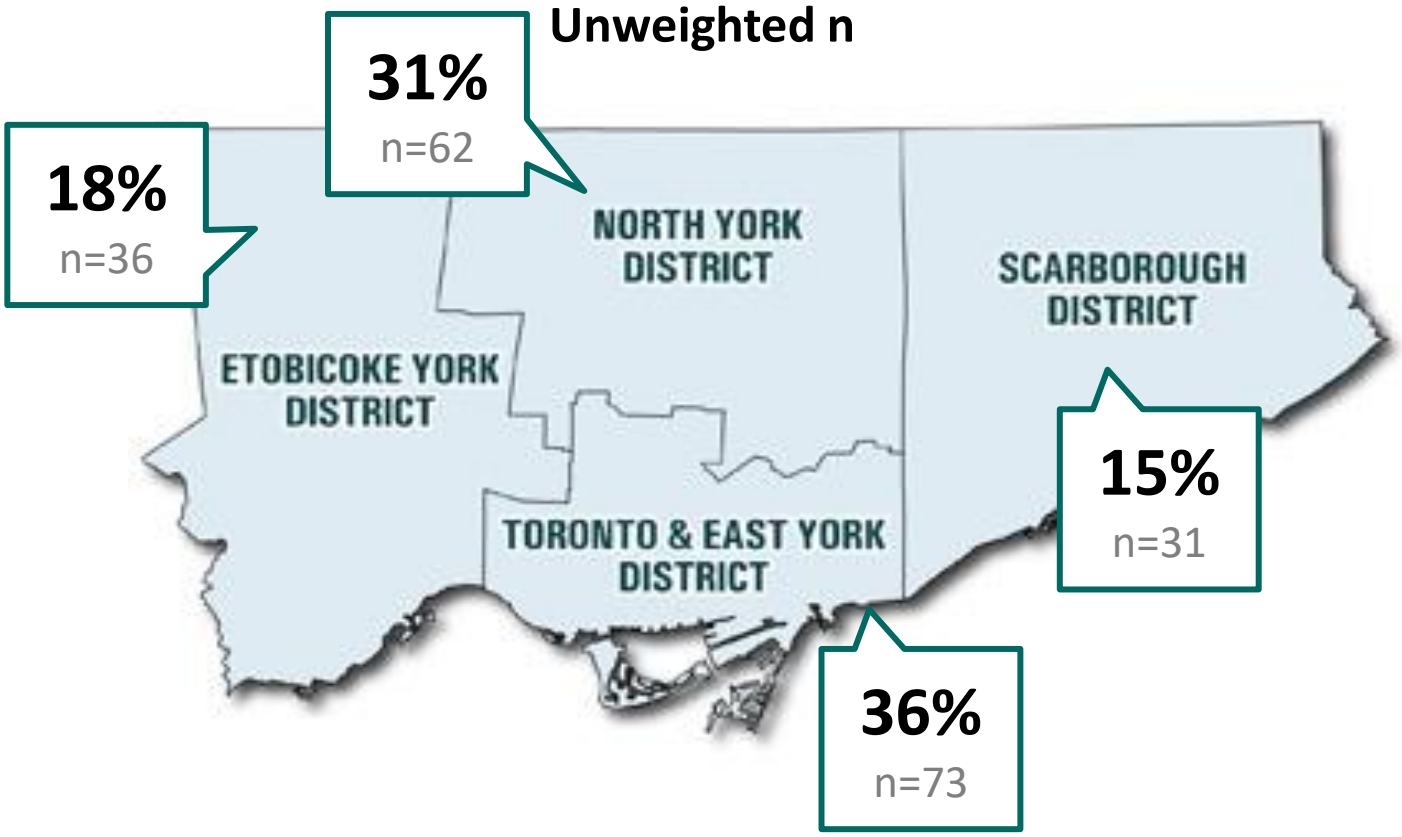
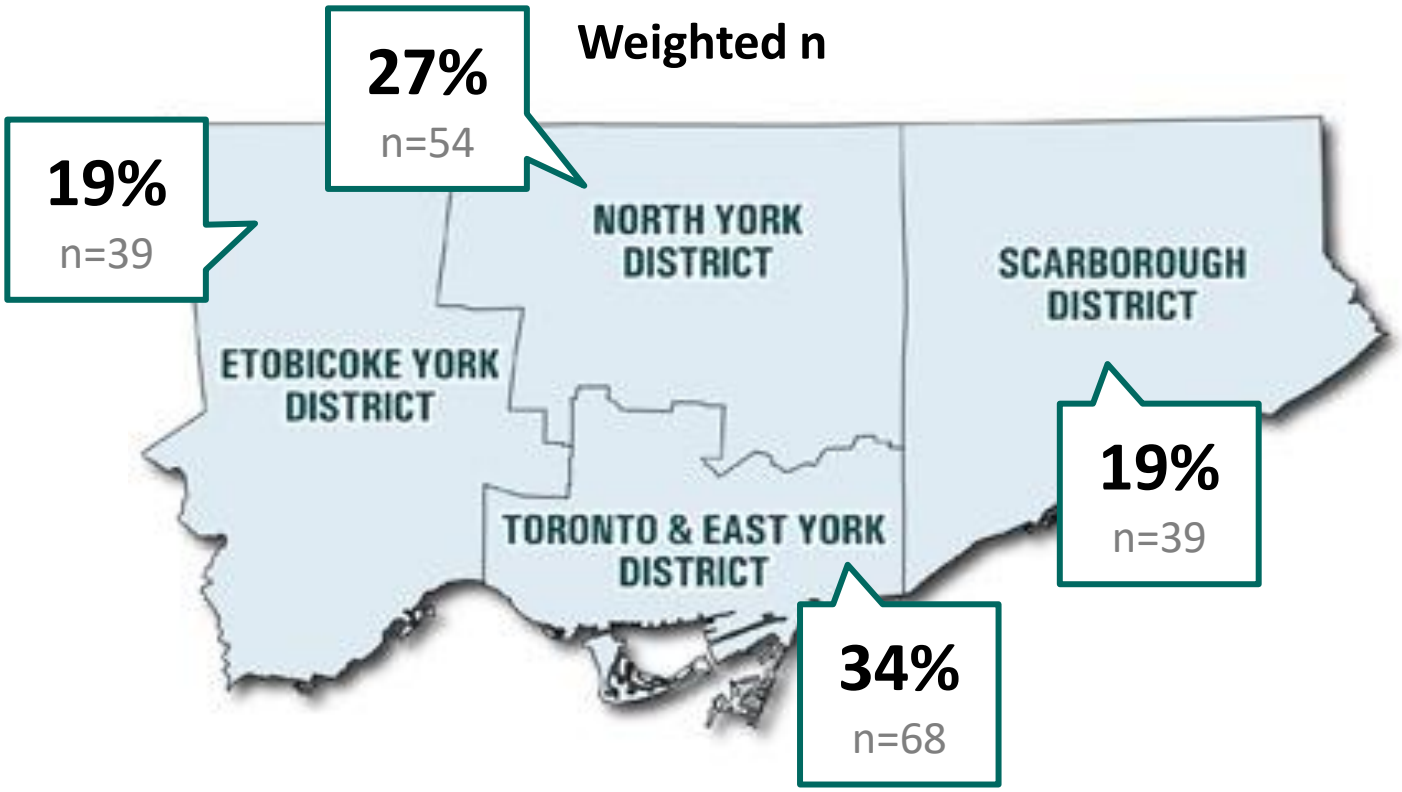
Regions

The charts below illustrate the overall regional distribution.

The charts below show the unweighted and weighted distributions.





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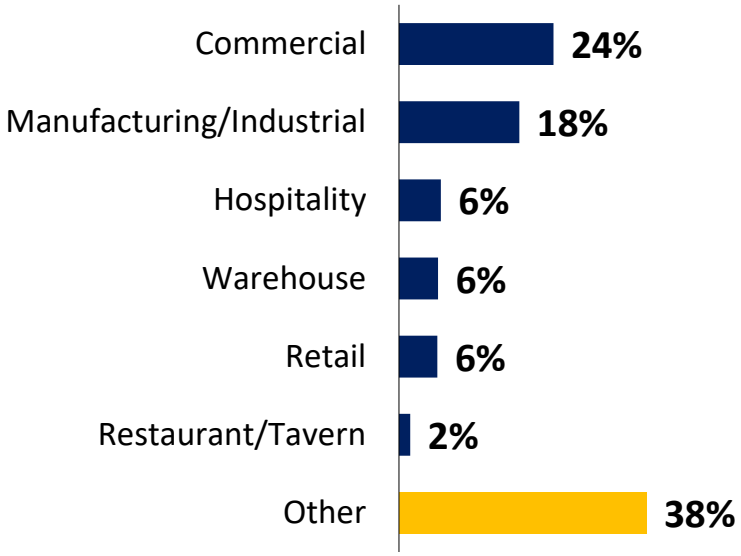
Segmentation and Demographics



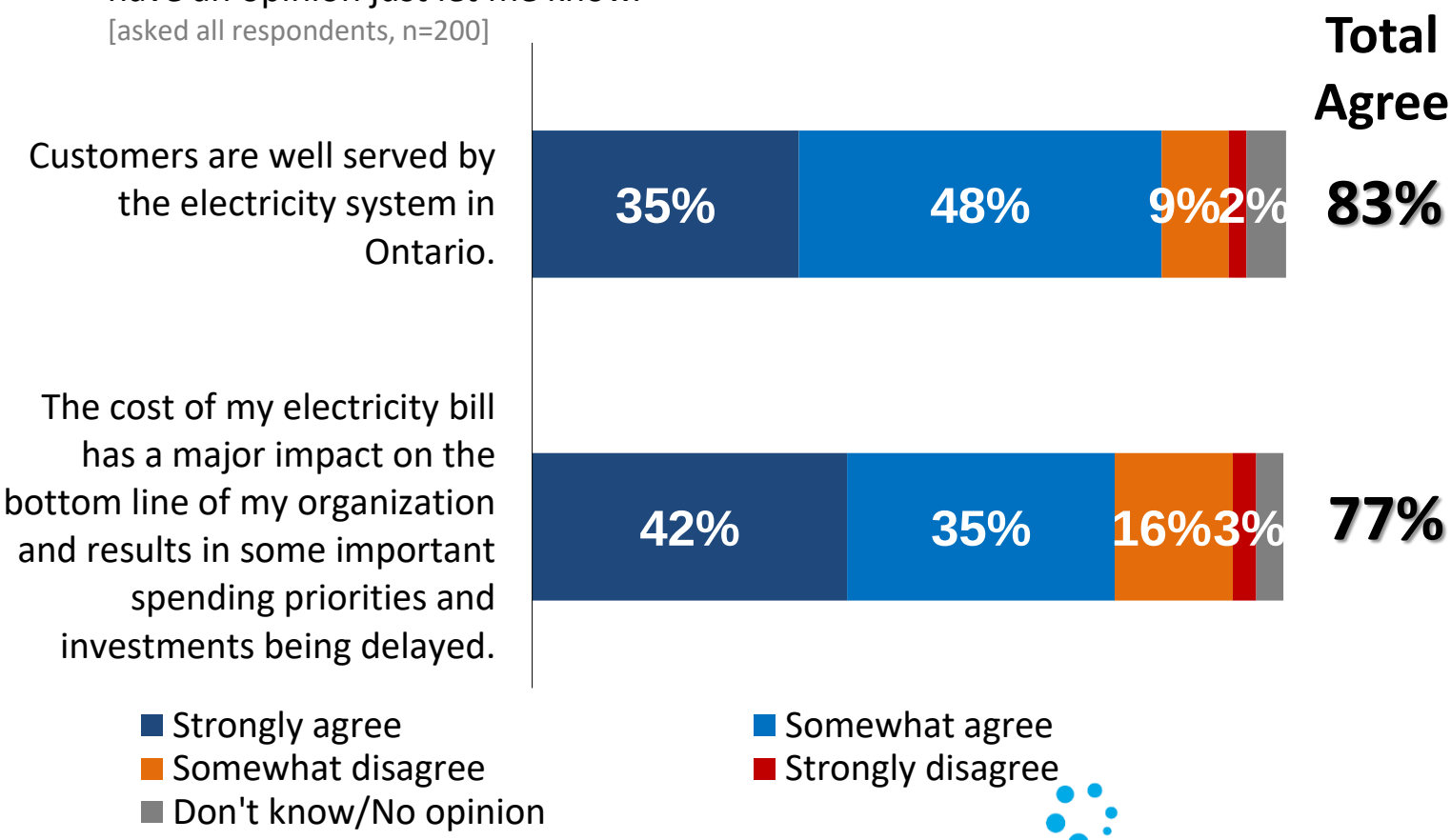
Segmentation & Demographics

Business Sector



Q For each statement please tell me if you would strongly agree, somewhat agree, somewhat disagree or strongly disagree. If you don't know enough to say or don't have an opinion just let me know.

[asked all respondents, n=200]



Familiarity Preamble

To start, I'd like to ask you a few questions about the electricity system …

As you may know, Ontario's electricity system has three key components: ***generation***, ***transmission*** *and* ***distribution****.*

- ***Generating stations*** *convert various forms of energy into electric power;*
- ***Transmission lines*** *connect the power produced at generating stations to where it is needed across the province; and*
- ***Distribution lines*** *carry electricity to the homes and businesses in our communities.*

Today we're going to talk about your ***local distribution system*** *which is maintained and operated by Toronto Hydro.*

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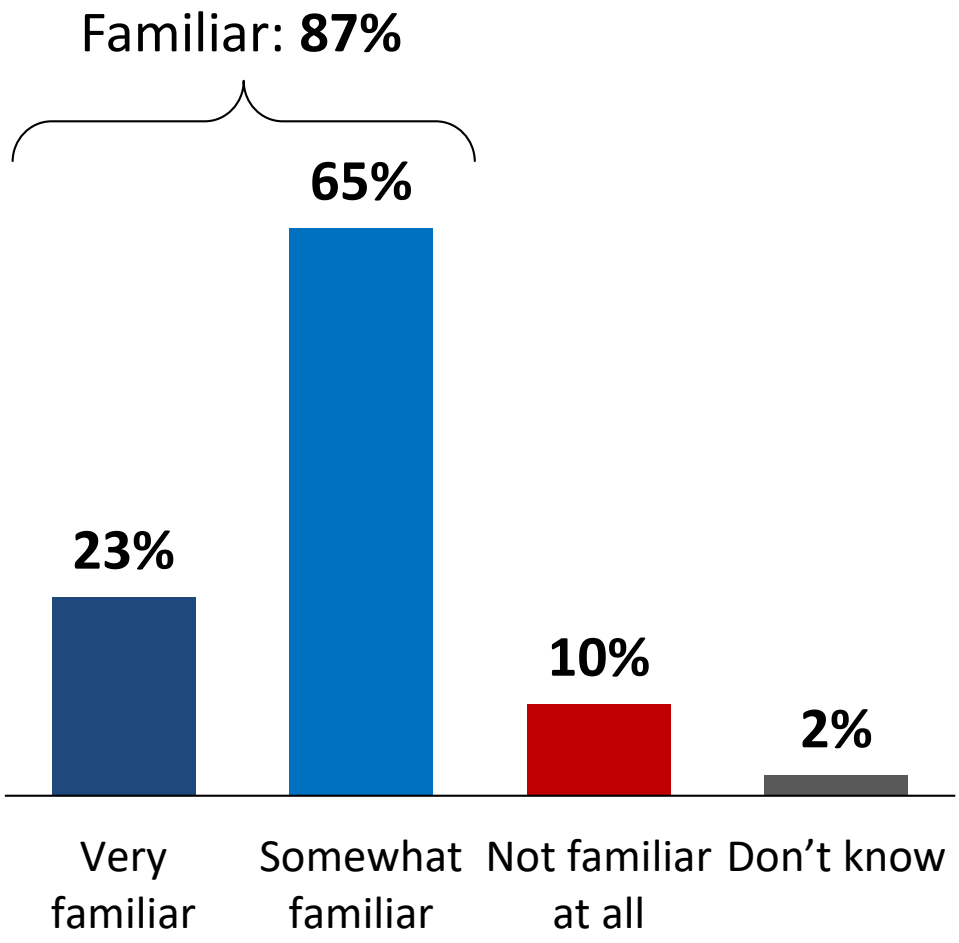
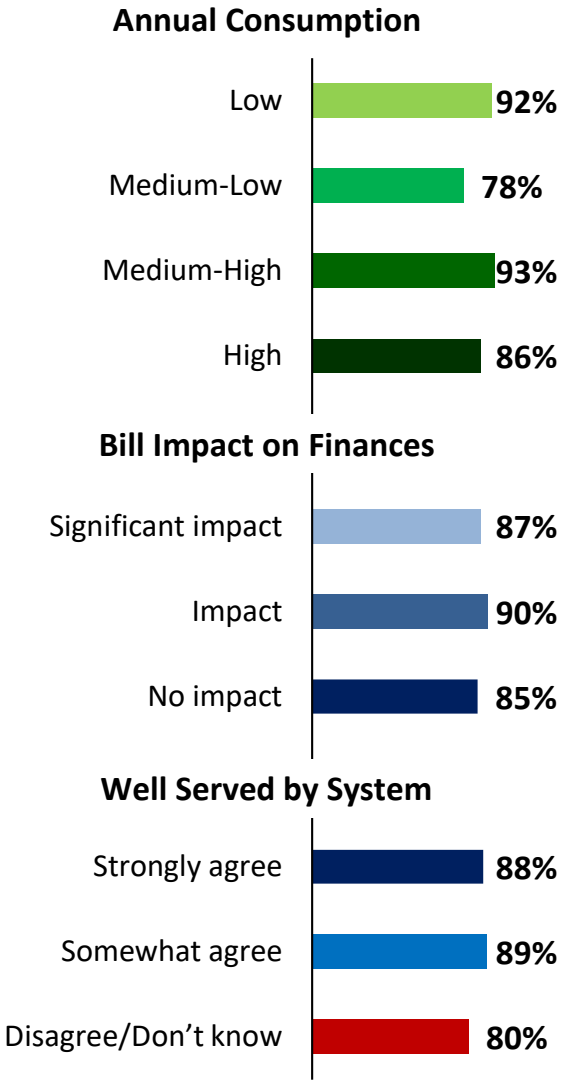
Familiarity with Toronto Hydro

How familiar are you with **Toronto Hydro**?
[asked all respondents, n=200]



Segmentation

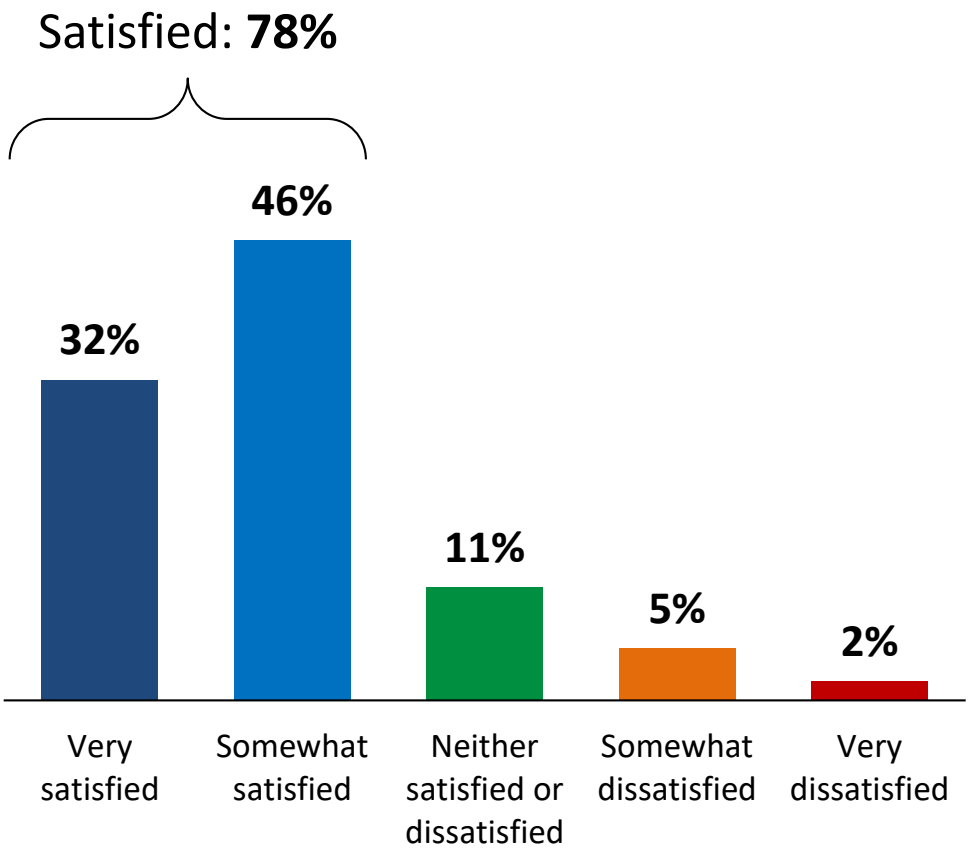
*Those who say "**Familiar**":*



Satisfaction with Services

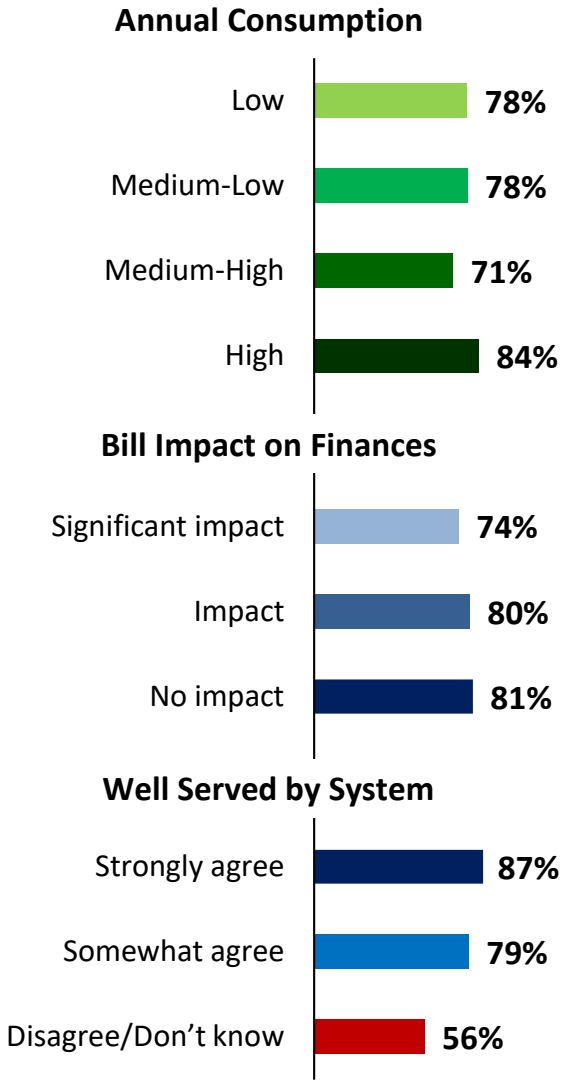
Q In general, how satisfied or dissatisfied are you with the services your organization receives from **Toronto Hydro**?

[asked all respondents, n=200]



Segmentation

*Those who say "**Satisfied**":*

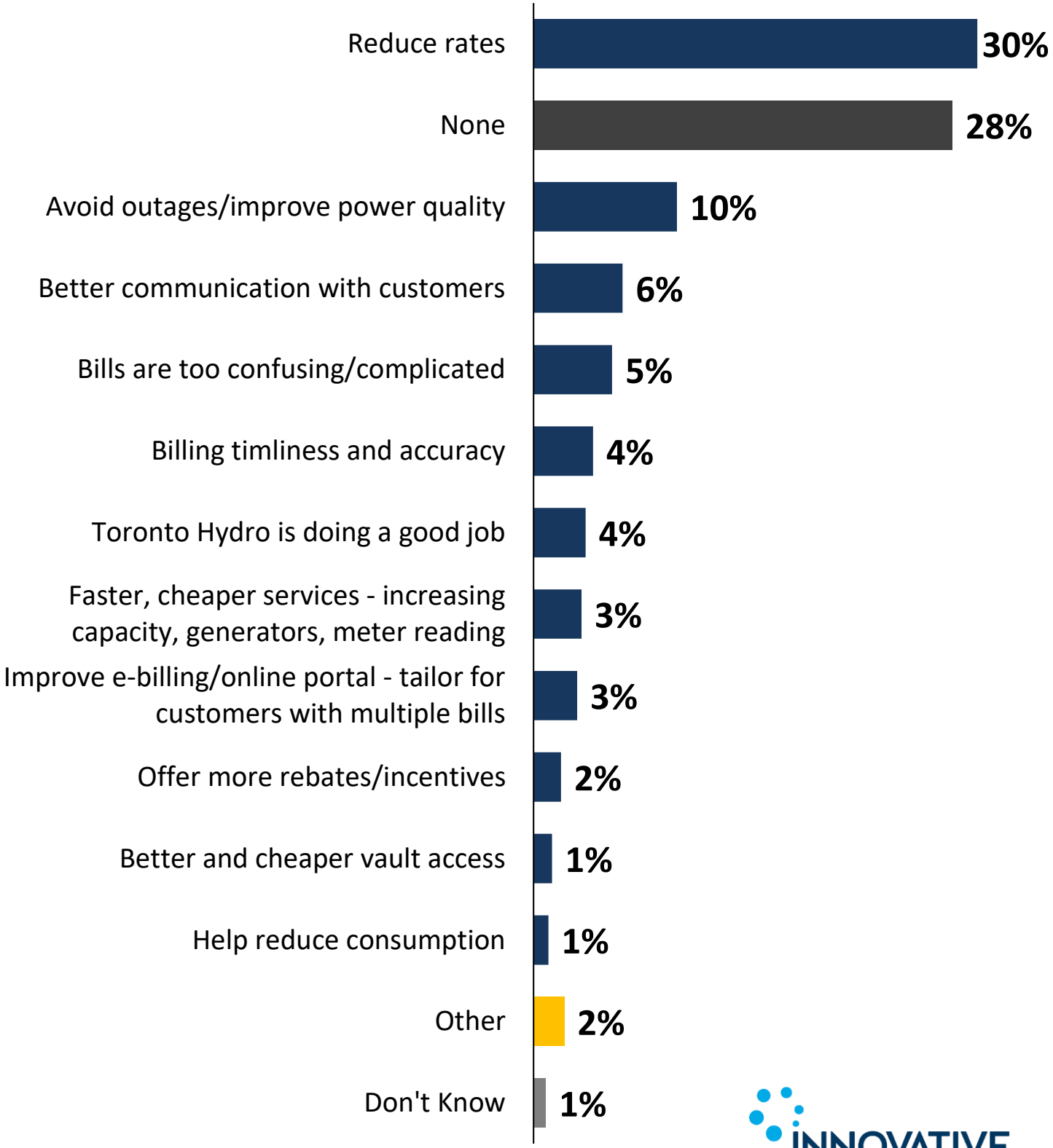


Note: "Don't know" (3%) not shown.

Suggestions for Improved Services

Q Is there anything in particular that **Toronto Hydro** can do to improve its services to your organization?

[asked all respondents, n=200]



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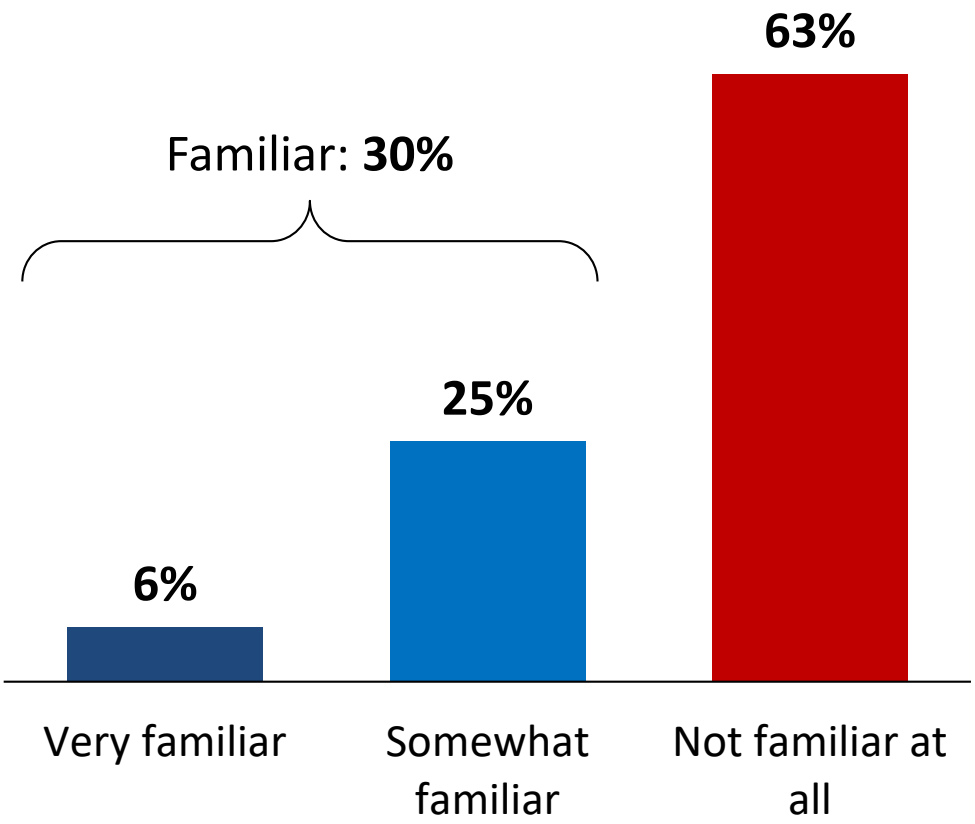
Amount of Bill Retained by Toronto Hydro

While **Toronto Hydro** is responsible for collecting payment for the entire electricity bill, they retain about **10%** of the typical mid-sized business customer's bill. This is about **$1,290** on an average **$13,513** monthly mid-sized business electricity bill. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.

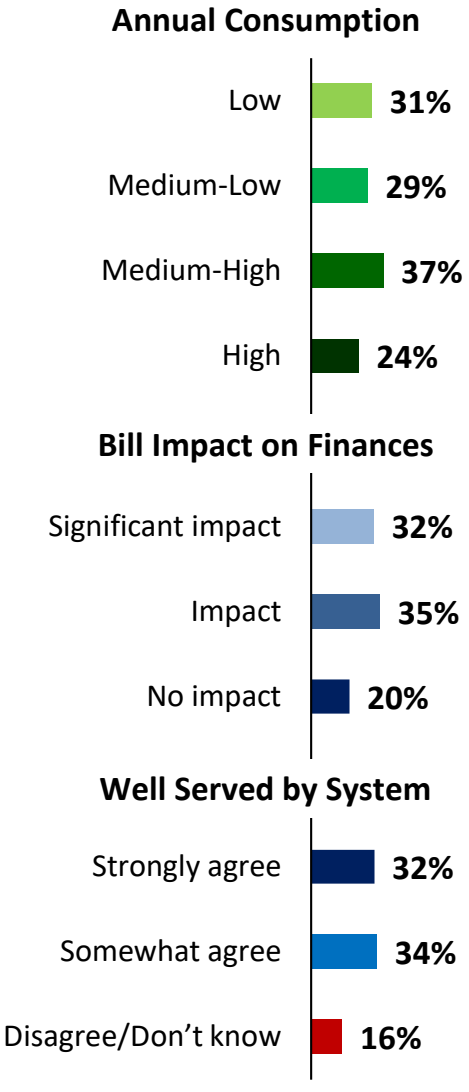
Before this survey, how familiar were you with the percentage of your organization's electricity bill that is retained by **Toronto Hydro**?

[asked all respondents, n=200]



Segmentation

*Those who say "**Familiar**":*



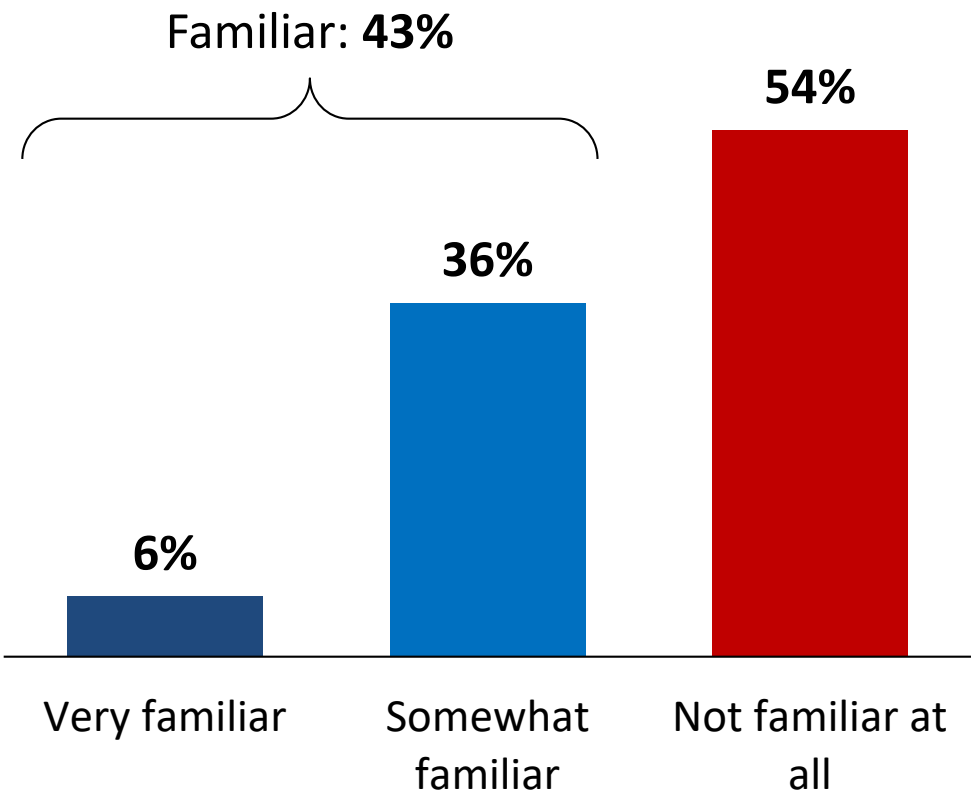
Note: "Don't Know" (7%) not shown.

Familiarity with Ontario Energy Board

Electricity distributors are required to file a rate application with the Ontario Energy Board (OEB) to request a change in distribution rates based on their plans for capital and operating spending. Toronto Hydro is now consulting on its plans for 2020 to 2024.

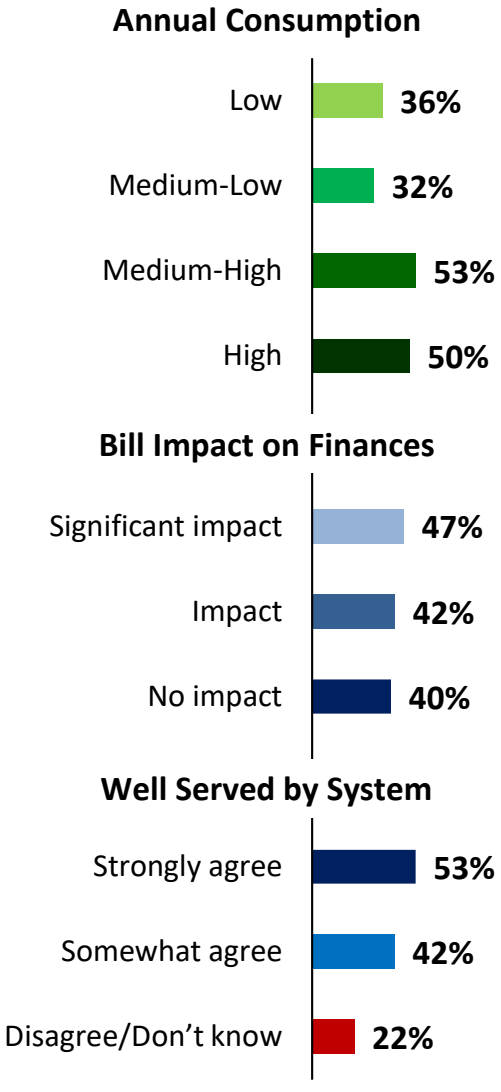
The OEB is mandated to protect consumers with respect to prices and the reliability and quality of electricity service.

How familiar would you say you are with the Ontario Energy Board or "OEB"?
[asked all respondents, n=200]



Segmentation

*Those who say "**Familiar**":*



Note: "Don't Know" (3%) not shown.

Customer Engagement Process Preamble

As part of **Toronto Hydro's** consultation, it has developed a five-phase approach to gathering and responding to customer feedback.

- First, **Toronto Hydro** identified customer priorities through a series of surveys and focus groups;
- Then, used this customer feedback to guide development of its Draft Plan;
- Now, **Toronto Hydro** is in the process of collecting customer feedback on its Draft Plan;
- The next phases will include re-examining its Draft Plan based on customer feedback and preparing a submission to the OEB.

This survey is part of the third stage of **collecting customer feedback on the Draft Plan.**

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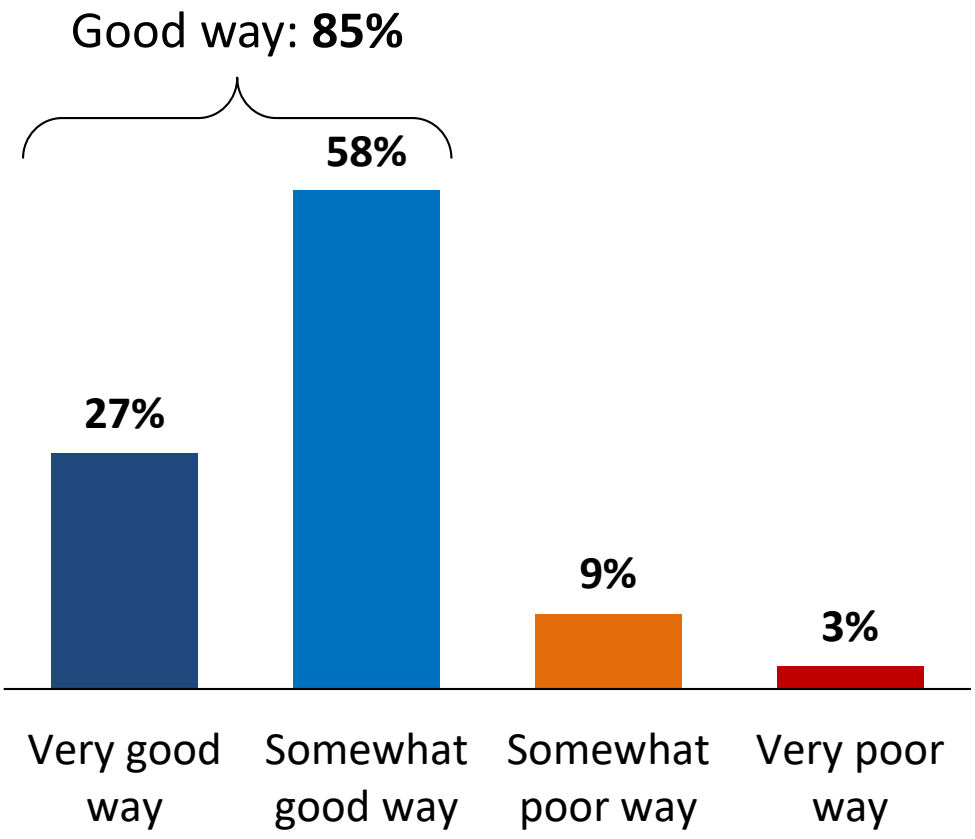
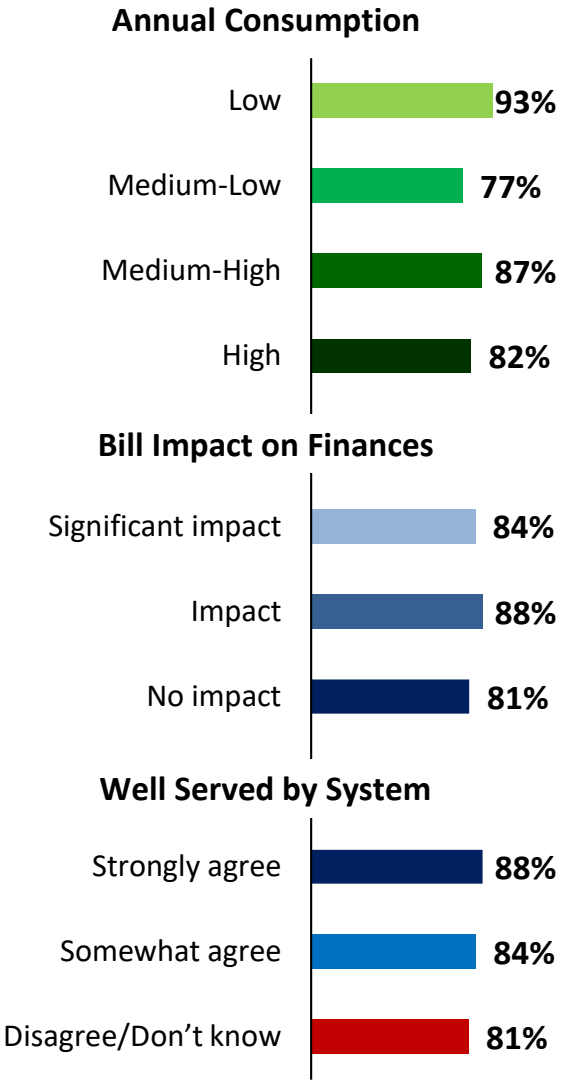
Feedback on Customer Engagement Process

Q Does this Customer Engagement process seem like a good way or a poor way to bring customer needs and preferences into **Toronto Hydro's** plan?
[asked all respondents, n=200]



Segmentation

*Those who say "**Good Way**":*



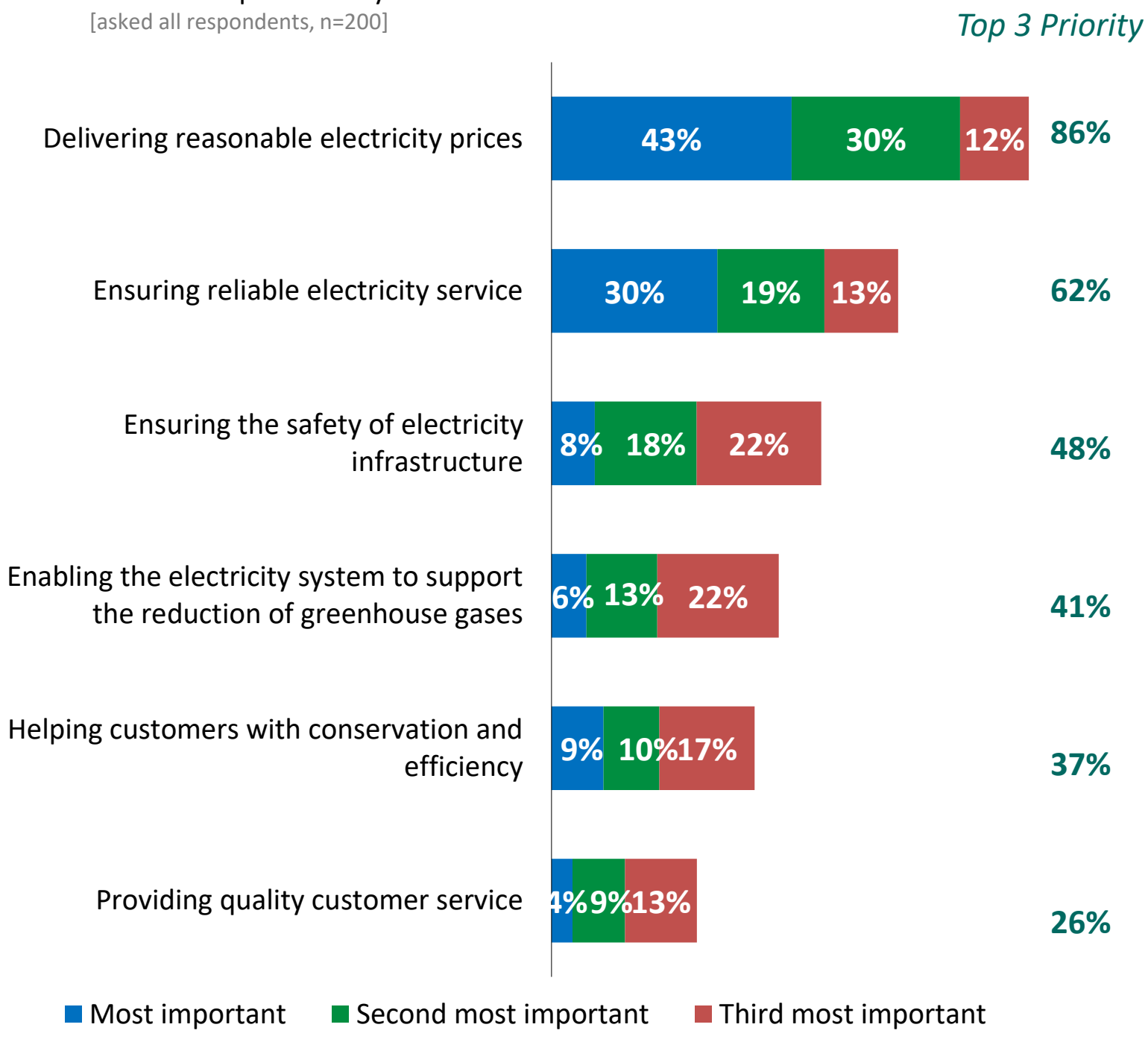
Note: "Don't Know" (4%) not shown.

Customer Priorities

Toronto Hydro wants to better understand customer priorities. In the first phase of customer engagement, residential and small business customers identified six core priorities which they believe should be a focus for **Toronto Hydro**.

Among the following customer identified priorities, please tell me which one is the most important to you.

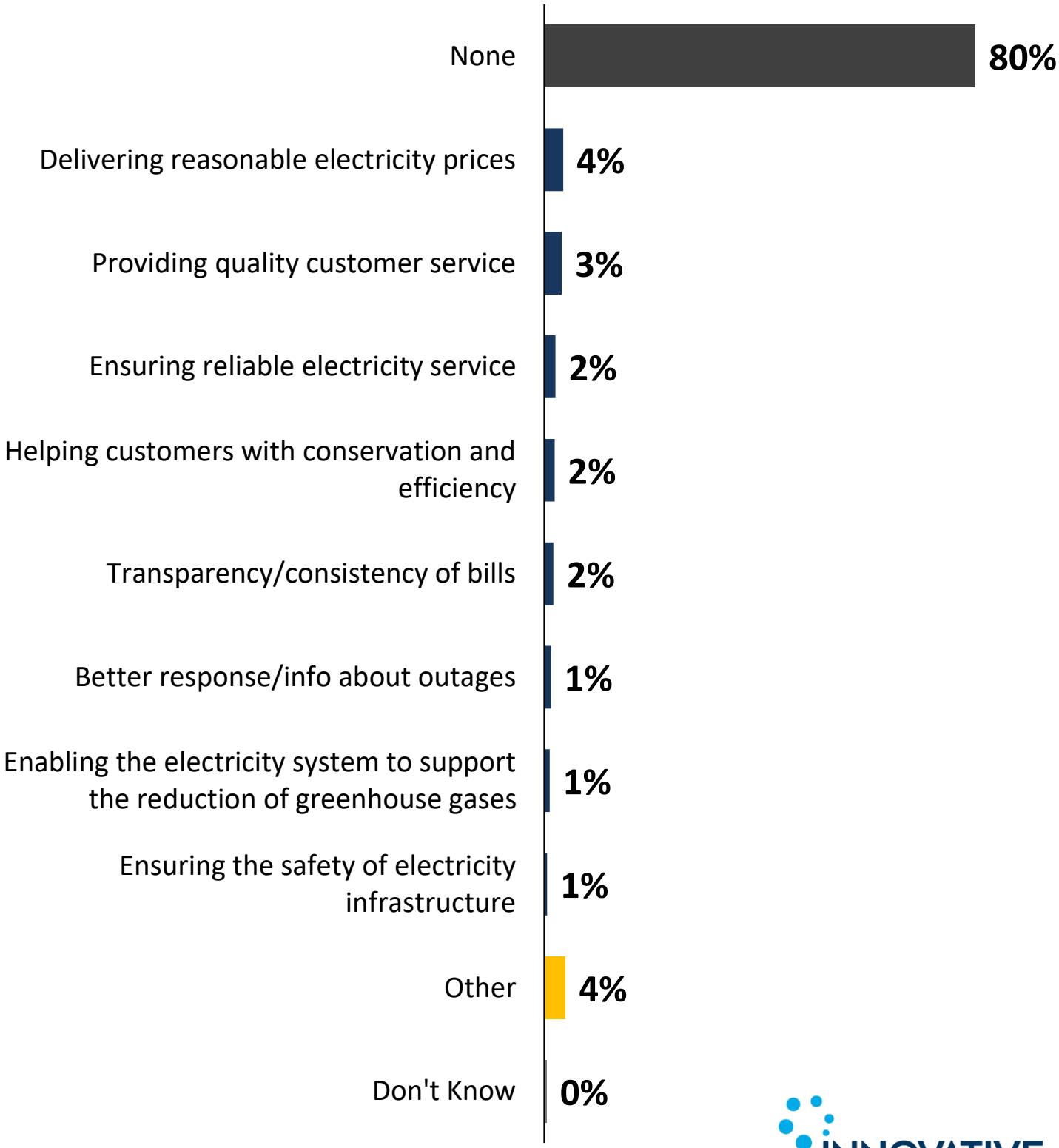
[asked all respondents, n=200]



Additional Customer Priorities

Q Are there any other important priorities that **Toronto Hydro** should be focusing on that weren't included in the previous list I read to you?

[asked all respondents, n=200]



INNOVATIVE RESEARCH GROUP

Planning Principles and Rate Impact Preamble

Based, in part, on the initial customer input, **Toronto Hydro** has drafted a plan totaling approximately $4.3B over five years.

Toronto Hydro's proposed plan focuses on delivering current levels of reliability and customer service for most customers and targeted improvements for customers experiencing below average service or who have special reliability needs, like hospitals.

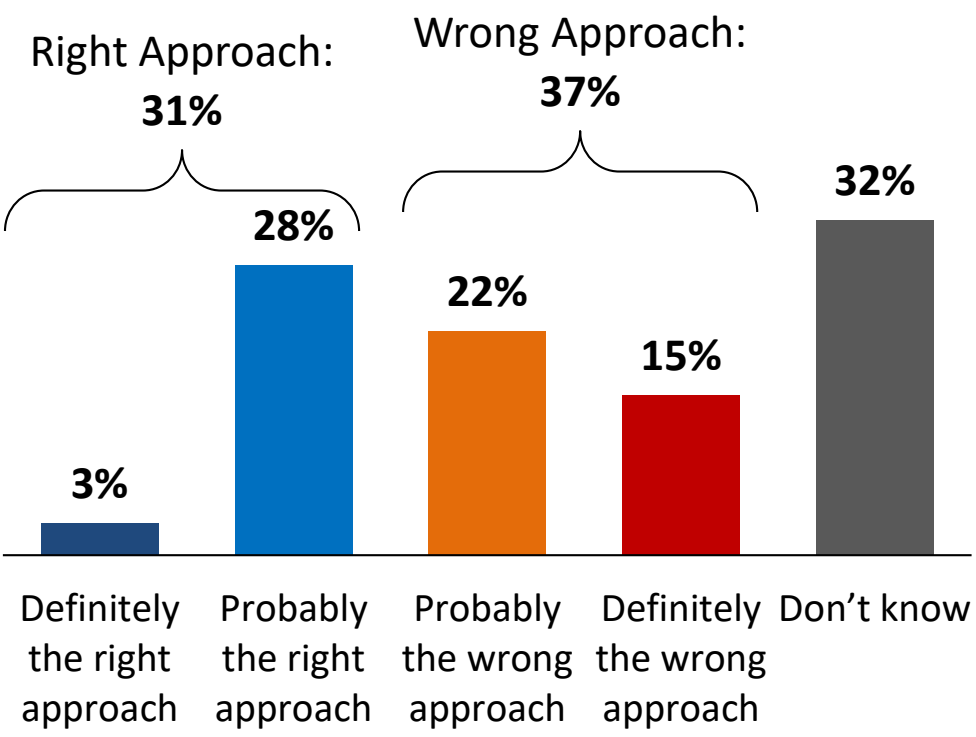
This proposed plan translates into an average 3.9% increase in your organization's distribution rates each year from 2020 to 2024. The distribution charges on the monthly bill would increase to $2,023 by 2024 for a typical mid-sized business customer.

INNOVATIVE RESEARCH GROUP

Approach to Planning for the Next Five Years

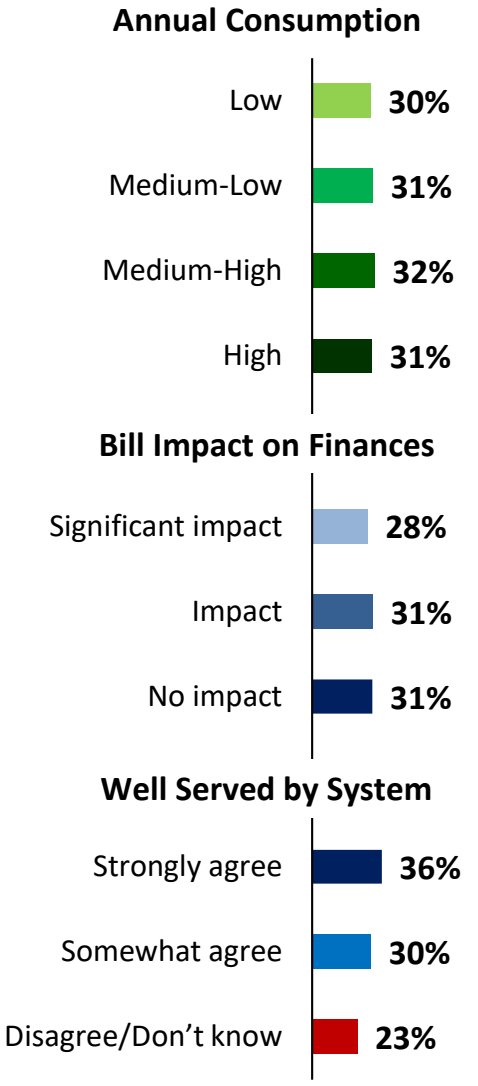
Q Do you feel that this is definitely the right approach, probably the right approach, probably the wrong approach or definitely the wrong approach to **Toronto Hydro's** planning for the next five years or would you say you don't know?

[asked all respondents, n=200]



Segmentation

*Those who say "**Right Approach**":*



Gathering Feedback on Capital Investment Decisions

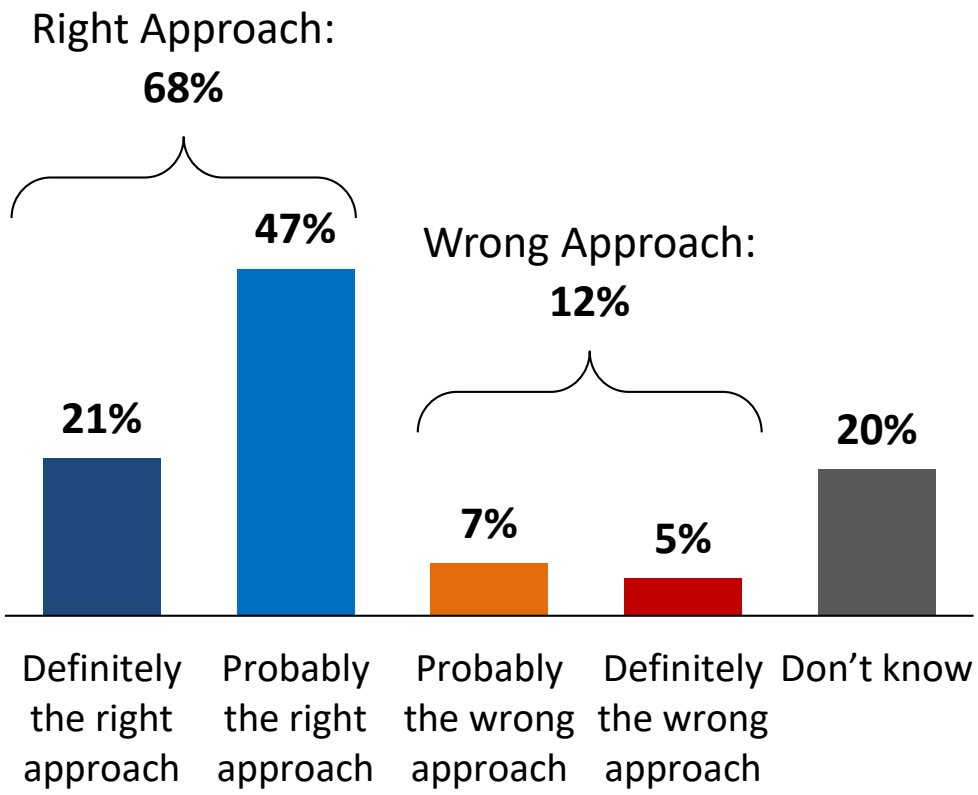
Toronto Hydro's total spending is benchmarked by the OEB against other utilities in Ontario. Toronto Hydro's operating costs of $305 per customer are within $1 of the provincial average.

However **Toronto Hydro's** capital investment costs are $739 per customer which are $245 more than the provincial average.

Since a number of capital investment decisions are based trade-offs between costs and customer outcomes – like services and reliability levels – the remaining questions in this survey ask for your feedback on those choices.

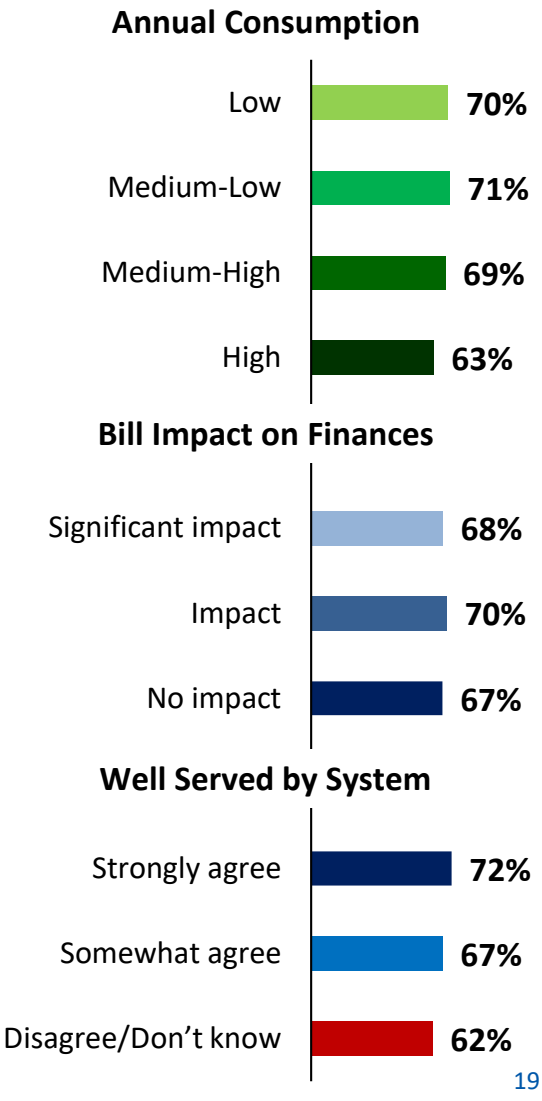
Do you feel that gathering feedback on capital investment decisions is *definitely the right approach, probably the right approach, probably the wrong approach, definitely the wrong approach or would you say you don't know*?

[asked all respondents, n=200]



Segmentation

*Those who say "**Right Approach**":*

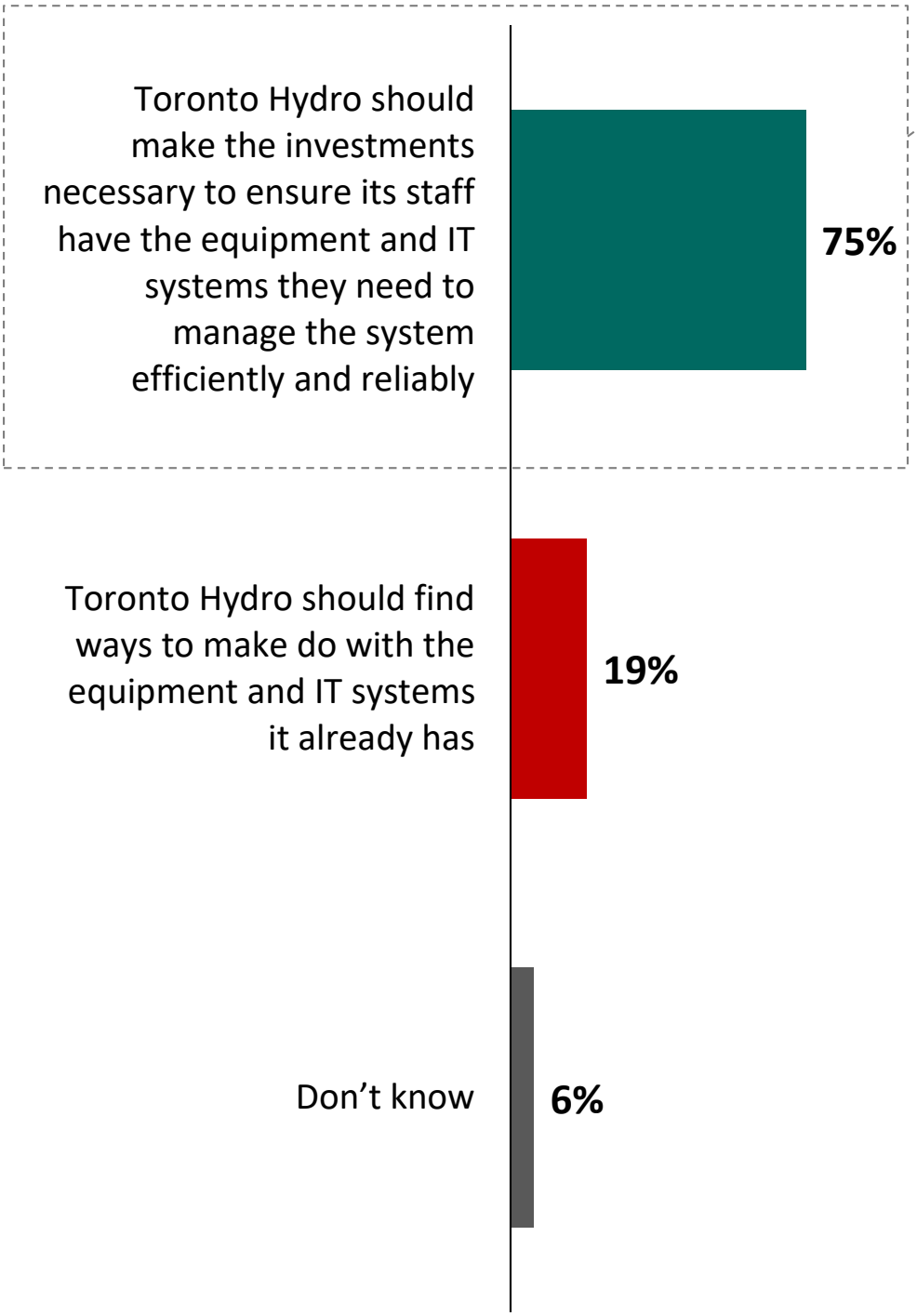


Investing in the Basics

As a company, **Toronto Hydro** needs vehicles and tools to service the power lines and IT systems to manage the system and customer information.

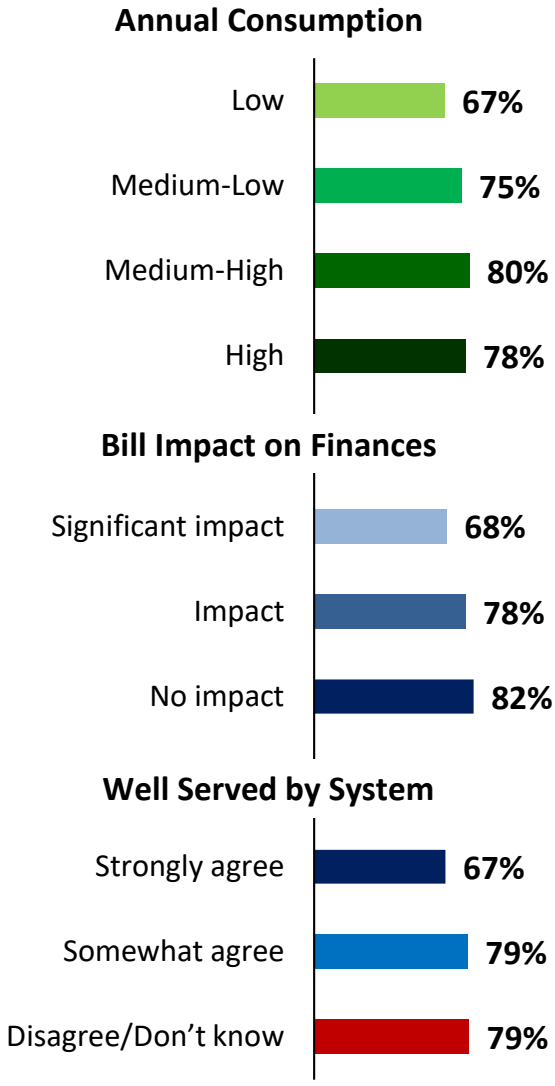
Which of the following statements best represents your point of view?

[asked all respondents, n=200]



Segmentation

*Those who say "**Make necessary investments**":*



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Addressing Safety and Reliability



Addressing Safety and Reliability Preamble

Toronto Hydro has identified areas where it could accelerate investments. These accelerated projects could increase the **typical customer's bill by $100 per month by 2024**. These projects are in addition to the 3.9% increase that is currently being proposed.

Toronto Hydro wants to get your feedback on particular projects before deciding whether or not to accelerate its investment plan in certain specific areas.

Right now, the typical **Toronto Hydro** customer averages 1.4 outages per year with an average of between 60 and 70 minutes without power over the year. While many of those outages are caused by events outside of **Toronto Hydro's** control, roughly 36% are caused by the failure of aging equipment.

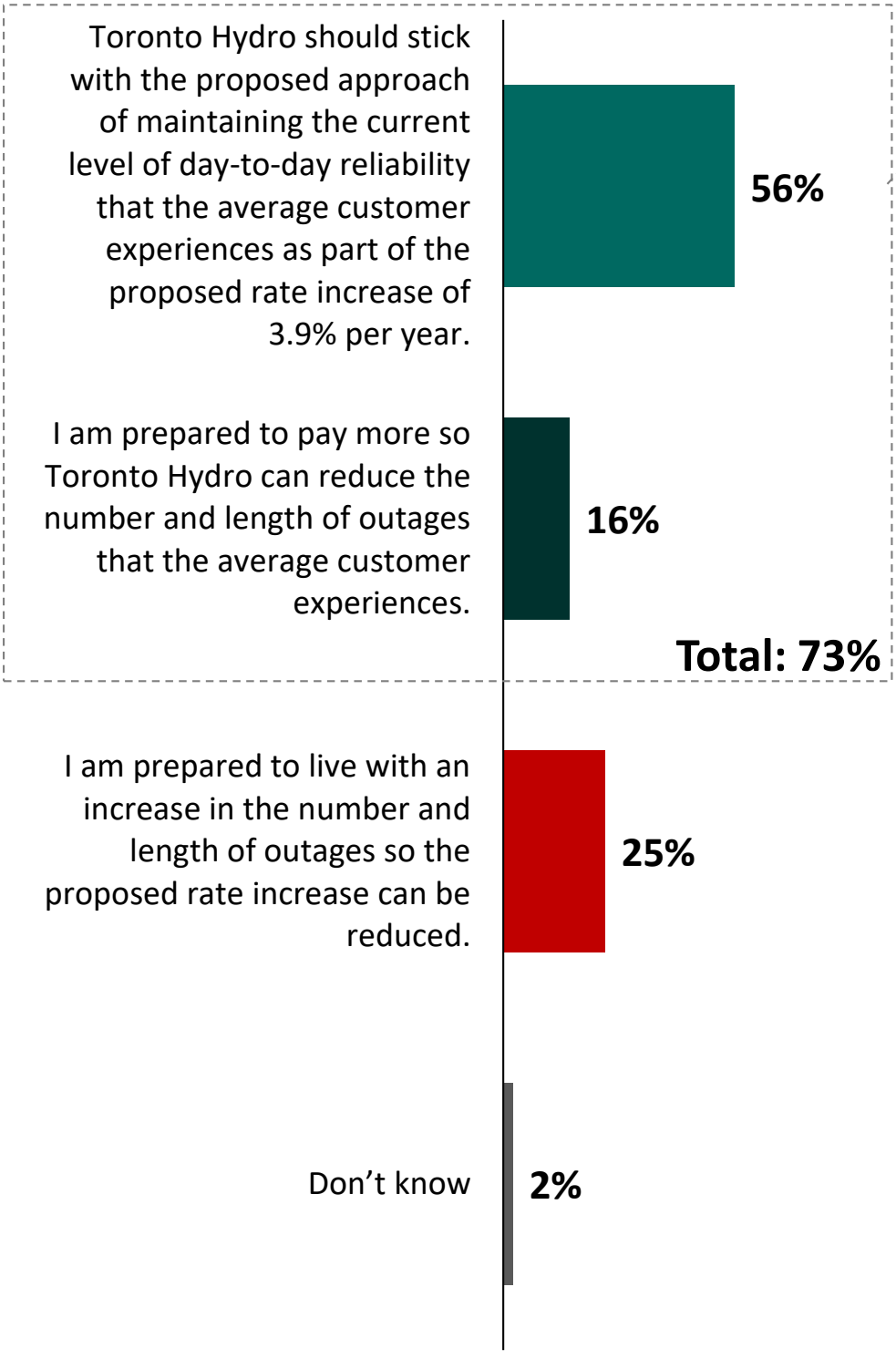
In this proposed plan, **Toronto Hydro's** general approach is to spend just enough on replacing equipment so that most customers can expect a similar level of reliability over the next five years as they are experiencing today, and to provide improved service for those customers whose reliability is poorer or who have special reliability needs such as hospitals.

INNOVATIVE RESEARCH GROUP

Approach to Addressing Reliability

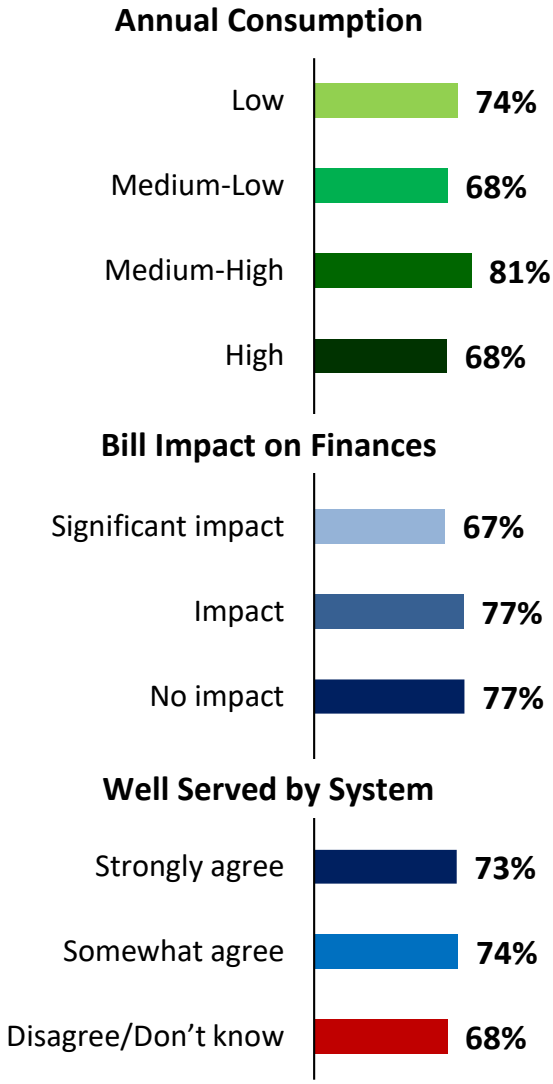
Q Which of the following is closest to your point of view regarding **Toronto Hydro's approach to addressing reliability?**

[asked all respondents, n=200]



Segmentation

*Those who say "**Stick with proposed approach or spend more**":*



Rear-Lot Replacement

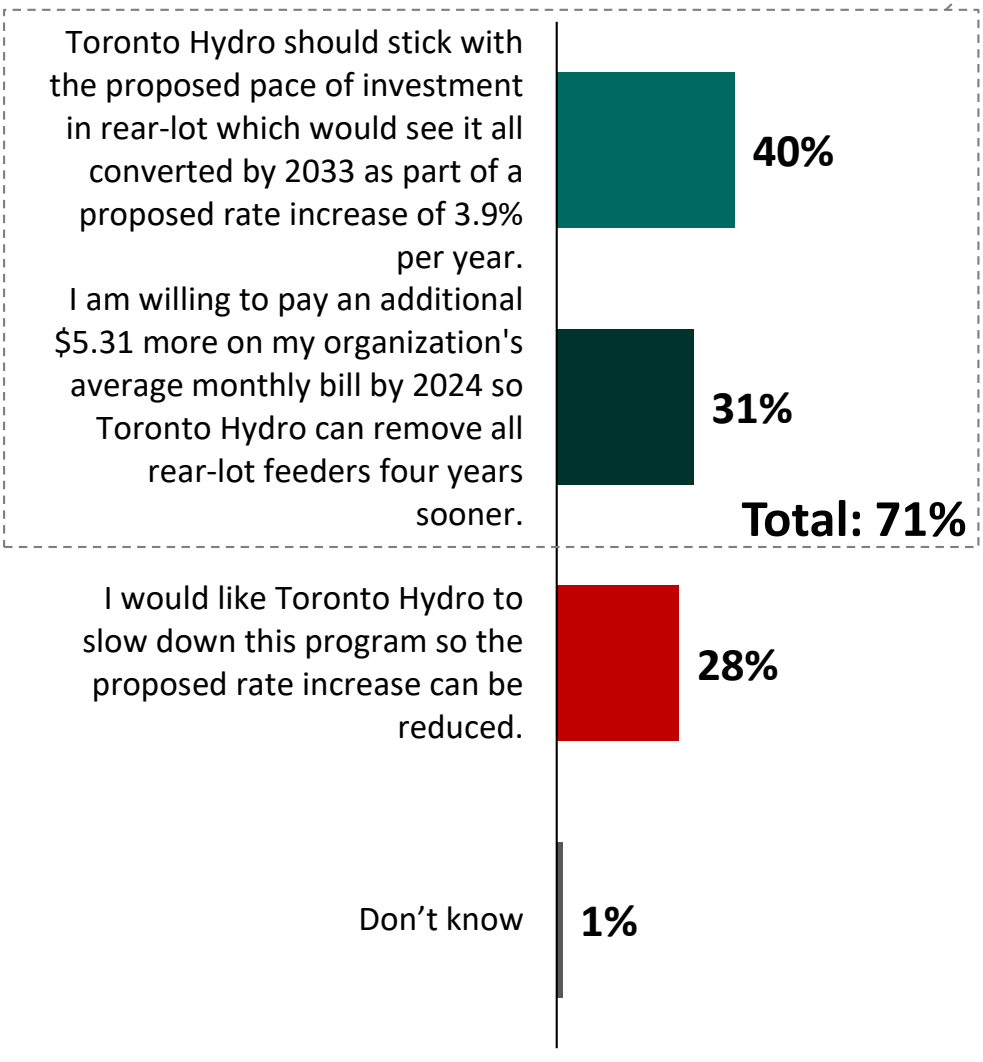
Some customers are served by older types of lines that are more likely to fail, causing more frequent, and longer lasting power outages. These customers are more likely to experience poorer reliability over time than most Toronto Hydro customers. The proposed plan will replace those lines over time but the work could be done faster.

I would like to ask you about two types of lines.

One example is **rear-lot lines**. They go through residential backyards and are often more difficult to service and more exposed to falling branches. The proposed plan will replace all existing rear-lot lines by 2033. **Toronto Hydro** could replace those lines 4 years sooner for an additional cost.

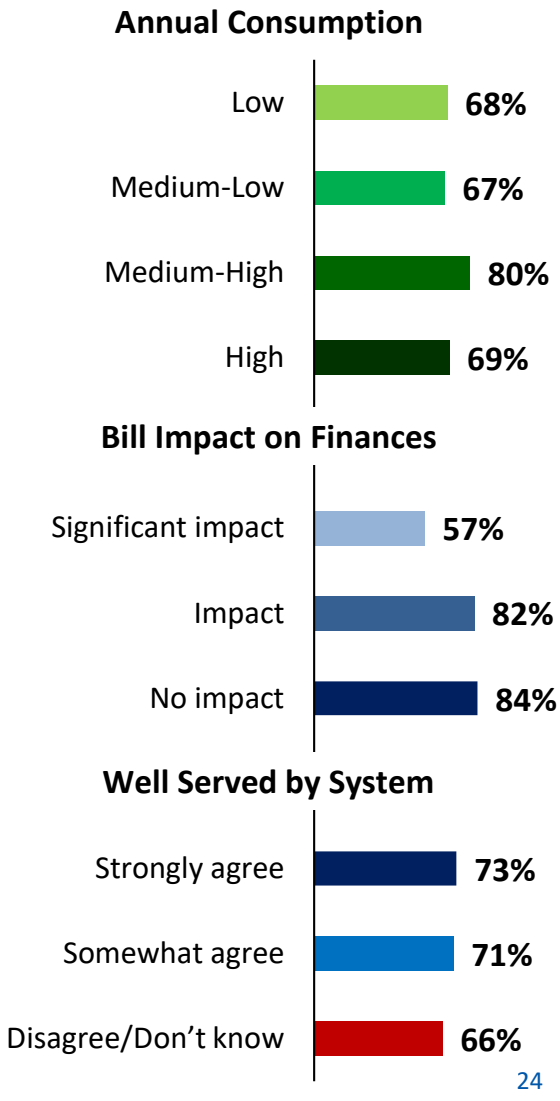
Which of the following statements is closest to your view?

[asked all respondents, n=200]



Segmentation

*Those who say "**Stick with proposed approach or spend more**":*



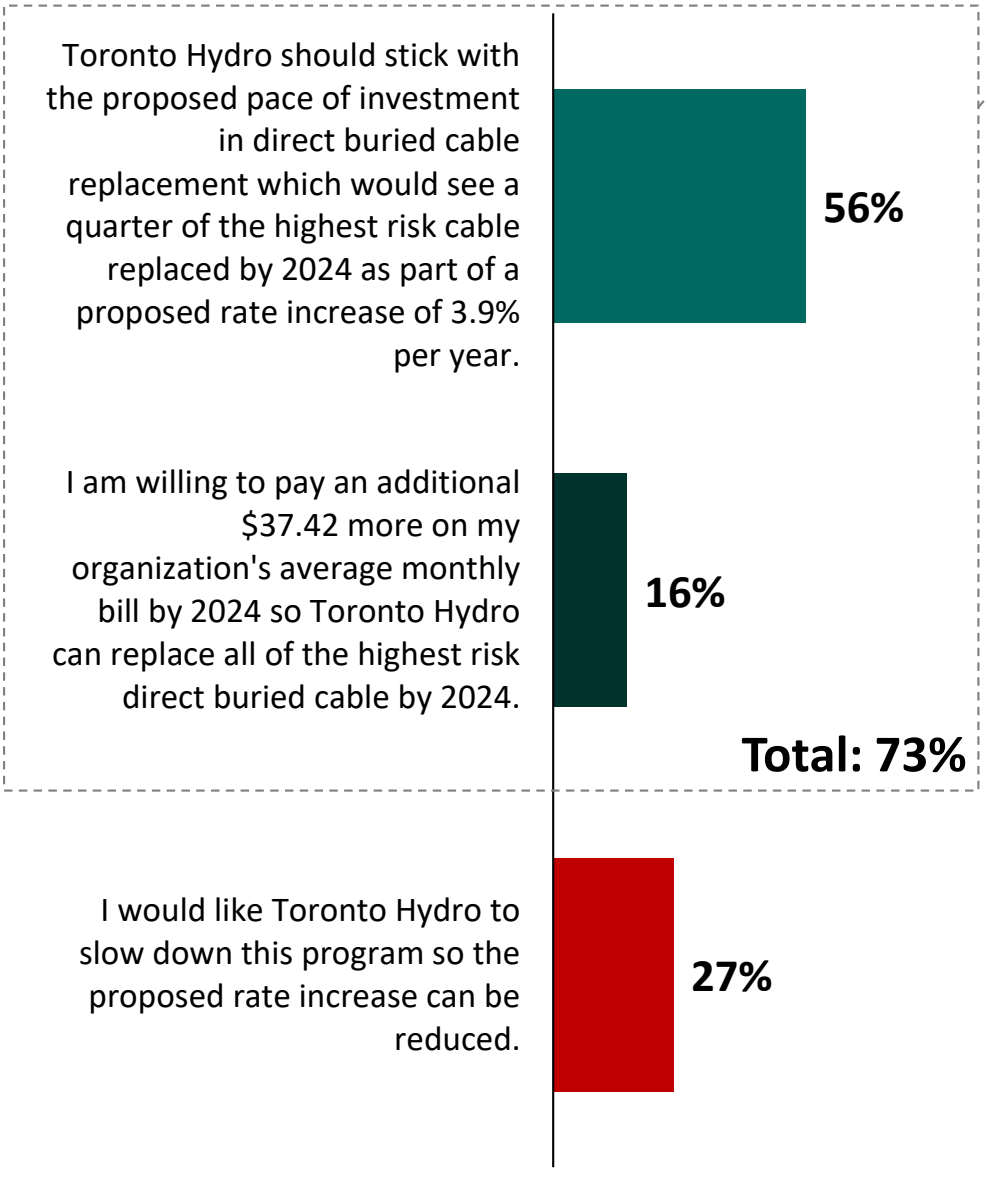
Direct Buried Cable Replacement

Another example is **direct buried cable** where cables are laid directly in underground trenches without a protective barrier. While equipment failure causes 36% of outages across the system, cable failure accounts for 70% of all outages on the underground system.

Once these cables start to fail, they tend to experience a rash of failures. The proposed plan will replace a quarter of the highest risk direct buried cable by 2024. **Toronto Hydro** could replace all of the highest risk direct buried cable by 2024 for an additional cost.

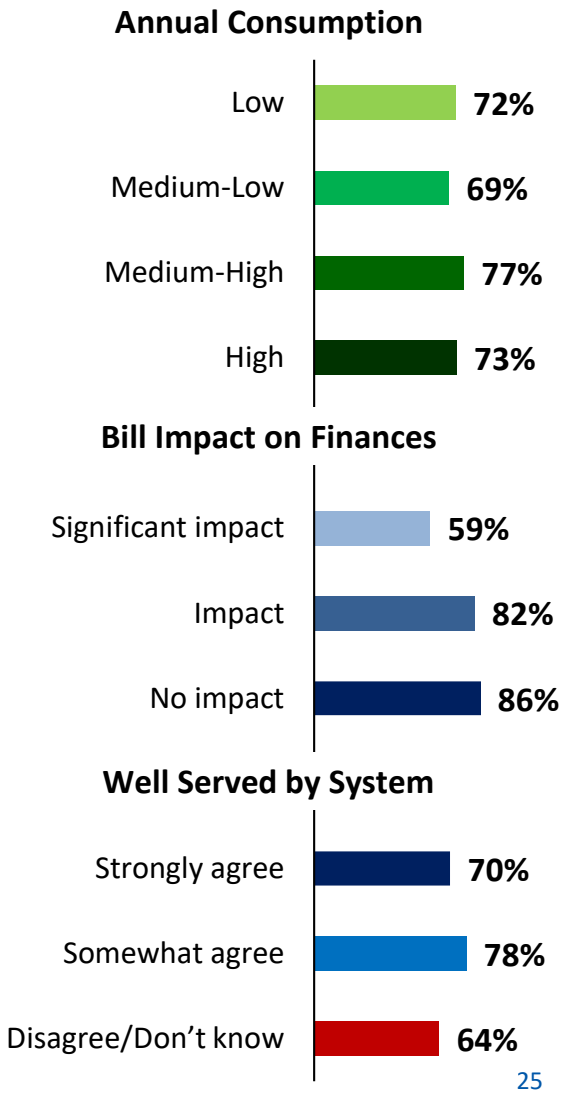
Which of the following statements is closest to your view?

[asked all respondents, n=200]



Segmentation

*Those who say "**Stick with proposed approach or spend more**":*



Note: "Don't Know" (1%) not shown.

Paper Insulated Lead Covered (PILC) Preamble

Toronto Hydro has identified three equipment upgrades that are needed within the next few years. If **Toronto Hydro** waits, those upgrades will be more expensive and disruptive as Toronto continues to grow.

Firstly, Paper Insulated Lead Covered (PILC) cable. PILC cable was an old type of underground cable that stopped being installed on **Toronto Hydro's** grid 20 years ago. While the equipment is resilient and is still providing electricity to the downtown core, the outer lead covers can begin to crack and leak oil. Replacing these cables is becoming increasingly difficult and expensive to resource and complete.

Toronto Hydro has a long-term plan to remove and replace PILC cable by 2049. But **Toronto Hydro** can replace all of this cable ten years earlier by 2039, at an additional cost now. This will improve reliability, reduce risks to the public, and avoid additional expense and disruption in the future.

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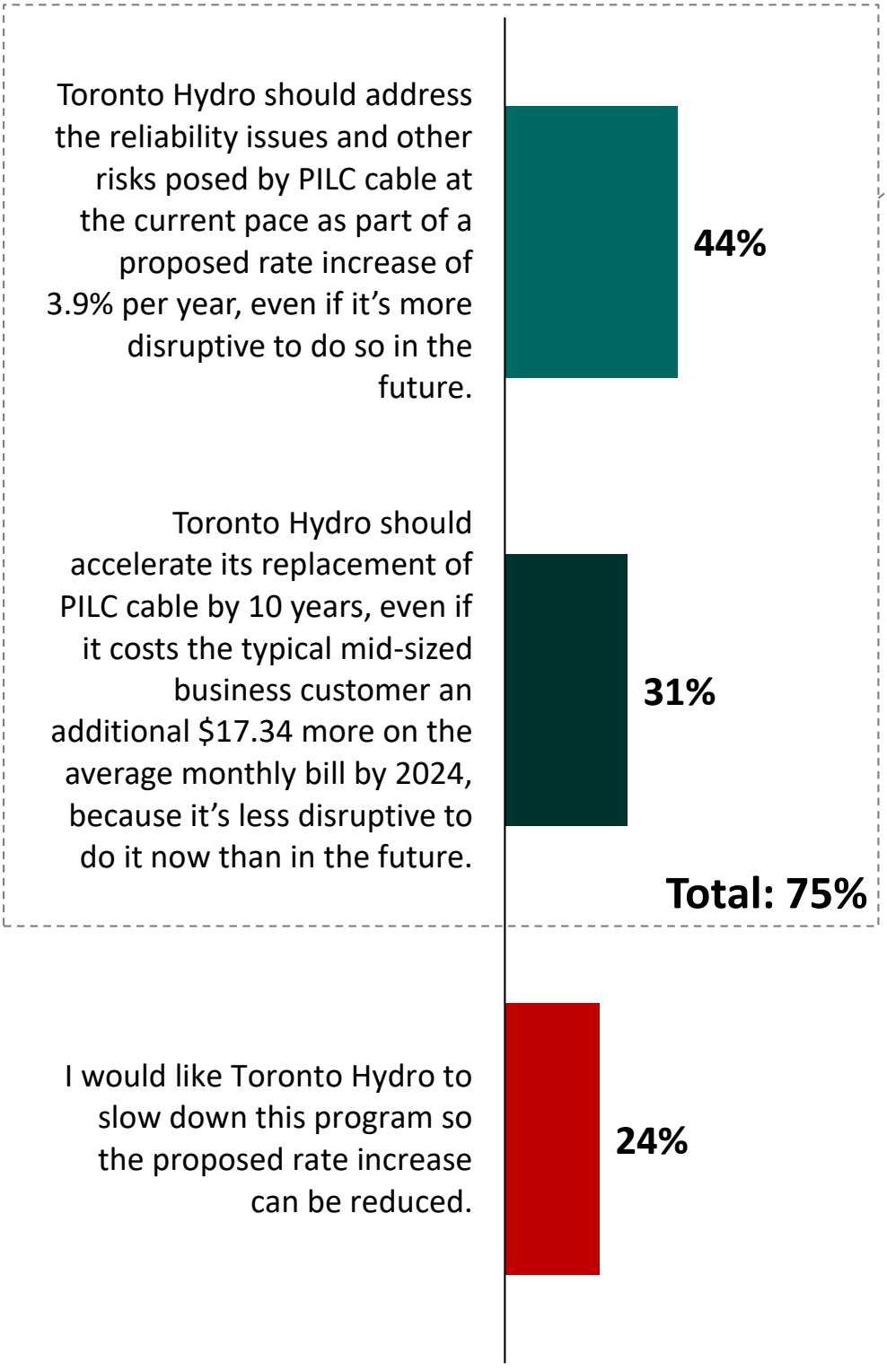
PILC Cable Replacement Program

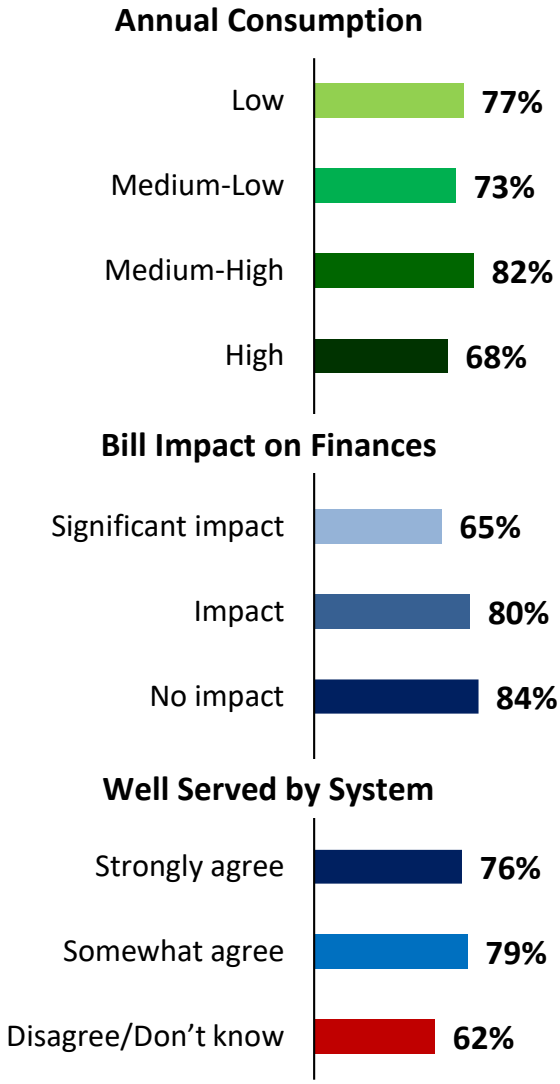
Q Which of the following is closest to your point of view regarding **Toronto Hydro's** PILC Cable replacement program?

[asked all respondents, n=200]



Segmentation

*Those who say "**Stick with proposed approach or spend more**":*



Note: "Don't Know" (1%) not shown.

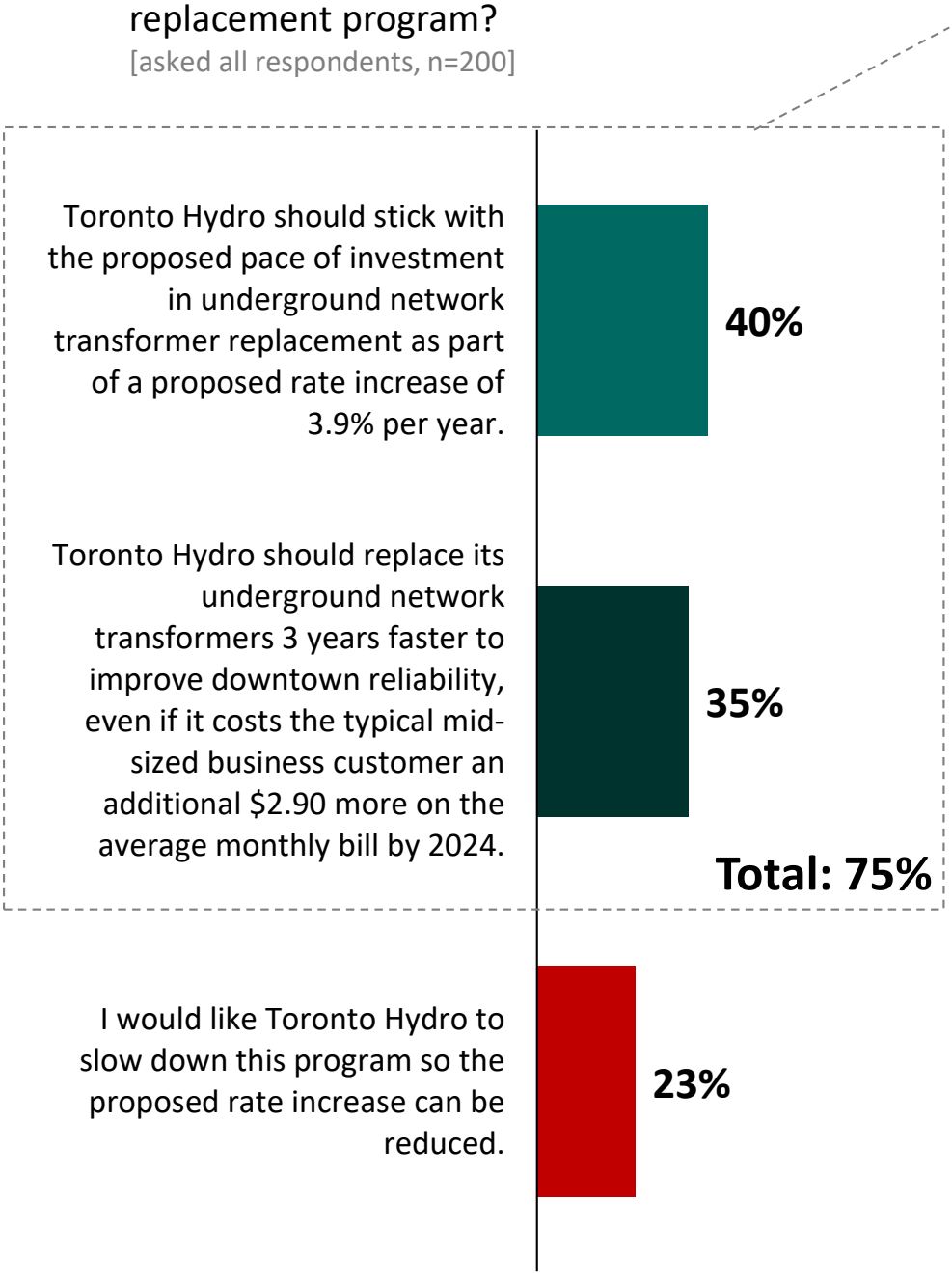
Network Unit Replacement Program

The second upgrade project identified is *Underground Network Transformers*. The key problem with these units is their older design which makes them prone to flooding.

Toronto Hydro plans to replace just enough of these units by 2031 so that outages, due to equipment failure, don't get any worse. But the process could be advanced by three years to replace all these units by 2028.

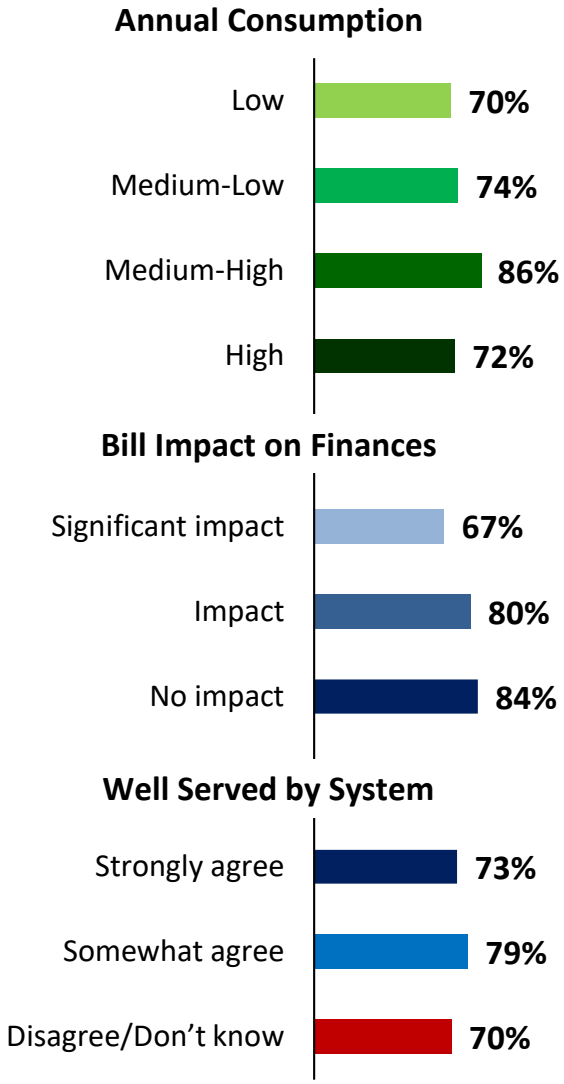
Which of the following is closest to your point of view regarding **Toronto Hydro's** Network Unit replacement program?

[asked all respondents, n=200]



Segmentation

*Those who say "**Stick with proposed approach or spend more**":*



Note: "Don't Know" (2%) not shown.

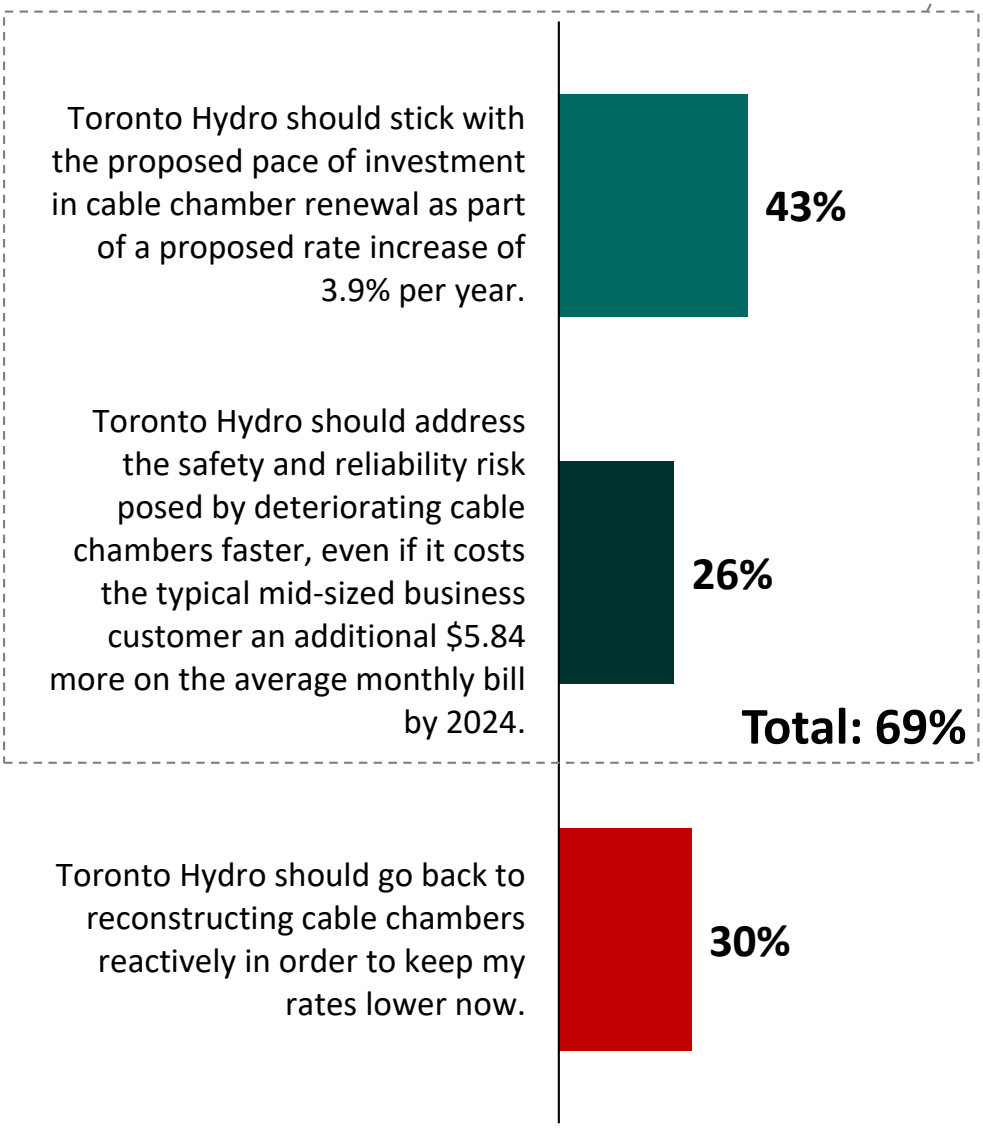
Cable Chamber Renewal Program

The third upgrade project identified is *Cable Chamber replacement*. Cable Chambers house, protect, and provide access to underground electrical equipment across the city. When they deteriorate or break, this equipment can cause outages and pose anything from a tripping hazard to something more serious like a collapsed chamber.

Toronto Hydro plans to take approximately 30 years to address the chambers in the worst condition. But accelerating the work could halve that period, at an additional cost now.

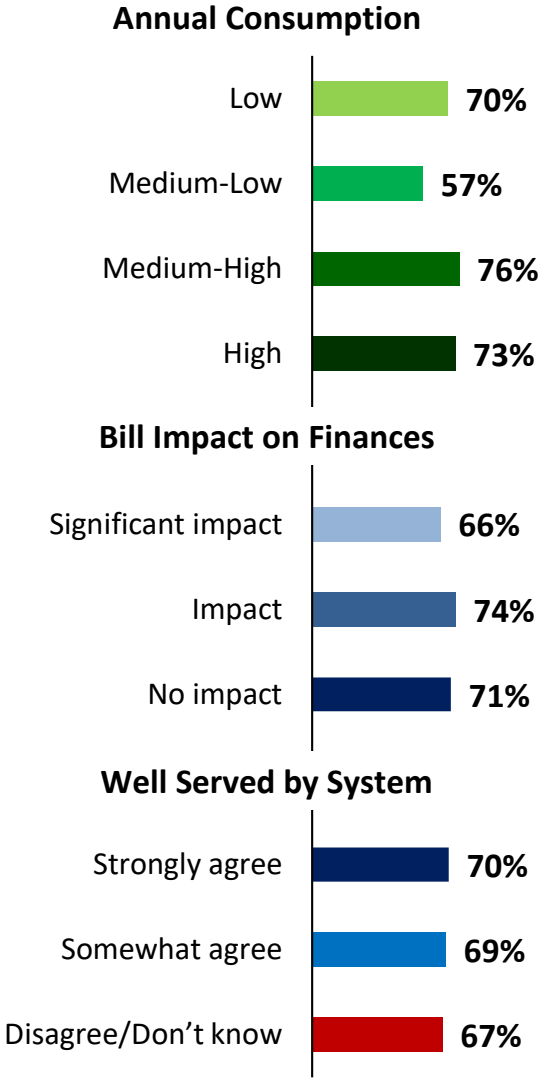
Which of the following is closest to your point of view regarding **Toronto Hydro's** Cable Chamber renewal program?

[asked all respondents, n=200]



Segmentation

*Those who say "**Stick with proposed approach or spend more**":*



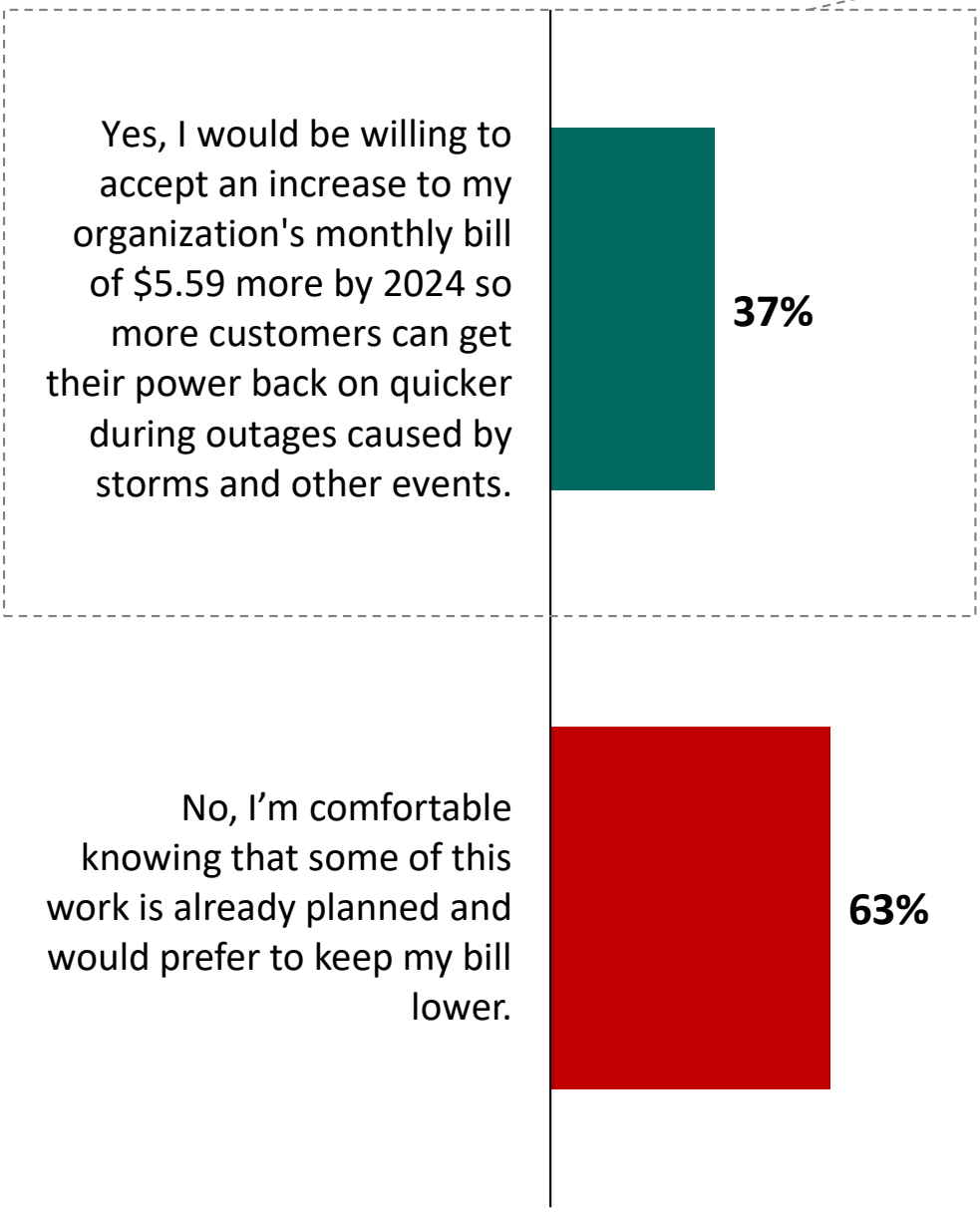
Note: "Don't Know" (1%) not shown.

Dealing with More Frequent Extreme Weather Events

As **Toronto Hydro's** distribution system is exposed to strong winds, freezing rain, and severe flooding, they are proposing a variety of enhancements to improve the resiliency of the distribution system against extreme weather events.

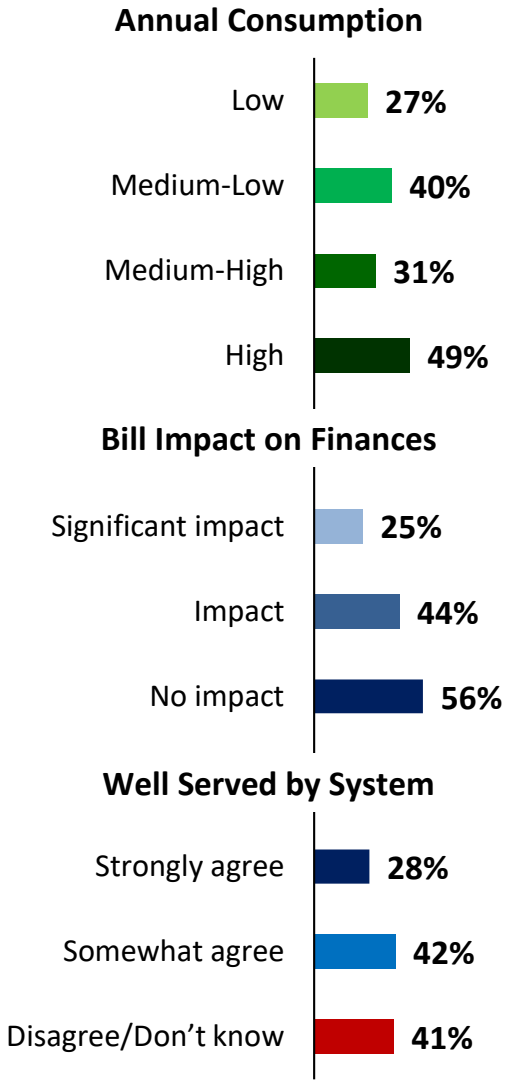
Toronto Hydro could enhance the system further in neighbourhoods outside of downtown. The improvements include adding remotely-operated technology and more back-up links within the grid. This will help **Toronto Hydro** to better isolate the problem and reduce outage times by as much as 50% in these areas.

Which of the following statements best represents your point of view?
[asked all respondents, n=200]



Segmentation

*Those who say "**Restore power more quickly during outages**":*



Note: "Don't Know" (1%) not shown.

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Innovation and Planning for the Future



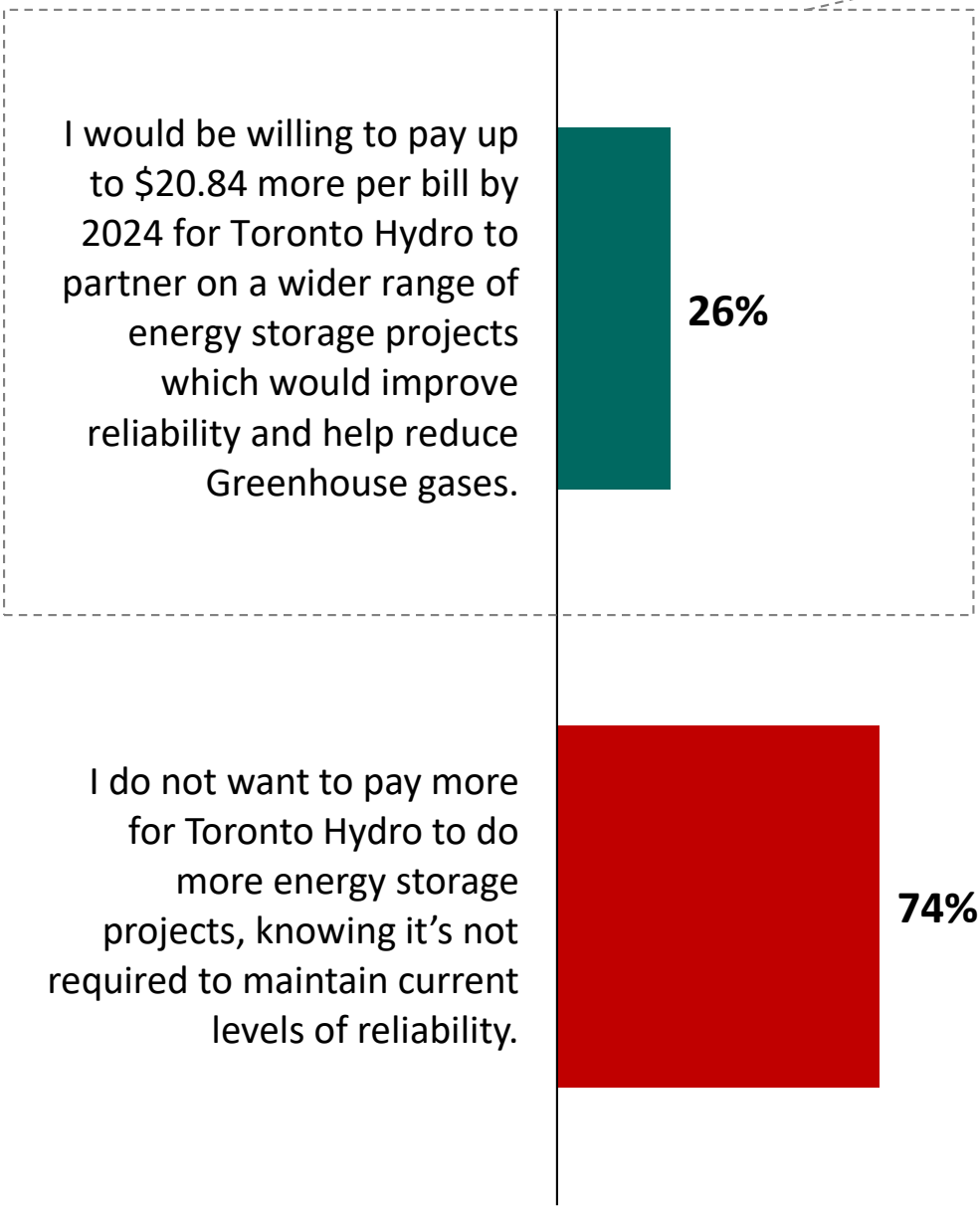
Investments in Energy Storage

3% of the proposed budget would be spent on innovation and planning for the future. The following questions are about this aspect of the budget.

Toronto Hydro has already begun to integrate large-scale battery electricity storage into the system. They have now identified more opportunities to partner on a wider range of energy storage projects. Integrating storage into the system can improve reliability and help reduce greenhouse gases, but it is not required to maintain current levels of reliability.

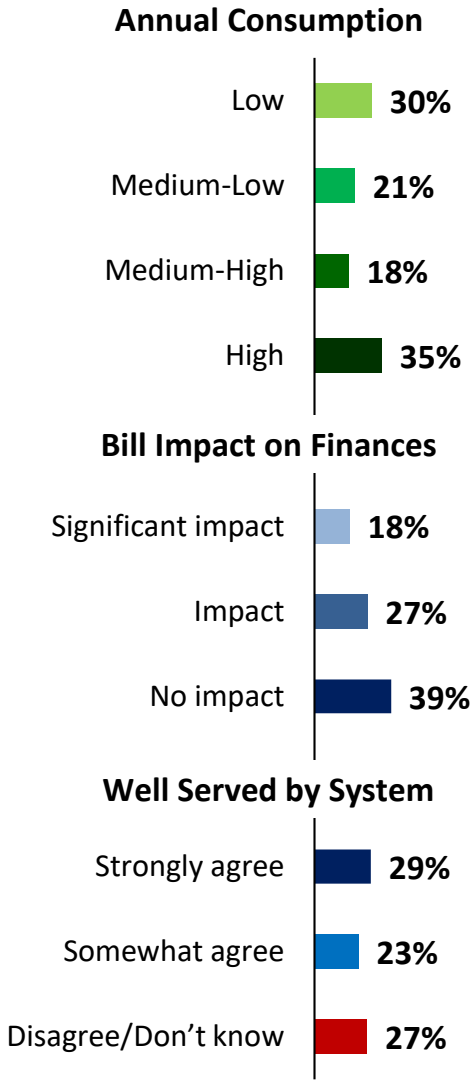
Which of the following is closest to your point of view?

[asked all respondents, n=200]



Segmentation

*Those who say "**Pay more to partner on energy storage projects**":*



Note: "Don't Know" (1%) not shown.

Monitoring and Control Equipment

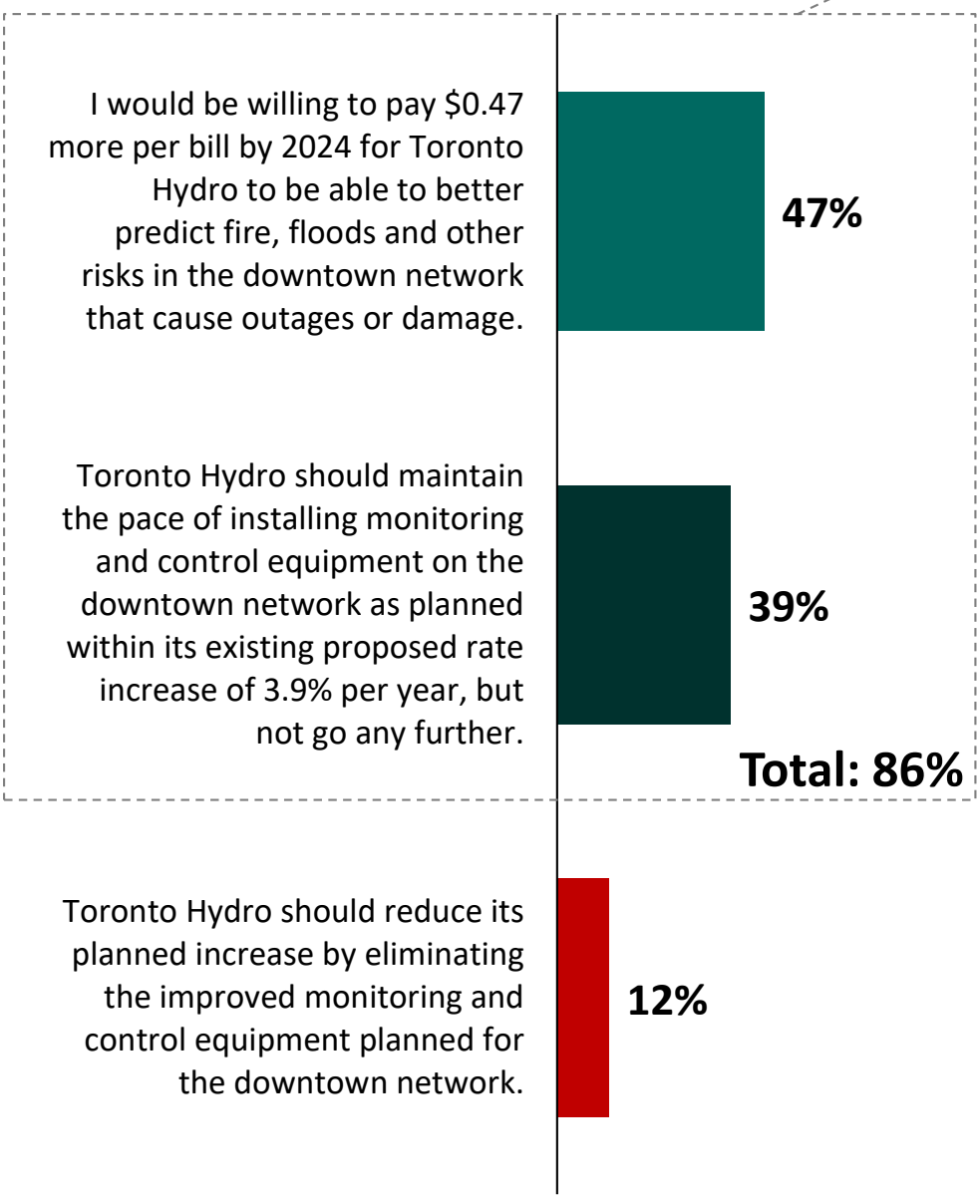
New communication technology has revolutionised the way the grid can be managed.

Toronto Hydro plans to take advantage of various new technologies wherever clear benefits can be established.

However, **Toronto Hydro** can improve the reliability of its grid further by installing communication devices in the downtown underground network that detect fire, floods or other risks more quickly.

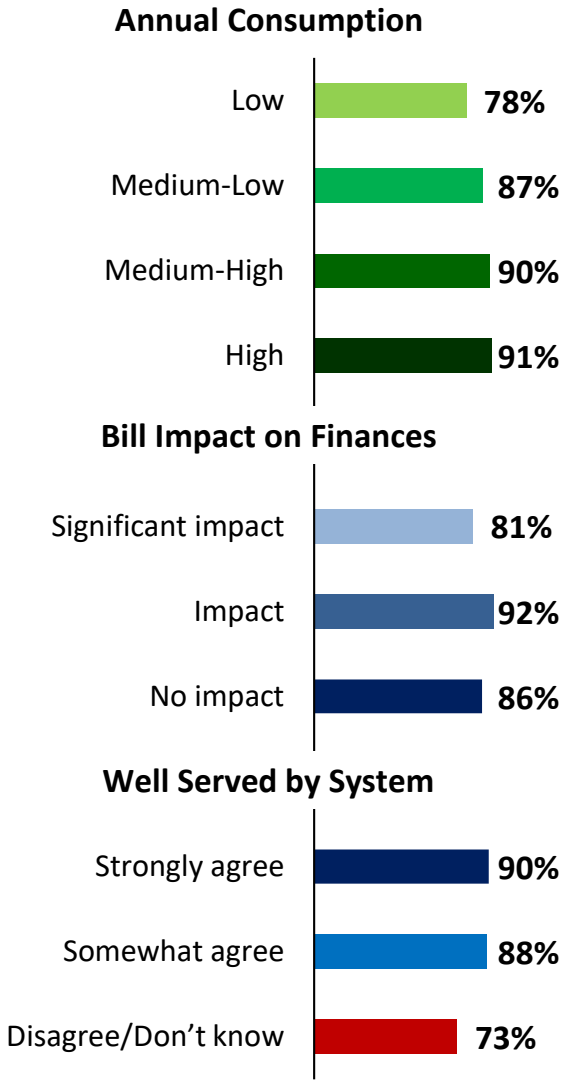
Which of the following is closest to your point of view?

[asked all respondents, n=200]



Segmentation

*Those who say "**Stick with proposed approach or spend more**":*



Note: "Don't Know" (2%) not shown.

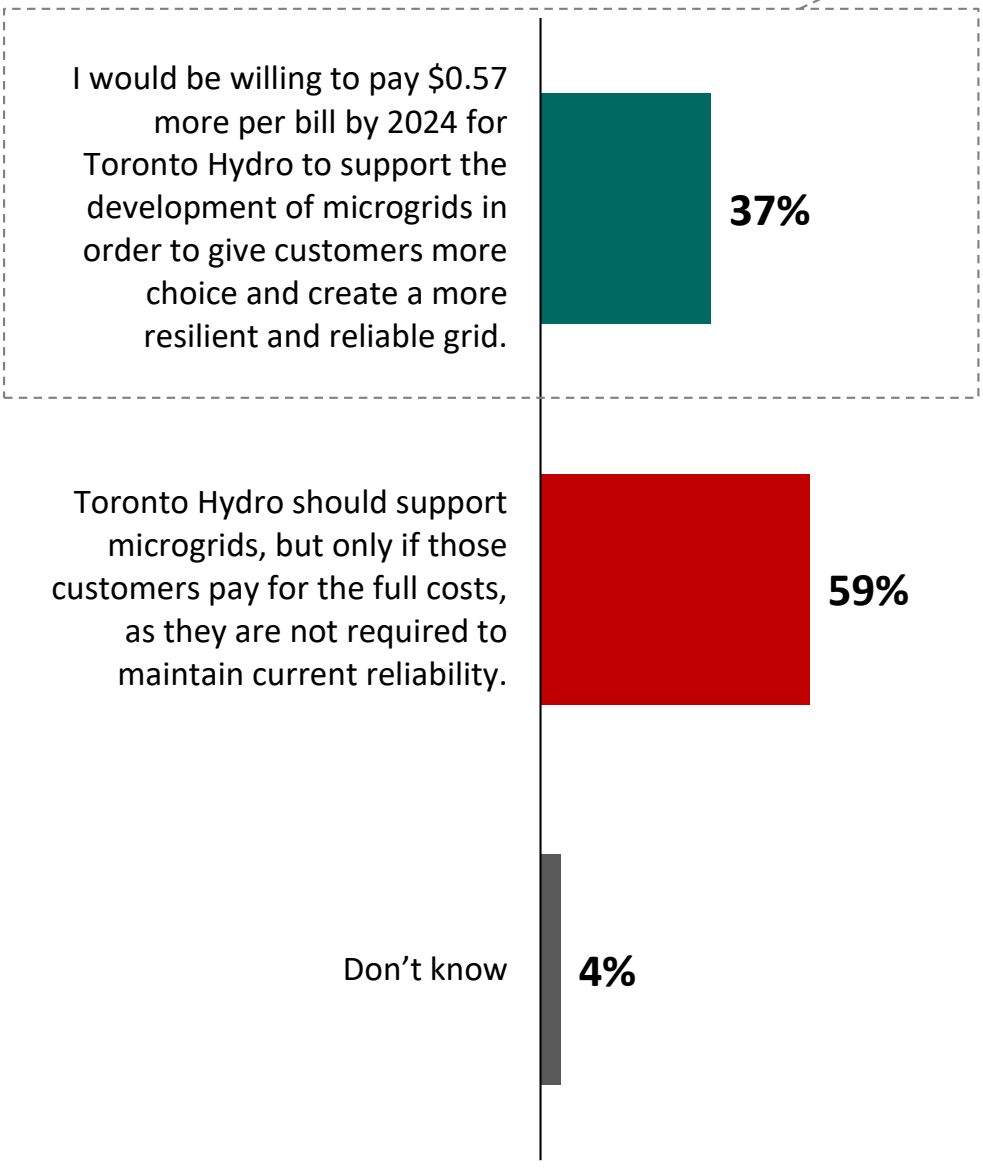
Supporting Microgrids

New types of generation (often renewable), storage, and supporting systems are making it possible for communities, institutions or other large customers to develop “microgrids”. They are a local electricity network linking smaller sources of electricity with nearby uses such as homes, businesses and institutions. In the event of a failure of the larger network, a microgrid can seal itself off and continue to provide power locally.

Microgrids would give customers more choices, while creating a more resilient and reliable grid. However, they are not required to maintain current reliability.

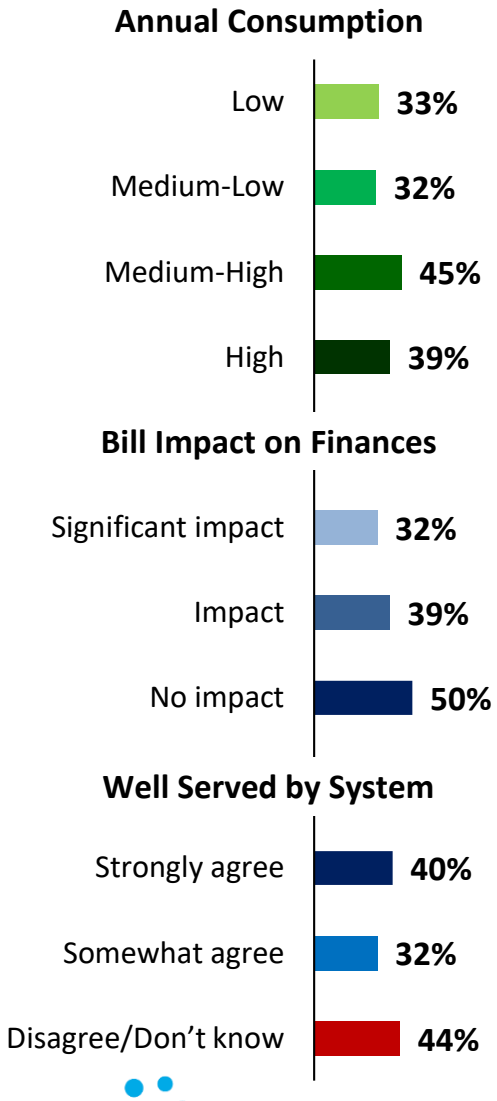
Which of the following is closest to your point of view?

[asked all respondents, n=200]



Segmentation

*Those who say “**Pay more to support microgrids**”:*



Investment Alternatives Summary Preamble

Toronto Hydro's current proposed plan, which translates into an average 3.9% annual increase, focuses on delivering current levels of reliability and customer service for most customers and targeted improvements for customers experiencing below average service or who have special reliability needs, like hospitals.

In dollars and cents, that means an average increase to the monthly bill of **$70.26 each year** for the typical mid-sized business customer.

Over the course of the proposed 5-year plan, the typical mid-sized business customer will see the distribution portion of their electricity bill **increase by $351.**

As a result, the distribution charges on the monthly bill would increase from a proposed amount of **$1,671 in 2019** to **$2,023 by 2024**.

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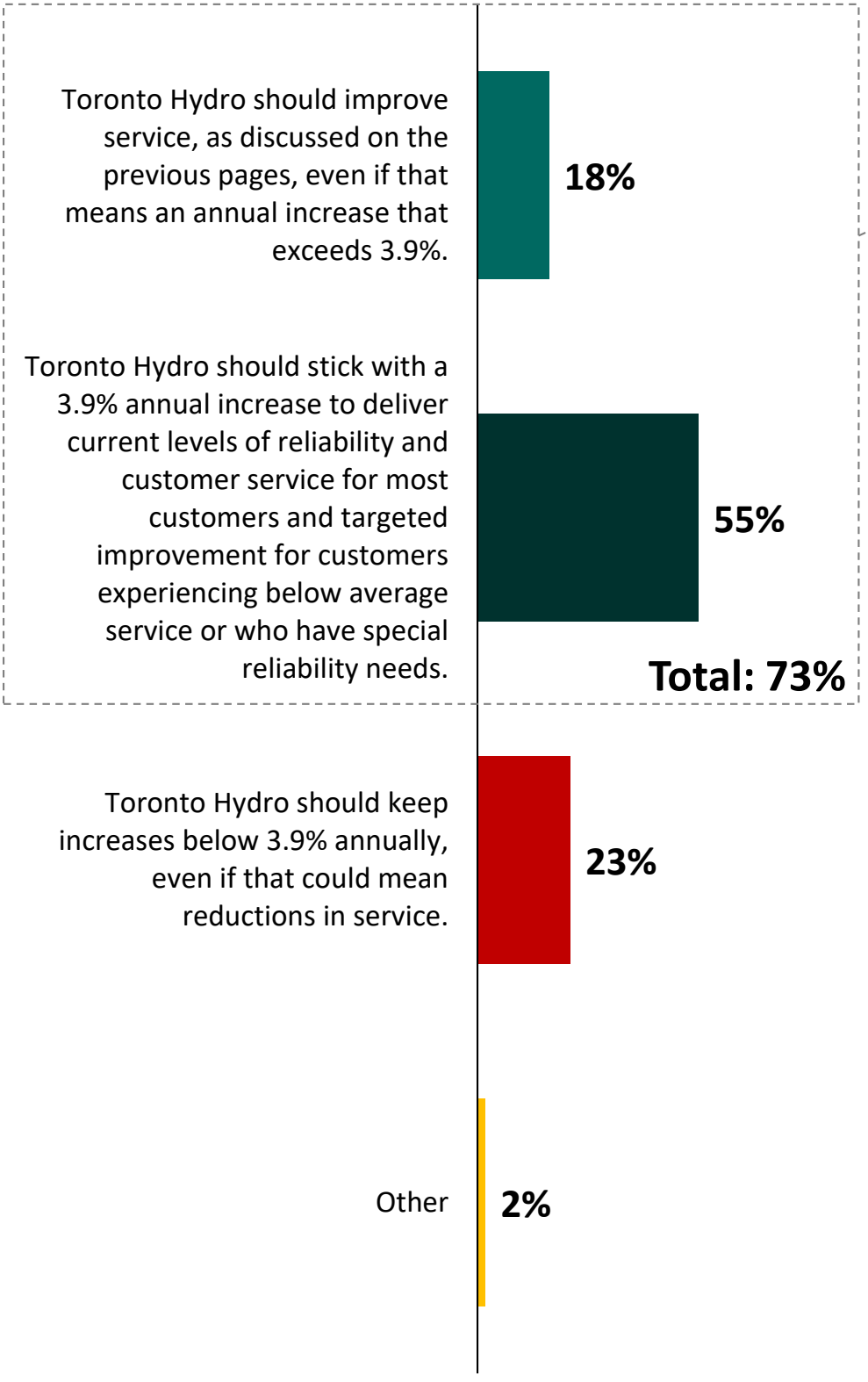
Opinion of Toronto Hydro's Proposed Plan

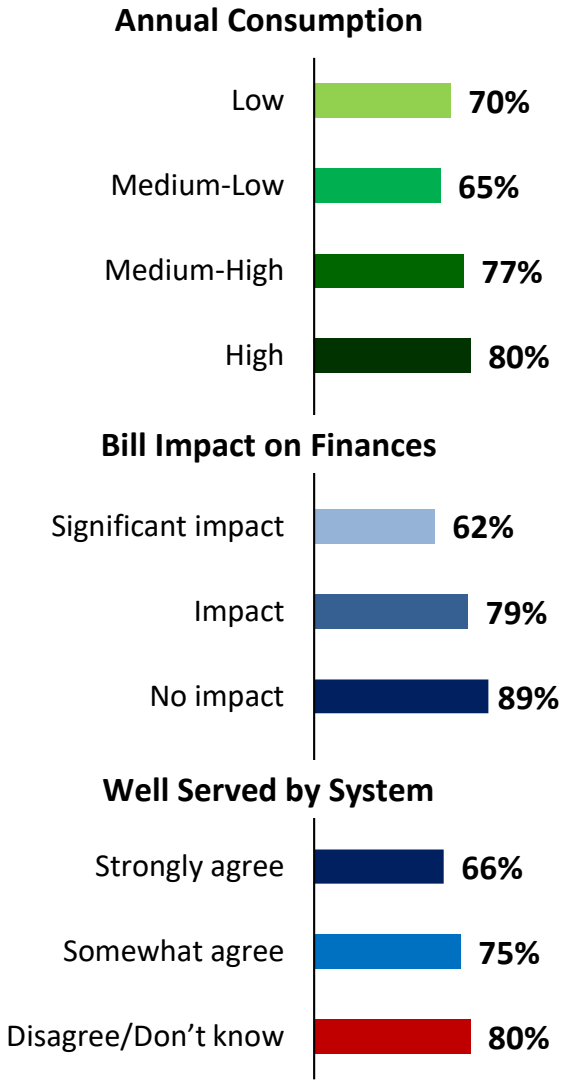
With regards to **Toronto Hydro's** proposed plan, which of the following statements best represents your view?

[asked all respondents, n=200]



Segmentation

*Those who say "**Stick with current pace of investment or increase to improve services**":*



Note: "Don't Know" (2%) not shown.

Opinion of Toronto Hydro's Proposed Plan by Segmentations

Q With regards to **Toronto Hydro's** proposed plan, which of the following statements best represents your view?
[asked all respondents, n=200]

Bill Impact on Finances

Opinion of Toronto Hydro's Proposed Plan	*The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being delayed.*			*Total*
	Sig. Impact [n=84]	Impact [n=71]	No Impact [n=38]	
Improve services, increase above 3.9%	12%	18%	33%	**18%**
	62%	79%	89%	
Stick with current plan at 3.9%	49%	61%	56%	**55%**
Keep increases below 3.9%	32%	19%	11%	**23%**

Well Served by System

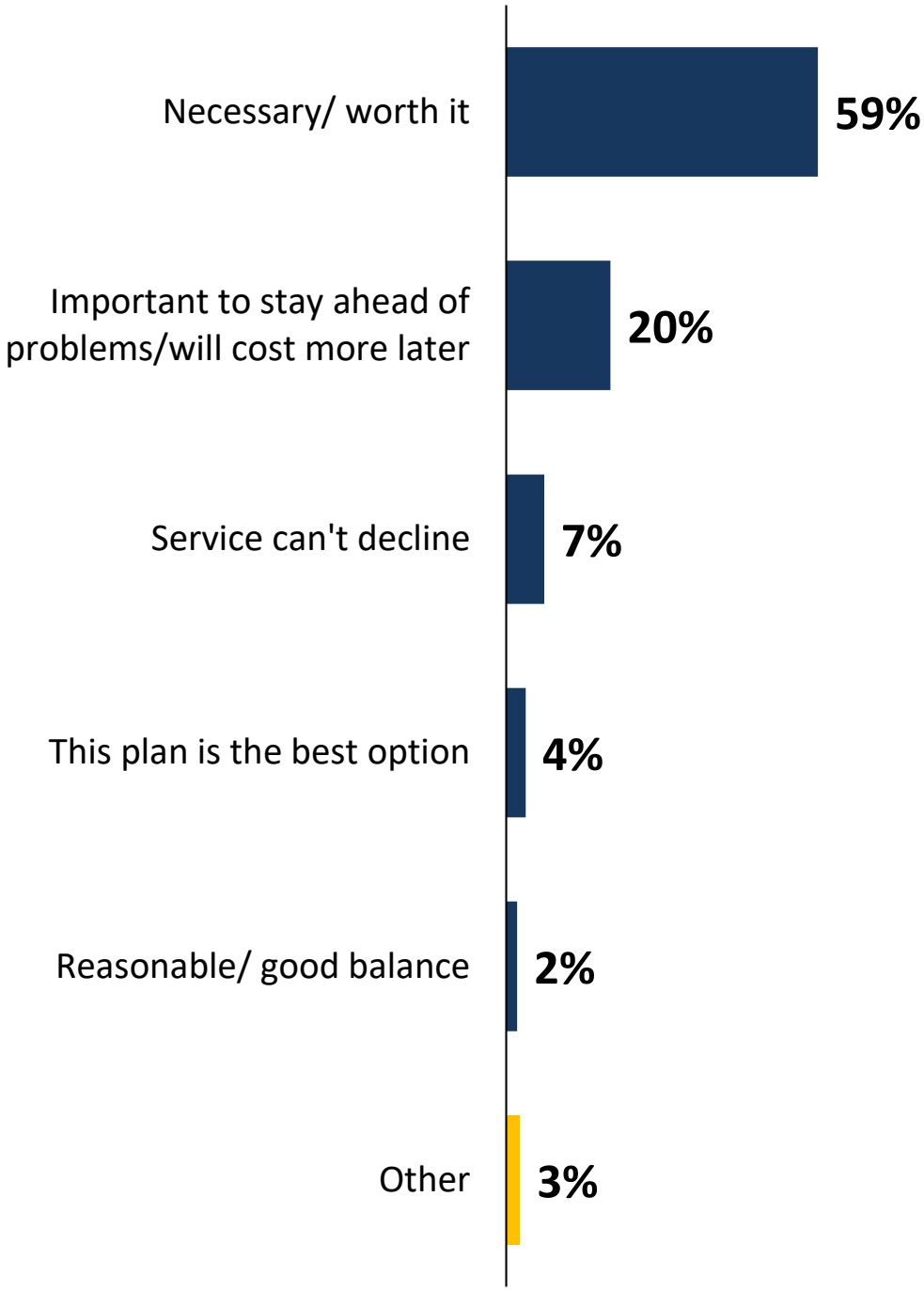
Opinion of Toronto Hydro's Proposed Plan	*Customers are well served by the electricity system in Ontario.*			*Total*
	Strongly agree [n=71]	Somewhat agree [n=96]	Disagree/ Don't know [n=33]	
Improve services, increase above 3.9%	17%	18%	18%	**18%**
	66%	75%	80%	
Stick with current plan at 3.9%	49%	57%	63%	**55%**
Keep increases below 3.9%	31%	19%	20%	**23%**

Note: "Other" and "Don't Know" not shown.

Opinion of Toronto Hydro's Proposed Plan

Q And why do you say that?
[asked of those who say Toronto Hydro should improve service, n=36]

For those who answered: Toronto Hydro should improve service, as discussed on the previous pages, even if that means an annual increase that exceeds 3.9%. (n=36)



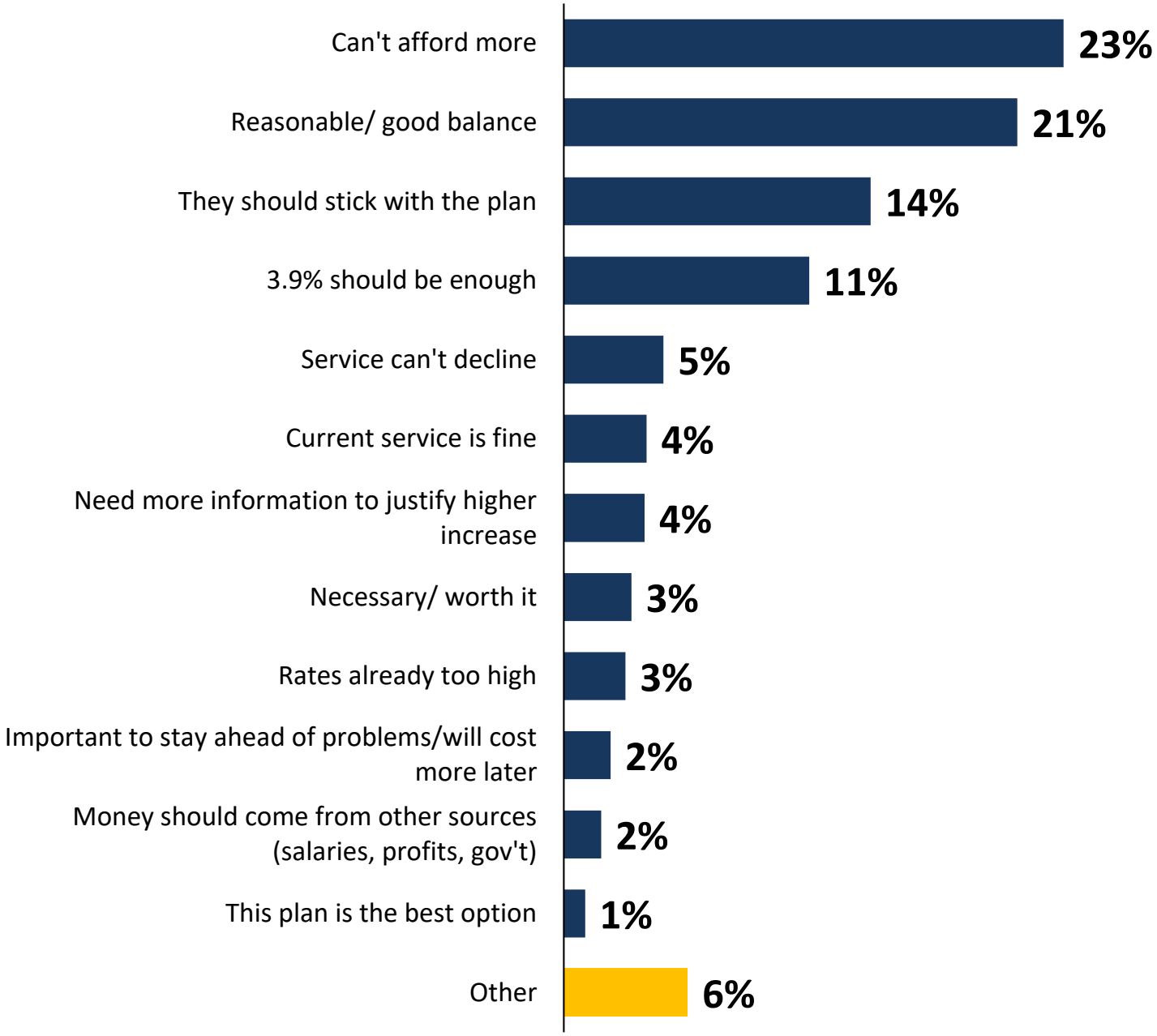
Note: "None" (6%) not shown.

Opinion of Toronto Hydro's Proposed Plan

Q And why do you say that?

[asked of those who say Toronto Hydro should stick with proposed plan, n=110]

For those who answered: Toronto Hydro should stick with a 3.9% annual increase to deliver current levels of reliability and customer service for most customers and targeted improvement for customers experiencing below average service or who have special reliability needs. (n=110)



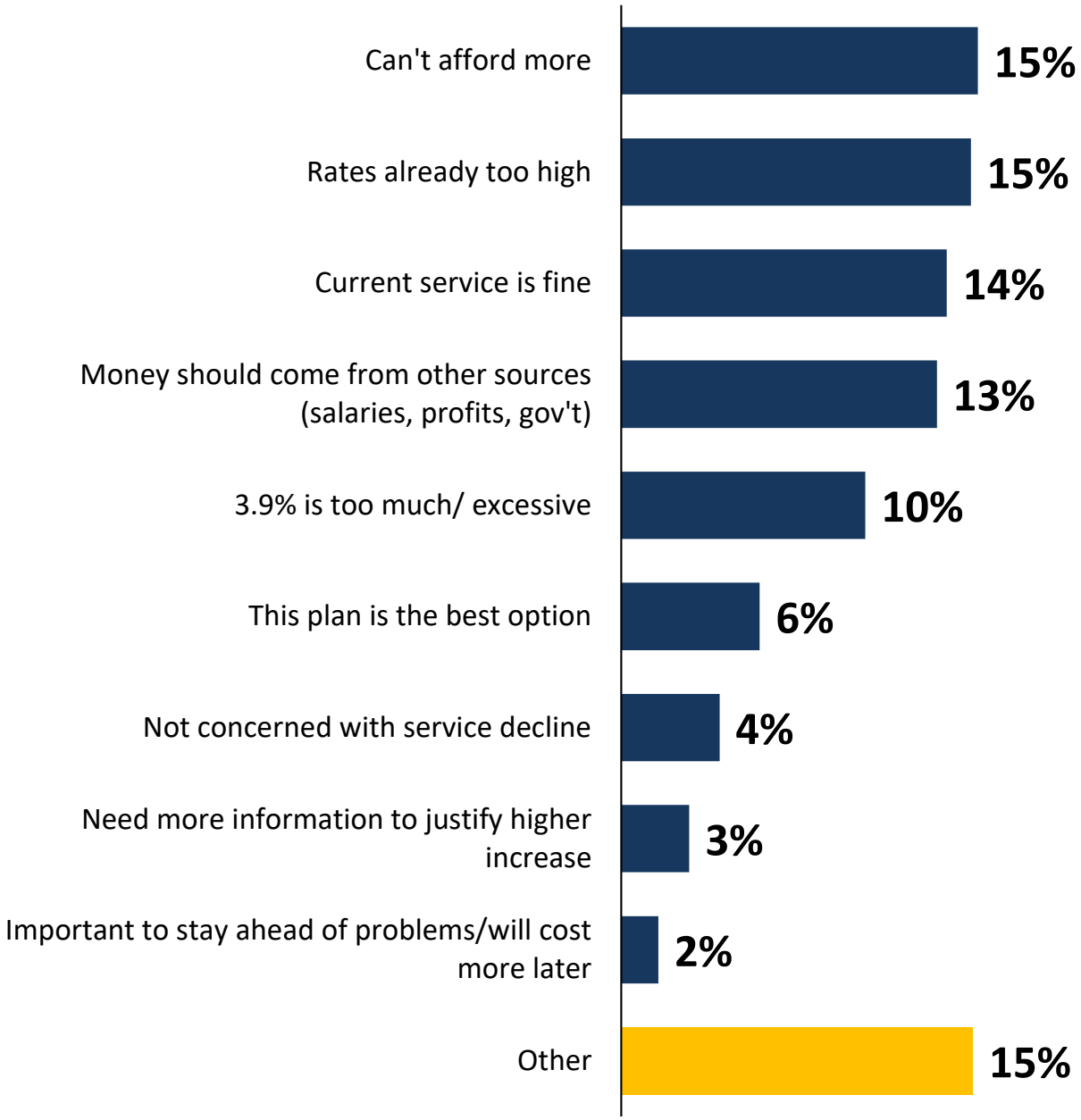
Note: "None" (3%) not shown.

Opinion of Toronto Hydro's Proposed Plan

Q And why do you say that?

[asked of those who say Toronto Hydro should keep increases below 3.9%, n=46]

For those who answered: Toronto Hydro should keep increases below 3.9% annually, even if that could mean reductions in service. (n=46)



Note: "Don't know" (2%) and "None" (3%) not shown.

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Personalized research to connect you and your audiences.

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Appendix 2.5

Toronto Hydro 2018 Customer Engagement

Key Account Telephone Survey Report

Key Account Report

June 2018

STRICTLY PRIVILEGED AND CONFIDENTIAL

Survey Methodologies



Field and Design

These are the findings of an Innovative Research Group (INNOVATIVE) online survey conducted among **n=37** Toronto Hydro **Key Accounts** between **June 7 and 18, 2018.**

Toronto Hydro provided INNOVATIVE with an email contact list consisting of the prime contact for each of its 336 Key Accounts. INNOVATIVE provided each Key Account contact with a unique URL via an email invitation so that only customers identified by Toronto Hydro were able to complete the survey and complete the survey only once.

Only one customer per organization was eligible to complete the survey. Respondents were screened to certify that only the personnel responsible for managing or overseeing their electricity bill were interviewed. This step was taken to ensure that survey respondents represented the most qualified person within an organization to answer questions.

Customers were sent three reminder emails to encourage survey participation. In addition, Toronto Hydro staff followed up with customers by telephone to encourage survey participation.

Individual Key Account responses were anonymous and no identifiable respondent information was shared with Toronto Hydro. Responses were combined to protect the confidentiality of individual Key Accounts.

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

INNOVATIVE RESEARCH GROUP

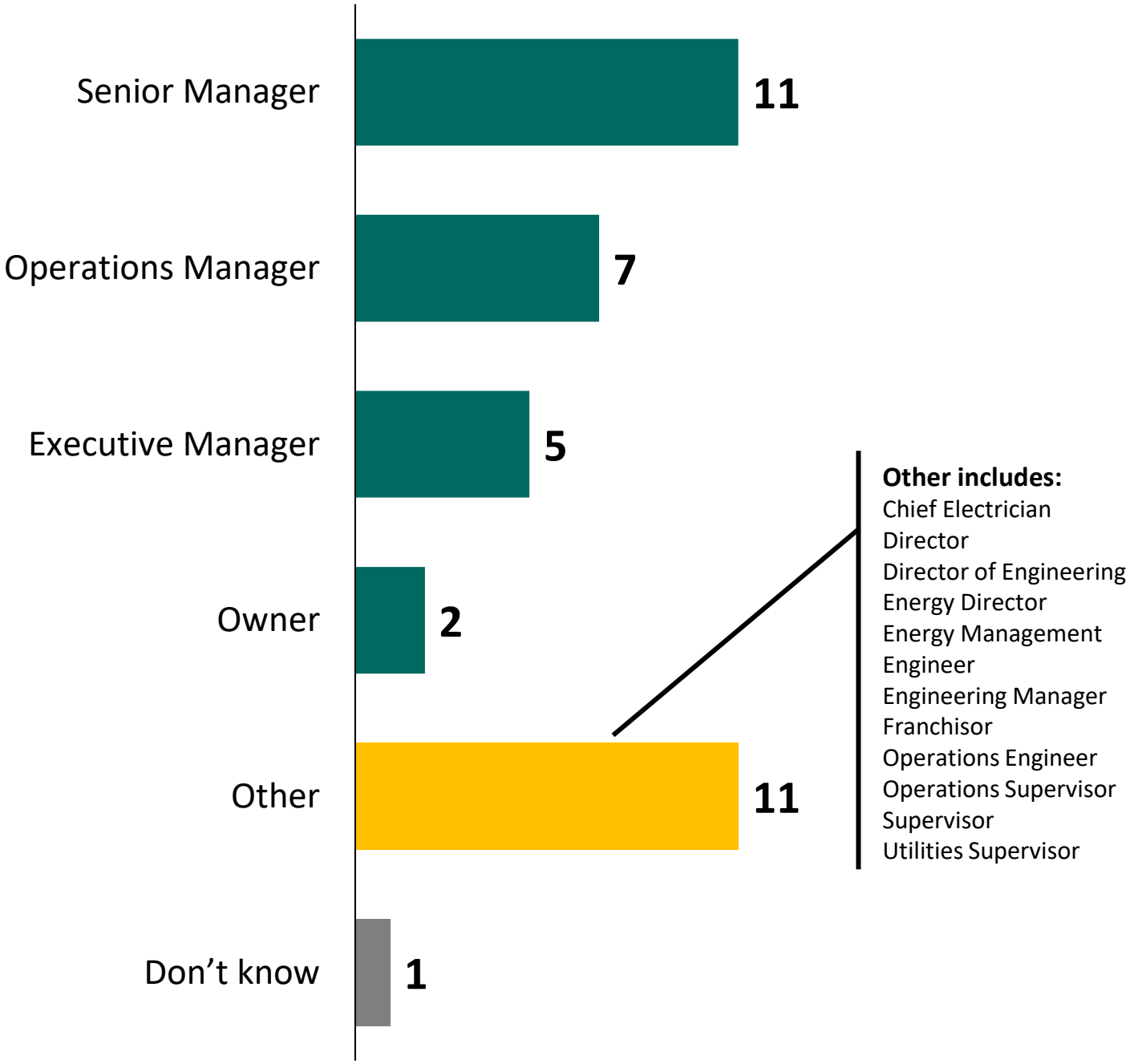
Demographics



Role within Organization

Q What occupation or position best describes your role at your organization?

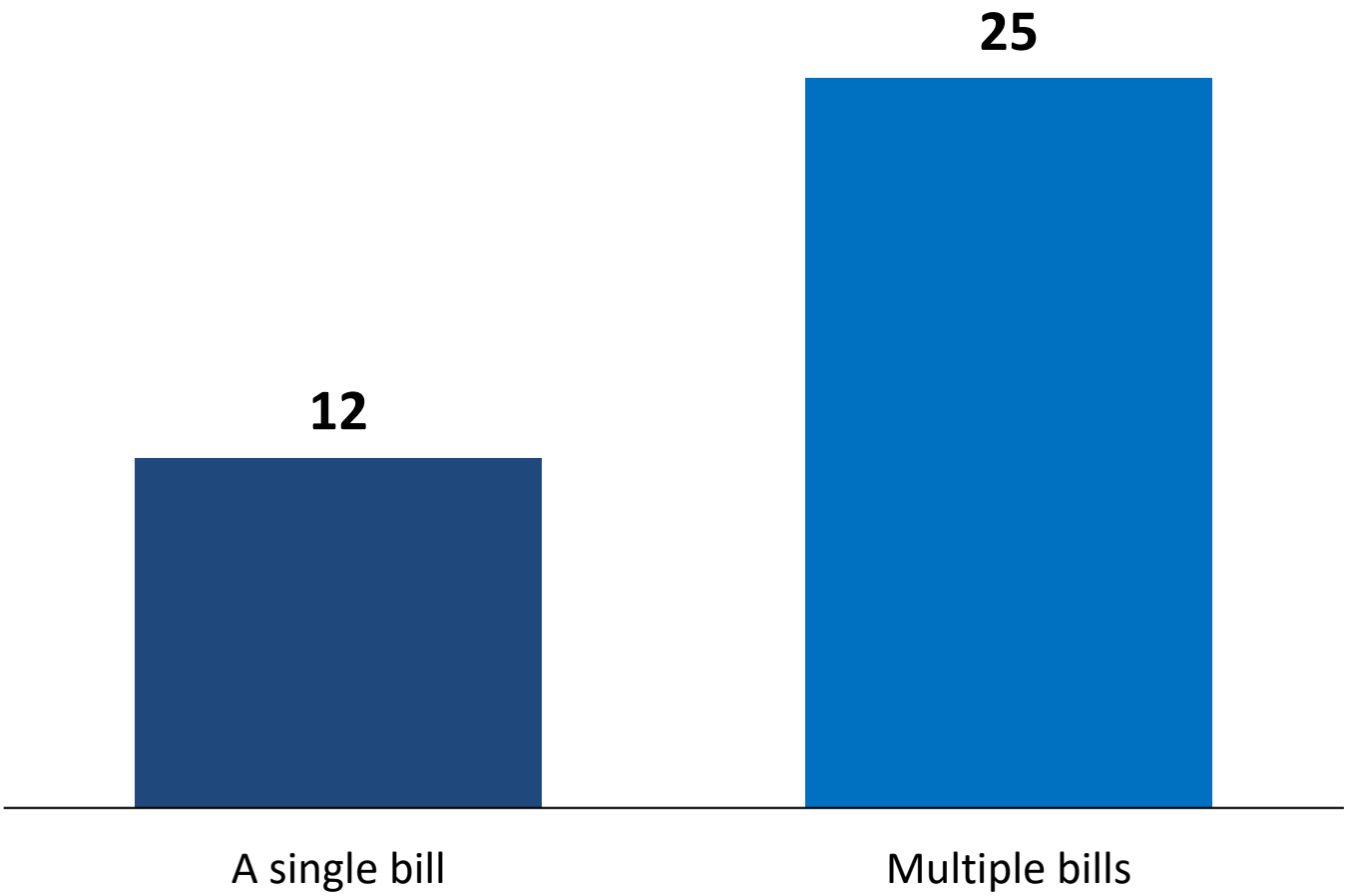
[asked all respondents, n=37]



Number of Bills

Q Does your organization receive a single bill or multiple bills from Toronto Hydro?

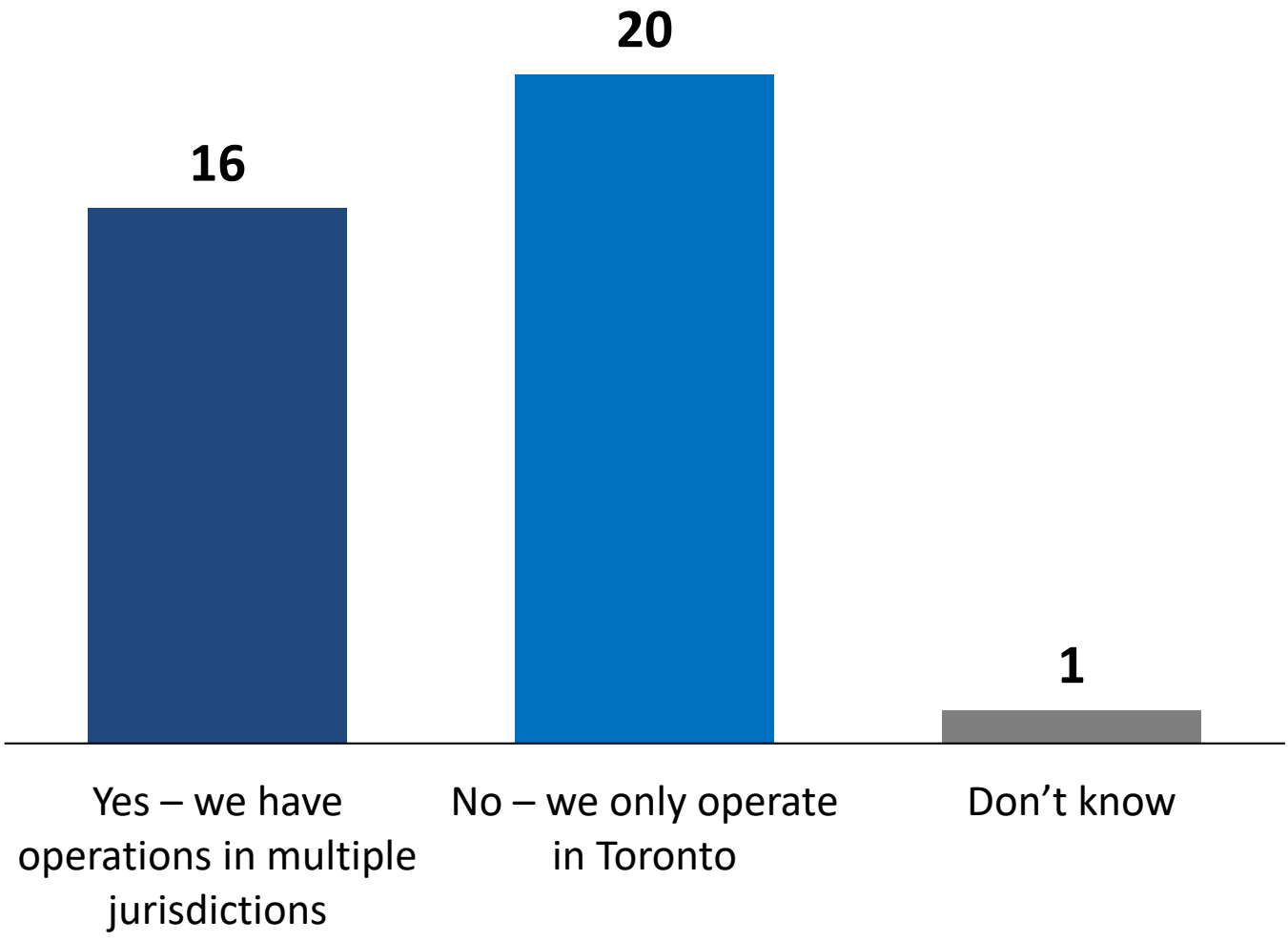
[asked all respondents, n=37]



Other Utilities

Q Does your organization receive electrical bills from utilities other than Toronto Hydro?

[asked all respondents, n=37]



INNOVATIVE RESEARCH GROUP

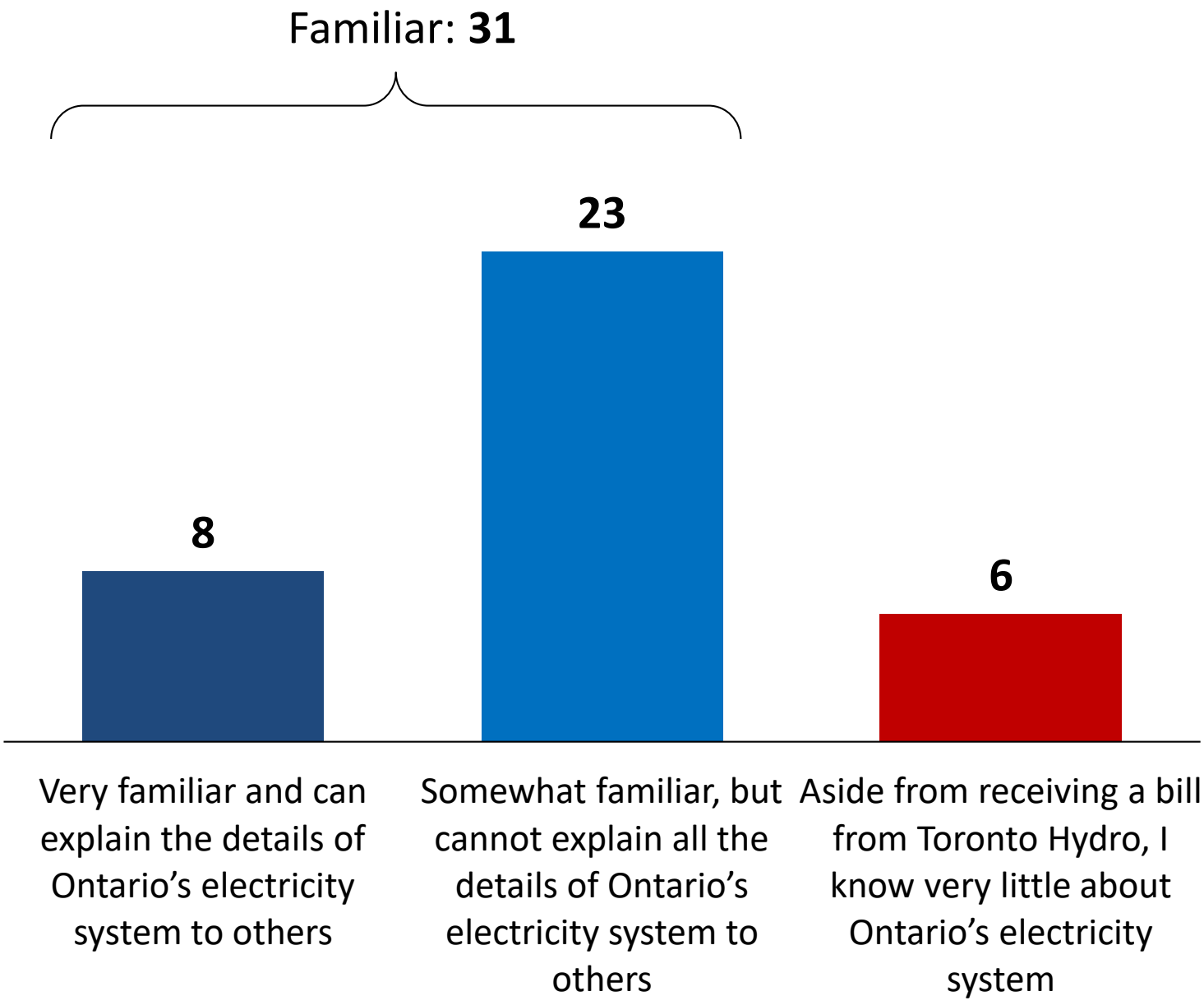
General Satisfaction

TORONTO HYDRO®

Familiarity with Electricity System

How familiar are you with the various parts of Ontario's electricity system, how they work together and which parts Toronto Hydro is responsible for?

[asked all respondents, n=37]

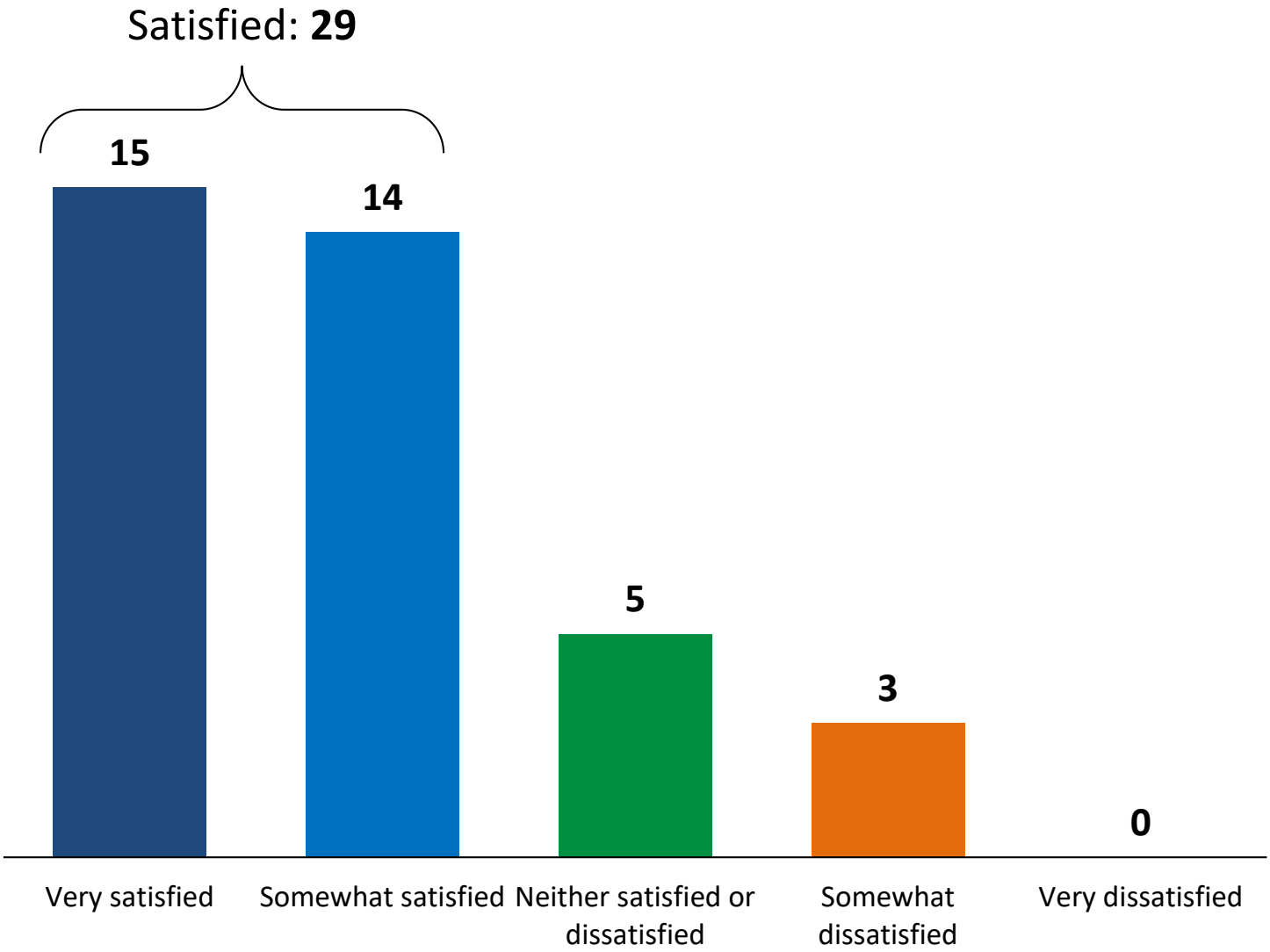


Satisfaction with Services

As you may know, Toronto Hydro operates and maintains the local electricity distribution system, reads meters, calculates your charges, answers your calls, responds during outages and clears trees and brush from power lines. Toronto Hydro does not set the commodity price of electricity or the Global Adjustment charge.

Generally, how satisfied are you with the service your organization receives from Toronto Hydro?

[asked all respondents, n=37]



Suggestions for Improved Services

Q Is there anything in particular that **Toronto Hydro** can do to improve its services to your organization? **[Sample verbatims]**

[asked all respondents, n=37]

Quicker responses:

- "Quicker and more streamlined response time from Toronto Hydro"
- "Faster response times"
- "Quicker response to service calls"

Improve Reliability:

- "Power supply quality/reliability is very poor and 20-40 power quality events, such as voltage sags and interruptions, are experienced every year"
- "Here in Scarborough, we are experiencing lots of power surges that affect our Building Automation and Elevator systems. Hoping they can lessen the occurrence of power surges"

Improve Communication:

- "Streamline communication"
- "Notification and Communication of Toronto Hydro site could be improved."
- "Using the online site is VERY confusing now that it's been changed"
- "Access to real time billing for monitoring the electricity consumption"
- "Better coordination for crews coming onto our site"
- "Toronto Hydro must streamline the processes and teams responsible for supporting large scale capital infrastructure projects"

Support with Global Adjustment:

- "Better details on global adjustment"
- "Assist customers with Global Adjustment reduction efforts and predicting the peak days of the year as a value added service."
- "Commodity price of electricity or the Global Adjustment charge should be clear to all users."

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Energy Awareness

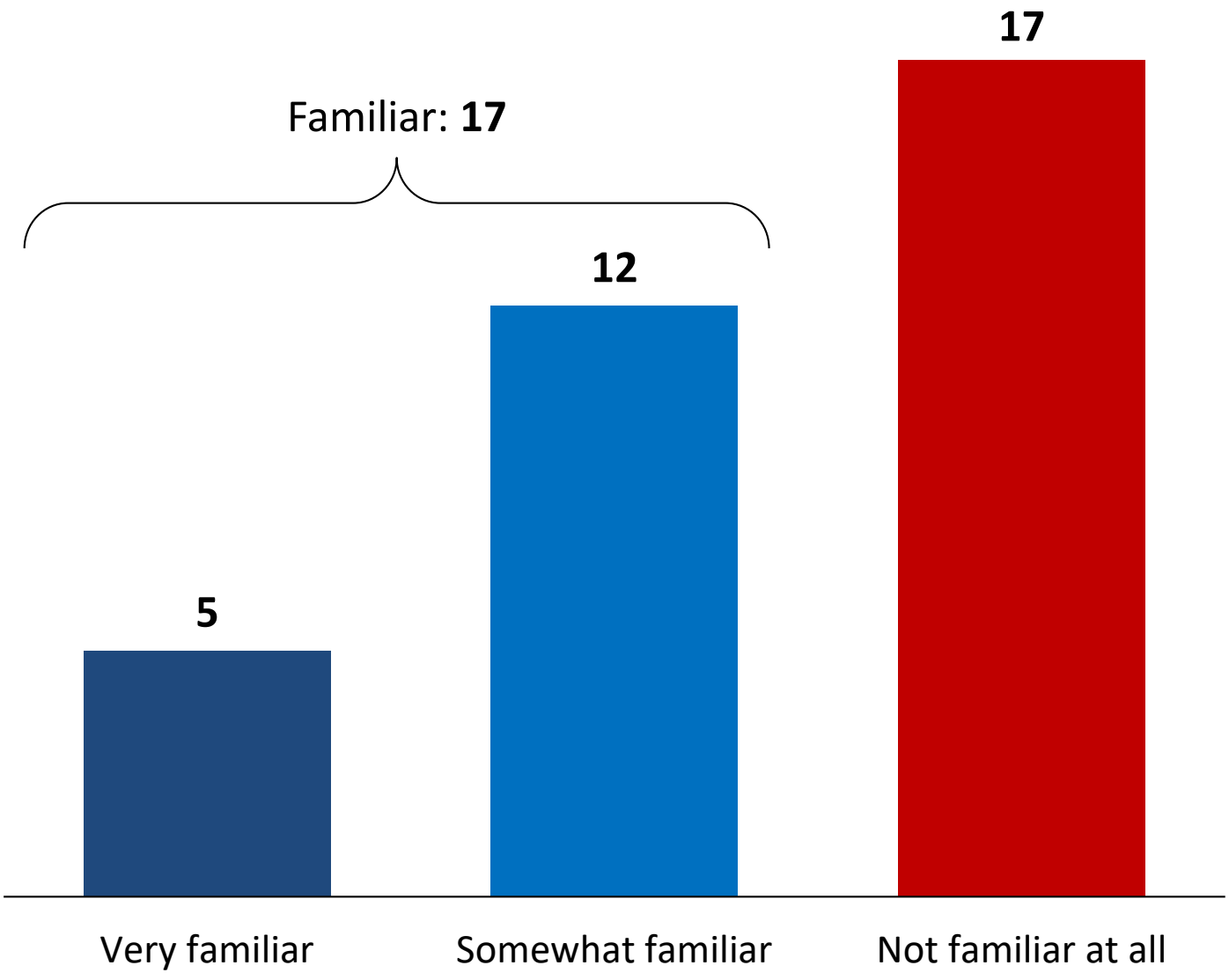


Amount of Bill Retained by Toronto Hydro

While Toronto Hydro is responsible for collecting payment for the entire electricity bill, it retains anywhere from 7% to 10% of the average Key Account's bill – depending on customer load and type of customer account. The rest of the bill goes to power generation companies, transmission companies (mainly Hydro One), the provincial government and regulatory agencies.

Before this survey, how familiar were you with the percentage of your organization's electricity bill that is retained by **Toronto Hydro**?

[asked all respondents, n=37]



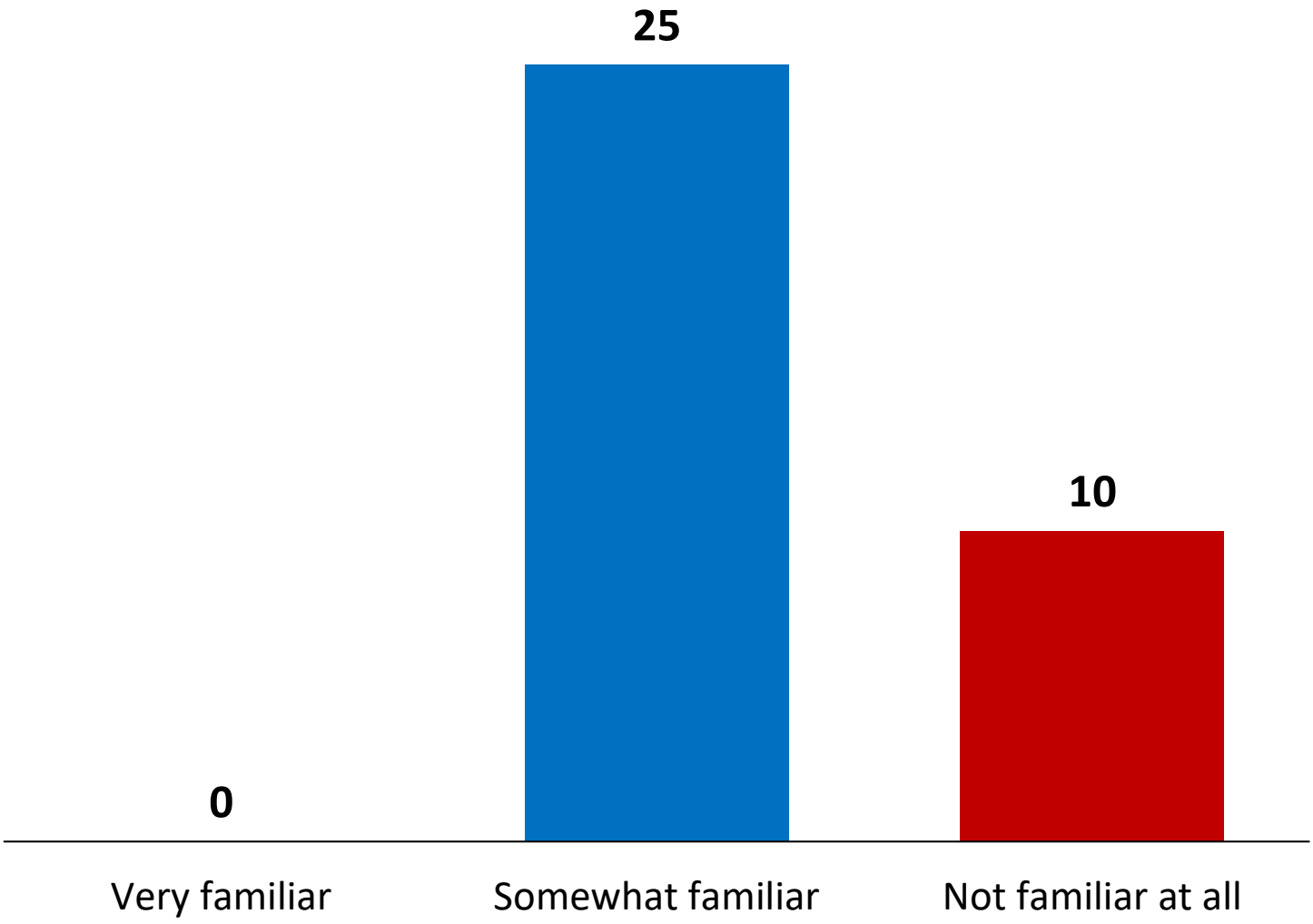
Note: "Don't Know" (3) not shown.

Familiarity with Ontario Energy Board

Electricity distributors are required to file a rate application with the Ontario Energy Board (OEB) to request a change in distribution rates based on the company's plans for capital and operating spending. Toronto Hydro is now consulting on its plans for 2020 to 2024.

The OEB is mandated to protect consumers with respect to prices and the reliability and quality of electricity service.

How familiar would you say you are with the Ontario Energy Board?
[asked all respondents, n=37]



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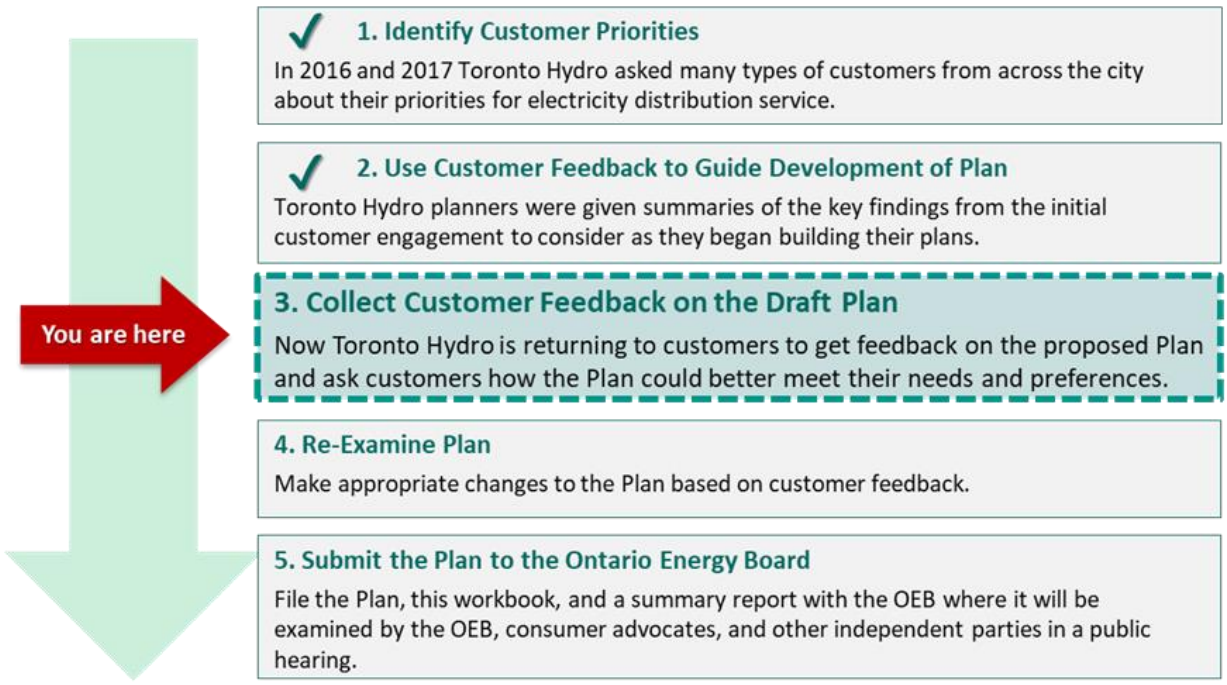
Engagement Process



Customer Engagement Process Preamble

Toronto Hydro has developed a five phase approach to gathering and responding to customer feedback.



You may recall being asked to complete a survey in early 2017. That was part of the first phase of Toronto Hydro's customer engagement. This survey is part of the third stage of collecting customer feedback on the Draft Plan.

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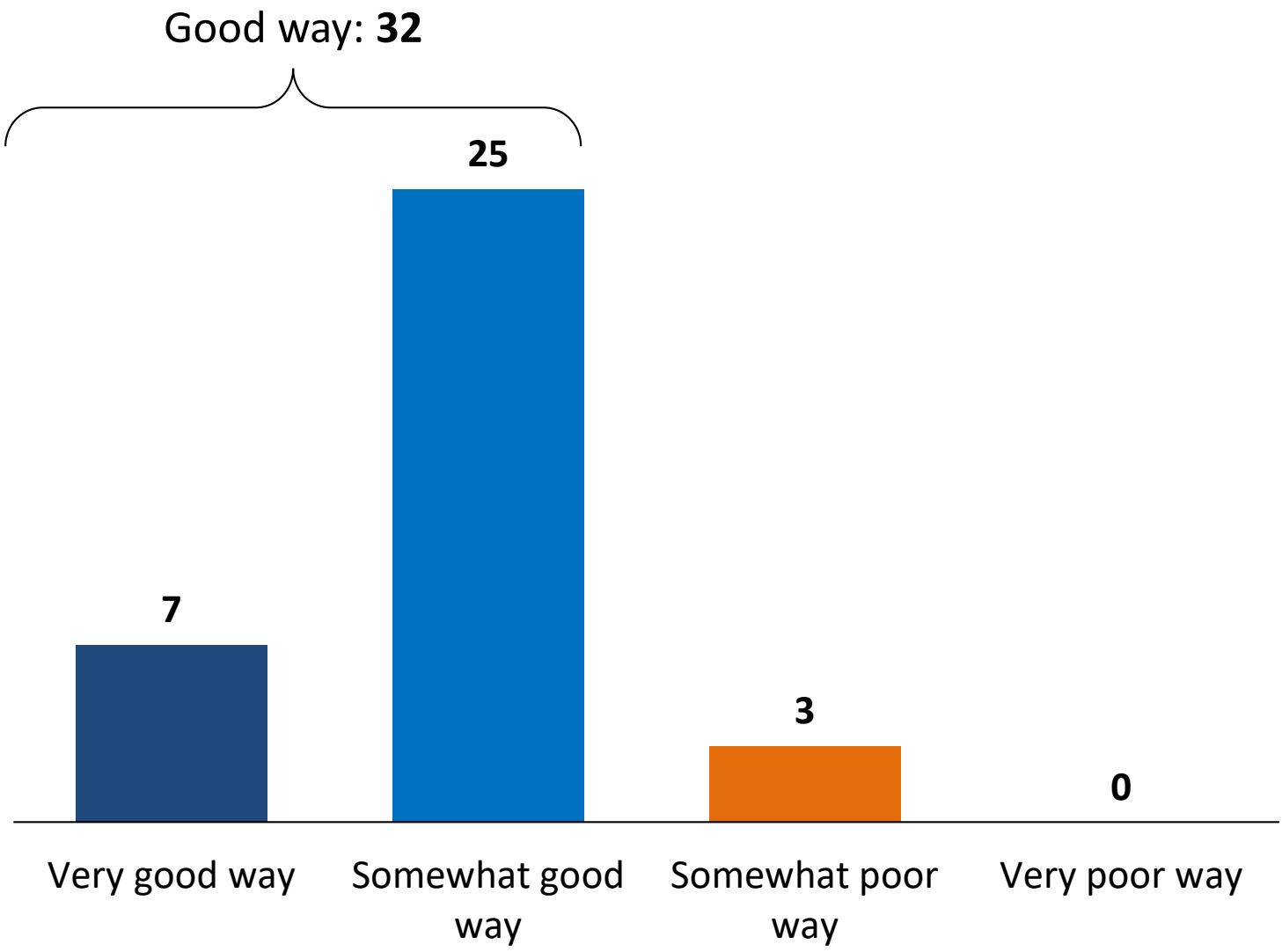
Feedback on Customer Engagement Process

Q Does this Customer Engagement process seem like a good way or a poor way to bring customer needs and preferences into Toronto Hydro's plan?

[asked all respondents, n=37]



Note: "Don't Know" (2) not shown.

Customer Priorities

In response to customer engagement efforts over the past year, Toronto Hydro customers identified a diverse range of customer stated priorities, ranging from price and reliability to customer service, outages and helping customers conserve electricity.

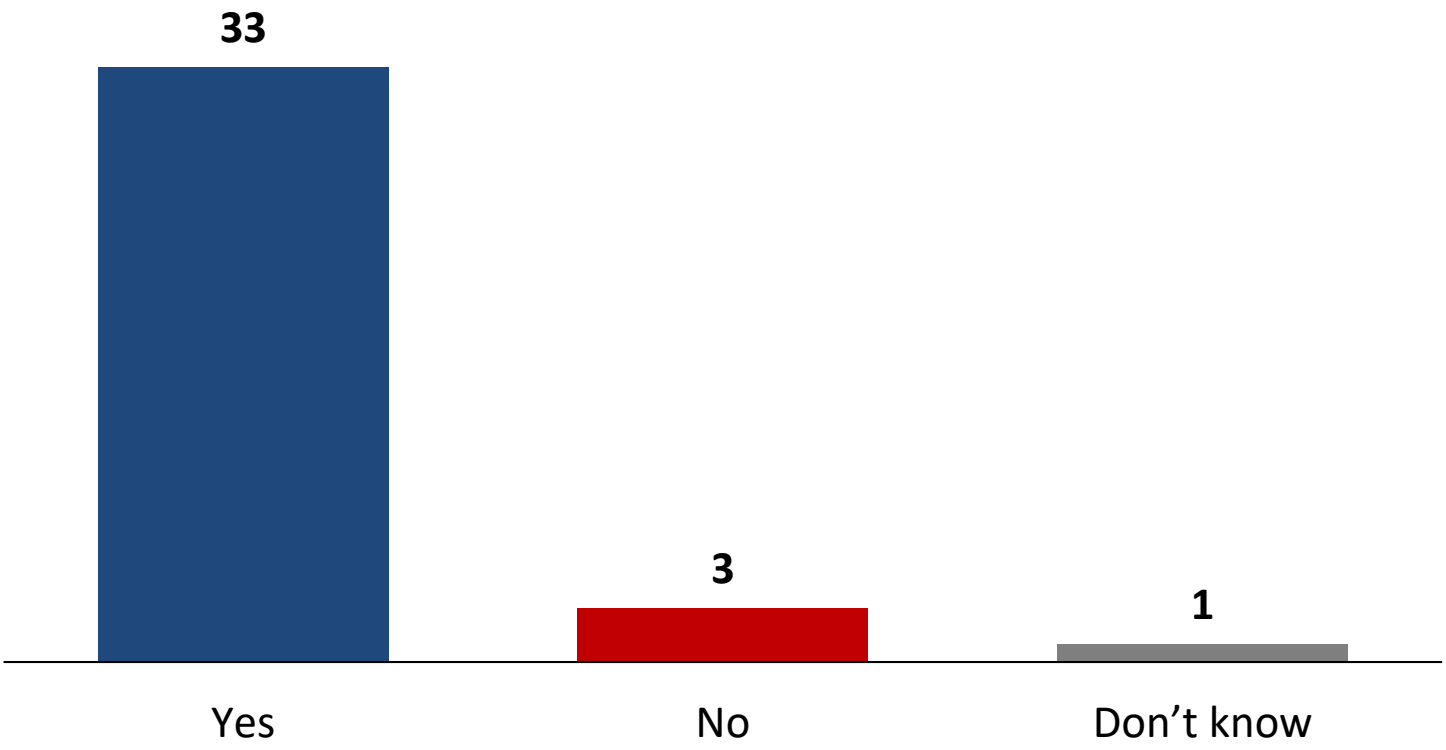
Understanding that not all customers value and prioritize the same things, Toronto Hydro is working to find a balance that works for all customers.

In February and March of 2017, Key Account customers told Toronto Hydro that the three most important priorities were:

1. Ensuring reliable electrical service;
2. Delivering reasonable electricity prices, and;
3. Preventing or reducing the length of prolonged power outages caused by extreme weather (e.g. high winds, floods and ice storms)

Are these three customer identified priorities aligned with what you expect Toronto Hydro to focus on?

[asked all respondents, n=37]



Additional Customer Priorities

Q

Are there any other priorities that you would rank ahead of the priorities above that Toronto Hydro should focus on?

[asked all respondents who say did not agree with the top three priorities identified or don't know if they agree, n=4]

"Single points of contact for all Toronto Hydro matters. Improve power quality management, improve aging infrastructure"

"REMOVE PRICE - you guys only control local distribution costs... the majority of the bill is out of your control... demand costs from you guys is peanuts on the overall hydro bill... PLEASE focus on distribution reliability for outage recovery, resilience and power quality."

Note: "Don't Know" (2) not shown.

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Trade-Offs

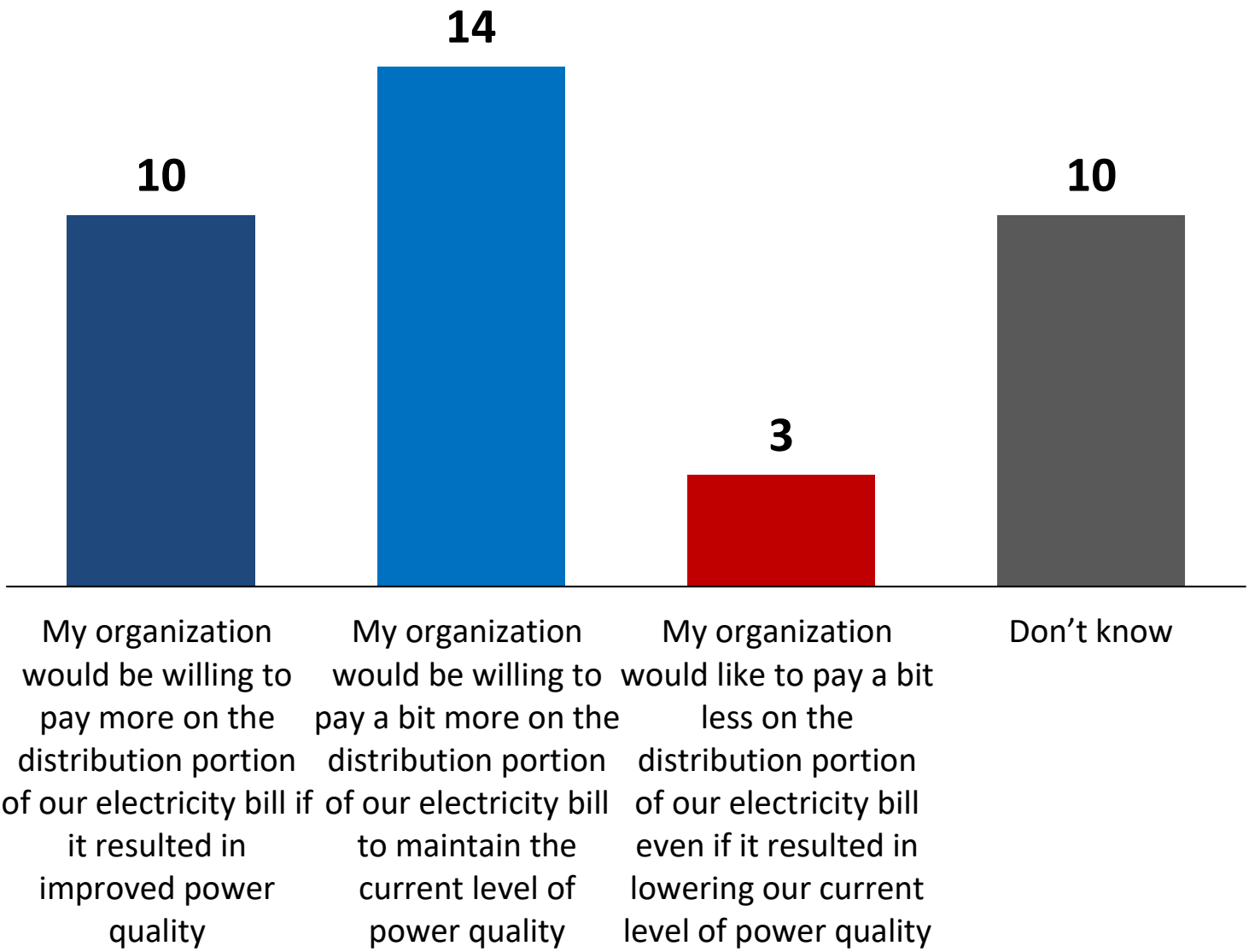


Trade-Offs

In the survey, Key Accounts customers identified power quality was the top priority not among those listed to choose from. Toronto Hydro would like to know how important power quality relative to the cost of your electricity bill.

Thinking about the trade-offs between power quality and the cost of your electricity bill, which of the following statements best represents your general point of view?

[asked all respondents, n=37]

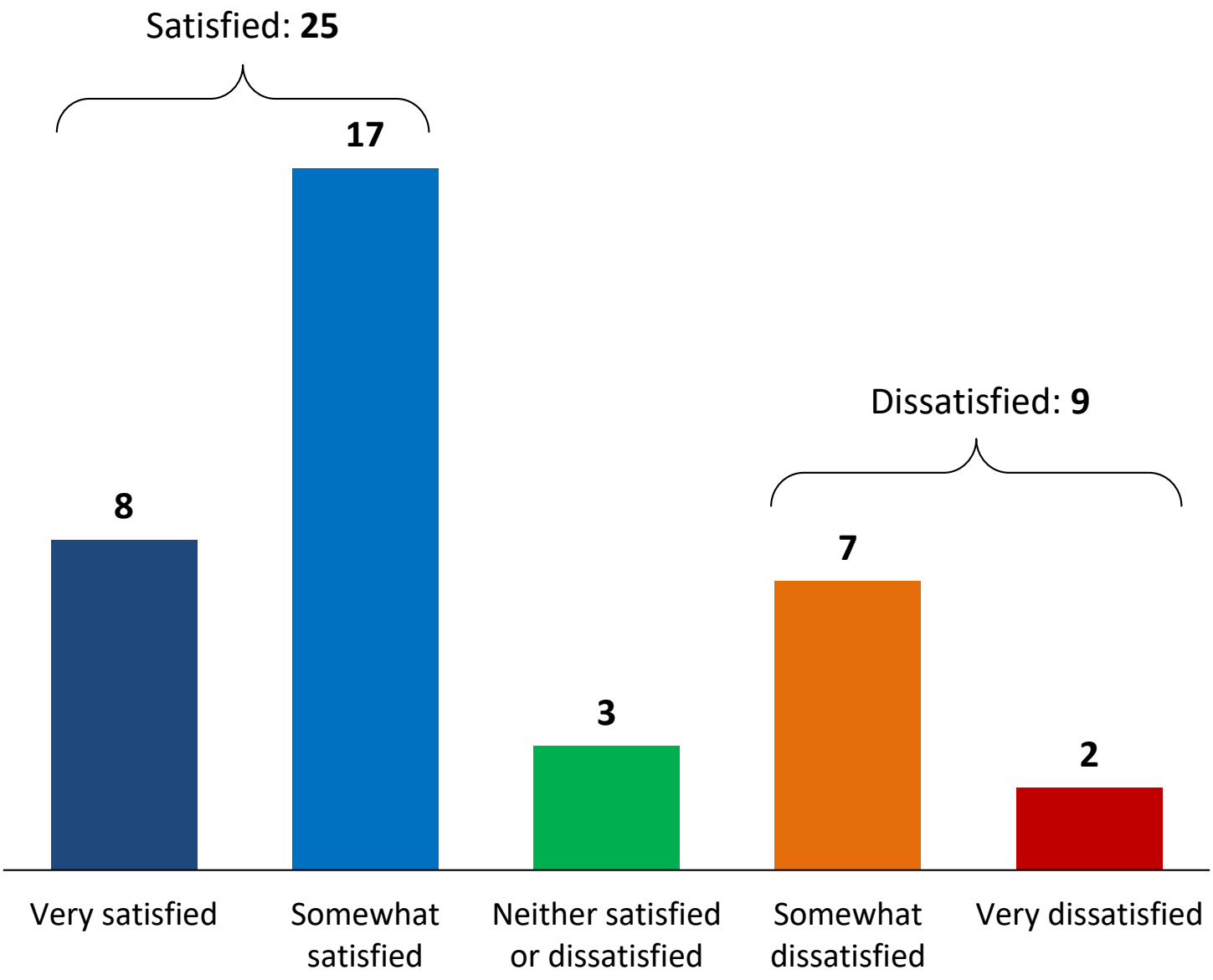


Reliability

The following statements are about the electrical service that your organization receives from Toronto Hydro. For each statement, please indicate your level of satisfaction or dissatisfaction

The reliability of your electricity service (as judged by the number of power outages you experience).

[asked all respondents, n=37]

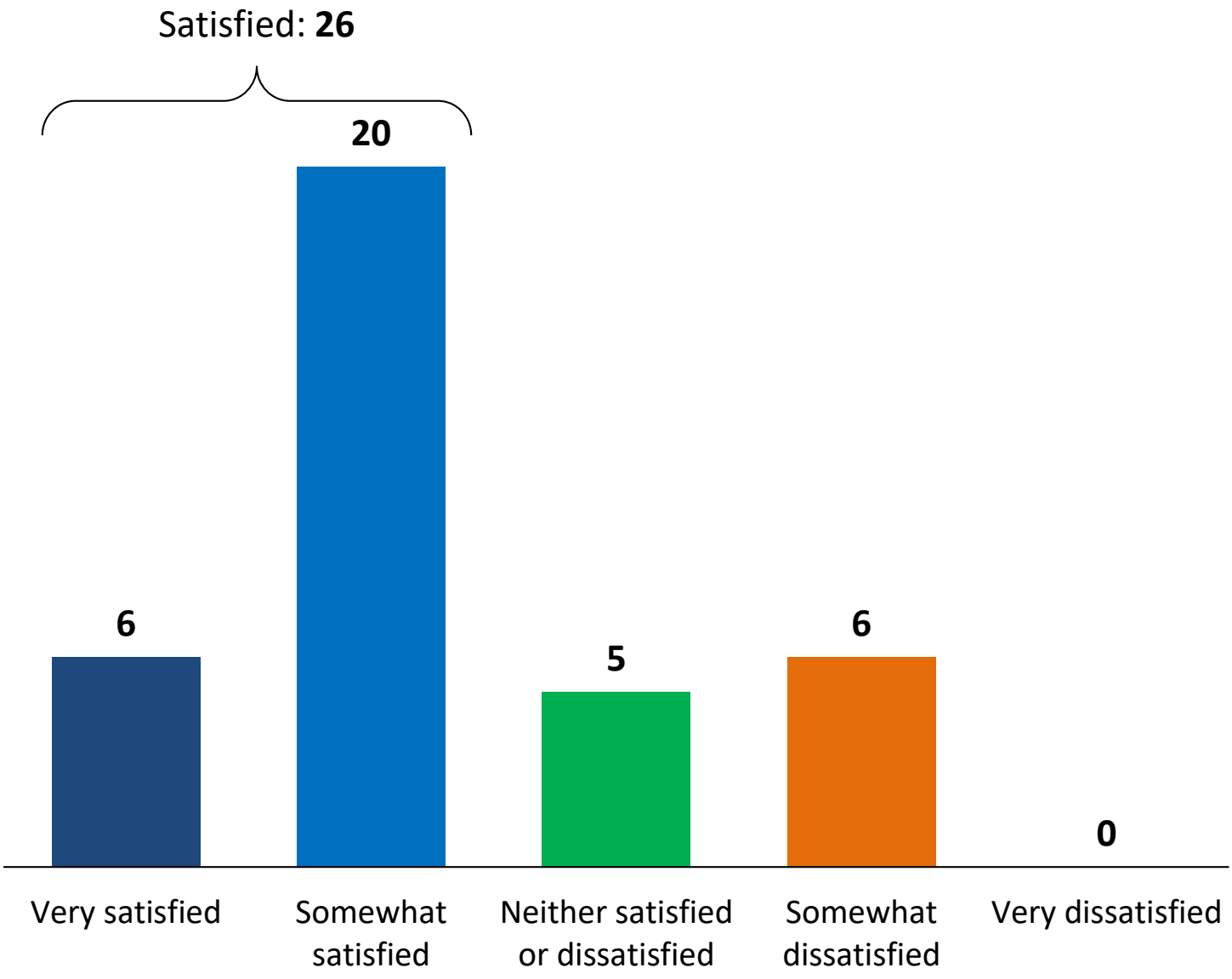


Outage Length

Q The following statements are about the electrical service that your organization receives from Toronto Hydro. For each statement, please indicate your level of satisfaction or dissatisfaction

The amount of time it takes to restore power when power outages occur.

[asked all respondents, n=37]



Planning Principles and Rate Impact

With customer feedback in mind, Toronto Hydro is proposing a plan that is responsive to:



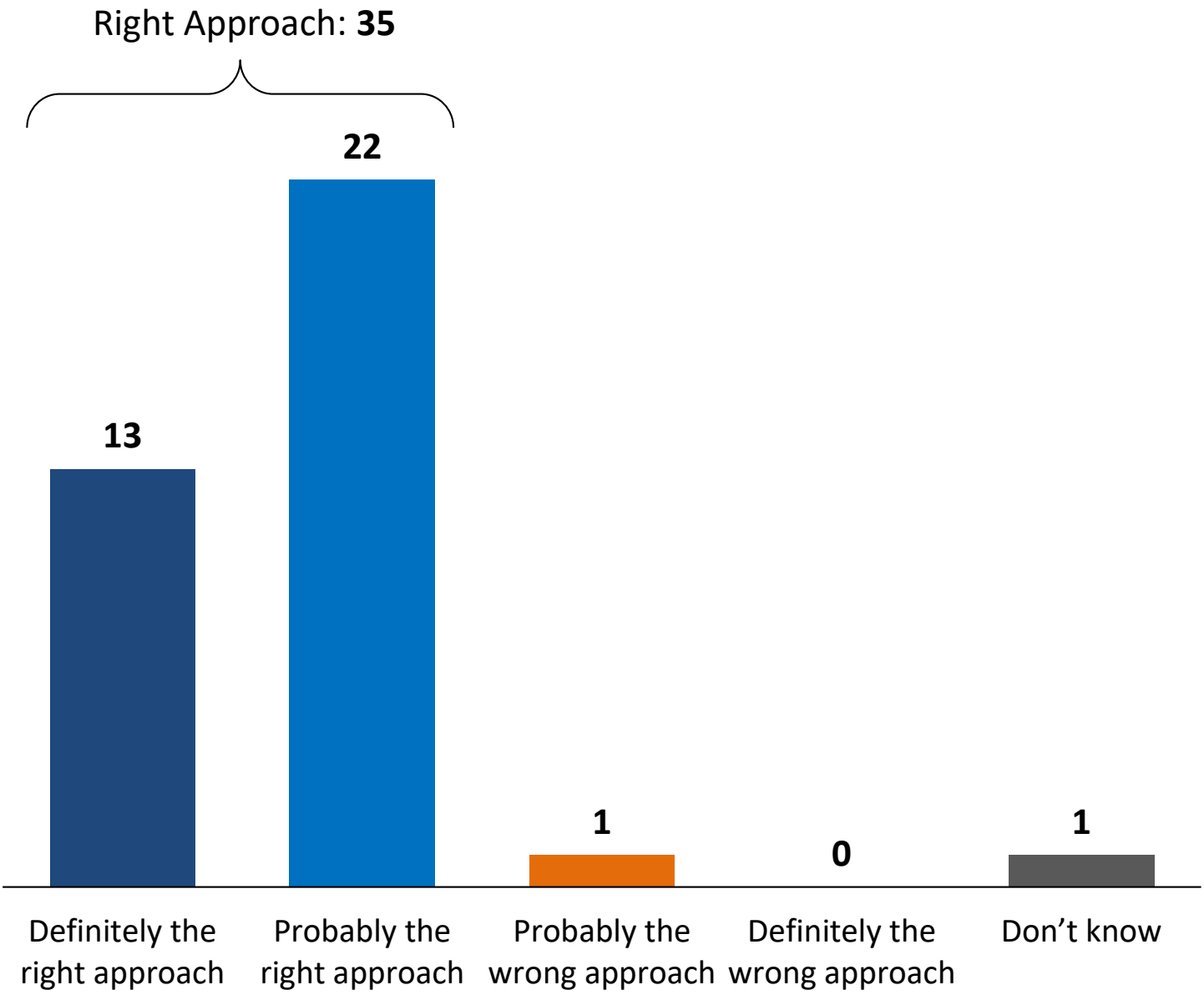
1. Legal requirements by continuing to meet its obligations, including safety;

2. Customer feedback by:
   a) Keeping distribution price increases as low as possible;
   b) Maintaining long-term performance for customers experiencing average or better service;
   c) Improve service levels for customers experiencing below average service or who have special reliability needs (e.g. hospitals); and,
   d) Balancing other customer priorities (e.g. customer service) with the need to contain rate increases.

3. Business input by relying on expert analysis and professional judgment to develop construction and operations programs that address technical and operational requirements.

Planning Principles

Q Does this seem like the right approach or the wrong approach?
[asked all respondents, n=37]



Planning Principles

Q And why do you say that? **[Sample verbatims]**

[asked all respondents, n=37]

Right Approach (n=35)

Balance Approach:

- "Meeting legal obligations, lowering prices and maintaining good customer services is a win-win proposition"
- "We realize that we do not live in a perfect world and some things will occur so it cannot only be price as service is important just as much"
- "Customers want lower rates but not at the cost of compromising service"
- "It address all facets to deliver reliable power to end customers"

The approach has limitations:

- "Surveys are only one method of feedback. For us, we have accounts across the city and the service/quality is not always consistent"
- "It seems like a global or motherhood approach. The questions seem skewed"
- "The question is phrased with only limited option of answers"

Helps Inform Customers:

- "Hydro is working better now at trying to foster information to their clients"
- "Customers will be enlightened of the electricity supply management"

Wrong Approach (n=1)

Building code:

"You rank "Tariff docs" then "service needs" then "business planning"... Nowhere do you address the comment I routinely brought up at the IESO LAC (Local Advisory Committees) meeting for Toronto Hydro where I whine that the Ontario building code only has to be exceeded by 15% to get a building permit from the Toronto Planning department... We are knocking down 10 story low rise buildings and replacing them with 50+ story high rise buildings yet we DO NOT demand that the kwhrs/m2 projected to ground level be EQUAL or less than the building replaced."

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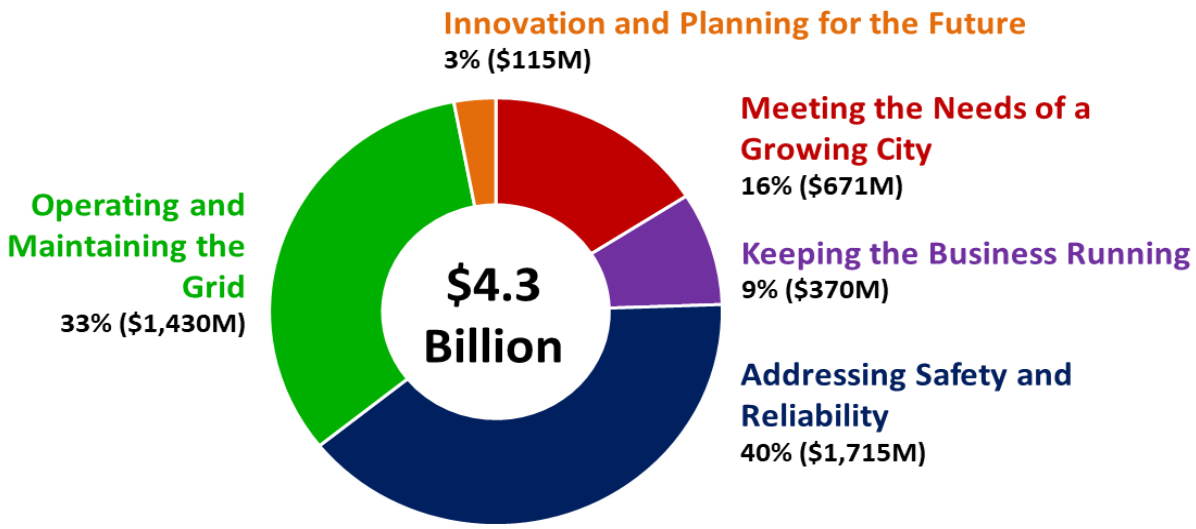
Note: "Don't Know" (1) not shown.

Investment Alternatives Preamble

Toronto Hydro has drafted a plan totaling approximately $4.3B over five years. The plan considered Toronto Hydro's legal obligations, engineering expertise and customers' needs and preferences when developing the plan. There are five key budget categories.

To learn more about each category, simply hover over the title.



Toronto Hydro's proposed plan focuses on delivering current levels of reliability and customer service for most customers and targeted improvements for customers experiencing below average service or who have special reliability needs, such as hospitals, industrial customers, and financial centres.

This proposed plan could translate into an annual average increase in your distribution rates of between 2.3% and 3.9% from 2020 to 2024.

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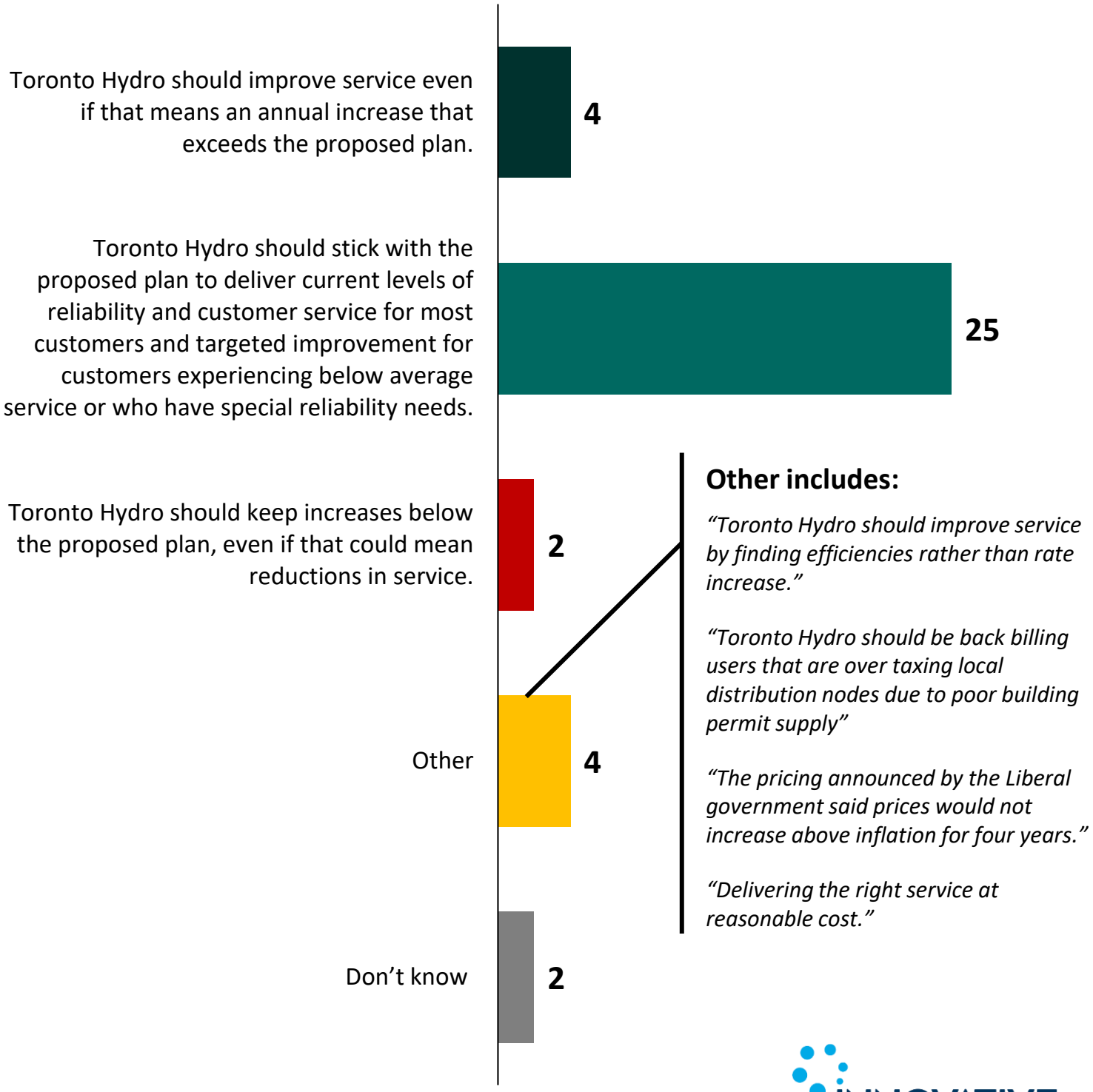
Opinion of Toronto Hydro's Proposed Plan

Q With regards to Toronto Hydro's proposed plan, which of the following statements best represents your view?

[asked all respondents, n=37]



Opinion of Toronto Hydro's Proposed Plan

Q And why do you say that?

[asked all respondents, n=37]

Improve Service (n=4)

Reliability:

- "This will prevent occasional brief outages that affect our operation"
- "Reliability is the most important aspect of the system"
- "Reliability is Key - prices will increase regardless"

Maintain Service (n=25)

Increase is reasonable as long as the service quality can be maintained:

- "The increase of 3.9 percent over four years is appropriate as long as service and reliability is not reduced"
- "I agree that the service should be at least maintained or even improved even we have to pay the related cost with an increase in distribution charges of maximum up to 4%"
- "New customer accounts should not impact existing rates but it is important to maintain the grid and ensure reliability"

Can't Afford More:

- "We don't need another price increase as cost of living is already high. So maintaining is key"
- "We have paid enough for the hydro"

Generally Positive:

- "That would be in our best interest"
- "It's consistent with the objectives from its customers"
- "The right thing to do"

Reduce Cost (n=2)

No comment:

- "No comment"
- "No further comments"

Note: "Don't Know" (2) and "Other" (4) not shown.

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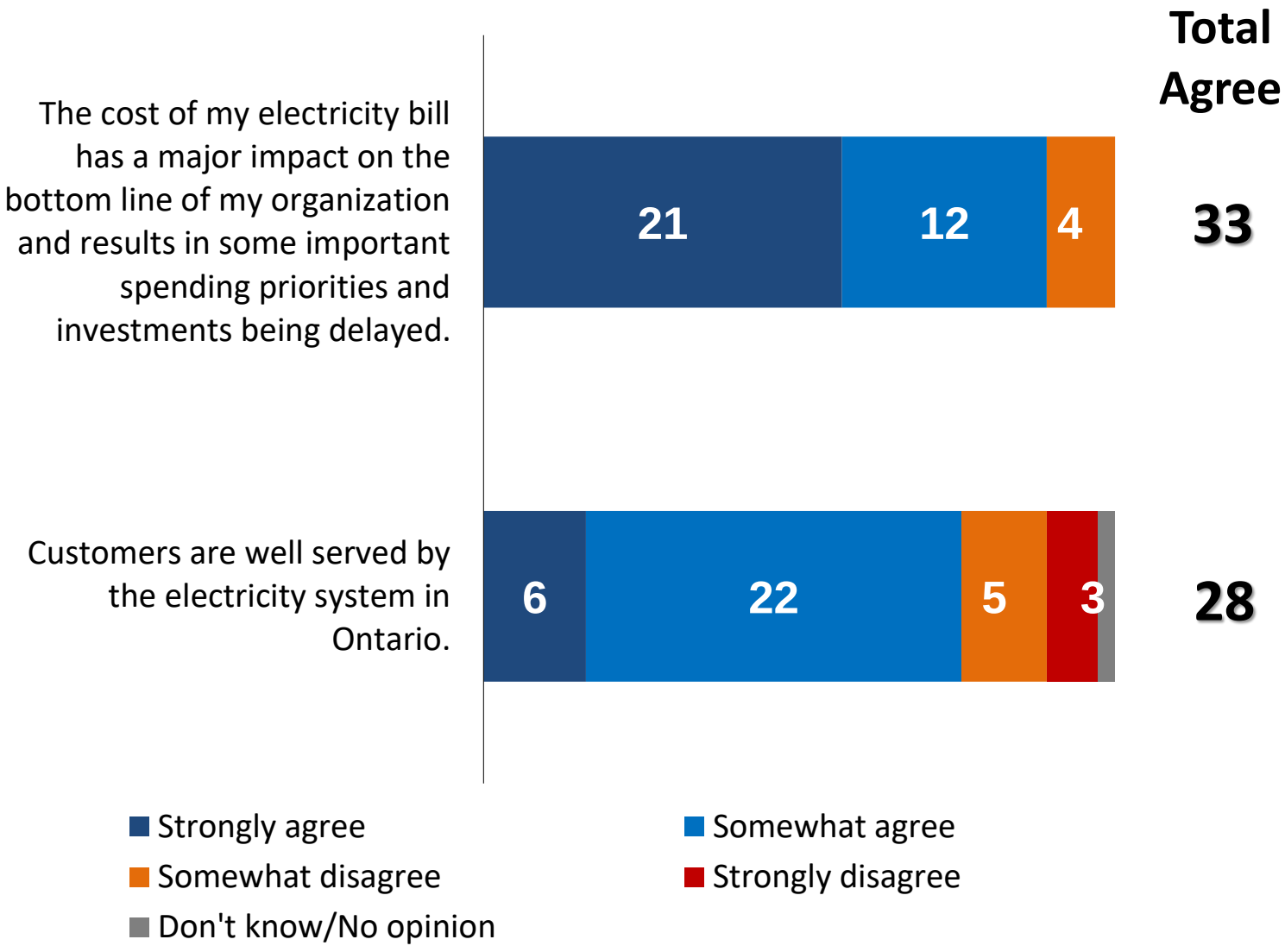
Energy Opinions



Energy Opinions

Q For each statement please tell me if you would strongly agree, somewhat agree, somewhat disagree or strongly disagree. If you don't know enough to say or don't have an opinion just let me know.

[asked all respondents, n=37]



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Final Comments



Additional Comments

Q Before this survey concludes, do you have any additional comments or feedback you'd like to share with Toronto Hydro?

[asked all respondents, n=37]

Rates:

- "Hoping that the electricity rates will go down"
- "Please keep the hydro price down"
- "The overall cost of electricity in Ontario is high and puts companies that are owned by US parents at a competitive disadvantage. Hydro cost are a significant influencing factor of the cost of manufacturing in our business and therefore has been a limiting factor for growth in our business in Ontario, compared to our US manufacturing plants. If we want to grow the manufacturing foot print in Ontario we need to reduce overall cost of Hydro, otherwise we will continue to loose jobs to the US or Mexico from Ontario."
- "My organization along with many others are being billed more then 55% towards alternative power (Global Adjustment) for more then a decade. I believe the amount of money that is being spent towards the Global Adjustment should have yielded better results instead of the excuses that more money is needed to increase better service. My company a lone has paid over $500,000 annually for Global Adjustment. Times that by 10 years and you have 5 million dollars over that period of time, and that one company. It is very difficult to know what your budget is when you have no idea what your charges are going to be on the adjustment. You want us to help you, you should help us so we can give back"
- "Hydro doesn't regulate the global adjustment however, we should be fighting for your customers and collect part of it to offset any increase to our billing"

Reliability:

- "Any power interruption is a major problem. A blip can cause expensive equipment damage and an extended power outage seriously affects our business partners"
- "Critical facilities such as hospitals must be given higher priority for power reliability/quality improvements given the risk of power interruptions on vulnerable occupants"

Note: Respondents with no comment not shown.

Additional Comments

Q

Before this survey concludes, do you have any additional comments or feedback you'd like to share with Toronto Hydro?

[asked all respondents, n=37]

General Positive Comments:

- "We have been happy with the service to date"
- "It's good that you are reaching out to your customers to help inform your strategic investments"
- "I've been involved with Toronto Hydro in the commercial industry and I find their support to be above average and the incentive programs division is outstanding"
- "Toronto Hydro contact representatives are the top in the industry. Victor da Rosa is a well respected representative and cares about his customers. Always helpful and a true professional. Jen Grado is also a great service provider. She was very helpful with a challenge our company was faced and she did a great job. Thank you for having them be our contact"
- "In my experience Toronto Hydro has been quite reliable and attentive to our critical needs. Outages are responded to very quickly and usually resolved in a timely manner as well. The crews, contractors and staff have all been attentive and courteous. We have taken advantage of some of the cost saving opportunities through Save on Energy program and have received exceptional customer service from those assisting with our projects. We understand that electricity prices are based on many variables beyond the control of Toronto Hydro but hope Toronto Hydro will continue to find ways to reduce associated electricity costs as they represent nearly 70% of the total cost of all utilities at our organization but less than 35% of the total consumption"

Other Comments:

- "Please do not sacrifice the condominium needs and obligations with loose and easy advice to proceed with projects without full analysis and scrutiny of the proposals and service providers. The lay person expects that when Toronto Hydro says it's a good project that you have scrutinized and analyzed the details...you don't do this"
- "Every homeowner and business owner should be encouraged and somewhat compensated to install standby generators at their location"
- "Suggesting to have account manager for big organizations in order to clear any concern or challenge in the shortest possible time"
- "Trust we will have a good operating relationship with Toronto Hydro because we have our own medium voltage infrastructure and we have internal staffs to carry out the related medium voltage switching which will impact the upstream Toronto Hydro distribution network. Thanks."
- "PLEASE get going on smart grid generation ability."
- "The province has spent far too much on windmills and solar photovoltaics when not needed The nuclear burden cost wise is not sustainable, Pickering is too old. Storage is being viewed far too narrow as electricity storage and not energy storage, gas and hydro must be viewed together"
- "Publicize energy saving & monitoring technologies in more forums to build know-how better"

Note: Respondents with no comment not shown.

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Building Understanding.

Personalized research to connect you and your audiences.

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Appendix 3.1

Customer Feedback Portal

Understanding Customer Needs and Preferences

TORONTO HYDRO®

Residential Workbook

Website Layout

APRIL 2018

STRICTLY PRIVILEGED AND CONFIDENTIAL

Welcome to Toronto Hydro's Planning Consultation!

We need your input on choices that will affect the service you receive from Toronto Hydro and the price you pay for that service.

1. In Ontario, electricity distributors are regulated by the **Ontario Energy Board** (OEB), the provincial energy regulator.

2. Toronto Hydro is developing its business plan for 2020 to 2024. This plan will determine the investments Toronto Hydro makes in equipment and infrastructure, the services it provides you as a customer, and the rates you pay.

3. **Your electricity rates pay for this plan so your views must be considered.**

4. You don't need to be an electricity expert to participate in this consultation. This workbook is focused on basic choices and provides the background information you need to answer the questions.

5. **Your feedback will be presented to the OEB when Toronto Hydro files its application with the OEB.**

In appreciation of your time, those who complete the questions that follow will be invited to enter a draw to win one of four (4) $500 prepaid credit cards.

All of your individual responses will be kept confidential. Innovative Research Group (INNOVATIVE), an independent research company, has been hired to gather your feedback. INNOVATIVE will combine your responses with others to provide an overall report to Toronto Hydro.

About you.

In order to have a better sense of the type of customers providing feedback, please answer the questions below.

Are you completing this questionnaire as a…

Residential Customer | **Small Business Customer**

More about you

The information below is only being requested for statistical purposes to better understand the different types of customers providing feedback to Toronto Hydro.

R1. Please enter the first 3 characters of your residential postal code.

(_ _ _)

R2. Are you the person primarily responsible for paying the electricity bill in your household?

- ❑ Yes – I pay the bill
- ❑ Yes – Shared responsibility
- ❑ No

R3. Which of the following best describes your living situation?

- ❑ I pay rent for my housing
- ❑ I own my home
- ❑ I live in housing where I do not pay rent

R4. How would you describe your primary residence?

- ❑ A fully-detached home
- ❑ A semi-detached home
- ❑ An apartment or condo building fewer than 5 storeys
- ❑ An apartment or condo building 5 storeys or higher
- ❑ Other

R5. How long have you been a Toronto Hydro residential customer?

- ❑ Less than 2 years
- ❑ 2 to less than 5 years
- ❑ 5 to less than 10 years
- ❑ 10 to less than 20 years
- ❑ 20 years or more

Web page break.

More about your organization

The information below is only being requested for statistical purposes to better understand the different types of customers providing feedback to Toronto Hydro.

B1. Please enter the first 3 characters of your organization's postal code.

(_ _ _)

B2. As part of your job, do you **make decisions** or **influence decisions** about electricity management?

- ❑ Yes
- ❑ No

B3. Thinking about the areas of your organization that you manage, how much would you estimate is spent every month on electricity as a Toronto Hydro customer?

- ❑ Less than $500
- ❑ $500 to less than $1,000
- ❑ $1,000 to less than $1,500
- ❑ $1,500 to less than $2,000
- ❑ $2,000 or more
- ❑ Don't know

B4. Which of the following best describes the sector in which your business operates?

- ❑ Commercial
- ❑ Manufacturing/Industrial
- ❑ Data Centre
- ❑ Hospitality
- ❑ Restaurant/Tavern
- ❑ Retail
- ❑ Warehouse
- ❑ Other

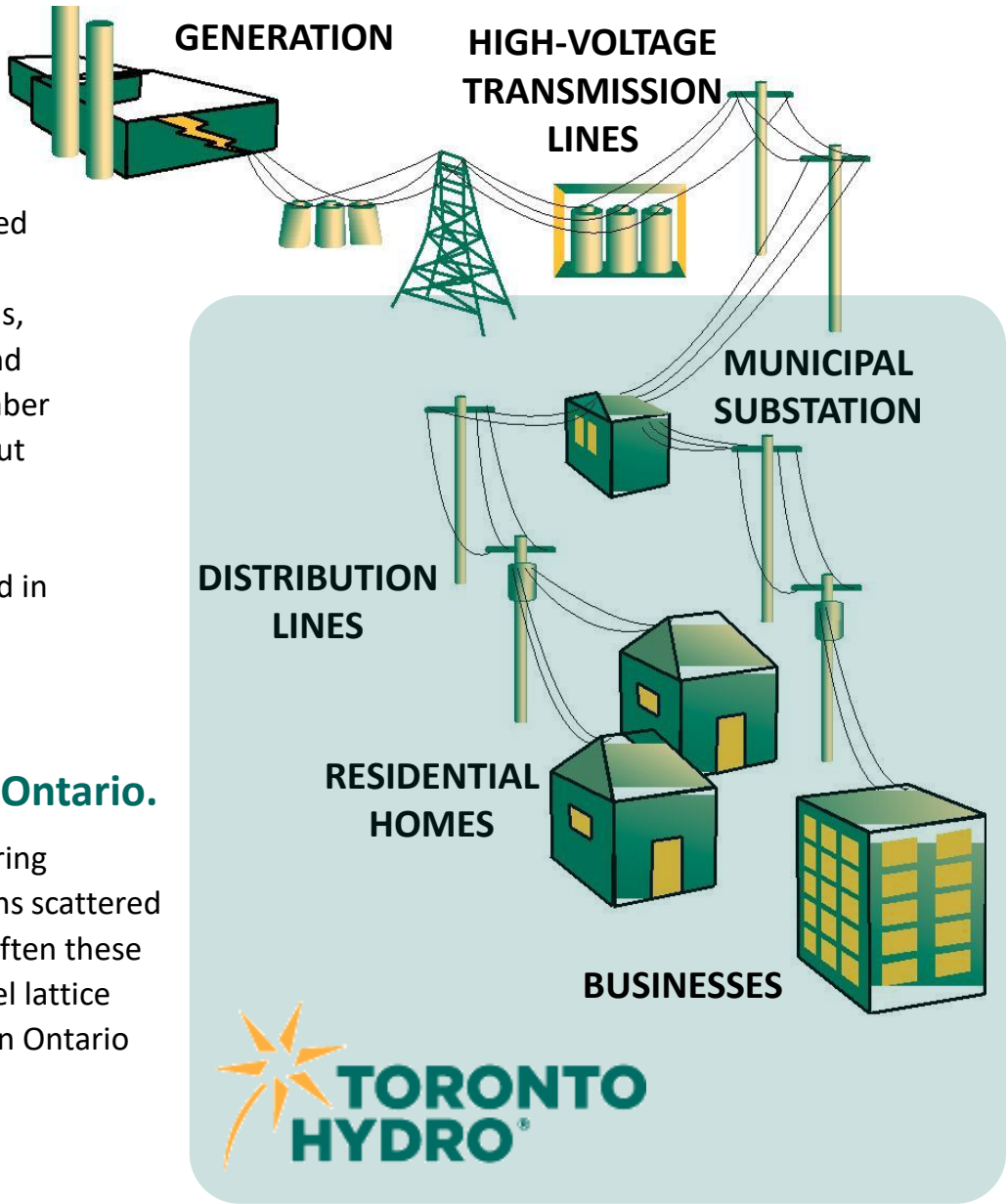
Where does Toronto Hydro fit within the electricity system?

There are three main parts to Ontario's electricity system:

1) Generation

Where electricity comes from.

The electricity you use is generated from a mix of nuclear generation stations, water power installations, natural gas generating plants, wind turbines, and solar panels. A number of companies own these plants but Ontario Power Generation, a provincial crown corporation, generates most of the power used in Ontario.



2) Transmission

Electricity travels across Ontario.

High voltage transmission lines bring electricity from generating stations scattered across the province to Toronto. Often these lines are suspended on large, steel lattice towers. Almost all of these lines in Ontario are owned by Hydro One.

3) Local Distribution

Delivering power to homes and businesses in your community.

Toronto Hydro runs the part of the electricity system that directly serves you. Distribution stations receive and convert electricity to safer voltages. Distribution poles, wires, and underground cables deliver it to your home or business. Toronto Hydro builds and operates this distribution system, reads meters, calculates and collects bills for all parts of the electricity system, answers customer calls, and delivers conservation programs. Toronto Hydro is owned by the City of Toronto. Its activities are funded by rates set by the OEB, not by government tax dollars.

Link to next page.

Continued from previous page

Fast Facts

- 100% owned by the City of Toronto
- Established in 1911
- Amalgamation of six utilities in 1998 across “metro Toronto”
- Owns and operates the electricity distribution system for Canada’s largest city
- Delivers electricity to approximately 766,000 customers in the City of Toronto
- Distributes approximately 20% of the electricity consumed in Ontario
- 1,490 employees
- $4.1 billion in capital assets
- ***Toronto Hydro does <u>not</u> generate electricity***
- ***Toronto Hydro does <u>not</u> receive taxpayer money to fund its operations or investments***
- ***Toronto Hydro is entirely funded through the rates its customers pay***

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Q1. Before this consultation, how familiar were you with the various parts of the electricity system, how they work together, and for which services Toronto Hydro is responsible?

- □ Very familiar and could explain the details of Ontario's electricity system, and Toronto Hydro's role in it, to others
- □ Somewhat familiar, but could not explain all the details of Ontario's electricity system to others
- □ Have heard of some of the terms and organizations mentioned in this workbook, but knew very little about Ontario's electricity system
- □ Aside from receiving a bill from Toronto Hydro, I knew nothing about Ontario's electricity system
- □ Don't know

Toronto Hydro operates and maintains the local electricity distribution system, delivers electricity throughout the community, reads meters, calculates and collects customer electricity bills, answers customer calls, responds during outages, clears trees and brush from power lines, and delivers conservation and demand programs.

Q2. Generally, how satisfied or dissatisfied are you with the services you receive from Toronto Hydro?

- □ Very satisfied
- □ Somewhat satisfied
- □ Neither satisfied nor dissatisfied
- □ Somewhat dissatisfied
- □ Very dissatisfied
- □ Don't know

Q3. Is there anything in particular that Toronto Hydro can do to improve its services to you?

Web page break.

Where does your money go?

Every item and charge on your bill is either mandated by the provincial government or approved by the Ontario Energy Board.

For the average residential customer, about **32%** of the bill goes to pay for the Toronto Hydro distribution system. The rest of the bill goes to power generation companies, transmission companies, the federal and provincial governments, and regulatory agencies.

Toronto Hydro is responsible for billing customers for all of these costs, including any applicable taxes. The "Delivery" charge pays for both the cost of transmission and the cost of distribution. Only the distribution portion is retained by Toronto Hydro to pay for its part of the system.

Typical Residential Bill

Sample Toronto Hydro Monthly Bill
(Based on consumption of 750 kWh)

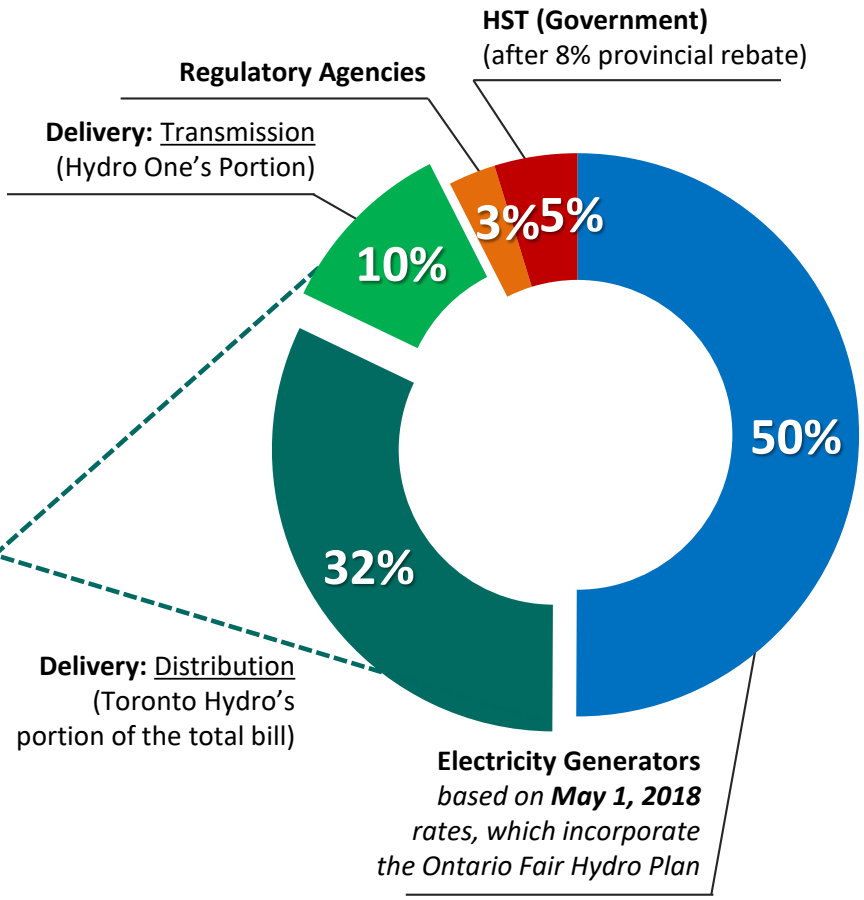
Account Number:
000 000 000 000 0000

Meter Number:
00000000

Toronto Hydro's portion of the bill: **$39.19**

Your Electricity Charges	
Electricity	
On-Peak (Highest Price) @ $0.132 /kWh	17.82
Mid-Peak (Mid Price) @ $0.095 /kWh	11.99
Off-Peak (Lowest Price) @ $0.065 /kWh	31.69
Delivery	52.21
Regulatory Charges	3.28
Debt Retirement Charge†	0.00
Total Electricity Charges	**$116.99**
HST	15.21
8% Provincial Rebate*	(-$9.36)
Total Amount	**$122.84**

*The Ontario government is providing a rebate on your electricity costs equal to the provincial portion of the HST



Q4. Before this engagement, how familiar were you with the percentage of your electricity bill that is retained by Toronto Hydro?

- □ Very familiar
- □ Somewhat familiar
- □ Not familiar

Web page break.

How will your views impact Toronto Hydro's plans and rates?

The Ontario Energy Board (OEB) sets electricity rates in Ontario.

Electricity distributors like Toronto Hydro are funded by the distribution rates paid by their customers. Electricity distributors are required to file a rate application with the OEB to request a change in distribution rates based on their plans for capital and operating spending. Toronto Hydro is consulting now on its plans for 2020 to 2024.

As a customer, how are my interests protected?

The OEB requires electricity distributors, like Toronto Hydro to consider customer needs and preferences as it develops its business plan and distribution system plan.

The OEB then reviews Toronto Hydro's plans and proposed rates in an open and transparent public process known as a rate hearing. Any individual or group may participate during Toronto Hydro's application to ask questions or challenge Toronto Hydro's plans and assumptions. Toronto Hydro will be held accountable for the way you were consulted, the information shared with you and the ways in which the plan considers what you say.

At the end of the process, the OEB weighs the evidence and decides on the rates Toronto Hydro can charge its customers.

How does Enhanced Customer Engagement work?

Toronto Hydro has developed a five phase approach to gathering and responding to customer feedback.

✓ **1. Identify Customer Priorities**

In 2016 and 2017 Toronto Hydro asked many types of customers from across the city about their priorities for electricity distribution service.

✓ **2. Use Customer Feedback to Guide Development of Plan**

Toronto Hydro planners were given summaries of the key findings from the initial customer engagement to consider as they began building their plans.

You are here

3. Collect Customer Feedback on the Draft Plan

Now Toronto Hydro is returning to customers to get feedback on the proposed Plan and ask customers how the Plan could better meet their needs and preferences.

4. Re-Examine Plan

Make appropriate changes to the Plan based on customer feedback.

5. Submit the Plan to the Ontario Energy Board

File the Plan, this workbook, and a summary report with the OEB where it will be examined by the OEB, consumer advocates, and other independent parties in a public hearing.

Link to next page

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Q5. Does this Customer Engagement process seem like a good way or a poor way to bring customer needs and preferences into Toronto Hydro's plan?

- □ Very good way
- □ Somewhat good way
- □ Somewhat poor way
- □ Very poor way
- □ Don't know

Q6. Are there things that you would change about how Toronto Hydro brings customer needs and preferences into Toronto Hydro's plan? If so, what would you change?

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In the initial customer engagement, residential and small business customers identified six core priorities which they believe should be a focus for Toronto Hydro. They are:

- *Delivering reasonable electricity prices*
- *Ensuring reliable electricity service*
- *Ensuring the safety of electricity infrastructure*
- *Enabling the electricity system to support the reduction of greenhouse gases*
- *Helping customers with conservation and efficiency*
- *Providing quality customer service*

More information on the initial round of customer input can be found **here**.

Q7. Are there any priorities on the list above that you feel don't belong? If so, please specify.

Q8. Are there any priorities that you would add to the list above? If so, please specify which priorities you would add.

Q9. Please rank your Top 3 priorities from the list below.

Drag and drop the priorities in order, starting with the priority most important to you, followed by the second most important, and ending with the third most important.

Priorities
Reasonable Prices
Reliability
Safety
Helping to reduce greenhouse gases
Helping customers conserve
Customer service
Other [Please specify:_____]
Other [Please specify:_____]

Top 3 Ranking
1
2
3

Web page break.

Building Toronto Hydro's Plan

With this customer feedback in mind, Toronto Hydro is proposing a Plan that is responsive to:



1. Legal requirements by continuing to meet its obligations, including safety;





2. Customer feedback by:
   a) Keeping distribution price increases as low as possible;
   b) Maintaining long-term performance for customers experiencing average or better service;
   c) Improve service levels for customers experiencing below average service or who have special reliability needs (e.g. hospitals); and,
   d) Balancing other customer priorities (e.g. customer service) with the need to contain rate increases.





3. Business input by relying on expert analysis and professional judgment to develop construction and operations programs that address technical and operational requirements.

More information on Toronto Hydro's planning process here.

Q10. Does this seem like the right approach or the wrong approach?

- □ Definitely the right approach
- □ Probably the right approach
- □ Probably the wrong approach
- □ Definitely the wrong approach
- □ Not sure
- □ Don't know

Q11. Is there is anything in particular you would change about this approach or any other comments you would like to make?

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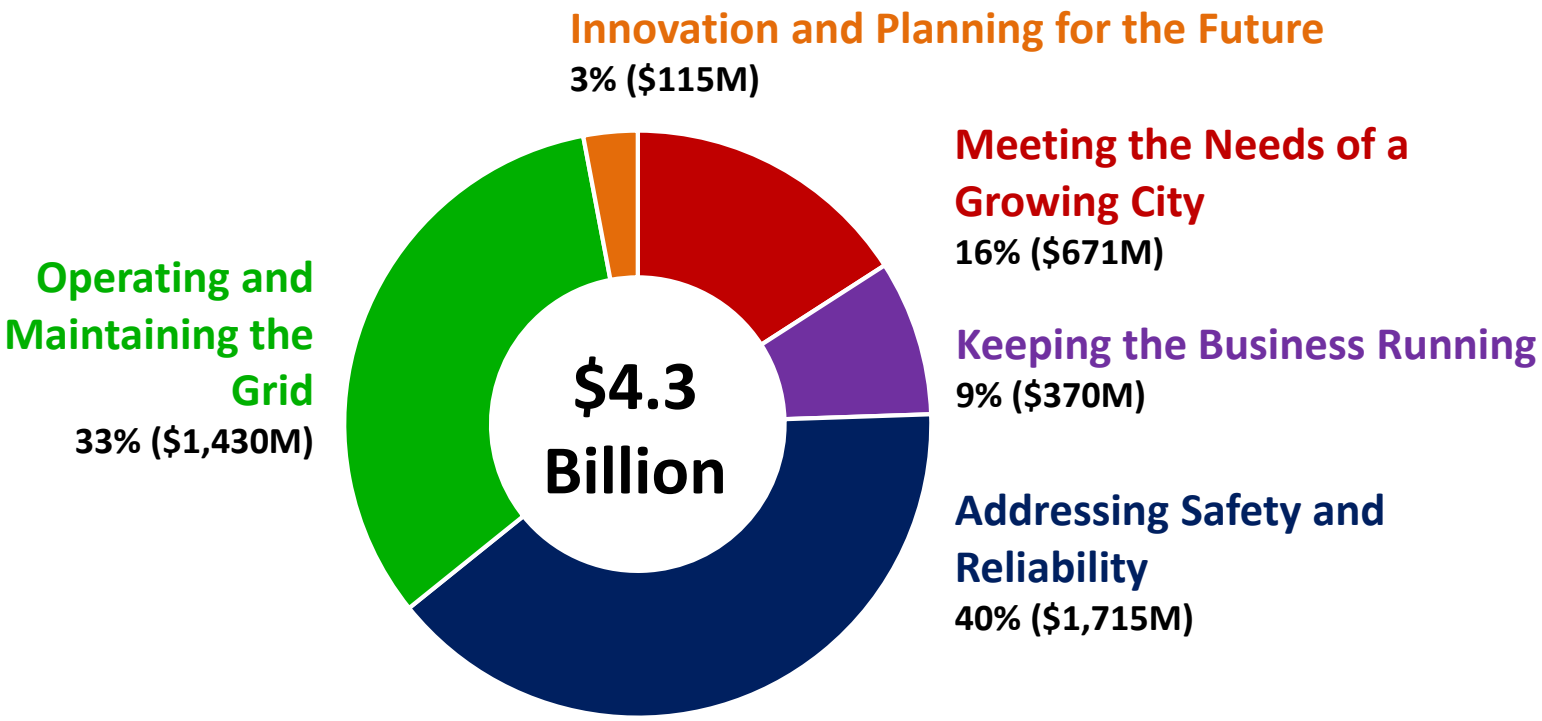
The Current Plan and Your Rates

Based on the initial customer input and the approach outlined on the previous page, Toronto Hydro has developed a plan totalling approximately $4.3B over five years. **There are five key budget categories.**

To learn more about each category, simply hover over the title.



That translates into an average 3.4% increase in your distribution rates in each of the five years of the plan. This compares to an average increase of 5.8% per year in Toronto Hydro's current plan for 2015 to 2019.



- In dollars and cents, that means an **average increase to the monthly bill of $1.51 each year** for the typical residential customer.
- Over the course of the proposed 5-year plan, the typical residential customer will see the distribution portion of their electricity bill **increase by $7.57.**
- As a result, the distribution charges on the monthly bill would increase from a proposed amount of **$41.60 in 2019** to **$49.17 by 2024.**

The next section of this workbook will explore some of the choices Toronto Hydro needs to make to finalize this plan. However, before that discussion, we would like to get your initial feedback on the cost of the current version of the plan.

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Q12. Which of the following statements best represents your view about a 3.4% annual increase to deliver current levels of reliability and customer service for most customers and targeted improvements for customers experiencing below average service or who have special reliability needs?

- □ I support it
- □ I don't like the increase but I think it's necessary
- □ I oppose it
- □ Don't know

Q13. Do you have any comments you wish to add?

[Roll-over definitions for pie chart]

Meeting the Needs of a Growing City

As the Local Distribution Company for the City of Toronto, Toronto Hydro has an obligation to connect customers to its grid, meet its legal obligations with respect to safety, the environment and other areas, and provide basic levels of service.

Keeping the Business Running

Investments in this category provide business continuity and support the core functions of the utility: fleet, facilities, and information technology and security.

Addressing Safety and Reliability

Customers expect Toronto Hydro to provide a reliable source of electricity. Investments in this category are directed toward all types of assets that are old or in poor condition and need to be replaced in order to prevent deteriorating service and keep the system running safely.

Operating and Maintaining the Grid

Toronto Hydro's grid is a 24/7 operation. These investments fund the day-to-day activities of the utility, including a control room, customer care services, maintenance work, storm and outage response crews, and standard administrative functions.

Innovation and Planning for the Future

Toronto Hydro deploys new technologies and conventional technologies in new ways to modernize the distribution system and generate benefits that provide cost savings and better service levels.

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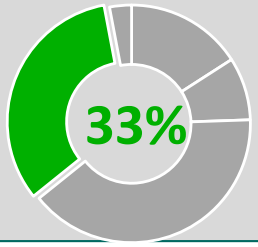
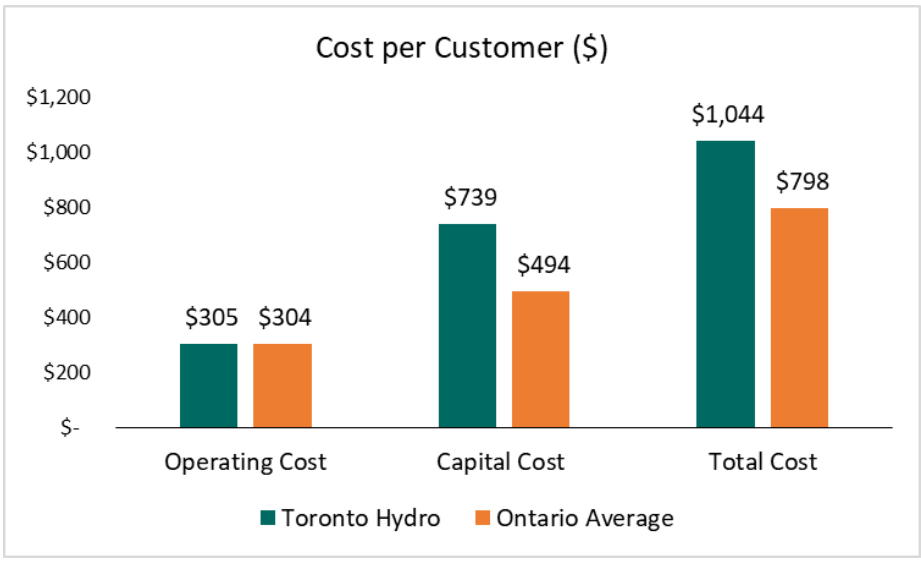


Making Choices

The following sections will ask about some key choices that could impact your rates.

Toronto Hydro's total spending is benchmarked by the OEB against other utilities in Ontario. In the last year of publicly available data collected by the OEB, Toronto Hydro's total cost per customer of $1,044 is higher than the average Ontario utility cost of $798. Those total costs are a combination of Toronto Hydro's operating and capital costs.

Toronto Hydro's **operating costs** of $305 per customer are close to the Ontario average of $304 dollars per customer. The choices in the operating budget are primarily driven by technical analysis and expert assessments of best practices.



As promised earlier, this customer feedback portal does not ask questions that expect you to be an electricity expert.

The OEB runs an open and transparent review process where experts from the OEB and intervenor groups review and challenge the Toronto Hydro's analyses and assessments. You are welcome to participate in the OEB process if you are interested in those issues. Details can be found here.

This consultation is focused on capital investments. Toronto Hydro's capital costs are $739 per customer compared to an Ontario average of $494 per customer. Some of this spending is required by the standards that apply to all electricity distributors, or technical analysis of requirements. In other cases, the final amount Toronto Hydro spends is based on choices on the appropriate balance between cost and other outcomes that matter to customers. Since you as a customer are the best judge of which outcomes are most important to you, the remaining questions in this workbook ask for your feedback on those choices.

Again, the following sections will ask about some key choices that could impact your rates.

At the end of the portal, you will have an opportunity to review your responses and their impact on your bill. You will then be able to adjust your choices to provide what you feel is the best balance.

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This workbook leaves detailed discussion of Toronto Hydro's operating budget to experts from the OEB and intervenors in the formal OEB review; the workbook focuses on collecting your view on competing trade-offs in infrastructure investments.

Q14. Does this seem like the right approach or the wrong approach to you?

- □ Definitely the right approach
- □ Probably the right approach
- □ Probably the wrong approach
- □ Definitely the wrong approach
- □ Don't know

Q15. Is there is anything in particular you would change about this approach or any other comments you would like to make?

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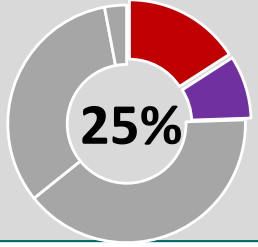

Investing in the Basics

Meeting the Needs of a Growing City

Toronto is Growing. Toronto Hydro has an obligation to serve it.

You just have to drive around Toronto to see how quickly this community of over 2.9 million people is growing. New condos, office buildings, and transit projects are creating increasing demands on the electricity grid. Toronto Hydro is required to connect new customers to the grid and move infrastructure at the request of government, including for transit projects or road widening.



Beyond this, Toronto Hydro's efforts to meet the needs of a growing city include making investments that meet new demands on the grid in ways that at least maintain current reliability.

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Keeping the Business Running



In addition to maintaining the distribution grid, Toronto Hydro has to ensure that it invests in tools required to keep up with the needs of customers and the grid. The types of tools in this category are:

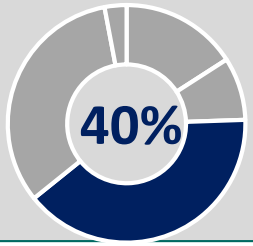
- **Information Technology**: systems required to securely operate the distribution system, manage customer information and privacy, and keep personnel working effectively and efficiently
- **Vehicles**: bucket trucks and other vehicles used to move personnel and supplies around the city to support the safe and reliable operation of the grid
- **Facilities:** offices and operations centers that house the people, vehicles, and equipment needed to serve customers

When deciding whether to continue to maintain existing tools or replace them, Toronto Hydro considers whether the risks and costs of continuing to use them outweighs the benefits of waiting longer to replace them. For example, Toronto Hydro intends to replace its system used for customer service and billing: the old version has reached the end of its useful life, no longer has full vendor support, and efforts to keep it going are becoming expensive and increasing the risks that Toronto Hydro cannot get accurate bills to customers on time.

Q16. As a company, Toronto Hydro needs vehicles and tools to service the power lines and IT systems to manage the system and customer information. Which of the following statements best represents your point of view?

- □ Toronto Hydro should find ways to make do with the equipment and IT systems it already has
- □ Toronto Hydro should make the investments necessary to ensure its staff have the equipment and IT systems they need to manage the system efficiently and reliably
- □ Don't know

Q17. Additional Feedback *(Optional)*



Addressing Safety and Reliability

What's in this category?

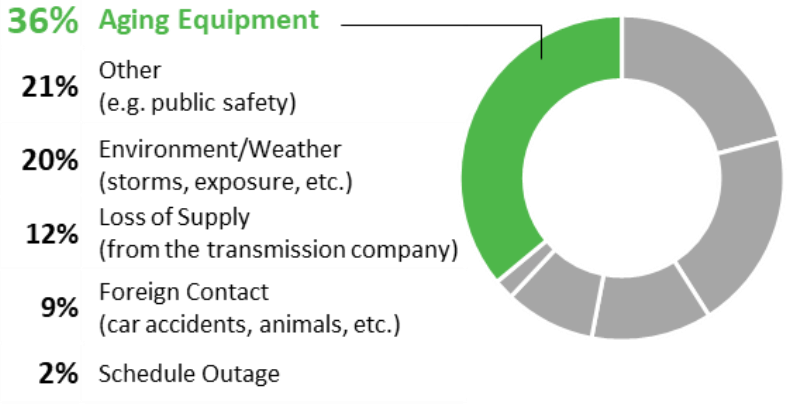
40% of Toronto Hydro's proposed budget will go towards ensuring safety and reliability is maintained and service improvements are made for customers experiencing below average reliability or who have special reliability needs (e.g. hospitals).

There are many reasons for poorer reliability (e.g. outages). In any given year, reliability can increase or decrease in response to unusual weather events. In fact, roughly 20% of all outages are caused by ice storms, severe winds, extreme rainfall, and other environmental events. However, the largest number of outages, roughly 36% of them, can be attributed to aging equipment.

Toronto Hydro measures both how many interruptions customers experience and how long those outages last. Over the past five years, excluding major events like ice storms, the average customer has experienced:

- Average of **1.4** outages per year.
- Between **60** and **70** minutes without power per year.

Aging equipment is responsible for approximately 36% of Outages



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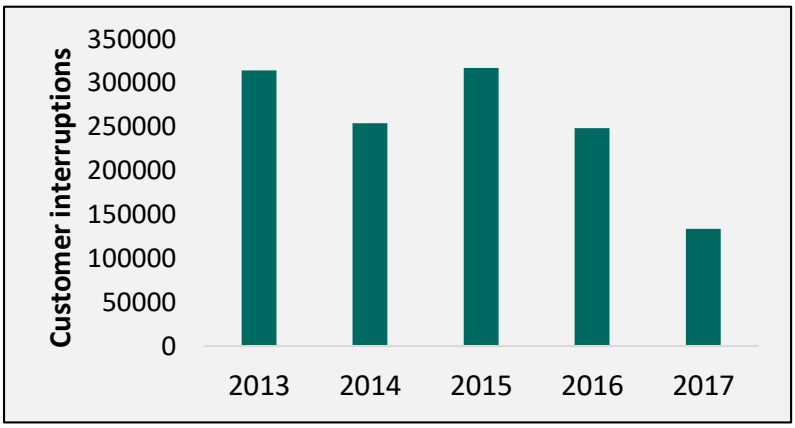
Approximately one-third of Toronto Hydro's distribution assets are beyond their expected useful lives or will reach their expected end of useful life within the next five years. Toronto Hydro takes a stewardship approach to that challenge: investing in infrastructure that benefits today's customers and future generations of customers.

Toronto Hydro's current five year plan (2015-2019) ramped up investment in replacing old equipment **and the average number and length of outages has been declining.** The chart below illustrates this improvement for people who were having the worst experiences.

In the new plan, Toronto Hydro's general approach is to spend just enough on the grid so that most customers can expect a similar level of reliability over the next five years as they are experiencing today, and to provide improved service for those customers whose reliability is poorer or who have special reliability needs (e.g. hospitals).



# of Customer Interruptions on Poor Performing Circuits

Q18. Which of the following is closest to your point of view regarding Toronto Hydro's stewardship approach to addressing reliability?

- □ Toronto Hydro should stick with the proposed approach of maintaining the current level of day-to-day reliability that the average customer experiences respectively as part of the proposed rate increase of 3.4% per year.
- □ I am prepared to pay more so Toronto Hydro can reduce the number and length of outages that the average customer experiences.
- □ I am prepared to live with an increase in the number and length of outages so the proposed rate increase can be reduced.
- □ Don't know

Q19. Additional Feedback *(Optional)*

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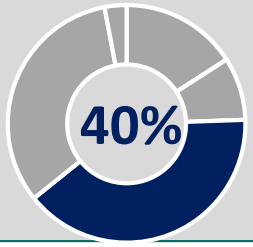

Dealing with types of lines that fail more often with more problems

Should we spend more to replace lines that cause more complicated problems more often?



While this is a general question, there are two particular types of neighbourhood power lines where there is a pressing issue - Rear-Lot Feeders and Direct Buried Cable. These are old technologies that have been in use for more than 50 years. While initially they served Toronto Hydro customers well, they now pose reliability and safety concerns. Customers served by these lines are more likely to experience power outages, and when they do those outages are more likely to last longer and be more expensive to fix.

- **Rear-Lot** refers to a type of overhead construction installed in residential backyards during the 1950s and 1960s. Because rear-lot lines are in customers' backyards, they are often difficult for crews to reach and have more exposure to risks such as falling trees and branches. Working on these lines often causes additional disruption and inconvenience to customers. Outages on rear-lot lines are about 1.3 hours longer on average as compared to outages on other power lines.

- **Direct Buried Cable** refers to a legacy type of underground construction where cables are laid directly in underground trenches without a protective barrier. While equipment failure causes 36% of outages across the system, cable failure accounts for 70% of all outages on the underground system. Once these cables start to fail, they tend to experience a rash of failures. On average 800 customers are affected by each buried cable failure and the outages last longer than average (between 4 and 24 hours).

Toronto Hydro's initial plan will phase out rear-lot feeders by 2033 and a quarter of the highest risk direct buried cable by 2024. Converting these lines faster will improve reliability for customers served by this type of equipment.

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Q20. Which of the following is closest to your point of view regarding Toronto Hydro's *rear-lot* replacement programs?

- □ Toronto Hydro should stick with the proposed pace of investment in rear-lot which would see it all converted by 2033 as part of a proposed rate increase of 3.4% per year.
- □ I am willing to pay an additional $0.02 per month annually ($0.11 more on the average monthly bill by 2024) so Toronto Hydro can remove all rear-lot feeders by 2029 (four years sooner).
- □ I would like Toronto Hydro to slow down this program so the proposed rate increase can be reduced.
- □ Don't know

Q21. Which of the following is closest to your point of view regarding Toronto Hydro's *direct buried cable* replacement programs?

- □ Toronto Hydro should stick with the proposed pace of investment in direct buried cable replacement which would see a quarter of the highest risk cable replaced by 2024 as part of a proposed rate increase of 3.4% per year.
- □ I am willing to pay an additional $0.19 per month annually ($0.94 more on the average monthly bill by 2024) so Toronto Hydro can replace all of the highest risk direct buried cable by 2024.
- □ I would like Toronto Hydro to slow down this program so the proposed rate increase can be reduced.
- □ Don't know

Q22. Additional Feedback *(Optional)*

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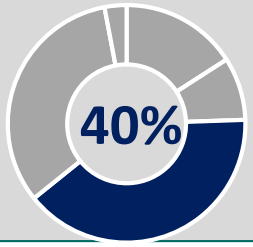

Dealing with complicated projects in built up areas

Should we spend more now to avoid increased cost and disruption later?





In order to keep rate increases down, Toronto Hydro has focused its spending on dealing with more urgent and immediate needs. However, with the current pace of growth in Toronto, there are a number of locations where Toronto Hydro knows that it will need to conduct work within a few years and where planned and current development will make those projects more expensive and more disruptive if Toronto Hydro waits.

Paper Insulated Lead Covered (PILC) Cable

One major example of this is PILC cable. PILC cable was the first type of underground cable installed as part of Toronto Hydro's grid and a lot of it is still providing electricity to the downtown core.

While this is a resilient type of equipment, all of these cables were installed more than 20 years ago. As these cables begin to age, the outer lead covers can begin to crack and leak oil.

Environmental regulations have changed, making it more costly and difficult to remove and replace these cables. As workers who first installed these types of cables continue to retire, fewer trades people have the expertise to deal with this equipment.

Toronto Hydro has a long-term plan to remove and replace PILC cable by 2049 while still meeting legal, safety, and regulatory obligations. However, as the downtown core becomes more densely populated, it becomes increasingly more difficult, complex, and expensive to complete this type of work.

Toronto Hydro has identified an opportunity to replace all of this cable by 2039 by replacing these assets proactively, instead of relying solely on maintenance, refurbishment, and reactive replacement. This will improve reliability, reduce risks to the public, and avoid additional expense and disruption in the future.

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Q23. Which of the following is closest to your point of view regarding Toronto Hydro's *PILC Cable* replacement program?

- □ Toronto Hydro should address the reliability issues and other risks posed by PILC cable at the current pace (completed by 2049) as part of a proposed rate increase of 3.4% per year, even if it's more disruptive to do so in the future.
- □ Toronto Hydro should accelerate its replacement of PILC cable by 10 years, even if it costs the typical residential customer an additional $0.09 per month annually ($0.44 more on the average monthly bill by 2024), because it's less disruptive to do it now than in the future.
- □ I would like Toronto Hydro to slow down this program so the proposed rate increase can be reduced
- □ Don't know

Q24. Additional Feedback *(Optional)*

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Underground Network Transformers

Other underground infrastructure in the downtown core also faces some of the same challenges as PILC cable. Underground network transformers, units whose old design makes them prone to flooding, are located in areas that have been growing in terms of density and congestion. It is more difficult to do this work as time goes on.

Toronto Hydro's current plan (2015-2019) is dealing with the most pressing of these units that pose safety and reliability concerns. In the plan for 2020 to 2024, the focus is to replace just enough of these units so that outages, due to equipment failure, don't get any worse.

However the new units are significantly superior to the existing infrastructure. Much of the old infrastructure is not designed for the flooding that has become increasingly common and which can cause equipment failure and public safety hazards. The new network units are submersible and equipped with sensors to monitor transformer, protector, and vault conditions, resulting in the cost-effective reduction of reliability, environmental, and safety risks.

While the proposed plan would replace all the unit by 2031, the process could be advanced by three years to replace all these units by 2028.



Q25. Which of the following is closest to your point of view regarding Toronto Hydro's *Network Unit* replacement program?

- □ Toronto Hydro should stick with the proposed pace of investment in underground network transformer replacement as part of a proposed rate increase of 3.4% per year.
- □ Toronto Hydro should replace its underground network transformers 3 years faster to improve downtown reliability, even if it costs the typical residential customer an additional $0.02 per month annually ($0.09 more on the average monthly bill by 2024).
- □ I would like Toronto Hydro to slow down this program so the proposed rate increase can be reduced
- □ Don't know

Q26. Additional Feedback *(Optional)*

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Cable Chambers

Cable chambers are a third example of equipment that will become more costly and disruptive to fix over time. Cable chambers house, protect, and provide access to underground electrical equipment across the city. There are over 10,000 in Toronto, but many of them – including the majority of the roughly 500 that are in the most urgent need of attention – are downtown where they are subject to increased foot traffic. When they deteriorate or break, they can pose anything from a tripping hazard to something much more serious in the case of a collapsed chamber. Such instances can also cause long outages, either by damaging equipment or requiring the power to be turned off to the cables in the chamber so repairs can be made.

As part of its plan, Toronto Hydro is now taking a proactive approach to rebuilding hundreds of cable chambers at risk of failing. At the current pace, it would take approximately 30 years to address the chambers in the worst condition. Accelerating the work could halve that period, at an additional cost now.

Q27. Which of the following is closest to your point of view regarding Toronto Hydro's *Cable Chamber* renewal program?

- □ Toronto Hydro should stick with the proposed pace of investment in cable chamber renewal as part of a proposed rate increase of 3.4% per year.
- □ Toronto Hydro should address the safety and reliability risk posed by deteriorating cable chambers faster, even if it costs the typical residential customer an additional $0.02 per month ($0.10 more on the average monthly bill by 2024).
- □ Toronto Hydro should go back to reconstructing cable chambers reactively in order to keep my rates lower now.
- □ Don't know

Q28. Additional Feedback *(Optional)*

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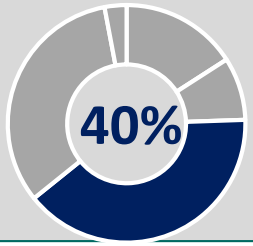

Dealing with more frequent extreme weather events

Should we spend more to make the distribution system more resilient to the effects of major storms?

Toronto Hydro's distribution system is exposed to the elements: strong winds, freezing rain, and severe flooding have all caused at least one wide-spread outage in Toronto in recent years. While it may be impossible or impractical to completely guard against extreme weather, steps can be taken to "harden" the distribution system. Toronto Hydro is proposing a variety of enhancements to continue to build resiliency. Toronto Hydro is looking for your opinion on whether it should do more in one area in particular: the overhead system outside of the downtown core.



System Restoration Improvements

This type of work makes it easier for Toronto Hydro to restore power customers outside of the downtown following an outage. By adding remotely-operated technology, more back-up links within the grid, and other improvements, Toronto Hydro can better isolate the problem and get more customers' power back on faster.

Given customer desires to keep rate increases down, Toronto Hydro is currently proposing to reduce spending in this category. Improvements have already been made to some parts of the City and the reliability of this part of the overhead system has shown improvement in recent years. It is possible for Toronto Hydro to address more areas during 2020 to 2024 not yet benefiting from these improvements.

Q29. Should Toronto Hydro spend more now to speed up the pace of reducing outage times by up to 50% in neighbourhoods outside of downtown?

- □ Yes, I would be willing to accept an increase to my monthly bill of $0.02 in each of the five years of the plan ($0.09 more by 2024) so more customers can get their power back on quicker during outages caused by storms and other events.
- □ No, I'm comfortable knowing that some of this work is already planned and would prefer to keep my bill lower.
- □ Don't know

Q30. Additional Feedback *(Optional)*

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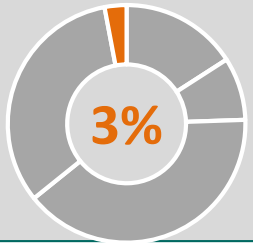

Innovation and Planning for the Future

Bring New Technology into the Toronto Hydro System

Technology is changing how people use electricity and the demands on the grid. Customers are not just taking power from the grid, they are also using technology like solar panels to produce their own power and send any extra back to the grid. Toronto Hydro is currently implementing new technologies in a limited manner and could increase the pace of that investment.

Energy Storage

Toronto Hydro has already begun to integrate large-scale electricity storage into the system. Storage provides a number of benefits to customers:

- It supports reliability by providing electricity when the connection to generators is interrupted
- It can allow low cost electricity generated in off-peak hours to be available during peak demands.
- It helps intermittent renewable sources such as wind and solar integrate into the system, thereby increasing the availability of clean energy and reducing greenhouse gases (GHGs).



Crosstown Battery Storage (3D rendering of Phase 1)

- It helps to enable the integration of electric vehicles into the system without requiring major increases in more traditional wires and transformers to deal with electric vehicle charging needs.

Storage also provides a number of benefits that are invisible to customers but critical to the stability of the grid including power quality, load following, and frequency regulation.

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Right now Toronto Hydro is primarily using energy storage where there is an immediate benefit to the system. For example, at one of Toronto Hydro's most congested downtown stations (Cecil TS), battery storage and conservation solutions are being used to delay a necessary upgrade for approximately five to six years. This approach is expected to reduce the total overall cost to ratepayers by approximately $6 million.



Poletop Energy Storage Unit

Toronto Hydro has identified a number of additional energy storage-related projects with critical large-scale public and private sector customers with a defined project need. These batteries would be located at host sites and provide benefits locally and to the distribution system. The host would pay most of the costs. Customers like you would pay for the portion that relates to the benefit they receive (e.g. area reliability).

These projects would improve reliability and help reduce GHGs but are not required to maintain current reliability. Pursuing these projects would increase the average annual bill impact of the plan by up to $0.11 per month or a total of $0.53 by 2024.

Q31. Which of the following is closest to your point of view?

- □ I would be willing to pay up to $0.53 more per bill by 2024 for Toronto Hydro to partner on a wider range of energy storage projects which would improve reliability and help reduce Greenhouse gases.
- □ No, I do not want to pay more for Toronto Hydro to do more energy storage projects, knowing it's not required to maintain current levels of reliability.
- □ Don't know

Q32. Additional Feedback *(Optional)*

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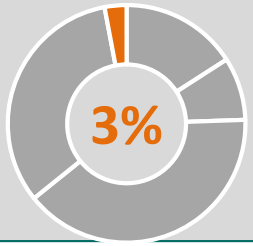


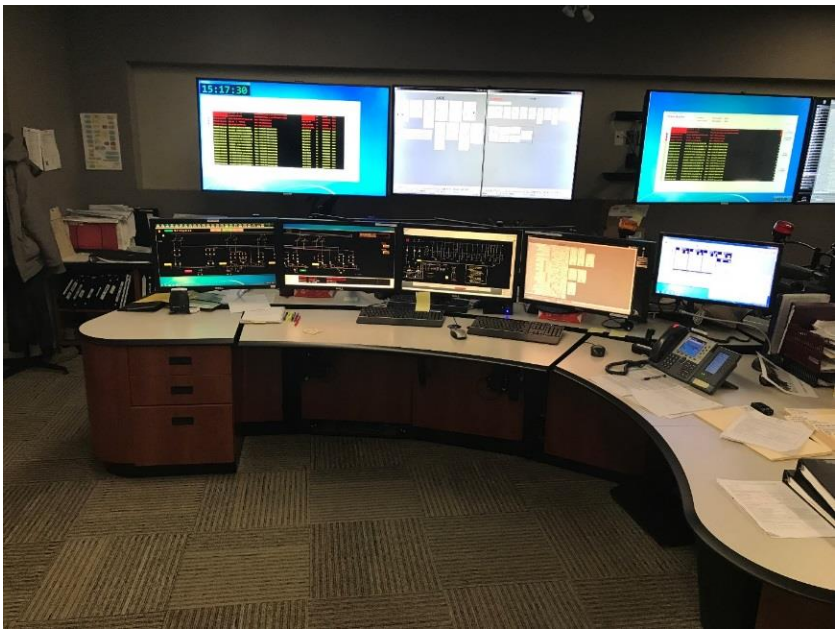
Innovation and Planning for the Future

Monitoring and Control Equipment

New communication technology has revolutionised the way the grid can be managed. New remote switches allow a Toronto Hydro system manager to restore power to many customers by flicking a switch in a control room before the line crew even leaves to repair the break. Remote monitors allow system managers to pinpoint where the break occurred instead of sending crews out in trucks visually inspecting the line. Environmental monitors at critical equipment facilities such as major transformers can identify changing conditions that threaten equipment before the equipment fails so preventative action can be taken to avoid an outage in the first place.

Within the base budget covered by the 3.4% annual increase, Toronto Hydro's new construction takes advantage of these new technologies wherever clear benefits can be established.

However, Toronto Hydro can improve the reliability of its grid by adding these devices to lines and transformers. In particular, installing devices in the downtown underground network that detect fire, floods or other risks can be completed more quickly.

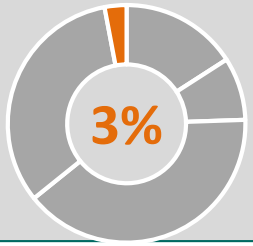


Toronto Hydro Control Room

Q33. Which of the following is closest to your point of view?

- □ I would be willing to pay $0.07 more per bill by 2024 for Toronto Hydro to be able to better predict fire, floods and other risks in the downtown network that cause outages or damage.
- □ Toronto Hydro should maintain the pace of installing monitoring and control equipment on the downtown network as planned within its existing proposed rate increase of 3.4% per year, but not go any further.
- □ Toronto Hydro should reduce its planned increase by eliminating the improved monitoring and control equipment planned for the downtown network.
- □ Don't know

Q34. Additional Feedback *(Optional)*



Innovation and Planning for the Future

Microgrids

New types of generation (often renewable), storage, and supporting systems are making it possible for communities, institutions or other large customers to develop “microgrids”. These are a local electricity network linking smaller sources of electricity with nearby uses such as homes, businesses and institutions. In the event of a failure of the larger network, a microgrid can seal itself off and continue to provide power locally. These offer customers increased choice for power supply, cost management, and improved resilience.



Microgrids would give customers more choices, while creating a more resilient and reliable grid. While spending on microgrids does benefit customers who are not on microgrids, those benefits are not required to maintain current reliability.

Q35. Which of the following is closest to your point of view?

- □ I would be willing to pay $0.09 more per bill by 2024 for Toronto Hydro to support the development of microgrids in order to give customers more choice and create a more resilient and reliable grid.
- □ Toronto Hydro should support microgrids, but only if those customers pay for the full costs, as they are not required to maintain current reliability.
- □ Don’t know

Q36. Additional Feedback *(Optional)*

Web page break.

Investment Alternatives Summary

Throughout this portal, you have been asked about some key choices that could impact your rates.

First a quick reminder:

- Toronto Hydro's current proposed plan would result in a monthly **bill increase of $1.51 each year** for the typical residential customer.
- Over the course of the proposed 5-year plan, the typical residential customer will see the distribution portion of their electricity bill **increase by $7.57**.
- As a result, the distribution charges on the monthly bill would increase from a proposed amount of **$41.60 in 2019** to **$49.17 by 2024.**

Below are your answers to questions that could impact your rates. At the bottom of this page you will find the total bill impact of all the answers you gave that would result in a bill increase.

Having seen the total bill impact, please review your answers and change your responses if you desire. Your potential rate impact will be re-calculated and you will be have the opportunity to adjust your answers again until you feel you've reached the best balance for you.

Addressing Safety & Reliability: Rear-lot replacement program

- ☑ Toronto Hydro should stick with the proposed pace of investment in rear-lot which would see it all converted by 2033 as part of a proposed rate increase of 3.4% per year.
- ☐ I am willing to pay an additional $0.02 per month annually ($0.11 more on the average monthly bill by 2024) so Toronto Hydro can remove all rear-lot feeders by 2029 (four years sooner).
- ☐ I would like Toronto Hydro to slow down this program so the proposed rate increase can be reduced.
- ☐ Don't know

Addressing Safety & Reliability : Direct buried cable replacement program

- ☑ Toronto Hydro should stick with the proposed pace of investment in direct buried cable replacement which would see a quarter of the highest risk cable replaced by 2024 as part of a proposed rate increase of 3.4% per year.
- ☐ I am willing to pay an additional $0.19 per month annually ($0.94 more on the average monthly bill by 2024) so Toronto Hydro can replace all of the highest risk direct buried cable by 2024.
- ☐ I would like Toronto Hydro to slow down this program so the proposed rate increase can be reduced.
- ☐ Don't know

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Addressing Safety & Reliability : Paper Insulated Lead Covered (PILC) cable replacement program

- ☑ Toronto Hydro should address the reliability issues and other risks posed by PILC cable at the current pace (completed by 2049) as part of a proposed rate increase of 3.4% per year, even if it's more disruptive to do so in the future.
- ☐ Toronto Hydro should accelerate its replacement of PILC cable by 10 years, even if it costs the typical residential customer an additional $0.09 per month annually ($0.44 more on the average monthly bill by 2024), because it's less disruptive to do it now than in the future.
- ☐ I would like Toronto Hydro to slow down this program so the proposed rate increase can be reduced
- ☐ Don't know

Addressing Safety & Reliability : Network Unit replacement program

- ☑ Toronto Hydro should stick with the proposed pace of investment in underground network transformer replacement as part of a proposed rate increase of 3.4% per year.
- ☐ Toronto Hydro should replace its underground network transformers 3 years faster to improve downtown reliability, even if it costs the typical residential customer an additional $0.02 per month annually ($0.09 more on the average monthly bill by 2024).
- ☐ I would like Toronto Hydro to slow down this program so the proposed rate increase can be reduced
- ☐ Don't know

Addressing Safety & Reliability : Cable chamber renewal program

- ☑ Toronto Hydro should stick with the proposed pace of investment in cable chamber renewal as part of a proposed rate increase of 3.4% per year.
- ☐ Toronto Hydro should address the safety and reliability risk posed by deteriorating cable chambers faster, even if it costs the typical residential customer an additional $0.02 per month ($0.10 more on the average monthly bill by 2024).
- ☐ Toronto Hydro should go back to reconstructing cable chambers reactively in order to keep my rates lower now.
- ☐ Don't know

Addressing Safety & Reliability : System Restoration Improvements

- ☑ Yes, I would be willing to accept an increase to my monthly bill of $0.02 in each of the five years of the plan ($0.09 more by 2024) so more customers can get their power back on quicker during outages caused by storms and other events.
- ☐ No, I'm comfortable knowing that some of this work is already planned and would prefer to keep my bill lower.
- ☐ Don't know

Link to next page.

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Innovation & Planning for the Future: Investments in energy storage projects

- ☑ I would be willing to pay up to $0.53 more per bill by 2024 for Toronto Hydro to partner on a wider range of energy storage projects which would improve reliability and help reduce Greenhouse gases.
- ☐ No, I do not want to pay more for Toronto Hydro to do more energy storage projects, knowing it's not required to maintain current levels of reliability.
- ☐ Don't know

Innovation & Planning for the Future: Investments in monitoring and control equipment

- ☑ I would be willing to pay $0.07 more per bill by 2024 for Toronto Hydro to be able to better predict fire, floods and other risks in the downtown network that cause outages or damage.
- ☐ Toronto Hydro should maintain the pace of installing monitoring and control equipment on the downtown network as planned within its existing proposed rate increase of 3.4% per year, but not go any further.
- ☐ Toronto Hydro should reduce its planned increase by eliminating the improved monitoring and control equipment planned for the downtown network.
- ☐ Don't know

Innovation & Planning for the Future: Investments in microgrids

- ☑ I would be willing to pay $0.09 more per bill by 2024 for Toronto Hydro to support the development of microgrids in order to give customers more choice and create a more resilient and reliable grid.
- ☐ Toronto Hydro should support microgrids, but only if those customers pay for the full costs, as they are not required to maintain current reliability.
- ☐ Don't know

Based on your responses above, by 2024, the incremental bill impact of your choices would result in:

+$X.XX per month

in addition to the estimated $49.17 in distribution charges on the average residential customer's electricity bill.

If you are satisfied with your responses above, click CONTINUE to submit your choices. If you would like to adjust your choices, please do so above, and click RECALCULATE in order to see your revised estimated bill impact. *Note: you can adjust your answers and recalculate your bill impact as many times as you would like in order to find the best balance for you.*

- ☐ **RECALCULATE** - I would like to recalculate my estimated bill impact based on my adjusted choices above.

Web page break.

Customer Feedback:
Investment Alternatives

Q38. With regards to Toronto Hydro's proposed plan, which of the following statements best represents you view?

- □ Toronto Hydro should improve service, as discussed on the previous pages, even if that means an annual increase that exceeds 3.4%
- □ Toronto Hydro should stick with a 3.4% annual increase to deliver current levels of reliability and customer service for most customers and targeted improvement for customers experiencing below average service or who have special reliability needs.
- □ Toronto Hydro should keep increases below 3.4% annually, even if that could mean reductions in service.
- □ Other [Please specify:_____]
- □ Don't know

Q39. Now that you have considered the various choices Toronto has to make and the cost implications of those choices, do you have any final comments for Toronto Hydro?

Web page break.

Customer Feedback

Q40. Please indicate the extent to which you agree or disagree with the following statement:

The cost of my electricity bill has a major impact on my household finances and requires I do without some other important priorities.

- □ Strongly agree
- □ Somewhat agree
- □ Neither agree nor disagree
- □ Somewhat disagree
- □ Strongly disagree
- □ Don't know

Web page break.

Customer Feedback:
Final Thoughts

Overall Impression: What did you think about the customer feedback portal?

Volume of Information: Did Toronto Hydro provide too much information, not enough, or just the right amount?

Content Covered: Was there any content missing that you would have liked to have seen included?

Outstanding Questions: Is there anything that you would still like answered?

Suggestions for Future Consultations: How would you prefer to participate in these consultations?

Web page break.

Thanks for participating!

You have now completed the customer feedback portal.

Please enter your email and customer billing address if you wish to be entered into the draw for your chance to win one of four $500 prepaid credit cards.

Your email will be used to contact you if you are one of the randomly selected prize winners and your billing address will be used to verify that you are a Toronto Hydro customer. Your email and customer billing address will be treated as strictly confidential and will not be shared with any third parties. This information will be deleted once the draw is complete.

Email Address: _____

Confirm Email: _____

Billing Address

Street Address: _____

Apartment #: _____

Postal Code: _____

NOTE: only Toronto Hydro customers are permitted to participate in this voluntary review, therefore, postal codes are collected and used by Innovative Research Group Inc. solely for maintaining the integrity of the consultation by validating legitimate participation in the process. Your personal information shall remain under the custody and control of Innovative Research Group Inc. and will not be disclosed to any third parties.

SUBMIT

Appendix

Additional Links to Information

Pop Up Page 12

Legal & Regulatory Obligations



There are three key organizations responsible for setting the policy direction of Ontario's electricity system. The decisions made by these organizations impact how utilities operate their business and serve customers.

Toronto Hydro is also held accountable by an ombudsman which acts as an independent bridge between people and their government.

Policy

The **Ontario Ministry of Energy** creates energy policy for the province.

Operations and Planning

The **Independent Electricity System Operator (IESO)** manages the provincial electricity grid, plans for the province's future energy needs, and develops conservation programs.

Regulation

The electricity industry in Ontario is regulated by the **Ontario Energy Board** (OEB), which was created through provincial legislation. One of the OEB's roles is to review the business and distribution plans of all electricity distributors and set the rates that they charge customers.

Ombudsman Toronto

If Toronto Hydro is unable to resolve a customer complaint, you may bring your complaint to **Ombudsman Toronto** which listens to and investigates complaints and concerns about City administration and unfairness in the delivery of City services, including at Toronto Hydro. They are independent and impartial.

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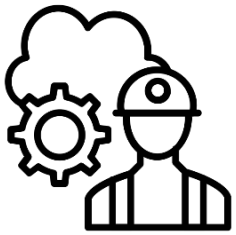
Pop Up Page 12



Business Input

Toronto Hydro's team of engineering and technical experts closely monitors the external pressures on the distribution system, develops solutions to address these challenges, and recommends investments that inform the business plan.



Infrastructure Health

- A large part of Toronto Hydro's distribution system was installed in the 1950s and 1960s. This infrastructure has served the city well and beyond its expected lifespan.
- Toronto Hydro has been actively renewing its electrical distribution system over the past few years, and that work must continue to maintain current levels of reliability.



A Growing City

- Toronto Hydro is serving a growing city. It has nearly a quarter of a million more residents than it did a decade ago.
- Toronto's highest growth neighbourhoods are all located in Downtown. For example, the population of the Waterfront neighbourhood increased by over 50% between 2011 and 2016.



Innovation

- Enhancing the distribution system to enable the mass adoption of electric vehicles in the near future.
- Investing in technology that enables enhanced tools and information for customers to better manage and monitor their electricity consumption.



Cyber Security

- Taking proactive steps to prevent cyber attacks that could impact the protection of customer information and distribution system reliability.



Climate Change Preparedness

- Taking proactive steps to prevent or reduce the length of prolonged power outages caused by extreme weather (e.g. high winds, floods and ice storms).

Web page break.

What has Toronto Hydro heard from customers?

Pop Up Page 11

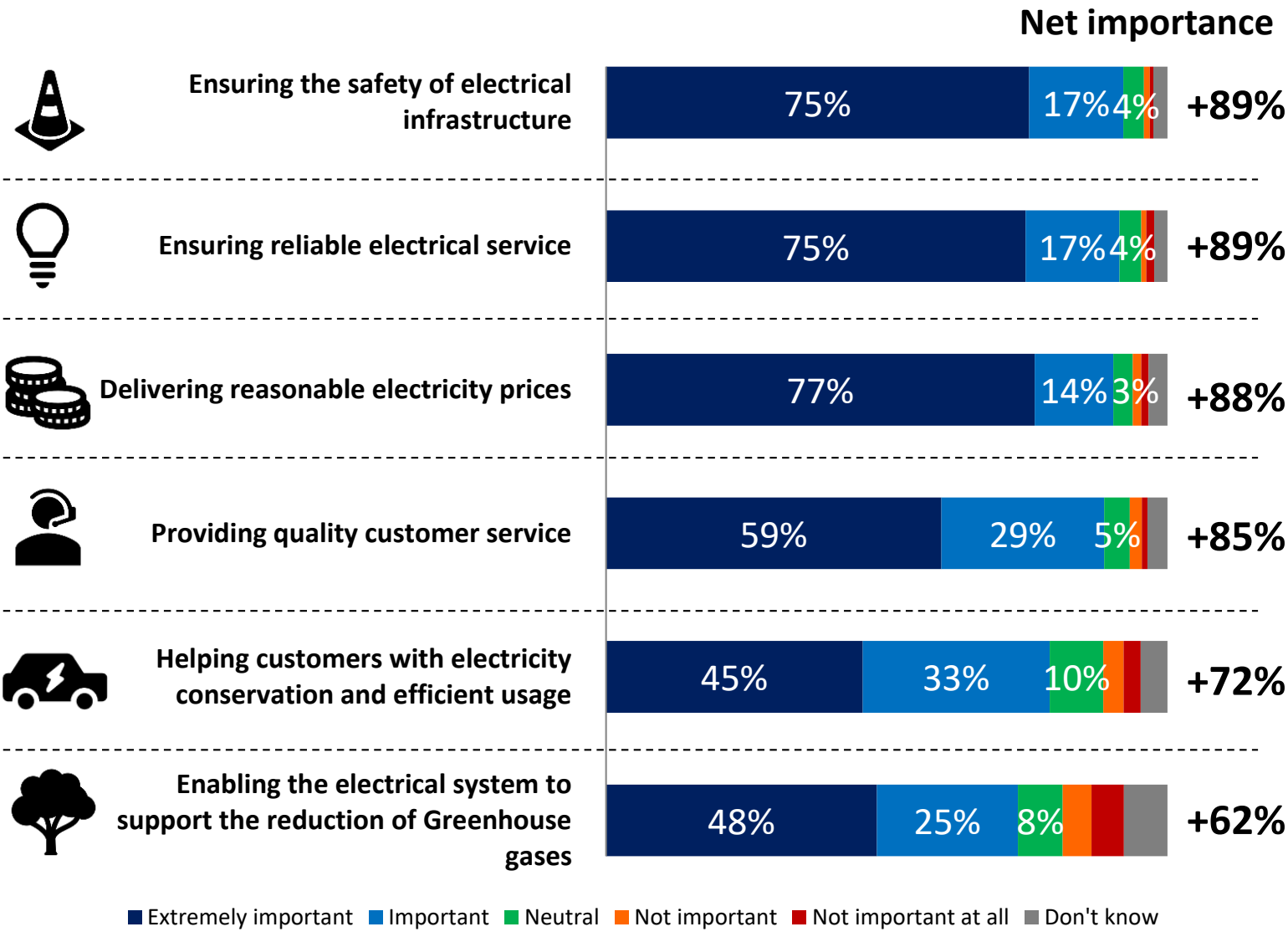
What do customers think about Toronto Hydro?

December 2016 Low-volume (Residential & Small Business) Customer Satisfaction Scorecard Survey

- **83%** say they are satisfied with the **services** they receive from Toronto Hydro.
- **84%** say they are satisfied with the **reliability** of the electricity they receive from Toronto Hydro.

What do Toronto Hydro customers think the utility should focus on?

A key focus of Toronto Hydro's early customer engagement for this plan is understanding the key outcomes of concern to customers. Six key outcomes were identified through discussions and then rated by customers in the December 2016 Customer Satisfaction Survey.



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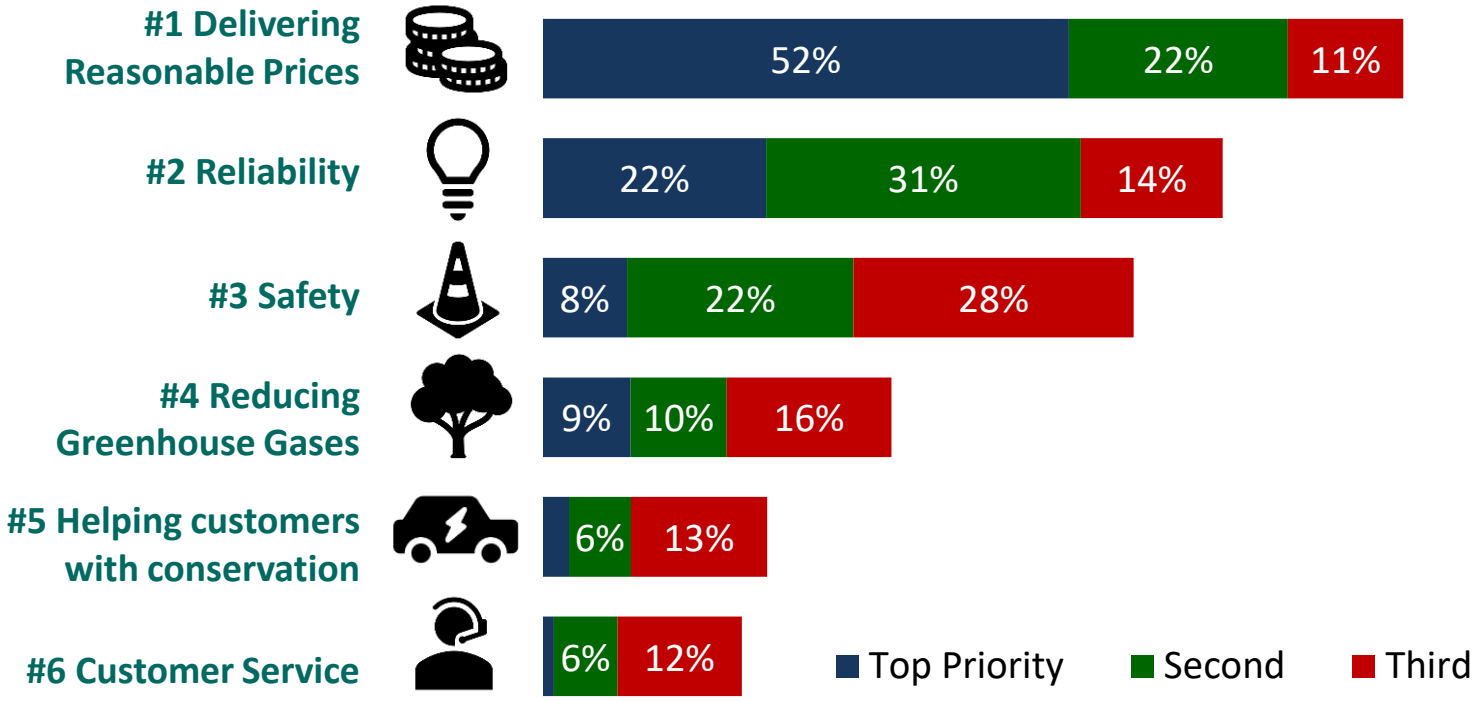
Pop Up Page 11

How do customer rank priorities?

While all six areas of focus for Toronto Hydro are deemed as important priorities to customers, in the survey, customers ranked some priorities higher than others.



Appendix 3.2.1

Residential Ratepayer Survey

Customer Consultation

Toronto Hydro Electric System Ltd
14 Carlton Street
Toronto, ON, M5B 1K5

May 2018

Prepared by:

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A. INTRODUCTION

INTRO. Hello, my name is _____ and I'm calling from **Innovative Research Group** on behalf of **Toronto Hydro**, your local electricity distributor.

Innovative Research Group is a national public opinion research firm. **We need your input on choices that will affect the service you receive from Toronto Hydro and the price you pay for that service.** Your answers will be combined with others to protect your privacy.

This survey should take about 20 minutes to complete. We know your time is valuable so at the end of the survey, you will have the opportunity to provide your name and email to receive a $10 Amazon Gift Card.

A1. Would you mind if I had **about 20** minutes of your time to ask you some questions? **All your responses will be kept strictly confidential.**

01	Yes	[continue]
02	No – Not responsible for paying bill	[go to TRANSFER-1]
03	No – Bad time	[Arrange Callback]
99	Refused (DO NOT READ)	[Terminate]

MONIT. This call may be monitored or audio taped for quality control and evaluation purposes.

01	PRESS TO CONTINUE	[continue]

CELL. Are you currently operating a car, truck or other motor vehicle?

01	Yes	[Arrange Callback]
02	No	[continue]
99	Refused (DO NOT READ)	[Terminate]

A2. Are you the person primarily responsible for paying the electricity bill in your household?

01	Yes – I pay the bill	[continue]
02	Yes – Shared responsibility	[continue]
03	No	[go to TRANSFER-1]
98	Don't know (DO NOT READ)	[Terminate]

TRANSFER-1. Can I speak with the person in your household who usually pays the electricity bill?

01	Yes	[Back to INTRO]
02	No – Not available/Bad time	[Arrange Callback]
98	Don't know (DO NOT READ)	[Terminate]
99	Refused (DO NOT READ)	[Terminate]

A3. Can you confirm that your household receives an electricity bill from **Toronto Hydro**?

01	Yes	[continue]
02	No	[Terminate]
98	Don't know	[Terminate]

GENDER. [**Interviewer Note**: By observation]

01	Male
02	Female

B. SYSTEM FAMILIARITY

B4. To start, I'd like to ask you a few questions about the electricity system …

As you may know, Ontario's electricity system has three key components**: generation, transmission** and **distribution.**

- **Generating stations** convert various forms of energy into electric power;
- **Transmission lines** connect the power produced at generating stations to where it is needed across the province; and
- **Distribution lines** carry electricity to the homes and businesses in our communities.

Today we're going to talk about your **local distribution system** which is maintained and operated by Toronto Hydro.

How familiar are you with **Toronto Hydro**? Would you say you are *very familiar*, *somewhat familiar*, or *not familiar at all*?

01	Very familiar
02	Somewhat familiar
03	Not familiar at all
98	Don't know
99	Refused (DO NOT READ)

B5. In general, how satisfied or dissatisfied are you with the services you receive from **Toronto Hydro**? Would you say you are *very satisfied, somewhat satisfied, neither satisfied or dissatisfied, somewhat dissatisfied, very dissatisfied, or would you say you don't know*?

01	Very satisfied
02	Somewhat satisfied
03	Neither satisfied or dissatisfied
04	Somewhat dissatisfied
05	Very dissatisfied
98	Don't know
99	Refused (DO NOT READ)

B6. Is there anything in particular that **Toronto Hydro** can do to improve its services to you?
[OPEN]

B7. I'd now like to talk with you about your electricity bill …

While **Toronto Hydro** is responsible for collecting payment for the entire electricity bill, they retain about **32%** of the typical residential customer's bill. This is about **$39** on an average **$123** monthly residential electricity bill. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.

Before this survey, how familiar were you with the percentage of your electricity bill that is retained by **Toronto Hydro**? Would you say… [**READ LIST**]

01	Very familiar
02	Somewhat familiar
03	Not familiar at all
98	Don't know
99	Refused (DO NOT READ)

C. CUSTOMER ENGAGEMENT PROCESS

C8. Electricity distributors are required to file a rate application with the Ontario Energy Board (OEB) to request a change in distribution rates based on their plans for capital and operating spending. Toronto Hydro is now consulting on its plans for 2020 to 2024.

The OEB is mandated to protect consumers with respect to prices and the reliability and quality of electricity service.

How familiar would you say you are with the Ontario Energy Board or "OEB"?

Would you say … [**READ LIST**]

01	Very familiar
02	Somewhat familiar
03	Not familiar at all
98	Don't know
99	Refused (DO NOT READ)

C9. As part of Toronto Hydro's consultation, it has developed a five-phase approach to gathering and responding to customer feedback.

- First, Toronto Hydro identified customer priorities through a series of surveys and focus groups;
- Then, used this customer feedback to guide development of its Draft Plan;
- Now, Toronto Hydro is in the process of collecting customer feedback on its Draft Plan;
- The next phases will include re-examining its Draft Plan based on customer feedback and preparing a submission to the OEB.

This survey is part of the third stage of **collecting customer feedback on the Draft Plan**.

Does this Customer Engagement process seem like a good way or a poor way to bring customer needs and preferences into Toronto Hydro's plan?

Would you say … [**READ LIST**]

01	Very good way
02	Somewhat good way
03	Somewhat poor way
04	Very poor way
98	Don't know

C10. Toronto Hydro wants to better understand customer priorities. In the first phase of customer engagement, residential and small business customers identified six core priorities which they believe should be a focus for Toronto Hydro.

C11. Among the following customer identified priorities, please tell me which one is the most important to you.

[READ OPTIONS; RANDOMIZE LIST]

01	Delivering reasonable electricity prices
02	Ensuring reliable electricity service
03	Ensuring the safety of electricity infrastructure
04	Enabling the electricity system to support the reduction of greenhouse gases
05	Helping customers with conservation and efficiency
06	Providing quality customer service

C12. What is the next most important priority you think **Toronto Hydro** should focus on?
[**Remove answer from C11 if asked to read again**]

C13. And what do you consider the third most important priority?
[**Remove answer from C11 and C12 if asked to read again**]

C14. Are there any other important priorities that **Toronto Hydro** should be focusing on that weren't included in the previous list I read to you? [**OPEN**]

D. PLANNING PRINCIPLES AND RATE IMPACT

D15. Based, in part, on the initial customer input, Toronto Hydro has drafted a plan totaling approximately $4.3B over five years.

Toronto Hydro's proposed plan focuses on delivering current levels of reliability and customer service for most customers and targeted improvements for customers experiencing below average service or who have special reliability needs, like hospitals.

This proposed plan translates into an average 3.4% increase in your distribution rates each year from 2020 to 2024. The distribution charges on the monthly bill would increase to $49 by 2024 for a typical residential customer.

Do you feel that this is *definitely the right approach*, *probably the right approach*, *probably the wrong approach* or *definitely the wrong approach* to Toronto Hydro's planning for the next five years or *would you say you don't know*?

01	Definitely the right approach
02	Probably the right approach
03	Probably the wrong approach
04	Definitely the wrong approach
98	Don't know

E. MAKING CHOICES

E16. Toronto Hydro's total spending is benchmarked by the OEB against other utilities in Ontario. Toronto Hydro's operating costs of $305 per customer are within $1 of the provincial average.

However Toronto Hydro's capital investment costs are $739 per customer which are $245 more than the provincial average.

Since a number of capital investment decisions are based trade-offs between costs and customer outcomes – like services and reliability levels – the remaining questions in this survey ask for your feedback on those choices.

E17. Do you feel that gathering feedback on capital investment decisions is *definitely the right approach*, *probably the right approach*, *probably the wrong approach, definitely the wrong approach or would you say you don't know*?

01	Definitely the right approach
02	Probably the right approach
03	Probably the wrong approach
04	Definitely the wrong approach
98	Don't know

F. INVESTING IN THE BASICS

F18. As a company, Toronto Hydro needs vehicles and tools to service the power lines and IT systems to manage the system and customer information.

Which of the following statements best represents your point of view? [**READ LIST; Rotate 01 and 02**]

01	Toronto Hydro should find ways to make do with the equipment and IT systems it already has
02	Toronto Hydro should make the investments necessary to ensure its staff have the equipment and IT systems they need to manage the system efficiently and reliably
98	Don't know

PREAMBLE TO NEXT SECTION

F19. Toronto Hydro has identified areas where it could accelerate investments. These accelerated projects could increase the **typical customer's bill by $2.46** per month by 2024. These projects are in addition to the 3.4% increase that is currently being proposed.

Toronto Hydro wants to get your feedback on particular projects before deciding whether or not to accelerate its investment plan in certain specific areas.

G. ADDRESSING SAFETY AND RELIABILITY

G20. Right now, the typical Toronto Hydro customer averages 1.4 outages per year with an average of between 60 and 70 minutes without power over the year. While many of those outages are caused by events outside of Toronto Hydro's control, roughly 36% are caused by the failure of aging equipment.

In this proposed plan, Toronto Hydro's general approach is to spend just enough on replacing equipment so that most customers can expect a similar level of reliability over the next five years as they are experiencing today, and to provide improved service for those customers whose reliability is poorer or who have special reliability needs such as hospitals.

Which of the following is closest to your point of view regarding Toronto Hydro's approach to addressing reliability? [**READ LIST; Rotate 01 and 03**]

01	Toronto Hydro should stick with the proposed approach of maintaining the current level of day-to-day reliability that the average customer experiences as part of the proposed rate increase of 3.4% per year.
02	I am prepared to pay more so Toronto Hydro can reduce the number and length of outages that the average customer experiences.
03	I am prepared to live with an increase in the number and length of outages so the proposed rate increase can be reduced.
98	Don't know

Dealing with types of lines that fail more often with more problems

G21. Some customers are served by older types of lines that are more likely to fail, causing more frequent, and longer lasting power outages. These customers are more likely to experience poorer reliability over time than most Toronto Hydro customers. The proposed plan will replace those lines over time but the work could be done faster.

I would like to ask you about two types of lines.

G22. One example is **rear-lot lines**. They go through residential backyards and are often more difficult to service and more exposed to falling branches. The proposed plan will replace all existing rear-lot lines by 2033. Toronto Hydro could replace those lines 4 years sooner for an additional cost.

Which of the following statements is closest to your view? [**READ LIST; ROTATE 01 and 03**]

01	Toronto Hydro should stick with the proposed pace of investment in rear-lot which would see it all converted by 2033 as part of a proposed rate increase of 3.4% per year.
02	I am willing to pay an additional $0.11 more on my average monthly bill by 2024 so Toronto Hydro can remove all rear-lot feeders four years sooner.
03	I would like Toronto Hydro to slow down this program so the proposed rate increase can be reduced.
98	Don't know

G23. Another example is **direct buried cable** where cables are laid directly in underground trenches without a protective barrier. While equipment failure causes 36% of outages across the system, cable failure accounts for 70% of all outages on the underground system.

Once these cables start to fail, they tend to experience a rash of failures. The proposed plan will replace a **quarter** of the highest risk direct buried cable by **2024**. Toronto Hydro could replace all of the highest risk direct buried cable by 2024 for an additional cost.

Which of the following statements is closest to your view? [**READ LIST; ROTATE 01 and 03**]

01	Toronto Hydro should stick with the proposed pace of investment in direct buried cable replacement which would see a quarter of the highest risk cable replaced by 2024 as part of a proposed rate increase of 3.4% per year.
02	I am willing to pay an additional $0.94 more on my average monthly bill by 2024 so Toronto Hydro can replace all of the highest risk direct buried cable by 2024.
03	I would like Toronto Hydro to slow down this program so the proposed rate increase can be reduced.
98	Don't know

Paper Insulated Lead Covered (PILC)

G24. Toronto Hydro has identified three equipment upgrades that are needed within the next few years. If Toronto Hydro waits, those upgrades will be more expensive and disruptive as Toronto continues to grow.

Firstly, Paper Insulated Lead Covered (PILC) cable. PILC cable was an old type of underground cable that stopped being installed on Toronto Hydro's grid 20 years ago. While the equipment is resilient and is still providing electricity to the downtown core, the outer lead covers can begin to crack and leak oil. Replacing these cables is becoming increasingly difficult and expensive to resource and complete.

Toronto Hydro has a long-term plan to remove and replace PILC cable by 2049. But Toronto Hydro can replace all of this cable ten years earlier by 2039, at an additional cost now. This will improve reliability, reduce risks to the public, and avoid additional expense and disruption in the future.

Which of the following is closest to your point of view regarding Toronto Hydro's PILC Cable replacement program? [**READ LIST ; ROTATE 01 and 03**]

01	Toronto Hydro should address the reliability issues and other risks posed by PILC cable at the current pace as part of a proposed rate increase of 3.4% per year, even if it's more disruptive to do so in the future.
02	Toronto Hydro should accelerate its replacement of PILC cable by 10 years, even if it costs the typical residential customer an additional $0.44 more on the average monthly bill by 2024, because it's less disruptive to do it now than in the future.
03	I would like Toronto Hydro to slow down this program so the proposed rate increase can be reduced.
98	Don't know

Underground Network Transformers

G25. The second upgrade project identified is *Underground Network Transformers*. The key problem with these units is their older design which makes them prone to flooding.

Toronto Hydro plans to replace just enough of these units by 2031 so that outages, due to equipment failure, don't get any worse. But the process could be advanced by three years to replace all these units by 2028.

G26. Which of the following is closest to your point of view regarding Toronto Hydro's Network Unit replacement program? [**READ LIST ; ROTATE 01 and 03**]

01	Toronto Hydro should stick with the proposed pace of investment in underground network transformer replacement as part of a proposed rate increase of 3.4% per year.
02	Toronto Hydro should replace its underground network transformers 3 years faster to improve downtown reliability, even if it costs the typical residential customer an additional $0.09 more on the average monthly bill by 2024.
03	I would like Toronto Hydro to slow down this program so the proposed rate increase can be reduced.
98	Don't know

Cable Chambers

G27. The third upgrade project identified is Cable Chamber replacement. Cable Chambers house, protect, and provide access to underground electrical equipment across the city. When they deteriorate or break, this equipment can cause outages and pose anything from a tripping hazard to something more serious like a collapsed chamber.

Toronto Hydro plans to take approximately 30 years to address the chambers in the worst condition. But accelerating the work could halve that period, at an additional cost now.

G28. Which of the following is closest to your point of view regarding Toronto Hydro's Cable Chamber renewal program? [**READ LIST; ROTATE 01 and 03**]

01	Toronto Hydro should stick with the proposed pace of investment in cable chamber renewal as part of a proposed rate increase of 3.4% per year.
02	Toronto Hydro should address the safety and reliability risk posed by deteriorating cable chambers faster, even if it costs the typical residential customer an additional $0.10 more on the average monthly bill by 2024.
03	Toronto Hydro should go back to reconstructing cable chambers reactively in order to keep my rates lower now.
98	Don't know

Dealing with more frequent extreme weather events

G29. As Toronto Hydro's distribution system is exposed to strong winds, freezing rain, and severe flooding, they are proposing a variety of enhancements to improve the resiliency of the distribution system against extreme weather events.

Toronto Hydro could enhance the system further in neighbourhoods outside of downtown. The improvements include adding remotely-operated technology and more back-up links within the grid. This will help Toronto Hydro to better isolate the problem and reduce outage times by as much as 50% in these areas.

Which of the following statements best represents your point of view? [**READ LIST; ROTATE 01 and 02**]

01	Yes, I would be willing to accept an increase to my monthly bill of $0.09 more by 2024 so more customers can get their power back on quicker during outages caused by storms and other events.
02	No, I'm comfortable knowing that some of this work is already planned and would prefer to keep my bill lower.
98	Don't know

H. INNOVATION AND PLANNING FOR THE FUTURE

H30. 3% of the proposed budget would be spent on innovation and planning for the future. The following questions are about this aspect of the budget.

Toronto Hydro has already begun to integrate large-scale battery electricity storage into the system. They have now identified more opportunities to partner on a wider range of energy storage projects. Integrating storage into the system can improve reliability and help reduce greenhouse gases, but it is not required to maintain current levels of reliability.

Which of the following is closest to your point of view? [**READ LIST; ROTATE 01 and 02**]

01	I would be willing to pay up to $0.53 more per bill by 2024 for Toronto Hydro to partner on a wider range of energy storage projects which would improve reliability and help reduce Greenhouse gases.
02	I do not want to pay more for Toronto Hydro to do more energy storage projects, knowing it's not required to maintain current levels of reliability.
98	Don't know

H31. New communication technology has revolutionised the way the grid can be managed.

Toronto Hydro plans to take advantage of various new technologies wherever clear benefits can be established.

However, Toronto Hydro can improve the reliability of its grid further by installing communication devices in the downtown underground network that detect fire, floods or other risks more quickly.

Which of the following is closest to your point of view? [**READ LIST; ROTATE 01 and 03**]

01	I would be willing to pay $0.07 more per bill by 2024 for Toronto Hydro to be able to better predict fire, floods and other risks in the downtown network that cause outages or damage.
02	Toronto Hydro should maintain the pace of installing monitoring and control equipment on the downtown network as planned within its existing proposed rate increase of 3.4% per year, but not go any further.
03	Toronto Hydro should reduce its planned increase by eliminating the improved monitoring and control equipment planned for the downtown network.
98	Don't know

H32. New types of generation (often renewable), storage, and supporting systems are making it possible for communities, institutions or other large customers to develop "microgrids". They are a local electricity network linking smaller sources of electricity with nearby uses such as homes, businesses and institutions. In the event of a failure of the larger network, a microgrid can seal itself off and continue to provide power locally.

Microgrids would give customers more choices, while creating a more resilient and reliable grid. However, they are not required to maintain current reliability.

Which is the following is closest to your point of view? [**READ LIST; ROTATE 01 and 02**]

01	I would be willing to pay $0.09 more per bill by 2024 for Toronto Hydro to support the development of microgrids in order to give customers more choice and create a more resilient and reliable grid.
02	Toronto Hydro should support microgrids, but only if those customers pay for the full costs, as they are not required to maintain current reliability.
98	Don't know

I. INVESTMENT ALTERNATIVES SUMMARY

I33. Toronto Hydro's current proposed plan, which translates into an average 3.4% annual increase, focuses on delivering current levels of reliability and customer service for most customers and targeted improvements for customers experiencing below average service or who have special reliability needs, like hospitals.

In dollars and cents, that means an average increase to the monthly bill of **$1.51 each year** for the typical residential customer.

Over the course of the proposed 5-year plan, the typical residential customer will see the distribution portion of their electricity bill **increase by $7.57**.

As a result, the distribution charges on the monthly bill would increase from a proposed amount of **$42 in 2019** to **$49 by 2024**.

I34. With regards to Toronto Hydro's proposed plan, which of the following statements best represents your view? [**READ LIST; ROTATE 01 and 03**]

01	Toronto Hydro should improve service, as discussed on the previous pages, even if that means an annual increase that exceeds 3.4%.
02	Toronto Hydro should stick with a 3.4% annual increase to deliver current levels of reliability and customer service for most customers and targeted improvement for customers experiencing below average service or who have special reliability needs.
03	Toronto Hydro should keep increases below 3.4% annually, even if that could mean reductions in service.
88	Other [Please specify]
98	Don't know

ASK if 01, 02, 03 or 98

I35. And why do you say that? [**OPEN**]

J. SEGMENTATION AND DEMOGRAPHICS

Lastly, I'd like to ask you some general questions about the electricity system in Ontario.
For each statement please tell me if you would strongly agree, somewhat agree, somewhat disagree or strongly disagree. If you don't know enough to say or don't have an opinion just let me know.

01	Strongly agree
02	Somewhat agree
03	Somewhat disagree
04	Strongly disagree
98	Don't know/ No opinion
99	Refused (DO NOT READ)

[ROTATE]

J36. The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.

J37. Customers are well served by the electricity system in Ontario.

[END BATTERY]

The following questions are only being requested for statistical purposes to better understand the different types of customers providing feedback to Toronto Hydro.

J38. Which of the following best describes your living situation?

01	I pay rent for my housing	
02	I own my home	
03	I live in housing where I do not pay rent	

J39. How would you describe your primary residence?

01	A fully-detached home	
02	A semi-detached home	
03	An apartment or condo building fewer than 5 storeys	
04	An apartment or condo building 5 storeys or higher	
88	Other	

J40. Some financial assistance programs are targeted based on income and the number of people in the home. To better allow us to understand the needs of customers who may be eligible for different programs, can you please tell me how many people reside in your home , including yourself (adults and children)?

01	Record **NUMERIC** response only	
98	Don't know [**DO NOT READ**]	

J41. To the best of your ability, please tell me which of the following categories best describes your household's AFTER TAX income. [**READ LIST**]

01	Less than $28,000	
02	Just over $28,000 to $39,000	
03	Just over $39,000 to $48,000	
04	Just over $48,000 to $52,000	
05	More than $52,000	
98	Not sure [**DO NOT READ**]	
99	Refused [**DO NOT READ**]	

J42. In order to claim your **$10 Amazon Gift Card**, please provide me with the following information… [*Note: Please read back name and email before proceeding to end*]

Your first and last name: _____ [**RECORD and CONFIRM**]

Your email address: _____ [**RECORD and CONFIRM**]

Your mailing address (if no internet access/email account): _____ [**RECORD and CONFIRM**]

THANK and END SURVEY

Thank you very much for taking the time to complete this survey.

Appendix 3.2.2

Small Business Ratepayer Survey

Customer Consultation

Toronto Hydro Electric System Ltd
14 Carlton Street
Toronto, ON, M5B 1K5

May 2018

Prepared by:

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A. INTRODUCTION

INTRO. Hello, my name is _____ and I'm calling from **Innovative Research Group** on behalf of **Toronto Hydro**, your local electricity distributor.

Innovative Research Group is a national public opinion research firm. **We need your input on choices that will affect the service you receive from Toronto Hydro and the price you pay for that service.** Your answers will be combined with others to protect your privacy.

This survey should take about 20 minutes to complete. We know your time is valuable so at the end of the survey, you will have the opportunity to provide your name and email to receive a $20 Amazon Gift Card.

Can I please speak to the person who is in-charge of managing the electricity bill at your organization?

1) Yes, speaking <**contact on the line**>	**[skip to A1]**
2) Yes <**transferred to contact**>	**[skip to A1]**
3) No <**not the right contact person**>	**[GO to "NEW"]**
4) No <**busy**> "When is a good time to callback?"	**[record callback time]**
5) Maybe <**may I ask who is calling?**>	**[skip to GATE]**

NEW. And … can I have their …

First Name _____
Last Name _____
Title/Position _____
Phone Number _____

ASK to be transferred …

- **if transferred → go to A2**
- **if not transferred → Thank & Add to Callback List**

GATE. Hello, my name is _____ and I'm calling from **Innovative Research** on behalf of **Toronto Hydro,** your local electricity utility.

INTERVIEWER NOTE: If gatekeeper asks the purpose of call → I'd like to ask the person in-charge of managing the electricity bill at your organization a few questions concerning a **Toronto Hydro** customer consultation.

1) Yes <**transferred to contact**>		**[skip to A2]**
2) No <**not available**>	"*When is a good time to callback*?	**[record call-back time and go to "NEW"]**
3) No <**not interested in talking**>		**[Thank & Terminate]**

A1 QUAL PREAMBLE:

Read preamable again, if transferred to new person:

Hello, my name is _____ and I'm calling from **Innovative Research** on behalf of **Toronto Hydro**, your local electricity utility.

Innovative Research is a national public opinion research firm**.** We have been hired by **Toronto Hydro** to help them better understand the needs and preferences of non-residential customers who are responsible for paying their organization's electricity bill.

A1. Can I have roughly **20 minutes** of your time to ask you some questions? All your responses will be kept strictly confidential.

Yes – I don't mind	1	[CONTINUE]
No – Not primary bill payer (i.e. not best person to speak to)	2	[go to TRANSFER]
No – BAD TIME	3	[ARRANGE CALLBACK]
No – HARD REFUSAL	4	[THANK & TERMINATE]

MONIT [INTERNAL]

This call may be monitored or audio taped for quality control and evaluation purposes.

PRESS TO CONTINUE	1

A2. Can you confirm that your organization receives an electricity or hydro bill from **Toronto Hydro**

YES	1	[CONTINUE]
NO	2	[THANK & TERMINATE]
DK (volunteered)	98	[THANK & TERMINATE]

Only those in charge of managing/overseeing organizations electricity bill will be interviewed.

A3. As part of your job, are you in charge of managing or overseeing your organization's electricity or hydro bill?

YES	1	[CONTINUE]
NO	2	"Can I speak to the person who manages your organization's electricity bill?" [Return to **NEW**]
DK	3	"Can I speak to the person who manages your organization's electricity bill?" [Return to **NEW**]

TRANSFER

Can I please speak to the person who is in-charge of managing the electricity bill at your organization?

Yes	1	[BACK TO *INTRO*]
No – NOT AVAILABLE/BAD TIME – (ARRANGE CALLBACK)	2	[ARRANGE CALLBACK]
No – HARD REFUSAL	3	[THANK & TERMINATE]

B. SYSTEM FAMILIARITY

B4. To start, I'd like to ask you a few questions about the electricity system …

As you may know, Ontario's electricity system has three key components**: generation, transmission** and **distribution.**

- **Generating stations** convert various forms of energy into electric power;
- **Transmission lines** connect the power produced at generating stations to where it is needed across the province; and
- **Distribution lines** carry electricity to the homes and businesses in our communities.

Today we're going to talk about your **local distribution system** which is maintained and operated by Toronto Hydro.

How familiar are you with **Toronto Hydro**? Would you say you are *very familiar*, *somewhat familiar*, or *not familiar at all*?

01	Very familiar
02	Somewhat familiar
03	Not familiar at all
98	Don't know
99	Refused (DO NOT READ)

B5. In general, how satisfied or dissatisfied are you with the services your organization receives from **Toronto Hydro**? Would you say you are *very satisfied, somewhat satisfied, neither satisfied or dissatisfied, somewhat dissatisfied, very dissatisfied, or would you say you don't know*?

01	Very satisfied
02	Somewhat satisfied
03	Neither satisfied or dissatisfied
04	Somewhat dissatisfied
05	Very dissatisfied
98	Don't know
99	Refused (DO NOT READ)

B6. Is there anything in particular that **Toronto Hydro** can do to improve its services to your organization?

[OPEN]

B7. I'd now like to talk with you about your organization's electricity bill …

While **Toronto Hydro** is responsible for collecting payment for the entire electricity bill, they retain about **30%** of the typical small business customer's bill. This is about **$94** on an average **$314** monthly small business electricity bill. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.

Before this survey, how familiar were you with the percentage of your organization's electricity bill that is retained by **Toronto Hydro**? Would you say… [**READ LIST**]

01	Very familiar
02	Somewhat familiar
03	Not familiar at all
98	Don't know
99	Refused (DO NOT READ)

C. CUSTOMER ENGAGEMENT PROCESS

C8. Electricity distributors are required to file a rate application with the Ontario Energy Board (OEB) to request a change in distribution rates based on their plans for capital and operating spending. Toronto Hydro is now consulting on its plans for 2020 to 2024.

The OEB is mandated to protect consumers with respect to prices and the reliability and quality of electricity service.

How familiar would you say you are with the Ontario Energy Board or "OEB"?

Would you say … [**READ LIST**]

01	Very familiar
02	Somewhat familiar
03	Not familiar at all
98	Don't know
99	Refused (DO NOT READ)

C9. As part of Toronto Hydro's consultation, it has developed a five-phase approach to gathering and responding to customer feedback.

- First, Toronto Hydro identified customer priorities through a series of surveys and focus groups;
- Then, used this customer feedback to guide development of its Draft Plan;
- Now, Toronto Hydro is in the process of collecting customer feedback on its Draft Plan;
- The next phases will include re-examining its Draft Plan based on customer feedback and preparing a submission to the OEB.

This survey is part of the third stage of **collecting customer feedback on the Draft Plan**.

Does this Customer Engagement process seem like a good way or a poor way to bring customer needs and preferences into Toronto Hydro's plan?

Would you say … [**READ LIST**]

01	Very good way
02	Somewhat good way
03	Somewhat poor way
04	Very poor way
98	Don't know

C10. Toronto Hydro wants to better understand customer priorities. In the first phase of customer engagement, residential and small business customers identified six core priorities which they believe should be a focus for Toronto Hydro.

C11. Among the following customer identified priorities, please tell me which one is the most important to you.

[READ OPTIONS; RANDOMIZE LIST]

01	Delivering reasonable electricity prices
02	Ensuring reliable electricity service
03	Ensuring the safety of electricity infrastructure
04	Enabling the electricity system to support the reduction of greenhouse gases
05	Helping customers with conservation and efficiency
06	Providing quality customer service

C12. What is the next most important priority you think **Toronto Hydro** should focus on?
[**Remove answer from C11 if asked to read again**]

C13. And what do you consider the third most important priority?
[**Remove answer from C11 and C12 if asked to read again**]

C14. Are there any other important priorities that **Toronto Hydro** should be focusing on that weren't included in the previous list I read to you? [**OPEN**]

D. PLANNING PRINCIPLES AND RATE IMPACT

D15. Based, in part, on the initial customer input, Toronto Hydro has drafted a plan totaling approximately $4.3B over five years.

Toronto Hydro's proposed plan focuses on delivering current levels of reliability and customer service for most customers and targeted improvements for customers experiencing below average service or who have special reliability needs, like hospitals.

This proposed plan translates into an average 4.4% increase in your organization's distribution rates each year from 2020 to 2024. The distribution charges on the monthly bill would increase to $126 by 2024 for a typical small business customer.

Do you feel that this is *definitely the right approach*, *probably the right approach*, *probably the wrong approach* or *definitely the wrong approach* to Toronto Hydro's planning for the next five years or *would you say you don't know*?

01	Definitely the right approach
02	Probably the right approach
03	Probably the wrong approach
04	Definitely the wrong approach
98	Don't know

E. MAKING CHOICES

E16. Toronto Hydro's total spending is benchmarked by the OEB against other utilities in Ontario. Toronto Hydro's operating costs of $305 per customer are within $1 of the provincial average.

However Toronto Hydro's capital investment costs are $739 per customer which are $245 more than the provincial average.

Since a number of capital investment decisions are based trade-offs between costs and customer outcomes – like services and reliability levels – the remaining questions in this survey ask for your feedback on those choices.

E17. Do you feel that gathering feedback on capital investment decisions is *definitely the right approach*, *probably the right approach*, *probably the wrong approach, definitely the wrong approach or would you say you don't know*?

01	Definitely the right approach
02	Probably the right approach
03	Probably the wrong approach
04	Definitely the wrong approach
98	Don't know

F. INVESTING IN THE BASICS

F18. As a company, Toronto Hydro needs vehicles and tools to service the power lines and IT systems to manage the system and customer information.

Which of the following statements best represents your point of view? [**READ LIST; Rotate 01 and 02**]

01	Toronto Hydro should find ways to make do with the equipment and IT systems it already has
02	Toronto Hydro should make the investments necessary to ensure its staff have the equipment and IT systems they need to manage the system efficiently and reliably
98	Don't know

PREAMBLE TO NEXT SECTION

F19. Toronto Hydro has identified areas where it could accelerate investments. These accelerated projects could increase the **typical customer's bill by $5.73** per month by 2024. These projects are in addition to the 4.4% increase that is currently being proposed.

Toronto Hydro wants to get your feedback on particular projects before deciding whether or not to accelerate its investment plan in certain specific areas.

G. ADDRESSING SAFETY AND RELIABILITY

G20. Right now, the typical Toronto Hydro customer averages 1.4 outages per year with an average of between 60 and 70 minutes without power over the year. While many of those outages are caused by events outside of Toronto Hydro's control, roughly 36% are caused by the failure of aging equipment.

In this proposed plan, Toronto Hydro's general approach is to spend just enough on replacing equipment so that most customers can expect a similar level of reliability over the next five years as they are experiencing today, and to provide improved service for those customers whose reliability is poorer or who have special reliability needs such as hospitals.

Which of the following is closest to your point of view regarding Toronto Hydro's approach to addressing reliability? [**READ LIST; Rotate 01 and 03**]

01	Toronto Hydro should stick with the proposed approach of maintaining the current level of day-to-day reliability that the average customer experiences as part of the proposed rate increase of 4.4% per year.
02	I am prepared to pay more so Toronto Hydro can reduce the number and length of outages that the average customer experiences.
03	I am prepared to live with an increase in the number and length of outages so the proposed rate increase can be reduced.
98	Don't know

Dealing with types of lines that fail more often with more problems

G21. Some customers are served by older types of lines that are more likely to fail, causing more frequent, and longer lasting power outages. These customers are more likely to experience poorer reliability over time than most Toronto Hydro customers. The proposed plan will replace those lines over time but the work could be done faster.

I would like to ask you about two types of lines.

G22. One example is **rear-lot lines**. They go through residential backyards and are often more difficult to service and more exposed to falling branches. The proposed plan will replace all existing rear-lot lines by 2033. Toronto Hydro could replace those lines 4 years sooner for an additional cost.

Which of the following statements is closest to your view? [**READ LIST; ROTATE 01 and 03**]

01	Toronto Hydro should stick with the proposed pace of investment in rear-lot which would see it all converted by 2033 as part of a proposed rate increase of 4.4% per year.
02	I am willing to pay an additional $0.22 more on my organization's average monthly bill by 2024 so Toronto Hydro can remove all rear-lot feeders four years sooner.
03	I would like Toronto Hydro to slow down this program so the proposed rate increase can be reduced.
98	Don't know

G23. Another example is **direct buried cable** where cables are laid directly in underground trenches without a protective barrier. While equipment failure causes 36% of outages across the system, cable failure accounts for 70% of all outages on the underground system.

Once these cables start to fail, they tend to experience a rash of failures. The proposed plan will replace a **quarter** of the highest risk direct buried cable by **2024**. Toronto Hydro could replace all of the highest risk direct buried cable by 2024 for an additional cost.

Which of the following statements is closest to your view? [**READ LIST; ROTATE 01 and 03**]

01	Toronto Hydro should stick with the proposed pace of investment in direct buried cable replacement which would see a quarter of the highest risk cable replaced by 2024 as part of a proposed rate increase of 4.4% per year.
02	I am willing to pay an additional $2.23 more on my organization's average monthly bill by 2024 so Toronto Hydro can replace all of the highest risk direct buried cable by 2024.
03	I would like Toronto Hydro to slow down this program so the proposed rate increase can be reduced.
98	Don't know

Paper Insulated Lead Covered (PILC)

G24. Toronto Hydro has identified three equipment upgrades that are needed within the next few years. If Toronto Hydro waits, those upgrades will be more expensive and disruptive as Toronto continues to grow.

Firstly, Paper Insulated Lead Covered (PILC) cable. PILC cable was an old type of underground cable that stopped being installed on Toronto Hydro's grid 20 years ago. While the equipment is resilient and is still providing electricity to the downtown core, the outer lead covers can begin to crack and leak oil. Replacing these cables is becoming increasingly difficult and expensive to resource and complete.

Toronto Hydro has a long-term plan to remove and replace PILC cable by 2049. But Toronto Hydro can replace all of this cable ten years earlier by 2039, at an additional cost now. This will improve reliability, reduce risks to the public, and avoid additional expense and disruption in the future.

Which of the following is closest to your point of view regarding Toronto Hydro's PILC Cable replacement program? [**READ LIST ; ROTATE 01 and 03**]

01	Toronto Hydro should address the reliability issues and other risks posed by PILC cable at the current pace as part of a proposed rate increase of 4.4% per year, even if it's more disruptive to do so in the future.
02	Toronto Hydro should accelerate its replacement of PILC cable by 10 years, even if it costs the typical small business customer an additional $1.05 more on the average monthly bill by 2024, because it's less disruptive to do it now than in the future.
03	I would like Toronto Hydro to slow down this program so the proposed rate increase can be reduced.
98	Don't know

Underground Network Transformers

G25. The second upgrade project identified is *Underground Network Transformers*. The key problem with these units is their older design which makes them prone to flooding.

Toronto Hydro plans to replace just enough of these units by 2031 so that outages, due to equipment failure, don't get any worse. But the process could be advanced by three years to replace all these units by 2028.

G26. Which of the following is closest to your point of view regarding Toronto Hydro's Network Unit replacement program? [**READ LIST ; ROTATE 01 and 03**]

01	Toronto Hydro should stick with the proposed pace of investment in underground network transformer replacement as part of a proposed rate increase of 4.4% per year.
02	Toronto Hydro should replace its underground network transformers 3 years faster to improve downtown reliability, even if it costs the typical small business customer an additional $0.19 more on the average monthly bill by 2024.
03	I would like Toronto Hydro to slow down this program so the proposed rate increase can be reduced.
98	Don't know

Cable Chambers

G27. The third upgrade project identified is Cable Chamber replacement. Cable Chambers house, protect, and provide access to underground electrical equipment across the city. When they deteriorate or break, this equipment can cause outages and pose anything from a tripping hazard to something more serious like a collapsed chamber.

Toronto Hydro plans to take approximately 30 years to address the chambers in the worst condition. But accelerating the work could halve that period, at an additional cost now.

G28. Which of the following is closest to your point of view regarding Toronto Hydro's Cable Chamber renewal program? [**READ LIST; ROTATE 01 and 03**]

01	Toronto Hydro should stick with the proposed pace of investment in cable chamber renewal as part of a proposed rate increase of 4.4% per year.
02	Toronto Hydro should address the safety and reliability risk posed by deteriorating cable chambers faster, even if it costs the typical small business customer an additional $0.23 more on the average monthly bill by 2024.
03	Toronto Hydro should go back to reconstructing cable chambers reactively in order to keep my rates lower now.
98	Don't know

Dealing with more frequent extreme weather events

G29. As Toronto Hydro's distribution system is exposed to strong winds, freezing rain, and severe flooding, they are proposing a variety of enhancements to improve the resiliency of the distribution system against extreme weather events.

Toronto Hydro could enhance the system further in neighbourhoods outside of downtown. The improvements include adding remotely-operated technology and more back-up links within the grid. This will help Toronto Hydro to better isolate the problem and reduce outage times by as much as 50% in these areas.

Which of the following statements best represents your point of view? [**READ LIST; ROTATE 01 and 02**]

01	Yes, I would be willing to accept an increase to my organization's monthly bill of $0.21 more by 2024 so more customers can get their power back on quicker during outages caused by storms and other events.
02	No, I'm comfortable knowing that some of this work is already planned and would prefer to keep my bill lower.
98	Don't know

H. INNOVATION AND PLANNING FOR THE FUTURE

H30. 3% of the proposed budget would be spent on innovation and planning for the future. The following questions are about this aspect of the budget.

Toronto Hydro has already begun to integrate large-scale battery electricity storage into the system. They have now identified more opportunities to partner on a wider range of energy storage projects. Integrating storage into the system can improve reliability and help reduce greenhouse gases, but it is not required to maintain current levels of reliability.

Which of the following is closest to your point of view? [**READ LIST; ROTATE 01 and 02**]

01	I would be willing to pay up to $1.25 more per bill by 2024 for Toronto Hydro to partner on a wider range of energy storage projects which would improve reliability and help reduce Greenhouse gases.
02	I do not want to pay more for Toronto Hydro to do more energy storage projects, knowing it's not required to maintain current levels of reliability.
98	Don't know

H31. New communication technology has revolutionised the way the grid can be managed.

Toronto Hydro plans to take advantage of various new technologies wherever clear benefits can be established.

However, Toronto Hydro can improve the reliability of its grid further by installing communication devices in the downtown underground network that detect fire, floods or other risks more quickly.

Which of the following is closest to your point of view? [**READ LIST; ROTATE 01 and 03**]

01	I would be willing to pay $0.16 more per bill by 2024 for Toronto Hydro to be able to better predict fire, floods and other risks in the downtown network that cause outages or damage.
02	Toronto Hydro should maintain the pace of installing monitoring and control equipment on the downtown network as planned within its existing proposed rate increase of 4.4% per year, but not go any further.
03	Toronto Hydro should reduce its planned increase by eliminating the improved monitoring and control equipment planned for the downtown network.
98	Don't know

H32. New types of generation (often renewable), storage, and supporting systems are making it possible for communities, institutions or other large customers to develop "microgrids". They are a local electricity network linking smaller sources of electricity with nearby uses such as homes, businesses and institutions. In the event of a failure of the larger network, a microgrid can seal itself off and continue to provide power locally.

Microgrids would give customers more choices, while creating a more resilient and reliable grid. However, they are not required to maintain current reliability.

Which is the following is closest to your point of view? [**READ LIST; ROTATE 01 and 02**]

01	I would be willing to pay $0.19 more per bill by 2024 for Toronto Hydro to support the development of microgrids in order to give customers more choice and create a more resilient and reliable grid.
02	Toronto Hydro should support microgrids, but only if those customers pay for the full costs, as they are not required to maintain current reliability.
98	Don't know

I. INVESTMENT ALTERNATIVES SUMMARY

I33. Toronto Hydro's current proposed plan, which translates into an average 4.4% annual increase, focuses on delivering current levels of reliability and customer service for most customers and targeted improvements for customers experiencing below average service or who have special reliability needs, like hospitals.

In dollars and cents, that means an average increase to the monthly bill of **$4.86 each year** for the typical small business customer.

Over the course of the proposed 5-year plan, the typical small business customer will see the distribution portion of their electricity bill **increase by $24.32**.

As a result, the distribution charges on the monthly bill would increase from a proposed amount of **$102 in 2019** to **$126 by 2024**.

I34. With regards to Toronto Hydro's proposed plan, which of the following statements best represents your view? [**READ LIST; ROTATE 01 and 03**]

01	Toronto Hydro should improve service, as discussed on the previous pages, even if that means an annual increase that exceeds 4.4%.
02	Toronto Hydro should stick with a 4.4% annual increase to deliver current levels of reliability and customer service for most customers and targeted improvement for customers experiencing below average service or who have special reliability needs.
03	Toronto Hydro should keep increases below 4.4% annually, even if that could mean reductions in service.
88	Other [Please specify]
98	Don't know

ASK if 01, 02, 03 or 98

I35. And why do you say that? [**OPEN**]

J. SEGMENTATION AND DEMOGRAPHICS

Lastly, I'd like to ask you some general questions about the electricity system in Ontario.
For each statement please tell me if you would strongly agree, somewhat agree, somewhat disagree or strongly disagree. If you don't know enough to say or don't have an opinion just let me know.

01	Strongly agree
02	Somewhat agree
03	Somewhat disagree
04	Strongly disagree
98	Don't know/ No opinion
99	Refused (DO NOT READ)

[ROTATE]

J36. The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being delayed.

J37. Customers are well served by the electricity system in Ontario.

[END BATTERY]

The following questions are only being requested for statistical purposes to better understand the different types of customers providing feedback to Toronto Hydro.

J38. Which of the following best describes the sector in which your business operates? [**READ LIST**]

01	Commercial	
02	Manufacturing/Industrial	
03	Data Centre	
04	Hospitality	
05	Restaurant/Tavern	
06	Retail	
07	Warehouse	
88	Other [Please specify:_____]	

J39. In order to claim your **$20 Amazon Gift Card**, please provide me with the following information… [*Note: Please read back name and email before proceeding to end*]

Your first and last name: _____ [**RECORD and CONFIRM**]

Your email address: _____ [**RECORD and CONFIRM**]

Your business mailing address (if no internet access/email account):
_____ [**RECORD and CONFIRM**]

THANK and END SURVEY

Thank you very much for taking the time to complete this survey.

Appendix 3.2.3

Mid-Market Ratepayer Survey

Customer Consultation

Toronto Hydro Electric System Ltd
14 Carlton Street
Toronto, ON, M5B 1K5

May 2018

Prepared by:

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A. INTRODUCTION

INTRO. Hello, my name is _____ and I'm calling from **Innovative Research Group** on behalf of **Toronto Hydro**, your local electricity distributor.

Innovative Research Group is a national public opinion research firm. **We need your input on choices that will affect the service you receive from Toronto Hydro and the price you pay for that service.** Your answers will be combined with others to protect your privacy.

This survey should take about 20 minutes to complete. We know your time is valuable so at the end of the survey, you will have the opportunity to provide your name and email to receive a $20 Amazon Gift Card.

Can I please speak to the person who is in-charge of managing the electricity bill at your organization?

1) Yes, speaking <**contact on the line**>	**[skip to A1]**
2) Yes <**transferred to contact**>	**[skip to A1]**
3) No <**not the right contact person**>	**[GO to "NEW"]**
4) No <**busy**> "When is a good time to callback?"	**[record callback time]**
5) Maybe <**may I ask who is calling?**>	**[skip to GATE]**

NEW. And … can I have their …

First Name _____
Last Name _____
Title/Position _____
Phone Number _____

ASK to be transferred …

- **if transferred → go to A2**
- **if not transferred → Thank & Add to Callback List**

GATE. Hello, my name is _____ and I'm calling from **Innovative Research** on behalf of **Toronto Hydro,** your local electricity utility.

INTERVIEWER NOTE: If gatekeeper asks the purpose of call → I'd like to ask the person in-charge of managing the electricity bill at your organization a few questions concerning a **Toronto Hydro** customer consultation.

1) Yes <**transferred to contact**>		**[skip to A2]**
2) No <**not available**>	"*When is a good time to callback*?	**[record call-back time and go to "NEW"]**
3) No <**not interested in talking**>		**[Thank & Terminate]**

A1 QUAL PREAMBLE:

Read preamable again, if transferred to new person:

Hello, my name is _____ and I'm calling from **Innovative Research** on behalf of **Toronto Hydro**, your local electricity utility.

Innovative Research is a national public opinion research firm**.** We have been hired by **Toronto Hydro** to help them better understand the needs and preferences of non-residential customers who are responsible for paying their organization's electricity bill.

A1. Can I have roughly **20 minutes** of your time to ask you some questions? All your responses will be kept strictly confidential.

Yes – I don't mind	1	[CONTINUE]
No – Not primary bill payer (i.e. not best person to speak to)	2	[go to TRANSFER]
No – BAD TIME	3	[ARRANGE CALLBACK]
No – HARD REFUSAL	4	[THANK & TERMINATE]

MONIT [INTERNAL]

This call may be monitored or audio taped for quality control and evaluation purposes.

PRESS TO CONTINUE	1

A2. Can you confirm that your organization receives an electricity or hydro bill from **Toronto Hydro**

YES	1	[CONTINUE]
NO	2	[THANK & TERMINATE]
DK (volunteered)	98	[THANK & TERMINATE]

Only those in charge of managing/overseeing organizations electricity bill will be interviewed.

A3. As part of your job, are you in charge of managing or overseeing your organization's electricity or hydro bill?

YES	1	[CONTINUE]
NO	2	"Can I speak to the person who manages your organization's electricity bill?" [Return to **NEW**]
DK	3	"Can I speak to the person who manages your organization's electricity bill?" [Return to **NEW**]

TRANSFER

Can I please speak to the person who is in-charge of managing the electricity bill at your organization?

Yes	1	[BACK TO *INTRO*]
No – NOT AVAILABLE/BAD TIME – (ARRANGE CALLBACK)	2	[ARRANGE CALLBACK]
No – HARD REFUSAL	3	[THANK & TERMINATE]

B. SYSTEM FAMILIARITY

B4. To start, I'd like to ask you a few questions about the electricity system …

As you may know, Ontario's electricity system has three key components**: generation, transmission** and **distribution.**

- **Generating stations** convert various forms of energy into electric power;
- **Transmission lines** connect the power produced at generating stations to where it is needed across the province; and
- **Distribution lines** carry electricity to the homes and businesses in our communities.

Today we're going to talk about your **local distribution system** which is maintained and operated by Toronto Hydro.

How familiar are you with **Toronto Hydro**? Would you say you are *very familiar*, *somewhat familiar*, or *not familiar at all*?

01	Very familiar
02	Somewhat familiar
03	Not familiar at all
98	Don't know
99	Refused (DO NOT READ)

B5. In general, how satisfied or dissatisfied are you with the services your organization receives from **Toronto Hydro**? Would you say you are *very satisfied, somewhat satisfied, neither satisfied or dissatisfied, somewhat dissatisfied, very dissatisfied, or would you say you don't know*?

01	Very satisfied
02	Somewhat satisfied
03	Neither satisfied or dissatisfied
04	Somewhat dissatisfied
05	Very dissatisfied
98	Don't know
99	Refused (DO NOT READ)

B6. Is there anything in particular that **Toronto Hydro** can do to improve its services to your organization?

[OPEN]

B7. I'd now like to talk with you about your organization's electricity bill …

While **Toronto Hydro** is responsible for collecting payment for the entire electricity bill, they retain about **10%** of the typical mid-sized business customer's bill. This is about **$1,290** on an average **$13,513** monthly mid-sized business' electricity bill. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.

Before this survey, how familiar were you with the percentage of your organization's electricity bill that is retained by **Toronto Hydro**? Would you say… [**READ LIST**]

01	Very familiar
02	Somewhat familiar
03	Not familiar at all
98	Don't know
99	Refused (DO NOT READ)

C. CUSTOMER ENGAGEMENT PROCESS

C8. Electricity distributors are required to file a rate application with the Ontario Energy Board (OEB) to request a change in distribution rates based on their plans for capital and operating spending. Toronto Hydro is now consulting on its plans for 2020 to 2024.

The OEB is mandated to protect consumers with respect to prices and the reliability and quality of electricity service.

How familiar would you say you are with the Ontario Energy Board or "OEB"?

Would you say … [**READ LIST**]

01	Very familiar
02	Somewhat familiar
03	Not familiar at all
98	Don't know
99	Refused (DO NOT READ)

C9. As part of Toronto Hydro's consultation, it has developed a five-phase approach to gathering and responding to customer feedback.

- First, Toronto Hydro identified customer priorities through a series of surveys and focus groups;
- Then, used this customer feedback to guide development of its Draft Plan;
- Now, Toronto Hydro is in the process of collecting customer feedback on its Draft Plan;
- The next phases will include re-examining its Draft Plan based on customer feedback and preparing a submission to the OEB.

This survey is part of the third stage of **collecting customer feedback on the Draft Plan**.

Does this Customer Engagement process seem like a good way or a poor way to bring customer needs and preferences into Toronto Hydro's plan?

Would you say … [**READ LIST**]

01	Very good way
02	Somewhat good way
03	Somewhat poor way
04	Very poor way
98	Don't know

C10. Toronto Hydro wants to better understand customer priorities. In the first phase of customer engagement, residential and small business customers identified six core priorities which they believe should be a focus for Toronto Hydro.

C11. Among the following customer identified priorities, please tell me which one is the most important to you.

[READ OPTIONS; RANDOMIZE LIST]

01	Delivering reasonable electricity prices
02	Ensuring reliable electricity service
03	Ensuring the safety of electricity infrastructure
04	Enabling the electricity system to support the reduction of greenhouse gases
05	Helping customers with conservation and efficiency
06	Providing quality customer service

C12. What is the next most important priority you think **Toronto Hydro** should focus on?
[**Remove answer from C11 if asked to read again**]

C13. And what do you consider the third most important priority?
[**Remove answer from C11 and C12 if asked to read again**]

C14. Are there any other important priorities that **Toronto Hydro** should be focusing on that weren't included in the previous list I read to you? [**OPEN**]

D. PLANNING PRINCIPLES AND RATE IMPACT

D15. Based, in part, on the initial customer input, Toronto Hydro has drafted a plan totaling approximately $4.3B over five years.

Toronto Hydro's proposed plan focuses on delivering current levels of reliability and customer service for most customers and targeted improvements for customers experiencing below average service or who have special reliability needs, like hospitals.

This proposed plan translates into an average 3.9% increase in your organization's distribution rates each year from 2020 to 2024. The distribution charges on the monthly bill would increase to $2,023 by 2024 for a typical mid-sized business customer.

Do you feel that this is *definitely the right approach*, *probably the right approach*, *probably the wrong approach* or *definitely the wrong approach* to Toronto Hydro's planning for the next five years or *would you say you don't know*?

01	Definitely the right approach
02	Probably the right approach
03	Probably the wrong approach
04	Definitely the wrong approach
98	Don't know

E. MAKING CHOICES

E16. Toronto Hydro's total spending is benchmarked by the OEB against other utilities in Ontario. Toronto Hydro's operating costs of $305 per customer are within $1 of the provincial average.

However Toronto Hydro's capital investment costs are $739 per customer which are $245 more than the provincial average.

Since a number of capital investment decisions are based trade-offs between costs and customer outcomes – like services and reliability levels – the remaining questions in this survey ask for your feedback on those choices.

E17. Do you feel that gathering feedback on capital investment decisions is *definitely the right approach*, *probably the right approach*, *probably the wrong approach, definitely the wrong approach or would you say you don't know*?

01	Definitely the right approach
02	Probably the right approach
03	Probably the wrong approach
04	Definitely the wrong approach
98	Don't know

F. INVESTING IN THE BASICS

F18. As a company, Toronto Hydro needs vehicles and tools to service the power lines and IT systems to manage the system and customer information.

Which of the following statements best represents your point of view? [**READ LIST; Rotate 01 and 02**]

01	Toronto Hydro should find ways to make do with the equipment and IT systems it already has
02	Toronto Hydro should make the investments necessary to ensure its staff have the equipment and IT systems they need to manage the system efficiently and reliably
98	Don't know

PREAMBLE TO NEXT SECTION

F19. Toronto Hydro has identified areas where it could accelerate investments. These accelerated projects could increase the **typical customer's bill by $100** per month by 2024. These projects are in addition to the 3.9% increase that is currently being proposed.

Toronto Hydro wants to get your feedback on particular projects before deciding whether or not to accelerate its investment plan in certain specific areas.

G. ADDRESSING SAFETY AND RELIABILITY

G20. Right now, the typical Toronto Hydro customer averages 1.4 outages per year with an average of between 60 and 70 minutes without power over the year. While many of those outages are caused by events outside of Toronto Hydro's control, roughly 36% are caused by the failure of aging equipment.

In this proposed plan, Toronto Hydro's general approach is to spend just enough on replacing equipment so that most customers can expect a similar level of reliability over the next five years as they are experiencing today, and to provide improved service for those customers whose reliability is poorer or who have special reliability needs such as hospitals.

Which of the following is closest to your point of view regarding Toronto Hydro's approach to addressing reliability? [**READ LIST; Rotate 01 and 03**]

01	Toronto Hydro should stick with the proposed approach of maintaining the current level of day-to-day reliability that the average customer experiences as part of the proposed rate increase of 3.9% per year.
02	I am prepared to pay more so Toronto Hydro can reduce the number and length of outages that the average customer experiences.
03	I am prepared to live with an increase in the number and length of outages so the proposed rate increase can be reduced.
98	Don't know

Dealing with types of lines that fail more often with more problems

G21. Some customers are served by older types of lines that are more likely to fail, causing more frequent, and longer lasting power outages. These customers are more likely to experience poorer reliability over time than most Toronto Hydro customers. The proposed plan will replace those lines over time but the work could be done faster.

I would like to ask you about two types of lines.

G22. One example is **rear-lot lines**. They go through residential backyards and are often more difficult to service and more exposed to falling branches. The proposed plan will replace all existing rear-lot lines by 2033. Toronto Hydro could replace those lines 4 years sooner for an additional cost.

Which of the following statements is closest to your view? [**READ LIST; ROTATE 01 and 03**]

01	Toronto Hydro should stick with the proposed pace of investment in rear-lot which would see it all converted by 2033 as part of a proposed rate increase of 3.9% per year.
02	I am willing to pay an additional $5.31 more on my organization's average monthly bill by 2024 so Toronto Hydro can remove all rear-lot feeders four years sooner.
03	I would like Toronto Hydro to slow down this program so the proposed rate increase can be reduced.
98	Don't know

G23. Another example is **direct buried cable** where cables are laid directly in underground trenches without a protective barrier. While equipment failure causes 36% of outages across the system, cable failure accounts for 70% of all outages on the underground system.

Once these cables start to fail, they tend to experience a rash of failures. The proposed plan will replace a **quarter** of the highest risk direct buried cable by **2024**. Toronto Hydro could replace all of the highest risk direct buried cable by 2024 for an additional cost.

Which of the following statements is closest to your view? [**READ LIST; ROTATE 01 and 03**]

01	Toronto Hydro should stick with the proposed pace of investment in direct buried cable replacement which would see a quarter of the highest risk cable replaced by 2024 as part of a proposed rate increase of 3.9% per year.
02	I am willing to pay an additional $37.42 more on my organization's average monthly bill by 2024 so Toronto Hydro can replace all of the highest risk direct buried cable by 2024.
03	I would like Toronto Hydro to slow down this program so the proposed rate increase can be reduced.
98	Don't know

Paper Insulated Lead Covered (PILC)

G24. Toronto Hydro has identified three equipment upgrades that are needed within the next few years. If Toronto Hydro waits, those upgrades will be more expensive and disruptive as Toronto continues to grow.

Firstly, Paper Insulated Lead Covered (PILC) cable. PILC cable was an old type of underground cable that stopped being installed on Toronto Hydro's grid 20 years ago. While the equipment is resilient and is still providing electricity to the downtown core, the outer lead covers can begin to crack and leak oil. Replacing these cables is becoming increasingly difficult and expensive to resource and complete.

Toronto Hydro has a long-term plan to remove and replace PILC cable by 2049. But Toronto Hydro can replace all of this cable ten years earlier by 2039, at an additional cost now. This will improve reliability, reduce risks to the public, and avoid additional expense and disruption in the future.

Which of the following is closest to your point of view regarding Toronto Hydro's PILC Cable replacement program? [**READ LIST ; ROTATE 01 and 03**]

01	Toronto Hydro should address the reliability issues and other risks posed by PILC cable at the current pace as part of a proposed rate increase of 3.9% per year, even if it's more disruptive to do so in the future.
02	Toronto Hydro should accelerate its replacement of PILC cable by 10 years, even if it costs the typical mid-sized business customer an additional $17.34 more on the average monthly bill by 2024, because it's less disruptive to do it now than in the future.
03	I would like Toronto Hydro to slow down this program so the proposed rate increase can be reduced.
98	Don't know

Underground Network Transformers

G25. The second upgrade project identified is *Underground Network Transformers*. The key problem with these units is their older design which makes them prone to flooding.

Toronto Hydro plans to replace just enough of these units by 2031 so that outages, due to equipment failure, don't get any worse. But the process could be advanced by three years to replace all these units by 2028.

G26. Which of the following is closest to your point of view regarding Toronto Hydro's Network Unit replacement program? [**READ LIST ; ROTATE 01 and 03**]

01	Toronto Hydro should stick with the proposed pace of investment in underground network transformer replacement as part of a proposed rate increase of 3.9% per year.
02	Toronto Hydro should replace its underground network transformers 3 years faster to improve downtown reliability, even if it costs the typical mid-sized business customer an additional $2.90 more on the average monthly bill by 2024.
03	I would like Toronto Hydro to slow down this program so the proposed rate increase can be reduced.
98	Don't know

Cable Chambers

G27. The third upgrade project identified is Cable Chamber replacement. Cable Chambers house, protect, and provide access to underground electrical equipment across the city. When they deteriorate or break, this equipment can cause outages and pose anything from a tripping hazard to something more serious like a collapsed chamber.

Toronto Hydro plans to take approximately 30 years to address the chambers in the worst condition. But accelerating the work could halve that period, at an additional cost now.

G28. Which of the following is closest to your point of view regarding Toronto Hydro's Cable Chamber renewal program? [**READ LIST; ROTATE 01 and 03**]

01	Toronto Hydro should stick with the proposed pace of investment in cable chamber renewal as part of a proposed rate increase of 3.9% per year.
02	Toronto Hydro should address the safety and reliability risk posed by deteriorating cable chambers faster, even if it costs the typical mid-sized business customer an additional $5.84 more on the average monthly bill by 2024.
03	Toronto Hydro should go back to reconstructing cable chambers reactively in order to keep my rates lower now.
98	Don't know

Dealing with more frequent extreme weather events

G29. As Toronto Hydro's distribution system is exposed to strong winds, freezing rain, and severe flooding, they are proposing a variety of enhancements to improve the resiliency of the distribution system against extreme weather events.

Toronto Hydro could enhance the system further in neighbourhoods outside of downtown. The improvements include adding remotely-operated technology and more back-up links within the grid. This will help Toronto Hydro to better isolate the problem and reduce outage times by as much as 50% in these areas.

Which of the following statements best represents your point of view? [**READ LIST; ROTATE 01 and 02**]

01	Yes, I would be willing to accept an increase to my organization's monthly bill of $5.59 more by 2024 so more customers can get their power back on quicker during outages caused by storms and other events.
02	No, I'm comfortable knowing that some of this work is already planned and would prefer to keep my bill lower.
98	Don't know

H. INNOVATION AND PLANNING FOR THE FUTURE

H30. 3% of the proposed budget would be spent on innovation and planning for the future. The following questions are about this aspect of the budget.

Toronto Hydro has already begun to integrate large-scale battery electricity storage into the system. They have now identified more opportunities to partner on a wider range of energy storage projects. Integrating storage into the system can improve reliability and help reduce greenhouse gases, but it is not required to maintain current levels of reliability.

Which of the following is closest to your point of view? [**READ LIST; ROTATE 01 and 02**]

01	I would be willing to pay up to $20.84 more per bill by 2024 for Toronto Hydro to partner on a wider range of energy storage projects which would improve reliability and help reduce Greenhouse gases.
02	I do not want to pay more for Toronto Hydro to do more energy storage projects, knowing it's not required to maintain current levels of reliability.
98	Don't know

H31. New communication technology has revolutionised the way the grid can be managed.

Toronto Hydro plans to take advantage of various new technologies wherever clear benefits can be established.

However, Toronto Hydro can improve the reliability of its grid further by installing communication devices in the downtown underground network that detect fire, floods or other risks more quickly.

Which of the following is closest to your point of view? [**READ LIST; ROTATE 01 and 03**]

01	I would be willing to pay $0.47 more per bill by 2024 for Toronto Hydro to be able to better predict fire, floods and other risks in the downtown network that cause outages or damage.
02	Toronto Hydro should maintain the pace of installing monitoring and control equipment on the downtown network as planned within its existing proposed rate increase of 3.9% per year, but not go any further.
03	Toronto Hydro should reduce its planned increase by eliminating the improved monitoring and control equipment planned for the downtown network.
98	Don't know

H32. New types of generation (often renewable), storage, and supporting systems are making it possible for communities, institutions or other large customers to develop "microgrids". They are a local electricity network linking smaller sources of electricity with nearby uses such as homes, businesses and institutions. In the event of a failure of the larger network, a microgrid can seal itself off and continue to provide power locally.

Microgrids would give customers more choices, while creating a more resilient and reliable grid. However, they are not required to maintain current reliability.

Which is the following is closest to your point of view? [**READ LIST; ROTATE 01 and 02**]

01	I would be willing to pay $0.57 more per bill by 2024 for Toronto Hydro to support the development of microgrids in order to give customers more choice and create a more resilient and reliable grid.
02	Toronto Hydro should support microgrids, but only if those customers pay for the full costs, as they are not required to maintain current reliability.
98	Don't know

I. INVESTMENT ALTERNATIVES SUMMARY

I33. Toronto Hydro's current proposed plan, which translates into an average 3.9% annual increase, focuses on delivering current levels of reliability and customer service for most customers and targeted improvements for customers experiencing below average service or who have special reliability needs, like hospitals.

In dollars and cents, that means an average increase to the monthly bill of **$70.26 each year** for the typical mid-sized business customer.

Over the course of the proposed 5-year plan, the typical mid-sized business customer will see the distribution portion of their electricity bill **increase by $351**.

As a result, the distribution charges on the monthly bill would increase from a proposed amount of **$1,671 in 2019** to **$2,023 by 2024**.

I34. With regards to Toronto Hydro's proposed plan, which of the following statements best represents your view? [**READ LIST; ROTATE 01 and 03**]

01	Toronto Hydro should improve service, as discussed on the previous pages, even if that means an annual increase that exceeds 3.9%.
02	Toronto Hydro should stick with a 3.9% annual increase to deliver current levels of reliability and customer service for most customers and targeted improvement for customers experiencing below average service or who have special reliability needs.
03	Toronto Hydro should keep increases below 3.9% annually, even if that could mean reductions in service.
88	Other [Please specify]
98	Don't know

ASK if 01, 02, 03 or 98

I35. And why do you say that? [**OPEN**]

J. SEGMENTATION AND DEMOGRAPHICS

Lastly, I'd like to ask you some general questions about the electricity system in Ontario.
For each statement please tell me if you would strongly agree, somewhat agree, somewhat disagree or strongly disagree. If you don't know enough to say or don't have an opinion just let me know.

01	Strongly agree
02	Somewhat agree
03	Somewhat disagree
04	Strongly disagree
98	Don't know/ No opinion
99	Refused (DO NOT READ)

[ROTATE]

J36. The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being delayed.

J37. Customers are well served by the electricity system in Ontario.

[END BATTERY]

The following questions are only being requested for statistical purposes to better understand the different types of customers providing feedback to Toronto Hydro.

J38. Which of the following best describes the sector in which your business operates? [**READ LIST**]

01	Commercial	
02	Manufacturing/Industrial	
03	Data Centre	
04	Hospitality	
05	Restaurant/Tavern	
06	Retail	
07	Warehouse	
88	Other [Please specify:_____]	

J39. In order to claim your **$20 Amazon Gift Card**, please provide me with the following information… [*Note: Please read back name and email before proceeding to end*]

Your first and last name: _____ [**RECORD and CONFIRM**]

Your email address: _____ [**RECORD and CONFIRM**]

Your business mailing address (if no internet access/email account):
_____ [**RECORD and CONFIRM**]

THANK and END SURVEY

Thank you very much for taking the time to complete this survey.

Appendix 3.2.4

Key Accounts Engagement

Customer Consultation

June 2018

Prepared by:

Innovative Research Group, Inc.
www.innovativeresearch.ca

Vancouver
888 Dunsmuir Street, Suite 350
Vancouver BC | V6C 3K4

Toronto
56 The Esplanade, Suite 310
Toronto, Ontario | M5E 1A7

Survey Introduction

Thank you for participating in this online survey.

Innovative Research Group is a national public opinion research and consultation firm**. Toronto Hydro** has hired us to help it better understand the needs and preferences of its largest customers –Key Account customers like you – as well as identify the priorities where you think it should focus its resources.

Last year, Toronto Hydro conducted an online survey about your needs and preferences. Those results informed Toronto Hydro's proposed plans, on which this survey is intended to get your feedback.

This survey should take you **approximately 10 minutes** to complete and your answers will be combined with others to protect your anonymity. While we've been provided your name and email address, no information that could be used to identify you or your company will be shared with Toronto Hydro.

Please answer all questions to the best of your ability. When answering the questions, please provide us with the response that holds most true for you. If you're unsure of how to answer a question or feel you don't know, please use the "don't know" or equivalent option.

Again, all information provided will be treated confidentially.

Note: *While you may be a Toronto Hydro residential customer, for the purposes of this survey, please answer the questions from the perspective of the business or organization that you represent*.

Thank you for your time,

Innovative Research Group

Click here for the **Innovative Research Group Inc.'s** privacy policy.

Page break.

A. SEGMENTATION

Most segmentation provided as sample variables.

A1. What occupation or position best describes your role at your organization?

Code	Response	
01	Owner	
02	Executive Manager	
03	Senior Manager	
04	Operations Manager	
88	Other [please specify: _____]	
98	Don't know	

A2. Does your organization receive a single bill or multiple bills from Toronto Hydro?

01	A single bill	
02	Multiple bills	
98	Don't know	

A3. Does your organization receive electrical bills from utilities other than Toronto Hydro?

01	Yes – we have operations in multiple jurisdictions	
02	No – we only operate in Toronto	
98	Don't know	

A1-A3 on the same page.

B. GENERAL SATISFACTION

B4. How familiar are you with the various parts of Ontario's electricity system, how they work together and which parts Toronto Hydro is responsible for?

Code	Response	
01	Very familiar and can explain the details of Ontario's electricity system to others	
02	Somewhat familiar, but cannot explain all the details of Ontario's electricity system to others	
03	Aside from receiving a bill from Toronto Hydro, I know very little about Ontario's electricity system	
98	Don't know	

Core Measure

B5. As you may know, **Toronto Hydro** operates and maintains the local electricity distribution system, reads meters, calculates your charges, answers your calls, responds during outages and clears trees and brush from power lines. **Toronto Hydro** does not set the commodity price of electricity or the Global Adjustment charge.

Generally, how satisfied are you with the service your organization receives from **Toronto Hydro**?

Code	Response	
01	Very satisfied	
02	Somewhat satisfied	
03	Neither satisfied or dissatisfied	
04	Somewhat dissatisfied	
05	Very dissatisfied	
98	Don't know	

B6. Is there anything in particular that **Toronto Hydro** can do to improve its services to your organization? [**OPEN**]

B4-B6 on the same page.

C. PRICE

C7. While **Toronto Hydro** is responsible for collecting payment for the entire electricity bill, it retains anywhere from 7% to 10% of the average Key Account's bill – depending on customer load and type of customer account. The rest of the bill goes to power generation companies, transmission companies (mainly Hydro One), the provincial government and regulatory agencies.

Key Account Type	Typical % of Bill Retained by Toronto Hydro
Multi-bill Aggregated Key Account (GS>50kW)	10%
1MW to 5MW Key Accounts	7%
5MW+ Key Accounts	8%

Before this survey, how familiar were you with the percentage of your organization's electricity bill that went to **Toronto Hydro**?

Code	Response
01	Very familiar
02	Somewhat familiar
03	Not familiar at all
98	Don't know

D. CUSTOMER ENGAGEMENT PROCESS

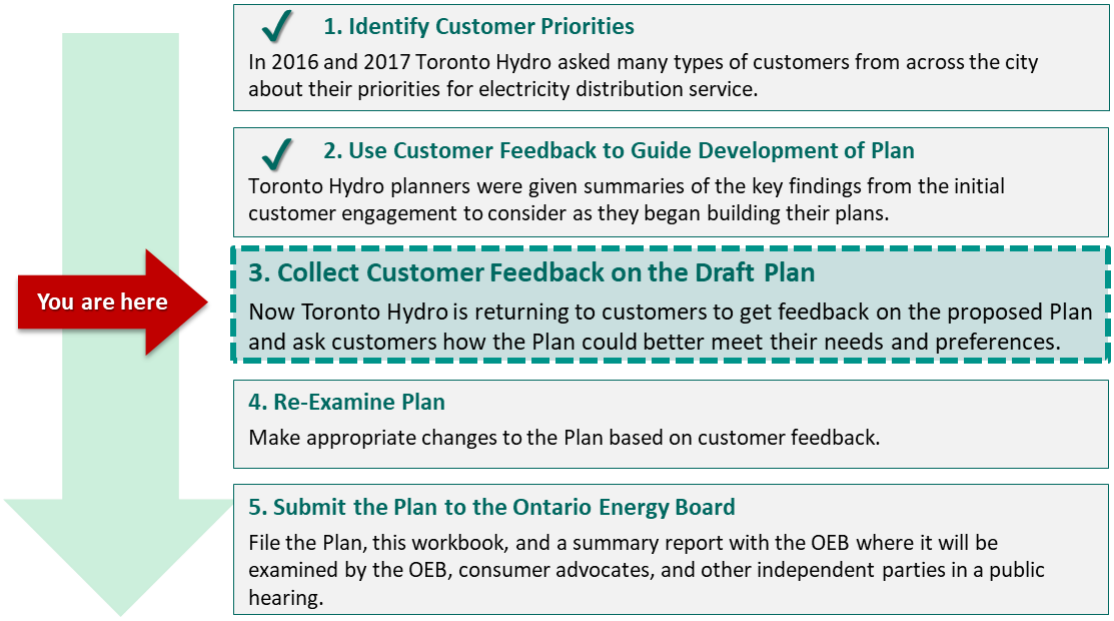
D8. Electricity distributors are required to file a rate application with the Ontario Energy Board (OEB) to request a change in distribution rates based on the company's plans for capital and operating spending. Toronto Hydro is now consulting on its plans for 2020 to 2024.

The OEB is mandated to protect consumers with respect to prices and the reliability and quality of electricity service.

How familiar would you say you are with the Ontario Energy Board?

01	Very familiar
02	Somewhat familiar
03	Not familiar at all
98	Don't know

D9. Toronto Hydro has developed a five phase approach to gathering and responding to customer feedback.



You may recall being asked to complete a survey in early 2017. That was part of the first phase of Toronto Hydro's customer engagement. This survey is part of the third stage of **collecting customer feedback on the Draft Plan**.

Does this Customer Engagement process seem like a good way or a poor way to bring customer needs and preferences into Toronto Hydro's plan?

01	Very good way
02	Somewhat good way
03	Somewhat poor way
04	Very poor way
98	Don't know

E. CUSTOMER PRIORITIES

E10. In response to customer engagement efforts over the past year, **Toronto Hydro** customers identified a diverse range of customer stated priorities, ranging from price and reliability to customer service, outages and helping customers conserve electricity.

Understanding that not all customers value and prioritize the same things, **Toronto Hydro** is working to find a balance that works for all customers.

E11. In February and March of 2017, Key Account customers, told **Toronto Hydro** that the three most important priorities were:

1. Ensuring reliable electrical service;
2. Delivering reasonable electricity prices, and;
3. Preventing or reducing the length of prolonged power outages causes by extreme weather (e.g. high winds, floods and ice storms)

Are these *three customer identified priorities* aligned with what you expect **Toronto Hydro** to focus on?

01	Yes	**SKIP TO E13**
02	No	CONTINUE
98	Don't know	CONTINUE

E12. Are there any other priorities that you would rank ahead of the priorities above that **Toronto Hydro** should focus on? [**OPEN**]

98	Don't know

E13. In the survey, Key Accounts customers identified power quality was the top priority not among those listed to choose from. Toronto Hydro would like to know how important power quality relative to the cost of your electricity bill.

Thinking about the trade-offs between power quality and the cost of your electricity bill, which of the following statements best represents your general point of view?

Code	Response	
01	My organization would be willing to **pay more** on the distribution portion of our electricity bill if it resulted in **improved** power quality	
02	My organization would be willing to **pay a bit more** on the distribution portion of our electricity bill to **maintain** the current level of power quality	
03	My organization would like to **pay a bit less** on the distribution portion of our electricity bill even if it resulted in **lowering our current level** of power quality	
98	Don't know	

F. RELIABILITY

The following statements are about the electrical service that your organization receives from **Toronto Hydro**. For each statement, please indicate your level of satisfaction or dissatisfaction

Code	Response	
01	Very satisfied	
02	Somewhat satisfied	
03	Neither satisfied or dissatisfied	
04	Somewhat dissatisfied	
05	Very dissatisfied	
98	Don't know	

[DO NOT RANDOMIZE]

F14. The reliability of your electricity service (as judged by the number of power outages you experience).

F15. The amount of time it takes to restore power when power outages occur.

[END BATTERY]

G. PLANNING PRINCIPLES AND RATE IMPACT

G16. With customer feedback in mind, Toronto Hydro is proposing a plan that is responsive to:



1. Legal requirements by continuing to meet its obligations, including safety;

2. Customer feedback by:
   a) Keeping distribution price increases as low as possible;
   b) Maintaining long-term performance for customers experiencing average or better service;
   c) Improve service levels for customers experiencing below average service or who have special reliability needs (e.g. hospitals); and,
   d) Balancing other customer priorities (e.g. customer service) with the need to contain rate increases.

3. Business input by relying on expert analysis and professional judgment to develop construction and operations programs that address technical and operational requirements.

Does this seem like the right approach or the wrong approach?

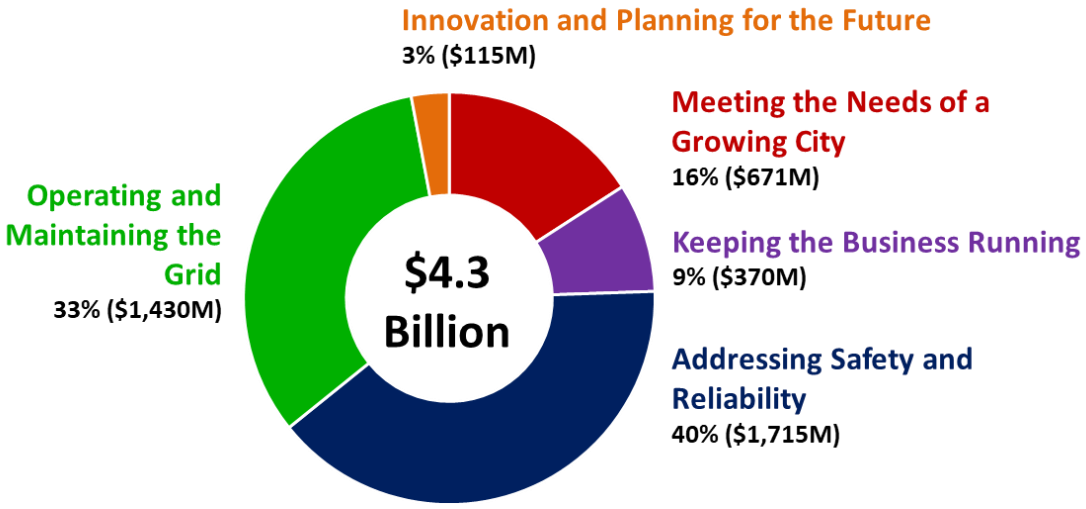
01	Definitely the right approach
02	Probably the right approach
03	Probably the wrong approach
04	Definitely the wrong approach
98	Don't know

G17. And why do you say that? [**OPEN**]

H. INVESTMENT ALTERNATIVES SUMMARY

H18. **Toronto Hydro** has drafted a plan totaling approximately $4.3B over five years. The plan considered Toronto Hydro's legal obligations, engineering expertise and customers' needs and preferences when developing the plan. **There are five key budget categories.**

To learn more about each category, simply hover over the title.



Toronto Hydro's proposed plan focuses on delivering current levels of reliability and customer service for most customers and targeted improvements for customers experiencing below average service or who have special reliability needs, such as hospitals, industrial customers, and financial centres.

<u>This proposed plan could translate into an annual average increase in your distribution rates of between 2.3% and 3.9% from 2020 to 2024.</u>

H19. With regards to Toronto Hydro's proposed plan, which of the following statements best represents your view? [**READ LIST; ROTATE 01 and 03**]

01	Toronto Hydro should improve service even if that means an annual increase that exceeds the proposed plan.
02	Toronto Hydro should stick with the proposed plan to deliver current levels of reliability and customer service for most customers and targeted improvement for customers experiencing below average service or who have special reliability needs.
03	Toronto Hydro should keep increases below the proposed plan, even if that could mean reductions in service.
88	Other [Please specify]
98	Don't know

H20. And why do you say that? [**OPEN**]

I. ENVIRONMENTAL CONTROLS

The survey is almost complete, with only a few general questions about Ontario's electricity system remaining.

For each statement, indicate to what extent you agree or disagree. If you don't know enough to say or don't have an opinion, please indicate below.

01	Strongly agree
02	Somewhat agree
03	Somewhat disagree
04	Strongly disagree
98	Don't know/No opinion

[ROTATE]

I21. The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.

I22. Business customers are well served by the electricity system in Ontario.

[END BATTERY]

I23. Before this survey concludes, do you have any additional comments or feedback you'd like to share with Toronto Hydro?
Note: all feedback is anonymous and you will not be identified to Toronto Hydro without your expressed permission.
[OPEN]

THANK and END SURVEY

Thank you for taking the time to complete this survey.

If you have additional feedback you'd like to share with Toronto Hydro or questions, please feel free to contact your account representative leads:

Commercial | Jen Grado, jgrado@torontohydro.com
Industrial | Dilesh Thurai, dthurai@torontohydro.com
Municipal, Academic, Health | Dean Anderson, danderson@torontohydro.com
Multi-Unit Residential, Social | Mike Mulqueen, mmulqueen@torontohydro.com

OEB Appendix 2-AC
Customer Engagement Activities Summary

Provide a list of customer engagement activities	Provide a list of customer needs and preferences identified through each engagement activity	Actions taken to respond to identified needs and preferences. If no action was taken, explain why.
Planning-Specific Customer Engagement: Phase I - Low Volume Customer Focus Groups - Mid-Market Customer Focus Groups - Low-Volume Customer Needs and Preferences Survey - Key Account Needs and Preferences Survey - Stakeholder In-depth Interviews	Various, including identification and ranking of six key customer priorities. Please refer to: - Exhibit 1B, Tab 3, Schedule 1 - Exhibit 1B, Tab 3, Schedule 1. Appendix A (Innovative Report, Executive Summary and Phase I Appendices)	- Informed the development of the Outcomes Framework - Informed the strategic parametres established for the business plan, which included an upper limit of 3.5% as a cap on the average annual increase to base distribution rates. - Informed the development of the penultimate business plan that was taken back to customers during Phase 2 Customer Engagement. See also: - Exhibit 1B, Tab 2, Schedule 1 - Exhibit 1B, Tab 1, Schedule 1 - Exhibit 2B, Section E2 - Exhibit 4A, Tab 1, Schedule 1
Planning-Specific Customer Engagement: Phase II - Online Customer Feedback Portal ("Workbook") - Residential Telephone Survey - Small Business Telephone Survey - Mid-Market Telephone Survey - Key Account Online Survey	Various, including general support for the business plan and strong support for doing more to address the risk of network vault floods and fires. Please refer to: - Exhibit 1B, Tab 3, Schedule 1 - Exhibit 1B, Tab 3, Schedule 1. Appendix A (Innovative Report, Executive Summary and Phase 2 Appendices)	- Customers generally supported Toronto Hydro's proposed plan. - Minor adjustments to the pace of two capital programs to address the risk of network vault floods and fires that received particularly strong support across customers classes. See also: - Exhibit 2B, Section E2
Ongoing Customer Engagement	Various Please refer to: - Exhibit 1B, Tab 3, Schedule 1 - Exhibit 4A, Tab 2, Schedule 14	- Informs the continuous improvement of Toronto Hydro's customer services - Informs the execution of Toronto Hydro's capital work - Informs the development of Toronto Hydro's capital programs

STAKEHOLDER CONSULTATIONS

1. INTRODUCTION

This schedule discusses the stakeholder consultation sessions held by Toronto Hydro in connection with the development of this Application. These sessions were distinct from the Customer Engagement activities described in Exhibit 1B, Tab 3, Schedule 1.

The Appendix to this schedule is a Toronto Hydro report that includes a list of participants, applicable Terms of Reference, and agendas for the consultation sessions. Participants were invited to provide feedback on the report and none was received.

2. PURPOSE

Toronto Hydro is committed to fostering and maintaining constructive relationships with its stakeholders. The utility actively pursues an open dialogue with relevant parties with a view to facilitating a more effective and efficient regulatory hearing process by:

- Helping to inform Toronto Hydro's analysis and evidence;
- Providing parties with an early view of the form and substance of parts of this Application, as well as Toronto Hydro's plans, to assist their preparation;
- Exploring the potential for consensus among the parties on elements of regulatory procedure and associated timing; and
- Establishing and reinforcing lines of communication to facilitate dialogue during the hearing process without incremental procedural steps.

3. APPROACH

Toronto Hydro held two phases of stakeholder consultation prior to filing the Application. Both phases were conducted on a without-prejudice basis for the purpose of facilitating a constructive and open dialogue among the parties.

Parties that frequently participate in Toronto Hydro's proceedings before the OEB (i.e. participants in EB-2014-0116 and EB-2015-0173), were invited to participate. Parties in attendance for each session are listed in the Appendix to this schedule.

Phase 1 consisted of consultations held with individual participants between April 16 and May 2, 2018. Toronto Hydro circulated Terms of Reference (see the Appendix) in advance of each consultation to outline parameters for the discussion. Toronto Hydro explored with stakeholders topics related to matters of substance and procedure, including principles, facts, concepts, and perspectives relevant to this CIR application. An identical agenda was used for each individual consultation, and is included in the Appendix to this schedule.

Phase 2 was a joint consultation with all participants held on July 16, 2018. The same Terms of Reference for Phase 1 was circulated in advance of Phase 2 consultation. The objective of this session was to maximize the opportunity to build a common understanding in respect of Toronto Hydro's Application prior to the filing. At this session, Toronto Hydro reported back to stakeholders regarding the status and evolution of its Application, including certain structural, methodological, and procedural aspects. The agenda for this session is included in the Appendix to this schedule.

The entire process assisted Toronto Hydro in developing the Application. Toronto Hydro appreciates the time and contributions of those who participated in the stakeholder consultations, and recognizes the value that constructive dialogue brings to the hearing room process.

Toronto Hydro 2020-2024 CIR Stakeholder Consultation Report

This Report describes Toronto Hydro's Stakeholder Consultations held in preparation for its 2020-2024 CIR Application.

Table 1 lists the organizations invited to participate in Toronto Hydro's stakeholder consultation process. Parties were provided Terms of Reference, included in Appendix A, in advance of their participation in the sessions.

Table 1: Participants in Stakeholder Consultations[1]

Invited	**Attended**
AMPCO	Yes
BOMA	No
CCC	Yes
Energy Probe	Yes
SEC	Yes
SIA	No
VECC	Yes

Individual consultations were held with participants between April 16, 2018 and May 2, 2018. The agenda for these sessions is included in Appendix B.

A joint consultation with all participants was held July 16, 2018. The agenda for that session is included in Appendix C.

[1] OEB Staff were invited to, and attended, Toronto Hydro's Phase 2 Consultation on July 16, 2018.

APPENDIX A: Terms of Reference

Stakeholder Consultation: 2020-2024 Custom Incentive Regulation Application Terms of Reference

What is the Purpose of this Document?

This document is intended to set out principles and logistical details relevant to a pre-filing stakeholder consultation regarding Toronto Hydro-Electric System Limited's ("THESL") 2020-2024 Custom Incentive Regulation ("CIR") application.

Why is THESL Engaging in this Consultation?

THESL is committed to fostering and maintaining constructive relationships with its stakeholders and believes that active two-way engagement is critical to achieving this objective.

THESL views this consultation as an opportunity to achieve a number of positive outcomes regarding this regulatory application, including enhanced engagement with customers and other interested/affected parties, contributing to hearing efficiency, and incorporating stakeholder perspective and feedback into its ultimate filing.

THESL expects that this multi-session consultation will provide stakeholders with insight into the utility's business drivers, as well as its approaches and methodologies as they relate to this CIR application. Additionally, THESL believes that it is also important to receive, understand the perspectives, input and feedback of stakeholders and requests the assistance of consultation participants in this regard.

What are the Guiding Principles for this Consultation?

THESL is seeking early and substantive input on its CIR application. While THESL is ultimately responsible for putting forward its application, it believes that constructive dialogue with stakeholders regarding the structure and content of the CIR will lead to a better application and a more effective hearing process.

THESL seeks to create an environment that supports open and candid discussion. This consultation will be carried out on a without-prejudice basis. Information obtained or shared during this consultation will not be used for any other purpose, with the exception of the limited information referenced in the Consultation Report (discussed below). THESL makes this commitment to participating stakeholders and in turn expects participating stakeholders to abide by the same commitment.

Who are the Invited Participants for this Consultation?

This consultation is focused on those stakeholders who are actively involved in THESL's regulatory processes such as intervenors and OEB staff. THESL encourages the attendance and engagement of stakeholders directly, as well as through external legal or consultant representatives.

What is the Format of this Consultation?

THESL plans to host two types of sessions with participants. The first sessions will be one-on-one meetings with participants at THESL's office. Subject to stakeholder feedback, the second session will be a large group session with all participants. These sessions will take place at the THESL office, the OEB office, or another suitably large venue. Brief outlines of each session are set out below. THESL seeks and

encourages live dialogue during the sessions, however will also provide participants an opportunity to provide comments and questions on an ongoing basis until the application is filed.

Session #1: One-on-One Discussions

This is an opportunity to discuss principles, facts, concepts and perspectives relevant to the CIR application. General topics include THESL's business needs/drivers, regulatory concepts and models (as relevant) with a view towards developing potential approaches to THESL's CIR application. THESL anticipates that the one-on-one format will maximize the opportunity to directly engage with our stakeholders.

Session #2: Large Group Discussion (Proposed)

This is an opportunity to report back to participants regarding the status and evolution of the CIR application and discuss certain structural and methodological aspects of the CIR application. THESL anticipates that a large group discussion will maximize the opportunity to build a common understanding of the CIR application prior to the filing.

Additional Consultation Opportunities

THESL seeks to maintain open channels of dialogue and engagement. In addition to the two sessions outlined above, THESL invites participants to approach THESL with any concerns, questions, or other matters relevant to this application.

What Will THESL File with the OEB Regarding this Consultation?

THESL will prepare a Report that may be submitted to the OEB. This report will include these Terms of Reference, identify attendees at each meeting, and include copies of agendas and generic correspondence sent to participants. No notes or characterizations of the actual consultations will form part of the Consultation Report. Stakeholders will be provided an opportunity to review and comment on the Consultation Report prior to its finalization.

How Do Participants Receive Funding for the Consultation?

THESL will fund intervenor participation at the OEB's approved tariff rates, on the basis of one attendee per stakeholder at each meeting. To the extent that stakeholders are of the view that funding for additional participants is required, THESL will address these requests on a case-by-case basis.

Who is the Contact at THESL for this Consultation?

Please direct any questions or concerns of a general nature to:

regulatoryaffairs@torontohydro.com

APPENDIX B: Agenda for Phase 1 Consultation

Toronto Hydro 2020-24 CIR Application

Intervenor Stakeholdering – Without Prejudice

Procedural Questions

1. What is your reflection on proportionate review at this stage? How do you think it should be applied to Toronto Hydro?
2. What is going well / poorly in other applications (procedurally)? What are applicants doing well, and what could they improve on?
3. What types of information would you be most interested in receiving from Toronto Hydro in a larger format pre-filing stakeholder session?
4. How do you think should Toronto Hydro talk to customers about the Ontario Fair Hydro Plan?
5. Are there any other matters of procedure that you'd like to talk to us about?

Content Questions

1. What approach to outcomes should a utility like Toronto Hydro take in their applications (both conceptually and in the evidence)?
2. What is your expectation regarding the role of asset condition in long-term capital planning?
3. Would you like to see anything new/different in utilities' Custom IR rate frameworks/formulas?
4. Are there any other substantive matters that you'd like to talk about?

APPENDIX C: Agenda for Phase 2 Consultation

AGENDA

Toronto Hydro 2020 Custom IR Application
Stakeholder Session

July 16, 2018

14 Carlton Street
THESL Corporate Office

Attendees	OEB Staff Ratepayer and Public Interest Group Intervenors from 2015 CIR Toronto Hydro Staff
Meeting Room	Lawrence Room, 5th Floor
12:30 – 1:00	**Light Lunch**
1:00 – 1:10	**Introductory Remarks**
1:10 – 1:30	**Application Overview**
1:30 – 2:00	**Customer Engagement and Business Planning**
2:00 – 2:30	**Asset Condition Assessment**
2:30 – 2:45	**Break & Refreshments**
2:45 – 3:45	**OM&A and Capital Programs Overview**
3:45 – 4:20	**Proceeding Schedule**
4:20 – 4:30	**Closing Remarks**

Enclosed:
Terms of Reference

CUSTOMER SUMMARY

Attached please find Toronto Hydro's Customer Summary, provided in accordance with Filing Requirement 2.1.3.

Understanding Toronto Hydro's Rate Application







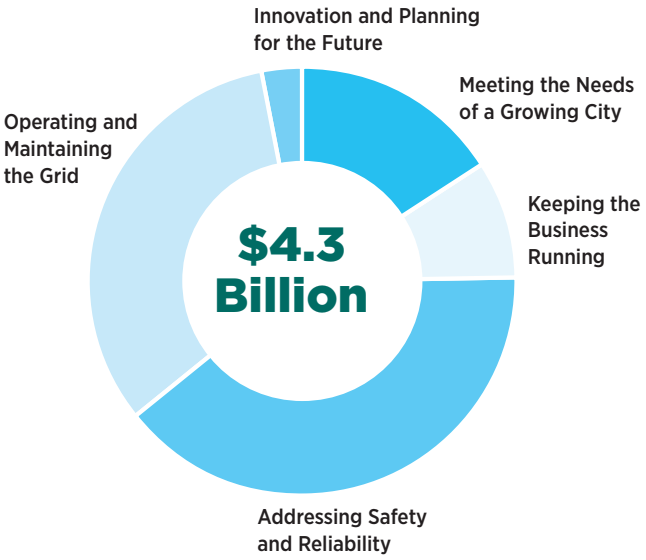

Toronto Hydro's Plan

Toronto Hydro is the electricity distributor that serves the city of Toronto. We're responsible for nearly one fifth of the electricity used in Ontario. We own and operate the poles, wires and other equipment needed to deliver power to homes and businesses.

We're proposing a five-year plan for **2020 to 2024**. The plan meets the needs of a growing city, addresses deteriorating infrastructure, and helps us prepare for more extreme weather and cyber threats.

We're seeking approval for distribution rates from 2020 to 2024 to fund the plan. The Ontario Energy Board and consumer groups will review our plan in a rigorous, transparent public hearing process.

For more on Toronto Hydro's Plan, see Exhibit 1B: Executive Summary and Business Plan



Customer Engagement

Electricity is an important resource in our customers' daily lives. So as we prepared our plan for 2020 to 2024, we asked customers what they thought. They told us price, reliability and safety were their top three priorities, and we developed a plan with those in mind. When we put that plan back to customers, we heard from over **10,000** people and businesses across the city. **71%** of residential customers supported the plan or one that does even more to improve services.

For more on Toronto Hydro's Customer Engagement process, see Exhibit 1B: Customer Engagement

1. Ask Customers what the Plan's Priorities should be.
2. Use Customer Priorities to prepare the Plan.
3. Ask Customers about the Plan.
4. Use Customer Feedback to finalize the Plan.
5. Submit the Plan to the Ontario Energy Board.

Costs of the Plan: Average Annual Rate Increase of 1.7%

Funding the plan requires increases to monthly distribution rates. For a residential customer who uses 750 kWh per month, distribution rates would increase by an average of **$0.77 (1.7%)** per month, annually from 2020 to 2024. This includes a decrease of $2.32 in 2020, the first year of the plan.

Bill Impact

	Usage [kWh]	Change in bill	2020 Proposed	2021 Proposed	2022 Proposed	2023 Proposed	2024 Proposed	Average ($)
Residential (typical)	650	$/30 days	-1.77	1.37	1.07	1.89	1.83	$0.88
		%	-4.1%	3.3%	2.5%	4.3%	4.0%	
Residential (750 kW)	750	$/30 days	-2.32	1.37	1.07	1.89	1.83	$0.77
		%	-5.3%	3.3%	2.5%	4.3%	4.0%	
General Service <50 kW (typical)	2,800	$/30 days	-5.91	4.35	3.38	5.97	5.78	$2.71
		%	-4.4%	3.3%	2.5%	4.3%	4.0%	

Toronto Hydro's Performance








Outcomes and Performance Measurement

Customers want to know that Toronto Hydro's 2020 to 2024 performance will provide them with value for money. We're proposing to report on **44** performance measures that will track how well we're doing.

For more on Toronto Hydro's Performance, See Exhibit 1B: Outcomes and Performance

Toronto Hydro Outcome	OEB Reporting Category	Performance Measures
Customer Service	Service Quality	9
	Customer Satisfaction	5
Safety	Safety	7
Reliability	System Reliability	6
	Asset Management	4
Financial	Cost Control	5
	Financial Ratios	3
Public Policy	Conservation and Demand Management	1
	Connecting Renewable Generation	2
Environment	Environment	2
Total Performance Measures		**44**

Past Performance and Continuous Improvement

Our previous plans are working and our performance is improving.

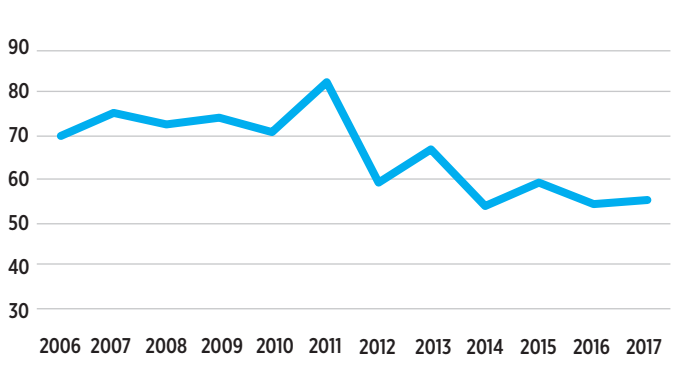
We're getting faster at connecting new customers. And we're exceeding industry standards for meeting scheduled appointments, answering calls on time and providing accurate bills.

We're also making the grid more reliable. Outages that aren't related to major events, like wind and ice storms, are becoming shorter and less frequent.

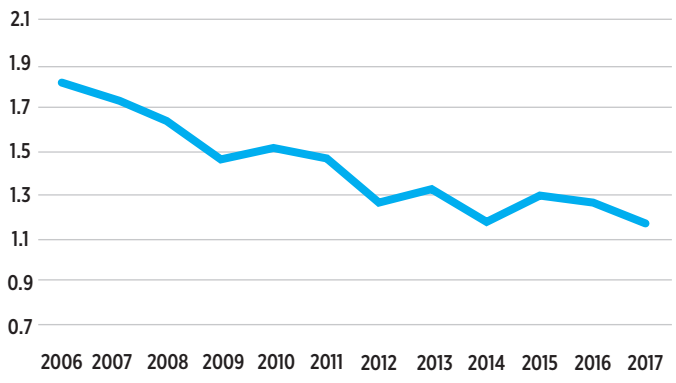
Performance Categories	Measures	2013	2014	2015	2016	2017	Industry
Service Quality	New Residential/Small Business Services Connected on Time	94.2%	91.5%	96.9%	97.7%	**98.3%**	90.0%
	Scheduled Appointments Met On Time	99.6%	99.8%	99.9%	99.5%	**99.4%**	90.0%
	Telephone Calls Answered On Time	82.0%	71.9%	76.8%	64.7%	**77.9%**	65.0%
Customer Satisfaction	Billing Accuracy	–	96.6%	97.5%	98.8%	**99.2%**	98.0%

System Reliability

Duration of Outages (minutes per year)*



Frequency of Outages (number per year)*



*Excludes Loss of Supply from Hydro One and Major Event Days

COMMUNITY MEETINGS

This schedule provides information in relation to the OEB-hosted community meetings described in the Filing Requirements.

Toronto Hydro proposes four community meetings. Toronto Hydro recommends one community meeting in each of Scarborough, North York, Etobicoke, and downtown in order to reflect the geographic diversity of the service area. Toronto Hydro further recommends that one of the community meetings be webcast.

There are many suitable locations in Toronto for these community meetings, including civic/community centres, schools, and libraries. Many of these locations are in close proximity to public transit. Toronto Hydro intends to work with the OEB to finalize locations, dates, and times for the community meetings, and to issue such bill inserts and such other advertising as may be stipulated by the OEB.

LETTERS OF COMMENT RESPONSES

Pursuant to section 2.1.7 of the OEB's Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications (July 12, 2018), Toronto Hydro provides in this schedule responses to all public letters of comment currently on the record. The utility will further update this section with any additional letters received and replies provided prior to the argument phase of the proceeding.

Toronto Hydro notes that a number of the letters of comment received to date were submitted either before or after the community meetings for this application, which were held from November 22 through December 6, 2018. Toronto Hydro did not have access to the list of attendees for those meetings, and unless they have self-identified as a community meeting attendee, it is not possible for Toronto Hydro to identify which of these individuals attended the community meetings, and may or may not be responding to what they heard from the utility, the OEB, or others at the community meetings. For that reason, unless the commenter has self-identified as a community meeting attendee, Toronto Hydro has responded to each letter assuming that the writers were not in attendance at the community meetings. Toronto Hydro apologizes to the authors of the letters if it is repeating something that they may have already heard from the utility or others during the community meetings, and encourages any and all customers to contact Toronto Hydro at any time should they have questions, comments or concerns via https://www.torontohydro.com/sites/electricsystem/Pages/ContactUs.aspx .

Please also see the process and results for Toronto Hydro's customer engagement activities, including those related to this application, in Exhibit 1B, Tab 2, Schedule 1.

Letter of Comment: Dean Lancaster: October 4, 2018

I do not believe Toronto Hydro has sufficiently informed the public on why rates are increasing. Rates should be decreasing assuming Toronto Hydro is operating in the interest of the people of Toronto, and any rate increase should be carefully considered along with supporting data to provide evidence as to the reasoning behind rate increases. Toronto Hydro should be requested to justify it's rates vs. other similar jurisdictions with a similar power distribution model (i.e. benchmarking against other Hydro-power majority source providers) along with exploring any opportunities for cost reduction through modernization etc. I believe careful regulation and transparent accounting practices are vital to ensuring a "good deal" for the people of Ontario within our current energy operating model - and with today's data-driven accounting platforms, this should be very easy to implement whilst balancing regulatory burden on Toronto Hydro.

Toronto Hydro Reply

Dear Mr. Lancaster,

Thank you for your letter of comment. Toronto Hydro recognizes your frustration in lacking access to information about how we have informed the public on why rates are increasing, and your interest in us supporting the proposed increase with data and evidence.

Toronto Hydro has taken a number of steps to not only inform, but also engage the public about the amount of the proposed rate increase, and why we believe this plan achieves the appropriate balance between factors such as price, safety, reliability, and service. In addition to our ongoing customer engagement activities, as part of developing our plan and having that plan tested by the Ontario Energy Board in an open

public process, Toronto Hydro heard from over 10,000 customers, through channels that include:

- Phase 1 customer engagement (2016/17): we asked for input and feedback from customers about their needs, priorities and outcomes they value – we used the results to help develop our business plan.
- Phase 2 customer engagement (2018): before we filed our business plan with the Ontario Energy Board, we went back to customers to confirm that we correctly understood their input from phase 1, and then asked for additional customer input and feedback on the plan itself (including costs of the plan). Approximately 2/3 of customers supported Toronto Hydro's plan, or one that does even more to improve services.
- Community Meetings (2018): after we filed our business plan with the Ontario Energy Board, we attended six community meetings between November 22 and December 6, 2018 to make a presentation on our plan (including the costs), receive feedback from customers and others in attendance, and answer questions.

Toronto Hydro's costs take up approximately one third of the average residential customer's bill. As a result of Toronto Hydro's five year plan for 2020-2024, a typical residential customer can expect an average annual increase of 1.7% on the Delivery line of the bill, and less than half of one percent on the total electricity bill. We have supported our request for this increase with approximately 4,300 pages of data and evidence filed with the Ontario Energy Board, including many details about our accounting assumptions and practices.

Toronto Hydro believes that the proposed rate increase is necessary to keep the lights on, maintain a grid that provides a safe source of electricity, and ensure that we are a steward of long-term service and value for our customers. Factors driving this rate increase include deteriorating infrastructure, a growing city, more extreme weather, workforce retirements and renewal, and technology advancements including protecting against cyber threats.

We're always looking for ways to minimize cost and rate increases through finding productivity and efficiencies in our plans and work. For example, as part of reducing our facilities footprint in Toronto, we consolidated from 7 operating centers down into 4. As part of this consolidation, we sold properties, and are returning proceeds of close to $140M to customers to help reduce bills.

As part of our business plan, Toronto Hydro asked external experts to assess our performance, including benchmarking with respect to productivity, reliability, and unit/cost efficiency. The results of those studies (which are publicly filed with our plan) demonstrate that Toronto Hydro's performance is similar or better than peer utilities.

Finally, Toronto Hydro took what it heard from customers about their priorities, and used this to create a customer-focused outcomes framework to measure its performance during the plan. As part of this plan, we propose to publicly report annually on how we're performing against over 40 unique measures that relate to our goals and objectives – measures such as how frequently you lose power, and when you do lose power, how long it takes us to get it back on.

If you are interested in learning more about Toronto Hydro's proposed plan, the executive summary of Toronto Hydro's application to the Ontario Energy Board may be a helpful document to begin with, and is available at Exhibit 1B, Tab 1, Schedule 1.

Letter of Comment: Lilly McIsaac: November 20, 2018

I object to rate changes and believe that ratepayers deserve to have more options regarding electricity use and billing. As a homeowner, I do not require a smart meter to tell me when to use my electricity and I never consented to time of use rates or to having a smart meter (RF) emitting device installed on my property. I have developed a disability called microwave sickness which prevents me from being in areas where there are wireless and radio frequencies. It has gotten to the point where I cannot even live comfortably in my own home because I have: headaches (particularly tension headaches along the sides of the head and temple area, heart palpitations and a pressure in the chest (a feeling that the heart wants to jump out of the chest while at the same time the chest is being stepped upon), skin burning, redness, rashes and tingling (particularly on the face and arms), difficulties sleeping (sleep is interrupted, light, dreamless and leaves the person feeling tired in the morning), Tinnitus (ringing in the ears), fatigue and tiredness during the day (even after many hours of sleep, tiredness pervades the day), and cognitive decline (memory and concentration difficulties – a "brain fog". All of these symptoms either disappear or get better when I am in an environment without wireless and radio frequencies, but they return when I am home. People who have symptoms form microwave radiation exposure need accommodation and the ability to opt out of the smart meter / time of use billing without additional costs to do so. I would like Toronto Hydro to offer an opt out for people with disabilities due to radio frequency and microwave (EMF) exposure such as myself. We deserve to live in a safe home without being penalized for asking that the meter be an analogue meter and one which

does not emit harmful emissions. The public has net seen any benefits to having a smart meter and in fact, the smart meter program increased costs for consumers, yet no one has seen any benefit, except for the electricity providers who saved on the cost of employing meter readers. That savings has not been passed on to consumers, not have consumers seen a decrease in electricity bills due to having a smart meter. Our smart mete r is "on" all of the time - even when we turn off our electricity inside our home. The signals wake us up every hour at night and prevents us from getting proper sleep. We have tracked this and it happens at approximately the same time every night. We would like the OMB to change the billing to allow for an opt out of the smart meter program and not agree to more rate increases. Thank you.

Toronto Hydro Reply

Dear Ms. McIsaac,

Thank you for your letter of comment. Toronto Hydro is sorry to hear about your experience, which we understand must be difficult.

Toronto Hydro uses a smart meter system that uses wireless technology to deliver the data from each meter to our billing system. Each smart meter has a low power transmitter that communicates with a device known as a gatekeeper, which in turn delivers the meter reading data to our billing system.

Toronto Hydro's customers have identified safe operation of the distribution system as one of their top three priorities. Toronto Hydro will only install smart meter models that have been extensively tested by the manufacturer and clearly demonstrate Radio Frequency ("RF") emissions that are below the City of Toronto precautionary recommendations and the Health Canada Safety Code 6 guideline.

These meters are valuable tools in maintaining the safety and reliability of the grid, as they assist distributors in identifying outages, including during major weather events.

Toronto Hydro is not able to offer you the ability to opt-out of Time of Use rates or using a smart meter, as they are required by provincial law and regulation. Although Toronto Hydro is able install a non-RF transmitting smart meter equipped with a regular telephone connection for you. There is however a cost associated with the installation of the telephone connection and its monthly operation, currently $201.77 and $23.13/month respectively.

Regarding rate increases and our plan to invest in the grid, you may also be interested in our reply to Mr. Lancaster's letter of October 4, 2018.

Letter of Comment: Beverly Brooks: November 22, 2018

This session was extremely disappointing. Neither the OEB or Toronto Hydro has any answers to questions. The first gentleman who gave a presentation had some excellent questions – the same questions that he had in a previous occasion. No answers were provided and he commented that he had never received answers to his previous questions. I strongly oppose the rate increases – nothing I heard tonight justifies the increases.

Toronto Hydro Reply

Dear Ms. Brooks,

Thank you for your letter of comment. Toronto Hydro is sorry that you were disappointed with the community meeting presentations and responses to questions by OEB and Toronto Hydro staff. Recognizing the value of your time, if you have any

specific feedback on how we in particular can do better, we would appreciate receiving that.

Regarding the gentleman who provided the presentation and asked questions, we believe you are speaking about Mr. Hann. We did not have the information readily available to answer those questions at the community meeting, and even if we had, providing the answers would have taken a number of hours and eliminated the time for other customers to provide their feedback and ask questions at the meeting. As you may recall, during the community meeting, we committed to providing written answers to Mr. Hann's questions on the public record as part of our application process before the Ontario Energy Board. As the OEB has since granted Mr. Hann intervenor status in this proceeding, he has now filed those and other questions in writing and Toronto Hydro is responding to them as part of the public record at the same time as filing this reply to your letter of comment.

Regarding rate increases and our plan to invest in the grid, you may also be interested in our reply to Mr. Lancaster's letter of October 4, 2018.

<u>Letter of Comment: Christine Douglas: November 22, 2018</u>

Please see the attached. I prepared a chart which is attached. The charges are in addition to my usage. As a single individual I am paying as much as a neighbour who is using hydro electricity – air conditioner, washer dryer, heat & I am paying as much as she and her family of 4 people.

Attachment:

Toronto Hydro Charges

DATE	DAYS	USAGE	CHARGES
MAY 9/11	40	49.06	53.46
MAR 4/13	63	93.76	91.61
MAY 2/13	61	91.56	88.66
SEPT 11/13	99	95.13	137.99
OCT 30.13	62	82.92	91.17
DEC 31/13	60	83.41	87.86
TOTAL:	**385**	**495.84**	**550.75**

FEB 28/14	63	95.16	96.81
MAY 1/14	60	90.33	91.41
JUL 18/14	60	87.19	89.92
AUG 29/14	62	98.07	97.77
OCT 30/14	60	88.13	89.58
DEC 31/14	60	117.335	74.32
TOTAL:	**365**	**576.215**	**539.81**

MAR 2/15	63	106.22	100.95
MAY 1/15	62	97.88	95.45
JUN 30.15	58	87.9	81.36
AUG 31/15	62	101.35	91.5
OCT 28/15	58	92.42	83.82
DEC 30/15	61	98.83	87.28
TOTAL:	**364**	**584.6**	**540.36**

FEB 26/16	62	109.43	105.04
APR 29/16	63	108.83	122.37
JUN 28/16	58	103.05	115.15
AUG 29/16	62	147.09	148.97
SEPT 29/16	31	75.63	71.85
OCT 28/16	31	48.04	57.24
NOV 29/16	30	50.77	57.3
DEC 30/16	29	50.46	56.79
TOTAL	**366**	**693.3**	**734.71**

JAN 30.17	33	57.89	59.13
FEB 28/17	29	52.85	50.45
MAR 28/17	28	53.46	49.64
MAY 1/17	34	60.59	58.76
MAY 29.17	28	44.05	47.15
JUN 28/17	30	44.04	49.16
JUL 28/17	32	41.42	51.54
SEPT 28/17	30	37.92	48.21
OCT 30.17	32	39.08	50.5
NOV 28/17	29	38.79	47.5
TOTAL	**305**	**470.09**	**512.04**

DATE	DAYS	USAGE	CHARGES
JAN 2/18	30	40.37	49.03
JAN 30.18	33	47.73	59.15
FEB 27.18	28	40.44	50.45
MAR 28/18	29	42.17	52.11
APR 27/18	32	48.56	58.05
MAY 31/18	32	48.56	58.05
JUN 28/18	28	40.45	50.01
JUL28/18	32	45.97	50.01
AUG 29/18	30	42.81	53.4
OCT 1.18	33	44.21	57.66
OCT 29.18	28	38.75	49.34
TOTAL	**335**	**480.02**	**587.26**

Toronto Hydro Reply

Dear Ms. Douglas,

Thank you for your letter of comment. Toronto Hydro apologizes that you are finding it difficult to understand your charges compared with those of a neighbour, and we recognize that it is complicated to do so. As you may know, the methodology and presentation of the electricity bill in Ontario is largely set by provincial law and

regulation, and there are a lot of complex charges and credits that go into your bill each month.

Thank you for preparing a table setting out your charges over several years, however without additional information about your and your neighbour's households, plus her consent for privacy purposes, we cannot give you a precise explanation of what is happening with your bill versus hers. Nevertheless, Toronto Hydro's experience is that there are a few common drivers for questions such as yours, relating to the different types of charges on the bill.

The Delivery Line:

Your column labelled charges represents the delivery line on the bill, which represents the cost of getting power from generators to your home, and ensuring electricity is available when you need it. The delivery line is made up of a number of costs (some ours and some related to others), such as:

- Toronto Hydro costs: this is your distribution charge, which is invested into the local distribution grid to maintain safety and reliability of our infrastructure, help support a growing city, and enable us to plan for and respond to extreme weather. This part of your bill may also include certain credits or charges related to temporary, unpredictable, or deferred costs for delivering electricity and services to customers.

- Non-Toronto Hydro costs:
    - Transmission rates which we collect on behalf of companies such as Hydro One
    - Pass-through charges in the form of rate riders that credit customers or collect from customers historic over-charges or under-charges on parts of

the bill related to transmission, generation and other commodity costs, and other provincially-administered charges.

Your Overall Bill

Provincial and OEB law and regulation mean that your delivery line and overall bill is partially based on your overall consumption. This means it includes both charges that do change depending on how much electricity you use (called variable charges) and those which don't change depending how much electricity you use (called fixed charges). The fixed portion of the charge helps cover the costs of the poles and wires that are
available 24/7 to deliver electricity to your home, on demand. Because of this, changes in the amount you pay on your delivery line often do not move by the same amount, or even in the same direction, as changes in how much electricity you use (called kilowatt hours or kWh).

Some of the common factors you may wish to consider in addition to those mentioned in your letter that influence the amount of energy usage and contribute to differences in charges between households include:

- Size and type of home
- Upgraded insulation or windows
- Heating and cooling factors such as gas or electric heating or air conditioning systems, baseboard or portable heaters, thermostat settings, heated floors, heated driveways, pool pumps, etc.
- Gas or electric water heating

Types and frequency of appliances in use, and their energy efficiency ratings.

We hope this information provides some additional insight into what may be driving the difference in charges. For further background on rates, please visit Toronto Hydro's website at www.torontohydro.com/rates, or for additional tips on managing energy usage, please visit http://www.torontohydro.com/saveonenergy.

Letter of Comment: Weston Trott: November 22, 2018

More transparency on Rates – How are distribution rates calculated? Show fixed and variable cost on the bill – Bill is not transparent.

Is the system working to allow utilities to ask and the reduce after the ask? It seems it does not work to have the utilities ask for the sky why not keep them honest from the beginning? The stats for reducing by 38% shows it does not work the current ask system.

Toronto Hydro Reply

Dear. Mr. Trott,

Thank you for your letter of comment. Toronto Hydro recognizes that the bill is complicated, and that you are frustrated by the way that the charges are calculated. As you may know, the methodology and presentation of the electricity bill in Ontario is largely set by provincial law and regulation, and there are a lot of complex charges and credits that go into your bill each month.

On the Toronto Hydro website we try to break down the bill and explain it as best as we can:
http://www.torontohydro.com/sites/electricsystem/residential/yourbilloverview/Pages/BillFormat.aspx.

Please see our reply to Ms. Douglas' letter of November 22, 2018 for your questions regarding distribution rates and the way charges are calculated.

Regarding your interest in how our plan has been developed and how the OEB will test it and ensure it strikes the right balance, we have supported our plan with 4,300 pages of evidence and data, and that plan is now before the regulator in a public process where the OEB, customer advocacy groups and other experts are scrutinizing and challenging it. Please also see our reply to Mr. Lancaster's letter of October 4, 2018.

Letter of Comment: An Ge: November 26, 2018

I'm very concerned and confused about your Delivery Charge. Delivery Charge should not be a fixed rate. It should be determined by the actual usage. The higher usage, the higher the delivery charge; the lower usage, the lower the delivery charge should be. Not on some fixed nonsense charge, IF someone is away from home for, say 6 mnths, barely have usage on the energy, only incure fixed cost of delivery charge. So re-define the delivery charge.

Toronto Hydro Reply

Dear Mr. Ge,

Thank you for your letter of comment. Toronto Hydro recognizes that the bill is complicated, and that you are frustrated by the fixed charges in the Delivery line. Provincial and OEB law, regulation and methodology for charges mean that your delivery line and overall bill is partially based on your overall consumption and partially based on fixed charges. This means it includes both charges that do change depending on how much electricity you use (called variable charges) and those which don't change depending how much electricity you use (called fixed charges). The fixed portion of the

charge helps cover the costs of the poles and wires that are available 24/7 to deliver electricity to your home, on demand.

Please see our reply to Ms. Douglas' letter of November 22, 2018 regarding the specific concerns that you raise in your letter regarding the delivery charge.

Letter of Comment: Caleb Kouahou: November 26, 2018

I'm concerned by the transmission poles (high tension) crossing residential area (like South Etobicoke) with risk of cancer.
Also the risk related to 50+ old nuclear plant and the safety gap for example populations not sensibilised or distributed the RADBLOCK pills.

Toronto Hydro Reply

Dear Mr. Kouahou,
Thank you for your letter. Toronto Hydro is the local distributor of electricity in Toronto, and owns and operates the poles and wires that bring electricity to your home. The transmission lines and nuclear plants are owned and operated by others such as Hydro One and Ontario Power Generation.

For more information about your local grid and our plan to invest it in, please see our reply to Mr. Lancaster's letter of October 4, 2018.

Letter of Comment: Sijing Liu: November 26, 2018

The Delivery Charge on a typical Residential Bill should NOT be set as a fixed rate. It should be billed based on the actual usage of energy. It's not fair to set delivery charge

a set rate. We use only <$20 energy bill, but our delivery charge is always around >$35. Is this Normal for a typical bill?
Anyways, delivery charge needs restructured however it's determined.

Toronto Hydro Reply

Dear Ms. Liu,

Thank you for your letter of comment. Toronto Hydro recognizes that the bill is complicated, and that you are frustrated by the fixed charges in the Delivery line. Provincial and OEB law, regulation and methodology for charges mean that your delivery line and overall bill is partially based on your overall consumption and partially based on fixed charges. This means it includes both charges that do change depending on how much electricity you use (called variable charges) and those which don't change depending how much electricity you use (called fixed charges). The fixed portion of the charge helps cover the costs of the poles and wires that are available 24/7 to deliver electricity to your home, on demand.

Please see our reply to Ms. Douglas' letter of November 22, 2018 regarding your comments regarding delivery charges. For more information about your local grid and our plan to invest it in, please see our reply to Mr. Lancaster's letter of October 4, 2018.

Letter of Comment: Slobodan and Dobrila Vujnovic: November 26, 2018

I participated in TIME OF USE for many years being probably among the first to apply. Now my husband Slobodan age 86 and myself Dobrila age 83 are not able to adjust our use no more It puts in need to use electricity when it is the most expensive increasing our financial burden as well as time of use schedule loosing any purpose. We are not

only old but old timers as well and know and participate in all possible means to save electricity not only for people of Ontario but for our own budget.
Please assist.

Toronto Hydro Reply

Dear Mr. and Mrs. Vujnovic,

Thank you for your letter of comment. While Toronto Hydro recognizes that not all customers favour Time of Use rates, Toronto Hydro is required by provincial law and regulation to bill customers in accordance with that pricing structure. To help customers better manage their energy costs, please visit Toronto Hydro's website for additional information and tips.
http://www.torontohydro.com/saveonenergy

Please see our reply to Ms. Douglas' letter of November 22, 2018 regarding delivery charges. For more information about your local grid and our plan to invest it in, please see our reply to Mr. Lancaster's letter of October 4, 2018.

Letter of Comment: Bill Gaw: November 29, 2018

Thank you for the opportunity to hear about and question Toronto Hydro's Rate Application for 2020-2024 at the Scarborough Civic Centre Community Meeting on November 26.

I have no issue with the proposed cost recovery rates, but I notice a couple of elements in the application that seem odd and might bear close examination by the Board. "approximately a quarter of the utility's asset base continues to operate beyond useful life..." and "continued investment is required to ensure there is no deterioration in

recently stabilized system performance" do not suggest a strong plan to eliminate the "beyond" part, but simply to maintain the current level of stuff "past their useful life" and accept whatever level of outages that implies.

I think it would be more appropriate to declare an ambition to reduce the "population of assets beyond their useful life" to less than 1% by 2024, and plan to drive it down from that level going forward until we bump into the structural minimum.
In section D 3.1.2 Asset Replacement Policy, "Toronto Hydro does not have a dedicated proactive renewal strategy for overhead conductors. Where appropriate conductors are replaced as part of a planned area rebuild or reactively upon failure due to age..."
Given the illustrated property damage, and potential personal injury risk due to "porcelain pothead failure" plus the know-how to replace "legacy porcelain insulators with new polymeric equivalents", a "dedicated proactive renewal strategy" could be a good thing - perhaps it would even reduce the maintenance expense of "washing the porcelain insulators every six months."

Similarly, if we recognize "below ground rotted poles" and "car accidents" as known risks of catastrophic pole failures, replacement of old wooden poles with new wooden poles rather than composite, concrete, or steel poles, and leaving the new poles unprotected by concrete-steel guard posts, are questionable practices. Those new wooden poles are subject to Toronto's belligerent woodpeckers, unnecessarily reduce our forest carbon absorption somewhere in Canada, and maintain a continuing risk of pole fires.

I did not see a compelling justification for choosing wooden poles going forward.

The argument that "removed assets are typically refurbished and kept as spares due to the scarcity of these obsolete asset types" seems seriously dubious. It might make at least as much sense to chuck the obsolete stuff and invest the savings from refurbishment expenses into fixing the next repair with current standard equipment. That might also conveniently drive down the inventory of obsolete assets that will need continued investment in the future.

Toronto Hydro Reply

Dear Mr. Gaw,

Thank you for your letter, and for your support of the proposed rate increase. We acknowledge your preference for a plan that would:

- do more to reduce the population of assets beyond useful life to less than 1% by 2024 (compared with Toronto Hydro's current age profile at approximately a quarter of assets past end of useful life);
- eliminate the practice of using refurbished assets removed from service for spare parts and instead redirect the expenses of refurbishment (and inventory) to additional investment;
- create a dedicated proactive renewal strategy for areas such as overhead conductors (e.g. porcelain insulators); and
- eliminate wooden poles as a replacement option.

Toronto Hydro has developed and refined its plan taking into account customer feedback that limiting price increases was a paramount concern, to the degree that doing so would not adversely affect service performance, and that performance would improve in certain areas. This means that our plan does not include all the reasonable funding requests that it assesses are appropriate given the needs of the system. We

constrained our capital plan, even though a higher level is preferable from an asset management perspective to better manage certain elevated asset risks.

For more information about your local grid and our plan to invest it in, please see our reply to Mr. Lancaster's letter of October 4, 2018.

Letter of Comment: Bruce Bryden: December 4, 2018

Allow me to get all the information on my bill as on my Micro fit Meter Credit, and not have to use a computer to gain this information.

Toronto Hydro Reply

Dear Mr. Bryden,

Thank you for your letter of comment. Toronto Hydro recognizes that the bill is complicated, and that you are frustrated by the way that the information is presented. As you may know, the methodology and presentation of the electricity bill in Ontario is largely set by provincial law and regulation, and there are a lot of complex charges and credits that go into your bill each month. As a MicroFIT customer, we appreciate that you may want additional billing information and as you may be aware, MicroFIT generation detail is available on Toronto Hydro's PowerLens web portal. Accessing the portal may be an added step, however, it does provide a wealth of account specific information useful for validating your charges and managing your electricity usage. To reduce this effort, we are planning an enhancement that will enable customers to enroll in auto receipt of regular emails providing information specific to their needs.

For more information about your local grid and our plan to invest it in, please see our reply to Mr. Lancaster's letter of October 4, 2018.

Letter of Comment: Joe Gudinskas: December 4, 2018

In the light of how Hydro is going wild, these meetings are very useful.

Toronto Hydro Reply

Dear Mr. Gudinskas,

Thank you for your letter, and we appreciate that you found the community meeting useful.

For more information about your local grid and our plan to invest it in, please see our reply to Mr. Lancaster's letter of October 4, 2018.

Letter of Comment: Josephine Ng: December 4, 2018

The changes I experienced are fine

1. Monthly bills
2. Summer deals

etc.

I did climate change research for a project and I knew nothing about the OEB. By coming to this meeting I can clearify the things that matter. I feel better about consuming electricity and conserving energy. I'm a new Toronto Hydro customer, but it was really important to make me be at the meeting. I feel appreciated to be someone that was here. So all I can think about now is that I pay hydro and get it at home and that's great! Thank you.

Toronto Hydro Reply

Dear Ms. Ng,

Thank you for your letter, and we appreciate that you found the community meeting to be a positive experience, and that your experience with your bill, conservation, and incentives has also been positive.

For more information about your local grid and our plan to invest it in, please see our reply to Mr. Lancaster's letter of October 4, 2018.

Letter of Comment: Paul Stuewe: December 4, 2018

The proposed changes will have no impact on my family. However, I am very concerned about how people on fixed incomes, and people who are just getting by, will be affected. I hoped that this would be addressed during this meeting; it was certainly raised, but I wasn't impressed by the somewhat vague response of the OEB chairman.

Toronto Hydro Reply

Dear Mr. Stuewe,

Thank you for your letter and your interest in help for those needing assistance paying their bills. A number of assistance programs are available with different types of support ranging from helping customers reduce their electricity usage to on-bill credits to help offset monthly charges. The following are programs available for eligible customers:

- The Independent Electricity System Operator's Home Assistance Program provides energy-efficient upgrades from free light bulbs to appliances;
- The Ontario Energy Board's Low-Income Energy Assistance Program (LEAP) provides a one-time emergency grant to help pay your electricity bill;

- The Ontario Energy Board's Ontario Electricity Support Program (OESP) provides an on-bill credit each month to qualifying households. In 2017, this program was expanded to include more eligible households, and;
- The provincial Affordability Fund provides free upgrades to help lower electricity costs.

Toronto Hydro uses a number of communication channels to make customers aware of these programs. Additional information is available at www.torontohydro.com/help or through the Customer Care team at 416-542-8000.

Letter of Comment: Greg Pimento: December 10, 2018

I attended the public meeting in Etobicoke on Dec 6th and would like to go on record as not supporting Toronto Hydro's application for a rate increase.

When compared against our natural gas supplier Toronto Hydro does not do well. This is from both a cost and level of service perspective. Both services are regulated but the differences in their structures make for the differences we've experienced as consumers, to my judgement. I pick natural gas over hydro every time.

Given the growth in Toronto I do not understand the need for the increased rate, unless the existing rate payers are subsidizing the capital costs of new connections. I also find the inflexibility with the acceptance of micro-grids bothersome and poorly justified by Toronto Hydro.

I know it is not under Toronto Hydro's or the OEB's control but I want to also go on record that the level of Global Adjustment is totally unacceptable. Incremental power production rates are close to 3 cents whereas the GA is three time that amount. Poorly

managed is the only conclusion I can determine.

I would be interested in helping in any way feasible knowing that the task at hand is massive at best.

Thanks for the opportunity to attend and see the presentations.

Best Regards,
Greg Pimento

Toronto Hydro Reply

Dear Mr. Pimento,
Thank you for your letter, and we appreciate that you found the community meeting to be a positive experience.

With respect to your concern about the differences in electricity and natural gas pricing, there are significant differences between the costs of generation and distribution of these fuel types, which leads to differences between costs, prices and services. For more information about the drivers of Toronto Hydro's costs, our plan to invest in the grid, and our performance and efforts to mitigate your rate increases, please see our reply to Mr. Lancaster's letter of October 4, 2018.

Regarding your questions about whether ratepayers are subsidizing developers and new customers, the Ontario Energy Board has regulations designed so that each type of customer pays their own way and cross-subsidization is avoided. This includes calculations around capital costs and a complete economic evaluation designed to

ensure developers pay their fair share. Toronto Hydro has a responsibility to connect customers to the grid and make sure enough capacity exists so that those new customers can receive a safe and reliable source of power.

Regarding your comments about the unacceptability of the global adjustment, we appreciate your recognition that this is not included in our part of the bill and we do not control it.

RATE FRAMEWORK

This schedule describes Toronto Hydro's rate framework for the 2020 to 2024 plan period. The utility's proposed rate framework continues the rate framework approved by the OEB in Toronto Hydro's 2015-2019 Rate Application.[1] The framework is aligned with OEB policy, and based on sound ratemaking principles. It has been structured in a way that includes productivity gains as part of the rate adjustment mechanism, constrains operational funding increases going forward at less than the rate of inflation, and reconciles a price-cap formula with funding requirements to address Toronto Hydro's significant, multi-year investment needs over the 2020 to 2024 period.

1. SUMMARY

Toronto Hydro's rate framework is a modification of the standard Fourth Generation Incentive Rate-Setting ("4th Generation IR") IR approach. The framework is comprehensive, covers the entirety of the application's term, and is informed by Toronto Hydro's forecasts. It is also informed by the OEB's current inflation and productivity analysis, and is aligned with Toronto Hydro's third party benchmarking of Toronto Hydro's costs. As noted, the framework is a continuation of the framework approved by the OEB in the utility's 2015-2019 Rate Application. As explained below, this includes the modifications required by the OEB in its 2015 decision, as related to the application of the stretch factor to capital and the inclusion of a growth variable to capture changes in revenue occurring due to changes in customers and loads.[2]
Year 1 is a traditional rebasing year, with costs allocated and rates set on the basis of a forecast Test Year.

[1] EB-2014-0116 Decision and Order (December 29, 2015).
[2] Ibid.

Distribution rates in Years 2 through 5 are adjusted annually by a Custom Price Cap Index ("CPCI"), as follows:

CPCI = I – X + C - g

Where,

- "**I**" is the OEB's inflation factor, determined annually;
- "**X**" is the sum of:
    - The OEB's productivity factor, as of the date of filing; and
    - Toronto Hydro's custom stretch factor;
- "**C**" provides funds incremental to "I – X" that are necessary to reconcile Toronto Hydro's capital need within a PCI framework;
- "**g**" captures revenue growth occurring due to customer and/or load changes over the forecast period, based on Toronto Hydro's forecast of loads and customers for the 2021-2024 period;

2. YEAR 1: STANDARD REBASING

The first year of the proposed rate application is a standard rebasing year, consistent with the OEB's 4th Generation IR approach. Toronto Hydro developed and has submitted in this application a forecast of its base revenue requirement for 2020. The utility developed forecasts of its costs based on its capital and operational plans for 2020. The Distribution System Plan ("DSP") and Operations, Maintenance, and Administration ("OM&A") evidence contained in Exhibits 2B and 4A, respectively, provides the details supporting these projected costs. The calculated revenue requirement resulting from these projections is detailed in the Revenue Requirement evidence filed at Exhibit 6, Tab 1.

Similarly, Toronto Hydro employed the OEB's Cost Allocation model to allocate the revenue requirement to its eight rate classes, and developed base distribution rates for each class. The standard rebasing approach maintains revenue-to-cost ratios for each class within the boundaries set out in the OEB's 2011 Review of Electricity Cost Allocation Policy.[3] For more information about Toronto Hydro's Cost Allocation and Rate Design, please refer to Exhibits 7 and 8, respectively.

In addition to base distribution rates, Toronto Hydro is applying to clear a number of Deferral and Variance accounts. Based on the values Toronto Hydro has proposed for clearance, a number of new rate riders are proposed for implementation beginning in 2020 pursuant to various clearance time frames. For more information about Toronto Hydro's proposed rate riders, please refer to Exhibit 9, Tab 3.

3. YEARS 2 TO 5: CUSTOM PRICE CAP INDEX ("CPCI")

Under 4th Generation IR, rates in the years following a rebasing year are subject to an incentive rate mechanism ("IRM"). The IRM is a formulaic approach to rate making under which distribution rates are adjusted annually using a two-component PCI:

$$\mathbf{PCI = I - X}$$

The I-factor is intended to reflect changes to the input prices faced by the industry (i.e. inflation), while the X-factor is intended to capture changes in the productivity of the Ontario electricity distribution industry as a whole, and differences among utilities within it.

[3] EB-2010-0219, EB-2012-0383 and OEB letter issued June 12, 2015 Issuance of New Cost Allocation Policy for Street Lighting Rate Class.

In the RRFE Report, the OEB offers alternative forms of rate making "to accommodate differences in the operations of distributors, some of which have capital programs that are expected to be significant."[4] The OEB notes that the CIR option in particular "will be most appropriate for distributors with significant large multi-year […] investment commitments that exceed historical levels," whereas 4th Generation IR is more suitable for utilities with "some" incremental needs.[5] The evidence at Exhibit 1B, Tab 2, Schedule 4 and the DSP at Exhibit 2B discuss Toronto Hydro's capital investment needs and, by extension, the appropriateness of the CIR option in greater detail.

A challenge for CIR applicants like Toronto Hydro is to reconcile their significantly large, multi-year investment commitments within a framework that aligns with RRFE guidance. To this end, Toronto Hydro proposes that these needs be reconciled within a CPCI framework that entrenches the OEB's inflation and productivity factors within a formulaic approach to adjusting distribution rates, with customization as set out in this evidence. The following subsections set out the approach in more detail.

3.1 Inflation and Productivity Factors

In 2013, the OEB updated its standard rate adjustment parameters following a consultation process that explicitly considered:[6]

1) The development of a more Ontario-specific inflation factor;
2) The estimation of long-run Ontario electricity distribution total factor productivity ("TFP"); and
3) The development and implementation of total cost benchmarking.

[4] RRFE Report at page 9.
[5] RRFE Report at page 14.
[6] EB-2010-0379, Report of the Board, Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors (December 4, 2013) [the "OEB Rate Setting Parameters Report"].

The OEB decided on a new methodology for the I-factor. The I-factor is based on a 30/70 weighting of labour and non-labour sub-indices and is updated annually. The labour sub-index is determined by changes in the average weekly earnings of Ontario workers, and the non-labour sub-index is determined by changes in the Canada Gross Domestic Product Implicit Price Index for final domestic demand.

Toronto Hydro proposes to use the OEB's I-factor in its CPCI. As the value for the I-factor is updated annually, Toronto Hydro will incorporate the updated value into its CPCI to appropriately adjust base distribution rates for the following year.

The productivity factor, one of the two X-factor components, was also updated. The productivity factor is intended to estimate the overall trend in the productivity of the electricity distribution industry in Ontario by measuring changes in TFP, defined by Pacific Economics Group ("PEG") as a "comprehensive measure of the extent to which firms convert inputs into outputs."[7]

In its report, PEG used an indexing method to estimate TFP for the Ontario distribution sector based on data from the 2002 to 2012 period.[8] This sample excluded the experience of both Toronto Hydro and Hydro One because, as a result of their large size relative to the rest of the industry, PEG determined that they were exerting a disproportionate impact on industry TFP.[9] Toronto Hydro presumes that this principle would have held if one or both had outperformed the sector on TFP.

[7] Pacific Economics Group (2013), Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario, (corrected January 24, 2014) at page 12 [the "PEG Report"].
[8] PEG suggests that a ten-year horizon is the minimum required for TFP Indexing.
[9] PEG Report, *supra* note 7 at page 4.

The result of PEG's analysis that excluded the two utilities suggested that industry TFP over that period changed at an average annual rate of -0.33 percent. That is, TFP for the sector actually declined over that period. In alignment with PEG's recommendation, the OEB ultimately adopted a zero productivity factor as a matter of policy, inclusive of an implicit stretch of 0.33 percent.

Toronto Hydro proposes to embed the OEB's productivity with its implicit incremental stretch factor unchanged within the proposed CPCI, fixed throughout the term of the ratemaking period.

3.2 Custom Stretch Factor

The second component of the X-factor is an explicit stretch factor. According to the OEB, "stretch factors promote, recognize, and reward distributors for efficiency improvements relative to the expected sector productivity trend."[10] Under the current methodology, which was updated most recently in 2013, utilities are assigned one of five stretch factors. This occurs on the basis of a comparison of the utility's total costs relative to their predicted total costs. The predicted total costs are determined using a total cost econometric model developed by PEG.[11]

As part of this application, Toronto Hydro is submitting alternative total cost benchmarking, the details of which can be found in the Power System Engineering's ("PSE") Econometric Benchmarking Report, at Exhibit 1B, Tab 4, Schedule 2 (the "PSE Report"). The alternative total cost benchmarking model prepared by PSE for Toronto Hydro is econometric in nature (similar to PEG's model) and includes an expanded data set. The results are statistically significant and relevant to the OEB's consideration of

[10] OEB Rate Setting Parameters Report, *supra* note 6 at page 18.
[11] OEB Rate Setting Parameters Report, *supra* note 6 at page 19.

Toronto Hydro's performance. The PSE Report also addresses the benchmarking comments set out in the OEB Decision in Toronto Hydro's 2015-2019 Rate Application.[12]

The PSE Report provides an appropriate and robust basis for setting Toronto Hydro's stretch factor. As noted in the PSE Report, Toronto Hydro's forecasts of its total costs are within 10 percent of its predicted total costs. Utilities within this demarcation point are assigned to Group III of the OEB's benchmarking cohorts, implying a stretch factor of 0.30 percent. Toronto Hydro therefore proposes that the stretch factor in the proposed CPCI framework be set at 0.30 percent, and fixed throughout the term of the ratemaking period.

Toronto Hydro's proposed plan and resulting revenue requirement in this CIR application reflects the results of a total cost econometric forecasting model, as envisioned in the Filing Requirements. A custom element of this CIR Application is using a PSE forecasting model in place of a PEG forecasting model.

3.3 Custom Capital Factor

The premise of the inclusion of a custom capital factor ("C-factor") is to reconcile the OEB's guidance that the CIR framework is best suited for utilities with significant, multi-year capital investment requirements as it is clear that the standard 4th Generation IR framework is not.

The proposed C-factor is designed as a rate adjustment mechanism that is directly proportional to the degree of capital investment required by Toronto Hydro, as detailed

[12] Supra note 1 at pp.16-17.

in its DSP (Exhibit 2B). It is comprised of two sub-components that serve two primary functions:

- Reconcile Toronto Hydro's capital investment need in a price cap framework; and
- Return to ratepayers the funding already provided for capital through the standard "I – X" increase.

The first sub-component, termed "C_n", is determined as the percent change in total revenue requirement that is attributable to changes in capital-related revenue requirement – that is, depreciation, return on equity, interest and PILs/taxes. Changes in capital-related revenue requirement are based on forecast changes in average annual rate base, associated depreciation, and taxes. Tax rates and the cost of capital are maintained at their 2020 levels, consistent with the standard 4th Generation IR treatment and the OEB approved treatment in Toronto Hydro's 2015-2019 Rate Application.

The OEB approved values of C_n from the 2015-2019 Rate Application are shown in Table 1 below.[13]

Table 1: OEB Approved C_n factors for 2016-2019

2016	2017	2018	2019
4.07	7.60	5.99	4.43

For the current application, Cn for 2021-2024 is be determined on the following basis:

[13] EB-2014-0116 Draft Rate Order Update (February 29, 2016) page 6.

Table 2: Calculation of C_n ($ Millions)

Revenue Requirement Component[14]	2020	2021	2022	2023	2024
Ratebase	4,615.3	4,829.0	5,081.6	5,374.5	5,650.0
Interest Expense	100.8	105.5	111.0	117.4	123.4
Return on Equity	162.8	170.4	179.3	189.6	199.3
Depreciation	268.7	281.9	293.1	310.9	325.4
PILs/Taxes	34.7	36.5	32.7	35.7	42.2
Capital-related RR (A)	567.0	594.3	616.0	653.6	690.3
OM&A	277.5	280.0	282.5	285.1	287.6
Revenue Offsets	-47.7	-48.1	-48.5	-49.0	-49.4
Total RR (B)	796.8	826.2	850.0	889.6	928.5
$Cn = (A_{yx} – A_{y(x-1)}) / B_{y(x-1)}$		3.43%	2.63%	4.42%	4.12%

For example, in the above table, the change in forecast capital related revenue requirement from 2020 to 2021 is $27.3 million ($594.3 million minus $567.0 million). The total revenue requirement in 2020 is $796.8 million. C_n for 2020 is therefore:

$$C_n = (594.3 – 567.0) / 796.8 = \mathbf{3.43\%}.$$

The values shown in Table 2 are filed as part of the OEB's Revenue Requirement Workforms, at Exhibit 6, Tab 1, Schedules 2-6. Capital-related revenue requirement, as noted, is determined on a forecast basis. By contrast, OM&A and Revenue Offsets are assumed to increase by "I – X".

The values of C_n represent the amount by which base rates would need to be increased to fund Toronto Hydro's capital needs over the course of the rate term.

[14] Each component can be found in the Revenue Requirement Workforms filed as Exhibit 6, Tab 1, Schedule 2-6.

With the inclusion of C_n in the CPCI, Toronto Hydro would receive sufficient funding for its capital needs as presented in the DSP. However, the "I – X" increase already included in the CPCI formula does provide some degree of incremental funding for capital. Absent adjustment, the CPCI formula with just C_n would risk over-funding relative to Toronto Hydro's capital needs. This risk is removed in the CPCI through a scaling of the C_n values. Termed S_{cap}, this scaling factor is calculated in the following fashion:

S_{cap} = (capital-related revenue requirement) / (total revenue requirement)

This scaling reduces the incremental funding for capital to capture just the capital component incremental to the "I – X" already included in the CPCI. Table 3 provides the information inputs for calculating S_{cap} for 2021-2024.

Table 3: Revenue Requirement Components for Determining S_{cap}

Revenue Requirement Component	2021	2022	2023	2024
Interest	105.5	111.0	117.4	123.4
ROE	170.4	179.3	189.6	199.3
Depreciation	281.9	293.1	310.9	325.4
PILs/Taxes	36.5	32.7	35.7	42.2
Capital-related RR (A)	**594.3**	**616.0**	**653.6**	**690.3**
OM&A	280.0	282.5	285.1	287.6
Revenue Offsets	-48.1	-48.5	-49.0	-49.4
Total RR (B)	**826.2**	**850.0**	**889.6**	**928.5**
S_{cap} = A / B	**71.9%**	**72.5%**	**73.5%**	**74.3%**

In Toronto Hydro's 2015-2019 Rate Application, the scaling factor was applied to a full "I – X". However, the OEB ruled that the scaling should only apply to "I", so that the

stretch factor incentive remained a component of the capital funding.[15] Toronto Hydro's proposed CPCI conforms to this finding.

3.4 Growth Factor

In its 2015 Decision, the OEB found that the inclusion of a growth variable in the CPCI was warranted to capture the change in distribution revenue that would naturally occur (in the absence of any rate changes) due to changes in billing units (customer numbers and loads) over the forecast period.[16]

Toronto Hydro has accordingly included the growth term, "g", in the CPCI. The value of the growth term is determined based on Toronto Hydro's forecast of loads and customers for the 2021-2024 period,[17] applied to 2020 proposed rates. This methodology is consistent with the OEB's approved methodology in Toronto Hydro's 2015-2019 Rate Application, and results in a g-factor value of 0.2 percent. Calculation of the g factor is shown in Table 4, below.

Table 4: Forecast Revenue at 2020 Proposed Rates ($ Millions)

	2020	2021	2022	2023	2024	Annual Average
Revenue at 2020 Rates	796.8	797.8	799.8	801.6	804.8	
Annual Growth Rate		0.1%	0.2%	0.2%	0.4%	0.2%

The above discussion sets out the variables that constitute Toronto Hydro's proposed CPCI. The resulting CPCI value for a given year would, in keeping with IRM principles, be applied to all distribution rates from the previous year to determine the following year's distribution rates.

[15] Supra note 1 at page 18.
[16] Supra note 1.
[17] See Exhibit 3, Tab 1, Schedule 1, for Toronto Hydro's forecast of loads and customers

To summarize, the CPCI is determined in the following fashion:

$$\textbf{CPCI} = \textbf{I} - \textbf{X} + \textbf{C} - \textbf{g, or}$$

$$\textbf{CPCI} = \textbf{I} - \textbf{X} + \textbf{C}_n - (\textbf{S}_{cap} * \textbf{I}) - \textbf{g}$$

Where,

- "**I**" is the OEB's inflation factor, determined annually;
- "**X**" is the sum of:
  - The OEB's productivity factor of 0.0 percent; and
  - Toronto Hydro's custom stretch factor, applied to both OM&A and capital expenditures;
- "**C**" is the difference between:
  - $\mathbf{C_n}$, a reflection of Toronto Hydro's capital investment need, and
  - $\mathbf{S_{cap}} * \mathbf{I}$, an offsetting adjustment required to ensure that the C-factor provides funding only in excess of what is already provided for capital through the inflation factor I;
- **"g"** is the growth factor determined by growth in distribution revenue due to changes in load and customers over the CPCI period.

Table 5, below, shows the components of the CPCI based on an assumed I-factor of 1.2 percent, the current OEB approved inflation value, the proposed stretch factor, the forecast values of C_n and S_{cap}, and the g factor, shown in Tables 1 and 2, above.

Table 5: CPCI Values Assuming an Inflation Factor of 1.2% for Each Year

CPCI Component (%)	2021	2022	2023	2024
I	1.2	1.2	1.2	1.2
X – productivity	0.0	0.0	0.0	0.0
X – custom stretch	0.3	0.3	0.3	0.3
C_n	3.43	2.63	4.42	4.12
S_{cap}	71.9	72.5	73.5	74.3
g	0.2	0.2	0.2	0.2
CPCI	**3.26**	**2.46**	**4.24**	**3.93**

For comparison purposes, the CPCI values approved by the OEB in EB-2014-0116 are shown in Table 6 below.[18]

Table 6: CPCI Values approved in EB-2014-0116

2016	2017	2018	2019
3.83	7.32	5.67	4.10

4. OFF-RAMPS AND Z-FACTOR

Toronto Hydro proposes to apply the OEB's existing policy with respect to off-ramps. The RRFE Report indicates that each rate-setting method includes a trigger mechanism with an annual return on equity dead band of plus or minus 300 basis points, at which point a regulatory review may be initiated. The OEB approved both a non-capital-related Earnings Sharing Mechanism and a Capital Related Revenue Requirement Variance Account in its EB-2014-0116 decision. Both of these mechanisms were established to protect ratepayers over the term of the CIR period. Toronto Hydro proposes to continue both of these mechanisms for the 2020-2024 period.

[18] EB-2014-0116 Draft Rate Order Update, February 29, 2016, page 6.

Finally, the OEB affirmed in its EB-2014-0116 decision that Z-factor relief was available to Toronto Hydro, if required, and based on the generic criteria for such applications. Toronto Hydro relies on this affirmation for the 2020-2024 period, should the need arise.

4.1 Earnings Sharing Mechanism Calculation

In its Decision and Order for Toronto Hydro's 2015-2019 CIR application, the OEB accepted the utility's proposal for a symmetrical earnings sharing mechanism ("ESM"), incorporating a 100 basis point dead band. As the OEB approved a separate Capital Related Revenue Requirement Variance Account, it approved the ESM to track the variance between the non-capital related revenue requirement embedded in rates and the actual non-capital related revenue requirement. Non-capital revenue requirement consists of OM&A expenditures and revenue offsets. Toronto Hydro determines whether to track an amount in the ESM variance account by calculating the contribution to ROE from the difference between actual and funded non-capital revenue requirement items. This calculation and determination is performed annually.

4.1.1 Calculation Methodology

To determine the variance in ROE resulting from non-capital related revenue requirement, Toronto Hydro uses an approach consistent with the OEB's ROE Workform – that is, ROE divided by deemed equity. Specifically, the utility calculates this as follows:

$$\frac{\text{(Actual non-capital revenue requirement) – (Funded non-capital revenue requirement)}}{\text{Actual equity on a deemed basis}}$$

The actual OM&A and revenue offset amounts included in the numerator are obtained from Toronto Hydro's RRR filing.[19] The funded amounts result from the base year approved OM&A and revenue offsets, adjusted for inflation and productivity.

[19] These amounts are adjusted, consistent with adjustments included the RRR ROE Workform and to make the actual results comparable to the amounts embedded in base rates.

Power System Engineering, Inc.

Full-service consultants



Econometric Benchmarking of Historical and Projected Total Cost and Reliability Levels

Prepared at the Request of:

Toronto Hydro-Electric System Limited

TORONTO HYDRO

Prepared by:

Power System Engineering, Inc.

July 16, 2018

Econometric Benchmarking of Historical and Projected Total Cost and Reliability Levels

for

Toronto Hydro-Electric System Limited

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Table of Contents

Contents

1 Executive Summary 1
1.1 Purpose of the 2018 PSE Report 2
1.2 Overview of PSE's Benchmarking Process 2
1.3 Total Cost Benchmark Findings 4
1.4 Reliability Benchmark Findings 7
1.5 Custom IR Conclusions 12

2 Total Cost Benchmarking Model: Dataset, Model Details, Variables 14
2.1 Summary of Dataset 14
2.2 Summary of Variables 15
2.3 Details of the Total Cost Model 16
2.3.1 The Definition of "Costs" 16
2.3.2 Output Variables 17
2.3.3 Business Condition Variables: Input Prices 17
2.3.4 Business Condition Variables: Other 18
2.3.5 Projected Variable Values 20
2.3.6 2020 CIR Total Cost Variables Compared to 2015 CIR Total Cost Variables 22
2.3.7 Perpetual Inventory Capital Cost Method 23
2.3.8 Total Cost Sample 25
2.4 Econometric Method (Detailed) 27
2.4.1 Estimation Procedure and Translog Cost Function 27
2.4.2 Statistical Tests 28

3 The Board's Three Key Areas on 2015 Total Cost Benchmarking 30
3.1 Urban Core Variable 30
3.1.1 PSE's Solution to the Urban Core Variable 31
3.2 Approach to CDM Costs 34
3.3 Asset Price Inflation Costs (Capital Cost Escalation Rate) 34

4 Total Cost Benchmarking Results 36

5 Reliability Benchmarking: Variable Definitions, Datasets, Models 40
5.1 Reliability Benchmarking: Summary 40
5.2 Data Sources 41
5.3 Reliability Dataset 41
5.4 Econometric Reliability Benchmarking Model 42

6 Reliability Benchmarking Results 44

7 Importance of U.S. Data for Benchmarking Toronto Hydro 48

8 Cost Benchmarking Results and Stretch Factor Recommendation 49

9 Appendix: Congested Urban Maps by Sampled Utility 50

List of Figures

Figure 1 Toronto Hydro's Cost Performance 2005-2024 7
Figure 2 Toronto Hydro's SAIFI Performance 2005-2024 10
Figure 3 Toronto Hydro's CAIDI Performance 2005-2024 12
Figure 4 Toronto Hydro Congested Urban Map 33
Figure 5 Toronto Hydro's Cost Performance 2005-2024 39
Figure 6 Toronto Hydro's SAIFI Performance 2005-2024 47
Figure 7 Toronto Hydro's CAIDI Performance 2005-2024 47

List of Tables

Table 1 Toronto Hydro's Cost Performance 2005-2024 6
Table 2 Toronto Hydro's SAIFI Performance 2005-2024 9
Table 3 Toronto Hydro's CAIDI Performance 2005-2024 11
Table 4 Cost Definitions 17
Table 5 Total Cost Sample 26
Table 6 Total Cost Model Estimates 37
Table 7 Toronto Hydro's Cost Performance 2005-2024 38
Table 8 Sampled Utilities for Reliability Benchmarking 42
Table 9 SAIFI Econometric Model Coefficients 43
Table 10 CAIDI Econometric Model Coefficients 43
Table 11 Toronto Hydro's SAIFI Performance 2005-2024 45
Table 12 Toronto Hydro's CAIDI Performance 2005-2024 46
Table 13 "Congested Urban" Percentages 50

1 Executive Summary

On October 18, 2012 the Ontario Energy Board (the "Board") released a report entitled "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach" ("RRF"). In the RRF, three rate-setting methods were discussed. One of those methods was labeled "custom incentive regulation," or "Custom IR." This report (the "2018 PSE Report") uses econometric benchmarking to inform the Board's decisions regarding Toronto Hydro-Electric System Limited ("Toronto Hydro") and its Custom IR application

On page 18 of the RRF, the Board states that "[i]n the Custom IR method, rates are set based on a five-year forecast of a distributor's revenue requirement and sales volumes." The RRF also lays out the use of benchmarking as a key element to inform the Board of the reasonableness of the revenue forecasts.[1] The 2018 PSE report benchmarks Toronto Hydro's historical and projected costs, using an econometric benchmarking method. The benchmarking results in this report can be used to evaluate the reasonableness of Toronto Hydro's revenue forecasts and to inform the appropriate stretch factor in the Custom IR application. PSE's benchmarking research for this application produces a recommended stretch factor of 0.3%.

In a November 21, 2013 Report of the Board, titled "Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors" ("November 2013 Board Report"), the Board clearly indicates its preference for econometric benchmarking over peer group benchmarking.[2] Furthermore, the Board indicated its preference for total cost benchmarking over partial cost benchmarking when calibrating stretch factors.[3] Therefore, Power System Engineering, Inc. utilizes econometric benchmarking of total costs in the current report.

PSE was involved in Toronto Hydro's previous Custom IR application. On December 29, 2015 the Board issued a decision for Toronto Hydro regarding its prior Custom IR application ("2015 Board Decision"). The Board in its 2015 Board Decision addressed three key areas of differences between PSE's 2015 benchmarking approach and the approach of the OEB staff expert. PSE has addressed these three key areas in the current research. Please see Section 3 of the present report for a detailed description of the three key areas identified in the 2015 Board Decision, and how PSE addresses each one in the current research.

[1] See "Table 1: Rate-Setting Overview – Elements of Three Methods," on page 13 of the RRF.

[2] The November 2013 Report is in Case EB-2010-0379.

[3] See page 19 of the November 2013 Board Report.

1.1 Purpose of the 2018 PSE Report

Power System Engineering, Inc. ("PSE") was retained by Toronto Hydro for the purpose of providing a report in connection with the benchmarking of Toronto Hydro's key operating parameters; in this case total costs and reliability. The benchmarking evaluation in this report is meant to objectively assess the reasonableness of the company's historical and projected cost and reliability metrics using external, objective, publicly-available data. The report uses the econometric benchmarking approach to study the total cost and reliability performance of Toronto Hydro. It builds upon the benchmarking research in Toronto Hydro's last Custom IR application and addresses the three key items discussed by the Board in the 2015 Board Decision.

PSE uses econometric benchmarking of total costs to evaluate the reasonableness of Toronto Hydro's spending forecasts and provide a recommended stretch factor. We also benchmark reliability, because when presented with total cost benchmarking, reliability benchmarking presents a more complete picture of a utility's performance.

1.2 Overview of PSE's Benchmarking Process

PSE conducted an econometric total cost and reliability benchmarking study of Toronto Hydro. This study was done as part of Toronto Hydro's 2020 Custom IR proposal. The purpose of PSE's benchmarking analysis is to evaluate the reasonableness of Toronto Hydro's historical and projected total cost amounts and system reliability metrics. This is done by comparing Toronto Hydro's actual and projected values with the benchmarking model's predicted values.[4]

The benchmarking analysis uses historical cost and reliability data from a dataset consisting of data from multiple utilities to create a model; this model relates cost and reliability to certain variables. The model is then used to predict Toronto Hydro's "expected" (benchmarked) cost and reliability. The general approach of our cost benchmarking analysis is as follows:

1. PSE assembled the historical costs of all utilities in the dataset, along with the variables that affect cost, such as number of customers, peak demand, wage levels, forestation levels, etc.
2. Using the historical data, PSE estimated an econometric model that expresses the relationship between the variables and cost. This is a general model that applies to the dataset as a whole.
3. For each utility in the sample, we can then produce "benchmark" values for any given year.

[4] In this paper we will use "forecasted" or "projected" costs and reliability to refer to Toronto Hydro's estimates of those values in the future, and "predicted" or "expected" or "benchmark" costs and reliability to refer to the econometric model's outputs for those metrics.

The benchmark values for any given utility are estimated by inserting the variable values for the specified utility into the model. In Toronto Hydro's case, the benchmarks represent the costs we would expect for an average-performing utility for a given year, with the same variable values faced by Toronto Hydro that year. In other words, the benchmark reflects the performance of a hypothetical average utility that faced Toronto Hydro's actual service territory and regional input price conditions for the given year.

4. We then compare the costs that are **expected** (predicted) for Toronto Hydro by the model to Toronto Hydro's **historical** and 2020 CIR **forecasted** costs. When we evaluate historical costs, we compare the model's expected historical costs for that utility, for that year, to the actual historical costs for that utility in that year. When we evaluate future costs, we compare the model's expected future costs for that utility for a given year to the forecasted costs for that utility for that year; this is done by putting projected values of variables (e.g. number of customers) into the model. The benchmarking process thus allows us to: (1) evaluate the historical cost performance, and (2) evaluate the reasonableness of forecasted costs.[5]

A process similar to the one described above can also be used to evaluate Toronto Hydro's past and future reliability metrics; the difference is that the model generated by Step 1 and Step 2 is an industry-wide reliability model (rather than a cost model); this reliability model expresses the relationship between the variables that affect reliability and the reliability metrics.

In PSE's 2015 Custom IR benchmarking research for Toronto Hydro, we created two total cost models, one using a combined Ontario and U.S. dataset, and a second model using a U.S.-only dataset. During that previous proceeding (EB-2014-0116), the OEB staff consultant (Pacific Economics Group, or "PEG") put forth their own results using a U.S.-only dataset. The ensuing discussion with stakeholders did not appear to take issue with the focus on a U.S.-only dataset to benchmark Toronto Hydro, nor was this mentioned as a key issue in the 2015 Board Decision. For these reasons, PSE's benchmarking dataset for the current research is primarily a U.S. dataset. However, PSE added six Ontario distributors to the dataset for the total cost benchmarking research. These six distributors are the only six in Ontario that contain a portion of their service territory that meets PSE's definition of "congested urban" areas; this definition is used in one of PSE's variables.[6]

[5] Here "reasonableness" refers to how the forecasted costs compare to the model's expected costs for that utility.

[6] The six Ontario distributors included in the total cost dataset, besides Toronto Hydro, are: Enersource Mississauga, Horizon Utilities, London Hydro, Kitchener-Wilmont Hydro, Hydro Ottawa, and EnWin. The utility data for Enersource Mississauga and Horizon Utilities are prior to the Alectra Utilities merger. See Section 2.3.4 for a discussion of the "congested urban" variable.

1.3 Total Cost Benchmark Findings

PSE compared Toronto Hydro's historical and projected total costs against its benchmark costs. The benchmark costs are what the econometric model "expects" Toronto Hydro's costs to be in any given year, based on the actual or projected values of variables for that year, such as input prices and number of retail customers. The econometric method is described in some detail below in this chapter, and in more detail in Chapter 2.

Total costs are defined as the sum of (1) OM&A expenses, and (2) the depreciation and opportunity costs of capital. This is similar to how revenue requirements are calculated, and so total costs are somewhat analogous to the distribution portion of revenue requirements.[7] Partial cost benchmarking approaches, such as benchmarking of only OM&A expenses, exclude large categories of costs, which can skew performance evaluations. The Board prefers total cost benchmarking to partial cost benchmarking when determining appropriate stretch factors, as stated in the November 2013 Board Report.

PSE endorses econometric benchmarking because of its increased accuracy relative to peer group approaches. The econometric benchmarking method has many advantages, including:

- The ability to statistically test included variables and results;
- The ability to assess a relatively large number of variables in its analysis; and
- Econometric benchmarking does not require the researcher to choose a peer group or exclude large portions of the available data.

PSE used a total cost econometric benchmarking model to benchmark Toronto Hydro's historical costs, and its proposed total costs during the Custom IR period (2020 to 2024). PSE first derived an econometric model from the historical dataset (using data from all utilities in the dataset). Using that model and its parameter values, we then calculated total cost benchmarks for Toronto Hydro for each year. For past years, we used Toronto Hydro's historical variable values to calculate the benchmarks. For 2018 to 2024 benchmarks, we used Toronto Hydro's projections for the variables that are in the model.

The result is a customized "benchmark" for each year, which can be thought of as the total costs we would expect from an average utility for that year, with those specific operating characteristics. The benchmark costs are then compared to the actual/proposed costs for each year. This process serves as a benchmark evaluation of the company's historical and proposed total costs.

Our total cost econometric benchmarking results indicate the following findings.

[7] Total costs are not exactly analogous to revenue requirements, however, because of the generalizations needed to offer a fair analysis between utilities with varying depreciation rates, rate of returns, historical capital addition patterns, and cost definitions.

1. The historical average total cost levels of Toronto Hydro from 2015 to 2017 are 18.6% below benchmark expectations. Toronto Hydro total annual costs amounted to around $157 million below benchmark values in 2017.

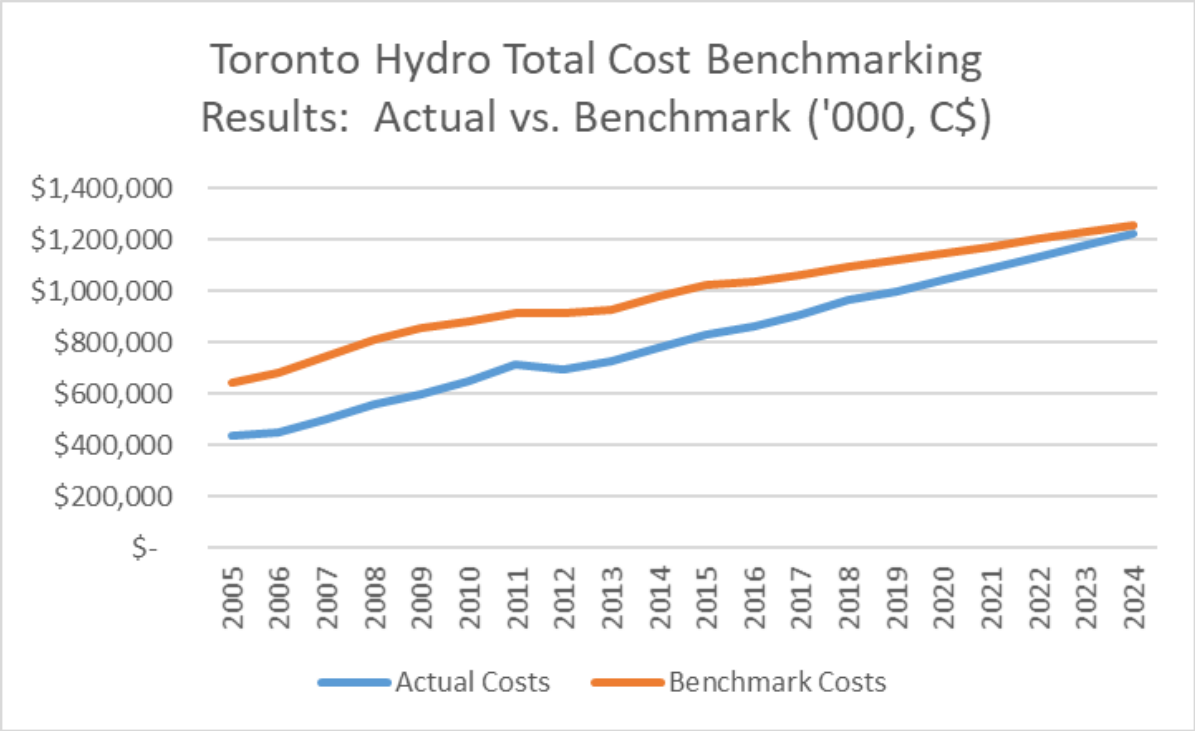
2. The projected total cost levels during the Custom IR period of 2020 to 2024 are 6.0% below benchmark expectations. At the company-proposed spending levels, Toronto Hydro's total annual costs are projected to still be around $32 million below benchmark values in 2024.

The following table and graph illustrate the historical and projected benchmark costs and benchmark costs for Toronto Hydro, using an econometric model derived from a dataset consisting of 83 distributors from the U.S. and 6 distributors from Ontario.

Table 1 Toronto Hydro's Cost Performance 2005-2024

Year	Toronto Hydro Actual Costs ('000, C$)	Toronto Hydro Benchmark Costs ('000, C$)	% Difference (Logarithmic)
2005	$ 436,128	$ 641,275	-38.6%
2006	$ 450,686	$ 681,212	-41.3%
2007	$ 502,433	$ 744,486	-39.3%
2008	$ 556,429	$ 813,528	-38.0%
2009	$ 595,932	$ 852,775	-35.8%
2010	$ 647,456	$ 882,130	-30.9%
2011	$ 710,544	$ 912,729	-25.0%
2012	$ 691,388	$ 910,814	-27.6%
2013	$ 727,152	$ 925,488	-24.1%
2014	$ 777,414	$ 976,095	-22.8%
2015	$ 826,886	$ 1,024,030	-21.4%
2016	$ 861,394	$ 1,034,492	-18.3%
2017	$ 904,560	$ 1,061,642	-16.0%
2018 (projected)	$ 964,885	$ 1,095,430	-12.7%
2019 (projected)	$ 999,492	$ 1,122,407	-11.6%
2020 (projected)	$ 1,044,567	$ 1,148,601	-9.5%
2021 (projected)	$ 1,085,324	$ 1,174,549	-7.9%
2022 (projected)	$ 1,134,689	$ 1,201,662	-5.7%
2023 (projected)	$ 1,180,820	$ 1,229,463	-4.0%
2024 (projected)	$ 1,225,282	$ 1,257,907	-2.6%
Average % Difference			
2015-2017			**-18.6%**
2020-2024			**-6.0%**

Figure 1 Toronto Hydro's Cost Performance 2005-2024



1.4 Reliability Benchmark Findings

In addition to total cost benchmarking, PSE conducted econometric reliability benchmarking of Toronto Hydro's system average interruption frequency index ("SAIFI") and the customer average interruption duration index ("CAIDI"). When presented with cost benchmarking, reliability benchmarking presents a more complete picture of a company's performance, since in general, lower total costs can come at the expense of reliability. Both indexes exclude major event days ("MEDs") from the calculation of the metrics, which permits them to gauge reliability performance during normal operating conditions.[8] SAIFI measures how many outages an average customer experiences, whereas CAIDI measures the average duration of those outages. This separates the evaluation into examining how often the system fails (SAIFI) and the length of the company's restoration time when the system fails (CAIDI).[9]

[8] This differed from the 2015 CIR reliability benchmarking research, where we included MEDs. The reason for including MEDs in the prior research was that MED exclusion information was not yet available for the Ontario distributors and we included Ontario distributors in the combined dataset. For the 2020 research, we decided to focus on the U.S.-only sample for the current reliability research, because of the limited MED excluded data for Ontario. This allowed us to exclude MEDs and provide a benchmark analysis that excludes the large variations that result from severe weather events.

[9] Our 2015 CIR research examined SAIFI and SAIDI. However, since SAIDI is the product of SAIFI and CAIDI, the SAIDI index includes both the system failure and the restoration time in the index. Separating the two evaluations

PSE gathered U.S. data for the reliability indexes from annual regulatory filings and the EIA-861 form.[10]

PSE's reliability benchmarking analysis resulted in the following findings.

1. Historical SAIFI metrics for Toronto Hydro are considerably higher than the benchmark values.
2. Projected SAIFI metrics remain higher than the benchmarks.
3. Historical CAIDI metrics for Toronto Hydro are considerably lower than the benchmark values.
4. Projected CAIDI metrics for Toronto Hydro continue to be lower than the benchmark values.

The following table and graph illustrate the historical and projected SAIFI values for Toronto Hydro as compared to benchmark values, using a dataset consisting of of 73 U.S. distributors.[11]

provides a cleaner look at how often the grid fails and how long it takes to restore electricity when it does fail.

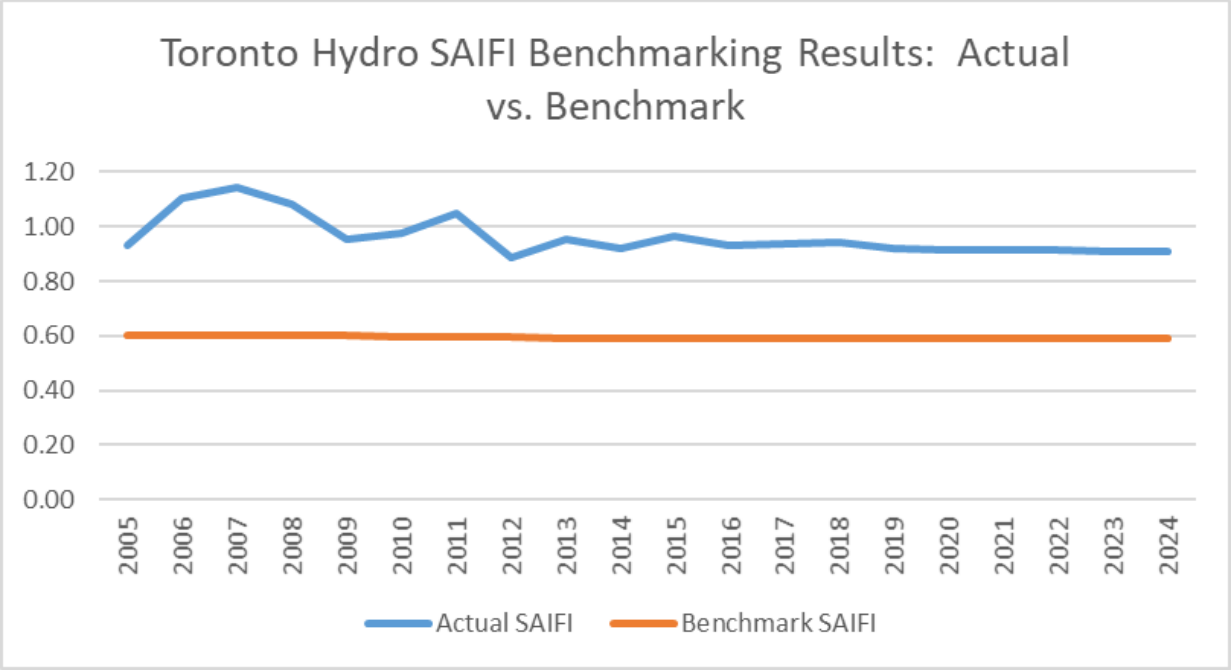
[10] Beginning in 2013, US utilities were required to file reliability data to the Energy Information Administration (EIA). This data is compiled in the EIA-861 form.

[11] The reliability sample is smaller than the total cost sample for two reasons: (1) Ontario distributors were not included (because data was not available in some cases and MED exclusion information was not available in other cases), and (2) Some of the U.S. utilities had missing or implausible reliability data, and so were left out of the dataset.

Table 2 Toronto Hydro's SAIFI Performance 2005-2024

Year	Toronto Hydro Actual SAIFI	Toronto Hydro Benchmark SAIFI	% Difference (Logarithmic)
2005	0.93	0.60	43.7%
2006	1.11	0.60	61.2%
2007	1.14	0.60	63.9%
2008	1.08	0.60	58.8%
2009	0.95	0.60	46.4%
2010	0.98	0.60	48.9%
2011	1.05	0.60	56.7%
2012	0.88	0.59	39.8%
2013	0.95	0.59	47.5%
2014	0.92	0.59	44.5%
2015	0.97	0.59	49.7%
2016	0.93	0.59	45.7%
2017	0.94	0.59	46.3%
2018 (projected)	0.94	0.59	46.7%
2019 (projected)	0.92	0.59	44.3%
2020 (projected)	0.92	0.59	44.0%
2021 (projected)	0.91	0.59	43.8%
2022 (projected)	0.91	0.59	43.6%
2023 (projected)	0.91	0.59	43.5%
2024 (projected)	0.91	0.59	43.5%
Average % Difference			
2015-2017			**47.2%**
2020-2024			**43.7%**

Figure 2 Toronto Hydro's SAIFI Performance 2005-2024

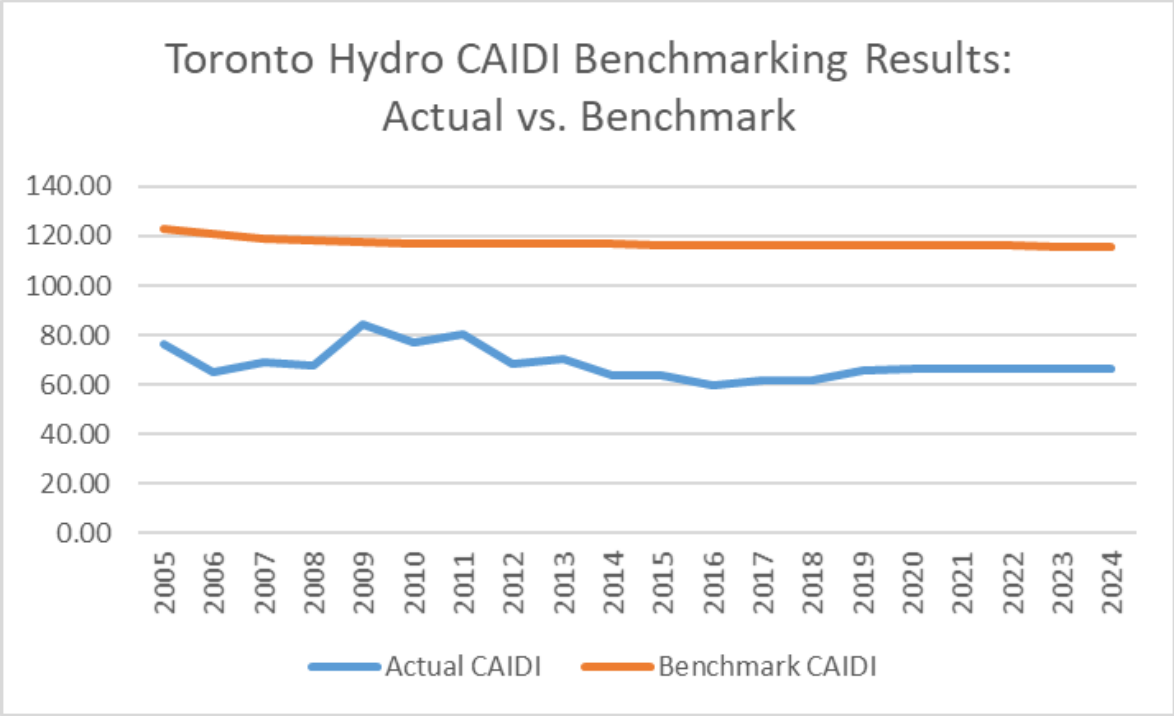


The following table and graph illustrates the historical and projected CAIDI values for Toronto Hydro against the benchmarked values.

Table 3 Toronto Hydro's CAIDI Performance 2005-2024

Year	Toronto Hydro Actual CAIDI	Toronto Hydro Benchmark CAIDI	% Difference (Logarithmic)
2005	76.59	122.67	-47.1%
2006	64.98	121.06	-62.2%
2007	69.12	119.21	-54.5%
2008	67.40	118.13	-56.1%
2009	84.13	117.47	-33.4%
2010	77.30	117.27	-41.7%
2011	80.13	117.12	-38.0%
2012	68.06	116.97	-54.2%
2013	70.61	116.84	-50.4%
2014	63.76	116.67	-60.4%
2015	64.04	116.48	-59.8%
2016	59.71	116.40	-66.8%
2017	61.54	116.26	-63.6%
2018 (projected)	61.96	116.21	-62.9%
2019 (projected)	65.96	116.16	-56.6%
2020 (projected)	66.10	116.11	-56.3%
2021 (projected)	66.21	116.06	-56.1%
2022 (projected)	66.34	116.01	-55.9%
2023 (projected)	66.51	115.95	-55.6%
2024 (projected)	66.64	115.90	-55.3%
Average % Difference			
2015-2017			**-63.4%**
2020-2024			**-55.9%**

Figure 3 Toronto Hydro's CAIDI Performance 2005-2024



1.5 Custom IR Conclusions

PSE's benchmark research leads us to the following conclusions relating to the company's Custom IR proposal:

1. **The PSE recommended stretch factor for Toronto Hydro's CIR is 0.3%.** This is grounded in the precedent of the 4GIR Decision, where distributors with total cost benchmark scores between plus/minus 10% are given the middle stretch factor of 0.3%. While a moderate stretch factor that requires Toronto Hydro to exceed the industry productivity expectation may be appropriate, the company should certainly not receive the most extreme stretch factor of 0.6%, which should be reserved for the poorest total cost performers. Based on PSE's results, Toronto Hydro is certainly not a poor total cost performer when an appropriate dataset is used in the benchmark analysis, with variables

that accurately account for Toronto Hydro's highly congested urban characteristics. The 4GIR decision and a 0.3% stretch factor align with the following results:

a. Toronto Hydro is entering the Custom IR period with total costs below benchmark values by 16.0% in 2017. The most recent 3-year average from 2015 to 2017 shows Toronto Hydro's costs are 18.6% below benchmark expectations.

b. Toronto Hydro's Custom IR period (2020 through 2024) total cost level projections remain within the 0.3% stretch factor threshold of +/- 10% during the CIR years. The 2020 to 2024 average benchmarking score is -6.0%.

2. **The Custom IR proposed spending levels of Toronto Hydro continue the better-than-expected cost performance of Toronto Hydro (i.e., proposed costs are lower than expected).** If actual spending comes in at the proposed spending levels, Toronto Hydro's total annual costs are projected to be approximately $32 million below benchmark values in 2024.

3. **Toronto Hydro's capital infrastructure seems to be producing a higher than expected number of outages.** The company's SAIFI for their 2015-2017 average is 47.2% above benchmark expectations. This implies Toronto Hydro customers experience 47.2% more outages than our models predict.

4. **Toronto Hydro's response to outages, measured by CAIDI, is faster than expected.** The company's 2015-2017 average is 63.4% below benchmark expectations. This implies that Toronto Hydro customers experience 63.4% shorter outage minutes per outage event than our models predict.

2 Total Cost Benchmarking Model: Dataset, Model Details, Variables

The benchmarking approach used in this report is the econometric approach. This is the most accurate and fair method to use when comparing utility cost and reliability levels. It is also the method preferred by the Board in the 4GIR Decision.

The econometric approach explicitly adjusts for differences in utilities' service territories. In the power distribution industry, simple comparisons of "raw" or unadjusted costs or reliability indexes do not result in appropriate performance comparisons. Uncontrollable factors, such as service territory characteristics and/or regional input prices, influence total costs. Therefore, more sophisticated tools that normalize for specific influencing factors must be employed to accurately assess performance. Otherwise, a utility could be rewarded (or punished) for simply having a favorable (or unfavorable) service territory or regional input price level. With this concept in mind, PSE has developed an econometric benchmarking model that considers factors that have proven to be statistically influential on distribution utility costs.

The econometric benchmarking approach relies on comparing actual data values to the predicted values obtained from the econometric models. The predicted or expected values obtained from the model represent the values we would expect from that utility for a given year, considering the specific operating characteristics faced by that utility that year (e.g., input prices, business condition variables, etc.).

To create an econometric benchmark, the researcher determines an appropriate functional form (a model) for the relationship between the studied metric and factors (variables) that influence it. This is done by using appropriate econometric methods to obtain parameter estimates for each variable of the specified model. The model is based on a particular dataset (in this case, a U.S. sample plus seven Ontario distributors including Toronto Hydro), and quantifies the relationship between the studied metric (total costs) and the variables that drive that metric (input prices, business condition variables, etc.).[12]

A more detailed description of the econometric method is given in Chapter 2.4 below.

2.1 Summary of Dataset

The data for the utilities used in the study were acquired from publicly available data sources.

[12] The model for reliability does not include the six Ontario utilities due to the limited data availability of reliability metrics with MEDs excluded.

There are 83 U.S. utilities in the sample for the cost model, plus seven Ontario distributors (including Toronto Hydro). The observations for the U.S. sample span the years 2002 to 2016. The observations for the Ontario distributors span the years 2005 to 2016.[13] Eight data points fall outside that range: Toronto Hydro's projected data from 2017-2024. The total number of observations in the dataset is 1,318.[14] Observations were excluded if key data (cost or outputs) were missing or implausible. Additional exclusions were made due to mergers, or where there was missing or implausible explanatory variable data. The large number of observations is more than sufficient for the creation of a statistically robust econometric model.

Ontario distributors were added if a portion of their service territory was classified as "congested urban" (see Section 2.3.4). This added six Ontario distributors to the sample. No other Ontario distributors have been identified as containing "congested urban" service territory.

2.2 Summary of Variables

In general, there are two types of variables used in econometric cost benchmarking: output variables and business condition variables. Output variables measure the output of the utility in question (i.e. what the utility "produces"). Business condition variables quantify the factors that drive costs in a particular service territory, such as regional input prices, highly congested urban areas, forestation, etc.

The output variables used in the total cost econometric benchmarking research are:

- Retail customers, and
- Maximum peak demand.

The business condition variables used in the total cost econometric benchmarking research are:

- Regional input prices;
- Percent electric customers (out of total gas and electric customers);
- Standard deviation of the elevation within the territory;
- Forestation of the service territory;
- Percent service territory classified as congested urban;
- Percent smart meters deployed on system;
- Percent distribution plant that is underground;
- Percent distribution plant that is underground multiplied by the congested urban variable;
- An Ontario binary variable indicating whether the distributor operates in Ontario or the

[13] 2005 is the first available year of Uniform System of Account data for the Ontario distributors.

[14] These total observations and the reported total cost model include Toronto Hydro's observations. However, when constructing the Toronto Hydro benchmarks, the company's observations are excluded from the modeling dataset to assure the benchmark is external to Toronto Hydro.

U.S.; and
- A time trend variable

2.3 Details of the Total Cost Model

2.3.1 The Definition of "Costs"

Both OM&A and total costs used in the benchmarking models for the U.S. distributors are derived using FERC Form 1 filing data.[15] United States investor-owned utilities ("IOUs") are required to file FERC Form 1 data annually, which includes operation and maintenance expenses broken down into specific cost categories (e.g. distribution, transmission, generation, customer billing, administrative and general). The Form 1 also includes plant in service and accumulated depreciation information that is used in constructing capital costs.

The Ontario utilities use the Reporting and Record Keeping Requirements ("RRR") rules for data in formulating the OM&A and total costs; these costs were used in the benchmarking models. Trial balance data for 2005 to 2016 was requested and sent from the Ontario Energy Board; this data enabled a consistent OM&A series in each year of the sample for the Ontario distributors, Toronto Hydro, and the U.S. sample.

PSE used a definition of "cost" for Toronto Hydro and the Ontario distributors that allowed us to achieve comparability with the definition used for the U.S. sample. PSE began with the benchmark-based cost definition used by the Board Staff's consultant (PEG) in the 4th Generation Incentive Regulation proceeding. PSE then added Toronto Hydro's high-voltage expenses to the company's cost definition. The FERC Form 1 does not break down high- versus low-voltage distribution expenses like Ontario reporting does. For that reason, Toronto Hydro's and the Ontario distributors' high-voltage expenses have been added to make costs comparable. For the same reasons, contributions in aid of construction ("CIAC") have been excluded from both Toronto Hydro's and the other six Ontario distributors' cost definition, due to those expenses not being included in the U.S. Form 1 data. Bad debt expenses have been excluded for all utilities, to match the 4GIR benchmark-based definition.

Pension and benefit costs have remained in the cost definition, because these costs appear to not be accurately disaggregated for the Ontario distributors.[16] If we excluded pension and benefit costs, this would likely create an inconsistent treatment between the U.S. and Ontario distributors.

[15] All FERC data was downloaded by PSE from SNL Energy's database tool.

[16] In the trial balance data, numerous distributors report zero pensions and benefits in accounts 5645 and 5646 (or if not zero, then implausibly low values). For example, in 2016 Enersource reports $62,510 spent on pensions and benefits.

The cost definition also excludes customer service and information ("CSI") expenses from total costs for all utilities. This is due to the possibility that the U.S. utilities include conservation demand management ("CDM") expenses in the CSI expense category. This assures cost consistency between the U.S. sample and the Ontario distributors; this issue was one of the key areas discussed by the Board in the 2015 Board Decision. We further discuss excluding CSI expenses in Chapter 3. The table below summarizes the cost definition treatment.

Table 4 Cost Definitions

Cost Element	Treatment
4th Generation IR Benchmark-Based Costs	Used this as a starting point for the cost definition
CIAC	Not included in Toronto Hydro costs or the Ontario distributor costs, since U.S. cost data does not include CIAC
High Voltage Expenses	Added to Toronto Hydro and the Ontario distributor costs, since U.S. cost data includes distribution high voltage costs
Customer Service and Information (CSI) Expenses	Excluded CSI expenses for all utilities, since there is a possibility that CDM expenses are included in the U.S. utility CSI expense category. This exclusion assures consistency in the cost definition and addresses one of the Board's key issues from the 2015 Decision.

2.3.2 Output Variables

The total cost model includes two output variables. The first is the total number of customers served, the second is the maximum peak demand for each utility since 2002. For U.S. utilities, the output variables are calculated from FERC Form 1s gathered from SNL Energy's dataset.[17] For the Ontario distributors, the output variables are from the RRR data. The forecasted output data for Toronto Hydro was provided to PSE by the company.

2.3.3 Business Condition Variables: Input Prices

The majority of the business condition variables are discussed in the following section (2.3.4). However, one important business condition variable merits detailed discussion: **input prices.** Input prices are divided into two categories: capital and OM&A. The capital input price calculation (using the perpetual inventory capital cost method) is discussed in detail later. The OM&A input price captures the regional market price level that each sampled company encounters when

[17] For the U.S. utilities, an adjustment was made to the peak demands reported in their FERC Form 1s, due to required "sales for resale" loads being included in the reported system peak demands. PSE adjusted the reported peak demands by the ratio of (retail sales) to (retail sales plus required sales for resale).

procuring OM&A inputs, such as employees or materials and services. There are two components used to construct the OM&A input price: labour and non-labour.

The labour component is calculated by taking wage levels of numerous job occupations and weighting them based on the U.S. Bureau of Labor Statistics ("BLS") estimates of job occupation weights in the Electric Power Generation, Transmission, and Distribution Industry. The BLS has estimates of wage levels for each job occupation by city and metropolitan area. For Toronto Hydro and the other six Ontario distributors, we gathered occupation wage estimates from the 2011 Canadian census, using wage data for the city they serve, translated job occupations to match their U.S. counterparts, and then weighted the job occupation wages by the BLS estimates.[18] This provides consistency between the U.S. and Ontario distributors regarding labour input prices and puts the input price in terms of each country's currency.

The non-labour component of the OM&A input price uses the gross domestic product price index ("GDP-PI") for the U.S. utilities. The Ontario non-labour component uses the same GDP-PI in each year, but adjusted for the purchasing power parity ("PPP") index. This translates the non-labour input price component into Canadian dollars.

To construct the overall OM&A input price, we weighted each index using a 70% labour and a 30% non-labour rate. This was the same weighting used in the 4GIR TFP and benchmarking research. Using the capital and OM&A cost shares, PSE calculated a total input price index.

Total cost is divided by this comprehensive input price index to adjust for regional input price differences between utilities and to account for annual inflation. Dividing total cost by the input price index imposes the requirement that total costs display linear homogeneity with respect to input prices. As the prices of inputs increase by X%, total cost should increase by that same percentage. For example, if all utility purchases (including labour) increase by 10%, its costs would also increase by 10%. This is derived from economic production theory, which states that costs equal input quantity multiplied by input price.

2.3.4 Business Condition Variables: Other

There are eight business condition variables aside from input prices, plus a time trend variable. Each variable is discussed briefly below.

The **percentage of electric customers** measures the percentage of electric customers served by a utility out of total gas and electric customers. This variable measures the economies of scope available from serving both electric and gas customers. Billing and other customer-related

[18] For Enersource Mississauga, PSE used City of Toronto data to formulate the wage level, since no data was available specifically for Mississauga.

activities can be shared between the gas and electric divisions when a utility serves its customers with both commodities. The value is set to 100% for Toronto Hydro and the six Ontario distributors, since they do not serve natural gas customers.

The **standard deviation of elevation** variable is calculated based on geographic information system ("GIS") elevation topography maps. A higher standard deviation of the elevation indicates increased elevation changes and variance within the utility's service territory. We would expect that a service territory with more hills, mountains, and other elevation changes would be more challenging and costly to serve, ceteris paribus. Therefore, a positive parameter estimate is expected.

The **percentage of forestation** variable is based on GIS land cover maps. PSE used the GlobCover 2009 product produced by the European Space Agency ("ESA") and the Université Catholique de Louvain. These maps are matched with the areas served by each utility to create the forestation variable. We would expect that the higher the level of forestation, the higher OM&A costs required for right-of-way clearing and service restoration activities. GIS variable data is available for all sampled U.S. utilities and for Toronto Hydro and the six Ontario distributors.

The **congested urban** variable measures the percentage of a utility's service territory that consists of a major urban load center that is "congested." Congested urban areas have physical constraints that necessitate complex and costly subterranean civil infrastructure for housing and operating electric distribution plant. Congested urban areas also often necessitate electrical equipment unique to such subterranean infrastructure. The variable is constructed using a combination of the following factors:

- Engineering knowledge of the physical constraints necessitating a complex and costly subterranean civil infrastructure,
- Classification of geographical areas developed from aerial imagery of urban areas with populations over 200,000, and
- GIS analysis of area classifications within a utility service territory.

The variable measures the percentage of service territory classified as congested urban area.

We expect a utility that has a congested urban area within its service territory would experience substantial incremental costs as compared to a utility that does not have such an area within its service territory. Likewise, we expect that the amount (or percentage) of congested urban area within a utility service territory has a variable impact on this incremental cost. The parameter value for this variable is expected to be positive, indicating a positive correlation of percent congested urban with total costs. Please see the Appendix for detailed maps used for the calculation.

The **percentage of smart meters** variable measures the percentage of customers that have an installed smart meter. Smart meters enable hourly or sub-hourly interval use data to be collected from the meter. While installing more capable meters and the necessary infrastructure is expected to increase distribution costs, these meters enable time-of-use electricity rates (TOU) that can create efficiencies for power suppliers. Since this study is focused on distribution total costs, we would expect a positive coefficient on the percent smart meter variable.

The **percent underground** variable measures the percentage of gross distribution plant in service that is underground. The variable has two possible impacts on total costs. The first is that underground lines have typically higher upfront costs than their overhead counterparts. Higher capital costs are especially large in urban settings. However, underground lines will also tend to lower OM&A expenses, due to lower exposure to environmental events and elements.

The **percent underground multiplied by congested urban variable** provides the interaction between the percent underground variable and the congested urban variable. Constructing underground lines in urban settings is far more costly than in more rural settings. For example, underground lines in rural settings can be "direct buried" without the need for concrete-enclosed banks and other capital infrastructure. We would expect a positive coefficient on the variable.

The **Ontario binary variable** measures the estimated cost differences between operating in Ontario versus the U.S. The variable is set equal to "1" if the utility operates in Ontario and "0" if the utility operates in the States. This variable adjusts for regulatory and other differences that may impact distribution costs between the two countries.

The **time trend** variable captures a general industry total cost level trend over the studied period. The time trend could reflect industry trends or influences that are not captured by the current variables (or perhaps even not captured by any possible variables). Time trend variables are often found in translog cost functions and econometric total cost benchmarking research. A similar variable was included in the 4GIR benchmarking models.

2.3.5 Projected Variable Values

For the years 2018-2024, projected values were used for Toronto Hydro's variables.

Input prices are calculated using the same procedures as the historical data, but with inflation projections. Input prices are divided into two categories: capital and OM&A. There are two components used to construct the OM&A input price: labour and non-labour. The non-labour OM&A component is based on the Conference Board of Canada's projections for the GDP-IPI as of April 2018. The projections range from 2.34% in 2018 to 1.99% in 2022 (we used the 2022 growth rate for 2023 and 2024). The labour component uses the Conference Board of Canada's

projections for average weekly earnings in Ontario. This ranges from 3.71% in 2018 to 2.49% in 2022 (we again used the 2022 growth rate for 2023 and 2024). The capital category is set to increase using the Conference Board of Canada's projections for Engineering Structures, Electric power generation, transmission, and distribution. This ranges from annual growth rates of 2.69% in 2018 to 2.18% in 2022, with 2.18% serving as the basis for the 2023 and 2024 growth rate.

The plant additions for 2018-2024 are based on Toronto Hydro projections. OM&A cost projections are set based on Toronto Hydro projections for 2018, 2019, and 2020 and then escalated following the inflation factor formula proposed by Toronto Hydro. This equals 1.82% growth per year from the 2020 value. This 1.82% projection is based on an assumed weighting of 30% labour and 70% non-labour within OM&A, using the Conference Board of Canada's projections for Average Weekly Earnings in Ontario (labour component) and their GDP-IPI projections (non-labour component) in 2021. This OM&A inflation value is 2.12%; then we subtract the X factor and stretch factor, which are set at 0.0% and 0.3%, respectively.

The projections for the other variables in the model are given below.

- **Retail customers** projections for 2018 to 2024 were given to PSE by Toronto Hydro.
- **Maximum peak demand** projections for 2018 to 2024 were given to PSE by Toronto Hydro.
- The **percentage of electric customers** is set to stay at 100% for Toronto Hydro.
- The **standard deviation of elevation** is set to stay at the historical value.
- The **percentage of forestation** variable is set to stay at the historical value.
- The **percent congested urban** variable is at the historical value of congested urban areas for Toronto Hydro.
- The **percent smart meter** variable uses the AMI meter projections provided to PSE by Toronto Hydro.
- The **percentage underground** variable is set at the historical value.
- The **percentage underground multiplied by the congested urban** variable is set at the historical value.
- The **time trend** variable continues to increase by one every year into the forecasted years.

2.3.6 2020 CIR Total Cost Variables Compared to 2015 CIR Total Cost Variables

The variables included in the present total cost model are similar to the variables used in PSE's 2015 CIR total cost research. The primary differences between the model variables in the present report and the 2015 CIR U.S. total cost model (discussed in Section 3) are as follows:

1. The 2015 CIR research used an "urban core" binary variable, whereas the present research instead uses a "congested urban" continuous variable.
2. The 2015 CIR research defined the maximum peak demand variable in terms of the peak demand for any given year, i.e. the peak demand changed every year. In contrast, the present research defines the maximum peak demand variable in terms of the peak demand since 2002, i.e. the highest demand level in the range applies to every subsequent year. The latter method is a better measure of the capacity level required for a utility to build its system to meet the historic maximum demand.
3. Three new variables have been constructed and included in the 2020 CIR research:

   (i) The percentage of smart meters;

   (ii) The percent of plant underground, multiplied by the new "congested urban" variable; and

   (iii) An Ontario binary variable.

   These variables capture the costs of adding smart meters, undergrounding in urban areas, and providing service in a different country than the majority of the sample, all of which are significant cost drivers.
4. Two variables that were used in the 2015 CIR total cost research have been dropped. These variables are:

   (i) The percent residential deliveries out of total deliveries, and

   (ii) The percentage of distribution plant out of total electric plant.

   The "percentage of distribution plant out of total electric plant" variable was dropped due to its incorrect coefficient sign.[19] The "percent residential deliveries out of total deliveries" variable was dropped because PSE could not identify the logical connection between total costs and percent residential deliveries served, as separate from the maximum peak demand variable. The "percent residential deliveries" variable would make sense as a proxy for load factor if the output variable were based on deliveries (rather than peak demand). However, since we are using an output variable that directly measures maximum

[19] The coefficient in the model is negative, whereas we would expect the coefficient to be positive, due to the expected economies of scope in providing more than just electric distribution service.

peak demand in the model, there is no valid reason to include the "percentage of residential deliveries" variable in the total cost model.

2.3.7 Perpetual Inventory Capital Cost Method

This report evaluates Toronto Hydro's capital costs as a component of the total cost definition. PSE's measure of capital cost is based on a service price approach. This approach has a solid basis in economic theory, and is the same method chosen by PEG in their 4th Generation IR research.[20] It allows for a clear-cut and standardized way to account for differences between utilities with respect to historical plant additions. The service price approach also has ample precedent in government-sponsored cost research. It is used by the Bureau of Labor Statistics of the U.S. Department of Labor in computing multi-factor productivity indexes for the U.S. private business sector and for several subsectors, including the utility services industry.

Based on this approach, the cost of capital in each period *t* is the product of indices of the capital service price and capital quantity in place at the end of the prior period. The formula for this is given by:

$$CK_t = WKS_t \cdot XK_{t-1}$$

Here, in each period *t*, CK_t is the cost of capital, WKS_t is the capital service price index, and XK_{t-1} is the capital quantity index value at the start of the period.

The capital quantity index is constructed using inflation-adjusted data on the value of net utility plant in a benchmark year, and on gross plant additions in subsequent years. It also uses an assumption about service lives. We use 1989 as the benchmark year in the current study for all U.S. utilities. We use 2002 as the benchmark year for Toronto Hydro because this is the earliest available year to begin the capital series. We use 2002 as the benchmark year for the six Ontario distributors to match the Toronto Hydro benchmark year and to avoid making imputations on the capital additions for years prior to 2002.

Based on the benchmark year, a "triangulated weighted average" ("TWA") is used to calculate the capital stock in 2002. Subsequent years use the previous year's capital stock and escalate it by plant additions minus depreciation. This method is used both for Toronto Hydro, the six Ontario distributors, and U.S. distributors. The formulas for the capital quantity index in 2002 and in subsequent years are provided below.[21]

[20] See Hall and Jorgensen (1967) for a discussion of the use of service price methods for measuring capital cost.

[21] For the U.S. utilities, the beginning year is 1989 instead of 2002.

$$XK_{2002}^{i} = \frac{Net\ Plant_{2002}^{i}}{TWA_{2002}^{i}}$$

$$XK_{t}^{i} = XK_{t-1}^{i} * d + \frac{Add_{t}^{i}}{WKA_{t}^{i}}$$

Under the service price approach employed in this study, capital cost has two components: opportunity cost and depreciation. The capital service price index is thus given by the formula:

$$WKS_t = r_t * WKA_{t-1} + d_t * WKA_t$$

Here, r_t is the allowed rate of return based on the Board's historical calculated returns. This same annual value is also used in the capital service price computation for the U.S utilities in the dataset. Setting the same rate of return for all distributors provides consistency in determining the capital costs, so that decisions by regulators do not enter the benchmark evaluation, which is attempting to assess the performance of the utility itself. The parameter d_t is the economic depreciation rate. We use the same value as was used in 4GIR (4.59%) for this parameter in the study.

The variable that the capital service price components have in common is WKA_t. This is an index of the price of capital assets used in power distribution. We compute this index using data on differences in the cost of constructing utility plant between regions, and within regions over time. In particular, for U.S. distributors we use the Handy-Whitman indexes for total power distribution plant, which vary over time and across six geographic regions. For Toronto Hydro and the six Ontario distributors, we used the Handy-Whitman index for the North Atlantic region.

We determine the relative levels of utility plant asset prices for 2012 by using the City Cost Indexes for electrical work in RSMeans' *Heavy Construction Cost Data*. These indexes measure differences among cities in the cost of labour needed to install electrical equipment and differences in equipment prices. The construction service categories covered are: raceways; conductors and grounding; boxes and wiring devices; motors, starters, boards, and switches; transformers and bus ducts; lighting; electric utilities; and power distribution. The level of the asset price index for each utility is the simple average of the RSMeans index values for cities in the service territory. This same source is used for the U.S., the six Ontario distributors, and Toronto Hydro.[22] The index is already adjusted for currency differences between the two countries.

[22] For the Enersource Mississauga observation, we used the City of Toronto to set the level of the asset price index, since Mississauga is not included in the RSMeans data.

2.3.8 Total Cost Sample

There are 90 utilities included in the total cost sample (this number includes Toronto Hydro). A diverse dataset including utilities with varying operational conditions is necessary to determine the influence on costs resulting from those conditions. There are many U.S. utilities in the PSE dataset which are larger than Toronto Hydro, and many that are smaller than Toronto Hydro. The utilities are listed in the following table, along with their 2016 number of customers.

Table 5 Total Cost Sample

Company Name	Number of Customers (2016)	Company Name	Number of Customers (2016)
Alabama Power Company	1,468,744	**London Hydro**	**155,496**
ALLETE (Minnesota Power)	145,622	Louisville Gas and Electric Company	404,744
Appalachian Power Company	956,718	Madison Gas and Electric Company	150,491
Arizona Public Service Company	1,193,511	MDU Resources Group, Inc.	142,948
Atlantic City Electric Company	548,442	Metropolitan Edison Company	562,850
Avista Corporation	374,507	Mississippi Power Company	187,553
Baltimore Gas and Electric Company	1,268,995	Monongahela Power Company	389,759
Black Hills Power, Inc.	71,081	Nevada Power Company	903,198
Central Hudson Gas & Electric Corporation	261,411	New York State Electric & Gas Corporation	890,260
Central Maine Power Company	619,312	Niagara Mohawk Power Corporation	1,323,415
Cleco Power LLC	288,013	Northern Indiana Public Service Company	464,146
Cleveland Electric Illuminating Company	747,748	Northern States Power Company - MN	1,454,285
Commonwealth Edison Company	3,953,907	Northern States Power Company - WI	256,540
Connecticut Light and Power Company	1,238,337	Ohio Edison Company	1,041,123
Consolidated Edison Company of New York,	3,420,121	Oklahoma Gas and Electric Company	830,057
Consumers Energy Company	1,804,630	Orange and Rockland Utilities, Inc.	229,533
Delmarva Power & Light Company	516,709	Pacific Gas and Electric Company	5,428,390
DTE Electric Company	2,169,416	PECO Energy Company	1,613,041
Duke Energy Carolinas, LLC	2,519,317	Pennsylvania Electric Company	587,251
Duke Energy Florida, LLC	1,743,136	Pennsylvania Power Company	164,285
Duke Energy Indiana, LLC	812,986	Portland General Electric Company	859,396
Duke Energy Kentucky, Inc.	140,014	Potomac Electric Power Company	848,171
Duke Energy Ohio, Inc.	706,793	PPL Electric Utilities Corporation	1,426,676
Duke Energy Progress, LLC	1,526,422	Public Service Company of Colorado	1,441,982
Duquesne Light Company	587,954	Public Service Company of New Hampshire	507,998
El Paso Electric Company	408,504	Public Service Company of Oklahoma	547,142
Empire District Electric Company	170,529	Public Service Electric and Gas Company	2,227,065
Enersource Mississauga	**204,728**	Puget Sound Energy, Inc.	1,119,711
Entergy Arkansas, Inc.	706,879	San Diego Gas & Electric Co.	1,425,132
Entergy Mississippi, Inc.	446,654	South Carolina Electric & Gas Co.	705,025
Entergy New Orleans, Inc.	198,416	Southern California Edison Company	5,049,192
EnWin	**87,901**	Southern Indiana Gas and Electric Company, Inc.	148,429
Florida Power & Light Company	4,840,266	Southwestern Public Service Company	389,483
Gulf Power Company	453,136	Tampa Electric Company	730,503
Horizon Utilities	**244,114**	**Toronto Hydro**	**761,920**
Hydro Ottawa	**327,880**	Toledo Edison Company	309,060
Idaho Power Co.	529,901	Tucson Electric Power Company	419,845
Indiana Michigan Power Company	589,041	Union Electric Company	1,208,934
Indianapolis Power & Light Company	486,827	United Illuminating Company	332,381
Jersey Central Power & Light Company	1,113,459	Virginia Electric and Power Company	2,550,018
Kansas City Power & Light Company	531,630	West Penn Power Company	723,352
Kansas Gas and Electric Company	325,932	Western Massachusetts Electric Company	209,939
Kentucky Power Company	168,848	Wisconsin Electric Power Company	1,142,983
Kentucky Utilities Company	547,069	Wisconsin Power and Light Company	466,052
Kitchener-Wilmont Hydro	**94,058**	Wisconsin Public Service Corporation	449,877

2.4 Econometric Method (Detailed)

The benchmarking approach used in this report is the econometric approach. PSE believes this is the most accurate and fair method to use when comparing utility cost and reliability levels. It is also the method preferred by the Board in the 4GIR Decision.

The econometric approach explicitly adjusts for differences in utilities' service territories. In the power distribution industry, simple comparisons of costs or reliability indexes do not result in appropriate comparisons when evaluating performance. Uncontrollable factors such as service territory characteristics influence total costs. Therefore, more sophisticated tools that normalize for specific influencing factors must be employed to accurately assess performance. With this concept in mind, PSE has developed an econometric benchmarking model that considers factors that have proven to be statistically influential on distribution utility costs.

The econometric benchmarking approach relies on comparing actual data values to the predicted values, which are obtained from the econometric models. The researcher determines an appropriate functional form (a model) for the relationship between the studied metric and factors (variables) that influence it. This is done by using appropriate econometric methods to obtain parameter estimates for each variable of the specified model.

In this report, we estimate the translog cost function, which is well established in academic literature and provides a high level of flexibility in estimating costs. This is also the functional form preferred by the Board in the 4th Generation IR proceeding.

Cost predictions for each firm are obtained by inserting company-specific variable values into the estimated equation for a given year. Performance is defined as the percentage difference between the observed (or projected) data to the predicted value of the data for the year in question, as shown below.

$$Performance = \ln\left(\frac{Observed\ Cost\ Data}{Predicted\ Cost\ Data}\right)$$

NOTE: The term "ln" above denotes the natural log. The formula above is utilized for calculating percentage differences. It is typically used by both PSE and PEG to display benchmark scores.

2.4.1 Estimation Procedure and Translog Cost Function

As a starting point, we assume that the relationship between a utility's cost and the conditions that affect it, called "cost drivers" (i.e., the variables), can be quantified and captured by a statistical function. This function, called a "cost function," allows PSE to specify cost as a dependent variable

that can be explained by relevant independent or explanatory variables and associated parameters; the latter captures the effect of the independent variables on cost. Such a cost function is estimated using econometric techniques that rest on certain fundamental assumptions.

In general, cost is assumed to be a function of: input prices, the output produced by the firm, and other independent variables that affect cost but are outside management's control. While a function specified in this manner can capture a reasonable level of cost variability, it does not explain all the elements that affect cost. Therefore, the function includes a random noise term to account for such idiosyncratic factors.

The following equation provides an example of a simple cost function:

$$C = \beta_o + \beta_1 * Y + \varepsilon$$

In this equation, the terms C and Y, denote cost and output, respectively. The beta terms denote model parameters that capture the magnitude and sign of the effect of the explanatory variables on cost, and the error term captures random noise. The latter is assumed to be independent of the explanatory variables.

The data used to estimate this cost relationship can consist of different types of observations, as follows:

- Data from a single utility with multiple time observations (time series data),
- Data from many utilities observed at a single time period (cross-sectional data), or
- Data from many utilities with multiple time observations (cross-sectional time-series or panel data).

The estimation procedure used to estimate model parameters is affected by the type of data used to estimate the model. In our present study, we have a panel dataset with cost data from multiple utilities with multiple observations starting in 2002 and extending to 2016 (or 2024 for Toronto Hydro). The model specification adjusts for heteroskedacity.

2.4.2 Statistical Tests

The precision of parameter estimates is an important dimension of the cost estimation exercise. It identifies business condition variables that have a statistically significant effect on cost. In particular, standard errors of parameter estimates, which measure the precision that a parameter is estimated, are used to construct a test of a relevant hypothesis. The null hypothesis to be tested is "the explanatory variable in question has no statistically significant effect on cost." This procedure is called the *t*-test. A variable is statistically significant if this hypothesis is rejected at a pre-specified level of confidence. We use a 90 percent confidence threshold for first-order terms in our research.

A cost model with plausibly signed and statistically significant parameter estimates is ultimately

used to assess the cost performance of each firm in the sample. By "plausibly signed" we mean that its sign (positive/negative) accords with our intuitive understanding of the relationship between that parameter and the variable. For example, we would expect to see costs rise as the number of customers served increases (i.e. the customer parameter would be positively signed).

A cost model with estimated parameters is fitted with the business conditions of each utility to generate cost benchmarks, against which actual cost is evaluated. A cost benchmark reflects the performance of an average utility facing the business conditions of the utility whose values are used to generate the benchmark. A benchmark can be determined for a particular utility for any given year; the particular business conditions and variables for that year are put into the model, producing an "expected" or benchmark value for that year.

If a given utility's actual cost is below the benchmark cost (for a given year or time period), its cost performance is better than average—it spent less than a hypothetical utility (with the same particular characteristics) would be expected to spend. If its actual cost is above the benchmark cost, the utility's cost performance is worse than average. A statistical test of a cost efficiency hypothesis, based on the *t*-test, can also be constructed to identify whether the cost performance identified by the above exercise is not statistically significantly different to the average.

3 The Board's Three Key Areas on 2015 Total Cost Benchmarking

In the 2015 Board Decision, the Board identified three key areas where the benchmarking evidence differed between the experts. On page 15, the Board wrote:

> The experts' evidence on benchmarking differs in three key areas;
>
> 1. The Urban core variable
> 2. Approach to CDM costs
> 3. Asset price inflation costs (capital cost escalation rate)

The Board then addressed its conclusions in each of the three key areas on pages 16 to 18 of the 2015 Board Decision. PSE has re-examined the 2015 Board Decision and has addressed these three key areas identified by the Board. We discuss each area and the approach taken by PSE in the current benchmarking research for the 2020 CIR application.

3.1 Urban Core Variable

The Board states on page 16 of the 2015 Board Decision: "While the OEB agrees that the premise of an urban core variable warrants further investigation, it cannot determine that the evidence demonstrates that it exists."

The Board cited the small sample size of four utilities that PSE used for the binary variable as one of the reasons for not being able to determine the validity of the variable.[23] The Board also notes that the Board Staff consultant, PEG, substituted in a dummy variable constituting 27 US cities. However, this variable included a number of cities that do not have a population or urban density similar to Toronto. The Board cited the city of Buffalo as an example of a city that PEG defined as an urban core city that does not match well with Toronto.

The Board also notes that it was not clear as to how much of the Toronto Hydro service area is part of the urban core and what capital projects are proposed to occur in that area.

[23] Page 16 of the 2015 Board Decision.

3.1.1 PSE's Solution to the Urban Core Variable

PSE noted the Board's reluctance in 2015 to depend on a variable that only included four observations (the four utilities with cities that had populations which exceeded one million, i.e. the "urban core" cities). We also noted the Board's reluctance to follow the PEG approach to the variable (including a binary variable of dissimilar cities).

PSE's recommended solution is as follows: rather than create a binary variable of four cities with similar population thresholds as Toronto, we used publicly available aerial imagery to examine the above-grade physical characteristics of cities with populations above 200,000, identified geographical areas within a GIS platform defined by PSE as "congested urban," and calculated the percentage of each utility's service territory that falls under this definition. This vastly improves upon the previously applied binary variable of four utilities, by replacing it with a continuous variable with varying percentages for each utility. The solution has resulted is a "congested urban" value that is above zero for over 40 U.S. utilities, Toronto Hydro, and six Ontario distributors.

Rather than using the blunt instrument of a binary variable that designates a utility as either a "one" or "zero" based on a given criteria, we calculate distinct values for each utility, based on the percentage of congested urban area within their respective service territories. Both PSE and PEG used the blunt urban core binary variable in the 2015 benchmarking research (albeit based on different criteria). However, the "congested urban" variable used in the present report uses the continuous variable approach. It should be noted that most of the other variables in the model (e.g., percent forestation, percent electric customers, etc.) are also continuous variables, rather than binary. This approach to the congested urban variable is a vast improvement from the 2015 research, and should help alleviate the Board's concerns. PSE's research produces evidence that serving a dense urban core increases cost and, therefore, serving a highly congested urban area should be adjusted for within the econometric total cost model. PSE makes this adjustment in our current research.

3.1.1.1 Definition of Congested Urban Area

PSE defines "congested urban" as a geographical area of a major urban load center with physical constraints that necessitate a complex and costly subterranean civil infrastructure for housing and operating electric distribution plant. Electrical equipment unique to such subterranean infrastructure is also required in these congested urban areas.

Characteristics of a major urban load center include a concentration of high-rise and mid-rise buildings.[24] Such a concentration of buildings results in a large amount of electric energy and demand within a relatively small geographical area. Physical constraints of congested urban areas

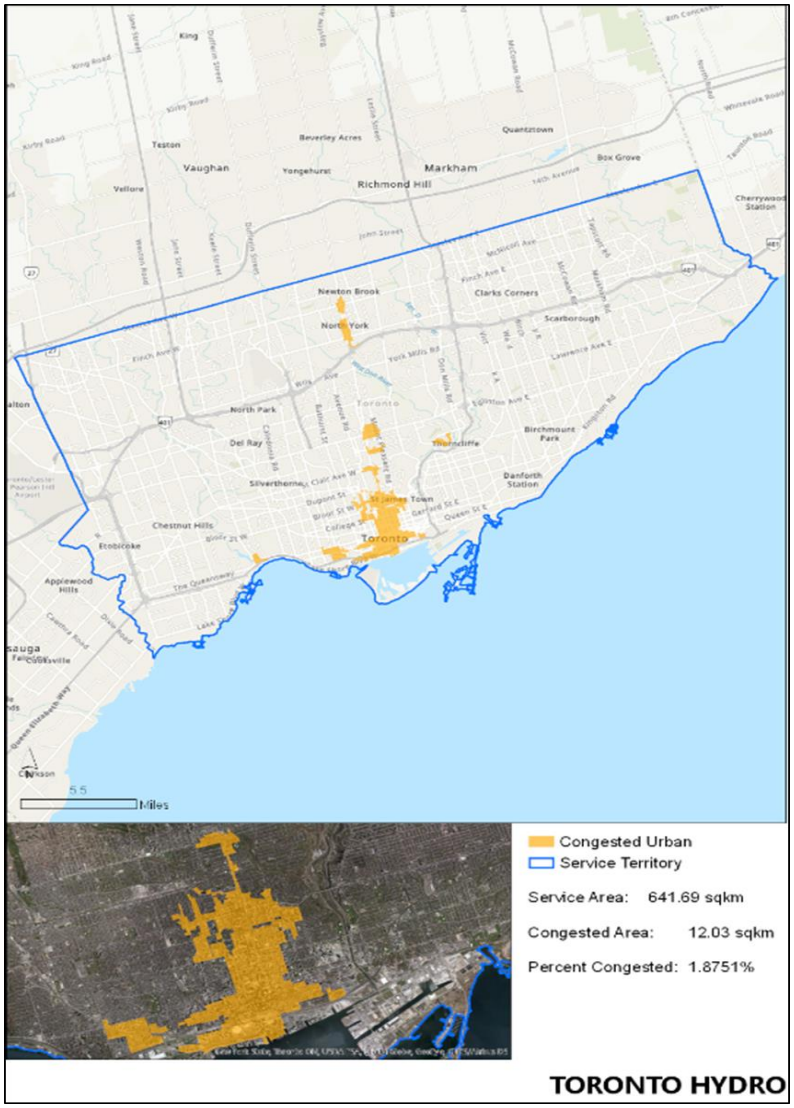
[24] For PSE's assessment, mid-rise buildings are defined as 7 to 12 stories and high-rise buildings are defined as 13 stories and greater.

necessitate subterranean civil infrastructure for housing electric distribution plant. For example, underground vaults may be required in areas where building setbacks, sidewalks, and roads do not accommodate the presence of overhead or pad-mounted electric utility lines and equipment. The combination of these factors (increased demand concentration plus lack of space for traditional equipment) results in the necessity of subterranean civil infrastructure, and corresponding electrical equipment, that is complex and costly to construction and maintain.

3.1.1.2 Congested Urban Area within Toronto Hydro's Service Territory

Guided by the considerations discussed above, PSE used publicly available aerial imagery of the City of Toronto, and a customized GIS tool that mapped each utility's service territory and the area identified as congested urban within that territory, to delineate congested urban areas. The map below illustrates the congested urban area (designated in orange) within the City of Toronto. This area accounts for a relatively large portion of the downtown area. The congested urban area also constitutes portions of midtown.

Figure 4 Toronto Hydro Congested Urban Map



3.1.1.3 Congested Urban Area for Other Cities

PSE undertook the approach used for the Toronto Hydro service territory and applied it to US cities with populations greater than 200,000 served by utilities within the dataset. We also applied the same approach to all Ontario distributors that served cities that had populations greater than 200,000 and contained congested urban territory. We only included the Ontario utilities that contained congested urban territory in their service territory in the sample. The maps for each corresponding sampled utility are provided in the Appendix to this report.

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3.2 Approach to CDM Costs

On page 17 of the 2015 Board Decision, the Board writes:

> The two experts took different approaches to account for CDM expenses. The issue arose as CDM expenses are reflected in the costs of the U.S. utility sample but not those of Toronto Hydro. PEG's approach was to eliminate customer service and information (CSI) expenses from the U.S. utility sample as CDM expenses account for the largest share of CSI costs. PSE's approach was to add CSI costs back to its U.S. cost measure, while also adding in Toronto Hydro's actual and projected CDM expenses.

The Board did not state its preference between the two approaches. PSE believes that both approaches are valid, as they assure a consistent cost definition between Toronto Hydro and the U.S. sample. In an effort to reduce potential differences and address this key area identified by the Board, PSE has adopted PEG's methodology in our current research and eliminated CSI expenses for the U.S. sample and for Toronto Hydro.

3.3 Asset Price Inflation Costs (Capital Cost Escalation Rate)

PSE used an asset price inflation assumption in our 2015 research that projected a rate of 4.55%. During the 2015 CIR proceeding, PEG stated that a 2% growth rate was a more reasonable assumption. PSE argued that 2% was too low, based on historical growth rates of electric distribution asset inflation. PSE noted that PEG's analysis was distorted due to declining interest rates during the recent time frame.

The Board stated on page 18 of the 2015 Board Decision that "[t]he OEB considers the asset price inflation value used by PEG to be more appropriate."

PSE noted PEG's recent research where they used a 2.58% assumption in their research for Oshawa PUC.[25] This growth rate used by PEG was based on using the Conference Board of Canada price projections for "Engineering Structures, Electric power generation, transmission, and distribution." PSE did not note any objections regarding the use of these price projections for the asset price inflation assumption.

[25] PEG Report, "Benchmarking the Forecasted Cost of Oshawa PUC Networks", December 18, 2014. EB-2014-0101, Exhibit 10, Tab A.

For this research, PSE gathered the same price projections from the Conference Board of Canada as used by PEG in the Oshawa PUC research and applied the growth rates to the asset price inflation assumption for 2018 to 2024. As of April 2018, the Conference Board of Canada had the 2018 growth rate at 2.69%, and the 2019, 2020, 2021, and 2022 growth rates at 2.18%. PSE then applied the 2022 growth rate of 2.18% to the remaining CIR period.

4 Total Cost Benchmarking Results

The estimates from the total cost model are presented in the following table. The results in the table show that the cost function parameter estimates have plausible signs and magnitudes. The output variables are fully interacted based on the translog cost function specification. The business condition variables have both a first order term and a quadratic term to capture the curvature in the cost impact as the value increases or decreases from the sample mean. The first order terms of all variables have the theoretically expected signs and are statistically significant at the standard 90% confidence level.

Table 6 Total Cost Model Estimates

Total Cost Model Estimates

VARIABLE KEY

N = Number of Retail Customers
D = Maximum peak demand
%E = Percent of electric customers
El = Elevation standard deviation
%F = Percent forestation
%CU = Percent congested urban
%AMI = Percent AMI meters
%UG = Percent underground distribution plant
%UGU = %UG * %CU
Ontario = Binary variable for Ontario distributor
Trend = Number of years since 2001

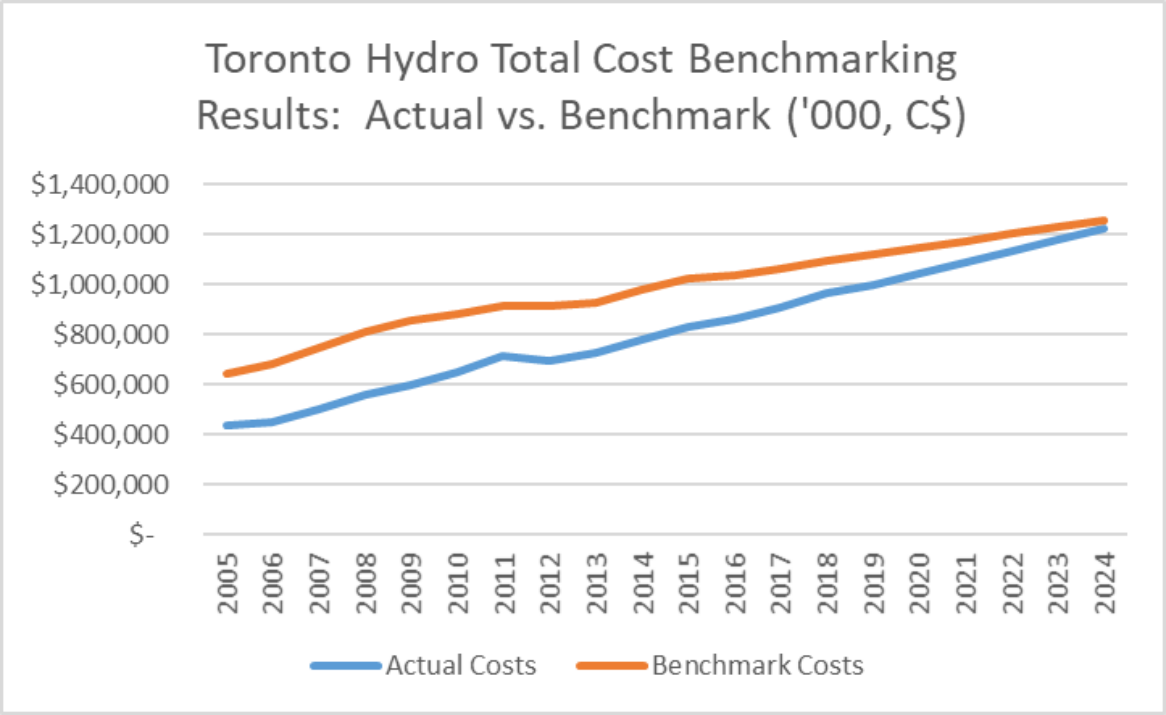
EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC	EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC
N	0.715	67.903	%UG	-0.077	-4.676
N*N	0.213	15.334	%UG*%UG	-0.002	-0.482
N*D	-0.308	-23.501	%UGU	104.843	10.564
			%UGU*%UGU	6080.017	7.620
D	0.261	24.040	Ontario	-0.304	-35.592
D*D	0.145	25.346			
			Trend	-0.005	-8.463
%E	0.407	17.431			
%E*%E	0.348	10.766	Constant	12.780	535.646
El	0.102	6.816			
El*El	-0.007	-3.942	Adjusted R-Squared		0.992
%F	0.081	18.163			
%F*%F	0.007	12.977	Sample Period:		2002-2024
%CU	160.845	19.382	Number of Observations		1318
%CU*%CU	-5664.714	-12.751			
%AMI	0.109	2.581			
%AMI*%AMI	-0.029	-0.642			

The next table and figure break down the benchmark total costs and company total costs from 2005 to 2024. Toronto Hydro has consistently been below its expected benchmark levels. During the most recent historical period of 2015 to 2017, Toronto Hydro's costs are 18.6% below the benchmark values. During the CIR period of 2020 to 2024, Toronto Hydro's costs are 6.0% below the benchmark values on average.

Table 7 Toronto Hydro's Cost Performance 2005-2024

Year	Toronto Hydro Actual Costs ('000, C$)	Toronto Hydro Benchmark Costs ('000, C$)	% Difference (Logarithmic)
2005	$ 436,128	$ 641,275	-38.6%
2006	$ 450,686	$ 681,212	-41.3%
2007	$ 502,433	$ 744,486	-39.3%
2008	$ 556,429	$ 813,528	-38.0%
2009	$ 595,932	$ 852,775	-35.8%
2010	$ 647,456	$ 882,130	-30.9%
2011	$ 710,544	$ 912,729	-25.0%
2012	$ 691,388	$ 910,814	-27.6%
2013	$ 727,152	$ 925,488	-24.1%
2014	$ 777,414	$ 976,095	-22.8%
2015	$ 826,886	$ 1,024,030	-21.4%
2016	$ 861,394	$ 1,034,492	-18.3%
2017	$ 904,560	$ 1,061,642	-16.0%
2018 (projected)	$ 964,885	$ 1,095,430	-12.7%
2019 (projected)	$ 999,492	$ 1,122,407	-11.6%
2020 (projected)	$ 1,044,567	$ 1,148,601	-9.5%
2021 (projected)	$ 1,085,324	$ 1,174,549	-7.9%
2022 (projected)	$ 1,134,689	$ 1,201,662	-5.7%
2023 (projected)	$ 1,180,820	$ 1,229,463	-4.0%
2024 (projected)	$ 1,225,282	$ 1,257,907	-2.6%
Average % Difference			
2015-2017			**-18.6%**
2020-2024			**-6.0%**

Figure 5 Toronto Hydro's Cost Performance 2005-2024



5 Reliability Benchmarking: Variable Definitions, Datasets, Models

5.1 Reliability Benchmarking: Summary

To present a more complete picture of Toronto Hydro's total cost performance, PSE also benchmarked reliability. To benchmark reliability, we need standard reliability metrics. Nearly all jurisdictions that require reporting of reliability indicators include the metrics of SAIDI, SAIFI, and CAIDI.[26] SAIDI measures the average duration of sustained interruptions per utility customer. SAIFI is a gauge of the average frequency of sustained interruptions per customer. CAIDI evaluates the average duration time per sustained interruption. SAIDI is thus the product of SAIFI and CAIDI.

$$SAIDI = SAIFI * CAIDI$$

The study focused on the reliability indexes of SAIFI and CAIDI. SAIFI measures the average number of outages a customer experiences per year. It indirectly measures the propensity of the distribution grid to fail. CAIDI measures the average restoration time when an outage does occur. It indirectly measures the company's response time and preparedness for outage restoration. Since SAIDI is the product of both SAIFI and CAIDI, it would be redundant to measure all three.

Several jurisdictions exclude extraordinary events from reliability statistics, with the goal of increasing historical comparability. The bulk of excluded events stem from major storms. These severe storms vary in number and intensity from year to year. MED definitions are determined by each regulatory commission. Definitions vary by state; some use the IEEE standard 1366-2003 to determine what constitutes a MED.[27] Other states have customized definitions. For example, in some states if 10 percent of a utility's customers experience an outage lasting more than a 24-hour period, a MED has occurred. States are gradually shifting towards the IEEE standard; however, considerable differences across states remain. As a result, we benchmark Toronto Hydro's reliability using the IEEE method for Toronto Hydro. Toronto Hydro also reported its reliability index using a sustained outage definition of five minutes, which matches what most of the sample uses as a sustained outage definition.

[26] Some states only require reporting of two of these measures. However, the excluded indicator can still be determined by the researcher. SAIDI is equal to the product of SAIFI and CAIDI.

[27] The IEEE 1366-2003 standard defines the "beta" method. If outages for a certain day exceed 2.5 standard deviations from the normal day, a major event day is declared. A normal day and the standard deviation are determined by the utility's previous five years of normal day data (not including the MEDs).

By excluding MEDs from the reliability indexes, we reduce the variance in the indexes associated with large and uncontrollable weather occurrences. The benchmark evaluation in this study is measuring the performance of utilities during the normal operations and not during severe weather events.

5.2 Data Sources

The industry reliability data for U.S. utilities is gathered through reports and rate case filings made public by state commissions and through the EIA-861 form. Reliability indices for Toronto Hydro were gathered directly from the company.

The variable values that appear in both the total cost model and the reliability model are equal. For example, the "percent forestation" variable will have the same value for a given utility/year in both models. The reliability benchmarking models we developed use the following variables:

- Number of customers;
- Percent forestation;
- Percent underground (in SAIFI model only);
- Standard deviation of the elevation changes in the service territory (in CAIDI model only);
- Square kilometers of territory per customer;
- Percent smart meters (in CAIDI model only);
- Percent congested urban in service territory (in CAIDI model only); and
- IEEE binary variable (in SAIFI model only).

5.3 Reliability Dataset

The reliability dataset is comprised of 74 distributors (this number includes Toronto Hydro). The dataset is the same for both the SAIFI and CAIDI models. The data for the U.S. utilities in each sample spans the years 2010 to 2016. Given the changes in reliability reporting and automation, we started the sample in 2010 to get more recent results. In each sample, some utilities have data available from 2010 to 2016, while others have more limited data available. We also inserted future reliability metric projections from Toronto Hydro, which assume full funding of the proposed capital program. The following table lists the utilities comprising the reliability sample, along with their 2016 number of customers.

Table 8 Sampled Utilities for Reliability Benchmarking

Company Name	Number of Customers (2016)	Company Name	Number of Customers (2016)
Alabama Power Company	1,468,744	Metropolitan Edison Company	562,850
ALLETE (Minnesota Power)	145,622	Monongahela Power Company	389,759
Appalachian Power Company	956,718	Nevada Power Company	903,198
Arizona Public Service Company	1,193,511	New York State Electric & Gas Corporation	890,260
Atlantic City Electric Company	548,442	Niagara Mohawk Power Corporation	1,323,415
Avista Corporation	374,507	Northern Indiana Public Service Company	464,146
Baltimore Gas and Electric Company	1,268,995	Northern States Power Company - WI	256,540
Central Hudson Gas & Electric Corporation	261,411	Ohio Edison Company	1,041,123
Central Maine Power Company	619,312	Oklahoma Gas and Electric Company	830,057
Cleveland Electric Illuminating Company	747,748	Orange and Rockland Utilities, Inc.	229,533
Commonwealth Edison Company	3,953,907	Pacific Gas and Electric Company	5,428,390
Connecticut Light and Power Company	1,238,337	PECO Energy Company	1,613,041
Consolidated Edison Company of New York,	3,420,121	Pennsylvania Electric Company	587,251
Consumers Energy Company	1,804,630	Pennsylvania Power Company	164,285
DTE Electric Company	2,169,416	Portland General Electric Company	859,396
Duke Energy Carolinas, LLC	2,519,317	Potomac Electric Power Company	848,171
Duke Energy Florida, LLC	1,743,136	PPL Electric Utilities Corporation	1,426,676
Duke Energy Indiana, LLC	812,986	Public Service Company of Colorado	1,441,982
Duke Energy Kentucky, Inc.	140,014	Public Service Company of New Hampshire	507,998
Duke Energy Ohio, Inc.	706,793	Public Service Company of Oklahoma	547,142
Duquesne Light Company	587,954	Public Service Electric and Gas Company	2,227,065
El Paso Electric Company	408,504	Puget Sound Energy, Inc.	1,119,711
Empire District Electric Company	170,529	San Diego Gas & Electric Co.	1,425,132
Entergy Arkansas, Inc.	706,879	South Carolina Electric & Gas Co.	705,025
Entergy Mississippi, Inc.	446,654	Southern California Edison Company	5,049,192
Entergy New Orleans, Inc.	198,416	Southern Indiana Gas and Electric Company, Inc.	148,429
Florida Power & Light Company	4,840,266	Tampa Electric Company	730,503
Gulf Power Company	453,136	THESL	761,920
Idaho Power Co.	529,901	Toledo Edison Company	309,060
Indiana Michigan Power Company	589,041	Union Electric Company	1,208,934
Indianapolis Power & Light Company	486,827	United Illuminating Company	332,381
Jersey Central Power & Light Company	1,113,459	Virginia Electric and Power Company	2,550,018
Kansas Gas and Electric Company	325,932	West Penn Power Company	723,352
Kentucky Power Company	168,848	Western Massachusetts Electric Company	209,939
Kentucky Utilities Company	547,069	Wisconsin Electric Power Company	1,142,983
Louisville Gas and Electric Company	404,744	Wisconsin Power and Light Company	466,052
Madison Gas and Electric Company	150,491	Wisconsin Public Service Corporation	449,877

5.4 Econometric Reliability Benchmarking Model

The basic econometric benchmarking procedure for reliability is similar to the one described for the total cost modeling. PSE's method applies regression techniques to the sampled data to form a mathematical model. The model accepts inputs (forestation levels, wind speeds, etc.) and produces an expected reliability index for each utility for a given year. By using the model, given a set of

operating conditions, PSE can estimate an "expected" or benchmark reliability level for each utility in each year.

This technique allows for "apples-to-apples" comparisons, and therefore produces a more accurate assessment of performance (relative to simply making industry comparisons of "raw" CAIDI and SAIFI).

Each model includes utilities with varying time-series lengths covering the years 2010 to 2016.[28] This type of dataset requires an estimation procedure that accounts for the cross-sectional time-series ("panel") nature of the data. We use an estimator that corrects for cross-sectional heterogeneity and addresses the panel form of the data.

The results from the SAIFI and CAIDI models are presented in the following two tables.

Table 9 SAIFI Econometric Model Coefficients

Variable	Coefficient Estimate	T-Stat
Constant	-0.454	-3.800
Number of Customers	-0.011	-1.565
% Forestation	0.018	1.936
% Underground	-0.336	-24.433
Sq. KM per Customer	0.020	1.675
IEEE	0.168	10.147

Table 10 CAIDI Econometric Model Coefficients

Variable	Coefficient Estimate	T-Stat
Constant	4.465	56.155
Number of Customers	0.024	5.399
% Forestation	0.090	21.325
S.D of Elevation	0.061	9.060
Sq. KM per Customer	0.064	5.999
% AMI	-0.090	-8.383
% Congested Urban	6.688	2.709

[28] Utilities in the United States began reporting reliability metrics at different times.

6 Reliability Benchmarking Results

We find that Toronto Hydro's 2015-2017 average SAIFI is 47.2% above the benchmark value. Our research on Toronto Hydro's 2015-2017 average CAIDI indicates that the reliability level is 63.4% below the benchmark value.

The year-by-year breakdowns for both SAIFI and CAIDI are provided in the following tables. These tables provide both the actual reliability values for Toronto Hydro, along with the econometric benchmark value.

Table 11 Toronto Hydro's SAIFI Performance 2005-2024

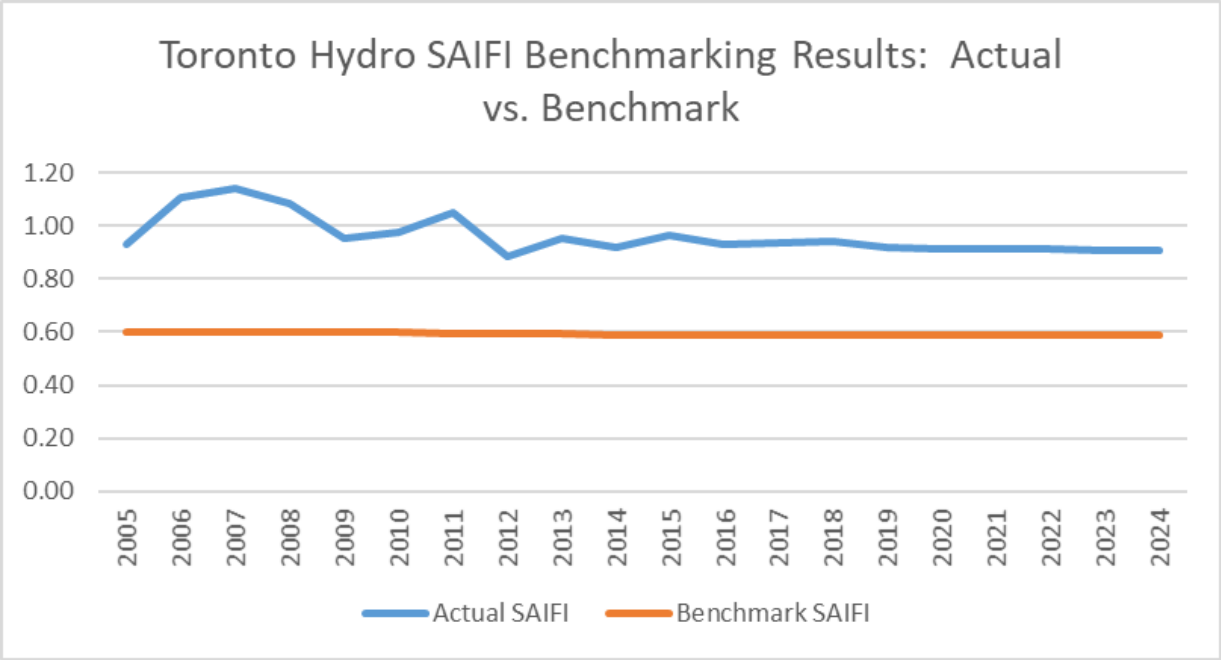
Year	Toronto Hydro Actual SAIFI	Toronto Hydro Benchmark SAIFI	% Difference (Logarithmic)
2005	0.93	0.60	43.7%
2006	1.11	0.60	61.2%
2007	1.14	0.60	63.9%
2008	1.08	0.60	58.8%
2009	0.95	0.60	46.4%
2010	0.98	0.60	48.9%
2011	1.05	0.60	56.7%
2012	0.88	0.59	39.8%
2013	0.95	0.59	47.5%
2014	0.92	0.59	44.5%
2015	0.97	0.59	49.7%
2016	0.93	0.59	45.7%
2017	0.94	0.59	46.3%
2018 (projected)	0.94	0.59	46.7%
2019 (projected)	0.92	0.59	44.3%
2020 (projected)	0.92	0.59	44.0%
2021 (projected)	0.91	0.59	43.8%
2022 (projected)	0.91	0.59	43.6%
2023 (projected)	0.91	0.59	43.5%
2024 (projected)	0.91	0.59	43.5%
Average % Difference			
2015-2017			**47.2%**
2020-2024			**43.7%**

Table 12 Toronto Hydro's CAIDI Performance 2005-2024

Year	Toronto Hydro Actual CAIDI	Toronto Hydro Benchmark CAIDI	% Difference (Logarithmic)
2005	76.59	122.67	-47.1%
2006	64.98	121.06	-62.2%
2007	69.12	119.21	-54.5%
2008	67.40	118.13	-56.1%
2009	84.13	117.47	-33.4%
2010	77.30	117.27	-41.7%
2011	80.13	117.12	-38.0%
2012	68.06	116.97	-54.2%
2013	70.61	116.84	-50.4%
2014	63.76	116.67	-60.4%
2015	64.04	116.48	-59.8%
2016	59.71	116.40	-66.8%
2017	61.54	116.26	-63.6%
2018 (projected)	61.96	116.21	-62.9%
2019 (projected)	65.96	116.16	-56.6%
2020 (projected)	66.10	116.11	-56.3%
2021 (projected)	66.21	116.06	-56.1%
2022 (projected)	66.34	116.01	-55.9%
2023 (projected)	66.51	115.95	-55.6%
2024 (projected)	66.64	115.90	-55.3%
Average % Difference			
2015-2017			**-63.4%**
2019-2024			**-55.9%**

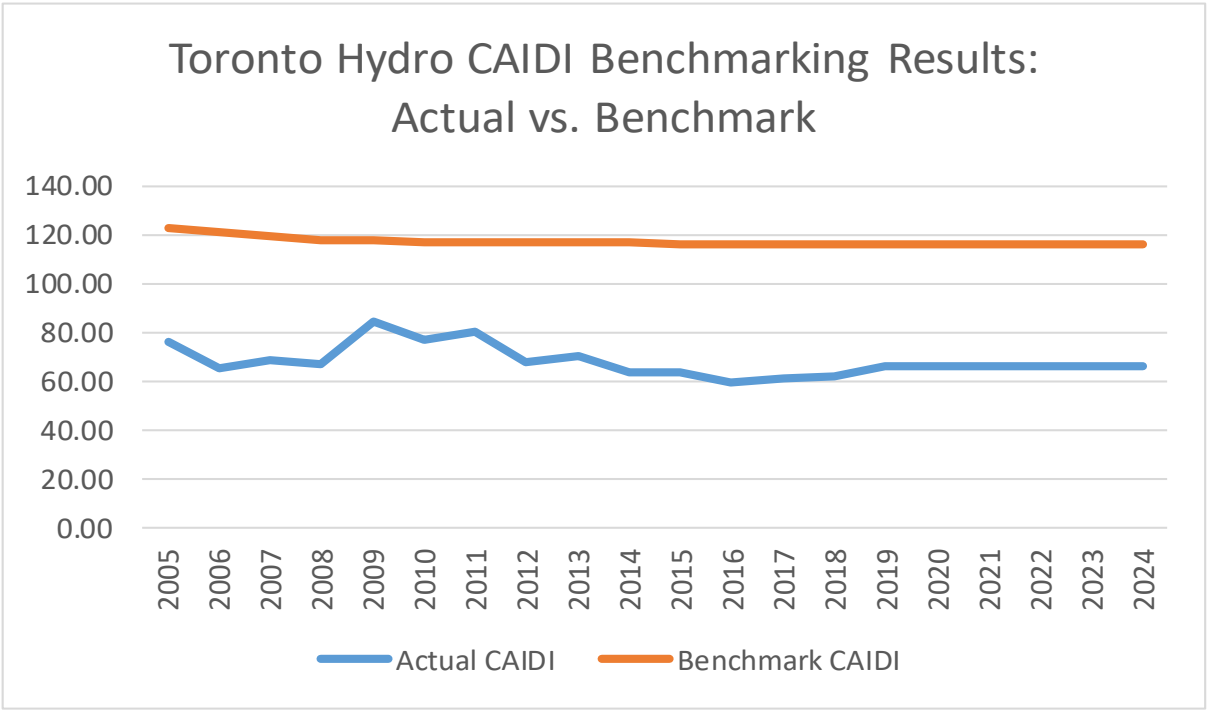
The figure below illustrates Toronto Hydro's SAIFI values compared to the benchmark values.

Figure 6 Toronto Hydro's SAIFI Performance 2005-2024



The figure below illustrates Toronto Hydro's CAIDI values compared to the benchmark values.

Figure 7 Toronto Hydro's CAIDI Performance 2005-2024



7 Importance of U.S. Data for Benchmarking Toronto Hydro

In PSE's 2015 Custom IR benchmarking research for Toronto Hydro, we presented a combined Ontario and U.S. dataset and a U.S.-only dataset. During that previous proceeding (EB-2014-0116), the OEB staff consultant put forth their own results using a U.S.-only dataset. The ensuing discussion with stakeholders did not appear to take issue with the focus on a U.S.-only dataset to benchmark Toronto Hydro, nor was this mentioned as a key issue in the 2015 Board Decision. For these reasons, PSE's cost benchmarking dataset for the current research is a U.S dataset plus Toronto Hydro, supplemented with six Ontario distributors that contain "congested urban" service territory. The reliability dataset is a U.S. dataset plus Toronto Hydro.

We emphasize the importance of including U.S. distributors into any benchmark evaluation involving Toronto Hydro (or any other extreme outlier in the Ontario dataset). While an Ontario-only dataset is appropriate for the clear majority of Ontario distributors, an Ontario-only dataset will not produce reliable results for Toronto Hydro, due to its outlier status within that dataset. This outlier status is shown by the fact that Toronto Hydro has over double the number of customers than the next largest distributor (prior to Alectra Utilities being formed), except for the extremely rural Hydro One Networks. Additionally, Toronto Hydro's "congested urban" variable is over three times as large as the next closest Ontario peer.

A benchmarking exercise evaluates utility performance relative to a given sample, which produces a benchmark value for each utility in the sample. The benchmark value is generated using the specific utility's independent variable values; this process assumes it has average efficiency relative to the sample. Thus, Toronto Hydro's benchmark values represent the values we would expect from an average utility with Toronto Hydro's specific circumstances, regional input prices, and service territory. If the average efficiency embodied in the benchmark value is generated using firms that are very dissimilar to the utility being benchmarked (i.e., if the benchmarked utility is an outlier), then its performance evaluation has a higher chance of being inaccurate.

The estimation procedure is designed to fit the data through the mean of model variables. As a result, parameter estimates are most accurate for those utilities with operating conditions that vary within a reasonable range of the mean of model variables. The further a utility's operating conditions are from the mean, especially if there are few sample observations "near" the utility (i.e. close in magnitude), the less accurate the cost benchmark based on the model will be. The inclusion of U.S. utilities ensures that Toronto Hydro is more in the "middle of the pack" in the dataset.

8 Cost Benchmarking Results and Stretch Factor Recommendation

In the 2015 Board Decision, the Board identified three key areas where the benchmarking evidence differed between the experts.

On page 15, the Board wrote:

> The experts' evidence on benchmarking differs in three key areas;
>
> 1. The Urban core variable
> 2. Approach to CDM costs
> 3. Asset price inflation costs (capital cost escalation rate)

The Board then addressed its conclusions in each of the three key areas on pages 16 to 18 of the 2015 Board Decision. PSE addressed these three key areas identified by the Board in this 2018 benchmarking study. Please see Section 3 for a more detailed explanation of the three key areas and how PSE addressed each one.

For the most recent three-year historical period (2015-2017), average total cost levels of Toronto Hydro are below benchmark expectations by 18.6%. In the most recent year of 2017, Toronto Hydro's total costs are 16.0% below benchmark expectations. During the CIR period, the scores are projected to trend more toward the benchmark, but remain below benchmark expectations. The 2020 to 2024 CIR average score is approximately 6.0% below benchmark expectations. Assuming that actual spending is at the company's proposed spending levels, Toronto Hydro's 2024 total annual costs are projected to be approximately $32 million below benchmark expectations.

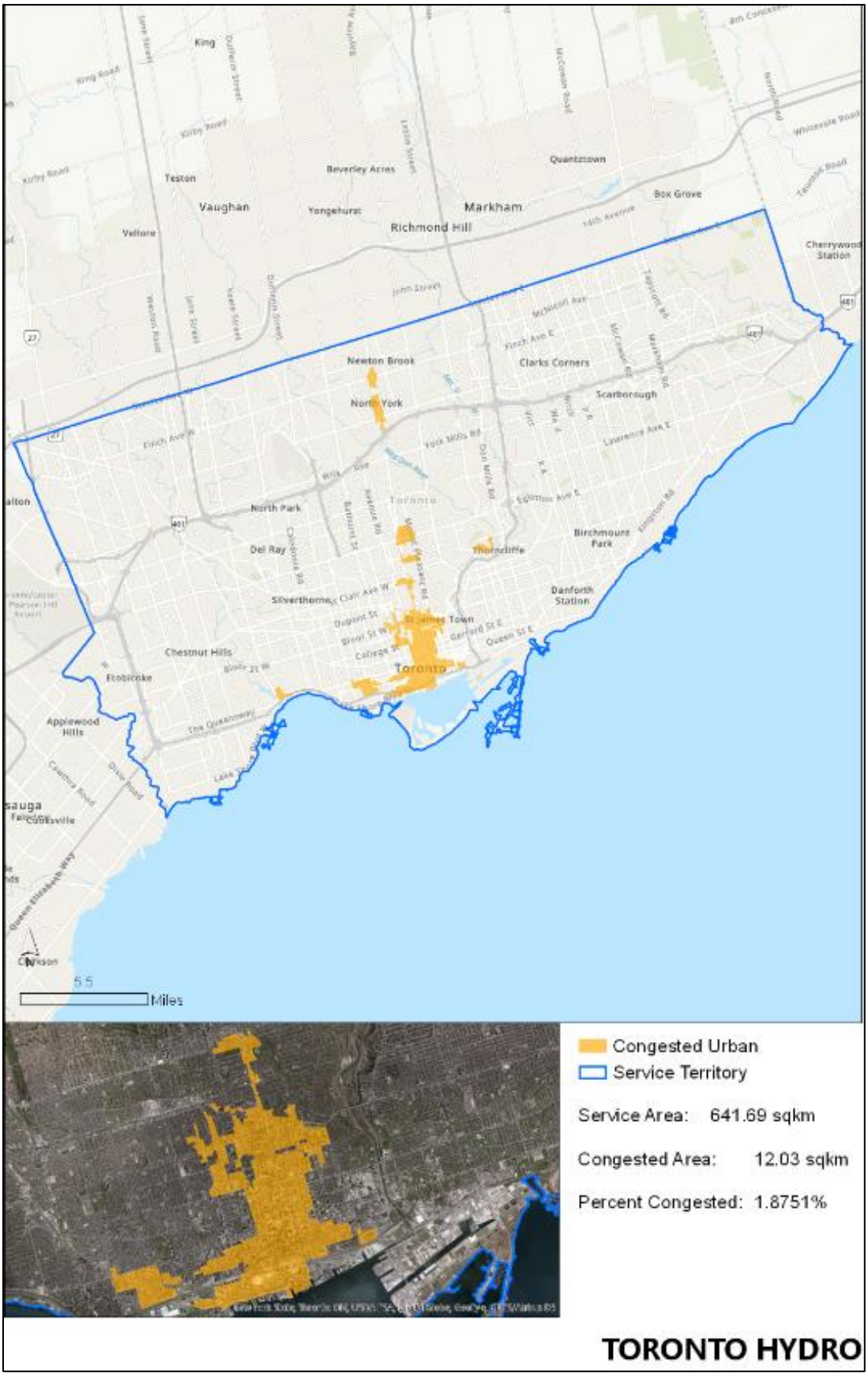
The stretch factors in 4th Generation Incentive Regulation are based on the total cost benchmarking scores of each distributor. Distributors with average scores between -10% to +10% are assigned a stretch factor of 0.30%. Based on PSE's total cost benchmark findings found in this report and the 4th Generation Incentive Regulation Board Decision, we recommend a stretch factor of 0.30% for Toronto Hydro's custom incentive regulation application. This recommendation is based on the full company-proposed spending plan for the CIR period.

9 Appendix: Congested Urban Maps by Sampled Utility

The table below shows the territory designated as "congested urban" along with each utility's total service territory and the percent congested urban. The maps for each service territory, along with the area designated as congested urban, are provided in the following pages.

Table 13 "Congested Urban" Percentages

Company Name	Service Area (sqkm)	Congested Area (sqkm)	Percent Congested	Company Name	Service Area (sqkm)	Congested Area (sqkm)	Percent Congested
Toronto Hydro	642	12.03	1.88%	Kentucky Power Co.	9,656	0.00	0.00%
Enersource Hydro Mississauga	289	1.33	0.46%	Kentucky Utilities Co.	15,104	0.40	0.00%
Enwin	124	0.60	0.48%	Louisville Gas & Electric Co.	1,942	1.62	0.08%
Horizon Utilities Corp.	363	0.36	0.10%	Madison Gas & Electric Co.	615	1.16	0.19%
Kitchner-Wilmont Hydro	405	0.53	0.13%	Montana Dakota Utilities Co.	64,726	0.00	0.00%
London Hydro	425	0.62	0.15%	Metropolitan Edison Co.	8,881	0.70	0.01%
Hydro Ottawa	1,113	1.26	0.11%	Mississippi Power Co.	2,985	0.00	0.00%
Alabama Power Co.	55,096	1.60	0.29%	Nevada Power Co.	12,130	9.37	0.08%
Minnesota Power, Inc.	8,035	0.00	0.00%	Monongahela Power Co.	34,322	0.00	0.00%
Appalachian Power Co.	47,417	0.00	0.00%	New York State Electric & Gas Corp.	42,655	0.00	0.00%
Arizona Public Service Co.	90,629	2.66	0.00%	Niagara Mohawk, A National Grid Co.	62,996	1.09	0.00%
Atlantic City Electric Co.	7,096	0.00	0.00%	Northern Indiana Public Service Co.	3,905	0.00	0.00%
Avista Corp.	32,461	0.00	0.00%	Northern States Power Co.	20,727	5.44	0.03%
Baltimore Gas & Electric Co.	5,785	3.45	0.06%	Northern States Power Co. Wisconsin	19,091	0.00	0.00%
Black Hills Power Inc.	9,372	0.00	0.00%	Ohio Edison Co.	14,956	8.88	0.06%
Central Hudson Gas & Electric Corp.	7,221	0.00	0.00%	Orange & Rockland Utilities, Inc.	2,631	0.00	0.00%
Central Maine Power Co.	29,707	0.00	0.00%	Oklahoma Gas & Electric Co. (OG&E)	8,392	9.16	0.11%
Cleco Power LLC	17,806	0.00	0.00%	Pacific Gas and Electric Co.	180,134	15.11	0.01%
Cleveland Electric Illuminating Co.	4,087	0.00	0.00%	PECO Energy Co.	4,880	4.22	0.09%
Commonwealth Edison Co.	27,977	12.73	0.05%	Pennsylvania Electric Co.	45,063	0.00	0.00%
Connecticut Light & Power Co.	11,688	0.00	0.00%	Pennsylvania Power Co.	3,781	0.00	0.00%
Consolidated Edison Co. of New York Inc.	1,661	48.92	2.95%	Portland General Electric Co.	11,545	1.06	0.01%
Consumers Energy Co.	78,367	0.00	0.00%	Potomac Edison Co.	17,957	0.00	0.00%
Delmarva Power & Light Co.	9,120	0.00	0.00%	PPL Electric Utilities Corp.	24,923	0.34	0.00%
Detroit Edison Co.	19,833	8.52	0.04%	PSC of Colorado	21,874	6.60	0.03%
Duke Energy Carolinas, LLC	28,776	3.87	0.01%	PSC of New Hampshire	14,584	0.00	0.00%
Florida Power Corp.	14,519	1.22	0.01%	PSC of Oklahoma	9,946	1.16	0.01%
Duke Energy Indiana, Inc.	11,461	0.00	0.00%	Public Service Electric and Gas Co.	3,583	3.06	0.09%
Duke Energy Kentucky, Inc.	820	0.00	0.00%	Puget Sound Energy, Inc.	23,931	0.00	0.00%
Duke Energy Ohio, Inc.	4,711	1.31	0.03%	San Diego Gas & Electric Co.	10,633	4.90	0.05%
Carolina Power & Light Co.	38,544	1.32	0.00%	South Carolina Electric & Gas Co.	14,431	0.00	0.00%
Duquesne Light Co.	2,078	1.13	0.05%	Southern California Edison Co.	133,616	3.36	0.00%
El Paso Electric CO.	13,573	1.52	0.01%	Southern Indiana Gas & Electric Co.	3,087	0.00	0.00%
Empire District Electric Co.	8,169	0.00	0.00%	Southwestern Public Service Co.	29,243	0.00	0.00%
Entergy Arkansas, Inc.	47,798	0.00	0.00%	Tampa Electric Co.	3,428	1.68	0.05%
Entergy Mississippi, Inc.	18,514	0.00	0.00%	Toledo Edison Co.	5,523	0.93	0.02%
Entergy New Orleans, Inc.	523	3.02	0.58%	Tucson Electric Power Co.	2,746	0.48	0.02%
Florida Power & Light Co.	40,083	3.67	0.01%	Union Electric Co.	29,207	2.60	0.01%
Gulf Power Co.	3,315	0.00	0.00%	United Illuminating Co.	985	0.00	0.00%
Idaho Power Co.	88,854	1.21	0.00%	Virginia Electric & Power Co.	35,901	2.07	0.01%
Indiana Michigan Power Co.	11,440	0.70	0.01%	West Penn Power Co.	25,425	0.00	0.00%
Indianapolis Power & Light Co.	1,558	2.33	0.15%	Western Massachusetts Electric Co.	3,872	0.00	0.00%
Jersey Central Power & Light Co.	8,410	0.00	0.00%	Wisconsin Electric Power Co.	27,022	5.71	0.02%
Kansas City Power & Light Co.	46,444	1.91	0.00%	Wisconsin Power & Light Co.	25,256	0.00	0.00%
KGE, A Westar Energy Co.	11,015	1.17	0.01%	Wisconsin Public Service Corp.	27,670	0.00	0.00%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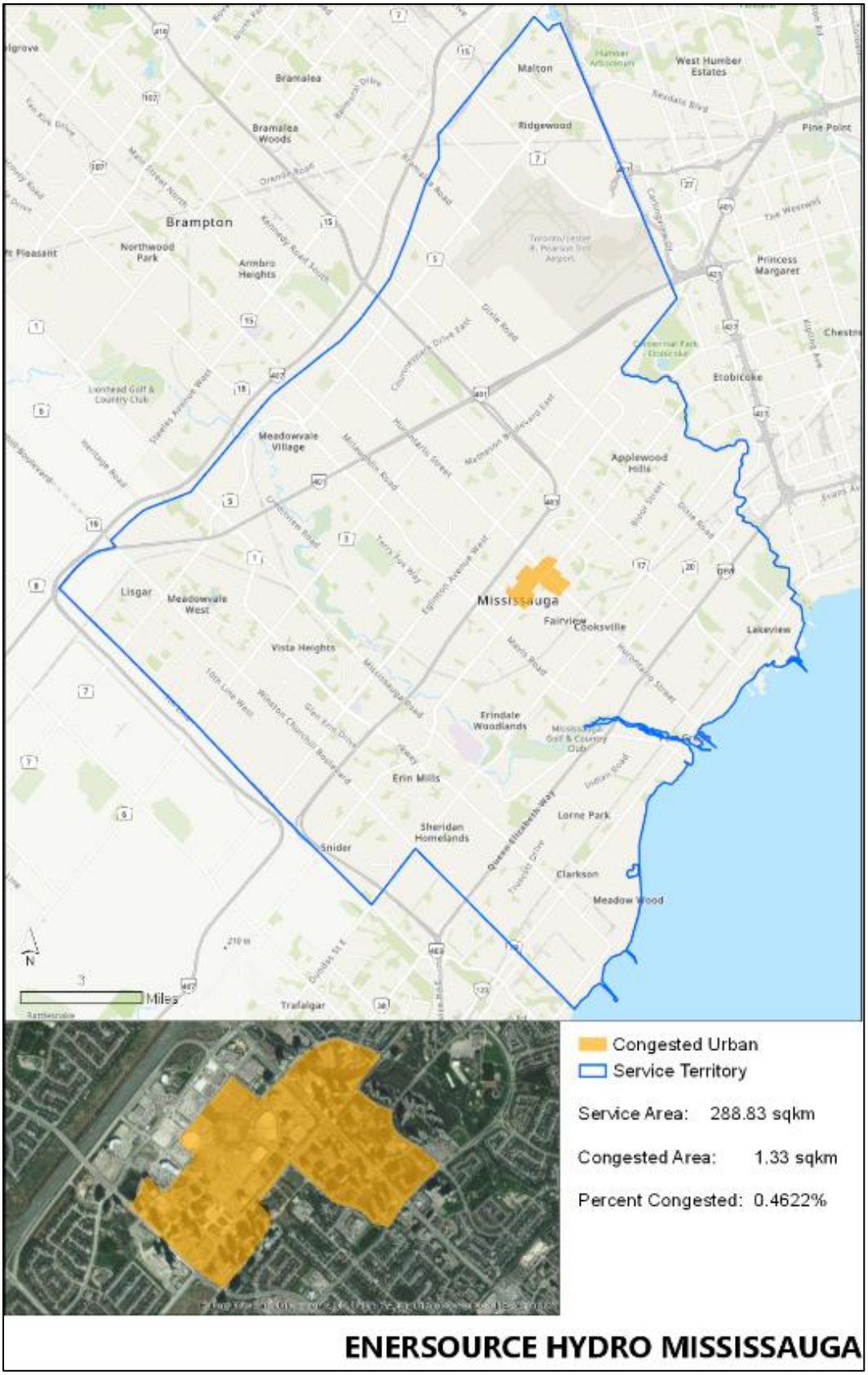
Scarborough
North Park
Del Ray
Silverthorne
Thorncliffe
Birchmount Park
Danforth Station
St. James Town
Toronto
Chestnut Hills
Etobicoke
Applewood Hills
Cooksville
Miles
Congested Urban
Service Territory
Service Area: 641.69 sqkm
Congested Area: 12.03 sqkm
Percent Congested: 1.8751%
TORONTO HYDRO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Northwood Park
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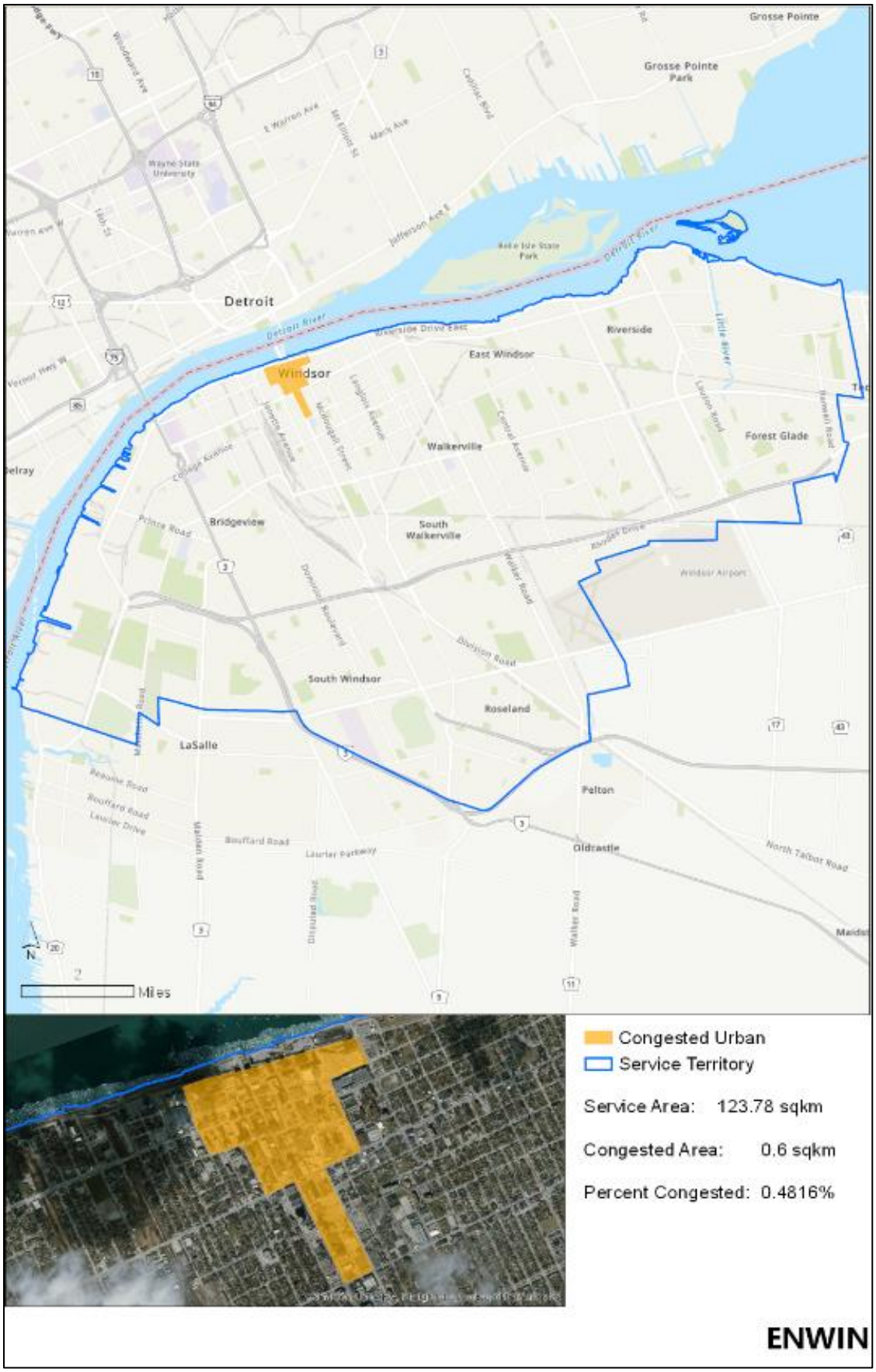
Meadowvale Village
Applewood Hills
Lisgar
Meadowvale West
Fairview
Cooksville
Lakeview
Vista Heights
Erindale Woodlands
Erin Mills
Lorne Park
Sheridan Homelands
Snider
Clarkson
Meadow Wood
Trafalgar
N
3
Miles
Congested Urban
Service Territory
Service Area: 288.83 sqkm
Congested Area: 1.33 sqkm
Percent Congested: 0.4622%
ENERSOURCE HYDRO MISSISSAUGA


Grosse Pointe
Grosse Pointe Park
Detroit
Windsor
East Windsor
Riverside
Walkerville
Forest Glade
Bridgeview
South Walkerville
South Windsor
Roseland
LaSalle
Pelton
Oldcastle
Miles
Congested Urban
Service Territory
Service Area: 123.78 sqkm
Congested Area: 0.6 sqkm
Percent Congested: 0.4816%
ENWIN





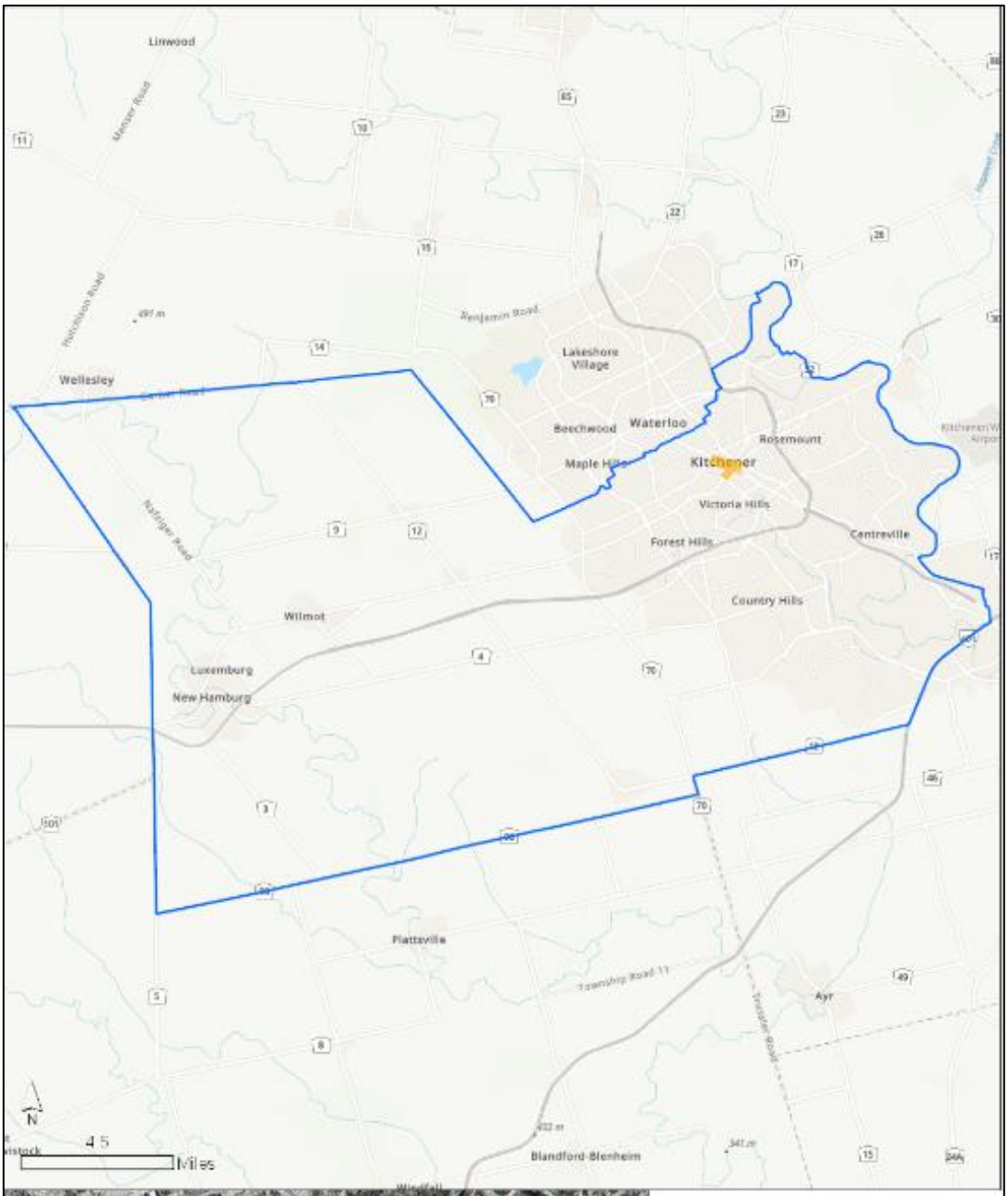
Congested Urban
Service Territory

Service Area: 362.93 sqkm

Congested Area: 0.36 sqkm

Percent Congested: 0.0986%

HORIZON UTILITIES CORP.





Congested Urban
Service Territory

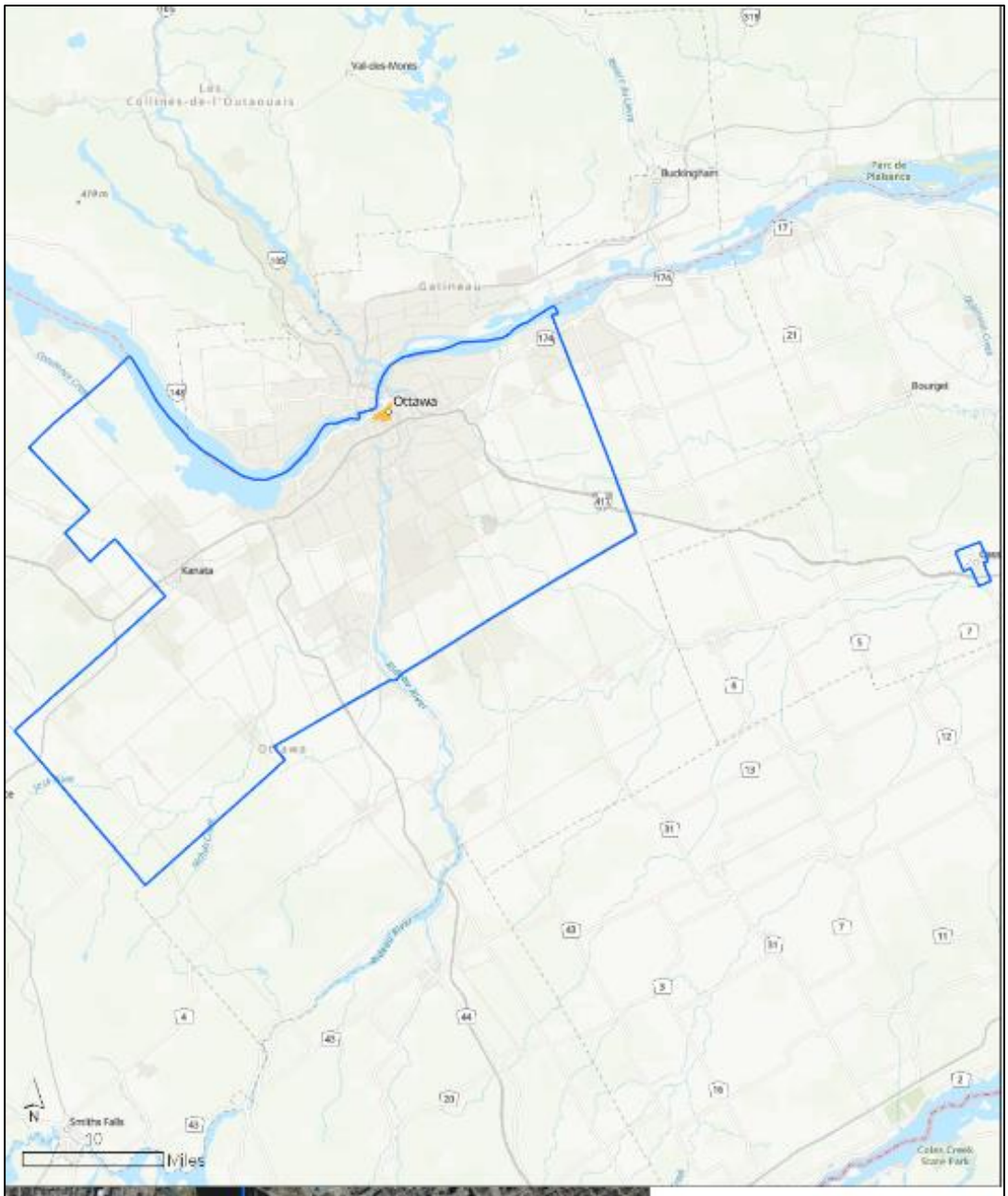
Service Area: 404.7 sqkm

Congested Area: 0.53 sqkm

Percent Congested: 0.1312%

KITCHENER-WILMONT HYDRO


Medway Road
Stoneybrook
Fanshawe
Huron Heights
White Hills
University Heights
London
Nelson Park
Oakridge Acres
Chelsea Green
Manor Park
Glen Cairn Woods
Byron
Westmount
Cleardale
Southdale
Wilton Grove
Lambeth
Hubrey
Sharon
Lockwood Park
Glanworth
Tempo
Littlewood
N
Miles
Congested Urban
Service Territory
Service Area: 425.17 sqkm
Congested Area: 0.62 sqkm
Percent Congested: 0.1468%
LONDON HYDRO





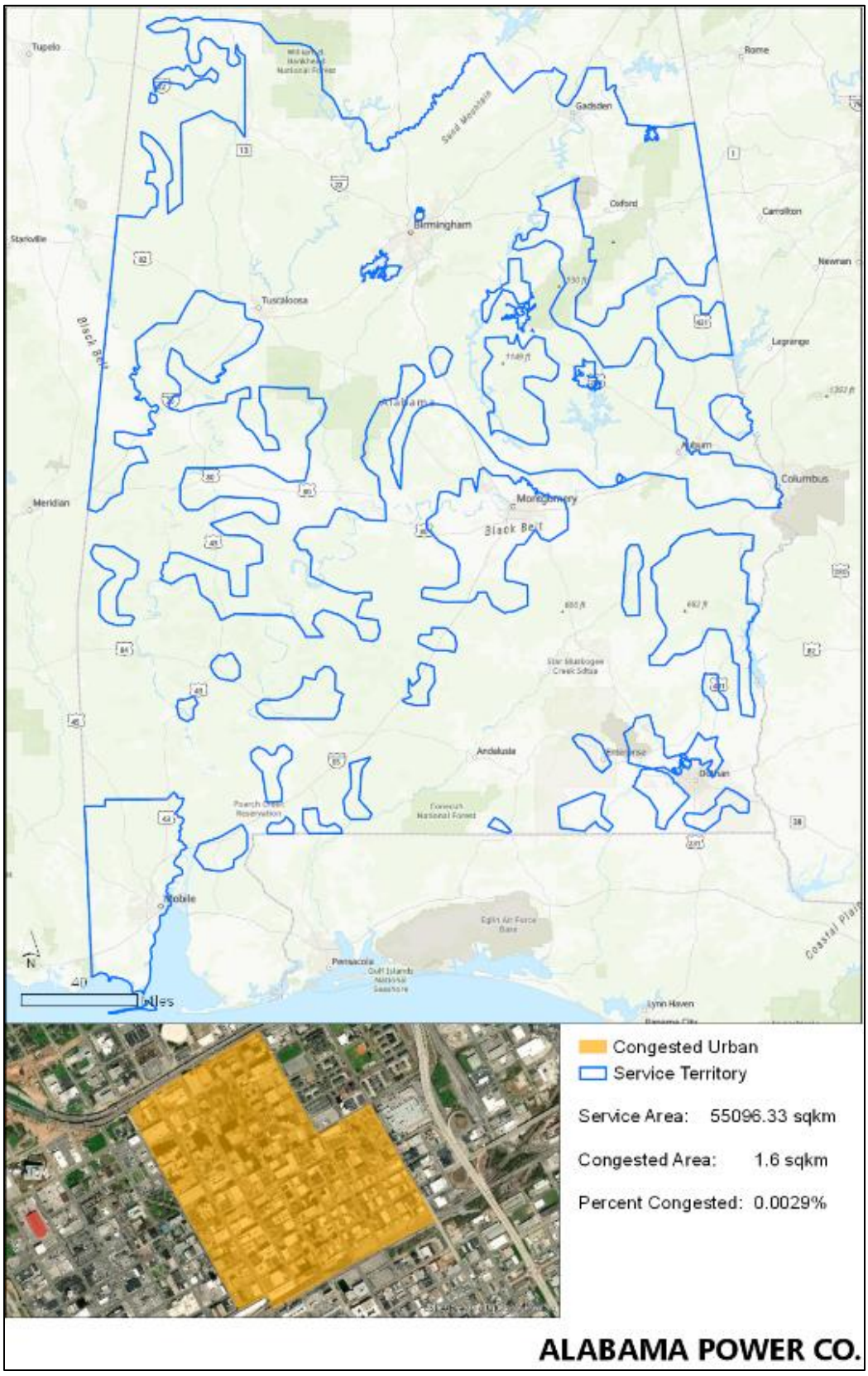
Congested Urban
Service Territory

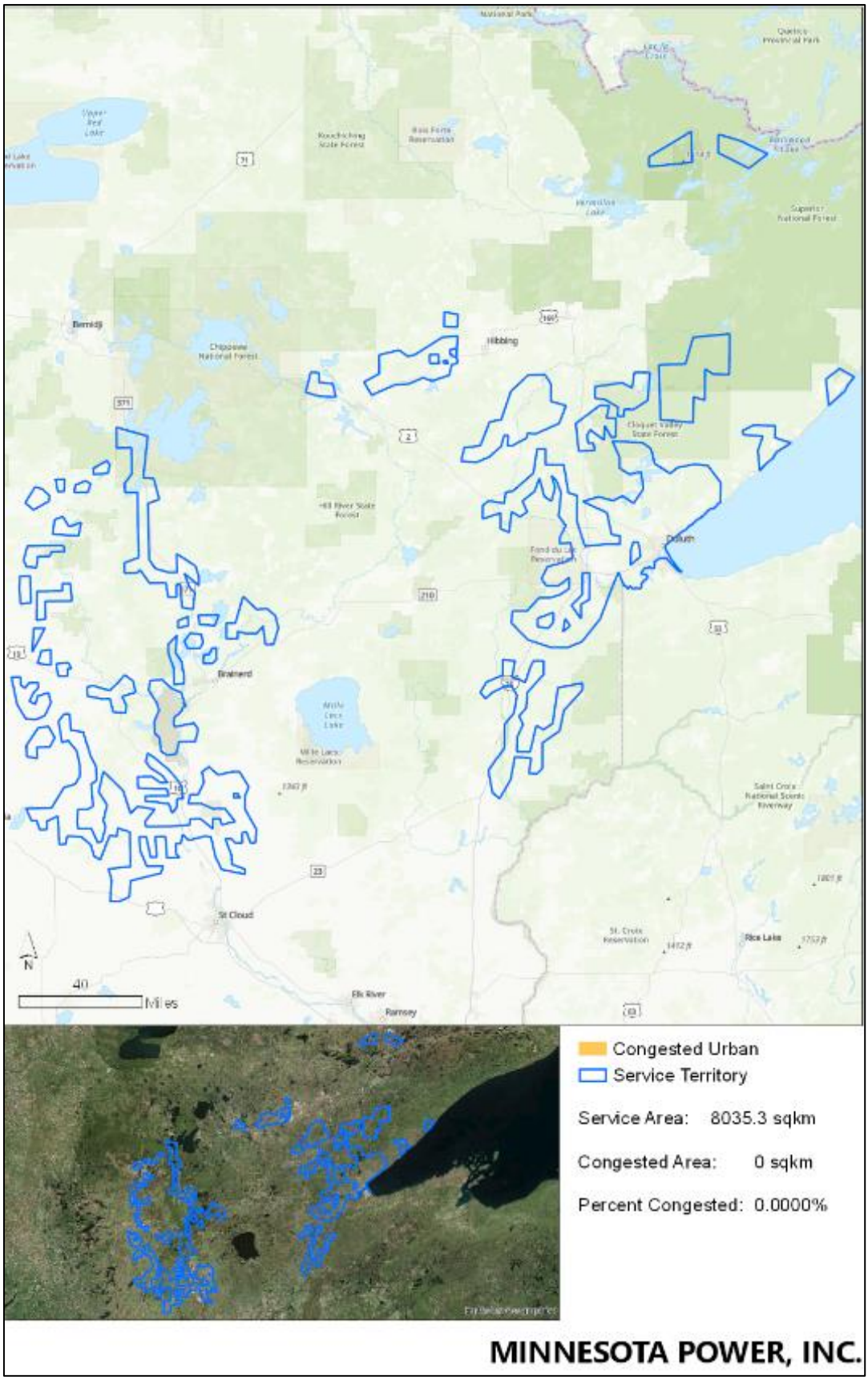
Service Area: 1112.7 sqkm

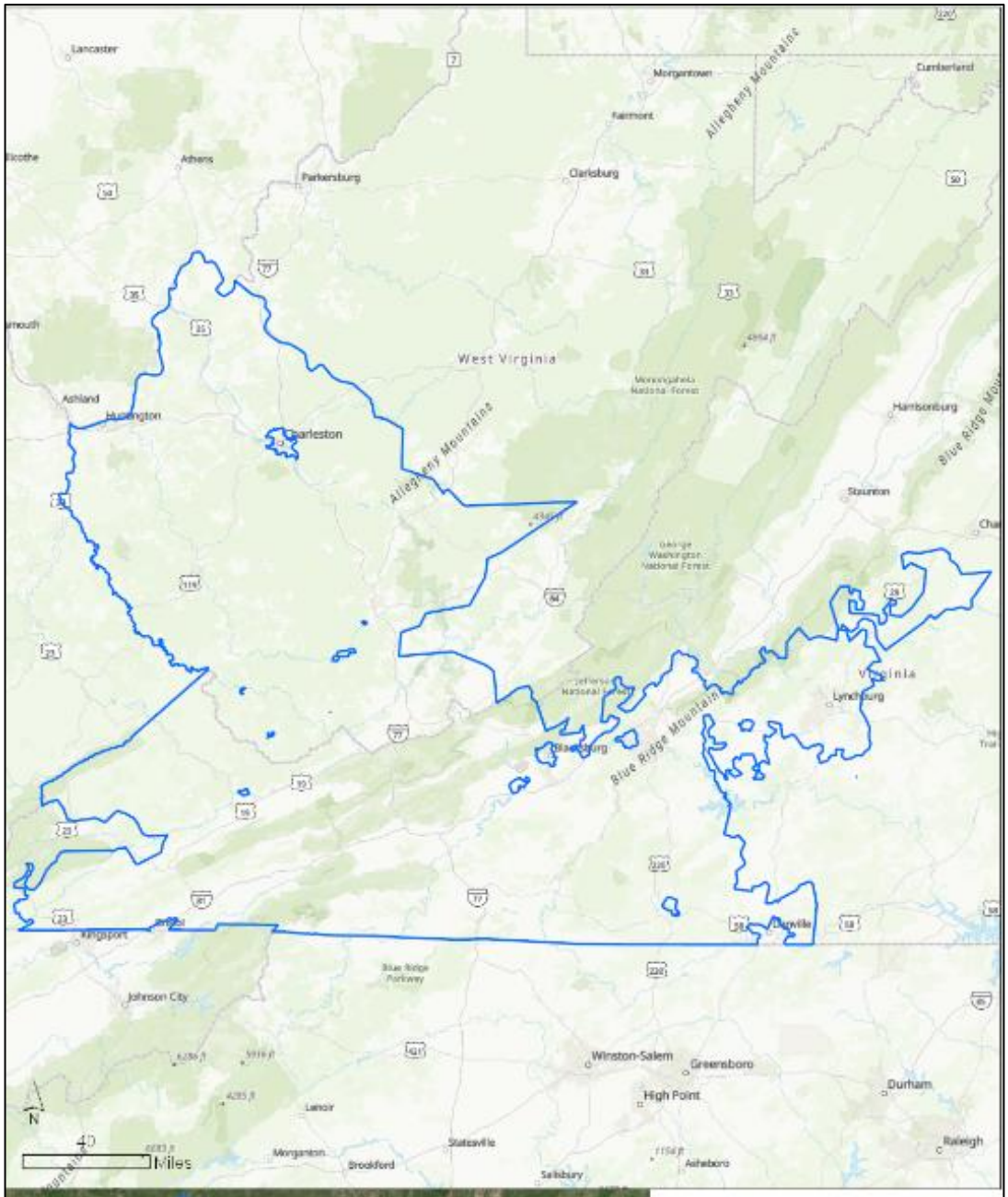
Congested Area: 1.26 sqkm

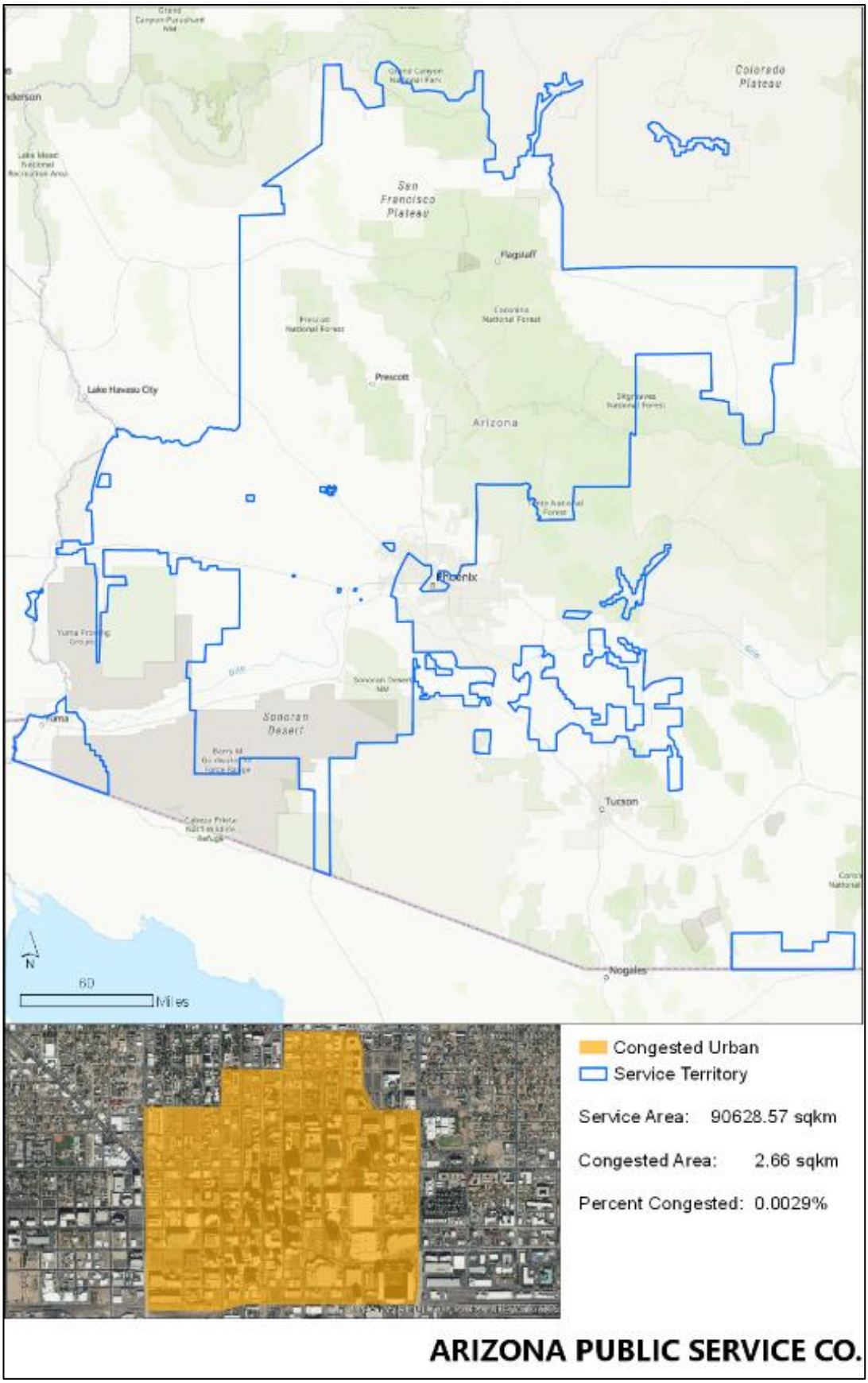
Percent Congested: 0.1132%

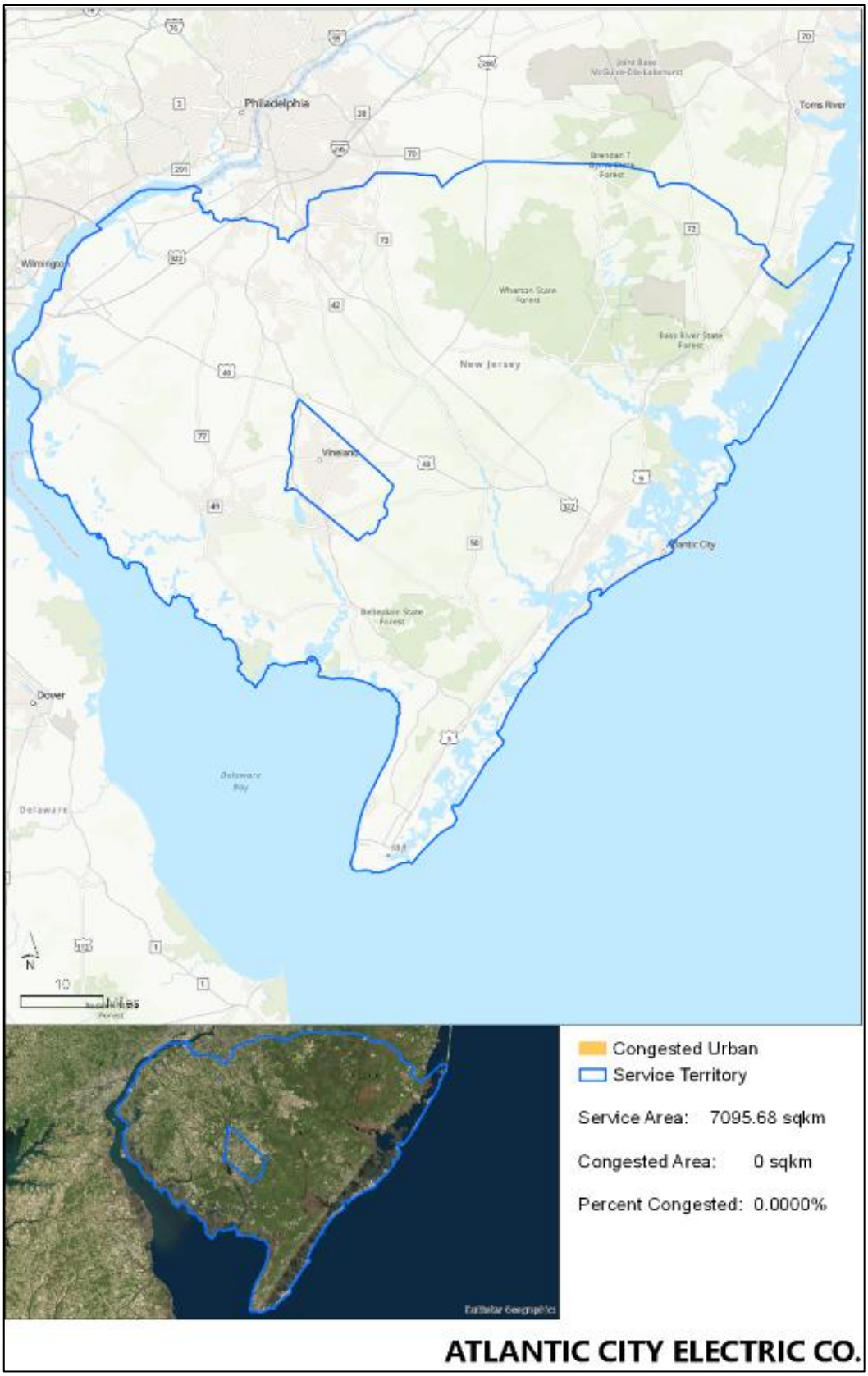
HYDRO OTTAWA

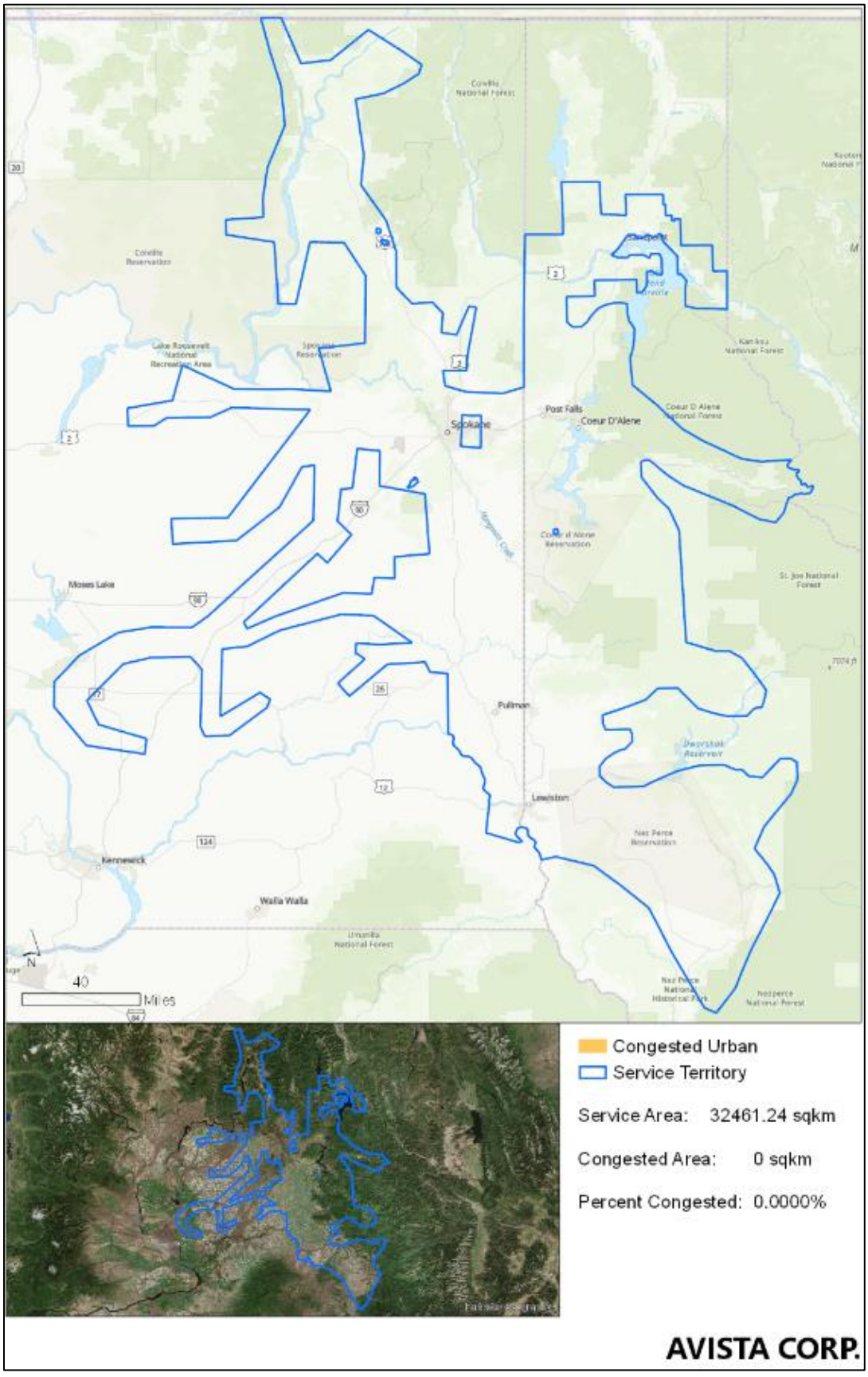

Tupelo
Rome
Gadsden
Sand Mountain
Oxford
Carrollton
Birmingham
Starkville
Newnan
Tuscaloosa
Black Belt
Lagrange
Alabama
Auburn
Columbus
Meridian
Montgomery
Black Belt
Andalusia
Mobile
Pensacola
Lynn Haven
Coastal Plain
40
Miles
Congested Urban
Service Territory
Service Area: 55096.33 sqkm
Congested Area: 1.6 sqkm
Percent Congested: 0.0029%
ALABAMA POWER CO.

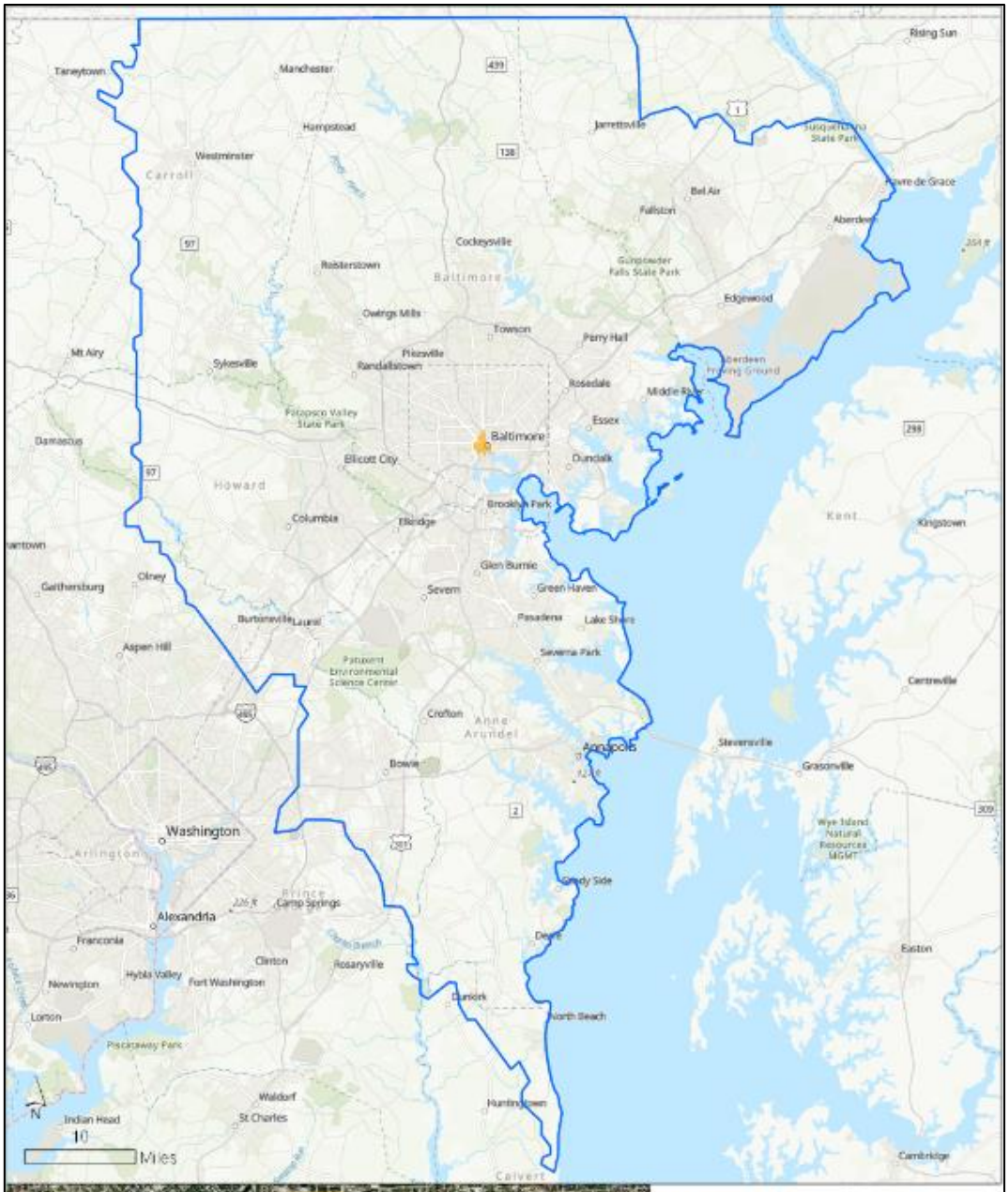

Congested Urban
Service Territory
Service Area: 8035.3 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
MINNESOTA POWER, INC.
40
Miles
N
Bemidji
Hibbing
Brainerd
St Cloud
Rice Lake
Ramsey
Elk River

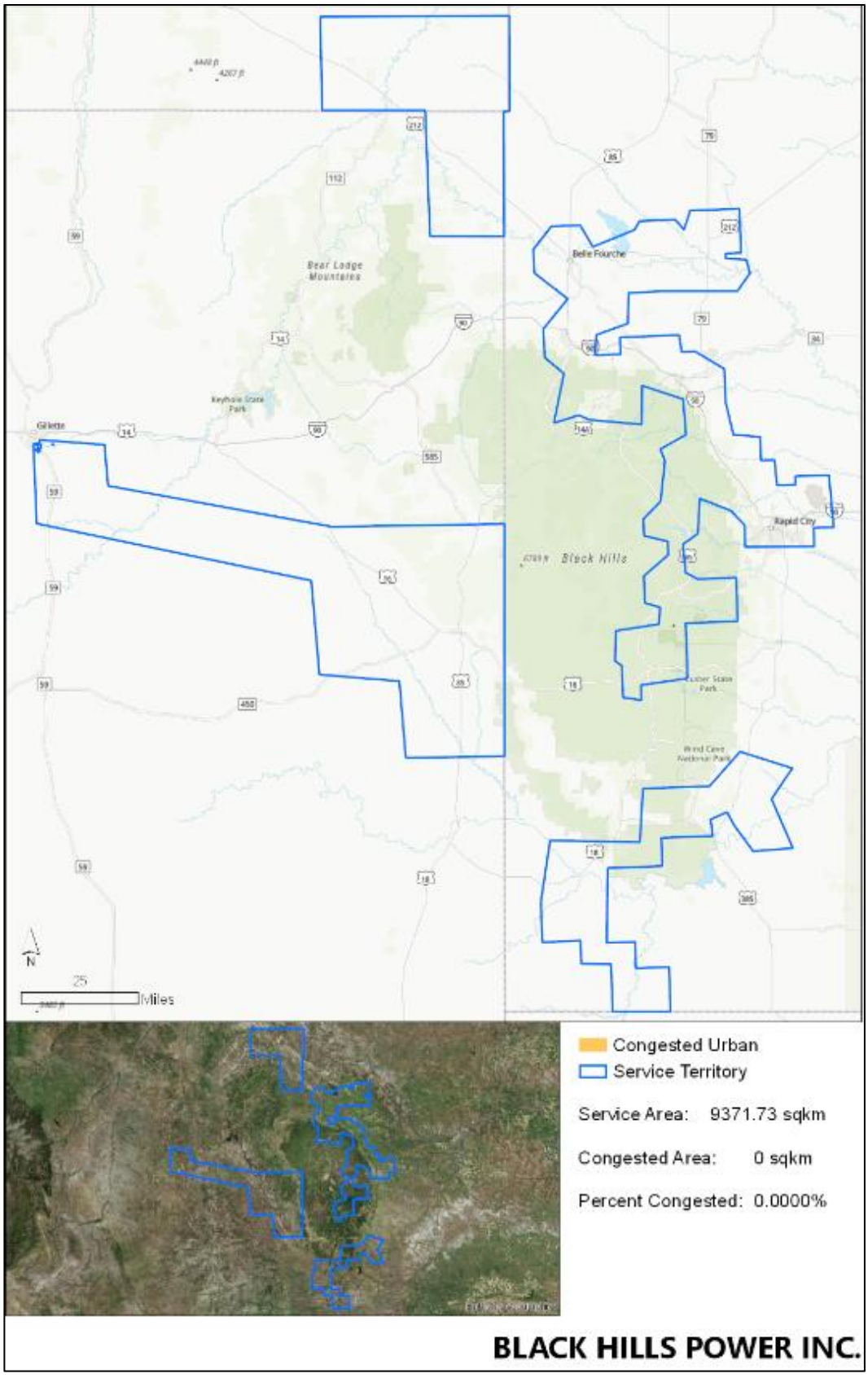

Lancaster
Morgantown
Cumberland
Fairmont
Allegheny Mountains
Athens
Parkersburg
Clarksburg
West Virginia
Ashland
Huntington
Charleston
Harrisonburg
Blue Ridge Mountains
Staunton
Lynchburg
Blacksburg
Danville
Kingsport
Johnson City
Blue Ridge Parkway
Winston-Salem
Greensboro
High Point
Durham
Lenoir
Statesville
Raleigh
Morganton
Brookford
Salisbury
Asheboro
N
40
Miles
Congested Urban
Service Territory
Service Area: 47416.64 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
APPALACHIAN POWER CO.

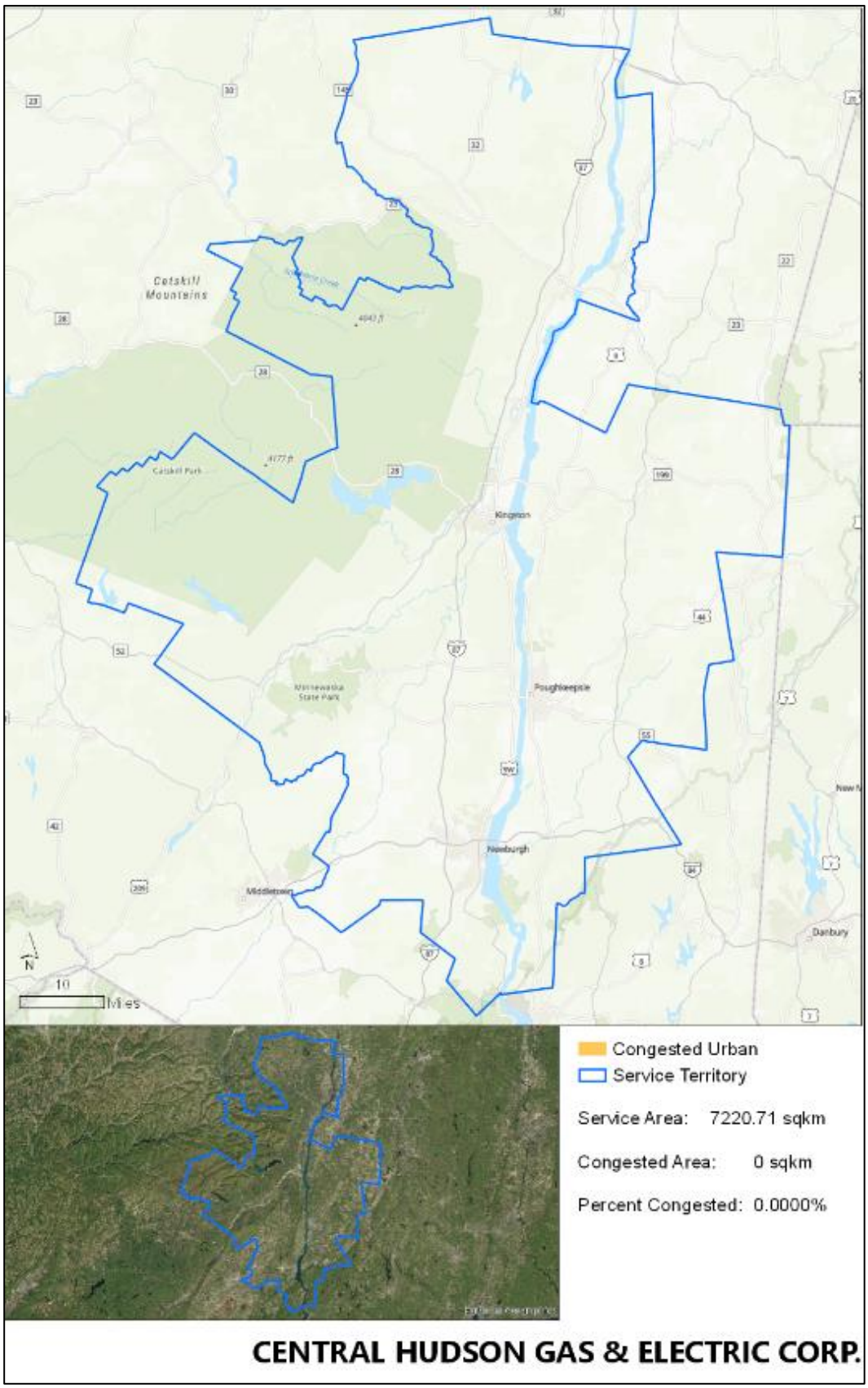

Colorado Plateau
San Francisco Plateau
Flagstaff
Prescott
Lake Havasu City
Arizona
Phoenix
Sonoran Desert
Tucson
Nogales
N
60
Miles
Congested Urban
Service Territory
Service Area: 90628.57 sqkm
Congested Area: 2.66 sqkm
Percent Congested: 0.0029%
ARIZONA PUBLIC SERVICE CO.

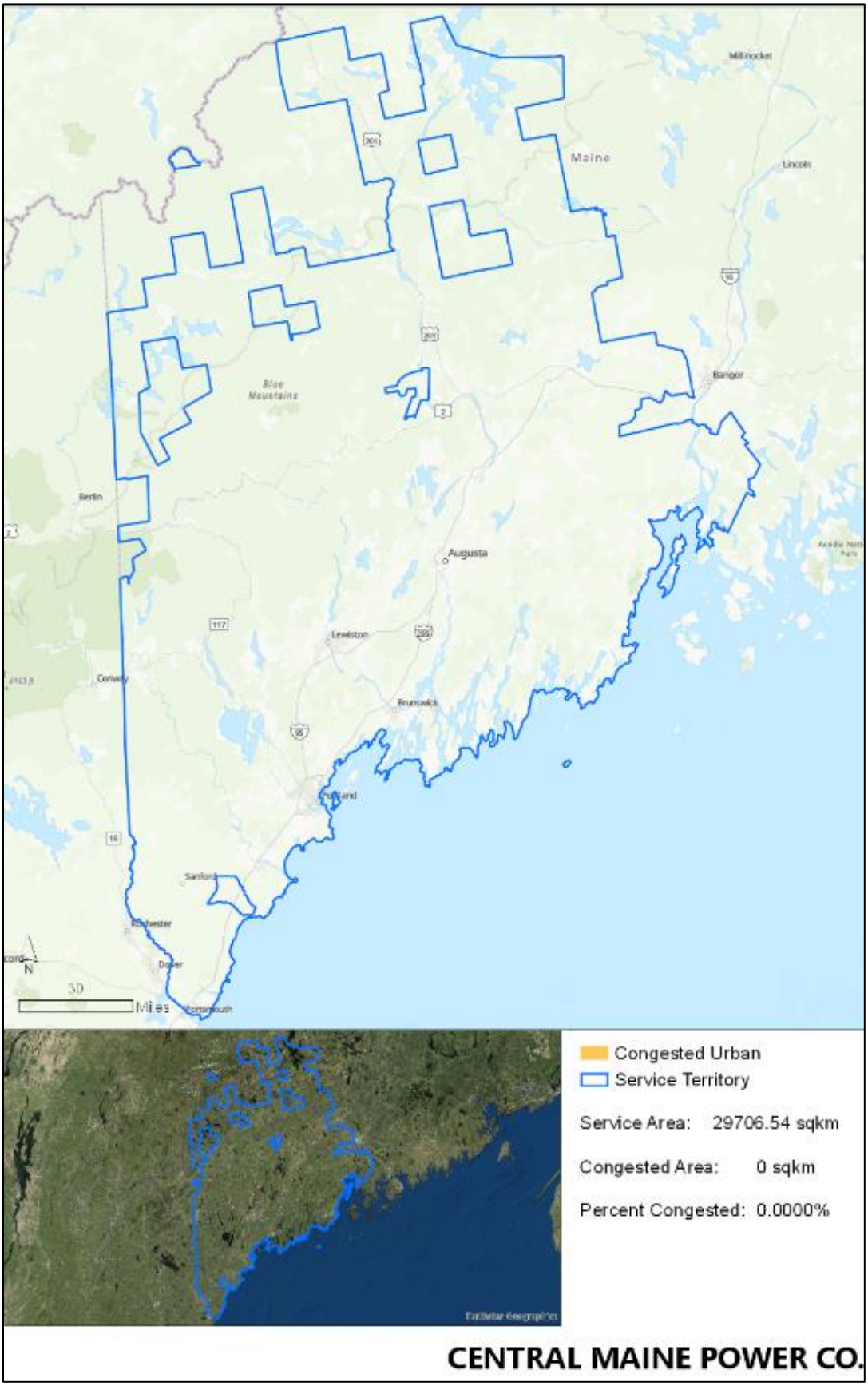

Philadelphia
Toms River
Wilmington
New Jersey
Vineland
Atlantic City
Dover
Delaware
Delaware Bay
10
Miles
Congested Urban
Service Territory
Service Area: 7095.68 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
ATLANTIC CITY ELECTRIC CO.

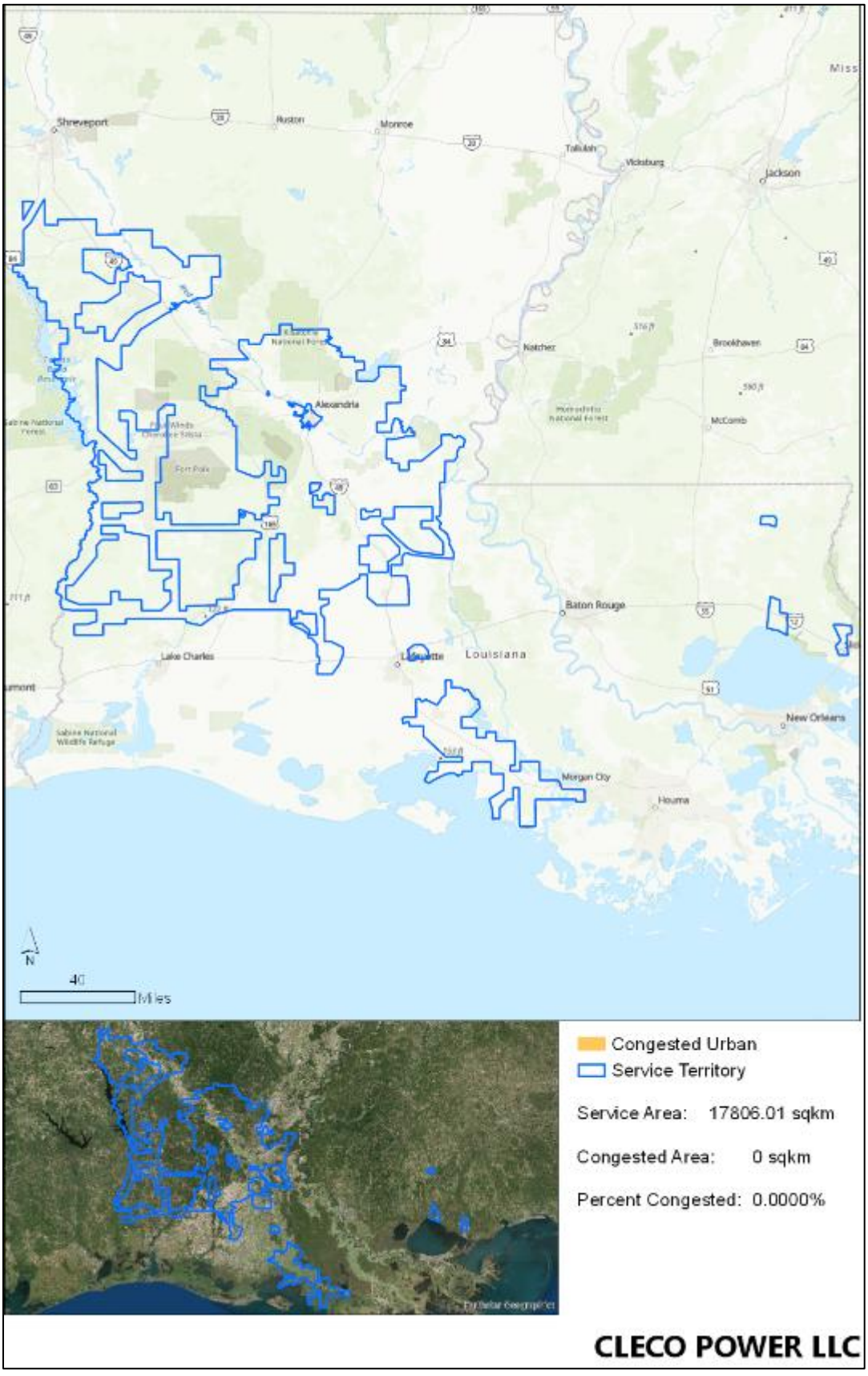

Spokane
Post Falls
Coeur D'Alene
Moses Lake
Pullman
Lewiston
Walla Walla
Kennewick
40
Miles
Congested Urban
Service Territory
Service Area: 32461.24 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
AVISTA CORP.

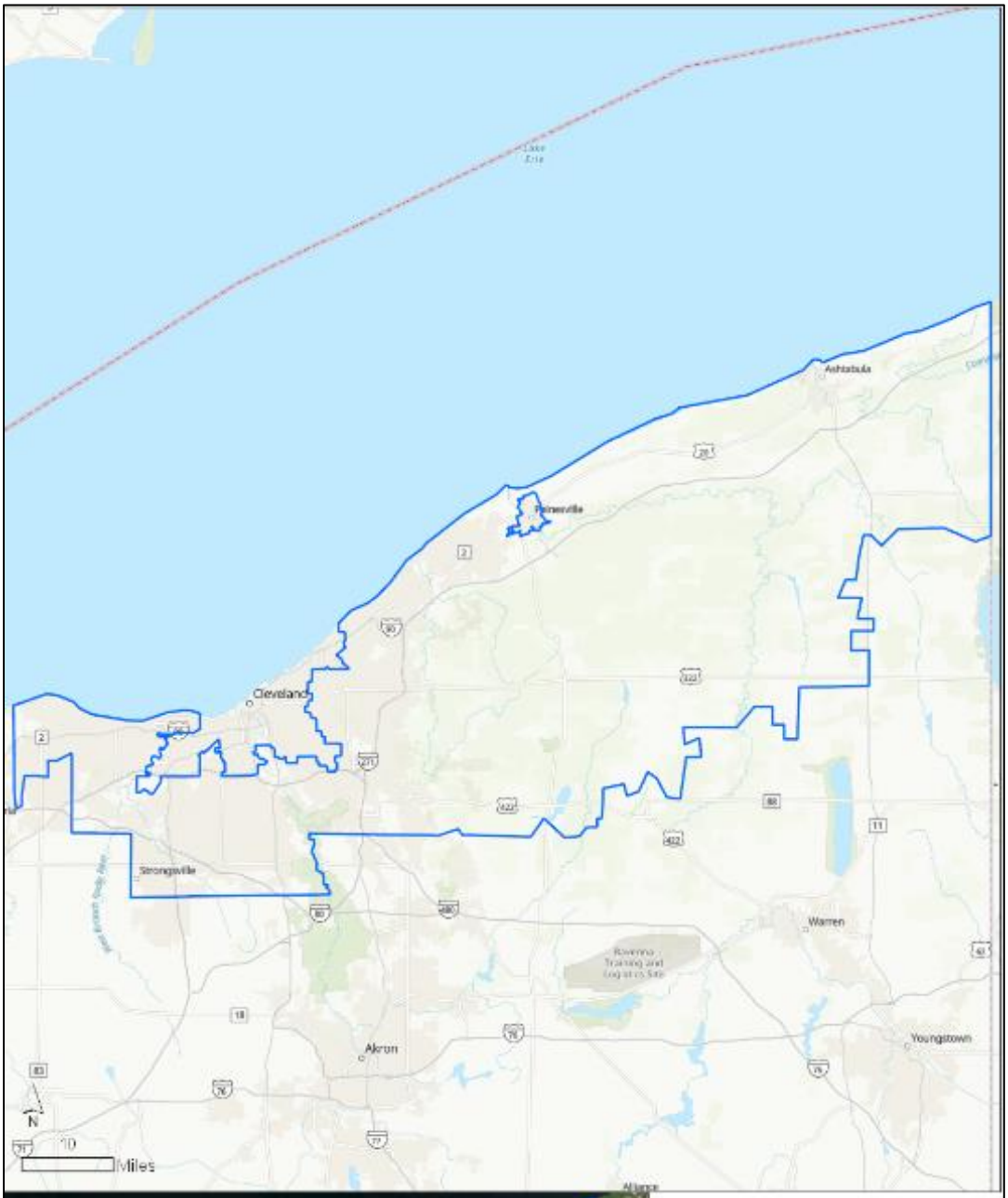

Rising Sun
Taneytown
Manchester
Hampstead
Westminster
Carroll
Jarrettsville
Havre de Grace
Bel Air
Fallston
Aberdeen
Cockeysville
Reisterstown
Baltimore
Gunpowder Falls State Park
Edgewood
Owings Mills
Towson
Perry Hall
Mt Airy
Sykesville
Pikesville
Randallstown
Rosedale
Middle River
Patapsco Valley State Park
Essex
Baltimore
Damascus
Ellicott City
Dundalk
Howard
Brooklyn Park
Columbia
Elkridge
Kent
Kingstown
Glen Burnie
Gaithersburg
Olney
Severn
Green Haven
Burtonsville
Laurel
Pasadena
Lake Shore
Aspen Hill
Severna Park
Patuxent Environmental Science Center
Centreville
Crofton
Anne Arundel
Annapolis
Stevensville
Bowie
Grasonville
Washington
Arlington
Wye Island Natural Resources Mgmt
Prince
Camp Springs
Alexandria
Franconia
Clinton
Rosaryville
Hybla Valley
Fort Washington
Newington
Dunkirk
North Beach
Lorton
Piscataway Park
Waldorf
St Charles
Indian Head
N
10
Miles
Calvert
Cambridge
Congested Urban
Service Territory
Service Area: 5784.92 sqkm
Congested Area: 3.45 sqkm
Percent Congested: 0.0596%
BALTIMORE GAS & ELECTRIC CO.


Bear Lodge Mountains
Belle Fourche
Keyhole State Park
Gillette
Rapid City
Black Hills
Custer State Park
Wind Cave National Park
N
25
Miles
Congested Urban
Service Territory
Service Area: 9371.73 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
BLACK HILLS POWER INC.


Catskill Mountains
Catskill Park
Kingston
Poughkeepsie
Newburgh
Middletown
Danbury
N
10
Miles
Congested Urban
Service Territory
Service Area: 7220.71 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
CENTRAL HUDSON GAS & ELECTRIC CORP.


Millinocket
Maine
Lincoln
Bangor
Blue Mountains
Berlin
Augusta
Lewiston
Conway
Brunswick
Sanford
Rochester
Dover
Portsmouth
N
30
Miles
Congested Urban
Service Territory
Service Area: 29706.54 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
CENTRAL MAINE POWER CO.


Shreveport
Ruston
Monroe
Vicksburg
Jackson
Natchez
Brookhaven
McComb
Alexandria
Baton Rouge
Lake Charles
Louisiana
New Orleans
Morgan City
Houma
N
40
Miles
Congested Urban
Service Territory
Service Area: 17806.01 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
CLECO POWER LLC





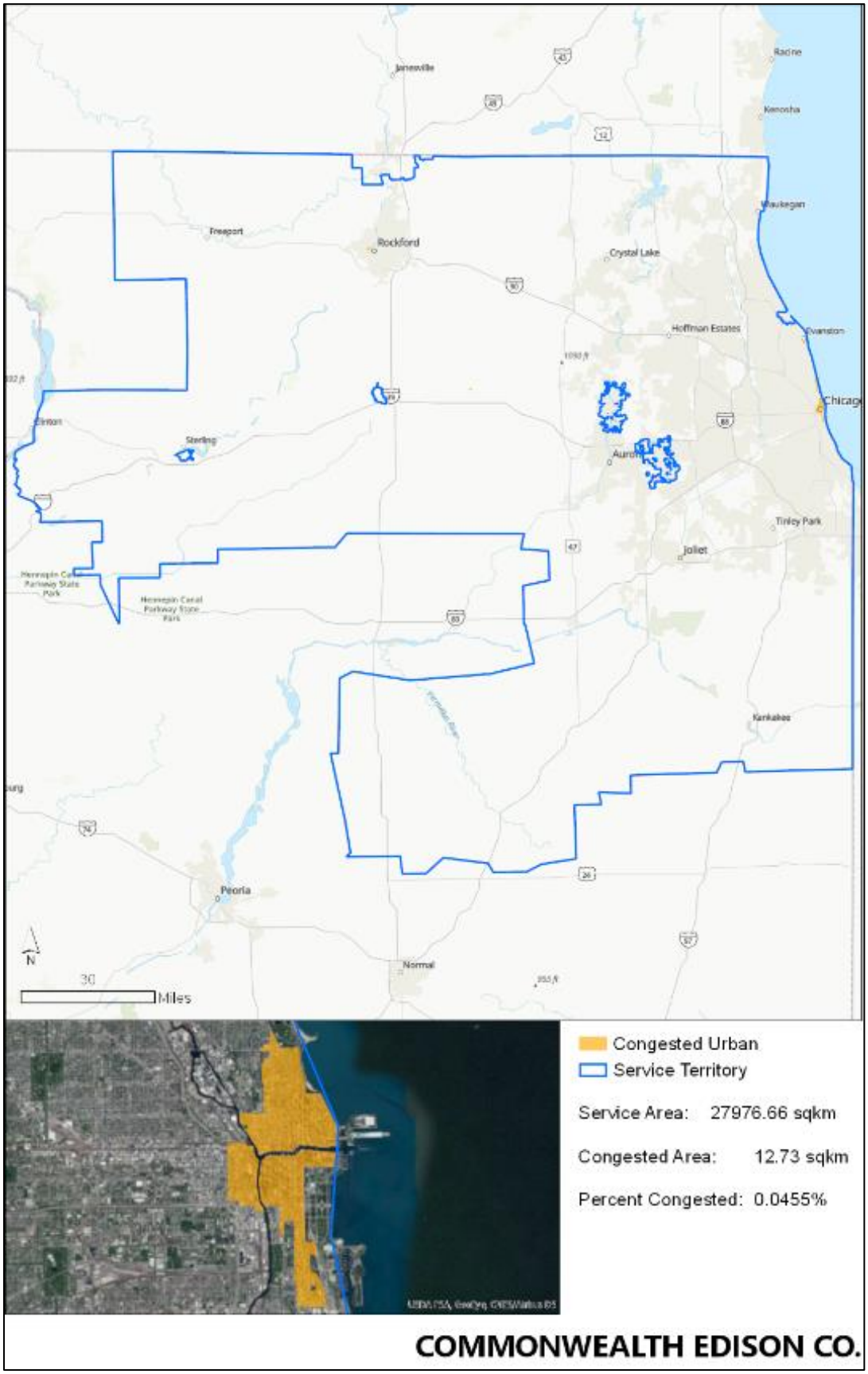
Congested Urban
Service Territory

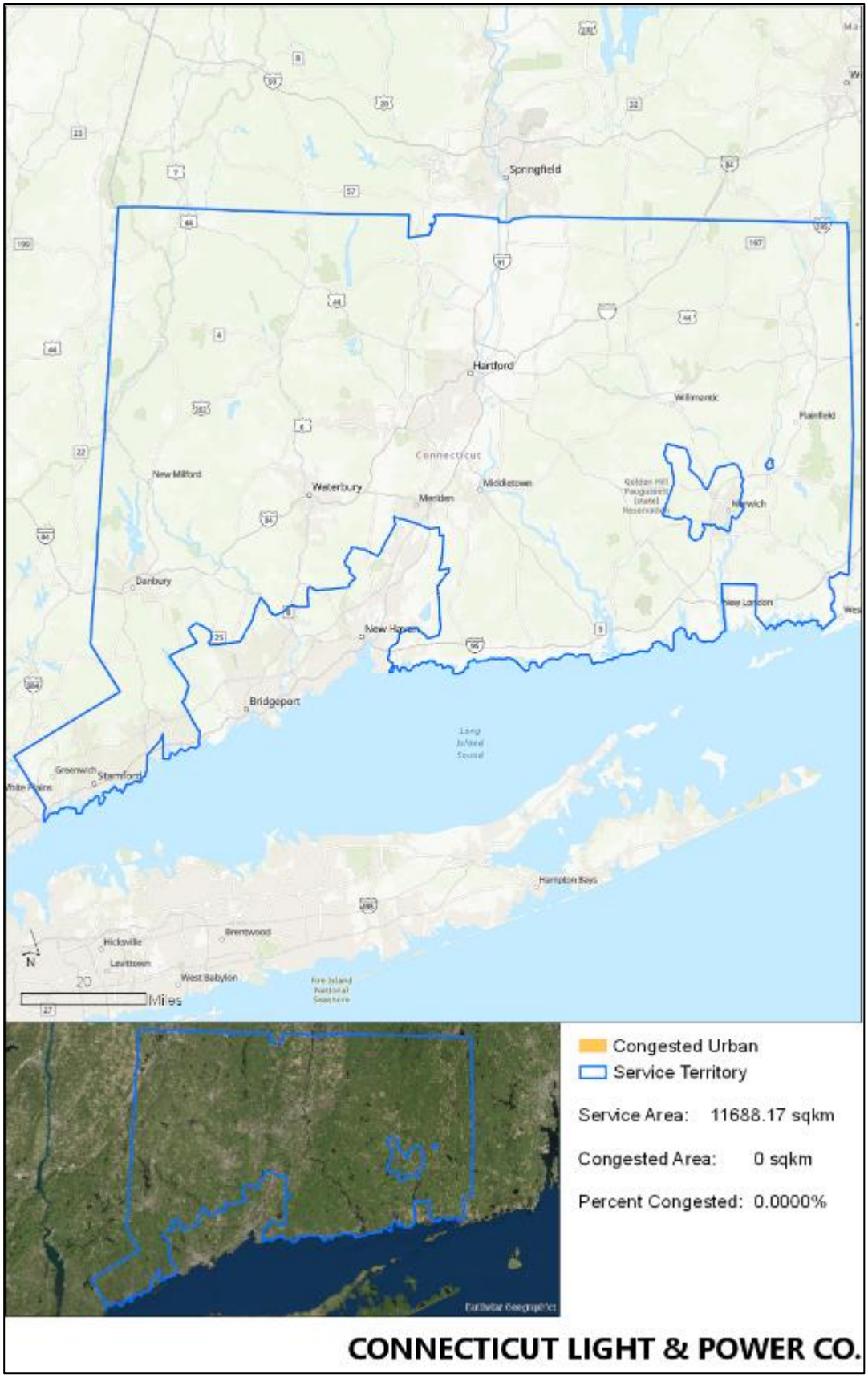
Service Area: 4086.69 sqkm

Congested Area: 0 sqkm

Percent Congested: 0.0000%

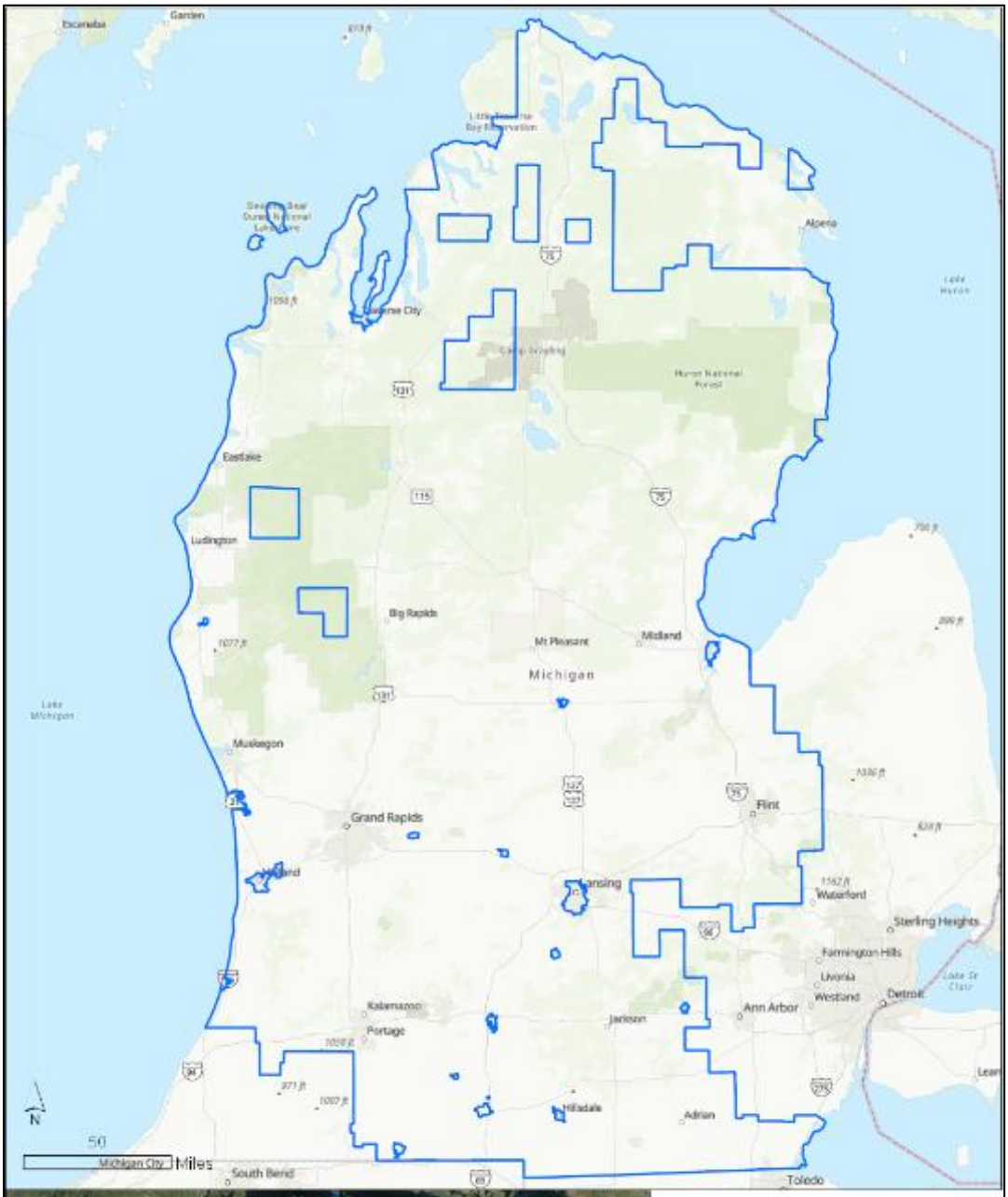
CLEVELAND ELECTRIC ILLUMINATING CO.


Janesville
Racine
Kenosha
Waukegan
Freeport
Rockford
Crystal Lake
Hoffman Estates
Evanston
Chicago
Clinton
Sterling
Aurora
Tinley Park
Joliet
Kankakee
Peoria
Normal
N
30
Miles
Congested Urban
Service Territory
Service Area: 27976.66 sqkm
Congested Area: 12.73 sqkm
Percent Congested: 0.0455%
COMMONWEALTH EDISON CO.


Springfield
Hartford
Willimantic
Plainfield
Connecticut
New Milford
Waterbury
Meriden
Middletown
Norwich
Danbury
New London
New Haven
Bridgeport
Long Island Sound
Greenwich
Stamford
White Plains
Hampton Bays
Brentwood
Hicksville
Levittown
West Babylon
Fire Island National Seashore
N
20
Miles
Congested Urban
Service Territory
Service Area: 11688.17 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
CONNECTICUT LIGHT & POWER CO.



CONSOLIDATED EDISON CO. OF NEW YORK INC.





Congested Urban

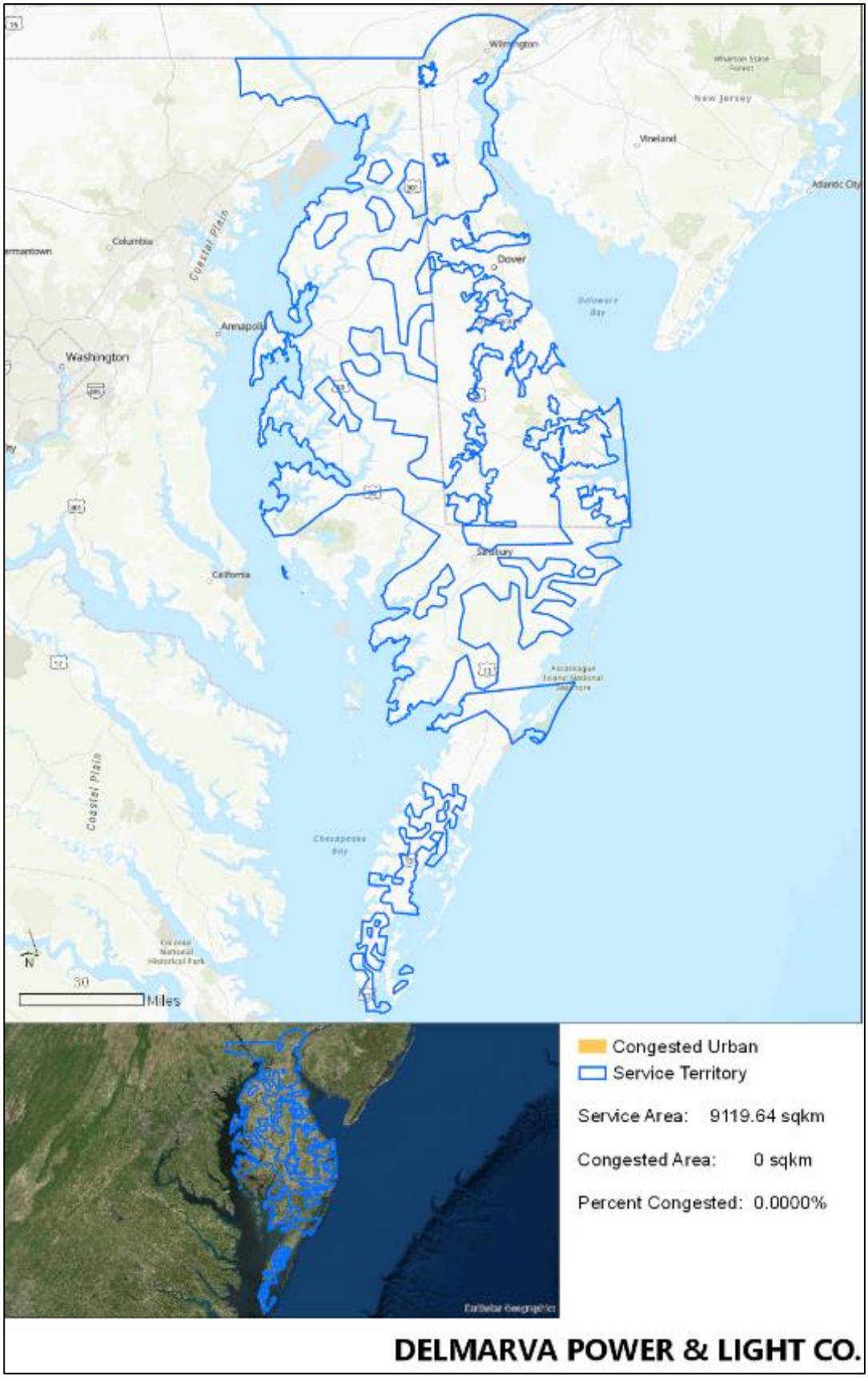
Service Territory

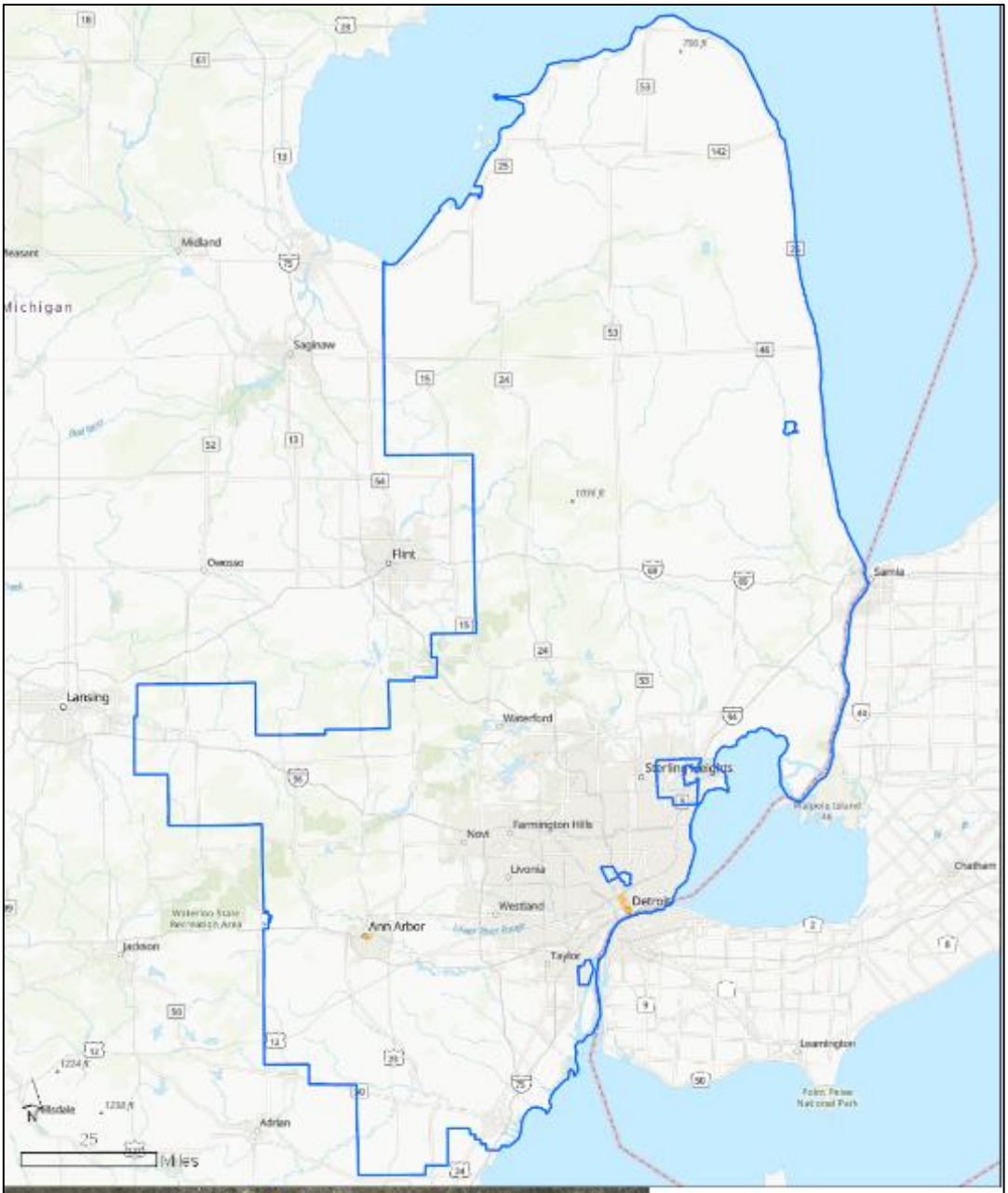
Service Area: 78366.96 sqkm

Congested Area: 0 sqkm

Percent Congested: 0.0000%

CONSUMERS ENERGY CO.


Wilmington
New Jersey
Vineland
Atlantic City
Columbia
Coastal Plain
Dover
Annapolis
Washington
Salisbury
California
Coastal Plain
Chesapeake Bay
30
Miles
Congested Urban
Service Territory
Service Area: 9119.64 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
DELMARVA POWER & LIGHT CO.





Congested Urban

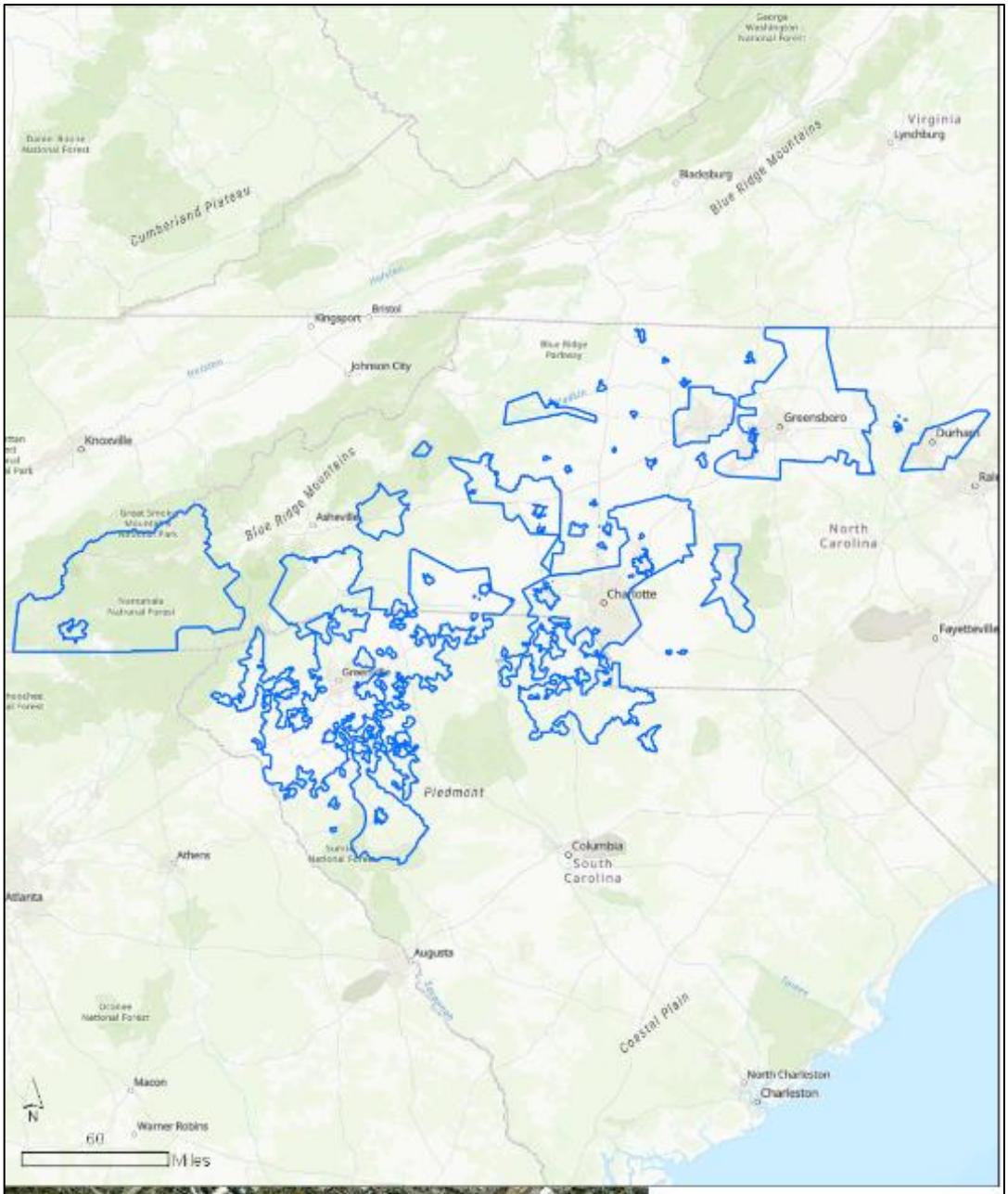
Service Territory

Service Area: 19833.46 sqkm

Congested Area: 8.52 sqkm

Percent Congested: 0.0430%

DETROIT EDISON CO.





Congested Urban

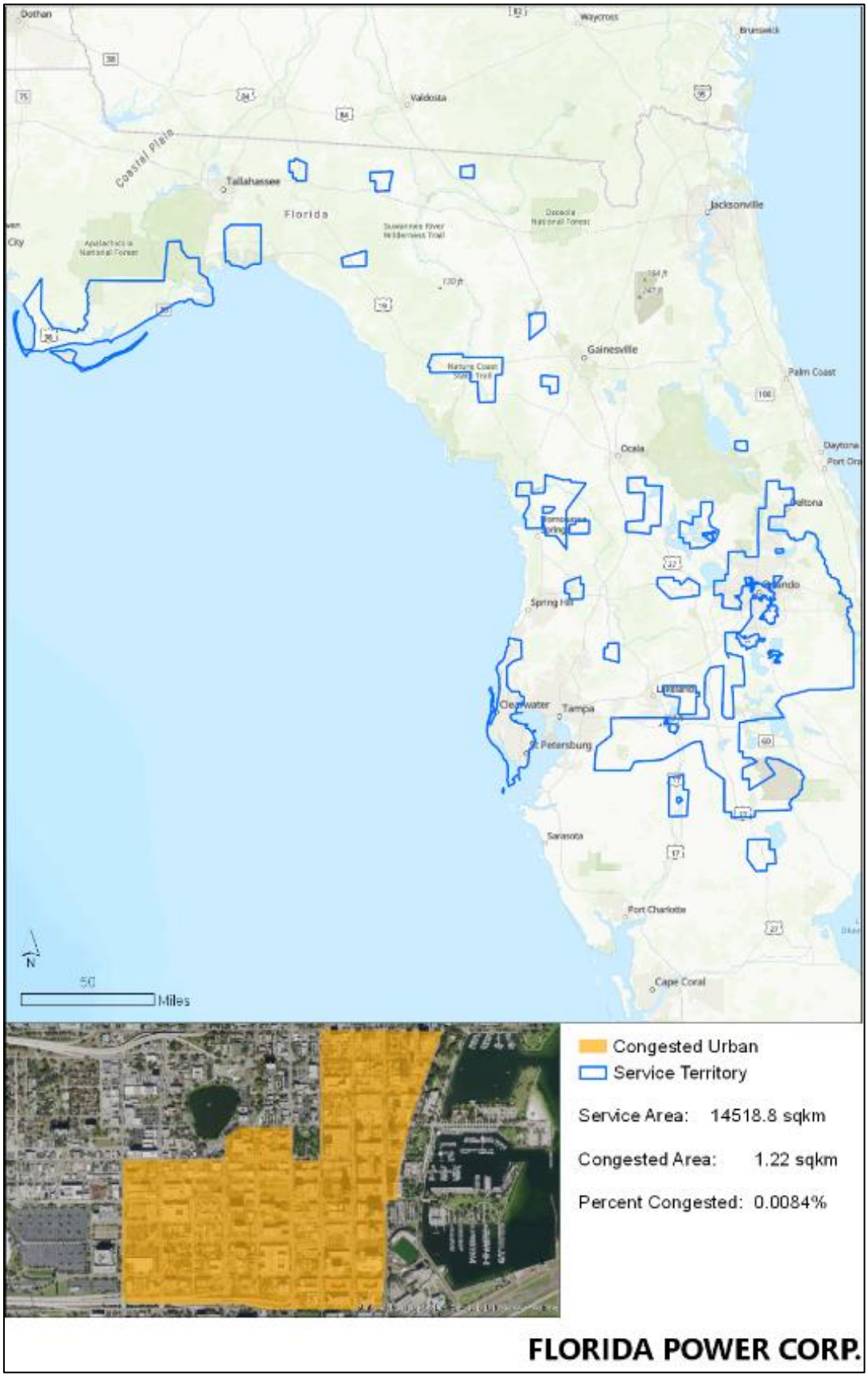
Service Territory

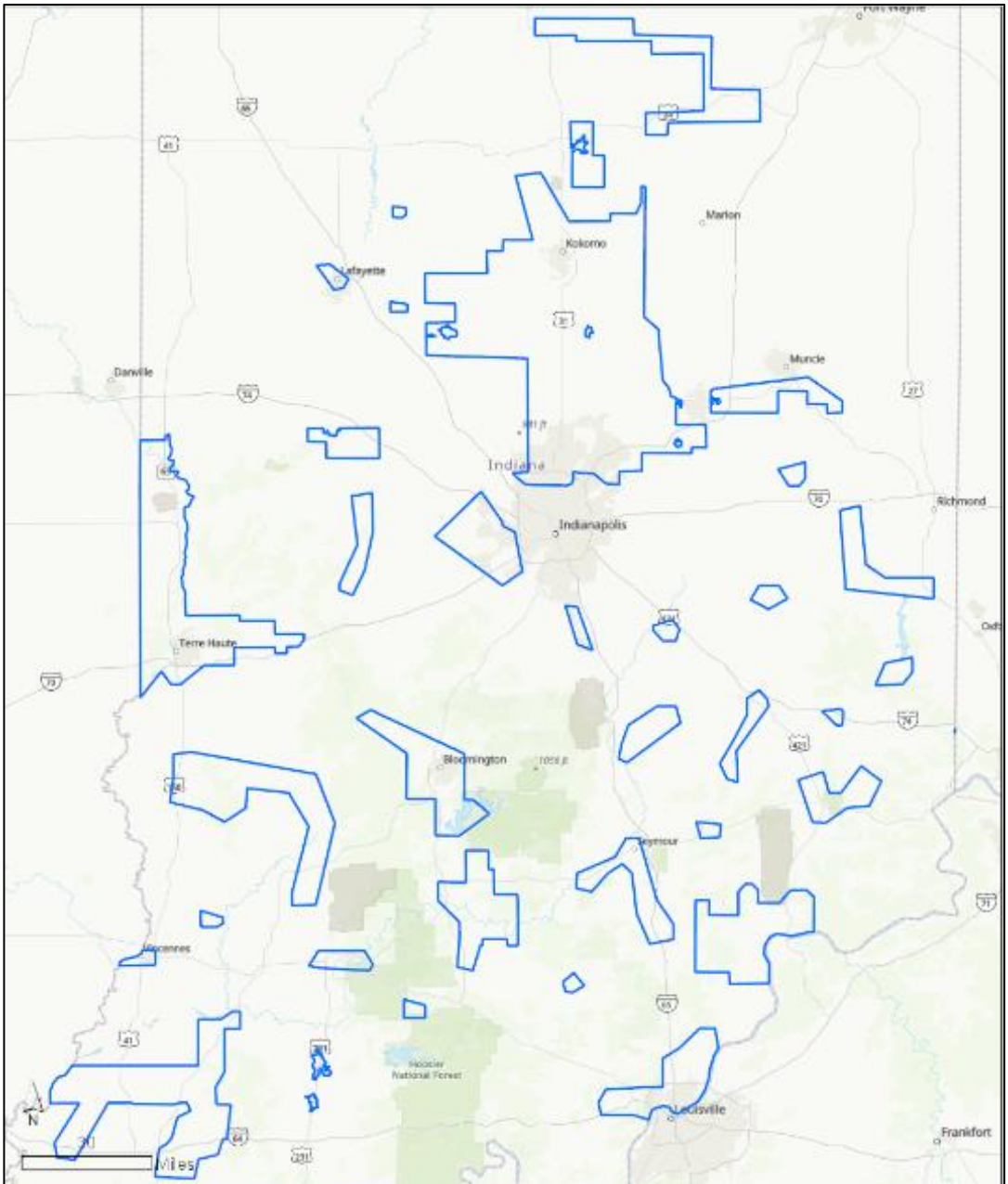
Service Area: 28776.02 sqkm

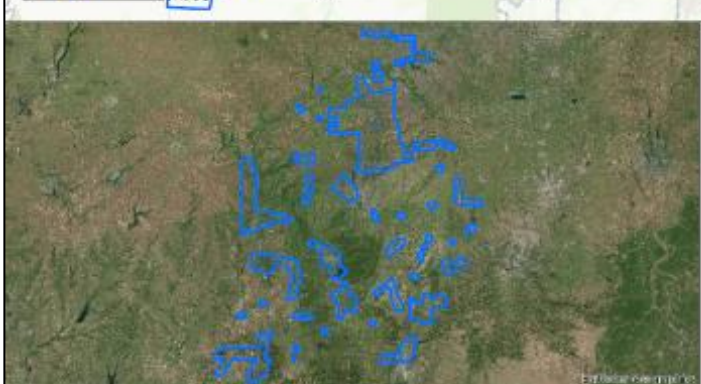
Congested Area: 3.87 sqkm

Percent Congested: 0.0134%

DUKE ENERGY CAROLINAS, LLC


Dothan
Waycross
Brunswick
Valdosta
Coastal Plain
Tallahassee
Florida
Jacksonville
Gainesville
Palm Coast
Ocala
Daytona
Spring Hill
Clearwater
Tampa
St Petersburg
Sarasota
Port Charlotte
Cape Coral
N
50
Miles
Congested Urban
Service Territory
Service Area: 14518.8 sqkm
Congested Area: 1.22 sqkm
Percent Congested: 0.0084%
FLORIDA POWER CORP.





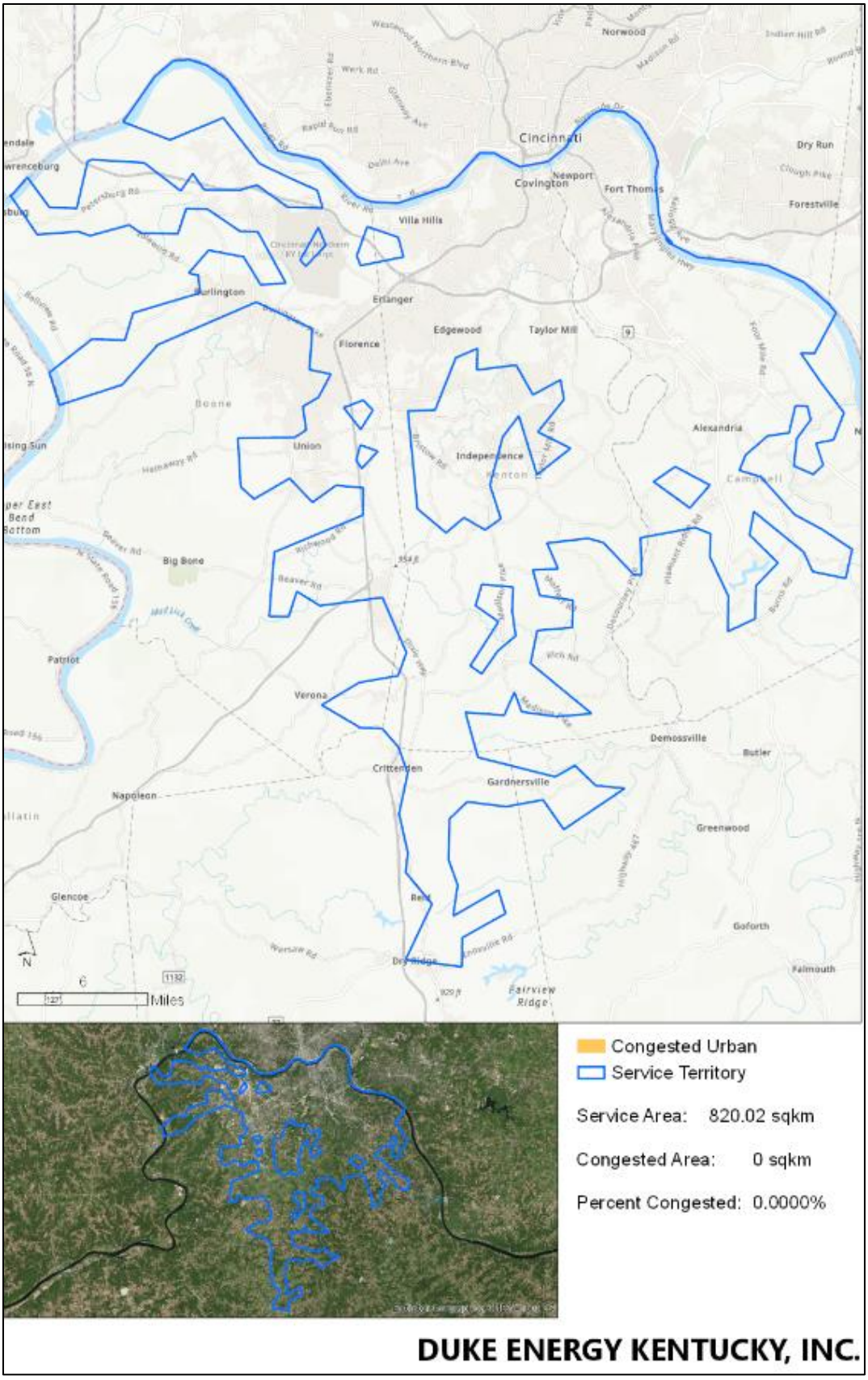
Congested Urban
Service Territory

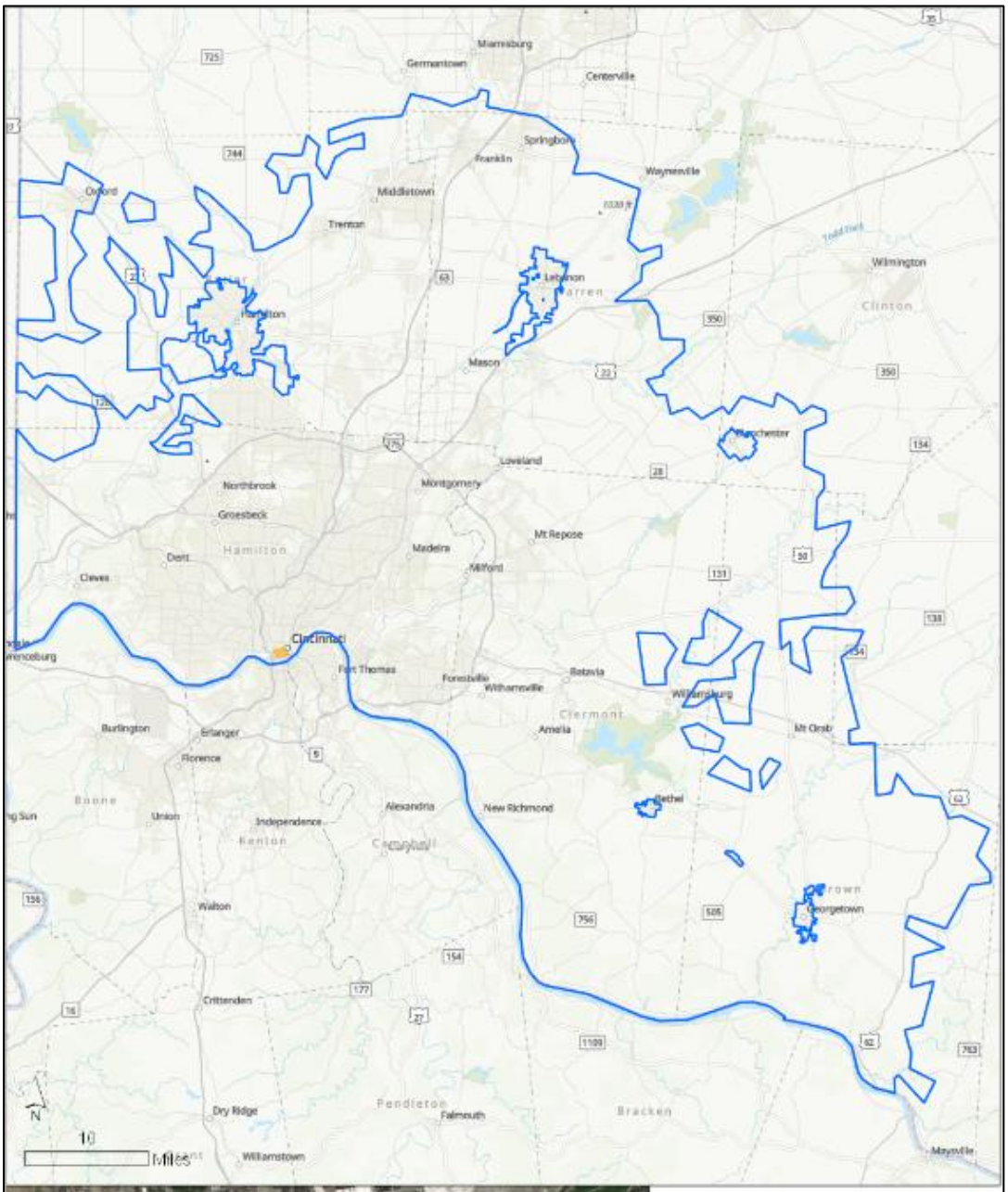
Service Area: 11460.76 sqkm

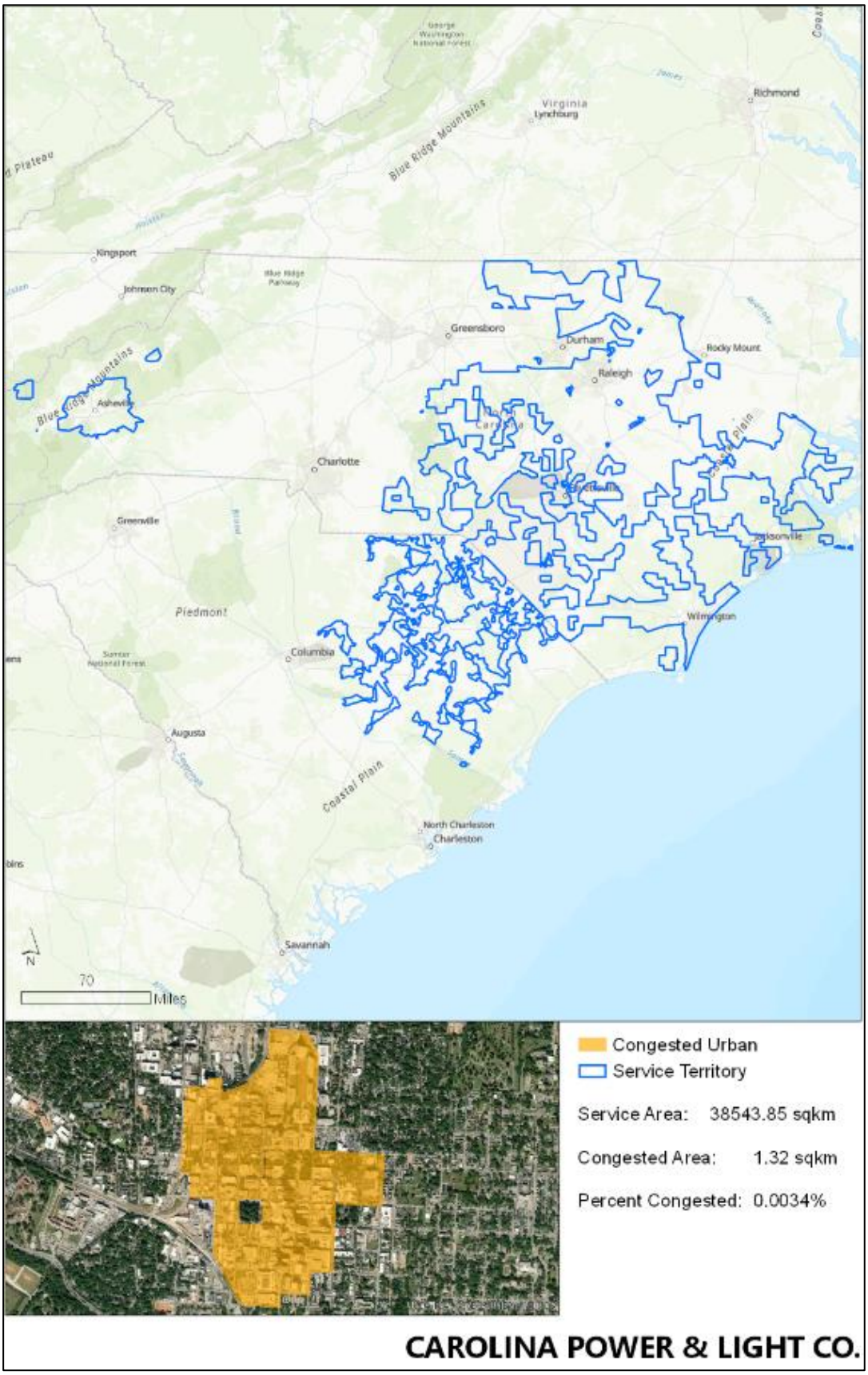
Congested Area: 0 sqkm

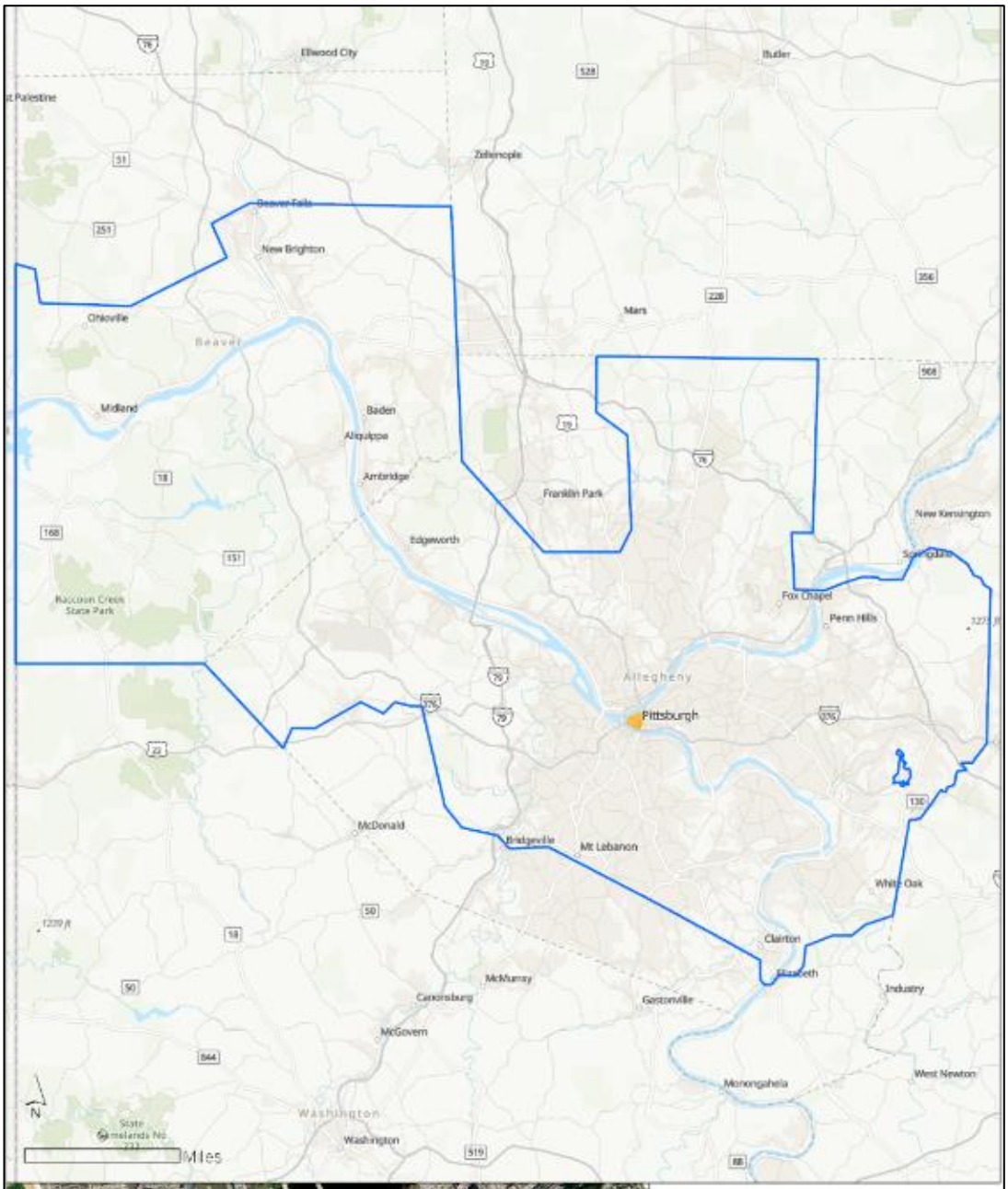
Percent Congested: 0.0000%

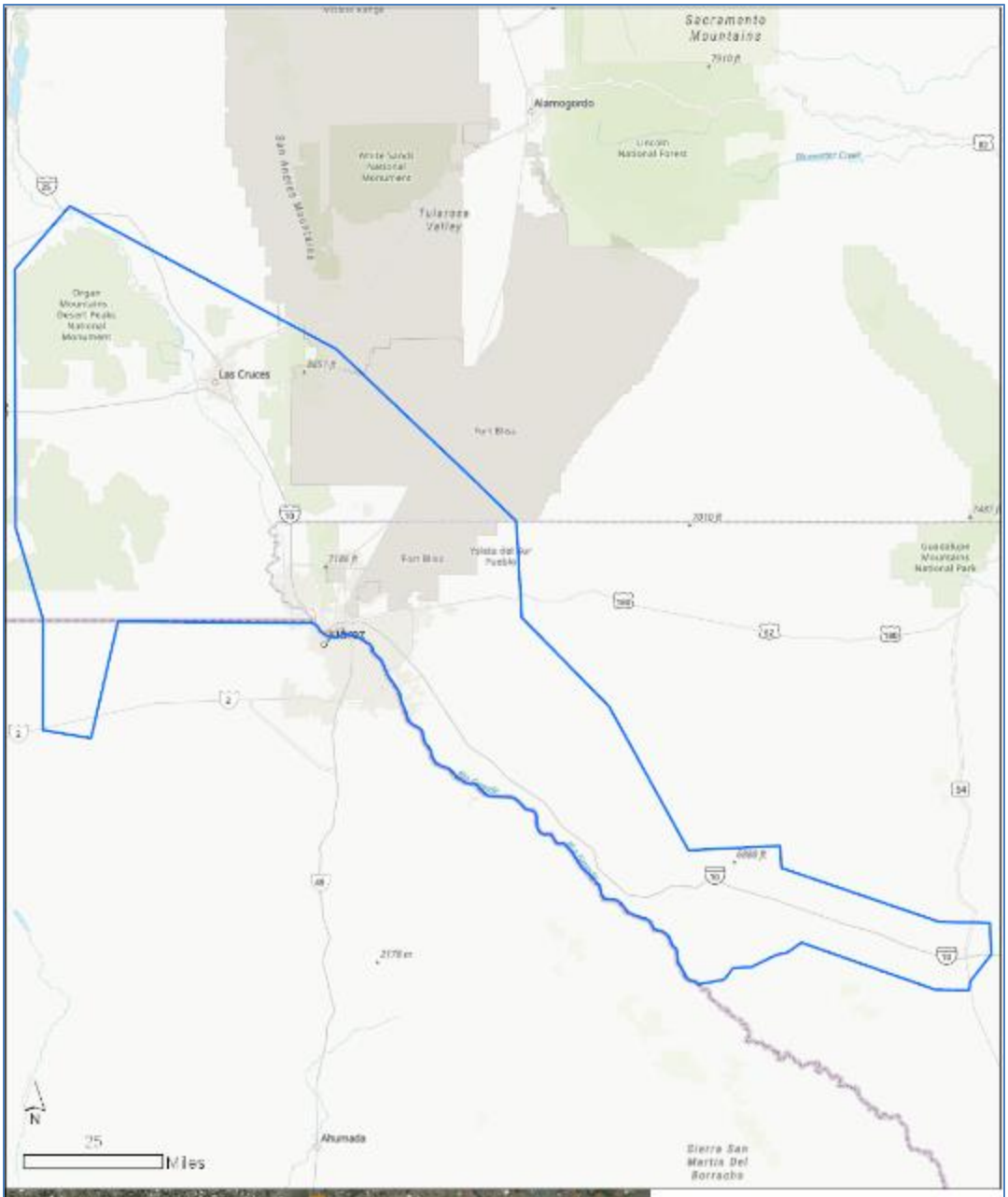
DUKE ENERGY INDIANA, INC.


Norwood
Cincinnati
Dry Run
Newport
Covington
Fort Thomas
Forestville
Villa Hills
Burlington
Erlanger
Florence
Edgewood
Taylor Mill
Alexandria
Union
Independence
Big Bone
Patriot
Verona
Demossville
Butler
Crittenden
Gardnersville
Napoleon
Greenwood
Glencoe
Goforth
Falmouth
Miles
Congested Urban
Service Territory
Service Area: 820.02 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
DUKE ENERGY KENTUCKY, INC.


Miamisburg
Germantown
Centerville
Springboro
Franklin
Waynesville
Middletown
Oxford
Trenton
Wilmington
Clinton
Lebanon
Warren
Hamilton
Mason
Loveland
Montgomery
Northbrook
Groesbeck
Mt Repose
Madeira
Milford
Deer Park
Cleves
Cincinnati
Fort Thomas
Forestville
Withamsville
Batavia
Williamsburg
Clermont
Amelia
Mt Orab
Burlington
Erlanger
Florence
Boone
Union
Independence
Kenton
Alexandria
New Richmond
Bethel
Georgetown
Walton
Crittenden
Dry Ridge
Pendleton
Falmouth
Bracken
Williamstown
Maysville
10
Miles
Congested Urban
Service Territory
Service Area: 4710.85 sqkm
Congested Area: 1.31 sqkm
Percent Congested: 0.0278%
DUKE ENERGY OHIO, INC.


Richmond
Virginia
Lynchburg
Blue Ridge Mountains
Kingsport
Johnson City
Greensboro
Durham
Rocky Mount
Raleigh
Asheville
Charlotte
Greenville
Piedmont
Columbia
Augusta
Coastal Plain
North Charleston
Charleston
Savannah
Wilmington
70
Miles
Congested Urban
Service Territory
Service Area: 38543.85 sqkm
Congested Area: 1.32 sqkm
Percent Congested: 0.0034%
CAROLINA POWER & LIGHT CO.


Ellwood City
Butler
Zelienople
Beaver Falls
New Brighton
Ohioville
Mars
Beaver
Midland
Baden
Aliquippa
Ambridge
Franklin Park
Edgeworth
New Kensington
Fox Chapel
Penn Hills
Allegheny
Pittsburgh
McDonald
Bridgeville
Mt Lebanon
White Oak
Clairton
McMurray
Canonsburg
Gastonville
Industry
McGovern
Monongahela
West Newton
Washington
Washington
Miles
Congested Urban
Service Territory
Service Area: 2078.25 sqkm
Congested Area: 1.13 sqkm
Percent Congested: 0.0543%
DUQUESNE LIGHT CO.





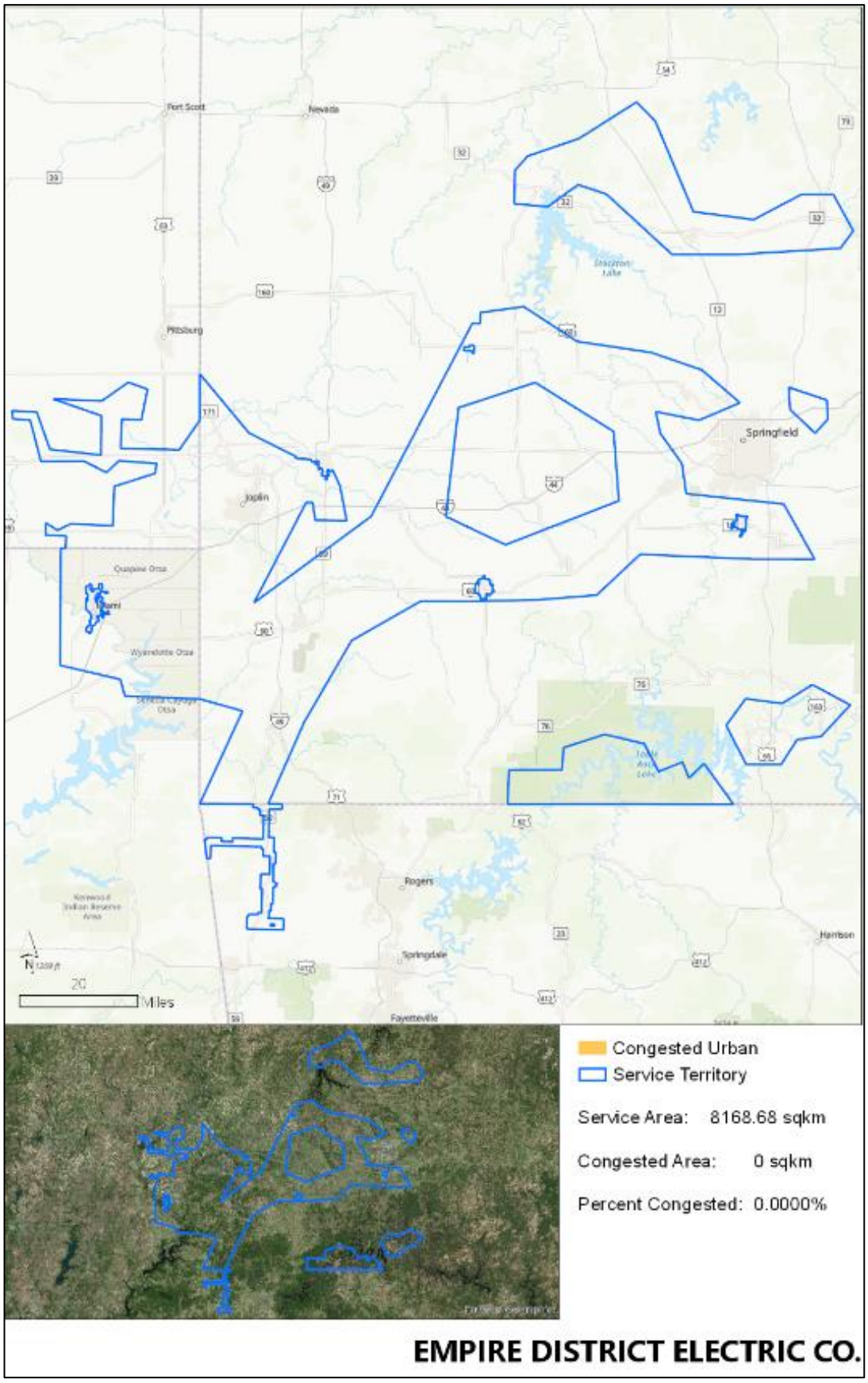
Congested Urban
Service Territory

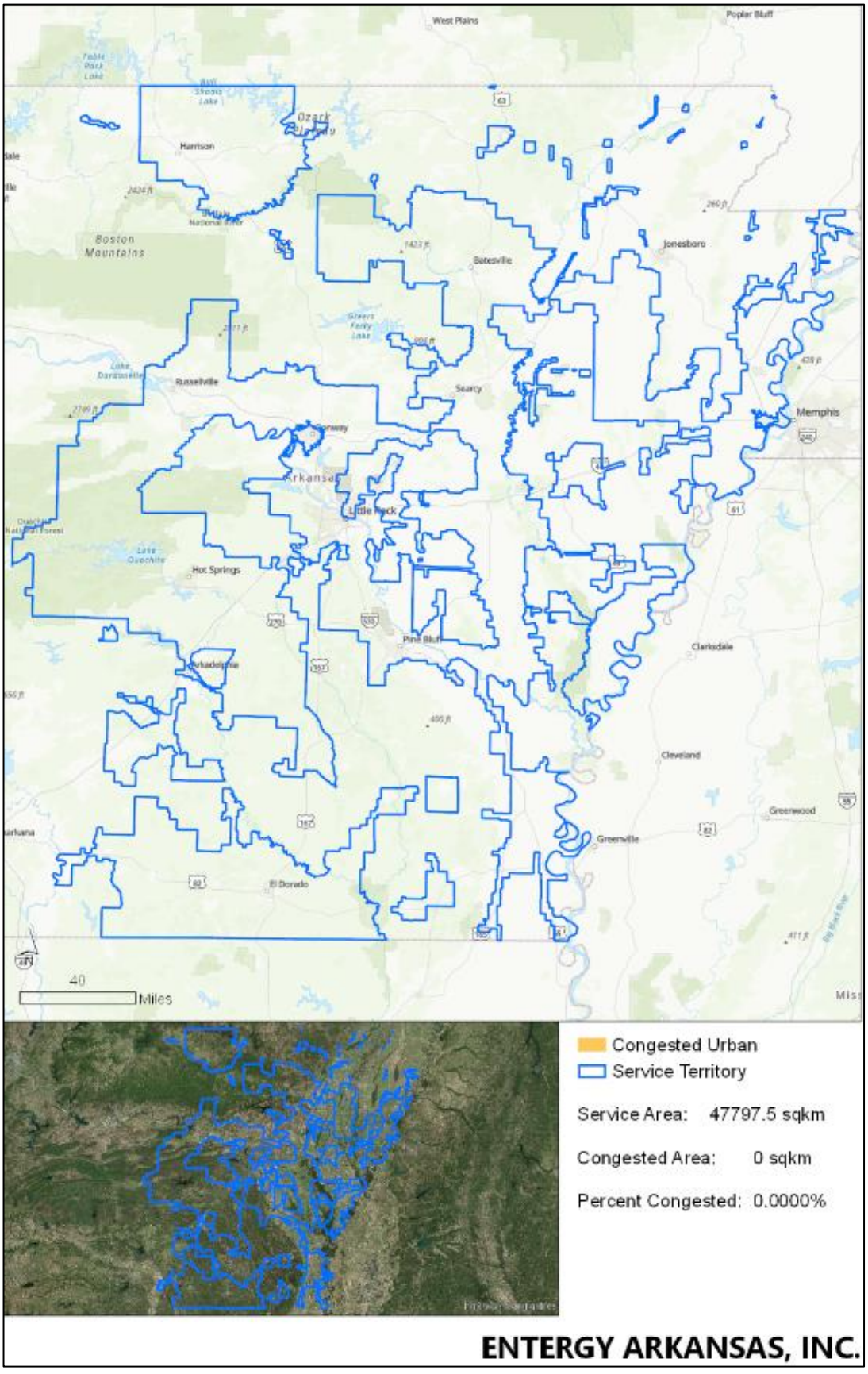
Service Area: 13572.88 sqkm

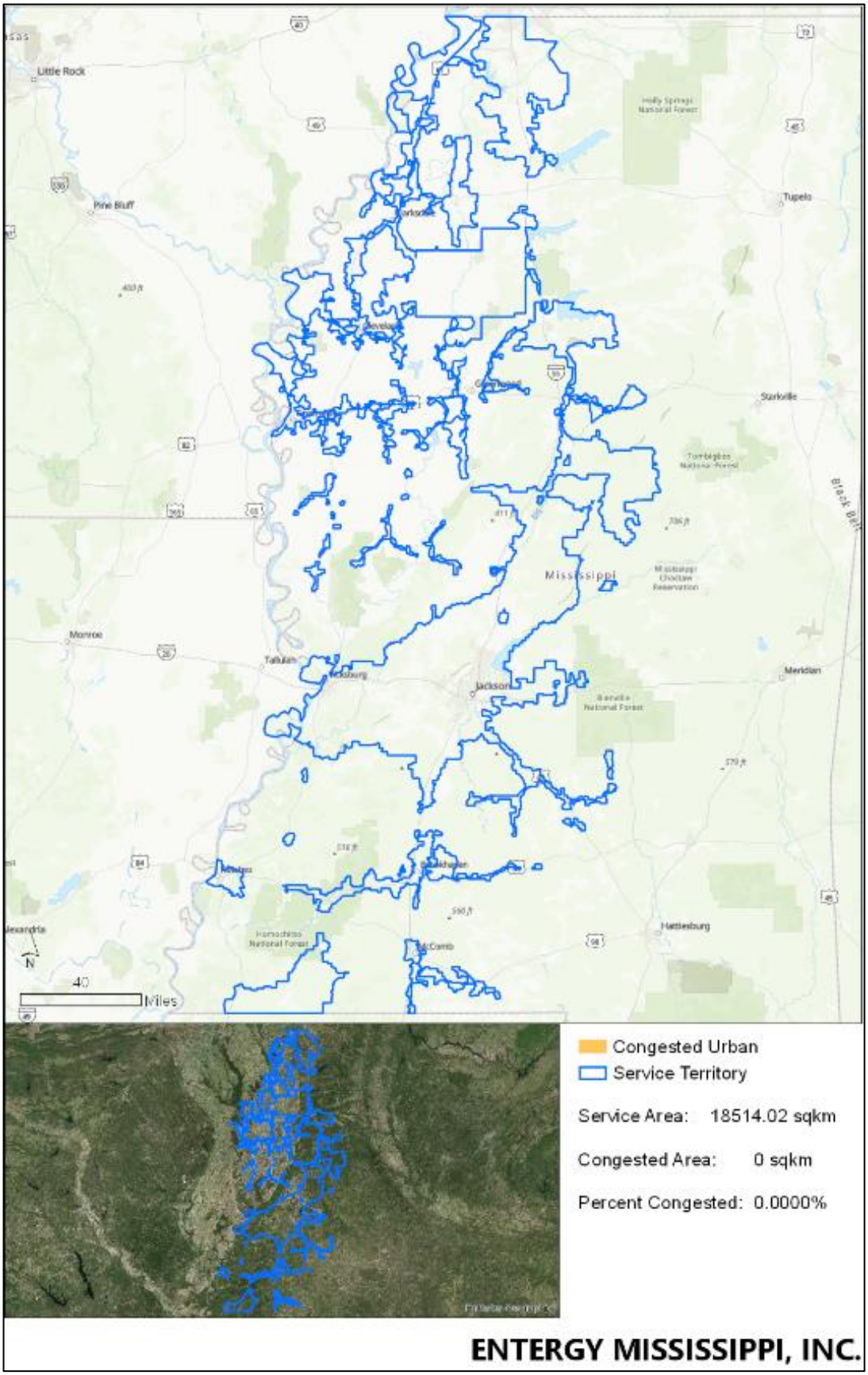
Congested Area: 1.52 sqkm

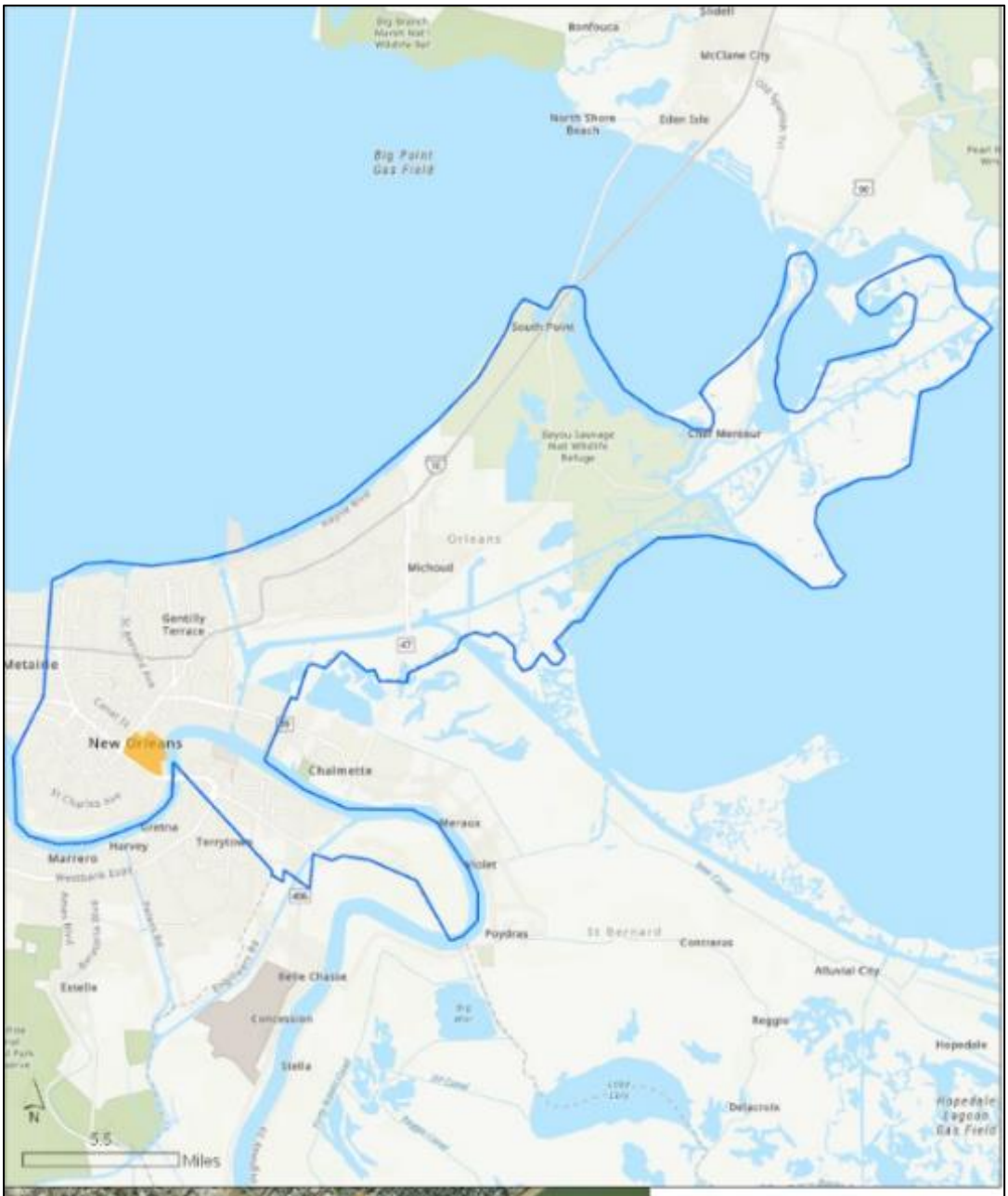
Percent Congested: 0.0112%

EL PASO ELECTRIC CO.


Fort Scott
Nevada
Pittsburg
Springfield
Joplin
Miami
Rogers
Springdale
Fayetteville
Harrison
20
Miles
Congested Urban
Service Territory
Service Area: 8168.68 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
EMPIRE DISTRICT ELECTRIC CO.


West Plains
Poplar Bluff
Harrison
Boston Mountains
Batesville
Jonesboro
Russellville
Searcy
Memphis
Little Rock
Hot Springs
Pine Bluff
Clarksdale
Cleveland
Greenwood
Greenville
El Dorado
40
Miles
Congested Urban
Service Territory
Service Area: 47797.5 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
ENTERGY ARKANSAS, INC.


Little Rock
Pine Bluff
Tupelo
Starkville
Mississippi
Monroe
Meridian
Hattiesburg
N
40
Miles
Congested Urban
Service Territory
Service Area: 18514.02 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
ENTERGY MISSISSIPPI, INC.





Congested Urban

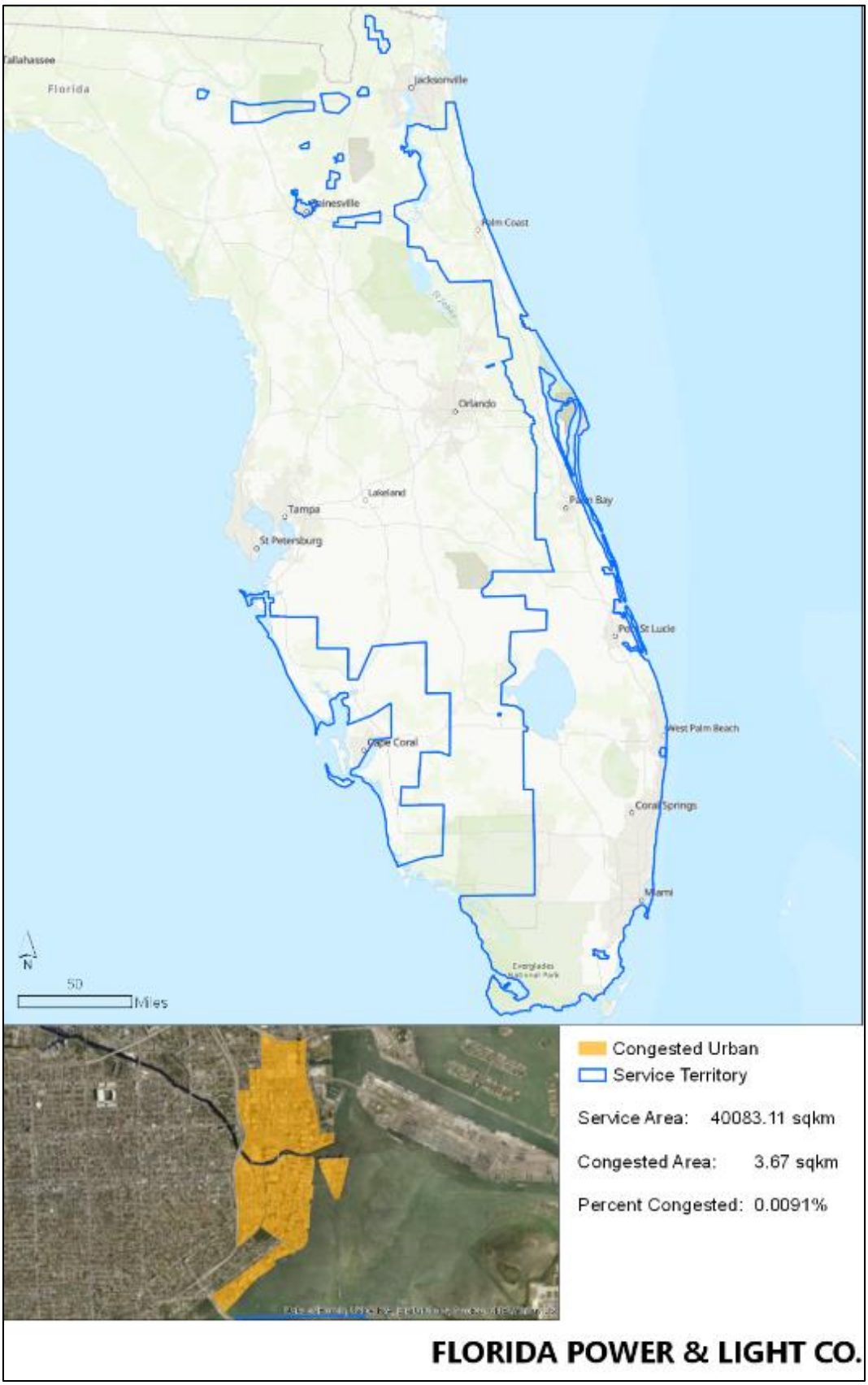
Service Territory

Service Area: 523.45 sqkm

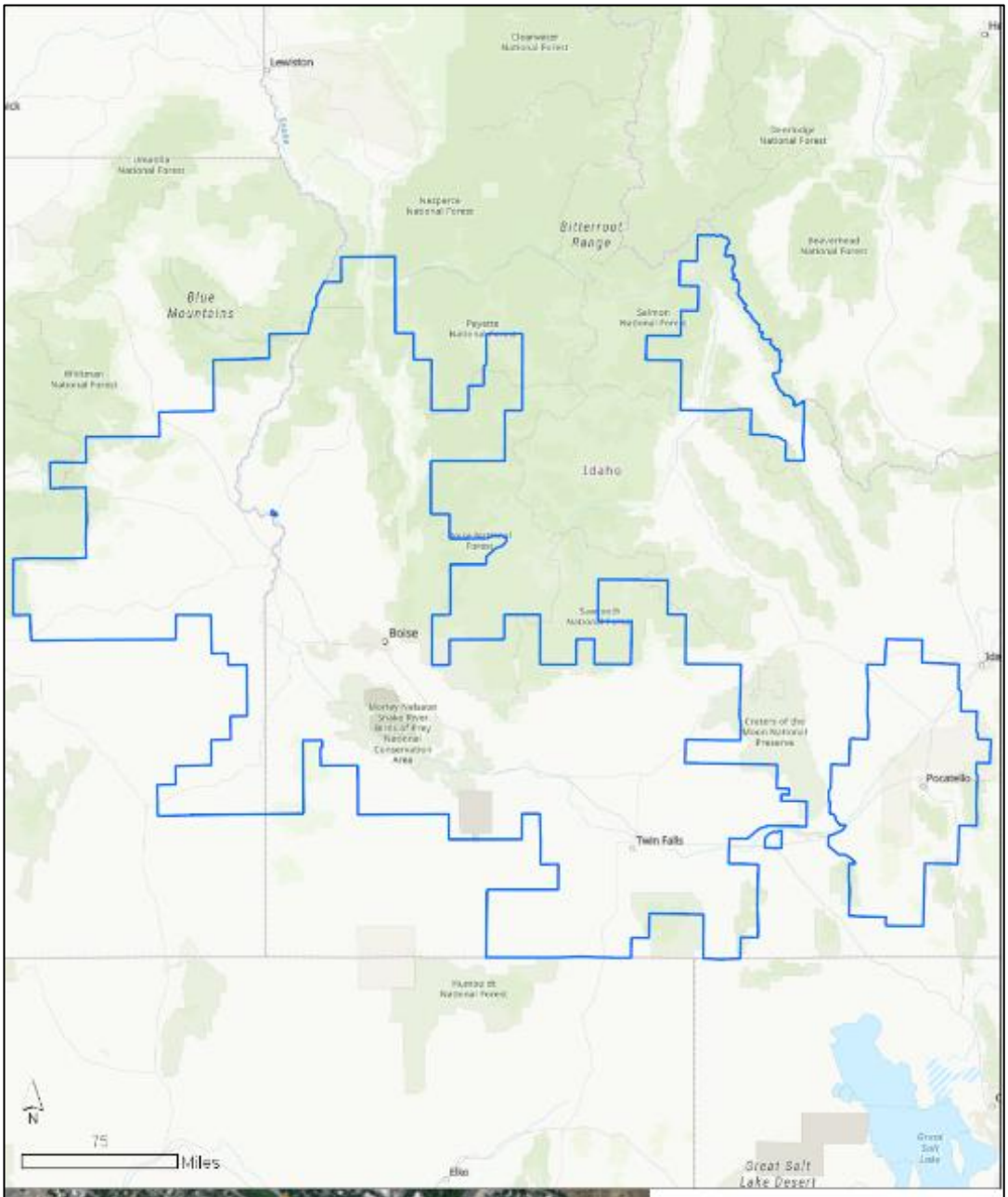
Congested Area: 3.02 sqkm

Percent Congested: 0.5762%

ENTERGY NEW ORLEANS, INC.


Florida
Jacksonville
Orlando
Tampa
St Petersburg
Lakeland
Cape Coral
West Palm Beach
Coral Springs
Miami
N
50
Miles
Congested Urban
Service Territory
Service Area: 40083.11 sqkm
Congested Area: 3.67 sqkm
Percent Congested: 0.0091%
FLORIDA POWER & LIGHT CO.


Monroeville
Andalusia
Enterprise
Dothan
Crestview
Eglin Air Force Base
Pensacola
Gulf Islands National Seashore
Fort Walton Beach
Panama City
Tyndall Air Force Base
N
25
Miles
Congested Urban
Service Territory
Service Area: 3314.63 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
GULF POWER CO.





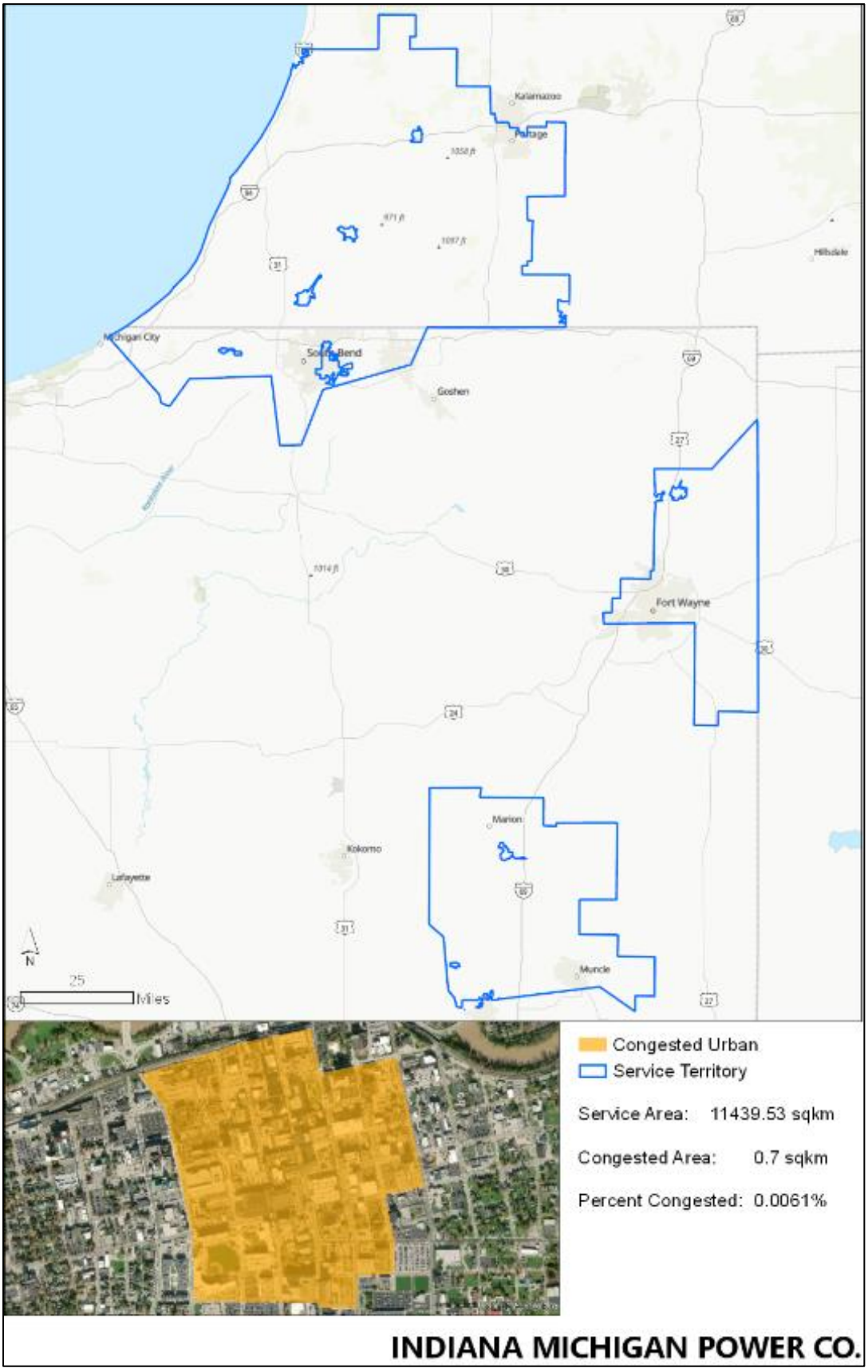
Congested Urban
Service Territory

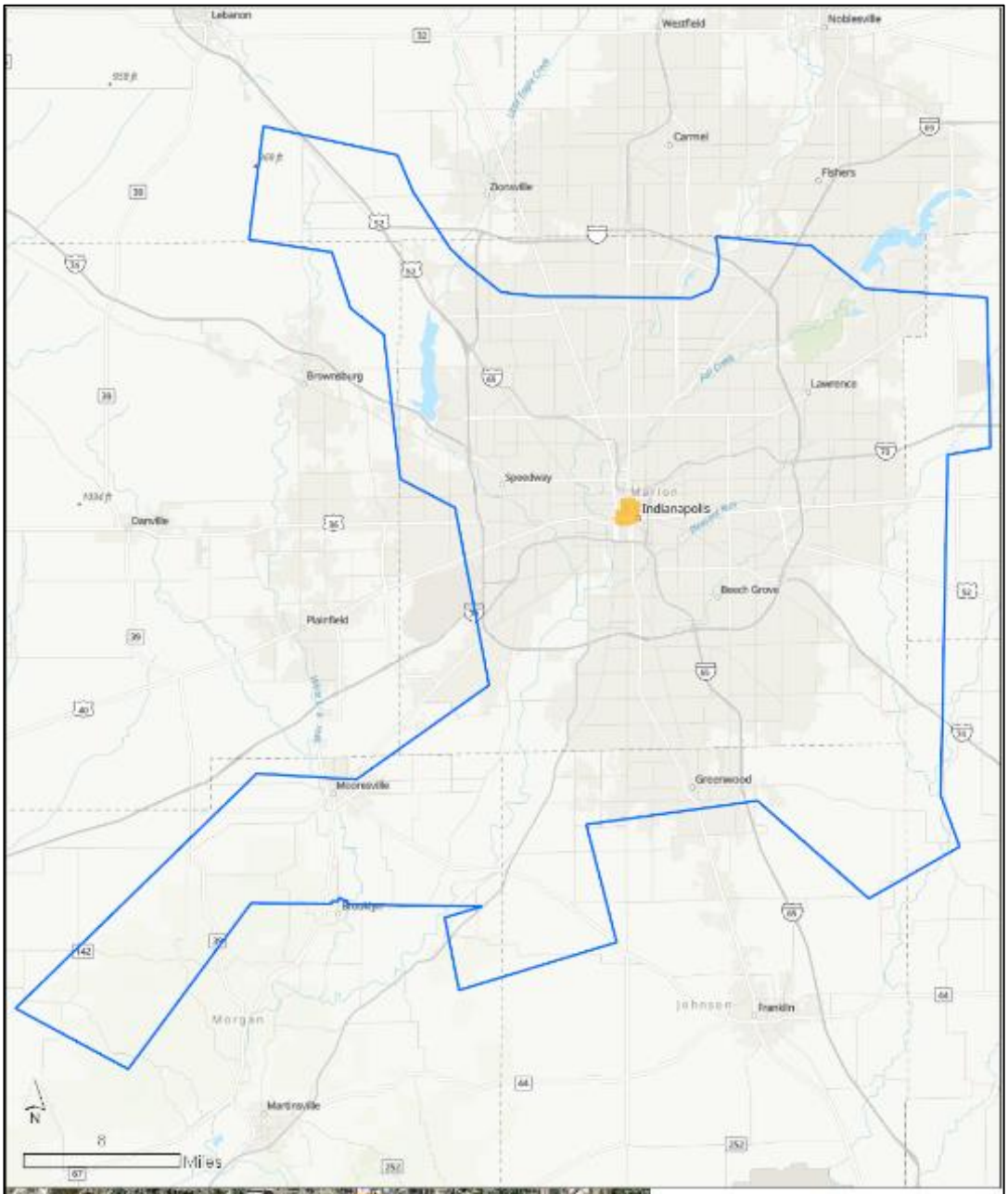
Service Area: 88853.73 sqkm

Congested Area: 1.21 sqkm

Percent Congested: 0.0014%

IDAHO POWER CO.


Kalamazoo
Portage
Hillsdale
Michigan City
South Bend
Goshen
Fort Wayne
Marion
Kokomo
Lafayette
Muncie
N
25
Miles
Congested Urban
Service Territory
Service Area: 11439.53 sqkm
Congested Area: 0.7 sqkm
Percent Congested: 0.0061%
INDIANA MICHIGAN POWER CO.





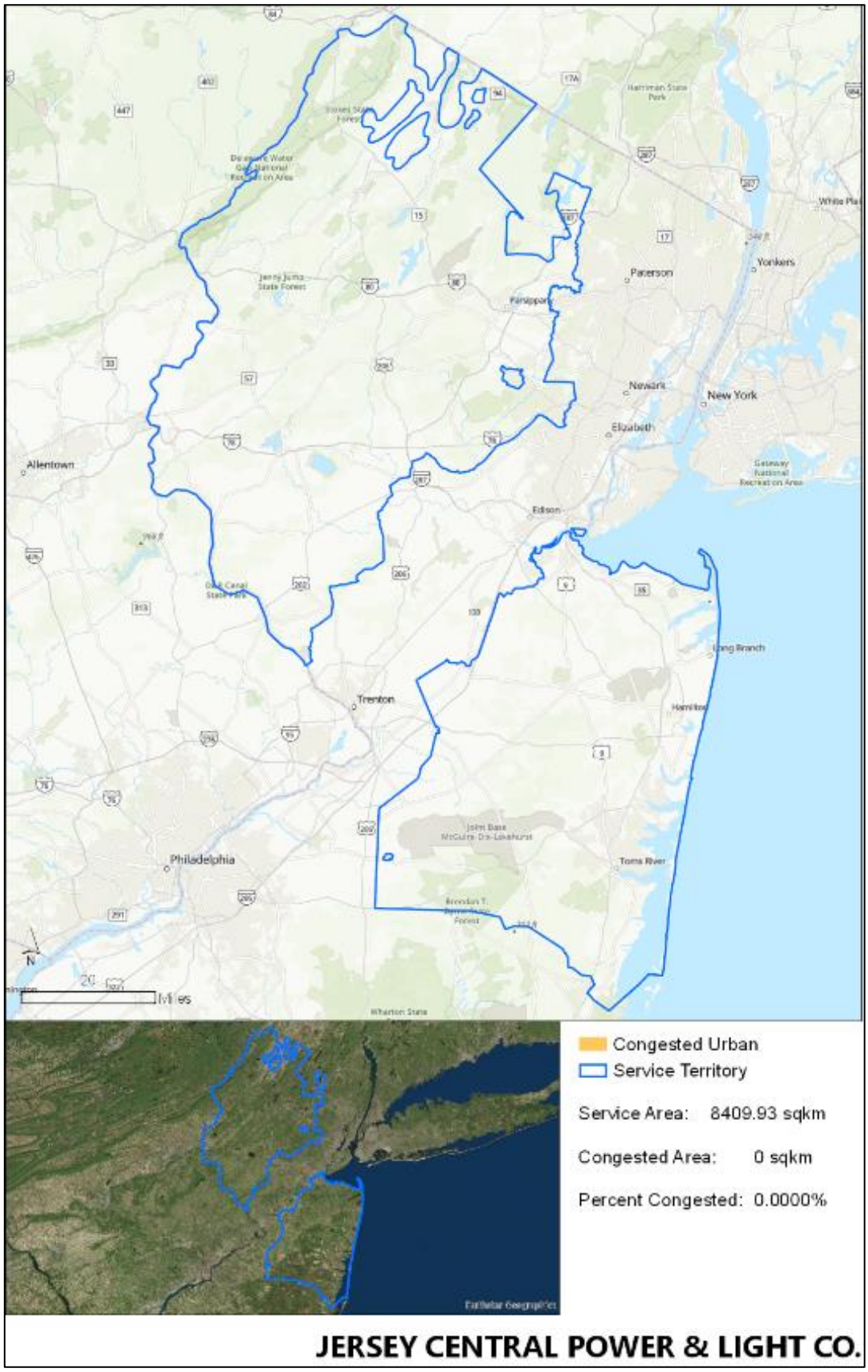
Congested Urban
Service Territory

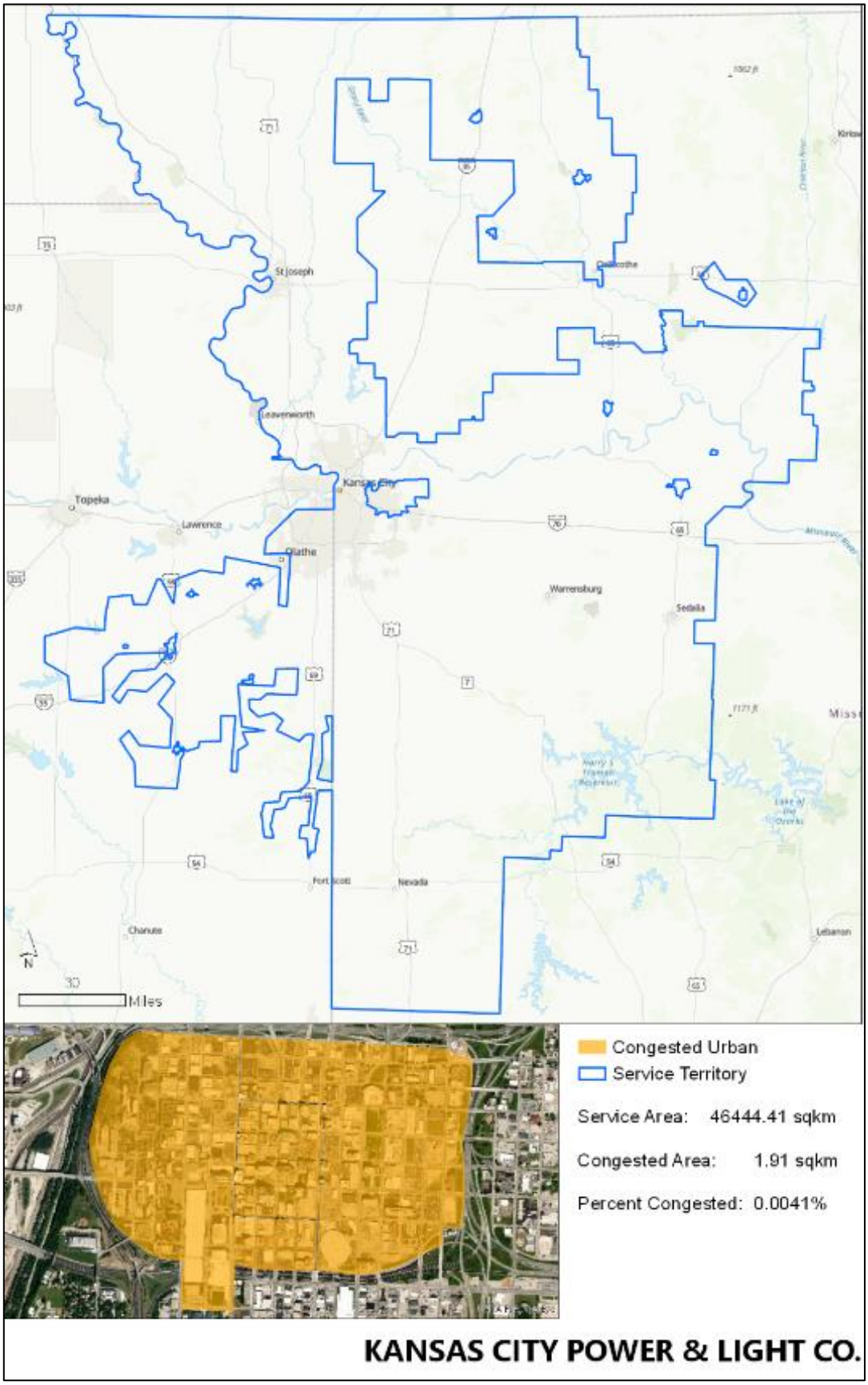
Service Area: 1557.86 sqkm

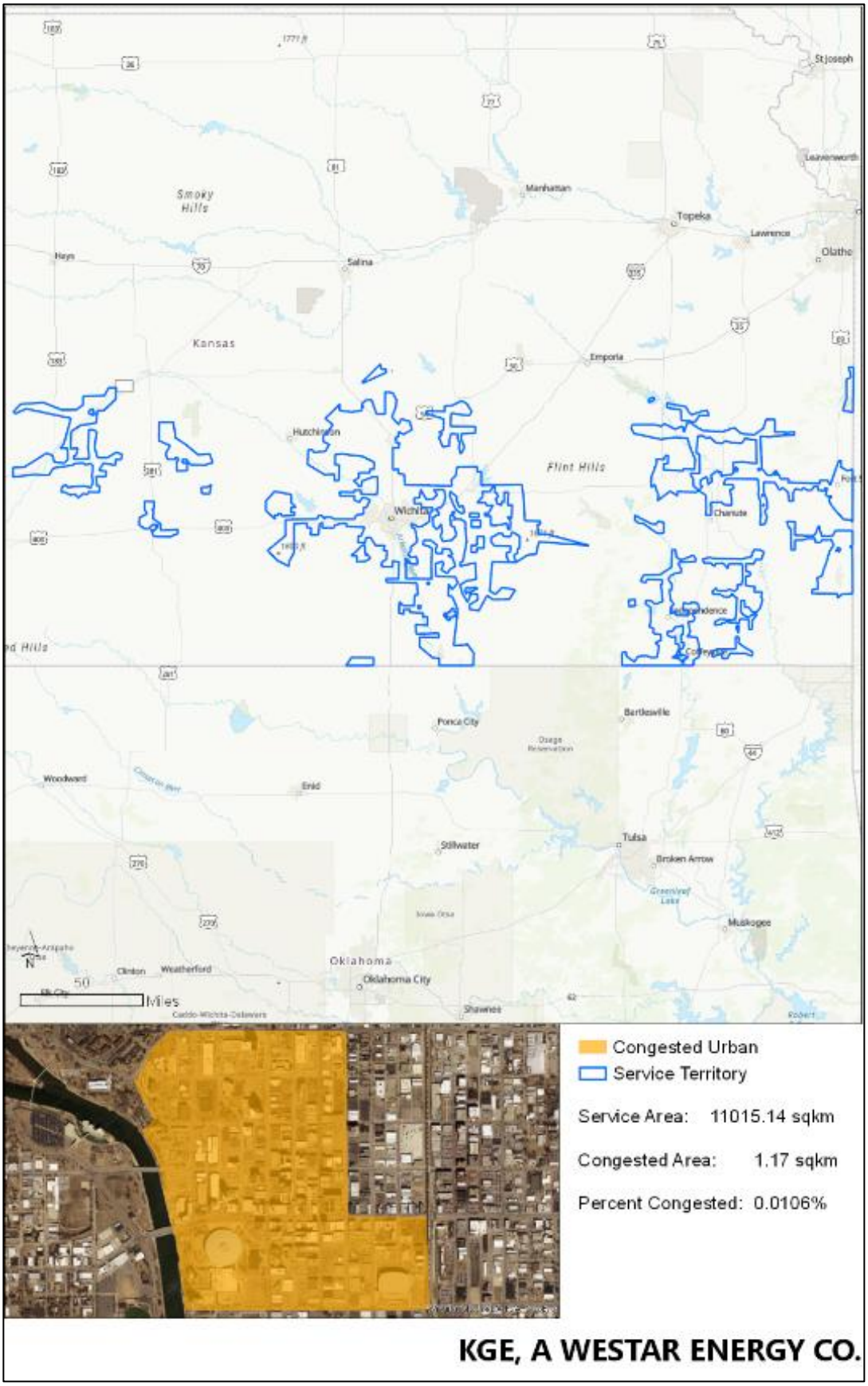
Congested Area: 2.33 sqkm

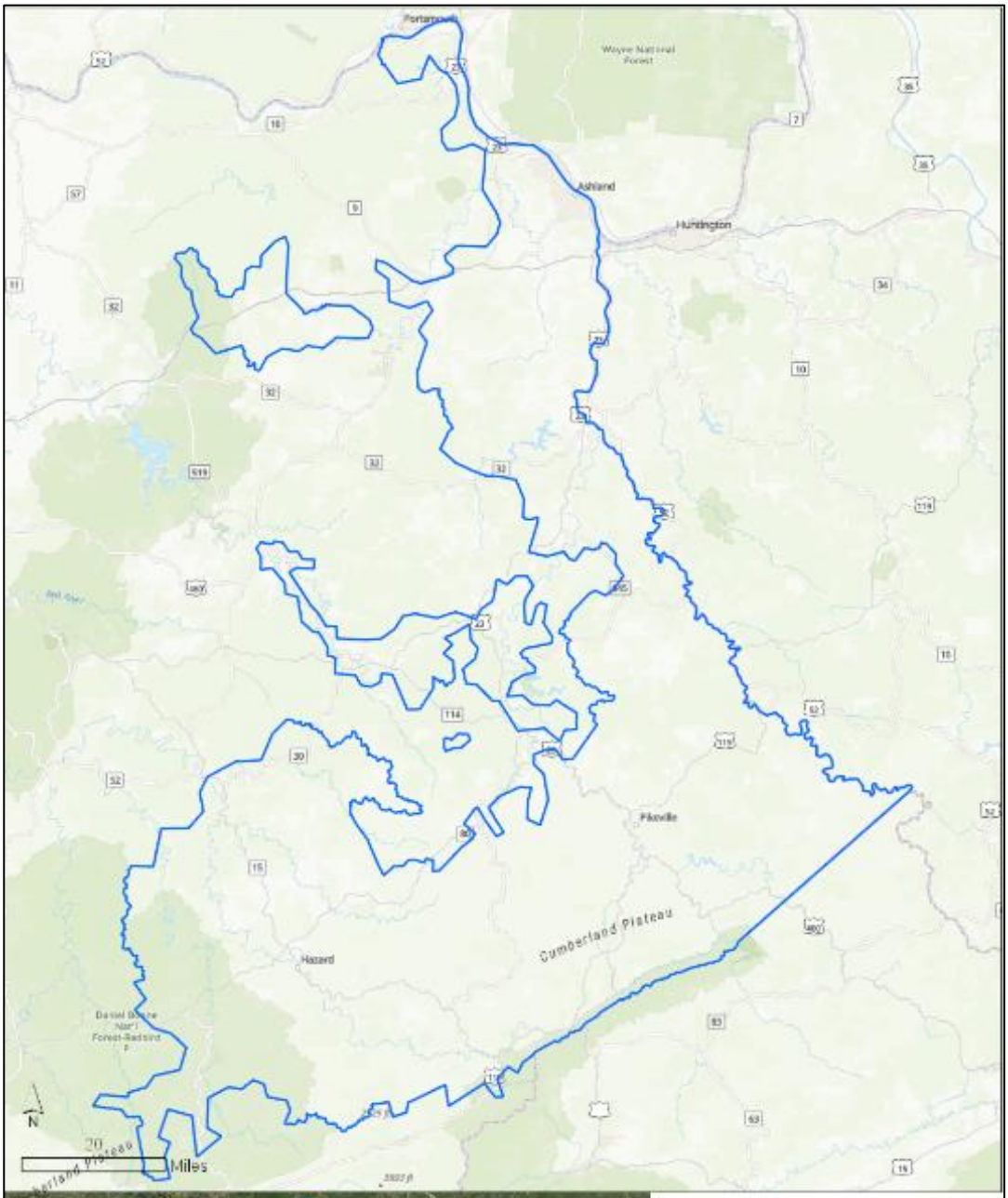
Percent Congested: 0.1498%

INDIANAPOLIS POWER & LIGHT CO.


Paterson
Yonkers
Newark
New York
Elizabeth
Allentown
Edison
Trenton
Philadelphia
Toms River
Long Branch
Hamilton
N
20
Miles
Congested Urban
Service Territory
Service Area: 8409.93 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
JERSEY CENTRAL POWER & LIGHT CO.


St Joseph
Leavenworth
Kansas City
Topeka
Lawrence
Olathe
Warrensburg
Sedalia
Fort Scott
Nevada
Chanute
Lebanon
Miles
Congested Urban
Service Territory
Service Area: 46444.41 sqkm
Congested Area: 1.91 sqkm
Percent Congested: 0.0041%
KANSAS CITY POWER & LIGHT CO.


St Joseph
Leavenworth
Manhattan
Topeka
Lawrence
Olathe
Smoky Hills
Hays
Salina
Kansas
Emporia
Hutchinson
Flint Hills
Wichita
Chanute
Bartlesville
Ponca City
Woodward
Enid
Stillwater
Tulsa
Broken Arrow
Muskogee
Oklahoma
Clinton
Weatherford
Oklahoma City
Shawnee
50
Miles
Congested Urban
Service Territory
Service Area: 11015.14 sqkm
Congested Area: 1.17 sqkm
Percent Congested: 0.0106%
KGE, A WESTAR ENERGY CO.





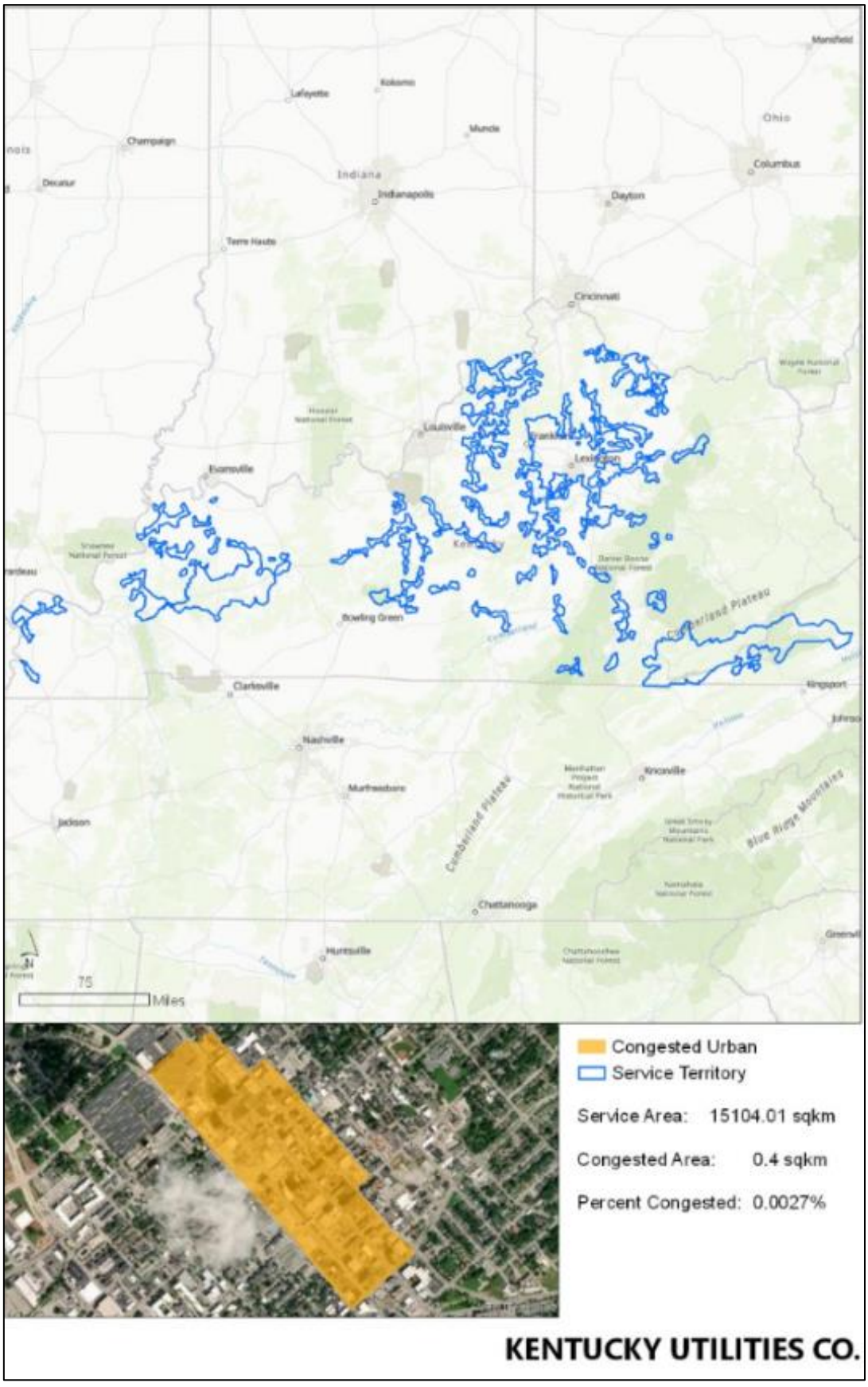
Congested Urban
Service Territory

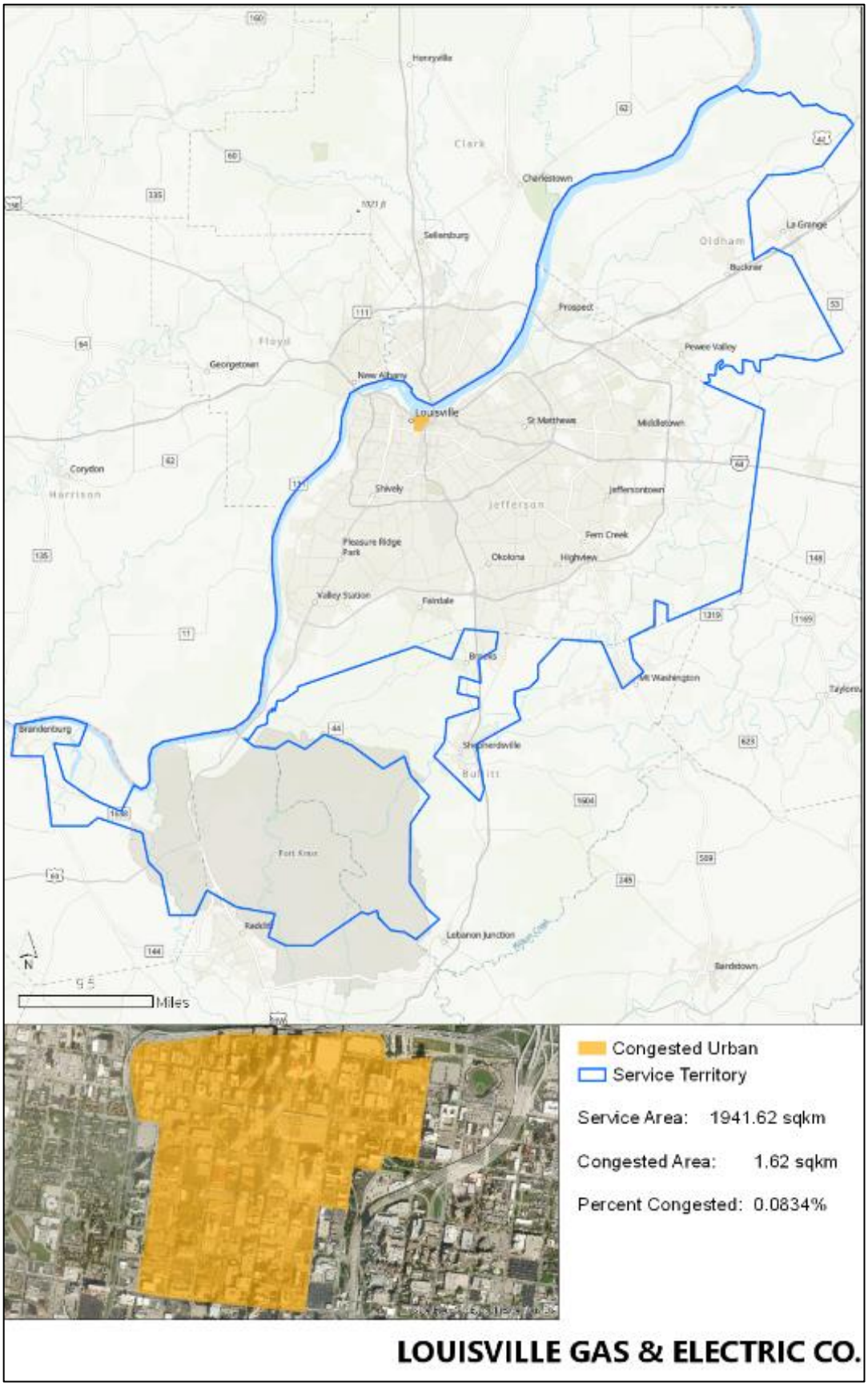
Service Area: 9655.81 sqkm

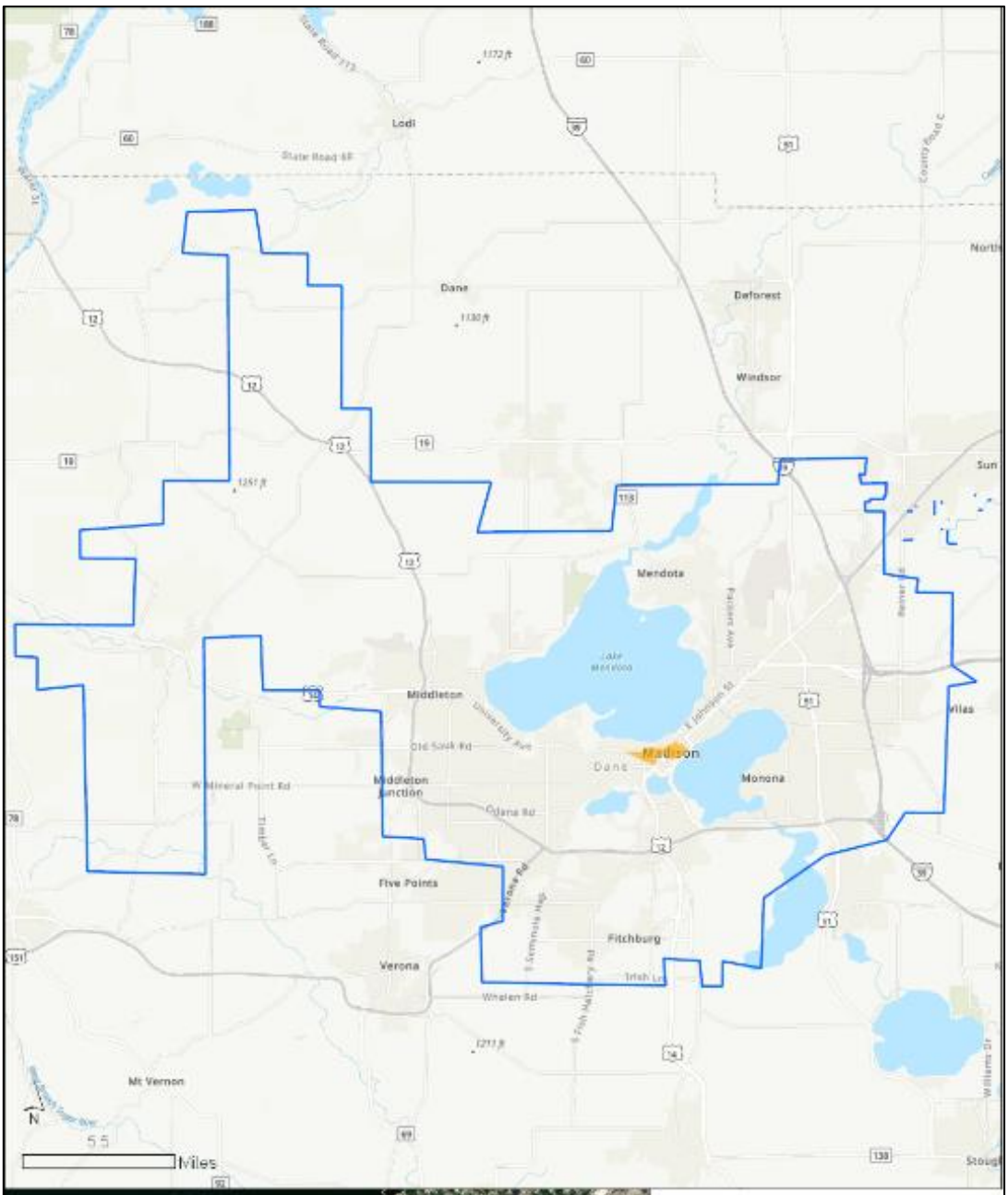
Congested Area: 0 sqkm

Percent Congested: 0.0000%

KENTUCKY POWER CO.


Mansfield
Lafayette
Kokomo
Ohio
Champaign
Muncie
Columbus
Indiana
Decatur
Indianapolis
Dayton
Terre Haute
Cincinnati
Louisville
Evansville
Lexington
Bowling Green
Clarksville
Kingsport
Nashville
Knoxville
Murfreesboro
Jackson
Cumberland Plateau
Blue Ridge Mountains
Chattanooga
Huntsville
75
Miles
Congested Urban
Service Territory
Service Area: 15104.01 sqkm
Congested Area: 0.4 sqkm
Percent Congested: 0.0027%
KENTUCKY UTILITIES CO.


Henryville
Clark
Charlestown
Sellersburg
La Grange
Oldham
Buckner
Prospect
Floyd
Georgetown
New Albany
Louisville
St Matthews
Middletown
Corydon
Harrison
Shively
Jefferson
Jeffersontown
Fern Creek
Pleasure Ridge Park
Okolona
Highview
Valley Station
Fairdale
Mt Washington
Brandenburg
Shepherdsville
Bullitt
Fort Knox
Radcliff
Lebanon Junction
Bardstown
N
Miles
Congested Urban
Service Territory
Service Area: 1941.62 sqkm
Congested Area: 1.62 sqkm
Percent Congested: 0.0834%
LOUISVILLE GAS & ELECTRIC CO.





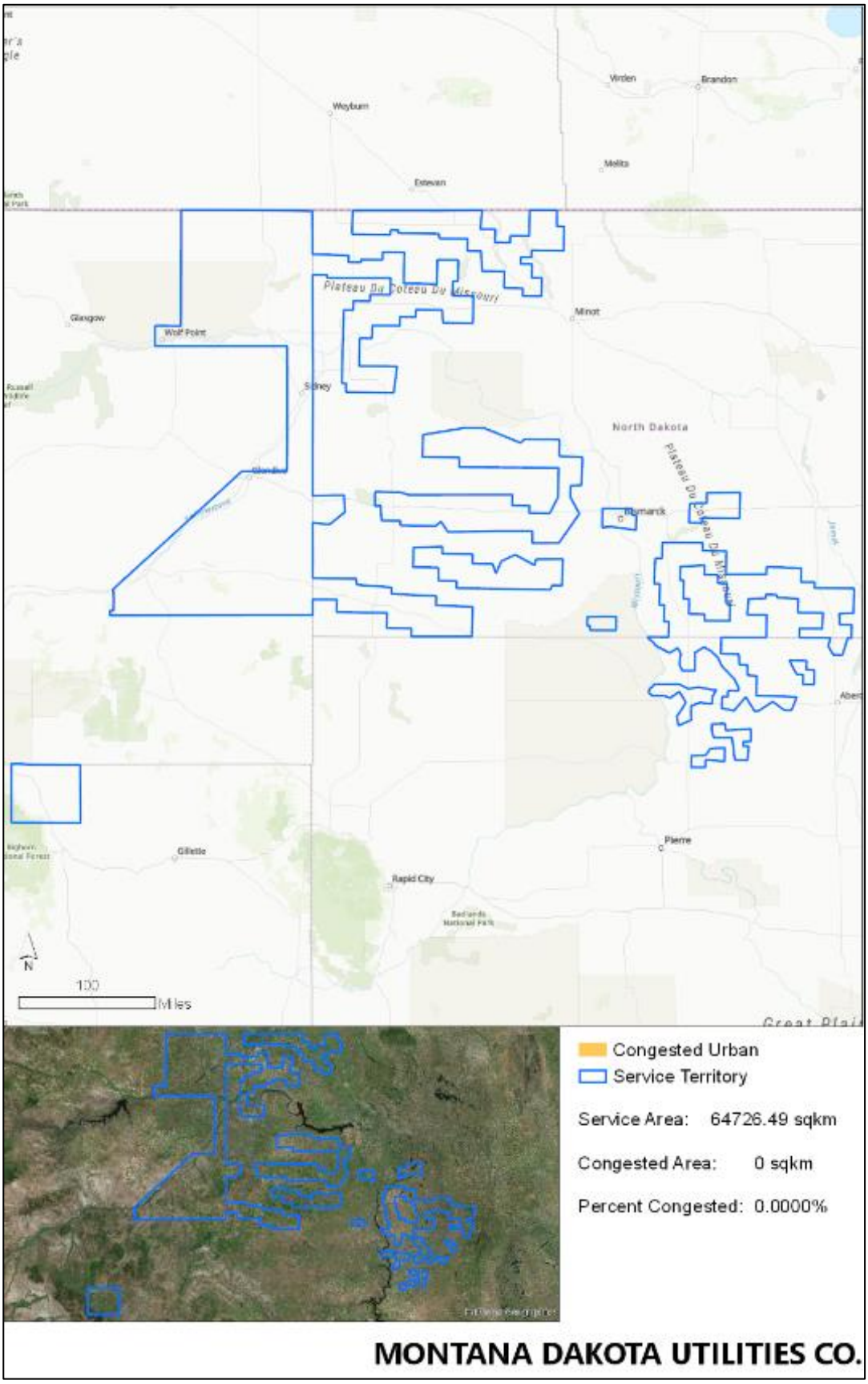
Congested Urban
Service Territory

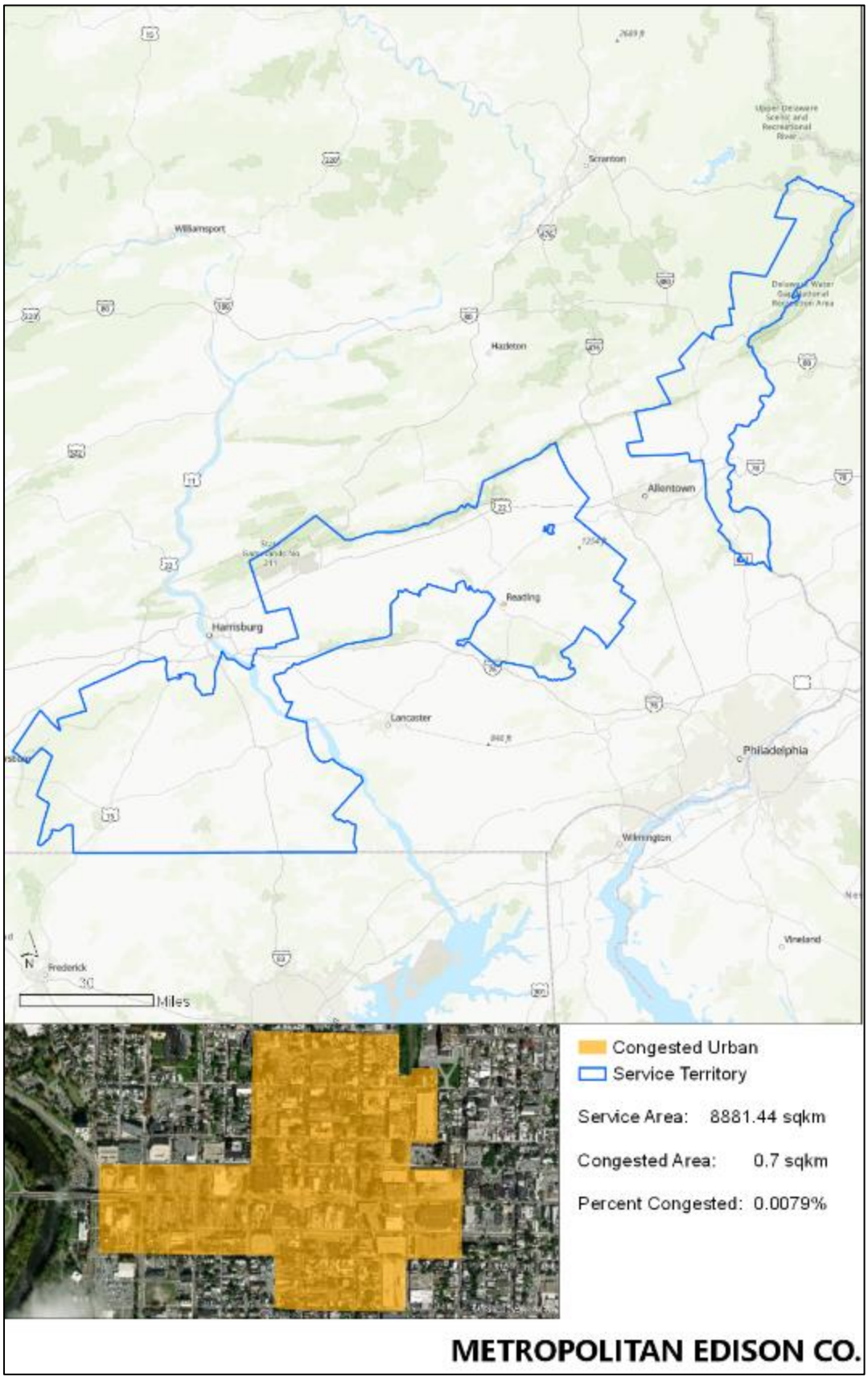
Service Area: 614.89 sqkm

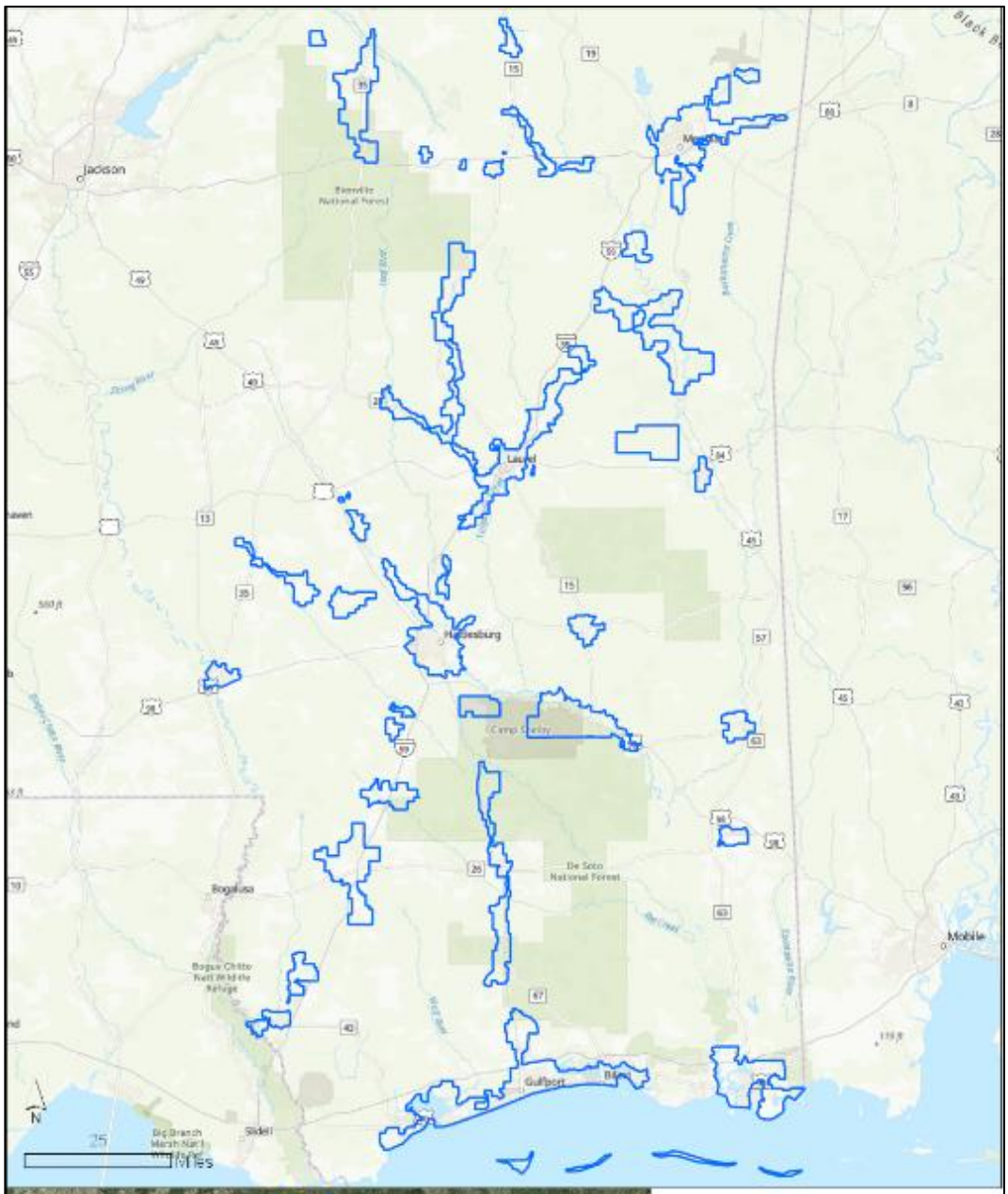
Congested Area: 1.16 sqkm

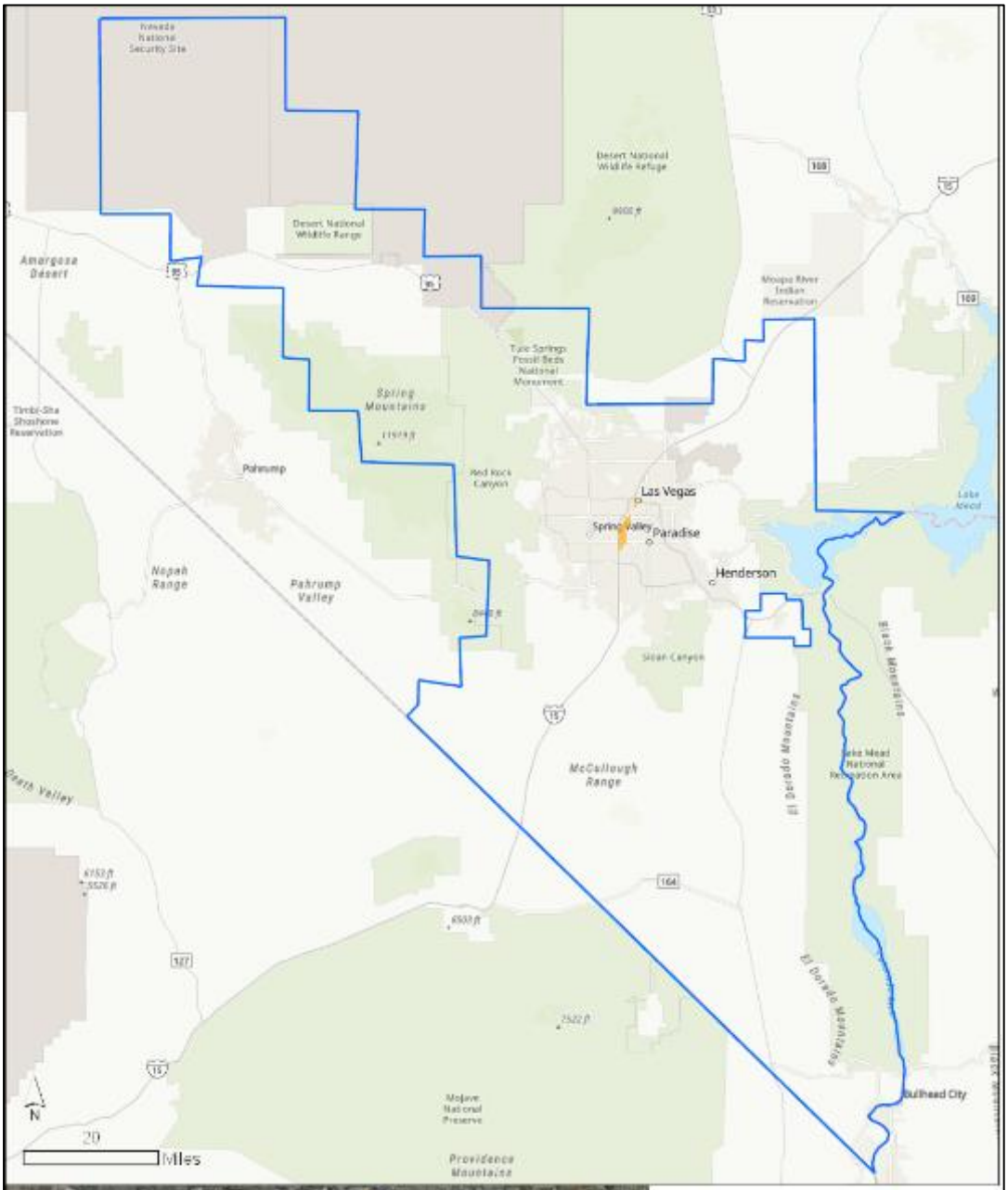
Percent Congested: 0.1884%

MADISON GAS & ELECTRIC CO.


Virden
Brandon
Weyburn
Melita
Estevan
Minot
Glasgow
Wolf Point
Sidney
North Dakota
Bismarck
Gillette
Pierre
Rapid City
100
Miles
Congested Urban
Service Territory
Service Area: 64726.49 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
MONTANA DAKOTA UTILITIES CO.


Williamsport
Scranton
Hazleton
Allentown
Reading
Harrisburg
Lancaster
Philadelphia
Wilmington
Vineland
Frederick
Miles
Congested Urban
Service Territory
Service Area: 8881.44 sqkm
Congested Area: 0.7 sqkm
Percent Congested: 0.0079%
METROPOLITAN EDISON CO.


Jackson
Laurel
Hattiesburg
Camp Shelby
De Soto National Forest
Bogalusa
Mobile
Gulfport
Slidell
N
25
Miles
Congested Urban
Service Territory
Service Area: 2984.65 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
MISSISSIPPI POWER CO.





Congested Urban

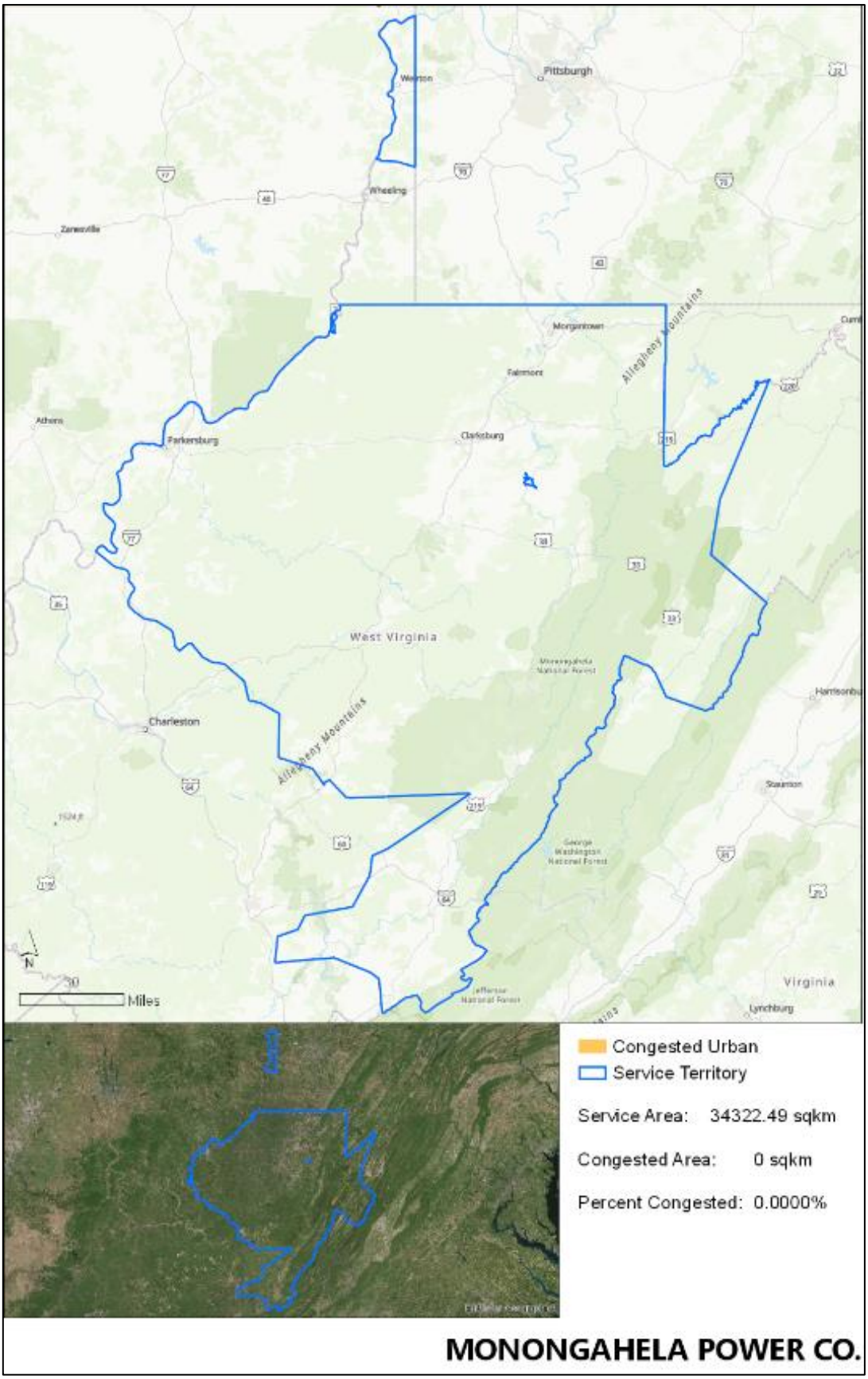
Service Territory

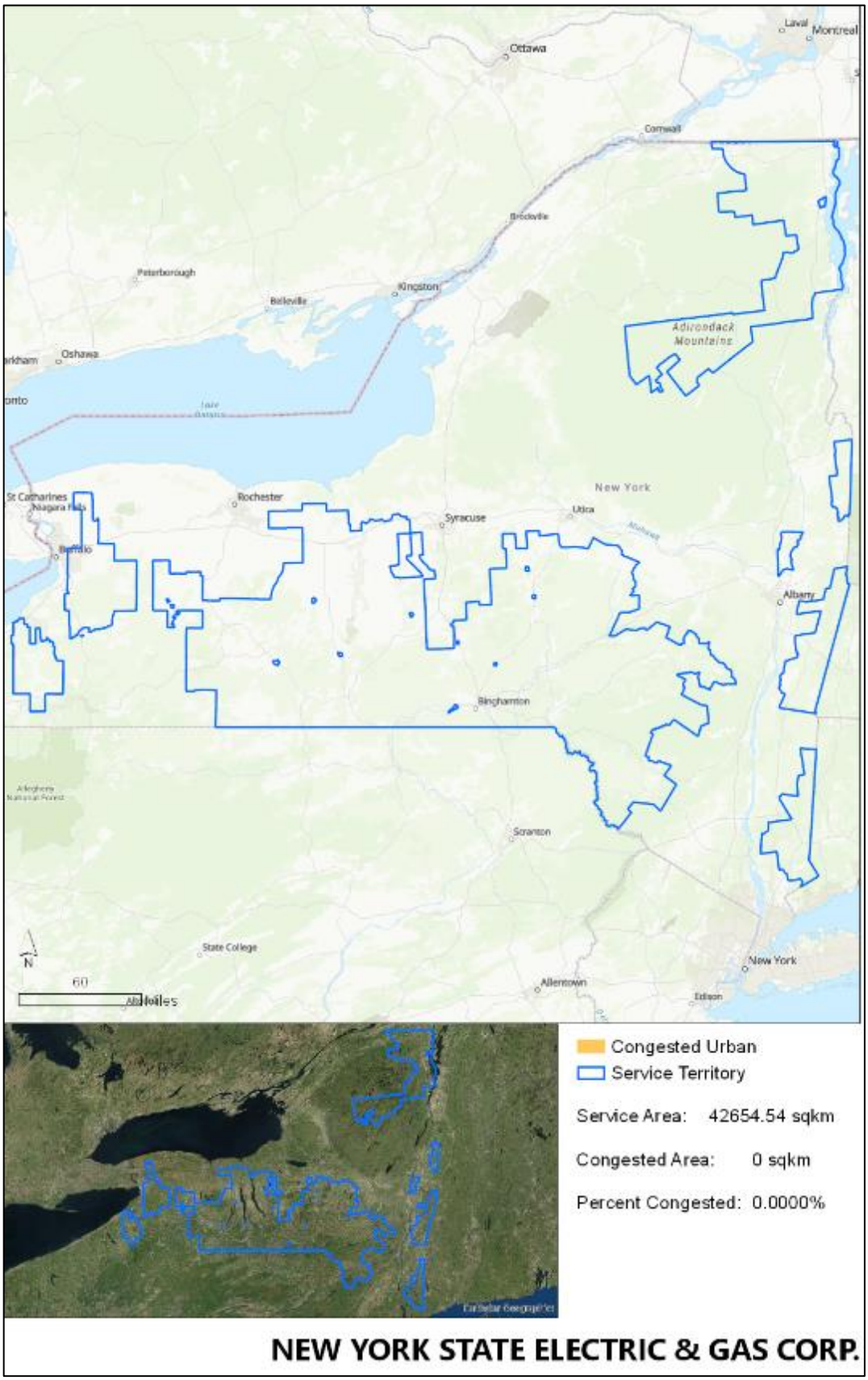
Service Area: 12130.36 sqkm

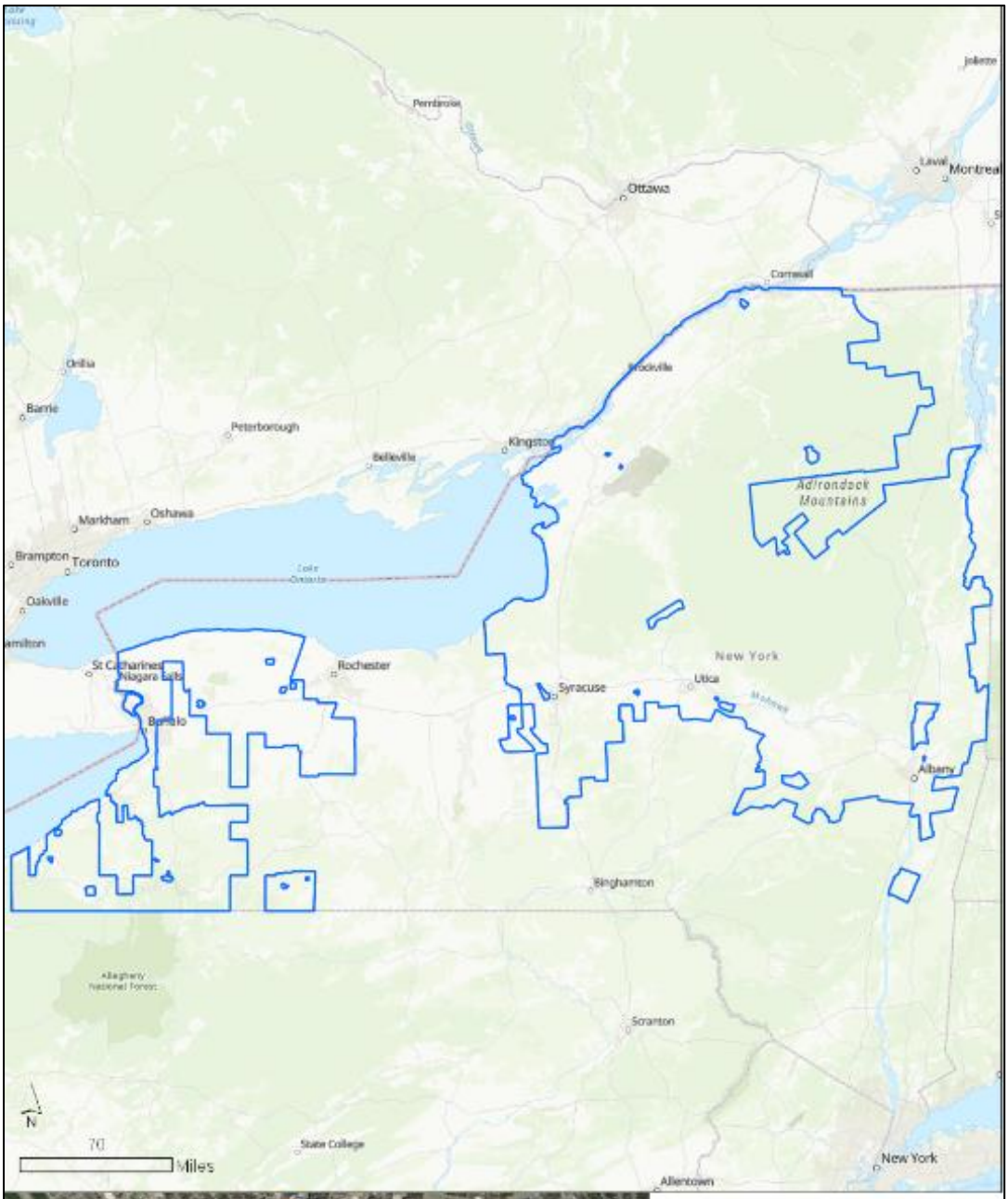
Congested Area: 9.37 sqkm

Percent Congested: 0.0773%

NEVADA POWER CO.


Pittsburgh
Wheeling
Zanesville
Morgantown
Fairmont
Clarksburg
Parkersburg
Athens
Allegheny Mountains
West Virginia
Charleston
Staunton
Harrisonburg
Virginia
Lynchburg
Miles
N
Congested Urban
Service Territory
Service Area: 34322.49 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
MONONGAHELA POWER CO.


Ottawa
Laval
Montreal
Cornwall
Brockville
Peterborough
Kingston
Belleville
Oshawa
Adirondack Mountains
St Catharines
Niagara Falls
Rochester
Syracuse
Utica
New York
Albany
Binghamton
Scranton
State College
New York
Allentown
Edison
N
60
Miles
Congested Urban
Service Territory
Service Area: 42654.54 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
NEW YORK STATE ELECTRIC & GAS CORP.





Congested Urban

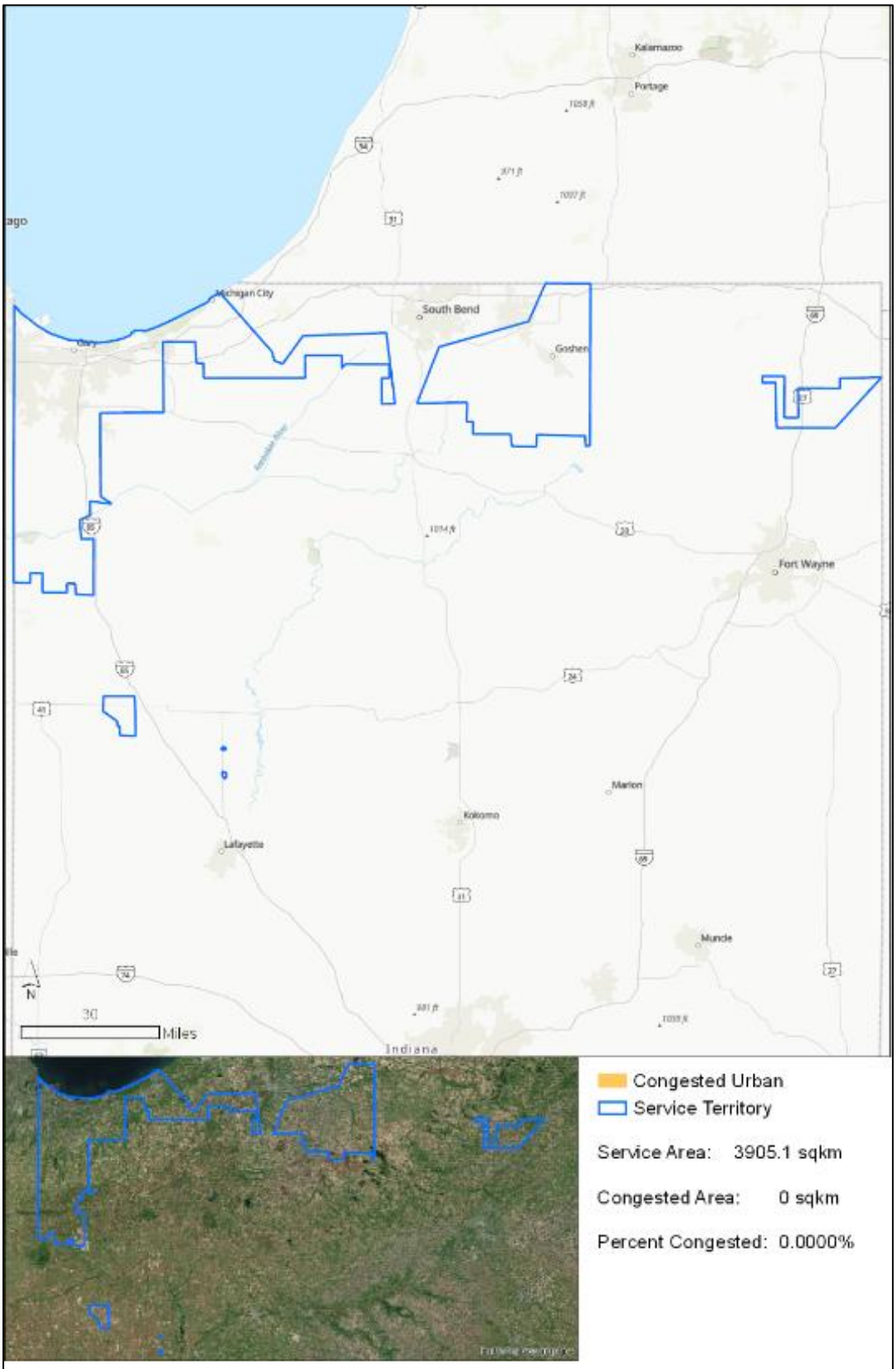
Service Territory

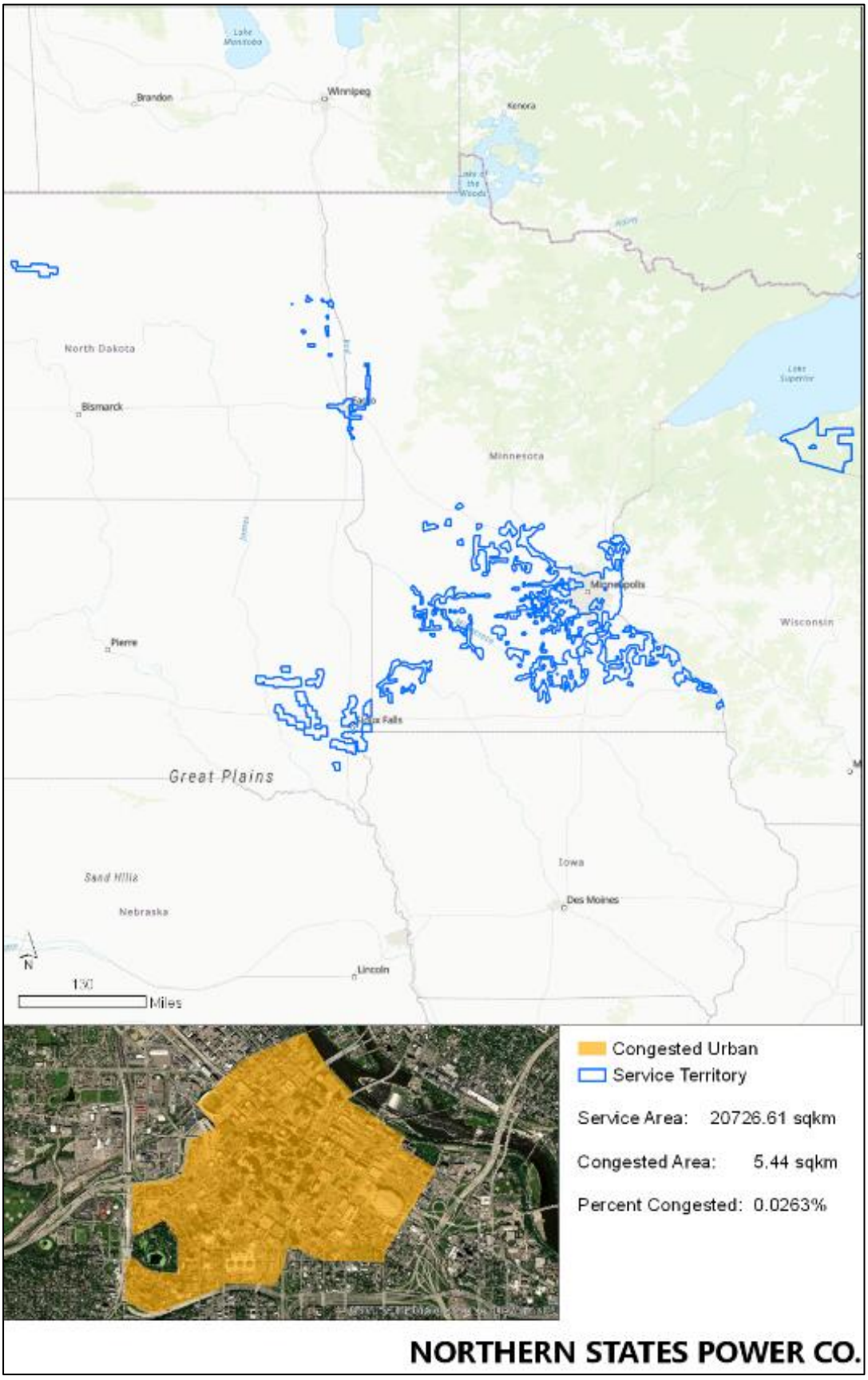
Service Area: 62996.24 sqkm

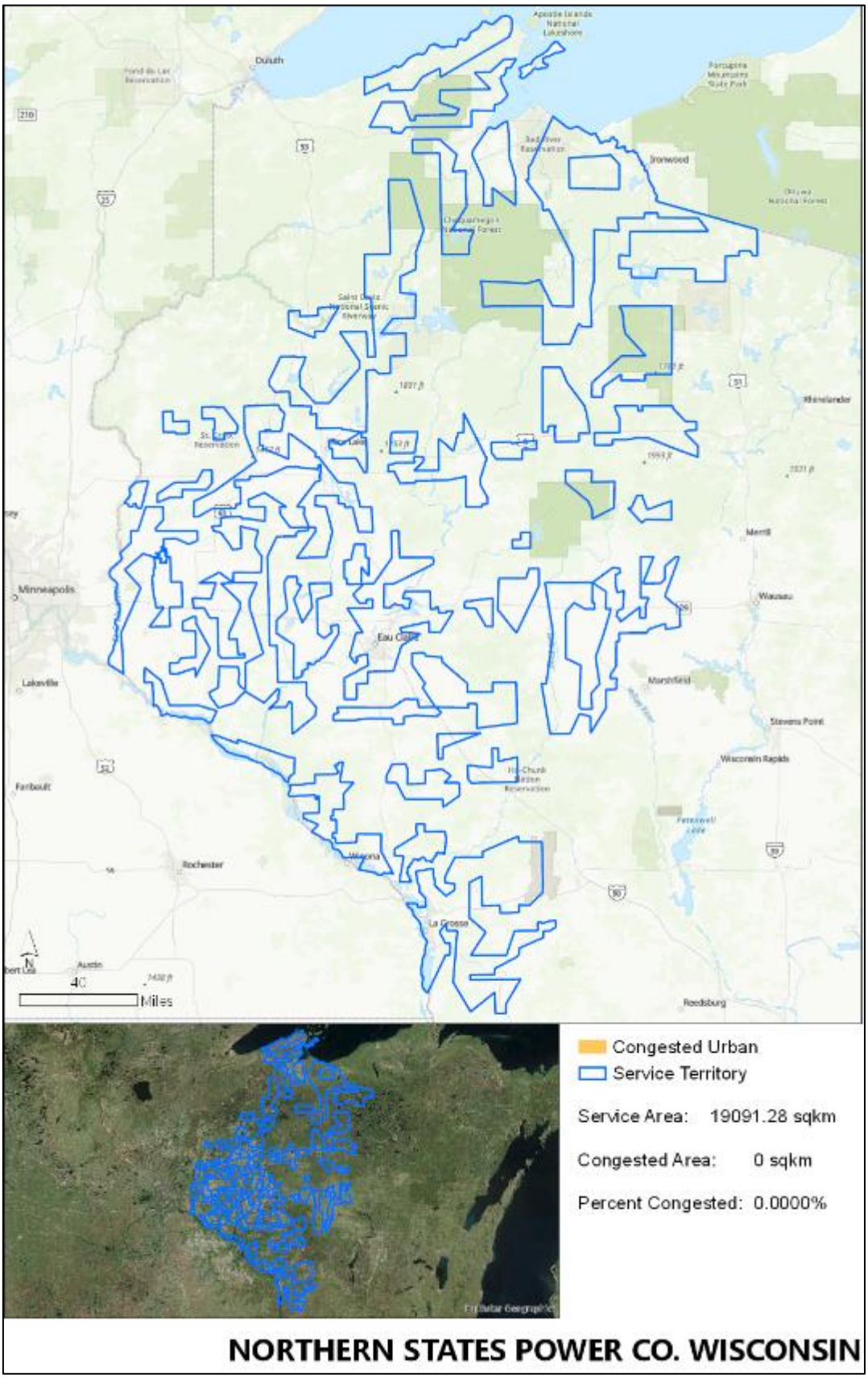
Congested Area: 1.09 sqkm

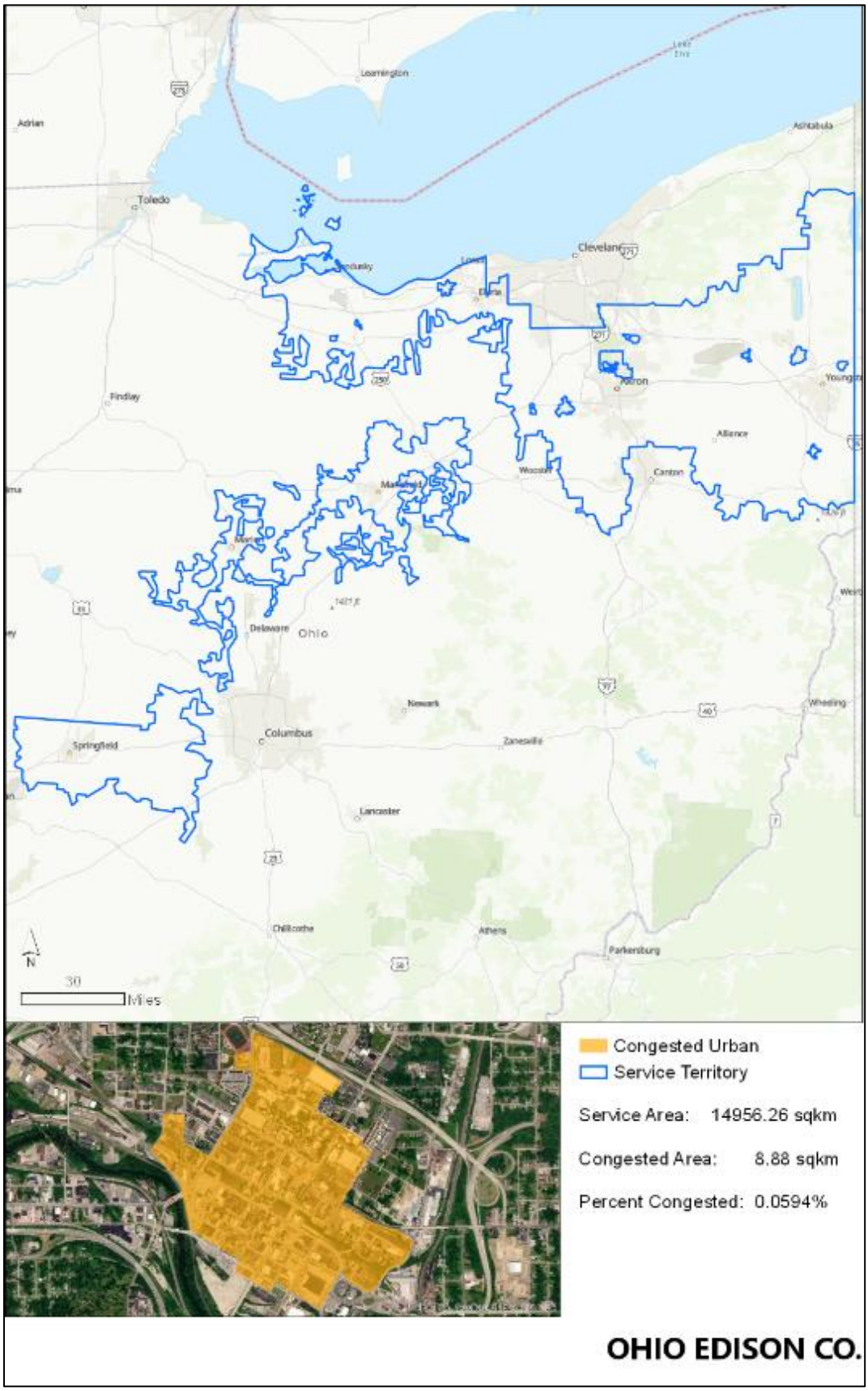
Percent Congested: 0.0017%

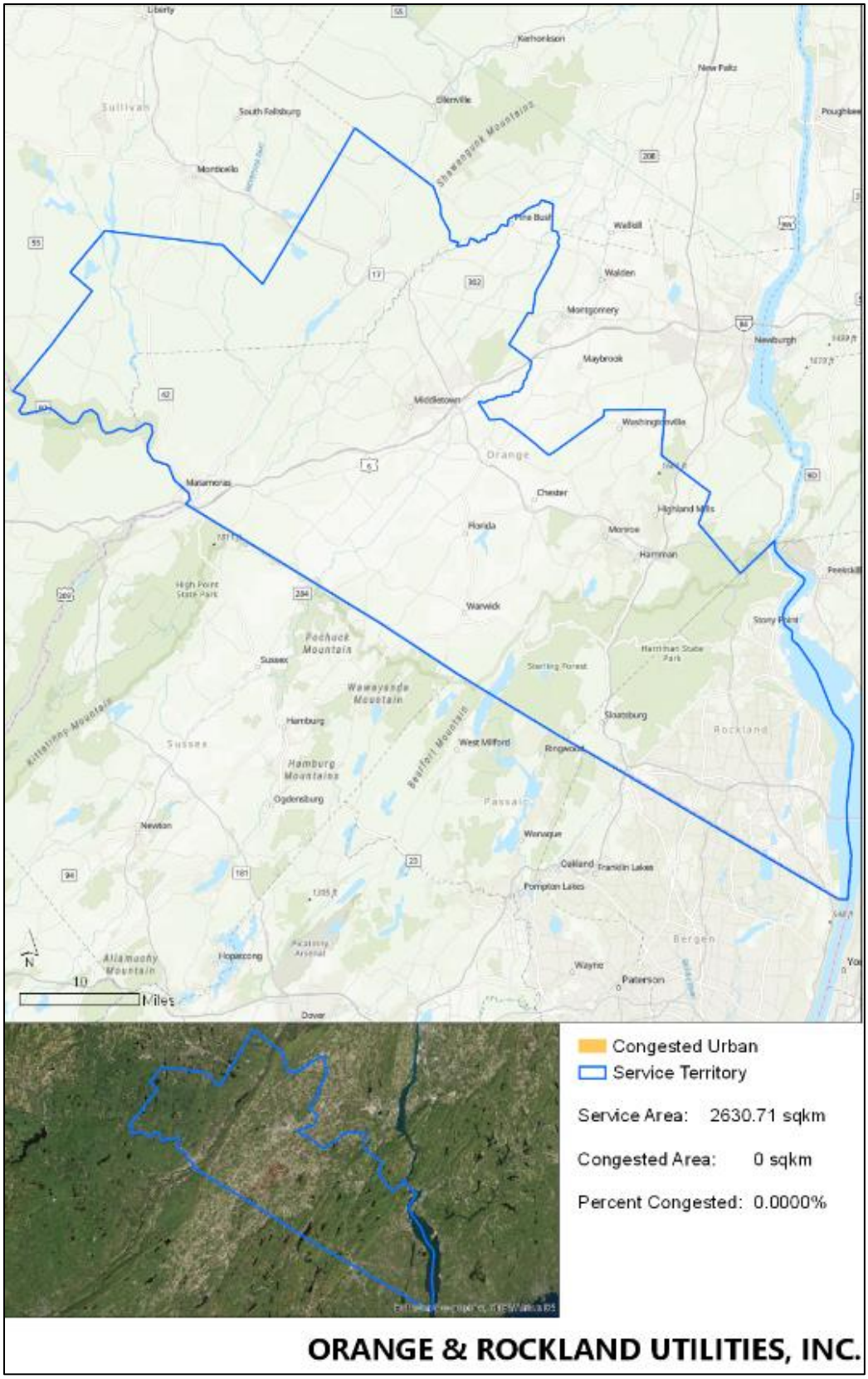
NIAGARA MOHAWK, A NATIONAL GRID CO.

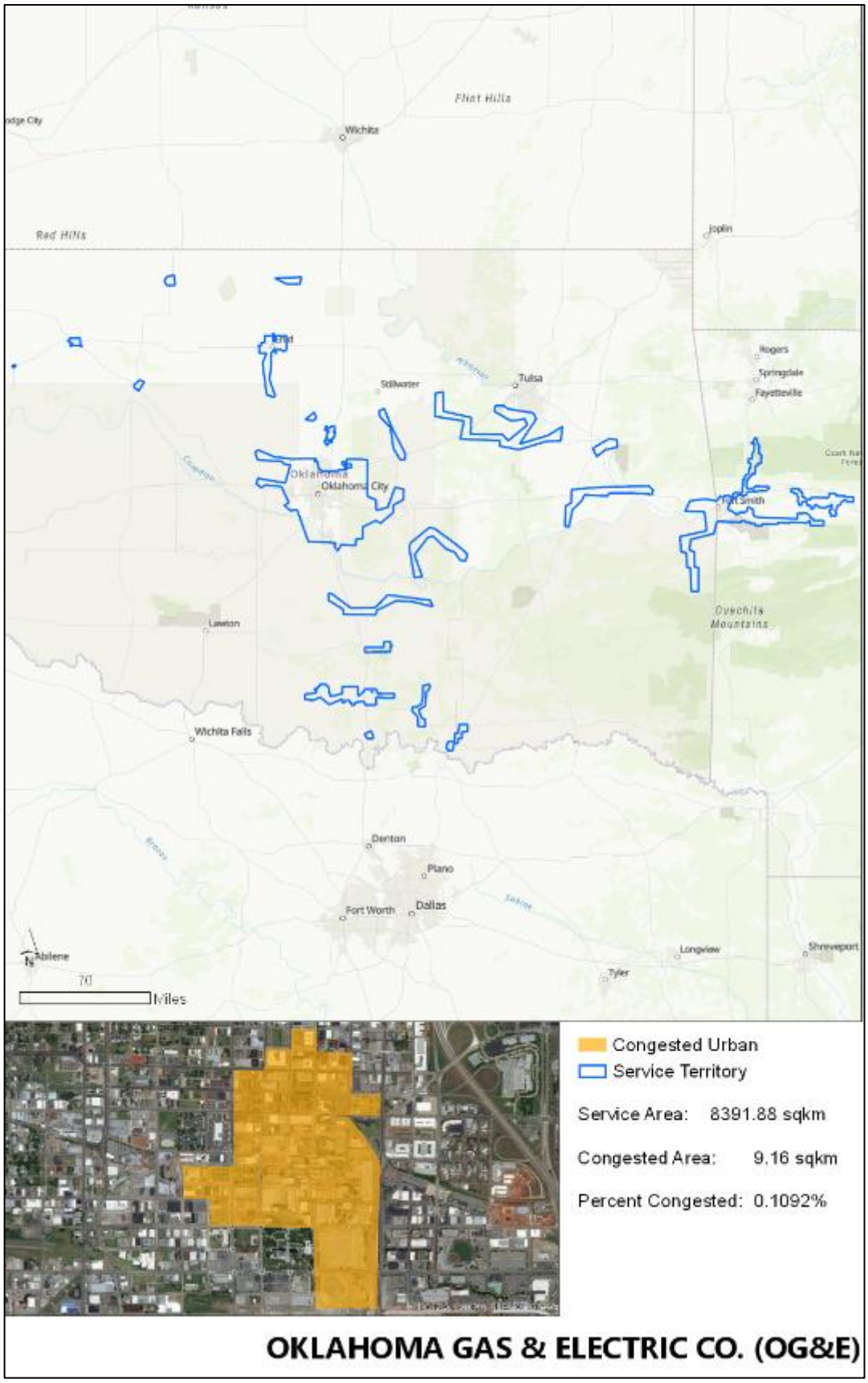

Kalamazoo
Portage
Michigan City
South Bend
Goshen
Fort Wayne
Marion
Kokomo
Lafayette
Muncie
30
Miles
Indiana
Congested Urban
Service Territory
Service Area: 3905.1 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
NORTHERN INDIANA PUBLIC SERVICE CO.


Brandon
Winnipeg
Kenora
North Dakota
Bismarck
Minnesota
Lake Superior
Minneapolis
Wisconsin
Pierre
Sioux Falls
Great Plains
Sand Hills
Nebraska
Iowa
Des Moines
Lincoln
N
130
Miles
Congested Urban
Service Territory
Service Area: 20726.61 sqkm
Congested Area: 5.44 sqkm
Percent Congested: 0.0263%
NORTHERN STATES POWER CO.

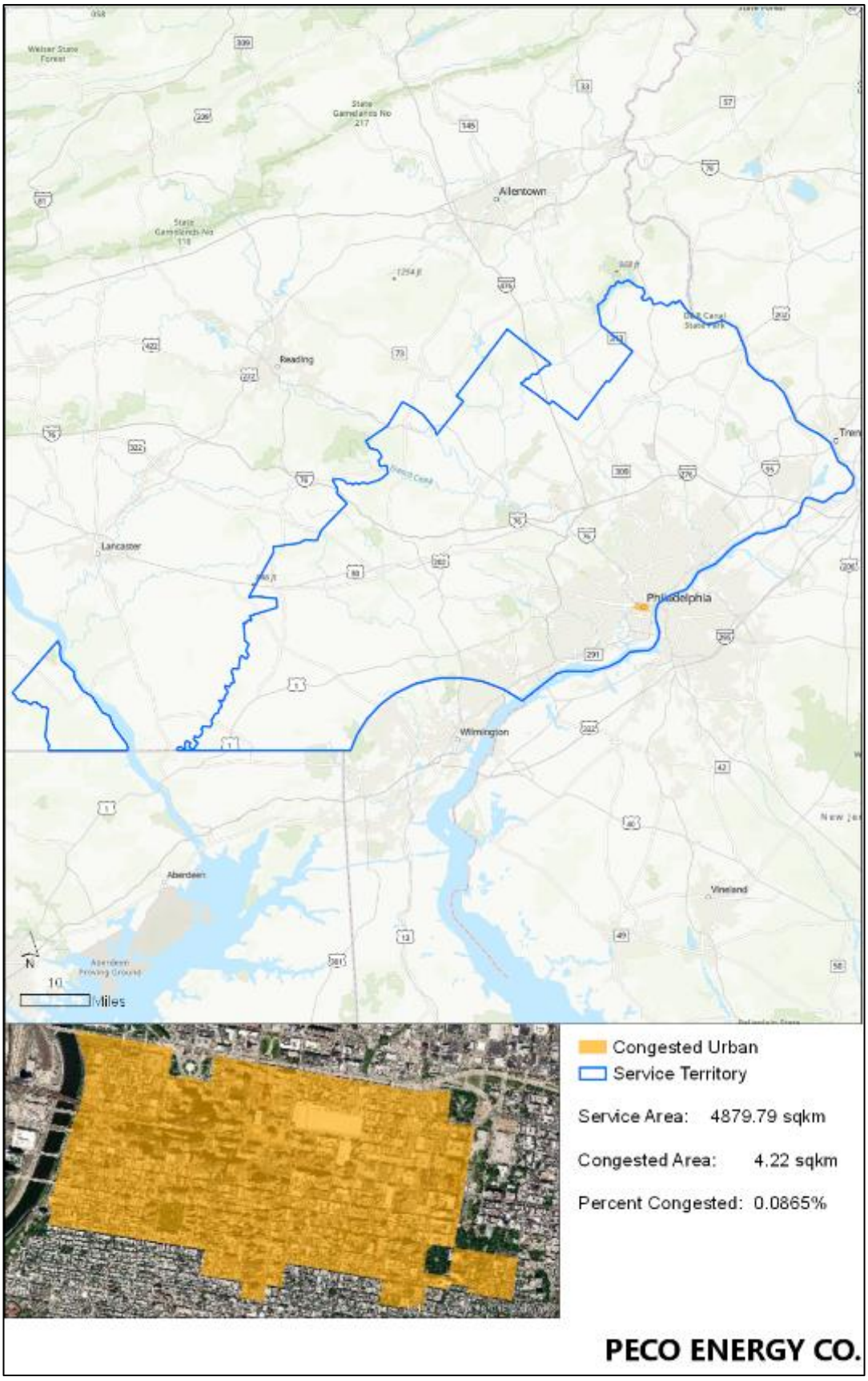

Duluth
Ironwood
Rhinelander
Minneapolis
Merrill
Wausau
Eau Claire
Lakeville
Marshfield
Stevens Point
Wisconsin Rapids
Faribault
Rochester
La Crosse
Austin
Reedsburg
40
Miles
Congested Urban
Service Territory
Service Area: 19091.28 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
NORTHERN STATES POWER CO. WISCONSIN

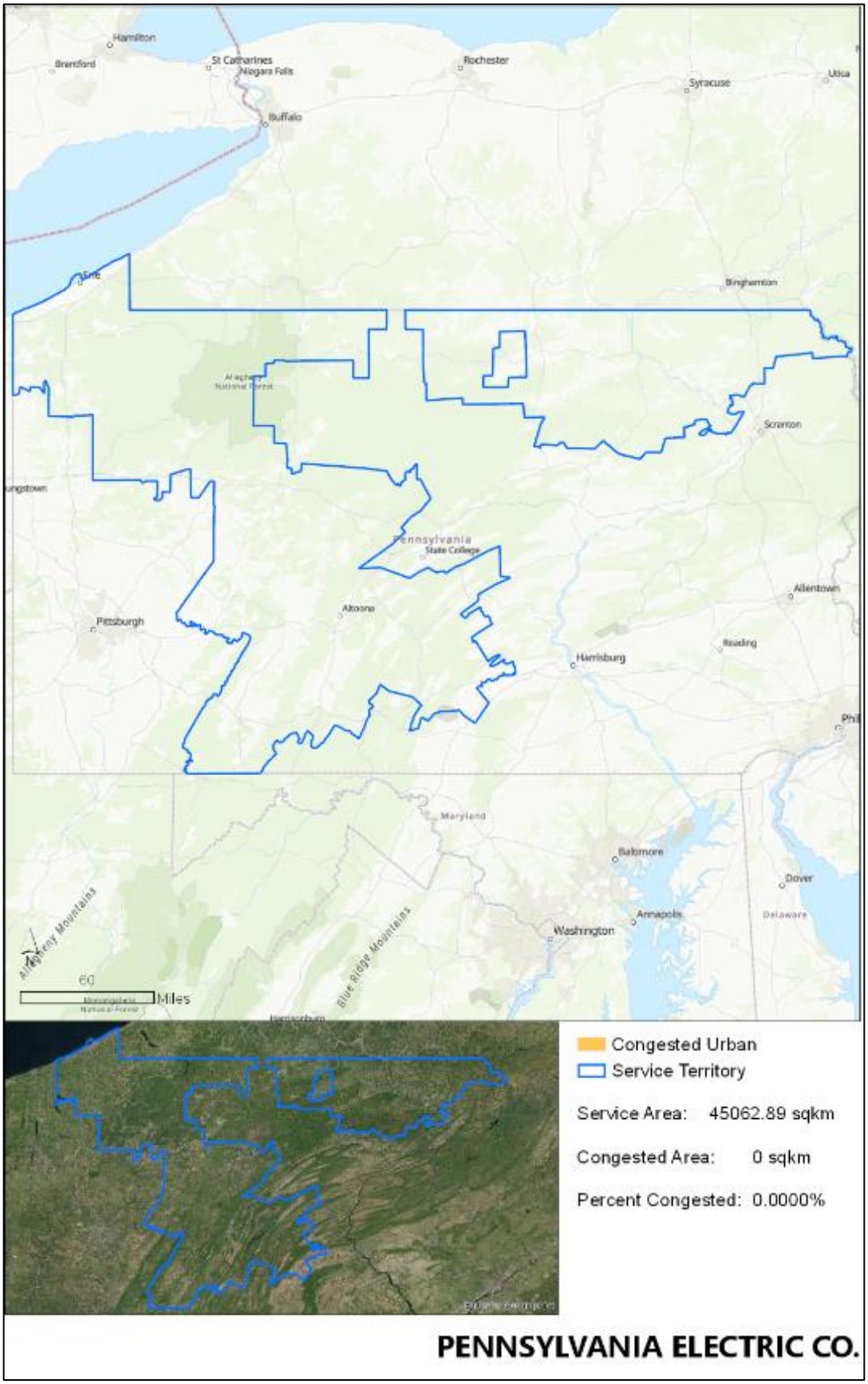

Leamington
Adrian
Ashtabula
Toledo
Cleveland
Findlay
Akron
Youngstown
Alliance
Canton
Wooster
Delaware
Ohio
Newark
Wheeling
Columbus
Zanesville
Springfield
Lancaster
Chillicothe
Athens
Parkersburg
N
30
Miles
Congested Urban
Service Territory
Service Area: 14956.26 sqkm
Congested Area: 8.88 sqkm
Percent Congested: 0.0594%
OHIO EDISON CO.

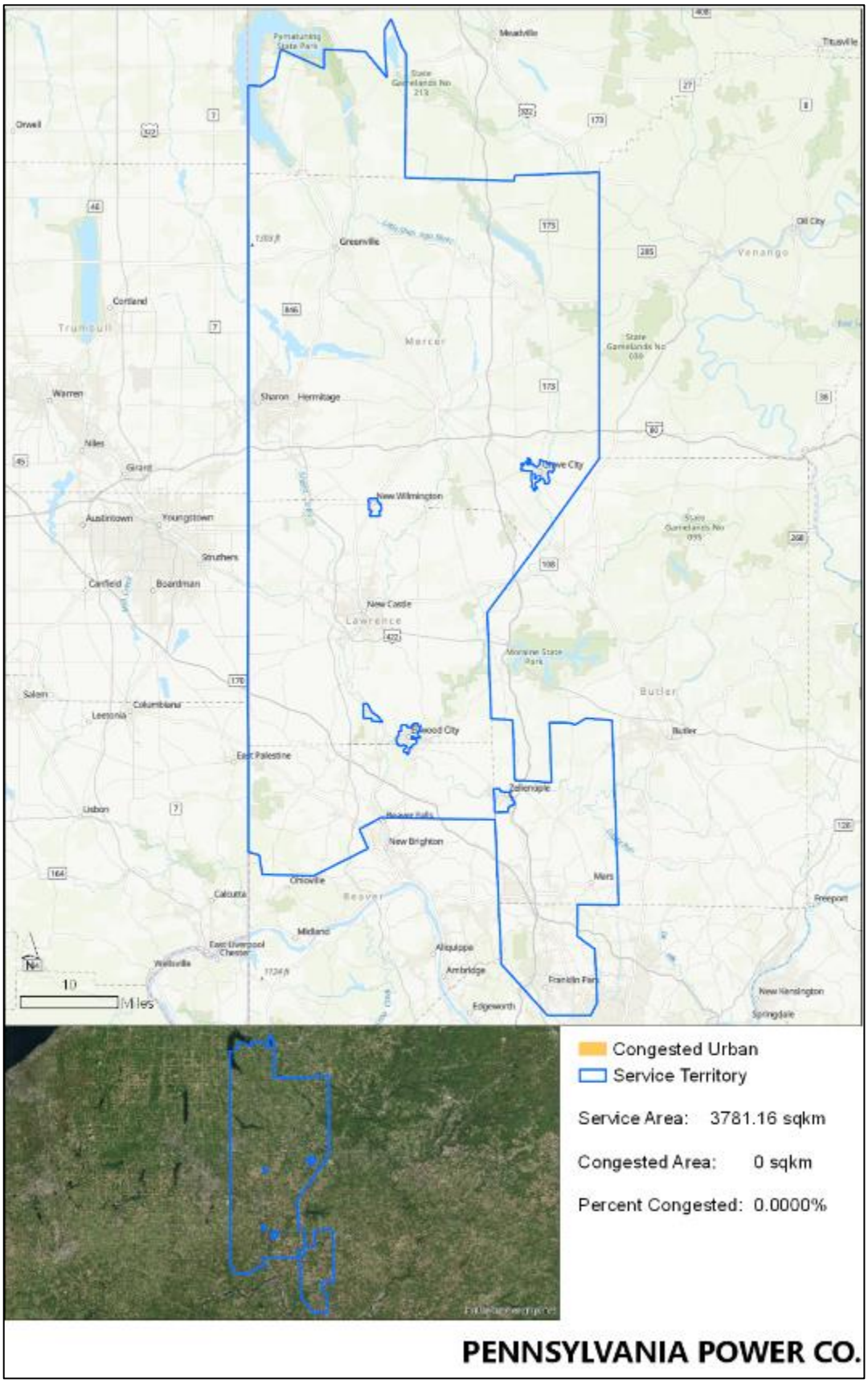

Liberty
Kerhonkson
New Paltz
Sullivan
South Fallsburg
Ellenville
Shawangunk Mountains
Monticello
Walkill
Walden
Montgomery
Newburgh
Maybrook
Middletown
Orange
Chester
Highland Mills
Florida
Monroe
Harriman
Warwick
Stony Point
High Point State Park
Pochuck Mountain
Sussex
Wawayanda Mountain
Harriman State Park
Hamburg
Sloatsburg
Rockland
West Milford
Ringwood
Hamburg Mountains
Ogdensburg
Passaic
Newton
Wanaque
Oakland
Franklin Lakes
Pompton Lakes
Bergen
Wayne
Paterson
Hopatcong
Allamuchy Mountain
Dover
10
Miles
Congested Urban
Service Territory
Service Area: 2630.71 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
ORANGE & ROCKLAND UTILITIES, INC.

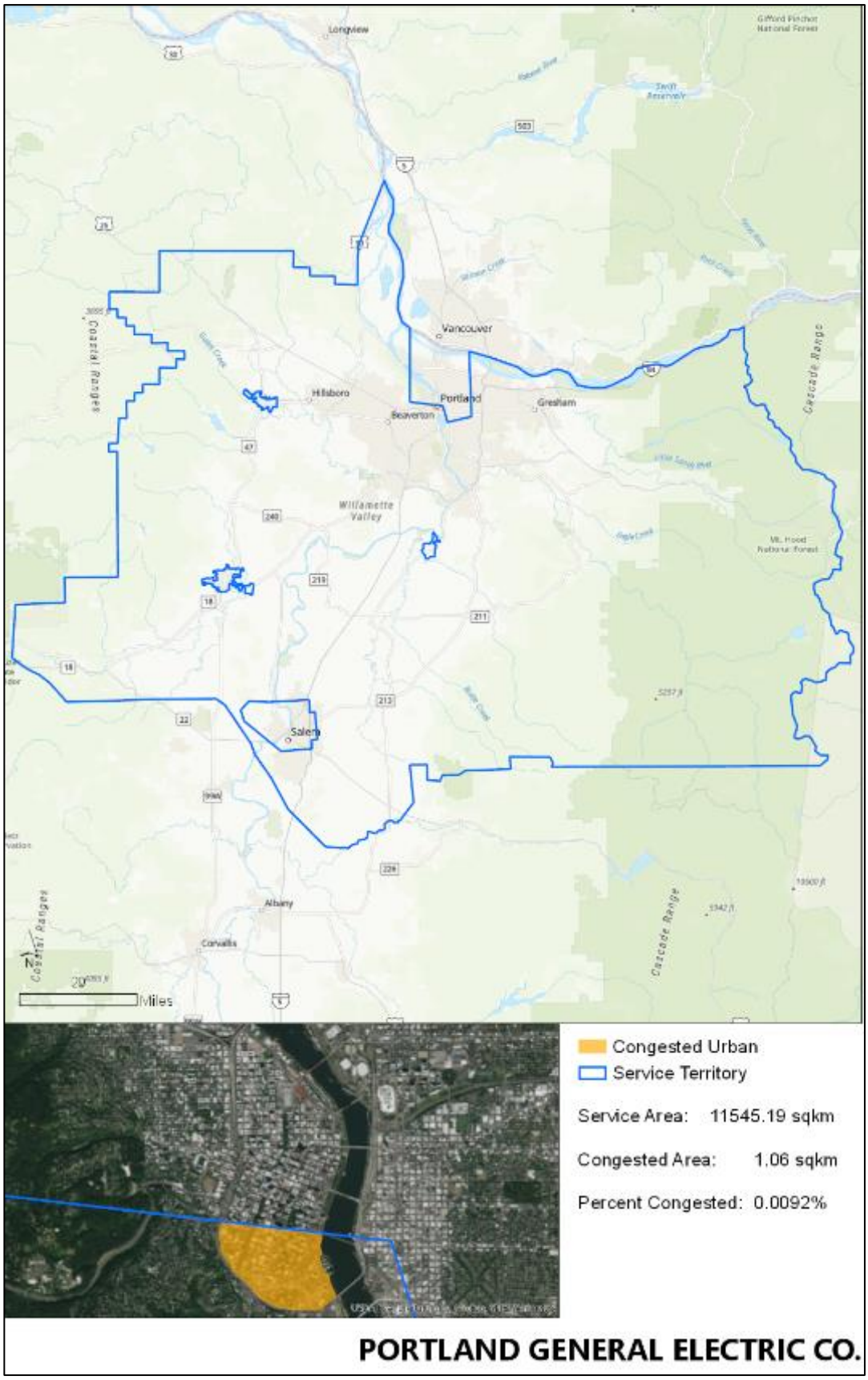

Flint Hills
Wichita
Red Hills
Joplin
Enid
Stillwater
Tulsa
Rogers
Springdale
Fayetteville
Oklahoma
Oklahoma City
Fort Smith
Lawton
Ouachita Mountains
Wichita Falls
Denton
Plano
Fort Worth
Dallas
Abilene
Longview
Shreveport
Tyler
70
Miles
Congested Urban
Service Territory
Service Area: 8391.88 sqkm
Congested Area: 9.16 sqkm
Percent Congested: 0.1092%
OKLAHOMA GAS & ELECTRIC CO. (OG&E)

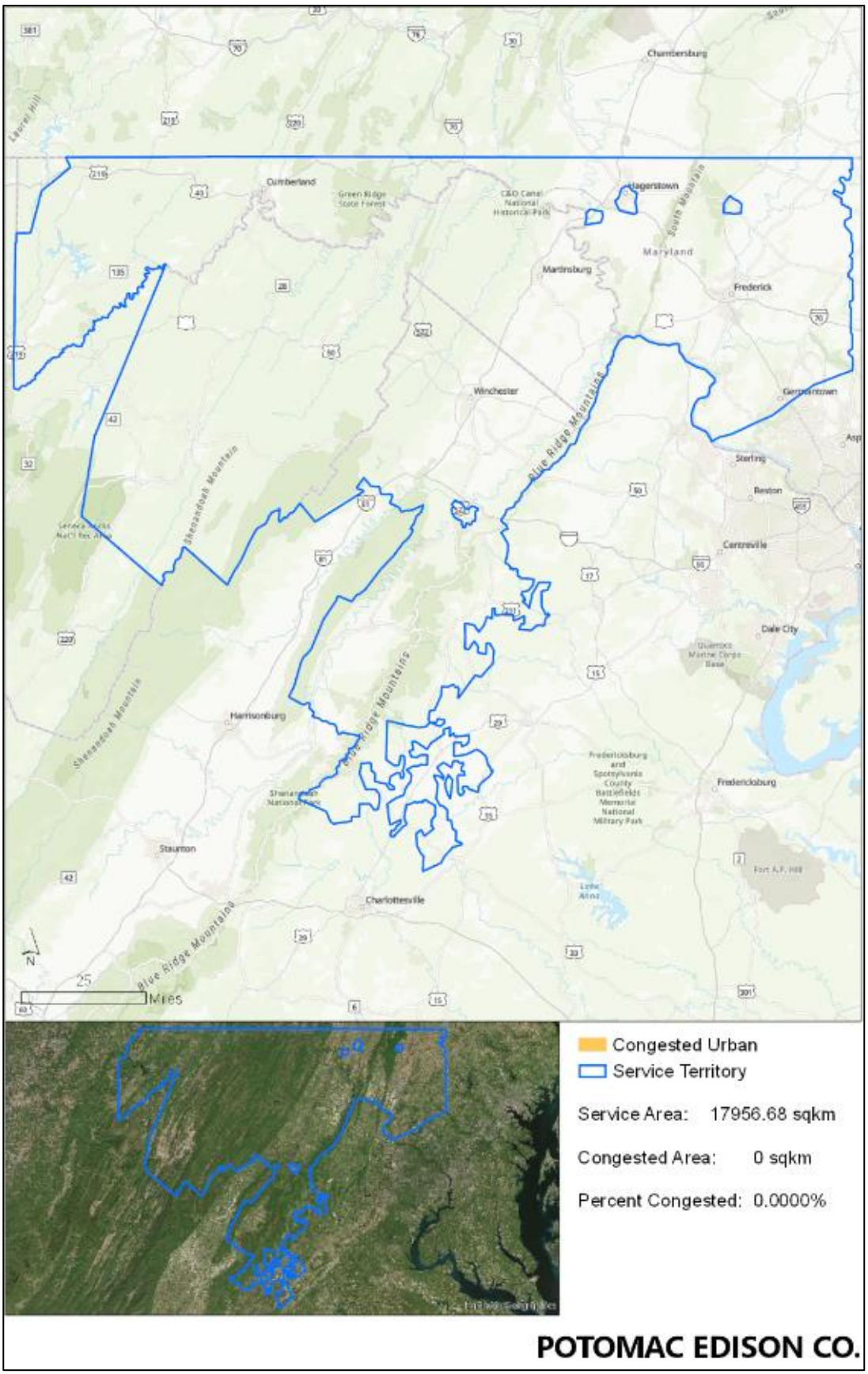

Eureka
Redding
Chico
Reno
Carson City
Sacramento
Fairfield
Stockton
San Francisco
Livermore
Fremont
Modesto
San Jose
Salinas
Fresno
Visalia
Bakersfield
San Luis Obispo
Santa Maria
Lompoc
Santa Barbara
Lancaster
Palmdale
Santa Clarita
Sierra Nevada Mountains
Coastal Range
N
80
Miles
Congested Urban
Service Territory
Service Area: 180133.77 sqkm
Congested Area: 15.11 sqkm
Percent Congested: 0.0084%
PACIFIC GAS AND ELECTRIC CO.

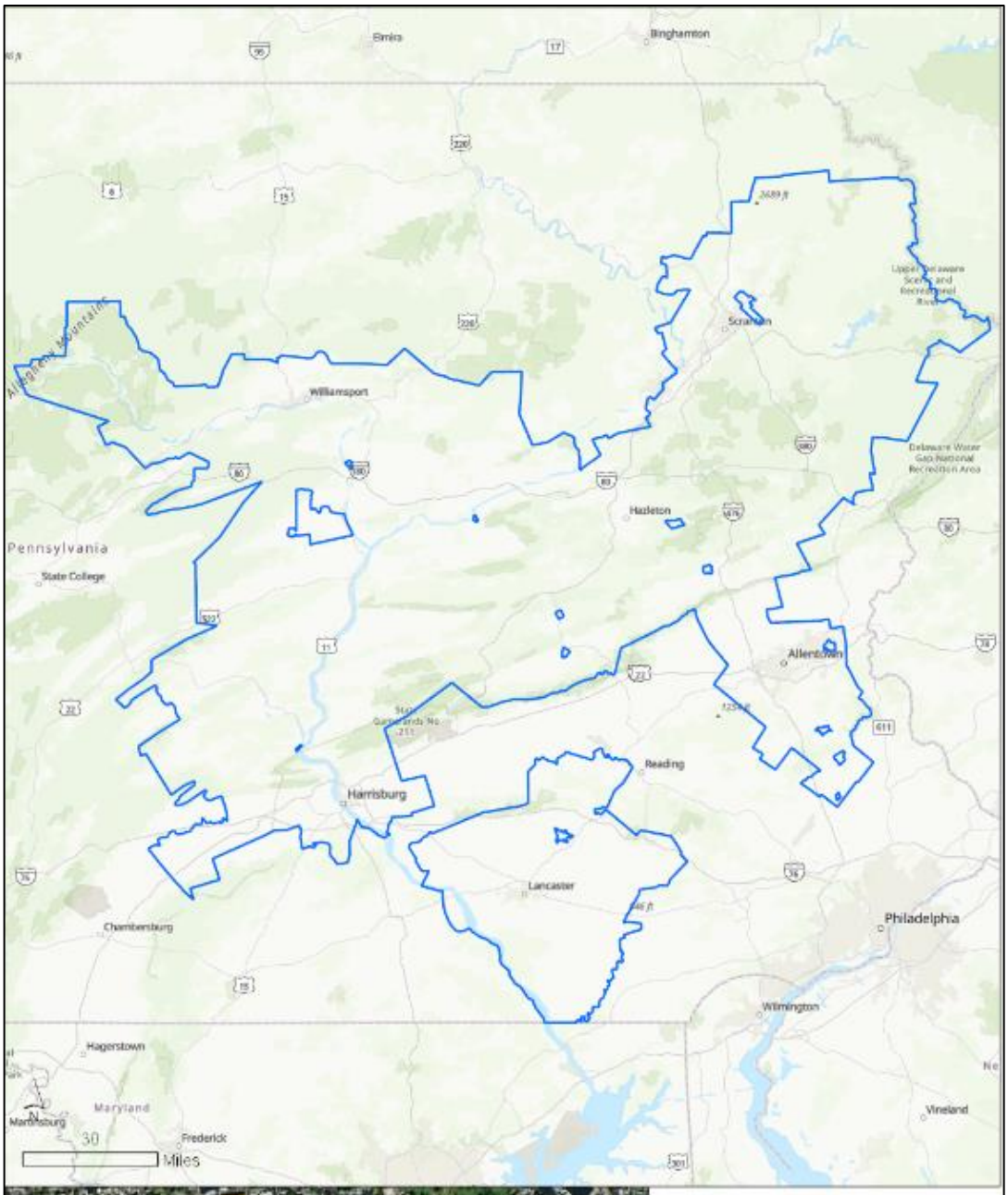

Allentown
Reading
Lancaster
Philadelphia
Wilmington
Aberdeen
Vineland
10
Miles
Congested Urban
Service Territory
Service Area: 4879.79 sqkm
Congested Area: 4.22 sqkm
Percent Congested: 0.0865%
PECO ENERGY CO.


Hamilton
Brantford
St Catharines
Niagara Falls
Rochester
Syracuse
Utica
Buffalo
Erie
Binghamton
Scranton
Pennsylvania
State College
Pittsburgh
Altoona
Allentown
Reading
Harrisburg
Maryland
Baltimore
Dover
Annapolis
Delaware
Washington
Allegheny Mountains
Blue Ridge Mountains
60
Miles
Congested Urban
Service Territory
Service Area: 45062.89 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
PENNSYLVANIA ELECTRIC CO.


Congested Urban
Service Territory
Service Area: 3781.16 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
PENNSYLVANIA POWER CO.
10
Miles


Longview
Vancouver
Hillsboro
Beaverton
Portland
Gresham
Willamette Valley
Salem
Albany
Corvallis
Coastal Ranges
Cascade Range
Miles
Congested Urban
Service Territory
Service Area: 11545.19 sqkm
Congested Area: 1.06 sqkm
Percent Congested: 0.0092%
PORTLAND GENERAL ELECTRIC CO.


Chambersburg
Cumberland
Hagerstown
Maryland
Martinsburg
Frederick
Winchester
Blue Ridge Mountains
Sterling
Reston
Centreville
Dale City
Harrisonburg
Fredericksburg
Staunton
Charlottesville
Shenandoah Mountain
25
Miles
N
Congested Urban
Service Territory
Service Area: 17956.68 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
POTOMAC EDISON CO.





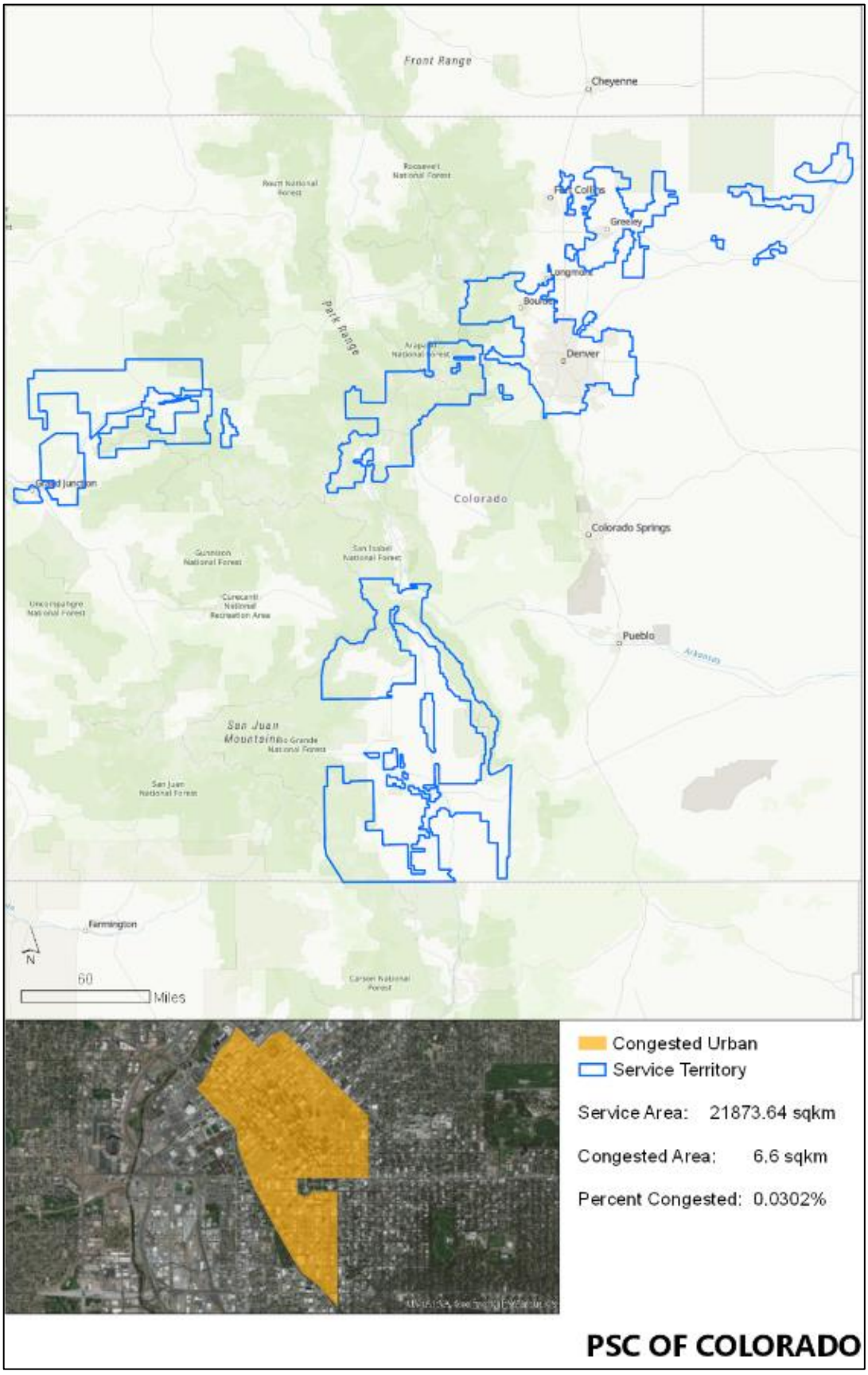
Congested Urban
Service Territory

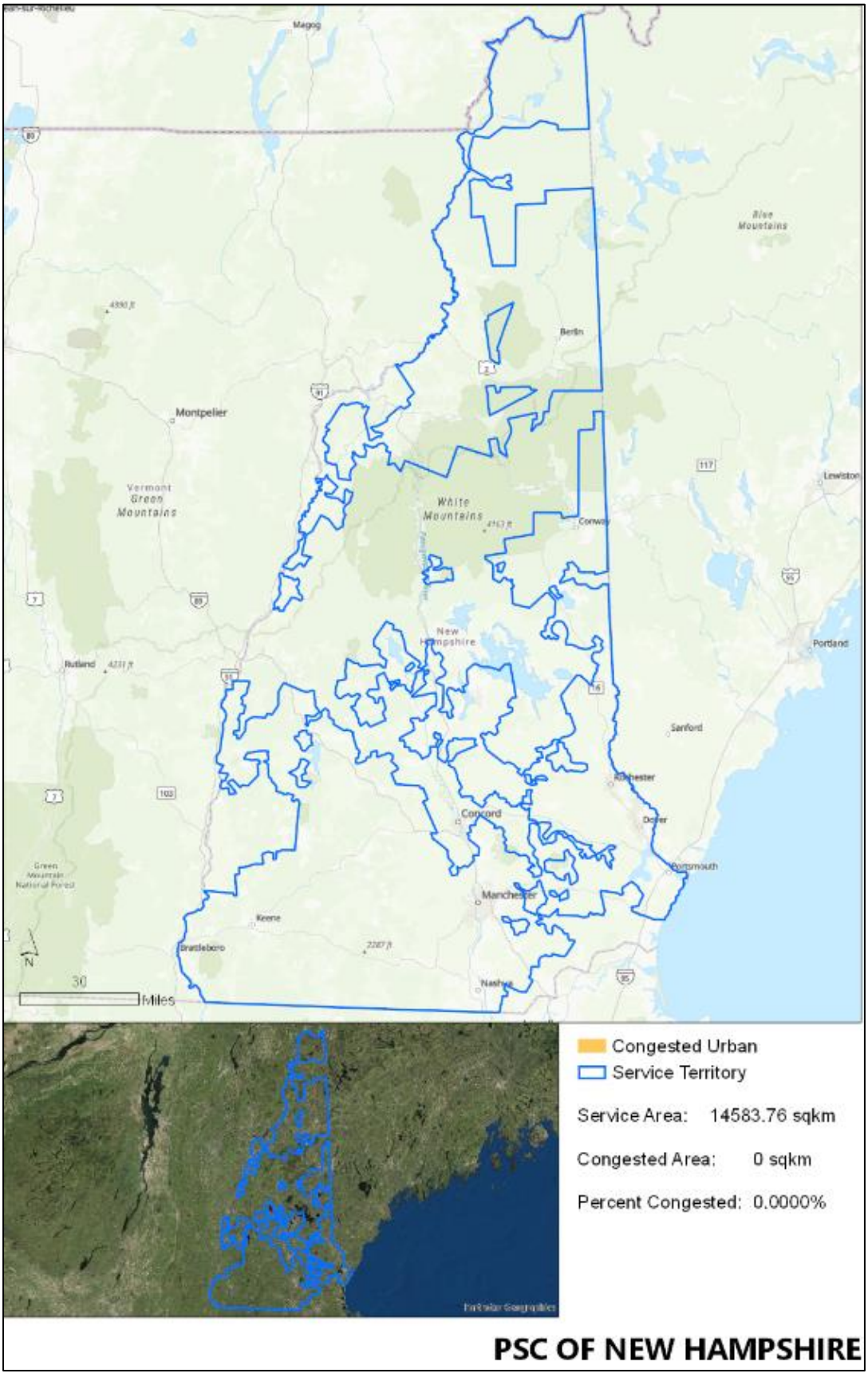
Service Area: 24923.06 sqkm

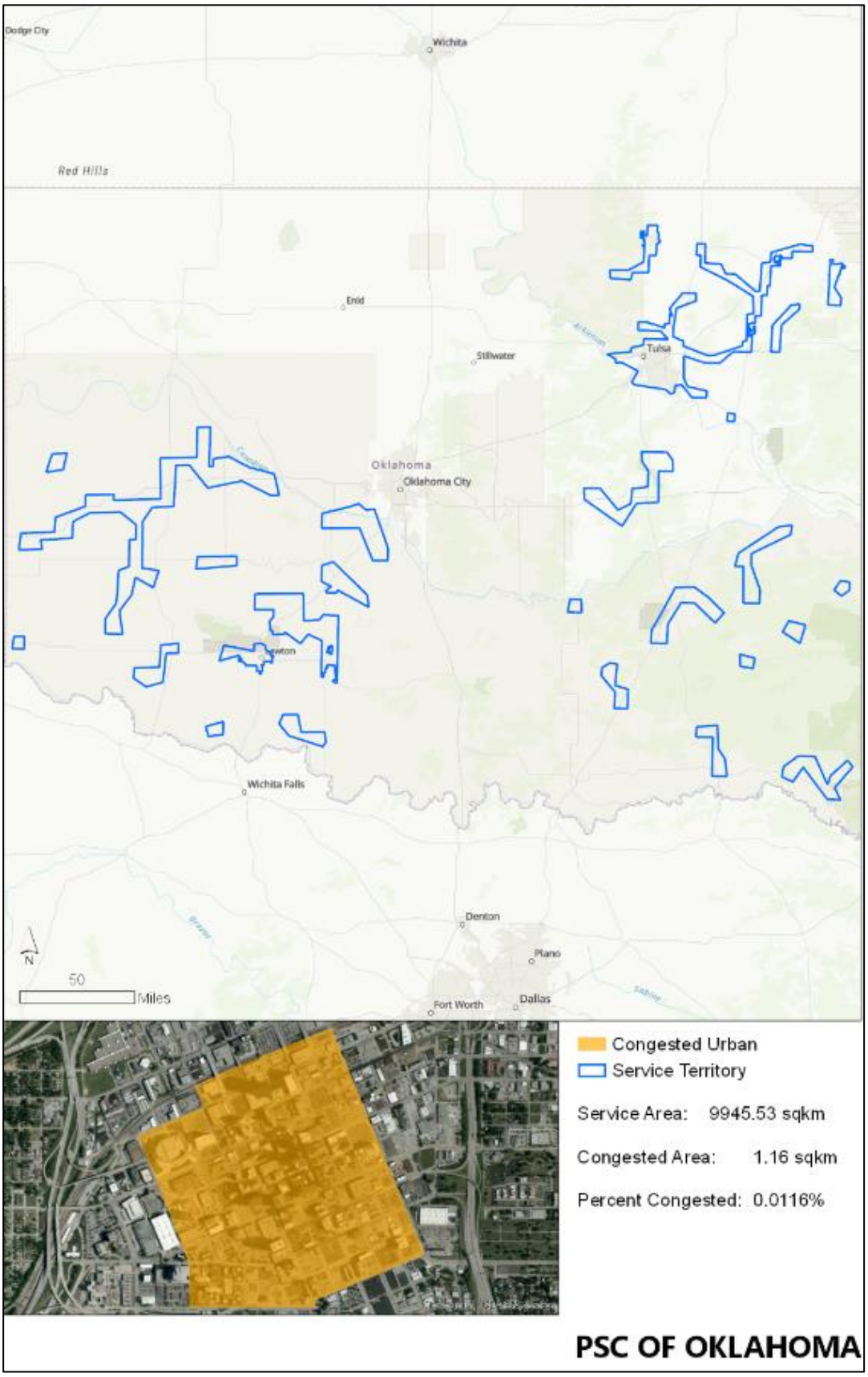
Congested Area: 0.34 sqkm

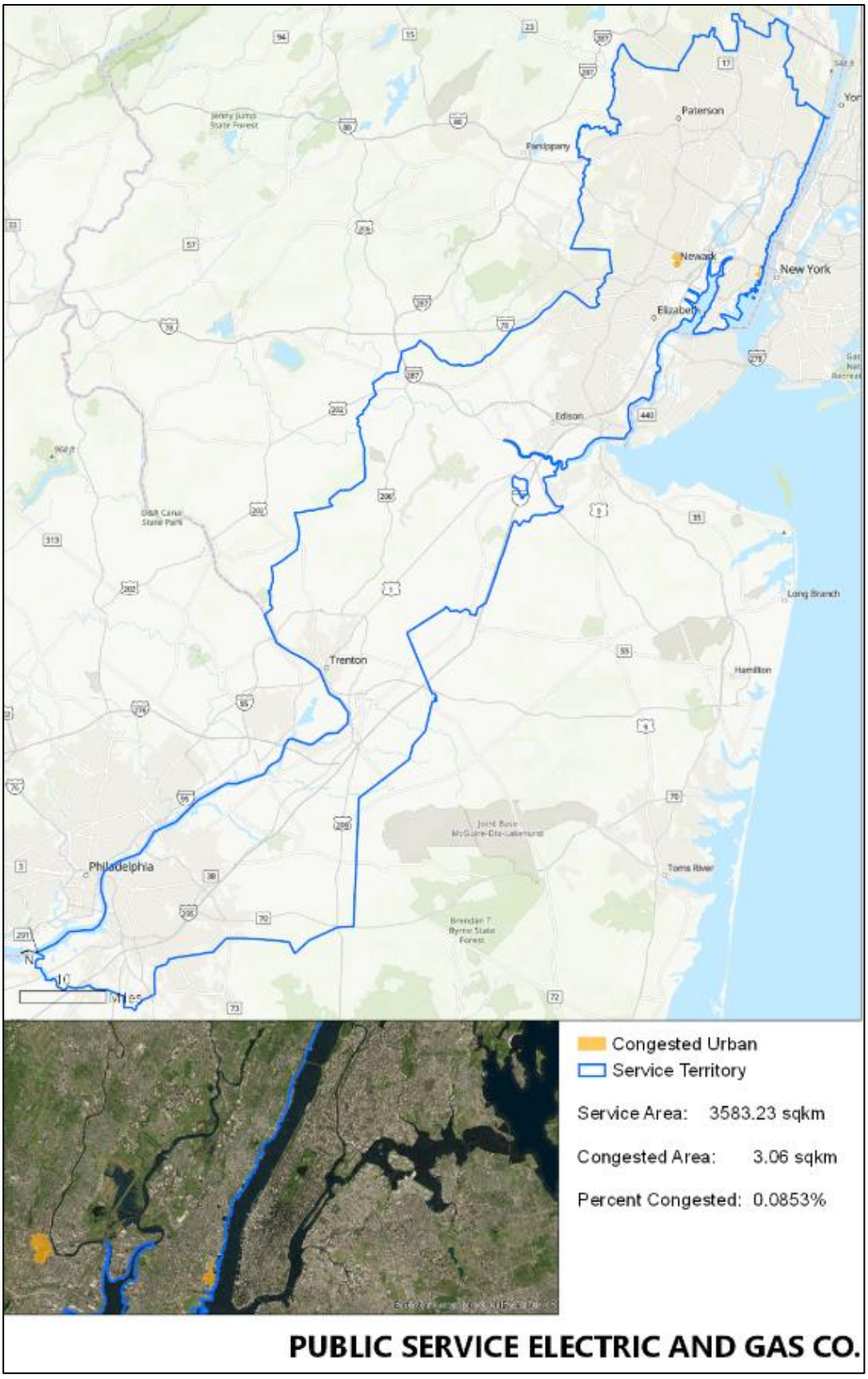
Percent Congested: 0.0014%

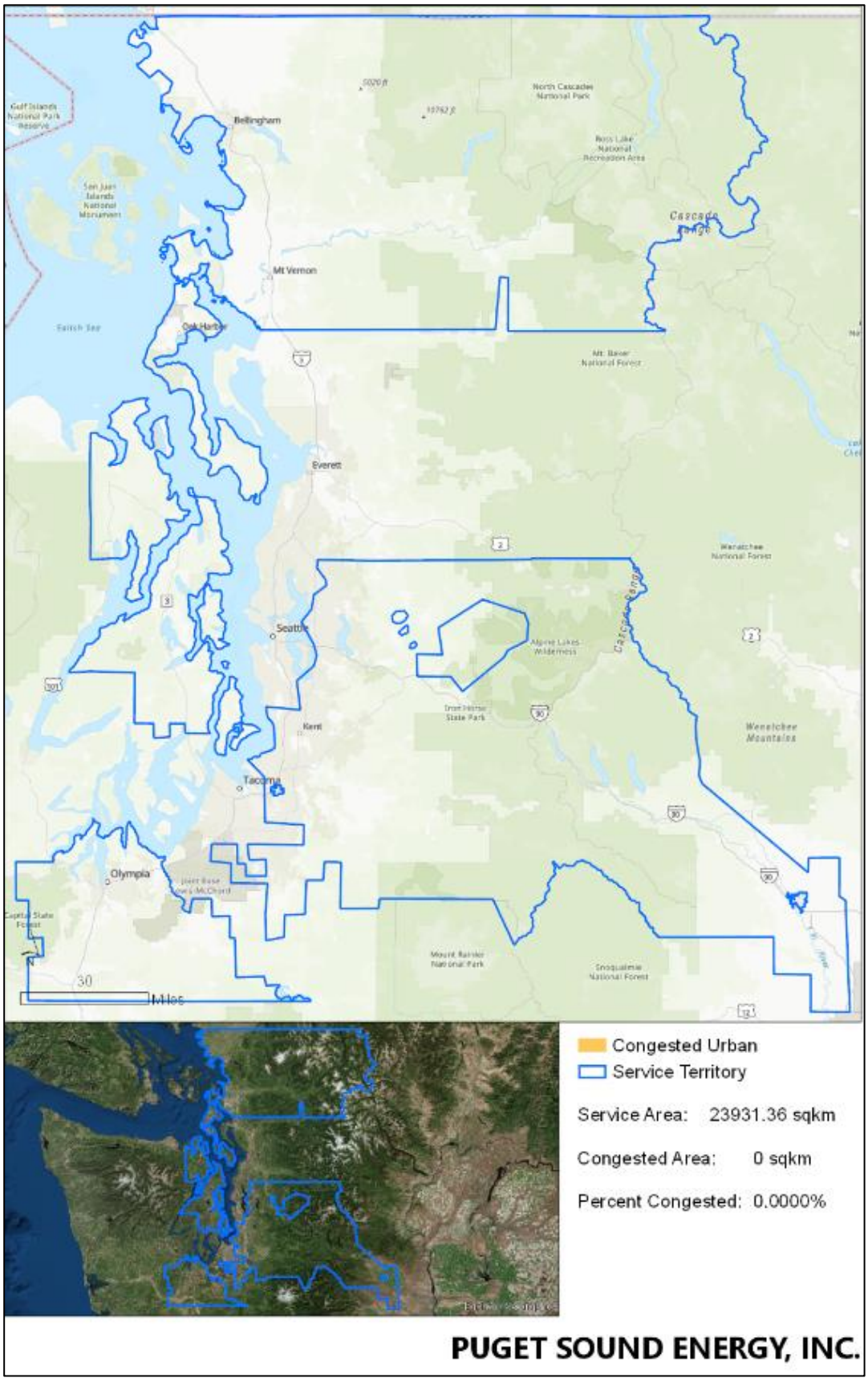
PPL ELECTRIC UTILITIES CORP.

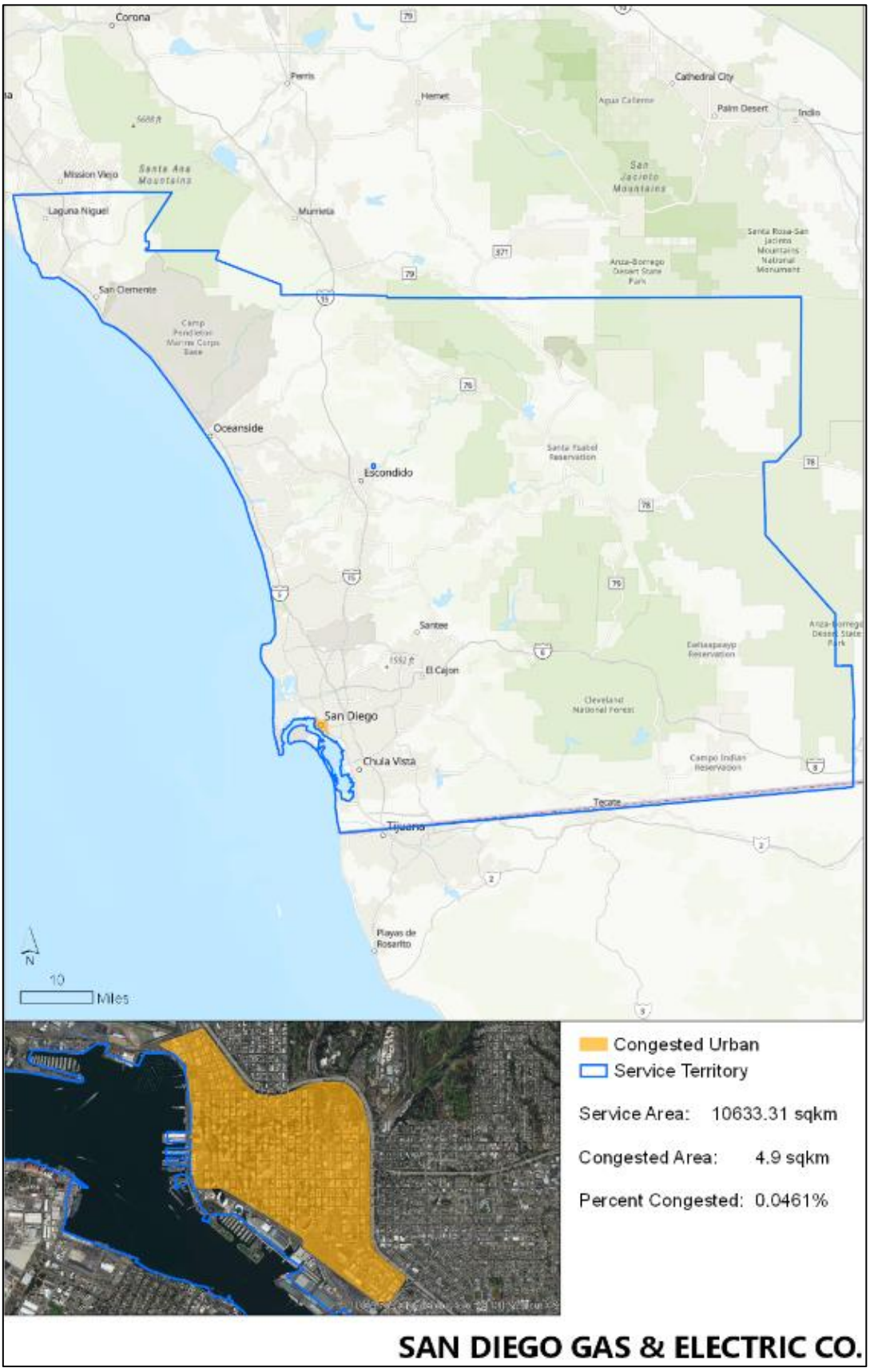

Front Range
Cheyenne
Roosevelt National Forest
Fort Collins
Greeley
Longmont
Boulder
Park Range
Arapaho National Forest
Denver
Grand Junction
Colorado
Colorado Springs
Gunnison National Forest
San Isabel National Forest
Curecanti National Recreation Area
Pueblo
San Juan Mountains
Rio Grande National Forest
San Juan National Forest
Farmington
N
60
Miles
Carson National Forest
Congested Urban
Service Territory
Service Area: 21873.64 sqkm
Congested Area: 6.6 sqkm
Percent Congested: 0.0302%
PSC OF COLORADO

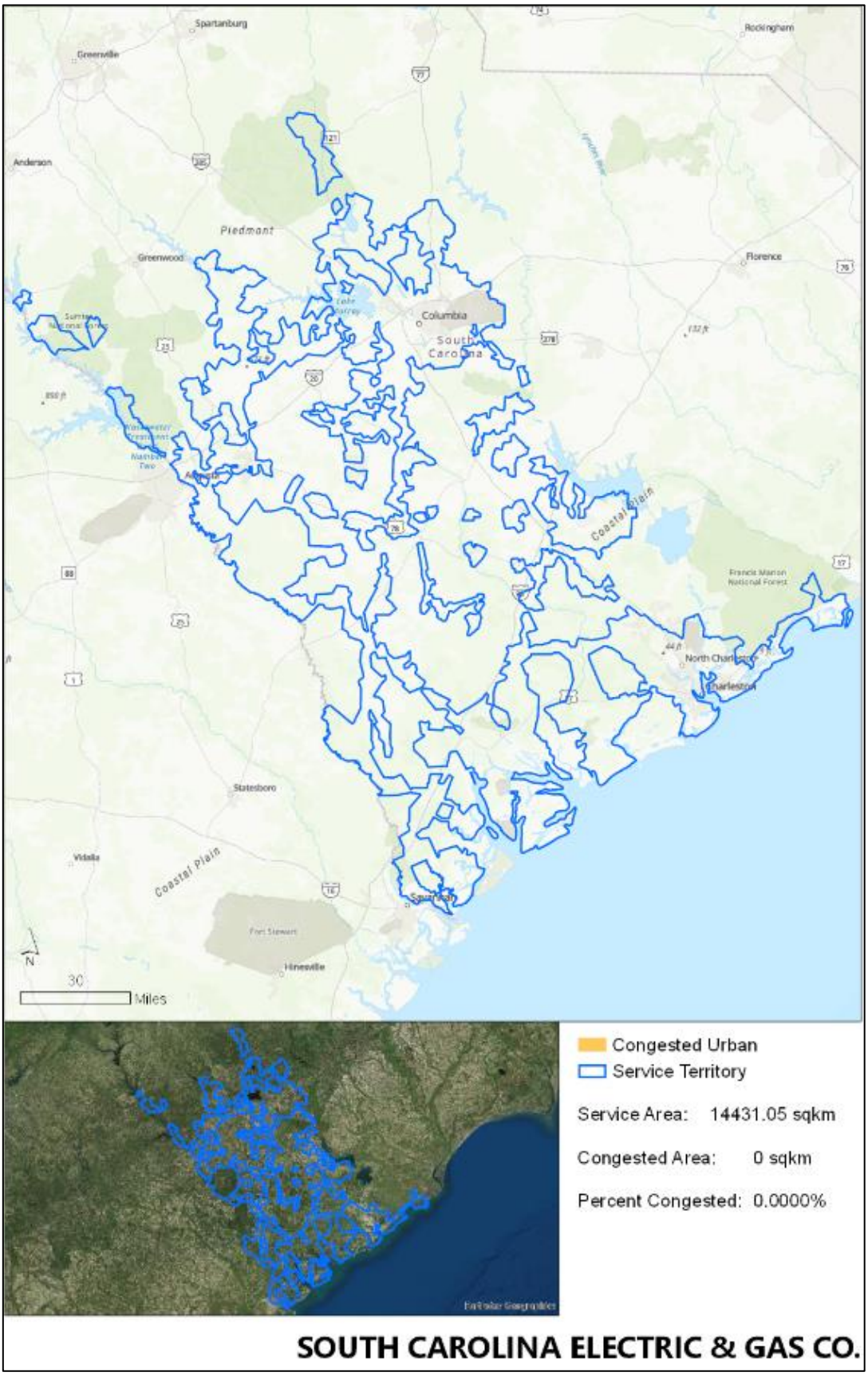

Magog
Montpelier
Vermont
Green
Mountains
White
Mountains
New
Hampshire
Berlin
Conway
Lewiston
Portland
Rutland
Sanford
Concord
Manchester
Keene
Brattleboro
Nashua
Dover
Portsmouth
Rochester
Green
Mountain
National Forest
N
30
Miles
Congested Urban
Service Territory
Service Area: 14583.76 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
PSC OF NEW HAMPSHIRE

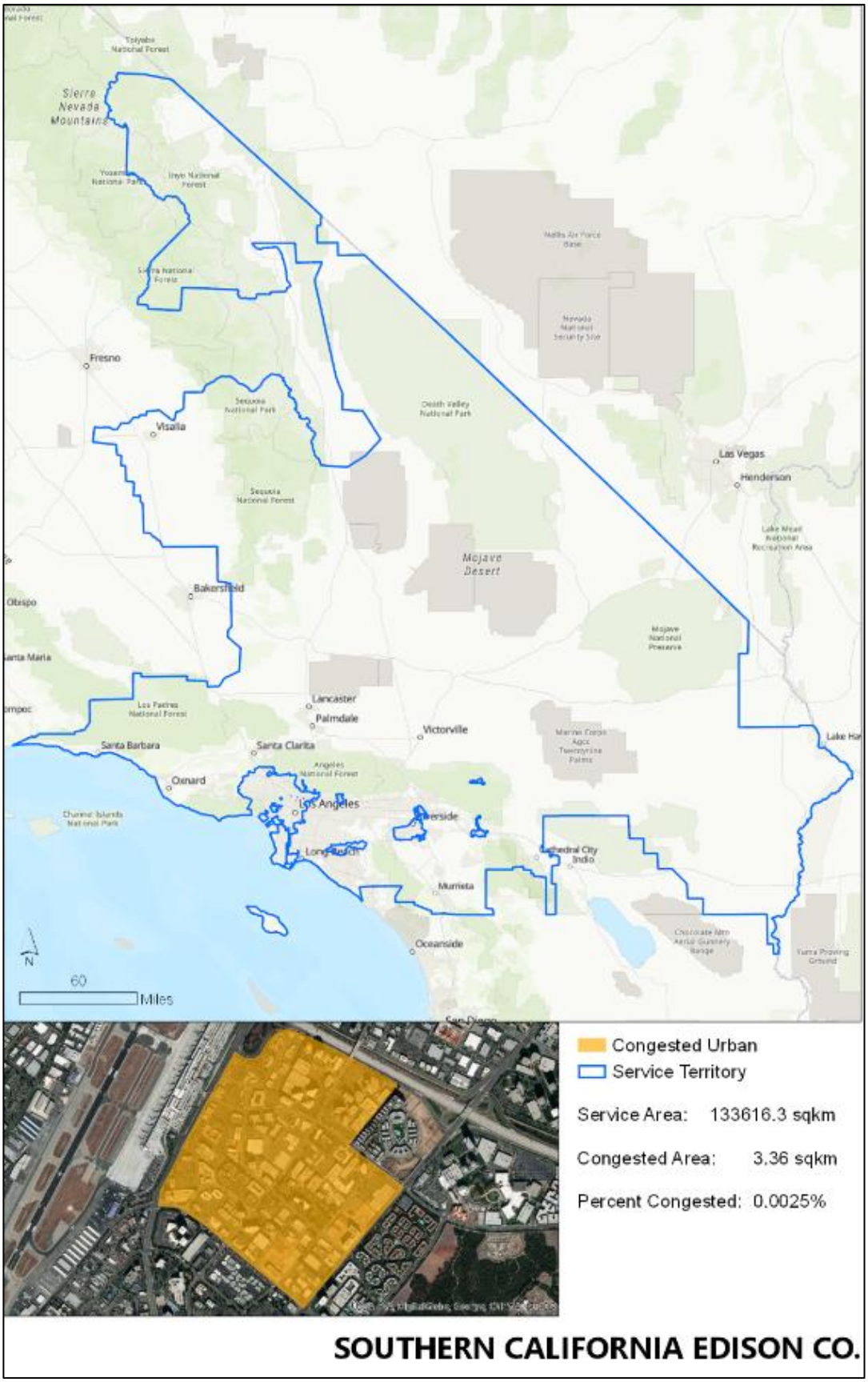

Dodge City
Wichita
Red Hills
Enid
Stillwater
Tulsa
Oklahoma
Oklahoma City
Wichita Falls
Denton
Plano
Fort Worth
Dallas
N
50
Miles
Congested Urban
Service Territory
Service Area: 9945.53 sqkm
Congested Area: 1.16 sqkm
Percent Congested: 0.0116%
PSC OF OKLAHOMA

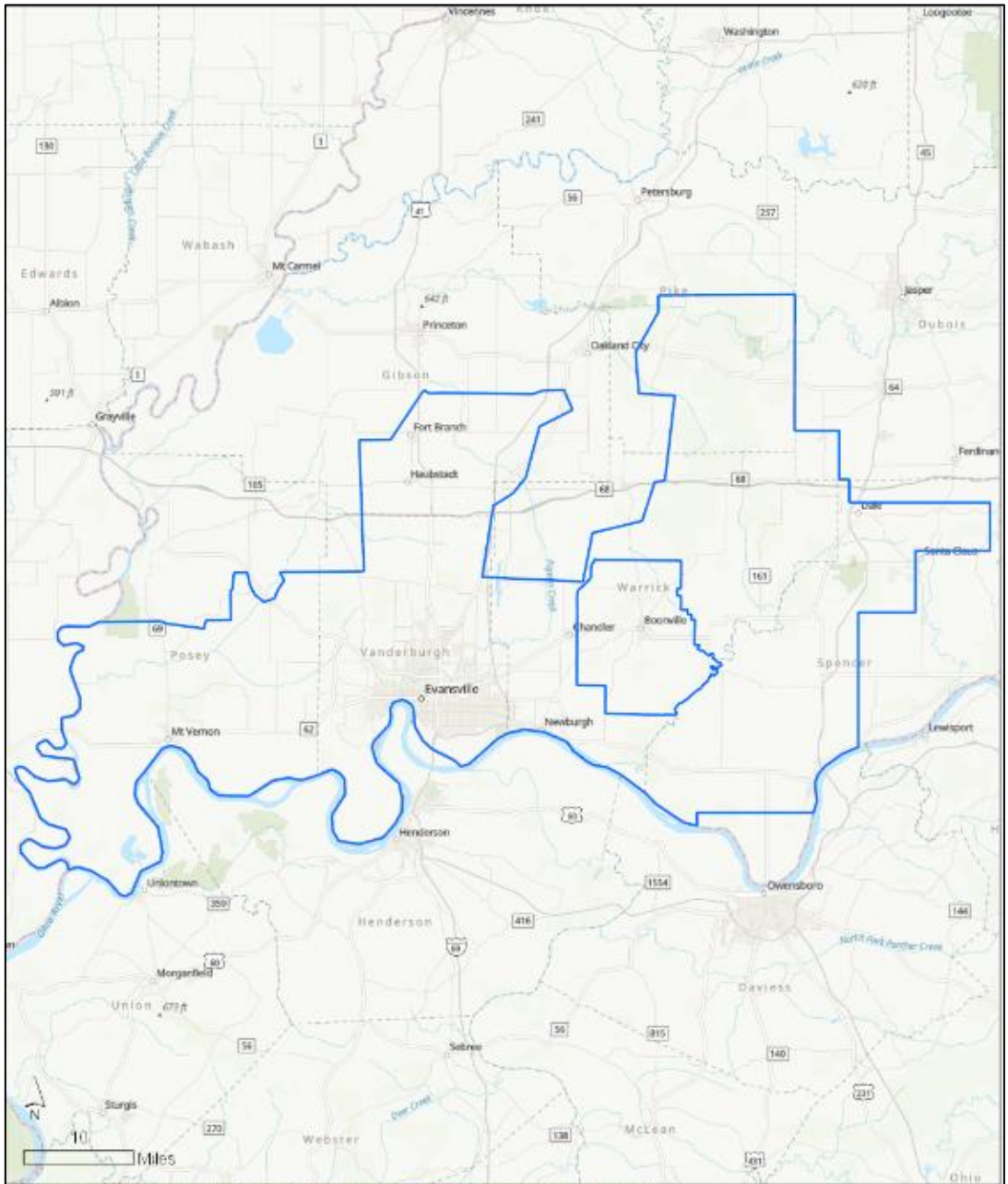

Paterson
Parsippany
Newark
New York
Elizabeth
Edison
Long Branch
Trenton
Hamilton
Philadelphia
Toms River
Congested Urban
Service Territory
Service Area: 3583.23 sqkm
Congested Area: 3.06 sqkm
Percent Congested: 0.0853%
PUBLIC SERVICE ELECTRIC AND GAS CO.

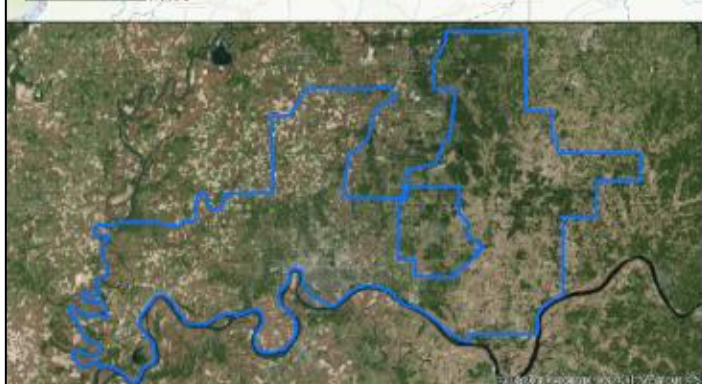

Bellingham
Mt Vernon
Everett
Seattle
Kent
Tacoma
Olympia
30
Miles
Congested Urban
Service Territory
Service Area: 23931.36 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
PUGET SOUND ENERGY, INC.


Corona
Perris
Hemet
Cathedral City
Palm Desert
Indio
Mission Viejo
Santa Ana Mountains
Laguna Niguel
Murrieta
San Jacinto Mountains
San Clemente
Oceanside
Escondido
Santee
El Cajon
San Diego
Chula Vista
Tecate
Tijuana
Playas de Rosarito
N
10
Miles
Congested Urban
Service Territory
Service Area: 10633.31 sqkm
Congested Area: 4.9 sqkm
Percent Congested: 0.0461%
SAN DIEGO GAS & ELECTRIC CO.


Spartanburg
Greenville
Rockingham
Anderson
Piedmont
Greenwood
Florence
Columbia
South Carolina
Coastal Plain
Francis Marion National Forest
North Charleston
Charleston
Statesboro
Vidalia
Coastal Plain
Hinesville
N
30
Miles
Congested Urban
Service Territory
Service Area: 14431.05 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
SOUTH CAROLINA ELECTRIC & GAS CO.


Sierra Nevada Mountains
Fresno
Visalia
Bakersfield
Mojave Desert
Las Vegas
Henderson
Lancaster
Palmdale
Victorville
Santa Barbara
Santa Clarita
Oxnard
Los Angeles
Riverside
Murrieta
Oceanside
60
Miles
Congested Urban
Service Territory
Service Area: 133616.3 sqkm
Congested Area: 3.36 sqkm
Percent Congested: 0.0025%
SOUTHERN CALIFORNIA EDISON CO.





Congested Urban

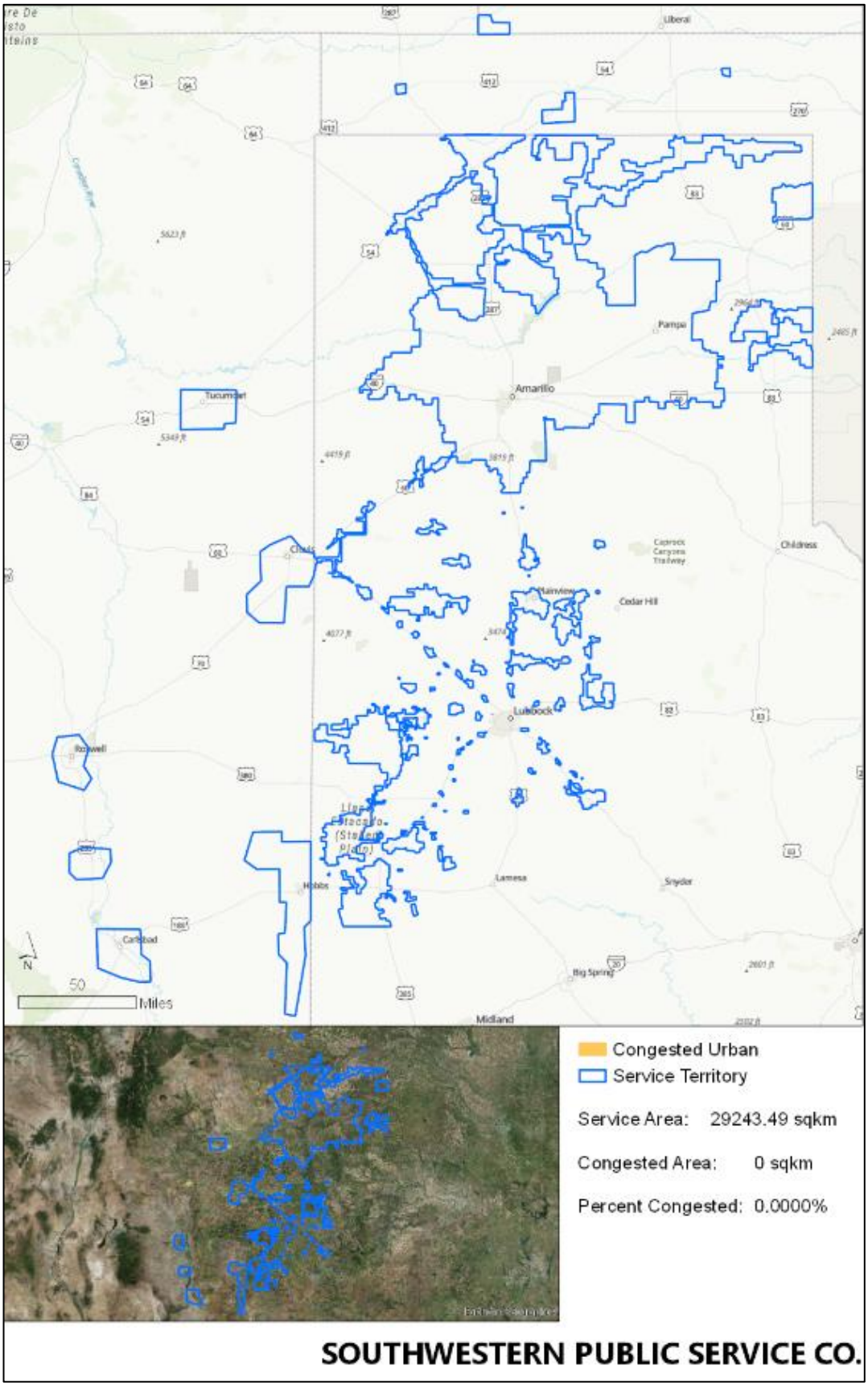
Service Territory

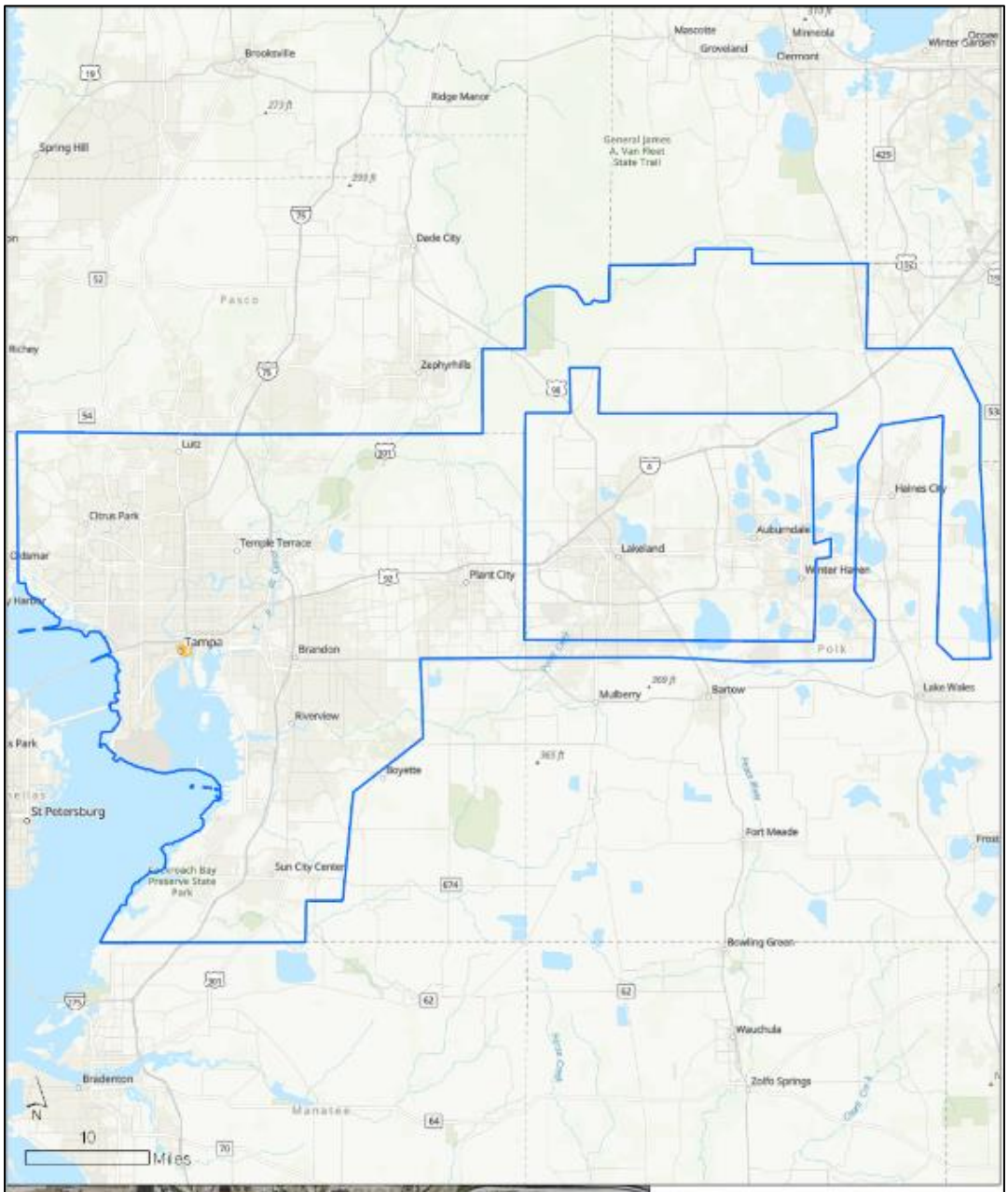
Service Area: 3086.73 sqkm

Congested Area: 0 sqkm

Percent Congested: 0.0000%

SOUTHERN INDIANA GAS & ELECTRIC CO.


Liberal
Pampa
Amarillo
Tucumcari
Clovis
Childress
Cedar Hill
Lubbock
Roswell
Hobbs
Lamesa
Snyder
Carlsbad
Big Spring
Midland
50
Miles
Congested Urban
Service Territory
Service Area: 29243.49 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
SOUTHWESTERN PUBLIC SERVICE CO.





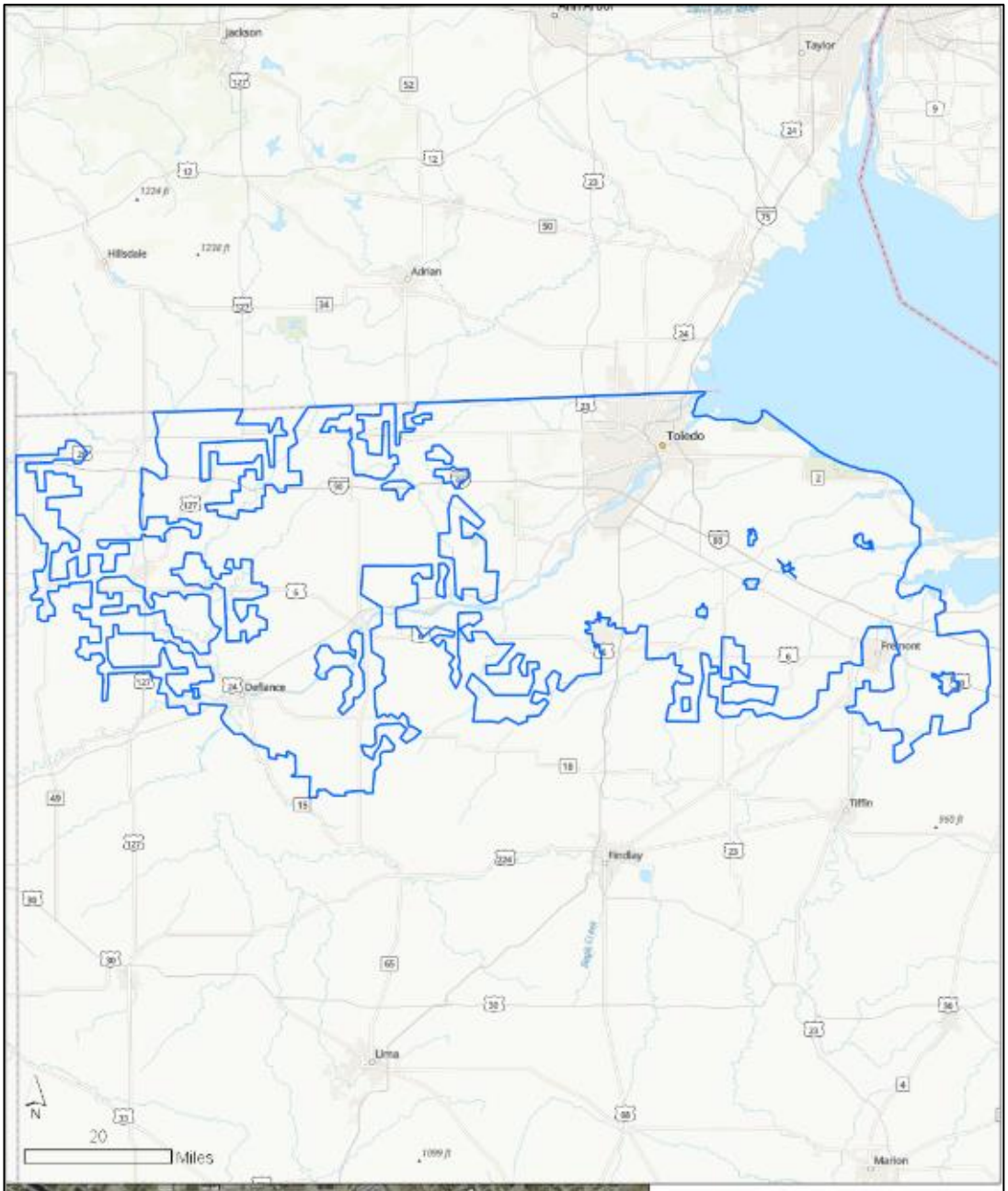
Congested Urban
Service Territory

Service Area: 3428.43 sqkm

Congested Area: 1.68 sqkm

Percent Congested: 0.0489%

TAMPA ELECTRIC CO.





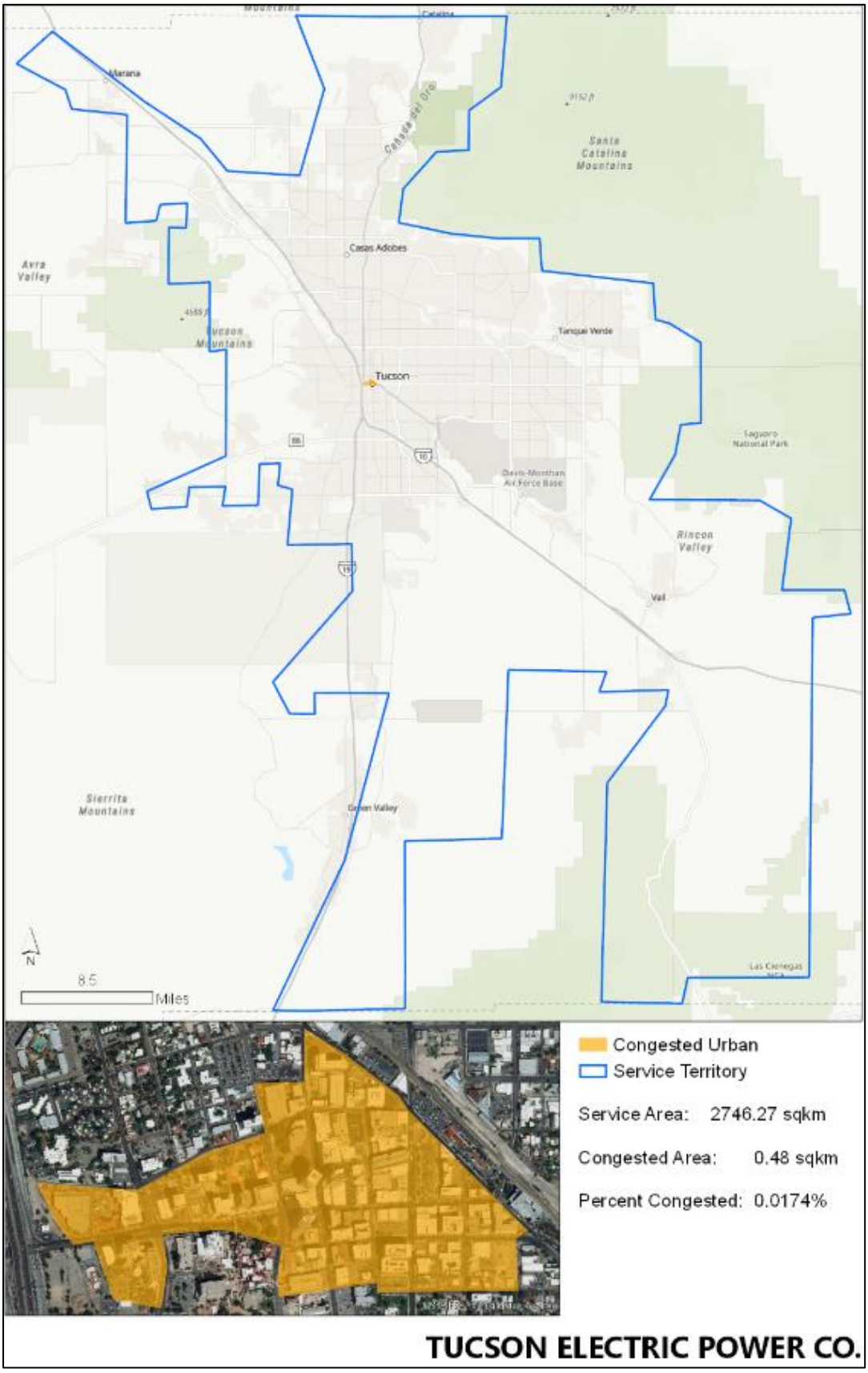
Congested Urban
Service Territory

Service Area: 5522.7 sqkm

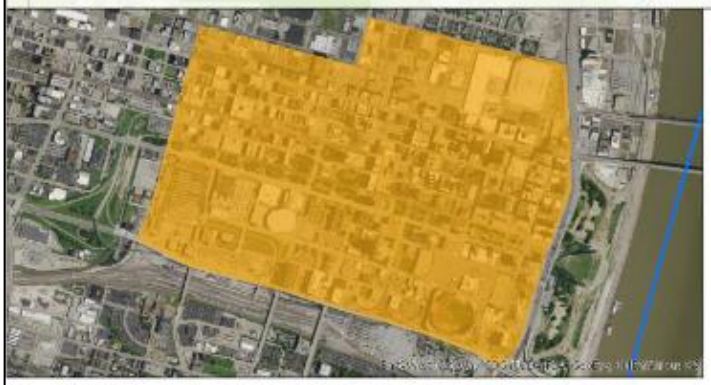
Congested Area: 0.93 sqkm

Percent Congested: 0.0169%

TOLEDO EDISON CO.


Marana
Casas Adobes
Avra Valley
Tucson Mountains
Tucson
Tanque Verde
Santa Catalina Mountains
Saguaro National Park
Davis-Monthan Air Force Base
Rincon Valley
Vail
Sierrita Mountains
Green Valley
Las Cienegas
N
8 5
Miles
Congested Urban
Service Territory
Service Area: 2746.27 sqkm
Congested Area: 0.48 sqkm
Percent Congested: 0.0174%
TUCSON ELECTRIC POWER CO.





Congested Urban
Service Territory

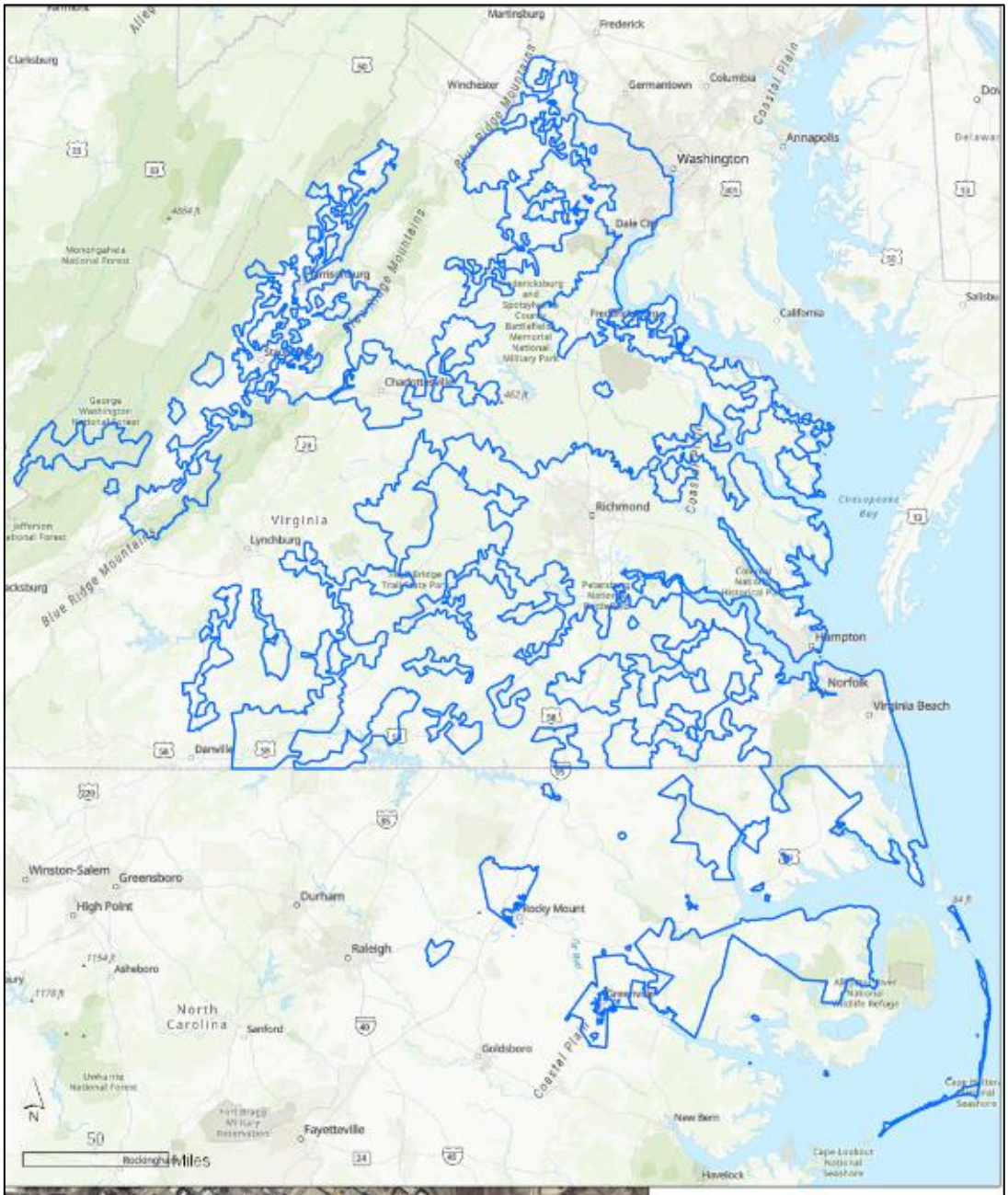
Service Area: 29207.41 sqkm

Congested Area: 2.6 sqkm

Percent Congested: 0.0089%

UNION ELECTRIC CO.


Southington
Oakville
Hotchkissville
Overlook
Waterbury
Woodbury
Town Plot Hill
Meriden
Heritage Village
Naugatuck
Southford
Wallingford
Sleeping Giant State Park
Sandy Hook
New Haven
North Haven
Palestine
Ansonia
Highwood
Monroe
Shelton
Foxon
Fair Haven
New Haven
Stepney
Huntington
Orange
West Haven
Milford
Woodmont
Bayview
Tollsome Hill
Stratford
Bridgeport
Fairfield
Westport
N
7
Miles
Congested Urban
Service Territory
Service Area: 985.49 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
UNITED ILLUMINATING CO.





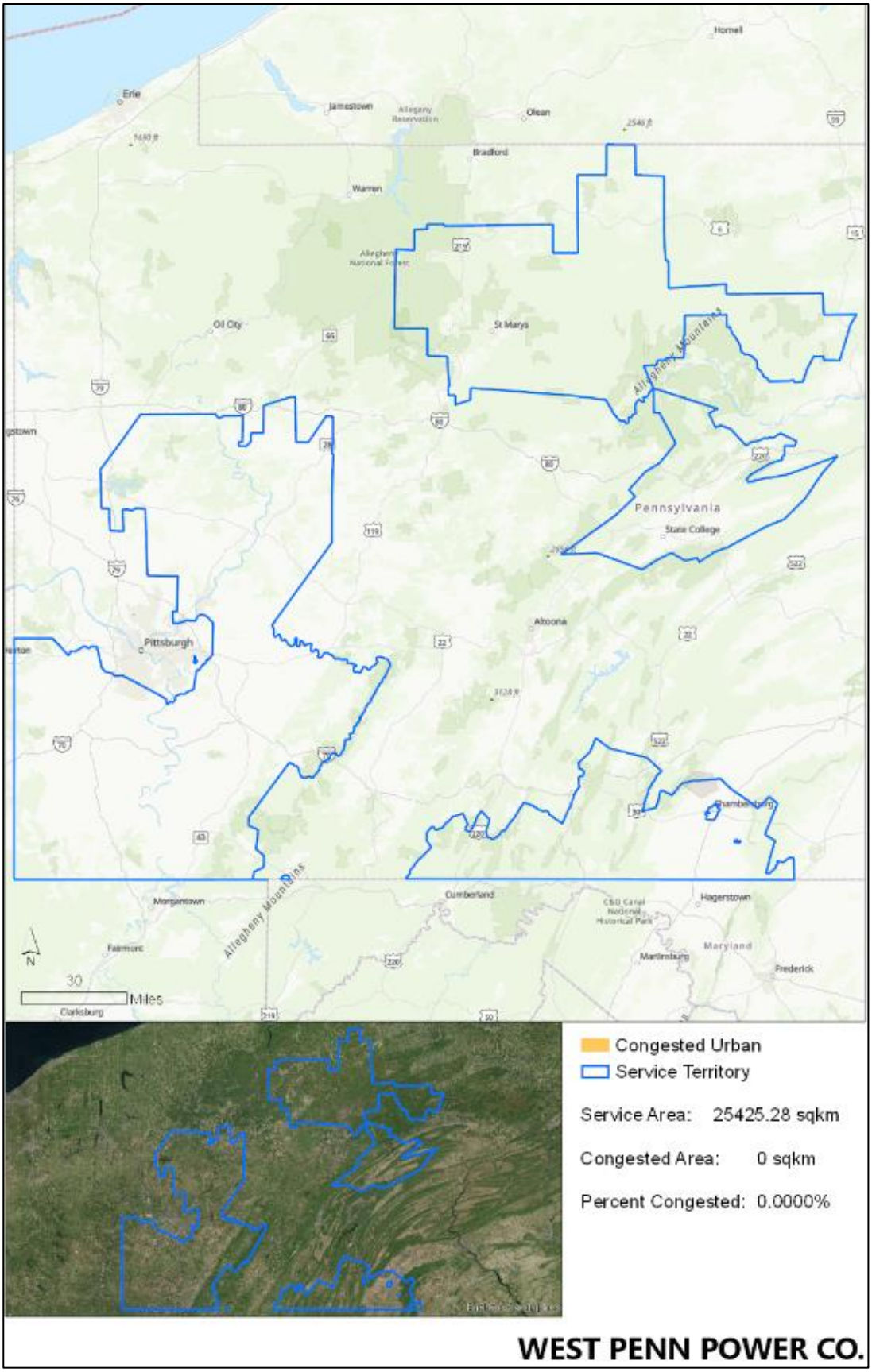
Congested Urban
Service Territory

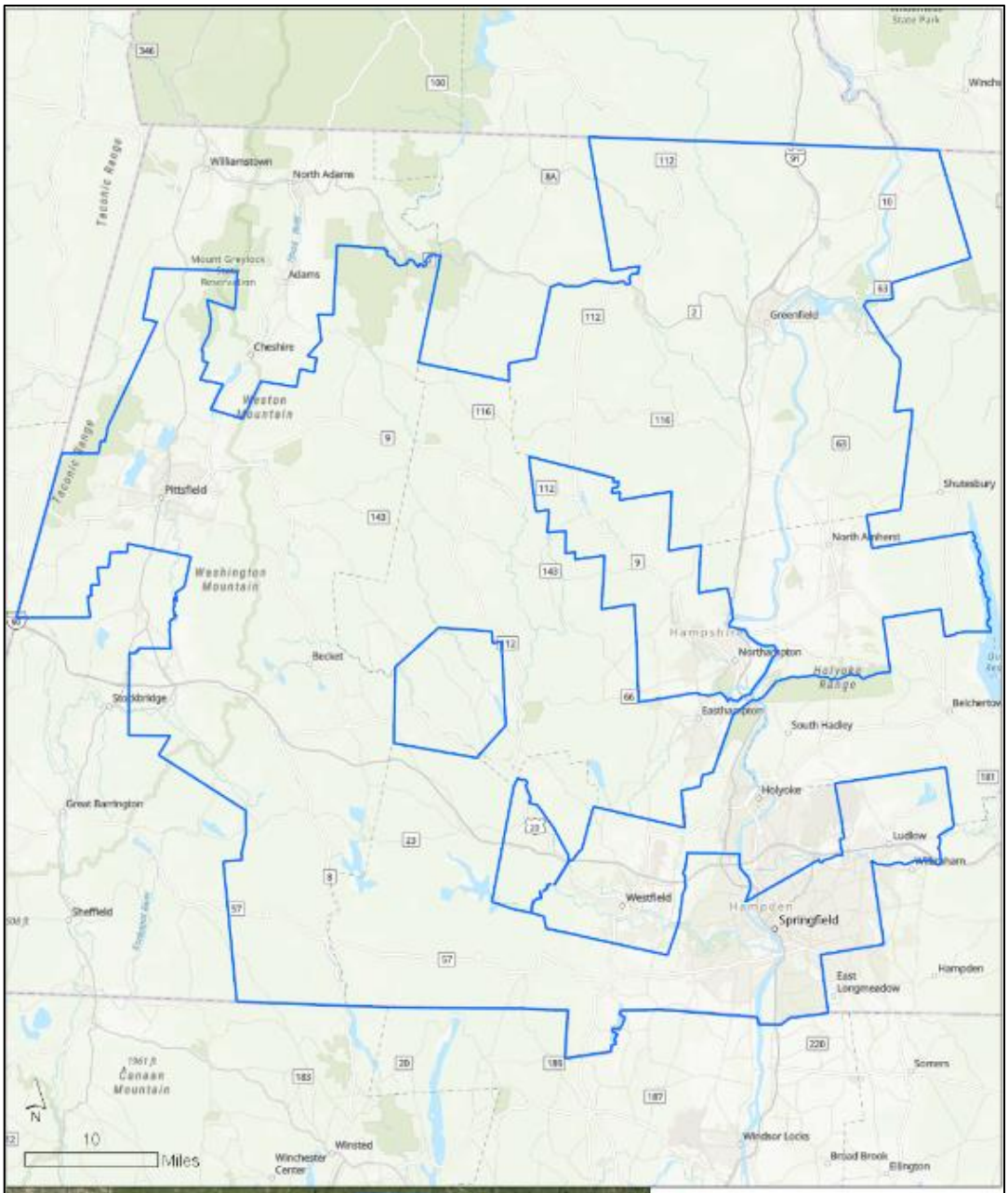
Service Area: 35900.78 sqkm

Congested Area: 2.07 sqkm

Percent Congested: 0.0058%

VIRGINIA ELECTRIC & POWER CO.


Hornell
Erie
Jamestown
Olean
Bradford
Warren
Oil City
St Marys
Pennsylvania
State College
Altoona
Pittsburgh
Morgantown
Cumberland
Hagerstown
Fairmont
Maryland
Frederick
Clarksburg
30
Miles
N
Congested Urban
Service Territory
Service Area: 25425.28 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
WEST PENN POWER CO.





Congested Urban

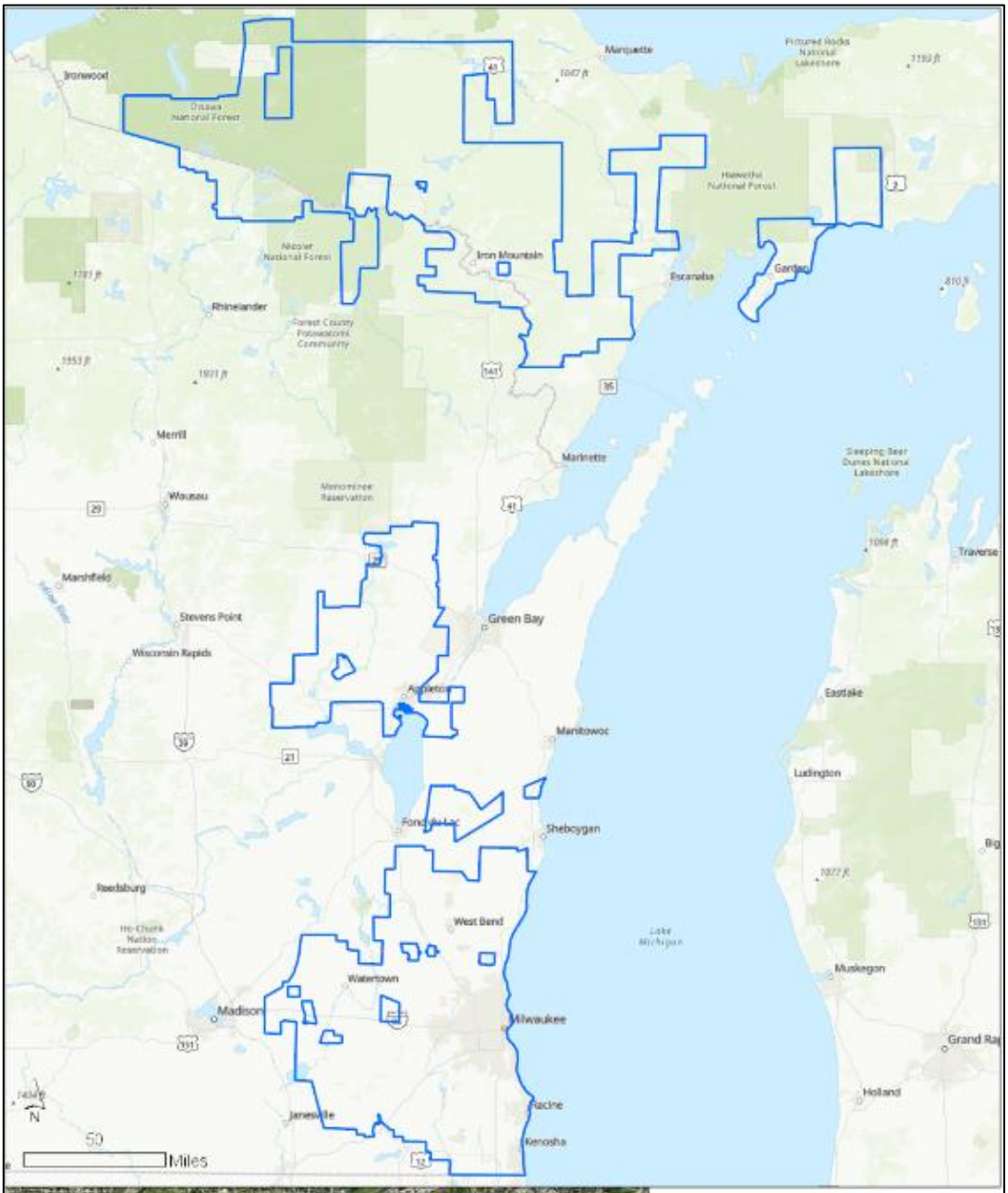
Service Territory

Service Area: 3871.73 sqkm

Congested Area: 0 sqkm

Percent Congested: 0.0000%

WESTERN MASSACHUSETTS ELECTRIC CO.





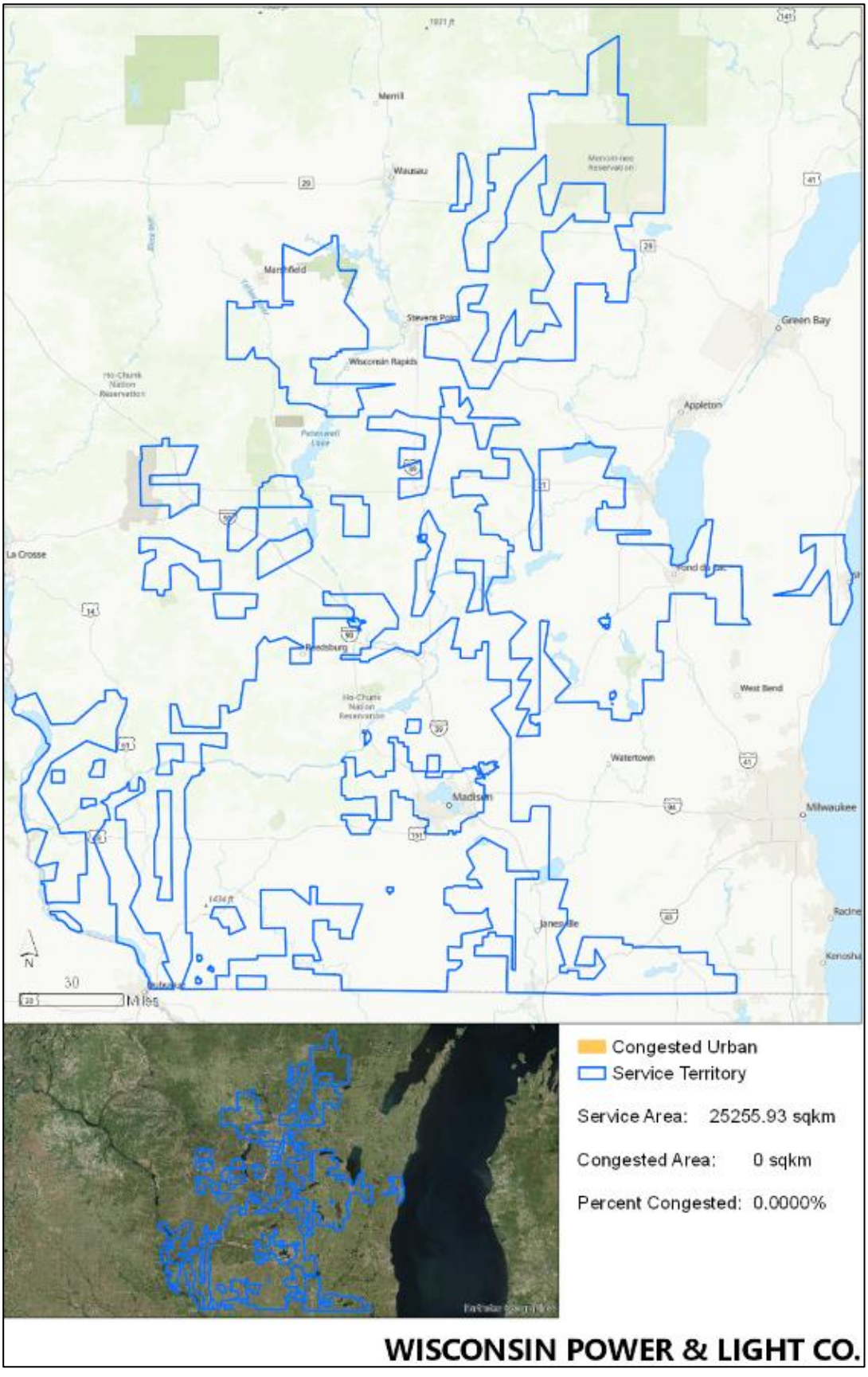
Congested Urban
Service Territory

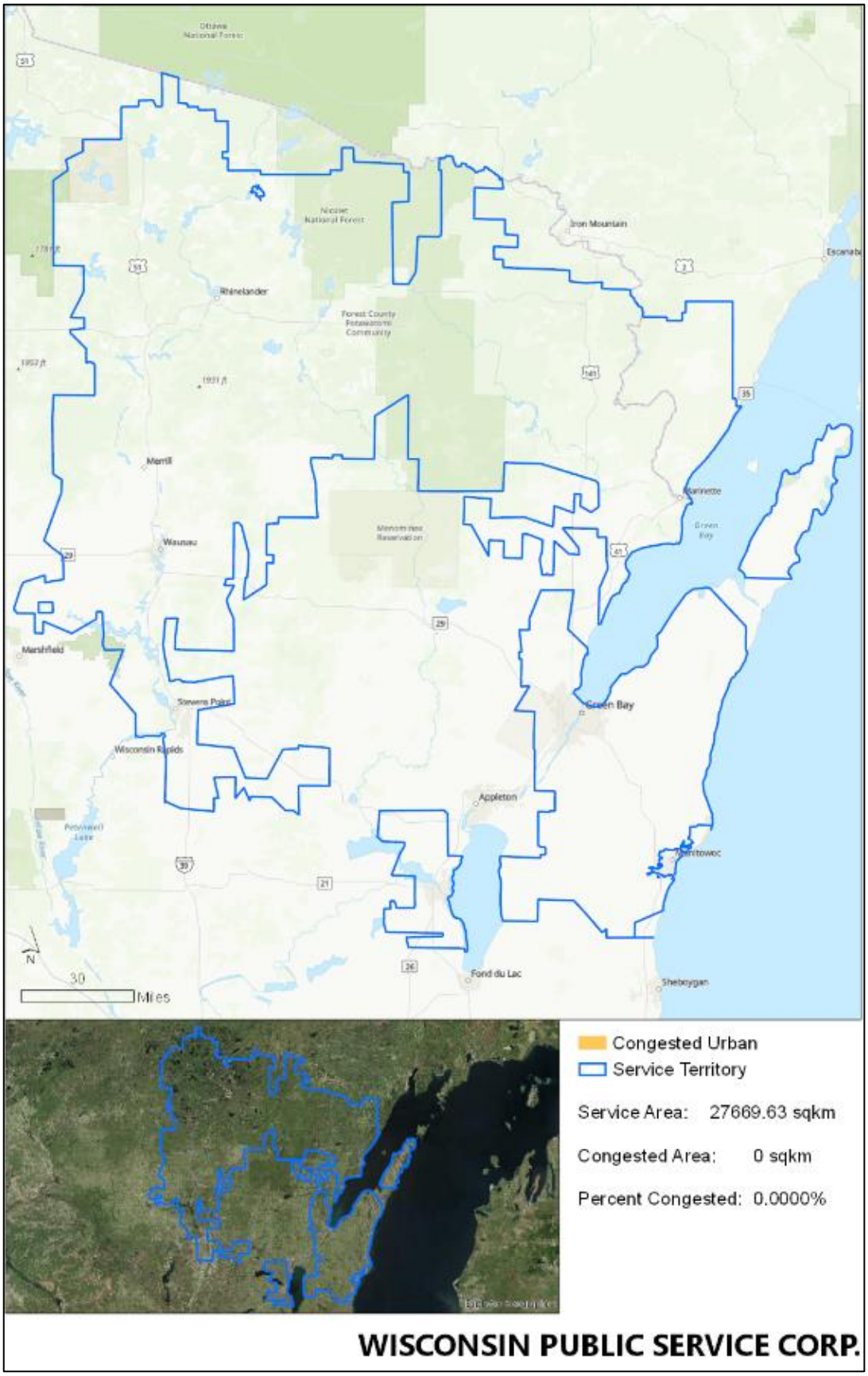
Service Area: 27021.71 sqkm

Congested Area: 5.71 sqkm

Percent Congested: 0.0211%

WISCONSIN ELECTRIC POWER CO.


Merrill
Wausau
Marshfield
Stevens Point
Wisconsin Rapids
Green Bay
Appleton
La Crosse
Reedsburg
West Bend
Watertown
Madison
Milwaukee
Janesville
Racine
Kenosha
30
Miles
Congested Urban
Service Territory
Service Area: 25255.93 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
WISCONSIN POWER & LIGHT CO.


Rhinelander
Iron Mountain
Merrill
Wausau
Marshfield
Stevens Point
Wisconsin Rapids
Green Bay
Appleton
Fond du Lac
Sheboygan
30
Miles
Congested Urban
Service Territory
Service Area: 27669.63 sqkm
Congested Area: 0 sqkm
Percent Congested: 0.0000%
WISCONSIN PUBLIC SERVICE CORP.

STEVEN A. FENRICK, M.S.

PROFESSIONAL EXPERIENCE

Power System Engineering, Inc. – Madison, WI (2009 to 2018)

Director of Economics

Responsible for providing consulting services to utilities and regulators in the areas of reliability and cost benchmarking, incentive regulation, value-based reliability planning, demand-side management including demand response and energy efficiency, load research, load forecasting, end-use surveys, and market research.

Pacific Economics Group – Madison, WI (2001 - 2009)

Senior Economist

Co-authored research reports submitted as testimony in numerous proceedings in several states and in international jurisdictions. Research topics included statistical benchmarking, alternative regulation, and revenue decoupling.

EDUCATION

University of Wisconsin - Madison, WI
Master of Science, Agriculture and Applied Economics

University of Wisconsin - Madison, WI
Bachelor of Science, Economics (Mathematical Emphasis)

Publications & Papers

- "Peak-Time Rebate Programs: A Success Story", *TechSurveillance*, July 2014 (with David Williams and Chris Ivanov).
- "Demand Impact of a Critical Peak Pricing Program: Opt-In and Opt-Out Options, Green Attitudes and other Customer Characteristics:, *The Energy Journal*, January 2014. (With Lullit Getachew, Chris Ivanov, and Jeff Smith).
- "Evaluating the Cost of Reliability Improvement Programs", *The Electricity Journal*, November 2013. (With Lullit Getachew)
- "Expected Useful Life of Energy Efficiency Improvements", Cooperative Research Network, 2013 (with David Williams).
- "Cost and Reliability Comparisons of Underground and Overhead Power Lines", *Utilities Policy*, March 2012. (With Lullit Getachew).
- "Formulating Appropriate Electric Reliability Targets and Performance Evaluations, *Electricity Journal*, March 2012. (With Lullit Getachew)
- "Enabling Technologies and Energy Savings: The Case of EnergyWise Smart Meter Pilot of Connexus Energy", November 2012. (With Chris Ivanov, Lullit Getachew, and Bethany Vittetoe)
- "The Value of Improving Load Factors through Demand-Side Management Programs", Cooperative Research Network, 2012 (with David Williams and Chris Ivanov).

- "Estimation of the Effects of Price and Billing Frequency on Household Water Demand Using a Panel of Wisconsin Municipalities", *Applied Economics Letters*, 2012, 19:14, 1373-1380.
- "Altreg Rate Designs Address Declining Average Gas Use", *Natural Gas & Electricity*. April 2008. (With Mark Lowry, Lullit Getachew, and David Hovde).
- "Regulation of Gas Distributors with Declining Use per Customer", *Dialogue*. August 2006. (With Mark Lowry and Lullit Getachew).
- "Balancing Reliability with Investment Costs: Assessing the Costs and Benefits of Reliability-Driven Power Transmission Projects." April 2011. *RE Magazine*.
- "Ex-Post Cost, Productivity, and Reliability Performance Assessment Techniques for Power Distribution Utilities". Master's Thesis.
- "Demand Response: How Much Value is Really There?" *PSE whitepaper.*
- "How is My Utility Performing" *PSE whitepaper*.
- "Improving the Performance of Power Distributors by Statistical Performance Benchmarking" *PSE whitepaper*.
- "Peak Time Rebate Programs: Reducing Costs While Engaging Customers" *PSE whitepaper*.
- "Performance Based Regulation for Electric and Gas Distributors" *PSE whitepaper*.

Expert Witness Experience

- Docket EB-2017-0049, Hydro One Distribution, TFP and Benchmarking research.
- Docket EB-2015-0004, Hydro Ottawa, Custom Incentive Regulation Application.
- Docket 15-SPEE-357-TAR, Application for Southern Pioneer Electric Cooperative, Inc., Demand Response Peak Time Rebate Pilot Program.
- Docket EB-2014-0116, Toronto Hydro, Custom Incentive Regulation Application.
- Docket EB-2010-0379, The Coalition of Large Distributors in Ontario regarding "Defining & Measuring Performance".
- Docket No. 6690-CE-198, Wisconsin Public Service Corporation, "Application for Certificate of Authority for System Modernization and Reliability Project".
- Expert Witness presentation to Connecticut Governors "Two Storm Panel", 2012.
- Docket No. EB-2012-0064, Toronto Hydro's Incremental Capital Module (ICM) request for added capital funding.
- Docket No. 09-0306, Central Illinois Light rate case filing.
- Docket No. 09-0307, Central Illinois Public Service Company rate case filing.
- Docket No. 09-0308, Illinois Power rate case filing.

Recent Conference Presentations

- Moderator at WPUI conference on cost allocation and innovative rate designs, June 2018.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2017.
- Wisconsin Manager's Meeting, "Reliability Target Setting Using Econometric Benchmarking". November 2016.

- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2016.
- Wisconsin Electric Cooperative Association (WECA) Conference, "An Introduction to Peak Time Rebates". September 2016.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2015.
- EUCI conference chair, 2015. "Evaluating the Performance of Gas and Electric Distribution Utilities."
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2014.
- Cooperative Exchange Conference, Williamsburg VA. "Smart Thermostat versus AC Direct Load Control Impacts". August 2014.
- EUCI conference chair in Chicago. "The Economics of Demand Response". February 2014.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2013.
- EUCI conference chair in Chicago. "Evaluating the Performance of Gas and Electric Distribution Utilities." August 2013.
- Presentation to the Ontario Energy Board, "Research and Recommendations on 4th Generation Incentive Regulation".
- Presentation to the Canadian Electricity Association's best practice working group. 2013
- Conference chair for EUCI conference in March 2013 titled, "Performance Benchmarking for Electric and Gas Distribution Utilities."
- Presentation to the board of directors of Great Lakes Energy on benchmarking results, December 2012.
- Presentation on making optimal infrastructure investments and the impact on rates, Electricity Distribution Association, Toronto, Ontario. November 2012.
- Conference chair for EUCI conference in August 2012 titled, "Performance Benchmarking for Electric and Gas Distribution Utilities."
- 2012 presentation in Springfield, IL to the Midwest Energy Association titled, "Reliability Target Setting and Performance Evaluation".
- 2012 presentation in Springfield, IL to the Midwest Energy Association titled, "Making the Business Case for Reliability-Driven Investments".
- Conference chair for EUCI conference in 2012 titled, "Balancing, Measuring, and Improving the Cost and Reliability Performance of Electric Distribution Utilities". St. Louis.
- Conference chair for EUCI conference in 2012 titled, "Demand Response: The Economic and Technology Considerations from Pilot to Deployment". St. Louis.
- 2012 Presentation in the Missouri PSC Smart Grid conference entitled, "Maximizing the Value of DSM Deployments". Jefferson City.
- 2011 conference chair on a nationwide benchmarking conference for rural electrical cooperatives. Madison.
- 2011 presentation on optimizing demand response program at the CRN Summit. Cleveland.

- Conference chair for EUCI conference in 2011 titled, “Balancing, Measuring, and Improving the Cost and Reliability Performance of Electric Distribution Utilities”. Denver.
- 2010 presentation on cost benchmarking techniques for REMC. Wisconsin Dells.

FORM A

Proceeding: EB-2018-0165

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Steven A. Fenrick (*name*). I live at Verona (*city*), in the Wisconsin (*province/state*) of United States.

2. I have been engaged by or on behalf of Toronto Hydro (*name of party/parties*) to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date 9-12-18

Signature

ERIK S. SONJU, P.E.
PRESIDENT

SUMMARY OF EXPERIENCE AND EXPERTISE

- Consultant in the electric utility sector helping clients analyze and develop strategic decisions around industry best practices, policies, standards, and contracts.
- Principal engineer for electric power studies and design projects.
- Instructor for professional development courses.
- Expert witness in regulatory hearings and civil trials.
- Licensed Professional Engineer in 20 states.

PROFESSIONAL EXPERIENCE

Power System Engineering, Inc. – Madison, WI (2006-present)

President (2018-present)

Active consultant to PSE clients in areas of expertise. Responsible for the day-to-day operations of PSE.

Executive Vice President (2017-2018)

Executive for PSE business operations and active consultant to PSE clients.

Vice President – Power Delivery Planning and Design (2010 - 2017)

Responsible for PSE's efforts in electric transmission and distribution studies and planning, substation design, transmission line design and distribution line design. Other responsibilities include overseeing system protection and coordination studies, system operations and maintenance support, distributed energy resource studies and design, and specialty studies of electric power systems.

Leader of System Planning and Line Design (2008 – 2010)

Senior engineer and leader of system planning and line design. Emphasis included short range and long range system planning studies, distributed generation system impact studies, system protection studies, and expert testimony in regulatory proceedings associated with engineering analysis used for State Commission and FERC filed tariffs. Other responsibilities included distribution and transmission line design.

Leader of System Planning (2006 – 2008)

Senior engineer and leader of distribution system planning projects.

Great Lakes Energy – Boyne City, MI (2001-2006)

System Engineer and Manager of Engineering

Heartland Engineering Services – Rockford, MN (1999-2001)

System Engineer

United Services Group – Elk River, MN (1997-1999)

Planning Engineer

EDUCATION

North Dakota State University, Fargo, ND
Bachelor of Science in Electrical Engineering with Emphasis in Power Systems, 1997

University of Nebraska, Lincoln, NE
NRECA Management Internship Program, 2006

Numerous technical and business continuing education courses focusing on issues and topics within the power industry.

TRAINING SEMINARS AND CONFERENCE PRESENTATIONS

- Instructor for professional development courses in the areas of:
  - Distribution System Planning
  - Distribution System Protection and Sectionalizing
  - Power Quality
  - Electric Power Line Design
  - Post Construction Inspections
- Industry conference presentations on:
  - Distribution Independent System Operators
  - Distributed Energy Resource Interconnection and Integration
  - Aging Electric Utility Infrastructure
  - Economic Conductor Analysis
  - Mechanical Loading of Overhead Electrical Equipment on Wood Poles
  - Application of Series Capacitors on Distribution Systems
  - Application of Shunt Reactors on Distribution Systems
  - Impact of Electric Motors, Drives, and Phase Converters on Distribution Systems
  - Substation Protection Considerations
  - National Electric Safety Code Rules and Requirements Pertaining to Communication Attachments on Power Supply Structures.

STATES LICENSED AS PROFESSIONAL ENGINEER

Arizona	Indiana	Montana	South Dakota
Arkansas	Iowa	Nebraska	Texas
Colorado	Kansas	New Hampshire	Virginia
Florida	Michigan	New Mexico	Wisconsin
Illinois	Minnesota	Ohio	Wyoming

EXPERT WITNESS AND TESTIMONY

Utility / Entity	Jurisdiction Body	Case No.	Description	Year
Chevron Pipe Line Company	United States District Court of Utah, Central Division	2:12-cv-00287	Industry expert on behalf of plaintiff in the matter of electrical damage to an oil pipeline. Included expert report and deposition.	2016-17
Lorain-Medina Rural Electric Cooperative	State of Ohio Median County Common Pleas Court	15CIV0749	Industry expert on behalf of defendant in the matter of the application of an electric rate schedule dispute. Included expert report and deposition.	2014-16
Toronto Hydro-Electric System Limited	Ontario Energy Board	EB-2015-0173	Industry expert on behalf of Toronto Hydro. Developed filed report regarding the variance of forecasted vs. actual expenditures associated with an OEB approved 2012-14 Incremental Capital Module request.	2015-16
Toronto Hydro-Electric System Limited	Ontario Energy Board	EB-2014-0116	Industry expert on behalf of Toronto Hydro. Developed filed report regarding independent review of the cost to serve developed environments including core downtown areas. Followed by oral testimony.	2014-15
Crow Wing Power	State of Minnesota District Court - Cass County	Court File No: 11-CV-12-1670	Testimony on behalf of defendant in the matter of a stray voltage lawsuit. Specific evidence related to conditions of underground distribution cable running adjacent to a dairy farm.	2013-14
MidAmerican Energy Company	State of Iowa District Court - Polk County	Law No. CL 114962	Industry expert on behalf of defendant providing engineering analysis showing the probable cause of failure of a 161kV transmission structure while under construction. Included affidavit of the analysis results and deposition.	2013
Toronto Hydro-Electric System Limited (THESL)	Ontario Energy Board	EB-2012-0064	Written and oral testimony regarding the replacement of aging electric infrastructure in the matter of THESL's application for 2012, 2013, and 2014 IRM Rate Adjustments and ICM Rate Adders	2012

Utility / Entity	Jurisdiction Body	Case No.	Description	Year
Governor Dannel P. Malloy's Two Storm Panel	State of Connecticut	N/A	Expert witness presentation to Governor Malloy's Two Storm Panel regarding distribution system reliability in the aftermath of Tropical Storm Irene and 2011 Halloween nor'easter snow storm.	2011
Mid-Kansas Electric Company	Kansas Corporation Commission	09-MKEE-969-RTS	Written expert rebuttal testimony on certain aspects of transmission and sub-transmission losses applied in proposed open access transmission tariffs and local access charges.	2009

FORM A

Proceeding: EB-2018-0165

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Erik S. Sonju (*name*). I live at Madison (*city*), in the Wisconsin (*province/state*) of United States .

2. I have been engaged by or on behalf of Toronto Hydro (*name of party/parties*) to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date 9-12-18

Erik S. Sonju
Signature

Data Required for Cost Benchmarking

Toronto Hydro-Electric System Limited

Select LDC from Dropdown Box: Toronto Hydro-Electric System Limited

Required Item		History	Bridge Year	Test Year	Additonal Years for Custom IR Filings					
		2016	2017	2018	2019	2020	2021	2022	2023	2024	
	Gross Capital Cost Additions Data										
1	Total Gross Capital Additions	617,138,762	548,964,114	680,697,572	482,190,579	568,662,447	553,558,130	662,090,855	640,457,963	813,349,859	Enter Values
2	HV Gross Capital Additions	53,844,210	31,583,172	142,355,192	5,579,006	46,229,405	3,979,367	32,939,467	73,666,872	45,686,811	Enter Values
	Output and Other Business Conditions										
3	Number of Customers	761,920	767,946	771,221	777,747	783,944	790,644	797,713	804,782	811,852	Enter Values
4	Delivery Volume	24,710,637,614	23,766,238,910	23,548,753,407	23,300,879,954	23,214,583,255	23,002,936,691	22,841,143,128	22,669,336,922	22,592,195,054	Enter Values
5	Annual Peak Demand	4,591,559	4,246,688	4,203,979	4,181,918	4,151,730	4,105,891	4,056,364	4,025,571	4,038,725	Enter Values
6	Distribution Circuit-km	28,605	28,763	28,922	29,082	29,242	29,404	29,566	29,729	29,894	Enter Values
7	Ten Year Customer Growth Percentage	12.36%	12.95%	12.73%	12.86%	11.93%	11.46%	11.00%	9.56%	9.08%	Enter Values
	Inflation Measures										
8	Wage Growth	1.10%	1.93%	2.25%	2.11%	2.13%	2.10%	2.09%	2.17%	2.37%	Optional: Default Values Provided
9	Growth in Economy-wide Inflation	1.21%	1.28%	1.88%	1.78%	1.75%	1.75%	1.76%	1.88%	1.94%	Optional: Default Values Provided
10	Rate of Return (WACC)	6.28%	5.67%	6.02%	7.03%	7.17%	7.18%	7.18%	7.18%	7.18%	Enter Values
	OM&A Expenses Included in Cost Benchmarking										
Choose a Method:	Y **Use Method 1 [1A - 1B + 1C]**	232,383,928	234,078,558	239,346,726	246,351,802	255,330,919	257,628,897	259,947,557	262,287,085	264,647,669	Formula
	N **Use Method 2 [2A - 2B + 2C]**	232,383,928	-	-	-	-	-	-	-	-	Formula
11	**OM&A Values Transfered to Calculations Worksheet**	232,383,928	234,078,558	239,346,726	246,351,802	255,330,919	257,628,897	259,947,557	262,287,085	264,647,669	Formula

Method 1: Enter Values Calculated Elsewhere

			Enter Values Supported by Separate Calculations								
1A	Total OM&A Consistent with accounts included in [2B]	232,383,928	234,903,518	240,565,658	247,436,842	256,320,032	258,626,912	260,954,554	263,303,145	265,672,874	Enter Values
1B	HV Cost (Accounts 5014, 5015, and 5112) if included in total	-	824,960	1,218,932	1,085,040	989,113	998,015	1,006,997	1,016,060	1,025,205	Enter Values
1C	LV Adjustment	-									Enter Values

Method 2: Enter Detailed Data

OM&A Data

5005	Operation Supervision and Engineering	23,026,740									Enter Values
5010	Load Dispatching	5,351,161									Enter Values
5012	Station Buildings and Fixtures	-									Enter Values
5014	Transformer Station Equipment - Operation Labor	-									Enter Values
5015	Transformer Station Equipment - Operation Supplies and Expenses	-									Enter Values
5016	Distribution Station Equipment - Operation Labor	4,003,573									Enter Values
5017	Distribution Station Equipment - Operation Supplies and Expenses	2,645,106									Enter Values
5020	Overhead Distribution Lines and Feeders - Operation Labor	624,866									Enter Values
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	3,737,901									Enter Values
5035	Overhead Distribution Transformers - Operation	-									Enter Values
5040	Underground Distribution Lines and Feeders - Operation Labor	663,662									Enter Values
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	2,460,512									Enter Values
5055	Overhead Distribution Lines and Feeders	4,683									Enter Values
5065	Meter Expense	531,226									Enter Values
5070	Customer Premises - Operation Labor	2,194,355									Enter Values
5075	Customer Premises - Operation Materials and Supplies	1,542,691									Enter Values
5085	Miscellaneous Distribution Expense	10,117,835									Enter Values
5090	Underground Distribution Lines and Feeders - Rental Paid	-									Enter Values
5095	Overhead Distribution Lines and Feeders - Rental Paid	-									Enter Values
5096	Other Rent (Distribution)	-									Enter Values
	Subtotal: Operation	**56,904,313**	-	-	-	-	-	-	-	-	Formula

Select LDC from Dropdown Box: Toronto Hydro-Electric System Limited

Required Item			History	Bridge Year	Test Year	Additonal Years for Custom IR Filings					
			2016	2017	2018	2019	2020	2021	2022	2023	2024	
	5105	Maintenance Supervision and Engineering	14,896,791									Enter Values
	5110	Maintenance of Buildings and Fixtures	14,810,485									Enter Values
	5112	Maintenance of Transformer Station Equipment	-									Enter Values
	5114	Maintenance of Distribution Station Equipement	3,877,544									Enter Values
	5120	Maintenance of Poles, Towers and Fixtures	1,766									Enter Values
	5125	Maintenance of Overhead Conductors and Devices	16,024,040									Enter Values
	5130	Maintenance of Overhead Services	2,068									Enter Values
	5135	Overhead Distribution Lines and Feeders - Right of Way	3,850,160									Enter Values
	5145	Maintenance of Underground Conduit	6,440									Enter Values
	5150	Maintenance of Underground Conductors and Devices	6,024,819									Enter Values
	5155	Maintenance of Underground Services	187,260									Enter Values
	5160	Maintenance of Line Transformers	2,046									Enter Values
	5175	Maintenance of Meters	-									Enter Values
		Subtotal: Maintenance	**59,683,418**	-	-	-	-	-	-	-	-	Formula
	5305	Supervision (Billing and Collection)	203,987									Enter Values
	5310	Meter Reading Expense	4,223,672									Enter Values
	5315	Customer Billing	8,772,066									Enter Values
	5320	Collecting	16,538,114									Enter Values
	5325	Collecting - Cash Over and Short	-									Enter Values
	5330	Collection Charges	-									Enter Values
	5340	Miscellaneous Customer Account Expenses	-									Enter Values
		Subtotal : Billing and Collections	**29,737,838**	-	-	-	-	-	-	-	-	Formula
	5405	Supervision (Community Relations)	-									Enter Values
	5410	Community Relations - Sundry	-									Enter Values
	5420	Community Safety Program	2,525,811									Enter Values
	5425	Miscellaneous Customer Service and Informational Expenses	-									Enter Values
		Subtotal: Community Relations	**2,525,811**	-	-	-	-	-	-	-	-	Formula
	5605	Executive Salaries and Expenses	3,203,104									Enter Values
	5610	Management Salaries and Expenses	802									Enter Values
	5615	General Administrative Salaries and Expenses	54,544,884									Enter Values
	5620	Office Supplies	4,196									Enter Values
	5625	Administrative Expense Transferred - Credit	14,706									Enter Values
	5630	Outside Services Employed	6,419,601									Enter Values
	5640	Injuries and Damages	1,562,179									Enter Values
	5645	OMERS Pensions and Benefits	-									Enter Values
	5646	Employee Pensions and OPEB	-									Enter Values
	5647	Employee Sick Leave	-									Enter Values
	5650	Franchise Requirements	-									Enter Values
	5655	Regulatory Expenses	5,188,491									Enter Values
	5665	Miscellaneous General Expenses	37,971									Enter Values
	5670	Rent (Administrative and General)	-									Enter Values
	5672	Lease Payment Expense	-									Enter Values
	5675	Maintenance of General Plant	10,393,074									Enter Values
	5680	Electrical Safety Authority Fees	406,037									Enter Values
		Sutotal: A&G Expenses	**81,775,045**	-	-	-	-	-	-	-	-	Formula
	5635	Property Insurance	1,757,502									Enter Values
	6210	Life Insurance	-									Enter Values
		Subtotal: Insurance	**1,757,502**	-	-	-	-	-	-	-	-	Formula
	5515	Advertinsing	-									Enter Values
		Subtotal Advertising	-	-	-	-	-	-	-	-	-	Formula
	2A	**Total of Above Accounts Used for Benchmarking**	232,383,928	-	-	-	-	-	-	-	-	Formula
Adjustments to OM&A for Benchmarking												
		5014	-	-	-	-	-	-	-	-	-	Formula
		5015	-	-	-	-	-	-	-	-	-	Formula
		5112	-	-	-	-	-	-	-	-	-	Formula
	2B	**Subtotal: HV Adjustment (to subtract from cost)**	-	-	-	-	-	-	-	-	-	**Formula**
	2C	**LV Adjustment**	-									**Enter Values**

Benchmarking Calculations for LDC Forecasting

Selected LDC: Toronto Hydro-Electric System Limited

Section 1: Source Data and OM&A Calculations

Line Reference Number	Account	Row Nur		2015	2016	Forecasted Values 2017	2018	2019	2020	2021	2022	2023	2024	Data Item Number
1	**OM&A Data (Detail may be hidden or expanded using the +/- buttons to the left of the row numbers)**													
2	5005	2	Operation Supervision and Engineering		23,026,740									
3	5010	3	Load Dispatching		5,351,161									
4	5012	4	Station Buildings and Fixtures		-									
5	5014	5	Transformer Station Equipment - Operation Labor		-									
6	5015	6	Transformer Station Equipment - Operation Supplies and Expenses		-									
7	5016	7	Distribution Station Equipment - Operation Labor		4,003,573									
8	5017	8	Distribution Station Equipment - Operation Supplies and Expenses		2,645,106									
9	5020	9	Overhead Distribution Lines and Feeders - Operation Labor		624,866									
10	5025	10	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses		3,737,901									
11	5035	11	Overhead Distribution Transformers - Operation		-									
12	5040	12	Underground Distribution Lines and Feeders - Operation Labor		663,662									
13	5045	13	Underground Distribution Lines and Feeders - Operation Supplies and Expenses		2,460,512									
14	5055	14	Overhead Distribution Lines and Feeders		4,683									
15	5065	15	Meter Expense		531,226									
16	5070	16	Customer Premises - Operation Labor		2,194,355									
17	5075	17	Customer Premises - Operation Materials and Supplies		1,542,691									
18	5085	18	Miscellaneous Distribution Expense		10,117,835									
19	5090	19	Underground Distribution Lines and Feeders - Rental Paid		-									
20	5095	20	Overhead Distribution Lines and Feeders - Rental Paid		-									
21	5096	21	Other Rent (Distribution)		-									
22			**Subtotal: Operation**		56,904,313									
23	5105	22	Maintenance Supervision and Engineering		14,896,791									
24	5110	23	Maintenance of Buildings and Fixtures		14,810,485									
25	5112	24	Maintenance of Transformer Station Equipment		-									
26	5114	25	Maintenance of Distribution Station Equipement		3,877,544									
27	5120	26	Maintenance of Poles, Towers and Fixtures		1,766									
28	5125	27	Maintenance of Overhead Conductors and Devices		16,024,040									
29	5130	28	Maintenance of Overhead Services		2,068									
30	5135	29	Overhead Distribution Lines and Feeders - Right of Way		3,850,160									
31	5145	30	Maintenance of Underground Conduit		6,440									
32	5150	31	Maintenance of Underground Conductors and Devices		6,024,819									
33	5155	32	Maintenance of Underground Services		187,260									
34	5160	33	Maintenance of Line Transformers		2,046									
35	5175	34	Maintenance of Meters		-									
36			**Subtotal: Maintenance**		59,683,418									
37	5305	35	Supervision (Billing and Collection)		203,987									
38	5310	36	Meter Reading Expense		4,223,672									
39	5315	37	Customer Billing		8,772,066									
40	5320	38	Collecting		16,538,114									
41	5325	39	Collecting - Cash Over and Short		-									
42	5330	40	Collection Charges		-									
43	5340	41	Miscellaneous Customer Account Expenses		-									
44			**Subtotal : Billing and Collections**		29,737,838									
45	5405	42	Supervision (Community Relations)		-									
46	5410	43	Community Relations - Sundry		-									
47	5420	44	Community Safety Program		2,525,811									
48	5425	45	Miscellaneous Customer Service and Informational Expenses		-									
49			**Subtotal: Community Relations**		2,525,811									

Line Reference Number		Row Nur	Account	2015	2016	Forecasted Values 2017	2018	2019	2020	2021	2022	2023	2024	Data Item Number
50	5605	47	Executive Salaries and Expenses		3,203,104									
51	5610	48	Management Salaries and Expenses		802									
52	5615	49	General Administrative Salaries and Expenses		54,544,884									
53	5620	50	Office Supplies		4,196									
54	5625	51	Administrative Expense Transferred - Credit		14,706									
55	5630	52	Outside Services Employed		6,419,601									
56	5640	53	Injuries and Damages		1,562,179									
57	5645	54	OMERS Pensions and Benefits		-									
58	5646	55	Employee Pensions and OPEB		-									
59	5647	56	Employee Sick Leave		-									
60	5650	57	Franchise Requirements		-									
61	5655	58	Regulatory Expenses		5,188,491									
62	5665	59	Miscellaneous General Expenses		37,971									
63	5670	60	Rent (Administrative and General)		-									
64	5672	61	Lease Payment Expense		-									
65	5675	62	Maintenance of General Plant		10,393,074									
66	5680	63	Electrical Safety Authority Fees		406,037									
67			**Sutotal: A&G Expenses**		81,775,045									
68	5635	64	Property Insurance		1,757,502									
69	6210	65	Life Insurance		-									
70			**Subtotal: Insurance**		1,757,502									
71	5515	46	Advertinsing		-									
72			**Subtotal Advertising**		-									
73			**Total of Above Accounts Used for Benchmarking**		232,383,928									
74														
75	**Adjustments to OM&A for Benchmarking**													
76			5014		-									
77			5015		-									
78			5112		-									
79			Subtotal: HV Adjustment (to subtract from cost)		-									
80			LV Adjustment		-									
81			Total Adjusted OM&A Expense		232,383,928	234,078,558	239,346,726	246,351,802	255,330,919	257,628,897	259,947,557	262,287,085	264,647,669	11
82														
83	**Gross Capital Cost Additions Data**													
84			Total Gross Capital Additions		617,138,762	548,964,114	680,697,572	482,190,579	568,662,447	553,558,130	662,090,855	640,457,963	813,349,859	1
85			HV Gross Capital Additions		53,844,210	31,583,172	142,355,192	5,579,006	46,229,405	3,979,367	32,939,467	73,666,872	45,686,811	2
86														
87	**Output and Other Business Conditions**													
88			Number of Customers		761,920	767,946	771,221	777,747	783,944	790,644	797,713	804,782	811,852	3
89			Delivery Volume		24,710,637,614	23,766,238,910	23,548,753,407	23,300,879,954	23,214,583,255	23,002,936,691	22,841,143,128	22,669,336,922	22,592,195,054	4
90			Annual Peak Demand		4,591,559	4,246,688	4,203,979	4,181,918	4,151,730	4,105,891	4,056,364	4,025,571	4,038,725	5
91			Distribution Circuit km		28,605	28,763	28,922	29,082	29,242	29,404	29,566	29,729	29,894	6
92														
93														

Section 2: Actual Cost Calculations

94	**Actual Cost**											
95												
96	OM&A			232,383,928.44	234,078,557.67	239,346,726.00	246,351,801.90	255,330,918.81	257,628,897.08	259,947,557.15	262,287,085.17	264,647,668.93	
97													
98	Capital												
99			Rate of Return	6.28%	5.67%	6.02%	7.03%	7.17%	7.18%	7.18%	7.18%	7.18%	10
100			Depreciation Rate	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	
101			Construction Cost Index	165.10	167.22	170.40	173.46	176.52	179.64	182.83	186.30	189.95	9
102			Capital Price	17.83	17.03	17.89	19.94	20.55	20.91	21.28	21.67	22.09	
103			Gross Plant Additions	617,138,762	548,964,114	680,697,572	482,190,579	568,662,447	553,558,130	662,090,855	640,457,963	813,349,859	1
104			HV Capital Additions	53,844,210	31,583,172	142,355,192	5,579,006	46,229,405	3,979,367	32,939,467	73,666,872	45,686,811	2
105			Quantity of Capital Additions	3,411,879	3,093,923	3,159,315	2,747,695	2,959,610	3,059,381	3,441,242	3,042,414	4,041,482	
106			Quantity of Capital Removed	1,356,026	1,450,389	1,525,828	1,600,805	1,653,447	1,713,400	1,775,180	1,851,653	1,906,309	
107			Capital Quantity	31,598,897	33,242,431	34,875,919	36,022,809	37,328,972	38,674,953	40,341,015	41,531,776	43,666,950	
108			Capital Cost	563,376,872	566,099,179	623,938,282	718,139,208	766,928,128	808,828,049	858,599,450	900,064,089	964,524,704	
109													
110	Total Actual Cost			795,760,801	800,177,736	863,285,008	964,491,010	1,022,259,047	1,066,456,946	1,118,547,007	1,162,351,174	1,229,172,373	

Line Reference Number	Row Nur	Account	2015	2016	Forecasted Values 2017	2018	2019	2020	2021	2022	2023	2024	Data Item Number
		Section 3: Predicted Cost Calculations											
111		**Predicted Cost**											
112													
113		**Output Quantity**											
114		Number of Customers		761,920	767,946	771,221	777,747	783,944	790,644	797,713	804,782	811,852	
115		Delivery Volume		24,710,637,614	23,766,238,910	23,548,753,407	23,300,879,954	23,214,583,255	23,002,936,691	22,841,143,128	22,669,336,922	22,592,195,054	
116		Annual Peak Demand		4,591,559	4,246,688	4,203,979	4,181,918	4,151,730	4,105,891	4,056,364	4,025,571	4,038,725	
117		Capacity Proxy		5,018,278	5,018,278	5,018,278	5,018,278	5,018,278	5,018,278	5,018,278	5,018,278	5,018,278	
118													
119		**Input Prices**											
120		GDP IPI [30% Weight]	115.4	116.8	118.3	120.5	122.7	124.8	127.0	129.3	131.7	134.3	9
121		Average Hourly Earnings [70% Weight]	962.94	973.56	992.53	1,015.12	1,036.76	1,059.08	1,081.56	1,104.40	1,128.63	1,155.70	8
122		OM&A Price Index Growth [30% GDPIPI growth + 70% AWE Growth]	2.287%	1.130%	1.735%	2.139%	2.011%	2.016%	1.995%	1.991%	2.083%	2.241%	
123		OM&A Price Index Level		142.41	144.90	148.04	151.04	154.12	157.22	160.39	163.76	167.47	
124													
125		Capital Price Index	17.93	17.83	17.03	17.89	19.94	20.55	20.91	21.28	21.67	22.09	
126													
127		**Business Conditions**											
128		Line km		28,605.00	28,763.00	28,921.87	29,081.62	29,242.26	29,403.78	29,566.19	29,729.50	29,893.71	
129		2002-2013 Average Line km		14,198.73	15,109.00	15,921.52	16,652.64	17,315.25	17,919.68	18,474.27	18,985.87	19,460.13	
130		Customers Ten Years Ago		678,106									
131		Ten Year Customer Growth Percentage		12.36%	12.95%	12.73%	12.86%	11.93%	11.46%	11.00%	9.56%	9.08%	
132													
133		(Details of the predicted cost calculations may be hidden by using the +/- button to the left of row 248)											
134													
135		**Company Values for Variables Used in the Prediction Equation**											
136													
137		Constant		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	
138		Capital Price / OM&A Price (WK)		0.1252	0.1175	0.1209	0.1320	0.1333	0.1330	0.1327	0.1323	0.1319	
139		Customers (Y1)		761,920	767,946	771,221	777,747	783,944	790,644	797,713	804,782	811,852	
140		Capacity (Y2)		5,018,278	5,018,278	5,018,278	5,018,278	5,018,278	5,018,278	5,018,278	5,018,278	5,018,278	
141		Deliveries (Y3)		24,710,637,614	23,766,238,910	23,548,753,407	23,300,879,954	23,214,583,255	23,002,936,691	22,841,143,128	22,669,336,922	22,592,195,054	
142		Average Line Length		14,198.7	15,109.0	15,921.5	16,652.6	17,315.3	17,919.7	18,474.3	18,985.9	19,460.1	
143		Customers Added in last 10 years		12.36%	12.95%	12.73%	12.86%	11.93%	11.46%	11.00%	9.56%	9.08%	
144		Trend		10	11	12	13	14	15	16	17	18	
145													
146													
147		**Company-Specific Parameter Estimates***											
148	91	Constant		12.8023	12.8023	12.8023	12.8023	12.8023	12.8023	12.8023	12.8023	12.8023	
149	92	Capital Price / OM&A Price (WK)		0.6323	0.6323	0.6323	0.6323	0.6323	0.6323	0.6323	0.6323	0.6323	
150	93	Customers (Y1)		0.4644	0.4644	0.4644	0.4644	0.4644	0.4644	0.4644	0.4644	0.4644	
151	94	Capacity (Y2)		0.1310	0.1310	0.1310	0.1310	0.1310	0.1310	0.1310	0.1310	0.1310	
152	95	Deliveries (Y3)		0.0895	0.0895	0.0895	0.0895	0.0895	0.0895	0.0895	0.0895	0.0895	
153	96	WKWK		0.1245	0.1245	0.1245	0.1245	0.1245	0.1245	0.1245	0.1245	0.1245	
154	97	Y1Y1		(0.3564)	(0.3564)	(0.3564)	(0.3564)	(0.3564)	(0.3564)	(0.3564)	(0.3564)	(0.3564)	
155	98	Y2Y2		0.2032	0.2032	0.2032	0.2032	0.2032	0.2032	0.2032	0.2032	0.2032	
156	99	Y3Y3		0.1464	0.1464	0.1464	0.1464	0.1464	0.1464	0.1464	0.1464	0.1464	
157	100	WKY1		0.0536	0.0536	0.0536	0.0536	0.0536	0.0536	0.0536	0.0536	0.0536	
158	101	WKY2		0.0130	0.0130	0.0130	0.0130	0.0130	0.0130	0.0130	0.0130	0.0130	
159	102	WKY3		0.0009	0.0009	0.0009	0.0009	0.0009	0.0009	0.0009	0.0009	0.0009	
160	103	Y1Y2		0.1137	0.1137	0.1137	0.1137	0.1137	0.1137	0.1137	0.1137	0.1137	
161	104	Y1Y3		0.0838	0.0838	0.0838	0.0838	0.0838	0.0838	0.0838	0.0838	0.0838	
162	105	Y2Y3		(0.2026)	(0.2026)	(0.2026)	(0.2026)	(0.2026)	(0.2026)	(0.2026)	(0.2026)	(0.2026)	
163	106	Average Line Length		0.2863	0.2863	0.2863	0.2863	0.2863	0.2863	0.2863	0.2863	0.2863	
164	107	Customers Added in last 10 years		0.0190	0.0190	0.0190	0.0190	0.0190	0.0190	0.0190	0.0190	0.0190	
165	108	Trend		0.0169	0.0169	0.0169	0.0169	0.0169	0.0169	0.0169	0.0169	0.0169	
166													
167		**Sample Mean Values**											
168													
169		Constant		1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	
170		Capital Price / OM&A Price (WK)		0.1644	0.1644	0.1644	0.1644	0.1644	0.1644	0.1644	0.1644	0.1644	
171		Customers (Y1)		63,422.3118	63,422.3118	63,422.3118	63,422.3118	63,422.3118	63,422.3118	63,422.3118	63,422.3118	63,422.3118	
172		Capacity (Y2)		345,129.0146	345,129.0146	345,129.0146	345,129.0146	345,129.0146	345,129.0146	345,129.0146	345,129.0146	345,129.0146	
173		Deliveries (Y3		1,630,327,994	1,630,327,994	1,630,327,994	1,630,327,994	1,630,327,994	1,630,327,994	1,630,327,994	1,630,327,994	1,630,327,994	
174		WKWK		1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	
175		Y1Y1		1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	
176		Y2Y2		1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	
177		Y3Y3		1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	
178		WKY1		1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	
179		WKY2		1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	
180		WKY3		1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	
181		Y1Y2		1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	
182		Y1Y3		1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	
183		Y2Y3		1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	
184		Average Line Length		2,723	2,723	2,723	2,723	2,723	2,723	2,723	2,723	2,723	
185		Customers Added in last 10 years		0.1286	0.1286	0.1286	0.1286	0.1286	0.1286	0.1286	0.1286	0.1286	

Line Reference Number	Row Nur	Account	2015	2016	Forecasted Values 2017	2018	2019	2020	2021	2022	2023	2024	Data Item Number
186													
187													
188													
189		**2013 Values Logged and Mean Scaled (where applicable)**											
190													
191		Constant		1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	
192		Capital Price / OM&A Price (WK)		(0.2724)	(0.3357)	(0.3077)	(0.2196)	(0.2096)	(0.2118)	(0.2142)	(0.2169)	(0.2203)	
193		Customers (Y1)		2.4860	2.4939	2.4982	2.5066	2.5145	2.5230	2.5319	2.5408	2.5495	
194		Capacity (Y2)		2.6769	2.6769	2.6769	2.6769	2.6769	2.6769	2.6769	2.6769	2.6769	
195		Deliveries (Y3)		2.7185	2.6795	2.6703	2.6597	2.6560	2.6468	2.6398	2.6322	2.6288	
196		WKWK		0.0371	0.0563	0.0474	0.0241	0.0220	0.0224	0.0229	0.0235	0.0243	
197		Y1Y1		3.0902	3.1098	3.1204	3.1415	3.1614	3.1828	3.2053	3.2277	3.2500	
198		Y2Y2		3.5830	3.5830	3.5830	3.5830	3.5830	3.5830	3.5830	3.5830	3.5830	
199		Y3Y3		3.6950	3.5898	3.5652	3.5370	3.5272	3.5029	3.4842	3.4643	3.4554	
200		WKY1		(0.6773)	(0.8371)	(0.7688)	(0.5504)	(0.5272)	(0.5344)	(0.5423)	(0.5512)	(0.5617)	
201		WKY2		(0.7293)	(0.8985)	(0.8238)	(0.5878)	(0.5612)	(0.5670)	(0.5734)	(0.5808)	(0.5898)	
202		WKY3		(0.7406)	(0.8994)	(0.8218)	(0.5841)	(0.5568)	(0.5607)	(0.5654)	(0.5711)	(0.5792)	
203		Y1Y2		6.6549	6.6760	6.6874	6.7099	6.7312	6.7540	6.7778	6.8014	6.8248	
204		Y1Y3		6.7581	6.6824	6.6708	6.6668	6.6786	6.6781	6.6838	6.6879	6.7022	
205		Y2Y3		7.2771	7.1728	7.1482	7.1198	7.1099	7.0854	7.0665	7.0463	7.0372	
206		Average Line Length		1.6515	1.7136	1.7660	1.8109	1.8499	1.8842	1.9147	1.9420	1.9667	
207		Customers Added in last 10 years		96.11%	100.68%	98.97%	99.98%	92.77%	89.15%	85.54%	74.32%	70.63%	
208		Trend		10.0000	11.0000	12.0000	13.0000	14.0000	15.0000	16.0000	17.0000	18.0000	
209													
210		**Product of Parameter and 2013 Values**											
211													
212		Constant		12.802	12.802	12.802	12.802	12.802	12.802	12.802	12.802	12.802	
213		Capital Price / OM&A Price (WK)		(0.172)	(0.212)	(0.195)	(0.139)	(0.133)	(0.134)	(0.135)	(0.137)	(0.139)	
214		Customers (Y1)		1.154	1.158	1.160	1.164	1.168	1.172	1.176	1.180	1.184	
215		Capacity (Y2)		0.351	0.351	0.351	0.351	0.351	0.351	0.351	0.351	0.351	
216		Deliveries (Y3)		0.243	0.240	0.239	0.238	0.238	0.237	0.236	0.235	0.235	
217		WKWK		0.005	0.007	0.006	0.003	0.003	0.003	0.003	0.003	0.003	
218		Y1Y1		(1.101)	(1.108)	(1.112)	(1.120)	(1.127)	(1.134)	(1.142)	(1.150)	(1.158)	
219		Y2Y2		0.728	0.728	0.728	0.728	0.728	0.728	0.728	0.728	0.728	
220		Y3Y3		0.541	0.525	0.522	0.518	0.516	0.513	0.510	0.507	0.506	
221		WKY1		(0.036)	(0.045)	(0.041)	(0.029)	(0.028)	(0.029)	(0.029)	(0.030)	(0.030)	
222		WKY2		(0.009)	(0.012)	(0.011)	(0.008)	(0.007)	(0.007)	(0.007)	(0.008)	(0.008)	
223		WKY3		(0.001)	(0.001)	(0.001)	(0.001)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	
224		Y1Y2		0.757	0.759	0.760	0.763	0.765	0.768	0.771	0.773	0.776	
225		Y1Y3		0.566	0.560	0.559	0.558	0.559	0.559	0.560	0.560	0.561	
226		Y2Y3		(1.474)	(1.453)	(1.448)	(1.442)	(1.440)	(1.435)	(1.431)	(1.427)	(1.425)	
227		Average Line Length		0.473	0.491	0.506	0.519	0.530	0.539	0.548	0.556	0.563	
228		Customers Added in last 10 years		0.018	0.019	0.019	0.019	0.018	0.017	0.016	0.014	0.013	
229		Trend		0.169	0.186	0.202	0.219	0.236	0.253	0.270	0.287	0.304	
230													
231		Log of Predicted Total Cost / OM&A Price		15.0127	14.9947	15.0466	15.1436	15.1782	15.2018	15.2246	15.2445	15.2653	
232		Real Predicted Total Cost / OM&A Price		3,310,896	3,251,864	3,424,959	3,773,912	3,906,532	4,000,101	4,092,072	4,174,605	4,262,035	
233		OM&A Price		142.41	144.90	148.04	151.04	154.12	157.22	160.39	163.76	167.47	
234		**Predicted Total Cost**		471,504,404	471,202,505	507,014,192	570,020,142	602,067,400	628,910,589	656,308,484	683,638,448	713,773,966	
235													
236													

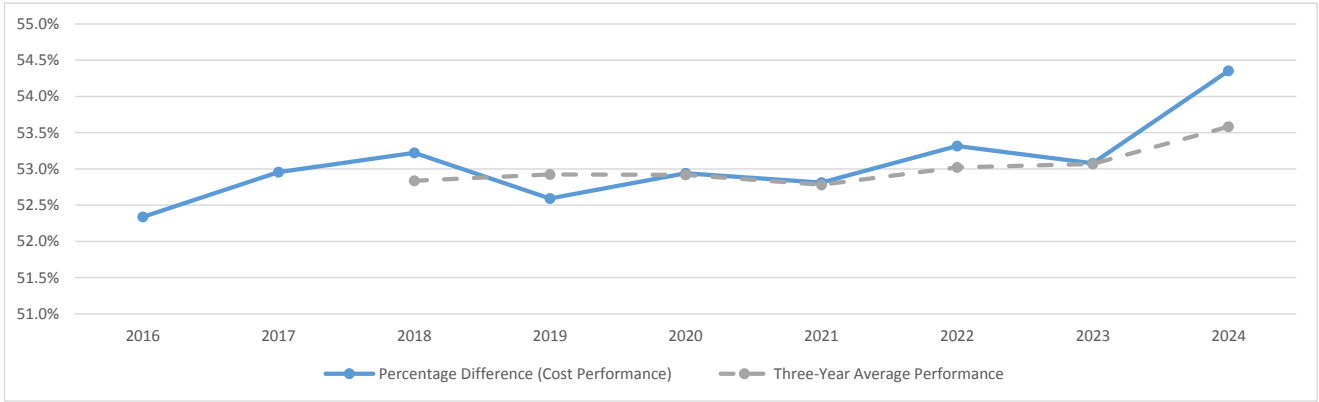
Section 4: Benchmarking Results

237	Actual Cost	795,760,801	800,177,736	863,285,008	964,491,010	1,022,259,047	1,066,456,946	1,118,547,007	1,162,351,174	1,229,172,373
238	Predicted Cost	471,504,404	471,202,505	507,014,192	570,020,142	602,067,400	628,910,589	656,308,484	683,638,448	713,773,966
239	Actual less Predicted Cost	324,256,397	328,975,232	356,270,816	394,470,868	420,191,647	437,546,358	462,238,524	478,712,727	515,398,407
240	Percentage Difference (Arithmetic for Comparison)	68.77%	69.82%	70.27%	69.20%	69.79%	69.57%	70.43%	70.02%	72.21%
241										
242	**Percent Difference (Logarithmic)**	**52.34%**	**52.95%**	**53.22%**	**52.59%**	**52.94%**	**52.81%**	**53.32%**	**53.08%**	**54.35%**

Summary of Cost Benchmarking Results

Toronto Hydro-Electric System Limited

Cost Benchmarking Summary	2016 (History)	2017 (History)	2018 (Bridge)	2019 (Bridge)	2020 (Test Year)	2021	2022	2023	2024
Actual Total Cost	795,760,801	800,177,736	863,285,008	964,491,010	1,022,259,047	1,066,456,946	1,118,547,007	1,162,351,174	1,229,172,373
Predicted Total Cost	471,504,404	471,202,505	507,014,192	570,020,142	602,067,400	628,910,589	656,308,484	683,638,448	713,773,966
Difference	324,256,397	328,975,232	356,270,816	394,470,868	420,191,647	437,546,358	462,238,524	478,712,727	515,398,407
Percentage Difference (Cost Performance)	**52.3%**	**53.0%**	**53.2%**	**52.59%**	**52.94%**	**52.81%**	**53.32%**	**53.08%**	**54.35%**
Three-Year Average Performance			52.8%	52.92%	52.92%	52.78%	53.02%	53.07%	53.58%
Stretch Factor Cohort									
Annual Result	5	5	5	5	5	5	5	5	5
Three Year Average			5	5	5	5	5	5	5



APPLICATION SUMMARY

This section provides an overview of Toronto Hydro's proposals that have a material impact on its customers, including all changes to rates and charges that may affect discrete customer groups.[1] Where relevant, specific customers or customer groups that are impacted by each proposal are identified.

1. BILL IMPACTS

On average, for each of the next five years, Toronto Hydro calculates that the bill impacts associated with this Application will be approximately $0.56 per month for a residential customer, or a less than 0.5 percent increase to the overall bill. Table 1, below, provides a summary of the total bill impacts for typical customers in all classes.[2]

Table 1: Bill Impacts – Change in Monthly Bill

Customer Class	Change in bill	2020 Proposed	2021 Proposed	2022 Proposed	2023 Proposed	2024 Proposed
Residential	$/30 days	-3.10	1.44	1.12	1.40	1.92
	%	*-2.4*	*1.1*	*0.9*	*1.1*	*1.5*
Competitive Sector Multi-Unit Residential	$/30 days	-1.19	1.14	0.89	0.99	1.52
	%	*-1.7*	*1.7*	*1.3*	*1.4*	*2.1*
General Service <50 kW	$/30 days	-6.60	3.62	2.81	4.39	4.82
	%	*-2.0*	*1.1*	*0.9*	*1.3*	*1.4*
General Service 50-999 kW	$/30 days	-156.17	63.57	49.55	87.48	84.52
	%	*-1.1*	*0.5*	*0.4*	*0.6*	*0.6*
General Service 1,000-4,999 kW	$/30 days	-1,452.01	521.66	406.45	717.98	693.76
	%	*-0.9*	*0.3*	*0.3*	*0.5*	*0.5*

[1] Please refer to Exhibit 1A, Tab 3, Schedule 1 (Administration) for information on Toronto Hydro's materiality threshold.
[2] Includes all rate riders.

Customer Class	Change in bill	2020 Proposed	2021 Proposed	2022 Proposed	2023 Proposed	2024 Proposed
Large Use	$/30 days	-3,187.65	2,692.82	2,098.05	3,704.72	3,579.26
	%	*-0.5*	*0.4*	*0.3*	*0.5*	*0.5*
Street Lighting	$/30 days	-2,514.52	4,577.71	3,585.65	6,320.80	6,149.95
	%	*-0.9*	*1.6*	*1.2*	*2.1*	*2.0*
Unmetered Scattered Load	$/30 days	-1.23	1.19	0.93	1.62	1.57
	%	*-1.9*	*1.9*	*1.4*	*2.5*	*2.3*

2. REVENUE REQUIREMENT

Toronto Hydro's Service Revenue Requirement, which is comprised of Operating Expenses, and Cost of Capital and payments in lieu of taxes ("PILs"), for the 2020 test year is $844.5 million. Table 2, below, summarizes Toronto Hydro's 2020 Forecast Revenue Requirement.

Table 2: 2020 Forecast Revenue Requirement ($ Millions)

Revenue Requirement Component	Total
Operations, Maintenance, and Administration ("OM&A") Expenses[3]	277.5
Amortization/Depreciation	268.7
Income Taxes (Grossed up)	34.7
Deemed Interest Expense	100.8
Return on Deemed Equity	162.8
Service Revenue Requirement	**844.5**
Revenue Offsets	47.7
Base Revenue Requirement	**796.8**

The increase/decrease (dollar and percent) from the most recent approved service revenue requirement (2015) and the main drivers of revenue requirement changes from the last OEB-approved year are outlined in Table 3, below.

[3] Includes property taxes.

Table 3: Comparison of 2015 and 2020 Total Service Revenue Requirement by Component ($ Millions)

	Most Recent Approved (2015)	2020 Test Year	Variance $M	Variance %
OM&A	243.9	277.5	33.6	13.8%
Depreciation	206	268.7	62.7	30.4%
Deemed Interest Expense	79.3	100.8	21.5	27.1%
Return on Equity	120.2	162.8	42.6	35.4%
PILs	25	34.7	9.8	39.2%
Total Service Revenue Requirement	**674.5**	**844.5**	**170.0**	**25.2%**

The main drivers for the increase in revenue requirement for the 2020 test year are the additions to rate base due to Toronto Hydro's significant capital program over the 2015-2019 period, and an increase in OM&A expenses.

For more information on Toronto Hydro's revenue requirement, please see Exhibit 6, Tab 1.

3. BUDGETING AND ACCOUNTING ASSUMPTIONS

3.1 Growth and Inflation

An inflation factor of 2.0 percent was applied to the utility's capital expenditures over the 2020 to 2024 rate period, consistent with the Statistics Canada Consumer Price Index for the City of Toronto. The utility applied an additional escalator to some of its programs to account for forecast construction costs inflation.

Toronto Hydro used both general inflation and specific cost assumptions in its 2020 forecast of operating costs. Since collective bargaining was ongoing at the time of budget planning, labour costs were adjusted to reflect historical annual rate adjustments that the utility has been required to pay under its collective agreement.

The labour cost forecast was also adjusted to reflect market-competitive increases for non-unionized employees. Otherwise, a general inflation factor of 2 percent was applied, consistent with the OEB's current inflation factor.

3.2 Accounting Standards

As outlined in Toronto Hydro's 2015-2019 Rate Application,[4] the utility adopted the International Financial Reporting Standards ("IFRS") accounting standard for financial reporting purposes in the year beginning on January 1, 2015.[5] For regulatory purposes, for the year beginning on January 1, 2015, the utility adopted modified IFRS, as per the OEB's Accounting Procedures Handbook ("APH"). Since that time, Toronto Hydro has adopted and applied the following three new standards, effective January 1, 2018 as required by the International Accounting Standards Board:

- **IFRS 9**: IFRS 9 introduces some new classification and measurement categories for financial assets, which impacts the measurement basis of the financial assets. The adoption of IFRS 9 led to a $0.3 million decrease to opening retained earnings. There is no impact to revenue requirement.
- **IFRS 15**: IFRS 15 introduces a five-step model that applies to customer contracts and contains new rules on the timing and measurement of revenue recognition. Upon adoption of IFRS 15, the only difference was a reclassification between Energy Sales and Energy Purchases. There is no impact to revenue requirement.
- **IFRS 16:** IFRS 16 eliminates the previous concepts of operating and finance leases and requires all contracts meeting the definition of a lease to be recognized on the balance sheet as a right-of-use asset and lease liability, with the exception of short-term leases and low-value leases. Upon the adoption of

[4] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015), Exhibit 1A, Tab 3, Schedule 1.
[5] *Ibid* at p. 4.

IFRS 16 on January 1, 2018, Toronto Hydro recognized $1.6 million as right-of-use assets and $1.6 million as lease liabilities for property leases.

For a detailed discussion of the utility's accounting standards, please see Exhibit 1C, Tab 3, Schedules 1 and 2.

4. LOAD FORECAST SUMMARY

Toronto Hydro's load forecast was developed using multivariate regression models by customer class to derive loads based on input variables for economic activity, weather, and other drivers of energy consumption. The forecast explicitly accounts for conservation and demand management ("CDM") impact on load. The utility's forecast of new customers is primarily derived from extrapolation models for each rate class with the exception of the Competitive Sector Multi-Unit Residential ("CSMUR") rate class (implemented on June 1, 2013), whose forecast customer additions are based on market knowledge of suite metering and multi-unit dwelling construction in Toronto Hydro's service area.

Toronto Hydro's load and customer growth changes are shown in Table 4, below.

Table 4: Customer and Load Growth Changes for 2015-2024

Year	Customer Count[1]	Customer Count Change (%)	Energy Forecast (kWh)[2]	Energy Forecast (kWh) Change (%)	Demand Forecast (kVa)[3]	Demand Forecast (kVa) Change (%)
2015	747,811		24,339,499,672		41,320,702	
2016	759,301	1.5%	24,221,254,752	-0.5%	41,335,567	0.0%
2017	765,559	0.9%	23,753,435,105	-1.9%	40,731,257	-1.5%
2018	771,079	0.7%	23,704,588,481	-0.2%	40,924,977	0.5%

Year	Customer Count[1]	Customer Count Change (%)	Energy Forecast (kWh)[2]	Energy Forecast (kWh) Change (%)	Demand Forecast (kVa)[3]	Demand Forecast (kVa) Change (%)
2019	776,786	0.7%	23,456,901,501	-1.0%	40,761,064	-0.4%
2020	784,330	1.0%	23,371,287,137	-0.4%	40,408,069	-0.9%
2021	790,944	0.8%	23,159,331,182	-0.9%	40,275,495	-0.3%
2022	798,591	1.0%	22,997,724,093	-0.7%	40,200,607	-0.2%
2023	806,238	1.0%	22,826,104,359	-0.7%	40,104,565	-0.2%
2024	813,886	0.9%	22,749,647,312	-0.3%	40,166,624	-0.2%

Notes: 1) Customer count excludes street lighting.
2) Historical distribution kWh (2015-2017) are normalized for weather.
3) Total distribution kVa are for customers billed on a demand basis.

Please see Exhibit 3, Tab 1 for details on Toronto Hydro's customer and load forecast.

5. RATE BASE AND DISTRIBUTION SYSTEM PLAN

5.1 Distribution System Plan

Toronto Hydro's Distribution System Plan ("DSP") reflects a balance between customer preferences, affordability, and prioritized outcomes (as described in Exhibit 2B, Section C), with the overriding objective of delivering value for money. As explained in further detail in the Capital Expenditures Plan,[6] Toronto Hydro's 2020-2024 capital expenditure plan is driven by needs that can be categorized as follows:

- **Legal and Regulatory**: The need to meet Toronto Hydro's mandated service obligations as well as its compliance with regulations for safe operations;
- **Reliability and Safety**: The need to replace assets to mitigate risks associated with all, or a combination of, increasing age, poor condition, safety, and environmental factors;

[6] See Exhibit 2B, Section E.

- **Load Capacity and Growth**: The need to ensure load growth, capacity and security of supply;
- **Resiliency**: The need to improve contingency constraints and operational flexibility in light of risks related to climate change and weather, and the evolving expectations of customers; and
- **Operational**: The need for Toronto Hydro to make necessary and mandatory day-to-day investments that support the 24/7 operations of Toronto Hydro including non-system physical plant investments associated with Information Technology, Fleet, and Facilities.

Programs are allocated to investment categories in accordance with their "trigger" drivers. Trigger drivers are the primary reason that a program must be carried out. Each capital program is defined by a single "trigger" driver and a number of secondary drivers. Note that although Safety is not listed as a primary trigger driver, it is a significant secondary driver for many programs. Secondary drivers may be as, or more, consequential than the trigger drivers. The "trigger" investment drivers of Toronto Hydro's DSP are summarized in Table 5, below.

1 **Table 5: Investment Category Primary Trigger Drivers**

	Driver	Description
System Access	Customer Service Requests	The fulfilment of Toronto Hydro's obligation to connect a customer to its system. This includes both traditional demand customers and distributed generation ("DG") customers. The obligation to connect exists as long as there are no safety concerns for the public or employees and there is no adverse effect on the reliability of the distribution system. The utility undertakes expansion or enhancements to the system when a connection cannot be made with existing infrastructure.
	Mandated Service Obligation	Compliance with all legal and regulatory requirements and government directives.
System Renewal	Functional Obsolescence	The asset and/or its installation is no longer aligned to Toronto Hydro's processes and practices such that it can no longer be maintained (e.g. lack of vendor support) or utilized as intended to support the utility's operations.
	Failure	Asset or critical component failure has taken place and Toronto Hydro must respond reactively as part of its capital investment activities.
	Failure Risk	There is imminent risk of failure due to age or condition deterioration. The potential failures will result in significant reliability impacts to customers as well as potential safety risks to crew workers or to the public.
System Service	Reliability	Maintain or improve reliability at a local, feeder-wide, or system-wide level.
	Capacity Constraints	Expected changes in load will constrain the ability of the system to provide consistent service delivery and handle demand requirements.
General Plant	Operational Resilience	The ability to mitigate and recover from disruptions to core business functions.
	System Maintenance and Capital Investment Support	Required investments to support day to day business operational activities; sustaining operations by providing its employees with a safer environment to operate in an efficient and reliable manner.

Toronto Hydro forecasts $2,383.5 million in capital expenditures for the 2015-2019 period, which results in an actual Capital-Related Revenue Requirement within the OEB approved amount for that period. The utility is forecasting total capital expenditures of $2,827.4 million over the 2020-2024 plan period,[7] which is $443.9 million, or 18.6 percent higher than 2015-2019. Table 6, below, provides the capital expenditure by investment category for the 2020-2024 period.

Table 6: Capital Investment Expenditures by Categories ($ Millions)

CATEGORY	Forecasted Spend						
	Avg.	2020	2021	2022	2023	2024	Total
System Access	100.3	91.8	93.3	93.9	106.0	116.4	**501.4**
System Renewal	324.0	306.6	325.7	323.1	339.0	325.5	**1,619.9**
System Service	47.5	34.2	60.1	71.3	33.6	38.5	**237.7**
General Plant	84.9	78.8	93.7	89.0	77.7	85.2	**424.4**
Other	8.8	7.0	9.0	9.8	9.5	8.7	**44.0**
Total	**565.5**	**518.4**	**581.8**	**587.1**	**565.7**	**574.4**	**2,827.4**

The 2020-2024 capital expenditure plan includes measureable objectives that directly or indirectly connect the proposed level of spending in each program to the utility's strategic objective of continuous improvement in six outcomes categories: Customer Service, Reliability, Safety, Public Policy, Environment, and Financial. For a detailed discussion of the utility's outcome objectives as well as the program drivers underlying its capital expenditure plan, please see Exhibit 2B, Section E1.

[7] This includes capital expenditures funded by provincial rate relief for Renewable Enabling Improvements, see Section 5.1.1 in this document.

5.1.1 Renewable Energy Connection Costs

Toronto Hydro has included approximately $18.6 million for new Renewable Enabling Improvements ("REI") projects over the 2020-2024 plan period, see Table 7, below.

Table 7: Renewable Enabling Improvements from 2020-2024 ($ Millions)[8]

REI Investment	2020	2021	2022	2023	2024	Total
Generation Protection, Monitoring, and Control (Exhibit 2B, Section E5.5)	3.7	2.3	2.0	2.5	2.7	13.6
Energy Storage Systems (Exhibit 2B, Section E7.2)	1.0	1.0	1.0	1.0	1.0	5.0
Totals	**4.7**	**3.3**	**3.4**	**3.5**	**3.7**	**13.6**

The utility has applied the mandated 6 percent direct benefit assumption provided by the OEB with respect to REI investments to calculate the provincial rate protection amounts.[9] The amount proposed for recovery from all provincial ratepayers, which includes the amount relating to investments approved by the OEB in Toronto Hydro's 2015-2019 Rate Application, is approximately $13.6 million over the 2020-2024 plan period.

Please see Exhibit 2A, Tab 6, Schedule 1 for details on Toronto Hydro's proposed REI investments. The detailed breakdown is provided in the OEB Appendices 2-FA and 2-FB at Exhibit 2A, Tab 6, Schedules 2 and 3, respectively.

5.1.2 Smart Grid Costs[10]

Table 8, below, contains the programs and segments costs that include smart grid related investments.

[8] For additional details on these, please see Exhibit 2A, Tab 6.
[9] Ontario Energy Board Filing Requirements for Electricity Rate Applications- 2018 Edition for 2019 Rate Applications, Chapter 2 (July 12, 2018) at s. 2.2.2.7.
[10] Toronto Hydro has used the term "grid modernization" as an alternative to "smart grid" throughout its Application.

Table 8: Costs Related to Smart Grid Investments ($ Millions)

Program or Segment with Smart Grid Investments	Forecasted Spend					
	2020	2021	2022	2023	2024	Total
Generation Connections (See Exhibit 2B, Section E5.1)	2.9	3.5	3.2	4.1	4.5	**18.2**
Wholesale Metering Compliance (See Exhibit 2B, Section E5.4)	7.3	1.6	0.0	0.0	0.0	**8.9**
Revenue Metering Compliance (See Exhibit 2B, Section E5.4)	15.3	13.2	23.6	30.6	39.2	**121.9**
Generation Protection, Monitoring, and Control (See Exhibit 2B, Section E5.5)	3.7	2.3	2.4	2.5	2.7	**13.6**
Legacy Network Equipment Renewal (See Exhibit 2B, Section E6.4)	1.9	2.0	1.2	-	-	**5.1**
Network Unit Renewal (See Exhibit 2B, Section E6.4)	9.5	9.8	10.0	10.1	10.2	**49.6**
Network Circuit Reconfiguration (See Exhibit 2B, Section E6.4)	1.2	1.4	1.1	1.2	1.7	**6.6**
Control and Monitoring (See Exhibit 2B, Section E6.6)	2.9	4.3	4.4	4.5	6.0	**22.1**
Battery and Ancillary Systems (See Exhibit 2B, Section E6.6)	0.9	1.2	1.6	1.7	1.7	**7.1**
Contingency Enhancement (See Exhibit 2B, Section E7.1)	5.5	5.6	5.1	4.3	4.4	**24.9**
Grid Performance Energy Storage System (See Exhibit 2B, Section E7.2)	-	2.7	2.8	-	-	**5.5**
Renewable Enabling Energy Storage System (See Exhibit 2B, Section E7.2)	1.0	1.0	1.0	1.0	1.0	**5.0**
Customer-Specific Energy Storage System (See Exhibit 2B, Section E7.2)	24.3	12.1	5.9	0.0	0.0	**42.3**
Network Condition Monitoring and Control (See Exhibit 2B, Section E7.3)	7.6	10.2	12.6	15.3	17.4	**63.1**
Local Demand Response (See Exhibit 2B, Section E7.4)	-	-	-	1.2	3.4	**4.6**
Control Operations Reinforcement (See Exhibit 2B, Section 8.1)	3.9	17.4	18.9	-	-	**40.2**
IT Hardware (See Exhibit 2B, Section E8.4)	11.5	10.3	11.6	14.0	14.5	**61.9**

Program or Segment with Smart Grid Investments	Forecasted Spend					
	2020	2021	2022	2023	2024	Total
IT Software (See Exhibit 2B, Section E8.4)	41.0	43.0	35.8	40.5	48.2	**208.5**
Communication Infrastructure (See Exhibit 2B, Section E8.4)	2.2	2.4	2.1	2.1	2.1	**10.9**
Total	**142.6**	**144.0**	**143.3**	**133.1**	**157.0**	**720.0**

5.1.3 Regional Planning Initiatives

Table 9, below, contains the programs and segments costs that include regional planning investments.[11]

Table 9: Costs Related to Regional Planning Investments ($ Millions)

Programs with Regional Planning Investments	Forecasted Spend					
	2020	2021	2022	2023	2024	Total
Generation Protection, Monitoring and Control (See Exhibit 2B, Section E5.5)	3.7	2.3	2.4	2.5	2.7	13.6
Energy Storage Systems (See Exhibit 2B, Section E7.2)	1.0	3.7	3.8	1.0	1.0	9.5
Stations Expansion (See Exhibit 2B, Section E7.4)	19.5	40.0	49.3	12.5	15.2	136.5
Total	**24.2**	**46.0**	**55.5**	**16.0**	**18.9**	**160.6**

5.2 Rate Base

Toronto Hydro's requested rate base for the 2020 test year is $4,615.3 million, which represents an increase of approximately $1,383.3 million, or 42.8 percent from the rate base amount of $3,232.0 million approved by the OEB in the utility's last rebasing application in 2015. See Table 10, below, for an overview of the costs.

[11] Please note that there is some overlap between these costs and the ones shown in Table 8, costs associated with smart grid investments.

The change in rate base is driven by an increase of approximately $1,388.3 million in the average net book value ("NBV") of property, plant, and equipment ("PP&E"), and a decrease of approximately $5.0 million in the working capital allowance ("WCA") component of rate base due to an updated WCA rate, as per Toronto Hydro's updated Lead Lag Study. The growth in PP&E includes continued investment in distribution assets, as well as the addition of street lighting assets into rate base as of the beginning of 2015.[12]

Table 10: Rate Base Overview ($ Millions)[13]

	OEB Approved[1]	Actual			Bridge		Forecast
	2015	2015	2016	2017	2018	2019	2020
Opening PP&E NBV	2,849.0	2,843.2	3,085.4	3,462.0	3,744.7	4,120.6	4,270.4
Closing PP&E NBV	3,134.7	3,085.4	3,462.0	3,744.7	4,120.6	4,269.0	4,489.8
Average PP&E NBV	**2,991.8**	**2,964.3**	**3,273.7**	**3,603.4**	**3,932.7**	**4,194.8**	**4,380.1**
Working Capital Allowance	240.2	247.9	275.8	247.4	273.6	287.2	235.2
Rate Base	**3,232.0**	**3,212.2**	**3,549.5**	**3,850.8**	**4,206.3**	**4,482.0**	**4,615.3**

For more information about Toronto Hydro's rate base, please refer to Exhibit 2A.

6. OPERATIONS, MAINTENANCE, AND ADMINISTRATION EXPENSE

Toronto Hydro's plan aims to efficiently maintain functional requirements such as safe and reliable grid operations and system performance, service levels, as well as legal and regulatory compliance. There are no new or materially expanded OM&A activities.

[12] As directed by the OEB in the utility's last Rate Application (EB-2014-0116), Toronto Hydro has transferred unregulated street lighting in-service capital additions into rate base.
[13] *Ibid*.

Toronto Hydro's total 2020 forecasted OM&A expenditures are $277.5 million – 13.8 percent or $33.6 million above the 2015 expenditures approved by the OEB ($243.9 million) in Toronto Hydro's last Rate Application.[14]

As mentioned in section 3, above, in arriving at its 2020 OM&A forecast Toronto Hydro used both general and specific cost and economic assumptions. Since collective bargaining was ongoing at the time of budget planning, labour costs were adjusted to reflect historical annual rate adjustments that the utility has been required to pay under its collective agreement. The labour cost forecast was also adjusted to reflect market-competitive pay increases for non-unionized employees. Otherwise, a general inflation factor of 2.0 percent was applied, consistent with the OEB's current inflation factor.

For more information on Toronto Hydro's OM&A Costs, see Exhibit 4A.

6.1 Cost Drivers & Trends

Table 11, below, provides a summary of the overall drivers and cost trends for operating expenditures.

Table 11: OM&A 2020-2024 Cost Drivers ($ Millions)

OM&A	Last Rebasing Year (2015 Board-Approved)	2016 Actual	2017 Actual	2018 Bridge Year	2019 Bridge Year	2020 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Opening Balance	243.9	244.0	249.8	255.3	261.2	268.2
Distribution Operations	-	10.3	(0.1)	0.5	4.1	(0.6)

[14] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015).

OM&A	Last Rebasing Year (2015 Board-Approved)	2016 Actual	2017 Actual	2018 Bridge Year	2019 Bridge Year	2020 Test Year
Customer Service and Communications	-	(2.7)	1.3	3.4	1.0	5.5
Human Resources and Safety	-	1.0	(0.5)	0.6	0.2	0.5
Information Technology	-	0.7	3.3	3.3	1.8	0.5
Common Corporate Costs	-	(1.2)	1.7	(2.3)	(0.6)	2.1
Facilities Management	-	0.4	(2.5)	(2.1)	0.2	0.6
Other Various	-	(2.7)	2.2	2.5	0.2	0.8
Closing Balance	**244.0**	**249.8**	**255.3**	**261.2**	**268.2**	**277.5**

For more information on Toronto Hydro's OM&A program cost drivers and trends, please see Exhibit 4A, Tab 2, Schedules 1-21.

6.2 Compensation

Toronto Hydro's forecasted total compensation cost for the 2020 test year is approximately $244.2 million, which represents an increase of approximately $33.1 million or 15.6 percent from 2015 actuals ($211.1 million). Please refer to Appendix 2K for more information on employee compensation and benefits.

7. COST OF CAPITAL

Toronto Hydro calculated its cost of capital based on the OEB's cost of capital guidance.[15] Toronto Hydro's debt to equity split for the test years is set at 60:40. The debt component in each year includes a deemed 4 percent short-term debt component.

[15] EB-2009-0084, Ontario Energy Board Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (December 11, 2009).

Toronto Hydro's long-term debt rate component is based on debt issued by its parent company in the public debt market. The weighted average debt rate is used instead of the OEB's deemed long-term debt rate.

Toronto Hydro's forecasted return on equity ("ROE") for the 2020 Test Year is based on the OEB's formulaic approach as outlined in the OEB's Cost of Capital Report.[16] For 2020, the ROE calculation uses the March 2018 bond yield spread[17] and the Ten-Year Government of Canada Bond Yield Forecast.[18]

Toronto Hydro uses the 2020 ROE forecast for the purpose of calculating revenue requirement for the 2020 Test Year (Exhibit 6, Tab 1) and the derivation of the C-factor in the Custom Price Cap Index (Exhibit 1B, Tab 4, Schedule 1). Toronto Hydro will rely on the deemed ROE approved by the OEB in late 2019, as part of the cost of capital parameters update for its 2020 rates, to determine the final revenue requirement for 2020 and the updated C-factor.

Table 12, below, provides the proposed capital structure and cost of capital parameters resulting in the Weighted Average Cost of Capital.

[16] Ibid.
[17] Difference between the average 30-Year A-Rated Canadian Utility bond yield from Bloomberg L.P. and the average 30-Year Government of Canada bond as published by the Bank of Canada.
[18] The average of the forecast Ten-Year Government of Canada bond yield as at December 31, 2019 and September 30, 2020 from Bloomberg L.P.

Table 12: Proposed Capital Structure and Cost of Capital Parameters

Capital Structure			Cost Rate
Debt			
Long-term Debt	56.00%	$2,584,564,841	3.71%
Short-term Debt	4.00%	$184,611,774	2.61%
Total Debt	60.0%	$2,769,176,616	3.64%
Equity			
Common Equity	40.00%	$1,846,117,744	8.82%
Preferred Shares	0.00%	$ -	
Total Equity	40.0%	$1,846,117,744	8.82%
Total / WACC		$4,615,294,360	5.71%

For more information on Toronto Hydro's Cost of Capital, see Exhibit 5, Tab 1, Schedule 1.

8. COST ALLOCATION AND RATE DESIGN

8.1 Cost Allocation

The 2020 base revenue requirement has been allocated to the utility's eight rate classes using the OEB's cost allocation model.[19] Toronto uses the latest version of this model, which includes the updated policy relating to the cost allocation for the Street Lighting class.[20] The resulting revenue to cost ratios for all classes are within the OEB's guidelines as established in EB-2010-0219.[21]

[19] EB-2010-0219, Ontario Energy Board Review of Electricity Distribution Cost Allocation Policy (March 31, 2011).
[20] EB-2012-0383, Ontario Energy Board Letter, Issuance of New Cost Allocation Policy for Street Lighting Rate Class (June 12, 2015).
[21] *Supra* note 9.

For more information on Toronto Hydro's cost allocation, please see Exhibit 7, Tab 1.

8.2 Rate Design

With the exception of Residential and Competitive Sector Multi-Unit Residential ("CSMUR") classes, Toronto Hydro proposes fixed and variable rates for all rate classes based on the current split of revenue generated through each of these components. For the Residential and CSMUR classes, 2020 is the final year of the implementation of the OEB's policy to set distribution rates for these classes on a fully fixed basis.[22]

Total bill impacts for all classes are below the 10 percent threshold, therefore mitigation measures are not required.

For more information on Toronto Hydro's rate design, please see Exhibit 8, Tab 1.

8.3 Specific Service Charges

Toronto Hydro updated some of its Specific Service Charges in its last 2015-2019 Rate Application.[23] In this Application, Toronto Hydro proposes no changes to these rates, subject to the following two exceptions. First, the utility is applying to update the wireline pole attachment rate to reflect OEB guidance in this area.[24] Toronto Hydro proposes to update its wireline pole attachment rate to $44.15 per pole per year effective January 1, 2020. This rate is calculated as the standard recommended rate of $43.63 provided by the OEB for 2019, and the application of 1.2 percent escalation (the

[22] EB-2012-0410, Ontario Energy Board, A New Distribution Rate Design for Residential Electricity Customers (April 2, 2015).
[23] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015), Exhibit 8, Tab 2, Schedule 1.
[24] EB-2015-0304, Ontario Energy Board Report, Wireline Pole Attachment Charges (March 22, 2018).

OEB's current inflation rate) for 2020. Toronto Hydro proposes to update this rate once the final OEB inflation factor for 2020 is determined.

Second, Toronto Hydro proposes to remove the following charge from its Tariff: Service Call- Customer Owned Equipment.

For more information on Toronto Hydro's Specific Service Charges, please see Exhibit 8, Tab 2.

9. DEFERRAL AND VARIANCE ACCOUNTS ("DVA")

Toronto Hydro proposes new rate riders to clear a number of DVA balances. Toronto Hydro also seeks approval to clear amounts relating to gains on sale of properties, accounts receivable credits, and excess expansion deposits.

The total net DVA balances proposed for clearance are $78.1 million (credit or refund) to customers beginning January 1, 2020.[25] The proposed disposition periods for all accounts is five years in order to smooth the impact of disposition. Toronto Hydro proposes to allocate the DVA balances to the customer classes based on the methodologies described in the OEB's Deferral and Variance Account Review ("EDDVAR").[26] For accounts where the EDDVAR indicated allocation was to be determined on a case-by-case basis, Toronto Hydro has proposed an allocator.

The above balances do not include clearance of Retail Settlement Variance Accounts ("RSVA"). Balances in these accounts as of the end of 2017 will be proposed for clearance in Toronto Hydro's 2019 Rate Application update. Toronto Hydro will update

[25] See Table 17 in Exhibit 9, Tab 1, Schedule 1.
[26] EB-2008-0046, Ontario Energy Board Deferral and Variance Account Review Initiative.

the RSVA balances at the close of 2018, and update its evidence to propose clearance of 2018 year-end balances at a later date.

Toronto Hydro proposes a single fixed rate rider for those classes that are charged a fully fixed distribution rate (Residential and CSMUR), and a single volumetric rate rider for all other classes for the clearance of all DVA amounts, with the exception of Stranded Meters which is to be recovered through a fixed charge for all applicable rate classes, as indicated in the OEB's Smart Meter Funding and Cost Recovery Guidelines. The impacts of all proposed rate riders combined with the distribution rate changes are discussed in Exhibit 8, Tab 1, Schedule 1.

Toronto Hydro is seeking OEB approval for the following new DVAs:

- Variance Account for Excess Expansion Deposits: Toronto Hydro requests a variance account to record the excess expansion deposits and to clear the balance to ratepayers through an OEB-approved rate rider in the current Application. The amount proposed for clearance is $5.5 million credit (refund) to customers; and
- Variance Accounts for Pension and Other Post-employment Benefits ("OPEB") Forecast Accrual versus Actual Cash Payment Differential Carrying Charges: As directed in the OEB's final report on the Regulatory Treatment of Pension and OPEB Costs,[27] Toronto Hydro will establish accounts to track the difference between the forecasted accrual amount in rates and actual cash payments made, with asymmetric carrying charges in favour of ratepayers applied to three differentials. Toronto Hydro will start using the three new accounts effective

[27] EB-2015-0040, Ontario Energy Board, Report on Regulatory Treatment of Pension and Other Post-employment Benefit (OPEBs) Costs (September 14, 2017) at p. 21.

January 1, 2020, but will not submit a draft accounting order as directed in the OEB report.[28] At a later time, Toronto Hydro will apply for disposition of the balance in the Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges account when the credit (refund) to customers is material.

Toronto Hydro is not seeking OEB approval to discontinue any DVAs.

For more information about Toronto Hydro's DVA accounts, and amounts proposed for clearance, please refer to Exhibit 9, Tab 1, Schedule 1.

[28] *Ibid*.

OPERATING ENVIRONMENT

Toronto Hydro-Electric System Limited ("Toronto Hydro") is the electricity distributor licensed (ED-2002-0497) by the Ontario Energy Board ("OEB") to serve the City of Toronto. Toronto Hydro is the successor to the six former hydro-electric commissions of the municipalities which amalgamated on January 1, 1998 to form the City of Toronto. For information about Toronto Hydro's Corporate Structure and Governance, please refer to Exhibit 1C, Tab 2.

Toronto Hydro is one of the largest municipal electrical distribution utility in North America and serves the largest city in Canada. In 2017, Toronto Hydro distributed 24.3 terawatt-hours of electricity representing approximately 18 percent of the electricity consumed in the province of Ontario, and served a peak demand of 4,980 megawatts.

Toronto Hydro serves two distinct customer demographic areas: (i) an urban centre in downtown Toronto; and (ii) a suburban area around downtown Toronto, which is often referred to as the Horseshoe. Toronto Hydro has approximately 768,000 customers of various classes, ranging from residential to general service and large use.[1]

The utility's service area includes some of Canada's largest banks, stock exchanges, major manufacturers, and other large customers that are sensitive to service interruptions. In addition, Toronto Hydro supplies electricity to numerous healthcare and long-term care facilities, data centres, schools (including colleges and universities),

[1] Toronto has over 2,900 high-rise multi-residential condominium and apartment building accounts, many of which are "bulk-metered". Taking these bulk-metered multi-residential buildings into account, Toronto Hydro's effective customer count exceeds 1 million customers.

Ontario's Provincial Legislature and Ministries, as well as Toronto's municipal government.

Toronto Hydro's distribution system consists of a mix of overhead, underground, secondary network and stations infrastructure. These systems operate at voltages of 27.6 kV, 13.8 kV, or 4.16 kV, and distribute power through a complex network of approximately 178,800 poles, 60,500 distribution transformers, 17,400 primary switches, 9,100 conductor-kilometres of overhead primary conductors, and 12,700 circuit-kilometres of underground primary cables. This network is composed of assets of varying vintages and types, reflective of the historical standards employed by the six pre-amalgamated utilities.

1. SERVICE TERRITORY

The City of Toronto is bounded by Lake Ontario to the South, Steeles Ave to the North, Mississauga (mainly Highway 427) to the West, and Scarborough/Pickering Townline to the East. A service territory map is filed at Exhibit 1C, Tab 1, Schedule 2.

2. NEIGHBOURING UTILITIES

Toronto Hydro's neighbouring electric distribution utilities are:

- To the north and west by Alectra Utilities Corp; and
- To the east, Veridian Connections Inc.

Toronto Hydro is not a host utility and there are no embedded utilities in Toronto Hydro's distribution service area.

3. TRANSMISSION ASSETS DEEMED DISTRIBUTION ASSETS

Toronto Hydro owns two transmission system terminal stations (one operational, one under construction) that have been deemed distribution assets, namely Cavanagh TS and Copeland TS, respectively. Toronto Hydro is not proposing any additional assets to be deemed as distribution assets as part of this application.

Toronto Hydro Service Territory



CORPORATE STRUCTURE AND GOVERNANCE

In accordance with s. 2.1.4 of the OEB's Filing Requirements, this schedule provides information about Toronto Hydro's organizational structure and corporate governance framework.[1]

1. CORPORATE STRUCTURE

1.1 Corporate Structure and Governance

Toronto Hydro Corporation ("THC") is a holding company, the sole shareholder of which is the City of Toronto, which wholly owns two subsidiaries (see Figure 1, below): Toronto Hydro-Electric System Limited, a local distribution company ("LDC") which distributes electricity and engages in conservation and demand management ("CDM") activities; and Toronto Hydro Energy Services Inc. ("TH Energy"), a company which provides street lighting and expressway lighting services in the City of Toronto (together, THC and its subsidiaries are hereby referred to as the "Company").

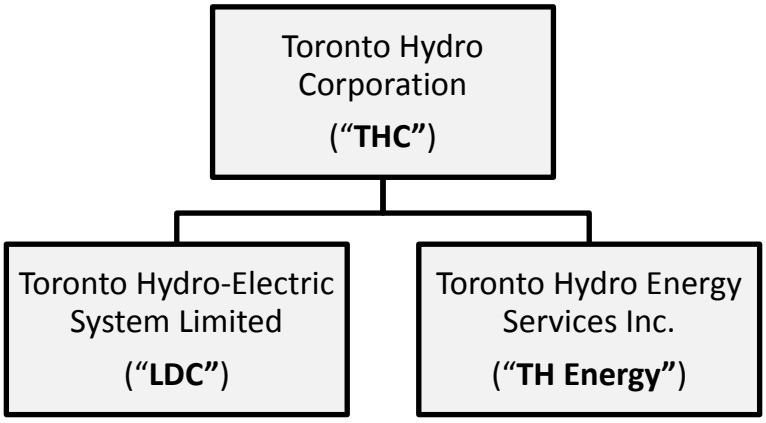


Figure 1: Toronto Hydro Corporate Organization Chart

[1] Ontario Energy Board Filing Requirements for Electricity Distribution Rate Applications, Chapter 2 (July 12, 2018).

Each of THC and its subsidiary entities have a Board of Directors, which is responsible for providing strategic guidance to management and supervising the business and affairs of their respective organizational segments. However, elements of the governance of the Company as a whole are undertaken at the THC level with its Board, and its standing committees each of which include representation from the LDC directors who are independent of THC. The THC Board has specific responsibility for approving the overall business strategy and related business plan of the Company which takes into account, among other things, the opportunities and risks of the businesses of the subsidiary entities, and approving the financing strategy.

As THC has no substantive business beyond the regulated activities of LDC, having elements of the corporate governance of LDC provided at the parent company level accomplishes the same objective as having corporate governance solely at the LDC level. Additionally, the LDC Board retains adequate scope for the exercise of independent judgment within the overall framework of good corporate governance of the Company. The LDC Board oversees the operations of the utility and its regulatory and public policy activities, asset planning, customer relations functions, retains decision-making authority related to approval of any dividends by the LDC, and approves its financial statements. The LDC Board also reviews and approves, in a manner consistent with the overall business plan and budget approved by the THC Board, significant corporate plans and initiatives, major acquisitions and dispositions and other significant matters of corporate strategy or policy.

This multi-layered corporate structure allows for matters of material importance to be dealt with at the most appropriate organizational level. A corporate entities

relationship chart, showing the extent to which THC is represented on the LDC's Board of Directors, is shown in Figure 2 below.

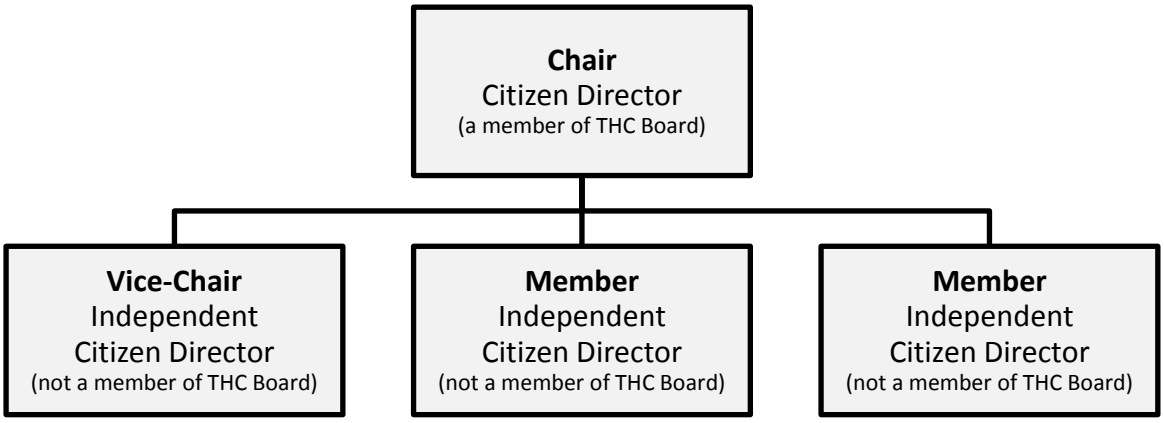


Figure 2: Toronto Hydro Corporate Entities Relationship Chart

1.2 Executive Team

THC's executive team is comprised of the Executive Vice-President and Chief Financial Officer ("CFO") and Executive Vice-President Regulatory Affairs and General Counsel, both of whom are accountable to the President and Chief Executive Officer ("CEO") of THC. The CEO of THC is also the President and CEO of the LDC and of TH Energy.

The LDC's executive management team consists of the following positions that are overseen directly by the CEO:

- Executive Vice-President and Chief Financial Officer, who is also an executive member of THC and of TH Energy;
- Executive Vice-President, Utility Innovation and Chief Conservation Officer;
- Executive Vice-President and Chief Engineering and Construction Officer;

- Executive Vice-President and Chief Customer Care, Electric Operations and Procurement Officer;
- Executive Vice-President and Chief Information Officer;
- Executive Vice-President and Chief Human Resources and Safety Officer; and
- Executive Vice-President, Regulatory Affairs and General Counsel, who is also an executive officer of THC and of TH Energy.

2. CORPORATE GOVERNANCE

2.1 Securities Law Requirements

THC is a reporting issuer in each province of Canada and issues debentures pursuant to a short form base shelf prospectus (dated May 8, 2017). For purposes of Canadian securities regulations, THC is a "venture issuer" (i.e. a reporting issuer that does not have any of its securities listed or quoted on the TSX or other marketplace specified under the Canadian Securities Administrators' National Instrument 51-102 *Continuous Disclosure Obligations*), and must comply with certain corporate governance and public disclosure requirements under applicable securities legislation. These requirements make the Company's operations, finances and governance practices, on a consolidated basis, subject to scrutiny from the Ontario Securities Commission ("OSC"), the investor marketplace and the broader public in a way not applicable to other privately-owned companies.

THC fulfills its securities law corporate governance and disclosure obligations, and in some cases, where in its best interests, even higher standards of governance. As a venture issuer, THC is exempt from the requirements of Part 3 of National Instrument 52-110 – *Audit Committees*, which mandates the composition of an issuer's audit committee. Nonetheless, THC's audit committee meets all of the mandated

requirements: it is composed of a minimum of three directors, and every audit committee voting member is a director of THC, is independent, and is financially literate. In addition, the audit committee includes representation from at least one LDC director who is independent of THC.

THC has filed an Annual Information Form ("AIF") in respect of each of the financial years ended December 31, 2004 through December 31, 2017, in accordance with National Instrument 51-102 - Continuous Disclosure Obligations. THC's AIF discloses material information about THC and its business to the public, including information about operations, prospects, risks, and other factors that impact the business of the Company as a whole. A copy of THC's 2017 AIF is filed at Exhibit 1C, Tab 3, Schedule 6.

In addition, to comply with National Instrument 58-101 - *Disclosure of Corporate Governance Practices*, THC provides extensive corporate governance disclosure in its AIF and annual Management Discussion and Analysis ("MD&A"). Such disclosure includes, amongst others, details about the following:

1) How the Board of Directors facilitates its exercise of independent supervision over management, including the identity and independence of its directors, and whether its directors are directors of any other reporting issuers and their identity;
2) Board of Directors written mandate or a description of how the board delineates its roles and responsibilities;
3) Written descriptions for the chair of the Board of Directors, the chair of each board committee and the CEO;
4) Board of Directors orientation and continuing education;

5) The promotion of a culture of ethical business conduct, including adoption of a written code for the directors, officers and employees;
6) The process for nominating new directors;
7) The process of determining CEO and director compensation;
8) Standing committees and their functions;
9) How the Board of Directors assesses whether it is performing effectively; and
10) Director term limits and other mechanisms of board renewal.

THC also provides disclosure in its AIF on the make-up of the Board of Directors (including percentage of female directors) and attendance of directors at the Board of Director and Committee meetings. The enhanced level of disclosure, in particular with respect to governance practices, required under securities legislation increases the transparency of the Company's operations and affairs, and facilitates effective monitoring of management by the Board and stakeholders.

As a financial oversight measure, and to comply with certification requirements in National Instrument 52-109 - *Certification of Disclosure in Issuers' Annual and Interim Filings*, all of THC's interim consolidated financial statements (i.e. including LDC's financial results), interim Management Discussion and Analysis (MD&A), AIFs, annual financial statements and annual MD&As are certified by the CEO and CFO. The CEO and CFO certify that the filings do not contain any misrepresentations and fairly present the financial condition, results of operations and cash flows of THC as of the date of and for the periods presented in the filings. The certification process is one example of the Company's system of internal checks and balances that fosters a culture of accountability amongst senior management. THC and LDC also maintain a significant

system of internal financial controls which are subject to internal and external audit to ensure that these certifications are accurate.

2.2 Shareholder Direction

As the sole shareholder of THC, the City of Toronto (the "Shareholder" or the "City") has adopted a Shareholder Direction which establishes, amongst other things, the following objectives and fundamental principles that govern the operations of the Company:

1) To operate the Company on an efficient and commercially prudent basis;
2) To optimize the Shareholder's return on equity and operate the Company with a view to meeting the financial performance objectives of the Shareholder as set out in the Shareholder Direction;
3) To provide a reliable, effective and efficient electricity distribution system that supports the electricity demands of residents and businesses in the City;
4) To operate the Company in an environmentally responsible manner consistent with the City's energy, climate change and urban forestry objectives and, as appropriate, utilizing emerging green technologies;
5) To ensure that the business is managed in material compliance with all law; and
6) To engage in recruitment and procurement practices designed to attract employees and suppliers from the City's diverse community.

The Shareholder Direction recognizes the central role of the Board of Directors under law, and does not operate as a unanimous shareholder declaration under the Ontario *Business Corporations Act* ("OBCA"). Though it reiterates the items for which shareholder approval is required under the OBCA as well as restricting some financial activities of THC, it emphasizes that the Board of Directors is responsible for determining and implementing the appropriate balance among the objectives and

fundamental principles specified in the Shareholder Direction. Ultimately, the City requires THC to operate on a commercially prudent and profitable basis in compliance with law, and expects the Board of Directors to provide stewardship and independently oversee management and operations in accordance with best corporate governance practices.

THC's economic relationship with the City of Toronto is governed principally by a dividend policy (the "Dividend Policy"), contained within the Shareholder Direction. The Dividend Policy sets an expectation, but does not create a legal requirement for the Board of Directors of THC to declare dividends. The LDC and THC Board of Directors keep a detailed record of the processes surrounding decisions relating to dividends paid by the respective corporation. In that regard, dividend checklists for each of the THC Board of Directors and the LDC Board of Directors have been developed (the "Dividend Checklists"). The Dividend Checklists specify that, before declaring a dividend, the directors must ensure that the applicable corporation meets statutory solvency and capital impairment tests.

At all times, Directors are required to exercise their discretion honestly and in good faith with a view to the best interests of the relevant corporation (fiduciary duty) and exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances (duty of care). When considering the best interests of the relevant corporation, directors are required to take into account the interests of various stakeholders, including shareholders, ratepayers, employees, and creditors. In the case of dividends paid by the LDC, Directors are obligated to balance the interests of the utility's shareholders against those of its ratepayers.

2.3 Board of Directors

THC's Board of Directors members are appointed by THC's sole shareholder, the City of Toronto. No members of management sit on the THC Board. Of the eleven directors currently on the THC Board of Directors, three are Councillors of the City (including one director who is the Mayor of the City or a member of City Council whom the Mayor recommends as his or her designate and who is appointed by City Council), and are not considered independent because of their positions. Eight of the eleven directors are not elected officials or employees of the City, and have no direct or indirect material relationship with THC and are independent within the meaning of applicable Canadian securities law. The Chair of the THC Board is an independent citizen director. As at December 31, 2017, female directors constituted 36.4 percent (four of eleven) of the members of the THC Board of Directors.

No members of management sit on the LDC Board of Directors. A majority of directors are independent, i.e. they are not elected officials or employees of the City or members of any affiliate of the LDC. Currently, one of the directors on the LDC Board of Directors is a citizen director who is also a member of the Board of Directors of THC.

2.3.1 Nomination of Directors

Pursuant to the Shareholder Direction, the City appoints directors who collectively represent a range of expertise including:

1) Experience on a public utility commission or board of a major corporation or other commercial enterprise;
2) Experience or knowledge with respect to:
    a) Corporate finance;
    b) Corporate governance;

c) Market development;
d) Large system operation and management;
e) Urban energy industries;
f) Public policy issues and the law relating to the Company and the electricity industry;
g) Environmental matters;
h) Labour relations;
i) Occupational health and safety issues;

3) Commercial sensitivity and acumen;
4) Independence of judgment;
5) Personal integrity; and
6) At least three directors with financial management expertise.

The Corporate Governance and Nominating Committee of the THC Board of Directors reviews a skills matrix for evaluation of all potential THC and LDC Board of Directors members. In the case of appointment of THC Directors, the matrix is provided to the City by the THC Board. The matrix's design reflects best practices for requirements for directors as recommended by the Institute of Corporate Directors.

THC appoints the LDC's Board of Directors from among the directors of THC and independent residents of Toronto who are not elected officials or employees of the City or any of its agencies or corporations. The Corporate Governance and Nominating Committee nominates independent candidates for appointment to the LDC Board of Directors for approval by the THC Board of Directors as required by the Affiliate Relationships Code, utilizing the board skills and competencies matrix developed by the Committee as well as expert external recruitment services. This ensures that the

directors have a mix of competencies and skills necessary to enable LDC's Board of Directors to properly discharge their responsibilities. Pursuant to the LDC's Board of Directors Mandate, the LDC Board of Directors is required to give due regard to the qualifications of the candidates including:

1) Experience on a public utility commission or board of a major corporation or other commercial enterprise and/or the completion of formal training in directorship / governance;
2) Experience in regulated electricity utility sector at a senior management level;
3) Experience at an executive level in resource and performance management / compensation, including ability to appoint and evaluate the performance of the CEO and senior executives; oversee strategic human resource management, including workforce planning, compensation models, and labour relations; and oversee large scale organizational change;
4) Educational background, including university degrees and professional designations;
5) Experience or knowledge with respect to:
    a) Strategic planning, including ability to identify and critically assess strategic opportunities and threats to the organization;
    b) Risk management, including ability to assess key risks to the organization on an enterprise basis and monitor the risk management framework systems;
    c) Corporate finance / accounting / audit / securities, including ability to analyze financial statements, assess financial viability, contribute to financial planning, oversee budgets, and oversee funding arrangements;
    d) Corporate governance;

e) Market development, innovation and development of new strategic business lines;
f) Large system operation and management;
g) Urban energy industries;
h) Public policy issues and laws relating to the Corporation and its subsidiary entities and the electricity industry;
i) Environmental matters, including experience in environmental management;
j) Labour relations;
k) Occupational health and safety issues;
l) Information technology governance, including privacy, data management and security;
m) Legal and regulatory compliance, including ability to monitor compliance of legal and regulatory requirements;
n) Stakeholder engagement / advocacy / communications, including ability to effectively engage and communicate to industry stakeholders and advocate on behalf of the organization;

6) The following interpersonal skills and attributes:
a) Leadership, including ability to make, and take responsibility for, decisions and take necessary actions in the best interest of the organization, set appropriate Board and organizational culture and represent the organization favourably;
b) Personal integrity / ethics, including understanding and fulfilling the duties and responsibilities of a director, being transparent and declaring any activities or conduct that might be a potential conflict, and maintaining Board confidentiality;

c) Communications skills, including ability to listen constructively and appropriately debate others' viewpoints, develop and deliver cogent arguments, and communicate effectively with a broad range of stakeholders;
d) Constructive questioning, including preparedness to ask questions and challenge management and peer directors in a constructive and appropriate manner;
e) Critical and innovative thinking/decision making, including ability to critically analyze complex and detailed information, readily distill key issues, and develop innovative approaches and solutions to problems;
f) Influencing and negotiating, including ability to negotiate outcomes and influence others to agree with those outcomes and gain stakeholder support for the Board's decisions;
g) Crisis management, including ability to constructively manage crises, provide leadership around solutions and contribute to communications strategy with stakeholders;
h) Individual and team contribution, including ability to work as part of a team, and demonstrate the passion and time to make a genuine and active contribution to the Board and the organization;
i) Commercial sensitivity and acumen; and
j) Independence of judgement

7) At least one director with financial management expertise.

2.3.2 Exercise of Independent Judgment

No members of management sit on the Boards of THC or LDC. The Board of Directors for each of THC and LDC has a number of practices and policies in place to facilitate its

ability to act independently of senior management and to ensure that its behaviour and decision-making processes are objective, responsible, and effective.

- **In Camera Board Meetings:** Each of the Boards of Directors meets regularly in the absence of management to discuss the management of the Company. A portion of each Board and Board committee meeting is reserved for Directors to meet without management present.
- **Board of Directors Mandates:** Each the THC and LDC Board of Directors has adopted a written mandate providing clear direction on the appropriate expectations and standards to be met by Directors, including with respect to independence. For example, the mandates specifically require the Directors, in undertaking their responsibilities and overseeing and authorizing the activities of the Company, to consider the interests of its customers as well as considering and balancing the interests of such other stakeholders as appropriate in the circumstances.
- **Outside Advisors:** Under their respective mandates, each of the Board of Directors of THC and LDC is authorized to retain independent legal counsel and other outside advisors if it considers this appropriate. Each of the LDC and THC Boards also has unrestricted access to the officers of the Company and are authorized to invite officers and employees of the Company and others to attend or participate in its meetings and proceedings if it considers this appropriate.
- **Internal Audit Function***:* The internal audit department provides independent, objective assurance and consulting services to evaluate and improve the effectiveness of the Company's risk management, internal control procedures and governance processes. The internal audit department's work is overseen by the Audit Committee of the Board of Directors of THC. To facilitate independence, the Vice President, Audit and Corporate Compliance of LDC has

unrestricted access to any member of the Board of Directors, as required. The Vice President, Audit and Corporate Compliance meets independently with the members of the Audit Committee on a regular basis and has a reporting relationship to the Chair of the Audit Committee.

- **Corporate Governance and Nominating Committee***:* The Corporate Governance and Nominating Committee facilitates the periodic assessment of the performance of the Board of Directors of THC, LDC and Board committees and reports the results of that assessment to the Boards.
- **Position Descriptions***:* A written position description has been developed for the Chair of each of the THC and LDC Boards which provides direction in the undertaking of these roles. In each case, the Chair is responsible for reporting to the Board, leading the directors and managing the day-to-day activities of the Board. The Chair is also responsible for engaging in discussions with the shareholder and its representatives as are necessary and desirable, maintaining an active and cooperative relationship with the affiliate Boards, the CEO and other senior management, acting as the principal interface between the Board and the CEO, and providing advice and counsel to the CEO and other senior management. The THC Board has also developed written position descriptions for the chair of each of the standing committees and the CEO.

2.3.3 Board of Directors Mandate

THC and LDC Board of Directors have adopted a written mandate which is reviewed periodically and revised as required.

2.3.4 Orientation and Continuing Education

Upon joining the Board of Directors of THC and/or LDC, each new director is given an orientation session with a comprehensive set of materials designed to provide him/her with a summary of the key organizational, financial, regulatory, reporting, planning and operational aspects of the Company. Orientation also engages Directors of THC and/or LDC with organizational representatives in these key areas and a key executive is appointed for ongoing responsibility with each Board and standing Committee. Directors have access to a variety of internal and external resources on topics related to THC's and LDC's businesses, as well as relating to the responsibilities of directors such as fiduciary obligations, issues of confidentiality and privilege, and public disclosure and whistleblowing requirements. Directors also have the opportunity to attend continuing education programs run by external or internal service providers such as the Institute of Corporate Directors.

2.3.5 Ethical Business Conduct

All employees, officers and directors of THC and LDC are required to comply with the principles set out in the written Code of Business Conduct and Whistleblower Procedure (the "Code"). The Code was implemented in 2004, and is periodically reviewed and re-approved by the Board of Directors of THC. The Code of Business Conduct is included in new directors' orientation materials and each director completes training connected therewith and signs an acknowledgement that he or she will comply with the Code.

2.3.6 Board Committees

THC's Board of Directors has established three standing committees to assist the THC and LDC Boards in fulfilling their responsibilities: the Audit Committee, the Corporate Governance and Nominating Committee, and the Human Resources and Environment

Committee. The standing committees are each composed of at least three directors of THC. In addition, each standing committee includes representation from at least one director of the LDC who is not also a director of THC. This ensures independent exercise of oversight by the LDC over all utility functions while allowing effective and efficient governance to be maintained for the Toronto Hydro organization as a whole.
Each committee has a written charter that establishes the committee's purpose, composition and responsibilities.

- **Audit Committee:** oversees the adequacy and effectiveness of financial reporting, accounting systems, internal financial control structures and financial risk management systems. Among other things, the Audit Committee reviews THC's and LDC's quarterly and annual financial statements (as well as financial statements prepared in connection with securities offerings or required by applicable regulatory authorities), reviews the audit plans of the external auditors, and oversees the internal audit of THC and LDC. All of the voting members of the Audit Committee are independent and financially literate in accordance with sections 1.4 and 3.1 of National Instrument 52-110 on Audit Committees. Of note, the committee includes at least one representative from the LDC who is not also a director of THC.
- **Corporate Governance and Nominating Committee:** advises the THC and LDC Boards of Directors with respect to matters relating to the corporate governance of the Company, including Board and committee composition and mandates, facilitates the periodic assessment of the performance and effectiveness of the THC and LDC Boards and the standing Board committees, and advises the boards on procedures to ensure that the THC and LDC Boards of Directors function independently from management. The Corporate Governance and Nominating Committee also nominates independent candidates for appointment to the LDC

Board of Directors for approval by the THC's Board of Directors. The Corporate Governance and Nominating Committee also reviews and approves all orientation and education materials and programs for new and current directors undertaken by management. The majority of members of the Corporate Governance and Nominating Committee are independent citizen directors who are not elected officials or employees of the City. Of note, the committee includes at least one representative from the LDC who is not also a director of THC.

- **Human Resources and Environment Committee:** assists the THC Board of Directors and the LDC Board of Directors with the recruitment, assessment and compensation of the CEO, oversees succession planning, reviews and approves the compensation of the executive officers, oversees executive compensation disclosure under applicable securities laws, and advises the boards of directors regarding the compensation structure, benefit plans and programs of the Company. The Human Resources and Environment Committee is also responsible for reviewing and approving the parameters of collective bargaining negotiations, the oversight of health and safety related functions, oversight of human resources related matters and the oversight of environmental related matters and processes of the Company. The majority of members of the Human Resources and Environment Committee are independent citizen directors who are not elected officials or employees of the City. Of note, the committee includes at least one representative from the LDC who is not also a director of THC.

FINANCIAL INFORMATION OVERVIEW

In accordance with section 2.1.9 of the OEB's Filing Requirements,[1] Exhibit 1C, Tab 4 provides the following financial information:

- Accounting Standards (Schedule 2);
- Toronto Hydro's Audited Financial Statements for 2015, 2016 and 2017 (Schedule 3);
- Reconciliation of the financial results shown in the Audited Financial Statements with regulatory financial results for 2015, 2016 and 2017 (Schedule 4);
- Toronto Hydro Corporation's Management's Discussion & Analysis for 2017 (Schedule 5);
- Toronto Hydro Corporation's Annual Information Form for 2017 (Schedule 6);
- Public Offering Information (Schedule 7);
- Rating Agency Reports (Schedule 8);
- Existing Accounting Orders and Departures from the Uniform System of Accounts ("USoA") (Schedule 9); and
- Toronto Hydro's Annual Report for 2017 (Schedule 10).

Toronto Hydro adopted and applied three new accounting standards, effective January 1, 2018 as required by the International Accounting Standards Board. These include International Financial Reporting Standard ("IFRS") 9 *Financial Instruments* ("IFRS 9"), IFRS 15 *Revenue from Contracts with Customers* ("IFRS 15"), and IFRS 16 *Leases* ("IFRS 16").

[1] Ontario Energy Board Filing Requirements for Electricity Distribution Rate Applications – Chapter 2 (July 12, 2018).

1. IFRS 9

IFRS 9 introduces some new classification and measurement categories for financial assets, which impacts the measurement basis of the financial assets. The changes do not have a significant impact on the measurement of Toronto Hydro's financial instruments. IFRS 9 also introduces impairment rules that dictate the allowance for doubtful accounts should be measured at an amount equal to the lifetime expected credit losses for accounts receivable and unbilled revenue rather than the previous incurred loss model. The new impairment model also includes qualitative information regarding its assessment including forward-looking information. The adoption of IFRS 9 led to a $0.3 million decrease to opening retained earnings. There is no impact to revenue requirement.

2. IFRS 15

IFRS 15 introduces a five-step model that applies to customer contracts and contains new rules on the timing and measurement of revenue recognition. Revenue is recognized at a point in time or over time depending on when control of goods or services has been transferred to the customer. Upon adoption of IFRS 15, the only difference was a reclassification between Energy Sales and Energy Purchases. There is no impact to revenue requirement.

3. IFRS 16

IFRS 16 eliminates the previous concepts of operating and finance leases and requires all contracts meeting the definition of a lease to be recognized on the balance sheet as a right-of-use asset and lease liability, with the exception of short-term leases and low-value leases.

Previously the assets related to finance leases were recognized as part of rate base. Given the adoption of IFRS 16, Toronto Hydro is proposes to continue to recognize the right-of-use assets related to leases as part of rate base. Upon the adoption of IFRS 16 on January 1, 2018, Toronto Hydro recognized $1.6 million as right-of-use assets and $1.6 million as lease liabilities for property leases.

ACCOUNTING STANDARDS

Toronto Hydro adopted International Financial Reporting Standards ("IFRS") for financial reporting purposes in the year beginning on January 1, 2015, and the utility continues the apply these standards through the bridge and test years. The Audited Financial Statements provided in Exhibit 1C, Tab 3, Schedule 3 have been prepared in accordance with IFRS.

The OEB Accounting Procedures Handbook ("APH") directs distributors to use Modified IFRS ("MIFRS") for regulatory purposes. Toronto Hydro adopted MIFRS for regulatory purposes in the year beginning on January 1, 2015. This application represents Toronto Hydro's second rebasing application under MIFRS.

Toronto Hydro confirms that it has segregated the accounting of all its non-rate regulated business activities from rate regulated activities. Also, there have been no changes to Toronto Hydro's capitalization policy (Exhibit 2A, Tab 5, Schedule 1) and depreciation and amortization practices (Exhibit 4B, Tab 1, Schedule 1) since the last rebasing application.

AUDITED FINANCIAL STATEMENTS

In accordance with s. 2.1.9 of the OEB's Filing Requirements,[1] this schedule provides Toronto Hydro-Electric System Limited's Audited Financial Statements, as follows:

- Appendix A: 2015 Audited Financial Statements
- Appendix B: 2016 Audited Financial Statements
- Appendix C: 2017 Audited Financial Statements

[1] Ontario Energy Board, Filing Requirements for Electricity Distributor Rate Applications, Chapter 2 (July 12, 2018).

Financial Statements

Toronto Hydro-Electric System Limited

DECEMBER 31, 2015 and 2014

See attached Glossary for abbreviations used in the audited financial statements.

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INDEPENDENT AUDITORS' REPORT

To the Shareholder of Toronto Hydro-Electric System Limited

We have audited the accompanying financial statements of Toronto Hydro-Electric System Limited, which comprise the balance sheets as at December 31, 2015, December 31, 2014 and January 1, 2014, the statements of income, comprehensive income, changes in equity and cash flows for the years ended December 31, 2015 and December 31, 2014, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Toronto Hydro-Electric System Limited as at December 31, 2015, December 31, 2014 and January 1, 2014, and its financial performance and its cash flows for the years ended December 31, 2015 and December 31, 2014 in accordance with International Financial Reporting Standards**.**

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants
March 2, 2016
Toronto, Canada

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KPMG Canada provides services to KPMG LLP.

Toronto Hydro-Electric System Limited

BALANCE SHEETS

[in millions of Canadian dollars]

	As at December 31, 2015 $	As at December 31, 2014 $	As at January 1, 2014 $
		[note 26]	*[note 26]*
ASSETS			
Current			
Cash and cash equivalents	**-**	84.7	15.7
Accounts receivable *[notes 5 and 15[b]]*	**190.0**	205.7	198.9
Unbilled revenue *[note 15[b]]*	**319.5**	306.6	326.1
Income tax receivable	**9.0**	0.2	0.3
Materials and supplies	**9.8**	8.6	8.6
Other assets *[note 6]*	**9.9**	9.9	8.8
Assets held for sale	**-**	4.0	-
Total current assets	**538.2**	619.7	558.4
Property, plant and equipment *[note 7]*	**3,561.9**	3,224.5	2,820.8
Intangible assets *[note 8]*	**199.3**	198.7	171.5
Deferred tax assets *[note 21]*	**114.3**	143.1	132.1
Other assets *[note 6]*	**1.2**	1.2	0.9
Total assets	**4,414.9**	4,187.2	3,683.7
Regulatory balances *[note 9]*	**241.7**	197.1	88.3
Total assets and regulatory balances	**4,656.6**	4,384.3	3,772.0
LIABILITIES AND EQUITY			
Current			
Bank indebtedness	**188.9**	-	-
Advance from related party *[note 23]*	**-**	308.0	150.0
Accounts payable and accrued liabilities *[note 10]*	**471.6**	512.1	426.5
Customer deposits	**37.5**	38.5	37.3
Deferred revenue *[note 11]*	**3.7**	2.2	-
Deferred conservation credit *[note 3[b]]*	**17.9**	-	20.0
Other liabilities *[note 24]*	**3.2**	2.6	2.1
Notes payable to related party *[notes 12 and 23]*	**60.0**	60.0	60.0
Total current liabilities	**782.8**	923.4	695.9
Notes payable to related party *[notes 12 and 23]*	**1,876.0**	1,632.2	1,433.2
Customer deposits	**9.9**	4.7	7.4
Deferred revenue *[note 11]*	**100.3**	71.4	45.7
Post-employment benefits *[note 13]*	**296.5**	287.4	236.0
Other liabilities *[note 24]*	**4.9**	8.0	14.5
Total liabilities	**3,070.4**	2,927.1	2,432.7
Commitments, contingencies and subsequent events *[notes 2, 24 and 25]*			
Equity			
Share capital *[note 17]*	**556.3**	556.3	556.3
Retained earnings	**845.5**	715.1	605.2
Contributed surplus	**12.8**	12.8	12.8
Total equity	**1,414.6**	1,284.2	1,174.3
Total liabilities and equity	**4,485.0**	4,211.3	3,607.0
Regulatory balances *[note 9]*	**171.6**	173.0	165.0
Total liabilities, equity and regulatory balances	**4,656.6**	4,384.3	3,772.0

See accompanying notes to the financial statements.

Toronto Hydro-Electric System Limited

STATEMENTS OF INCOME

[in millions of Canadian dollars]

Year ended December 31	**2015** **$**	2014 **$**
		[note 26]
Revenues		
Energy sales	**2,925.6**	2,655.0
Distribution revenue	**555.4**	555.1
Other *[note 18]*	**48.3**	51.7
	3,529.3	3,261.8
Expenses		
Energy purchases	**2,898.5**	2,700.4
Operating expenses *[note 19]*	**259.0**	258.1
Depreciation and amortization *[notes 7 and 8]*	**192.8**	183.5
	3,350.3	3,142.0
Finance costs *[note 20]*	**73.2**	64.4
Gain on disposals of property, plant and equipment	**10.1**	1.5
Income before income taxes	**115.9**	56.9
Income tax expense *[note 21]*	**31.5**	13.9
Net income	**84.4**	43.0
Net movements in regulatory balances, net of tax *[note 9]*	**46.0**	66.9
Net income after net movements in regulatory balances	**130.4**	109.9

STATEMENTS OF COMPREHENSIVE INCOME

[in millions of Canadian dollars]

Year ended December 31	**2015** **$**	2014 **$**
		[note 26]
Net income after net movements in regulatory balances	**130.4**	109.9
Other comprehensive income		
Items that will not be reclassified to income or loss		
Remeasurements of post-employment benefits, net of tax (2015 - $nil, 2014 - $12.2) *[note 13]*	-	(33.9)
Net movements in regulatory balances related to OCI, net of tax (2015 - $nil, 2014 - $12.2) *[note 9]*	-	33.9
Other comprehensive income, net of tax	-	-
Total comprehensive income	**130.4**	109.9

See accompanying notes to the financial statements.

Toronto Hydro-Electric System Limited

STATEMENTS OF CHANGES IN EQUITY

[in millions of Canadian dollars]

Year ended December 31	**2015** **$**	2014 **$**
		[note 26]
Share capital ***[note 17]***	**556.3**	556.3
Retained earnings, beginning of year	**715.1**	605.2
Net income after net movements in regulatory balances	**130.4**	109.9
Retained earnings, end of year	**845.5**	715.1
Contributed surplus	**12.8**	12.8
Total equity	**1,414.6**	1,284.2

See accompanying notes to the financial statements.

Toronto Hydro-Electric System Limited

STATEMENTS OF CASH FLOWS

[in millions of Canadian dollars]

Year ended December 31	**2015** **$**	2014 $
		[note 26]
OPERATING ACTIVITIES		
Net income after net movements in regulatory balances	**130.4**	109.9
Adjustments		
Depreciation and amortization *[notes 7 and 8]*	**192.8**	183.5
Amortization of deferred revenue *[note 11]*	**(2.2)**	(0.7)
Finance costs	**73.2**	64.4
Income tax expense	**31.5**	13.9
Post-employment benefits	**9.1**	5.3
Gain on disposals of property, plant and equipment	**(10.1)**	(1.5)
Other	**0.7**	(1.8)
Capital contributions received *[note 11]*	**33.0**	28.2
Net change in other non-current assets and liabilities	**(0.6)**	(6.9)
Increase (decrease) in customer deposits	**4.2**	(1.5)
Changes in non-cash working capital balances *[note 22]*	**20.5**	36.3
Income tax paid	**(8.5)**	(10.1)
Net movements in regulatory balances *[note 9]*	**(46.0)**	(66.9)
Net cash provided by operating activities	**428.0**	352.1
INVESTING ACTIVITIES		
Purchase of property, plant and equipment *[note 22]*	**(547.9)**	(523.3)
Purchase of intangible assets *[note 22]*	**(21.1)**	(46.8)
Proceeds on disposals of property, plant and equipment	**14.4**	1.8
Net cash used in investing activities	**(554.6)**	(568.3)
FINANCING ACTIVITIES		
Increase (decrease) in advance from related party *[note 23]*	**(308.0)**	158.0
Increase in notes payable to related party *[note 12]*	**243.1**	198.4
Repayment of finance lease liability	**(2.9)**	(2.2)
Interest received	**1.4**	1.0
Interest paid	**(80.6)**	(70.0)
Net cash provided by (used in) financing activities	**(147.0)**	285.2
Net increase (decrease) in cash and cash equivalents (bank indebtedness) during the year	**(273.6)**	69.0
Cash and cash equivalents, beginning of year	**84.7**	15.7
Cash and cash equivalents (bank indebtedness), end of year	**(188.9)**	84.7

See accompanying notes to the financial statements.

1. NATURE OF BUSINESS

On June 23, 1999, Toronto Hydro-Electric System Limited ["LDC"] was incorporated under the *Business Corporations Act* (Ontario), and is wholly-owned by Toronto Hydro Corporation [the "Corporation"]. The incorporation was required in accordance with the Electricity Act. LDC is domiciled in Canada and its registered office is located at 14 Carlton Street, Toronto, Ontario, M5B 1K5.

LDC distributes electricity to customers located in the City of Toronto [the "City"] and is subject to rate regulation. LDC is also engaged in the delivery of CDM activities.

2. BASIS OF PRESENTATION

LDC's audited financial statements have been prepared in accordance with IFRS with respect to the preparation of annual financial information. These are LDC's first financial statements prepared in accordance with IFRS and IFRS 1 *First-time Adoption of IFRS* ["IFRS 1"], and applying the accounting policies described in note 4. LDC's date of transition to IFRS and its opening IFRS balance sheet is as at January 1, 2014. An explanation of how the transition to IFRS has affected the reported financial position, financial performance and cash flows of LDC is provided in note 26.

These financial statements are presented in Canadian dollars, LDC's functional currency, and have been prepared on the historical cost basis, except for the valuation of post-employment benefits.

LDC has evaluated the events and transactions occurring after the balance sheet date through March 2, 2016 when LDC's financial statements were authorized for issue by LDC's Board of Directors, and identified the events and transactions which required recognition in the financial statements and/or disclosure in the notes to the financial statements *[notes 3, 4 and 9]*.

3. REGULATION

In April 1999, the Government of Ontario began restructuring the province's electricity industry. Under regulations passed pursuant to the restructuring, LDC and other electricity distributors purchase electricity from the wholesale market administered by the IESO and recover the costs of electricity and certain other costs in accordance with procedures mandated by the OEB.

The OEB has regulatory oversight of electricity matters in Ontario. The OEB Act sets out the OEB's authority to issue a distribution licence that must be obtained by owners or operators of an electricity distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, separation of accounts for distribution and other activities, and requirements for rate-setting and other legal filings.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to approve the amounts paid to non-contracted generators, the responsibility to provide rate protection for rural or remote electricity customers, and the responsibility for ensuring that electricity distribution companies fulfill their obligations to connect and service customers.

LDC is required to charge its customers for the following amounts (all of which, other than distribution rates, represent a pass-through of amounts payable to third parties):

- *Commodity Charge* – The commodity charge represents the market price of electricity consumed by customers and is passed through the IESO to operators of generating stations. It includes the global adjustment, which represents the difference between the market price of electricity and the rates paid to regulated and contracted generators.

- *Retail Transmission Rate* – The retail transmission rate represents the costs incurred in respect of the transmission of electricity from generating stations to local distribution networks. Retail transmission rates are passed through to operators of transmission facilities.

- *WMS Charge* – The WMS charge represents various wholesale market support costs, such as the cost of the IESO to administer the wholesale electricity system, operate the electricity market, and maintain reliable operation of the provincial grid. Wholesale charges are passed through to the IESO.

- *Distribution Rate* – The distribution rate is designed to recover the costs incurred by LDC in delivering electricity to customers, including the OEB-allowed cost of capital. Distribution rates are regulated by the OEB and include fixed and variable (usage-based) components, based on a forecast of LDC's customers and load.

LDC is required to satisfy and maintain prudential requirements with the IESO, which include credit support with respect to outstanding market obligations in the form of letters of credit, cash deposits or guarantees from third parties with prescribed credit ratings.

The IESO and the OPA were merged under the name IESO starting on January 1, 2015. The IESO supports CDM plans during their design and throughout their entire lifespan, including the sharing of best practices, offering of program delivery services, and the building of awareness in the marketplace through marketing and communication. The IESO provides centralized customer service and technical support, market research, program evaluation and measurement, and training.

a) Electricity Distribution Rates

Regulatory developments in Ontario's electricity industry, including current and possible future consultations between the OEB and interested stakeholders, may affect LDC's electricity distribution rates and other permitted recoveries in the future.

The OEB's regulatory framework for electricity distributors is designed to support the cost-effective planning and operation of the electricity distribution network and to provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price.

The OEB typically regulates the electricity rates for distributors using a combination of detailed cost of service reviews and IRM adjustments. A cost of service review uses a future test-year to establish rates, and provides for revenues required to recover the forecasted costs of providing the regulated service, and a fair and reasonable return on rate base (i.e. the aggregate of approved investment in PP&E and intangible assets excluding work in progress, less accumulated depreciation and amortization and unamortized capital contributions from customers, plus an allowance for working capital). IRM adjustments are typically used for one or more years following a cost of service review and provide for adjustments to rates based on an inflationary factor net of a productivity factor and an efficiency factor as determined relative to other electricity distributors.

Administratively, the OEB currently regulates the electricity rates for distributors through one of three specific rate-setting methods: Price Cap Incentive Rate-setting (suitable for most distributors), CIR (suitable for distributors with large or highly variable capital requirements), and Annual Incentive Rate-setting Index (suitable for distributors requiring limited rate adjustments). Under each of these methods, the OEB also allows recovery of costs arising from significant events satisfying certain criteria which are considered external to the regulatory regime and beyond the control of management.

Under the Price Cap Incentive Rate-setting method, rates are set on a single forward test-year cost of service basis for the first year and indexed for four subsequent years through an industry-standard IRM adjustment (using the 4th generation price cap index formula). Under this method, the ICM is available to address any incremental capital investment needs that may arise during the term. In order to determine whether a distributor is eligible for the ICM,

the OEB conducts a review of the distributor's ICM application by way of a detailed examination of evidence and consideration of a number of criteria, such as materiality, need and prudence.

Under the CIR method, rates are set for a minimum period of five years, typically on a forward test-year cost of service basis for the first year with subsequent annual adjustments based on a distributor-specific custom index. The particular mechanics through which rates are set and adjusted are determined by the OEB on a case-by-case basis.

The Annual Incentive Rate-setting Index method sets a distributor's rates through an industry-standard IRM adjustment (using a limited form of the 4th generation price cap index formula) for one or more years.

Under each method, actual operating conditions may vary from forecasts such that actual returns achieved can differ from approved returns. Approved electricity rates are generally not adjusted as a result of actual costs or revenues being different from forecasted amounts, other than for certain prescribed costs that are eligible for deferral for future collection from, or refund to, customers.

On May 10, 2012, LDC filed an application for electricity distribution rates for 2012, 2013 and 2014 using the IRM framework, including the filing of an ICM application. On April 2, 2013, the OEB approved new rates for LDC effective June 1, 2013, which reflected approved capital expenditures amounting to $203.3 million for 2012 and $484.2 million for 2013. In a separate decision rendered on December 19, 2013, the OEB approved capital expenditures amounting to $398.8 million for 2014.

On January 16, 2014, the OEB approved LDC's request for disposition of the smart meter regulatory balances related to smart meter installations in 2008, 2009 and 2010 through two separate rate riders effective May 1, 2014 *[note 9[e]]*. The first rate rider related to the recovery of $23.9 million, representing the cumulative revenue requirement net of recoveries from an existing smart meter rate rider. This existing smart meter rate rider was discontinued when the new rate riders became effective. The second rate rider related to the recovery of $9.6 million, representing the forecasted 2014 incremental revenue requirement.

On July 31, 2014, LDC filed a rate application with the OEB under the CIR method which sought approval of LDC's 2015 test-year revenue requirement on a cost of service basis and the corresponding electricity distribution rates effective May 1, 2015, and the subsequent annual rate adjustments based on a custom index specific to LDC for the period commencing on January 1, 2016 and ending on December 31, 2019. The rate application included requests for approval of capital expenditures of approximately $2.5 billion over the 2015-2019 period. The rate application also sought approval to include in LDC's rate base capital amounts that were prudently incurred prior to 2015, subject to review by the OEB. In addition, LDC sought approval to recover the net book value of stranded meters *[note 9[e]]*.

On August 3, 2011, the OEB issued its final decision allowing the transfer of a portion of the street lighting assets from Toronto Hydro Energy Services Inc. ["TH Energy"] to a new wholly-owned legal entity (1798594 Ontario Inc.), and for LDC to amalgamate with the new legal entity. The OEB decided that the rate base, revenue requirement and rate consequences of the transfer would be decided at LDC's next cost of service or rebasing rate application. On January 1, 2012, the Corporation completed the asset transfer and amalgamation. The purchase price for such assets as of January 1, 2012, including a post-closing adjustment, was $42.5 million, subject to transaction costs. LDC sought a final determination of the rate base, revenue requirement and rate consequences of the street lighting transfer in the rate application filed on July 31, 2014.

On April 28, 2015, the OEB declared LDC's existing rates as interim rates, effective May 1, 2015, pending a final CIR decision and rate order. On December 29, 2015, the OEB issued its CIR decision and on March 1, 2016, the OEB issued its CIR rate order, both in relation to the rate application filed on July 31, 2014. The CIR decision and rate order approved a rate base of $3,232.0 million and revenue requirement of $633.1 million for 2015, and rates calculated on that basis. The CIR decision and rate order also approved subsequent annual rate adjustments based on a custom index for the period commencing on January 1, 2016 and ending on December 31, 2019. The OEB-approved revenue requirement generates an increase in funded capital expenditures over the CIR period.

The OEB approved new deferral and variance accounts including accounts to capture variances related to revenue requirement for ICM capital work undertaken from 2012 to 2014 and revenue requirement associated with capital work during the CIR term. The OEB approved recovery of the $15.8 million forecasted net book value relating to the stranded meters. The OEB also approved foregone revenue rate riders for the May 1, 2015 to February 29, 2016 period as well as other requested rate riders *[note 9]*. In addition, the OEB approved the transfer of the street lighting assets into rate base effective January 1, 2015 at a transfer price of $39.8 million, representing the opening net book value of the assets in 2015. The financial impact of the OEB's CIR decision and rate order has been reflected in these financial statements.

The rates for 2015 and 2016 were implemented on March 1, 2016, with effective dates of May 1, 2015 and January 1, 2016, respectively *[note 9[b]]*.

b) CDM Activities

On March 31, 2010, the Minister of Energy and Infrastructure of Ontario, under the guidance of sections 27.1 and 27.2 of the OEB Act, directed the OEB to establish CDM targets to be met by electricity distributors. Accordingly, on November 12, 2010, the OEB amended LDC's distribution licence to require LDC, as a condition of its licence, to achieve 1,304 GWh of energy savings and 286 MW of summer peak demand savings over the period beginning January 1, 2011 through December 31, 2014.

Effective January 1, 2011, LDC entered into an agreement with the OPA in the amount of approximately $50.0 million to deliver CDM programs extending from January 1, 2011 to December 31, 2014 to support achievement of the mandatory CDM targets described above. LDC applied to the OPA in March 2014 to revise the program administration budget to $45.8 million for the delivery of CDM programs from 2011 to 2014. All programs delivered are fully funded and paid in advance by the OPA. Amounts received but not yet spent are presented on the balance sheets under current liabilities as deferred conservation credit. Upon the expiration of the agreement, LDC is required to repay to the OPA any excess funding received for program administration less any cost efficiency incentives. As at December 31, 2014, LDC estimated that approximately $5.7 million qualified as cost efficiency incentives, and approximately $4.9 million was repayable to the OPA for the remaining program administration budget, included within accounts payable and accrued liabilities *[note 4[i]]*. On May 8, 2015, the IESO confirmed both the cost efficiency incentives of $5.7 million and the amount payable by LDC of $4.9 million plus applicable taxes, which was paid in July 2015.

On December 21, 2012, the Minister of Energy of Ontario issued a direction to the OPA under subsection 25.32(4.1) of the Electricity Act to extend the funding time period for OPA-contracted province-wide CDM initiatives under the Green Energy Act framework to December 31, 2015. Funding and respective targets for CDM programs approved pursuant to the 2011-2014 OPA agreement with in-service dates in 2015 would be allocated toward the 2011-2014 program. On March 18, 2015, LDC received approval from the IESO for separate funding of $11.2 million relating to these transitional CDM programs for 2015. Funding was fully received in the third quarter of 2015.

On March 26, 2014, the Minister of Energy of Ontario, under the guidance of sections 27.1 and 27.2 of the OEB Act, directed the OEB to amend the licence of each licensed electricity distributor to require the electricity distributor, as a condition of its licence, to make CDM programs available to customers in its licensed service area and to do so in relation to each customer segment in its service area, over the period beginning January 1, 2015 through December 31, 2020. On March 31, 2014, the Minister of Energy of Ontario issued a direction to require the OPA to coordinate, support and fund the delivery of CDM programs through electricity distributors. The objective of the new CDM efforts is to reduce electricity consumption in the Province of Ontario by a total of 7 terawatt hours between January 1, 2015 and December 31, 2020, of which LDC's share is approximately 1,576 GWh of energy savings.

On November 13, 2014, LDC entered into an energy conservation agreement with the OPA for the delivery of CDM programs over the 2015-2020 period with funding of approximately $400.0 million, which included participant

incentives and LDC's program administration costs. LDC provided the IESO with its plan for achieving its CDM target and received conditional approval as of March 26, 2015.

Under the energy conservation agreement, LDC has an option to submit a joint CDM plan with one or more distribution companies. On April 30, 2015, LDC submitted a joint CDM plan with Oakville Hydro Electricity Distribution Inc. for the delivery of CDM programs over the 2015-2020 period, to replace the CDM plan that had been conditionally approved as of March 26, 2015, and received approval from the IESO with combined funding of approximately $425.0 million and an energy savings target of approximately 1,668 GWh. The programs under the joint CDM plan for Oakville Hydro Electricity Distribution Inc. started on January 1, 2016. LDC received $17.2 million as at December 31, 2015 and $1.5 million subsequent to December 31, 2015 from the IESO for the delivery of CDM programs under the energy conservation agreement. Amounts received but not yet spent are presented on the balance sheets under current liabilities as deferred conservation credit.

LDC can choose between full cost recovery funding, pay-for-performance funding, or a combination of both, on a CDM program by program basis. Under the full cost recovery funding method, the IESO reimburses LDC for all adequately documented incurred costs, with an option to receive a portion of its funding in advance. Cost efficiency incentives may be awarded if LDC's electricity savings meet or exceed certain CDM plan targets for programs under the full cost recovery funding method, with a mid-term review to be performed by the IESO for the 2015-2017 period. Under the pay-for-performance funding method, LDC receives payment in arrears based on verified electricity savings achieved with various options for frequency of payment. The programs under the joint CDM plan with Oakville Hydro Electricity Distribution Inc. are only being offered under the full cost recovery funding method.

4. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

a) Regulation

The following regulatory treatments have resulted in accounting treatments which differ from those prescribed by IFRS for enterprises operating in an unregulated environment and regulated entities that did not adopt IFRS 14 *Regulatory Deferral Accounts* ["IFRS 14"]:

Regulatory Balances

In January 2014, the IASB issued IFRS 14 as an interim standard giving entities conducting rate-regulated activities the option of continuing to recognize regulatory balances according to their previous GAAP. Regulatory balances provide useful information about LDC's financial position, financial performance and cash flows. IFRS 14 is restricted to first-time adopters of IFRS and remains in force until either repealed or replaced by permanent guidance on rate-regulated accounting from the IASB. The standard is effective for annual periods beginning on or after January 1, 2016. Early adoption is permitted. LDC has elected to early adopt IFRS 14.

LDC has determined that certain debit and credit balances arising from rate-regulated activities qualify for the application of regulatory accounting treatment in accordance with IFRS 14 and the accounting principles prescribed by the OEB in the "Accounting Procedures Handbook for Electricity Distributors". Under rate-regulated accounting, the timing and recognition of certain expenses and revenues may differ from those otherwise expected under other IFRS in order to appropriately reflect the economic impact of regulatory decisions regarding LDC's regulated revenues and expenditures. These amounts arising from timing differences are recorded as regulatory debit and credit balances on LDC's balance sheets, and represent existing rights and obligations regarding cash flows expected to be recovered from or refunded to customers, based on decisions and approvals by the OEB. Regulatory balances can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment or if future OEB direction is determined by management to be probable. In the event that the disposition of these balances are assessed to no longer be probable based on management's judgment, the balances are recorded in LDC's statements of income in the period when the assessment is made. Regulatory balances that do not meet the definition of an asset or liability under any other IFRS are segregated on the balance sheets, on the statements of income as net movements in regulatory balances, net of tax, and on the statements of

comprehensive income as net movements in regulatory balances related to OCI, net of tax. The netting of regulatory debit and credit balances is not permitted. The measurement of regulatory balances is subject to certain estimates and assumptions, including assumptions made in the interpretation of the OEB's regulations and decisions.

b) Cash and cash equivalents

Cash and cash equivalents include cash in bank accounts and short-term investments with terms to maturity of 90 days or less from their date of acquisition. On the statements of cash flows, cash and cash equivalents (bank indebtedness) include bank overdrafts that are repayable on demand and form an integral part of LDC's cash management.

c) Accounts receivable and unbilled revenue

Accounts receivable is recorded at the invoiced amount and overdue amounts bear interest at OEB-approved rates. Unbilled revenue is recorded based on an estimated amount for electricity delivered and for other services provided and not yet billed. The estimate is primarily based on the customers' previous billings with adjustments mainly for assumptions related to seasonality and weighted average price. The carrying amount of accounts receivable and unbilled revenue is reduced through an allowance for doubtful accounts, if applicable, and the amount of the related impairment loss is recognized in the statements of income. The impairment loss is the difference between an asset's carrying amount and the estimated future cash flows. When LDC considers that there are no realistic prospects of recovery of the financial assets, the relevant amounts are written off. If the amount of impairment loss subsequently decreases due to an event occurring after the impairment was recognized, then the previously recognized impairment loss is reversed through net income.

Accounts receivable and unbilled revenue are assessed at each reporting date to determine whether there is objective evidence of impairment, which includes default or delinquency by a debtor, indications that a debtor or issuer will enter bankruptcy, and adverse changes in the payment status of borrowers or issuers. Accounts receivable and unbilled revenue that are not individually assessed for impairment are collectively assessed for impairment by grouping together receivables with similar risk characteristics, and LDC considers historical trends on the timing of recoveries and the amount of loss incurred, as well as current economic and credit conditions.

d) Materials and supplies

Materials and supplies consist primarily of small consumable materials mainly related to the maintenance of the electricity distribution infrastructure. LDC classifies all major construction related components of its electricity distribution infrastructure to PP&E. Materials and supplies are carried at the lower of cost and net realizable value, with cost determined on a weighted average cost basis net of a provision for obsolescence.

e) Property, plant and equipment

PP&E are measured at cost less accumulated depreciation and any accumulated impairment losses, if applicable. For PP&E used in rate-regulated activities, LDC elected to use the exemption available for assets subject to rate regulation such that the previous US GAAP carrying amount became the deemed cost under IFRS at the date of transition *[note 26]*. The cost of PP&E represents the original cost, consisting of direct materials and labour, contracted services, borrowing costs, and directly attributable overhead. Subsequent costs are capitalized only if it is probable that the future economic benefits associated with the expenditure will flow to LDC and the costs can be measured reliably. If significant parts of an item of PP&E have different useful lives, then they are accounted for as separate major components of PP&E. The carrying amount of an item of PP&E is derecognized on disposal of the asset or when no future economic benefits are expected to accrue to LDC from its continued use. Any gain or loss arising on derecognition is recorded in the statements of income in the period in which the asset is derecognized. The gain or loss on disposal of an item of PP&E is determined as the difference between the sale proceeds less the carrying amount of the asset and costs of removal and is recognized in the statements of income.

Depreciation begins when an asset becomes available for use. Depreciation is provided on a straight-line basis over the estimated useful lives at the following annual rates:

Distribution assets:	
Distribution lines	1.7% to 5.0%
Transformers	3.3% to 5.0%
Meters	2.5% to 6.7%
Stations	2.5% to 10.0%
Buildings	1.3% to 5.0%
Equipment and other:	
Assets under finance lease	1.0% to 14.3%
Other capital assets	4.0% to 25.0%

Leased assets are depreciated over the shorter of the lease term and their useful lives unless it is reasonably certain that LDC will obtain ownership by the end of the lease term. Assets under finance lease included a 99-year land lease. Construction in progress relates to assets not currently available for use and therefore is not depreciated. The depreciation method and useful lives are reviewed each financial year-end and adjusted if appropriate. There are no residual values for items of PP&E.

f) Intangible assets

Intangible assets are measured at cost less accumulated amortization and any accumulated impairment losses, if applicable. For intangible assets used in rate-regulated activities, LDC elected to use the exemption available for assets subject to rate regulation such that the previous US GAAP carrying amount became the deemed cost under IFRS at the date of transition *[note 26]*.

Amortization begins when an asset becomes available for use. Amortization is provided on a straight-line basis over the estimated useful lives at the following annual rates:

Computer software	10.0% to 25.0%
Contributions	4.0%

Software in development and contributions for work in progress relate to assets not currently available for use and therefore are not amortized. Contributions represent payments made to HONI for dedicated infrastructure in order to receive connections to transmission facilities. The amortization method and useful lives are reviewed each financial year-end and adjusted if appropriate.

g) Impairment of non-financial assets

LDC reviews the carrying amounts of its non-financial assets other than materials and supplies and deferred tax assets at each reporting date to determine whether there is any indication of impairment, in which case the assets' recoverable amounts are estimated. For impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent on the cash inflows of other assets or CGUs. LDC has determined that its assets are a single CGU due to interdependencies of its assets to generate cash flows. An impairment loss is recognized if the carrying amount of an asset or CGU exceeds its recoverable amount. Impairment losses are recognized in the statements of income, and are allocated to reduce the carrying amounts of assets in the CGU on a pro rata basis. An impairment loss recognized in prior periods is reversed when an asset's recoverable amount has increased, but not exceeding the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior years.

h) Capitalized borrowing costs

Borrowing costs directly attributable to the acquisition, construction or development of qualifying assets that necessarily take a substantial period of time to get ready for their intended use are capitalized, until such time as the assets are substantially ready for their intended use. The interest rate for capitalization is LDC's weighted average cost of borrowing, and is applied to the carrying amount of the construction-in-progress assets or assets under development including borrowing costs previously capitalized, net of capital contributions received. Borrowing costs are included in PP&E and intangible assets for financial reporting purposes, and charged to operations through depreciation and amortization expense over the useful lives of the related assets.

i) Revenue recognition

Revenues from energy sales and distribution are recorded on the basis of cyclical billings and include an estimated amount for electricity delivered and not yet billed. These revenues are impacted by energy demand primarily driven by outside temperature, and customer class usage patterns and composition.

Energy sales arise from charges to customers for electricity consumed, based on regulated rates. LDC applies judgment to determine whether revenues are recorded on a gross or net basis. These charges are passed through to customers over time and are considered revenue by LDC due to the collection risk of the related balances. LDC has primary responsibility for the delivery of electricity to the customer. The difference between the amounts charged by LDC to customers, based on regulated rates, and the corresponding cost of electricity and non-competitive electricity service costs billed monthly by the IESO to LDC, is recorded as a settlement variance. In accordance with IFRS 14, this settlement variance is presented within regulatory balances on the balance sheets and within net movements in regulatory balances, net of tax on the statements of income.

Distribution revenue is recorded based on OEB-approved distribution rates to recover the costs incurred by LDC in delivering electricity to customers. Distribution revenue also includes revenue related to the collection of OEB-approved rate riders.

Other revenue, which includes revenue from services ancillary to the distribution of electricity and revenue from demand billable activities, is recognized as the services are rendered. When services are made up of different components which are not separately identifiable, the related other revenues are recognized on a straight-line basis over the term of the contract. Capital contributions received from electricity customers to construct or acquire PP&E for the purpose of connecting a customer to a network are recorded as deferred revenue and amortized into other revenue at an equivalent rate to that used for the depreciation of the related PP&E. Revenue not yet recognized from demand billable activities is also included within deferred revenue.

Revenues and costs associated with CDM programs are presented using the net basis of accounting. Cost efficiency incentives related to the CDM programs, included as part of other revenue, are recognized when it is probable that future economic benefits will flow to the entity and the amount can be reasonably measured.

j) Financial instruments

All financial assets are classified as "Loans and Receivables" and all financial liabilities are classified as "Other Financial Liabilities". These financial instruments are recognized initially at fair value adjusted for any directly attributable transaction costs. Subsequently, they are measured at amortized cost using the effective interest method less any impairment for the financial assets. The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's length transaction between willing parties.

LDC uses the following methods and assumptions to estimate the fair value of each class of financial instruments for which carrying amounts are included in the balance sheets:

- Cash, cash equivalents and short-term investments are classified as "Loans and Receivables" and are measured at fair value. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Accounts receivable and unbilled revenue are classified as "Loans and Receivables" and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Bank indebtedness is classified as "Other Financial Liabilities" and is initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Advance from related party is classified as "Other Financial Liabilities" and is initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amount approximates fair value due to the short maturity of this instrument.

- Accounts payable and accrued liabilities are classified as "Other Financial Liabilities" and are initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value because of the short maturity of these instruments.

- Customer deposits are classified as "Other Financial Liabilities" and are initially measured at fair value. Subsequent measurements are recorded at cost plus accrued interest. The carrying amounts approximate fair value taking into account interest accrued on the outstanding balance.

- Obligations under finance leases are classified as "Other Financial Liabilities" and are initially measured at fair value, or the present value of the minimum lease payments if lower. Subsequent measurements are based on a discounted cash flow analysis and approximate the carrying amount as management believes that the fixed interest rates are representative of current market rates.

- Notes payable to related party are classified as "Other Financial Liabilities" and are initially measured at fair value. The carrying amounts are carried at amortized cost, based on the fair value of the notes payable at issuance, which was the fair value of the consideration received adjusted for transaction costs. The fair values of the notes payable are based on the present value of contractual cash flows, discounted at LDC's current borrowing rate for similar debt instruments *[note 15[a]]*. Debt issuance costs incurred in connection with LDC's debt offerings are capitalized as part of the carrying amount of the notes payable and amortized over the term of the related notes payable, using the effective interest method, and the amortization is included in finance costs.

k) Fair value measurements

LDC utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. A fair value hierarchy exists that prioritizes observable and unobservable inputs used to measure fair value. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect LDC's assumptions with respect to how market participants would price an asset or liability. The fair value hierarchy includes three levels of inputs that may be used to measure fair value:

- Level 1: Unadjusted quoted prices in active markets for identical assets or liabilities. An active market for the asset or liability is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis;

- Level 2: Other than quoted prices included within Level 1 that are observable for the assets or liabilities, either directly or indirectly; and

- Level 3: Unobservable inputs, supported by little or no market activity, used to measure the fair value of the assets or liabilities to the extent that observable inputs are not available.

l) Employee benefits

(i) Short-term employee benefits

Short-term employee benefit obligations that are due to be settled wholly within twelve months after the end of the annual reporting period in which the employees render the related service are measured on an undiscounted basis and are expensed as the related service is provided. A liability is recognized for the amount expected to be paid if LDC has a present legal or constructive obligation to pay this amount as a result of past service provided by the employee and the obligation can be estimated reliably.

(ii) Multi-employer pension plan

LDC's full-time employees participate in a pension plan through OMERS. The OMERS plan is a jointly sponsored, multi-employer defined benefit pension plan established in 1962 by the Province of Ontario for employees of municipalities, local boards and school boards. Both participating employers and employees are required to make plan contributions equally based on participating employees' contributory earnings, and share equally in funding gains or losses. The plan assets and pension obligations are not segregated in separate accounts for each member entity. The OMERS plan is accounted for as a defined contribution plan and the contribution payable is recognized as an employee benefit expense in the statements of income in the period when the service is rendered by the employee, since it is not practicable to determine LDC's portion of pension obligations or of the fair value of plan assets.

(iii) Post-employment benefits other than pension

LDC has a number of unfunded benefit plans providing post-employment benefits (other than pension) to its employees. LDC pays certain medical, dental and life insurance benefits under unfunded defined benefit plans on behalf of its retired employees. LDC also pays accumulated sick leave credits, up to certain established limits based on service, in the event of retirement, termination or death of certain employees.

The cost of providing benefits under the benefit plans is actuarially determined using the projected unit credit method, which incorporates management's best estimate of future salary levels, retirement ages of employees, health care costs, and other actuarial factors. Changes in actuarial assumptions and experience adjustments give rise to actuarial gains and losses. Actuarial gains and losses on medical, dental and life insurance benefits are recognized in OCI as they arise. Actuarial gains and losses related to rate-regulated activities are subsequently reclassified from OCI to a regulatory balance on the balance sheets. Actuarial gains and losses on accumulated sick leave credits are recognized in the statements of income in the period in which they arise.

The measurement date used to determine the present value of the benefit obligation is December 31 of the applicable year. The latest actuarial valuation was performed as at January 1, 2014.

m) Customer deposits

Security deposits from electricity customers are cash collections to guarantee the payment of electricity bills. The electricity customer security deposits liability includes related interest amounts owed to the customers with a corresponding amount charged to finance costs. Deposits that are refundable upon demand are classified as a current liability.

Security deposits on offers to connect are cash collections from specific customers to guarantee the payment of additional costs relating to expansion projects. This liability includes related interest amounts owed to the customers

with a corresponding amount charged to finance costs. Deposits are classified as a current liability when LDC no longer has an unconditional right to defer payment of the liability for at least 12 months after the reporting period.

n) Income taxes

Under the Electricity Act, LDC is required to make PILs to the Ontario Electricity Financial Corporation. These payments are calculated in accordance with the ITA and the TA as modified by regulations made under the Electricity Act and related regulations. This effectively results in LDC paying income taxes equivalent to what would be imposed under the Federal and Ontario Tax Acts.

LDC uses the liability method of accounting for income taxes. Under the liability method, current income taxes payable are recorded based on taxable income. LDC recognizes deferred tax assets and liabilities for the future tax consequences of events that have been included in the financial statements or income tax returns. Deferred tax assets and liabilities are determined based on the difference between the carrying value of assets and liabilities on the balance sheets and their respective tax basis, using the tax rates enacted or substantively enacted by the balance sheet date that are in effect for the year in which the differences are expected to reverse. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when it is probable that they will be realized, and are measured at the best estimate of the tax amount expected to be paid to or recovered from the taxation authorities. Deferred tax assets are reviewed at each reporting date and reduced to the extent that it is no longer probable that the related tax benefits will be realized. The calculation of current and deferred taxes requires management to make certain judgments with respect to changes in tax interpretations, regulations and legislation, and to estimate probable outcomes on the timing and reversal of temporary differences and tax authority audits of income tax.

Rate-regulated accounting requires the recognition of regulatory balances and related deferred tax assets and liabilities for the amount of deferred taxes expected to be refunded to or recovered from customers through future electricity distribution rates. A gross up to reflect the income tax benefits associated with reduced revenues resulting from the realization of deferred tax assets is recorded within regulatory credit balances. Deferred taxes that are not included in the rate-setting process are charged or credited to the statements of income.

The benefits of the refundable and non-refundable apprenticeship and other ITCs are credited against the related expense in the statements of income.

o) Use of estimates

The preparation of LDC's financial statements in accordance with IFRS requires management to make estimates and assumptions which affect the application of accounting policies, reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses for the year. The estimates are based on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities as well as for identifying and assessing the accounting treatment with respect to commitments and contingencies. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the IESO, the Ontario Ministry of Energy or the Ontario Ministry of Finance.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to estimates are recognized prospectively. Assumptions and estimates with a significant risk of resulting in a material adjustment within the next financial year are used in the following:

- Note 4[a] – Recognition and measurement of regulatory balances;
- Note 4[i] – Revenue recognition – measurement of unbilled revenue, determination of the CDM incentive;
- Notes 4[e] and 4[f] – Determination of useful lives of depreciable assets;
- Notes 4[l] and 13 – Measurement of post-employment benefits – key actuarial assumptions;

- Notes 4[n] and 21 – Recognition of deferred tax assets – availability of future taxable income against which deductible temporary differences and tax loss carryforwards can be used; and
- Note 25 – Recognition and measurement of provisions and contingencies.

p) Future accounting pronouncements

A number of new standards, amendments and interpretations are not yet effective for the year ended December 31, 2015, and have not yet been applied in preparing these financial statements. LDC continues to analyze these standards and has determined that the following could have an impact on its financial statements.

Disclosure Initiative

In December 2014, the IASB issued Disclosure Initiative (Amendments to IAS 1 *Presentation of Financial Statements*). These amendments improve the existing presentation and disclosure requirements and encourage entities to apply professional judgment regarding disclosure and presentation in their financial statements. These amendments are effective for annual periods beginning on or after January 1, 2016. LDC expects these amendments to have no material impact on its financial statements.

Revenue from Contracts with Customers

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers* ["IFRS 15"], which replaces existing revenue recognition guidance, including IAS 18 *Revenue* and IFRIC 18 *Transfers of Assets from Customers* ["IFRIC 18"]. IFRS 15 contains a single model that applies to contracts with customers with two approaches for recognizing revenue: at a point in time or over time. The model features a contract-based five-step analysis of transactions to determine whether revenue should be recognized and the respective timing and amount. New estimates and judgmental thresholds have been introduced, which may affect the amount and/or timing of revenue recognized. The new standard does not apply to insurance contracts, financial instruments or lease contracts, which fall in the scope of other IFRS. On July 22, 2015, the IASB confirmed a one-year deferral of the effective date of IFRS 15 to annual periods beginning on or after January 1, 2018. LDC is currently evaluating the impact of the new standard.

Financial Instruments

In July 2014, the IASB issued the final version of IFRS 9 *Financial Instruments* ["IFRS 9"], which replaces IAS 39 *Financial Instruments: Recognition and Measurement* ["IAS 39"]. IFRS 9 includes revised guidance on the classification and measurement of financial instruments, including a new expected credit loss model for measuring impairment on financial assets, and new general hedge accounting requirements. It also carries forward the guidance on recognition and derecognition of financial instruments from IAS 39. The standard is effective for annual periods beginning on or after January 1, 2018, and will be applied retrospectively with some exceptions. LDC is currently evaluating the impact of the new standard.

Leases

In January 2016, the IASB issued IFRS 16 *Leases* ["IFRS 16"], which replaces IAS 17 *Leases* ["IAS 17"]. IFRS 16 provides a single lessee accounting model, requiring the recognition of assets and liabilities for all leases, unless the lease term is twelve months or less or the underlying asset has a low value. Lessor accounting remains largely unchanged from IAS 17 and the distinction between operating and finance leases is retained. In addition, lessees will recognize a front-loaded pattern of expense for most leases, even when they pay constant annual rentals. The standard is effective for annual periods beginning on or after January 1, 2019, and will be applied retrospectively with some exceptions. Early adoption is permitted if IFRS 15 has been adopted. LDC is currently evaluating the impact of the new standard.

5. ACCOUNTS RECEIVABLE

Accounts receivable consists of the following:

	December 31 2015 $	December 31 2014 $	January 1 2014 $
Trade receivables	**183.9**	195.0	195.7
Due from related parties *[note 23]*	**4.2**	8.2	2.1
Other	**1.9**	2.5	1.1
	190.0	205.7	198.9

6. OTHER ASSETS

Other assets consist of the following:

	December 31 2015 $	December 31 2014 $	January 1 2014 $
Prepaid expenses	**9.5**	9.6	8.5
Deferred financing costs	**1.6**	1.5	1.2
Total other assets	**11.1**	11.1	9.7
Less: Current portion of other assets relating to:			
Prepaid expenses	**9.5**	9.6	8.5
Deferred financing costs	**0.4**	0.3	0.3
Non-current portion of other assets	**1.2**	1.2	0.9

7. PROPERTY, PLANT AND EQUIPMENT

PP&E consist of the following:

	Distribution assets $	Land and buildings $	Equipment and other $	Construction in progress $	Total $
Cost or deemed cost					
Balance as at January 1, 2014	2,284.6	111.7	87.7	336.8	2,820.8
Additions	428.4	34.3	19.6	94.4	576.7
Disposals and retirements	(27.3)	(3.6)	(0.1)	—	(31.0)
Transfers to assets held for sale	—	(4.8)	—	—	(4.8)
Balance as at December 31, 2014	2,685.7	137.6	107.2	431.2	3,361.7
Additions	**368.0**	**67.6**	**12.5**	**65.1**	**513.2**
Disposals and retirements	**(26.5)**	**(2.1)**	—	—	**(28.6)**
Balance as at December 31, 2015	**3,027.2**	**203.1**	**119.7**	**496.3**	**3,846.3**
Accumulated depreciation					
Balance as at January 1, 2014	—	—	—	—	—
Depreciation	107.2	7.9	24.2	—	139.3
Disposals and retirements	(1.1)	(0.1)	(0.1)	—	(1.3)
Transfers to assets held for sale	—	(0.8)	—	—	(0.8)
Balance as at December 31, 2014	106.1	7.0	24.1	—	137.2
Depreciation	**118.9**	**9.1**	**22.0**	—	**150.0**
Disposals and retirements	**(2.4)**	**(0.4)**	—	—	**(2.8)**
Balance as at December 31, 2015	**222.6**	**15.7**	**46.1**	—	**284.4**
Carrying amount					
Balance as at January 1, 2014	2,284.6	111.7	87.7	336.8	2,820.8
Balance as at December 31, 2014	2,579.6	130.6	83.1	431.2	3,224.5
Balance as at December 31, 2015	**2,804.6**	**187.4**	**73.6**	**496.3**	**3,561.9**

As at December 31, 2015, Equipment and other included assets under finance lease with cost of $18.2 million [December 31, 2014 - $18.2 million; January 1, 2014 - $16.1 million] and accumulated depreciation of $6.0 million [December 31, 2014 - $3.8 million; January 1, 2014 - $nil]. For the year ended December 31, 2015, LDC recorded depreciation expense of $2.2 million [2014 - $3.8 million] related to assets under finance lease.

For the year ended December 31, 2015, borrowing costs in the amount of $7.0 million [2014 - $4.9 million] were capitalized to PP&E and credited to finance costs, with an average capitalization rate of 3.74% [2014 - 3.84%].

Construction in progress additions are net of transfers to the other PP&E categories.

8. INTANGIBLE ASSETS

Intangible assets consist of the following:

	Computer software	Contributions	Software in development	Contributions for work in progress	Total
	$	$	$	$	$
Cost or deemed cost					
Balance as at January 1, 2014	69.6	19.0	11.7	71.2	171.5
Additions	17.1	0.9	1.5	27.3	46.8
Balance as at December 31, 2014	86.7	19.9	13.2	98.5	218.3
Additions	**14.9**	**1.8**	**(1.4)**	**5.8**	**21.1**
Balance as at December 31, 2015	**101.6**	**21.7**	**11.8**	**104.3**	**239.4**
Accumulated amortization					
Balance as at January 1, 2014	—	—	—	—	—
Amortization	18.7	0.9	—	—	19.6
Balance as at December 31, 2014	18.7	0.9	—	—	19.6
Amortization	**19.4**	**1.1**	**—**	**—**	**20.5**
Balance as at December 31, 2015	**38.1**	**2.0**	**—**	**—**	**40.1**
Carrying amount					
Balance as at January 1, 2014	69.6	19.0	11.7	71.2	171.5
Balance as at December 31, 2014	68.0	19.0	13.2	98.5	198.7
Balance as at December 31, 2015	**63.5**	**19.7**	**11.8**	**104.3**	**199.3**

For the year ended December 31, 2015, borrowing costs in the amount of $3.8 million [2014 - $3.2 million] were capitalized to intangible assets and credited to finance costs, with an average capitalization rate of 3.74% [2014 - 3.84%].

Software in development and contributions for work in progress additions are net of transfers to the other intangible asset categories.

Computer software is externally acquired. The remaining amortization periods for computer software and contributions range from less than one year to 7 years, and from 13 to 24 years, respectively.

9. REGULATORY BALANCES

Debit balances consist of the following:

	January 1, 2015	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2015	Remaining recovery/ reversal period (months)
	$	$	$	$	$	
Post-employment benefits	**81.2**	**—**	**—**	**—**	**81.2**	(1)
Foregone revenue	**—**	**61.1**	**—**	**—**	**61.1**	46[2]
IFRS transitional adjustments	**24.2**	**4.7**	**—**	**—**	**28.9**	46[2]
Settlement variances	**51.7**	**(26.4)**	**—**	**—**	**25.3**	(3)
Stranded meters	**14.4**	**—**	**—**	**—**	**14.4**	46[2]
Smart meters	**20.9**	**—**	**(10.9)**	**—**	**10.0**	16
LRAM	**—**	**9.1**	**—**	**—**	**9.1**	(4)
Named properties	**—**	**5.8**	**—**	**—**	**5.8**	46[2]
Capital contributions	**—**	**1.9**	**—**	**—**	**1.9**	46[2]
OPEB cash versus accrual	**—**	**1.8**	**—**	**—**	**1.8**	(5)
Other	**4.7**	**2.0**	**(0.1)**	**(4.4)**	**2.2**	10[2]
	197.1	**60.0**	**(11.0)**	**(4.4)**	**241.7**	

	January 1, 2014	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2014	Remaining recovery/ reversal period (months)
	$	$	$	$	$	
Post-employment benefits	36.9	45.3	(1.0)	—	81.2	(1)
Settlement variances	5.8	45.9	—	—	51.7	(3)
IFRS transitional adjustments	0.9	23.3	—	—	24.2	48[6]
Smart meters	25.2	9.5	(13.8)	—	20.9	28
Stranded meters	16.9	—	(2.5)	—	14.4	60[6]
Other	2.6	2.5	(0.2)	(0.2)	4.7	12-60[6]
	88.3	126.5	(17.5)	(0.2)	197.1	

(1) LDC did not seek recovery from the OEB as changes in underlying assumptions may reduce the balance in the account. LDC expects to recover this regulatory balance as per OEB direction when recovery is sought.

(2) Disposition period is based on the CIR decision and rate order *[note 3[a]]*.

(3) Disposition period of the low voltage variances of $1.3 million over 10 months is based on the CIR decision and rate order *[note 3[a]]*. LDC intends to apply for disposition of remaining settlement variances in its next rate applications.

(4) Disposition period of the 2011-2013 LRAM of $3.6 million over 10 months is based on the CIR decision and rate order *[note 3[a]]*. LDC intends to apply for disposition of the LRAM balances for 2014 and 2015 at a later date, for which timing is currently unknown.

(5) LDC intends to apply for disposition of the balance following the OEB consultation process on pension and OPEB, for which timing is currently unknown.

(6) Disposition period was based on the CIR application pending as at December 31, 2014 *[note 3[a]]*.

Credit balances consist of the following:

	January 1, 2015	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2015	Remaining recovery/ reversal period (months)
	$	$	$	$	$	
Deferred taxes	**143.4**	**(28.6)**	**—**	**—**	**114.8**	(1)
Tax-related variances	**25.3**	**1.2**	**—**	**—**	**26.5**	10-34[(2)]
Derecognition	**—**	**9.9**	**—**	**—**	**9.9**	(3)
ICM	**2.3**	**—**	**7.4**	**—**	**9.7**	(3)
Gain on disposal	**—**	**5.9**	**—**	**—**	**5.9**	(4)
Capital-related revenue requirement	**—**	**2.8**	**—**	**—**	**2.8**	(3)
Other	**2.0**	**—**	**—**	**—**	**2.0**	10[(5)]
	173.0	**(8.8)**	**7.4**	**—**	**171.6**	

	January 1, 2014	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2014	Remaining recovery/ reversal period (months)
	$	$	$	$	$	
Deferred taxes	132.0	11.4	—	—	143.4	(1)
Tax-related variances	25.2	2.9	(2.8)	—	25.3	12-36[(6)]
ICM	6.0	(25.1)	21.4	—	2.3	(3)
Other	1.8	0.2	0.2	(0.2)	2.0	12[(6)]
	165.0	(10.6)	18.8	(0.2)	173.0	

(1) LDC did not apply for disposition of the balance since it is being reversed through timing differences in the recognition of deferred tax assets.
(2) Disposition period of the revision of prior year tax position account over 34 months and the income tax variance account over 10 months is based on the CIR decision and rate order *[note 3[a]]*.
(3) LDC intends to apply for disposition of the balance at a later date, for which timing is currently unknown.
(4) Disposition period for forecasted net gains of 34 months is based on the CIR decision and rate order *[note 3[a]]*. LDC intends to apply for disposition of the variance account at a later date, for which timing is currently unknown.
(5) Disposition period is based on the CIR decision and rate order *[note 3[a]]*.
(6) Disposition period was based on the CIR application pending as at December 31, 2014 *[note 3[a]]*.

The "Balances arising in the period" column consists of new additions to regulatory balances (for both debits and credits). The "Recovery/reversal" column consists of amounts collected through rate riders or transactions reversing an existing regulatory balance. The "Other movements" column consists of impairment and reclassification between the regulatory debit and credit balances. For the year ended December 31, 2015, LDC recorded an impairment of $4.4 million on regulatory debit balances within 'Other' as a result of the CIR decision and rate order. There was no impairment recorded for the year ended December 31, 2014.

Refer to Regulatory Developments and Electricity Consumption paragraphs in the Risk Management and Risk Factors section of the December 31, 2015 MD&A for a discussion of the risks and uncertainties that affect the future recovery of the regulatory balances.

The regulatory balances of LDC consist of the following:

a) Post-Employment Benefits

This regulatory balance accumulates the actuarial gains and losses arising from changes in actuarial assumptions and experience adjustments. The balance arising during the years ended December 31, 2015 and December 31, 2014 primarily related to the actuarial gain and loss recorded for the year, respectively. As at December 31, 2015, the regulatory balance did not include carrying charges.

b) Foregone Revenue

This regulatory balance relates to the revenue that LDC would have recovered in 2015 if new rates were implemented as of May 1, 2015. In the CIR decision and rate order, the OEB approved foregone revenue rate riders for May 1, 2015 to December 31, 2015 based on approved 2015 rates and for January 1, 2016 to February 29, 2016 based on approved 2016 rates *[note 3[a]]*. Based on that approval, a new regulatory balance of $61.1 million was recorded as at December 31, 2015 to reflect the amount associated with the 2015 year to be recovered through rates over a 46-month period commencing on March 1, 2016. As at December 31, 2015, the regulatory balance did not include carrying charges.

c) IFRS Transitional Adjustments

This regulatory balance relates to the differences arising from accounting policy changes for PP&E and intangible assets due to the transition from US GAAP to IFRS in 2014, primarily related to derecognition of certain assets and additional capitalized borrowing costs. In the CIR decision and rate order, the OEB approved disposition of the forecasted balance of $25.8 million plus an additional $4.7 million for the associated rate of return of 6.19% *[note 3[a]]*. Based on that approval, an additional $4.7 million was recorded as at December 31, 2015 to reflect the amount to be recovered through rates over a 46-month period commencing on March 1, 2016. As at December 31, 2015, the regulatory balance did not include carrying charges.

d) Settlement Variances

This account includes the variances between amounts charged by LDC to customers, based on regulated rates, and the corresponding cost of electricity and non-competitive electricity service costs incurred by LDC. The settlement variances relate primarily to non-competitive electricity charges and the global adjustment. Accordingly, LDC has deferred the variances between the costs incurred and the related recoveries in accordance with the criteria set out in the accounting principles prescribed by the OEB. Carrying charges were added to the regulatory balance in accordance with the OEB's direction at a rate of 1.47% for the period from January 1, 2015 to March 31, 2015 and 1.10% for the period from April 1, 2015 to December 31, 2015 [January 1, 2014 – December 31, 2014 - 1.47%]. In the CIR decision and rate order, the OEB approved disposition of variances related to low voltage in 2013 of $1.3 million inclusive of carrying charges over a 10-month period commencing on March 1, 2016 *[note 3[a]]*.

e) Stranded Meters and Smart Meters

These regulatory balances relate to the provincial government's decision to install smart meters throughout Ontario. As at December 31, 2015, the regulatory balances did not include carrying charges.

The net book value of stranded meters related to the deployment of smart meters was reclassified from PP&E to a new regulatory balance as at December 31, 2013. Depreciation expense on the stranded meters of $2.5 million was recorded within net movements in regulatory balances, net of tax until the end of 2014. Included in the 2015-2019 rate application was recovery of the forecasted net book value of the stranded meters as at December 31, 2014. In the CIR decision and rate order, the OEB approved LDC's request for recovery of the forecasted net book value of $15.8 million over a 46-month period commencing on March 1, 2016 *[note 3[a]]*.

On January 16, 2014, the OEB approved LDC's request for incremental revenue and disposition of the smart meter regulatory balances *[note 3[a]]*. The OEB ruling on smart meters also permitted the recovery in principle of LDC's allowed cost of capital on smart meters since 2008, with a rate order issued to this effect. This allows LDC to recover the incremental revenue requirement associated with these assets for the period during which they remained outside of rate base. Accordingly, a new regulatory balance of $25.2 million was recorded as at December 31, 2013 to reflect the future amount to be recovered through rates over a 36-month period commencing on May 1, 2014 and ending on April 30, 2017. LDC recognized $9.5 million of smart meter incremental revenue within net movements in regulatory balances, net of tax during 2014. LDC recognized distribution revenue of $10.9 million from the collection of OEB-approved rate riders for the year ended December 31, 2015 [2014 - $13.8 million].

f) Lost Revenue Adjustment Mechanism

This regulatory balance relates to the difference between the level of CDM program activities included in LDC's load forecast used to set rates and the actual impact of authorized CDM activities achieved. Carrying charges were added to the regulatory balance in accordance with the OEB's direction at a rate of 1.47% for the period from January 1, 2015 to March 31, 2015 and 1.10% for the period from April 1, 2015 to December 31, 2015. In the CIR decision and rate order, the OEB approved LDC's request for disposition of $3.6 million inclusive of carrying charges related to this variance for the 2011-2013 period *[note 3[a]]*. Based on that approval, a new regulatory balance was recorded as at December 31, 2015 to reflect the amount to be recovered through rates over a 10-month period commencing on March 1, 2016. As at December 31, 2015, LDC also recorded an amount of $4.9 million and $0.6 million inclusive of carrying charges related to the variance for 2014 and 2015, respectively.

g) Named Properties

This regulatory balance relates to the difference between the forecasted net gains on certain properties that LDC planned to sell and included as part of 2010 rates and the actual net gains realized upon the sale of the named properties between 2007 to 2011. In the CIR decision and rate order, the OEB approved LDC's request for disposition of $5.8 million related to this variance *[note 3[a]]*. Based on that approval, a new regulatory balance was recorded as at December 31, 2015 to reflect the amount to be recovered through rates over a 46-month period commencing on March 1, 2016. As at December 31, 2015, the regulatory balance did not include carrying charges.

h) Capital Contributions

This regulatory balance relates to the difference between amounts included in rates for HONI capital contributions and actual contributions in 2010 and 2011. In the CIR decision and rate order, the OEB approved LDC's request for disposition of $1.9 million related to this variance *[note 3[a]]*. Based on that approval, a new regulatory balance was recorded as at December 31, 2015 to reflect the amount to be recovered through rates over a 46-month period commencing on March 1, 2016. As at December 31, 2015, the regulatory balance did not include carrying charges.

i) OPEB Cash versus Accrual

This regulatory balance relates to the difference between LDC's forecasted OPEB costs on an accrual basis and the cash payments made to the OPEB plans. In the CIR decision and rate order *[note 3[a]]*, the OEB directed LDC to account for OPEB costs on a cash basis rather than accrual basis for rate-making purposes and approved a new variance account to record the difference. This is a temporary arrangement, pending the OEB's conclusion of the sector-wide policy consultation it initiated on rate-regulated utility OPEB costs. LDC does not consider the OEB's direction to constitute a change in the basis of its recovery of OPEB costs at this time considering the OEB's approval of the variance account, which LDC is expected to apply for disposition in the future. LDC recorded $1.8 million to reflect the OPEB variance related to 2015. As at December 31, 2015, the regulatory balance did not include carrying charges.

j) Deferred Taxes

This regulatory credit balance relates to both deferred tax amounts reclassified under IFRS 14 *[note 4[a]]* and to the expected future electricity distribution rate reduction for customers arising from timing differences in the recognition of deferred tax assets. As at December 31, 2015, the regulatory balance did not include carrying charges.

The amounts reclassified under IFRS 14 include the deferred tax liability related to regulatory balances of $42.1 million as at December 31, 2015 [December 31, 2014 - $32.7 million; January 1, 2014 - $16.4 million] offset by the recognition of a regulatory balance in respect of additional temporary differences for which a deferred tax amount was recognized of $26.2 million as at December 31, 2015 [December 31, 2014 - $39.9 million; January 1, 2014 - $41.7 million].

The deferred tax amount related to the expected future electricity distribution rate reduction for customers was $98.9 million as at December 31, 2015 [December 31, 2014 - $150.6 million; January 1, 2014 - $157.3 million].

k) Tax-related Variance Accounts

This regulatory balance includes the revision of prior year tax positions based on reassessments received and in process and income tax variances resulting from legislative or regulatory changes.

The revision of prior year tax position regulatory balance related to changes to certain prior year tax positions based on reassessments received and in process, not reflected in electricity distribution rates charged to customers, in the amount of $23.5 million as at December 31, 2015 [December 31, 2014 - $22.3 million; January 1, 2014 - $19.4 million]. An amount of $1.2 million was recorded to reflect new additions to the regulatory balance for the year ended December 31, 2015 [2014 - $2.9 million]. Carrying charges were added to the regulatory balance in accordance with the OEB's direction at a rate of 1.47% for the period from January 1, 2015 to March 31, 2015 and 1.10% for the period from April 1, 2015 to December 31, 2015 [January 1, 2014 – December 31, 2014 - 1.47%]. In the CIR decision and rate order, the OEB approved disposition of $23.3 million inclusive of carrying charges over a 34-month period commencing on March 1, 2016 *[note 3[a]]*.

The income tax variance regulatory balance related to differences resulting from a legislative or regulatory change to the tax rates or rules assumed in applications for electricity distribution rates in the amount of $3.0 million as at December 31, 2015 [December 31, 2014 - $3.0 million; January 1, 2014 - $5.8 million]. These differences have been deferred by LDC in accordance with the criteria set out in the accounting principles prescribed by the OEB. Carrying charges were added to the regulatory balance in accordance with the OEB's direction at a rate of 1.47% for the period from January 1, 2015 to March 31, 2015 and 1.10% for the period from April 1, 2015 to December 31, 2015 [January 1, 2014 – December 31, 2014 - 1.47%]. In the CIR decision and rate order, the OEB approved disposition of $3.0 million inclusive of carrying charges over a 10-month period commencing on March 1, 2016 *[note 3[a]]*.

On April 2, 2013, the OEB approved the disposition of $7.1 million of PILs regulatory variance accounts, over an 11-month period commencing on June 1, 2013 and ending on April 30, 2014. For the year ended December 31, 2014, electricity distribution rates charged to customers were reduced by $2.8 million.

l) Derecognition

This regulatory balance relates to the difference between the revenue requirement on derecognition amounts for PP&E and intangible assets included in the OEB-approved rates and the actual amounts of derecognition. This account was approved by the OEB in the CIR decision and rate order *[note 3[a]]*. A new regulatory balance was recorded as at December 31, 2015 to reflect the derecognition variance related to 2015 of $9.9 million. Carrying charges were added to the regulatory balance at a rate of 1.47% for the period from January 1, 2015 to March 31, 2015 and 1.10% for the period from April 1, 2015 to December 31, 2015.

m) Incremental Capital Module

This regulatory balance relates to the ICM application approved by the OEB and the associated rate riders, which became effective June 1, 2013 *[note 3[a]]*. This account included the amount collected through the ICM rate riders of $7.4 million for the year ended December 31, 2015 [2014 - $21.4 million], offset by the revenue recorded within net movements in regulatory balances, net of tax as it related to the eligible in-service capital expenditures of $nil million for the year ended December 31, 2015 [2014 - $25.1 million]. Carrying charges were added to the regulatory balance in accordance with the OEB's direction at a rate of 1.47% for the period from January 1, 2015 to March 31, 2015 and 1.10% for the period from April 1, 2015 to December 31, 2015 [January 1, 2014 – December 31, 2014 - 1.47%].

n) Gain on Disposal

This regulatory balance relates to the realized gain in connection with the disposal of certain properties by LDC under the facilities consolidation program. This balance is expected to reduce future electricity distribution rates for customers. In the CIR decision and rate order, the OEB approved disposition of the forecasted net gains on the sale of certain properties, including the future tax savings, over a 34-month period commencing on March 1, 2016 *[note 3[a]]*. The OEB also approved a variance account for LDC to record the difference between the total forecasted net gains and future tax savings and the actual net gains and tax savings. The new regulatory balance recorded as at December 31, 2015 reflected the forecasted net gains and future tax savings fully offset by the variance account. The net amount of $5.9 million related to the realized gain in connection with the disposal of a surplus property by LDC in the first quarter of 2015. Carrying charges were added to the regulatory balance at a rate of 1.47% for the period from January 1, 2015 to March 31, 2015 and 1.10% for the period from April 1, 2015 to December 31, 2015.

o) Capital-related Revenue Requirement

This regulatory balance relates to the asymmetrical variance between the cumulative 2015 to 2019 capital-related revenue requirement included in rates and the actual capital in-service additions related revenue requirement over the same period. This account was approved by the OEB in the CIR decision and rate order *[note 3[a]]*. A new regulatory balance was recorded as at December 31, 2015 to reflect the capital-related revenue requirement variance related to 2015 of $2.8 million. Carrying charges were added to the regulatory balance at a rate of 1.47% for the period from January 1, 2015 to March 31, 2015 and 1.10% for the period from April 1, 2015 to December 31, 2015.

10. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

Accounts payable and accrued liabilities consist of the following:

	December 31 2015 $	December 31 2014 $	January 1 2014 $
Trade payables	**316.2**	325.7	274.5
Accrued liabilities	**100.7**	128.2	102.1
Due to related parties *[note 23]*	**52.8**	56.0	49.9
Other	**1.9**	2.2	—
	471.6	512.1	426.5

11. DEFERRED REVENUE

Deferred revenue consists of capital contributions received from electricity customers to construct or acquire PP&E which have not yet been recognized into other revenue, and revenue not yet recognized from demand billable activities.

	December 31 2015 $	December 31 2014 $	January 1 2014 $
Capital contributions	**103.0**	72.6	45.7
Other	**1.0**	1.0	—
Total deferred revenue	**104.0**	73.6	45.7
Less: Current portion of deferred revenue relating to:			
Capital contributions	**2.7**	1.2	—
Other	**1.0**	1.0	—
Non-current portion of deferred revenue	**100.3**	71.4	45.7

Reconciliation between the opening and closing capital contribution balances is as follows:

	2015 $	2014 $
Balance, beginning of year	**72.6**	45.7
Receipt of capital contributions	**33.0**	28.2
Amortization	**(2.2)**	(0.7)
Other	**(0.4)**	(0.6)
Balance, end of year	**103.0**	72.6

12. NOTES PAYABLE TO RELATED PARTY

Notes payable to related party consist of the following:

	December 31 2015 $	December 31 2014 $	January 1 2014 $
Notes payable to related party:			
5.20% Long-term note payable to the Corporation due November 14, 2017	**245.1**	245.1	245.1
4.54% Long-term note payable to the Corporation due November 12, 2019	**245.1**	245.1	245.1
5.59% Long-term note payable to the Corporation due May 21, 2040	**200.0**	200.0	200.0
3.59% Long-term note payable to the Corporation due November 18, 2021	**300.0**	300.0	300.0
2.96% Long-term note payable to the Corporation due April 10, 2023	**250.0**	250.0	250.0
4.01% Long-term note payable to the Corporation due April 9, 2063	**200.0**	200.0	200.0
4.13% Long-term note payable to the Corporation due September 16, 2044	**200.0**	200.0	—
3.60% Long-term note payable to the Corporation due July 28, 2045	**200.0**	—	—
3.988% Long-term note payable to the Corporation due April 9, 2063	**45.0**	—	—
6.16% Demand note payable to the Corporation due on demand	**45.0**	45.0	45.0
3.32% Demand note payable to the Corporation due on the earlier of demand and January 1, 2022	**15.0**	15.0	15.0
Total notes payable to related party	**1,945.2**	1,700.2	1,500.2
Less: Unamortized debt issuance costs	**9.2**	8.0	7.0
Current portion of notes payable to related party *[note 23]*	**60.0**	60.0	60.0
Long-term portion of notes payable to related party *[note 23]*	**1,876.0**	1,632.2	1,433.2

All notes payable to related party of LDC rank equally.

On September 16, 2014, LDC issued a promissory note to the Corporation. The principal amount of the promissory note is $200.0 million payable on September 16, 2044, which bears interest at a rate of 4.13% per annum. Interest is calculated and payable semi-annually in arrears on March 16 and September 16 of each year. The net proceeds of the promissory note were used to repay certain existing indebtedness of LDC and for general corporate purposes.

On March 16, 2015, LDC issued a promissory note to the Corporation. The principal amount of the promissory note is $200.0 million payable on July 28, 2045, which bears interest at a rate of 3.60% per annum. Interest is calculated and payable semi-annually in arrears on January 28 and July 28 of each year. The net proceeds of the promissory note were used to repay certain existing indebtedness of LDC and for general corporate purposes.

On September 2, 2015, LDC issued a promissory note to the Corporation. The principal amount of the promissory note is $45.0 million payable on April 9, 2063, which bears interest at a rate of 3.988% per annum. Interest is calculated and payable semi-annually in arrears on April 9 and October 9 of each year. The net proceeds of the promissory note were used to repay certain existing indebtedness of LDC and for general corporate purposes.

13. EMPLOYEE FUTURE BENEFITS

Pension

LDC's eligible employees participate in a defined benefit pension plan through OMERS. As at December 31, 2015, the OMERS plan was 91.5% funded [December 31, 2014 – 90.8%]. OMERS has a strategy to return the plan to a fully funded position. LDC is not able to assess the implications, if any, of this strategy or of the withdrawal of other participating entities from the OMERS plan on its future contributions. For the year ended December 31, 2015, the total contributions of all participating employers and employees were approximately $3.8 billion [2014 -

$3.7 billion], of which LDC's contributions were $17.2 million [2014 - $17.7 million], representing less than five percent of total contributions to the OMERS plan. LDC expects to contribute approximately $17.9 million to the OMERS plan in 2016.

Post-employment benefits other than pension

a) Benefit obligation

	2015 $	2014 $
Balance, beginning of year	**287.4**	236.0
Current service cost	**5.6**	5.0
Interest cost	**11.4**	11.0
Benefits paid	**(9.3)**	(11.2)
Experience loss [(1)]	**0.9**	4.9
Actuarial loss arising from changes in demographic assumptions [(1)]	**—**	8.5
Actuarial loss arising from changes in financial assumptions [(1)]	**—**	32.6
Transfer from related parties	**0.5**	0.6
Balance, end of year	**296.5**	287.4

[(1)] Total experience loss and actuarial loss is $0.9 million [2014 - $46.0 million]. Actuarial loss on accumulated sick leave credits of $0.8 million [2014 - $0.2 million actuarial gain] is recognized in benefit cost *[note 13[c]]* and $0.1 million in transfer from related parties [2014 - $0.1 million], and $nil [2014 - $46.1 million] of actuarial loss on medical, dental and insurance benefits is recognized in OCI *[note 13[d]]*.

The weighted average duration of the benefit obligation as at December 31, 2015 is 17.1 years [2014 – 17.7 years].

b) Amounts recognized in regulatory balances

As at December 31, 2015, the amount recognized in regulatory balances related to net actuarial loss and IFRS transitional adjustments was $81.2 million [December 31, 2014 - $81.2 million; January 1, 2014 - $36.9 million] *[note 9[a]]*.

c) Benefit cost recognized

	2015 $	2014 $
Current service cost	**5.6**	5.0
Interest cost	**11.4**	11.0
Actuarial loss (gain) on other employee benefits *[note 13[a]]*	**0.8**	(0.2)
Benefit cost	**17.8**	15.8
Capitalized to PP&E and intangible assets	**7.7**	6.3
Charged to operating expenses	**10.1**	9.5

d) Amounts recognized in OCI (before income taxes)

	2015 $	2014 $
Actuarial loss *[note 13[a]]*	—	46.1
Net movements in regulatory balances related to OCI	—	(46.1)
	—	—

e) Significant assumptions

	2015	2014
Discount rate (%) used in the calculation of:		
Benefit obligation as at December 31	**4.00**	4.00
Assumed medical and dental cost trend rates (%) as at December 31:		
Rate of increase in dental costs assumed for next year	**4.00**	4.00
Rate of increase in medical costs assumed for next year		
For pre July 2000 retirements	**5.00**	5.00
For other retirements	**6.00**	6.50
Rate that medical cost trend rate gradually declines to		
For pre July 2000 retirements	**5.00**	5.00
For other retirements	**5.00**	5.00
Year that the medical cost trend rate reaches the ultimate trend rate		
For pre July 2000 retirements	**2015**	2015
For other retirements	**2018**	2018

f) Sensitivity analysis

Significant actuarial assumptions for benefit obligation measurement purposes are discount rate and assumed medical and dental cost trend rates. The sensitivity analysis below has been determined based on reasonably possible changes of the assumptions, in isolation of one another, occurring at the end of the reporting period. This analysis may not be representative of the actual change since it is unlikely that the change in the assumptions would occur in isolation of one another as some of the assumptions may be correlated.

Changes in key assumptions would have had the following effect on the benefit obligation:

	Change in assumption	2015 $	2014 $
As reported		**296.5**	287.4
Discount rate	1% -	**(45.5)**	(44.1)
	1%	**54.1**	52.4
Medical and dental cost trend rate	1% -	**38.6**	37.4
	1%	**(34.7)**	(33.6)

14. CAPITAL MANAGEMENT

LDC's main objectives when managing capital are to:

- ensure ongoing access to funding to maintain, refurbish and expand the electricity distribution system;
- ensure sufficient liquidity is available (either through cash and cash equivalents, investments or borrowings through TH Energy or the Corporation) to meet the needs of the business; and
- minimize finance costs while taking into consideration current and future industry, market and economic risks and conditions.

LDC monitors forecasted cash flows, capital expenditures, debt repayment and key credit ratios similar to those used by key rating agencies. LDC manages capital by preparing short-term and long-term cash flow forecasts. In addition, LDC borrows from TH Energy or the Corporation as required to help fund some of the periodic net cash outflows and to maintain available liquidity. There have been no changes in LDC's approach to capital management during the year. As at December 31, 2015, LDC's definition of capital included bank indebtedness, borrowings through the Corporation and obligations under finance leases, including the current portion thereof, and equity, and had remained unchanged from the definition as at December 31, 2014 and as at January 1, 2014. As at December 31, 2015, equity amounted to $1,414.6 million [December 31, 2014 - $1,284.2 million; January 1, 2014 - $1,174.3 million], and bank indebtedness, borrowings through the Corporation and obligations under finance leases, including the current portion thereof, amounted to $2,132.9 million [December 31, 2014 - $2,009.6 million; January 1, 2014 - $1,653.5 million].

15. FINANCIAL INSTRUMENTS

a) Recognition and measurement

As at December 31, 2015, December 31, 2014 and January 1, 2014, the fair values of cash and cash equivalents, accounts receivable, unbilled revenue, bank indebtedness, advance from related party, and accounts payable and accrued liabilities approximated their carrying amounts due to the short maturity of these instruments *[note 4[j]]*. The fair values of customer deposits approximate their carrying amounts taking into account interest accrued on the outstanding balance. Obligations under finance leases are measured based on a discounted cash flow analysis and approximate the carrying amounts as management believes that the fixed interest rates are representative of current market rates.

The carrying amounts and fair values of LDC's notes payable consist of the following:

	December 31 2015 $		December 31 2014 $		January 1 2014 $	
	Carrying amount	**Fair value [1]**	**Carrying amount**	**Fair value [1]**	**Carrying amount**	**Fair value [1]**
Long-term notes payable to the Corporation						
5.20% due November 14, 2017	**244.7**	**262.1**	244.6	268.1	244.5	269.6
4.54% due November 12, 2019	**244.4**	**271.5**	244.2	270.9	244.1	265.2
5.59% due May 21, 2040	**198.8**	**248.2**	198.8	255.4	198.7	226.7
3.59% due November 18, 2021	**298.9**	**326.2**	298.7	321.1	298.5	302.8
2.96% due April 10, 2023	**249.0**	**259.7**	248.8	254.1	248.7	232.9
4.01% due April 9, 2063	**198.7**	**194.2**	198.7	201.8	198.7	172.9
4.13% due September 16, 2044	**198.4**	**203.4**	198.4	209.2	—	—
3.60% due July 28, 2045	**198.6**	**185.2**	—	—	—	—
3.988% due April 9, 2063	**44.5**	**43.5**	—	—	—	—
Demand note payable to the Corporation due on demand	**45.0**	**45.0**	45.0	45.0	45.0	45.0
Demand note payable to the Corporation due on the earlier of demand and January 1, 2022	**15.0**	**16.1**	15.0	15.0	15.0	15.0
	1,936.0	**2,055.1**	1,692.2	1,840.6	1,493.2	1,530.1

[1] The fair value measurement of financial instruments for which the fair value has been disclosed is included in Level 2 of the fair value hierarchy *[note 4[j]]*.

b) Financial risks

The following is a discussion of financial risks and related mitigation strategies that have been identified by LDC for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks listed.

Credit risk

LDC is exposed to credit risk as a result of the risk of counterparties defaulting on their obligations. LDC's exposure to credit risk primarily relates to accounts receivable and unbilled revenue. LDC monitors and limits its exposure to credit risk on a continuous basis.

LDC's credit risk associated with accounts receivable is primarily related to electricity bill payments from customers. As at December 31, 2015, LDC had approximately 756,000 customers. LDC obtains security instruments from certain customers in accordance with direction provided by the OEB. As at December 31, 2015, LDC held security deposits in the amount of $47.4 million [December 31, 2014 - $43.2 million; January 1, 2014 - $44.7 million], of which $25.1 million [December 31, 2014 - $19.8 million; January 1, 2014 - $22.2 million] was related to security deposits on offers to connect to guarantee the payment of additional costs related to expansion projects. As at December 31, 2015, there were no significant concentrations of credit risk with respect to any customer. The credit risk and mitigation strategies with respect to unbilled revenue are the same as for accounts receivable. The credit risk related to cash, cash equivalents and investments is mitigated by LDC's treasury policies on assessing and monitoring the credit exposures of counterparties.

LDC did not have any single customer that generated more than 10% of total revenue for the years ended December 31, 2015 and December 31, 2014.

Credit risk associated with accounts receivable and unbilled revenue is as follows:

	December 31 2015 $	December 31 2014 $	January 1 2014 $
Accounts receivable (net of allowance for doubtful accounts)			
Outstanding for not more than 30 days	**170.5**	179.9	174.8
Outstanding for more than 30 days and not more than 120 days	**16.4**	21.4	20.9
Outstanding for more than 120 days	**3.1**	4.4	3.2
Total accounts receivable	**190.0**	205.7	198.9
Unbilled revenue	**319.5**	306.6	326.1
Total accounts receivable and unbilled revenue	**509.5**	512.3	525.0

LDC has a broad base of customers. As at December 31, 2015, LDC's accounts receivable and unbilled revenue which were not past due or impaired were assessed by management to have no significant collection risk and no additional allowance for doubtful accounts was required for these balances.

Reconciliation between the opening and closing allowance for doubtful accounts balances is as follows:

	2015 $	2014 $
Balance, beginning of year	**(11.8)**	(10.8)
Provision for doubtful accounts	**(7.1)**	(7.4)
Write-offs	**7.6**	7.1
Recoveries	**(0.2)**	(0.7)
Balance, end of year	**(11.5)**	(11.8)

Unbilled revenue represents amounts for which LDC has a contractual right to receive cash through future billings and are unbilled at period-end. Unbilled revenue is considered current and no allowance for doubtful accounts was provided as at December 31, 2015, December 31, 2014 and January 1, 2014.

Interest rate risk

LDC is exposed to fluctuations in interest rates for the valuation of its post-employment benefit obligations *[note 13[f]]*. LDC is also exposed to short-term interest rate risk on the net of cash and cash equivalents, advances from related party, and customer deposits. LDC manages interest rate risk by monitoring its mix of fixed and floating rate instruments, and taking action as necessary to maintain an appropriate balance. Advances from related party bear interest based on the prevailing market conditions at the time of issuance.

As at December 31, 2015, aside from the valuation of its post-employment benefit obligations, LDC was exposed to interest rate risk predominately from advances from the Corporation and customer deposits, while most of its remaining obligations were either non-interest bearing or bear fixed interest rates, and its financial assets were predominately short-term in nature and mostly non-interest bearing. LDC estimates that a 100 basis point increase (decrease) in short-term interest rates, with all other variables held constant, would result in an increase (decrease) of approximately $2.4 million to annual finance costs.

Liquidity risk

LDC is exposed to liquidity risk related to its ability to fund its obligations as they become due. LDC monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and financial requirements. LDC has access to credit facilities and borrowings through the Corporation and monitors cash balances daily. LDC's

objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing finance costs.

Liquidity risks associated with financial commitments are as follows:

December 31, 2015						
	Due within 1 year $	**Due within 2 years $**	**Due within 3 years $**	**Due within 4 years $**	**Due within 5 years $**	**Due after 5 years $**
Bank indebtedness	**188.9**	—	—	—	—	—
Accounts payable and accrued liabilities [(1)]	**454.9**	—	—	—	—	—
Obligations under finance lease	**3.5**	**3.3**	**1.7**	—	—	—
Long-term notes payable to the Corporation						
5.20% due November 14, 2017	—	**245.1**	—	—	—	—
4.54% due November 12, 2019	—	—	—	**245.1**	—	—
5.59% due May 21, 2040	—	—	—	—	—	**200.0**
3.59% due November 18, 2021	—	—	—	—	—	**300.0**
2.96% due April 10, 2023	—	—	—	—	—	**250.0**
4.01% due April 9, 2063	—	—	—	—	—	**200.0**
4.13% due September 16, 2044	—	—	—	—	—	**200.0**
3.60% due July 28, 2045	—	—	—	—	—	**200.0**
3.988% due April 9, 2063	—	—	—	—	—	**45.0**
Demand note payable to the Corporation due on demand	**45.0**	—	—	—	—	—
Demand note payable to the Corporation due on the earlier of demand and January 1, 2022	**15.0**	—	—	—	—	—
Interest payments on long-term notes payable and demand notes payable	**82.3**	**82.3**	**69.3**	**69.3**	**57.9**	**1,046.4**
	789.6	**330.7**	**71.0**	**314.4**	**57.9**	**2,441.4**

[(1)] Accounts payable and accrued liabilities exclude $16.7 million of accrued interest on long-term notes payable and demand notes payable included within “Interest payments on long-term notes payable and demand notes payable”.

December 31, 2014						
	Due within 1 year $	**Due within 2 years $**	**Due within 3 years $**	**Due within 4 years $**	**Due within 5 years $**	**Due after 5 years $**
Advance from related party	308.0	—	—	—	—	—
Accounts payable and accrued liabilities [(1)]	498.9	—	—	—	—	—
Obligations under finance lease	3.0	3.0	2.8	1.4	—	—
Long-term notes payable to the Corporation						
5.20% due November 14, 2017	—	—	245.1	—	—	—
4.54% due November 12, 2019	—	—	—	—	245.1	—
5.59% due May 21, 2040	—	—	—	—	—	200.0
3.59% due November 18, 2021	—	—	—	—	—	300.0
2.96% due April 10, 2023	—	—	—	—	—	250.0
4.01% due April 9, 2063	—	—	—	—	—	200.0
4.13% due September 16, 2044	—	—	—	—	—	200.0
Demand note payable to the Corporation due on demand	45.0	—	—	—	—	—
Demand note payable to the Corporation due on the earlier of demand and January 1, 2022	15.0	—	—	—	—	—
Interest payments on long-term notes payable and demand notes payable	72.8	72.8	72.8	60.0	60.0	838.5
	942.7	75.8	320.7	61.4	305.1	1,988.5

[(1)] Accounts payable and accrued liabilities exclude $13.2 million of accrued interest on long-term notes payable and demand notes payable included within "Interest payments on long-term notes payable and demand notes payable".

January 1, 2014						
	Due within 1 year $	Due within 2 years $	Due within 3 years $	Due within 4 years $	Due within 5 years $	Due after 5 years $
Advance from related party	150.0	—	—	—	—	—
Accounts payable and accrued liabilities [(1)]	415.7	—	—	—	—	—
Obligations under finance lease	2.5	2.5	2.5	2.5	1.4	—
Long-term notes payable to the Corporation						
5.20% due November 14, 2017	—	—	—	245.1	—	—
4.54% due November 12, 2019	—	—	—	—	—	245.1
5.59% due May 21, 2040	—	—	—	—	—	200.0
3.59% due November 18, 2021	—	—	—	—	—	300.0
2.96% due April 10, 2023	—	—	—	—	—	250.0
4.01% due April 9, 2063	—	—	—	—	—	200.0
Demand note payable to the Corporation due on demand	45.0	—	—	—	—	—
Demand note payable to the Corporation due on the earlier of demand and January 1, 2022	15.0	—	—	—	—	—
Interest payments on long-term notes payable and demand notes payable	50.5	61.2	61.2	61.2	48.5	674.0
	678.7	63.7	63.7	308.8	49.9	1,869.1

[(1)] Accounts payable and accrued liabilities exclude $10.8 million of accrued interest on long-term notes payable and demand notes payable included within "Interest payments on long-term notes payable and demand notes payable".

Foreign exchange risk

As at December 31, 2015, LDC had limited exposure to the changing values of foreign currencies. While LDC purchases goods and services which are payable in US dollars, and purchases US currency to meet the related commitments when required, the impact of these transactions is not material to the financial statements.

16. FINANCIAL ASSISTANCE

As at December 31, 2015, $32.4 million [December 31, 2014 - $29.7 million; January 1, 2014 - $50.1 million] was utilized under the Corporation's demand credit facility in the form of letters of credit mainly to satisfy the prescribed prudential requirements of LDC with the IESO for the purchase of electricity.

17. SHARE CAPITAL

Share capital consists of the following:

	December 31 2015 $	December 31 2014 $	January 1 2014 $
Authorized			
The authorized share capital of LDC consists of an unlimited number of common shares without par value.			
Issued and outstanding			
1,000 common shares, of which all were fully paid.	**556.3**	556.3	556.3

18. OTHER REVENUE

Other revenue consists of the following:

	2015 $	2014 $
Other regulatory service charges	**13.5**	13.2
Pole and duct rentals	**10.5**	8.7
Ancillary services revenue	**9.9**	9.7
Street lighting service fee	**4.7**	5.1
Amortization of deferred revenue	**2.2**	0.7
Miscellaneous	**7.5**	14.3
	48.3	51.7

19. OPERATING EXPENSES

Operating expenses consist of the following:

	2015 $	2014 $
Salaries and benefits	**224.9**	224.7
External services	**93.1**	88.1
Materials and supplies	**14.8**	15.2
Other support costs [(1)]	**37.7**	36.1
Less: Capitalized costs	**(111.5)**	(106.0)
	259.0	258.1

[(1)] Includes taxes other than income taxes, utilities, rental, communication, insurance, and other general and administrative expenses.

For the year ended December 31, 2015, LDC recognized operating expenses of $6.6 million related to materials and supplies used to service electrical distribution assets [2014 - $5.8 million].

20. FINANCE COSTS

Finance costs consist of the following:

	2015 $	2014 $
Interest income	**(1.4)**	(1.0)
Interest expense		
Interest on long-term debt [(1)]	**79.8**	67.5
Interest on short-term debt	**4.5**	4.6
Other interest	**1.1**	1.4
Capitalized borrowing costs	**(10.8)**	(8.1)
	73.2	64.4

[(1)] Includes amortization of debt issuance costs, discounts and premiums.

21. INCOME TAXES

Income tax expense differs from the amount that would have been recorded using the combined statutory Canadian federal and provincial income tax rate. Reconciliation of income tax expense computed at the statutory income tax rate to the income tax provision is set out below:

	2015 $	2014 $
Rate reconciliation before net movements in regulatory balances		
Income before income taxes	**115.9**	56.9
Statutory Canadian federal and provincial income tax rate	**26.5%**	26.5%
Expected income tax expense	**30.7**	15.1
Change in unrecognized tax benefits	**—**	0.1
Other	**0.8**	(1.3)
Income tax expense	**31.5**	13.9
Effective tax rate	**27.2%**	24.5%
Rate reconciliation after net movements in regulatory balances		
Net income after net movements in regulatory balances, before income tax [(1)]	**133.3**	123.0
Statutory Canadian federal and provincial income tax rate	**26.5%**	26.5%
Expected income tax expense	**35.3**	32.6
Temporary differences recoverable in future rates	**(31.7)**	(18.0)
Change in unrecognized tax benefits	**—**	0.1
Other	**(0.7)**	(1.6)
Income tax expense and income tax recorded in net movements in regulatory balances	**2.9**	13.1
Effective tax rate	**2.2%**	10.7%

[(1)] Income tax includes income tax expense and income tax recorded in net movements in regulatory balances.

Income tax expense as presented in the statements of income and comprehensive income are as follows:

	2015 $	2014 $
Income tax expense	**31.5**	13.9
Income tax recorded in net movements in regulatory balances	**(28.6)**	(0.8)
Income tax expense and income tax recorded in net movements in regulatory balances	**2.9**	13.1
Income tax recovery in OCI	**—**	(12.2)
Income tax expense in OCI recorded in net movements in regulatory balances	**—**	12.2
Income tax expense in OCI	**—**	—

Components of income tax expense and income tax recorded in net movements in regulatory balances are as follows:

	2015 $	2014 $
Current tax expense		
Current year	**3.1**	13.7
Adjustment for tax positions taken in prior periods	**(0.3)**	(1.0)
	2.8	12.7
Deferred tax expense		
Origination and reversal of temporary differences	**0.1**	0.4
Income tax expense and income tax recorded in net movements in regulatory balances	**2.9**	13.1

Deferred tax assets consist of the following:

	Net balance, January 1 2015 $	Recognized in net income $	Recognized in OCI $	Net balance, December 31 2015 $
PP&E and intangible assets	**55.0**	**(20.5)**	**—**	**34.5**
Post-employment benefits	**76.2**	**2.4**	**—**	**78.6**
Other taxable temporary differences	**11.9**	**(10.7)**	**—**	**1.2**
	143.1	**(28.8)**	**—**	**114.3**

	Net balance, January 1 2014 $	Recognized in net income $	Recognized in OCI $	Net balance, December 31 2014 $
PP&E and intangible assets	70.4	(15.4)	—	55.0
Post-employment benefits	62.6	1.4	12.2	76.2
Other taxable temporary differences	(0.9)	12.8	—	11.9
	132.1	(1.2)	12.2	143.1

LDC had recorded a net deferred tax asset as it expects to earn sufficient taxable income to realize the future reversal of deductible temporary differences.

22. STATEMENTS OF CASH FLOWS

Changes in non-cash working capital provided/(used) cash as follows:

	2015 $	2014 $
Accounts receivable	**14.3**	(7.8)
Unbilled revenue	**(12.9)**	19.5
Income tax receivable	**(8.8)**	0.1
Materials and supplies	**(1.2)**	—
Other current assets	**—**	(1.1)
Accounts payable and accrued liabilities	**9.1**	43.2
Deferred revenue	**1.5**	2.2
Deferred conservation credit	**17.9**	(20.0)
Other current liabilities	**0.6**	0.2
	20.5	36.3

Reconciliation between the amount presented on the statements of cash flows after factoring in the non-cash additions and total additions to PP&E and intangible assets is as follows:

	2015 $	2014 $
Purchase of PP&E, cash basis	**547.9**	523.3
Net change in accruals related to PP&E	**(36.4)**	48.3
Other	**1.7**	5.1
Total additions to PP&E	**513.2**	576.7
Purchase of intangible assets, cash basis	**21.1**	46.8
Total additions to PP&E and intangible assets	**534.3**	623.5

23. RELATED PARTY TRANSACTIONS

For LDC, transactions with related parties include transactions with the City, which wholly owns the Corporation, the Corporation and TH Energy, a wholly-owned subsidiary of the Corporation.

	City $	Corporation $	TH Energy $
For period ended December 31, 2015			
Revenues	**222.6**	**—**	**7.6**
Operating expenses and capital expenditures	**19.7**	**3.6**	**0.5**
Finance costs	**—**	**80.4**	**—**
As at December 31, 2015			
Accounts receivable	**3.2**	**—**	**1.0**
Unbilled revenue	**20.8**	**—**	**—**
Accounts payable and accrued liabilities	**36.6**	**16.2**	**—**
Current portion of notes payable to related party	**—**	**60.0**	**—**
Long-term portion of notes payable to related party	**—**	**1,876.0**	**—**
Customer deposits	**11.7**	**—**	**—**
Deferred revenue	**1.0**	**—**	**—**

	City $	Corporation $	TH Energy $
For period ended December 31, 2014			
Revenues	222.5	—	6.1
Operating expenses (recoveries) and capital expenditures	20.7	2.4	(0.6)
Finance costs	—	68.8	—
As at December 31, 2014			
Accounts receivable	7.2	—	1.0
Unbilled revenue	22.3	—	—
Advance from related party	—	308.0	—
Accounts payable and accrued liabilities	41.7	14.3	—
Current portion of notes payable to related party	—	60.0	—
Long-term portion of notes payable to related party	—	1,632.2	—
Customer deposits	8.2	—	—
Deferred revenue	1.5	—	—

	City $	Corporation $	TH Energy $
As at January 1, 2014			
Accounts receivable	2.1	—	—
Unbilled revenue	19.4	—	—
Advance from related party	—	150.0	—
Accounts payable and accrued liabilities	38.3	11.6	—
Current portion of notes payable to related party	—	60.0	—
Long-term portion of notes payable to related party	—	1,433.2	—
Customer deposits	8.8	—	—
Deferred revenue	6.8	—	—

Revenues represent amounts charged to the City primarily for electricity and ancillary services, and to TH Energy for street lighting and demand billable services. Operating expenses and capital expenditures represent amounts charged by the City for purchased road cut repairs, property taxes and other services, and the Corporation for

purchased corporate and management services. Operating expense recoveries represent amounts charged to TH Energy for the provision of goods and services. Finance costs represent interest charged by the Corporation on the advances and notes payable *[note 12]*.

Accounts receivable represents receivables from the City primarily for electricity and ancillary services, and TH Energy for the provision of goods and services. Unbilled revenue represents receivables from the City mainly related to electricity provided and not yet billed. Advance from related party represents amounts payable to the Corporation for short-term borrowings obtained under the Corporation's revolving credit facility and commercial paper program. Accounts payable and accrued liabilities represent amounts payable to the City related to road cut repairs and other services. Included in the accounts payable and accrued liabilities are amounts payable to the Corporation for purchased corporate and management services and interest accruing on the notes payable to the Corporation. Notes payable to related party represent amounts borrowed from the Corporation *[note 12]*. Customer deposits represent amounts received from the City for future expansion projects. Deferred revenue represents amounts received from the City primarily for the construction of electricity distribution assets.

Key management personnel are comprised of LDC's senior executive officers and members of the Board of Directors. The compensation costs associated with the key management personnel are as follows:

	2015 $	2014 $
Short-term employee benefits	**4.2**	4.2
Post-employment benefits	**1.0**	0.8
Termination benefits	**0.9**	1.0
	6.1	6.0

24. COMMITMENTS

Operating leases and capital projects

As at December 31, 2015, the future minimum payments under property operating leases, capital projects and other commitments were as follows:

	Operating leases $	Capital projects [2] and other $
Less than one year	**6.2**	**37.3**
Between one and five years	**5.1**	**20.5**
More than five years	**—**	—
Total amount of future minimum payments [1]	**11.3**	**57.8**

[1] Refer to note 15 for future cash outflows excluded from the table above.
[2] Reflects capital project commitments for construction services and estimated capital contributions.

LDC has the option to renew its two major property operating leases at the end of the current lease term for an additional five years at the then fair rental value.

Operating lease expense for the year ended December 31, 2015 was $6.3 million [2014 - $6.2 million].

Finance leases

As at December 31, 2015, December 31, 2014 and January 1, 2014, reconciliation between the future minimum lease payments and their present value was as follows:

	December 31 2015 $			December 31 2014 $			January 1 2014 $		
	Future minimum lease payments	Interest	Present value of minimum lease payments	Future minimum lease payments	Interest	Present value of minimum lease payments	Future minimum lease payments	Interest	Present value of minimum lease payments
Less than one year	**3.5**	**0.3**	**3.2**	3.0	0.4	2.6	2.5	0.4	2.1
Between one and five years	**5.0**	**0.2**	**4.8**	7.2	0.4	6.8	8.9	0.7	8.2
More than five years	**—**	**—**	**—**	—	—	—	—	—	—
	8.5	**0.5**	**8.0**	10.2	0.8	9.4	11.4	1.1	10.3
Current portion included in Other liabilities			**3.2**			2.6			2.1
Non-current portion included in Other liabilities			**4.8**			6.8			8.2

25. CONTINGENCIES

Legal Proceedings

In the ordinary course of business, LDC is subject to various legal actions and claims from customers, suppliers, former employees and other parties. On an ongoing basis, LDC assesses the likelihood of any adverse judgments or outcomes as well as potential ranges of probable costs and losses. A determination of the provision required, if any, for these contingencies is made after an analysis of each individual issue. The provision may change in the future due to new developments in each matter or changes in approach, such as a change in settlement strategy. If damages were awarded under these actions, LDC would make a claim under any applicable liability insurance policies which LDC believes would cover any damages which may become payable by LDC in connection with these actions, subject to such claim not being disputed by the insurer.

2 Secord Avenue

An action was commenced against LDC in September 2008 in the Ontario Superior Court of Justice under the *Class Proceedings Act* which sought damages in the amount of $30.0 million as compensation for damages allegedly suffered as a result of a fire and explosion in an underground vault at 2 Secord Avenue on July 20, 2008. On June 16, 2014, a settlement reached by the parties was approved by Order of the Ontario Superior Court of Justice pursuant to which LDC paid the amount of $6.5 million, including all taxes and legal fees in settlement of the action of the class plaintiffs. LDC's liability insurance covered the settlement payment.

On March 10, 2009, a third party claim was served by LDC related to the above action and on June 15, 2009, a third party defence and counterclaim against LDC seeking damages in the amount of $51.0 million were served by the owner and manager of 2 Secord Avenue. Given the preliminary status of the unsettled actions, it is not possible to reasonably quantify the effect, if any, of this action on the financial performance of LDC.

On December 20, 2010, LDC was served with a statement of claim by the City seeking damages in the amount of $2.0 million as a result of the fire at 2 Secord Avenue. A statement of defence and a third party claim have been served. Given the preliminary status of this action, it is not possible to reasonably quantify the effect, if any, of this action on the financial performance of LDC.

By order of the court dated January 24, 2012, the above actions involving the same incident will be tried at the same time or consecutively.

2369 Lakeshore Boulevard West

A third party action was commenced against LDC in October 2009 in the Ontario Superior Court of Justice under the *Class Proceedings Act* seeking damages in the amount of $30.0 million as compensation for damages allegedly suffered as a result of a fire in the electrical room at 2369 Lakeshore Boulevard West on March 19, 2009. Subsequently, in March 2010, the plaintiff in the main action amended its statement of claim to add LDC as a defendant. The plaintiff in the main action seeks general damages in the amount of $10.0 million and special damages in the amount of $20.0 million from LDC. The plaintiff's motion for certification of the class action was granted on September 11, 2014. Statements of defence to the main action and to the third party claim have not been filed. Given the preliminary status of these actions, it is not possible at this time to reasonably quantify the effect, if any, of these actions on the financial performance of LDC.

On August 29, 2011, LDC was served with a statement of claim by the owner of the building and the property management company for the building seeking damages in the amount of $2.0 million as a result of the fire at 2369 Lakeshore Boulevard West. LDC has filed a statement of defence and counterclaim. Given the preliminary status of this action, it is not possible to reasonably quantify the effect, if any, of this action on the financial performance of LDC.

26. IFRS TRANSITION

On July 21, 2011, the OSC granted an exemption to allow the Corporation to prepare its consolidated financial statements in accordance with US GAAP for fiscal years beginning on or after January 1, 2012 but before January 1, 2015. In the absence of the exemption, the Corporation would have been required to adopt IFRS on January 1, 2012. Accordingly, LDC decided to adopt US GAAP at the time to mirror the decision of the Corporation. On March 19, 2014, the Board of Directors of the Corporation approved the adoption of IFRS for the year beginning on January 1, 2015 due to the pending expiration of the exemption. Since the Corporation was converting to IFRS, on March 19, 2014 the Board of Directors of LDC also approved the adoption of IFRS for the year beginning on January 1, 2015. As described in note 2, these are LDC's first financial statements prepared in accordance with IFRS. IFRS 1 sets out the transitional requirements that LDC must apply in preparing its first IFRS financial statements.

The accounting policies set out in notes 2 and 4 have been applied in preparing the financial statements as at and for the year ended December 31, 2015, the comparative information as at and for the year ended December 31, 2014 and the opening IFRS balance sheet as at January 1, 2014 (LDC's date of transition to IFRS). All comparative figures for 2014 that were previously reported in accordance with US GAAP are now reported in accordance with IFRS. An explanation of the significant transitional adjustments as a result of the transition from US GAAP to IFRS on LDC's financial position, financial performance and cash flows is set out in the following tables and accompanying notes.

IFRS 1 requires retrospective application of IFRS in place as at the reporting date. However, IFRS 1 contains certain mandatory exceptions and optional exemptions from the general requirement for retrospective application. LDC applied the following mandatory exceptions and optional exemptions in the preparation of the opening IFRS balance sheet:

Mandatory exceptions

IFRS 1 states that estimates made in accordance with IFRS at the date of transition should be consistent with estimates made under previous GAAP. Accordingly, estimates previously made under US GAAP were not revised at the date of transition except where necessary to reflect changes in accounting policies.

Optional exemptions

a) Rate-regulated deemed cost

Entities with operations subject to rate regulation may hold items of PP&E or intangible assets where the carrying amount of such items might include amounts that were determined under previous GAAP but do not qualify for capitalization under IFRS. In such cases, a first-time adopter may deem the previous GAAP carrying amount of such items at the date of transition as the new IFRS cost basis. Under US GAAP, the carrying amount of LDC's PP&E and intangible assets used in rate-regulated activities was based on historical cost but included certain amounts that would not qualify for capitalization under IFRS.

LDC qualifies for the IFRS 1 exemption as it is subject to rate regulation. Accordingly, LDC elected to use the deemed cost exemption for its PP&E and intangible assets, except for construction in progress items for which capital contributions were received. The accumulated depreciation recognized under US GAAP prior to the transition date was included as part of the deemed cost such that the carrying amounts were not affected. The impact of this change was a decrease to both the cost and accumulated depreciation of PP&E by $2,424.0 million and to both the cost and accumulated amortization of intangible assets by $201.9 million, as at January 1, 2014.

LDC tested for asset impairment under this exemption and no impairment was recorded.

b) Borrowing costs

IAS 23 *Borrowing Costs* ["IAS 23"] specifies detailed methodology for capitalizing borrowing costs. Under US GAAP, an allowance for funds used during construction was applied and capitalized as part of the cost of PP&E and intangible assets, where applicable. Under an optional exemption in IFRS 1, an entity would be exempted from determining the applicable borrowing costs under IFRS for items reconstructed under IFRS. LDC elected this exemption and used the borrowing costs determined under US GAAP at the date of transition and applied IAS 23 prospectively to borrowing costs for qualifying assets capitalized after the transition date.

c) Decommissioning costs included in PP&E

IFRIC 1 *Changes in Existing Decommissioning, Restoration and Similar Liabilities* requires specified changes in a decommissioning, restoration or similar liability to be adjusted retrospectively from the cost of the asset to which it relates, with the adjusted depreciable amount of the asset being depreciated prospectively over its remaining useful life. LDC elected the exemption available in IFRS 1 which allows a first-time adopter to use a simplified method to recalculate its decommissioning provisions in accordance with IFRS at the transition date. The effect of electing the exemption was an increase to regulatory balances and a decrease to PP&E of $0.9 million as at January 1, 2014.

d) Leases

IFRIC 4 *Determining Whether an Arrangement Contains a Lease* ["IFRIC 4"] requires the assessment of whether an arrangement contains a lease to be based on the facts and circumstances existing at the date of the inception of the arrangement. Under an optional exemption in IFRS 1, an entity that made the same determination of whether an arrangement contains a lease under its previous GAAP as that required by IFRIC 4, but at a date other than that required by IFRIC 4, does not have to reassess that determination when it adopts IFRS. As LDC made the same determination of whether an arrangement contained a lease under US GAAP as that required by IFRIC 4, LDC elected this exemption and did not reassess its arrangements at the date of transition.

e) Business combinations

IFRS 1 provides an optional exemption for a first-time adopter to elect not to apply IFRS 3 *Business Combinations* ["IFRS 3"] retrospectively to past business combinations that occurred before the date of transition to IFRS, or to elect to restate all business combinations to comply with IFRS 3 prospectively from any date before the date of

transition. LDC elected not to apply IFRS 3 to past business combinations that occurred prior to the date of transition.

f) Transfer of Assets from Customers (Capital Contributions)

IFRS 1 provides an optional exemption for a first-time adopter to apply IFRIC 18 prospectively to transfers of assets from customers received on or after the date of transition. LDC did not elect this exemption and instead applied IFRIC 18 retrospectively to all customer contributions received prior to the date of transition. However, the use of the rate-regulated deemed cost exemption noted above resulted in no adjustment to the capital contributions included in the PP&E deemed cost.

The reconciliation of the January 1, 2014 and December 31, 2014 balance sheets from US GAAP to IFRS is as follows:

BALANCE SHEET

As at January 1, 2014	Notes	US GAAP $	Transitional Adjustments $	IFRS $
ASSETS				
Current				
Cash and cash equivalents		15.7	—	**15.7**
Accounts receivable		198.9	—	**198.9**
Unbilled revenue		326.1	—	**326.1**
Income tax receivable		0.3	—	**0.3**
Materials and supplies		8.6	—	**8.6**
Other assets	B	8.9	(0.1)	**8.8**
Regulatory assets	A	7.1	(7.1)	**—**
Total current assets		565.6	(7.2)	**558.4**
Property, plant and equipment	A, B, C	2,640.0	180.8	**2,820.8**
Intangible assets		171.5	—	**171.5**
Deferred tax assets	A	155.9	(23.8)	**132.1**
Other assets	B	8.0	(7.1)	**0.9**
Regulatory assets	A	234.4	(234.4)	**—**
Total assets		3,775.4	(91.7)	**3,683.7**
Regulatory balances	A, D	—	88.3	**88.3**
Total assets and regulatory balances		3,775.4	(3.4)	**3,772.0**
LIABILITIES AND EQUITY				
Current				
Advance from related party		150.0	—	**150.0**
Accounts payable and accrued liabilities	C	455.7	(29.2)	**426.5**
Customer deposits		37.3	—	**37.3**
Deferred conservation credit		20.0	—	**20.0**
Post-employment benefits	D	8.0	(8.0)	**—**
Other liabilities		2.1	—	**2.1**
Notes payable to related party		60.0	—	**60.0**
Regulatory liabilities	A	2.5	(2.5)	**—**
Total current liabilities		735.6	(39.7)	**695.9**
Notes payable to related party		1,433.2	—	**1,433.2**
Customer deposits		7.4	—	**7.4**
Deferred revenue	C	—	45.7	**45.7**
Post-employment benefits	D	230.8	5.2	**236.0**
Other liabilities		14.4	0.1	**14.5**
Regulatory liabilities	A	180.6	(180.6)	**—**
Total liabilities		2,602.0	(169.3)	**2,432.7**
Equity				
Share capital		556.3	—	**556.3**
Retained earnings	D	604.3	0.9	**605.2**
Contributed surplus		12.8	—	**12.8**
Total equity		1,173.4	0.9	**1,174.3**
Total liabilities and equity		3,775.4	(168.4)	**3,607.0**
Regulatory balances	A	—	165.0	**165.0**
Total liabilities, equity and regulatory balances		3,775.4	(3.4)	**3,772.0**

BALANCE SHEET

As at December 31, 2014	Notes	US GAAP $	Transitional Adjustments $	IFRS $
ASSETS				
Current				
Cash and cash equivalents		84.7	—	**84.7**
Accounts receivable		205.7	—	**205.7**
Unbilled revenue		306.6	—	**306.6**
Income tax receivable		0.2	—	**0.2**
Materials and supplies		8.6	—	**8.6**
Other assets	B	10.0	(0.1)	**9.9**
Regulatory assets	A	11.8	(11.8)	**—**
Assets held for sale		4.0	—	**4.0**
Total current assets		631.6	(11.9)	**619.7**
Property, plant and equipment	A, B, C, D, E, F	2,792.5	432.0	**3,224.5**
Intangible assets	E	197.9	0.8	**198.7**
Deferred tax assets	A	129.8	13.3	**143.1**
Other assets	B	8.1	(6.9)	**1.2**
Regulatory assets	A	564.4	(564.4)	**—**
Total assets		4,324.3	(137.1)	**4,187.2**
Regulatory balances	A, D, E, F	—	197.1	**197.1**
Total assets and regulatory balances		4,324.3	60.0	**4,384.3**
LIABILITIES AND EQUITY				
Current				
Advance from related party		308.0	—	**308.0**
Accounts payable and accrued liabilities	C	535.0	(22.9)	**512.1**
Customer deposits		38.5	—	**38.5**
Deferred revenue	C	1.0	1.2	**2.2**
Post-employment benefits	D	8.0	(8.0)	**—**
Other liabilities		2.6	—	**2.6**
Notes payable to related party		60.0	—	**60.0**
Regulatory liabilities	A	1.6	(1.6)	**—**
Total current liabilities		954.7	(31.3)	**923.4**
Notes payable to related party		1,632.2	—	**1,632.2**
Customer deposits		4.7	—	**4.7**
Deferred revenue	C	—	71.4	**71.4**
Post-employment benefits	D	285.6	1.8	**287.4**
Other liabilities		6.8	1.2	**8.0**
Regulatory liabilities	A	156.2	(156.2)	**—**
Total liabilities		3,040.2	(113.1)	**2,927.1**
Equity				
Share capital		556.3	—	**556.3**
Retained earnings	A, D	715.0	0.1	**715.1**
Contributed surplus		12.8	—	**12.8**
Total equity		1,284.1	0.1	**1,284.2**
Total liabilities and equity		4,324.3	(113.0)	**4,211.3**
Regulatory balances	A	—	173.0	**173.0**
Total liabilities, equity and regulatory balances		4,324.3	60.0	**4,384.3**

The reconciliations of the statement of income and the statement of comprehensive income from US GAAP to IFRS for the year ended December 31, 2014 are as follows:

STATEMENT OF INCOME

Year ended December 31, 2014	Notes	US GAAP $	Transitional Adjustments $	IFRS $
Revenues				
Energy sales	A	2,700.4	(45.4)	**2,655.0**
Distribution revenue	A	554.2	0.9	**555.1**
Other	C	50.6	1.1	**51.7**
		3,305.2	(43.4)	**3,261.8**
Expenses				
Energy purchases		2,700.4	—	**2,700.4**
Operating expenses	A, D	257.8	0.3	**258.1**
Depreciation and amortization	A, C, F	159.4	24.1	**183.5**
		3,117.6	24.4	**3,142.0**
Finance costs	A, E	66.9	(2.5)	**64.4**
Gain on disposals of property, plant and equipment		1.5	—	**1.5**
Income before income taxes		122.2	(65.3)	**56.9**
Income tax expense	A	11.5	2.4	**13.9**
Net income		110.7	(67.7)	**43.0**
Net movements in regulatory balances, net of tax	A, D, E, F	—	66.9	**66.9**
Net income after net movements in regulatory balances		110.7	(0.8)	**109.9**

STATEMENT OF COMPREHENSIVE INCOME

Year ended December 31, 2014	Notes	US GAAP $	Transitional Adjustments $	IFRS $
Net income after net movements in regulatory balances		110.7	(0.8)	**109.9**
Other comprehensive income				
Items that will not be reclassified to income or loss				
Remeasurements of post-employment benefits, net of tax of $12.2	A, D	—	(33.9)	**(33.9)**
Net movements in regulatory balances related to OCI, net of tax of $12.2	A, D	—	33.9	**33.9**
Other comprehensive income, net of tax		—	—	—
Total comprehensive income		110.7	(0.8)	**109.9**

The reconciliation of the statement of changes in equity from US GAAP to IFRS for the year ended December 31, 2014 is as follows:

STATEMENT OF CHANGES IN EQUITY

Year ended December 31, 2014	Notes	US GAAP $	Transitional Adjustments $	IFRS $
Share capital		556.3	—	**556.3**
Retained earnings, beginning of year	D	604.3	0.9	**605.2**
Net income after net movements in regulatory balances		110.7	(0.8)	**109.9**
Retained earnings, end of year		715.0	0.1	**715.1**
Contributed surplus		12.8	—	**12.8**
Total equity		1,284.1	0.1	**1,284.2**

Notes to the transitional adjustments

A. Regulatory balances

IFRS 14 permits a rate-regulated entity to continue to apply its previous GAAP accounting policies for the recognition, measurement, impairment and derecognition of regulatory balances. However, all regulatory balances and related deferred tax amounts are reclassified to a new and separate section of the balance sheet. As well, the net income effect of all changes in regulatory balances must be segregated in a new separate section of the statement of income. Amounts that are permitted or required to be recognized under another IFRS are excluded from the regulatory balances. The effect of the reclassifications would enhance comparability of IFRS 14 compliant financial statements with those entities not applying IFRS 14. IFRS 14 also requires disclosure regarding the movements in the period, risks, and expected period of recovery/amortization of individual regulatory balances.

For LDC, the impact of IFRS 14 at January 1, 2014 was to transfer the ICM eligible in-service capital expenditures *[note 9[m]]* to PP&E, to transfer the deferred tax asset gross-up and deferred tax liabilities on regulatory balances to regulatory balances, and to transfer all other regulatory debit and credit balances to separate lines below what was formerly known as “Total assets” and “Total liabilities and equity”, respectively. The impact of this change as at January 1, 2014 was to reduce current regulatory assets by $7.1 million, non-current regulatory assets by $234.4 million, deferred tax assets by $23.8 million, current regulatory liabilities by $2.5 million and non-current regulatory liabilities by $180.6 million, and increase PP&E by $157.0 million, regulatory debit balances by $90.2 million and regulatory credit balances by $165.0 million.

As at December 31, 2014, the impact was to reduce current regulatory assets by $11.8 million, non-current regulatory assets by $564.4 million, current regulatory liabilities by $1.6 million and non-current regulatory liabilities by $156.2 million, and increase PP&E by $399.0 million, deferred tax assets by $13.3 million, regulatory debit balances by $179.0 million and regulatory credit balances by $173.0 million. For the year ended December 31, 2014, the impact was to increase distribution revenue by $0.9 million, operating expenses by $2.6 million, income tax expense by $0.8 million, finance costs by $0.1 million, net movements in regulatory balances, net of tax by $45.4 million and net movements in regulatory balances related to OCI, net of tax by $33.9 million, and to decrease energy sales by $45.4 million, depreciation and amortization expense by $2.5 million, and remeasurements of post-employment benefits, net of tax within OCI by $33.9 million.

B. Prepaid lease

Under US GAAP, prepaid land lease was included in other assets. Under IFRS, prepaid land lease is included in PP&E as a finance lease as substantially all of the risks and rewards incidental to ownership of the land are transferred to LDC. The impact as at January 1, 2014 and December 31, 2014 was a decrease to current other assets of $0.1 million, a decrease to non-current other assets of $7.1 million and $7.0 million, respectively, and an increase to PP&E of $7.2 million and $7.1 million, respectively.

C. Capital contributions

Under US GAAP, capital contributions received and used to finance additions to PP&E were offset against the cost of the constructed asset and depreciated at an equivalent rate as the related PP&E as a reduction in depreciation expense. Under IFRIC 18, contributions received in order to construct an item of PP&E are treated as deferred revenue and recognized as revenues over the useful lives of the related PP&E. LDC applied IFRIC 18 to capital contributions received for projects not yet in service, excluding PP&E items for which the deemed cost exemption was applied. As at January 1, 2014, the impact was to increase PP&E by $16.5 million, decrease accounts payable and accrued liabilities by $29.2 million and increase deferred revenue by $45.7 million. As at December 31, 2014, the impact was to increase PP&E by $50.5 million, current deferred revenue by $1.2 million and non-current deferred revenue by $71.4 million, and reduce accounts payable and accrued liabilities by $22.1 million. For the year ended December 31, 2014, $0.7 million was reclassified from depreciation and amortization expense to other revenue.

D. Employee benefits

The attribution methods and attribution periods are different between IFRS and US GAAP and result in a measurement difference of the post-employment benefit liability. In addition, under IFRS, a liability is recognized for both non-vested accumulating and vested sick leave benefits, unlike US GAAP, which only requires a liability for the vested sick leave component. Under IFRS, actuarial gains and losses resulting from experience adjustments and changes in actuarial assumptions are recognized in OCI as they arise, and amounts related to rate regulation are subsequently reclassified to a regulatory balance on the balance sheets. The impact of these recognition and measurement differences as at January 1, 2014 was an overall decrease to the post-employment benefits liability by $2.8 million and regulatory debit balances of $1.9 million, and an increase to retained earnings of $0.9 million.

As at December 31, 2014, the impact of these recognition and measurement differences was a decrease to PP&E of $0.4 million, regulatory debit balances of $5.7 million (of which $6.1 million related to post-employment benefits, offset by $0.4 million related to IFRS transitional adjustments), post-employment benefit liability of $6.2 million, and an increase to opening retained earnings of $0.9 million. For the year ended December 31, 2014, the impact of these recognition and measurement differences was a decrease to operating expenses of $0.6 million, net movements in regulatory balances, net of tax of $1.4 million, and remeasurements of post-employment benefits within pre-tax OCI of $46.1 million, and an increase to net movements in regulatory balances related to pre-tax OCI of $46.1 million.

Under US GAAP, the amount of the actuarial present value of benefits expected to be paid in the next twelve months was presented as a current liability. Under IFRS, it is a policy choice whether or not to separately present a component as current as it relates to post-employment benefits. However, IFRS does specify that short-term employee benefits, such as sick leave benefits, are classified as current if they are expected to be settled wholly within twelve months after the end of the reporting period. LDC elected to present post-employment benefit obligation as non-current since it is not expected to be settled wholly within twelve months. As LDC does not expect to settle all of its sick leave benefits within twelve months, sick leave benefits have been included in the non-current liability as well. This presentation difference resulted in a decrease to current post-employment benefits and an increase to non-current post-employment benefits as at January 1, 2014 and December 31, 2014 in the amount of $8.0 million.

E. Borrowing costs

Under US GAAP, an allowance for funds used during construction was applied based on OEB-prescribed rates on a simple interest basis and capitalized as part of the cost of PP&E and intangible assets where applicable. Under IFRS, the applicable borrowing costs are determined by applying the methodology in IAS 23 to qualifying assets. The capitalization rate under IFRS is based on the weighted average interest rate of LDC's external general borrowings using the effective interest rate method which is applied to the carrying amount of the asset including borrowing costs previously capitalized. In addition, under IFRS, capitalization commences immediately as the expenditure on a qualifying asset is incurred. The differences arising as a result of this accounting policy change due to the transition from US GAAP to IFRS for the year of transition were recorded within IFRS transitional adjustments in regulatory debit balances and net movements in regulatory balances, net of tax. For the year ended December 31, 2014, the impact was to increase PP&E by $2.1 million and intangible assets by $0.5 million, and decrease regulatory debit balances, finance costs and net movements in regulatory balances, net of tax by $2.6 million.

F. PP&E derecognition

Under the group depreciation policy adopted under US GAAP, assets in a group were not removed from the accounts on disposition and depreciation continued to be recorded until the asset group was fully depreciated. Under IFRS, the carrying amount of an item of PP&E is derecognized on disposal of the asset or when no future economic benefits are expected to accrue to LDC from its continued use and the related loss is recorded within depreciation and amortization expense. The differences arising as a result of this accounting policy change due to the transition from US GAAP to IFRS for the year of transition were recorded within IFRS transitional adjustments in regulatory debit balances and net movements in regulatory balances, net of tax. For the year ended December 31, 2014, the impact was to decrease PP&E and increase depreciation and amortization expense, regulatory debit balances and net movements in regulatory balances, net of tax by $26.5 million.

Impact on the statements of cash flows

The changes in classifications of cash flows from US GAAP to IFRS were mainly due to:

- Reclassification of capital contributions received to finance additions to PP&E from investing activities to operating activities, and inclusion of amortization of deferred revenue related to capital contributions in operating activities. Under US GAAP, capital contributions were treated as a reduction of PP&E and associated cash flows were classified as investing activities. Under IFRS, LDC treats capital contributions as deferred revenue and classifies the associated cash flows as operating activities;
- Presentation of income taxes paid and interest paid within the body of the statements of cash flows as part of operating and financing activities, respectively, whereas they were previously disclosed as supplementary information; and
- Reclassification of adjustments relating to regulatory balances within operating activities to "Net movements in regulatory balances" in the application of IFRS 14.

Financial Statements

Toronto Hydro-Electric System Limited

DECEMBER 31, 2016 and 2015

See attached Glossary for abbreviations used in the audited financial statements.

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INDEPENDENT AUDITORS' REPORT

To the Shareholder of Toronto Hydro-Electric System Limited

We have audited the accompanying financial statements of Toronto Hydro-Electric System Limited, which comprise the balance sheets as at December 31, 2016 and December 31, 2015, the statements of income, comprehensive income, changes in equity and cash flows for the years ended December 31, 2016 and December 31, 2015, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the) financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Toronto Hydro-Electric System Limited as at December 31, 2016 and December 31, 2015, and its financial performance and its cash flows for the years ended December 31, 2016 and December 31, 2015 in accordance with International Financial Reporting Standards**.**

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants
March 2, 2017
Toronto, Canada

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Toronto Hydro-Electric System Limited

BALANCE SHEETS

[in millions of Canadian dollars]

As at December 31	2016 $	2015 $
ASSETS		
Current		
Accounts receivable *[notes 4 and 14[b]]*	**226.2**	190.0
Unbilled revenue *[note 14[b]]*	**319.7**	319.5
Income tax receivable	**-**	9.0
Materials and supplies	**9.7**	9.8
Other assets *[note 5]*	**13.5**	9.9
Total current assets	**569.1**	538.2
Property, plant and equipment *[note 6]*	**3,876.3**	3,561.9
Intangible assets *[note 7]*	**217.8**	199.3
Deferred tax assets *[note 20]*	**63.8**	114.3
Other assets *[note 5]*	**1.3**	1.2
Total assets	**4,728.3**	4,414.9
Regulatory balances *[note 8]*	**190.8**	241.7
Total assets and regulatory balances	**4,919.1**	4,656.6
LIABILITIES AND EQUITY		
Current		
Joint bank indebtedness	**50.5**	188.9
Accounts payable and accrued liabilities *[note 9]*	**500.4**	471.6
Income tax payable	**9.0**	-
Customer deposits	**39.1**	37.5
Deferred revenue *[note 10]*	**4.3**	3.7
Deferred conservation credit *[note 3[b]]*	**5.5**	17.9
Notes payable to related party *[notes 11 and 22]*	**304.9**	60.0
Other liabilities *[note 23]*	**3.1**	3.2
Total current liabilities	**916.8**	782.8
Notes payable to related party *[notes 11 and 22]*	**1,830.6**	1,876.0
Customer deposits	**15.0**	9.9
Deferred revenue *[note 10]*	**139.9**	100.3
Post-employment benefits *[note 12]*	**280.5**	296.5
Other liabilities *[note 23]*	**1.9**	4.9
Total liabilities	**3,184.7**	3,070.4
Commitments and contingencies *[notes 23 and 24]*		
Equity		
Share capital *[note 16]*	**556.3**	556.3
Retained earnings	**995.9**	845.5
Contributed surplus	**12.8**	12.8
Total equity	**1,565.0**	1,414.6
Total liabilities and equity	**4,749.7**	4,485.0
Regulatory balances *[note 8]*	**169.4**	171.6
Total liabilities, equity and regulatory balances	**4,919.1**	4,656.6

See accompanying notes to the financial statements.

Toronto Hydro-Electric System Limited

STATEMENTS OF INCOME

[in millions of Canadian dollars]

Year ended December 31	**2016 $**	2015 **$**
Revenues		
Energy sales	**3,306.2**	2,925.6
Distribution revenue	**647.9**	555.4
Other *[note 17]*	**66.3**	48.3
	4,020.4	3,529.3
Expenses		
Energy purchases	**3,216.9**	2,898.5
Operating expenses *[note 18]*	**267.6**	259.0
Depreciation and amortization *[notes 6 and 7]*	**210.6**	192.8
	3,695.1	3,350.3
Finance costs *[note 19]*	**76.6**	73.2
Gain on disposals of property, plant and equipment	**2.1**	10.1
Income before income taxes	**250.8**	115.9
Income tax expense *[note 20]*	**67.2**	31.5
Net income	**183.6**	84.4
Net movements in regulatory balances	**(77.2)**	17.4
Net movements in regulatory balances arising from deferred tax assets	**44.0**	28.6
Net income after net movements in regulatory balances	**150.4**	130.4

STATEMENTS OF COMPREHENSIVE INCOME

[in millions of Canadian dollars]

Year ended December 31	**2016 $**	2015 **$**
Net income after net movements in regulatory balances	**150.4**	130.4
Other comprehensive income		
Items that will not be reclassified to income or loss		
Remeasurements of post-employment benefits, net of tax (2016 - $5.5, 2015 - $nil) *[note 12]*	**15.5**	-
Net movements in regulatory balances related to OCI, net of tax (2016 - $5.5, 2015 - $nil) *[note 12]*	**(15.5)**	-
Other comprehensive income, net of tax	**-**	-
Total comprehensive income	**150.4**	130.4

See accompanying notes to the financial statements.

Toronto Hydro-Electric System Limited

STATEMENTS OF CHANGES IN EQUITY

[in millions of Canadian dollars]

Year ended December 31	2016 $	2015 $
Share capital ***[note 16]***	**556.3**	556.3
Retained earnings, beginning of year	**845.5**	715.1
Net income after net movements in regulatory balances	**150.4**	130.4
Retained earnings, end of year	**995.9**	845.5
Contributed surplus	**12.8**	12.8
Total equity	**1,565.0**	1,414.6

See accompanying notes to the financial statements.

Toronto Hydro-Electric System Limited

STATEMENTS OF CASH FLOWS

[in millions of Canadian dollars]

Year ended December 31	**2016** **$**	2015 $
OPERATING ACTIVITIES		
Net income after net movements in regulatory balances	**150.4**	130.4
Net movements in regulatory balances	**77.2**	(17.4)
Net movements in regulatory balances arising from deferred tax assets	**(44.0)**	(28.6)
Adjustments		
Depreciation and amortization *[notes 6 and 7]*	**210.6**	192.8
Amortization of deferred revenue *[note 10]*	**(3.8)**	(2.2)
Finance costs	**76.6**	73.2
Income tax expense	**67.2**	31.5
Post-employment benefits	**5.0**	9.1
Gain on disposals of property, plant and equipment	**(2.1)**	(10.1)
Other	**0.7**	0.7
Capital contributions received *[note 10]*	**44.3**	33.0
Net change in other non-current assets and liabilities	**(0.4)**	(0.6)
Increase in customer deposits	**6.7**	4.2
Changes in non-cash working capital balances *[note 21]*	**(14.2)**	20.5
Income tax paid	**(0.9)**	(8.5)
Net cash provided by operating activities	**573.3**	428.0
INVESTING ACTIVITIES		
Purchase of property, plant and equipment *[note 21]*	**(506.6)**	(547.9)
Purchase of intangible assets *[note 21]*	**(39.9)**	(21.1)
Proceeds on disposals of property, plant and equipment	**2.2**	14.4
Net cash used in investing activities	**(544.3)**	(554.6)
FINANCING ACTIVITIES		
Decrease in advance from related party	**-**	(308.0)
Increase in notes payable to related party *[note 11]*	**198.7**	243.1
Repayment of finance lease liability	**(3.1)**	(2.9)
Interest received	**0.3**	1.4
Interest paid	**(86.5)**	(80.6)
Net cash provided by (used in) financing activities	**109.4**	(147.0)
Net increase (decrease) in cash and cash equivalents (joint bank indebtedness) during the year	**138.4**	(273.6)
Cash and cash equivalents (joint bank indebtedness), beginning of year	**(188.9)**	84.7
Joint bank indebtedness, end of year	**(50.5)**	(188.9)

See accompanying notes to the financial statements.

1. NATURE OF BUSINESS

Toronto Hydro-Electric System Limited ["LDC"] was incorporated on June 23, 1999 under the *Business Corporations Act* (Ontario) in accordance with the Electricity Act. LDC is wholly-owned by Toronto Hydro Corporation [the "Corporation"] and is domiciled in Canada, with its registered office is located at 14 Carlton Street, Toronto, Ontario, M5B 1K5.

LDC distributes electricity to customers located in the City of Toronto [the "City"] and is subject to rate regulation. LDC is also engaged in the delivery of CDM activities.

2. BASIS OF PRESENTATION

LDC's audited financial statements have been prepared in accordance with IFRS with respect to the preparation of annual financial information.

These financial statements are presented in Canadian dollars, LDC's functional currency, and have been prepared on the historical cost basis, except for the valuation of post-employment benefits.

LDC has evaluated the events and transactions occurring after the balance sheet date through March 2, 2017 when LDC's financial statements were authorized for issue by LDC's Board of Directors, and identified no events and transactions which required recognition in the financial statements and/or disclosure in the notes to the financial statements.

The summary of significant accounting policies has been disclosed in note 25.

3. REGULATION

The OEB has regulatory oversight of electricity matters in Ontario. The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to approve the amounts paid to non-contracted generators, the responsibility to provide rate protection for rural or remote electricity customers, and the responsibility for ensuring that electricity distribution companies fulfill their obligations to connect and service customers.

LDC is required to charge its customers for the following amounts (all of which, other than distribution rates, represent a pass-through of amounts payable to third parties):

- *Commodity Charge* – The commodity charge represents the market price of electricity consumed by customers and is passed through the IESO to operators of generating stations. It includes the global adjustment, which represents the difference between the market price of electricity and the rates paid to regulated and contracted generators.

- *Retail Transmission Rate* – The retail transmission rate represents the costs incurred in respect of the transmission of electricity from generating stations to local distribution networks. Retail transmission rates are passed through to operators of transmission facilities.

- *WMS Charge* – The WMS charge represents various wholesale market support costs, such as the cost of the IESO to administer the wholesale electricity system, operate the electricity market, and maintain reliable operation of the provincial grid. Wholesale charges are passed through to the IESO.

- *Distribution Rate* – The distribution rate is designed to recover the costs incurred by LDC in delivering electricity to customers, including the OEB-allowed cost of capital. Distribution rates are regulated by the OEB and include fixed and variable (usage-based) components, based on a forecast of LDC's customers and load.

a) Electricity Distribution Rates

The OEB's regulatory framework for electricity distributors is designed to support the cost-effective planning and operation of the electricity distribution network and to provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price.

The OEB typically regulates the electricity rates for distributors using a combination of detailed cost of service reviews and IRM adjustments. Under the OEB's rate-setting methods, actual operating conditions may vary from forecasts such that actual returns achieved can differ from approved returns. Approved electricity rates are generally not adjusted as a result of actual costs or revenues being different from forecasted amounts, other than for certain prescribed costs that are eligible for deferral for future collection from, or refund to, customers.

On December 29, 2015, the OEB issued its CIR decision and on March 1, 2016, the OEB issued its CIR rate order, both in relation to the 2015-2019 rate application filed on July 31, 2014 [the "CIR decision and rate order"]. The CIR decision and rate order approved a rate base of $3,232.0 million and revenue requirement of $633.1 million for 2015, and rates calculated on that basis. The CIR decision and rate order also approved, on an interim basis, subsequent annual rate adjustments based on a custom index for the period commencing on January 1, 2016 and ending on December 31, 2019. The rates for 2015 and 2016 were implemented on March 1, 2016, with effective dates of May 1, 2015 and January 1, 2016, respectively *[note 8[a]]*. On August 22, 2016, LDC filed its 2017 rate application seeking OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2017 and ending on December 31, 2017. On December 21, 2016, the OEB issued a decision finalizing LDC's 2017 rates and providing for other deferral and variance account dispositions.

On July 28, 2016, the OEB approved a settlement proposal submitted by LDC and intervenors to the ICM rate application, which provided that there would be no change to the 2015-2019 rate base previously approved in the CIR decision and the 2012-2014 ICM process would be closed with no future disposition to or from ratepayers. Further to this approval, $9.8 million previously recorded as an ICM regulatory credit balance *[note 8]* was recorded as an increase in equity through net movements in regulatory balances in 2016.

b) CDM Activities

On December 21, 2012, the Minister of Energy of Ontario issued a direction to the OPA under subsection 25.32(4.1) of the Electricity Act to extend the funding time period for OPA-contracted province-wide CDM initiatives under the Green Energy Act framework to December 31, 2015. Funding for CDM programs approved pursuant to the 2011-2014 OPA agreement with in-service dates in 2015 would be allocated toward the 2011-2014 program budget. On March 18, 2015, LDC received approval from the IESO for separate funding of $11.2 million relating to these transitional CDM programs for 2015. Funding was fully received in the third quarter of 2015.

On March 26, 2014, the Minister of Energy of Ontario, under the guidance of sections 27.1 and 27.2 of the OEB Act, directed the OEB to amend the licence of each licensed electricity distributor to require the electricity distributor, as a condition of its licence, to make CDM programs available to its customers and to do so in relation to each customer segment in its service area, over the period beginning January 1, 2015 through December 31, 2020. On March 31, 2014, the Minister of Energy of Ontario issued a direction to require the OPA to coordinate, support and fund the delivery of CDM programs through electricity distributors. The objective of the new CDM efforts is to reduce electricity consumption in the Province of Ontario by a total of 7 terawatt hours between January 1, 2015 and December 31, 2020, of which LDC's share is approximately 1,576 GWh of energy savings.

On November 13, 2014, LDC entered into an energy conservation agreement with the OPA for the delivery of CDM programs over the 2015-2020 period. The IESO and the OPA were merged under the name IESO starting on January 1, 2015. Under the energy conservation agreement with the IESO, LDC has a joint CDM plan with Oakville Hydro Electricity Distribution Inc. for the delivery of CDM programs over the 2015-2020 period. The joint CDM plan provides combined funding of approximately $425.0 million, including participant incentives and program administration costs to achieve an aggregate energy savings target of approximately 1,668 GWh. The programs for Oakville Hydro Electricity Distribution Inc. under the joint CDM plan started on January 1, 2016. LDC received

$17.2 million as at December 31, 2015 and $27.7 million in the year ended December 31, 2016 from the IESO for the delivery of CDM programs. Amounts received but not yet spent are presented on the balance sheets under current liabilities as deferred conservation credit.

LDC can choose between full cost recovery funding, pay-for-performance funding, or a combination of both, on a CDM program by program basis. Under the full cost recovery funding method, the IESO reimburses LDC for all adequately documented incurred costs, with an option to receive a portion of its funding in advance. Cost efficiency incentives may be awarded if LDC's electricity savings meet or exceed certain CDM plan targets for programs under the full cost recovery funding method, with a mid-term review to be performed by the IESO for the 2015-2017 period. Under the pay-for-performance funding method, LDC receives payment in arrears based on verified electricity savings achieved with various options for frequency of payment. The programs under the joint CDM plan with Oakville Hydro Electricity Distribution Inc. are only being offered under the full cost recovery funding method.

4. ACCOUNTS RECEIVABLE

Accounts receivable consists of the following:

	2016 $	2015 $
Trade receivables	**214.7**	183.9
Due from related parties *[note 22]*	**10.1**	4.2
Other	**1.4**	1.9
	226.2	190.0

5. OTHER ASSETS

Other assets consist of the following:

	2016 $	2015 $
Prepaid expenses	**12.3**	9.5
Deferred financing costs	**1.6**	1.6
Other	**0.9**	—
Total other assets	**14.8**	11.1
Less: Current portion of other assets relating to:		
Prepaid expenses	**12.3**	9.5
Deferred financing costs	**0.4**	0.4
Other	**0.8**	—
Current portion of other assets	**13.5**	9.9
Non-current portion of other assets	**1.3**	1.2

6. PROPERTY, PLANT AND EQUIPMENT

PP&E consist of the following:

	Distribution assets $	Land and buildings $	Equipment and other $	Construction in progress $	Total $
Cost					
Balance as at January 1, 2015	2,685.7	137.6	107.2	431.2	3,361.7
Additions/(Transfers)	368.0	67.6	12.5	65.1	513.2
Disposals and retirements	(26.5)	(2.1)	—	—	(28.6)
Balance as at December 31, 2015	3,027.2	203.1	119.7	496.3	3,846.3
Additions/(Transfers)	**381.2**	**111.3**	**61.7**	**(48.1)**	**506.1**
Disposals and retirements	**(32.1)**	**(0.1)**	**(0.3)**	—	**(32.5)**
Balance as at December 31, 2016	**3,376.3**	**314.3**	**181.1**	**448.2**	**4,319.9**
Accumulated depreciation					
Balance as at January 1, 2015	106.1	7.0	24.1	—	137.2
Depreciation	118.9	9.1	22.0	—	150.0
Disposals and retirements	(2.4)	(0.4)	—	—	(2.8)
Balance as at December 31, 2015	222.6	15.7	46.1	—	284.4
Depreciation	**129.3**	**10.3**	**24.3**	—	**163.9**
Disposals and retirements	**(4.6)**	—	**(0.1)**	—	**(4.7)**
Balance as at December 31, 2016	**347.3**	**26.0**	**70.3**	—	**443.6**
Carrying amount					
Balance as at December 31, 2015	2,804.6	187.4	73.6	496.3	3,561.9
Balance as at December 31, 2016	**3,029.0**	**288.3**	**110.8**	**448.2**	**3,876.3**

As at December 31, 2016, Equipment and other included assets under finance lease with cost of $18.2 million [December 31, 2015 - $18.2 million] and accumulated depreciation of $8.3 million [December 31, 2015 - $6.0 million]. For the year ended December 31, 2016, LDC recorded depreciation expense of $2.3 million [2015 - $2.2 million] related to assets under finance lease.

For the year ended December 31, 2016, borrowing costs in the amount of $9.5 million [2015 - $7.0 million] were capitalized to PP&E and credited to finance costs, with an average capitalization rate of 3.61% [2015 - 3.74%].

Construction in progress additions are net of transfers to the other PP&E categories.

7. INTANGIBLE ASSETS

Intangible assets consist of the following:

	Computer software	Contributions	Software in development	Contributions for work in progress	Total
	$	$	$	$	$
Cost					
Balance as at January 1, 2015	86.7	19.9	13.2	98.5	218.3
Additions/(Transfers)	14.9	1.8	(1.4)	5.8	21.1
Balance as at December 31, 2015	101.6	21.7	11.8	104.3	239.4
Additions/(Transfers)	**11.9**	**53.8**	**8.4**	**(34.2)**	**39.9**
Balance as at December 31, 2016	**113.5**	**75.5**	**20.2**	**70.1**	**279.3**
Accumulated amortization					
Balance as at January 1, 2015	18.7	0.9	—	—	19.6
Amortization	19.4	1.1	—	—	20.5
Balance as at December 31, 2015	38.1	2.0	—	—	40.1
Amortization	**19.3**	**2.1**	—	—	**21.4**
Balance as at December 31, 2016	**57.4**	**4.1**	—	—	**61.5**
Carrying amount					
Balance as at December 31, 2015	63.5	19.7	11.8	104.3	199.3
Balance as at December 31, 2016	**56.1**	**71.4**	**20.2**	**70.1**	**217.8**

For the year ended December 31, 2016, borrowing costs in the amount of $3.0 million [2015 - $3.8 million] were capitalized to intangible assets and credited to finance costs, with an average capitalization rate of 3.61% [2015 - 3.74%].

Software in development and contributions for work in progress additions are net of transfers to the other intangible asset categories.

Computer software is externally acquired. The remaining amortization periods for computer software and contributions range from less than one year to 6 years, and from 12 to 25 years, respectively.

8. REGULATORY BALANCES

Debit balances consist of the following:

	January 1, 2016	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2016	Remaining recovery/ reversal period (months)	Carrying charges applicable
	$	$	$	$	$		
Foregone revenue	**61.1**	**19.2**	**(16.0)**	**—**	**64.3**	36	—
OPEB actuarial net loss	**81.2**	**(21.0)**	**—**	**—**	**60.2**	note 8[b]	—
IFRS transitional adjustments	**28.9**	**—**	**(6.1)**	**—**	**22.8**	36	—
Stranded meters	**14.4**	**—**	**(3.0)**	**—**	**11.4**	36	*
LRAM	**9.1**	**4.7**	**(3.3)**	**—**	**10.5**	note 8[e]	*
Gain on disposal	**—**	**—**	**14.5**	**(5.9)**	**8.6**	note 8[f]	*
Named properties	**5.8**	**—**	**(1.2)**	**—**	**4.6**	36	—
OPEB cash versus accrual	**1.8**	**1.1**	**—**	**—**	**2.9**	note 8[h]	—
Smart meters	**10.0**	**—**	**(7.9)**	**—**	**2.1**	4	—
Capital contributions	**1.9**	**—**	**(0.4)**	**—**	**1.5**	36	—
Settlement variances	**25.3**	**—**	**—**	**(25.3)**	**—**	—	*
Other	**2.2**	**1.6**	**—**	**(1.9)**	**1.9**	—	*
	241.7	**5.6**	**(23.4)**	**(33.1)**	**190.8**		

	January 1, 2015	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2015	Remaining recovery/ reversal period (months)	Carrying charges applicable
	$	$	$	$	$		
OPEB actuarial net loss	81.2	—	—	—	81.2	note 8[b]	—
Foregone revenue	—	61.1	—	—	61.1	46	—
IFRS transitional adjustments	24.2	4.7	—	—	28.9	46	—
Settlement variances	51.7	(26.4)	—	—	25.3	note 8[k]	*
Stranded meters	14.4	—	—	—	14.4	46	—
Smart meters	20.9	—	(10.9)	—	10.0	16	—
LRAM	—	9.1	—	—	9.1	note 8[e]	*
Named properties	—	5.8	—	—	5.8	46	—
Capital contributions	—	1.9	—	—	1.9	46	—
OPEB cash versus accrual	—	1.8	—	—	1.8	note 8[h]	—
Other	4.7	2.0	(0.1)	(4.4)	2.2	10	*
	197.1	60.0	(11.0)	(4.4)	241.7		

* Carrying charges were added to the regulatory balance in accordance with the OEB's direction at a rate of 1.10% for 2016 [January 1, 2015 to March 31, 2015 - 1.47%; April 1, 2015 to December 31, 2015 - 1.10%].

Credit balances consist of the following:

	January 1, 2016	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2016	Remaining recovery/ reversal period (months)	Carrying charges applicable
	$	$	$	$	$		
Deferred taxes	**114.8**	**(49.5)**	**—**	**—**	**65.3**	note 8[j]	—
Settlement variances	**—**	**89.3**	**1.2**	**(27.7)**	**62.8**	note 8[k]	*
Tax-related variances	**26.5**	**—**	**(8.5)**	**(0.5)**	**17.5**	24	*
Derecognition	**9.9**	**2.9**	**—**	**—**	**12.8**	note 8[m]	*
Capital-related revenue requirement	**2.8**	**6.0**	**—**	**—**	**8.8**	note 8[n]	*
ICM	**9.7**	**0.1**	**(9.8)**	**—**	**—**	—	*
Gain on disposal	**5.9**	**—**	**—**	**(5.9)**	**—**	—	*
Other	**2.0**	**1.2**	**(2.0)**	**1.0**	**2.2**	—	*
	171.6	**50.0**	**(19.1)**	**(33.1)**	**169.4**		

	January 1, 2015	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2015	Remaining recovery/ reversal period (months)	Carrying charges applicable
	$	$	$	$	$		
Deferred taxes	143.4	(28.6)	—	—	114.8	note 8[j]	—
Tax-related variances	25.3	1.2	—	—	26.5	10-34	*
Derecognition	—	9.9	—	—	9.9	note 8[m]	*
ICM	2.3	—	7.4	—	9.7	note 8[o]	*
Gain on disposal	—	5.9	—	—	5.9	note 8[f]	*
Capital-related revenue requirement	—	2.8	—	—	2.8	note 8[n]	*
Other	2.0	—	—	—	2.0	10	*
	173.0	(8.8)	7.4	—	171.6		

* Carrying charges were added to the regulatory balance in accordance with the OEB's direction at a rate of 1.10% for 2016 [January 1, 2015 to March 31, 2015 - 1.47%; April 1, 2015 to December 31, 2015 - 1.10%].

The "Balances arising in the period" column consists of new additions to regulatory balances (for both debits and credits). The "Recovery/reversal" column consists of amounts disposed through OEB-approved rate riders or transactions reversing an existing regulatory balance. The "Other movements" column consists of impairment and reclassification between the regulatory debit and credit balances. In addition, the "Other movements" column includes reclassification of regulatory deferral accounts considered to be insignificant into the "Other" categories. During 2016, residual regulatory balances approved by the OEB for disposition over a 10-month period commencing on March 1, 2016 were reclassified from "Other" regulatory debit balance, settlement variances and tax-related variances into "Other" regulatory credit balance. For the year ended December 31, 2015, LDC recorded an impairment of $4.4 million on regulatory debit balances within 'Other' as a result of the CIR decision and rate order. There was no impairment recorded for the year ended December 31, 2016.

Reconciliation between the net movements in regulatory balances shown above and the net movements presented on the statements of income and the statements of comprehensive income is as follows:

	2016 $	2015 $
Total movements per regulatory debit balances table	**(50.9)**	44.6
Total movements per regulatory credit balances table	**2.2**	1.4
Total net movements	**(48.7)**	46.0
Net movements per financial statements:		
Net movements in regulatory balances	**(77.2)**	17.4
Net movements in regulatory balances arising from deferred tax assets	**44.0**	28.6
Net movements in regulatory balances related to OCI, net of tax	**(15.5)**	—
Total net movements per financial statements	**(48.7)**	46.0

Ontario's electricity industry regulatory developments and other governmental policy changes may affect the electricity distribution rates charged by LDC and the costs LDC is permitted to recover. There is a risk that the OEB may disallow the recovery of a portion of certain costs incurred in the current period through future rates or disagree with the proposed recovery period. In the event that the disposition of these balances is assessed to no longer be probable based on management's judgment, any impairment will be recorded in the period when the assessment is made.

The regulatory balances of LDC consist of the following:

a) Foregone Revenue

This regulatory balance relates to the revenue that LDC would have recovered in 2015 and 2016 if new OEB-approved rates were implemented as of May 1, 2015 and January 1, 2016, respectively. In the CIR decision and rate order, the OEB approved foregone revenue rate riders commencing on March 1, 2016 for May 1, 2015 to December 31, 2015 based on approved 2015 rates and for January 1, 2016 to February 29, 2016 based on approved 2016 rates *[note 3[a]]*.

b) OPEB Actuarial Net Loss

This regulatory balance accumulates the actuarial gains and losses arising from changes in actuarial assumptions and experience adjustments recognized in OCI. The balance arising during the year ended December 31, 2016 of $21.0 million is related to the actuarial gain recorded for the year [2015 - $nil] *[note 12[a]]*; however, the net position is an actuarial loss that is recoverable in future rates. LDC has not sought recovery to date from the OEB as changes in underlying assumptions may reduce the balance in the account. LDC expects to recover this regulatory balance as per OEB direction when recovery is sought.

c) IFRS Transitional Adjustments

This regulatory balance relates to the differences arising from accounting policy changes for PP&E and intangible assets due to the transition from US GAAP to IFRS in 2014, primarily related to derecognition of certain assets and additional capitalized borrowing costs. In the CIR decision and rate order, the OEB approved disposition of the balance commencing on March 1, 2016 *[note 3[a]]*.

d) Stranded Meters and Smart Meters

These regulatory balances relate to the provincial government's decision to install smart meters throughout Ontario.

The net book value of stranded meters related to the deployment of smart meters was reclassified from PP&E to a new regulatory balance as at December 31, 2013. In the CIR decision and rate order, the OEB approved LDC's request for recovery of the forecasted net book value of the stranded meters as at December 31, 2014 commencing on March 1, 2016 *[note 3[a]]*.

On January 16, 2014, the OEB approved LDC's request for incremental revenue and disposition of the smart meter regulatory balances to be recovered through rates commencing on May 1, 2014. The OEB ruling on smart meters also permitted the recovery in principle of LDC's allowed cost of capital on smart meters since 2008, with a rate order issued to this effect. This allows LDC to recover the incremental revenue requirement associated with these assets for the period during which they remained outside of rate base.

e) Lost Revenue Adjustment Mechanism ["LRAM"]

This regulatory balance relates to the difference between the level of CDM program activities included in LDC's load forecast used to set approved rates and the actual impact of CDM activities achieved. New variances are accrued based on current CDM activities while approved variances up to 2014 are disposed through OEB-approved rate riders over twelve months commencing on January 1, 2017. Variances pertaining to years subsequent to 2014 have yet to be applied for disposition.

f) Gain on Disposal

This regulatory balance consists of the net of amounts disposed through the OEB-approved rate riders offset by the related tax savings (debits), and the after-tax gain realized on two significant LDC properties (credits). As part of the CIR decision and rate order, LDC agreed to a rate rider that would pass the total forecasted net gains along with future tax savings on both properties back to ratepayers, effective from March 1, 2016 to December 31, 2018. During 2015, the gain on one of the properties was realized by LDC resulting in a net credit balance at December 31, 2015. As at December 31, 2016, the amount disposed through the rate riders exceeded the gain realized on the first property as the second property was still not sold, resulting in a net debit balance. Upon the sale of the second property, the account would revert to a credit balance if actual net gains and tax savings exceed the total amount of the approved rate riders. LDC expects to seek disposition for any residual balance in a future rate application.

g) Named Properties

As part of 2010 rates, LDC had forecasted net gains on certain properties which were planned for sale in between 2007 and 2011. This regulatory balance relates to the excess of those forecasted net gains over the actual net gains realized upon the sale of the named properties. In the CIR decision and rate order, the OEB approved disposition of this variance commencing on March 1, 2016 *[note 3[a]]*.

h) OPEB Cash versus Accrual

This regulatory balance relates to the difference between LDC's forecasted OPEB costs determined on an accrual basis and the cash payments made under the OPEB plans. The OEB directed LDC to track the difference as a temporary arrangement, pending the OEB's conclusion on the sector-wide policy consultation it initiated on the regulatory treatment of pension and OPEB costs. LDC does not consider the OEB's direction to constitute a change in the basis of its recovery of OPEB costs at this time, considering the OEB's approval of the variance account. The timing of disposition of the balance is currently unknown.

i) Capital Contributions

This regulatory balance relates to the difference between amounts included in rates for HONI capital contributions and actual contributions made in 2010 and 2011. In the CIR decision and rate order, the OEB approved disposition of this variance commencing on March 1, 2016 *[note 3[a]]*.

j) Deferred Taxes

This regulatory credit balance relates to both deferred tax amounts reclassified under IFRS 14 *[note 25[a]]* and to the expected future electricity distribution rate reduction for customers arising from timing differences in the recognition of deferred tax assets. LDC did not apply for disposition of the balance since it is being reversed through timing differences in the recognition of deferred tax assets.

The amounts reclassified under IFRS 14 include the deferred tax liability related to regulatory balances of $36.4 million as at December 31, 2016 [December 31, 2015 - $42.1 million] offset by the recognition of a regulatory balance in respect of additional temporary differences for which a deferred tax amount was recognized of $10.4 million as at December 31, 2016 [December 31, 2015 - $26.2 million].

The deferred tax amount related to the expected future electricity distribution rate reduction for customers was $39.3 million as at December 31, 2016 [December 31, 2015 - $98.9 million].

k) Settlement Variances

This account includes the variances between amounts charged by LDC to customers, based on regulated rates, and the corresponding cost of electricity and non-competitive electricity service costs incurred by LDC. LDC has deferred the variances between the costs incurred and the related recoveries in accordance with the criteria set out in the accounting principles prescribed by the OEB. New variances are accrued based on current charges while approved variances up to 2015, including carrying charges forecasted to the end of 2016, are disposed through OEB-approved rate riders over twelve months commencing on January 1, 2017. Settlement variances pertaining to years subsequent to 2015 have yet to be applied for disposition.

l) Tax-related Variance Accounts

This regulatory credit balance arose from favourable income tax reassessments on certain prior year tax positions received, which differed from those assumed in previous applications for electricity distribution rates. In the CIR decision and rate order, the OEB approved disposition of the balance commencing on March 1, 2016 *[note 3[a]]*.

m) Derecognition

This regulatory balance relates to the difference between the revenue requirement on derecognition of PP&E and intangible assets included in the OEB-approved rates and the actual amounts of derecognition. This account was approved by the OEB in the CIR decision and rate order *[note 3[a]]*. The timing of disposition of the balance is currently unknown.

n) Capital-related Revenue Requirement

This regulatory balance relates to the asymmetrical variance between the cumulative 2015 to 2019 capital-related revenue requirement included in rates and the actual capital-related revenue requirement over the same period. If the cumulative 2015 to 2019 capital-related revenue requirement included in rates exceeds the actual capital-related revenue requirement over the same rate period, LDC must apply for disposition of this account in order to clear the balance to ratepayers through a rate rider. This account was approved by the OEB in the CIR decision and rate order *[note 3[a]]*. The timing of disposition of the balance is currently unknown.

o) Incremental Capital Module

This regulatory balance related to the ICM application approved by the OEB and the associated rate riders, which became effective June 1, 2013. The balance of $9.8 million represented the net of amounts collected through the ICM rate riders from 2013 to 2014 and amounts recognized in profit or loss in relation to the eligible in-service capital expenditures. Further to the OEB's decision of July 28, 2016, the entire balance of $9.8 million was recorded as an increase in equity through net movements in regulatory balances in 2016 *[note 3[a]]*.

9. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

Accounts payable and accrued liabilities consist of the following:

	2016 $	2015 $
Trade payables	**323.6**	316.2
Accrued liabilities	**116.3**	100.7
Due to related parties *[note 22]*	**58.7**	52.8
Other	**1.8**	1.9
	500.4	471.6

10. DEFERRED REVENUE

Deferred revenue consists of capital contributions received from electricity customers to construct or acquire PP&E which have not yet been recognized into other revenue, and revenue not yet recognized from ancillary services *[note 25[i]]*.

	2016 $	2015 $
Capital contributions, beginning of year	**103.0**	72.6
Capital contributions received	**44.3**	33.0
Amortization	**(3.8)**	(2.2)
Other	**(0.3)**	(0.4)
Capital contributions, end of year	**143.2**	103.0
Other	**1.0**	1.0
Total deferred revenue	**144.2**	104.0
Less: Current portion of deferred revenue relating to:		
Capital contributions	**3.3**	2.7
Other	**1.0**	1.0
Current portion of deferred revenue	**4.3**	3.7
Non-current portion of deferred revenue	**139.9**	100.3

11. NOTES PAYABLE TO RELATED PARTY

Notes payable to related party consist of the following:

	2016 $	2015 $
Notes payable to related party:		
5.20% Long-term note payable to the Corporation due November 14, 2017	**245.1**	245.1
4.54% Long-term note payable to the Corporation due November 12, 2019	**245.1**	245.1
5.59% Long-term note payable to the Corporation due May 21, 2040	**200.0**	200.0
3.59% Long-term note payable to the Corporation due November 18, 2021	**300.0**	300.0
2.96% Long-term note payable to the Corporation due April 10, 2023	**250.0**	250.0
4.01% Long-term note payable to the Corporation due April 9, 2063	**200.0**	200.0
4.13% Long-term note payable to the Corporation due September 16, 2044	**200.0**	200.0
3.60% Long-term note payable to the Corporation due July 28, 2045	**200.0**	200.0
3.988% Long-term note payable to the Corporation due April 9, 2063	**45.0**	45.0
2.572% Long-term note payable to the Corporation due August 25, 2026	**200.0**	—
6.16% Demand note payable to the Corporation due on demand	**45.0**	45.0
3.32% Demand note payable to the Corporation due on the earlier of demand and January 1, 2022	**15.0**	15.0
Total notes payable to related party	**2,145.2**	1,945.2
Less: Unamortized debt issuance costs	**9.7**	9.2
Current portion of notes payable to related party *[note 22]*	**304.9**	60.0
Long-term portion of notes payable to related party *[note 22]*	**1,830.6**	1,876.0

All notes payable to related party of LDC rank equally.

On March 16, 2015, LDC issued a promissory note to the Corporation. The principal amount of the promissory note is $200.0 million payable on July 28, 2045, which bears interest at a rate of 3.60% per annum. Interest is calculated and payable semi-annually in arrears on January 28 and July 28 of each year. The net proceeds from the promissory note were used to repay certain existing indebtedness of LDC and for general corporate purposes.

On September 2, 2015, LDC issued a promissory note to the Corporation. The principal amount of the promissory note is $45.0 million payable on April 9, 2063, which bears interest at a rate of 3.988% per annum. Interest is calculated and payable semi-annually in arrears on April 9 and October 9 of each year. The net proceeds from the promissory note were used to repay certain existing indebtedness of LDC and for general corporate purposes.

On June 14, 2016, LDC issued a promissory note to the Corporation. The principal amount of the promissory note is $200.0 million payable on August 25, 2026, which bears interest at a rate of 2.572% per annum. Interest is calculated and payable semi-annually in arrears on February 25 and August 25 of each year. The net proceeds from the promissory note were used to repay certain existing indebtedness of LDC and for general corporate purposes.

12. EMPLOYEE FUTURE BENEFITS

Pension

LDC's eligible employees participate in a defined benefit pension plan through OMERS. As at December 31, 2016, the OMERS plan was 93.4% funded [December 31, 2015 - 91.5%]. OMERS has a strategy to return the plan to a fully funded position. LDC is not able to assess the implications, if any, of this strategy or of the withdrawal of other participating entities from the OMERS plan on its future contributions. For the year ended December 31, 2016, LDC's contributions were $17.3 million [2015 - $17.2 million], representing less than five percent of total contributions to the OMERS plan. LDC expects to contribute approximately $18.8 million to the OMERS plan in 2017.

Post-employment benefits other than pension

a) Benefit obligation

	2016 $	2015 $
Balance, beginning of year	**296.5**	287.4
Current service cost	**5.8**	5.6
Interest cost	**11.7**	11.4
Benefits paid	**(10.9)**	(9.3)
Experience loss (gain) [(1)]	**(4.2)**	0.9
Actuarial gain arising from changes in demographic assumptions [(1)]	**(17.5)**	—
Actuarial gain arising from changes in financial assumptions [(1)]	**(1.6)**	—
Transfer from related parties	**0.7**	0.5
Balance, end of year	**280.5**	296.5

[(1)] Actuarial loss (gain) on accumulated sick leave credits of ($2.1) million [2015 - $0.8 million] is recognized in benefit cost *[note 12[c]]* and ($0.2) million in transfer from related parties [2015 - $0.1 million], and ($21.0) million [2015 - $nil] of actuarial gain on medical, dental and life insurance benefits is recognized in OCI *[note 12[d]]*.

The weighted average duration of the benefit obligation as at December 31, 2016 is 16.7 years [2015 – 17.1 years].

b) Amounts recognized in regulatory balances

As at December 31, 2016, the amount recognized in regulatory balances related to net actuarial loss and IFRS transitional adjustments was $60.2 million [December 31, 2015 - $81.2 million] *[note 8[b]]*.

c) Benefit cost recognized

	2016 $	2015 $
Current service cost	**5.8**	5.6
Interest cost	**11.7**	11.4
Actuarial loss (gain) on other employee benefits *[note 12[a]]*	**(2.1)**	0.8
Benefit cost	**15.4**	17.8
Capitalized to PP&E and intangible assets	**6.4**	7.7
Charged to operating expenses	**9.0**	10.1

d) Amounts recognized in OCI

	2016 $	2015 $
Actuarial gain *[note 12[a]]*	**(21.0)**	—
Income tax expense in OCI *[note 20]*	**5.5**	—
Remeasurements of post-employment benefits, net of tax	**(15.5)**	—
Net movements in regulatory balances related to OCI, net of tax	**15.5**	—
OCI, net of tax	—	—

e) Significant assumptions

	2016	2015
Discount rate (%) used in the calculation of:		
Benefit obligation as at December 31	**4.00**	4.00
Assumed medical and dental cost trend rates (%) as at December 31:		
Rate of increase in dental costs assumed for next year	**4.00**	4.00
Rate of increase in medical costs assumed for next year		
For pre July 2000 retirements	**5.00**	5.00
For other retirements	**5.50**	6.00
Rate that medical cost trend rate gradually declines to		
For pre July 2000 retirements	**5.00**	5.00
For other retirements	**5.00**	5.00
Year that the medical cost trend rate reaches the ultimate trend rate		
For pre July 2000 retirements	**2015**	2015
For other retirements	**2018**	2018

f) Sensitivity analysis

Significant actuarial assumptions for benefit obligation measurement purposes are discount rate and assumed medical and dental cost trend rates. The sensitivity analysis below has been determined based on reasonably possible changes of the assumptions, in isolation of one another, occurring at the end of the reporting period. This analysis may not be

representative of the actual change since it is unlikely that the change in the assumptions would occur in isolation of one another as some of the assumptions may be correlated.

Changes in key assumptions would have had the following effect on the benefit obligation:

	Change in assumption	2016 $	2015 $
As reported		**280.5**	296.5
Discount rate	1% ↑	**(42.0)**	(45.5)
	1% ↓	**54.0**	54.1
Medical and dental cost trend rate	1% ↑	**36.1**	38.6
	1% ↓	**(32.3)**	(34.7)

13. CAPITAL MANAGEMENT

LDC's main objectives when managing capital are to:

- ensure ongoing access to funding to maintain, refurbish and expand the electricity distribution system;
- ensure sufficient liquidity is available (either through cash and cash equivalents, investments or borrowings through TH Energy or the Corporation) to meet the needs of the business; and
- minimize finance costs while taking into consideration current and future industry, market and economic risks and conditions.

LDC monitors forecasted cash flows, capital expenditures, debt repayment and key credit ratios similar to those used by key rating agencies. LDC manages capital by preparing short-term and long-term cash flow forecasts. In addition, LDC borrows from TH Energy or the Corporation as required to help fund some of the periodic net cash outflows and to maintain available liquidity. There have been no changes in LDC's approach to capital management during the year. As at December 31, 2016, LDC's definition of capital included bank indebtedness, borrowings through the Corporation and obligations under finance leases, including the current portion thereof, and equity, and had remained unchanged from the definition as at December 31, 2015. As at December 31, 2016, equity amounted to $1,565.0 million [December 31, 2015 - $1,414.6 million], and bank indebtedness, borrowings through the Corporation and obligations under finance leases, including the current portion thereof, amounted to $2,191.0 million [December 31, 2015 - $2,132.9 million].

14. FINANCIAL INSTRUMENTS

a) Recognition and measurement

As at December 31, 2016 and December 31, 2015, the fair values of cash and cash equivalents, accounts receivable, unbilled revenue, bank indebtedness, advance from related party, and accounts payable and accrued liabilities approximated their carrying amounts due to the short maturity of these instruments *[note 25[j]]*. The fair value of customer deposits approximates their carrying amounts taking into account interest accrued on the outstanding balance. Obligations under finance leases are measured based on a discounted cash flow analysis and approximate the carrying amounts as management believes that the fixed interest rates are representative of current market rates.

The carrying amounts and fair values of LDC's notes payable consist of the following:

	2016 $		2015 $	
	Carrying amount	**Fair value [1]**	**Carrying amount**	**Fair value [1]**
Long-term notes payable to the Corporation				
5.20% due November 14, 2017	**244.9**	**253.7**	244.7	262.1
4.54% due November 12, 2019	**244.6**	**265.6**	244.4	271.5
5.59% due May 21, 2040	**198.8**	**253.3**	198.8	248.2
3.59% due November 18, 2021	**299.0**	**322.9**	298.9	326.2
2.96% due April 10, 2023	**249.1**	**259.7**	249.0	259.7
4.01% due April 9, 2063	**198.7**	**201.2**	198.7	194.2
4.13% due September 16, 2044	**198.5**	**209.4**	198.4	203.4
3.60% due July 28, 2045	**198.6**	**191.3**	198.6	185.2
3.988% due April 9, 2063	**44.5**	**45.1**	44.5	43.5
2.572% due August 25, 2026	**198.8**	**194.6**	—	—
Demand note payable to the Corporation due on demand	**45.0**	**45.0**	45.0	45.0
Demand note payable to the Corporation due on the earlier of demand and January 1, 2022	**15.0**	**16.0**	15.0	16.1
	2,135.5	**2,257.8**	1,936.0	2,055.1

[1] The fair value measurement of financial instruments for which the fair value has been disclosed is included in Level 2 of the fair value hierarchy *[note 25[j]]*.

b) Financial risks

The following is a discussion of financial risks and related mitigation strategies that have been identified by LDC for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks listed.

Credit risk

LDC is exposed to credit risk as a result of the risk of counterparties defaulting on their obligations. LDC's exposure to credit risk primarily relates to accounts receivable and unbilled revenue. LDC monitors and limits its exposure to credit risk on a continuous basis.

LDC is subject to credit risk with respect to customer non-payment of electricity bills. As at December 31, 2016, LDC had approximately 761,000 customers. LDC obtains security instruments from certain customers in accordance with direction provided by the OEB. As at December 31, 2016, LDC held security deposits in the amount of $54.1 million [December 31, 2015 - $47.4 million], of which $30.0 million [December 31, 2015 - $25.1 million] was related to security deposits on offers to connect to guarantee the payment of additional costs related to expansion projects. As at December 31, 2016, there were no significant concentrations of credit risk with respect to any customer. The credit risk and mitigation strategies with respect to unbilled revenue are the same as for accounts receivable. The credit risk related to cash, cash equivalents and investments is mitigated by LDC's treasury policies on assessing and monitoring the credit exposures of counterparties.

LDC did not have any single customer that generated more than 10% of total revenue for the years ended December 31, 2016 and December 31, 2015.

Credit risk associated with accounts receivable and unbilled revenue is as follows:

	2016 $	2015 $
Accounts receivable (net of allowance for doubtful accounts)		
Outstanding for not more than 30 days	**196.7**	170.5
Outstanding for more than 30 days and not more than 120 days	**25.4**	16.4
Outstanding for more than 120 days	**4.1**	3.1
Total accounts receivable	**226.2**	190.0
Unbilled revenue	**319.7**	319.5
Total accounts receivable and unbilled revenue	**545.9**	509.5

LDC has a broad base of customers. As at December 31, 2016 and December 31, 2015, LDC's accounts receivable and unbilled revenue which were not past due or impaired were assessed by management to have no significant collection risk and no additional allowance for doubtful accounts was required for these balances.

Reconciliation between the opening and closing allowance for doubtful accounts balances is as follows:

	2016 $	2015 $
Balance, beginning of year	**(11.5)**	(11.8)
Provision for doubtful accounts	**(5.5)**	(7.1)
Write-offs	**7.6**	7.6
Recoveries	**(0.3)**	(0.2)
Balance, end of year	**(9.7)**	(11.5)

Unbilled revenue represents amounts for which LDC has a contractual right to receive cash through future billings and are unbilled at period-end. Unbilled revenue is considered current and no allowance for doubtful accounts was provided as at December 31, 2016 and December 31, 2015.

Interest rate risk

LDC is exposed to fluctuations in interest rates for the valuation of its post-employment benefit obligations *[note 12[f]]*. LDC is also exposed to short-term interest rate risk on the net of cash and cash equivalents, notes payable to related party, and customer deposits. Notes payable to related party bear interest based on the prevailing market conditions at the time of issuance.

As at December 31, 2016, aside from the valuation of its post-employment benefit obligations, LDC was exposed to interest rate risk predominately from notes payable to related party and customer deposits, while most of its remaining obligations were either non-interest bearing or bear fixed interest rates, and its financial assets were predominately short-term in nature and mostly non-interest bearing. LDC estimates that a 100 basis point increase (decrease) in short-term interest rates, with all other variables held constant, would result in an increase (decrease) of approximately $1.0 million to annual finance costs.

Liquidity risk

LDC is exposed to liquidity risk related to its ability to fund its obligations as they become due. LDC monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and financial requirements. LDC has access to credit facilities and borrowings through the Corporation and monitors cash balances daily. LDC's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing finance costs.

Liquidity risks associated with financial commitments are as follows:

2016	Due within 1 year $	Due within 2 years $	Due within 3 years $	Due within 4 years $	Due within 5 years $	Due after 5 years $
Bank indebtedness	**50.5**	—	—	—	—	—
Accounts payable and accrued liabilities [(1)]	**481.9**	—	—	—	—	—
Obligations under finance lease	**3.2**	**1.6**	—	—	—	—
Long-term notes payable to the Corporation						
5.20% due November 14, 2017	**245.1**	—	—	—	—	—
4.54% due November 12, 2019	—	—	**245.1**	—	—	—
5.59% due May 21, 2040	—	—	—	—	—	**200.0**
3.59% due November 18, 2021	—	—	—	—	**300.0**	—
2.96% due April 10, 2023	—	—	—	—	—	**250.0**
4.01% due April 9, 2063	—	—	—	—	—	**200.0**
4.13% due September 16, 2044	—	—	—	—	—	**200.0**
3.60% due July 28, 2045	—	—	—	—	—	**200.0**
3.988% due April 9, 2063	—	—	—	—	—	**45.0**
2.572% due August 25, 2026	—	—	—	—	—	**200.0**
Demand note payable to the Corporation due on demand	**45.0**	—	—	—	—	—
Demand note payable to the Corporation due on the earlier of demand and January 1, 2022	**15.0**	—	—	—	—	—
Interest payments on long-term notes payable and demand notes payable	**85.5**	**77.8**	**71.4**	**65.8**	**60.3**	**1,014.0**
	926.2	**79.4**	**316.5**	**65.8**	**360.3**	**2,309.0**

[(1)] Accounts payable and accrued liabilities exclude $18.5 million of accrued interest on long-term notes payable and demand notes payable included within "Interest payments on long-term notes payable and demand notes payable".

Foreign exchange risk

As at December 31, 2016, LDC had limited exposure to the changing values of foreign currencies. While LDC purchases goods and services which are payable in US dollars, and purchases US currency to meet the related commitments when required, the impact of these transactions is not material to the financial statements.

15. FINANCIAL ASSISTANCE

As at December 31, 2016, $33.4 million [December 31, 2015 - $32.4 million] of letters of credit had been issued by the Corporation, on behalf of LDC, under its $75.0 million demand facility mainly to support LDC's prudential requirements with the IESO.

16. SHARE CAPITAL

Share capital consists of the following:

	2016 $	2015 $
Authorized		
The authorized share capital of LDC consists of an unlimited number of common shares without par value.		
Issued and outstanding		
1,000 common shares, of which all were fully paid.	**556.3**	556.3

17. OTHER REVENUE

Other revenue consists of the following:

	2016 $	2015 $
Other regulatory service charges	**16.7**	13.5
Ancillary services	**15.2**	9.9
Pole and duct rentals	**12.0**	10.5
Street lighting service fee	**5.8**	4.7
Amortization of deferred revenue	**3.8**	2.2
Miscellaneous	**12.8**	7.5
	66.3	48.3

18. OPERATING EXPENSES

Operating expenses consist of the following:

	2016 $	2015 $
Salaries and benefits	**218.9**	224.9
External services	**108.6**	93.1
Materials and supplies	**16.4**	14.8
Other support costs [(1)]	**32.2**	37.7
Less: Capitalized costs	**(108.5)**	(111.5)
	267.6	259.0

[(1)] Includes taxes other than income taxes, utilities, rental, communication, insurance, and other general and administrative expenses.

For the year ended December 31, 2016, LDC recognized operating expenses of $7.6 million related to materials and supplies used to service electricity distribution assets [2015 - $6.6 million].

19. FINANCE COSTS

Finance costs consist of the following:

	2016 $	2015 $
Interest income	**(0.3)**	(1.4)
Interest expense		
Interest on long-term debt [(1)]	**85.4**	79.8
Interest on short-term debt	**3.6**	4.5
Other interest	**0.5**	1.1
Capitalized borrowing costs	**(12.6)**	(10.8)
	76.6	73.2

[(1)] Includes amortization of debt issuance costs, discounts and premiums.

20. INCOME TAXES

Income tax expense differs from the amount that would have been recorded using the combined statutory Canadian federal and provincial income tax rate. Reconciliation of income tax expense computed at the statutory income tax rate to the income tax provision is set out below:

	2016 $	2015 $
Rate reconciliation before net movements in regulatory balances		
Income before income taxes	**250.8**	115.9
Statutory Canadian federal and provincial income tax rate	**26.5%**	26.5%
Expected income tax expense	**66.5**	30.7
Other	**0.7**	0.8
Income tax expense	**67.2**	31.5
Effective tax rate	**26.8%**	27.2%
Rate reconciliation after net movements in regulatory balances		
Net income after net movements in regulatory balances, before income tax [(1)]	**173.6**	133.3
Statutory Canadian federal and provincial income tax rate	**26.5%**	26.5%
Expected income tax expense	**46.0**	35.3
Temporary differences recoverable in future rates	**(22.7)**	(31.7)
Other	**(0.1)**	(0.7)
Income tax expense and income tax recorded in net movements in regulatory balances	**23.2**	2.9
Effective tax rate	**13.4%**	2.2%

[(1)] Income tax includes income tax expense and income tax recorded in net movements in regulatory balances.

Income tax expense as presented in the statements of income and OCI are as follows:

	2016 $	2015 $
Income tax expense	**67.2**	31.5
Income tax recorded in net movements in regulatory balances	**(44.0)**	(28.6)
Income tax expense and income tax recorded in net movements in regulatory balances	**23.2**	2.9
Income tax expense in OCI *[note 12[d]]*	**5.5**	—
Income tax recovery in OCI recorded in net movements in regulatory balances	**(5.5)**	—
Income tax expense in OCI	**—**	—

Components of income tax expense and income tax recorded in net movements in regulatory balances are as follows:

	2016 $	2015 $
Current tax expense		
Current year	**24.4**	3.1
Adjustment for tax positions taken in prior periods	**(2.2)**	(0.3)
	22.2	2.8
Deferred tax expense		
Origination and reversal of temporary differences	**1.0**	0.1
Income tax expense and income tax recorded in net movements in regulatory balances	**23.2**	2.9

Deferred tax assets consist of the following:

	Net balance, January 1 2016 $	Recognized in net income $	Recognized in OCI $	Net balance, December 31 2016 $
PP&E and intangible assets	**34.5**	**(22.8)**	**—**	**11.7**
Post-employment benefits	**78.6**	**1.2**	**(5.5)**	**74.3**
Other taxable temporary differences	**1.2**	**(23.4)**	**—**	**(22.2)**
	114.3	**(45.0)**	**(5.5)**	**63.8**

	Net balance, January 1 2015 $	Recognized in net income $	Recognized in OCI $	Net balance, December 31 2015 $
PP&E and intangible assets	55.0	(20.5)	—	34.5
Post-employment benefits	76.2	2.4	—	78.6
Other taxable temporary differences	11.9	(10.7)	—	1.2
	143.1	(28.8)	—	114.3

LDC had recorded a net deferred tax asset as it expects to earn sufficient taxable income to realize the future reversal of deductible temporary differences.

21. STATEMENTS OF CASH FLOWS

Changes in non-cash working capital provided/(used) cash as follows:

	2016 $	2015 $
Accounts receivable	**(36.5)**	14.3
Unbilled revenue	**(0.2)**	(12.9)
Income tax receivable	**9.0**	(8.8)
Materials and supplies	**0.1**	(1.2)
Other current assets	**(3.6)**	—
Accounts payable and accrued liabilities	**19.9**	9.1
Income tax payable	**9.0**	—
Deferred revenue	**0.6**	1.5
Deferred conservation credit	**(12.4)**	17.9
Other current liabilities	**(0.1)**	0.6
	(14.2)	20.5

Reconciliation between the amount presented on the statements of cash flows and total additions to PP&E and intangible assets is as follows:

	2016 $	2015 $
Purchase of PP&E, cash basis	**506.6**	547.9
Net change in accruals related to PP&E	**(2.3)**	(36.4)
Other	**1.8**	1.7
Total additions to PP&E	**506.1**	513.2
Purchase of intangible assets, cash basis	**39.9**	21.1
Total additions to PP&E and intangible assets	**546.0**	534.3

22. RELATED PARTY TRANSACTIONS

For LDC, transactions with related parties include transactions with the City, which wholly owns the Corporation, the Corporation and TH Energy, a wholly-owned subsidiary of the Corporation.

	City $	Corporation $	TH Energy $
For period ended December 31, 2016			
Revenues	**258.5**	—	**8.7**
Operating expenses and capital expenditures	**26.9**	**1.5**	**0.9**
Finance costs	—	**85.8**	—
As at December 31, 2016			
Accounts receivable	**9.3**	—	**0.8**
Unbilled revenue	**23.1**	—	—
Accounts payable and accrued liabilities	**41.0**	**17.7**	—
Current portion of notes payable to related party	—	**304.9**	—
Long-term portion of notes payable to related party	—	**1,830.6**	—
Customer deposits	**14.1**	—	—
Deferred revenue	**3.0**	—	—

	City $	Corporation $	TH Energy $
For period ended December 31, 2015			
Revenues	222.6	—	7.6
Operating expenses and capital expenditures	19.7	3.6	0.5
Finance costs	—	80.4	—
As at December 31, 2015			
Accounts receivable	3.2	—	1.0
Unbilled revenue	20.8	—	—
Accounts payable and accrued liabilities	36.6	16.2	—
Current portion of notes payable to related party	—	60.0	—
Long-term portion of notes payable to related party	—	1,876.0	—
Customer deposits	11.7	—	—
Deferred revenue	1.0	—	—

Revenues represent amounts charged to the City primarily for electricity and ancillary services, and to TH Energy for street lighting and ancillary services. Operating expenses and capital expenditures represent amounts charged by the City for purchased road cut repairs, property taxes and other services, the Corporation for purchased corporate and management services, and TH Energy for the provision of goods and services. Finance costs represent interest charged by the Corporation on the notes payable *[note 11]*.

Accounts receivable represents receivables from the City primarily for electricity and ancillary services, and TH Energy for the provision of goods and services. Unbilled revenue represents receivables from the City mainly related to electricity provided and not yet billed. Accounts payable and accrued liabilities represent amounts payable to the City related to road cut repairs and other services. Included in the accounts payable and accrued liabilities are amounts payable to the Corporation for purchased corporate and management services and interest accruing on the notes payable to the Corporation. Notes payable to related party represent amounts borrowed from the Corporation *[note 11]*. Customer deposits represent amounts received from the City for future expansion projects. Deferred revenue represents amounts received from the City primarily for the construction of electricity distribution assets.

Key management personnel include LDC's senior executive officers and members of the Board of Directors. The compensation costs associated with the key management personnel are as follows:

	2016 $	2015 $
Short-term employee benefits	**3.7**	4.2
Post-employment benefits	**1.0**	1.0
Termination benefits	**—**	0.9
	4.7	6.1

23. COMMITMENTS

Operating leases and capital projects

As at December 31, 2016, the future minimum payments under property operating leases, capital projects and other commitments were as follows:

	Operating leases $	Capital projects [2] and other $
Less than one year	**2.6**	**20.2**
Between one and five years	**3.0**	**2.5**
Total amount of future minimum payments [1]	**5.6**	**22.7**

[1] Refer to note 14 for financial commitments excluded from the table above.
[2] Mainly commitments for construction services.

Operating lease expense for the year ended December 31, 2016 was $6.4 million [2015 - $6.3 million].

Finance leases

As at December 31, 2016 and December 31, 2015, reconciliation between the future minimum lease payments and their present value was as follows:

	2016 $			2015 $		
	Future minimum lease payments	Interest	Present value of minimum lease payments	Future minimum lease payments	Interest	Present value of minimum lease payments
Less than one year	**3.2**	**0.2**	**3.0**	3.5	0.3	3.2
Between one and five years	**1.6**	**—**	**1.6**	5.0	0.2	4.8
More than five years	**—**	**—**	**—**	—	—	—
	4.8	**0.2**	**4.6**	8.5	0.5	8.0
Current portion included in Other liabilities			**3.0**			3.2
Non-current portion included in Other liabilities			**1.6**			4.8

24. CONTINGENCIES

Legal Proceedings

In the ordinary course of business, LDC is subject to various legal actions and claims from customers, suppliers, former employees and other parties. On an ongoing basis, LDC assesses the likelihood of any adverse judgments or outcomes as well as potential ranges of probable costs and losses. A determination of the provision required, if any, for these contingencies is made after an analysis of each individual issue. The provision may change in the future due to new developments in each matter or changes in approach, such as a change in settlement strategy. If damages were awarded under these actions, LDC would make a claim under any applicable liability insurance policies which LDC believes would cover any damages which may become payable by LDC in connection with these actions, subject to such claim not being disputed by the insurers.

25. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

a) Regulation

The following regulatory treatments have resulted in accounting treatments which differ from those prescribed by IFRS for enterprises operating in an unregulated environment and regulated entities that did not adopt IFRS 14 *Regulatory Deferral Accounts* ["IFRS 14"]:

Regulatory Balances

In January 2014, the IASB issued IFRS 14 as an interim standard giving entities conducting rate-regulated activities the option of continuing to recognize regulatory balances according to their previous GAAP. Regulatory balances provide useful information about LDC's financial position, financial performance and cash flows. IFRS 14 is restricted to first-time adopters of IFRS and remains in force until either repealed or replaced by permanent guidance on rate-regulated accounting from the IASB. LDC elected to early adopt IFRS 14 for the year ended December 31, 2015.

LDC has determined that certain debit and credit balances arising from rate-regulated activities qualify for the application of regulatory accounting treatment in accordance with IFRS 14 and the accounting principles prescribed by the OEB in the "Accounting Procedures Handbook for Electricity Distributors". Under rate-regulated accounting, the timing and recognition of certain expenses and revenues may differ from those otherwise expected under other IFRS in order to appropriately reflect the economic impact of regulatory decisions regarding LDC's regulated revenues and expenditures. These amounts arising from timing differences are recorded as regulatory debit and credit balances on LDC's balance sheets, and represent existing rights and obligations regarding cash flows expected to be recovered from or refunded to customers, based on decisions and approvals by the OEB. Regulatory balances can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment or if future OEB direction is determined by management to be probable. In the event that the disposition of these balances is assessed to no longer be probable based on management's judgment, the balances are recorded in LDC's statements of income in the period when the assessment is made. Regulatory balances that do not meet the definition of an asset or liability under any other IFRS are segregated on the balance sheets, the statements of income and the statements of comprehensive income as net movements in regulatory balances and net movements in regulatory balances related to OCI, net of tax. The netting of regulatory debit and credit balances is not permitted. The measurement of regulatory balances is subject to certain estimates and assumptions, including assumptions made in the interpretation of the OEB's regulations and decisions.

b) Cash and cash equivalents

Cash and cash equivalents include cash in bank accounts and short-term investments with terms to maturity of 90 days or less from their date of acquisition. On the statements of cash flows, cash and cash equivalents (joint bank indebtedness) include bank overdrafts that are repayable on demand and form an integral part of LDC's cash management.

c) Accounts receivable and unbilled revenue

Accounts receivable is recorded at the invoiced amount and overdue amounts bear interest at OEB-approved rates. Unbilled revenue is recorded based on an estimated amount for electricity delivered and for other services provided and not yet billed. The estimate is primarily based on the customers' previous billings with adjustments mainly for assumptions related to seasonality and weighted average price. The carrying amount of accounts receivable and unbilled revenue is reduced through an allowance for doubtful accounts, if applicable, and the amount of the related impairment loss is recognized in the statements of income. The impairment loss is the difference between an asset's carrying amount and the estimated future cash flows. When LDC considers that there are no realistic prospects of recovery of the financial assets, the relevant amounts are written off. If the amount of impairment loss subsequently decreases due to an event occurring after the impairment was recognized, then the previously recognized impairment loss is reversed through net income.

Accounts receivable and unbilled revenue are assessed at each reporting date to determine whether there is objective evidence of impairment, which includes default or delinquency by a debtor, indications that a debtor or issuer will enter bankruptcy, and adverse changes in the payment status of borrowers or issuers. Accounts receivable and unbilled revenue that are not individually assessed for impairment are collectively assessed for impairment by grouping together receivables with similar risk characteristics, and LDC considers historical trends on the timing of recoveries and the amount of loss incurred, as well as current economic and credit conditions.

d) Materials and supplies

Materials and supplies consist primarily of small consumable materials mainly related to the maintenance of the electricity distribution infrastructure. LDC classifies all major construction related components of its electricity distribution infrastructure to PP&E. Materials and supplies are carried at the lower of cost and net realizable value, with cost determined on a weighted average cost basis net of a provision for obsolescence.

e) Property, plant and equipment

PP&E are measured at cost less accumulated depreciation and any accumulated impairment losses, if applicable. The cost of PP&E represents the original cost, consisting of direct materials and labour, contracted services, borrowing costs, and directly attributable overhead. Subsequent costs are capitalized only if it is probable that the future economic benefits associated with the expenditure will flow to LDC and the costs can be measured reliably. If significant parts of an item of PP&E have different useful lives, then they are accounted for as separate major components of PP&E. The carrying amount of an item of PP&E is derecognized on disposal of the asset or when no future economic benefits are expected to accrue to LDC from its continued use. Any gain or loss arising on derecognition is recorded in the statements of income in the period in which the asset is derecognized. The gain or loss on disposal of an item of PP&E is determined as the difference between the sale proceeds less the carrying amount of the asset and costs of removal and is recognized in the statements of income.

Depreciation begins when an asset becomes available for use. Depreciation is provided on a straight-line basis over the estimated useful lives at the following annual rates:

Distribution assets:	
Distribution lines	1.7% to 5.0%
Transformers	3.3% to 5.0%
Meters	2.5% to 6.7%
Stations	2.5% to 10.0%
Buildings	1.3% to 5.0%
Equipment and other:	
Assets under finance lease	1.0% to 14.3%
Other capital assets	4.0% to 25.0%

Leased assets are depreciated over the shorter of the lease term and their useful lives unless it is reasonably certain that LDC will obtain ownership by the end of the lease term. Assets under finance lease included a 99-year land lease. Construction in progress relates to assets not currently available for use and therefore is not depreciated. The depreciation method and useful lives are reviewed each financial year-end and adjusted if appropriate. There are no residual values for items of PP&E.

f) Intangible assets

Intangible assets are measured at cost less accumulated amortization and any accumulated impairment losses, if applicable.

Amortization begins when an asset becomes available for use. Amortization is provided on a straight-line basis over the estimated useful lives at the following annual rates:

Computer software	10.0% to 25.0%
Contributions	4.0%

Software in development and contributions for work in progress relate to assets not currently available for use and therefore are not amortized. Contributions represent payments made to HONI for dedicated infrastructure in order to receive connections to transmission facilities. The amortization method and useful lives are reviewed each financial year-end and adjusted if appropriate.

g) Impairment of non-financial assets

LDC reviews the carrying amounts of its non-financial assets other than materials and supplies and deferred tax assets at each reporting date to determine whether there is any indication of impairment, in which case the assets' recoverable amounts are estimated. For impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent on the cash inflows of other assets or CGUs. LDC has determined that its assets are a single CGU due to interdependencies of its assets to generate cash flows. An impairment loss is recognized if the carrying amount of an asset or CGU exceeds its recoverable amount. Impairment losses are recognized in the statements of income, and are allocated to reduce the carrying amounts of assets in the CGU on a pro rata basis. An impairment loss recognized in prior periods is reversed when an asset's recoverable amount has increased, but not exceeding the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior years.

h) Capitalized borrowing costs

Borrowing costs directly attributable to the acquisition, construction or development of qualifying assets that necessarily take a substantial period of time to get ready for their intended use are capitalized, until such time as the assets are substantially ready for their intended use. The interest rate for capitalization is LDC's weighted average cost of borrowing, and is applied to the carrying amount of the construction-in-progress assets or assets under development including borrowing costs previously capitalized, net of capital contributions received. Capitalization commences immediately as the expenditure on a qualifying asset is incurred. Borrowing costs are included in PP&E and intangible assets for financial reporting purposes, and charged to operations through depreciation and amortization expense over the useful lives of the related assets.

i) Revenue recognition

Revenues from energy sales and distribution are recorded on the basis of cyclical billings and include an estimated amount for electricity delivered and not yet billed. These revenues are impacted by energy demand primarily driven by outside temperature, and customer class usage patterns and composition.

Energy sales arise from charges to customers for electricity consumed, based on regulated rates. Energy sales include amounts billed or billable to customers for commodity charges, retail transmission charges, and WMS charges at current rates. LDC applies judgment to determine whether revenues are recorded on a gross or net basis. These charges are passed through to customers over time and are considered revenue by LDC due to the collection risk of the related balances. LDC has primary responsibility for the delivery of electricity to the customer. During the same period, energy sales should be equal to the cost of energy purchased. However, a difference between energy sales and energy purchases arises when there is a timing difference between the amounts charged by LDC to customers, based on regulated rates, and the electricity and non-competitive electricity service costs billed monthly by the IESO to LDC. This difference is recorded as a settlement variance, representing future amounts to be recovered from or refunded to customers through future billing rates approved by the OEB. In accordance with IFRS 14, this settlement variance is presented within regulatory balances on the balance sheets and within net movements in regulatory balances on the statements of income.

Distribution revenue is recorded based on OEB-approved distribution rates to recover the costs incurred by LDC in delivering electricity to customers. Distribution revenue also includes revenue related to the collection of OEB-approved rate riders.

Other revenue, which includes revenue from services ancillary to the electricity distribution, delivery of street lighting services, and pole and duct rentals, is recognized as the services are rendered. When services are made up of different components which are not separately identifiable, the related other revenues are recognized on a straight-line basis over the term of the contract. Capital contributions received from electricity customers to construct or acquire PP&E for the purpose of connecting a customer to a network are recorded as deferred revenue and amortized into other revenue at an equivalent rate to that used for the depreciation of the related PP&E. Revenue not yet recognized from ancillary services is also included within deferred revenue.

Revenues and costs associated with CDM programs are presented using the net basis of accounting. Cost efficiency incentives related to the CDM programs, included as part of other revenue, are recognized when it is probable that future economic benefits will flow to the entity and the amount can be reasonably measured.

j) Financial instruments

All financial assets are classified as "Loans and Receivables" and all financial liabilities are classified as "Other Financial Liabilities". These financial instruments are recognized initially at fair value adjusted for any directly attributable transaction costs. Subsequently, they are measured at amortized cost using the effective interest method less any impairment for the financial assets. The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's length transaction between willing parties.

LDC uses the following methods and assumptions to estimate the fair value of each class of financial instruments for which carrying amounts are included in the balance sheets:

- Cash, cash equivalents and short-term investments are classified as "Loans and Receivables" and are measured at fair value. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Accounts receivable and unbilled revenue are classified as "Loans and Receivables" and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Bank indebtedness is classified as "Other Financial Liabilities" and is initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Advance from related party is classified as "Other Financial Liabilities" and is initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amount approximates fair value due to the short maturity of this instrument.

- Accounts payable and accrued liabilities are classified as "Other Financial Liabilities" and are initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value because of the short maturity of these instruments.

- Customer deposits are classified as "Other Financial Liabilities" and are initially measured at fair value. Subsequent measurements are recorded at cost plus accrued interest. The carrying amounts approximate fair value taking into account interest accrued on the outstanding balance.

- Obligations under finance leases are classified as "Other Financial Liabilities" and are initially measured at fair value, or the present value of the minimum lease payments if lower. Subsequent measurements are based on a discounted cash flow analysis and approximate the carrying amount as management believes that the fixed interest rates are representative of current market rates.

- Notes payable to related party are classified as "Other Financial Liabilities" and are initially measured at fair value. The carrying amounts are carried at amortized cost, based on the fair value of the notes payable at issuance, which was the fair value of the consideration received adjusted for transaction costs. The fair values of the notes payable are based on the present value of contractual cash flows, discounted at LDC's current borrowing rate for similar debt instruments *[note 14[a]]*. Debt issuance costs incurred in connection with LDC's debt offerings are capitalized as part of the carrying amount of the notes payable and amortized over the term of the related notes payable, using the effective interest method, and the amortization is included in finance costs.

k) Fair value measurements

LDC utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. A fair value hierarchy exists that prioritizes observable and unobservable inputs used to measure fair value. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect LDC's assumptions with respect to how market participants would price an asset or liability. The fair value hierarchy includes three levels of inputs that may be used to measure fair value:

- Level 1: Unadjusted quoted prices in active markets for identical assets or liabilities. An active market for the asset or liability is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis;

- Level 2: Other than quoted prices included within Level 1 that are observable for the assets or liabilities, either directly or indirectly; and

- Level 3: Unobservable inputs, supported by little or no market activity, used to measure the fair value of the assets or liabilities to the extent that observable inputs are not available.

l) Employee benefits

(i) Short-term employee benefits

Short-term employee benefit obligations that are due to be settled wholly within twelve months after the end of the annual reporting period in which the employees render the related service are measured on an undiscounted basis and are expensed as the related service is provided. A liability is recognized for the amount expected to be paid if LDC has a present legal or constructive obligation to pay this amount as a result of past service provided by the employee and the obligation can be estimated reliably.

(ii) Multi-employer pension plan

LDC's full-time employees participate in a pension plan through OMERS. The OMERS plan is a jointly sponsored, multi-employer defined benefit pension plan established in 1962 by the Province of Ontario for employees of municipalities, local boards and school boards. Both participating employers and employees are required to make plan contributions equally based on participating employees' contributory earnings, and share equally in funding gains or losses. The plan assets and pension obligations are not segregated in separate accounts for each member entity. The OMERS plan is accounted for as a defined contribution plan and the contribution payable is recognized as an employee benefit expense in the statements of income in the period when the service is rendered by the employee, since it is not practicable to determine LDC's portion of pension obligations or of the fair value of plan assets.

(iii) Post-employment benefits other than pension

LDC has a number of unfunded benefit plans providing post-employment benefits (other than pension) to its employees. LDC pays certain medical, dental and life insurance benefits under unfunded defined benefit plans on behalf of its retired employees. LDC also pays accumulated sick leave credits, up to certain established limits based on service, in the event of retirement, termination or death of certain employees.

The cost of providing benefits under the benefit plans is actuarially determined using the projected unit credit method, which incorporates management's best estimate of future salary levels, retirement ages of employees, health care costs, and other actuarial factors. Changes in actuarial assumptions and experience adjustments give rise to actuarial gains and losses. Actuarial gains and losses on medical, dental and life insurance benefits are recognized in OCI as they arise. Actuarial gains and losses related to rate-regulated activities are subsequently reclassified from OCI to a regulatory balance on the balance sheets. Actuarial gains and losses on accumulated sick leave credits are recognized in the statements of income in the period in which they arise.

The measurement date used to determine the present value of the benefit obligation is December 31 of the applicable year. The latest actuarial valuation was performed as at January 1, 2016.

m) Customer deposits

Security deposits from electricity customers are cash collections to guarantee the payment of electricity bills. The electricity customer security deposits liability includes related interest amounts owed to the customers with a corresponding amount charged to finance costs. Deposits that are refundable upon demand are classified as a current liability.

Security deposits on offers to connect are cash collections from specific customers to guarantee the payment of additional costs relating to expansion projects. This liability includes related interest amounts owed to the customers with a corresponding amount charged to finance costs. Deposits are classified as a current liability when LDC no longer has an unconditional right to defer payment of the liability for at least 12 months after the reporting period.

n) Income taxes

Under the Electricity Act, LDC is required to make PILs to the Ontario Electricity Financial Corporation. These payments are calculated in accordance with the ITA and the TA as modified by regulations made under the Electricity Act and related regulations. This effectively results in LDC paying income taxes equivalent to what would be imposed under the Federal and Ontario Tax Acts.

LDC uses the liability method of accounting for income taxes. Under the liability method, current income taxes payable are recorded based on taxable income. LDC recognizes deferred tax assets and liabilities for the future tax consequences of events that have been included in the financial statements or income tax returns. Deferred tax assets and liabilities are determined based on the difference between the carrying value of assets and liabilities on the balance sheets and their respective tax basis, using the tax rates enacted or substantively enacted by the balance sheet date that are in effect for the year in which the differences are expected to reverse. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when it is probable that they will be realized, and are measured at the best estimate of the tax amount expected to be paid to or recovered from the taxation authorities. Deferred tax assets are reviewed at each reporting date and reduced to the extent that it is no longer probable that the related tax benefits will be realized. The calculation of current and deferred taxes requires management to make certain judgments with respect to changes in tax interpretations, regulations and legislation, and to estimate probable outcomes on the timing and reversal of temporary differences and tax authority audits of income tax.

Rate-regulated accounting requires the recognition of regulatory balances and related deferred tax assets and liabilities for the amount of deferred taxes expected to be refunded to or recovered from customers through future electricity distribution rates. A gross up to reflect the income tax benefits associated with reduced revenues resulting from the realization of deferred tax assets is recorded within regulatory credit balances. Deferred taxes that are not included in the rate-setting process are charged or credited to the statements of income.

The benefits of the refundable and non-refundable apprenticeship and other ITCs are credited against the related expense in the statements of income.

o) Use of judgments and estimates

The preparation of LDC's financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions which affect the application of accounting policies, reported assets, liabilities and regulatory balances, and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported revenues and expenses for the year. The estimates are based on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities as well as for identifying and assessing the accounting treatment with respect to commitments and contingencies. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the IESO, the Ontario Ministry of Energy or the Ontario Ministry of Finance.

Information about judgments in applying accounting policies that have the most significant effects on the amounts recognized in the financial statements is included in note 25[i] relating to principal versus agent determination.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to estimates are recognized prospectively. Assumptions and estimates with a significant risk of resulting in a material adjustment within the next financial year are used in the following:

- Note 25[a] – Recognition and measurement of regulatory balances;
- Note 25[i] – Revenue recognition – measurement of unbilled revenue, determination of the CDM incentive;
- Notes 25[e] and 25[f] – Determination of useful lives of depreciable assets;
- Notes 25[l] and 12 – Measurement of post-employment benefits – key actuarial assumptions;
- Notes 25[n] and 20 – Recognition of deferred tax assets – availability of future taxable income against which deductible temporary differences and tax loss carryforwards can be used; and
- Note 24 – Recognition and measurement of provisions and contingencies.

p) Changes in accounting policies

In December 2014, the IASB issued Disclosure Initiative (Amendments to IAS 1 *Presentation of Financial Statements*). These amendments improve the existing presentation and disclosure requirements and encourage entities to apply professional judgment regarding disclosure and presentation in their financial statements. These amendments were adopted effective January 1, 2016. The adoption of these amendments has no material impact on LDC's financial statements.

q) Future accounting pronouncements

A number of new standards, amendments and interpretations are not yet effective for the year ended December 31, 2016, and have not yet been applied in preparing these financial statements. LDC continues to analyze these standards and has determined that the following could have an impact on its financial statements.

Revenue from Contracts with Customers

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers* ["IFRS 15"], which replaces existing revenue recognition guidance, including IAS 18 *Revenue* and IFRIC 18 *Transfers of Assets from Customers* ["IFRIC 18"]. IFRS 15 contains a single model that applies to contracts with customers with two approaches for recognizing revenue: at a point in time or over time. The model features a contract-based five-step analysis of transactions to determine whether revenue should be recognized and the respective timing and amount. New estimates and judgmental thresholds have been introduced, which may affect the amount and/or timing of revenue recognized. The new standard does not apply to insurance contracts, financial instruments or lease contracts, which fall in the scope of other IFRS. On July 22, 2015, the IASB confirmed a one-year deferral of the effective date of IFRS 15 to annual periods beginning on or after January 1, 2018.

In April 2016, the IASB issued amendments to IFRS 15, which was originally issued in May 2014. These amendments do not change the underlying principles of the standard but clarify how those principles should be applied. The amendments clarify how to identify a performance obligation in a contract, determine whether a company is a principal or an agent, and determine whether the revenue from granting a licence should be recognized at a point in time or over time. The amendments also include two additional transitional reliefs. The amendments are effective for annual periods beginning on or after January 1, 2018, consistent with the effective date of the standard.

LDC will adopt IFRS 15 on January 1, 2018 using the modified retrospective approach with practical expedients. LDC has completed its initial assessment of the key revenue streams and continues to evaluate the impact of the new standard.

Financial Instruments

In July 2014, the IASB issued the final version of IFRS 9 *Financial Instruments* ["IFRS 9"], which replaces IAS 39 *Financial Instruments: Recognition and Measurement* ["IAS 39"]. IFRS 9 includes revised guidance on the

classification and measurement of financial instruments, including a new expected credit loss model for measuring impairment on financial assets, and new general hedge accounting requirements. It also carries forward the guidance on recognition and derecognition of financial instruments from IAS 39. The standard is effective for annual periods beginning on or after January 1, 2018, and will be applied retrospectively with some exceptions. LDC is currently evaluating the impact of the new standard.

Leases

In January 2016, the IASB issued IFRS 16 *Leases* ["IFRS 16"], which replaces IAS 17 *Leases* ["IAS 17"] and related interpretations. IFRS 16 provides a single lessee accounting model, requiring the recognition of assets and liabilities for all leases, unless the lease term is twelve months or less or the underlying asset has a low value. Lessor accounting remains largely unchanged from IAS 17 and the distinction between operating and finance leases is retained. In addition, lessees will recognize a front-loaded pattern of expense for most leases, even when they pay constant annual rentals. The standard is effective for annual periods beginning on or after January 1, 2019, and will be applied retrospectively with some exceptions. Early adoption is permitted if IFRS 15 is also adopted.

LDC will elect to early adopt IFRS 16 on January 1, 2018 using the full retrospective approach for lessee's measurement of leases with practical expedients, and apply the practical expedient on lease definition. LDC has completed its initial assessment of its existing operating leases and anticipates that IFRS 16 will not have a significant impact on the LDC's consolidated financial statements.

Disclosure Initiative

In January 2016, the IASB issued amendments to IAS 7 *Statement of Cash Flows* as part of the IASB's Disclosure Initiative. These amendments require entities to provide disclosures that enable users of financial statements to evaluate changes in liabilities arising from financing activities, including changes from cash flows and non-cash changes. These amendments are effective for annual periods beginning on or after January 1, 2017. The adoption of these amendments are expected to increase disclosures relating to changes in liabilities arising from financing activities with no impact to the LDC's financial position or results of operations.

Financial Statements

Toronto Hydro-Electric System Limited

DECEMBER 31, 2017 and 2016

KPMG LLP
Chartered Professional Accountants
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333 Bay Street
Toronto, ON M5H 2S5

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INDEPENDENT AUDITORS' REPORT

To the Shareholder of Toronto Hydro-Electric System Limited

We have audited the accompanying financial statements of Toronto Hydro-Electric System Limited, which comprise the balance sheets as at December 31, 2017 and December 31, 2016, the statements of income, comprehensive income, changes in equity and cash flows for the years ended December 31, 2017 and December 31, 2016, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Toronto Hydro-Electric System Limited as at December 31, 2017 and December 31, 2016, and its financial performance and its cash flows for the years ended December 31, 2017 and December 31, 2016 in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants
March 6, 2018
Toronto, Canada

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Toronto Hydro-Electric System Limited

BALANCE SHEETS

[in millions of Canadian dollars]

As at December 31	**2017** **$**	2016 $
ASSETS		
Current		
Accounts receivable *[notes 4 and 15[b]]*	**217.2**	226.2
Unbilled revenue *[note 15[b]]*	**276.0**	319.7
Materials and supplies	**9.3**	9.7
Other assets *[note 5]*	**12.7**	13.5
Assets held for sale *[note 8]*	**8.7**	-
Total current assets	**523.9**	569.1
Property, plant and equipment *[note 6]*	**4,107.8**	3,876.3
Intangible assets *[note 7]*	**296.2**	217.8
Deferred tax assets *[note 21]*	**57.0**	63.8
Other assets *[note 5]*	**3.0**	1.3
Total assets	**4,987.9**	4,728.3
Regulatory balances *[note 9]*	**199.9**	190.8
Total assets and regulatory balances	**5,187.8**	4,919.1
LIABILITIES AND EQUITY		
Current		
Bank indebtedness	**125.0**	50.5
Accounts payable and accrued liabilities *[note 10]*	**513.3**	500.4
Income tax payable	**12.5**	9.0
Customer deposits	**49.2**	39.1
Deferred revenue *[note 11]*	**9.9**	4.3
Deferred conservation credit *[note 3[c]]*	**9.3**	5.5
Notes payable to related party *[notes 12 and 23]*	**60.0**	304.9
Other liabilities *[note 24]*	**1.5**	3.1
Total current liabilities	**780.7**	916.8
Notes payable to related party *[notes 12 and 23]*	**2,029.9**	1,830.6
Customer deposits	**8.9**	15.0
Deferred revenue *[note 11]*	**178.8**	139.9
Post-employment benefits *[note 13]*	**313.0**	280.5
Other liabilities *[note 24]*	**0.2**	1.9
Total liabilities	**3,311.5**	3,184.7
Commitments, contingencies and subsequent events *[notes 2, 24 and 25]*		
Equity		
Share capital *[note 17]*	**556.3**	556.3
Retained earnings	**1,147.2**	995.9
Contributed surplus	**12.8**	12.8
Total equity	**1,716.3**	1,565.0
Total liabilities and equity	**5,027.8**	4,749.7
Regulatory balances *[note 9]*	**160.0**	169.4
Total liabilities, equity and regulatory balances	**5,187.8**	4,919.1

See accompanying notes to the financial statements.

Toronto Hydro-Electric System Limited

STATEMENTS OF INCOME

[in millions of Canadian dollars]

Year ended December 31	2017 $	2016 $
Revenues		
Energy sales	**3,017.8**	3,306.2
Distribution revenue	**724.2**	647.9
Other *[note 18]*	**96.7**	66.3
	3,838.7	4,020.4
Expenses		
Energy purchases	**3,063.5**	3,216.9
Operating expenses *[note 19]*	**284.2**	267.6
Depreciation and amortization *[notes 6 and 7]*	**222.3**	210.6
	3,570.0	3,695.1
Finance costs *[note 20]*	**(81.0)**	(76.6)
Gain on disposals of property, plant and equipment	**9.8**	2.1
Income before income taxes	**197.5**	250.8
Income tax expense *[note 21]*	**(44.2)**	(67.2)
Net income	**153.3**	183.6
Net movements in regulatory balances *[note 9]*	**(13.1)**	(77.2)
Net movements in regulatory balances arising from deferred tax assets *[note 9]*	**13.2**	44.0
Net income after net movements in regulatory balances	**153.4**	150.4

STATEMENTS OF COMPREHENSIVE INCOME

[in millions of Canadian dollars]

Year ended December 31	2017 $	2016 $
Net income after net movements in regulatory balances	**153.4**	150.4
Other comprehensive income		
Items that will not be reclassified to income or loss		
Remeasurements of post-employment benefits, net of tax (2017 - $6.7, 2016 - $5.5) *[note 13]*	**(18.4)**	15.5
Net movements in regulatory balances related to OCI, net of tax (2017 - $6.7, 2016 - $5.5) *[note 13]*	**18.4**	(15.5)
Other comprehensive income, net of tax	**-**	-
Total comprehensive income	**153.4**	150.4

See accompanying notes to the financial statements.

Toronto Hydro-Electric System Limited

STATEMENTS OF CHANGES IN EQUITY

[in millions of Canadian dollars]

Year ended December 31	2017 $	2016 $
Share capital ***[note 17]***	**556.3**	556.3
Retained earnings, beginning of year	**995.9**	845.5
Net income after net movements in regulatory balances	**153.4**	150.4
Dividends *[notes 17 and 23]*	**(2.1)**	-
Retained earnings, end of year	**1,147.2**	995.9
Contributed surplus	**12.8**	12.8
Total equity	**1,716.3**	1,565.0

See accompanying notes to the financial statements.

Toronto Hydro-Electric System Limited

STATEMENTS OF CASH FLOWS

[in millions of Canadian dollars]

Year ended December 31	2017 $	2016 $
OPERATING ACTIVITIES		
Net income after net movements in regulatory balances	**153.4**	150.4
Net movements in regulatory balances *[note 9]*	**13.1**	77.2
Net movements in regulatory balances arising from deferred tax assets *[note 9]*	**(13.2)**	(44.0)
Adjustments		
Depreciation and amortization *[notes 6 and 7]*	**222.3**	210.6
Amortization of deferred revenue *[note 11]*	**(4.7)**	(3.8)
Finance costs	**81.0**	76.6
Income tax expense	**44.2**	67.2
Post-employment benefits	**7.4**	5.0
Gain on disposals of property, plant and equipment	**(9.8)**	(2.1)
Other	**1.1**	0.7
Capital contributions received *[note 11]*	**50.8**	44.3
Net change in other non-current assets and liabilities	**(6.5)**	(0.4)
Increase in customer deposits	**4.0**	6.7
Changes in non-cash working capital balances *[note 22]*	**60.7**	(14.2)
Income tax paid	**(22.1)**	(0.9)
Net cash provided by operating activities	**581.7**	573.3
INVESTING ACTIVITIES		
Purchase of property, plant and equipment *[note 22]*	**(433.8)**	(506.6)
Purchase of intangible assets *[note 22]*	**(93.4)**	(39.9)
Proceeds on disposals of property, plant and equipment	**12.5**	2.2
Net cash used in investing activities	**(514.7)**	(544.3)
FINANCING ACTIVITIES		
Issuance of notes payable to related party *[note 12]*	**198.6**	198.7
Repayment of notes payable to related party *[note 12]*	**(245.1)**	-
Repayment of finance lease liability	**(3.0)**	(3.1)
Dividends paid *[note 17]*	**(2.1)**	-
Interest received	**0.3**	0.3
Interest paid	**(90.2)**	(86.5)
Net cash provided by (used in) financing activities	**(141.5)**	109.4
Net decrease (increase) in bank indebtedness during the year	**(74.5)**	138.4
Bank indebtedness, beginning of year	**(50.5)**	(188.9)
Bank indebtedness, end of year	**(125.0)**	(50.5)

See accompanying notes to the financial statements.

1. NATURE OF BUSINESS

Toronto Hydro-Electric System Limited was incorporated on June 23, 1999 under the *Business Corporations Act* (Ontario) in accordance with the Electricity Act. LDC is wholly-owned by the Corporation and is domiciled in Canada, with its registered office located at 14 Carlton Street, Toronto, Ontario, M5B 1K5.

LDC distributes electricity to customers located in the City and is subject to rate regulation. LDC is also engaged in the delivery of CDM activities.

2. BASIS OF PRESENTATION

LDC's audited financial statements for the years ended December 31, 2017 and 2016 have been prepared in accordance with IFRS with respect to the preparation of annual financial information.

These financial statements are presented in Canadian dollars, LDC's functional currency, and have been prepared on the historical cost basis, except for post-employment benefits which are recorded at actuarial value.

LDC has evaluated the events and transactions occurring after the balance sheet date through March 6, 2018 when LDC's financial statements were authorized for issue by LDC's Board of Directors, and identified the events and transactions which required recognition in the LDC's financial statements and/or disclosure in these notes to the LDC's financial statements *[note 8]*.

The summary of significant accounting policies has been disclosed in note 26.

3. REGULATION

The OEB has regulatory oversight of electricity matters in Ontario. The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to approve the amounts paid to non-contracted generators, the responsibility to provide rate protection for rural or remote electricity customers, and the responsibility for ensuring that electricity distribution companies fulfill their obligations to connect and service customers.

LDC is required to charge its customers for the following amounts (all of which, other than distribution rates, represent a pass-through of amounts payable to third parties):

- *Commodity Charge* – The commodity charge represents the market price of electricity consumed by customers and is passed through the IESO back to operators of generating stations. It includes the global adjustment, which represents the difference between the market price of electricity and the rates paid to regulated and contracted generators.

- *Retail Transmission Rate* – The retail transmission rate represents the costs incurred in respect of the transmission of electricity from generating stations to local distribution networks. Retail transmission rates are passed through back to operators of transmission facilities.

- *WMS Charge* – The WMS charge represents various wholesale market support costs, such as the cost of the IESO to administer the wholesale electricity system, operate the electricity market, and maintain reliable operation of the provincial grid. Wholesale charges are passed through back to the IESO.

- *Distribution Rate* – The distribution rate is designed to recover the costs incurred by LDC in delivering electricity to customers, including the OEB-allowed cost of capital. Distribution rates are regulated by the OEB and include fixed and variable (usage-based) components, based on a forecast of LDC's customers and load.

a) Electricity Distribution Rates

The OEB's regulatory framework for electricity distributors is designed to support the cost-effective planning and operation of the electricity distribution network and to provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price.

The OEB typically regulates the electricity rates for distributors using a combination of detailed cost of service reviews and IRM adjustments. Under the OEB's rate-setting methods, actual operating conditions may vary from forecasts such that actual returns achieved can differ from approved returns. Approved electricity rates are generally not adjusted as a result of actual costs or revenues being different from forecasted amounts, other than for certain prescribed costs that are eligible for deferral for future collection from, or refund to, customers.

On March 1, 2016 pursuant to LDC's 2015 – 2019 CIR application, the OEB set 2018 distribution rates on an interim basis. On August 23, 2017, LDC filed its 2018 rate application seeking OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2018 and ending on December 31, 2018. On December 14, 2017, the OEB issued a decision and rate order approving LDC's 2018 rates, with an effective date of January 1, 2018, and the disposition of certain deferral and variance accounts.

b) Ontario's Fair Hydro Plan

On March 2, 2017, the Government of Ontario announced the OFHP, which includes a number of initiatives, some of which affect LDC or its customers.

OFHP includes the OREC, which came into effect on January 1, 2017. The OREC provides eligible customers with financial assistance in the form of an 8% rebate of the pre-tax cost of their electricity. The OREC rebates are administered by LDC and paid by the IESO in the month following customer billing. Current accounts receivable and unbilled revenue include the amount owing by the IESO to LDC. No effect on revenue or expense is recognized by LDC in respect of the OREC rebates.

OFHP also includes the OFHA, which enacted the Ontario Fair Hydro Plan Act, 2017 and amended the Electricity Act, 1998 and the Ontario Energy Board Act, 1998. The OFHA came into effect on June 1, 2017 and its impact is reflected in the financial statements. The OFHA provides eligible customers with financial assistance through various changes to commodity pricing, new or amended programs, and eliminating or reducing certain provincial charges on the electricity bill. The OFHA reduces the total electricity bill for eligible customers and, accordingly, reduces current accounts receivable, unbilled revenue, accounts payable and accrued liabilities for LDC. No effect on distribution revenue or expense is recognized by LDC in respect of the OFHA.

c) CDM Activities

On March 26, 2014, the Minister of Energy of Ontario, under the guidance of sections 27.1 and 27.2 of the OEB Act, directed the OEB to amend the licence of each licensed electricity distributor to require the electricity distributor, as a condition of its licence, to make CDM programs available to its customers and to do so in relation to each customer segment in its service area, over the period beginning January 1, 2015 through December 31, 2020. On March 31, 2014, the Minister of Energy of Ontario issued a direction to require the OPA to coordinate, support and fund the delivery of CDM programs through electricity distributors. The objective of the CDM efforts is to reduce electricity consumption in the Province of Ontario by a total of 7 terawatt hours between January 1, 2015 and December 31, 2020, of which LDC's share is approximately 1,576 GWh of energy savings.

On November 13, 2014, LDC entered into an energy conservation agreement with the OPA for the delivery of CDM programs over the 2015-2020 period. The IESO and the OPA were merged under the name IESO starting on January 1, 2015.

Under the energy conservation agreement with the IESO, LDC has a joint CDM plan with Oakville Hydro Electricity Distribution Inc. ["Oakville Hydro"] for the delivery of CDM programs over the 2015-2020 period. LDC can choose between full cost recovery funding, pay-for-performance funding, or a combination of both, on a CDM program by

program basis. Under the full cost recovery funding method, the IESO reimburses LDC for all adequately documented incurred costs, with an option to receive a portion of its funding in advance. Cost efficiency incentives may be awarded if LDC's electricity savings meet or exceed certain CDM plan targets for programs under the full cost recovery funding method, with a mid-term review to be performed by the IESO for the 2015-2017 period. Under the pay-for-performance funding method, LDC receives payment in arrears based on verified electricity savings achieved with various options for frequency of payment. The programs under the joint CDM plan with Oakville Hydro are only being offered under the full cost recovery funding method.

The joint CDM plan provides combined funding of approximately $425.0 million, including participant incentives and program administration costs to achieve an aggregate energy savings target of approximately 1,668 GWh. Oakville Hydro's programs under the joint CDM plan started on January 1, 2016. LDC received $44.9 million as at December 31, 2016 and $57.4 million in the year ended December 31, 2017 from the IESO for the delivery of CDM programs. Amounts received but not yet spent are presented on the balance sheets under current liabilities as deferred conservation credit. As at December 31, 2017, LDC estimated that approximately $12.9 million qualified as a joint mid-term incentive, of which $12.2 million represents LDC's portion and is included within accounts receivable.

Effective October 16, 2017, LDC entered into an agreement to transfer $4.0 million of funding and a corresponding 20 GWh of its energy savings target to another local distribution company. This agreement will decrease the joint CDM plan funding with Oakville Hydro to $421.0 million, with a revised energy savings target of 1,648 GWh. The revised CDM plan was approved by the IESO on December 14, 2017.

4. ACCOUNTS RECEIVABLE

Accounts receivable consists of the following:

	2017 $	2016 $
Trade receivables	**188.6**	214.7
Due from related parties *[note 23]*	**14.8**	10.1
CDM mid-term incentive *[note 3[c]]*	**12.2**	—
Other	**1.6**	1.4
	217.2	226.2

5. OTHER ASSETS

Other assets consist of the following:

	2017 $	2016 $
Prepaid expenses	**11.3**	12.3
Deferred financing costs	**1.6**	1.6
Other	**2.8**	0.9
Total other assets	**15.7**	14.8
Less: Current portion of other assets relating to:		
Prepaid expenses	**11.3**	12.3
Deferred financing costs	**0.4**	0.4
Other	**1.0**	0.8
Current portion of other assets	**12.7**	13.5
Non-current portion of other assets	**3.0**	1.3

6. PROPERTY, PLANT AND EQUIPMENT

PP&E consist of the following:

	Distribution assets $	Land and buildings $	Equipment and other $	Construction in progress $	Total $
Cost					
Balance as at January 1, 2016	3,027.2	203.1	119.7	496.3	3,846.3
Additions/(Transfers)	381.2	111.3	61.7	(48.1)	506.1
Disposals and retirements	(32.1)	(0.1)	(0.3)	—	(32.5)
Balance as at December 31, 2016	3,376.3	314.3	181.1	448.2	4,319.9
Additions/(Transfers)	**404.4**	**84.8**	**32.8**	**(77.1)**	**444.9**
Assets held for sale *[note 8]*	—	**(21.2)**	—	—	**(21.2)**
Disposals and retirements	**(31.5)**	**(3.2)**	**(0.3)**	—	**(35.0)**
Balance as at December 31, 2017	**3,749.2**	**374.7**	**213.6**	**371.1**	**4,708.6**
Accumulated depreciation					
Balance as at January 1, 2016	222.6	15.7	46.1	—	284.4
Depreciation	129.3	10.3	24.3	—	163.9
Disposals and retirements	(4.6)	—	(0.1)	—	(4.7)
Balance as at December 31, 2016	347.3	26.0	70.3	—	443.6
Depreciation	**138.1**	**13.5**	**24.8**	—	**176.4**
Assets held for sale *[note 8]*	—	**(12.5)**	—	—	**(12.5)**
Disposals and retirements	**(5.9)**	**(0.5)**	**(0.3)**	—	**(6.7)**
Balance as at December 31, 2017	**479.5**	**26.5**	**94.8**		**600.8**
Carrying amount					
Balance as at December 31, 2016	3,029.0	288.3	110.8	448.2	3,876.3
Balance as at December 31, 2017	**3,269.7**	**348.2**	**118.8**	**371.1**	**4,107.8**

As at December 31, 2017, "Equipment and other" included assets under finance lease with cost of $18.2 million [December 31, 2016 - $18.2 million] and accumulated depreciation of $10.4 million [December 31, 2016 - $8.3 million]. For the year ended December 31, 2017, LDC recorded depreciation expense of $2.1 million [2016 - $2.3 million] related to assets under finance lease.

For the year ended December 31, 2017, borrowing costs in the amount of $6.2 million [2016 - $9.5 million] were capitalized to PP&E and credited to finance costs, with an average capitalization rate of 3.73% [2016 - 3.61%].

"Construction in progress" additions are net of transfers to the other PP&E categories.

7. INTANGIBLE ASSETS

Intangible assets consist of the following:

	Computer software	Contributions	Software in development	Contributions for work in progress	Total
	$	$	$	$	$
Cost					
Balance as at January 1, 2016	101.6	21.7	11.8	104.3	239.4
Additions/(Transfers)	11.9	53.8	8.4	(34.2)	39.9
Balance as at December 31, 2016	113.5	75.5	20.2	70.1	279.3
Additions/(Transfers)	**23.4**	**—**	**34.0**	**44.0**	**101.4**
Balance as at December 31, 2017	**136.9**	**75.5**	**54.2**	**114.1**	**380.7**
Accumulated amortization					
Balance as at January 1, 2016	38.1	2.0	—	—	40.1
Amortization	19.3	2.1	—	—	21.4
Balance as at December 31, 2016	57.4	4.1	—	—	61.5
Amortization	**20.0**	**3.0**	**—**	**—**	**23.0**
Balance as at December 31, 2017	**77.4**	**7.1**	**—**	**—**	**84.5**
Carrying amount					
Balance as at December 31, 2016	56.1	71.4	20.2	70.1	217.8
Balance as at December 31, 2017	**59.5**	**68.4**	**54.2**	**114.1**	**296.2**

For the year ended December 31, 2017, borrowing costs in the amount of $3.6 million [2016 - $3.0 million] were capitalized to intangible assets and credited to finance costs, with an average capitalization rate of 3.73% [2016 - 3.61%].

"Software in development" and "Contributions for work in progress" additions are net of transfers to the other intangible asset categories.

"Computer software" is externally acquired. The remaining amortization periods for computer software and contributions range from less than one year to 5 years, and from 11 to 25 years, respectively.

8. ASSETS HELD FOR SALE

In 2017, LDC commenced the process to sell a property including land and buildings to a third party. Accordingly, the carrying amount of the identified assets of $8.7 million was transferred from PP&E to assets held for sale as at December 31, 2017. Upon reclassification as assets held for sale, no further depreciation was recorded by LDC on the related assets. On January 16, 2018, LDC entered into an agreement to sell the property, which is expected to close on April 16, 2018. Upon completion of the sale, the net gain including the future tax savings will be deferred as a regulatory credit balance *[note 9[c]]*.

9. REGULATORY BALANCES

Debit balances consist of the following:

	January 1, 2017	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2017	Remaining recovery/ reversal period (months)	Carrying charges applicable
	$	$	$	$	$		
OPEB actuarial net loss	**60.2**	**25.1**	**—**	**—**	**85.3**	note 9[a]	—
Foregone revenue	**64.3**	**—**	**(20.3)**	**—**	**44.0**	24	—
Gain on disposal	**8.6**	**(8.1)**	**18.6**	**—**	**19.1**	note 9[c]	*
LRAM	**10.5**	**11.0**	**(4.8)**	**—**	**16.7**	note 9[d]	*
IFRS transitional adjustments	**22.8**	**—**	**(7.8)**	**—**	**15.0**	24	—
Stranded meters	**11.4**	**—**	**(3.9)**	**—**	**7.5**	24	*
OPEB cash versus accrual	**2.9**	**1.3**	**—**	**—**	**4.2**	note 9[g]	—
Named properties	**4.6**	**—**	**(1.5)**	**—**	**3.1**	24	—
Capital contributions	**1.5**	**—**	**(0.5)**	**—**	**1.0**	24	—
Smart meters	**2.1**	**—**	**(3.1)**	**1.0**	**—**	—	—
Other	**1.9**	**2.1**	**—**	**—**	**4.0**	—	*
	190.8	**31.4**	**(23.3)**	**1.0**	**199.9**		

	January 1, 2016	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2016	Remaining recovery/ reversal period (months)	Carrying charges applicable
	$	$	$	$	$		
OPEB actuarial net loss	81.2	(21.0)	—	—	60.2	note 9[a]	—
Foregone revenue	61.1	19.2	(16.0)	—	64.3	36	—
Gain on disposal	—	—	14.5	(5.9)	8.6	note 9[c]	*
LRAM	9.1	4.7	(3.3)	—	10.5	note 9[d]	*
IFRS transitional adjustments	28.9	—	(6.1)	—	22.8	36	—
Stranded meters	14.4	—	(3.0)	—	11.4	36	*
OPEB cash versus accrual	1.8	1.1	—	—	2.9	note 9[g]	—
Named properties	5.8	—	(1.2)	—	4.6	36	—
Capital contributions	1.9	—	(0.4)	—	1.5	36	—
Smart meters	10.0	—	(7.9)	—	2.1	4	—
Settlement variances	25.3	—	—	(25.3)	—	—	*
Other	2.2	1.6	—	(1.9)	1.9	—	*
	241.7	5.6	(23.4)	(33.1)	190.8		

* In accordance with the OEB's direction, carrying charges were accrued to certain regulatory balances at a rate of 1.10% for January 1, 2017 to September 30, 2017 and 1.50% for October 1, 2017 to December 31, 2017 [2016 - 1.10%].

Credit balances consist of the following:

	January 1, 2017	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2017	Remaining recovery/ reversal period (months)	Carrying charges applicable
	$	$	$	$	$		
Deferred taxes	**65.3**	**(6.5)**	**—**	**—**	**58.8**	note 9[j]	—
Settlement variances	**62.8**	**(45.2)**	**23.4**	**—**	**41.0**	note 9[k]	*
Capital-related revenue requirement	**8.8**	**16.2**	**—**	**—**	**25.0**	note 9[l]	*
Derecognition	**12.8**	**3.1**	**—**	**—**	**15.9**	note 9[m]	*
Tax-related variances	**17.5**	**—**	**(8.2)**	**—**	**9.3**	12	*
Development charges	**—**	**5.3**	**—**	**—**	**5.3**	note 9[o]	*
Smart meters	**—**	**—**	**(0.7)**	**1.0**	**0.3**	—	*
Other	**2.2**	**2.7**	**(0.5)**	**—**	**4.4**	—	*
	169.4	**(24.4)**	**14.0**	**1.0**	**160.0**		

	January 1, 2016	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2016	Remaining recovery/ reversal period (months)	Carrying charges applicable
	$	$	$	$	$		
Deferred taxes	114.8	(49.5)	—	—	65.3	note 9[j]	—
Settlement variances	—	89.3	1.2	(27.7)	62.8	note 9[k]	*
Capital-related revenue requirement	2.8	6.0	—	—	8.8	note 9[l]	*
Derecognition	9.9	2.9	—	—	12.8	note 9[m]	*
Tax-related variances	26.5	—	(8.5)	(0.5)	17.5	24	*
ICM	9.7	0.1	(9.8)	—	—	—	*
Gain on disposal	5.9	—	—	(5.9)	—	—	*
Other	2.0	1.2	(2.0)	1.0	2.2	—	*
	171.6	50.0	(19.1)	(33.1)	169.4		

* In accordance with the OEB's direction, carrying charges were accrued to certain regulatory balances at a rate of 1.10% for January 1, 2017 to September 30, 2017 and 1.50% for October 1, 2017 to December 31, 2017 [2016 - 1.10%].

The "Balances arising in the period" column consists of new additions to regulatory balances (for both debits and credits). The "Recovery/reversal" column consists of amounts disposed through OEB-approved rate riders or transactions reversing an existing regulatory balance. The "Other movements" column consists of impairment and reclassification between the regulatory debit and credit balances. In addition, the "Other movements" column includes reclassification of regulatory deferral accounts considered to be insignificant into the "Other" categories. During 2016, residual regulatory balances approved by the OEB for disposition over a 10-month period commencing on March 1, 2016 were reclassified from "Other" regulatory debit balance, settlement variances and tax-related variances into "Other" regulatory credit balance. There was no impairment recorded for the year ended December 31, 2017.

Reconciliation between the net movements in regulatory balances shown above and the net movements presented on the statements of income and the statements of comprehensive income is as follows:

	2017 $	2016 $
Total movements per regulatory debit balances table	**9.1**	(50.9)
Total movements per regulatory credit balances table	**9.4**	2.2
Total net movements	**18.5**	(48.7)
Net movements per financial statements:		
Net movements in regulatory balances	**(13.1)**	(77.2)
Net movements in regulatory balances arising from deferred tax assets	**13.2**	44.0
Net movements in regulatory balances related to OCI, net of tax	**18.4**	(15.5)
Total net movements per financial statements	**18.5**	(48.7)

Regulatory developments in Ontario's electricity industry regulatory developments and other governmental policy changes may affect the electricity distribution rates charged by LDC and the costs LDC is permitted to recover. There is a risk that the OEB may disallow the recovery of a portion of certain costs incurred in the current period through future rates or disagree with the proposed recovery period. In the event that the disposition of these balances is assessed to no longer be probable based on management's judgment, any impairment will be recorded in the period when the assessment is made.

The regulatory balances of LDC consist of the following:

a) OPEB Actuarial Net Loss

This regulatory balance accumulates the actuarial gains and losses arising from changes in actuarial assumptions and experience adjustments recognized in OCI. The balance arising during the year ended December 31, 2017 of $25.1 million is related to the actuarial loss recorded for the year [2016 - $21.0 million actuarial gain] *[note 13[a]]*. The net position is an actuarial loss that is recoverable in future rates. LDC has not sought recovery to date from the OEB as changes in underlying assumptions may reduce the balance in the account. LDC expects to recover this regulatory balance as per OEB direction, in a future rate application.

b) Foregone Revenue

This regulatory balance relates to the revenue that LDC would have recovered in 2015 and 2016 if new OEB-approved rates were implemented as of May 1, 2015 and January 1, 2016, respectively. In the CIR decision and rate order, the OEB approved foregone revenue rate riders over 46 months commencing on March 1, 2016 for May 1, 2015 to December 31, 2015 based on approved 2015 rates and for January 1, 2016 to February 29, 2016 based on approved 2016 rates.

c) Gain on Disposal

This regulatory balance consists of the net of amounts disposed through the OEB-approved rate riders offset by the related tax savings (debits), and the after-tax gain realized on two significant LDC properties (credits). As part of the CIR decision and rate order, LDC agreed to a rate rider that would pass the total forecasted net gains along with future tax savings on both properties back to ratepayers, effective from March 1, 2016 to December 31, 2018. During 2015, the gain on one of the properties was realized by LDC resulting in a net credit balance at December 31, 2015. As at December 31, 2016, the amount disposed through the rate riders exceeded the gain realized on the first property as the second property was still not sold, resulting in a net debit balance. Upon the sale of the second property, the account would revert to a credit balance if actual net gains and tax savings exceed the total amount of the approved rate riders *[note 8]*. In the second quarter of 2017, LDC realized a gain in connection with the disposal of a third property. LDC expects to seek disposition for any residual balance in a future rate application.

d) Lost Revenue Adjustment Mechanism

This regulatory balance relates to the difference between the level of CDM program activities included in LDC's load forecast used to set approved rates and the actual impact of CDM activities achieved. New variances are accrued based on current CDM activities. Approved variances up to 2014 were disposed through OEB-approved rate riders over 12 months commencing on January 1, 2017 and approved variances for 2015 and 2016 will be disposed through OEB-approved rate riders over 12 months commencing on January 1, 2018. Variances pertaining to years subsequent to 2016 have yet to be applied for disposition.

e) IFRS Transitional Adjustments

This regulatory balance relates to the differences arising from accounting policy changes for PP&E and intangible assets due to the transition from US GAAP to IFRS in 2014, primarily related to derecognition of certain assets and additional capitalized borrowing costs. In the CIR decision and rate order, the OEB approved disposition of the balance over 46 months commencing on March 1, 2016.

f) Stranded Meters and Smart Meters

These regulatory balances relate to the provincial government's decision to install smart meters throughout Ontario.

The net book value of stranded meters related to the deployment of smart meters was reclassified from PP&E to a new regulatory balance as at December 31, 2013. In the CIR decision and rate order, the OEB approved LDC's request for recovery of the forecasted net book value of the stranded meters as at December 31, 2014 over 46 months commencing on March 1, 2016.

On January 16, 2014, the OEB approved LDC's request for incremental revenue and disposition of the smart meter regulatory balances to be recovered through rates over 36 months commencing on May 1, 2014. The OEB ruling on smart meters also permitted the recovery in principle of LDC's allowed cost of capital on smart meters since 2008, with a rate order issued to this effect. This allows LDC to recover the incremental revenue requirement associated with these assets for the period during which they remained outside of rate base.

g) OPEB Cash versus Accrual

This regulatory balance relates to the difference between LDC's forecasted OPEB costs determined on an accrual basis and the cash payments made under the OPEB plans. The OEB directed LDC to track the difference as a temporary arrangement, pending the OEB's conclusion on the sector-wide policy consultation it initiated on the regulatory treatment of pension and OPEB costs. On September 14, 2017, the OEB issued its final report on the consultation and established the use of the accrual accounting method as the default method on which to set rates for OPEB costs. LDC will continue to track the cash versus accrual difference until its next rate application when the disposition of this regulatory balance will be considered. The timing of disposition of the balance is currently unknown.

h) Named Properties

As part of 2010 rates, LDC had forecasted net gains on certain properties which were planned for sale between 2007 and 2011. This regulatory balance relates to the excess of those forecasted net gains over the actual net gains realized upon the sale of the named properties. In the CIR decision and rate order, the OEB approved disposition of this variance over 46 months commencing on March 1, 2016.

i) Capital Contributions

This regulatory balance relates to the difference between amounts included in rates for HONI capital contributions and actual contributions made in 2010 and 2011. In the CIR decision and rate order, the OEB approved disposition of this variance over 46 months commencing on March 1, 2016.

j) Deferred Taxes

This regulatory credit balance relates to both deferred tax amounts reclassified under IFRS 14 *[note 26[a]]* and the expected future electricity distribution rate reduction for customers arising from timing differences in the recognition of deferred tax assets. LDC did not apply for disposition of the balance since it is reversed through timing differences in the recognition of deferred tax assets.

The amounts reclassified under IFRS 14 include the deferred tax liability related to regulatory balances of $34.9 million as at December 31, 2017 [December 31, 2016 - $36.4 million], offset by the recognition of a regulatory balance in respect of additional temporary differences for which a deferred tax amount was recognized of $8.5 million as at December 31, 2017 [December 31, 2016 - $10.4 million].

The deferred tax amount related to the expected future electricity distribution rate reduction for customers was $32.4 million as at December 31, 2017 [December 31, 2016 - $39.3 million].

k) Settlement Variances

This account includes the variances between amounts charged by LDC to customers, based on regulated rates, and the corresponding cost of electricity and non-competitive electricity service costs incurred by LDC. LDC has deferred the variances between the costs incurred and the related recoveries in accordance with the criteria set out in the accounting principles prescribed by the OEB. New variances are accrued based on current charges while approved variances up to 2016, including carrying charges forecasted to the end of 2017, will be disposed through OEB-approved rate riders over 12 months commencing on January 1, 2018. Settlement variances pertaining to years subsequent to 2016 have yet to be applied for disposition.

l) Capital-related Revenue Requirement

This regulatory balance relates to the asymmetrical variance between the cumulative 2015 to 2019 capital-related revenue requirement included in rates and the actual capital-related revenue requirement over the same period. If the cumulative 2015 to 2019 capital-related revenue requirement included in rates exceeds the actual capital-related revenue requirement over the same rate period, LDC must apply for disposition of this account in order to clear the balance to ratepayers through a rate rider. This account was approved by the OEB in the CIR decision and rate order. The timing of disposition of the balance is currently unknown.

m) Derecognition

This regulatory balance relates to the difference between the revenue requirement on derecognition of PP&E and intangible assets included in the OEB-approved rates and the actual amounts of derecognition. This account was approved by the OEB in the CIR decision and rate order. The timing of disposition of the balance is currently unknown.

n) Tax-related Variance Accounts

This regulatory credit balance arose from favourable income tax reassessments on certain prior year tax positions received, which differed from those assumed in previous applications for electricity distribution rates. In the CIR decision and rate order, the OEB approved disposition of the balance over 10-34 months commencing on March 1, 2016.

o) Development charges

This regulatory balance relates to excess expansion deposits retained by LDC where the requested number of connections or electricity demand were not met by the connecting customer. Pursuant to the OEB's Distribution System Code, LDC may collect expansion deposits on offers to connect from specific customers to guarantee the payment of additional costs relating to expansion projects. During the customer connection horizon, LDC has an obligation to annually return the expansion deposit to the connecting customer in proportion to the actual connections or electricity demand that occurred in that year. If the number of connections or electricity demand requested by the customer do not materialize by the end of the specified customer connection horizon, LDC retained the excess expansion deposit not otherwise returned to the connecting customer.

The excess expansion deposits were recorded as a regulatory balance on the balance sheets, with a corresponding offset in net movements in regulatory balances. This regulatory balance is expected to offset future electricity distribution rates for customers, although application has yet to be made to dispose of the balance.

p) Incremental Capital Module

This regulatory balance related to the ICM application approved by the OEB and the associated rate riders, which became effective June 1, 2013. The balance of $9.8 million represented the net of amounts collected through the ICM rate riders from 2013 to 2014 and amounts recognized in profit or loss in relation to the eligible in-service capital expenditures. Further to the OEB's decision on July 28, 2016, the entire balance of $9.8 million was recorded as an increase in equity through net movements in regulatory balances in 2016.

10. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

Accounts payable and accrued liabilities consist of the following:

	2017 $	2016 $
Trade payables	**323.7**	323.6
Accrued liabilities	**129.6**	116.3
Due to related parties *[note 23]*	**58.3**	58.7
Other	**1.7**	1.8
	513.3	500.4

11. DEFERRED REVENUE

Deferred revenue consists of capital contributions received from electricity customers to construct or acquire PP&E which have not yet been recognized into other revenue, and revenue not yet recognized from ancillary services *[note 26[i]]*.

	2017 $	2016 $
Capital contributions, beginning of year	**143.2**	103.0
Capital contributions received	**50.8**	44.3
Amortization	**(4.7)**	(3.8)
Other	**(1.5)**	(0.3)
Capital contributions, end of year	**187.8**	143.2
Other	**0.9**	1.0
Total deferred revenue	**188.7**	144.2
Less: Current portion of deferred revenue relating to:		
Capital contributions	**9.0**	3.3
Other	**0.9**	1.0
Current portion of deferred revenue	**9.9**	4.3
Non-current portion of deferred revenue	**178.8**	139.9

12. NOTES PAYABLE TO RELATED PARTY

Notes payable to related party consist of the following:

	2017 $	2016 $
Notes payable to related party:		
5.20% Long-term note payable to the Corporation due November 14, 2017	**—**	245.1
4.54% Long-term note payable to the Corporation due November 12, 2019	**245.1**	245.1
5.59% Long-term note payable to the Corporation due May 21, 2040	**200.0**	200.0
3.59% Long-term note payable to the Corporation due November 18, 2021	**300.0**	300.0
2.96% Long-term note payable to the Corporation due April 10, 2023	**250.0**	250.0
4.01% Long-term note payable to the Corporation due April 9, 2063	**200.0**	200.0
4.13% Long-term note payable to the Corporation due September 16, 2044	**200.0**	200.0
3.60% Long-term note payable to the Corporation due July 28, 2045	**200.0**	200.0
3.988% Long-term note payable to the Corporation due April 9, 2063	**45.0**	45.0
2.572% Long-term note payable to the Corporation due August 25, 2026	**200.0**	200.0
3.535% Long-term note payable to the Corporation due February 28, 2048	**200.0**	—
6.16% Demand note payable to the Corporation due on demand	**45.0**	45.0
3.32% Demand note payable to the Corporation due on the earlier of demand and January 1, 2022	**15.0**	15.0
Total notes payable to related party	**2,100.1**	2,145.2
Less: Unamortized debt issuance costs	**10.2**	9.7
Current portion of notes payable to related party *[note 23]*	**60.0**	304.9
Long-term portion of notes payable to related party *[note 23]*	**2,029.9**	1,830.6

All notes payable to the Corporation are unsecured, rank equally and will be settled in cash.

On June 14, 2016, LDC issued a promissory note to the Corporation. The principal amount of the promissory note is $200.0 million payable on August 25, 2026, which bears interest at a rate of 2.572% per annum. Interest is calculated and payable semi-annually in arrears on February 25 and August 25 of each year. The net proceeds from the promissory note were used to repay certain existing indebtedness of LDC and for general corporate purposes.

On November 14, 2017, LDC issued a promissory note to the Corporation. The principal amount of the promissory note is $200.0 million payable on February 28, 2048, which bears interest at a rate of 3.535% per annum. Interest is calculated and payable semi-annually in arrears on February 28 and August 28 of each year. The net proceeds from the promissory note were used to repay certain existing indebtedness of LDC and for general corporate purposes.

13. EMPLOYEE FUTURE BENEFITS

Pension

LDC's eligible employees participate in a defined benefit pension plan through OMERS. As at December 31, 2017, the OMERS plan was 94.0% funded [December 31, 2016 - 93.4%]. OMERS has a strategy to return the plan to a fully funded position. LDC is not able to assess the implications, if any, of this strategy or of the withdrawal of other participating entities from the OMERS plan on its future contributions. For the year ended December 31, 2017, LDC's contributions were $17.5 million [2016 - $17.3 million], representing less than five percent of total contributions to the OMERS plan. LDC expects to contribute approximately $18.7 million to the OMERS plan in 2018.

Post-employment benefits other than pension

a) Benefit obligation

	2017 $	2016 $
Balance, beginning of year	**280.5**	296.5
Current service cost	**4.0**	5.8
Interest cost	**11.0**	11.7
Benefits paid	**(11.0)**	(10.9)
Experience loss (gain) [(1)]	**1.9**	(4.2)
Actuarial gain arising from changes in demographic assumptions [(1)]	**—**	(17.5)
Actuarial loss (gain) arising from changes in financial assumptions [(1)]	**26.3**	(1.6)
Transfer from related parties	**0.3**	0.7
Balance, end of year	**313.0**	280.5

[(1)] Actuarial loss (gain) on accumulated sick leave credits of $3.1 million [2016 - ($2.1) million] is recognized in benefit cost *[note 13[c]]* and $nil million in transfer from related parties [2016 - ($0.2) million], and actuarial loss (gain) on medical, dental and life insurance benefits of $25.1 million [2016 - ($21.0) million] is recognized in OCI *[note 13[d]]*.

The weighted average duration of the benefit obligation as at December 31, 2017 is 16.7 years [2016 – 16.7 years].

b) Amounts recognized in regulatory balances

As at December 31, 2017, the amount recognized in regulatory balances related to net actuarial loss was $85.3 million [December 31, 2016 - $60.2 million] *[note 9[a]]*.

c) Benefit cost recognized

	2017 $	2016 $
Current service cost	**4.0**	5.8
Interest cost	**11.0**	11.7
Actuarial loss (gain) on other employee benefits *[note 13[a]]*	**3.1**	(2.1)
Benefit cost	**18.1**	15.4
Capitalized to PP&E and intangible assets	**8.1**	6.4
Charged to operating expenses	**10.0**	9.0

d) Amounts recognized in OCI

	2017 $	2016 $
Actuarial loss (gain) *[note 13[a]]*	**25.1**	(21.0)
Income tax expense (recovery) in OCI *[note 21]*	**(6.7)**	5.5
Remeasurements of post-employment benefits, net of tax	**18.4**	(15.5)
Net movements in regulatory balances related to OCI, net of tax	**(18.4)**	15.5
OCI, net of tax	**—**	—

e) Significant assumptions

	2017	2016
Discount rate (%) used in the calculation of:		
Benefit obligation as at December 31	**3.50**	4.00
Assumed medical and dental cost trend rates (%) as at December 31:		
Rate of increase in dental costs assumed for next year	**4.00**	4.00
Rate of increase in medical costs assumed for next year		
For pre July 2000 retirements	**5.00**	5.00
For other retirements	**5.50**	5.50
Rate that medical cost trend rate gradually declines to		
For pre July 2000 retirements	**5.00**	5.00
For other retirements	**5.00**	5.00
Year that the medical cost trend rate reaches the ultimate trend rate		
For pre July 2000 retirements	**2015**	2015
For other retirements	**2018**	2018

f) Sensitivity analysis

Significant actuarial assumptions for benefit obligation measurement purposes are discount rate and assumed medical and dental cost trend rates. The sensitivity analysis below has been determined based on reasonably possible changes of the assumptions, in isolation of one another, occurring at the end of the reporting period. This analysis may not be representative of the actual change since it is unlikely that changes in the assumptions would occur in isolation of one another as some of the assumptions may be correlated.

Changes in key assumptions would have had the following effect on the benefit obligation:

	Change in assumption	2017 $	2016 $
Benefit obligation		**313.0**	280.5
Discount rate	1% -	**(46.8)**	(42.0)
	1%	**60.2**	54.0
Medical and dental cost trend rate	1% -	**40.2**	36.1
	1%	**(36.0)**	(32.3)

14. CAPITAL MANAGEMENT

LDC's main objectives when managing capital are to:

- ensure ongoing access to funding to maintain, refurbish and expand the electricity distribution system;
- ensure sufficient liquidity is available (either through cash and cash equivalents, investments or borrowings through TH Energy or the Corporation) to meet the needs of the business; and
- minimize finance costs while taking into consideration current and future industry, market and economic risks and conditions.

LDC monitors forecasted cash flows, capital expenditures, debt repayment and key credit ratios similar to those used by key rating agencies. LDC manages capital by preparing short-term and long-term cash flow forecasts. In addition, LDC borrows from TH Energy or the Corporation as required to help fund some of the periodic net cash outflows and to maintain available liquidity. There have been no changes in LDC's approach to capital management during the year. As at December 31, 2017, LDC's definition of capital included equity, bank indebtedness, borrowings through the Corporation and obligations under finance leases, including the current portion thereof, and had remained unchanged from the definition as at December 31, 2016. As at December 31, 2017, equity amounted to $1,716.3 million [December 31, 2016 - $1,565.0 million], and bank indebtedness, borrowings through the Corporation and obligations under finance leases, including the current portion thereof, amounted to $2,216.4 million [December 31, 2015 - $2,191.0 million].

15. FINANCIAL INSTRUMENTS

a) Recognition and measurement

As at December 31, 2017 and December 31, 2016, the fair values of cash and cash equivalents, accounts receivable, unbilled revenue, bank indebtedness, and accounts payable and accrued liabilities approximated their carrying amounts due to the short maturity of these instruments *[note 26[j]]*. The fair value of customer deposits approximates their carrying amounts taking into account interest accrued on the outstanding balance. Obligations under finance leases are measured based on a discounted cash flow analysis and approximate the carrying amounts as management believes that the fixed interest rates are representative of current market rates.

The carrying amounts and fair values of LDC's notes payable to related party consist of the following:

	2017 $		2016 $	
	Carrying amount	**Fair value [1]**	**Carrying amount**	**Fair value [1]**
Long-term notes payable to the Corporation				
5.20% due November 14, 2017	—	—	244.9	253.7
4.54% due November 12, 2019	**244.7**	**255.6**	244.6	265.6
5.59% due May 21, 2040	**198.9**	**263.9**	198.8	253.3
3.59% due November 18, 2021	**299.2**	**313.9**	299.0	322.9
2.96% due April 10, 2023	**249.2**	**255.8**	249.1	259.7
4.01% due April 9, 2063	**198.7**	**217.4**	198.7	201.2
4.13% due September 16, 2044	**198.5**	**221.1**	198.5	209.4
3.60% due July 28, 2045	**198.7**	**202.9**	198.6	191.3
3.988% due April 9, 2063	**44.5**	**48.7**	44.5	45.1
2.572% due August 25, 2026	**198.9**	**195.4**	198.8	194.6
3.535% due February 28, 2048	**198.6**	**202.5**	—	—
Demand note payable to the Corporation due on demand	**45.0**	**45.0**	45.0	45.0
Demand note payable to the Corporation due on the earlier of demand and January 1, 2022	**15.0**	**15.6**	15.0	16.0
	2,089.9	**2,237.8**	2,135.5	2,257.8

[1] The fair value measurement of financial instruments for which the fair value has been disclosed is included in Level 2 of the fair value hierarchy *[note 26[j]]*.

b) Financial risks

The following is a discussion of financial risks and related mitigation strategies that have been identified by LDC for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks listed.

Credit risk

LDC is exposed to credit risk as a result of the risk of counterparties defaulting on their obligations. LDC's exposure to credit risk primarily relates to accounts receivable and unbilled revenue. LDC monitors and limits its exposure to credit risk on a continuous basis.

LDC is subject to credit risk with respect to customer non-payment of electricity bills. LDC obtains security instruments from certain customers in accordance with direction provided by the OEB. As at December 31, 2017, LDC held security deposits in the amount of $58.2 million [December 31, 2016 - $54.1 million], of which $29.8 million [December 31, 2016 - $30.0 million] was related to security deposits on offers to connect to guarantee the payment of additional costs related to expansion projects. LDC's security instruments may not provide sufficient protection from counterparties defaulting on their obligations. As at December 31, 2017, there were no significant concentrations of credit risk with respect to any customer. The credit risk and mitigation strategies with respect to unbilled revenue are the same as those for accounts receivable. The credit risk related to cash, cash equivalents and investments is mitigated by LDC's treasury policies on assessing and monitoring the credit exposures of counterparties.

LDC did not have any single customer that generated more than 10% of total revenue for the years ended December 31, 2017 and December 31, 2016.

Credit risk associated with accounts receivable and unbilled revenue is as follows:

	2017 $	2016 $
Accounts receivable (net of allowance for doubtful accounts)		
Outstanding for not more than 30 days	**180.3**	196.7
Outstanding for more than 30 days and not more than 120 days	**32.6**	25.4
Outstanding for more than 120 days	**4.3**	4.1
Total accounts receivable	**217.2**	226.2
Unbilled revenue	**276.0**	319.7
Total accounts receivable and unbilled revenue	**493.2**	545.9

LDC has a broad base of customers. As at December 31, 2017 and December 31, 2016, LDC's accounts receivable and unbilled revenue which were not past due or impaired were assessed by management to have no significant collection risk and no additional allowance for doubtful accounts was required for these balances.

Reconciliation between the opening and closing allowance for doubtful accounts balances is as follows:

	2017 $	2016 $
Balance, beginning of year	**(9.7)**	(11.5)
Provision for doubtful accounts	**(6.2)**	(3.8)
Write-offs	**5.9**	5.9
Recoveries	**(0.2)**	(0.3)
Balance, end of year	**(10.2)**	(9.7)

Unbilled revenue represents amounts for which LDC has a contractual right to receive cash through future billings and are unbilled at period-end. Unbilled revenue is considered current and no allowance for doubtful accounts was provided as at December 31, 2017 and December 31, 2016.

Interest rate risk

LDC is exposed to fluctuations in interest rates for the valuation of its post-employment benefit obligations *[note 13[f]]*. LDC is also exposed to short-term interest rate risk on the net of cash and cash equivalents, notes payable to related party, and customer deposits. Notes payable to related party bear interest based on the prevailing market conditions at the time of issuance.

As at December 31, 2017, aside from the valuation of its post-employment benefit obligations, LDC was exposed to interest rate risk predominately from notes payable to related party and customer deposits, while most of its remaining obligations were either non-interest bearing or bear fixed interest rates, and its financial assets were predominately short-term in nature and mostly non-interest bearing. LDC estimates that a 100 basis point increase (decrease) in short-term interest rates, with all other variables held constant, would result in an increase (decrease) of approximately $1.8 million to annual finance costs.

Liquidity risk

LDC is exposed to liquidity risk related to its ability to fund its obligations as they become due. LDC monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and financial requirements. LDC has access to credit facilities and borrowings through the Corporation and monitors cash balances daily. LDC's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing finance costs.

Liquidity risks associated with financial commitments are as follows:

2017	Due within 1 year $	Due within 2 years $	Due within 3 years $	Due within 4 years $	Due within 5 years $	Due after 5 years $
Bank indebtedness	**125.0**	—	—	—	—	—
Accounts payable and accrued liabilities [1]	**495.6**	—	—	—	—	—
Obligations under finance lease	**1.5**	—	—	—	—	—
Long-term notes payable to the Corporation						
4.54% due November 12, 2019	—	**245.1**	—	—	—	—
5.59% due May 21, 2040	—	—	—	—	—	**200.0**
3.59% due November 18, 2021	—	—	—	**300.0**	—	—
2.96% due April 10, 2023	—	—	—	—	—	**250.0**
4.01% due April 9, 2063	—	—	—	—	—	**200.0**
4.13% due September 16, 2044	—	—	—	—	—	**200.0**
3.60% due July 28, 2045	—	—	—	—	—	**200.0**
3.988% due April 9, 2063	—	—	—	—	—	**45.0**
2.572% due August 25, 2026	—	—	—	—	—	**200.0**
3.535% due February 28, 2048	—	—	—	—	—	**200.0**
Demand note payable to the Corporation due on demand	**45.0**	—	—	—	—	—
Demand note payable to the Corporation due on the earlier of demand and January 1, 2022	**15.0**	—	—	—	—	—
Interest payments on long-term notes payable and demand notes payable	**78.3**	**78.5**	**67.3**	**67.3**	**56.3**	**1,145.0**
	760.4	**323.6**	**67.3**	**367.3**	**56.3**	**2,640.0**

[1] Accounts payable and accrued liabilities exclude $17.7 million of accrued interest on long-term notes payable and demand notes payable included within "Interest payments on long-term notes payable and demand notes payable".

Foreign exchange risk

As at December 31, 2017, LDC had limited exposure to the changing values of foreign currencies. While LDC purchases goods and services which are payable in US dollars, and purchases US currency to meet the related commitments when required, the impact of these transactions is not material to the financial statements.

16. FINANCIAL ASSISTANCE

As at December 31, 2017, $38.4 million [December 31, 2016 - $33.4 million] of letters of credit had been issued by the Corporation, on behalf of LDC, under its $75.0 million demand facility mainly to support LDC's prudential requirements with the IESO.

17. SHARE CAPITAL

Share capital consists of the following:

	2017 $	2016 $
Authorized		
The authorized share capital of LDC consists of an unlimited number of common shares without par value		
Issued and outstanding		
1,000 common shares, of which all were fully paid.	**556.3**	556.3

Dividends

On May 11, 2017, the Board of Directors of LDC declared dividends in the amount of $2.1 million to the Corporation [2016 - $nil], which was paid out on June 27, 2017.

18. OTHER REVENUE

Other revenue consists of the following:

	2017 $	2016 $
Ancillary services	**21.1**	15.2
Pole and duct rentals	**15.8**	12.0
Other regulatory service charges	**13.3**	16.7
CDM mid-term incentive *[note 3[c]]*	**12.2**	—
Street lighting service fee	**6.7**	5.8
Development charges *[note 9[o]]*	**5.1**	—
Amortization of deferred revenue *[note 11]*	**4.7**	3.8
Miscellaneous	**17.8**	12.8
	96.7	66.3

19. OPERATING EXPENSES

Operating expenses consist of the following:

	2017 $	2016 $
Salaries and benefits	**225.4**	218.9
External services	**131.9**	108.6
Other support costs [(1)]	**21.6**	32.2
Materials and supplies	**21.3**	16.4
Less: Capitalized costs	**(116.0)**	(108.5)
	284.2	267.6

[(1)] Includes taxes other than income taxes, utilities, rental, communication, insurance, and other general and administrative expenses.

For the year ended December 31, 2017, LDC recognized operating expenses of $13.0 million related to materials and supplies used to service electricity distribution assets [2016 - $7.6 million].

20. FINANCE COSTS

Finance costs consist of the following:

	2017 $	2016 $
Interest income	**(0.3)**	(0.3)
Interest expense		
Interest on long-term debt [(1)]	**87.1**	85.4
Interest on short-term debt	**3.3**	3.6
Other interest	**0.7**	0.5
Capitalized borrowing costs	**(9.8)**	(12.6)
	81.0	76.6

[(1)] Includes amortization of debt issuance costs, discounts and premiums.

21. INCOME TAXES

Income tax expense differs from the amount that would have been recorded using the combined statutory Canadian federal and provincial income tax rate. Reconciliation of income tax expense computed at the statutory income tax rate to the income tax provision is set out below:

	2017 $	2016 $
Rate reconciliation before net movements in regulatory balances		
Income before income taxes	**197.5**	250.8
Statutory Canadian federal and provincial income tax rate	**26.5%**	26.5%
Expected income tax expense	**52.3**	66.5
Non-taxable amounts	**(8.7)**	0.4
Other	**0.6**	0.3
Income tax expense	**44.2**	67.2
Effective tax rate	**22.4%**	26.8%
Rate reconciliation after net movements in regulatory balances		
Net income after net movements in regulatory balances, before income tax [(1)]	**184.4**	173.6
Statutory Canadian federal and provincial income tax rate	**26.5%**	26.5%
Expected income tax expense	**48.9**	46.0
Temporary differences recoverable in future rates	**(15.5)**	(22.7)
Other	**(2.4)**	(0.1)
Income tax expense and income tax recorded in net movements in regulatory balances	**31.0**	23.2
Effective tax rate	**16.8%**	13.4%

[(1)] Income tax includes income tax expense and income tax recorded in net movements in regulatory balances.

Income tax expense as presented in the statements of income and OCI are as follows:

	2017 $	2016 $
Income tax expense	**44.2**	67.2
Income tax recorded in net movements in regulatory balances	**(13.2)**	(44.0)
Income tax expense and income tax recorded in net movements in regulatory balances	**31.0**	23.2
Income tax expense (recovery) in OCI *[note 13[d]]*	**(6.7)**	5.5
Income tax expense (recovery) in OCI recorded in net movements in regulatory balances	**6.7**	(5.5)
Income tax expense in OCI	—	—

Components of income tax expense and income tax recorded in net movements in regulatory balances are as follows:

	2017 $	2016 $
Current tax expense		
Current year	**32.0**	24.4
Adjustment for tax positions taken in prior periods	**(1.1)**	(2.2)
	30.9	22.2
Deferred tax expense		
Origination and reversal of temporary differences	**0.1**	1.0
Income tax expense and income tax recorded in net movements in regulatory balances	**31.0**	23.2

Deferred tax assets consist of the following:

	Net balance, January 1 2017 $	Recognized in net income $	Recognized in OCI $	Net balance, December 31 2017 $
PP&E and intangible assets	**11.7**	**(26.6)**	**—**	**(14.9)**
Post-employment benefits	**74.3**	**1.9**	**6.7**	**82.9**
Other taxable temporary differences	**(22.2)**	**11.2**	**—**	**(11.0)**
	63.8	**(13.5)**	**6.7**	**57.0**

	Net balance, January 1 2016 $	Recognized in net income $	Recognized in OCI $	Net balance, December 31 2016 $
PP&E and intangible assets	34.5	(22.8)	—	11.7
Post-employment benefits	78.6	1.2	(5.5)	74.3
Other taxable temporary differences	1.2	(23.4)	—	(22.2)
	114.3	(45.0)	(5.5)	63.8

LDC had recorded a net deferred tax asset as it expects to earn sufficient taxable income to realize the future reversal of deductible temporary differences.

22. STATEMENTS OF CASH FLOWS

Changes in non-cash working capital provided/(used) cash as follows:

	2017 $	2016 $
Accounts receivable	**8.7**	(36.5)
Unbilled revenue	**43.7**	(0.2)
Income tax receivable	**—**	9.0
Materials and supplies	**0.4**	0.1
Other current assets	**0.8**	(3.6)
Accounts payable and accrued liabilities	**(4.2)**	19.9
Income tax payable	**3.5**	9.0
Deferred revenue	**5.6**	0.6
Deferred conservation credit	**3.8**	(12.4)
Other current liabilities	**(1.6)**	(0.1)
	60.7	(14.2)

Reconciliation between the amount presented on the statements of cash flows and total additions to PP&E and intangible assets is as follows:

	2017 $	2016 $
Purchase of PP&E, cash basis	**433.8**	506.6
Net change in accruals related to PP&E	**9.5**	(2.3)
Other	**1.6**	1.8
Total additions to PP&E	**444.9**	506.1
Purchase of intangible assets, cash basis	**93.4**	39.9
Net change in accruals related to intangible assets	**8.0**	**—**
Total additions to intangible assets	**101.4**	**39.9**

Summary of changes in liabilities arising from financing activities:

	2016 $	Cash flows [1] $	Non-cash changes $		2017 $
			Foreign exchange	Other	
Year ended December					
Dividends payable	—	(2.1)	—	2.1	—
Notes payable to related party *[note 12]*	2,135.5	(46.5)	—	0.9	2,089.9
Accrued interest [2]	18.5	(90.2)	—	89.4	17.7
Lease liability [3]	4.6	(3.0)	(0.1)	—	1.5
	2,158.6	(141.8)	(0.1)	92.4	2,109.1

	2015 $	Cash flows [1] $	Non-cash changes $		2016 $
			Foreign exchange	Other	
Year ended December					
Notes payable to related party *[note 12]*	1,936.0	198.7	—	0.8	2,135.5
Accrued interest [2]	16.7	(86.5)	—	88.3	18.5
Lease liability [3]	8.0	(3.1)	(0.3)	—	4.6
	1,960.7	109.1	(0.3)	89.1	2,158.6

[1] Cash inflows and cash outflows arising from notes payable to related parties are presented on a net basis
[2] Included within accounts payable and accrued liabilities *[note 15[b]]*
[3] Included within other liabilities

23. RELATED PARTY TRANSACTIONS

For LDC, transactions with related parties include transactions with the City, which is the sole shareholder of the Corporation, the Corporation, and TH Energy, a wholly-owned subsidiary of the Corporation.

	City $	Corporation $	TH Energy $
For period ended December 31, 2017			
Revenues	263.1	—	10.7
Operating expenses (recoveries) and capital expenditures	22.1	1.6	(1.1)
Finance costs	—	87.0	—
Dividends	—	2.1	—
As at December 31, 2017			
Accounts receivable	12.7	—	2.1
Unbilled revenue	24.7	—	—
Accounts payable and accrued liabilities	40.0	18.3	—
Current portion of notes payable to related party	—	60.0	—
Long-term portion of notes payable to related party	—	2,029.9	—
Customer deposits	15.7	—	—
Deferred revenue	1.5	—	—

	City $	Corporation $	TH Energy $
For period ended December 31, 2016			
Revenues	258.5	—	8.7
Operating expenses and capital expenditures	26.9	1.5	0.9
Finance costs	—	85.8	—
As at December 31, 2016			
Accounts receivable	9.3	—	0.8
Unbilled revenue	23.1	—	—
Accounts payable and accrued liabilities	41.0	17.7	—
Current portion of notes payable to related party	—	304.9	—
Long-term portion of notes payable to related party	—	1,830.6	—
Customer deposits	14.1	—	—
Deferred revenue	3.0	—	—

Revenues represent amounts charged to the City primarily for electricity and ancillary services, and to TH Energy for street lighting and ancillary services. Operating expenses and capital expenditures represent amounts charged by the City for purchased road cut repairs, property taxes and other services, and the Corporation for purchased corporate and management services. Operating expense recoveries represent amounts charged to TH Energy for the provision of goods and services. Finance costs represent interest charged by the Corporation on the notes payable *[note 20]*. Dividends are paid to the Corporation *[note 17]*.

Accounts receivable represents receivables from the City primarily for electricity and ancillary services, and TH Energy for the provision of goods and services. Unbilled revenue represents receivables from the City mainly related to electricity provided and not yet billed. Accounts payable and accrued liabilities represent amounts payable to the City related to road cut repairs and other services. Included in the accounts payable and accrued liabilities are amounts payable to the Corporation for purchased corporate and management services and interest accruing on the notes payable to the Corporation. Notes payable to related party represent amounts borrowed from the Corporation *[note 12]*. Customer deposits represent amounts received from the City for future expansion projects. Deferred revenue represents amounts received from the City primarily for the construction of electricity distribution assets.

Key management personnel include LDC's senior executive officers and members of the Board of Directors. The compensation costs associated with the key management personnel are as follows:

	2017 $	2016 $
Short-term employee benefits	**4.3**	3.7
Post-employment benefits	**1.1**	1.0
	5.4	4.7

24. COMMITMENTS

Operating leases and capital projects

As at December 31, 2017, the future minimum payments under property operating leases, capital projects and other commitments were as follows:

	Operating leases $	Capital projects [1] and other $
Less than one year	**0.3**	**17.5**
Between one and five years	**1.1**	**28.5**
Total amount of future minimum payments [2]	**1.4**	**46.0**

[1] Mainly commitments for construction services and estimated capital contributions.
[2] Refer to note 15 for financial commitments excluded from the table above.

Operating lease expense for the year ended December 31, 2017 was $0.8 million [2016 - $2.8 million].

Finance leases

As at December 31, 2017 and December 31, 2016, reconciliation between the future minimum lease payments and their present value was as follows:

	2017 $			2016 $		
	Future minimum lease payments	Interest	Present value of minimum lease payments	Future minimum lease payments	Interest	Present value of minimum lease payments
Less than one year	**1.5**	—	**1.5**	3.2	0.2	3.0
Between one and five years	—	—	—	1.6	—	1.6
More than five years	—	—	—	—	—	—
	1.5	—	**1.5**	4.8	0.2	4.6
Current portion included within Other liabilities			**1.5**			3.0
Non-current portion included within Other liabilities			—			1.6

25. CONTINGENCIES

Legal Proceedings

In the ordinary course of business, LDC is subject to various legal actions and claims from customers, suppliers, former employees and other parties. On an ongoing basis, LDC assesses the likelihood of any adverse judgments or outcomes as well as potential ranges of probable costs and losses. A determination of the provision required, if any, for these contingencies is made after an analysis of each individual issue. The provision may change in the future due to new developments in each matter or changes in approach, such as a change in settlement strategy. If damages were awarded under these actions, LDC would make a claim under any applicable liability insurance policies which LDC believes would cover any damages which may become payable by LDC in connection with these actions, subject to such claim not being disputed by the insurers.

26. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

a) Regulation

The following regulatory treatments have resulted in accounting treatments which differ from those prescribed by IFRS for enterprises operating in an unregulated environment and regulated entities that did not adopt IFRS 14 *Regulatory Deferral Accounts* ["IFRS 14"]:

Regulatory Balances

In January 2014, the IASB issued IFRS 14 as an interim standard giving entities conducting rate-regulated activities the option of continuing to recognize regulatory balances according to their previous GAAP. Regulatory balances provide useful information about LDC's financial position, financial performance and cash flows. IFRS 14 is restricted to first-time adopters of IFRS and remains in force until either repealed or replaced by permanent guidance on rate-regulated accounting from the IASB.

LDC has determined that certain debit and credit balances arising from rate-regulated activities qualify for the application of regulatory accounting treatment in accordance with IFRS 14 and the accounting principles prescribed by the OEB in the "Accounting Procedures Handbook for Electricity Distributors". Under rate-regulated accounting, the timing and recognition of certain expenses and revenues may differ from those otherwise expected under other IFRS in order to appropriately reflect the economic impact of regulatory decisions regarding LDC's regulated revenues and expenditures. These amounts arising from timing differences are recorded as regulatory debit and credit balances on LDC's balance sheets, and represent existing rights and obligations regarding cash flows expected to be recovered from or refunded to customers, based on decisions and approvals by the OEB. Regulatory balances can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment or if future OEB direction is determined by management to be probable. In the event that the disposition of these balances is assessed to no longer be probable based on management's judgment, the balances are recorded in LDC's statements of income in the period when the assessment is made. Regulatory balances, which do not meet the definition of an asset or liability under any other IFRS, are segregated on the balance sheets and are presented on the statements of income and the statements of comprehensive income as net movements in regulatory balances and net movements in regulatory balances related to OCI, net of tax. The netting of regulatory debit and credit balances is not permitted. The measurement of regulatory balances is subject to certain estimates and assumptions, including assumptions made in the interpretation of the OEB's regulations and decisions.

b) Cash and cash equivalents

Cash and cash equivalents include cash in bank accounts and short-term investments with terms to maturity of 90 days or less from their date of acquisition. On the statements of cash flows, cash and cash equivalents (bank indebtedness) include bank overdrafts that are repayable on demand and form an integral part of LDC's cash management.

c) Accounts receivable and unbilled revenue

Accounts receivable is recorded at the invoiced amount and overdue amounts bear interest at OEB-approved rates. Unbilled revenue is recorded based on an estimated amount for electricity delivered and for other services provided and not yet billed. The estimate is primarily based on the customers' previous billings with adjustments mainly for assumptions related to seasonality and weighted average price. The carrying amount of accounts receivable and unbilled revenue is reduced through an allowance for doubtful accounts, if applicable, and the amount of the related impairment loss is recognized in the statements of income. The impairment loss is the difference between an asset's carrying amount and the estimated future cash flows. When LDC considers that there are no realistic prospects of recovery of the financial assets, the relevant amounts are written off. If the amount of impairment loss subsequently decreases due to an event occurring after the impairment was recognized, then the previously recognized impairment loss is reversed through net income.

Accounts receivable and unbilled revenue are assessed at each reporting date to determine whether there is objective evidence of impairment, which includes default or delinquency by a debtor, indications that a debtor or issuer will enter bankruptcy, and adverse changes in the payment status of borrowers or issuers. Accounts receivable and unbilled revenue that are not individually assessed for impairment are collectively assessed for impairment by grouping together receivables with similar risk characteristics, and LDC considers historical trends on the timing of recoveries and the amount of loss incurred, as well as current economic and credit conditions.

d) Materials and supplies

Materials and supplies consist primarily of small consumable materials mainly related to the maintenance of the electricity distribution infrastructure. LDC classifies all major construction related components of its electricity distribution infrastructure to PP&E. Materials and supplies are carried at the lower of cost and net realizable value, with cost determined on a weighted average cost basis net of a provision for obsolescence.

e) Property, plant and equipment

PP&E are measured at cost less accumulated depreciation and any accumulated impairment losses, if applicable. The cost of PP&E represents the original cost, consisting of direct materials and labour, contracted services, borrowing costs, and directly attributable overhead. Subsequent costs are capitalized only if it is probable that the future economic benefits associated with the expenditure will flow to LDC and the costs can be measured reliably. If significant parts of an item of PP&E have different useful lives, then they are accounted for as separate major components of PP&E. The carrying amount of an item of PP&E is derecognized on disposal of the asset or when no future economic benefits are expected to accrue to LDC from its continued use. Any gain or loss arising on derecognition is recorded in the statements of income in the period in which the asset is derecognized. The gain or loss on disposal of an item of PP&E is determined as the sale proceeds less the carrying amount of the asset and costs of removal and is recognized in the statements of income.

Depreciation begins when an asset becomes available for use. Depreciation is provided on a straight-line basis over the estimated useful lives at the following annual rates:

Distribution assets:	
Distribution lines	1.7% to 5.0%
Transformers	3.3% to 5.0%
Meters	2.5% to 6.7%
Stations	2.0% to 10.0%
Buildings	1.3% to 5.0%
Equipment and other:	
Assets under finance lease	1.0% to 14.3%
Other capital assets	4.0% to 25.0%

Leased assets are depreciated over the shorter of the lease term and their useful lives unless it is reasonably certain that LDC will obtain ownership by the end of the lease term. Assets under finance lease included a 99-year land lease. Construction in progress relates to assets not currently available for use and therefore is not depreciated. The depreciation method and useful lives are reviewed at each financial year-end and adjusted if appropriate. There are no residual values for items of PP&E.

f) Intangible assets

Intangible assets are measured at cost less accumulated amortization and any accumulated impairment losses, if applicable.

Amortization begins when an asset becomes available for use. Amortization is provided on a straight-line basis over the estimated useful lives at the following annual rates:

Computer software	10.0% to 25.0%
Contributions	4.0%

Software in development and contributions for work in progress relate to assets not currently available for use and therefore are not amortized. Contributions represent payments made to HONI for dedicated infrastructure in order to receive connections to transmission facilities. The amortization method and useful lives are reviewed at each financial year-end and adjusted if appropriate.

g) Impairment of non-financial assets

LDC reviews the carrying amounts of its non-financial assets other than materials and supplies and deferred tax assets at each reporting date to determine whether there is any indication of impairment, in which case the assets' recoverable amounts are estimated. For impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent on the cash inflows of other assets or CGUs. LDC has determined that its assets are a single CGU due to interdependencies of its assets to generate cash flows. An impairment loss is recognized if the carrying amount of an asset or CGU exceeds its recoverable amount. Impairment losses are recognized in the statements of income, and are allocated to reduce the carrying amounts of assets in the CGU on a pro rata basis. An impairment loss recognized in prior periods is reversed when an asset's recoverable amount has increased, but not exceeding the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior years.

h) Capitalized borrowing costs

Borrowing costs directly attributable to the acquisition, construction or development of qualifying assets that necessarily take a substantial period of time to get ready for their intended use are capitalized, until such time as the assets are substantially ready for their intended use. The interest rate for capitalization is LDC's weighted average cost of borrowing, and is applied to the carrying amount of the construction-in-progress assets or assets under development including borrowing costs previously capitalized, net of capital contributions received. Capitalization commences immediately as the expenditure on a qualifying asset is incurred. Borrowing costs are included in PP&E and intangible assets for financial reporting purposes, and charged to operations through depreciation and amortization expense over the useful lives of the related assets.

i) Revenue recognition

Revenues from energy sales and electricity distribution are recorded on the basis of cyclical billings and include an estimated amount for electricity delivered and not yet billed. These revenues are impacted by energy demand primarily driven by outside temperature, and customer class usage patterns and composition.

Energy sales arise from charges to customers for electricity consumed, based on regulated rates. Energy sales include amounts billed or billable to customers for commodity charges, retail transmission charges, and WMS charges at current rates. These charges are passed through to customers over time and are considered revenue by LDC due to the collection risk of the related balances. LDC applies judgment to determine whether revenues are recorded on a gross or net basis. LDC has primary responsibility for the delivery of electricity to the customer. During the same period, energy sales should be equal to the cost of energy purchased. However, a difference between energy sales and energy purchases arises when there is a timing difference between the amounts charged by LDC to customers, based on regulated rates, and the electricity and non-competitive electricity service costs billed monthly by the IESO to LDC. This difference is recorded as a settlement variance, representing future amounts to be recovered from or refunded to customers through future billing rates approved by the OEB. In accordance with IFRS 14, this settlement variance is presented within regulatory balances on the balance sheets and within net movements in regulatory balances on the statements of income.

Distribution revenue is recorded based on OEB-approved distribution rates to recover the costs incurred by LDC in delivering electricity to customers. Distribution revenue also includes revenue related to the collection of OEB-approved rate riders.

Other revenue, which includes revenue from services ancillary to the electricity distribution, delivery of street lighting services, and pole and duct rentals, is recognized as the services are rendered. When services are made up of different components which are not separately identifiable, the related other revenues are recognized on a straight-line basis over the term of the contract. Capital contributions received from electricity customers to construct or acquire PP&E for the purpose of connecting a customer to a network are recorded as deferred revenue and amortized into other revenue at an equivalent rate to that used for the depreciation of the related PP&E. Revenue from ancillary services not yet recognized is also included within deferred revenue.

Revenues and costs associated with CDM programs are presented using the net basis of accounting. Cost efficiency incentives related to the CDM programs, included as part of other revenue, are recognized when it is probable that future economic benefits will flow to the entity and the amount can be reasonably measured.

j) Financial instruments

All financial assets are classified as "Loans and Receivables" and all financial liabilities are classified as "Other Financial Liabilities". These financial instruments are recognized initially at fair value adjusted for any directly attributable transaction costs. Subsequently, they are measured at amortized cost using the effective interest method less any impairment for the financial assets. The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's length transaction between willing parties.

LDC uses the following methods and assumptions to estimate the fair value of each class of financial instruments for which carrying amounts are included in the balance sheets:

- Cash, cash equivalents and short-term investments are classified as "Loans and Receivables" and are measured at fair value. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Accounts receivable and unbilled revenue are classified as "Loans and Receivables" and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Bank indebtedness is classified as "Other Financial Liabilities" and is initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Accounts payable and accrued liabilities are classified as "Other Financial Liabilities" and are initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value because of the short maturity of these instruments.

- Customer deposits are classified as "Other Financial Liabilities" and are initially measured at fair value. Subsequent measurements are recorded at cost plus accrued interest. The carrying amounts approximate fair value taking into account interest accrued on the outstanding balance.

- Obligations under finance leases are classified as "Other Financial Liabilities" and are initially measured at fair value, or the present value of the minimum lease payments if lower. Subsequent measurements are based on a discounted cash flow analysis and approximate the carrying amount as management believes that the fixed interest rates are representative of current market rates.

- Notes payable to related party are classified as "Other Financial Liabilities" and are initially measured at fair value. The carrying amounts are carried at amortized cost, based on the fair value of the notes payable at issuance, which was the fair value of the consideration received adjusted for transaction costs. The fair values of the notes payable are based on the present value of contractual cash flows, discounted at LDC's current borrowing rate for similar debt instruments *[note 15[a]]*. Debt issuance costs incurred in connection with LDC's debt offerings are capitalized as part of the carrying amount of the notes payable and amortized over the term of the related notes payable, using the effective interest method, and the amortization is included in finance costs.

k) Fair value measurements

LDC utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. A fair value hierarchy exists that prioritizes observable and unobservable inputs used to measure fair value. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect LDC's assumptions with respect to how market participants would price an asset or liability. The fair value hierarchy includes three levels of inputs that may be used to measure fair value:

- Level 1: Unadjusted quoted prices in active markets for identical assets or liabilities. An active market for the asset or liability is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis;

- Level 2: Other than quoted prices included within Level 1 that are observable for the assets or liabilities, either directly or indirectly; and

- Level 3: Unobservable inputs, supported by little or no market activity, used to measure the fair value of the assets or liabilities to the extent that observable inputs are not available.

l) Employee benefits

(i) Short-term employee benefits

Short-term employee benefit obligations that are due to be settled wholly within twelve months after the end of the annual reporting period in which the employees render the related service are measured on an undiscounted basis and are expensed as the related service is provided. A liability is recognized for the amount expected to be paid if LDC has a present legal or constructive obligation to pay this amount as a result of past service provided by the employee and the obligation can be estimated reliably.

(ii) Multi-employer pension plan

LDC's full-time employees participate in a pension plan through OMERS. The OMERS plan is a jointly sponsored, multi-employer defined benefit pension plan established in 1962 by the province of Ontario for employees of municipalities, local boards and school boards. Both participating employers and employees are required to make plan contributions equally based on participating employees' contributory earnings, and share equally in funding gains or losses. The plan assets and pension obligations are not segregated in separate accounts for each member entity. The OMERS plan is accounted for as a defined contribution plan and the contribution payable is recognized as an employee benefit expense in the statements of income in the period when the service is rendered by the employee, since it is not practicable to determine LDC's portion of pension obligations or of the fair value of plan assets.

(iii) Post-employment benefits other than pension

LDC has a number of unfunded benefit plans providing post-employment benefits (other than pension) to its employees. LDC pays certain medical, dental and life insurance benefits under unfunded defined benefit plans on behalf of its retired employees. LDC also pays accumulated sick leave credits, up to certain established limits based on service, in the event of retirement, termination or death of certain employees.

The cost of providing benefits under the benefit plans is actuarially determined using the projected unit credit method, which incorporates management's best estimate of future salary levels, retirement ages of employees, health care costs, and other actuarial factors. Changes in actuarial assumptions and experience adjustments give rise to actuarial gains and losses. Actuarial gains and losses on medical, dental and life insurance benefits are recognized in OCI as they arise. Actuarial gains and losses related to rate-regulated activities are subsequently reclassified from OCI to a regulatory balance on the balance sheets. Actuarial gains and losses on accumulated sick leave credits are recognized in the statements of income in the period in which they arise.

The measurement date used to determine the present value of the benefit obligation is December 31 of the applicable year. The latest actuarial valuation was performed as at January 1, 2016.

m) Customer deposits

Security deposits from electricity customers are cash collections to guarantee the payment of electricity bills. This liability includes related interest amounts owed to the customers with a corresponding amount charged to finance costs. Deposits that are refundable upon demand are classified as a current liability.

Security deposits on offers to connect are cash collections from specific customers to guarantee the payment of additional costs relating to expansion projects. This liability includes related interest amounts owed to the customers with a corresponding amount charged to finance costs. Deposits are classified as a current liability when LDC no longer has an unconditional right to defer payment of the liability for at least 12 months after the reporting period.

n) Income taxes

Under the Electricity Act, LDC is required to make PILs to the Ontario Electricity Financial Corporation. These payments are calculated in accordance with the ITA and the TA as modified by regulations made under the Electricity Act and related regulations. This effectively results in LDC paying income taxes equivalent to what would be imposed under the Federal and Ontario Tax Acts.

LDC uses the liability method of accounting for income taxes. Under the liability method, current income taxes payable are recorded based on taxable income. LDC recognizes deferred tax assets and liabilities for the future tax consequences of events that have been included in the financial statements or income tax returns. Deferred tax assets and liabilities are determined based on the difference between the carrying value of assets and liabilities on the balance sheets and their respective tax basis, using the tax rates enacted or substantively enacted by the balance sheet date that are in effect for the year in which the differences are expected to reverse. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when it is probable that they will be realized, and are measured at the best estimate of the tax amount expected to be paid to or recovered from the taxation authorities. Deferred tax assets are reviewed at each reporting date and reduced to the extent that it is no longer probable that the related tax benefits will be realized. The calculation of current and deferred taxes requires management to make certain judgments with respect to changes in tax interpretations, regulations and legislation, and to estimate probable outcomes on the timing and reversal of temporary differences and tax authority audits of income tax.

Rate-regulated accounting requires the recognition of regulatory balances and related deferred tax assets and liabilities for the amount of deferred taxes expected to be refunded to or recovered from customers through future electricity distribution rates. A gross up to reflect the income tax benefits associated with reduced revenues resulting from the realization of deferred tax assets is recorded within regulatory credit balances. Deferred taxes that are not included in the rate-setting process are charged or credited to the statements of income.

The benefits of the refundable and non-refundable apprenticeship and other ITCs are credited against the related expense in the statements of income.

o) Use of judgments and estimates

The preparation of LDC's financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions which affect the application of accounting policies, reported assets, liabilities and regulatory balances, and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported revenues and expenses for the year. The estimates are based on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities as well as for identifying and assessing the accounting treatment with respect to commitments and contingencies. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the IESO, the Ontario Ministry of Energy or the Ontario Ministry of Finance.

Information about judgments in applying accounting policies that have the most significant effects on the amounts recognized in the financial statements is included in note 26[i] relating to principal versus agent determination for recording revenue on a gross or net basis.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to estimates are recognized prospectively. Assumptions and estimates with a significant risk of resulting in a material adjustment within the next financial year are used in the following:

- Note 26[a] – Recognition and measurement of regulatory balances;
- Note 26[i] – Revenue recognition – measurement of unbilled revenue, determination of the CDM incentive;
- Notes 26[e] and 26[f] – Determination of useful lives of depreciable assets;
- Notes 26[l] and 13 – Measurement of post-employment benefits – key actuarial assumptions;
- Notes 26[n] and 21 – Recognition of deferred tax assets – availability of future taxable income against which deductible temporary differences and tax loss carryforwards can be used; and
- Note 25 – Recognition and measurement of provisions and contingencies.

p) Changes in accounting policies

In January 2016, the IASB issued amendments to IAS 7 *Statement of Cash Flows* as part of the IASB's Disclosure Initiative. These amendments require entities to provide disclosures that enable users of financial statements to evaluate changes in liabilities arising from financing activities, including changes from cash flows and non-cash changes. These amendments are effective for annual periods beginning on or after January 1, 2017. The additional disclosures relating to changes in liabilities arising from financing activities are included in note 22 and have no impact to the LDC's financial position or results of operations.

q) Future accounting pronouncements

A number of new standards, amendments and interpretations are not yet effective for the year ended December 31, 2017, and have not yet been applied in preparing these financial statements.

Revenue from Contracts with Customers

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers* ["IFRS 15"], which replaces existing revenue recognition guidance, including IAS 18 *Revenue* and IFRIC 18 *Transfers of Assets from Customers*. IFRS 15 contains a single model that applies to contracts with customers with two methods for recognizing revenue: at a point in time or over time. IFRS 15 is effective for annual periods beginning on or after January 1, 2018.

LDC will adopt IFRS 15 on January 1, 2018 using the modified retrospective approach. LDC has completed its assessment of the key revenue streams. The majority of LDC's revenue (energy sales and distribution revenue) is generated from electricity distribution at regulated prices. LDC concluded that IFRS 15 will not have a material impact on the accounting for these revenue streams. Upon adoption of IFRS 15, there will be a $167.6 million income statement reclassification between Energy Sales and Energy Purchases for the comparative year ended December 31, 2017 and there is no impact to opening retained earnings as at January 1, 2018. LDC is currently finalizing its assessment on capital contributions. LDC has determined that IFRS 15 will also increase its required disclosure on revenue streams.

Financial Instruments

In July 2014, the IASB issued the final version of IFRS 9 *Financial Instruments* ["IFRS 9"], which replaces IAS 39 *Financial Instruments: Recognition and Measurement* ["IAS 39"]. IFRS 9 includes revised guidance on the classification and measurement of financial instruments, including a new expected credit loss model for measuring impairment on financial assets, and new general hedge accounting requirements. It also carries forward the guidance on recognition and derecognition of financial instruments from IAS 39. The standard is effective for annual periods beginning on or after January 1, 2018, and will be applied retrospectively with some exceptions. LDC has assessed the impact of adopting IFRS 9, and concluded that the new classification under IFRS 9 will not have a material impact on the financial statements. Management is currently evaluating the impact of adopting the new expected credit loss model for measuring impairment.

Leases

In January 2016, the IASB issued IFRS 16 *Leases* ["IFRS 16"], which replaces IAS 17 *Leases* ["IAS 17"] and related interpretations. IFRS 16 introduces a single lessee accounting model eliminating the current distinction between finance and operating leases. It requires the recognition of lease-related assets and liabilities on the balance sheet, except for short-term leases and leases of low value underlying assets. In addition, the nature and timing of expenses related to leases will change, as IFRS 16 replaces the straight-line operating leases expense with the depreciation expense for the assets and interest expense on the lease liabilities. Lessor accounting remains substantially unchanged. The standard is effective for annual periods beginning on or after January 1, 2019, and may be applied either retrospectively or using a modified retrospective approach. Early adoption is permitted if IFRS 15 is also adopted.

LDC intends to early adopt IFRS 16 on January 1, 2018. LDC has completed its assessment of existing operating leases. IFRS 16 will not have a significant impact on LDC's financial statements and LDC has assessed the quantitative impact of adopting IFRS 16 to be $nil in opening retained earnings, and an increase of $1.6 million in total assets and total liabilities for the right-of-use assets and the lease liabilities, respectively, as at January 1, 2018.

GLOSSARY

CDM – Conservation and demand management

CIR – Custom Incentive Rate-setting

City – City of Toronto

Corporation – Toronto Hydro Corporation

Electricity Act – *Electricity Act, 1998* (Ontario), as amended

GAAP – Generally Accepted Accounting Principles

GWh – Gigawatt hour

HONI – Hydro One Networks Inc.

IAS – International Accounting Standard

IASB – International Accounting Standards Board

ICM – Incremental Capital Module

IESO – Independent Electricity System Operator. The IESO and the Ontario Power Authority were merged under the name Independent Electricity System Operator on January 1, 2015.

IFRIC – International Financial Reporting Interpretations Committee

IFRS – International Financial Reporting Standards

IRM – Incentive Regulation Mechanism

ITA – *Income Tax Act* (Canada), as amended

LDC – Toronto Hydro-Electric System Limited

LRAM – Lost revenue adjustment mechanism

OCI – Other comprehensive income

OEB – Ontario Energy Board

OEB Act – *Ontario Energy Board Act, 1998* (Ontario), as amended

OFHP – Ontario's Fair Hydro Plan

OFHA – *Fair Hydro Act, 2017* (Ontario)

OMERS – Ontario Municipal Employees Retirement System

OPA – Ontario Power Authority. The IESO and the OPA were merged under the name Independent Electricity System Operator on January 1, 2015.

OPEB – Other post-employment benefits

OREC – *Ontario Rebate for Electricity Consumers Act*, 2016 (Ontario).

PILs – Payments in lieu of corporate taxes

PP&E – Property, plant and equipment

TA – *Taxation Act, 2007* (Ontario), as amended

TH Energy – Toronto Hydro Energy Services Inc.

US GAAP – United States Generally Accepted Accounting Principles

WMS – Wholesale Market Service

RECONCILIATIONS

In accordance with s. 2.1.9 of the OEB's Filing Requirements,[1] this schedule provides reconciliations of the financial results shown in the Audited Financial Statements (Exhibit 1C, Tab 3, Schedule 3) with the regulatory financial results filed under s. 2.1.13 of the OEB's Electricity Reporting & Record Keeping Requirements for the years 2015 through 2017:

- Appendix A: 2015 Reconciliation
- Appendix B: 2016 Reconciliation
- Appendix C: 2017 Reconciliation

[1] Ontario Energy Board, Filing Requirements for Electricity Distributor Rate Applications, Chapter 2 (July 12, 2018).

		C1	C2	C3	C4=C1:C3	
RRR Reporting **Rate Base Calculation** **Reconciliation - Total PP&E**		**PP&E (incl CWIP)**	**ROE Exclusions** **Remove CWIP**	**Other**	**ROE Calc** **Net**	**Comment**
As Reported - US GAAP RRR Dec 31, 2014	*R1*	$2,903,903	-$518,239	$0	$2,385,664	PPE per ROE Calc. 2014
Difference to mIFRS	*R2*	$25,841	-$24,250	$0	$1,591	Adjustments due to conversion from US GAAP to MIFRS
mIFRS - Trial Balance	*R3=R1+R2*	**$2,929,744**	**-$542,489**	**$0**	**$2,387,255**	
A/C 2440 Deferred Revenue LT	*R4*			-$43,571	-$43,571	Capital contributions recorded in A/C 2440 is netted in the determination of rate base
CWIP portion of A/C 2440	*R5*			$22,706	$22,706	CWIP portion of A/C 2440 is excluded in determination of rate base
mIFRS Balance	*R6=R3:R5*	**$2,929,744**	**-$542,489**	**-$20,865**	**$2,366,390**	
Inclusions for new Rate Regime						
ICM Assets	*R7*	$439,074			$439,074	As a result of the December 29, 2015 OEB Decision and Order, the approved rate base as at January 1, 2015 included the ICM and street lighting assets.
Streetlighting Assets	*R8*	$38,475			$38,475	As a result of the December 29, 2015 OEB Decision and Order, the approved rate base as at January 1, 2015 included the ICM and street lighting assets.
Total Jan 1 2015 PP&E - RRR	*R9=R6:R8*	**$3,407,293**	**-$542,489**	**-$20,865**	**$2,843,939**	Jan 1, 2015 PP&E for ROE Purposes
Total Adjustment to RRR Opening PP&E	*R10=R9-R1*				**$458,275**	
2015 ROE						
mIFRS - RRR Balances per ledger - OEB roll up		$3,750,644	-$609,194		$3,141,450	
A/C 2440 Deferred Revenue LT				-$86,773	-$86,773	
CWIP portion of A/C 2440				$31,475	$31,475	
Submission per RRR		**$3,750,644**	**-$609,194**	**-$55,298**	**$3,086,151**	Dec 31, 2015 PP&E for ROE Purposes

Toronto Hydro-Electric System Limited - 2.1.13
Balance Sheet
December 31, 2015

Filing: April 30, 2016

		Regulated 2015 Actual OEB Acct TB	Regulated 2015 Actual (in thousands)	Unregulated 2015 Actual (in thousands)	Consol Adj 2015 Actual (in thousands)	Calculated THESL Consol 2015 Actual (in thousands)	Audited THESL Consol 2015 Actual (in thousands)	Diff	Comment
Assets									
Current Assets									
Cash and cash equivalents	1005_Cash	-	-						
	1010_Cash Advances and Working Funds	-	-						
		-	-	7,588	-7,588	-	-	-	
Accounts receivable	1100_Customer Accounts Receivable	188,642,297	188,642						
	1104_Accounts Receivable - Recoverable Work	5,364,989	5,365						
	1110_Other Accounts Receivable	612	1						
	1130_Accumulated Provision for Uncollectible Accounts-- Credit	- 11,451,441	-11,451						
	1200_Accounts Receivable from Associated Companies	949,071	949						
		183,505,530	183,506	7,096	-746	189,855	189,855	-0	
Unbilled revenue	1120_Accrued Utility Revenues	319,034,891	319,035	509		319,544	319,544	-0	
Income tax receivable	2294_Accrual for Taxes Payments in Lieu of Taxes Etc.	8,213,756	8,214			8,214	8,964	750	Note 1
Materials and supplies	1330_Plant Materials and Operating Supplies	9,827,944	9,828			9,828	9,828	-	
Other assets	1180_Prepayments	9,932,782	9,933			9,933	9,933	-	
	1190_Miscellaneous Current and Accrued Assets	875,659	876			876	-	-876	Note 2
		347,885,033	347,885	509	-	348,394	348,268	-126	
Property, plant and equipment	1805_Land	7,101,021	7,101						
	1808_Buildings and Fixtures	51,400,864	51,401						
	1815_Transformer Station Equipment - Normally Primary above 50 kV	5,839,979	5,840						
	1820_Distribution Station Equipment - Normally Primary below 50 kV	149,863,147	149,863						
	1830_Poles Towers and Fixtures	310,997,642	310,998						
	1835_Overhead Conductors and Devices	299,369,433	299,369						
	1840_Underground Conduit	951,961,159	951,961						
	1845_Underground Conductors and Devices	609,870,852	609,871						
	1850_Line Transformers	412,408,347	412,408						
	1855_Services	93,304,634	93,305						
	1860_Meters	168,697,558	168,698						
	1905_Land	17,738,078	17,738						
	1908_Buildings and Fixtures	126,908,339	126,908						
	1910_Leasehold Improvements	753,840	754						
	1915_Office Furniture and Equipment	10,757,047	10,757						
	1920_Computer Equipment - Hardware	27,318,767	27,319						
	1930_Transportation Equipment	27,217,305	27,217						
	1935_Stores Equipment	7,066	7						
	1940_Tools Shop and Garage Equipment	14,696,369	14,696						
	1945_Measurement and Testing Equipment	480,243	480						
	1955_Communication Equipment	8,025,828	8,026						
	1960_Miscellaneous Equipment	267,071	267						
	1970_Load Management Controls - Customer Premises	3,022,834	3,023						
	1975_Load Management Controls - Utility Premises	-	-						
	1980_System Supervisory Equipment	25,425,079	25,425						
	1995_Contributions and Grants - Credit	-	-						
	1612_Land Rights	7,191,090	7,191						
	2005_Property Under Capital Leases	10,979,744	10,980						
	2055_Construction Work in Progress-Electric	493,198,903	493,199						
	2105_Accum. Amortization of Electric Utility Plant - Property Plant & Equipment	- 282,768,843	-282,769						
	2120_Accumulated Amortization of Electric Utility Plant - Intangibles	-698,681	-699						
		3,551,334,715	3,551,335	10,590	-	3,561,925	3,561,925	-0	

Toronto Hydro-Electric System Limited - 2.1.13
Balance Sheet
December 31, 2015

Filing: April 30, 2016

		Regulated 2015 Actual OEB Acct TB	Regulated 2015 Actual (in thousands)	Unregulated 2015 Actual (in thousands)	Consol Adj 2015 Actual (in thousands)	Calculated THESL Consol 2015 Actual (in thousands)	Audited THESL Consol 2015 Actual (in thousands)	Diff	Comment
Intangible assets	1609_Capital Contributions Paid	21,730,287	21,730						
	1611_Computer Software	101,649,562	101,650						
	2055_Construction Work in Progress--Electric	115,995,560	115,996						
	2120_Accumulated Amortization of Electric Utility Plant - Intangibles	- 40,065,975	-40,066						
		199,309,434	199,309	-	-	199,309	199,309	-	
Deferred tax assets	1495_Deferred Taxes - Non-Current Assets	99,859,048	99,859	-	-	99,859	114,345	14,486	Note 3
Other assets	1460_Other Non-Current Assets	3,838,091	3,838	-	-	3,838	1,211	-2,627	Note 2
Regulatory balances	1508_Other Regulatory Assets	151,906,897	151,907						
	1520_Power Purchase Variance Account	0	0						
	1521_Special Purpose Chg Assessment Variance Account	-	-						
	1550_Low Voltage Variance Acct	2,198,398	2,198						
	1551_Smart Metering Entity Charge Variance Acct	140,568	141						
	1555_Smart Meter Capital Offset Variance	14,404,067	14,404						
	1556_Smart Meter Operating Variance	-	-						
	1562_Deferred Payments in Lieu of Taxes	-	-						
	1563_Deferred PILs Contra Account	-	-						
	1568_LRAM Variance Account	9,105,233							
	1575_IFRS-UGAAP Transitional PPE Amounts	24,193,438							
	1580_RSVAWMS	- 156,333,491	-156,333						
	1584_RSVANW	69,472,636	69,473						
	1586_RSVACN	36,894,013	36,894						
	1588_RSVAPOWER	- 22,246,709	-22,247						
	1589_RSVAGA	97,731,157	97,731						
	1592_PILs and Tax Variance for 2006 and Subsequent Years	- 2,494,112							
	1595_Disposition Recovery Reg Balances Control Acct	- 1,742,385	-1,742						
		223,229,711	223,230	-	-	223,230	241,718	18,488	Note 4
Total Assets		4,608,961,562	4,608,962	25,782	-8,334	4,626,410	4,656,631	30,222	
Liabilities and Shareholder's Equity									
Bank indebtedness	2225_Notes and Loans Payable	- 196,521,453	-196,521	-	7,588	-188,934	-188,934	-	
Advance from related party		-	-	-	-	-	-	-	
Accounts payable and accrued liabilities	2205_Accounts Payable	- 389,106,383	-389,106						
	2208_Customer Credit Balances	- 16,243,629	-16,244						
	2220_Miscellaneous Current and Accrued Liabilities	- 15,426,009	-15,426						
	2240_Accounts Payable to Associated Companies Notes	- 54,010,977	-54,011						
	2250_Debt Retirement Charges(DRC) Payable	- 12,683,957	-12,684						
	2290_Commodity Taxes	- 759,852	-760						
	2294_Accrual for Taxes Payments in Lieu of Taxes Etc.	650,961	651						
	2292_Payroll Deductions / Expenses Payable	- 7,815,043	-7,815						
		- 495,394,890	-495,395	23,122	746	-471,527	-471,527	0	
Customer deposits	2210_Current Portion of Customer Deposits	- 37,469,696	-37,470				-37,470		
	2335_Long Term Customer Deposits	-	-						
		- 37,469,696	-37,470	-	-	-37,470	-37,470	-	
Deferred revenue	2220_Miscellaneous Current and Accrued Liabilities	-973,180	-973	-		-973	-3,740	-2,766	Note 5
Deferred conservation credit		0	-	-17,885		-17,885	-17,885	-	
Other liabilities	2285_Obligations Under Finance Leases--Current	- 3,235,715	-3,236			-3,236	-3,236	-	
Note payable to related party	2242_ Payable to Associated Companies	- 60,000,000	-60,000			-60,000	-		
	2240_Accounts Payable to Associated Companies Notes	-	-			-	-		
	2260_Current Portion of Long Term Debt	-	-	-		-	-		
		- 60,000,000	-60,000	-	-	-60,000	-60,000	-	
Note payable to related party	2550_Advances from Associated Companies	- 1,875,984,003	-1,875,984			-1,875,984	-1,875,984	0	
	2505_Debentures Outstanding - Long Term Portion	-	-			-	-	-	
Customer deposits	2335_Long Term Customer Deposits	-9,888,218	-9,888			-9,888	-9,888	-	

Toronto Hydro-Electric System Limited - 2.1.13
Balance Sheet
December 31, 2015

Filing: April 30, 2016

		Regulated 2015 Actual OEB Acct TB	Regulated 2015 Actual (in thousands)	Unregulated 2015 Actual (in thousands)	Consol Adj 2015 Actual (in thousands)	Calculated THESL Consol 2015 Actual (in thousands)	Audited THESL Consol 2015 Actual (in thousands)	Diff	Comment
Deferred revenue	2440_Deferred Revenues	- 86,772,590	-86,773			-86,773	-100,281		
	2320_Other Miscellaneous Non-Current Liabilities	-	-			-	-		
	2335_Long Term Customer Deposits	- 16,275,062	-16,275			-16,275	-		
		- 103,047,652	-103,048	-	-	-103,048	-100,281	2,766	Note 5
Post-employment benefits	2306_Employee Future Benefits	- 295,351,821	-295,352	-1,168		-296,520	-296,520	-	
Other liabilities	2325_Obligations Under Capital Lease-Non-Current	- 4,773,123	-4,773			-4,773	-4,942		
	2320_Other Miscellaneous Non-Current Liabilities	- 168,633	-169			-169			
		- 4,941,757	-4,942	-	-	-4,942	-4,942	-	
Total Liabilities		- 3,082,808,385	-3,082,808	4,069	8,334	-3,070,406	-3,070,406	0	
Share Capital	3005_Common Shares Issued	- 527,816,668	-527,817	-28,461		-556,278	-556,278	0	
Retained Earnings	3045_Unappropriated Retained Earnings	- 989,001,291	-989,001						
	3046_Balance Transferred From Income	- 140,491,242	-140,491						
	3049_Dividends Payable-Common Shares	321,526,000	321,526						
	3055_Adjustment to Retained Earnings	- 5,969,175	-5,969						
		- 813,935,709	-813,936	-1,390	-	-815,325	-845,547	-30,222	Note 6
Contributed Surplus	3010_Contributed Surplus	- 12,757,392	-12,757			-12,757	-12,757	-	
Regulatory balances	1508_Other Regulatory Assets	- 72,714,445	-72,714						
	2350_Future Income Tax - Non-Current	- 98,928,963	-98,929						
		- 171,643,408	-171,643	-	-	-171,643	-171,643	-	
Total liabilities, equity and regulatory balances		- 4,608,961,562	-4,608,962	-25,782	8,334	-4,626,410	-4,656,631	-30,222	
		- 0	- 0	-	-	-0	-	0	

Toronto Hydro-Electric System Limited - 2.1.13 Filing: April 30, 2016
Balance Sheet
December 31, 2015

Notes: The Uniform System of Account balances are mapped and reconciled to the audited financial statements (AFS) (in dollars thousands).

Note 1: Difference in "Income tax receivable" of $750: Calculated balance of $8,214 & AFS balance of $8,964, a difference of $750, as follows:
The difference represents the non-regulated business income tax receivable included in the AFS.

Note 2: This relates to the CIR Costs Deferral re-instatement on the Balance Sheet.
For OSC purposes, as a result of the OEB's Decision with regards to the DRO, the CIR costs were considered no longer recoverable, and as such it was considered impaired and written-off to the P&L.
For RRR purposes, since the CIR Costs were approved to be recovered over the 5 year term in the original OEB Decision on December 29, 2015 with regards to the 2015-2019 CIR Application, the CIR costs were re-instated on the balance sheet and will be amortized over the 5 years. The current portion and the long-term portion of the re-instated CIR costs on the balance sheet was $876 and $2,627 respectively.

Note 3: Difference in "Deferred tax assets" of $14,486: Calculated balance of $99,859 & AFS balance of $114,345, a difference of $14,486, as follows:
a. The deferred tax balance related to regulatory balances and gross up in respect of deferred tax assets are recorded in regulatory balances in accordance with IFRS 14 for AFS.
For purposes of RRR reporting, these balances are reclassified to deferred tax assets in the amount of $15,918.
b. For purposes of RRR reporting, an adjustment was made to remove deferred income tax asset in respect of the non-rate regulated assets in the amount of ($1,432).

Note 4: Difference in "Regulatory balances - deferred debits" of $18,488: Calculated balance of $223,230 & AFS balance of $241,718, a difference of $18,488, as follows:

a. A "Smart meter recovery" regulatory asset (RA) was booked for AFS, and is not considered a regulatory asset for purposes of RRR reporting:	$9,947
b. Incremental Capital Model (ICM) revenue and depreciation expense was booked in the AFS in the past, and this considered a regulatory asset for purposes of RRR reporting.	$20,884
c. The deferred tax balance related to regulatory balances and gross up in respect of deferred tax assets are recorded in regulatory balances in accordance with IFRS 14 for AFS. For purposes of RRR reporting, these balances are reclassified to deferred tax assets.	-$15,918
d. HST Contra account adjustment: In prior years' AFS, THESL has booked to the OEB account 1592, "PILs and Tax Variances for 2006 and Subsequent Years, Sub-account HST / OVAT Input Tax credits (ITCs)" the ITC savings arising from the elimination of Provincial Sales Tax and implementation of the HST on July 1, 2010. For AFS purposes, the offsetting entry was booked to the income statement rather the regulatory sub-account established, a contra account within Account 1592, "PILS and Tax Variances for 2006 and subsequent years - HST/OVAT Contra Account" of Account 1592. The following adjustment has been made to the AFS to reflect for RRR Reporting the amount in the above mentioned contra account: The adjustment entry is, HST/OVAT Contra Account (Dr.) $1,180k, Misc. Interest (Cr.) $14k and Retained Earnings (Cr.) 1,166k.	-$1,180
e. For RRR purposes, as per the APH, Article 510, "The return on rate base shall not be recorded in Account 1575 IFRS-GAAP Transitional PP&E Return on Rate Base. On disposition of the account balance, the return is applied prospectively in rates as an adjustment to the revenue requirement." In the AFS, the return on rate base was accrued at year-end 2015 since the OEB approved the disposition of Account 1575 with the return on rate base of $4.7 million. For RRR purposes, the $4.7 million accrual has been reversed.	$4,755
Total difference:	$18,488

Note 5: Difference in "Deferred revenue - current", offset by difference in "Deferred revenue - long-term" of $2,766 as follows:
For the AFS the Deferred revenue was split between current and long-term. For the RRR purposes, the Deferred revenue is not split between current and long-term.

Note 6: Difference in "Retained Earnings" of ($30,222): Calculated balance of ($815,325) & AFS balance of ($845,547), a difference of ($30,222).
Adjustments have been made to certain AFS income statement items to arrive at the RRR reporting as follows:

A. Adjustments made to certain AFS income statement items in prior years as follows:

a. Reduction for prior years AFS Distribution revenue booked for Smart Meter "net revenue requirement" on the disposition of Account 1555 "Smart Meter Capital & Recovery" and 1556 "Smart Meter OM&A Variance account" balances. The is recorded to Distribution revenue for RRR reporting, to OEB account 4080 as the amount is billed to THESL customers in the future.	-$20,879
b. Incremental Capital Model (ICM) revenue and depreciation expense booked in the AFS in prior year, and this considered a regulatory asset for purposes of RRR reporting. This ICM revenue and depreciation expense shall be booked for RRR reporting in the future under regulatory prescribed ICM accounting treatment.	- 20,884
c. HST Contra account adjustment: In prior years' AFS, THESL has booked to the OEB account 1592, "PILs and Tax Variances for 2006 and Subsequent Years, Sub-account HST / OVAT Input Tax credits (ITCs)" the ITC savings arising from the elimination of Provincial Sales Tax and implementation of the HST on July 1, 2010. For AFS purposes, the offsetting entry was booked to the income statement rather the regulatory sub-account established, a contra account within Account 1592, "PILS and Tax Variances for 2006 and subsequent years - HST/OVAT Contra Account" of Account 1592. The following adjustment has been made to the AFS to reflect for RRR Reporting the amount in the above mentioned contra account: The adjustment entry is, HST/OVAT Contra Account (Dr.) $1,166k, Misc. Interest (Cr.) $16k and Retained Earnings (Cr.) 1,150k.	1,166
d. "Wireless pole attachments" regulatory asset (RA) was booked for purposes of RRR reporting while for prior year AFS purposes the RA amount was included in the income statement.	- 113
e. For purposes of RRR reporting, an adjustment was made to remove deferred income tax asset in respect of the non-rate regulated assets related to prior year.	1,275

B. Adjustments made to certain AFS income statement items in 2015, with these differences as explained in the Income Statement attached.

a. The total impact on net income or difference for the year 2015 was $9,213, per the Income Statement attached.	9,213
Total difference:	-$30,222

Toronto Hydro-Electric System Limited - 2.1.13
Statement of Income
December 31, 2015

Filing: April 30, 2016

		Regulated 2015 Actual OEB Acct TB	Regulated 2015 Actual (in thousands)	Unregulated 2015 Actual (in thousands)	Net Movement Adj 2015 Actual (in thousands)	Consol Adj 2015 Actual (in thousands)	Calculated THESL Consol 2015 Actual (in thousands)	Audited THESL Consol 2015 Actual (in thousands)	Diff	Comment
Revenue										
Energy sales	4006_Residential Energy Sales	-511,505,959	- 511,506							
	4010_Commercial Energy Sales	-1,473,500,371	- 1,473,500							
	4020_Energy Sales to Large Users	-216,615,501	- 216,616							
	4025_Street Lighting Energy Sales	-12,384,109	- 12,384							
	4035_General Energy Sales	-252,285,805	- 252,286							
	4050_Revenue Adjustment	-6,409,770	- 6,410							
	4062_Billed WMS	-84,969,806	- 84,970							
	4066_Billed NW	-166,194,728	- 166,195							
	4068_Billed CN	-116,495,879	- 116,496							
	4075_Billed LV	43	0							
		-2,840,361,885	- 2,840,362		- 30,834	-	- 2,871,195	- 2,925,630	- 54,434	Note 1
Distribution revenue	4080_Distribution Services Revenue	-612,354,538	- 612,355		50,751	-	- 561,603	- 555,424	6,179	Note 2
		-3,452,716,423	- 3,452,716	-	19,918	-	- 3,432,799	- 3,481,054	- 48,255	
Other income	4082_Retail Services Revenues	-397,235	- 397							
	4084_Service Transaction Requests (STR) Revenues	-20,107	- 20							
	4086_SSS Administration Revenue	-2,196,126	- 2,196							
	4090_Electric Services Incidental to Energy Sales	0	-							
	4210_Rent from Electric Property	-10,406,330	- 10,406							
	4215_Other Utility Operating Income	-1,111,340	- 1,111							
	4220_Other Electric Revenues	-7,055,723	- 7,056							
	4225_Late Payment Charges	-4,126,310	- 4,126							
	4235_Miscellaneous Service Revenues	-6,786,826	- 6,787							
	4245_Government and Other Assistance Directly Credited to Income	-2,210,580	- 2,211							
	4325_Revenues from Merchandise Jobbing Etc.	-12,747,564	- 12,748							
	4330_Costs and Expenses of Merchandising Jobbing Etc.	14,047,565	14,048							
	4076_Billed Smart Metering Entity Charge	-6,756,356	- 6,756							
		-39,766,931	- 39,767	- 1,177	- 250	-	- 41,194	- 48,335	- 7,141	Note 3
Costs										
Energy purchases	4705_Power Purchased	1,363,933,297	1,363,933							
	4707_Charges - Global Adjustment	1,096,864,597	1,096,865							
	4708_Charges-WMS	64,322,666	64,323							
	4714_Charges-NW	166,193,052	166,193							
	4716_Charges-CN	116,497,555	116,498							
	4730_Rural Rate Assistance Expense	32,551,447	32,551							
	4750_Charges LV	-43	- 0							
		2,840,362,572	2,840,363	-	3,697	-	2,844,060	2,898,492	54,432	Note 4
Operating expenses	4380_Expenses of Non-Utility Operations	91,941	92							
	4398_Foreign Exchange Gains and Losses Including Amortization	1,500,430	1,500							
	5005_Distribution Operation Supervision and Engineering	20,195,329	20,195							
	5010_Distribution Load Dispatching	5,728,776	5,729							
	5012_Station Buildings and Fixtures Expense	0	-							
	5016_Distribution Station Equipment - Operation Labour	2,791,165	2,791							
	5017_Distribution Station Equipment - Operation Supplies and Expenses	2,876,993	2,877							
	5020_Overhead Distribution Lines and Feeders - Operation Labour	810,769	811							
	5025_Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1,163,363	1,163							
	5035_Overhead Distribution Transformers- Operation	0	-							
	5040_Underground Distribution Lines and Feeders - Operation Labour	1,462,007	1,462							
	5045_Underground Distribution Lines & Feeders - Operation Supplies & Expenses	1,800,410	1,800							
	5055_Underground Distribution Transformers - Operation	14,266	14							
	5065_Meter Expense	484,730	485							
	5070_Customer Premises - Operation Labour	2,798,435	2,798							
	5075_Customer Premises - Materials and Expenses	1,997,164	1,997							
	5085_Miscellaneous Distribution Expense	6,437,256	6,437							
	5105_Maintenance Supervision and Engineering	19,129,502	19,130							
	5110_Maintenance of Buildings and Fixtures - Distribution Stations	14,284,733	14,285							
	5112_Maintenance of Transformer Station Equipment	0	-							
	5114_Maintenance of Distribution Station Equipment	3,212,202	3,212							
	5120_Maintenance of Poles Towers and Fixtures	426,963	-							
	5125_Maintenance of Overhead Conductors and Devices	15,645,627	16,913							

Toronto Hydro-Electric System Limited - 2.1.13
Statement of Income
December 31, 2015

Filing: April 30, 2016

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	5130_Maintenance of Overhead Services	840,012	-							
	5135_Overhead Distribution Lines and Feeders - Right of Way	3,204,037	3,204							
	5145_Maintenance of Underground Conduit	-182	- 0							
	5150_Maintenance of Underground Conductors and Devices	7,685,651	7,686							
	5155_Maintenance of Underground Services	15,992	16							
	5160_Maintenance of Line Transformers	0	-							
	5165_Maintenance of Street Lighting and Signal Systems	2,379,914	2,380							
	5305_Supervision	230,612	231							
	5310_Meter Reading Expense	3,578,418	3,578							
	5315_Customer Billing	8,714,033	8,714							
	5320_Collecting	17,591,343	17,591							
	5335_Bad Debt Expense	6,630,000	6,630							
	5410_Community Relations - Sundry	-16,029	- 16							
	5415_Energy Conservation	84	0							
	5420_Community Safety Program	3,472,067	3,472							
	5605_Executive Salaries and Expenses	1,610,316	1,610							
	5610_Management Salaries and Expenses	2,827	3							
	5615_General Administrative Salaries and Expenses	52,024,951	52,025		- 304					
	5620_Office Supplies and Expenses	3,001	3							
	5625_Administrative Expense Transferred Credit	138,439	138							
	5630_Outside Services Employed	6,130,421	6,130							
	5635_Property Insurance	1,566,037	1,566							
	5640_Injuries and Damages	1,642,100	1,642							
	5655_Regulatory Expenses	4,878,459	4,878							
	5660_General Advertising Expenses	0	-							
	5665_Miscellaneous General Expenses	-630	- 1		-					
	5675_Maintenance of General Plant	11,320,163	11,320							
	5680_Electrical Safety Authority Fees	409,601	410							
	6105_Taxes Other Than Income Taxes	5,192,007	5,192							
	6205_Donations	968,556	969							
	4375_Revenues from Non-Utility Operations	-2,927,027	- 2,927							
	4751_Charges Smart Metering Entity Chg	6,756,356	6,756							
		246,893,592	246,894	1,582	- 304	-	248,172	258,928	10,756	Note 5
Depreciation and amortization	5705_Amortization Expense - Property Plant and Equipment	171,911,093								
	5715_Amortization of Intangible Assets	20,418,336								
		192,329,429	192,329	479		-	192,809	192,809	-	
		-212,897,762	- 212,898	884	23,061	-	- 188,953	- 179,161	9,792	
Financing costs										
Interest Income	4375_Revenues from Non-Utility Operations	0	-							
	4405_Interest and Dividend Income	-1,298,537	- 1,299							
		-1,298,537	- 1,299	- 60		-	- 1,358	- 1,358	-	
Interest Expense, Long-term Debt	6030_Interest on Debt to Associated Companies	79,824,748	79,825	-			79,825	79,825	-	
Interest Expense, Other	5615_General Administrative Salaries and Expenses	2,175,207	2,175				2,175	-	- 2,175	
	5420_Community Safety Program	41,513	42				42	-	- 42	
	5105_Maintenance Supervision and Engineering	292,895	293				293	-	- 293	
	6035_Other Interest Expense	2,951,987	2,952	1	152	-	3,104	- 5,179	- 8,283	
	6040_Allowance for Borrowed Funds Used During Construction--Credit	-10,806,600	- 10,807				- 10,807	-	10,807	
		74,479,750	74,480	1	152	-	74,632	74,646	14	Note 6
Gain on disposals of property, plant and equipment	4355_Gain on Disposition of Utility and Other Property	-4,062,681								
	4335_Profits and Losses from Financial Instrument Hedges	-211,338								
		-4,274,019	- 4,274		- 5,844		- 10,118	- 10,118	-	
Income Tax Expense	6110_Income Taxes	3,518,763	3,519	-	28,590	-	32,108	31,358	- 750	Note 7
	6115_Provision for Deferred Taxes - Inc. Statement	-19,437	- 19				- 19	138	157	Note 8
Net Income		-140,491,242	- 140,491	825	45,958	-	- 93,708	- 84,495	9,213	
Net movements in regulatory balances, net of tax		0			- 45,958		- 45,958	- 45,958	-	
Net income after net movements in regulatory balances		-140,491,242	-140,491,242	825	-	-	- 139,667	- 130,453	9,213	

Toronto Hydro-Electric System Limited - 2.1.13 Filing: April 30, 2016
Statement of Income
December 31, 2015
Notes: The Uniform System of Account balances are mapped and reconciled to the audited financial statements (AFS) (in dollars thousands).

Note 1: Difference in "Energy sales" of ($54,434): Calculated balance of ($2,871,195) & AFS balance of ($2,925,629), a difference of ($54,434), as follows:	
a. For RRR reporting, THESL books the RSVA change to the higher of COP Revenue or COP expense. For the AFS, the RSVA change is booked to COP Revenue.	-38,944
The difference between the amounts charged by THESL to customers, based on regulated rates, and the corresponding cost of electricity and non-competitive electricity service costs billed monthly by the IESO to THESL, is recorded as a settlement variance. In accordance with IFRS 14, this settlement variance is presented within "net movements in regulatory balances, net of tax" for AFS. For purpose of RRR reporting, the regulatory impact within net movement is reversed into COP revenue.	
b. For RRR Reporting, for the period Jan to Sept 2015, THESL booked to "Cost of Power revenue" and "COP expense" the amount of the IESO settlement invoices charge type 142, in the amounts of $3,160 and ($3,160), respectively. For the AFS, for the period Jan to Sept 2015, THESL does not book IESO settlement invoices charge type 142 to either COP revenue or COP expense.	-3,160
c. For RRR Reporting, for the period Oct to Dec 15, THESL booked to "Cost of Power revenue" the amount of the IESO settlement invoices charge type 142, in the amounts of $12,328. For the AFS, for the period Oct to Dec 2015, THESL book IESO settlement invoices charge type 142 to COP expense.	-12,328
d. Other	-2
Total difference:	-54,434
Note 2: Difference in "Distribution revenue" of $6,179: Calculated balance of ($561,603) & AFS balance of ($555,424), a difference of $6,179, as follows:	
a. A "Smart meter recovery" regulatory asset (RA) was booked for AFS, with AFS Distribution revenue booked on an accrual basis. This is not considered a regulatory asset for purposes of RRR reporting. The AFS Distribution revenue amount has been adjusted so the Distribution revenue booked for RRR Reporting is appropriately reflected on a cash basis.	10,932
b. This relates to the reversal of the Account 1575 IFRS-GAAP Transitional PP&E Return on Rate Base. For RRR purposes, as per the APH, Article 510, "The return on rate base shall not be recorded in this account. On disposition of the account balance, the return is applied prospectively in rates as an adjustment to the revenue requirement." In the AFS, the return on rate base was accrued at year-end 2015 since the OEB approved the disposition of Account 1575 with the return on rate base of $4,755. As such, for RRR purposes, the $4,755 accrual will need to be reversed.	-4,755
c. Other	2
Total difference:	6,179
Note 3: Difference in "Other income" of ($7,141): Calculated balance of ($41,194) & AFS balance of ($48,335), a difference of ($7,141), as follows:	
a. Demand Billable Charges: As per GAAP, THESL booked demand billable charges on a gross basis while for RRR it is reported on a net basis:	-14,047
b. Smart Metering Entity charge: As per AFS GAAP, THESL books the Smart Metering entity revenue and charge on a net basis, while for RRR it is booked on a gross basis, in the prescribed regulatory accounts 4076 "Billed Smart Metering Entity Charge" and 4751 "Charges Smart Metering Entity Charge":	6,756
c. "Wireless pole attachments" revenue was booked to a regulatory asset (RA) for purposes of RRR reporting, while for AFS purposes the wireless pole attachment revenues were included in "Other income" in the amount of $150:	150
Total difference:	-7,141
Note 4: Difference in "Energy purchases" of $58,129: Calculated balance of $2,840,363 & AFS balance of $2,898,492, a difference of $58,129, as follows:	
a. For RRR reporting, THESL books the RSVA change to the higher of COP Revenue or COP expense. For the AFS, the RSVA change is booked to COP Revenue.	38,944
b. For RRR Reporting, for the period Jan to Sept 2015, THESL booked to "Cost of Power revenue" and "COP expense" the amount of the IESO settlement invoices charge type 142, in the amounts of $3,160 and ($3,160), respectively. For the AFS, for the period Jan to Sept 2015, THESL does not book IESO settlement invoices charge type 142 to either COP revenue or COP expense.	3,160
c. For RRR Reporting, for the period Oct to Dec 15, THESL booked to "Cost of Power revenue" the amount of the IESO settlement invoices charge type 142, in the amounts of $12,328. For the AFS, for the period Oct to Dec 2015, THESL book IESO settlement invoices charge type 142 to COP expense.	12,328
Total difference:	54,432
Note 5: Difference in "Operating expenses" of $7,059: Calculated balance of $251,869 & AFS balance of $258,928, a difference of $7,059, as follows:	
a. Demand Billable Charges: As per AFS GAAP, THESL booked demand billable charges on a gross basis while for RRR it is reported on a net basis:	14,047
b. Smart Metering Entity charge: As per AFS GAAP, THESL books the Smart Metering entity revenue and charge on a net basis, while for RRR it is booked on a gross basis, in the prescribed regulatory accounts 4076 "Billed Smart Metering Entity Charge" and 4751 "Charges Smart Metering Entity Charge":	-6,756
c. This relates to the CIR Costs Deferral re-instatement on the Balance Sheet. For OSC purposes, as a result of the OEB's Decision with regards to the DRO, the CIR costs were considered no longer recoverable, and as such it was considered impaired and written-off to the P&L. For RRR purposes, since the CIR Costs were approved to be recovered over the 5 year term in the original OEB Decision on December 29, 2015 with regards to the 2015-2019 CIR Application, the CIR costs were re-instated on the balance sheet and will be amortized over the 5 years.	3,503
e. Other	-38
Total difference:	10,756
Note 6: Difference in "Financing Costs - Interest expense" of $14: Calculated balance of $74,632 & AFS balance of $74,646, a difference of $14, as follows:	14
a. HST Contra account adjustment: In prior years' AFS, THESL has booked to the OEB account 1592, "PILs and Tax Variances for 2006 and Subsequent Years, Sub-account HST / OVAT Input Tax credits (ITCs)" the ITC savings arising from the elimination of Provincial Sales Tax and implementation of the HST on July 1, 2010. For AFS purposes, the offsetting entry was booked to the income statement rather the regulatory sub-account established, a contra account within Account 1592, "PILS and Tax Variances for 2006 and subsequent years - HST/OVAT Contra Account" of Account 1592. The following adjustment has been made to the AFS to reflect for RRR Reporting the amount in the above mentioned contra account: The adjustment entry is, HST/OVAT Contra Account (Dr.) $1,180k, Misc. Interest (Cr.) $14k and Retained Earnings (Cr.) 1,166k.	
Note 7: Difference in "Income tax expense - Income taxes" of ($750): Calculated balance of $32,108 & AFS balance of $31,358, a difference of ($750), as follows: The difference represents the non-regulated business current income tax expense included in the AFS.	-750
Note 8: Difference in "Income tax expense - Provision for deferred taxes" of $157: Calculated balance of ($19) & AFS balance of $138, a difference of $157, as follows: For purposes of RRR reporting, an adjustment was made to remove deferred income tax asset in respect of the non-rate regulated assets.	157

Toronto Hydro-Electric System Limited - 2.1.13

Filing: April 30, 2016

Balance Sheet

December 31, 2014

		USGAAP	USGAAP				mIFRS	mIFRS						
		Regulated 2014 Actual OEB Acct TB	Regulated 2014 Actual (in thousands)	Notes	Adjustments	Adjustments (in thousands)	Regulated 2014 Actual OEB Acct TB	Regulated 2014 Actual (in thousands)	Unregulated 2014 Actual (in thousands)	Consol Adj 2014 Actual (in thousands)	Calculated THESL Consol 2014 Actual (in thousands)	Audited THESL Consol 2014 Actual (in thousands)	Diff	Comment
Assets														
Current Assets														
Cash and cash equivalents	1005_Cash	87,642,549	87,643		-	-	87,642,549	87,643						
	1010_Cash Advances and Working Funds	10,378	10		-	-	10,378	10						
		87,652,927	87,653		-	-	87,652,927	87,653	-2,925	-	84,728	84,728	-	
Accounts receivable	1100_Customer Accounts Receivable	199,557,426	199,557		0	0	199,557,426	199,557						
	1104_Accounts Receivable - Recoverable Work	7,235,439	7,235		-	-	7,235,439	7,235						
	1110_Other Accounts Receivable	14,148	14		-	-	14,148	14						
	1130_Accumulated Provision for Uncollectible Accounts-- Credit	- 11,758,208	-11,758		-	-	- 11,758,208	-11,758						
	1200_Accounts Receivable from Associated Companies	795,509	796		26,450	26	821,960	822						
		195,844,314	195,844	A	26,450	26	195,870,765	195,871	10,588	-692	205,766	205,766	-0	
Unbilled revenue	1120_Accrued Utility Revenues	306,481,105	306,481		0	0	306,481,105	306,481	129		306,610	306,610	-0	
Income tax receivable	2294_Accrual for Taxes Payments in Lieu of Taxes Etc.	194,618	195		- 0	-0	194,617	195			195	195	-0	
Materials and supplies	1330_Plant Materials and Operating Supplies	8,649,272	8,649		-	-	8,649,272	8,649			8,649	8,649	-	
Other assets	1180_Prepayments	12,487,592	12,488	B	- 88,276	-88	12,399,316	12,399			12,399	9,878	-2,521	Note 1
Assets held for sale	1190_Miscellaneous Current and Accrued Assets	4,045,847	4,046		- 24,581	-25	4,021,266	4,021			4,021	4,021	-	
Current portion of regulatory assets	1508_Other Regulatory Assets	11,812,612	11,813	C	- 11,812,612	-11,813								
		343,671,047	343,671		- 11,925,470	-11,925	331,745,577	331,746	129	-	331,874	329,353	-2,521	
Property, plant and equipment	1805_Land	7,580,501	7,581		-	-	7,580,501	7,581						
	1808_Buildings and Fixtures	49,223,004	49,223		- 20,488,806	-20,489	28,734,199	28,734						
	1815_Transformer Station Equipment - Normally Primary above 50 kV	10,972,681	10,973		- 5,132,702	-5,133	5,839,979	5,840						
	1820_Distribution Station Equipment - Normally Primary below 50 kV	243,832,471	243,832		- 109,718,097	-109,718	134,114,373	134,114						
	1830_Poles Towers and Fixtures	411,108,296	411,108		- 204,436,233	-204,436	206,672,063	206,672						
	1835_Overhead Conductors and Devices	477,275,658	477,276		- 268,525,879	-268,526	208,749,780	208,750						
	1840_Underground Conduit	1,451,620,240	1,451,620		- 784,267,392	-784,267	667,352,848	667,353						
	1845_Underground Conductors and Devices	923,599,543	923,600		- 498,410,431	-498,410	425,189,112	425,189						
	1850_Line Transformers	815,359,725	815,360		- 495,099,610	-495,100	320,260,115	320,260						
	1855_Services	88,280,402	88,280		- 23,396,553	-23,397	64,883,849	64,884						
	1860_Meters	201,190,539	201,191		- 63,069,563	-63,070	138,120,976	138,121						
	1905_Land	18,401,025	18,401		-	-	18,401,025	18,401						
	1908_Buildings and Fixtures	133,816,591	133,817		- 51,464,224	-51,464	82,352,367	82,352						
	1910_Leasehold Improvements	20,404,897	20,405		- 19,651,057	-19,651	753,840	754						
	1915_Office Furniture and Equipment	22,329,700	22,330		- 12,493,951	-12,494	9,835,750	9,836						
	1920_Computer Equipment - Hardware	65,167,799	65,168		- 45,195,780	-45,196	19,972,019	19,972						
	1930_Transportation Equipment	72,270,772	72,271		- 47,535,946	-47,536	24,734,826	24,735						
	1935_Stores Equipment	5,506,283	5,506		- 5,499,217	-5,499	7,066	7						
	1940_Tools Shop and Garage Equipment	44,410,493	44,410		- 31,550,676	-31,551	12,859,818	12,860						
	1945_Measurement and Testing Equipment	5,120,008	5,120		- 4,640,005	-4,640	480,004	480						
	1955_Communication Equipment	36,011,961	36,012		- 28,497,996	-28,498	7,513,965	7,514						
	1960_Miscellaneous Equipment	369,101	369		- 102,031	-102	267,071	267						
	1970_Load Management Controls - Customer Premises	14,843,095	14,843		- 11,820,262	-11,820	3,022,834	3,023						
	1975_Load Management Controls - Utility Premises	554,382	554		- 554,382	-554	-	-						
	1980_System Supervisory Equipment	62,188,595	62,189		- 41,874,894	-41,875	20,313,701	20,314						
	1995_Contributions and Grants - Credit	- 361,198,753	-361,199		361,198,753	361,199	-	-						
	1612_Land Rights	-	-		7,191,090	7,191	7,191,090	7,191						
	2005_Property Under Finance Leases	15,815,421	15,815		- 4,835,677	-4,836	10,979,744	10,980						
	2055_Construction Work in Progress--Electric	407,121,264	407,121		23,766,940	23,767	430,888,204	430,888						
	2105_Accum. Depreciation of Electric Utility Plant - Property Plant & Equipment	- 2,295,387,700	-2,295,388		2,169,784,284	2,169,784	- 125,603,416	-125,603						
	2120_Accumulated Amortization of Electric Utility Plant - Intangibles	- 241,754,780	-241,755		241,380,237	241,380	- 374,543	-375						
		2,706,033,215	2,706,033	A, B, C, D, E, I, M, N	25,059,944	25,060	2,731,093,158	2,731,093	47,434	-	2,778,527	3,224,536	446,009	Note 2
Intangible assets	1609_Capital Contributions Paid	23,039,470	23,039		- 3,072,683	-3,073	19,966,787	19,967						
	1611_Computer Software	285,531,224	285,531		- 198,800,474	-198,800	86,730,750	86,731						
	2055_Construction Work in Progress--Electric	111,117,488	111,117		483,462	483	111,600,950	111,601						
	2120_Accumulated Amortization of Electric Utility Plant - Intangibles	-	-		- 19,647,639	-19,648	- 19,647,639	-19,648						
	2105_Accum. Depreciation of Electric Utility Plant - Property Plant & Equipment	- 221,818,227	-221,818		221,818,227	221,818	-	-						
		197,869,955	197,870	D, E, N	780,893	781	198,650,848	198,651	-	-	198,651	198,651	-	
Deferred tax assets	1495_Deferred Taxes - Non-Current Assets	129,808,574	129,809	G	20,427,303	20,427	150,235,877	150,236	-	-	150,236	143,072	-7,163	Note 3
Other assets	1460_Other Non-Current Assets	8,066,234	8,066	B	- 7,014,538	-7,015	1,051,695	1,052	-	-	1,052	1,052	-	
Regulatory balances	1508_Other Regulatory Assets	490,133,299	490,133	A, C	10,402,184	10,402	500,535,483	500,535						
	1520_Power Purchase Variance Account	0	0		-	-	0	0						
	1521_Special Purpose Chg Assessment Variance Account	-	-		-	-	-	-						
	1550_Low Voltage Variance Acct	1,728,591	1,729		-	-	1,728,591	1,729						
	1551_Smart Metering Entity Charge Variance Acct	241,003	241		-	-	241,003	241						
	1555_Smart Meter Capital Offset Variance	14,404,067	14,404		0	0	14,404,067	14,404						
	1556_Smart Meter Operating Variance	-	-		-	-	-	-						
	1562_Deferred Payments in Lieu of Taxes	-	-		-	-	-	-						
	1563_Deferred PILs Contra Account	-	-		-	-	-	-						
	1568_LRAM Variance Account	-	-		-	-	-	-						
	1575_IFRS-UGAAP Transitional PPE Amounts	-	-	D	24,193,438	24,193	24,193,438	24,193						
	1580_RSVAWMS	- 108,421,020	-108,421		-	-	- 108,421,020	-108,421						
	1584_RSVANW	62,266,249	62,266		-	-	62,266,249	62,266						
	1586_RSVACN	29,067,376	29,067		-	-	29,067,376	29,067						
	1588_RSVAPOWER	- 18,770,687	-18,771		-	-	- 18,770,687	-18,771						
	1589_RSVAGA	88,291,117	88,291		-	-	88,291,117	88,291						
	1592_PILs and Tax Variance for 2006 and Subsequent Years	-	-		-	-	-	-						
	1595_Disposition Recovery Reg Balances Control Acct	-	-	F	- 1,713,099	-1,713	- 1,713,099	-1,713						
		558,939,995	558,940		32,882,524	32,883	591,822,519	591,823	-	-	591,823	197,146	-394,677	Note 4

Toronto Hydro-Electric System Limited - 2.1.13

Filing: April 30, 2016

Balance Sheet

December 31, 2014

		USGAAP	USGAAP				mIFRS	mIFRS						
		Regulated 2014 Actual OEB Acct TB	Regulated 2014 Actual (in thousands)	Notes	Adjustments	Adjustments (in thousands)	Regulated 2014 Actual OEB Acct TB	Regulated 2014 Actual (in thousands)	Unregulated 2014 Actual (in thousands)	Consol Adj 2014 Actual (in thousands)	Calculated THESL Consol 2014 Actual (in thousands)	Audited THESL Consol 2014 Actual (in thousands)	Diff	Comment
Total Assets		4,227,886,261	4,227,886		60,237,106	60,237	4,288,123,367	4,288,123	55,226	-692	4,342,657	4,384,304	41,648	
Liabilities and equity														
Bank indebtedness		-	-				-	-	-	-	-	-	-	
Advance from related party	2242_ Payable to Associated Companies	-	-	H	- 308,000,000	-308,000	- 308,000,000	-308,000	-	-	-308,000	-308,000	-	
Accounts payable and accrued liabilities	2205_Accounts Payable	- 421,555,928	-421,556	K, M	851,539	852	- 420,704,389	-420,704						
	2208_Customer Credit Balances	- 40,808,916	-40,809	I	22,132,108	22,132	- 18,676,807	-18,677						
	2220_Miscellaneous Current and Accrued Liabilities	- 13,780,070	-13,780	A	965,386	965	- 12,814,683	-12,815						
	2240_Accounts Payable to Associated Companies Notes	- 12,388,608	-12,389	A	- 956,386	-956	- 13,344,994	-13,345						
	2250_Debt Retirement Charges(DRC) Payable	- 12,973,211	-12,973		-	-	- 12,973,211	-12,973						
	2290_Commodity Taxes	- 3,316,585	-3,317		-	-	- 3,316,585	-3,317						
	2294_Accrual for Taxes Payments in Lieu of Taxes Etc.	-	-		0	0	0	0						
	2292_Payroll Deductions / Expenses Payable	- 7,638,080	-7,638		0	0	- 7,638,080	-7,638						
		- 512,461,397	-512,461		22,992,648	22,993	- 489,468,749	-489,469	-23,447	692	-512,224	-512,224	0	
Customer deposits	2210_Customer Deposits	- 15,122,093	-15,122	J	- 23,333,176	-23,333	- 38,455,269	-38,455				-38,455		
	2335_Non-Current Customer Deposits	- 23,333,176	-23,333	J	23,333,176	23,333	-	-						
			-											
		- 38,455,269	-38,455		-	-	- 38,455,269	-38,455	-	-	-38,455	-38,455	-	
Current portion of regulatory liabilities	1595_Disposition Recovery Reg Balances Control Acct	- 1,644,343	-1,644	F	1,644,343	1,644								
Current portion of Post-employment benefits	2306_Employee Future Benefits	- 7,958,000	-7,958	A	7,958,000	7,958								
Deferred revenue	2220_Miscellaneous Current and Accrued Liabilities				(965,386.35)	-965	-965,386	-965	-		-965	-2,159	-1,194	Note 5
	2240_Accounts Payable to Associated Companies Notes	- 965,386	-965		965,386.35	965								
		- 965,386	-965		-	-	- 965,386	-965			-965	-2,159	-1,194	
Deferred conservation credit		-	-				0	-	-		-	-	-	
Other liabilities	2285_Obligations Under Finance Leases--Current	- 2,624,659	-2,625		- 0	-0	- 2,624,659	-2,625			-2,625	-2,625	-	
Note payable to related party	2242_ Payable to Associated Companies	- 368,000,000	-368,000		308,000,000	308,000	- 60,000,000	-60,000			-60,000	-		
	2240_Accounts Payable to Associated Companies Notes	-	-		-	-	-	-				-		
	2260_Current Long Term Debt	-	-		-	-	-	-	-		-	-		
							-							
		- 368,000,000	-368,000	H	308,000,000	308,000	- 60,000,000	-60,000	-	-	-60,000	-60,000	-	
Note payable to related party	2550_Advances from Associated Companies	- 1,632,196,529	-1,632,197		- 0	-0	- 1,632,196,529	-1,632,197			-1,632,197	-1,632,197	0	
	2505_Debentures Outstanding - Long Term	-	-				-	-			-	-	-	
Customer deposits	2335_Non-Current Customer Deposits	- 4,669,307	-4,669		-	-	- 4,669,307	-4,669			-4,669	-4,669	-	
Deferred revenue	2440_Deferred Revenues			I	- 43,571,006	-43,571	- 43,571,006	-43,571			-43,571	-71,444		
	2320_Other Miscellaneous Non-Current Liabilities				-	-	-	-			-	-		
	2335_Non-Current Customer Deposits			I	- 22,132,108	-22,132	- 22,132,108	-22,132			-22,132	-		
		-	-		- 65,703,115	-65,703	- 65,703,115	-65,703	-	-	-65,703	-71,444	-5,741	Note 6
Post-employment benefits	2306_POEB Liability	- 284,485,208	-284,485	A	- 1,782,033	-1,782	- 286,267,241	-286,267	-1,103		-287,370	-287,370	-	
Other liabilities	2325_Obligations Under Finance Lease--Non-Current	- 6,771,630	-6,772		20,440	20	- 6,751,190	-6,751			-6,751	-8,018		
	2320_Other Miscellaneous Non-Current Liabilities	- 22,321,322	-22,321	K	- 1,266,730	-1,267	- 23,588,052	-23,588			-23,588			
		- 29,092,952	-29,093		- 1,246,290	-1,246	- 30,339,242	-30,339	-	-	-30,339	-8,018	22,321	Note 7
Regulatory liability	1592_PILs and Tax Variance for 2006 and Subsequent Years	- 2,466,509	-2,467	L	2,466,509	2,467								
	1595_Disposition Recovery Reg Balances Control Acct	- 68,757	-69	F	68,757	69								
	2350_Future Income Tax - Non-Current	- 130,161,389	-130,161	G	130,161,389	130,161								
		- 132,696,655	- 132,696,655		132,696,655	132,696,655	-	-						
Total Liabilities		- 3,015,249,703	-3,015,250		96,560,207	96,560	- 2,918,689,496	-2,918,689	-24,550	692	-2,942,547	-2,927,161	15,386	
Share Capital	3005_Common Shares Issued	- 527,816,668	-527,817		-	-	- 527,816,668	-527,817	-28,461		-556,278	-556,278	0	
Retained Earnings	3045_Unappropriated Retained Earnings	- 893,470,038	-893,470		2	0	- 893,470,036	-893,470						
	3046_Balance Transferred From Income	- 94,945,708	-94,946	O	689,046	689	- 94,256,662	-94,257						
	3049_Dividends Payable-Common Shares	321,526,000	321,526		-	-	321,526,000	321,526						
	3055_Adjustment to Retained Earnings	- 5,172,752	-5,173	A	- 796,423	-796	- 5,969,175	-5,969						
		- 672,062,498	-672,062		- 107,375	-107	- 672,169,874	-672,170	-2,214	-	-674,384	-715,094	-40,710	Note 8
Contributed Surplus	3010_Contributed Surplus	- 12,757,392	-12,757		-	-	- 12,757,392	-12,757			-12,757	-12,757	-	
Regulatory balances	1508_Other Regulatory Assets	-	-	C	- 3,623,607	-3,624	- 3,623,607	-3,624						
	1592_PILs and Tax Variance for 2006 and Subsequent Years	-	-	L	- 2,466,509	-2,467	- 2,466,509	-2,467						
	2350_Deferred Tax - Non-Current Liability	-	-	G	- 150,599,822	-150,600	- 150,599,822	-150,600						
		-	-		- 156,689,937	-156,690	- 156,689,937	-156,690	-	-	-156,690	-173,014	-16,324	Note 9
Total liabilities, equity and regulatory balances		- 4,227,886,261	-4,227,886		- 60,237,106	-60,237	- 4,288,123,367	-4,288,123	-55,226	692	-4,342,657	-4,384,304	-41,648	
		-	-		- 0	-0	- 0	-0	-	-	-0	-	0	

Toronto Hydro-Electric System Limited - 2.1.13

Filing: April 30, 2016

Balance Sheet

December 31, 2014

Notes on the adjustments from OEB US GAAP to mIFRS:

A Other Post-Employment Benefits (OPEB):

between mIFRS and US GAAP and result in a measurement difference of the post-employment benefit liability. In addition, under mIFRS, a liability is recognized for both non-vested accumulating and vested sick leave benefits, unlike US GAAP, which only requires a liability for the vested sick leave

B Land Lease:

assets. Under mIFRS, prepaid land lease is included in PP&E as a finance lease as substantially all of the risks and rewards incidental to ownership of the land are transferred to LDC. The

C 1508 - Other Regulatory Assets:

The total difference between US GAAP and mIFRS for account 1508 - Other Regulatory Assets after considering presentation differences is ($5.0 million). The difference is primarily comprised of the following:

OPEB measurement difference between US GAAP and mIFRS	-$6.1	million
ICM assets that was transferred from PP&E measurement difference between US GAAP and mIFRS primarily related to capitalized borrowing costs	$1.1	million
	-$5.0	million

D 1575 - IFRS - GAAP Transitional PP&E:

Transitional Issues, PP&E and intangibles transitional differences from US GAAP to mIFRS are to be recorded in USoA 1575 IFRS - GAAP Transitional PP&E. The balance of

E Rate-Regulated Deemed Costs Exemption:

LDC has applied the rate-regulated deemed cost exemption on its PP&E and intangibles. As such, LDC has elected to use the US GAAP net book value as its deemed cost on the date of transition, January 1, 2014.

F 1595 - Disposition and Recovery/Refund of Regulatory Balances Control Account:

The total difference between US GAAP and mIFRS for account 1595 - Disposition and Recovery/Refund of Regulatory Balances Control Account after considering presentation differences is $nil.

G Deferred Tax Asset and Liability:

The difference between US GAAP and mIFRS is primarily the tax impact as a result of the transition from US GAAP to IFRS.

H 2242 - Notes Payable to Associated Companies:

The total difference between US GAAP and mIFRS for account 2242 - Notes Payable to Associated Companies after considering presentation differences is $nil.

I Contributions in Aid of Construction:

Construction, under mIFRS the initial receipt of cash related to contributions in aid of construction are recorded in customer deposits. Under US GAAP, these amounts were recorded

Construction, under mIFRS when the cash related to contributions in aid of construction are spent on the construction or acquisition of PP&E or intangibles, the customer deposit account is drawn down and an entry is made

J Customer Deposits Reclassification

cash collections to guarantee the payment of electricity bills. The electricity customer security deposits liability includes

Toronto Hydro-Electric System Limited - 2.1.13

Filing: April 30, 2016

Balance Sheet

December 31, 2014

K Reclassification of Other Long-Term Benefits:

The difference primarily relates to the reclassification of other long-term benefits from Accounts Payable under US GAAP to USoA 2320 Other Miscellaneous Non-Current Liabilities under mIFRS.

L 1592 - PILs and Tax Variance for 2006 and Subsequent Years:

The total difference between US GAAP and mIFRS for account 1592 - PILs and Tax Variance for 2006 and Subsequent Years after considering presentation differences is $nil.

M Decommissioning Provision:

remeasured at the end of each period, whereas under US
GAAP, remeasurement was not required. After adjusting for
the Day 1 adjustment and for the difference in retired value,

N January 1, 2015 PP&E and Intangibles for Rate Base Purposes under mIFRS:

on the Application for electricity distribution rates effective
from May 1, 2015 and for
each following year effective January 1 through to December

December 31, 2014 PP&E under mIFRS	2,731,093
December 31, 2014 Intangibles under mIFRS	198,651
	2,929,744
Less: USoA 2055 - Construction Work in Progress--Electric	-542,489
December 31, 2014 PP&E and Intangibles excluding CWIP	2,387,255
Add: USoA 2440 - Deferred Revenues	-43,571
Less: Capital Contribution CWIP included in USoA 2440 - Deferred Revenues	22,706
December 31, 2014 PP&E and Intangibles excluding CWIP, net of capital contributions	2,366,390
Add: ICM Assets transferred to PP&E on January 1, 2015	439,074
Add: Street lighting Assets transferred to PP&E on January 1, 2015	38,475
January 1, 2015 PP&E and Intangibles for rate base purposes under mIFRS	2,843,939

O 3046 - Balance Transferred From Income

Refer to the income statement reconciliation for details.

Notes: The Uniform System of Account balances are mapped and reconciled to the audited financial statements (AFS) (in dollars thousands).

Note 1: Difference in "Current portion of other assets" of ($2,521). Calculated balance of $12,399 & AFS balance of $9,878, a difference of ($2,521), due to transfer of AFS regulatory asset for CIRA cost deferral to Prepaids account 1180 for RRR purposes.	-$2,521
Note 2: Difference in "Property, plant and equipment" of $446,009. Calculated balance of 2,778,527 & AFS balance of $3,224,536, a difference of $446,009, due to transfer of AFS PP&E Assets to Regulatory asset account 1508 Other Regulatory asset, sub-account Incremental Capital Expenditures.	$446,009
Note 3: Difference in "Deferred tax assets" of ($7,163). Calculated balance of $150,236 & AFS balance of $143,072, a difference of ($7,163), due to transfer of the gross up on the deferred tax asset and deferred tax liability on regulatory balances from Regulatory balance accont to AFS Deferred tax assets in the amount of $7,163.	-$7,163
Note 4: Difference in "Regulatory balances (debit)" of ($394,677): Calculated balance of $591,823 & AFS balance of $197,146, a difference of ($394,677), as follows:	
a. A "Smart meter recovery" regulatory balance was booked for AFS, and is not considered a regulatory balance for purposes of RRR reporting:	$20,879
b. Incremental Capital Model (ICM) revenue and depreciation expense contra account RA were booked for the AFS, and this not considered a regulatory balance for purposes of RRR reporting:	$22,493
c. Due to the transfer of AFS PP&E Assets to Regulatory asset account 1508 Other Regulatory asset, sub-account Incremental Capital Expenditures:	-$440,682
d. "Wireless pole attachments" regulatory balance was booked for purposes of RRR reporting and not included the AFS:	$113
e.Transfer of AFS regulatory balance for CIRA cost deferral to Prepaids account 1180 for RRR purposes.	$2,521
Total difference:	-$394,677

Toronto Hydro-Electric System Limited - 2.1.13 Filing: April 30, 2016

Balance Sheet

December 31, 2014

Note 5: Difference in "Current portion of deferred revenue" of ($1,194). Calculated balance of ($965) & AFS balance of ($2,159), a difference of ($1,194), due to the transfer of capital contributions in 2220_Miscellaneous Current and Accrued Liabilities to 2440_Deferred Revenues for OEB reporting purpose.	-$1,194
Note 6: Difference in "Deferred revenue" of ($5,741). Calculated balance of ($65,703) & AFS balance of ($71,444), a difference of ($5,741), due to:	
a. The transfer of AFS Deferred revenue to Regulatory asset account 1508 Other Regulatory asset, sub-account Incremental Capital Expenditures.	-$6,935
b. The transfer of capital contributions in 2320_Other Miscellaneous Non-Current Liabilities to 2440_Deferred Revenues for OEB reporting purpose.	$1,194
Total difference:	-$5,741
Note 7: Difference in "Other long-term liabilities" of $22,321. Calculated balance of ($30,339) & AFS balance of ($8,018), a difference of $22,321, due to: A Revision of prior year tax position" regulatory credit balance was booked for AFS, and is not considered a regulatory balance for purposes of RRR reporting: For RRR Reporting, the amount was transferred to OEB account 2320 "Other Miscellaneous Non-Current Liabilities".	$22,321
Note 8: Difference in "Retained Earnings" of ($40,710): Calculated balance of ($674,384) & AFS balance of ($715,094), a difference of ($40,710). Adjustments have been made to certain AFS income statement items to arrive at the RRR reporting as follows:	
a. Reduction to AFS Distribution revenue booked for Smart Meter "net revenue requirement" on the disposition of Account 1555 "Smart Meter Capital & Recovery" and 1556 "Smart Meter OM&A Variance account" balances. The amount shall be booked to Distribution revenue for RRR reporting, to OEB account 4080 as the amount is billed to THESL customers in the future:	-$20,879
b. Reverse the ICM revenue and related depreciation expense booked LTD 2014 in the AFS. This ICM revenue and depreciation expense shall be booked for RRR reporting in the future under regulatory prescribed ICM accounting treatment:	- 22,493
c. HST Contra account adjustment: In prior years' AFS, THESL has booked to the OEB account 1592, "PILs and Tax Variances for 2006 and Subsequent Years, Sub-account HST / OVAT Input Tax credits (ITCs)" the ITC savings arising from the elimination of Provincial Sales Tax and implementation of the HST on July 1, 2010. For AFS purposes, the offsetting entry was booked to the income statement rather the regulatory sub-account established, a contra account within Account 1592, "PILS and Tax Variances for 2006 and subsequent years - HST/OVAT Contra Account" of Account 1592. The following adjustment has been made to the AFS to reflect for RRR Reporting the amount in the above mentioned contra account: The adjustment entry is, HST/OVAT Contra Account (Dr.) $1,166k, Misc. Interest (Cr.) $16k and Retained Earnings (Cr.) 1,150k.	1,166
d. Due to the transfer of AFS Depreciation expense to Regulatory asset account 1508 Other Regulatory asset, sub-account Incremental Capital Expenditures in the amount of $1,608.	1,608
e. "Wireless pole attachments" regulatory balance was booked for purposes of RRR reporting while for AFS purposes the amount was included in the income statement:	- 113
Total difference:	-$40,710
Note 9: Difference in "Regulatory credit balances" of ($16,324): Calculated balance of ($156,690) & AFS balance of ($173,014), a difference of ($16,324), as follows:	
a. A Revision of prior year tax position" regulatory credit balance was booked for AFS, and is not considered a regulatory balance for purposes of RRR reporting: For RRR Reporting, the amount was transferred to OEB account 2320 "Other Miscellaneous Non-Current Liabilities" from Regulatory Liabilities.	-$22,321
b. HST Contra account adjustment: In prior years' AFS, THESL has booked to the OEB account 1592, "PILs and Tax Variances for 2006 and Subsequent Years, Sub-account HST / OVAT Input Tax credits (ITCs)" the ITC savings arising from the elimination of Provincial Sales Tax and implementation of the HST on July 1, 2010. For AFS purposes, the offsetting entry was booked to the income statement rather the regulatory sub-account established, a contra account within Account 1592, "PILS and Tax Variances for 2006 and subsequent years - HST/OVAT Contra Account" of Account 1592. The following adjustment has been made to the AFS to reflect for RRR Reporting the amount in the above mentioned contra account: The adjustment entry is, HST/OVAT Contra Account (Dr.) $1,166k, Misc. Interest (Cr.) $16k and Retained Earnings (Cr.) 1,150k.	- 1,166
c. The gross up on the deferred tax asset and deferred tax liability on regulatory balances was booked as part of Regulatory balances and transferred to Deferred tax assets for purpose of RRR reporting.	7,163
Total difference:	-$16,324

Toronto Hydro-Electric System Limited - 2.1.13

Filing: April 30, 2016

Statement of Income

December 31, 2014

		USGAAP	USGAAP				mIFRS	mIFRS							
		Regulated 2014 Actual OEB Acct TB	Regulated 2014 Actual (in thousands)	Notes	Adjustments	Adjustments (in thousands)	Regulated 2014 Actual OEB Acct TB	Regulated 2014 Actual (in thousands)	Unregulated 2014 Actual (in thousands)	Consol Adj 2014 Actual (in thousands)	Calculated THESL Consol 2014 Actual (in thousands)	Audited THESL Consol 2014 Actual (in thousands)	Diff	Comment
Revenue														
Energy sales	4006_Residential Energy Sales	-486,662,662	- 486,663		0	-	-486,662,662	- 486,663						
	4010_Commercial Energy Sales	-1,385,714,616	- 1,385,715		47,589,091	47,589	-1,338,125,525	- 1,338,126						
	4020_Energy Sales to Large Users	-199,844,824	- 199,845		0	-	-199,844,824	- 199,845						
	4025_Street Lighting Energy Sales	-10,813,462	- 10,813		0	-	-10,813,462	- 10,813						
	4035_General Energy Sales	-210,750,959	- 210,751		0	-	-210,750,959	- 210,751						
	4050_Revenue Adjustment	20,840,986	20,841		0	-	20,840,986	20,841						
	4062_Billed WMS	-140,981,015	- 140,981		0	-	-140,981,015	- 140,981						
	4066_Billed NW	-177,393,894	- 177,394		15,032,996	15,033	-162,360,898	- 162,361						
	4068_Billed CN	-122,500,059	- 122,500		6,865,068	6,865	-115,634,991	- 115,635						
	4075_Billed LV	-483,426	- 483		487,421	487	3,995	4						
		-2,714,303,930	- 2,714,304	A	69,974,576	69,975	-2,644,329,354	- 2,644,329		-	- 2,644,329	- 2,654,966	- 10,637	Note 1
Distribution revenue	4080_Distribution Services Revenue	-533,456,671	- 533,457		0	-	-533,456,671	- 533,457		-	- 533,457	- 555,051	- 21,594	Note 2
		-3,247,760,602	- 3,247,761	A	69,974,576	69,975	-3,177,786,025	- 3,177,786	-	-	- 3,177,786	- 3,210,017	- 32,231	
Other income	4082_Retail Services Revenues	-439,346	- 439		0	-	-439,346	- 439						
	4084_Service Transaction Requests (STR) Revenues	-19,204	- 19		0	-	-19,204	- 19						
	4086_SSS Administration Revenue	-2,142,518	- 2,143		0	-	-2,142,518	- 2,143						
	4090_Electric Services Incidental to Energy Sales	0	-		0	-	0	-						
	4210_Rent from Electric Property	-8,694,567	- 8,695		0	-	-8,694,567	- 8,695						
	4215_Other Utility Operating Income	-956,230	- 956		0	-	-956,230	- 956						
	4220_Other Electric Revenues	0	-		0	-	0	-						
	4225_Late Payment Charges	-4,072,861	- 4,073		0	-	-4,072,861	- 4,073						
	4235_Miscellaneous Service Revenues	-6,543,450	- 6,543		0	-	-6,543,450	- 6,543						
	4245_Government and Other Assistance Directly Credited to Income	0	-	B	-711,174	- 711	-711,174	- 711						
	4325_Revenues from Merchandise Jobbing Etc.	-15,789,942	- 15,790	C	-325,077	- 325	-16,115,018	- 16,115						
	4330_Costs and Expenses of Merchandising Jobbing Etc.	14,815,407	14,815		0	0	14,815,408	14,815						
	4390_Miscellaneous Non-Operating Income	0	-	C	377,506	378	377,506	378						
	4355_Gain on Disposition of Utility and Other Property	0	-		-39,226	- 39	-39,226	- 39						
	4076_Billed Smart Metering Entity Charge	-6,674,801	- 6,675		0	-	-6,674,801	- 6,675						
		-30,517,512	- 30,518		-697,970	- 698	-31,215,483	- 31,215	- 11,786	-	- 43,001	- 51,650	- 8,649	Note 3
Expenses														
Energy purchases	4705_Power Purchased	1,450,996,403	1,450,996		0	-	1,450,996,403	1,450,996						
	4707_Charges - Global Adjustment	821,950,228	821,950		-47,589,091	- 47,589	774,361,137	774,361						
	4708_Charges-WMS	109,089,063	109,089		0	-	109,089,063	109,089						
	4714_Charges-NW	177,373,782	177,374		-15,032,996	- 15,033	162,340,786	162,341						
	4716_Charges-CN	122,520,171	122,520		-6,865,068	- 6,865	115,655,103	115,655						
	4730_Rural Rate Assistance Expense	31,891,953	31,892		0	-	31,891,953	31,892						
	4750_Charges LV	483,426	483		-487,421	- 487	-3,995	- 4						
		2,714,305,025	2,714,305	A	-69,974,576	- 69,975	2,644,330,449	2,644,330	-	-	2,644,330	2,700,378	56,047	Note 4
Operating expenses	4380_Expenses of Non-Rate Regulated Operations	299,017	299		10,000	10	309,017	309						
	4398_Foreign Exchange Gains and Losses Including Amortization	836,217	836		0	-	836,217	836						
	5005_Distribution Operation Supervision and Engineering	23,877,567	23,878		0	-	23,877,567	23,878						
	5010_Distribution Load Dispatching	5,970,719	5,971		0	-	5,970,719	5,971						
	5012_Station Buildings and Fixtures Expense	-595	- 1		0	-	-595	- 1						
	5016_Distribution Station Equipment - Operation Labour	2,802,147	2,802		0	-	2,802,147	2,802						
	5017_Distribution Station Equipment - Operation Supplies and Expenses	2,979,166	2,979		0	-	2,979,166	2,979						
	5020_Overhead Distribution Lines and Feeders - Operation Labour	870,363	870		0	-	870,363	870						
	5025_Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1,087,913	1,088		0	-	1,087,913	1,088						
	5035_Overhead Distribution Transformers- Operation	0	-		0	-	0	-						
	5040_Underground Distribution Lines and Feeders - Operation Labour	1,474,740	1,475		0	-	1,474,740	1,475						
	5045_Underground Distribution Lines & Feeders - Operation Supplies & Expenses	-65,611	- 66		0	-	-65,611	- 66						
	5055_Underground Distribution Transformers - Operation	19,221	19		0	-	19,221	19						
	5065_Meter Expense	703,792	704		0	-	703,792	704						
	5070_Customer Premises - Operation Labour	2,225,487	2,225		0	-	2,225,487	2,225						
	5075_Customer Premises - Materials and Expenses	1,152,544	1,153		0	-	1,152,544	1,153						
	5085_Miscellaneous Distribution Expense	5,772,413	5,772		0	-	5,772,413	5,772						
	5105_Maintenance Supervision and Engineering	19,684,342	19,684		0	-	19,684,342	19,684						
	5110_Maintenance of Buildings and Fixtures - Distribution Stations	14,384,807	14,385		0	-	14,384,807	14,385						
	5112_Maintenance of Transformer Station Equipment	1,675	2		0	-	1,675	2						
	5114_Maintenance of Distribution Station Equipment	2,391,986	2,392		0	-	2,391,986	2,392						
	5120_Maintenance of Poles Towers and Fixtures	792	1		0	-	792	1						
	5125_Maintenance of Overhead Conductors and Devices	18,182,819	18,183		0	-	18,182,819	18,183						

Toronto Hydro-Electric System Limited - 2.1.13

Filing: April 30, 2016

Statement of Income

December 31, 2014

		USGAAP	USGAAP				mIFRS	mIFRS						
		Regulated 2014 Actual OEB Acct TB	Regulated 2014 Actual (in thousands)	Notes	Adjustments	Adjustments (in thousands)	Regulated 2014 Actual OEB Acct TB	Regulated 2014 Actual (in thousands)	Unregulated 2014 Actual (in thousands)	Consol Adj 2014 Actual (in thousands)	Calculated THESL Consol 2014 Actual (in thousands)	Audited THESL Consol 2014 Actual (in thousands)	Diff	Comment
	5130_Maintenance of Overhead Services	-6	- 0		0	-	-6	- 0						
	5135_Overhead Distribution Lines and Feeders - Right of Way	2,461,534	2,462		0	-	2,461,534	2,462						
	5145_Maintenance of Underground Conduit	15,930	16		0	-	15,930	16						
	5150_Maintenance of Underground Conductors and Devices	6,472,704	6,473		0	-	6,472,704	6,473						
	5155_Maintenance of Underground Services	5,378	5		0	-	5,378	5						
	5160_Maintenance of Line Transformers	233	0		0	-	233	0						
	5165_Maintenance of Street Lighting and Signal Systems	64,308	64		0	-	64,308	64						
	5305_Supervision	238,889	239		0	-	238,889	239						
	5310_Meter Reading Expense	3,729,620	3,730		0	-	3,729,620	3,730						
	5315_Customer Billing	13,258,274	13,258		0	-	13,258,274	13,258						
	5320_Collecting	12,960,393	12,960		0	-	12,960,393	12,960						
	5335_Bad Debt Expense	6,500,000	6,500		0	-	6,500,000	6,500						
	5410_Community Relations - Sundry	2,833	3		0	-	2,833	3						
	5415_Energy Conservation	0	-		0	-	0	-						
	5420_Community Safety Program	2,567,716	2,568	G	-102,824	- 103	2,464,892	2,465						
	5605_Executive Salaries and Expenses	1,288,765	1,289		0	-	1,288,765	1,289						
	5610_Management Salaries and Expenses	2,437	2		0	-	2,437	2						
	5615_General Administrative Salaries and Expenses	52,420,167	52,420	D, E	733,007	733	53,153,173	53,153						
	5620_Office Supplies and Expenses	4,241	4		0	-	4,241	4						
	5625_Administrative Expense Transferred Credit	18,848	19		0	-	18,848	19						
	5630_Outside Services Employed	7,682,506	7,683	E	-1,551,628	- 1,552	6,130,878	6,131						
	5635_Property Insurance	2,109,526	2,110		0	-	2,109,526	2,110						
	5640_Injuries and Damages	1,647,295	1,647		0	-	1,647,295	1,647						
	5655_Regulatory Expenses	4,322,741	4,323		0	-	4,322,741	4,323						
	5660_General Advertising Expenses	0	-		0	-	0	-						
	5665_Miscellaneous General Expenses	700	1		0	0	700	1						
	5675_Maintenance of General Plant	11,092,442	11,092	F	-88,276	- 88	11,004,166	11,004						
	5680_Electrical Safety Authority Fees	402,600	403		0	-	402,600	403						
	6105_Taxes Other Than Income Taxes	5,784,625	5,785		0	-	5,784,625	5,785						
	6205_Donations	660,000	660		0	-	660,000	660						
	4375_Revenues from Non-Rate Regulated Operations	-3,316,031	- 3,316		0	-	-3,316,031	- 3,316						
	4751_Charges Smart Metering Entity Chg	6,674,801	6,675		0	-	6,674,801	6,675						
		243,724,988	243,725		-999,721	- 1,000	242,725,267	242,725	5,904	-	248,629	257,889	9,260	Note 5
Depreciation and amortization	5705_Depreciation Expense - Property Plant and Equipment	128,411,008	128,411	B	717,661	718	129,128,669	129,129						
	5715_Amortization of Intangible Assets	19,925,483	19,925		0	-	19,925,483	19,925						
		148,336,490	148,336		717,661	718	149,054,151	149,054	2,007	-	151,061	183,549	32,488	Note 6
		-171,911,611	- 171,912		-980,030	- 980	-172,891,641	- 172,892	- 3,875	-	- 176,767	- 119,852	56,915	
Financing costs														
Interest Income	4375_Revenues from Non-Rate Regulated Operations	-2,198	- 2		0	0	-2,198	- 2						
	4405_Interest and Dividend Income	-1,474,251	- 1,474		0	-	-1,474,251	- 1,474						
		-1,476,449	- 1,476		0	0	-1,476,449	- 1,476	- 33	-	- 1,509	- 1,048	462	
Interest Expense, Long-term Debt	6030_Interest on Debt to Associated Companies	67,585,841	67,586		0	-	67,585,841	67,586	-		67,586	67,586	-	
Interest Expense, Other	5615_General Administrative Salaries and Expenses	1,870,971	1,871		0	-	1,870,971	1,871			1,871	-	- 1,871	
	5420_Community Safety Program	0	-	G	94,388	94	94,388	94			94	-	- 94	
	5105_Maintenance Supervision and Engineering	0	-		0	-	0	-			-	-	-	
	5675_Maintenance of General Plant	0	-		0	-	0	-			-	-	-	
	6035_Other Interest Expense	4,455,557	4,456		-0	- 0	4,455,557	4,456	- 33	-	4,423	- 2,123	- 6,546	
	6040_Allowance for Borrowed Costs Applied to CWIP--Credit	-5,516,998	- 5,517		0	0	-5,516,998	- 5,517			- 5,517	-	5,517	
		68,395,372	68,395		94,388	94	68,489,759	68,490	- 33	-	68,457	65,463	- 2,994	
		66,918,922	66,919		94,388	94	67,013,310	67,013	- 66	-	66,948	64,415	- 2,533	Note 7
Gain on disposals of property, plant and equipment	4355_Gain on Disposition of Utility and Other Property	-1,478,662	- 1,479		0	-	-1,478,662	- 1,479						
	4335_Profits and Losses from Financial Instrument Hedges	0	-		0	-	0	-						
		-1,478,662	- 1,479		0	-	-1,478,662	- 1,479			- 1,479	- 1,479	-	
Income Tax Expense	6110_Income Taxes	11,158,421	11,158	E	1,573,628	1,574	12,732,049	12,732	-	-	12,732	12,732	-	
	6115_Provision for Deferred Taxes - Inc. Statement	367,222	367		1,060	1	368,282	368			368	1,193	825	
		11,525,643	11,526		1,574,688	1,575	13,100,331	13,100	-	-	13,100	13,925	825	Note 8
Net Income		-94,945,708	- 94,946		689,046	689	-94,256,662	- 94,257	- 3,941	-	- 98,197	- 42,990	55,207	
Net movements in regulatory balances, net of tax		0	-		0	-	0	-			-	- 66,923	- 66,923	Note 9
Net income after net movements in regulatory balances		-94,945,708	- 94,946		689,046	689	-94,256,662	- 94,257	- 3,941	-	- 98,197	- 109,913	- 11,715	

Toronto Hydro-Electric System Limited - 2.1.13

Filing: April 30, 2016

Statement of Income

December 31, 2014

Notes on the adjustments from OEB US GAAP to mIFRS:

A RSVA Adjustments:
In accordance with the APH Article 490 - Retail Services and Settlement Variances, for recording the difference between Cost of Power Revenue and Cost of Power Expense, the

B Amortization of Contributions in Aid of Construction:
The difference between US GAAP and mIFRS is primarily comprised of the amortization of Contributions in Aid of Construction. In accordance with the APH Article 430 - Contributions in Aid of Construction, under mIFRS the

C Decommissioning Provision:
decommissioning provision asset and liability of ($0.3 million) and the transitional adjustment for decommissioning provision

D Other Post-Employment Benefits (OPEB):
between IFRS and US GAAP and result in a measurement difference of the post-employment benefit liability. In addition, under IFRS, a liability is recognized for both non-vested

E Non-Refundable Investment Tax Credits:
Under US GAAP, the non-refundable investment tax credits are recorded in income tax expenses. Under mIFRS, these tax credits are recorded in operating expenses. For December 31,

F Land Lease:
Under US GAAP, prepaid land lease was included in other assets, and as such, the amortization was recorded in operating expenses. Under mIFRS, prepaid land lease is included in PP&E as a finance lease as substantially all of the risks and rewards incidental to ownership of the land are

G Decommissioning Provision Accretion Expense Presentation
The difference between US GAAP and mIFRS is primarily related to the presentation of the decommissioning provision accretion expense, where under US GAAP, the accretion expense is presented in operating expenses. Under mIFRS,

Notes: The Uniform System of Account balances are mapped and reconciled to the audited financial statements (AFS) (in dollars thousands).

Note 1: Difference in "Energy sales" of ($10,637): Calculated balance of ($2,644,329) & AFS balance of ($2,654,966), a difference of ($10,637), as follows:	
a. For RRR Reporting, THESL booked to "Cost of Power revenue" and "COP expense" the amount of the IESO settlement invoices charge type 142, in the amounts of ($13,927) and $13,927, respectively. For the AFS, THESL does not book IESO settlement invoices charge type 142 to either COP revenue or COP expense.	13,927
b. For RRR reporting, THESL books the RSVA change to the higher of COP Revenue or COP expense. For the AFS, the RSVA change is booked to COP Revenue.	-69,975
c. The difference between the amounts charged by THESL to customers, based on regulated rates, and the corresponding cost of electricity and non-competitive electricity service costs billed monthly by the IESO to THESL, is recorded as a settlement variance. In accordance with IFRS 14, this settlement variance is presented within "net movements in regulatory balances, net of tax" for AFS. For purpose of RRR reporting, the regulatory impact within net movement is reversed into COP revenue.	45,410
Total difference:	-10,637

Toronto Hydro-Electric System Limited - 2.1.13

Filing: April 30, 2016

Statement of Income

December 31, 2014

Note 2: Difference in "Distribution revenue" of ($21,594): Calculated balance of ($533,457) & AFS balance of ($555,051), a difference of ($21,594), as follows:	
a. A "Smart meter recovery" regulatory balance was booked for AFS, with AFS Distribution revenue booked on an accrual basis. This is not considered a regulatory balance for purposes of RRR reporting. The AFS Distribution revenue amount has been adjusted so the Distribution revenue booked for RRR Reporting is appropriately reflected on a cash basis.	4,351
b. An Incremental Capital Model (ICM) revenue contra account Regulatory balance was booked for the AFS, with an offsetting entry to Distribution revenue. This is not considered a regulatory balance for purposes of RRR reporting. The Regulatory balance and related Distribution revenue have been reversed for RRR reporting:	-25,063
c. The difference between revenue recorded based on collection of OEB-approved rate riders and revenue booked on an accrual basis is presented within "net movements in regulatory balances, net of tax" ☐ in accordance with IFRS 14 for AFS. For purpose of RRR reporting, the regulatory impact within net movement is reversed into distribution revenue.	-883
Total difference:	-21,594
Note 3: Difference in "Other income" of ($8,649): Calculated balance of ($43,001) & AFS balance of ($51,650), a difference of ($8,649), as follows:	
a. Demand Billable Charges: $14,792. As per IFRS, THESL booked demand billable charges on a gross basis while for RRR it is reported on a net basis:	-14,793
b. Smart Metering Entity charge: As per IFRS, THESL books the Smart Metering entity revenue and charge on a net basis, while for RRR it is booked on a gross basis, in the prescribed regulatory accounts 4076 "Billed Smart Metering Entity Charge" and 4751 "Charges Smart Metering Entity Charge":	6,675
c. "Wireless pole attachments" revenue was booked to a regulatory balance for purposes of RRR reporting, while for AFS purposes the wireless pole attachment revenues were included in "Other income" in the amount of $150:	-150
d. The differences arising from accounting policy changes for PP&E and intangible assets due to the transition from US GAAP to IFRS in 2014 was recorded in a regulatory account "IFRS Transitional Adjustments". ☐ In accordance with IFRS 14, the related impact was presented within "net movements in regulatory balances, net of tax" for AFS. For purpose of RRR reporting, a portion of the amount related to write off of certain assets within net movement is reversed into other income.	-379
Total difference:	-8,647
Note 4: Difference in "Energy purchases" of $56,047: Calculated balance of $2,644,330 & AFS balance of $2,700,378, a difference of $56,047, as follows:	
a. For RRR Reporting, THESL booked to "Cost of Power revenue" and "COP expense" the amount of the IESO settlement invoices charge type 142, in the amounts of ($13,927) and $13,927, respectively. For the AFS, THESL does not book IESO settlement invoices charge type 142 to either COP revenue or COP expense:	-13,927
b. For RRR reporting, THESL books the RSVA change to the higher of COP Revenue or COP expense. For the AFS, the RSVA change is booked to COP Revenue.	69,975
Total difference:	56,047
Note 5: Difference in "Operating expenses" of $9,260: Calculated balance of $248,629 & AFS balance of $257,889, a difference of $9,260, as follows:	
a. Demand Billable Charges: As per IFRS, THESL booked demand billable charges on a gross basis while for RRR it is reported on a net basis:	14,793
b. Smart Metering Entity charge: As per IFRS, THESL books the Smart Metering entity revenue and charge on a net basis, while for RRR it is booked on a gross basis, in the prescribed regulatory accounts 4076 "Billed Smart Metering Entity Charge" and 4751 "Charges Smart Metering Entity Charge":	-6,675
c. "Wireless pole attachments" Operating expenses were booked to a regulatory balance for purposes of RRR reporting, while for AFS purposes the wireless pole attachment operating expenses were included in "Operating expenses" in the amount of $38:	38
d. THESL deferred costs relating to OPEB and CIR application as regulatory balances under IFRS, with related impact presented separately in "net movements in regulatory balances, net of tax" under IFRS 14 for AFS.☐ For purpose of RRR reporting, the regulatory impact within net movement is reversed into operating expenses.	1,104
Total difference:	9,260
Note 6: Difference in "Depreciation and amortization" of $32,488: Calculated balance of $151,061 & AFS balance of $183,549, a difference of $32,488, as follows:	
a. An Incremental Capital Model (ICM) depreciation contra account Regulatory balance was booked for the AFS, with an offsetting entry to Depreciation expense. This is not considered a regulatory asset for purposes of RRR reporting. The RA and related depreciation expense have been reversed for RRR reporting:	7,485
b. Due to the transfer of AFS Depreciation expense to Regulatory asset account 1508 Other Regulatory asset, sub-account Incremental Capital Expenditures	1,608
c. The differences arising from accounting policy changes for PP&E and intangible assets due to the transition from US GAAP to IFRS in 2014 related to derecognition of certain assets was recorded☐ in a regulatory account "IFRS Transitional Adjustments". In accordance with IFRS 14, the related impact was presented within "net movements in regulatory balances, net of tax" for AFS. For purpose of RRR reporting, the regulatory impact within net movement is reversed into depreciation and amortization expense.	23,394
Total difference:	32,487

Toronto Hydro-Electric System Limited - 2.1.13

Filing: April 30, 2016

Statement of Income

December 31, 2014

Note 7: Difference in "Finance costs" of ($2,533): Calculated balance of $66,948 & AFS balance of $64,415, a difference of ($2,533), as follows:

a. HST Contra account adjustment: In prior years' AFS, THESL has booked to the OEB account 1592, "PILs and Tax Variances for 2006 and Subsequent Years, Sub-account HST / OVAT Input Tax credits (ITCs)" the ITC savings arising from the elimination of Provincial Sales Tax and implementation of the HST on July 1, 2010. For AFS purposes, the offsetting entry was booked to the income statement rather the regulatory sub-account established, a contra account within Account 1592, "PILS and Tax Variances for 2006 and subsequent years - HST/OVAT Contra Account" of Account 1592. The following adjustment has been made to the AFS to reflect for RRR Reporting the amount in the above mentioned contra account: The adjustment entry is, HST/OVAT Contra Account (Dr.) $1,166k, Misc. Interest (Cr.) $16k and Retained Earnings (Cr.) 1,150k.	$16
b. "Wireless pole attachments" carrying charges were booked to a regulatory balance for purposes of RRR reporting, while for AFS purposes the wireless pole attachment carrying charges were included in "interest expenses" in the amount of $1:	-$1
c. The differences arising from accounting policy changes for PP&E and intangible assets due to the transition from US GAAP to IFRS in 2014 related to additional capitalized borrowing costs was recorded☐ in a regulatory account "IFRS Transitional Adjustments". In accordance with IFRS 14, the related impact was presented within "net movements in regulatory balances, net of tax" for AFS. In accordance with IFRS 14, carrying charges on regulatory balances are presented within finance costs with related impact included within "net movements in regulatory balances, net of tax" for AFS. For purpose of RRR reporting, the regulatory impact within net movement is reversed into finance costs.	-$2,548
Total difference:	-$2,533

Note 8: Difference in "Income tax expense" of $825. Calculated balance of $13,100 & AFS balance of $13,925, a difference of $825, as follows:

The deferred tax balance related to regulatory balances and gross up in respect of deferred tax assets and corresponding regulatory liability balance are recorded in regulatory balances in accordance with IFRS 14 for AFS. ☐ The net change of these balances is presented within "net movements in regulatory balances, net of tax" for AFS. For purposes of RRR reporting, the regulatory impact within net movement is reversed into income tax expense.	$825

Note 9: Difference in "Net movements in regulatory balances, net of tax" of $66,923. Calculated balance of $nil & AFS balance of $66,923, a difference of ($66,923), as follows:

Under IFRS 14 for AFS, the "net movements in regulatory balances, net of tax" line includes the net of all the related regulaory impact to the various income statement lines noted above.☐ For purpose of RRR reporting, the regulatory impact within net movement is reversed into the various income statement lines based on their nature.	-$66,923

RRR Reporting Rate Base Calculation Reconciliation - Total PP&E (Amount in $ thousands)	PP&E (incl CWIP)	ROE Exclusions Reomve CWIP	 Other	ROE Calc Net	Comment
As Reported - US GAAP RRR Dec 31, 2014	$2,903,903	-$518,239	$0	$2,385,664	PPE per ROE Calc. 2014
Difference to mIFRS	$25,841	-$24,250	$0	$1,591	
mIFRS - Trial Balance	**$2,929,744**	**-$542,489**		**$2,387,255**	
A/C 2440 Deferred Revenue LT			-$43,571	-$43,571	manual entries on ROE web site
CWIP portion of A/C 2440			$22,706	$22,706	manual entries on ROE web site
mIFRS Balance	**$2,929,744**	**-$542,489**	**-$20,865**	**$2,366,390**	
Inclusions for new Rate Regime					
ICM Assets	$439,074			$439,074	
Streetlighting Assets	$38,475			$38,475	
Total Jan 1 2015 PP&E - RRR	**$3,407,293**	**-$542,489**	**-$20,865**	**$2,843,939**	Jan 1, 2015 PP&E for ROE Purposes
Total Adjustment to RRR Openning PP&E				**$458,275**	
2015 ROE					
mIFRS - RRR Balances per ledger - OEB roll up	$3,750,644	-$609,194		$3,141,450	
A/C 2440 Deferred Revenue LT			-$86,773	-$86,773	
CWIP portion of A/C 2440			$31,475	$31,475	
Submission per RRR	**$3,750,644**	**-$609,194**	**-$55,298**	**$3,086,151**	Dec 31, 2015 PP&E for ROE Purposes
2016 ROE					
mIFRS - RRR Balances per ledger - OEB roll up	4,084,341	-$537,863		$3,546,478	
A/C 2440 Deferred Revenue LT			-$116,238	-$116,238	
CWIP portion of A/C 2440			$32,364	$32,364	
Submission per RRR	**$4,084,341**	**-$537,863**	**-$83,874**	**$3,462,604**	Dec 31, 2016 PP&E for ROE Purposes

Toronto Hydro-Electric System Limited - 2.1.13
Balance Sheet
December 31, 2016

Filing: May 1, 2017

		Regulated 2016 Actual OEB Acct TB	Regulated 2016 Actual (in thousands)	Unregulated 2016 Actual (in thousands)	Consol Adj 2016 Actual (in thousands)	Calculated THESL Consol 2016 Actual (in thousands)	Audited THESL Consol 2016 Actual (in thousands)	Diff	Comment
Assets									
Current Assets									
Cash and cash equivalents	1005_Cash	0	0						
	1010_Cash Advances and Working Funds	-	-						
		0	0	34,744	-34,744	0	-	-0	
Accounts receivable	1100_Customer Accounts Receivable	223,296,063	223,296						
	1104_Accounts Receivable - Recoverable Work	7,387,522	7,388						
	1110_Other Accounts Receivable	861,863	862						
	1130_Accumulated Provision for Uncollectible Accounts-- Credit	- 9,719,364	-9,719						
	1200_Accounts Receivable from Associated Companies	749,564	750						
		222,575,647	222,576	6,217	-2,634	226,159	226,159	0	
Unbilled revenue	1120_Accrued Utility Revenues	319,248,302	319,248	477		319,725	319,725	0	
Income tax receivable	2294_Accrual for Taxes Payments in Lieu of Taxes Etc.	-	-			-	0	0	
Materials and supplies	1330_Plant Materials and Operating Supplies	9,664,954	9,665			9,665	9,665	-	
Other assets	1180_Prepayments	13,484,370	13,484			13,484	13,484	-	
	1190_Miscellaneous Current and Accrued Assets	1,005,039	1,005			1,005	-	-1,005	Note 1
		343,402,665	343,403	477	-	343,879	342,874	-1,005	
Property, plant and equipment	1805_Land	7,099,147	7,099						
	1808_Buildings and Fixtures	105,068,042	105,068						
	1815_Transformer Station Equipment - Normally Primary above 50 kV	5,992,646	5,993						
	1820_Distribution Station Equipment - Normally Primary below 50 kV	156,772,442	156,772						
	1830_Poles Towers and Fixtures	339,483,342	339,483						
	1835_Overhead Conductors and Devices	349,487,472	349,487						
	1840_Underground Conduit	1,050,984,568	1,050,985						
	1845_Underground Conductors and Devices	690,624,155	690,624						
	1850_Line Transformers	465,305,585	465,306						
	1855_Services	109,093,637	109,094						
	1860_Meters	180,923,164	180,923						
	1905_Land	17,738,379	17,738						
	1908_Buildings and Fixtures	184,456,714	184,457						
	1910_Leasehold Improvements	753,840	754						
	1915_Office Furniture and Equipment	15,352,125	15,352						
	1920_Computer Equipment - Hardware	47,237,874	47,238						
	1930_Transportation Equipment	30,558,319	30,558						
	1935_Stores Equipment	7,066	7						
	1940_Tools Shop and Garage Equipment	17,825,609	17,826						
	1945_Measurement and Testing Equipment	480,243	480						
	1955_Communication Equipment	35,886,586	35,887						
	1960_Miscellaneous Equipment	270,978	271						
	1970_Load Management Controls - Customer Premises	3,022,834	3,023						
	1975_Load Management Controls - Utility Premises	-	-						
	1980_System Supervisory Equipment	28,172,657	28,173						
	1995_Contributions and Grants - Credit	-	-						
	1612_Land Rights	7,191,090	7,191						
	2005_Property Under Finance Leases	10,979,744	10,980						
	2055_Construction Work in Progress--Electric	447,746,006	447,746						
	2105_Accum. Depreciation of Electric Utility Plant - Property Plant & Equipment	- 441,042,862	-441,043						
	2120_Accumulated Amortization of Electric Utility Plant - Intangibles	-972,158	-972						
		3,866,499,243	3,866,499	9,774	-	3,876,273	3,876,273	-0	

Toronto Hydro-Electric System Limited - 2.1.13
Balance Sheet
December 31, 2016

Filing: May 1, 2017

		Regulated 2016 Actual OEB Acct TB	Regulated 2016 Actual (in thousands)	Unregulated 2016 Actual (in thousands)	Consol Adj 2016 Actual (in thousands)	Calculated THESL Consol 2016 Actual (in thousands)	Audited THESL Consol 2016 Actual (in thousands)	Diff	Comment
Intangible assets	1609_Capital Contributions Paid	75,574,497	75,574						
	1611_Computer Software	113,563,764	113,564						
	2055_Construction Work in Progress--Electric	90,117,426	90,117						
	2120_Accumulated Amortization of Electric Utility Plant - Intangibles	- 61,413,708	-61,414						
		217,841,978	217,842	-	-	217,842	217,842	-	
Deferred tax assets	1495_Deferred Taxes - Non-Current Assets	39,332,676	39,333	-	-	39,333	63,758	24,425	Note 2
Other assets	1460_Other Non-Current Assets	3,357,517	3,358	-	-	3,358	1,347	-2,010	Note 1
Regulatory balances	1508_Other Regulatory Assets	137,733,885	137,734						
	1520_Power Purchase Variance Account	0	0						
	1521_Special Purpose Chg Assessment Variance Account	-	-						
	1533_Renewable Generation Connection Funding Adder Deferral Account	- 1,026,599	-1,027						
	1550_Low Voltage Variance Acct	1,268,066	1,268						
	1551_Smart Metering Entity Charge Variance Acct	- 677,184	-677						
	1555_Smart Meter Capital Offset Variance	11,411,865	11,412						
	1556_Smart Meter Operating Variance	-	-						
	1562_Deferred Payments in Lieu of Taxes	-	-						
	1563_Deferred PILs Contra Account	-	-						
	1568_LRAM Variance Account	10,174,673	10,175						
	1575_IFRS-UGAAP Transitional PPE Amounts	19,014,359	19,014						
	1580_RSVAWMS	- 183,172,404	-183,172						
	1584_RSVANW	53,722,512	53,723						
	1586_RSVACN	7,215,493	7,215						
	1588_RSVAPOWER	- 27,061,247	-27,061						
	1589_RSVAGA	85,222,910	85,223						
	1592_PILs and Tax Variance for 2006 and Subsequent Years	- 0	-0						
	1595_Disposition Recovery Reg Balances Control Acct	70,438,691	70,439						
		184,265,019	184,265	-	-	184,265	190,884	6,619	Note 3
Total Assets		4,877,274,745	4,877,275	51,212	-37,378	4,891,109	4,919,137	28,028	
Liabilities and Equity									
Joint Bank indebtedness	2225_Notes and Loans Payable	- 85,288,819	-85,289	-	34,744	-50,545	-50,545	0	
Advance from related party		-	-	-	-	-	-	-	
Accounts payable and accrued liabilities	2205_Accounts Payable	- 418,669,174	-418,669						
	2208_Customer Credit Balances	- 13,950,489	-13,950						
	2220_Miscellaneous Current and Accrued Liabilities	- 16,565,749	-16,566						
	2240_Accounts Payable to Associated Companies Notes	- 20,357,895	-20,358						
	2250_Debt Retirement Charges(DRC) Payable	- 7,814,334	-7,814						
	2290_Commodity Taxes	- 4,049,856	-4,050						
	2292_Payroll Deductions / Expenses Payable	- 8,821,613	-8,822						
		- 490,229,109	-490,229	-12,837	2,634	-500,432	-500,432	0	
Income tax payable	2294_Accrual for Taxes Payments in Lieu of Taxes Etc.	- 8,597,103	-8,597	-		-8,597	-8,986	-389	Note 4

Toronto Hydro-Electric System Limited - 2.1.13

Filing: May 1, 2017

Balance Sheet
December 31, 2016

		Regulated 2016 Actual OEB Acct TB	Regulated 2016 Actual (in thousands)	Unregulated 2016 Actual (in thousands)	Consol Adj 2016 Actual (in thousands)	Calculated THESL Consol 2016 Actual (in thousands)	Audited THESL Consol 2016 Actual (in thousands)	Diff	Comment
Customer deposits	2210_Customer Deposits	- 39,145,495	-39,145			-39,145	-39,145		
	2335_Long Term Customer Deposits	-	-			-			
		- 39,145,495	-39,145	-	-	-39,145	-39,145	-	
Deferred revenue	2220_Miscellaneous Current and Accrued Liabilities	-1,000,524	-1,001	-		-1,001	-4,324	-3,323	Note 5
Deferred conservation credit		0	-	-5,529		-5,529	-5,529	-	
Other liabilities	2285_Obligations Under Finance Leases--Current	- 3,050,846	-3,051			-3,051			
	2220_Miscellaneous Current and Accrued Liabilities	- 54,792	-55			-55			
		- 3,105,638	-3,106	-	-	-3,106	-3,106	-	
Notes payable to related party	2242_ Payable to Associated Companies	- 304,910,193	-304,910			-304,910	-304,910		
	2260_Current Portion of Long Term Debt	-	-	-		-	-		
			-						
		- 304,910,193	-304,910	-	-	-304,910	-304,910	-	
Notes payable to related party	2550_Advances from Associated Companies	- 1,830,595,099	-1,830,595			-1,830,595	-1,830,595	0	
	2505_Debentures Outstanding - Long Term Portion	-	-			-	-	-	
Customer deposits	2335_Non-Current Customer Deposits	-14,961,988	-14,962			-14,962	-14,962	-	
Deferred revenue	2440_Deferred Revenues	- 116,237,970	-116,238			-116,238			
	2320_Other Miscellaneous Non-Current Liabilities	-	-			-			
	2335_Non-Current Customer Deposits	- 26,944,576	-26,945			-26,945			
		- 143,182,546	-143,183	-	-	-143,183	-139,859	3,323	Note 5
Post-employment benefits	2306_POEB Liability	- 279,290,000	-279,290	-1,195		-280,485	-280,485	0	
Other liabilities	2325_Obligations Under Finance Lease--Non-Current	- 1,579,842	-1,580			-1,580			
	2320_Other Miscellaneous Non-Current Liabilities	379,632	380			380			
		- 1,200,210	-1,200	-	-	-1,200	-1,922	-721	Note 6
Total Liabilities		- 3,201,506,724	-3,201,507	-19,560	37,378	-3,183,689	-3,184,799	-1,111	
Share Capital	3005_Common Shares Issued	- 527,816,668	-527,817	-28,461		-556,278	-556,278	0	
Retained Earnings	3045_Unappropriated Retained Earnings	- 1,129,492,533	-1,129,493						
	3046_Balance Transferred From Income	- 177,744,793	-177,745						
	3049_Dividends Payable-Common Shares	321,526,001	321,526						
	3055_Adjustment to Retained Earnings	- 5,969,175	-5,969						
		- 991,680,501	-991,681	-3,191	-	-994,871	-995,879	-1,007	Note 7
Contributed Surplus	3010_Contributed Surplus	- 12,757,392	-12,757			-12,757	-12,757	-	
Regulatory balances	1508_Other Regulatory Assets	- 87,895,862	-87,896						
	1595_Disposition Recovery Reg Balances Control Acct	- 16,284,919	-16,285						
	2350_Deferred Tax - Non-Current Liability	- 39,332,677	-39,333						
		- 143,513,459	-143,513	-	-	-143,513	-169,424	-25,911	Note 8
Total liabilities, equity and regulatory balances		- 4,877,274,745	-4,877,275	-51,212	37,378	-4,891,109	-4,919,137	-28,028	
		-	-	-	-	-	0	0	

Toronto Hydro-Electric System Limited - 2.1.13 Filing: May 1, 2017
Balance Sheet
December 31, 2016

Notes: The Uniform System of Account balances are mapped and reconciled to the audited financial statements (AFS) (in dollars thousands).

Note 1: This relates to the CIR Costs Deferral re-instatement on the Balance Sheet.
For OSC purposes, as a result of the OEB's Decision with regards to the DRO, the CIR costs were considered no longer recoverable, and as such it was considered impaired and written-off to the P&L.
For RRR purposes, since the CIR Costs were approved to be recovered over the 5 year term in the original OEB Decision on December 29, 2015 with regards to the 2015-2019 CIR Application, the CIR costs were re-instated on the balance sheet and will be amortized over the 5 years. The current portion and the long-term portion of the re-instated CIR costs on the balance sheet was $1,005 and $2,010 respectively.

Note 2: Difference in "Deferred tax assets" of $24,425: Calculated balance of $39,333 & AFS balance of $63,758, a difference of $24,425, as follows:
a. The deferred tax balance related to regulatory balances and gross up in respect of deferred tax assets are recorded in regulatory balances in accordance with IFRS 14 for AFS.
For purposes of RRR reporting, these balances are reclassified to deferred tax assets in the amount of $25,911.
b. For purposes of RRR reporting, an adjustment was made to remove deferred income tax asset in respect of the non-rate regulated assets in the amount of ($1,486).

Note 3: Difference in "Regulatory balances - deferred debits" of $6,619: Calculated balance of $184,265 & AFS balance of $190,884, a difference of $6,619, as follows:

a. A "Smart meter recovery" regulatory asset (RA) was booked for AFS, and is not considered a regulatory asset for purposes of RRR reporting:	2,092
b. For RRR purposes, as per the APH, Article 510, "The return on rate base shall not be recorded in Account 1575 IFRS-GAAP Transitional PP&E Return on Rate Base. On disposition of the account balance, the return is applied prospectively in rates as an adjustment to the revenue requirement." In the AFS, the return on rate base was accrued at year-end 2015 since the OEB approved the disposition of Account 1575 with the return on rate base of $4.7 million. For RRR purposes, the $4.7 million accrual has been reversed. As such, in the AFS, the disposition of the account 1575 includes offsetting entries on the balance sheet related to the disposition of the return on rate base, whereas for RRR purposes, the collection of the return on rate base is recorded in the income statement in accordance with the OEB's Accounting Procedures Handbook Guidance - March 2015 - #6.	3,806
c. The capital-related revenue requirement variance account is calculated using rate base for the AFS and calculated based on capital in-service additions for RRR reporting.	721
Total difference:	6,619

Note 4: Difference in "Income tax payable" of ($389): Calculated balance of ($8,597) & AFS balance of ($8,986), a difference of ($389), as follows:
The difference represents the non-regulated business income tax payable included in the AFS.

Note 5: Difference in "Deferred revenue - current", offset by difference in "Deferred revenue - long-term" of $3,323 as follows:
For the AFS the Deferred revenue was split between current and long-term. For the RRR purposes, the Deferred revenue is not split between current and long-term.

Note 6: Difference in "Other liabilities" of ($721): Calculated balance of ($1,200) & AFS balance of ($1,922), a difference of ($721), as follows:
The difference represents the capital-related revenue requirement variance account calculated using rate base for the AFS and calculated based on capital in-service additions for RRR reporting.

Note 7: Difference in "Retained Earnings" of ($1,007): Calculated balance of ($994,871) & AFS balance of ($995,879), a difference of ($1,007).
Adjustments have been made to certain AFS income statement items to arrive at the RRR reporting as follows:

A. Adjustments made to certain AFS income statement items in prior years as follows:	
a. Reduction for prior years' AFS Distribution revenue booked for Smart Meter "net revenue requirement" on the disposition of Account 1555 "Smart Meter Capital & Recovery" and 1556 "Smart Meter OM&A Variance account" balances. The amount is recorded to Distribution revenue for RRR reporting, to OEB account 4080 as the amount is billed to THESL customers in the future.	- 9,947
b. Incremental Capital Model (ICM) revenue and depreciation expense booked in the AFS in prior year, and this was considered a regulatory asset for purposes of RRR reporting. This ICM revenue and depreciation expense was to be booked for RRR reporting under regulatory prescribed ICM accounting treatment.	- 20,884
c. HST Contra account adjustment: In prior years' AFS, THESL has booked to the OEB account 1592, "PILs and Tax Variances for 2006 and Subsequent Years, Sub-account HST / OVAT Input Tax credits (ITCs)" the ITC savings arising from the elimination of Provincial Sales Tax and implementation of the HST on July 1, 2010. For AFS purposes, the offsetting entry was booked to the income statement rather the regulatory sub-account established, a contra account within Account 1592, "PILS and Tax Variances for 2006 and subsequent years - HST/OVAT Contra Account" of Account 1592.	1,180
d For purposes of RRR reporting, an adjustment was made to remove deferred income tax asset in respect of the non-rate regulated assets related to prior year.	1,432
e. This relates to the reversal of the Account 1575 IFRS-GAAP Transitional PP&E Return on Rate Base. For RRR purposes, as per the APH, Article 510, "The return on rate base shall not be recorded in this account. On disposition of the account balance, the return is applied prospectively in rates as an adjustment to the revenue requirement." In the AFS, the return on rate base was accrued at year-end 2015 since the OEB approved the disposition of Account 1575 with the return on rate base of $4,755k. As such, for 2015 RRR purposes, the $4,755k accrual was reversed.	- 4,755
f. This relates to the CIR Costs Deferral re-instatement on the Balance Sheet. For OSC purposes, as a result of the OEB's Decision with regards to the DRO, the CIR costs were considered no longer recoverable, and as such it was considered impaired and written-off to the P&L. For RRR purposes, since the CIR Costs were approved to be recovered over the 5 year term in the original OEB Decision on December 29, 2015 with regards to the 2015-2019 CIR Application, the CIR costs were re-instated on the balance sheet and will be amortized over the 5 years.	3,503
g. The difference represents the non-regulated business current income tax expense included in the AFS.	- 750
h. Other	- 1
B. Adjustments made to certain AFS income statement items in 2016, with these differences as explained in the Income Statement attached.	
a. The total impact on net income or difference for the year 2016 was $29,215, per the Income Statement attached.	29,215
Total difference:	- 1,007

Note 8: Difference in "Regulatory balances - deferred credits" of ($25,911): Calculated balance of ($143,513) & AFS balance of ($169,424), a difference of ($25,911), as follows:
The deferred tax balance related to regulatory balances and gross up in respect of deferred tax assets are recorded in regulatory balances in accordance with IFRS 14 for AFS. For purposes of RRR reporting, these balances are reclassified to deferred tax assets.

Toronto Hydro-Electric System Limited - 2.1.13
Statement of Income
December 31, 2016

Filing: May 1, 2017

		Regulated 2016 Actual OEB Acct TB	Regulated 2016 Actual (in thousands)	Unregulated 2016 Actual (in thousands)	Net Movement Adj 2016 Actual (in thousands)	Consol Adj 2016 Actual (in thousands)	Calculated THESL Consol 2016 Actual (in thousands)	Audited THESL Consol 2016 Actual (in thousands)	Diff	Comment
Revenue										
Energy sales	4006_Residential Energy Sales	-584,394,405	- 584,394							
	4010_Commercial Energy Sales	-1,672,640,074	- 1,672,640							
	4020_Energy Sales to Large Users	-199,743,477	- 199,743							
	4025_Street Lighting Energy Sales	-14,801,546	- 14,802							
	4035_General Energy Sales	-285,294,010	- 285,294							
	4050_Revenue Adjustment	323,259	323							
	4062_Billed WMS	-127,291,573	- 127,292							
	4066_Billed NW	-171,339,860	- 171,340							
	4068_Billed CN	-127,357,471	- 127,357							
	4075_Billed LV	0	-							
		-3,182,539,156	- 3,182,539	-	- 89,608	-	- 3,272,147	- 3,306,175	- 34,028	Note 1
Distribution revenue	4080_Distribution Services Revenue	-696,533,948	- 696,534		9,191	-	- 687,343	- 647,869	39,474	Note 2
		-3,879,073,104	- 3,879,073	-	- 80,416	-	- 3,959,490	- 3,954,044	5,446	
Other income	4082_Retail Services Revenues	-347,875	- 348							
	4084_Service Transaction Requests (STR) Revenues	-18,378	- 18							
	4086_SSS Administration Revenue	-2,317,539	- 2,318							
	4090_Electric Services Incidental to Energy Sales	0	-							
	4210_Rent from Electric Property	-11,868,496	- 11,868							
	4215_Other Utility Operating Income	-1,102,337	- 1,102							
	4220_Other Electric Revenues	-8,200,259	- 8,200							
	4225_Late Payment Charges	-4,540,398	- 4,540							
	4235_Miscellaneous Service Revenues	-9,496,223	- 9,496							
	4245_Government and Other Assistance Directly Credited to Income	-3,765,318	- 3,765							
	4325_Revenues from Merchandise Jobbing Etc.	-20,950,568	- 20,951							
	4310_Regulatory Credits	-5,179,079	- 5,179							
	4330_Costs and Expenses of Merchandising Jobbing Etc.	19,805,704	19,806							
	5615_General Administrative Salaries and Expenses	238,629	239							
	4076_Billed Smart Metering Entity Charge	-6,919,230	- 6,919							
		-54,661,367	- 54,661	- 3,466	- 488	-	- 58,615	- 66,322	- 7,707	Note 3
Costs										
Energy purchases	4705_Power Purchased	1,391,825,709	1,391,826							
	4707_Charges - Global Adjustment	1,364,724,543	1,364,725							
	4708_Charges-WMS	94,602,317	94,602							
	4714_Charges-NW	171,339,860	171,340							
	4716_Charges-CN	127,357,471	127,357							
	4730_Rural Rate Assistance Expense	32,689,256	32,689							
	4750_Charges LV	0	0							
		3,182,539,156	3,182,539	-	312	-	3,182,851	3,216,879	34,028	Note 4
Operating expenses	4380_Expenses of Non-Rate Regulated Operations	3,486,726	3,487							
	4398_Foreign Exchange Gains and Losses Including Amortization	-162,383	- 162							
	5005_Distribution Operation Supervision and Engineering	23,026,740	23,027							
	5010_Distribution Load Dispatching	5,351,161	5,351							
	5012_Station Buildings and Fixtures Expense	0	-							
	5016_Distribution Station Equipment - Operation Labour	4,003,573	4,004							
	5017_Distribution Station Equipment - Operation Supplies and Expenses	2,645,106	2,645							
	5020_Overhead Distribution Lines and Feeders - Operation Labour	624,866	625							
	5025_Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	3,737,901	3,738							
	5035_Overhead Distribution Transformers- Operation	0	-							
	5040_Underground Distribution Lines and Feeders - Operation Labour	663,662	664							
	5045_Underground Distribution Lines & Feeders - Operation Supplies & Expenses	2,460,512	2,461							
	5055_Underground Distribution Transformers - Operation	4,683	5							
	5065_Meter Expense	531,226	531							
	5070_Customer Premises - Operation Labour	2,194,355	2,194							
	5075_Customer Premises - Materials and Expenses	1,542,691	1,543							
	5085_Miscellaneous Distribution Expense	10,117,835	10,118							
	5105_Maintenance Supervision and Engineering	14,808,760	14,809							
	5110_Maintenance of Buildings and Fixtures - Distribution Stations	14,810,485	14,810							
	5112_Maintenance of Transformer Station Equipment	0	-							
	5114_Maintenance of Distribution Station Equipment	3,877,544	3,878							
	5120_Maintenance of Poles Towers and Fixtures	415,958	2							
	5125_Maintenance of Overhead Conductors and Devices	14,995,019	16,024							

Toronto Hydro-Electric System Limited - 2.1.13
Statement of Income
December 31, 2016

Filing: May 1, 2017

		Regulated 2016 Actual OEB Acct TB	Regulated 2016 Actual (in thousands)	Unregulated 2016 Actual (in thousands)	Net Movement Adj 2016 Actual (in thousands)	Consol Adj 2016 Actual (in thousands)	Calculated THESL Consol 2016 Actual (in thousands)	Audited THESL Consol 2016 Actual (in thousands)	Diff	Comment
	5130_Maintenance of Overhead Services	616,897	2							
	5135_Overhead Distribution Lines and Feeders - Right of Way	3,850,160	3,850							
	5145_Maintenance of Underground Conduit	6,440	6							
	5150_Maintenance of Underground Conductors and Devices	6,024,819	6,025							
	5155_Maintenance of Underground Services	187,260	187							
	5160_Maintenance of Line Transformers	2,046	2							
	5165_Maintenance of Street Lighting and Signal Systems	3,371,509	3,372							
	5305_Supervision	203,987	204							
	5310_Meter Reading Expense	4,223,672	4,224							
	5315_Customer Billing	8,772,066	8,772							
	5320_Collecting	16,538,114	16,538							
	5335_Bad Debt Expense	5,229,919	5,230							
	5410_Community Relations - Sundry	0	-							
	5415_Energy Conservation	0	-							
	5420_Community Safety Program	2,501,576	2,502							
	5605_Executive Salaries and Expenses	3,203,104	3,203							
	5610_Management Salaries and Expenses	802	1							
	5615_General Administrative Salaries and Expenses	52,007,614	52,008							
	5620_Office Supplies and Expenses	4,196	4							
	5625_Administrative Expense Transferred Credit	14,706	15							
	5630_Outside Services Employed	6,419,601	6,420							
	5635_Property Insurance	1,757,502	1,758							
	5640_Injuries and Damages	1,562,179	1,562							
	5655_Regulatory Expenses	5,188,491	5,188							
	5660_General Advertising Expenses	0	-							
	5665_Miscellaneous General Expenses	37,971	38		3,159					
	5675_Maintenance of General Plant	10,393,074	10,393							
	5680_Electrical Safety Authority Fees	406,037	406							
	6105_Taxes Other Than Income Taxes	4,648,749	4,649							
	6205_Donations	965,726	966							
	4375_Revenues from Non-Rate Regulated Operations	-3,212,613	- 3,213							
	4751_Charges Smart Metering Entity Chg	6,919,230	6,919							
		250,981,257	250,981	1,200	3,159	-	255,339	267,738	12,399	Note 5
Depreciation and amortization	5705_Depreciation Expense - Property Plant and Equipment	204,558,212	204,558							
	5715_Amortization of Intangible Assets	21,347,733	21,348							
		225,905,945	225,906	759		-	226,665	210,601	- 16,064	Note 6
		-274,308,114	- 274,308	- 1,507	- 77,434	-	- 353,249	- 325,148	28,101	
Finance costs										
Interest Income	4375_Revenues from Non-Rate Regulated Operations	0	-							
	4405_Interest and Dividend Income	-19,393	- 19							
		-19,393	- 19	- 277		-	- 297	- 297	0	
Interest Expense, Long-term Debt	6030_Interest on Debt to Associated Companies	85,425,373	85,425	-			85,425	85,425	-	
Interest Expense, Other	5615_General Administrative Salaries and Expenses	2,298,641	2,299					-	-	
	5420_Community Safety Program	24,235	24					-	-	
	5105_Maintenance Supervision and Engineering	88,031	88					-	-	
	4405_Interest and Dividend Income	-166,995	- 167							
	6035_Other Interest Expense	1,678,198	1,678			-			-	
	6040_Allowance for Borrowed Costs Applied to CWIP--Credit	-12,574,989	- 12,575					-	-	
		-8,652,879	- 8,653	- 17	237	-	- 8,433	- 8,512	- 80	Note 7
Gain on disposals of property, plant and equipment	4355_Gain on Disposition of Utility and Other Property	-2,132,160	- 2,132							
	4335_Profits and Losses from Financial Instrument Hedges	0	0							
		-2,132,160	- 2,132	-			- 2,132	- 2,132	-	
Income Tax Expense	6110_Income Taxes	21,762,400	21,762	-		-	21,762	22,152	389	Note 8
	6115_Provision for Deferred Taxes - Inc. Statement	179,979	180		44,033		44,213	45,017	804	Note 9
Net Income		-177,744,793	- 177,745	- 1,801	- 33,164	-	- 212,710	- 183,495	29,215	
Net movements in regulatory balances, net of tax		0			33,164		33,164	33,164	-	
Net income after net movements in regulatory balances		-177,744,793	- 177,745	- 1,801	-	-	- 179,546	- 150,331	29,215	

Toronto Hydro-Electric System Limited - 2.1.13 Filing: May 1, 2017
Statement of Income
December 31, 2016
Notes: The Uniform System of Account balances are mapped and reconciled to the audited financial statements (AFS) (in dollars thousands).

Note 1: Difference in "Energy sales" of ($34,028): Calculated balance of ($3,272,147) & AFS balance of ($3,306,175), a difference of ($34,028), as follows:	
For RRR Reporting, THESL booked to "Cost of Power expense" the amount of the IESO settlement invoices charge type 142, in the credit amount of $34,028.	-34,028
For the AFS, THESL book IESO settlement invoices charge type 142 to COP revenue.	
Total difference:	
Note 2: Difference in "Distribution revenue" of $39,474: Calculated balance of ($687,343) & AFS balance of ($647,869), a difference of $39,474, as follows:	
a. A "Smart meter recovery" regulatory asset (RA) was booked for AFS, with AFS Distribution revenue booked on an accrual basis. This is not considered a regulatory	7,855
asset for purposes of RRR reporting. The AFS Distribution revenue amount has been adjusted so the Distribution revenue booked for RRR Reporting is appropriately reflected on a cash basis.	
b. This relates to the reversal of the Account 1575 IFRS-GAAP Transitional PP&E Return on Rate Base.	949
For RRR purposes, as per the APH, Article 510, "The return on rate base shall not be recorded in this account. On disposition of the account balance, the return is	
applied prospectively in rates as an adjustment to the revenue requirement." In the AFS, the return on rate base was accrued at year-end 2015 since the	
OEB approved the disposition of Account 1575 with the return on rate base of $4,755. For 2015 RRR purposes, the $4,755 accrual has been reversed.	
As such, in the AFS, the disposition of the account 1575 includes offsetting entries on the balance sheet related to the disposition of the return on rate base, whereas for RRR purposes, the	
collection of the return on rate base is recorded in the income statement in accordance with the OEB's Accounting Procedures Handbook Guidance - March 2015 - #6.	
c. HST Contra account adjustment: In prior years' AFS, THESL has booked to the OEB account 1592, "PILs and Tax Variances for 2006 and Subsequent Years, Sub-account HST / OVAT Input Tax	-1,100
credits (ITCs)" the ITC savings arising from the elimination of Provincial Sales Tax and implementation of the HST on July 1, 2010.	
For AFS purposes, the offsetting entry was booked to the income statement rather the regulatory sub-account established, a contra account within Account 1592, "PILS and Tax	
Variances for 2006 and subsequent years - HST/OVAT Contra Account" of Account 1592. As a result of the OEB's Decision to clear the OEB account 1592 "PILs and Tax Variances for 2006	
and Subsequent Years, Sub-account HST / OVAT Input Tax" to recover from customers effective March 1, 2016 over a 10 month period, the offsetting contra account OEB account 1592	
"PILS and Tax Variances for 2006 and subsequent years - HST/OVAT Contra Account" was cleared over a 10 month period into the income statement.	
d. Incremental Capital Model (ICM) revenue and depreciation expense booked in the AFS in prior year, and this was considered a regulatory asset for purposes of RRR reporting in previous years.	31,770
As a result of the ICM Settlement in 2016, the ICM regulatory accounts have been cleared. As such, for RRR purposes, the ICM rate rider collected of $41.2 million has been recognized	
into Distribution Revenue, and the depreciation on ICM assets of $10.9 million that was deferred in regulatory assets has been recognized into Depreciation Expense in the income statement.	
Therefore, an additional amount was recorded to increase the revenue recognized for AFS to $41.2 million for RRR purpose.	
Total difference:	39,474
Note 3: Difference in "Other income" of ($7,707): Calculated balance of ($58,615) & AFS balance of ($66,322), a difference of ($7,707), as follows:	
a. Demand Billable Charges: As per AFS GAAP, THESL booked demand billable charges on a gross basis while for RRR it is reported on a net basis:	-19,806
b. Smart Metering Entity charge: As per AFS GAAP, THESL books the Smart Metering entity revenue and charge on a net basis, while for RRR it is booked on a gross basis, in the prescribed regulatory	6,919
accounts 4076 "Billed Smart Metering Entity Charge" and 4751 "Charges Smart Metering Entity Charge":	
c. As per the OEB's Accounting Procedures Handbook Guidance - March 2015 - #6, the approved disposition of the account balance for both Account 1575 and Account 1576 would be reflected	5,179
as an offset to depreciation expense over the approved amortization period." As well, based on the OEB's Accounting Procedures Handbook Guidance - March 2015 - #6, to ensure that	
only the return on rate base component is recorded in distribution revenues, the offsetting credit entry is recorded in OEB Account 4310 Regulatory Credits.	
d. Other	1
Total difference:	-7,707
Note 4: Difference in "Energy purchases" of $34,028: Calculated balance of $3,182,851 & AFS balance of $3,216,879, a difference of $34,028, as follows:	
For RRR Reporting, THESL booked to "Cost of Power expense" the amount of the IESO settlement invoices charge type 142, in the credit amount of $34,028.	34,028
For the AFS, THESL book IESO settlement invoices charge type 142 to COP revenue.	
Note 5: Difference in "Operating expenses" of $12,399: Calculated balance of $255,339 & AFS balance of $267,738, a difference of $12,399, as follows:	
a. Demand Billable Charges: As per AFS GAAP, THESL booked demand billable charges on a gross basis while for RRR it is reported on a net basis:	19,806
b. Smart Metering Entity charge: As per AFS GAAP, THESL books the Smart Metering entity revenue and charge on a net basis, while for RRR it is booked on a gross basis, in the prescribed regulatory	-6,919
accounts 4076 "Billed Smart Metering Entity Charge" and 4751 "Charges Smart Metering Entity Charge":	
c. This relates to the CIR Costs Deferral re-instatement on the Balance Sheet.	-488
For OSC purposes, as a result of the OEB's Decision with regards to the DRO, the CIR costs were considered no longer recoverable, and as such it was considered impaired and written-off to the P&L.	
For RRR purposes, since the CIR Costs were approved to be recovered over the 5 year term in the original OEB Decision on December 29, 2015 with regards to the 2015-2019 CIR Application, the	
CIR costs were re-instated on the balance sheet and will be amortized over the 5 years.	
Total difference:	12,399
Note 6: Difference in "Depreciation and amortization" of ($16,064): Calculated balance of ($226,665) & AFS balance of ($210,601), a difference of ($16,064), as follows:	-5,179
a. As per the OEB's Accounting Procedures Handbook Guidance - March 2015 - #6, the approved disposition of the account balance for both Account 1575 and Account 1576 would be reflected	
as an offset to depreciation expense over the approved amortization period." As well, based on the OEB's Accounting Procedures Handbook Guidance - March 2015 - #6, to ensure that	
only the return on rate base component is recorded in distribution revenues, the offsetting credit entry is recorded in OEB Account 4310 Regulatory Credits.	
b. Incremental Capital Model (ICM) revenue and depreciation expense booked in the AFS in prior year, and this was considered a regulatory asset for purposes of RRR reporting in previous years.	-10,885
As a result of the ICM Settlement in 2016, the ICM regulatory accounts have been cleared. As such, for RRR purposes, the ICM rate rider collected of $41.2 million has been recognized	
into Distribution Revenue, and the depreciation on ICM assets of $10.9 million that was deferred in regulatory assets has been recognized into Depreciation Expense in the income statement.	
Total difference:	-16,064
Note 7: Difference in "Finance Costs - Interest expense, other" of ($80): Calculated balance of ($8,433) & AFS balance of ($8,512), a difference of ($80), as follows:	-80
HST Contra account adjustment: In prior years' AFS, THESL has booked to the OEB account 1592, "PILs and Tax Variances for 2006 and Subsequent Years, Sub-account HST / OVAT Input Tax	
credits (ITCs)" the ITC savings arising from the elimination of Provincial Sales Tax and implementation of the HST on July 1, 2010.	
For AFS purposes, the offsetting entry was booked to the income statement rather the regulatory sub-account established, a contra account within Account 1592, "PILS and Tax	
Variances for 2006 and subsequent years - HST/OVAT Contra Account" of Account 1592. As a result of the OEB's Decision to clear the OEB account 1592 "PILs and Tax Variances for 2006	
and Subsequent Years, Sub-account HST / OVAT Input Tax" to recover from customers effective March 1, 2016 over a 10 month period, the offsetting contra account OEB account 1592	
"PILS and Tax Variances for 2006 and subsequent years - HST/OVAT Contra Account" was being cleared over a 10 month period into the income statement.	
Note 8: Difference in "Income tax expense - Income taxes" of $389: Calculated balance of $21,762 & AFS balance of $22,152, a difference of $389, as follows:	389
The difference represents the non-regulated business current income tax expense included in the AFS.	
Note 9: Difference in "Income tax expense - Provision for deferred taxes" of $804: Calculated balance of $44,213 & AFS balance of $45,017, a difference of $804, as follows:	804
For purposes of RRR reporting, an adjustment was made to remove deferred income tax asset in respect of the non-rate regulated assets.	

RRR Reporting

Rate Base Calculation **Reconciliation - Total PP&E**	**PP&E** **(incl CWIP)**	**ROE Exclusions** **Remove CWIP**	 **Other**	**ROE Calc** **Net**	**Comment**
As Reported - US GAAP RRR Dec 31, 2014	$2,903,903	-$518,239	$0	$2,385,664	PPE per ROE Calc. 2014
Difference to mIFRS	$25,841	-$24,250	$0	$1,591	
mIFRS - Trial Balance	**$2,929,744**	**-$542,489**		**$2,387,255**	
A/C 2440 Deferred Revenue LT			-$43,571	-$43,571	manual entries on ROE web site
CWIP portion of A/C 2440			$22,706	$22,706	manual entries on ROE web site
mIFRS Balance	**$2,929,744**	**-$542,489**	**-$20,865**	**$2,366,390**	
Inclusions for new Rate Regime					
ICM Assets	$439,074			$439,074	
Streetlighting Assets	$38,475			$38,475	
Total Jan 1 2015 PP&E - RRR	**$3,407,293**	**-$542,489**	**-$20,865**	**$2,843,939**	Jan 1, 2015 PP&E for ROE Purposes
Total Adjustment to RRR Openning PP&E				**$458,275**	
2015 ROE					
mIFRS - RRR Balances per ledger - OEB roll up	$3,750,644	-$609,194		$3,141,450	
A/C 2440 Deferred Revenue LT			-$86,773	-$86,773	
CWIP portion of A/C 2440			$31,475	$31,475	
Submission per RRR	**$3,750,644**	**-$609,194**	**-$55,298**	**$3,086,151**	Dec 31, 2015 PP&E for ROE Purposes
2016 ROE					
mIFRS - RRR Balances per ledger - OEB roll up	$4,084,341	-$537,863		$3,546,478	
A/C 2440 Deferred Revenue LT			-$116,238	-$116,238	
CWIP portion of A/C 2440			$32,364	$32,364	
Submission per RRR	**$4,084,341**	**-$537,863**	**-$83,874**	**$3,462,604**	Dec 31, 2016 PP&E for ROE Purposes
2017 ROE					
mIFRS - RRR Balances per ledger - OEB roll up	4,393,492	-$537,732		$3,855,760	
A/C 2440 Deferred Revenue LT			-$158,039	-$158,039	
CWIP portion of A/C 2440			$51,285	$51,285	
Non rate-regulated assets A/C 2075 & 2180			-$1,969	-$1,969	
Monthly billing			-$2,289	-$2,289	
Submission per RRR	**$4,393,492**	**-$537,732**	**-$111,011**	**$3,744,749**	Dec 31, 2017 PP&E for ROE Purposes

Toronto Hydro-Electric System Limited - 2.1.13
Balance Sheet
December 31, 2017

Filing: April 30, 2018

		Regulated 2017 Actual OEB Acct TB	Regulated 2017 Actual (in thousands)	Unregulated 2017 Actual (in thousands)	Consol Adj 2017 Actual (in thousands)	Calculated THESL Consol 2017 Actual (in thousands)	Audited THESL Consol 2017 Actual (in thousands)	Diff	Comment
Assets									
Current Assets									
Cash and cash equivalents	1005_Cash	-	-						
	1010_Cash Advances and Working Funds	-	-						
		-	-	31,691	-31,691	-	-	-	
Accounts receivable	1100_Customer Accounts Receivable	175,929,618	175,930						
	1104_Accounts Receivable - Recoverable Work	14,986,696	14,987						
	1110_Other Accounts Receivable	18,277,743	18,278						
	1130_Accumulated Provision for Uncollectible Accounts-- Credit	- 10,173,788	-10,174						
	1200_Accounts Receivable from Associated Companies	2,041,500	2,042						
		201,061,769	201,062	20,454	-4,458	217,058	217,058	-0	
Unbilled revenue	1120_Accrued Utility Revenues	273,670,964	273,671	2,333		276,004	276,004	0	
Income tax receivable	2294_Accrual for Taxes Payments in Lieu of Taxes Etc.	-	-			-	0	0	
Materials and supplies	1330_Plant Materials and Operating Supplies	9,345,336	9,345			9,345	9,345	-	
Other assets	1180_Prepayments	12,655,839	12,656			12,656	12,656	-	
	1190_Miscellaneous Current and Accrued Assets	9,736,934	9,737			9,737	8,732	-1,005	Note 1
		305,409,073	305,409	2,333	-	307,742	306,737	-1,005	
Property, plant and equipment	1805_Land	7,006,433	7,006						
	1808_Buildings and Fixtures	116,632,610	116,633						
	1815_Transformer Station Equipment - Normally Primary above 50 kV	36,917,966	36,918						
	1820_Distribution Station Equipment - Normally Primary below 50 kV	184,513,183	184,513						
	1830_Poles Towers and Fixtures	362,478,012	362,478						
	1835_Overhead Conductors and Devices	390,547,495	390,547						
	1840_Underground Conduit	1,127,938,656	1,127,939						
	1845_Underground Conductors and Devices	782,844,299	782,844						
	1850_Line Transformers	515,354,184	515,354						
	1855_Services	122,134,425	122,134						
	1860_Meters	199,703,400	199,703						
	1905_Land	17,358,657	17,359						
	1908_Buildings and Fixtures	225,535,597	225,536						
	1910_Leasehold Improvements	753,840	754						
	1915_Office Furniture and Equipment	19,308,596	19,309						
	1920_Computer Equipment - Hardware	58,683,341	58,683						
	1930_Transportation Equipment	33,718,724	33,719						
	1935_Stores Equipment	7,066	7						
	1940_Tools Shop and Garage Equipment	21,151,564	21,152						
	1945_Measurement and Testing Equipment	480,243	480						
	1950_Power Operated Equipment	845,773	846						
	1955_Communication Equipment	45,358,046	45,358						
	1960_Miscellaneous Equipment	270,978	271						
	1970_Load Management Controls - Customer Premises	3,022,834	3,023						
	1975_Load Management Controls - Utility Premises	-	-						
	1980_System Supervisory Equipment	33,585,011	33,585						
	1995_Contributions and Grants - Credit	-	-						
	1612_Land Rights	-	-						
	2005_Property Under Finance Leases	18,170,834	18,171						
	2055_Construction Work in Progress--Electric	369,579,569	369,580						
	2075_Non-Rate Regulated Property Owned or Under Finance Leases	2,002,023	2,002						
	2105_Accum. Depreciation of Electric Utility Plant - Property Plant & Equipment	- 598,528,934	-598,529						
	2120_Accumulated Amortization of Electric Utility Plant - Intangibles	0	-						
	2180_Accumulated Depreciation of Non Rate-Regulated Property	- 33,367	-33						
		4,097,341,055	4,097,341	10,474	-	4,107,815	4,107,815	-0	

Toronto Hydro-Electric System Limited - 2.1.13
Balance Sheet
December 31, 2017

Filing: April 30, 2018

		Regulated 2017 Actual OEB Acct TB	Regulated 2017 Actual (in thousands)	Unregulated 2017 Actual (in thousands)	Consol Adj 2017 Actual (in thousands)	Calculated THESL Consol 2017 Actual (in thousands)	Audited THESL Consol 2017 Actual (in thousands)	Diff	Comment
Assets									
Current Assets									
Intangible assets	1609_Capital Contributions Paid	75,574,497	75,574						
	1611_Computer Software	136,960,666	136,961						
	2055_Construction Work in Progress--Electric	168,152,290	168,152						
	2120_Accumulated Amortization of Electric Utility Plant - Intangibles	- 84,536,557	-84,537						
		296,150,895	296,151	-	-	296,151	296,151	-	
Deferred tax assets	1495_Deferred Taxes - Non-Current Assets	32,385,644	32,386	-	-	32,386	57,042	24,656	Note 2
Other assets	1460_Other Non-Current Assets	3,987,240	3,987	-	-	3,987	2,982	-1,005	Note 1
Regulatory balances	1508_Other Regulatory Assets	158,766,321	158,766						
	1520_Power Purchase Variance Account	-	-						
	1521_Special Purpose Chg Assessment Variance Account	-	-						
	1533_Renewable Generation Connection Funding Adder Deferral Account	- 2,427,009	-2,427						
	1550_Low Voltage Variance Acct	714,420	714						
	1551_Smart Metering Entity Charge Variance Acct	- 489,957	-490						
	1555_Smart Meter Capital Offset Variance	7,535,784	7,536						
	1556_Smart Meter Operating Variance	-	-						
	1562_Deferred Payments in Lieu of Taxes	-	-						
	1563_Deferred PILs Contra Account	-	-						
	1568_LRAM Variance Account	16,272,081	16,272						
	1575_IFRS-UGAAP Transitional PPE Amounts	12,431,316	12,431						
	1580_RSVAWMS	- 49,829,210	-49,829						
	1584_RSVANW	- 8,471,333	-8,471						
	1586_RSVACN	- 22,014,588	-22,015						
	1588_RSVAPOWER	- 8,354,608	-8,355						
	1589_RSVAGA	44,040,688	44,041						
	1592_PILs and Tax Variance for 2006 and Subsequent Years	- 0	-0						
	1595_Disposition Recovery Reg Balances Control Acct	51,509,248	51,509						
		199,683,155	199,683	-	-	199,683	200,030	346	Note 3
Total Assets		5,136,018,830	5,136,019	64,952	-36,149	5,164,821	5,187,814	22,993	
Liabilities and Equity									
Joint Bank indebtedness	2225_Notes and Loans Payable	- 156,716,639	-156,717	-	31,691	-125,026	-125,026	-	
Advance from related party		-	-	-	-	-	-	-	
Accounts payable and accrued liabilities	2205_Accounts Payable	- 434,815,015	-434,815						
	2208_Customer Credit Balances	- 16,484,303	-16,484						
	2220_Miscellaneous Current and Accrued Liabilities	- 17,477,970	-17,478						
	2240_Accounts Payable to Associated Companies Notes	- 22,739,630	-22,740						
	2250_Debt Retirement Charges(DRC) Payable	- 8,129,135	-8,129						
	2290_Commodity Taxes	- 3,102,310	-3,102						
	2292_Payroll Deductions / Expenses Payable	- 7,370,143	-7,370						
		- 510,118,505	-510,119	-7,772	4,458	-513,432	-513,432	-0	
Income tax payable	2294_Accrual for Taxes Payments in Lieu of Taxes Etc.	- 8,661,391	-8,661	-		-8,661	-12,468	-3,807	Note 4
Customer deposits	2210_Customer Deposits	- 49,218,946	-49,219			-49,219	-49,219		
Deferred revenue	2220_Miscellaneous Current and Accrued Liabilities	- 838,273	-838	-		-838			
	2210_Customer Deposits	- 4,938,272	-4,938			-4,938			
		- 5,776,546	-5,777	-	-	-5,777	-9,877	-4,100	Note 5
Deferred conservation credit		0	-	-9,274		-9,274	-9,274	-	
Other liabilities	2285_Obligations Under Finance Leases--Current	- 1,476,064	-1,476			-1,476			
	2220_Miscellaneous Current and Accrued Liabilities	- 54,792	-55			-55			
		- 1,530,856	-1,531	-	-	-1,531	-1,531	-	
Notes payable to related party	2242_ Payable to Associated Companies	- 60,000,002	-60,000			-60,000	-60,000		
	2260_Current Portion of Long Term Debt	-	-	-		-	-		
			-						
		- 60,000,002	-60,000	-	-	-60,000	-60,000	-	
Notes payable to related party	2550_Advances from Associated Companies	- 2,029,892,220	-2,029,892			-2,029,892	-2,029,892	0	
	2505_Debentures Outstanding - Long Term Portion	-	-			-	-	-	
		- 2,029,892,220	-2,029,892	-	-	-2,029,892	-2,029,892	0	

Toronto Hydro-Electric System Limited - 2.1.13
Balance Sheet
December 31, 2017

Filing: April 30, 2018

		Regulated 2017 Actual OEB Acct TB	Regulated 2017 Actual (in thousands)	Unregulated 2017 Actual (in thousands)	Consol Adj 2017 Actual (in thousands)	Calculated THESL Consol 2017 Actual (in thousands)	Audited THESL Consol 2017 Actual (in thousands)	Diff	Comment
Assets									
Current Assets									
Customer deposits	2335_Non-Current Customer Deposits	- 8,936,138	-8,936			-8,936	-8,936	-	
Deferred revenue	2440_Deferred Revenues	- 158,039,186	-158,039			-158,039			
	2320_Other Miscellaneous Non-Current Liabilities	-	-			-			
	2335_Non-Current Customer Deposits	- 24,822,672	-24,823			-24,823			
		- 182,861,858	-182,862	-	-	-182,862	-178,761	4,100	Note 5
Post-employment benefits	2306_POEB Liability	- 311,560,000	-311,560	-1,410		-312,970	-312,970	0	
Other liabilities	2325_Obligations Under Finance Lease--Non-Current	-	-			-			
	2320_Other Miscellaneous Non-Current Liabilities	- 15,555,997	-15,556			-15,556			
		- 15,555,997	-15,556	-	-	-15,556	-205	15,351	Note 6
Total Liabilities		- 3,340,829,098	-3,340,829	-18,456	36,149	-3,323,136	-3,311,592	11,544	
Share Capital	3005_Common Shares Issued	- 527,816,668	-527,817	-28,461		-556,278	-556,278	0	
Retained Earnings	3045_Unappropriated Retained Earnings	- 1,307,237,327	-1,307,237						
	3046_Balance Transferred From Income	- 144,669,212	-144,669						
	3049_Dividends Payable-Common Shares	323,626,000	323,626						
	3055_Adjustment to Retained Earnings	- 5,969,175	-5,969						
		- 1,134,249,713	-1,134,250	-18,035	-	-1,152,285	-1,147,176	5,108	Note 7
Contributed Surplus	3010_Contributed Surplus	- 12,757,392	-12,757			-12,757	-12,757	-	
Regulatory balances	1508_Other Regulatory Assets	- 78,674,761	-78,675						
	1595_Disposition Recovery Reg Balances Control Acct	- 9,305,552	-9,306						
	2350_Deferred Tax - Non-Current Liability	- 32,385,645	-32,386						
		- 120,365,958	-120,366	-	-	-120,366	-160,011	-39,645	Note 8
Total liabilities, equity and regulatory balances		- 5,136,018,830	-5,136,019	-64,952	36,149	-5,164,821	-5,187,814	-22,993	
		-	-	-	-	-	-	-0	

Toronto Hydro-Electric System Limited - 2.1.13 Filing: April 30, 2018
Balance Sheet
December 31, 2017

Notes: The Uniform System of Account balances are mapped and reconciled to the audited financial statements (AFS) (in dollars thousands).

Note 1: This relates to the CIR Costs Deferral re-instatement on the Balance Sheet.
For OSC purposes, as a result of the OEB's Decision with regards to the DRO, the CIR costs were considered no longer recoverable, and as such it was considered impaired and written-off to the P&L.
For RRR purposes, since the CIR Costs were approved to be recovered over the 5 year term in the original OEB Decision on December 29, 2015 with regards to the 2015-2019 CIR Application, the
CIR costs were re-instated on the balance sheet and will be amortized over the 5 years. The current portion and the long-term portion of the re-instated CIR costs on the balance sheet was $1,005 and $1,005 respectively.

Note 2: Difference in "Deferred tax assets" of $24,656: Calculated balance of $32,386 & AFS balance of $57,042, a difference of $24,656, as follows:
a. The deferred tax balance related to regulatory balances and gross up in respect of deferred tax assets are recorded in regulatory balances in accordance with IFRS 14 for AFS.
For purposes of RRR reporting, these balances are reclassified to deferred tax assets in the amount of $26,263.
b. For purposes of RRR reporting, an adjustment was made to remove deferred income tax asset in respect of the non-rate regulated assets in the amount of ($1,607).

Note 3: Difference in "Regulatory balances - deferred debits" of $346: Calculated balance of $199,683 & AFS balance of $200,030, a difference of $346,
is due to balances considered regulatory balances for the AFS but not for the purpose of RRR reporting in accordance with APH.

Note 4: Difference in "Income tax payable" of ($3,807): Calculated balance of ($8,661) & AFS balance of ($12,468), a difference of ($3,807), as follows:
The difference represents the non-regulated business income tax payable included in the AFS.

Note 5: Difference in "Deferred revenue - current", offset by difference in "Deferred revenue - long-term" of $4,100 as follows:
For the AFS the Deferred revenue was split between current and long-term. For the RRR purposes, the Deferred revenue is not split between current and long-term.

Note 6: Difference in "Other liabilities" of $15,351: Calculated balance of ($15,556) & AFS balance of ($205), a difference of $15,351, primarily related to
a deferral of gain on sale of surplus property in a regulatory account for the AFS and recorded as miscellaneous liability for RRR reporting and deferral
of excess expansion deposits withholdings in a regulatory account for the AFS and recorded as miscellaneous liability for RRR reporting.

Note 7: Difference in "Retained Earnings" of $5,108: Calculated balance of ($1,152,285) & AFS balance of ($1,147,176), a difference of $5,108.
Adjustments have been made to certain AFS income statement items to arrive at the RRR reporting as follows:

A. Adjustments made to certain AFS income statement items in prior years as follows:

a. Reduction for prior years' AFS Distribution revenue booked for Smart Meter "net revenue requirement" on the disposition of Account 1555 "Smart Meter Capital & Recovery" and 1556 "Smart Meter OM&A Variance account" balances. The amount is recorded to Distribution revenue for RRR reporting, to OEB account 4080 as the amount is billed to THESL customers in the future.	- 2,092
b. For purposes of RRR reporting, an adjustment was made to remove deferred income tax asset in respect of the non-rate regulated assets related to prior year.	2,236
c. This relates to the reversal of the Account 1575 IFRS-GAAP Transitional PP&E Return on Rate Base. For RRR purposes, as per the APH, Article 510, "The return on rate base shall not be recorded in this account. On disposition of the account balance, the return is applied prospectively in rates as an adjustment to the revenue requirement." In the AFS, the return on rate base was accrued at year-end 2015 since the OEB approved the disposition of Account 1575 with the return on rate base of $4,755k. As such, for 2015 RRR purposes, the $4,755k accrual was reversed. As such, in the AFS, the disposition of the account 1575 includes offsetting entries on the balance sheet related to the disposition of the return on rate base, whereas for RRR purposes, the collection of the return on rate base is recorded in the income statement in accordance with the OEB's Accounting Procedures Handbook Guidance - March 2015 - #6.	- 3,806
d. This relates to the CIR Costs Deferral re-instatement on the Balance Sheet. For OSC purposes, as a result of the OEB's Decision with regards to the DRO, the CIR costs were considered no longer recoverable, and as such it was considered impaired and written-off to the P&L. For RRR purposes, since the CIR Costs were approved to be recovered over the 5 year term in the original OEB Decision on December 29, 2015 with regards to the 2015-2019 CIR Application, the CIR costs were re-instated on the balance sheet and will be amortized over the 5 years.	3,015
e. The difference represents the non-regulated business current income tax expense included in the AFS.	- 361

B. Adjustments made to certain AFS income statement items in 2017, with these differences as explained in the Income Statement attached.

a. The total impact on net income or difference for the year 2017 was $6,116, per the Income Statement attached.	6,116
Total difference:	5,108

Note 8: Difference in "Regulatory balances - deferred credits" of ($39,645): Calculated balance of ($120,366) & AFS balance of ($160,011), a difference of ($39,645), as follows:

a. The deferred tax balance related to regulatory balances and gross up in respect of deferred tax assets are recorded in regulatory balances in accordance with IFRS 14 for AFS. For purposes of RRR reporting, these balances are reclassified to deferred tax assets.

b. Deferral of gain on sale of surplus property in a regulatory account for the AFS and recorded as miscellaneous liabilities for RRR reporting.

c. Deferral of excess expansion deposit withholdings in a regulatory account for the AFS and recorded as miscellaneous liabilities for RRR reporting.

Toronto Hydro-Electric System Limited - 2.1.13

Filing: April 30, 2018

Statement of Income
December 31, 2017

		Regulated 2017 Actual OEB Acct TB	Regulated 2017 Actual (in thousands)	Unregulated 2017 Actual (in thousands)	Net Movement Adj 2017 Actual (in thousands)	Consol Adj 2017 Actual (in thousands)	Calculated THESL Consol 2017 Actual (in thousands)	Audited THESL Consol 2017 Actual (in thousands)	Diff	Comment
Revenue										
Energy sales	4006_Residential Energy Sales	-474,760,705	- 474,761							
	4010_Commercial Energy Sales	-1,569,021,325	- 1,569,021							
	4020_Energy Sales to Large Users	-181,584,398	- 181,584							
	4025_Street Lighting Energy Sales	-19,279,286	- 19,279							
	4035_General Energy Sales	-251,021,568	- 251,022							
	4050_Revenue Adjustment	39,210,601	39,211							
	4062_Billed WMS	-100,285,375	- 100,285							
	4066_Billed NW	-151,982,231	- 151,982							
	4068_Billed CN	-113,435,813	- 113,436							
	4075_Billed LV	0	-							
		-2,822,160,099	- 2,822,160	-	- 28,013	-	- 2,850,173	- 3,017,754	- 167,581	Note 1
Distribution revenue	4080_Distribution Services Revenue	-679,157,674	- 679,158		- 48,578	-	- 727,736	- 724,154	3,582	Note 2
		-3,501,317,774	- 3,501,318	-	- 76,591	-	- 3,577,909	- 3,741,908	- 163,999	
Other income	4082_Retail Services Revenues	-289,666	- 290							
	4084_Service Transaction Requests (STR) Revenues	-14,835	- 15							
	4086_SSS Administration Revenue	-2,269,960	- 2,270							
	4090_Electric Services Incidental to Energy Sales	0	-							
	4210_Rent from Electric Property	-14,763,364	- 14,763							
	4215_Other Utility Operating Income	-1,564,164	- 1,564							
	4220_Other Electric Revenues	-9,229,601	- 9,230							
	4225_Late Payment Charges	-3,696,196	- 3,696							
	4235_Miscellaneous Service Revenues	-7,179,528	- 7,180							
	4245_ Government Assistance Directly Credited to Income	-4,710,955	- 4,711							
	4325_Revenues from Merchandise Jobbing Etc.	-31,227,688	- 31,228							
	4310_Regulatory Credits	-6,583,043	- 6,583							
	4330_Costs and Expenses of Merchandising Jobbing Etc.	29,913,621	29,914							
	4076_Billed Smart Metering Entity Charge	-7,066,705	- 7,067							
		-58,682,082	- 58,682	- 16,536	- 5,236	-	- 80,454	- 96,718	- 16,264	Note 3
Costs										
Energy purchases	4705_Power Purchased	1,172,692,119	1,172,692							
	4707_Charges - Global Adjustment	1,283,764,561	1,283,765							
	4708_Charges-WMS	71,671,510	71,672							
	4714_Charges-NW	151,982,231	151,982							
	4716_Charges-CN	113,435,813	113,436							
	4730_Rural Rate Assistance Expense	28,613,864	28,614							
	4750_Charges LV	0	-							
		2,822,160,099	2,822,160	-	73,744	-	2,895,904	3,063,485	167,581	Note 4
Operating expenses	4380_Expenses of Non-Rate Regulated Operations	5,249,117	5,249							
	4398_Foreign Exchange Gains and Losses Including Amortization	-54,784	- 55							
	5005_Distribution Operation Supervision and Engineering	24,069,938	24,070							
	5010_Distribution Load Dispatching	7,710,962	7,711							
	5012_Station Buildings and Fixtures Expense	0	-							
	5014_Transformer Station Equipment - Operation Labour	453,547	454							
	5015_Transformer Station Equipment - Operation Supplies and Expenses	10,034	10							
	5016_Distribution Station Equipment - Operation Labour	2,624,503	2,625							
	5017_Distribution Station Equipment - Operation Supplies and Expenses	5,712,912	5,713							
	5020_Overhead Distribution Lines and Feeders - Operation Labour	740,680	741							
	5025_Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1,441,347	1,441							
	5035_Overhead Distribution Transformers- Operation	0	-							
	5040_Underground Distribution Lines and Feeders - Operation Labour	529,753	530							
	5045_Underground Distribution Lines & Feeders - Operation Supplies & Expenses	2,470,332	2,470							
	5055_Underground Distribution Transformers - Operation	1,027	1							
	5065_Meter Expense	617,716	618							
	5070_Customer Premises - Operation Labour	1,345,682	1,346							
	5075_Customer Premises - Materials and Expenses	797,487	797							
	5085_Miscellaneous Distribution Expense	6,414,401	6,414							
	5105_Maintenance Supervision and Engineering	13,822,661	13,823							
	5110_Maintenance of Buildings and Fixtures - Distribution Stations	14,996,119	14,996							
	5112_Maintenance of Transformer Station Equipment	361,379	361							
	5114_Maintenance of Distribution Station Equipment	3,125,251	3,125							
	5120_Maintenance of Poles Towers and Fixtures	512,564	6							
	5125_Maintenance of Overhead Conductors and Devices	16,295,974	17,041							

Toronto Hydro-Electric System Limited - 2.1.13

Filing: April 30, 2018

Statement of Income
December 31, 2017

		Regulated 2017 Actual OEB Acct TB	Regulated 2017 Actual (in thousands)	Unregulated 2017 Actual (in thousands)	Net Movement Adj 2017 Actual (in thousands)	Consol Adj 2017 Actual (in thousands)	Calculated THESL Consol 2017 Actual (in thousands)	Audited THESL Consol 2017 Actual (in thousands)	Diff	Comment
	5130_Maintenance of Overhead Services	242,870	4							
	5135_Overhead Distribution Lines and Feeders - Right of Way	3,331,822	3,332							
	5145_Maintenance of Underground Conduit	3,880	4							
	5150_Maintenance of Underground Conductors and Devices	7,525,324	7,525							
	5155_Maintenance of Underground Services	3,919	4							
	5160_Maintenance of Line Transformers	0	-							
	5165_Maintenance of Street Lighting and Signal Systems	4,147,502	4,148							
	5305_Supervision	198,911	199							
	5310_Meter Reading Expense	3,872,325	3,872							
	5315_Customer Billing	10,125,184	10,125							
	5320_Collecting	15,411,600	15,412							
	5335_Bad Debt Expense	5,299,255	5,299							
	5410_Community Relations - Sundry	0	-							
	5415_Energy Conservation	0	-							
	5420_Community Safety Program	2,307,166	2,307							
	5605_Executive Salaries and Expenses	5,466,485	5,466							
	5610_Management Salaries and Expenses	0	-							
	5615_General Administrative Salaries and Expenses	52,815,260	52,815							
	5620_Office Supplies and Expenses	3,270	3							
	5625_Administrative Expense Transferred Credit	0	-							
	5630_Outside Services Employed	7,006,111	7,006							
	5635_Property Insurance	1,527,559	1,528							
	5640_Injuries and Damages	1,585,786	1,586							
	5655_Regulatory Expenses	5,091,470	5,091							
	5660_General Advertising Expenses	0	-							
	5665_Miscellaneous General Expenses	-45	- 0							
	5675_Maintenance of General Plant	11,707,173	11,707							
	5680_Electrical Safety Authority Fees	448,895	449							
	6105_Taxes Other Than Income Taxes	5,277,110	5,277							
	6205_Donations	957,879	958							Note 9
Note to file: Shared Service Recovery - EE 9949	4375_Revenues from Non-Utility Operations	-4,829,010	- 4,829							
	4751_Charges Smart Metering Entity Chg	7,066,705	7,067							
		255,843,010	255,843	1,446	5,088	-	262,378	284,220	21,842	Note 5
Depreciation and amortization	5705_Depreciation Expense - Property Plant and Equipment	205,161,961	205,162							
	5715_Amortization of Intangibles and Other Electric Plant	23,122,849	23,123							
	4380_Expenses of Non-Rate Regulated Operations	33,367	33							
		228,318,178	228,318	590		-	228,908	222,325	- 6,583	Note 6
		-253,678,569	- 253,679	- 14,499	- 2,995	-	- 271,173	- 268,596	2,577	
Finance costs										
Interest Income	4375_Revenues from Non-Utility Operations	0	-							
	4405_Interest and Dividend Income	-9	- 0							
		-9	- 0	- 346		-	- 346	- 346	-	
Interest Expense, Long-term Debt	6030_Interest on Debt to Associated Companies	87,088,624	87,089	-			87,089	87,089	-	
Interest Expense, Other	5615_General Administrative Salaries and Expenses	2,146,774	2,147					-	-	
	5420_Community Safety Program	27,508	28					-	-	
	6035_Other Interest Expense	2,636,623	2,637			-			-	
	6040_Allowance for Borrowed Funds Used During Construction--Credit	-9,804,020	- 9,804					-	-	
		-4,993,115	- 4,993	1	- 854	-	- 5,846	- 5,846	0	
Gain on disposals of property, plant and equipment	4355_Gain on Disposition of Utility and Other Property	-515,158	- 515							
	4335_Profits and Losses from Financial Instrument Hedges	0	0							
		-515,158	- 515	-	- 9,279		- 9,794	- 9,794	-	
Income Tax Expense	6110_Income Taxes	27,039,751	27,040	-		-	27,040	30,847	3,807	Note 7
	6115_Provision for Future Income Taxes	389,265	389		13,244		13,633	13,365	- 268	Note 8
Net Income		-144,669,212	- 144,669	- 14,844	116	-	- 159,397	- 153,282	6,116	
Net movements in regulatory balances, net of tax		0			- 116		- 116	- 116	- 0	
Net income after net movements in regulatory balances		-144,669,212	- 144,669	- 14,844	0	-	- 159,513	- 153,398	6,116	

Toronto Hydro-Electric System Limited - 2.1.13 Filing: April 30, 2018
Statement of Income
December 31, 2017

Notes: The Uniform System of Account balances are mapped and reconciled to the audited financial statements (AFS) (in dollars thousands).

Note 1: Difference in "Energy sales" of ($167,581): Calculated balance of ($2,850,173) & AFS balance of ($3,017,754), a difference of ($167,581), as follows:	
For RRR Reporting, THESL booked to "Cost of Power expense" the amount of the IESO settlement invoices charge type 142, in the credit amount of $167,581.	-167,581
For the AFS, THESL book IESO settlement invoices charge type 142 to COP revenue.	
Total difference:	
Note 2: Difference in "Distribution revenue" of $3,582: Calculated balance of ($727,736) & AFS balance of ($724,154), a difference of $3,582, as follows:	
a. A "Smart meter recovery" regulatory account was booked for AFS, with AFS Distribution revenue booked on an accrual basis. This is not considered a regulatory	2,376
account for purposes of RRR reporting. The AFS Distribution revenue amount has been adjusted so the Distribution revenue booked for RRR Reporting is appropriately reflected on a cash basis.	
b. This relates to the reversal of the Account 1575 IFRS-GAAP Transitional PP&E Return on Rate Base.	1,206
For RRR purposes, as per the APH, Article 510, "The return on rate base shall not be recorded in this account. On disposition of the account balance, the return is	
applied prospectively in rates as an adjustment to the revenue requirement." In the AFS, the return on rate base was accrued at year-end 2015 since the	
OEB approved the disposition of Account 1575 with the return on rate base of $4,755. For 2015 RRR purposes, the $4,755 accrual has been reversed.	
As such, in the AFS, the disposition of the account 1575 includes offsetting entries on the balance sheet related to the disposition of the return on rate base, whereas for RRR purposes, the	
collection of the return on rate base is recorded in the income statement in accordance with the OEB's Accounting Procedures Handbook Guidance - March 2015 - #6.	
Total difference:	3,582
Note 3: Difference in "Other income" of ($16,264): Calculated balance of ($80,454) & AFS balance of ($96,718), a difference of ($16,264), as follows:	
a. Demand Billable Charges: As per AFS GAAP, THESL booked demand billable charges on a gross basis while for RRR it is reported on a net basis:	-29,914
b. Smart Metering Entity charge: As per AFS GAAP, THESL books the Smart Metering entity revenue and charge on a net basis, while for RRR it is booked on a gross basis, in the prescribed regulatory	7,067
accounts 4076 "Billed Smart Metering Entity Charge" and 4751 "Charges Smart Metering Entity Charge":	
c. As per the OEB's Accounting Procedures Handbook Guidance - March 2015 - #6, the approved disposition of the account balance for both Account 1575 and Account 1576 would be reflected	6,583
as an offset to depreciation expense over the approved amortization period." As well, based on the OEB's Accounting Procedures Handbook Guidance - March 2015 - #6, to ensure that	
only the return on rate base component is recorded in distribution revenues, the offsetting credit entry is recorded in OEB Account 4310 Regulatory Credits.	
Total difference:	-16,264
Note 4: Difference in "Energy purchases" of $167,581: Calculated balance of $2,895,904 & AFS balance of $3,063,485, a difference of $167,581, as follows:	
For RRR Reporting, THESL booked to "Cost of Power expense" the amount of the IESO settlement invoices charge type 142, in the credit amount of $167,581.	167,581
For the AFS, THESL book IESO settlement invoices charge type 142 to COP revenue.	
Note 5: Difference in "Operating expenses" of $21,842: Calculated balance of $262,378 & AFS balance of $284,220, a difference of $21,842, as follows:	
a. Demand Billable Charges: As per AFS GAAP, THESL booked demand billable charges on a gross basis while for RRR it is reported on a net basis:	29,914
b. Smart Metering Entity charge: As per AFS GAAP, THESL books the Smart Metering entity revenue and charge on a net basis, while for RRR it is booked on a gross basis, in the prescribed regulatory	-7,067
accounts 4076 "Billed Smart Metering Entity Charge" and 4751 "Charges Smart Metering Entity Charge":	
c. This relates to the CIR Costs Deferral re-instatement on the Balance Sheet.	-1,005
For OSC purposes, as a result of the OEB's Decision with regards to the DRO, the CIR costs were considered no longer recoverable, and as such it was considered impaired and written-off to the P&L.	
For RRR purposes, since the CIR Costs were approved to be recovered over the 5 year term in the original OEB Decision on December 29, 2015 with regards to the 2015-2019 CIR Application, the	
CIR costs were re-instated on the balance sheet and will be amortized over the 5 years.	
Total difference:	21,842
Note 6: Difference in "Depreciation and amortization" of ($6,583): Calculated balance of $228,908 & AFS balance of $222,325, a difference of ($6,583), as follows:	-6,583
As per the OEB's Accounting Procedures Handbook Guidance - March 2015 - #6, the approved disposition of the account balance for both Account 1575 and Account 1576 would be reflected	
as an offset to depreciation expense over the approved amortization period." As well, based on the OEB's Accounting Procedures Handbook Guidance - March 2015 - #6, to ensure that	
only the return on rate base component is recorded in distribution revenues, the offsetting credit entry is recorded in OEB Account 4310 Regulatory Credits.	
Note 7: Difference in "Income tax expense - Income taxes" of $3,807: Calculated balance of $27,040 & AFS balance of $30,847, a difference of $3,807, as follows:	3,807
The difference represents the non-regulated business current income tax expense included in the AFS.	
Note 8: Difference in "Income tax expense - Provision for deferred taxes" of ($268): Calculated balance of $13,633 & AFS balance of $13,365, a difference of ($268), as follows:	-268
For purposes of RRR reporting, an adjustment was made to remove deferred income tax asset in respect of the non-rate regulated assets.	

Note 9: Sub-account LEAP Funding included credit transfer of $9,886.51 applied to customers in 2017 and paid to social service agency in 2018.



FINANCIAL REPORT
DECEMBER 31, 2017

TORONTO HYDRO CORPORATION

TABLE OF CONTENTS

Glossary	3
Management's Discussion and Analysis	4
Executive Summary	5
Introduction	5
Business of Toronto Hydro Corporation	6
Electricity Distribution – Industry Overview	7
Results of Operations	8
Summary of Quarterly Results of Operations	15
Financial Position	16
Liquidity and Capital Resources	17
Corporate Developments	22
Legal Proceedings	24
Share Capital	24
Transactions with Related Parties	25
Controls and Procedures	25
Risk Management and Risk Factors	26
Critical Accounting Estimates	32
Significant Accounting Policies	32
Changes in Accounting Policies	32
Future Accounting Pronouncements	32
Forward-Looking Information	33
Selected Annual Information	36
Additional Information	36
Consolidated Financial Statements	37
Notes to the Consolidated Financial Statements	44

GLOSSARY

CDM – Conservation and demand management

CGU – Cash generating unit

CIR – Custom Incentive Rate-setting

City – City of Toronto

Copeland Station – The Clare R. Copeland transformer station, formerly called "Bremner Station".

Corporation – Toronto Hydro Corporation

Electricity Act – *Electricity Act, 1998* (Ontario), as amended

ERM – Enterprise risk management

ERP – Enterprise resource planning

GAAP – Generally Accepted Accounting Principles

GWh – Gigawatt hour

HONI – Hydro One Networks Inc.

IAS – International Accounting Standard

IASB – International Accounting Standards Board

ICM – Incremental Capital Module

IESO – Independent Electricity System Operator. The IESO and the Ontario Power Authority were merged under the name Independent Electricity System Operator on January 1, 2015

IFRIC – International Financial Reporting Interpretations Committee

IFRS – International Financial Reporting Standards

IRM – Incentive Regulation Mechanism

ITA – *Income Tax Act* (Canada), as amended

kW – Kilowatt

LDC – Toronto Hydro-Electric System Limited

LRAM – Lost revenue adjustment mechanism

MD&A – Management's Discussion and Analysis

MEU – Municipal electricity utility

OCI – Other comprehensive income

OEB – Ontario Energy Board

OEB Act – *Ontario Energy Board Act, 1998* (Ontario), as amended

OFHP – Ontario's Fair Hydro Plan

OFHA – *Fair Hydro Act, 2017* (Ontario)

OMERS – Ontario Municipal Employees Retirement System

OPA – Ontario Power Authority. The IESO and the OPA were merged under the name Independent Electricity System Operator on January 1, 2015

OPEB – Other post-employment benefits

OREC – *Ontario Rebate for Electricity Consumers Act*, 2016 (Ontario).

PILs – Payments in lieu of corporate taxes

PP&E – Property, plant and equipment

TA – *Taxation Act, 2007* (Ontario), as amended

TH Energy – Toronto Hydro Energy Services Inc.

US GAAP – United States Generally Accepted Accounting Principles

WMS – Wholesale Market Service



MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE YEARS ENDED DECEMBER 31, 2017 AND 2016

Executive Summary

- Net income after net movements in regulatory balances for the three months and year ended December 31, 2017 was $35.1 million and $156.5 million, respectively, compared to $23.4 million and $151.4 million for the comparable periods in 2016;
- Capital expenditures were primarily related to the renewal of the electricity infrastructure of LDC and were $148.9 million and $552.9 million for the three months and year ended December 31, 2017, respectively, compared to $149.2 million and $551.7 million for the comparable periods in 2016;
- On June 28, 2017, the Corporation issued 200 common shares to the City for total proceeds of $250.0 million, net of share issue costs and expenses;
- On August 23, 2017, LDC filed its 2018 rate application seeking OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2018 and ending on December 31, 2018. On December 14, 2017, the OEB issued a decision and rate order approving LDC's 2018 rates and the disposition of certain deferral and variance accounts;
- On November 14, 2017, the Corporation issued $200.0 million of 3.485% senior unsecured debentures due February 28, 2048;
- The Corporation's Series 2 debentures in the amount of $250.0 million, matured and were repaid on November 14, 2017; and
- Under the terms of the energy conservation agreement with the IESO for the delivery of CDM programs over the 2015 – 2020 period, the Corporation is entitled to a performance incentive if the verified mid-term electricity savings target is achieved by December 31, 2017. The Corporation exceeded the mid-term energy savings target and recognized a performance incentive of $12.2 million.

Introduction

This MD&A should be read in conjunction with the Corporation's audited consolidated financial statements and accompanying notes as at and for the years ended December 31, 2017 and 2016, which were prepared in accordance with IFRS (the "Consolidated Financial Statements").

Copies of these documents are available on the System for Electronic Document Analysis and Retrieval website at www.sedar.com.

Business of Toronto Hydro Corporation

The Corporation is a holding company which wholly owns two subsidiaries:

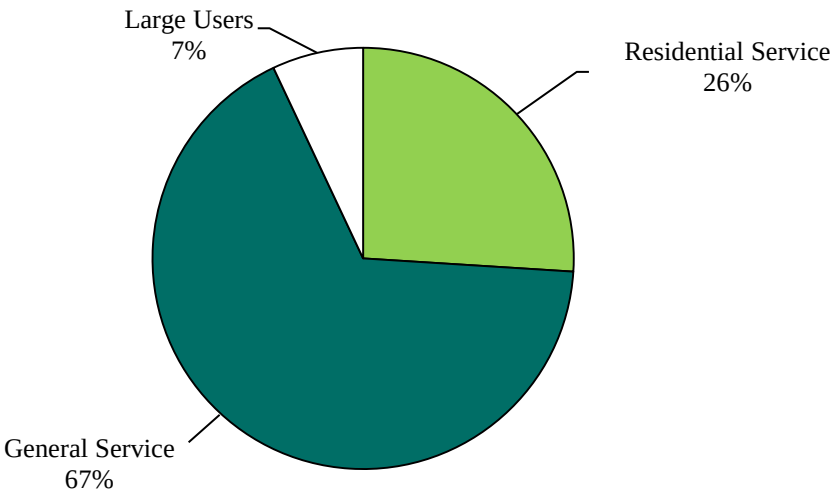
- LDC - distributes electricity and engages in CDM activities; and
- TH Energy - provides street lighting and expressway lighting services in the City.

The Corporation supervises the operations of, and provides corporate, management services and strategic direction to its subsidiaries.

The principal business of the Corporation and its subsidiaries is the distribution of electricity by LDC. LDC owns and operates an electricity distribution system, delivering electricity to approximately 768,000 customers located in the City. The City is the sole shareholder of the Corporation. LDC serves the largest city in Canada and distributes approximately 19% of the electricity consumed in Ontario. The business of LDC and other electricity distributors is regulated by the OEB, which has broad powers relating to licensing, standards of conduct and service, and the regulation of electricity distribution rates charged by LDC and other electricity distributors in Ontario. For the year ended December 31, 2017, LDC earned energy sales and distribution revenues of $3,742.0 million from general service users[1], residential service users[2] and large users[3].

LDC Energy Sales and Distribution Revenues by Class

Year ended December 31, 2017



[1] "general service" means a service supplied to premises other than those receiving "residential service" and "large users" and typically includes small businesses and bulk-metered multi-unit residential establishments. This service is provided to customers with a monthly peak demand of 5,000 kW or less averaged over a twelve-month period.

[2] "residential service" means a service that is for domestic or household purposes, including single family or individually metered multi-family units and seasonal occupancy.

[3] "large users" means a service provided to a customer with a monthly peak demand of more than 5,000 kW averaged over a twelve-month period.

Electricity Distribution – Industry Overview

In April 1999, the Government of Ontario began restructuring the province's electricity industry. Under regulations passed pursuant to the restructuring, LDC and other electricity distributors purchase electricity from the wholesale market administered by the IESO and recover the costs of electricity and certain other costs from customers in accordance with rate-setting procedures mandated by the OEB.

The OEB has regulatory oversight of electricity matters in Ontario. The OEB Act sets out the OEB's authority to issue a distribution licence that must be obtained by owners or operators of an electricity distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, separation of accounts for distribution and other activities, and requirements for rate-setting and other legal filings.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to approve the amounts paid to non-contracted generators, the responsibility to provide rate protection for rural or remote electricity customers, and the responsibility for ensuring that electricity distribution companies fulfill their obligations to connect and service customers.

LDC is required to charge its customers for the following amounts (all of which, other than distribution rates, represent a pass-through of amounts payable to third parties):

- *Commodity Charge* – The commodity charge represents the market price of electricity consumed by customers and is passed through the IESO back to operators of generating stations. It includes the global adjustment, which represents the difference between the market price of electricity and the rates paid to regulated and contracted generators.

- *Retail Transmission Rate* – The retail transmission rate represents the costs incurred in respect of the transmission of electricity from generating stations to local distribution networks. Retail transmission rates are passed through back to operators of transmission facilities.

- *WMS Charge* – The WMS charge represents various wholesale market support costs, such as the cost of the IESO to administer the wholesale electricity system, operate the electricity market, and maintain reliable operation of the provincial grid. Wholesale charges are passed through back to the IESO.

- *Distribution Rate* – The distribution rate is designed to recover the costs incurred by LDC in delivering electricity to customers, including the OEB-allowed cost of capital. Distribution rates are regulated by the OEB and include fixed and variable (usage-based) components, based on a forecast of LDC's customers and load.

LDC is required to satisfy and maintain prudential requirements with the IESO, which include credit support with respect to outstanding market obligations in the form of letters of credit, cash deposits or guarantees from third parties with prescribed credit ratings.

The Corporation is exempt from tax under the ITA if not less than 90% of the capital of the Corporation is owned by the City and not more than 10% of the income of the Corporation is derived from activities carried on outside the municipal geographical boundaries of the City. In addition, the Corporation's subsidiaries are also exempt from tax under the ITA provided that all of their capital is owned by the Corporation and not more than 10% of their respective income is from activities carried on outside the municipal geographical boundaries of the City. A corporation exempt from tax under the ITA is also exempt from tax under the TA.

The Corporation and each of its subsidiaries are MEUs for purposes of the PILs regime contained in the Electricity Act. The Electricity Act provides that a MEU that is exempt from tax under the ITA and the TA is required to make, for each taxation year, a PILs payment to the Ontario Electricity Financial Corporation in an amount equal to the tax that it would be liable to pay under the ITA and the TA if it were not exempt from tax. The PILs regime came into effect on October 1, 2001, at which time the Corporation and each of its subsidiaries were deemed to have commenced a new taxation year for purposes of determining their respective liabilities for PILs payments.

Results of Operations

Net Income after Net Movements in Regulatory Balances

Interim Consolidated Statements of Income
Three months ended December 31
(in millions of Canadian dollars)

	2017 $	2016 $	Change $
Revenues			
Energy sales	728.9	813.3	(84.4)
Distribution revenue	181.7	159.0	22.7
Other	27.7	22.0	5.7
	938.3	994.3	(56.0)
Expenses			
Energy purchases	750.7	782.6	31.9
Operating expenses	77.8	78.6	0.8
Depreciation and amortization	62.0	59.6	(2.4)
	890.5	920.8	30.3
Finance costs	(18.9)	(19.5)	0.6
Gain on disposals of PP&E	0.2	2.1	(1.9)
Income before income taxes	29.1	56.1	(27.0)
Income tax expense	(11.1)	(28.0)	16.9
Net income	18.0	28.1	(10.1)
Net movements in regulatory balances	10.9	(30.6)	41.5
Net movements in regulatory balances arising from deferred tax assets	6.2	25.9	(19.7)
Net income after net movements in regulatory balances	35.1	23.4	11.7

The increase in net income after net movements in regulatory balances for the three months ended December 31, 2017 was primarily due to higher 2017 electricity distribution rates, higher electricity consumption, and higher other revenue related to the recognition of the CDM mid-term incentive and pole and duct rentals. These variances were partially offset by amounts being deferred into capital related regulatory accounts for future refunds to customers, higher income taxes (including regulatory balances arising from deferred tax assets), and higher depreciation and amortization related to new in-service asset additions.

Consolidated Statements of Income
Year ended December 31
(in millions of Canadian dollars)

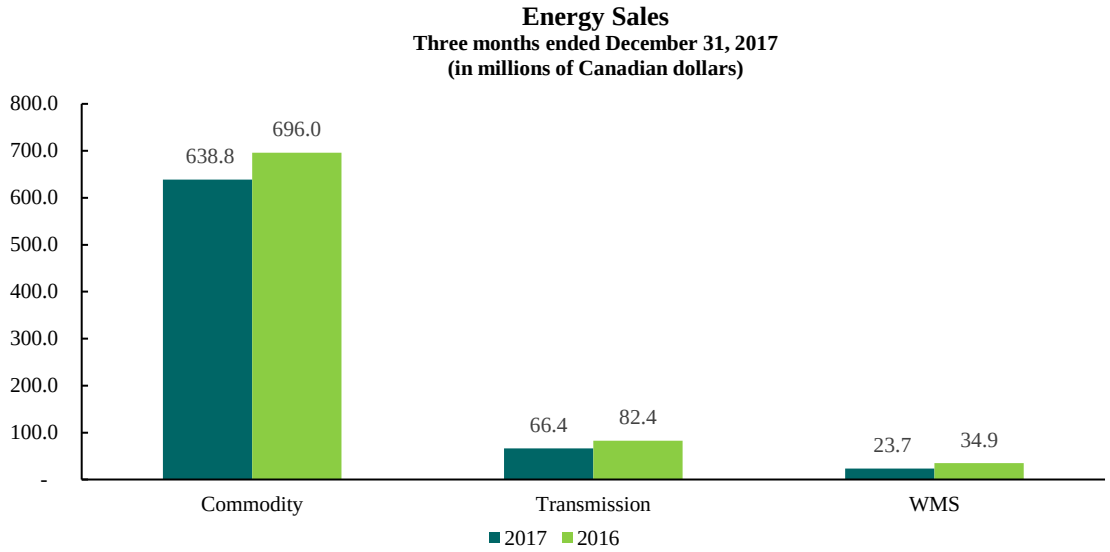
	2017 $	2016 $	Change $
Revenues			
Energy sales	3,017.8	3,306.2	(288.4)
Distribution revenue	724.2	647.9	76.3
Other	107.7	75.9	31.8
	3,849.7	4,030.0	(180.3)
Expenses			
Energy purchases	3,063.5	3,216.9	153.4
Operating expenses	293.0	277.1	(15.9)
Depreciation and amortization	224.2	212.2	(12.0)
	3,580.7	3,706.2	125.5
Finance costs	(77.7)	(74.2)	(3.5)
Gain on disposals of PP&E	9.8	2.1	7.7
Income before income taxes	201.1	251.7	(50.6)
Income tax expense	(44.7)	(67.1)	22.4
Net income	156.4	184.6	(28.2)
Net movements in regulatory balances	(13.1)	(77.2)	64.1
Net movements in regulatory balances arising from deferred tax assets	13.2	44.0	(30.8)
Net income after net movements in regulatory balances	156.5	151.4	5.1

The increase in net income after net movements in regulatory balances for the year ended December 31, 2017 was primarily due to higher 2017 electricity distribution rates and higher other revenue related to the recognition of the CDM mid-term incentive and pole and duct rentals. These variances were partially offset by lower electricity consumption, higher operating expenses in connection with system maintenance, higher depreciation and amortization related to new in-service asset additions, higher income taxes (including regulatory balances arising from deferred tax assets), amounts being deferred into capital related regulatory accounts for future refunds to customers, and a one-time residual ICM balance recorded as an increase in equity through net movements in regulatory balances in 2016. The 2016 first quarter implementation of the new electricity distribution rates also resulted in $19.2 million of foregone revenue being recorded in net movements in regulatory balances for the comparable period, instead of distribution revenue given IFRS 14 - *Regulatory Deferral Accounts* ("IFRS 14") treatment.

Energy Sales

LDC's energy sales arise from charges to customers for electricity consumed, based on regulated rates. Energy sales include amounts billed or billable to customers for commodity charges, retail transmission charges, and WMS charges at current rates. These charges are passed through to customers over time and are considered revenue by LDC. During the same period, energy sales should be equal to the cost of energy purchased. However, a difference between energy sales and energy purchases arises when there is a timing difference between the amounts charged by LDC to customers, based on regulated rates, and the electricity and non-competitive electricity service costs billed monthly by the IESO to LDC. This difference is recorded as a settlement variance, representing amounts to be recovered from or refunded to customers through future rates approved by the OEB. In accordance with IFRS 14, this settlement variance is presented within regulatory balances on the consolidated balance sheets ("Consolidated Balance Sheets")

and within net movements in regulatory balances on the consolidated statements of income and comprehensive income ("Consolidated Statements of Income").



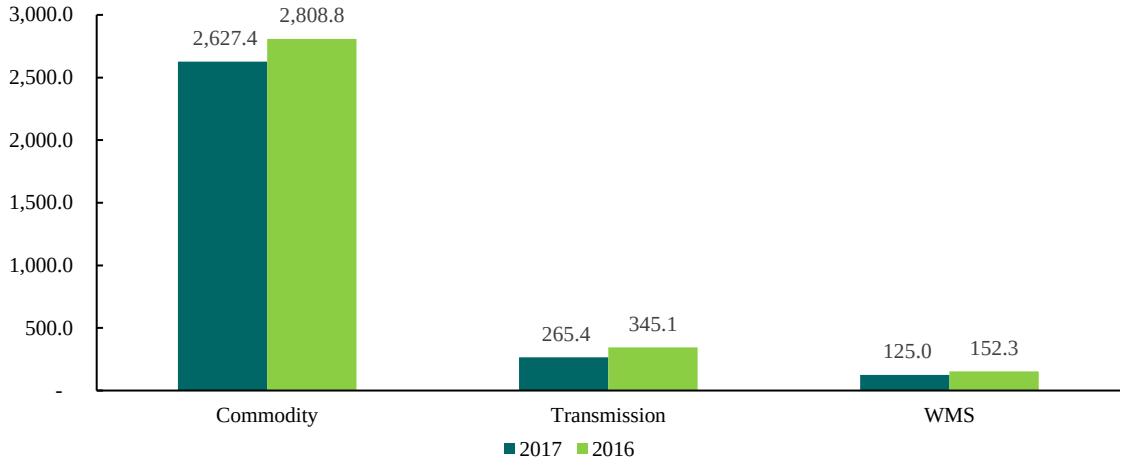
Energy sales for the three months ended December 31, 2017 were $728.9 million compared to $813.3 million for the comparable period in 2016. The decrease was primarily due to lower commodity charges ($57.2 million) and lower retail transmission charges ($16.0 million). The decrease in commodity and retail transmission charges was primarily due to lower pass-through electricity costs.

Energy Purchases , Energy Sales, and Settlement Variances
Three months ended December 31, 2017
(in millions of Canadian dollars)

	Energy Purchases $	Energy Sales $	Settlement Variances $
Commodity Charges	673.1	638.8	34.3
Retail Transmission Charges	65.2	66.4	(1.2)
WMS Charges	12.4	23.7	(11.3)
Total	750.7	728.9	21.8

For the three months ended December 31, 2017, LDC recognized $728.9 million in energy sales to customers and was billed $750.7 million for energy purchases from the IESO. The difference between energy sales and energy purchases represents a $21.8 million settlement variance for the period. The settlement variance was recorded as a decrease to the regulatory credit balance ($21.8 million including carrying charges on the accumulated settlement variance balance) on the Consolidated Balance Sheets, and presented within net movements in regulatory balances on the Consolidated Statements of Income.

Energy Sales
Year ended December 31, 2017
(in millions of Canadian dollars)



Energy sales for the year ended December 31, 2017 were $3,017.8 million compared to $3,306.2 million for the comparable period in 2016. The decrease was primarily due to lower commodity charges ($181.4 million) and lower retail transmission charges ($79.7 million). The decrease in commodity and retail transmission charges was primarily due to lower electricity consumption and lower pass-through electricity costs.

Energy Purchases, Energy Sales, and Settlement Variances
Year ended December 31, 2017
(in millions of Canadian dollars)

	Energy Purchases $	Energy Sales $	Settlement Variances $
Commodity Charges	2,681.4	2,627.4	54.0
Retail Transmission Charges	281.8	265.4	16.4
WMS Charges	100.3	125.0	(24.7)
Total	3,063.5	3,017.8	45.7

For the year ended December 31, 2017, LDC recognized $3,017.8 million in energy sales to customers and was billed $3,063.5 million for energy purchases from the IESO. The difference between energy sales and energy purchases represents a $45.7 million settlement variance for the year. The settlement variance was recorded as a decrease to the regulatory credit balance ($45.2 million including carrying charges on the accumulated settlement variance balance, see the regulatory credit balance table in note 9 to the Consolidated Financial Statements) on the Consolidated Balance Sheets, and presented within net movements in regulatory balances on the Consolidated Statements of Income.

Distribution Revenue

Distribution revenue is recorded based on OEB-approved distribution rates to recover the costs incurred by LDC in delivering electricity to customers, and includes revenue collected through OEB-approved rate riders.

Distribution revenue for the three months and year ended December 31, 2017 was $181.7 million and $724.2 million, respectively, compared to $159.0 million and $647.9 million for the comparable periods in 2016.

The increase in distribution revenue for the three months ended December 31, 2017 was primarily due to higher electricity distribution rates ($11.7 million), higher electricity consumption ($5.6 million), and additional revenue collected through OEB-approved rate riders ($5.5 million).

The increase in distribution revenue for the year ended December 31, 2017 was primarily due to higher electricity distribution rates ($48.8 million) and additional revenue collected through OEB-approved rate riders ($22.6 million), partially offset by lower electricity consumption in 2017 ($14.9 million). The remaining increase was related to the recognition of 2016 foregone revenue ($19.2 million) from the implementation of the new electricity distribution rates effective March 1, 2016, which was recorded in net movements in regulatory balances for the year ended December 31, 2016 given the IFRS 14 treatment, instead of distribution revenue.

Other Revenue

Other revenue includes revenue from services ancillary to electricity distribution, delivery of street lighting services, pole and duct rentals, amortization of deferred revenue related to capital contributions from customers, and CDM cost efficiency incentives.

Other revenue for the three months and year ended December 31, 2017 was $27.7 million and $107.7 million, respectively, compared to $22.0 million and $75.9 million for the comparable periods in 2016.

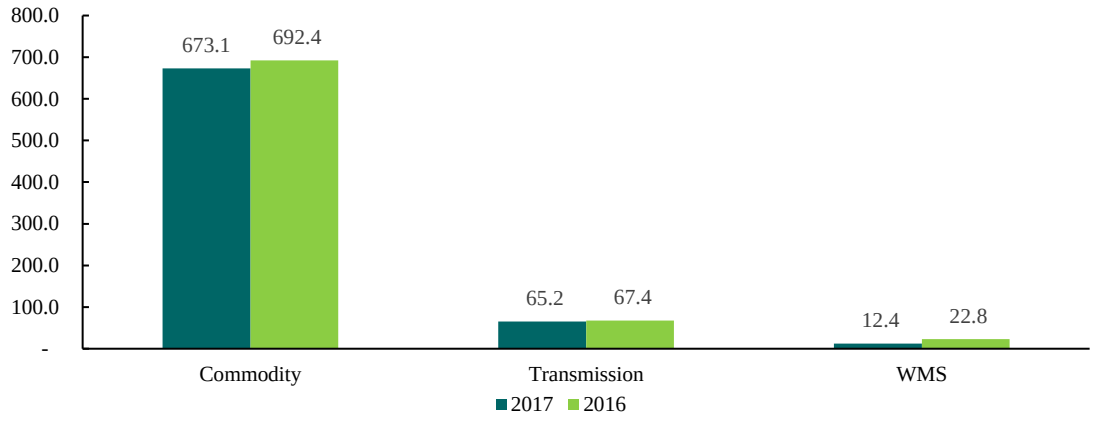
The increase was primarily due to higher revenue in connection with ancillary services, street lighting services, pole and duct rentals, recognition of the CDM mid-term incentive, and deferral of development charges. The development charges are excess expansion deposits retained by LDC where the requested number of connections or demand were not met by the connecting customer (see development charges in note 9(o) to the Consolidated Financial Statements).

The development charges were recorded as a regulatory balance on the Consolidated Balance Sheets, with a corresponding offset in net movements in regulatory balances on the Consolidated Statements of Income. This regulatory balance is expected to offset future electricity distribution rates for customers, although application has yet to be made to dispose of the balance.

Energy Purchases

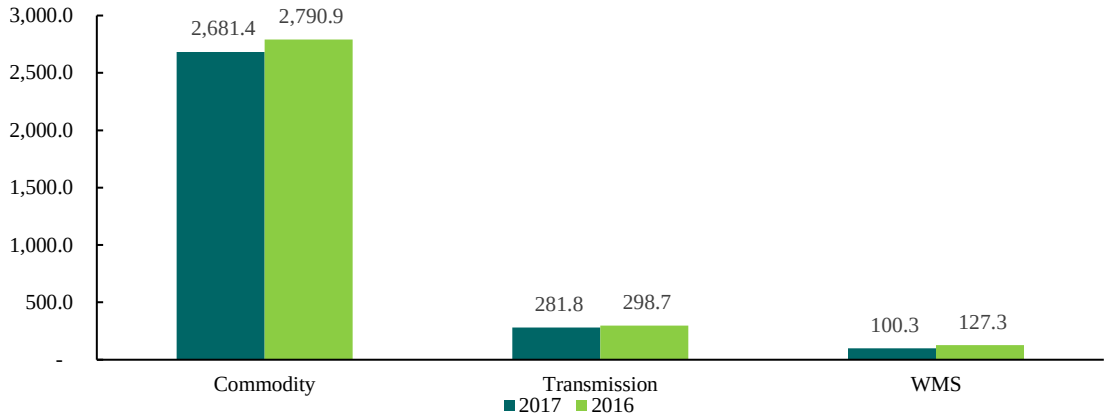
LDC's energy purchases consist of actual charges for electricity generated by third parties, which are passed through to customers over time in the form of energy sales. Energy purchases are billed monthly by the IESO and include commodity charges, retail transmission charges and WMS charges.

LDC Energy Purchases
Three months ended December 31, 2017
(in millions of Canadian dollars)



Energy purchases for the three months ended December 31, 2017 were $750.7 million compared to $782.6 million for the comparable period in 2016. The decrease was primarily due to lower commodity charges ($19.3 million) and lower WMS charges ($10.4 million). The decrease in commodity and WMS charges was primarily due to lower rates.

LDC Energy Purchases
Year ended December 31, 2017
(in millions of Canadian dollars)



Energy purchases for the year ended December 31, 2017 were $3,063.5 million compared to $3,216.9 million for the comparable period in 2016. The decrease was primarily due to lower commodity charges ($109.5 million) and lower WMS charges ($27.0 million). The decrease in commodity and WMS charges was primarily due to lower electricity consumption and lower rates.

Operating Expenses

Operating expenses for the three months and year ended December 31, 2017 were $77.8 million and $293.0 million, respectively, compared to $78.6 million and $277.1 million for the comparable periods in 2016.

The decrease in operating expenses for the three months ended December 31, 2017 was primarily due to lower street lighting maintenance costs, lower rental expenses due to expiration of rental agreements, and lower service fees for third party warehouse costs, partially offset by higher ancillary service costs.

The increase in operating expenses for the year ended December 31, 2017 was primarily due to higher costs in connection with ancillary services and system maintenance programs, partially offset by lower rental expenses due to expiration of rental agreements and lower street lighting maintenance costs.

Depreciation and Amortization

Depreciation and amortization expense for the three months and year ended December 31, 2017 was $62.0 million and $224.2 million, respectively, compared to $59.6 million and $212.2 million for the comparable periods in 2016.

The increase in depreciation and amortization expense for the three months and year ended December 31, 2017 was primarily due to new in-service asset additions in 2017, partially offset by certain assets being fully depreciated, and lower derecognition of assets removed from service.

Finance Costs

Finance costs for the three months and year ended December 31, 2017 were $18.9 million and $77.7 million, respectively, compared to $19.5 million and $74.2 million for the comparable periods in 2016.

The decrease in finance costs for the three months ended December 31, 2017 was primarily due to a lower average amount of outstanding long-term debt ($2,058.6 million) in the fourth quarter of 2017 compared with the same period in 2016 ($2,084.6 million) (see "Liquidity and Capital Resources" below).

The increase in finance costs for the year ended December 31, 2017 was primarily due to a higher average amount of outstanding long-term debt ($2,078.4 million) during 2017 compared with the same period in 2016 ($2,001.4 million) and lower capitalized borrowing costs (see "Liquidity and Capital Resources" below).

Gain on Disposals of PP&E

Gain on disposals of PP&E for the three months and year ended December 31, 2017 were $0.2 million and $9.8 million, respectively, compared to $2.1 million for the comparable periods in 2016. The increase in gain on disposals of PP&E for the year ended December 31, 2017 was primarily due to the gain realized on disposal of a surplus property in the second quarter of 2017 ($9.3 million), offset by lower gain realized on other disposals. The gain on disposal of a surplus property, net of tax of $8.0 million was recorded as a regulatory balance on the Consolidated Balance Sheets to reduce future electricity distribution rates for customers, with a corresponding offset in net movements in regulatory balances on the Consolidated Statements of Income.

Income Tax Expense and Income Tax Recorded in Net Movements in Regulatory Balances

Income tax expense and income tax recorded in net movements in regulatory balances for the three months and year ended December 31, 2017 were $4.9 million and $31.5 million, respectively, compared to $2.1 million and $23.1 million for the comparable periods in 2016.

The unfavourable variance in income tax expense and income tax recorded in net movements in regulatory balances for the three months ended December 31, 2017 was primarily due to higher income before taxes (including net movements in regulatory balances), offset by higher net deductions for permanent and temporary differences between accounting and tax treatments.

The unfavourable variance in income tax expense and income tax recorded in net movements in regulatory balances for the year ended December 31, 2017 was primarily due to higher income before taxes (including net movements in regulatory balances) and lower net deductions for permanent and temporary differences between accounting and tax treatments.

Net Movements in Regulatory Balances

In accordance with IFRS 14, the Corporation separately presents regulatory balances and related net movements on the Consolidated Balance Sheets and Consolidated Statements of Income.

The increase in the regulatory debit ($9.1 million) and the decrease in the regulatory credit ($9.4 million) balances for the year ended December 31, 2017 equals the sum ($18.5 million) of net movements in regulatory balances, net movements in regulatory balances arising from deferred tax assets, and net movements in regulatory balances related to OCI, net of tax for the relevant period (see "Financial Position" below).

Energy purchases record the actual cost of power purchased which varies from month to month. Since the selling price of power within energy sales is fixed for set periods of time, a gain or loss usually results, and is part of the calculation of net income. However, per OEB regulations, such gains or losses on energy sales are deferred within balance sheet regulatory variance accounts for later disposition to or from rate payers via rate riders after approval by the OEB. Deferrals of gains or losses on energy sales (see discussion on "settlement variance" under "Results of Operations" above), or disposition of past deferrals in electricity rates will usually represent the largest single element of the net movements in regulatory balances for a period.

Net movements in regulatory balances for the three months ended December 31, 2017 were a recovery of $10.9 million compared to a charge of $30.6 million for the comparable period in 2016. The recovery of $10.9 million for the three months ended December 31, 2017 was primarily due to the timing difference between the electricity costs billed monthly by the IESO and LDC's billing to customers, partially offset by amounts disposed through OEB approved rate riders and amounts being deferred into capital-related regulatory accounts for future refunds to customers. The charge of $30.6 million for the three months ended December 31, 2016 was primarily due to the timing difference between the electricity costs billed monthly by the IESO and LDC's billing to customers.

Net movements in regulatory balances for the year ended December 31, 2017 were a charge of $13.1 million compared to a charge of $77.2 million for the comparable period in 2016. The charge of $13.1 million for the year ended December 31, 2017 was primarily due to the timing difference between the electricity costs billed monthly by the IESO and LDC's billing to customers, partially offset by amounts disposed through OEB approved rate riders and amounts being deferred into capital-related regulatory accounts for future refunds to customers. The charge of $77.2 million for the year ended December 31, 2016 was primarily due to the timing difference between the electricity costs billed monthly by the IESO and LDC's billing to customers, partially offset by the recognition of the 2016 approved foregone revenue per the OEB's CIR decision and rate order.

Net movements in regulatory balances related to OCI, net of tax for the three months and year ended December 31, 2017 were a recovery of $18.4 million, compared to a charge of $15.5 million for the comparable periods in 2016. The recovery of $18.4 million for the three months and year ended December 31, 2017 was due to the actuarial loss recognized for post-employment benefits. The charge of $15.5 million for the three months and year ended December 31, 2016 was due to the actuarial gain recognized for post-employment benefits.

Summary of Quarterly Results of Operations

The table below presents a summary of the Corporation's results of operations for eight quarters including and immediately preceding December 31, 2017.

Summary of Quarterly Results of Operations
(in millions of Canadian dollars)

	December 31 2017 $	September 30 2017 $	June 30 2017 $	March 31 2017 $
Energy sales	728.9	817.9	721.8	749.2
Distribution revenue	181.7	186.1	178.2	178.2
Other	27.7	36.6	23.0	20.4
Revenues	938.3	1,040.6	923.0	947.8
Net income after net movements in regulatory balances	35.1	46.8	35.0	39.6
	December 31 2016 $	**September 30 2016 $**	**June 30 2016 $**	**March 31 2016 $**
Energy sales	813.3	899.9	801.1	791.9
Distribution revenue	159.0	183.3	158.8	146.8
Other	22.0	21.2	16.8	15.9
Revenues	994.3	1,104.4	976.7	954.6
Net income after net movements in regulatory balances	23.4	52.5	31.2	44.3

The Corporation's revenues, all other things being equal, are impacted by temperature fluctuations and unexpected weather conditions. Revenues would tend to be higher in the first quarter as a result of higher energy consumption for winter heating, and in the third quarter due to air conditioning/cooling. The Corporation's revenues are also impacted by fluctuations in electricity prices and the timing and recognition of regulatory decisions and rate orders.

Financial Position

The following table outlines the significant changes in the consolidated balance sheets as at December 31, 2017 as compared to the consolidated balance sheets as at December 31, 2016.

Consolidated Balance Sheet Data
(in millions of Canadian dollars)

Balance Sheet Account	Increase (Decrease) $	Explanation of Significant Change
Assets		
Accounts receivable and unbilled revenue	(54.3)	The decrease was primarily due to lower pass-through electricity costs, partially offset by the recognition of the CDM mid-term incentive receivable.
Assets held for sale	8.7	In 2017, LDC commenced the process to sell a property to a third party and subsequently entered into a sales agreement. Accordingly, the carrying amount of the property of $8.7 million was reclassified from PP&E to Assets held for sale.
PP&E and intangible assets	314.6	The increase was primarily due to capital expenditures, partially offset by depreciation and derecognition, and reclassification of assets held for sale during the year.
Deferred tax assets	(6.8)	The decrease was primarily due to lower net deductible temporary differences between tax and accounting values of PP&E and intangible assets.
Liabilities and Equity		
Commercial paper	(102.0)	The decrease was primarily due to repayment using the proceeds from the equity investment received from the City in June 2017 ($250.0 million), offset by issuances required for general corporate purposes (see "Liquidity and Capital Resources" below).
Debentures	(50.6)	The decrease was primarily due to the repayment of the Series 2 debentures ($250.0 million), partially offset by the issuance of Series 13 debentures ($200.0 million) in the fourth quarter of 2017 (see "Liquidity and Capital Resources" below).
Accounts payable and accrued liabilities	11.9	The increase was primarily due to timing differences in payments, partially offset by lower electricity costs payable to the IESO.
Deferred revenue	44.5	The increase was primarily due to capital contributions received in 2017.

Consolidated Balance Sheet Data
(in millions of Canadian dollars)

Balance Sheet Account	Increase (Decrease) $	Explanation of Significant Change
Post-employment benefits	32.5	The increase was primarily due to the recognized actuarial loss driven by the annually updated actuarial assumptions.
Retained earnings	81.5	The increase was due to net income after net movements in regulatory balances ($156.5 million) offset by dividends paid ($75.0 million).
Regulatory Balances		
Regulatory debit balances	9.1	The increase was primarily due to the OPEB actuarial loss recorded as regulatory debit balance, partially offset by amounts disposed through OEB-approved rate riders primarily related to foregone revenue.
Regulatory credit balances	(9.4)	The decrease was primarily due to balances arising in the period related to settlement variances, partially offset by amounts being deferred into capital related regulatory accounts for future refunds to customers and amounts disposed through OEB-approved rate riders.

Liquidity and Capital Resources

The Corporation's current assets and current liabilities amounted to $526.7 million and $770.5 million, respectively, as at December 31, 2017, resulting in a working capital deficit of $243.8 million. The deficit is attributable to the Corporation's preference for utilizing its Commercial Paper Program and Working Capital Facility (both defined below) before issuing additional debentures to fulfill the Corporation's ongoing liquidity requirements, including funding of significant capital spending in the current year. The Corporation seeks to maintain an optimal mix of short-term and long-term debt in order to lower overall financing costs and to enhance borrowing flexibility.

The Corporation's primary sources of liquidity and capital resources are cash provided by operating activities, issuances of commercial paper, amounts available to be drawn against its credit facilities, and borrowings from debt capital markets. The Corporation's liquidity and capital resource requirements are mainly for capital expenditures to maintain and improve the electricity distribution system of LDC, for energy purchases and to meet financing obligations. See "Liquidity Risk" under note 16 to the Consolidated Financial Statements.

The amount available under the Revolving Credit Facility and the outstanding borrowings under the Revolving Credit Facility and Commercial Paper Program are as follows:

(in millions of Canadian dollars)	Revolving Credit Facility Limit $	Revolving Credit Facility Borrowings $	Commercial Paper Outstanding $	Revolving Credit Facility Availability $
December 31, 2017	800.0	-	159.0	641.0
December 31, 2016	800.0	-	261.0	539.0

The Corporation is a party to a $20.0 million demand facility with a Canadian chartered bank for the purpose of working capital management ("Working Capital Facility"). As at December 31, 2017, $11.7 million had been drawn under the Working Capital Facility compared to $7.1 million as at December 31, 2016.

Consolidated Statements of Cash Flow Data
(in millions of Canadian dollars)

	Three months ended December 31		Year ended December 31	
	2017 $	2016 $	2017 $	2016 $
Working capital facility beginning of period	(10.1)	(9.1)	(7.1)	(14.2)
Net cash provided by operating activities	211.4	191.7	584.7	571.3
Net cash used in investing activities	(132.3)	(138.2)	(520.9)	(549.4)
Net cash used in financing activities	(80.7)	(51.5)	(68.4)	(14.8)
Working capital facility, end of period	(11.7)	(7.1)	(11.7)	(7.1)

Operating Activities

Net cash provided by operating activities for the three months and year ended December 31, 2017 was $211.4 million and $584.7 million, respectively, compared to $191.7 million and $571.3 million for the comparable periods in 2016.

The increase in net cash provided by operating activities for the three months and year ended December 31, 2017 was primarily due to improved working capital mainly related to timing differences in the settlement of receivable and payables (see note 22 to the Consolidated Financial Statements), and lower net movements in regulatory balances arising from deferred tax assets, partially offset by lower collection from energy sales in excess of energy purchases, which were deferred as a settlement variance and timing of income tax instalments paid.

Investing Activities

Net cash used in investing activities for the three months and year ended December 31, 2017 was $132.3 million and $520.9 million, respectively, compared to $138.2 million and $549.4 million for the comparable periods in 2016.

The decrease in net cash used in investing activities for the three months ended December 31, 2017 was due to lower cash spending on capital projects, partially offset by lower proceeds on disposals of PP&E in the fourth quarter of 2017.

The decrease in net cash used in investing activities for the year ended December 31, 2017 was due to lower cash spending on capital projects and higher proceeds on disposals.

Electricity distribution is a capital-intensive business. As the municipal electricity distribution company serving the largest city in Canada, LDC continues to invest in the renewal of existing aging infrastructure to address safety, reliability and customer service requirements.

The following table summarizes the Corporation's capital expenditures, both PP&E and intangible assets, which are inclusive of capital accruals, for the periods indicated.

Capital Expenditures
(in millions of Canadian dollars)

	Three months ended December 31		Year ended December 31	
	2017 $	2016 $	2017 $	2016 $
Regulated LDC				
Distribution system				
Planned [1]	103.1	85.1	373.0	365.3
Reactive	12.8	16.9	48.1	47.6
Copeland Station	4.9	7.8	23.2	22.6
Facilities consolidation	-	16.1	35.2	50.6
Technology assets	20.3	17.0	54.9	49.1
Other [2]	5.3	3.8	10.5	10.8
Regulated capital expenditures	146.4	146.7	544.9	546.0
Unregulated capital expenditures [3]	2.5	2.5	8.0	5.7
Total capital expenditures	148.9	149.2	552.9	551.7

[1] Includes, among other initiatives, the replacement of underground and overhead infrastructures, station programs, and the delivery of customer connections.

[2] Includes fleet capital and buildings.

[3] Primarily relates to street lighting and generation equipment.

The total regulated capital expenditures for the three months and year ended December 31, 2017 were $146.4 million and $544.9 million, respectively, compared to $146.7 million and $546.0 million for the comparable periods in 2016.

For the three months ended December 31, 2017, spending on regulated capital expenditure year over year was relatively consistent. Changes were primarily related to lower spending on the facilities consolidation program ($16.1 million), partially offset by higher spending on the implementation of an SAP ERP project ($8.1 million), station programs related to the renewal of aging station infrastructure ($4.7 million), network infrastructure ($1.8 million), and metering ($1.7 million).

For the year ended December 31, 2017, the decrease in regulated capital expenditures was primarily related to lower spending on overhead infrastructure ($19.1 million), the radio project ($16.0 million), and the facilities consolidation program ($15.4 million). These variances were partially offset by higher spending on station programs related to the renewal of aging station infrastructure ($26.2 million), the implementation of an SAP ERP project ($19.9 million), and metering ($7.3 million).

The largest capital initiatives in 2017 include the replacement of underground and overhead infrastructures, station programs, delivery of customer connections, the facilities consolidation program, and the construction of Copeland Station in response to the growing need for distribution options in the downtown core of the City.

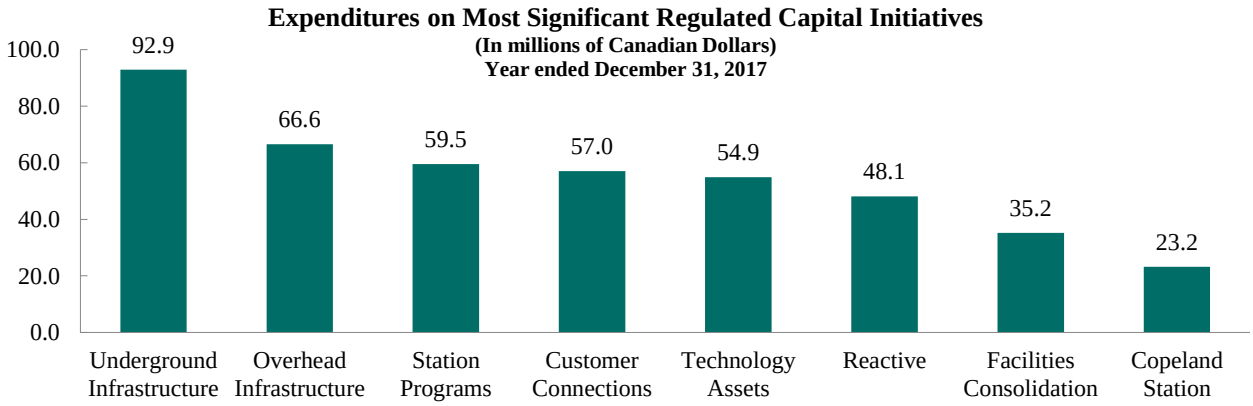
The replacement of underground infrastructure includes replacing direct buried cables, transformer switches, handwells and other aging underground infrastructure. The replacement of overhead infrastructure includes replacing poles, overhead transformers, conductors, overhead switches and other aging overhead infrastructure and equipment. Both initiatives will allow LDC to continue to provide ongoing safe and reliable service to its customers. For the year ended December 31, 2017, capital expenditures for the underground and overhead infrastructures were $92.9 million and $66.6 million, respectively.

The station programs relate to the lifecycle management of electrical equipment installed at each of the Corporation's active Municipal and transformer stations, while ensuring that adequate capacity is available to serve customers. For the year ended December 31, 2017, capital expenditures for the station programs were $59.5 million.

The delivery of customer connections includes spending related to new services and upgrades to existing services for specific commercial customers. For the year ended December 31, 2017, capital expenditures for the delivery of customer connections were $57.0 million.

The facilities consolidation program relates to the consolidation of operating centres to lower operating centre costs and simplify long-term planning. In the year ended December 31, 2017, the Corporation continued relocating staff, equipment and operations as well as performing the required capital investment on specific properties and incurred costs of $35.2 million.

Copeland Station will be the first transformer station built in downtown Toronto since the 1960's and will be the second underground transformer station in Canada. When in service, it will provide electricity to buildings and neighbourhoods in the central-southwest area of Toronto. During 2017, major electrical equipment including power transformers and high and medium voltage switchgear, medium voltage cable, control wiring and DC systems was installed, tested and commissioned, and the high voltage cable was completed. The electric station service equipment was installed and energized. Protection and control equipment was installed and testing and commissioning commenced. In addition, the machine shop installation and landscaping were completed and sidewalks and roadway were paved. HONI, the electricity transmission provider, commenced the installation of their transmission equipment, including high voltage switchgear and protection and control equipment. As at December 31, 2017, the cumulative capital expenditures on the Copeland Station project amounted to $195.1 million, plus capitalized borrowing costs. All capital expenditures related to Copeland Station are recorded to PP&E. Copeland Station is one of the most complex projects ever undertaken by the Corporation and the expected completion date is 2018. The total capital expenditure required to complete the project is approximately $200.0 million, plus capitalized borrowing costs. There may be additional unforeseen delays and expenditures prior to completion of the project. See "Risk Management and Risk Factors" below for further information on the Copeland Station project.



Financing Activities

Net cash used in financing activities for the three months and year ended December 31, 2017 was $80.7 million and $68.4 million, respectively, compared to $51.5 million and $14.8 million for the comparable periods in 2016. The change for the year was primarily due to the repayment of the Corporation's Series 2 debentures and commercial paper and an increase in dividends paid, partially offset by the equity investment received from the City in June 2017.

The Corporation is a party to a credit agreement with a syndicate of Canadian chartered banks which established a revolving credit facility expiring on October 10, 2022 ("Revolving Credit Facility"), pursuant to which it may borrow up to $800.0 million, of which up to $210.0 million is available in the form of letters of credit. On August 1, 2017, the maturity date of the Revolving Credit Facility was extended by one year from October 10, 2021 to October 10, 2022. As at December 31, 2017, the Corporation was in compliance with all covenants included in its Revolving Credit Facility agreement.

The Corporation has a commercial paper program allowing up to $600.0 million of unsecured short-term promissory notes ("Commercial Paper Program") to be issued in various maturities of no more than one year. The Commercial Paper Program is supported by liquidity facilities available under the Revolving Credit Facility; hence, available borrowing under the Revolving Credit Facility is reduced by the amount of commercial paper outstanding at any point in time. Proceeds from the Commercial Paper Program are used for general corporate purposes.

For the three months and year ended December 31, 2017, the average aggregate outstanding borrowings under the Corporation's Revolving Credit Facility, Working Capital Facility and Commercial Paper Program were $140.2 million and $210.3 million respectively, with a weighted average interest rate of 1.21% and 0.93% (compared to $253.2 million and $348.7 million with a weighted average interest rate of 0.83% and 0.89% for the three months and year ended December 31, 2016).

Additionally, the Corporation is a party to a $75.0 million demand facility with a Canadian chartered bank for the purpose of issuing letters of credit mainly to support LDC's prudential requirements with the IESO ("Prudential Facility"). As at December 31, 2017, $38.4 million of letters of credit were issued against the Prudential Facility.

The Corporation filed a base shelf prospectus dated May 8, 2017 with the securities commissions or similar regulatory authorities in each of the provinces of Canada. These filings allow the Corporation to make offerings of unsecured debt securities of up to $1.0 billion during the 25-month period following the date of the prospectus.

On November 14, 2017, the Corporation issued $200.0 million senior unsecured debentures at a rate of 3.485% ("Series 13"). The Series 13 debentures due on February 28, 2048 were priced at $999.29 per $1,000 principal amount and bear interest payable semi-annually in arrears. The net proceeds were used to repay certain existing indebtedness and for general corporate purposes. Debt issuance costs of $1.4 million relating to the Series 13 debentures were recorded against the carrying amount of the debentures in the fourth quarter of 2017 and are amortized to finance costs using the effective interest method.

The Corporation's Series 2 debentures matured and were repaid on November 14, 2017.

As at December 31, 2017, the Corporation had debentures outstanding in the principal amount of $2.0 billion. These debentures will mature between 2019 and 2063. As at December 31, 2017, the Corporation was in compliance with all covenants included in its trust indenture and supplemental trust indentures.

The following table sets out the current credit ratings of the Corporation:

Credit Ratings
As at December 31, 2017

	DBRS		Standard & Poor's	
	Credit Rating	Trend	Credit Rating	Outlook
Issuer rating	A	Stable	A	Stable
Senior unsecured debentures	A	Stable	A	-
Commercial paper	R-1 (low)	Stable	-	-

The Corporation believes that it has sufficient available sources of liquidity and capital to satisfy working capital requirements for the next twelve months.

On March 2, 2017, the Board of Directors of the Corporation declared dividends in the amount of $6.25 million with respect to the first quarter of 2017 (March 31, 2016 – $44.6 million), which was paid to the City on March 31, 2017.

On May 11, 2017, the Board of Directors of the Corporation declared dividends in the amount of $6.25 million with respect to the second quarter of 2017 (June 30, 2016 – $6.25 million), which was paid to the City on June 30, 2017.

In connection with receipt of the equity investment from the City, the Board of Directors of the Corporation declared dividends payable to the City and approved amendments to the Corporation's Dividend Policy, as follows:

- In respect of fiscal 2017, an aggregate amount of $75.0 million shall be paid to the City, consisting of the two previously declared and paid instalments of $6.25 million each and a further $62.5 million. The $62.5 million was paid to the City on July 7, 2017.

- In respect of fiscal 2018 and subsequent fiscal years, 60% of the Corporation's consolidated net income after net movements in regulatory balances for the prior fiscal year shall be declared separately in four equal quarterly instalments, with each instalment payable to the City on the last business day of each fiscal quarter.

On March 7, 2018, the Board of Directors of the Corporation declared a quarterly dividend in the amount of $23.5 million, payable to the City by March 31, 2018.

Summary of Contractual Obligations and Other Commitments

The following table presents a summary of the Corporation's debentures, major contractual obligations and other commitments.

Summary of Contractual Obligations and Other Commitments
As at December 31, 2017
(in millions of Canadian dollars)

	Total $	2018 $	2019/2020 $	2021/2022 $	After 2022 $
Working Capital Facility	11.7	11.7	-	-	-
Commercial paper [1]	159.0	159.0	-	-	-
Debentures – principal repayment	2,045.0	-	250.0	300.0	1,495.0
Debentures – interest payments	1,471.3	75.7	143.1	121.3	1,131.2
Operating leases	1.4	0.3	0.6	0.5	-
Capital projects [2] and other	46.0	17.5	27.5	1.0	-
Finances leases	1.5	1.5	-	-	-
Total contractual obligations and other commitments	3,735.9	265.7	421.2	422.8	2,626.2

[1] The notes under the Commercial Paper Program were issued at a discount and are repaid at their principal amount.
[2] Primarily commitments for construction services and estimated capital contributions.

Corporate Developments

Changes to the Corporation's Board of Directors and Audit Committee

Effective January 1, 2017, the City, as the sole shareholder of the Corporation, re-appointed Councillor Paul Ainslie, Deputy Mayor Stephen Holyday (as the Mayor's designate), and Deputy Mayor Denzil Minnan-Wong to the Board of Directors for a term ending November 30, 2018, or until their successors are appointed.

On March 2, 2017, the Board of Directors of the Corporation confirmed the Chair of the Corporation, David McFadden, as an ex officio member of each of its Audit, Corporate Governance and Nominating, and Human Resources and Environment Committees, with all the responsibilities and privileges of the regular members of each committee.

Effective April 26, 2017, the City appointed Juliana Lam to the Board of Directors. The appointment is effective for a term ending April 26, 2019, or until her successor is appointed. Juliana Lam was appointed by the Board of Directors to the Audit Committee to replace Brian Chu who retired from the Audit Committee, effective May 11, 2017.

Effective December 10, 2017, the City re-appointed David McFadden, Brian Chu, Heather Zordel, the Honourable Howard Weston, Senator, Mary Ellen Richardson, Michael Nobrega and Tamara Kronis to the Board of Directors for a term ending December 10, 2019, or until their successors are appointed.

Electricity Distribution Rates

The OEB's regulatory framework for electricity distributors is designed to support the cost-effective planning and operation of the electricity distribution network and to provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price.

The OEB typically regulates the electricity rates for distributors using a combination of detailed cost of service reviews and IRM adjustments. Under the OEB's rate-setting methods, actual operating conditions may vary from forecasts such that actual returns achieved can differ from approved returns. Approved electricity rates are generally not adjusted as a result of actual costs or revenues being different from forecasted amounts, other than for certain prescribed costs that are eligible for deferral for future collection from, or refund to, customers.

On March 1, 2016 pursuant to LDC's 2015 – 2019 CIR application, the OEB set 2018 distribution rates on an interim basis. On August 23, 2017, LDC filed its 2018 rate application seeking OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2018 and ending on December 31, 2018. On December 14, 2017, the OEB issued a decision and rate order approving LDC's 2018 rates, with an effective date of January 1, 2018, and the disposition of certain deferral and variance accounts.

Ontario's Fair Hydro Plan

On March 2, 2017, the Government of Ontario announced the OFHP, which includes a number of initiatives, some of which affect LDC or its customers.

OFHP includes the OREC, which came into effect on January 1, 2017. The OREC provides eligible customers with financial assistance in the form of an 8% rebate of the pre-tax cost of their electricity. The OREC rebates are administered by LDC and paid by the IESO in the month following customer billing. Current accounts receivable and unbilled revenue include the amount owing by the IESO to LDC. No effect on revenue or expense is recognized by LDC in respect of the OREC rebates.

OFHP also includes the OFHA, which enacted the Ontario Fair Hydro Plan Act, 2017 and amended the Electricity Act, 1998 and the Ontario Energy Board Act, 1998. The OFHA came into effect on June 1, 2017 and its impact is reflected in the Consolidated Financial Statements. The OFHA provides eligible customers with financial assistance through various changes to commodity pricing, new or amended programs, and eliminating or reducing certain provincial charges on the electricity bill. The OFHP reduces electricity bills by 25% on average for eligible customers, which includes the 8% OREC rebate. The OFHA reduces the total electricity bill for eligible customers and, accordingly, reduces current accounts receivable, unbilled revenue, accounts payable and accrued liabilities for LDC. No effect on distribution revenue or expense is recognized by LDC in respect of the OFHA.

CDM Activities

On March 26, 2014, the Minister of Energy of Ontario, under the guidance of sections 27.1 and 27.2 of the OEB Act, directed the OEB to amend the licence of each licensed electricity distributor to require the electricity distributor, as a condition of its licence, to make CDM programs available to its customers and to do so in relation to each customer segment in its service area, over the period beginning January 1, 2015 through December 31, 2020. On March 31, 2014, the Minister of Energy of Ontario issued a direction to require the OPA to coordinate, support and fund the delivery of CDM programs through electricity distributors. The objective of the CDM efforts is to reduce electricity consumption in the Province of Ontario by a total of 7 terawatt hours between January 1, 2015 and December 31, 2020, of which LDC's share is approximately 1,576 GWh of energy savings.

On November 13, 2014, LDC entered into an energy conservation agreement with the OPA for the delivery of CDM programs over the 2015-2020 period. The IESO and the OPA were merged under the name IESO starting on January 1, 2015.

Under the energy conservation agreement with the IESO, LDC has a joint CDM plan with Oakville Hydro Electricity Distribution Inc. ("Oakville Hydro") for the delivery of CDM programs over the 2015-2020 period. LDC can choose between full cost recovery funding, pay-for-performance funding, or a combination of both, on a CDM program by program basis. Under the full cost recovery funding method, the IESO reimburses LDC for all adequately documented incurred costs, with an option to receive a portion of its funding in advance. Cost efficiency incentives may be awarded

if LDC's electricity savings meet or exceed certain CDM plan targets for programs under the full cost recovery funding method, with a mid-term review to be performed by the IESO for the 2015-2017 period. Under the pay-for-performance funding method, LDC receives payment in arrears based on verified electricity savings achieved with various options for frequency of payment. The programs under the joint CDM plan with Oakville Hydro are only being offered under the full cost recovery funding method.

The joint CDM plan provides combined funding of approximately $425.0 million, including participant incentives and program administration costs to achieve an aggregate energy savings target of approximately 1,668 GWh. Oakville Hydro's programs under the joint CDM plan started on January 1, 2016. LDC received $44.9 million as at December 31, 2016 and $57.4 million in the year ended December 31, 2017 from the IESO for the delivery of CDM programs. Amounts received but not yet spent are presented on the consolidated balance sheets under current liabilities as deferred conservation credit. As at December 31, 2017, LDC estimated that approximately $12.9 million qualified as a joint mid-term incentive, of which $12.2 million represents LDC's portion and is included within accounts receivable.

Effective October 16, 2017, LDC entered into an agreement to transfer $4.0 million of funding and a corresponding 20 GWh of its energy savings target to another local distribution company. This agreement will decrease the joint CDM plan funding with Oakville Hydro to $421.0 million, with a revised energy savings target of 1,648 GWh. The revised CDM plan was approved by the IESO on December 14, 2017.

Legal Proceedings

In the ordinary course of business, the Corporation is subject to various legal actions and claims from customers, suppliers, former employees and other parties. On an ongoing basis, the Corporation assesses the likelihood of any adverse judgments or outcomes as well as potential ranges of probable costs and losses. A determination of the provision required, if any, for these contingencies is made after an analysis of each individual issue. The provision may change in the future due to new developments in each matter or changes in approach, such as a change in settlement strategy. If damages were awarded under these actions, the Corporation and its subsidiaries would make a claim under any applicable liability insurance policies which the Corporation believes would cover any damages which may become payable by the Corporation and its subsidiaries in connection with these actions, subject to such claim not being disputed by the insurers. There have been no material changes in legal proceedings as disclosed in note 25 to the Consolidated Financial Statements.

Share Capital

Share capital consists of the following:

	Number of Shares	$
Authorized The authorized share capital of the Corporation consists of an unlimited number of common shares without par value. All shares issued were fully paid.		
Issued and outstanding		
Common shares, beginning of the year	1,000	567.8
Common shares issued [1]	200	250.0
Common shares issued and outstanding, end of the year	1,200	817.8

[1] On June 28, 2017, the Corporation issued 200 common shares to the City for total proceeds of $250.0 million, net of share issue costs and expenses.

Transactions with Related Parties

As the City is the sole shareholder of the Corporation, the Corporation and the City are considered related parties. The Corporation provides electricity, street lighting and ancillary services to the City. All transactions with the City are conducted on terms similar to those offered to unrelated parties.

Summary of Transactions with Related Parties
(in millions of Canadian dollars)

	Year ended December 31	
	2017 **$**	**2016** **$**
Revenues	**283.3**	275.3
Operating expenses and capital expenditures	**22.2**	26.9
Dividends	**75.0**	63.4

Summary of Amounts Due to/from Related Parties
(in millions of Canadian dollars)

	As at December 31	
	2017 **$**	**2016** **$**
Accounts receivable	**13.8**	12.7
Unbilled revenue	**26.3**	23.2
Accounts payable and accrued liabilities	**40.1**	41.0
Customer deposits	**15.7**	14.1
Deferred revenue	**1.9**	3.5

Revenues represent amounts charged to the City primarily for electricity, street lighting and ancillary services. Operating expenses and capital expenditures represent amounts charged by the City for purchased road cut repairs, property taxes and other services. Dividends are paid to the City.

Accounts receivable represents receivables from the City primarily for electricity, street lighting and ancillary services. Unbilled revenue represents receivables from the City mainly related to electricity provided and not yet billed. Accounts payable and accrued liabilities represent amounts payable to the City related to road cut repairs and other services. Customer deposits represent amounts received from the City for future expansion projects. Deferred revenue represents amounts received from the City primarily for the construction of electricity distribution assets.

Controls and Procedures

For purposes of certain Canadian securities regulations, the Corporation is a "Venture Issuer". As such, it is exempt from certain requirements of National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings. Accordingly, the Chief Executive Officer and Chief Financial Officer have reviewed the Consolidated Financial Statements and the MD&A for the year ended December 31, 2017 and 2016. Based on their knowledge and exercise of reasonable diligence, they have concluded that these documents fairly present in all material respects the financial condition, financial performance and cash flows of the Corporation as at the date of and for the period presented.

Risk Management and Risk Factors

The Corporation faces various risks that could impact the achievement of its strategic objectives. It adopts an enterprise wide approach to risk management, achieved through a process of consolidating and aligning the various views of risk across the enterprise via a risk governance structure. The Corporation executes its ERM activities via an ERM framework that is aligned to industry best practices and international guidelines. The Corporation views ERM as a management activity undertaken to add value and improve overall operations. It helps the Corporation by enabling the attainment of its strategic goals and objectives through a systematic, disciplined approach towards identifying, evaluating, treating, monitoring and reporting of risks. Accordingly, ERM is an integral part of the strategic management of the Corporation and is routinely considered in forecasting, planning and executing all aspects of the business.

The ERM framework is operationalized by a consistent, disciplined methodology that clearly defines the risk management process which incorporates subjective elements, risk quantification and risk interdependencies.

While the Corporation's philosophy is that ERM is the responsibility of all business units, at all levels, in strategic and operational matters, the ERM governance structure is comprised of three key levels.

At the top level is the Board, which works to maintain a general understanding of the Corporation's risk profile, the risk categories, the types of risks to which the Corporation may be exposed and the practices used to identify, assess, measure and manage those risks. The risk profile is a list of key risks that represent the greatest threats to achieving the Corporation's strategic objectives.

The second level is the executive team, the lead body to ensure systems are in place to identify, manage, and monitor risks. Through its review of reports from the business and other areas, the executive team assesses the appropriateness and consistent application of systems to manage risks within the Corporation. The executive team also ensures that key risks are brought forward to the attention of the Board for discussion and action, as required.

Finally, the third level is the senior leadership team. The senior leadership team supports the executive team and is a collection of subject matter experts from across the Corporation who actively engage in the day-to-day management of risks. Working with the executive team, this group oversees the Corporation's risk profile, its performance against the defined risk appetite and determines appropriate risk responses. They also work to ensure effective, efficient, complete and transparent risk reporting to the executive team.

The Corporation's business is subject to a variety of risks including those described in the following sections. There can be no assurance that any steps the Corporation may take to manage risks will avoid future loss resulting from the occurrence of such risks.

Risks from External Influences

Ownership by the City and Inconsistent Policy Risk

The Corporation is subject to the risk that its shareholder can potentially limit the Corporation's ability to meet its business objectives as laid out in the Shareholder Direction principles. Under the Shareholder Direction, the City also has the power to direct the Corporation and its subsidiaries to conduct their affairs and govern their operations in accordance with such rules, policies, directives or objectives as are directed by City Council from time to time. These council approved directions can be inconsistent and/or divergent with the Shareholder Direction principles and could materially adversely affect the Corporation's business, operations, financial condition or prospects if the Corporation is required to comply with such directions.

Regulatory Risk

The Corporation is subject to the risk that its business activities may be impeded by the OEB (includes both traditional regulated Cost of Service work and non-traditional new ancillary service model work). There is a risk that future changes to Ontario's regulatory model, manner of regulation and/or broader government policy framework does not align with the Corporation's business direction and could materially adversely affect the Corporation's strategic goals and financial results.

Ontario's electricity industry regulatory developments may affect the electricity distribution rates charged by LDC and the costs LDC is permitted to recover. This may in turn have a material adverse effect on the financial performance of the Corporation and/or LDC's ability to deliver effective and efficient operations and reliable service to its customers, and as well as create barriers to LDC achieving its strategic objectives. Among other things, there can be no assurance that:

- the OEB will approve LDC's electricity distribution rates, at levels that will permit LDC to carry out its planned capital expenditures required to maintain safe and reliable service to its customers and earn the allowed rate of return on the investment in the business;
- all capital expenditures incurred by LDC will be approved by the OEB. In particular, capital cost overruns due to project delays or increased costs may not be recoverable in distribution rates;
- the regulatory instruments that are made available to LDC will be sufficient to address LDC's operations, needs and circumstances in respect of future applications for electricity distribution rates;
- the OEB will not set a lower recovery for LDC's cost of capital;
- the full cost of providing service to distribution customers will be permitted to be recovered through LDC's electricity distribution rates;
- the OEB will not permit competitors to provide distribution services in LDC's licensed area, or permit loads within LDC's service area to become electrically served by a means other than through LDC's electricity distribution system;
- the OEB will allow recovery for revenue lost as a consequence of unanticipated effects of CDM;
- parts of LDC's services will not be separated from LDC and opened to competition; or
- regulatory or other changes will not be made to the PILs regime.

Any future regulatory decision to disallow or limit the recovery of costs could lead to potential asset impairment and charges to results from operations, which could have a material adverse effect on the Corporation.

Political and Legislative Risk

The Corporation is subject to the risk that government bodies and policy priorities of government may impact the Corporation's ability to deliver effective and efficient operations and meet business objectives. Changes to any of the laws, rules, regulations and policies applicable to the businesses carried on by the Corporation could materially adversely affect the Corporation. There can be no assurance that the Corporation will be able to comply with applicable future laws, rules, regulations and policies. Failure by the Corporation to comply with applicable laws, rules, regulations and policies may subject the Corporation to civil or regulatory proceedings that could have a material adverse effect on the Corporation. The OEB may not allow recovery for the costs of coming into or maintaining compliance with these laws, rules, regulations and policies.

Risks to Maintaining Operations

Human Capital Risk

The Corporation is subject to the risk that human resources may not be available with the necessary knowledge, skills and education to support the Corporation's future talent requirements. All retirements pose risks for knowledge management and business continuity, both at the Corporation and the industry. Development and retention of talent to meet the evolving needs of the business requires LDC to focus on a series of proactive activities and programs to mitigate these risks, such as strategic workforce planning, promotion of apprenticeship programs, investments in colleges and universities, succession planning, knowledge transfer and a robust training program.

The Corporation's ability to operate successfully in the electricity industry in Ontario will continue to depend in part on its ability to make changes to existing work processes and conditions in order to adapt to changing circumstances. The Corporation's ability to make such changes, in turn, will continue to depend in part on its relationship with its

labour unions including reaching a new collective bargaining agreement with Power Workers' Union. There can be no assurance that the Corporation will be able to secure the support of its labour unions.

Strategy and Business Model Risk

The Corporation is subject to the risk that it may fail to monitor the external environment and or develop and pursue strategies through appropriate business models, thus failing to gain a strategic advantage, which could materially adversely affect the Corporation. The OEB distribution licence issued to LDC stipulates a service area that reflects the territory within the City. By law, only the OEB can grant such a licence for a service area and only an entity with such a licence can provide licenced services to the public-at-large within a service area. The OEB has not granted any other distribution licence that permits distribution within LDC's service area. In addition to this regulatory barrier to entry, there are other barriers to entry, including the cost of constructing an electricity distribution system, physical space limitations within and legal access to the right-of-way, the specialized skills associated with the distribution business, the level of expertise required to achieve operational and regulatory compliance, and LDC's relationships with its customers. There can be no assurance that these barriers will continue to be sufficient to prevent this type of competition. Other regulated and unregulated entities have always competed with LDC and its predecessors to provide customers with other sources of energy, including electricity. The pervasiveness of this competition and its effects on LDC's distribution business have varied over time and continue to vary based on many factors, including the relative price of energy source (e.g., natural gas, grid-supplied electricity, behind-the-meter generation) and technology advancements (e.g., multi-unit building sub-metering, micro-grids, electricity storage).

There can be no assurance that the future nature, prevalence, or effects of these forms of competition will be comparable to current or historic experience. Failure to effectively scan our external and internal environment could lead to missed business opportunities and loss of competitive advantage (see "Customer Risk" section for additional details).

Asset Integrity Risk

The Corporation is subject to the risk that it may be unable to maintain continuous supply due to failure of the existing distribution infrastructure and assets which could materially adversely affect the Corporation. Electricity distribution is a capital-intensive business. As the municipal electricity distribution company serving the largest city in Canada, LDC continues to invest in the renewal of existing aging infrastructure and in the development of new infrastructure (such as the Copeland Station project) to address safety, reliability and customer service requirements.

LDC estimates that approximately one-third of its electricity distribution assets have already exceeded or will reach the end of their expected useful lives within the next 5-year period. At the same time, Toronto is a growing city, and LDC must make system upgrades to expand its capacity to keep pace with urban intensification and electrification. In addition, as the City, Ontario and the Government of Canada implement policies and programs to respond to climate change, the pressures on the Corporation's system will only increase. Widespread adoption of electric vehicles, fuel switching and changing emissions standards make electricity the comparatively clean energy choice. This drives the need for significant capital expenditures for system upgrades so that the grid can handle such increased load. LDC's ability to continue to provide a safe work environment for its employees and a reliable and safe distribution service to its customers and the general public will depend on, among other things, the ability of the Corporation to fund additional infrastructure, and the OEB allowing recovery of costs in respect of LDC's maintenance program and capital expenditure requirements for distribution plant refurbishment and replacement.

One of LDC's largest capital initiatives currently in progress is the construction of Copeland Station, which is also one of the most complex projects ever undertaken by the Corporation. Due to unforeseen delays, the expected completion date for the Copeland Station project has been extended to 2018 and it is currently anticipated that the total expenditure required to complete the project will increase from $195.0 million to approximately $200.0 million, plus capitalized borrowing costs as applicable. There may be additional unforeseen delays and expenditures prior to the completion of the project. On January 25, 2017, the Corporation was informed that Carillion Construction Inc., the general contractor for the Copeland Station Project, filed for creditor protection under the Companies' Creditors Arrangement Act after its affiliate, Carillion plc, went into compulsory liquidation in the United Kingdom.

All capital projects for new and replacement infrastructure have risks related to delays or increased costs due to many factors, including: necessary modifications to project plans; the availability, scheduling and cost of materials,

equipment and qualified personnel; LDC's ability to obtain necessary environmental and other regulatory and governmental approvals; and the impact of weather conditions, site conditions and contractor performance.

LDC is focused on overcoming the above challenges and executing its capital and maintenance programs. However, if LDC is unable to carry out these plans in a timely and optimal manner or becomes subject to significant unforeseen equipment failures, equipment performance will degrade. Such degradation may compromise the reliability of distribution assets, the ability to deliver sufficient electricity and/or customer supply security and increase the costs of operating and maintaining these assets.

Occupational Health and Safety Risk

The Corporation is subject to the risk that employees may be exposed to serious or fatal injuries or illness as a result of the work environment in which they operate. Due to the nature of the Corporation's business and business activities, occupational safety is an integral part of our corporate culture. Employees could be exposed to hazards when performing their work duties. This includes hazards such as electrical contact, working in confined spaces, fires and explosions, slips, trips and falls and motor vehicle accidents. The Corporation is subject to compliance with provincial Health and Safety legislation. The Corporation's management approach to occupational safety is to meet or excel on legal compliance and eliminate or safeguard known occupational hazards and risks. There are processes in place to develop and nurture good leadership practices through recruitment, education, training and performance management practices that encourage the application of our corporate values, including safety. LDC received OHSAS 18001 certification in 2013 and conducts annual third party audits to maintain certification, in addition occupational health and safety legal compliance audits are conducted every two years.

Customer Risk

The Corporation is subject to the risk that it may fail to identify and meet its customers' needs and expectations, within approved OEB funding levels, and consequently customers leave the Corporation's distribution area or opt for alternative sources of electricity. This includes all customer classes, but is primarily related to general service and large users. This may lead to erosion of the Corporation's revenue base and monopoly position. It is important that the Corporation maintains its relationship with its customers to better understand the specific needs and expectations of each class. The political environment and government policy regarding the energy sector may impact customer satisfaction and perception of value, especially with concerns around hydro costs. The Corporation is taking steps to help its customers through cost saving CDM programs. Service interruptions due to increasing weather events, or unexpected events could further impact customer satisfaction and service quality (see "Business Interruption Risk" section for additional details).

Advances in technology may compete with the Corporation by affecting energy consumption levels and, as a result, customer demand for the Corporation's services could be negatively impacted in a material way. As customers increasingly prioritize energy efficiency and awareness of energy costs, and governments increasingly provide subsidies to encourage energy efficiency, primarily in response to climate change concerns, there will be a corresponding increase in the demand for technologies that enable customers to better monitor and minimize their energy consumption and otherwise exercise greater control over their electricity supply and demand. For example, distributed generation technologies draw on renewable sources of energy, such as solar power and wind, allowing customers to generate their own supply of electricity. The effect of such technologies may be reduced reliance on larger-scale utilities such as the Corporation. Likewise, energy-efficient homes and improvements to energy storage technologies like batteries may further affect consumption levels and the demand for the Corporation's services. Although OEB's current policy is moving residential customers to fixed delivery charges as opposed to consumption-based delivery charges, as technologies continue to advance and become more widely adopted, the Corporation may be required to make changes to its business and operations, which may present additional risks and challenges for the Corporation.

The Corporation is affected by energy demand which may change as a result of technology change, available customer choice and CDM programs, as well as general economic conditions, energy prices, disposable income and population growth, among other things. Reduced or increased energy demand could have a material adverse effect on the Corporation's business, operations, financial condition or prospects, as well as on the Corporation's need for, and ability to, fund future capital expenditures.

Information Technology and Cybersecurity Risk

The Corporation is subject to the risk that it may be unable to preserve the confidentiality, integrity, authenticity, availability, accountability and non-repudiation of information assets. The Corporation's ability to operate effectively is in part dependent on the development, maintenance and management of complex information technology systems. Computer systems are employed to operate LDC's electricity distribution system, and the Corporation's financial, billing and business systems to capture data and to produce timely and accurate information. Failures of any one of the financial, business and operating systems could have a material adverse effect on the Corporation's business, operations, financial condition or prospects. The Corporation mitigates this risk through various methods including the implementation of high availability and redundancy in its core infrastructure and application components. Operational technology systems are isolated from business systems and operate independently.

LDC's electricity distribution infrastructure and technology systems are also potentially vulnerable to damage or interruption from cyber-attacks, breaches or other compromises, which could result in business interruption, service disruptions, theft of intellectual property and confidential information (about customers, suppliers, counterparties and employees), additional regulatory scrutiny, litigation and reputational damage. The Corporation has implemented security controls aligned with industry best practices and standards including the National Institute of Standards and Technology Cybersecurity Framework, and maintains cyber insurance. Cyber-attacks, breaches or other compromises of electricity distribution infrastructure and technology systems could result in service disruptions and system failures, including as a result of a failure to provide electricity to customers, property damage, corruption or unavailability of critical data or confidential employee or customer information. A significant breach could materially adversely affect the financial performance of the Corporation or its reputation and standing with customers, regulators and in the financial markets. It could also expose the Corporation to third-party claims.

LDC must also comply with legislative and licence requirements relating to the collection, use and disclosure of personal information (including the personal information of customers), as well as information provided by suppliers, contractors, employees, counterparties, and others. Such information could be exposed in the event of a cybersecurity incident or other unauthorized access, which could materially adversely affect the Corporation and also result in third-party claims against the Corporation.

Preventative controls are employed to protect information and technology assets against cyber-attacks and mitigate their effects. Detective controls are employed to continuously monitor information systems so that the Corporation can respond appropriately to minimize the damage in the event of a cyber-attack. Even with these measures in place, since the techniques used to obtain unauthorized access, disable or degrade service, or sabotage systems change frequently and often are not recognized until launched against a target, the Corporation may be unable to anticipate these techniques or to implement adequate preventative measures. As such, there can be no assurance that such measures will be effective in protecting LDC's electricity distribution infrastructure or assets, or the personal information of its customers, from a cyber-attack or the effects therefrom.

Brand and Reputation Risk

The Corporation is subject to the risk that an action or inaction by it or its representatives will impair the Corporation's image in the community, public confidence or brand. The Corporation is committed to delivering safe and reliable electricity to its customers in an environmentally responsible manner at optimal costs. Failure to deliver on our commitment could impact the public's perception of the Corporation. In addition, events and/or external factors that draw negative media attention to the Corporation could cause reputational damages and impact the Corporation's business and relationship with its stakeholders.

Business Interruption Risk

The Corporation is subject to the risk that it may be unable to maintain continuing and sustainable business operations, or recover from business interruption, in an effective manner. The Corporation's operations are exposed to the effects of natural and other unexpected occurrences such as extreme storm and other weather conditions and natural disasters, as well as terrorism and pandemics. Although the Corporation's facilities and operations are constructed, operated and maintained to withstand such occurrences, there can be no assurance that they will successfully do so in all circumstances. Any major damage to the Corporation's facilities or interruption of the Corporation's operations arising from these occurrences could result in lost revenues and repair costs that can be substantial. Although the Corporation has insurance which it considers to be consistent with industry practice, if it sustained a large uninsured loss caused

by natural or other unexpected occurrences, LDC may apply to the OEB for the recovery of the loss related to the electricity distribution system. There can be no assurance that the OEB would approve, in whole or in part, such an application.

Risks to Maintaining Financial Condition

Capital Structure Risk

The Corporation is subject to the risk that it may not be able to optimize its debt to equity ratio or access capital markets at effective rates. There can be no assurance that debt or equity financing will be available or sufficient to meet the Corporation's requirements, objectives, or strategic opportunities. If and when financing is available, there can be no assurance that it will be on acceptable terms to the Corporation.

The Corporation relies on debt financing through its MTN Program, CP Program or existing credit facilities to finance the Corporation's daily operations, repay existing indebtedness, and fund capital expenditures. The Corporation's ability to arrange sufficient and cost-effective debt financing could be materially adversely affected by a number of factors, including financial market conditions and activity in the global capital markets, the regulatory environment in Ontario, the Corporation's business, operations, financial condition or prospects, compliance with covenants, the ratings assigned to the Corporation or the debentures issued under the Corporation's MTN Program by credit rating agencies, the rating assigned to short-term borrowings under the CP Program by a credit rating agency, and the availability of the commercial paper market.

In the event the Corporation is unable to maintain an R-1 (low) credit rating for its CP Program, the Corporation has sufficient liquidity through its Revolving Credit Facility to repay its commercial paper obligations as they become due.

Market and Credit Risk

The Corporation is directly and indirectly subject to various market and credit fluctuations which could materially adversely affect the Corporation. For example, LDC is exposed to credit risk with respect to customer non-payment of electricity bills. LDC is permitted, at certain times of the year, to mitigate the risk of customer non-payment using any means permitted by law, including security deposits (i.e. letters of credit, surety bonds, cash deposits or lock-box arrangements, under terms prescribed by the OEB), late payment penalties, pre-payment, pre-authorized payment, load limiters or disconnection. While LDC would be liable for the full amount of the default, there can be no assurance that the OEB would allow recovery of the bad debt expense. Established practice in such cases is that the OEB would examine any electricity distributor's application for recovery of extraordinary bad debt expenses on a case-by-case basis. LDC's security interest or other measures, if any, may also not provide sufficient protection. Additionally, security interests and other measures taken by, or in favour of, LDC, if any, may not provide sufficient protection.

The Corporation is exposed to fluctuations in interest rates for the valuation of its post-employment benefit obligations. The Corporation estimates that a 1% (100 basis point) increase in the discount rate used to value these obligations would decrease the accrued benefit obligation of the Corporation, as at December 31, 2017, by $46.8 million, and a 1% (100 basis point) decrease in the discount rate would increase the accrued benefit obligation, as at December 31, 2017, by $60.2 million.

The Corporation is exposed to short-term interest rate risk on the short-term borrowings under its CP Program and Working Capital Facility, and customer deposits, while most of its remaining obligations were either non-interest bearing or bear fixed interest rates, and its financial assets were predominately short-term in nature and mostly non-interest bearing. The Corporation manages interest rate risk by monitoring its mix of fixed and floating rate instruments, and taking action as necessary to maintain an appropriate balance. The Corporation estimates that a 100 basis point increase (decrease) in short-term interest rates, with all other variables held constant, would result in an increase (decrease) of approximately $2.3 million to annual finance costs.

The Corporation had limited exposure to the changing values of foreign currencies. While the Corporation purchases goods and services which are payable in US dollars, and purchases US currency to meet the related commitments when required, the impact of these transactions as at December 31, 2017 was not material.

Critical Accounting Estimates

The preparation of the Corporation's Consolidated Financial Statements in accordance with IFRS requires management to make judgments, estimates and assumptions which affect the application of accounting policies, reported assets, liabilities and regulatory balances, and the disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements, and the reported revenues and expenses for the year. The estimates are based on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities as well as for identifying and assessing the accounting treatment with respect to commitments and contingencies. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the IESO, the Ontario Ministry of Energy or the Ontario Ministry of Finance.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to estimates are recognized prospectively. Assumptions and estimates with a significant risk of resulting in a material adjustment within the next financial year are used in the following:

- Note 26(b) – Recognition and measurement of regulatory balances;
- Note 26(j) – Revenue recognition – measurement of unbilled revenue, determination of the CDM incentive;
- Notes 26(f) and 26(g) – Determination of useful lives of depreciable assets;
- Notes 26(m) and 14 – Measurement of post-employment benefits – key actuarial assumptions;
- Notes 26(o) and 21 – Recognition of deferred tax assets – availability of future taxable income against which deductible temporary differences and tax loss carryforwards can be used; and
- Note 25 – Recognition and measurement of provisions and contingencies.

Significant Accounting Policies

The Corporation's Consolidated Financial Statements have been prepared in accordance with IFRS with respect to the preparation of financial information. The Consolidated Financial Statements are presented in Canadian dollars, which is the Corporation's functional currency. The significant accounting policies of the Corporation are summarized in notes 2 and 26 to the Consolidated Financial Statements.

Changes in Accounting Policies

In January 2016, the IASB issued amendments to IAS 7 *Statement of Cash Flows* as part of the IASB's Disclosure Initiative. These amendments require entities to provide disclosures that enable users of financial statements to evaluate changes in liabilities arising from financing activities, including changes from cash flows and non-cash changes. These amendments are effective for annual periods beginning on or after January 1, 2017. The additional disclosures relating to changes in liabilities arising from financing activities are included in note 22 to the Consolidated Financial Statements and have no impact to the Corporation's financial position or results of operations.

Future Accounting Pronouncements

A number of new standards, amendments and interpretations are not yet effective for the year ended December 31, 2017, and have not yet been applied in preparing the Consolidated Financial Statements.

Revenue from Contracts with Customers

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers* ("IFRS 15"), which replaces existing revenue recognition guidance, including IAS 18 *Revenue* and IFRIC 18 *Transfers of Assets from Customers*. IFRS 15 contains a single model that applies to contracts with customers with two methods for recognizing revenue: at a point in time or over time. IFRS 15 is effective for annual periods beginning on or after January 1, 2018.

The Corporation will adopt IFRS 15 on January 1, 2018 using the modified retrospective approach. The Corporation has completed its assessment of the key revenue streams. The majority of the Corporation's revenue (energy sales and distribution revenue) is generated from electricity distribution at regulated prices. The Corporation concluded that IFRS 15 will not have a material impact on the accounting for these revenue streams. Upon adoption of IFRS 15, there will be a $167.6 million income statement reclassification between Energy Sales and Energy Purchases for the comparative year ended December 31, 2017 and no impact to opening retained earnings as at January 1, 2018. The

Corporation is currently finalizing its assessment on capital contributions. The Corporation has determined that IFRS 15 will also increase its required disclosure on revenue streams.

Financial Instruments

In July 2014, the IASB issued the final version of IFRS 9 *Financial Instruments* ("IFRS 9"), which replaces IAS 39 *Financial Instruments: Recognition and Measurement* ("IAS 39"). IFRS 9 includes revised guidance on the classification and measurement of financial instruments, including a new expected credit loss model for measuring impairment on financial assets, and new general hedge accounting requirements. It also carries forward the guidance on recognition and derecognition of financial instruments from IAS 39. The standard is effective for annual periods beginning on or after January 1, 2018, and will be applied retrospectively with some exceptions. The Corporation has assessed the impact of adopting IFRS 9, and concluded that the new classification under IFRS 9 will not have a material impact on the consolidated financial statements. Management is currently evaluating the impact of adopting the new expected credit loss model for measuring impairment.

Leases

In January 2016, the IASB issued IFRS 16 *Leases* ("IFRS 16"), which replaces IAS 17 *Leases* ("IAS 17") and related interpretations. IFRS 16 introduces a single lessee accounting model eliminating the current distinction between finance and operating leases. It requires the recognition of lease-related assets and liabilities on the balance sheet, except for short-term leases and leases of low value underlying assets. In addition, the nature and timing of expenses related to leases will change, as IFRS 16 replaces the straight-line operating leases expense with the depreciation expense for the assets and interest expense on the lease liabilities. Lessor accounting remains substantially unchanged. The standard is effective for annual periods beginning on or after January 1, 2019, and may be applied either retrospectively or using a modified retrospective approach. Early adoption is permitted if IFRS 15 is also adopted.

The Corporation intends to early adopt IFRS 16 on January 1, 2018. The Corporation has completed its assessment of existing operating leases. IFRS 16 will not have a significant impact on the Corporation's consolidated financial statements and the Corporation has assessed the quantitative impact of adopting IFRS 16 to be $nil in opening retained earnings, and an increase of $1.6 million in total assets and total liabilities for the right-of-use assets and the lease liabilities, respectively, as at January 1, 2018.

Forward-Looking Information

Certain information included in this MD&A constitutes "forward-looking information" within the meaning of applicable securities legislation. The purpose of the forward-looking information is to provide the Corporation's current expectations regarding future results of operations, performance, business prospects and opportunities and may not be appropriate for other purposes. All information, other than statements of historical fact, which address activities, events or developments that we expect or anticipate may or will occur in the future, are forward-looking information. The words "anticipates", "believes", "budgets", "committed", "can", "could", "estimates", "expects", "focus", "forecasts", "future", "intends", "may", "might", "plans", "propose", "projects", "schedule", "seek", "should", "trend", "will", "would", "objective", "outlook" or the negative or other variations of these words or other comparable words or phrases, are intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects the Corporation's current beliefs and is based on information currently available to the Corporation.

Specific forward-looking information in the MD&A includes, but is not limited to, the statements regarding the settlement variance and other regulatory balance variances as described in the section entitled "Results of Operations"; the effect of changes in energy consumption on future revenue as described in the sections entitled "Summary of Quarterly Results of Operations" and "Risk Management and Risk Factors"; the Corporation's plans to finance the investment in LDC's infrastructure and, the Corporation's available sources of liquidity and capital resources and the sufficiency thereof to satisfy working capital requirements for the next twelve months as described in the section entitled "Liquidity and Capital Resources"; the planned and proposed capital initiatives and the expected results of such initiatives as described in the section entitled "Liquidity and Capital Resources"; the expected capital expenditures required to complete Copeland Station and the anticipated completion date for Copeland Station as described in the section entitled "Liquidity and Capital Resources" and "Risk Management and Risk Factors"; the anticipated contractual obligations and other commitments of the Corporation over the next five years as set out in the section entitled "Liquidity and Capital Resources"; the payment of dividends as described in the section entitled

"Liquidity and Capital Resources"; plans to meet CDM targets as described in the section entitled "Corporate Developments"; the Corporation's expectation that cash generated from operations, after the payment of dividends, is not expected to be sufficient to repay existing indebtedness, fund capital expenditures and meet other liquidity requirements over the next 12 months as described in the section entitled "Risk Management and Risk Factors"; the ability to claim under applicable liability insurance policies and/or pay any damages with respect to legal actions and claims as described in the section entitled "Legal Proceedings"; the Corporation's reliance on debt financing through its medium-term note program, Commercial Paper Program or existing credit facilities to finance the Corporation's daily operations, repay existing indebtedness, and fund capital expenditures as described in the section entitled "Risk Management and Risk Factors"; the effect of changes in interest rates and discount rates on future revenue requirements and future post-employment benefit obligations, respectively, as described in the section entitled "Risk Management and Risk Factors"; the Corporation's plans to attract, train and retain skilled employees and mitigate risks from retiring employees as described in the section entitled "Risk Management and Risk Factors"; the possibility that advances in technology may compete with the Corporation by affecting energy consumption levels and, as a result, customer demand for the Corporation's services as described in the section entitled "Risk Management and Risk Factors"; the expectation that one-third of the Corporation's electricity distribution assets have already exceeded or will reach the end of their expected useful lives within the next 5-year period as described in the section entitled "Risk Management and Risk Factors";; and the adoption and impact of new standards, amendments and interpretations on the Corporation's consolidated financial statements in the section entitled "Future Accounting Pronouncements".

The forward-looking information is based on estimates and assumptions made by the Corporation's management in light of past experience and perception of historical trends, current conditions and expected future developments, as well as other factors that management believes to be reasonable in the circumstances, including, but not limited to, the amount of indebtedness of the Corporation, changes in funding requirements, the future course of the economy and financial markets, no unforeseen delays and costs in the Corporation's capital projects (including Copeland Station), no unforeseen changes in the legislative and operating framework for Ontario's electricity market, the receipt of applicable regulatory approvals and requested rate orders, no unexpected delays in obtaining required approvals, the receipt of applicable IESO approvals for mid-term CDM incentives, the ability of the Corporation to obtain and retain qualified staff, equipment and services in a timely and cost efficient manner, the receipt of favourable judgments, no unforeseen changes in rate orders or rate setting methodologies, no unfavourable changes in environmental regulation, the level of interest rates and the Corporation's ability to borrow, and assumptions regarding general business and economic conditions.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to, risks associated with the execution of the Corporation's capital and maintenance programs necessary to maintain the performance of our aging distribution assets and make required infrastructure improvements; risks associated with capital projects, including Copeland Station; risks associated with electricity industry regulatory developments and other governmental policy changes; risks associated with the timing and results of regulatory decisions regarding the Corporation's revenue requirements, cost recovery and rates; risks associated with information system security and with maintaining complex information technology systems; risk to the Corporation's facilities and operations posed by unexpected weather conditions caused by climate change and other factors, terrorism and pandemics and the Corporation's limited insurance coverage for losses resulting from these events; risks associated with being controlled by the City, including the risk that the City could introduce rules, policies or directives that can potentially limit the Corporation's ability to meet its business objectives as laid out in the Shareholder Direction principles; risks related to the Corporation's work force demographic and its potential inability to attract, train and retain skilled employees; risks associated with possible labour disputes and the Corporation's ability to negotiate appropriate collective agreements; risk that the Corporation may fail to monitor the external environment and or develop and pursue strategies through appropriate business models, thus failing to gain a strategic advantage; risk that the Corporation is not able to arrange sufficient and cost-effective debt financing to repay maturing debt and to fund capital expenditures and other obligations; risk of downgrades to the Corporation's credit rating; risks related to the timing and extent of changes in prevailing interest rates and discounts rates and their effect on future revenue requirements and future post-employment benefit obligations; risk of substantial and currently undetermined or underestimated environmental costs and liabilities; risk that assumptions that form the basis of the Corporation's recorded environmental liabilities and related regulatory balances may change; risk that the presence or release of hazardous or harmful substances could lead to claims by third parties and/or governmental orders and other factors which are discussed in more detail under the section entitled "Risk Management and Risk Factors" in this MD&A. Please review this section – "Risk Management and Risk Factors" in detail. All of the forward-looking information included in this MD&A is qualified by the cautionary

statements in this "Forward-Looking Information" section and the "Risk Management and Risk Factors" section of this MD&A. These factors are not intended to represent a complete list of the factors that could affect the Corporation; however, these factors should be considered carefully and readers should not place undue reliance on forward-looking information made herein. Furthermore, the forward-looking information contained herein is dated as of the date of this MD&A or as of the date specified in this MD&A, as the case may be, and the Corporation has no intention and undertakes no obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

Selected Annual Information

The following table sets forth selected annual financial information of the Corporation for the three years ended December 31, 2017, 2016 and 2015. This information has been derived from the Corporation's consolidated financial statements.

Selected Annual Consolidated Financial Information
(in millions of Canadian dollars)

	2017 $	2016 $	2015 $
Year Ended December 31			
Total Revenues [1]	3,849.7	4,030.0	3,539.9
Net income after net movements in regulatory balances [1]	156.5	151.4	126.7
As at December 31			
Total assets and regulatory balances [2]	5,226.2	4,954.4	4,686.9
Total debentures [2,3]	2,034.0	2,084.6	1,885.1
Other non-current financial liabilities [4]	9.1	17.3	16.6
Total equity [2]	1,760.4	1,428.9	1,340.9
Dividends [5]	75.0	63.4	56.3

[1] See "Results of Operations" for further details on distribution revenue, other revenue, and net income after net movements in regulatory balances.

[2] See "Financial Position" for further details of significant changes in assets, debentures and shareholder's equity.

[3] Total debentures include current and long-term debentures.

[4] Other non-current financial liabilities include primarily non-current obligations under capital lease and non-current customer deposits. Under IFRS, deposits that are due or will be due on demand within one year from the end of the reporting period have been reclassified to other current financial liabilities.

[5] See "Liquidity and Capital Resources" for further details on dividends.

Additional Information

Additional information with respect to the Corporation (including its annual information form) is available on the System for Electronic Document Analysis and Retrieval website at www.sedar.com.

Toronto, Canada

March 7, 2018



ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2017

March 29, 2018

TABLE OF CONTENTS

PART 1 - FORWARD-LOOKING INFORMATION 4
PART 2 - GLOSSARY OF DEFINED TERMS 6
PART 3 - CORPORATE STRUCTURE 11
3.1 Name, Address, Incorporation 11
3.2 Inter-corporate Relationships 11
PART 4 - BUSINESS OF TORONTO HYDRO 12
4.1 Industry Structure 12
4.2 Toronto Hydro Corporation 13
4.3 Toronto Hydro-Electric System Limited ("LDC") 13
(a) LDC's Electricity Distribution System 13
(i) Control Centre 13
(ii) Terminal Stations 13
(iii) Transmission System Terminal Stations 13
(iv) Distribution Transformers and Municipal Substations 14
(v) Wires 14
(vi) Metering 14
(vii) Reliability of Distribution System 14
(b) LDC's Service Area and Customers 15
(c) LDC's Real Property 16
(d) Regulation of LDC 16
(i) Legislative Framework 16
(ii) Licences 17
(iii) Industry Codes 18
(e) Distribution Rates 19
(i) Rate Setting Mechanism 19
(ii) Other Regulated Charges 20
4.4 Toronto Hydro Energy Services Inc. 20
4.5 Environmental Matters 20
(a) Environmental Protection Requirements 20
(b) Financial and Operational Effects of Environmental Protection Requirements 20
(c) Environmental Policy and Oversight 21
4.6 Additional Information Regarding Toronto Hydro 21
(a) Employees 21
(b) Specialized Skills and Knowledge 22
(c) Health and Safety 22
(d) Code of Business Conduct and Whistleblower Procedure 23
(e) Insurance 23
(f) Intangible Property 23
(g) Seasonal Effects 23
PART 5 - GENERAL DEVELOPMENT OF THE BUSINESS 24
5.1 Business Operations 24
(a) Three Year History 24
(b) Business Operations 24
5.2 Rate Applications 24
(a) 2015-2019 Rate Application 24
(b) 2012-2014 ICM True-Up Application 25
5.3 Ontario's Fair Hydro Plan 25
5.4 Conservation and Demand Management 25
PART 6 - RELATIONSHIP WITH THE CITY 26
6.1 Shareholder Direction 26
(a) Shareholder Objectives and Principles 26
(b) Shareholder Approval 27
(c) Financial Performance 27
(d) Credit Rating 27

(e) Equity Contribution ... 28
(f) Dividends ... 28
6.2 Services Provided to the City ... 28
6.3 Shareholder Engagement ... 28
PART 7 - TAXATION ... 29
7.1 Tax Regime ... 29
7.2 PILs Recoveries through Rates ... 30
PART 8 - RISK FACTORS ... 30
PART 9 - CAPITAL STRUCTURE ... 36
9.1 Share Capital ... 36
9.2 Debentures ... 36
9.3 Credit Facilities ... 37
9.4 Credit Rating ... 38
PART 10 - DIRECTORS AND OFFICERS ... 38
10.1 Nomination of Directors ... 38
10.2 Committees of the Board of Directors ... 39
(a) Audit Committee ... 39
(b) Corporate Governance and Nominating Committee ... 39
(c) Human Resources and Environment Committee ... 40
10.3 Directors ... 40
10.4 Executive Officers ... 52
10.5 Cease Trade Orders, Bankruptcies, Penalties or Sanctions ... 52
10.6 Independence ... 53
10.7 Board Orientation and Continuing Education ... 54
10.8 Board, Committee and Director Assessments ... 54
10.9 Board Oversight and Management of Risks ... 54
10.10 Indebtedness of Directors and Executive Officers ... 54
PART 11 - AUDIT COMMITTEE ... 55
11.1 Composition, Independence and Financial Literacy ... 55
11.2 Audit Committee Charter ... 55
11.3 Policy on the Provision of Services by the External Auditors ... 55
11.4 External Auditors Service Fees ... 56
PART 12 - EXECUTIVE COMPENSATION ... 56
PART 13 - LEGAL PROCEEDINGS ... 66
PART 14 - MATERIAL CONTRACTS ... 66
PART 15 - NAMED AND INTERESTS OF EXPERTS ... 66
PART 16 - TRANSFER AGENTS AND REGISTRARS ... 66
PART 17 - ADDITIONAL INFORMATION ... 66
ANNEX A - CHARTER – AUDIT COMMITTEE ... A-1
ANNEX B - MANDATE – BOARD OF DIRECTORS ... B-1

PART 1 - FORWARD-LOOKING INFORMATION

Certain information included in this AIF constitutes "forward-looking information" within the meaning of applicable securities legislation. The purpose of the forward-looking information is to provide the Corporation's current expectations regarding future results of operations, performance, business prospects and opportunities and may not be appropriate for other purposes. All information, other than statements of historical fact, which address activities, events or developments that we expect or anticipate may or will occur in the future, are forward-looking information. The words "anticipates", "believes", "budgets", "committed", "can", "could", "estimates", "expects", "focus", "forecasts", "future", "intends", "may", "might", "plans", "propose", "projects", "schedule", "seek", "should", "trend", "will", "would", "objective", "outlook" or the negative or other variations of these words or other comparable words or phrases, are intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects the Corporation's current beliefs and is based on information currently available to the Corporation.

Specific forward-looking information in this AIF includes, but is not limited to, the statements regarding: anticipated capacity to be provided by Copeland Station, the expected completion date of Copeland Station and the expected capital expenditures required to complete Copeland Station as described in the sections entitled "LDC's Electricity Distribution System" and "Asset Integrity Risk"; the future financial and operational effects of LDC's environmental protection requirements as described in the section entitled "Financial and Operational Effects of Environmental Protection Requirements"; wage increases for employees as described in the section entitled "Employees"; the effect of changes in energy consumption on future revenue as described in the section entitled "Seasonal Effects"; electricity distribution rates and rate applications as described in the section entitled "Rate Applications"; the plans to meet CDM targets as described in the section entitled "Conservation and Demand Management"; the payment of dividends as described in the section entitled "Dividends"; the effects of the Corporation or a subsidiary ceasing to be exempt from tax under the ITA and the TA and the payment of transfer taxes and the prescribed transfer tax rate for any future transfer of interest by the Corporation and its subsidiaries, or any changes to tax rates, as described in the section entitled "Tax Regime"; the Corporation's reliance on debt financing through its MTN Program, CP Program or existing credit facilities to finance Toronto Hydro's daily operations, repay existing indebtedness, and fund Capital Expenditures as described in the section entitled "Capital Structure Risk"; the effect of changes in interest rates and discount rates on future revenue requirements and future post-employment benefit obligations, respectively, as described in the section entitled "Market and Credit Risk"; the Corporation's plans to attract, train and retain skilled employees and mitigate risks from retiring employees as described in the section entitled "Human Capital Risk"; the possibility that advances in technology may compete with Toronto Hydro by affecting energy consumption levels and, as a result, customer demand for Toronto Hydro's services as described in the section entitled "Customer Risk"; the expectation that one-third of Toronto Hydro's electricity distribution assets have already exceeded or will reach the end of their expected useful lives within the next 5-year period as described in the section entitled "Asset Integrity Risk"; and the ability to claim under applicable liability insurance policies and/or pay any damages with respect to legal actions and claims as described in the section entitled "Legal Proceedings".

The forward-looking information is based on estimates and assumptions made by the Corporation's management in light of past experience and perception of historical trends, current conditions and expected future developments, as well as other factors that management believes to be reasonable in the circumstances, including, but not limited to, the amount of indebtedness of the Corporation, changes in funding requirements, the future course of the economy and financial markets, no unforeseen delays and costs in the Corporation's capital projects (including Copeland Station), no unforeseen changes in the legislative and operating framework for electricity distribution in Ontario, the receipt of applicable regulatory approvals and requested rate orders, no unexpected delays in obtaining required approvals, the receipt of applicable IESO approvals for mid-term CDM incentives, the ability of the Corporation to obtain and retain qualified staff, equipment and services in a timely and cost efficient manner, the receipt of favourable judgments, no unforeseen changes in electricity distribution rate orders or rate setting methodologies, no unfavourable changes in environmental regulation, the level of interest rates and the Corporation's ability to borrow, and assumptions regarding general business and economic conditions.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to, risks associated with the execution of LDC's capital and maintenance programs necessary to maintain the performance of our aging distribution assets and make required infrastructure improvements; risks associated with capital projects, including

Copeland Station; risks associated with electricity industry regulatory developments and other governmental policy changes; risks associated with the timing and results of regulatory decisions regarding LDC's revenue requirements, cost recovery and rates; risks associated with information system security and with maintaining complex information technology systems; risk to LDC's facilities and operations posed by unexpected weather conditions caused by climate change and other factors, terrorism and pandemics and LDC's limited insurance coverage for losses resulting from these events; risks associated with being controlled by the City, including the risk that the City could introduce rules, policies, or directives that can potentially limit Toronto Hydro's ability to meet its business objectives as laid out in the Shareholder Direction principles; risks related to LDC's work force demographic and its potential inability to attract, train and retain skilled employees; risks associated with possible labour disputes and LDC's ability to negotiate appropriate collective agreements; risk that Toronto Hydro may fail to monitor the external environment and or develop and pursue strategies through appropriate business models, thus failing to gain a strategic advantage; risk that Toronto Hydro is not able to arrange sufficient and cost-effective debt financing to repay maturing debt and to fund capital expenditures and other obligations; risk of downgrades to the Corporation's credit rating; risks related to the timing and extent of changes in prevailing interest rates and discounts rates and their effect on future revenue requirements and future post-employment benefit obligations; risk of substantial and currently undetermined or underestimated environmental costs and liabilities; risk that assumptions that form the basis of LDC's recorded environmental liabilities and related regulatory balances may change; risk that the presence or release of hazardous or harmful substances could lead to claims by third parties and/or governmental orders and other factors which are discussed in more detail under Part 8 "Risk Factors" in this AIF.

All of the forward-looking information included in this AIF is qualified by the cautionary statements in this "Forward-Looking Information" section and the "Risk Factors" section of this AIF. These factors are not intended to represent a complete list of the factors that could affect the Corporation; however, these factors should be considered carefully and readers should not place undue reliance on forward-looking information made herein. Furthermore, the forward-looking information contained herein is dated as of the date of this AIF or as of the date specified in this AIF, as the case may be, and the Corporation has no intention and undertakes no obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

PART 2 - GLOSSARY OF DEFINED TERMS

"Affiliate Relationships Code" refers to the Affiliate Relationships Code for Electricity Distributors and Transmitters that was published by the OEB and became effective on April 1, 1999, as amended.

"AIF" refers to the Corporation's Annual Information Form for the year ended December 31, 2017.

"Board" refers to the board of directors of the Corporation.

"CAIDI" refers to the Customer Average Interruption Duration Index and is a measure (in hours) of the average duration of interruptions experienced by customers, not including MED. CAIDI represents the quotient obtained by dividing SAIDI by SAIFI.

"Canadian Environmental Protection Act" refers to the *Canadian Environmental Protection Act, 1999* (Canada), as amended.

"Capital Assets" refers to the sum of property, plant and equipment and intangible assets, net of accumulated depreciation and amortization. See note 6, note 7, note 26(f) and note 26(g) to the Consolidated Financial Statements.

"Capital Expenditures" refers to expenditures relating to property, plant and equipment and intangible assets.

"CDM" refers to conservation and demand management.

"CEA" refers to the Canadian Electricity Association.

"CEO" refers to the President and Chief Executive Officer of the Corporation.

"CFO" refers to the Executive Vice-President and Chief Financial Officer or Interim, Chief Financial Officer of the Corporation.

"CIR" refers to Custom Incentive Rate-setting.

"City" refers to the city incorporated under the *City of Toronto Act, 1997* (Ontario), as amended, and comprised of the former municipalities of Metropolitan Toronto, Toronto, East York, Etobicoke, North York, Scarborough and York.

"City Council" refers to Toronto City Council.

"City Councillor" refers to a councillor of City Council.

"Conservation and Demand Management Code" refers to the Conservation and Demand Management Code for Electricity Distributors that was published and became effective on September 16, 2010.

"Consolidated Financial Statements" refers to the comparative audited consolidated financial statements of the Corporation together with the auditors' report thereon and the notes thereto as at and for the years ended December 31, 2017 and December 31, 2016, a copy of which is available on the SEDAR website at www.sedar.com.

"Consumer Price Index" refers to the index measuring price movements published by Statistics Canada.

"Consumer Protection Act" refers to the *Consumer Protection Act, 2002* (Ontario), as amended.

"Copeland Station" refers to the Clare R. Copeland transformer station, formerly called "Bremner Station".

"Corporation" refers to Toronto Hydro Corporation.

"CPAB" refers to Canadian Public Accountability Board.

"CP Program" refers to the commercial paper program established by the Corporation under which the Corporation issues commercial paper. See section 9.3 under the heading "Credit Facilities".

"Dangerous Goods Transportation Act" refers to the *Dangerous Goods Transportation Act, 1990* (Ontario), as amended.

"DBRS" refers to DBRS Limited.

"Debentures" has the meaning set forth under section 9.2 under the heading "Debentures".

"Distribution System Code" refers to the Distribution System Code that was published by the OEB on July 14, 2000, as amended.

"EHSMS" refers to the Environment, Health and Safety Management System.

"Electricity Act" refers to the *Electricity Act, 1998* (Ontario), as amended.

"Electricity Property" refers to a municipal corporation's or an MEU's interest in real or personal property used in connection with generating, transmitting, distributing or retailing electricity.

"Electricity Restructuring Act" refers to the *Electricity Restructuring Act, 2004* (Ontario), as amended.

"Energy Competition Act" refers to the *Energy Competition Act, 1998* (Ontario), as amended.

"Energy Consumer Protection Act" refers to the *Energy Consumer Protection Act, 2010* (Ontario), as amended.

"Environmental Protection Act" refers to the *Environmental Protection Act, 1990* (Ontario), as amended.

"ERM" refers to Enterprise Risk Management.

"Fire Protection and Prevention Act" refers to the *Fire Protection and Prevention Act, 1997* (Ontario), as amended.

"GWh" refers to a gigawatt-hour, a standard unit for measuring electrical energy produced or consumed over time. One GWh is equal to one million kWh.

"Hydro One" refers to Hydro One Limited, Hydro One Inc. or Hydro One Networks Inc. and their respective subsidiaries, as appropriate.

"ICD.D" refers to the designation granted by the Institute of Corporate Directors, through the Directors Education Program at University of Toronto.

"ICM" refers to Incremental Capital Module. See section 4.3(e)(i) under the heading "Rate Setting Mechanism" for more information.

"IEEE" refers to the Institute of Electrical and Electronic Engineers.

"IESO" refers to the Independent Electricity System Operator. Through amendments to the Electricity Act, the operations of the IESO and the OPA were merged under the name Independent Electricity System Operator on January 1, 2015, bringing together real-time operations of the grid with long-term planning, procurement and conservation efforts.

"IRM" refers to Incentive Regulation Mechanism. See section 4.3(e)(i) under the heading "Rate Setting Mechanism" for more information.

"ISO" refers to the International Organization for Standardization.

"ITA" refers to the *Income Tax Act, 1985* (Canada), as amended.

"kW" refers to a kilowatt, a common measure of electrical power equal to 1,000 Watts.

"kWh" refers to a kilowatt-hour, a standard unit for measuring electrical energy produced or consumed over time. One kWh is the amount of electricity consumed by ten 100 Watt light bulbs burning for one hour.

"LDC" refers to the Corporation's wholly-owned subsidiary, Toronto Hydro-Electric System Limited.

"Management's Discussion and Analysis" or "MD&A" refers to Management's Discussion and Analysis of Financial Condition and Results of Operations of the Corporation for the year ended December 31, 2017, a copy of which is available on the SEDAR website at www.sedar.com.

"MED" refers to Major Event Days as defined by IEEE Std 1366-2012, IEEE Guide for Electric Power Distribution Reliability Indices.

"Mercer" refers to Mercer (Canada) Limited.

"MEU" refers to a Municipal Electricity Utility in the Province of Ontario.

"Moody's" refers to Moody's Canada Inc.

"MTN Program" refers to the medium term note program established by the Corporation under which the Corporation issues debentures. See section 9.2 under the heading "Debentures" for the debentures currently outstanding.

"Named Executive Officer" or **"NEO"** means, collectively, the Corporation's CEO, the CFO, and/or a person serving in either of those capacities during the year and the three most highly compensated executive officers of Toronto Hydro who were serving as executive officers as at December 31, 2017, and each individual who would be amongst the three most highly compensated executive officers for Toronto Hydro, but for the fact that such individual was not an executive officer on December 31, 2017, if any.

"Oakville Hydro" refers to Oakville Hydro Electricity Distribution Inc.

"OBCA" refers to the *Business Corporations Act* (Ontario), as amended.

"OEB" refers to the Ontario Energy Board.

"OEB Act" refers to the *Ontario Energy Board Act, 1998* (Ontario), as amended.

"OEFC" refers to the Ontario Electricity Financial Corporation.

"OFHA" refers to the *Fair Hydro Act, 2017* (Ontario).

"OFHP" refers to Ontario's Fair Hydro Plan.

"OHSAS" refers to the Occupational Health and Safety Assessment Series.

"OMERS" refers to the Ontario Municipal Employees Retirement System, a multi-employer, contributory, defined benefit pension plan established in 1962 by the Province for employees of municipalities, local boards and school boards in Ontario.

"OPA" refers to the Ontario Power Authority. Through amendments to the Electricity Act, the operations of the IESO and the OPA were merged under the name Independent Electricity System Operator on January 1, 2015, bringing together real-time operations of the grid with long-term planning, procurement and conservation efforts.

"Open Access" refers to the opening of the Province's wholesale and retail electricity markets to competition pursuant to the requirement under the Electricity Act that transmitters and distributors of electricity in the Province provide generators, retailers and consumers with non-discriminatory access to their transmission and electricity distribution systems. Open Access commenced on May 1, 2002.

"OPG" refers to Ontario Power Generation Inc.

"**OREC**" refers to *Ontario Rebate for Electricity Consumers Act*, 2016 (Ontario).

"OSC" refers to the Ontario Securities Commission.

"PCBs" refers to polychlorinated biphenyls, a synthetic chemical compound consisting of chlorine, carbon and hydrogen. PCBs are used primarily as insulating and cooling elements in electrical equipment. Secondary uses include hydraulic and heat transfer fluids, flame proofing adhesives, paints, sealants and cable insulating paper.

"PILs" refers to the Payments In Lieu of Corporate Taxes regime contained in the Electricity Act pursuant to which MEUs that are exempt from tax under the ITA and the TA are required to make, for each taxation year, payments in lieu of corporate taxes to the OEFC. See note 26(o) and note 21 to the Consolidated Financial Statements.

"PP&E" refers to property, plant and equipment.

"Province" refers to the Province of Ontario.

"Residential Tenancies Act" refers to the *Residential Tenancies Act, 2006* (Ontario), as amended.

"Retail Settlement Code" refers to the Retail Settlement Code that was published by the OEB on December 13, 2000 and became effective on the commencement of Open Access (except with respect to "Service Agreements", as that term is defined in the Retail Settlement Code, which came into effect on March 1, 2001), as amended.

"S&P" refers to Standard & Poor's Financial Services LLC, a subsidiary of S&P Global Inc.

"SAIDI" means System Average Interruption Duration Index and is a measure (in hours) of the annual system average interruption duration for customers served, not including MED. SAIDI represents the quotient obtained by dividing the total customer hours of interruptions longer than one minute by the number of customers served.

"SAIFI" means System Average Interruption Frequency Index and is a measure of the frequency of service interruptions for customers served, not including MED. SAIFI represents the quotient obtained by dividing the total number of customer interruptions longer than one minute by the number of customers served.

"SEDAR" refers to the Canadian Securities Administrators' System for Electronic Document Analysis and Retrieval. SEDAR's website is www.sedar.com.

"Shareholder Direction" refers to the Shareholder Direction adopted by the Council of the City with respect to the Corporation, as amended and/or restated from time to time, pursuant to which the City has set out certain corporate governance principles with respect to the Corporation.

"Smart Meter" refers to a metering device capable of recording and transmitting hourly consumption information of a residential or general service customer.

"Standard Supply Customers" refers to persons connected to an electricity distributor's distribution system who are not served by retailers or whose retailer is unable to sell them electricity or who request the distributor to sell electricity to them.

"Standard Supply Service" refers to an electricity distributor's obligation to sell electricity to Standard Supply Customers, or to give effect to such rates as determined by the OEB under section 79.16 of the OEB Act.

"Standard Supply Service Code" refers to the Standard Supply Service Code for Electricity Distributors that was published by the OEB on December 8, 1999 and became effective on the commencement of Open Access, as amended.

"TA" refers to the *Taxation Act, 2007* (Ontario), as amended.

"Technical Standards and Safety Act" refers to the *Technical Standards and Safety Act, 2000* (Ontario), as amended.

"TH Energy" refers to the Corporation's wholly-owned subsidiary, Toronto Hydro Energy Services Inc.

"Toronto Hydro" refers to Toronto Hydro Corporation and its subsidiaries.

"Total Recordable Injury Frequency" refers to the number of recordable injuries multiplied by 200,000 divided by exposure hours, as per CEA standards.

"Transfer By-law" refers to By-law No. 374-1999 of the City made under section 145 of the Electricity Act pursuant to which the Toronto Hydro-Electric Commission and the City transferred their assets and liabilities and employees in respect of the electricity distribution system to LDC and in respect of electricity generation, co-generation and energy services to TH Energy. The Transfer By-law permits the Treasurer of the City to adjust the fair market value of the assets and the consideration paid in respect of the electricity distribution assets transferred to LDC as a consequence of OEB rate orders and permitted rates of return for 2000 or any subsequent year.

"Transportation of Dangerous Goods Act" refers to the *Transportation of Dangerous Goods Act, 1992* (Canada), as amended.

"Unit Smart Meter" refers to a unit Smart Meter installed by LDC in a unit of a multi-unit complex where the multi-unit complex is not connected solely to a bulk meter, and includes such other meters as may be prescribed by the Energy Consumer Protection Act.

"Watt" or **"W"** refers to a common measure of electrical power. One Watt equals the power used when one ampere of current flows through an electrical circuit with a potential of one volt.

Unless otherwise specified, all references to statutes are to statutes of the Province and all references to dollars are to Canadian dollars.

PART 3 - CORPORATE STRUCTURE

3.1 Name, Address, Incorporation

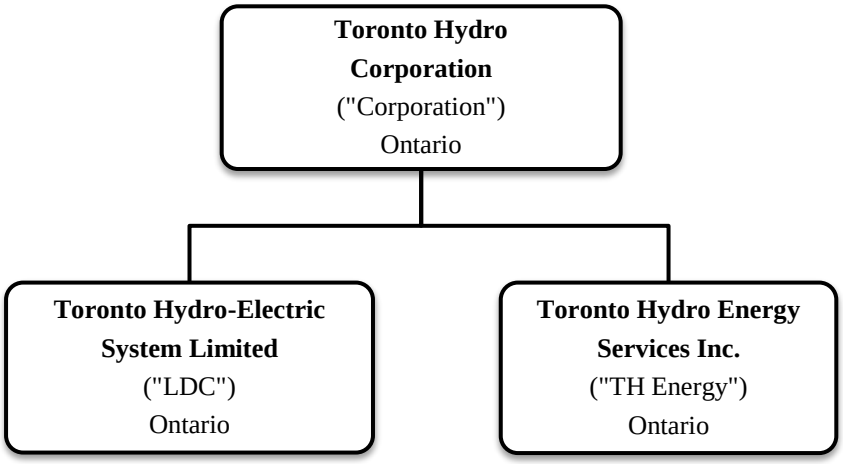
On January 1, 1998, the former municipalities of Metropolitan Toronto, Toronto, East York, Etobicoke, North York, Scarborough and York amalgamated to form the City. At the same time, the electric commissions of Toronto, East York, Etobicoke, North York, Scarborough and York were combined to form the Toronto Hydro-Electric Commission. Toronto Hydro is the successor to the Toronto Hydro-Electric Commission.

The Corporation, LDC and TH Energy were incorporated under the OBCA on June 23, 1999. Pursuant to the Transfer By-law, the Toronto Hydro-Electric Commission and the City transferred their assets and liabilities in respect of the electricity distribution system to LDC and electricity generation, co-generation and energy services to TH Energy.

The registered and head office of the Corporation is located at 14 Carlton Street, Toronto, Ontario, M5B 1K5.

3.2 Inter-corporate Relationships

The sole shareholder of the Corporation is the City. The Corporation, in turn, owns 100% of the shares of the principal subsidiaries listed below:



PART 4 - BUSINESS OF TORONTO HYDRO

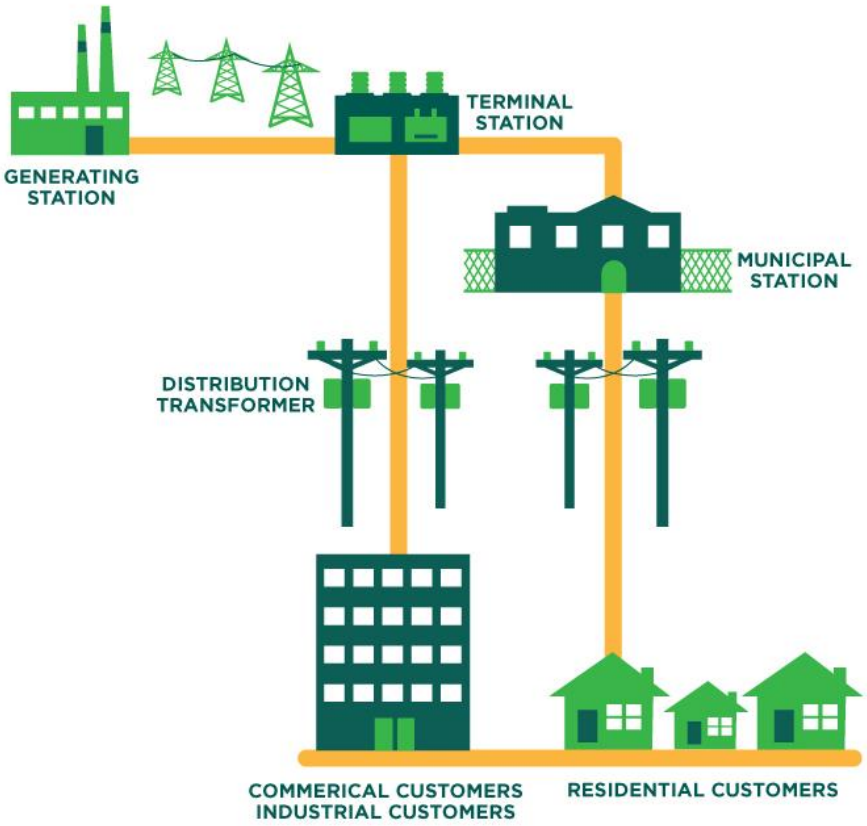
4.1 Industry Structure

The electricity industry in the Province is divided into four principal segments:

- Generation - the production of electricity at generating stations using nuclear, fossil, hydro, solar, wind or other sources of energy;
- Transmission - the transfer of electricity from generating stations to local areas using large, high-voltage power lines;
- Distribution - the delivery of electricity to homes and businesses within local areas using relatively low-voltage power lines; and
- Retailing - the purchase of electricity from generators and its sale to consumers together with a range of related services.

Electricity produced at generating stations is boosted to high voltages by nearby transformers so that the electricity can be transmitted long distances over transmission lines with limited power loss. The voltage is then reduced (stepped down) at terminal stations for supply to electricity distributors or large customers. Electricity distributors carry the electricity to distribution transformers that further reduce the voltage for supply to local customers. Electricity is distributed in the Province through a network of local electricity distributors that includes municipal electricity distributors, privately owned electricity distributors, and Hydro One.

The following diagram illustrates the basic structure of an electricity infrastructure system:



4.2 Toronto Hydro Corporation

Toronto Hydro Corporation is a holding company which wholly-owns two subsidiaries:

- LDC – distributes electricity and engages in CDM activities; and
- TH Energy – provides street lighting and expressway lighting services in the City.

The Corporation supervises the operations of, and provides corporate, management services and strategic direction to its subsidiaries.

4.3 Toronto Hydro-Electric System Limited ("LDC")

The principal business of Toronto Hydro is the distribution of electricity by LDC. LDC owns and operates $4.4 billion of Capital Assets comprised primarily of an electricity distribution system that delivers electricity to approximately 768,000 customers located in the City. LDC serves the largest city in Canada and distributes approximately 19% of the electricity consumed in the Province.

(a) LDC's Electricity Distribution System

Electricity produced at generating stations is transmitted through transmission lines owned by Hydro One to terminal stations at which point the voltage is then reduced (or stepped down) to distribution-level voltages. Distribution-level voltages are then distributed across LDC's electricity distribution system to distribution class transformers at which point the voltage is further reduced (or stepped down) for supply to end use customers. Electricity typically passes through a meter before reaching a distribution board or service panel that directs the electricity to end use circuits.

LDC's electricity distribution system is serviced from 1 control centre, 34 terminal stations and 1 transmission system terminal station, and is comprised of approximately 17,350 primary switches, approximately 60,540 distribution transformers, 153 in-service municipal substations, approximately 15,540 kilometres of overhead wires supported by approximately 178,800 poles and approximately 13,220 kilometres of underground wires.

(i) *Control Centre*

LDC has one control centre. The control centre co-ordinates and monitors the distribution of electricity throughout LDC's electricity distribution assets, and provides isolation and work protection for LDC's construction and maintenance crews and external customers. LDC's control centre utilizes supervisory control and data acquisition (SCADA) systems to monitor, operate, sectionalize and restore the electricity distribution system.

(ii) *Terminal Stations*

LDC receives electricity at 34 terminal stations at which high voltage is stepped down to distribution-level voltages. These terminal stations contain power transformers and high-voltage switching equipment that are owned by Hydro One. These terminal stations also contain equipment such as circuit breakers, switches and station busses.

(iii) *Transmission System Terminal Stations*

LDC receives electricity at Cavanagh transmission system terminal station at which high voltage is stepped down to distribution-level voltages. The transmission system terminal station contains power transformers, high-voltage switching equipment, and low-voltage equipment such as circuit breakers, switches and station busses that are owned by LDC.

One of LDC's largest capital initiatives currently in progress is the construction of Copeland Station in response to the developing need for distribution solutions in the downtown core of the City. Copeland Station will be considered a transmission system terminal station.

Copeland Station will be the first transformer station built in downtown Toronto since the 1960's and will be the second underground transformer station in Canada. It will provide electricity to buildings and neighbourhoods in the

central-southwest area of Toronto. During 2017, major electrical equipment including power transformers and high and medium voltage switchgear, medium voltage cable, control wiring and DC systems was installed, tested and commissioned and high voltage cable was installed. The electric station service equipment was installed and energized. Protection and control equipment was installed and testing and commissioning commenced. In addition, the machine shop installation and landscaping were completed and sidewalks and roadway were paved. Hydro One, the electricity transmission provider, commenced the installation of their equipment, including high voltage switchgear and protection and control equipment. As at December 31, 2017, the cumulative capital expenditures on the Copeland Station project amounted to $195.1 million, plus capitalized borrowing costs. All capital expenditures related to Copeland Station are recorded to PP&E. The total capital expenditures required to complete the project are approximately $200.0 million, plus capitalized borrowing costs. There may be additional unforeseen delays and expenditures prior to completion of the project. See Part 8 under the heading "Risk Factors" below for further information on the Copeland Station project.

(iv) *Distribution Transformers and Municipal Substations*

Electricity at distribution voltages is distributed from the terminal stations to distribution transformers that are typically located in buildings or vaults or mounted on poles or surface pads that are used to reduce or step down voltages to utilization levels for supply to customers. The electricity distribution system includes approximately 60,540 distribution transformers. The electricity distribution system also includes 153 in-service municipal substations that are located in various parts of the City and are used to reduce or step down electricity voltage prior to delivery to distribution transformers. LDC also delivers electricity at distribution voltages directly to certain commercial and industrial customers that own their own substations.

(v) *Wires*

LDC distributes electricity through a network comprised of an overhead circuit of approximately 15,540 kilometres supported by approximately 178,800 poles and an underground circuit of approximately 13,220 kilometres.

(vi) *Metering*

LDC provides its customers with meters through which electricity passes before reaching a distribution board or service panel that directs the electricity to end use circuits on the customer's premises. The meters are used to measure electricity consumption. LDC owns the meters and is responsible for their maintenance and accuracy.

As part of its metering services, LDC also installs Unit Smart Meters in multi-unit complexes that fall within the Competitive Sector Multi-Unit Residential rate class. As at December 31, 2017, LDC had installed approximately 74,000 Unit Smart Meters in these types of multi-unit complexes.

(vii) *Reliability of Distribution System*

The table below sets forth certain industry recognized measurements of system reliability with respect to LDC's electricity distribution system and the composite measures reported by LDC and the CEA for the twelve month periods ending December 31 in the years indicated below.

	LDC 2017	LDC 2016	CEA 2016 [(1)]
SAIDI	0.99	0.95	4.39
SAIFI	1.43	1.40	2.78
CAIDI	0.69	0.68	1.58

Note:

(1) Data was extracted from the CEA's 2016 Service Continuity Report on Distribution System Performance in Electrical Utilities, excluding significant events. At the date of this AIF, such report for the year 2017 has not been published by the CEA.

(b) LDC's Service Area and Customers

LDC is the sole provider of electricity distribution services in the City, and serves approximately 768,000 customers. The City is the largest city in Canada with a population of approximately 2.8 million. The City is a financial centre with large and diversified service and industrial sectors.

The table below sets out LDC's customer classes and certain operating data with respect to each class for each of the years in the two-year period ended December 31, 2017:

	Year ended December 31	
	2017	**2016**
Residential Service [1]		
Number of customers (as at December 31)..……..	685,292	679,717
kWh	4,933,060,853	5,313,163,852
Revenue	$983,275,614	$967,852,216
% of total service revenue	26.3%	24.5%
General Service [2]		
Number of customers (as at December 31)	82,233	81,321
kWh	17,276,676,523	17,835,656,434
Revenue	$2,515,519,940	$2,713,668,691
% of total service revenue	67.2%	68.6%
Large Users [3]		
Number of customers (as at December 31)	44	44
kWh	2,171,461,259	2,224,615,859
Revenue.....	$243,176,259	$272,532,953
% of total service revenue	6.5%	6.9%
Total		
Number of customers (as at December 31)	767,569	761,082
kWh.....	24,381,198,635	25,373,436,145
Revenue	$3,741,971,813	$3,954,053,860

Notes:

(1) "Residential Service" means a service that is for domestic or household purposes, including single family or individually metered multi-family units and seasonal occupancy.

(2) "General Service" means a service supplied to premises other than those receiving "Residential Service" and "Large Users" and typically includes small businesses and bulk-metered multi-unit residential establishments. This service is provided to customers with a monthly peak demand of 5,000 kW or less averaged over a twelve-month period.

(3) "Large Users" means a service provided to a customer with a monthly peak demand of more than 5,000 kW averaged over a twelve-month period.

(c) LDC's Real Property

The following table sets forth summary information with respect to the principal real property owned, leased or otherwise used by LDC as at December 31, 2017:

Property	Total
Terminal stations	34 sites
Transmission system terminal stations	1 site
Municipal substations	153 sites
Decommissioned municipal substations	18 sites
Control centre[(1)]	1 site
Operation centres[(2)]	5 sites
Other[(3)]	35 sites

Notes:

(1) LDC's control centre is located within one of its operation centres.

(2) LDC's operation centres accommodate office, staff, crews, vehicles, equipment and material necessary to operate and monitor the electricity distribution system.

(3) Other properties include locations under construction (including Copeland Station), small work centres and surplus properties.

Under the OEB Act, electricity distributors are entitled to apply to the OEB for authority to expropriate land required in connection with new or expanded electricity distribution lines or interconnections. If, after a hearing, the OEB is of the opinion that the expropriation of land is in the public interest, the OEB may make an order authorizing expropriation upon payment of specified compensation. The Electricity Act grandfathered thousands of existing unregistered easements, principally for distribution over third-party lands. The Electricity Act also authorizes electricity distributors to locate assets on, over or under public streets and highways.

(d) Regulation of LDC

(i) *Legislative Framework*

The Electricity Act and the OEB Act provide the broad legislative framework for the Province's electricity market.

The Electricity Act restructured the Province's electricity industry. Under the Electricity Act, the former Ontario Hydro was reorganized into five separate corporations (listed below under their current names):

- OPG, the entity responsible for the former Ontario Hydro's generation business;
- Hydro One, the entity responsible for the former Ontario Hydro's electricity transmission, distribution and energy services businesses;
- OEFC, the entity responsible for managing and retiring the former Ontario Hydro's outstanding indebtedness and remaining liabilities;
- IESO, a non-profit corporation responsible for central market operations, long-term planning, procurement and conservation efforts; and
- Electrical Safety Authority, a non-profit corporation responsible for the electric installation inspection function.

Additionally, the Electricity Act requires electricity distributors in the Province to keep their distribution businesses separate from their other businesses.

The business of LDC and other electricity distributors is regulated by the OEB, which has broad powers relating to licensing, standards of conduct and service, the regulation of electricity distribution rates charged by LDC and other electricity distributors and transmission rates charged by Hydro One and other transmitters. The OEB Act states that,

subject to certain exceptions, LDC and other electricity distributors shall not carry on any business activity other than the distribution of electricity, except through affiliated companies. As an exception to the general restriction on its business activities, the OEB Act permits LDC to provide additional services related to the promotion of CDM activities and alternative, cleaner and renewable sources of energy and energy storage. As well, the OEB may authorize LDC to carry on a non-distribution business activity.

In 2004, the Electricity Restructuring Act established the OPA as a non-profit, self-financed organization with the mandate to ensure long-term electricity supply adequacy in the Province. The OPA is authorized and has the responsibility to implement an integrated power system supply plan and deliver CDM programs in the Province.

Through amendments to the Electricity Act, the operations of the IESO and the OPA were merged under the name Independent Electricity System Operator on January 1, 2015, bringing together real-time operations of the grid with long-term planning, procurement and conservation efforts.

The Energy Consumer Protection Act came into force on January 1, 2011. The Energy Consumer Protection Act amends several statutes, including the OEB Act, the Electricity Act, the Consumer Protection Act and the Residential Tenancies Act. The Energy Consumer Protection Act also enables and sets out the requirements relating to LDC's installation of Unit Smart Meters in multi-unit complexes and provides new rules regarding the manner in which energy consumers are to be billed for their electricity consumption.

On December 3, 2015, Bill 112 – Strengthening Consumer Protection and Electricity System Oversight Act, 2015 received Royal Assent and certain provisions thereunder were proclaimed into force effective as of March 4, 2016. The bill's measures as proclaimed into force amend the Energy Consumer Protection Act and the OEB Act by further enhancing consumer protection and increasing the OEB's powers with regard to utility regulation, including increases to potential administrative penalties for non-compliance. The bill also eliminates limitations on LDC affiliate lines of business and gives the OEB the discretion to authorize LDC and other electricity distributors to carry on a non-distribution business activity.

(ii) *Licences*

Distribution Licence

The OEB has granted LDC a distribution licence. The term of the current licence is until October 16, 2023. The licence allows LDC to own and operate an electricity distribution system in the City. Among other things, the licence provides that LDC must keep financial records associated with distributing electricity separate from its financial records associated with other activities, may not impose charges for the distribution of electricity except in accordance with distribution rate orders approved by the OEB and must comply with industry codes established by the OEB.

Electricity Generation Licence

On December 18, 2002, the OEB issued an electricity generation licence to TH Energy and TREC Windpower Co-operative (No.1) Incorporated (the co-venturers), in connection with a wind turbine located at Exhibition Place in the City. The licence allows the co-venturers to generate electricity or provide ancillary services for sale through the IESO-administered markets, or directly to another person, subject to certain terms and conditions. This licence terminates on December 17, 2022, although the term may be extended by the OEB.

(iii) *Industry Codes*

The OEB has established the Affiliate Relationships Code, the Distribution System Code, the Retail Settlement Code, the Standard Supply Service Code, and the Conservation and Demand Management Code. These codes prescribe minimum standards of conduct, as well as standards of service, for electricity distributors in the non-competitive electricity market, and have been assigned the following ranking in the event there is a conflict between them:

(1) Affiliate Relationships Code
(2) Distribution System Code
(3) Retail Settlement Code
(4) Standard Supply Service Code
(5) Conservation and Demand Management Code

These codes are summarized below.

Affiliate Relationships Code

The Affiliate Relationships Code establishes standards and conditions for the interaction between electricity distributors and their affiliated companies. It is intended to minimize the potential for an electricity distributor to cross-subsidize competitive or non-monopoly activities, protect the confidentiality of consumer information collected by an electricity distributor and ensure that there is no preferential access to regulated services. The Affiliate Relationships Code prescribes standards of conduct for an electricity distributor with respect to the following: the degree of separation from affiliates; sharing of services and resources; transfer pricing; financial transactions with affiliates; equal access to services; and confidentiality of customer information.

Distribution System Code

The Distribution System Code establishes the minimum conditions that an electricity distributor must meet in carrying out its obligations to distribute electricity under its licence and under the Energy Competition Act, and has been amended as the regulatory environment has evolved. Generally, the Distribution System Code prescribes the rights and responsibilities of electricity distributors and electricity distribution customers with respect to the following: connections; connection agreements and conditions of service; expansion projects; alternative bids (available to customers for work otherwise done by an electricity distributor); metering; operations; disconnection and security deposits; and other matters.

Retail Settlement Code

The Retail Settlement Code outlines the obligations of an electricity distributor with respect to its relationship with retail market participants and its role as a retail market settlements administrator. Under the terms of the Retail Settlement Code, an electricity distributor is required to do the following: unbundle the costs of competitive electricity services and non-competitive electricity services; record, in variance accounts, the difference between amounts billed by the IESO to the electricity distributor for competitive and non-competitive electricity services, and the aggregate amounts billed by the electricity distributor to consumers, retailers and others for the same services; and provide electricity billing and settlement services to retailers and customers.

Standard Supply Service Code

The Standard Supply Service Code requires an electricity distributor to act as a default supplier and provide Standard Supply Service to persons connected to the electricity distributor's distribution system. The Standard Supply Service Code also specifies the conditions and manner by which OEB approved Standard Supply Service rates are to be charged to customers. Under the Standard Supply Service Code, an electricity distributor's rates for Standard Supply Service must be approved by the OEB and must consist of the price of electricity and an administrative charge that will allow the electricity distributor to cover its costs of providing the service.

Conservation and Demand Management Code

CDM activities over the January 1, 2015 to December 31, 2020 timeframe are governed by the OEB's Conservation and Demand Management Requirement Guidelines for Electricity Distributors issued on December 19, 2014. See section 5.4 under the heading "Conservation and Demand Management" for more information on LDC's CDM activities.

(e) Distribution Rates

(i) *Rate Setting Mechanism*

The OEB's regulatory framework for electricity distributors is designed to support the cost-effective planning and operation of the electricity distribution network and to provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price.

The OEB typically regulates the electricity rates for distributors using a combination of detailed cost of service reviews and IRM adjustments. A cost of service review uses a future test-year to establish rates, and provides for revenues required to recover the forecasted costs of providing the regulated service, and a fair and reasonable return on rate base (i.e. the aggregate of approved investment in PP&E and intangible assets excluding work in progress, less accumulated depreciation and amortization and unamortized capital contributions from customers, plus an allowance for working capital). IRM adjustments are typically used for one or more years following a cost of service review and provide for adjustments to rates based on an inflationary factor net of a productivity factor and an efficiency factor as determined relative to other electricity distributors.

Administratively, the OEB currently regulates the electricity rates for distributors through one of three specific rate-setting methods: Price Cap Incentive Rate-setting (suitable for most distributors), CIR (suitable for distributors with large or highly variable capital requirements), and Annual Incentive Rate-setting Index (suitable for distributors requiring limited rate adjustments). Under each of these methods, the OEB also allows recovery of costs arising from significant events satisfying certain criteria which are considered external to the regulatory regime and beyond the control of management.

Under the Price Cap Incentive Rate-setting method, rates are set on a single forward test-year cost of service basis for the first year and indexed for four subsequent years through an industry-standard IRM adjustment (using the 4th generation price cap index formula). Under this method, the ICM is available to address any incremental capital investment needs that may arise during the term. In order to determine whether a distributor is eligible for the ICM, the OEB conducts a review of the distributor's ICM application by way of a detailed examination of evidence and consideration of a number of criteria, such as materiality, need and prudence.

Under the CIR method, rates are set for a minimum period of five years, typically on a forward test-year cost of service basis for the first year with subsequent annual adjustments based on a distributor-specific custom index. The particular mechanics through which rates are set and adjusted are determined by the OEB on a case-by-case basis.

The Annual Incentive Rate-setting Index method sets a distributor's rates through an industry-standard IRM adjustment (using a limited form of the 4th generation price cap index formula) for one or more years.

Under each method, actual operating conditions may vary from forecasts such that actual returns achieved can differ from approved returns. Approved electricity rates are generally not adjusted as a result of actual costs or revenues being different from forecasted amounts, other than for certain prescribed costs that are eligible for deferral for future collection from, or refund to, customers.

On July 31, 2014, LDC filed a rate application with the OEB under the CIR method which sought approval of LDC's 2015 test-year revenue requirement on a cost of service basis and the corresponding electricity distribution rates effective May 1, 2015, and the subsequent annual rate adjustments based on a custom index specific to LDC for the period commencing on January 1, 2016 and ending on December 31, 2019. On December 29, 2015, the OEB issued its CIR decision and on March 1, 2016, the OEB issued its CIR rate order.

See section 5.2 under the heading "Rate Applications" for more information on LDC's rate applications.

(ii) *Other Regulated Charges*

The OEB's 2006 Electricity Distribution Rate Handbook provides standard rates and guidelines to electricity distributors with respect to other regulated charges that are non-competitive in nature, required under OEB codes and guidelines, governed by the market rules or are under the direction of the Province, including transmission charges and retail service charges relating to services provided by electricity distributors to electricity retailers in accordance with the Retail Settlement Code. As part of its rate application filed on July 31, 2014, LDC sought the OEB's approval to update its other regulated charges commencing on May 1, 2015. In the CIR decision and rate order, the OEB approved updates to these other regulated charges.

4.4 Toronto Hydro Energy Services Inc.

TH Energy owns and operates $35.6 million of Capital Assets as of December 31, 2017. TH Energy owns certain street lighting assets located in the City, and has an agreement with the City to provide street lighting system maintenance and capital improvement services to the City. TH Energy sub-contracts street lighting services to LDC.

TH Energy also operates a wind turbine located at the Better Living Centre (Exhibition Place) in a joint venture with TREC Windpower Cooperative (No.1) Incorporated.

4.5 Environmental Matters

(a) Environmental Protection Requirements

Toronto Hydro is subject to extensive federal, provincial and local regulation relating to the protection of the environment. The principal federal legislation is the Canadian Environmental Protection Act which regulates the use, import, export and storage of toxic substances, including PCBs and ozone-depleting substances. Toronto Hydro is also subject to the federal Transportation of Dangerous Goods Act which prescribes safety standards and requirements for the handling and transportation of hazardous goods including PCBs and sets reporting, training and inspection requirements relating thereto.

The principal provincial legislation is the Environmental Protection Act which regulates releases and spills of contaminants, including PCBs, ozone-depleting substances and other halocarbons, contaminated sites, waste management, and the monitoring and reporting of airborne contaminant discharge. The provincial Technical Standards and Safety Act also applies to Toronto Hydro's operations with respect to the handling of and training related to compressed gas, propane and liquid fuels. The provincial Fire Protection and Prevention Act requires Toronto Hydro to incorporate procedures and training for dealing with any spills of flammable or combustible liquids. The provincial Dangerous Goods Transportation Act prescribes safety standards and requirements for the transportation of dangerous goods on provincial highways and sets out inspection requirements related thereto.

Municipal by-laws regulate discharges of industrial sewage and storm water run-off to the municipal sewer system and the reporting of the release of certain toxic substances into the environment.

(b) Financial and Operational Effects of Environmental Protection Requirements

In 2017, LDC spent approximately $10.0 million to meet environmental protection requirements. These costs are not anticipated to significantly increase for future years, and do not currently have a material impact on Toronto Hydro's financial and operational results.

Toronto Hydro recognizes a liability for its best estimate of the future removal and handling costs for contamination in electricity distribution equipment in service. The liability is recognized when the decommissioning provision is incurred and when the fair value is determined. Actual future environmental costs may vary materially from the estimates used in the calculation of the decommissioning provision on Toronto Hydro's balance sheet.

(c) Environmental Policy and Oversight

Toronto Hydro has a strong commitment to the environment through the enforcement of a well-defined Environmental Policy. Conformance with the Environmental Policy is managed by Toronto Hydro's Environmental, Health and Safety department led by the Executive Vice-President and Chief Human Resources & Safety Officer. The content of the Environmental Policy is reviewed and approved annually by the Board.

Toronto Hydro's Environmental Policy identifies several core environmental principles, which include:

- Commitment from leadership to provide suitable and sufficient resources for the environmental management system;
- Compliance with all applicable laws, codes and standards;
- Continual improvement of environmental performance through the establishment of annual objectives, targets and programs;
- Employee engagement through education, training and providing general awareness of the Environmental Policy requirements and the environmental management system;
- Stakeholder engagement including consultation and engagement of environmental issues within the community and various stakeholders such as suppliers, customers, regulators, industry and the public;
- Pollution prevention through the implementation of policies, programs and procedures; and
- Integration of environmental considerations into our business processes.

LDC manages its environmental aspects in conformance with ISO 14001:2015 and was certified on November 18, 2017 as meeting the requirements of the ISO 14001:2015 standard by a third party auditor.

Legislative environmental reporting for federal, provincial and municipal governments is compiled and submitted annually. Third party environmental compliance audits are also conducted biennially in conformance with LDC's environment, health and safety audit plan.

Toronto Hydro's environmental policies, programs and procedures are reviewed and approved by management. Quarterly updates are presented to the Board's Human Resources and Environment Committee covering current environmental risks, environmental compliance audit findings, mitigation strategies and other material environmental matters.

4.6 Additional Information Regarding Toronto Hydro

(a) Employees

At December 31, 2017, Toronto Hydro had approximately 1,440 employees. Included in Toronto Hydro's employees are 804 members of bargaining units represented by the Power Workers' Union ("PWU"), and 67 engineers represented by the Society of Energy Professionals. Toronto Hydro employees currently represented by PWU were formerly represented by Canadian Union of Public Employees, Local One ("CUPE One"), which merged with PWU on October 6, 2016.

On February 13, 2014, CUPE One ratified collective agreements governing inside and outside employees for a four-year period expiring January 31, 2018. The collective agreements implemented a wage increase of 1.5% on February 1, 2014 and provide for general wage increases of 1.75%, effective on each of February 1, 2015 and February 1, 2016, respectively, and 2% effective February 1, 2017. The collective agreements also contain cost of living escalator clauses that provide for wage adjustments corresponding to the percentage change in the Consumer Price Index. The escalator clauses only become effective if certain prescribed thresholds are exceeded. Bargaining for a new collective agreement between the PWU and Toronto Hydro began on October 23, 2017. Negotiations are ongoing. The terms and conditions of the 2014-2018 collective agreements continue to apply until a new collective agreement is reached.

On July 7, 2016, the Society of Energy Professionals ratified a new collective agreement for a four-year period expiring December 31, 2019. The collective agreement implemented wage increases of 1.25% retroactive to January 1, 2016, 1.25% effective on January 1, 2017, 1.5% effective on January 1, 2018 and 2.0% effective on January 1, 2019.

Full time employees of Toronto Hydro participate in the OMERS pension plan. Plan benefits are determined based on a formula that takes into account the highest 5-year average contributory earnings and the number of years of service and are indexed to increases in the Consumer Price Index, subject to an annual maximum of 6%. Any increase in the Consumer Price Index above 6% per year is carried forward for later years. Both participating employers and participating employees are required to make equal plan contributions based on participating employees' eligible contributory earnings. All obligations to make payments to retirees under the OMERS pension plan are the responsibility of OMERS.

In addition to OMERS, Toronto Hydro provides other employment and post-employment benefits to employees, including medical, dental and life insurance benefits. See note 26(m) and note 14 to the Consolidated Financial Statements.

(b) Specialized Skills and Knowledge

Trades and technical jobs play a critical role in the safe and reliable design, construction and maintenance of LDC's electricity distribution system. These jobs include overhead, underground, and stations trades as well as controllers, designers and engineers. LDC hires experienced workers when available, along with apprentices to trades and technical positions. Trade apprentices require between 4 and 6 years to become fully competent and capable of performing all aspects of their job. LDC provides trades, legislative and compliance training through its apprenticeship program.

(c) Health and Safety

Toronto Hydro is committed to a safe and injury free work environment for all employees, contractors, visitors and the public. Through LDC's EHSMS, based on British Standards Institution OHSAS 18001:2007 Standard "*Occupational Health and Safety Management System - Requirements*", LDC maintains and reviews procedures, programs and the Occupational Health and Safety Policy which outlines several core principles including:

- Compliance
- Continual Improvement
- Engagement and Consultation
- Communication
- Accountability
- Risk Management
- Contractor Management
- Incident Investigation
- Performance Monitoring

The content of the Occupational Health and Safety Policy is reviewed and approved annually by the Board.

Toronto Hydro's health and safety performance is reviewed periodically by the Human Resources and Environment Committee of the Board. In 2017, the Total Recordable Injury Frequency was 1.06 recordable injuries per 200,000 hours worked compared to 0.80 in 2016.

LDC's legislated occupational health and safety requirements come under provincial jurisdiction exclusively and all legislated occupational health and safety reporting requirements are complied with. Management assurance that these requirements are met is accomplished by commissioning third party health and safety compliance audits conducted in conformance with LDC's environmental, health and safety audit plan.

Toronto Hydro's occupational health and safety policies, programs and procedures are reviewed and approved by management. Quarterly updates are presented to the Board covering current occupational health and safety risks, performance, compliance audit findings, mitigation strategies and other occupational health and safety matters.

(d) Code of Business Conduct and Whistleblower Procedure

All employees, officers and directors of Toronto Hydro are required to comply with the principles set out in the Code of Business Conduct and Whistleblower Procedure (the "Code"), which was originally implemented by Toronto Hydro in 2003, and is reviewed, revised and approved by the Board from time to time. The Code provides guidance to all employees in situations of perceived conflict of interest. All employees, officers and directors of Toronto Hydro are required to complete training in respect of the Code and sign an attestation in accordance with the Code upon commencement of employment and every three years thereafter.

The Code provides for the appointment of an Ethics Officer and establishes a direct hotline to the Ethics Officer by which perceived violations of the principles set out in the Code may be reported, anonymously or otherwise. Where the complaint involves the conduct of a director or officer of Toronto Hydro, the Ethics Officer is required to report it to the Chair of the Human Resources and Environment Committee of the Board, or, where such conduct relates to questionable auditing or accounting matters, to the Chair of the Audit Committee of the Board, who oversees the investigation of that complaint. In addition to the provisions of the Code, the Ethics Officer reports quarterly to the Human Resources and Environment Committee of the Board on the nature of complaints received and the Vice-President, Audit and Corporate Compliance reports quarterly to the Audit Committee on matters related to audit and accounting. A copy of Toronto Hydro's Code of Business Conduct and Whistleblower Procedure is available on the SEDAR website at www.sedar.com.

(e) Insurance

Toronto Hydro's current insurance policies provide coverage for a variety of losses and expenses which might arise from time to time, including:

- comprehensive general liability insurance;
- all risk property, property terrorism, boiler and machinery insurance;
- automobile liability insurance;
- directors and officers liability insurance;
- cyber insurance;
- crime insurance; and
- insurance covering loss or damage on certain physical assets.

Toronto Hydro believes that the coverage, amounts and terms of its insurance arrangements are consistent with industry practice.

(f) Intangible Property

The Corporation owns various intangible assets, such as computer software systems used in the course of business, and intellectual property, including the "Toronto Hydro" brand name and the trademark Toronto Hydro & Star Design. The Corporation also owns the trademarks peakSAVER®, POWERSHIFT® and PEAKSAVER PLUS®. The trademarks peakSAVER® and PEAKSAVER PLUS® have been licensed by the Corporation to the IESO and sub-licensed to various electricity distributors in the Province for the promotion of a province-wide demand response CDM program.

(g) Seasonal Effects

Toronto Hydro's revenues, all other things being equal, are impacted by temperature fluctuations and unexpected weather conditions. Revenues would tend to be higher in the first quarter as a result of higher energy consumption for winter heating, and in the third quarter due to air conditioning/cooling. Toronto Hydro's revenues are also impacted by fluctuations in electricity prices and the timing and recognition of regulatory decisions and rate orders.

PART 5 - GENERAL DEVELOPMENT OF THE BUSINESS

5.1 Business Operations

(a) Three Year History

The following table sets forth selected annual financial information of the Corporation for the three years ended December 31, 2017, 2016 and 2015. This information has been derived from the Consolidated Financial Statements and is presented in millions of dollars.

	Year ended December 31		
	2017	**2016**	**2015**
Net income after net movements in regulatory balances	$156.5	$151.4	$126.7
Capital expenditures	$552.9	$551.7	$537.2
Total assets and regulatory balances	$5,226.2	$4,954.4	$4,686.9
Total equity	$1,760.4	$1,428.9	$1,340.9

(b) Business Operations

Over the past three years, Toronto Hydro continued to streamline its business operations to focus on LDC's core businesses of distributing electricity and engaging in CDM activities. See section 5.4 under the heading "Conservation and Demand Management" for more information on LDC's CDM activities.

5.2 Rate Applications

The following is an overview of LDC's rate applications from 2015 to date.

(a) 2015-2019 Rate Application

On July 31, 2014, LDC filed a rate application with the OEB under the CIR method which sought approval of LDC's 2015 test-year revenue requirement on a cost of service basis and the corresponding electricity distribution rates effective May 1, 2015, and the subsequent annual rate adjustments based on a custom index specific to LDC for the period commencing on January 1, 2016 and ending on December 31, 2019. The rate application included requests for approval of capital expenditures of approximately $2.5 billion over the 2015-2019 period. The rate application also sought approval to include in LDC's rate base capital amounts that were prudently incurred prior to 2015, subject to review by the OEB. In addition, LDC sought approval to recover the net book value of stranded meters.

On April 28, 2015, the OEB declared LDC's existing rates as interim rates, effective May 1, 2015, pending a final CIR decision and rate order. On December 29, 2015, the OEB issued its CIR decision and on March 1, 2016, the OEB issued its CIR rate order, both in relation to the 2015-2019 rate application filed on July 31, 2014. The CIR decision and rate order approved a rate base of $3,232.0 million and revenue requirement of $633.1 million for 2015, and rates calculated on that basis. The CIR decision and rate order also approved, on an interim basis, subsequent annual rate adjustments based on a custom index for the period commencing on January 1, 2016 and ending on December 31, 2019. The OEB-approved revenue requirement generates an increase in funded capital expenditures over the CIR period.

The OEB approved new deferral and variance accounts including accounts to capture variances related to revenue requirement for ICM capital work undertaken from 2012 to 2014 and revenue requirement associated with capital work during the CIR term. The OEB approved recovery of the $15.8 million forecasted net book value relating to the stranded meters. The OEB also approved foregone revenue rate riders for the May 1, 2015 to February 29, 2016 period as well as other requested rate riders. In addition, the OEB approved the transfer of LDC's street lighting assets into rate base effective January 1, 2015 at a transfer price of $39.8 million, representing the opening net book value of the assets in 2015. The financial impact of the OEB's CIR decision and rate order has been reflected in 2015.

The rates for 2015 and 2016 were implemented on March 1, 2016, with effective dates of May 1, 2015 and January 1, 2016, respectively.

On August 22, 2016, LDC filed its 2017 rate application seeking OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2017 and ending on December 31, 2017. On December 21, 2016, the OEB issued a decision finalizing LDC's 2017 rates and providing for other deferral and variance account dispositions.

On August 23, 2017, LDC filed its 2018 rate application seeking OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2018 and ending on December 31, 2018. On December 14, 2017, the OEB issued a decision and rate order approving LDC's 2018 rates, with an effective date of January 1, 2018, and the disposition of certain deferral and variance accounts.

(b) 2012-2014 ICM True-Up Application

The OEB's decision and rate order on LDC's 2012-2014 rate application directed that a reconciliation process take place to reflect the difference between the revenue collected pursuant to the ICM and the actual revenue requirement associated with actual in-service assets eligible for ICM funding. On March 8, 2016, LDC filed a rate application to reconcile those amounts, in accordance with the OEB directive. The rate application requests approval to recover an additional $11.1 million from ratepayers.

On July 28, 2016, the OEB approved a settlement proposal submitted by LDC and intervenors to the ICM rate application, which provided that there would be no change to the 2015–2019 rate base previously approved in the CIR decision and the 2012-2014 ICM process would be closed with no future disposition to or from ratepayers. Further to this approval, $9.8 million previously recorded as an ICM regulatory credit balance was recorded as an increase in equity through net movements in regulatory balances in the third quarter of 2016.

5.3 Ontario's Fair Hydro Plan

On March 2, 2017, the Government of Ontario announced the OFHP which includes a number of initiatives, some of which affect LDC or its customers.

OFHP includes the OREC, which came into effect on January 1, 2017. The OREC provides eligible customers with financial assistance in the form of an 8% rebate of the pre-tax cost of their electricity. The OREC rebates are administered by LDC and paid by the IESO in the month following customer billing. Current accounts receivable and unbilled revenue include the amount owing by the IESO to LDC. No effect on revenue or expense is recognized by LDC in respect of the OREC rebates.

OFHP also includes the OFHA, which enacted the Ontario Fair Hydro Plan Act, 2017 and amended the Electricity Act, 1998 and the Ontario Energy Board Act, 1998. The OFHA came into effect on June 1, 2017 and its impact is reflected in the Consolidated Financial Statements. The OFHA provides eligible customers with financial assistance through various changes to commodity pricing, new or amended programs, and eliminating or reducing certain provincial charges on the electricity bill. The OFHP reduces electricity bills by 25% on average for eligible customers, which includes the 8% OREC rebate. The OFHA reduces the total electricity bill for eligible customers and, accordingly, reduces current accounts receivable, unbilled revenue, accounts payable and accrued liabilities for LDC. No effect on distribution revenue or expense is recognized by LDC in respect of the OFHA.

5.4 Conservation and Demand Management

On March 26, 2014, the Minister of Energy of Ontario, under the guidance of sections 27.1 and 27.2 of the OEB Act, directed the OEB to amend the licence of each licensed electricity distributor to require the electricity distributor, as a condition of its licence, to make CDM programs available to its customers and to do so in relation to each customer segment in its service area, over the period beginning January 1, 2015 through December 31, 2020. On March 31, 2014, the Minister of Energy of Ontario issued a direction to require the OPA to coordinate, support and fund the delivery of CDM programs through electricity distributors. The objective of the CDM efforts is to reduce electricity consumption in the Province of Ontario by a total of 7 terawatt hours between January 1, 2015 and December 31, 2020, of which LDC's share is approximately 1,576 GWh of energy savings.

On November 13, 2014, LDC entered into an energy conservation agreement with the OPA for the delivery of CDM programs over the 2015-2020 period. The IESO and the OPA were merged under the name IESO starting on January 1, 2015.

Under the energy conservation agreement with the IESO, LDC submitted a joint CDM plan with Oakville Hydro for the delivery of CDM programs over the 2015-2020 period on April 30, 2015. LDC can choose between full cost recovery funding, pay-for-performance funding, or a combination of both, on a CDM program by program basis. Under the full cost recovery funding method, the IESO reimburses LDC for all adequately documented incurred costs, with an option to receive a portion of its funding in advance. Cost efficiency incentives may be awarded if LDC's electricity savings meet or exceed certain CDM plan targets for programs under the full cost recovery funding method, with a mid-term review to be performed by the IESO for the 2015-2017 period. Under the pay-for-performance funding method, LDC receives payment in arrears based on verified electricity savings achieved with various options for frequency of payment. The programs under the joint CDM plan with Oakville Hydro are only being offered under the full cost recovery funding method.

The joint CDM plan provides combined funding of approximately $425.0 million, including participant incentives and program administration costs to achieve an aggregate energy savings target of approximately 1,668 GWh. Oakville Hydro's programs under the joint CDM plan started on January 1, 2016. LDC received $44.9 million as at December 31, 2016 and $57.4 million in the year ended December 31, 2017 from the IESO for the delivery of CDM programs. Amounts received but not yet spent are presented on the consolidated balance sheets under current liabilities as deferred conservation credit. As at December 31, 2017, LDC estimated that approximately $12.9 million qualified as a joint mid-term incentive, of which $12.2 million represents LDC's portion and is included within accounts receivable.

Effective October 16, 2017, LDC entered into an agreement to transfer $4.0 million of funding and a corresponding 20 GWh of its energy savings target to another local distribution company. This agreement will decrease the joint CDM plan funding with Oakville Hydro to $421.0 million, with a revised energy savings target of 1,648 GWh. The revised CDM plan was approved by the IESO on December 14, 2017.

PART 6 - RELATIONSHIP WITH THE CITY

6.1 Shareholder Direction

As sole shareholder of the Corporation, the City has adopted the Shareholder Direction that sets out the following corporate governance principles with respect to Toronto Hydro:

- the objectives and principles that govern the operations of Toronto Hydro;
- the matters in addition to those set out in the OBCA that require the approval of the City as the sole shareholder of the Corporation; and
- certain financial and administrative arrangements between the Corporation and the City.

The Shareholder Direction requires Toronto Hydro to conduct its affairs and govern its operations in accordance with such rules, policies, directives or objectives as directed by City Council from time to time.

(a) Shareholder Objectives and Principles

The Shareholder Direction provides that the following objectives and principles shall govern the operations of Toronto Hydro:

- to operate Toronto Hydro on an efficient and commercially prudent basis;
- to optimize the City's return on equity as the sole shareholder of the Corporation and operate Toronto Hydro with a view to meeting the financial performance objectives of the City as set out in the Shareholder Direction;

- to provide a reliable, effective and efficient electricity distribution system that supports the electricity demands of residents and businesses in the City;
- to operate Toronto Hydro in an environmentally responsible manner consistent with the City's energy, climate change and urban forestry objectives and, as appropriate, utilizing emerging green technologies;
- to ensure that the business is managed in material compliance with all law; and
- to engage in recruitment and procurement practices designed to attract employees and suppliers from the City's diverse community.

The Shareholder Direction provides that the Board is responsible for determining and implementing the appropriate balance among these objectives and principles and for causing Toronto Hydro to conduct its affairs in accordance with the same.

(b) Shareholder Approval

In addition to those matters set out in the OBCA, the following matters, among others, require the approval of the City as the sole shareholder of the Corporation:

- subject to certain exceptions in the case of LDC, creating any security over the assets of the Corporation or LDC;
- in the case of LDC, providing any financial assistance to any person other than in accordance with the Shareholder Direction;
- in the case of the Corporation and LDC, making any investment in or providing any financial assistance to any subsidiary of the Corporation (other than LDC), other than trade payables incurred in the ordinary course of business on customary terms and an investment in or financial assistance to a subsidiary that originally was an investment in or financial assistance to LDC, in excess of 12% of the shareholder's equity of LDC as shown in its most recent financial statements; and
- acquiring any interest in the electricity distribution system, undertaking or securities of a distributor operating outside the City unless, among other things, the acquisition does not adversely affect the dividend payable to the City and there is no dilution of the City's shareholding in the Corporation.

The City has authorized the Corporation to provide financial assistance to its subsidiaries for the purpose of enabling them to carry on their respective businesses, including, in the case of LDC, for the purpose of satisfying the prudential requirements of the IESO. The Shareholder Direction limits the financial assistance that may be provided by the Corporation to its subsidiaries to an aggregate amount of $500.0 million, except in the case of LDC, which financial assistance is unlimited.

(c) Financial Performance

The Shareholder Direction provides that the Board will use its best efforts to ensure that Toronto Hydro meets certain financial performance standards, including those relating to the credit rating and dividends.

(d) Credit Rating

The Shareholder Direction provides that the Corporation will obtain and maintain a rating of A minus or higher (or its equivalent rating, depending on the credit rating agency) on its senior debt securities, as rated by two accredited credit rating agencies in Ontario (which include S&P, DBRS and Moody's).

(e) Equity Contribution

In December 2016, City Council approved making an equity contribution to the Corporation. On June 28, 2017, the Corporation issued 200 common shares to the City for total proceeds of $250.0 million, net of share issue costs and expenses.

(f) Dividends

In connection with receipt of the equity contribution of $250.0 million from the City on June 28, 2017, the Board declared dividends payable to the City and approved amendments to the Corporation's Dividend Policy, as follows:

- In respect of fiscal 2017, an aggregate amount of $75.0 million shall be paid to the City, consisting of two previously declared installments of $6.25 million each and a further $62.5 million. The $62.5 million was paid to the City on July 7, 2017.
- In respect of fiscal 2018 and subsequent fiscal years, 60% of the Corporation's consolidated net income after net movements in regulatory balances for the prior fiscal year shall be declared separately in four equal quarterly instalments, with each instalment payable to the City on the last business day of each fiscal quarter.

The revised Dividend Policy was set out in further detail, including that any dividends will be subject to restrictions imposed by law and the Shareholder Direction, in an amendment of the Shareholder Direction, which included the Corporation's former Dividend Policy. These changes also superseded the Board's previous decision announced in November 2016 that it would reduce dividend payments to the City to $25.0 million per year until further notice.

The Corporation declared and paid dividends to the City totalling $56.25 million in 2015, $63.35 million in 2016, and $75.0 million in 2017.

On March 7, 2018, the Board declared a quarterly dividend in the amount of $23.48 million, payable to the City by March 31, 2018.

LDC declared and paid $nil dividends to the Corporation in 2015 and 2016, and declared and paid $2.1 million in 2017.

TH Energy declared and paid $nil dividends to the Corporation in 2015, 2016, and 2017.

6.2 Services Provided to the City

Toronto Hydro provides certain services to the City at commercial and regulated rates, including street lighting services. Ongoing street lighting services are provided by TH Energy and sub-contracted to LDC. See section 4.4 under the heading "Toronto Hydro Energy Services Inc." for more information. See note 23 to the Consolidated Financial Statements.

6.3 Shareholder Engagement

The Corporation believes that regular and constructive engagement with its shareholder is an important part of creating an open, candid and informed dialogue. In addition to the Corporation's annual shareholder meetings, representatives of the Corporation engage with the shareholder through formal attendance at City of Toronto Council meetings and other engagements with Councillors throughout the year as required. Other means of communications with the shareholder include the Corporation's annual and quarterly financial and management reports, and ward-specific updates.

PART 7- TAXATION

7.1 Tax Regime

The Corporation is exempt from tax under the ITA, if not less than 90% of the capital of the Corporation is owned by the City and not more than 10% of the income of the Corporation is derived from activities carried on outside the municipal geographical boundaries of the City. In addition, the Corporation's subsidiaries are also exempt from tax under the ITA provided that all of their capital is owned by the Corporation and not more than 10% of their respective income is from activities carried on outside the municipal geographical boundaries of the City. A corporation exempt from tax under the ITA is also exempt from tax under the TA.

The Corporation and each of its subsidiaries are MEUs for purposes of the PILs regime contained in the Electricity Act. The Electricity Act provides that a MEU that is exempt from tax under the ITA and the TA is required to make, for each taxation year, a PILs payment to the OEFC in an amount equal to the tax that it would be liable to pay under the ITA and the TA if it were not exempt from tax. The PILs regime came into effect on October 1, 2001, at which time the Corporation and each of its subsidiaries were deemed to have commenced a new taxation year for purposes of determining their respective liabilities for PILs payments.

If the Corporation or a subsidiary ceases to be exempt from tax under the ITA and the TA, it will become subject to tax under those statutes, will no longer be required to make PILs payments to the OEFC, and will be deemed to have disposed of its assets for proceeds of disposition equal to their fair market value at that time and to have reacquired its assets at the same amount with the result that:

- such corporation would become liable to make a PILs payment in respect of any income or gains arising as a result of these deemed dispositions; and
- the amount of annual taxes payable by the corporation under the ITA, and the TA may be different from the PILs payment that would be payable without a loss of tax-exempt status to reflect, among other things, the consequences of these deemed dispositions and acquisitions.

The Electricity Act also provides that a municipal corporation or an MEU is required to pay a transfer tax when it transfers Electricity Property. An interest in Electricity Property includes any interest in a corporation, partnership or other entity that derives its value in whole or in part from Electricity Property. The transfer tax is the prescribed percentage (33% for transfers occurring prior to January 1, 2016, 22% for transfers occurring between January 1, 2016 and December 31, 2018, and 33% for transfers occurring thereafter) of the fair market value of the interest transferred. The amount of transfer tax payable where the interest that is transferred is an interest in a corporation, partnership or other entity, is calculated in accordance with a special rule. The amount of transfer tax payable by an MEU on a transfer of Electricity Property may be reduced by:

- any PILs payment made by the MEU in respect of the part of the taxation year up to and including the date that the transfer takes place or a previous taxation year; and
- any amount that the MEU has paid as tax under Part III of the TA in respect of the part of the taxation year up to and including the date of the transfer or a previous taxation year.

Transfers of Electricity Property made to a municipal corporation, a MEU, Hydro One or OPG, and where the transferee is exempt from tax under the ITA at the time of transfer, the transfer will be an excluded transfer and thereby exempt from the transfer tax. Capital gains arising from a transfer of Electricity Property occurring between January 1, 2016 and December 31, 2018 are also exempt from the transfer tax.

In addition, a refund of transfer tax may be made where such tax had been paid on the sale or transfer of Electricity Property and where the proceeds of that transfer were reinvested in certain other capital or depreciable assets used in connection with generating, transmitting, distributing or retailing electricity in Ontario and, subject to certain deeming rules, before the end of the second taxation year following the taxation year in which the liability to pay the transfer tax arose.

PILs payments are deductible in computing the transfer tax only to the extent that they have not been previously applied to reduce transfer tax payable by a municipal corporation or a MEU.

7.2 PILs Recoveries through Rates

The OEB's Filing Requirements for Electricity Distribution Rate Applications provides for electricity distribution rate adjustments to permit recoveries relating to PILs payments. These recoveries are recalculated and submitted for recovery by LDC in each cost of service or rebasing distribution rate application. LDC is also generally at risk for variances between forecasted and actual PILs paid, excluding variances arising from changes in tax legislation not assumed in the setting of rates for the period in question, which variances are disposed of through deferral accounts under cost of service, IRM or CIR. See note 9(j) to the Consolidated Financial Statements.

PART 8 - RISK FACTORS

Risk Oversight

Toronto Hydro faces various risks that could impact the achievement of its strategic objectives. It adopts an enterprise wide approach to risk management, achieved through a process of consolidating and aligning the various views of risk across the enterprise via a risk governance structure. Toronto Hydro executes its ERM activities via an ERM framework that is aligned to industry best practices and international guidelines. Toronto Hydro views ERM as a management activity undertaken to add value and improve overall operations. It helps Toronto Hydro by enabling the attainment of its strategic goals and objectives through a systematic, disciplined approach towards identifying, evaluating, treating, monitoring and reporting of risks. Accordingly, ERM is an integral part of the strategic management of Toronto Hydro and is routinely considered in forecasting, planning and executing all aspects of the business.

The ERM framework is operationalized by a consistent, disciplined methodology that clearly defines the risk management process which incorporates subjective elements, risk quantification and risk interdependencies.

While Toronto Hydro's philosophy is that ERM is the responsibility of all business units, at all levels, in strategic and operational matters, the ERM governance structure is comprised of three key levels.

At the top level is the Board, which works to maintain a general understanding of Toronto Hydro’s risk profile, the risk categories, the types of risks to which Toronto Hydro may be exposed and the practices used to identify, assess, measure and manage those risks. The risk profile is a list of key risks that represent the greatest threats to achieving the Corporation's strategic objectives.

The second level is the executive team, the lead body to ensure systems are in place to identify, manage, and monitor risks. Through its review of reports from the business and other areas, the executive team assesses the appropriateness and consistent application of systems to manage risks within Toronto Hydro. The executive team also ensures that key risks are brought forward to the attention of the Board for discussion and action, as required.

Finally, the third level is the senior leadership team. The senior leadership team supports the executive team and is a collection of subject matter experts from across Toronto Hydro who actively engage in the day-to-day management of risks. Working with the executive team, this group oversees Toronto Hydro's risk profile, its performance against the defined risk appetite and determines appropriate risk responses. They also work to ensure effective, efficient, complete and transparent risk reporting to the executive team.

Toronto Hydro's business is subject to a variety of risks including those described in the following sections. There can be no assurance that any steps Toronto Hydro may take to manage risks will avoid future loss resulting from the occurrence of such risks.

Risks from External Influences

Ownership by the City and Inconsistent Policy Risk

The Corporation is subject to the risk that its shareholder can potentially limit the Corporation's ability to meet its business objectives as laid out in the Shareholder Direction principles. Under the Shareholder Direction, the City also has the power to direct the Corporation and its subsidiaries to conduct their affairs and govern their operations in accordance with such rules, policies, directives or objectives as are directed by City Council from time to time. These council approved directions can be inconsistent and/or divergent with the Shareholder Direction principles and could materially adversely affect the Corporation's business, operations, financial condition or prospects if the Corporation is required to comply with such directions.

Regulatory Risk

Toronto Hydro is subject to the risk that its business activities may be impeded by the OEB (includes both traditional regulated Cost of Service work and non-traditional new ancillary service model work). There is a risk that future changes to Ontario's regulatory model, manner of regulation and/or broader government policy framework does not align with Toronto Hydro's business direction and could materially adversely affect the Corporation's strategic goals and financial results.

Ontario's electricity industry regulatory developments may affect the electricity distribution rates charged by LDC and the costs LDC is permitted to recover. This may in turn have a material adverse effect on the financial performance of the Corporation and/or LDC's ability to deliver effective and efficient operations and reliable service to its customers, and as well as create barriers to LDC achieving its strategic objectives. Among other things, there can be no assurance that:

- the OEB will approve LDC's electricity distribution rates, at levels that will permit LDC to carry out its planned capital expenditures required to maintain safe and reliable service to its customers and earn the allowed rate of return on the investment in the business;
- all capital expenditures incurred by LDC will be approved by the OEB. In particular, capital cost overruns due to project delays or increased costs may not be recoverable in distribution rates;
- the regulatory instruments that are made available to LDC will be sufficient to address LDC's operations, needs and circumstances in respect of future applications for electricity distribution rates;
- the OEB will not set a lower recovery for LDC's cost of capital;
- the full cost of providing service to distribution customers will be permitted to be recovered through LDC's electricity distribution rates;
- the OEB will not permit competitors to provide distribution services in LDC's licensed area, or permit loads within LDC's service area to become electrically served by a means other than through LDC's electricity distribution system;
- the OEB will allow recovery for revenue lost as a consequence of unanticipated effects of CDM;
- parts of LDC's services will not be separated from LDC and opened to competition; or
- regulatory or other changes will not be made to the PILs regime.

Any future regulatory decision to disallow or limit the recovery of costs could lead to potential asset impairment and charges to results from operations, which could have a material adverse effect on Toronto Hydro.

Political and Legislative Risk

Toronto Hydro is subject to the risk that government bodies and policy priorities of government may impact Toronto Hydro's ability to deliver effective and efficient operations and meet business objectives. Changes to any of the laws, rules, regulations and policies applicable to the businesses carried on by Toronto Hydro could materially adversely affect Toronto Hydro. There can be no assurance that Toronto Hydro will be able to comply with applicable future laws, rules, regulations and policies. Failure by Toronto Hydro to comply with applicable laws, rules, regulations and policies may subject Toronto Hydro to civil or regulatory proceedings that could have a material adverse effect on Toronto Hydro. The OEB may not allow recovery for the costs of coming into or maintaining compliance with these laws, rules, regulations and policies.

Risks to Maintaining Operations

Human Capital Risk

Toronto Hydro is subject to the risk that human resources may not be available with the necessary knowledge, skills and education to support Toronto Hydro's future talent requirements. All retirements pose risks for knowledge management and business continuity, both at Toronto Hydro and the industry. Development and retention of talent to meet the evolving needs of the business requires LDC to focus on a series of proactive activities and programs to mitigate these risks, such as strategic workforce planning, promotion of apprenticeship programs, investments in colleges and universities, succession planning, knowledge transfer and a robust training program.

Toronto Hydro's ability to operate successfully in the electricity industry in Ontario will continue to depend in part on its ability to make changes to existing work processes and conditions in order to adapt to changing circumstances. Toronto Hydro's ability to make such changes, in turn, will continue to depend in part on its relationship with its labour unions including reaching a new collective bargaining agreement with PWU. There can be no assurance that Toronto Hydro will be able to secure the support of its labour unions.

Strategy and Business Model Risk

Toronto Hydro is subject to the risk that it may fail to monitor the external environment and or develop and pursue strategies through appropriate business models, thus failing to gain a strategic advantage, which could materially adversely affect the Corporation. The OEB distribution licence issued to LDC stipulates a service area that reflects the territory within the City. By law, only the OEB can grant such a licence for a service area and only an entity with such a licence can provide licenced services to the public-at-large within a service area. The OEB has not granted any other distribution licence that permits distribution within LDC's service area. In addition to this regulatory barrier to entry, there are other barriers to entry, including the cost of constructing an electricity distribution system, physical space limitations within and legal access to the right-of-way, the specialized skills associated with the distribution business, the level of expertise required to achieve operational and regulatory compliance, and LDC's relationships with its customers. There can be no assurance that these barriers will continue to be sufficient to prevent this type of competition. Other regulated and unregulated entities have always competed with LDC and its predecessors to provide customers with other sources of energy, including electricity. The pervasiveness of this competition and its effects on LDC's distribution business have varied over time and continue to vary based on many factors, including the relative price of energy source (e.g., natural gas, grid-supplied electricity, behind-the-meter generation) and technology advancements (e.g., multi-unit building sub-metering, micro-grids, electricity storage).

There can be no assurance that the future nature, prevalence, or effects of these forms of competition will be comparable to current or historic experience. Failure to effectively scan our external and internal environment could lead to missed business opportunities and loss of competitive advantage (see "Customer Risk" section for additional details).

Asset Integrity Risk

Toronto Hydro is subject to the risk that it may be unable to maintain continuous supply due to failure of the existing distribution infrastructure and assets which could materially adversely affect the Corporation. Electricity distribution is a capital-intensive business. As the municipal electricity distribution company serving the largest city in Canada,

LDC continues to invest in the renewal of existing aging infrastructure and in the development of new infrastructure (such as the Copeland Station project) to address safety, reliability and customer service requirements.

LDC estimates that approximately one-third of its electricity distribution assets have already exceeded or will reach the end of their expected useful lives within the next 5-year period. At the same time, Toronto is a growing city, and LDC must make system upgrades to expand its capacity to keep pace with urban intensification and electrification. In addition, as the City, Ontario and the Government of Canada implement policies and programs to respond to climate change, the pressures on Toronto Hydro's system will only increase. Widespread adoption of electric vehicles, fuel switching and changing emissions standards make electricity the comparatively clean energy choice. This drives the need for significant capital expenditures for system upgrades so that the grid can handle such increased load. LDC's ability to continue to provide a safe work environment for its employees and a reliable and safe distribution service to its customers and the general public will depend on, among other things, the ability of Toronto Hydro to fund additional infrastructure, and the OEB allowing recovery of costs in respect of LDC's maintenance program and capital expenditure requirements for distribution plant refurbishment and replacement.

As described in section 4.3(a)(iii) under the heading "Transmission System Terminal Stations", one of LDC's largest capital initiatives currently in progress is the construction of Copeland Station, which is also one of the most complex projects ever undertaken by Toronto Hydro. Due to unforeseen delays, the expected completion date for the Copeland Station project has been extended to 2018 and it is currently anticipated that the total expenditure required to complete the project will increase from $195.0 million to approximately $200.0 million, plus capitalized borrowing costs as applicable. There may be additional unforeseen delays and expenditures prior to the completion of the project. On January 25, 2017, Toronto Hydro was informed that Carillion Construction Inc., the general contractor for the Copeland Station Project, filed for creditor protection under the Companies' Creditors Arrangement Act after its affiliate, Carillion plc, went into compulsory liquidation in the United Kingdom.

All capital projects for new and replacement infrastructure have risks related to delays or increased costs due to many factors, including: necessary modifications to project plans; the availability, scheduling and cost of materials, equipment and qualified personnel; LDC's ability to obtain necessary environmental and other regulatory and governmental approvals; and the impact of weather conditions, site conditions and contractor performance.

LDC is focused on overcoming the above challenges and executing its capital and maintenance programs. However, if LDC is unable to carry out these plans in a timely and optimal manner or becomes subject to significant unforeseen equipment failures, equipment performance will degrade. Such degradation may compromise the reliability of distribution assets, the ability to deliver sufficient electricity and/or customer supply security and increase the costs of operating and maintaining these assets.

Occupational Health and Safety Risk

Toronto Hydro is subject to the risk that employees may be exposed to serious or fatal injuries or illness as a result of the work environment in which they operate. Due to the nature of Toronto Hydro's business and business activities, occupational safety is an integral part of our corporate culture. Employees could be exposed to hazards when performing their work duties. This includes hazards such as electrical contact, working in confined spaces, fires and explosions, slips, trips and falls and motor vehicle accidents. Toronto Hydro is subject to compliance with provincial Health and Safety legislation. Toronto Hydro's management approach to occupational safety is to meet or excel on legal compliance and eliminate or safeguard known occupational hazards and risks. There are processes in place to develop and nurture good leadership practices through recruitment, education, training and performance management practices that encourage the application of our corporate values, including safety. LDC received OHSAS 18001 certification in 2013 and conducts annual third party audits to maintain certification, in addition occupational health and safety legal compliance audits are conducted every two years.

Customer Risk

Toronto Hydro is subject to the risk that it may fail to identify and meet its customers' needs and expectations, within approved OEB funding levels, and consequently customers leave Toronto Hydro's distribution area or opt for alternative sources of electricity. This includes all customer classes, but is primarily related to general service and large users. This may lead to erosion of Toronto Hydro's revenue base and monopoly position. It is important that Toronto Hydro maintains its relationship with its customers to better understand the specific needs and expectations of each class. The political environment and government policy regarding the energy sector may impact customer

satisfaction and perception of value, especially with concerns around hydro costs. Toronto Hydro is taking steps to help its customers through cost saving CDM programs. Service interruptions due to increasing weather events, or unexpected events could further impact customer satisfaction and service quality (see "Business Interruption Risk" section for additional details).

Advances in technology may compete with Toronto Hydro by affecting energy consumption levels and, as a result, customer demand for Toronto Hydro's services could be negatively impacted in a material way. As customers increasingly prioritize energy efficiency and awareness of energy costs, and governments increasingly provide subsidies to encourage energy efficiency primarily in response to climate change concerns, there will be a corresponding increase in the demand for technologies that enable customers to better monitor and minimize their energy consumption and otherwise exercise greater control over their electricity supply and demand. For example, distributed generation technologies draw on renewable sources of energy, such as solar power and wind, allowing customers to generate their own supply of electricity. The effect of such technologies may be reduced reliance on larger-scale utilities such as Toronto Hydro. Likewise, energy-efficient homes and improvements to energy storage technologies like batteries may further affect consumption levels and the demand for Toronto Hydro's services. Although OEB's current policy is moving residential customers to fixed delivery charges as opposed to consumption-based delivery charges, as technologies continue to advance and become more widely adopted, Toronto Hydro may be required to make changes to its business and operations, which may present additional risks and challenges for Toronto Hydro.

The Corporation is affected by energy demand which may change as a result of technology change, available customer choice and CDM programs, as well as general economic conditions, energy prices, disposable income and population growth, among other things. Reduced or increased energy demand could have a material adverse effect on the Corporation's business, operations, financial condition or prospects, as well as on the Corporation's need for, and ability to, fund future capital expenditures.

Information Technology and Cybersecurity Risk

Toronto Hydro is subject to the risk that it may be unable to preserve the confidentiality, integrity, authenticity, availability, accountability and non-repudiation of information assets. Toronto Hydro's ability to operate effectively is in part dependent on the development, maintenance and management of complex information technology systems. Computer systems are employed to operate LDC's electricity distribution system, and Toronto Hydro's financial, billing and business systems to capture data and to produce timely and accurate information. Failures of any one of the financial, business and operating systems could have a material adverse effect on the Corporation's business, operations, financial condition or prospects. Toronto Hydro mitigates this risk through various methods including the implementation of high availability and redundancy in its core infrastructure and application components. Operational technology systems are isolated from business systems and operate independently.

LDC's electricity distribution infrastructure and technology systems are also potentially vulnerable to damage or interruption from cyber-attacks, breaches or other compromises, which could result in business interruption, service disruptions, theft of intellectual property and confidential information (about customers, suppliers, counterparties and employees), additional regulatory scrutiny, litigation and reputational damage. Toronto Hydro has implemented security controls aligned with industry best practices and standards including the National Institute of Standards and Technology Cybersecurity Framework, and maintains cyber insurance. Cyber-attacks, breaches or other compromises of electricity distribution infrastructure and technology systems could result in service disruptions and system failures, including as a result of a failure to provide electricity to customers, property damage, corruption or unavailability of critical data or confidential employee or customer information. A significant breach could materially adversely affect the financial performance of the Corporation or its reputation and standing with customers, regulators and in the financial markets. It could also expose Toronto Hydro to third-party claims.

LDC must also comply with legislative and licence requirements relating to the collection, use and disclosure of personal information (including the personal information of customers), as well as information provided by suppliers, contractors, employees, counterparties, and others. Such information could be exposed in the event of a cybersecurity incident or other unauthorized access, which could materially adversely affect Toronto Hydro and also result in third-party claims against Toronto Hydro.

Preventative controls are employed to protect information and technology assets against cyber-attacks and mitigate their effects. Detective controls are employed to continuously monitor information systems so that Toronto Hydro can respond appropriately to minimize the damage in the event of a cyber-attack. Even with these measures in place, since the techniques used to obtain unauthorized access, disable or degrade service, or sabotage systems change frequently and often are not recognized until launched against a target, Toronto Hydro may be unable to anticipate these techniques or to implement adequate preventative measures. As such, there can be no assurance that such measures will be effective in protecting LDC's electricity distribution infrastructure or assets, or the personal information of its customers, from a cyber-attack or the effects therefrom.

Brand and Reputation Risk

Toronto Hydro is subject to the risk that an action or inaction by it or its representatives will impair Toronto Hydro's image in the community, public confidence or brand. Toronto Hydro is committed to delivering safe and reliable electricity to its customers in an environmentally responsible manner at optimal costs. Failure to deliver on our commitment could impact the public's perception of Toronto Hydro. In addition, events and/or external factors that draw negative media attention to Toronto Hydro could cause reputational damages and impact Toronto Hydro's business and relationship with its stakeholders.

Business Interruption Risk

Toronto Hydro is subject to the risk that it may be unable to maintain continuing and sustainable business operations, or recover from business interruption, in an effective manner. Toronto Hydro's operations are exposed to the effects of natural and other unexpected occurrences such as extreme storm and other weather conditions and natural disasters, as well as terrorism and pandemics. Although Toronto Hydro's facilities and operations are constructed, operated and maintained to withstand such occurrences, there can be no assurance that they will successfully do so in all circumstances. Any major damage to Toronto Hydro's facilities or interruption of Toronto Hydro's operations arising from these occurrences could result in lost revenues and repair costs that can be substantial. Although Toronto Hydro has insurance which it considers to be consistent with industry practice, if it sustained a large uninsured loss caused by natural or other unexpected occurrences, LDC may apply to the OEB for the recovery of the loss related to the electricity distribution system. There can be no assurance that the OEB would approve, in whole or in part, such an application.

Risks to Maintaining Financial Condition

Capital Structure Risk

Toronto Hydro is subject to the risk that it may not be able to optimize its debt to equity ratio or access capital markets at effective rates. There can be no assurance that debt or equity financing will be available or sufficient to meet the Corporation's requirements, objectives, or strategic opportunities. If and when financing is available, there can be no assurance that it will be on acceptable terms to the Corporation.

The Corporation relies on debt financing through its MTN Program, CP Program or existing credit facilities to finance Toronto Hydro's daily operations, repay existing indebtedness, and fund capital expenditures. The Corporation's ability to arrange sufficient and cost-effective debt financing could be materially adversely affected by a number of factors, including financial market conditions and activity in the global capital markets, the regulatory environment in Ontario, the Corporation's business, operations, financial condition or prospects, compliance with covenants, the ratings assigned to the Corporation or the debentures issued under the Corporation's MTN Program by credit rating agencies, the rating assigned to short-term borrowings under the CP Program by a credit rating agency, and the availability of the commercial paper market.

In the event the Corporation is unable to maintain an R-1 (low) credit rating for its CP Program, the Corporation has sufficient liquidity through its Revolving Credit Facility to repay its commercial paper obligations as they become due.

Market and Credit Risk

Toronto Hydro is directly and indirectly subject to various market and credit fluctuations which could materially adversely affect the Corporation. For example, LDC is exposed to credit risk with respect to customer non-payment of electricity bills. LDC is permitted, at certain times of the year, to mitigate the risk of customer non-payment using any means permitted by law, including security deposits (i.e. letters of credit, surety bonds, cash deposits or lock-box arrangements, under terms prescribed by the OEB), late payment penalties, pre-payment, pre-authorized payment, load limiters or disconnection. While LDC would be liable for the full amount of the default, there can be no assurance that the OEB would allow recovery of the bad debt expense. Established practice in such cases is that the OEB would examine any electricity distributor's application for recovery of extraordinary bad debt expenses on a case-by-case basis. LDC's security interest or other measures, if any, may also not provide sufficient protection. Additionally, security interests and other measures taken by, or in favour of, LDC, if any, may not provide sufficient protection.

Toronto Hydro is exposed to fluctuations in interest rates for the valuation of its post-employment benefit obligations. Toronto Hydro estimates that a 1% (100 basis point) increase in the discount rate used to value these obligations would decrease the accrued benefit obligation of Toronto Hydro, as at December 31, 2017, by $46.8 million, and a 1% (100 basis point) decrease in the discount rate would increase the accrued benefit obligation, as at December 31, 2017, by $60.2 million.

The Corporation is exposed to short-term interest rate risk on the short-term borrowings under its CP Program and Working Capital Facility, and customer deposits, while most of its remaining obligations were either non-interest bearing or bear fixed interest rates, and its financial assets were predominately short-term in nature and mostly non-interest bearing. Toronto Hydro manages interest rate risk by monitoring its mix of fixed and floating rate instruments, and taking action as necessary to maintain an appropriate balance. Toronto Hydro estimates that a 100 basis point increase (decrease) in short-term interest rates, with all other variables held constant, would result in an increase (decrease) of approximately $2.3 million to annual finance costs.

Toronto Hydro had limited exposure to the changing values of foreign currencies. While Toronto Hydro purchases goods and services which are payable in US dollars, and purchases US currency to meet the related commitments when required, the impact of these transactions as at December 31, 2017 was not material.

PART 9 - CAPITAL STRUCTURE

9.1 Share Capital

The authorized capital of the Corporation consists of an unlimited number of common shares without par value, of which 1,200 common shares are issued and outstanding as at the date of this AIF.

The City is the sole shareholder of the Corporation. See note 17 to the Consolidated Financial Statements.

9.2 Debentures

As at December 31, 2017, the Corporation had the following debentures (the "Debentures") outstanding, which have been issued pursuant to its MTN Program:

- $250.0 million of 4.49% Series 3 senior unsecured debentures, due November 12, 2019;
- $200.0 million of 5.54% Series 6 senior unsecured debentures due May 21, 2040;
- $300.0 million of 3.54% Series 7 senior unsecured debentures, due November 18, 2021;
- $250.0 million of 2.91% Series 8 senior unsecured debentures due April 10, 2023;
- $245.0 million of 3.96% Series 9 senior unsecured debentures due April 9, 2063;
- $200.0 million of 4.08% Series 10 senior unsecured debentures due September 16, 2044;
- $200.0 million of 3.55% Series 11 senior unsecured debentures due July 28, 2045;
- $200.0 million of 2.52% Series 12 senior unsecured debentures due August 25, 2026; and
- $200.0 million of 3.485% Series 13 senior unsecured debentures due February 28, 2048.

The Debentures are not listed, posted for trading or quoted on any stock exchange or quotation system.

The Debentures have been issued under the CDSX book entry system administered by CDS Clearing and Depository Services Inc. ("CDS") with BNY Trust Company of Canada as trustee. Accordingly, a nominee of CDS is the registered holder of the Debentures and beneficial ownership of the Debentures is evidenced through book entry credits to securities accounts of CDS participants (e.g., banks, trust companies and securities dealers), who act as agents on behalf of beneficial owners who are their customers, rather than by physical certificates representing the Debentures.

9.3 Credit Facilities

The Corporation is a party to a credit agreement with a syndicate of Canadian chartered banks which established a revolving credit facility ("Revolving Credit Facility"), pursuant to which it may borrow up to $800.0 million, of which up to $210.0 million is available in the form of letters of credit. On July 30, 2015, the borrowing capacity under the Revolving Credit Facility was increased by $100.0 million from $700.0 million to $800.0 million and the maturity date extended by one year from October 10, 2019 to October 10, 2020. On August 19, 2016, the maturity date was extended by an additional year to October 10, 2021. On August 1, 2017, the maturity date of the Revolving Credit Facility was extended by one year from October 10, 2021 to October 10, 2022. Borrowings under the Revolving Credit Facility bear interest at short-term floating rates plus a fixed spread, which varies in accordance with the Corporation's credit rating.

The Revolving Credit Facility contains certain covenants, the most significant of which is a requirement that the Corporation's debt to capitalization ratio not exceed 75%. As at December 31, 2017, the Corporation was in compliance with all covenants included in its Revolving Credit Facility agreement.

The Corporation has a CP Program allowing up to $600.0 million of unsecured short-term promissory notes to be issued in various maturities of no more than one year. On July 30, 2015, the amount the Corporation may issue under this program was increased by $100.0 million from $500.0 million to $600.0 million. The CP Program is supported by liquidity facilities available under the Revolving Credit Facility; hence, available borrowing under the Revolving Credit Facility is reduced by the amount of commercial paper outstanding at any point in time. Proceeds from the CP Program are used for general corporate purposes. Borrowings under the CP Program bear interest based on the prevailing market conditions at the time of issuance.

Additionally, the Corporation is a party to:

- a $75.0 million demand facility with a Canadian chartered bank for the purpose of issuing letters of credit mainly to support LDC's prudential requirements with the IESO ("Prudential Facility"); and
- a $20.0 million demand facility with a second Canadian chartered bank for the purpose of working capital management ("Working Capital Facility").

The available amount under the Revolving Credit Facility as well as outstanding borrowings under the Revolving Credit Facility and CP Program are as follows:

	Revolving Credit Facility Limit	Revolving Credit Facility Borrowings	Commercial Paper Outstanding	Revolving Credit Facility Availability
December 31, 2017.....	$800.0 million	-	$159.0 million	$641.0 million
December 31, 2016.....	$800.0 million	-	$261.0 million	$539.0 million

For the year ended December 31, 2017, the average aggregate outstanding borrowings under the Corporation's Revolving Credit Facility, Working Capital Facility and CP Program were $210.3 million with a weighted average interest rate of 0.93%.

As at December 31, 2017, $11.7 million had been drawn under the Working Capital Facility and $38.4 million of letters of credit had been issued against the Prudential Facility.

9.4 Credit Rating

As at December 31, 2017, the credit ratings of the Corporation were as follows:

	DBRS		S&P	
	Credit Rating	**Trend**	**Credit Rating**	**Outlook**
Issuer rating	A	Stable	A	Stable
Debentures	A	Stable	A	-
Commercial paper	R-l (low)	Stable	-	-

On April 25, 2017, S&P announced its decision to maintain the credit rating on the Corporation as “A” and revised their outlook from negative to stable.

On April 27, 2017, DBRS announced its decision to maintain the credit rating on the Corporation as “A” with a stable trend.

DBRS rates long-term debt instruments by rating categories ranging from a high of "AAA" to a low of "D". All rating categories other than AAA and D also contain the subcategories "(high)" and "(low)" to indicate relative standing within the major rating categories. The absence of either a "(high)" or "(low)" designation indicates the rating is in the middle of the category. An A rating is the third highest of the ten rating categories. Long-term debt instruments which are rated in the "A" category by DBRS are considered to be of good credit quality, with substantial capacity for the payment of financial obligations. Entities in the "A" category, however, may be vulnerable to future events, but qualifying negative factors are considered manageable.

DBRS rates short-term debt instruments by rating categories ranging from a high of "R-1 (high)" to a low of "D". An R-1 (low) rating is the third highest of the ten rating categories. Short-term debt instruments which are rated in the "R-1 (low)" category by DBRS are considered to be of good credit quality, with substantial capacity for the payment of financial obligations. Entities in the "R-1 (low)" category, however, may be vulnerable to future events, but qualifying negative factors are considered manageable.

S&P rates long-term debt instruments by rating categories ranging from a high of "AAA" to a low of "D". Ratings from "AA" to "CCC" may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories. An A rating is the third highest of the ten rating categories. Long-term debt instruments which are rated in the "A" category by S&P are considered somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher-rated categories; however, the obligor's capacity to meet its financial commitment on the obligation is still strong.

Credit ratings are intended to provide investors with an independent measure of the credit quality of an issue of securities. A rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the rating agency.

For the years ended December 31, 2017 and 2016, payments were made to both DBRS and S&P for credit rating services only.

PART 10 - DIRECTORS AND OFFICERS

10.1 Nomination of Directors

As at the date of this AIF, the Board consists of eleven directors, all of whom are appointed by the sole shareholder of the Corporation, the City.

Pursuant to the Shareholder Direction, in electing directors to the Board, the City gives due regard to the qualifications of a candidate, including: experience or knowledge; commercial sensitivity and acumen; independence of judgment; and personal integrity. The City seeks candidates with experience and knowledge in: public utility commissions or boards of major corporations or other commercial enterprises; corporate finance; corporate governance; market development; large system operation and management; urban energy industries; and public policy issues and laws relating to Toronto Hydro, the electricity industry, environmental matters, labour relations and occupational health

and safety issues. Each citizen director is elected to serve for a term of up to two years or until his or her successor is appointed, and may be elected for a maximum of four consecutive terms for a maximum of eight consecutive years or such longer term until a successor is appointed. Each City Councillor director is elected to serve for two years or until his or her successor is elected. As at the date of this AIF, female directors constituted 36.4% (4 of 11) of the members of the Corporation's Board.

10.2 Committees of the Board of Directors

The Board had established three standing committees (Audit Committee, Corporate Governance and Nominating Committee, and Human Resources and Environment Committee) as shown in the following chart.



(a) Audit Committee

The Audit Committee is responsible for overseeing the adequacy and effectiveness of financial reporting, accounting systems, internal financial control structures and financial risk management systems. The Audit Committee reviews the Corporation's quarterly and annual financial statements as well as financial statements prepared in connection with the requirements of applicable regulatory authorities, reviews the audit plans of the external auditors, oversees the internal audit of the Corporation, reviews and makes recommendations to the Board with respect to the payment of dividends or distribution of capital by the Corporation, and recommends the external auditor to the Board for appointment by the Corporation's sole shareholder. See Part 11 under the heading "Audit Committee" below for further information on the Audit Committee.

(b) Corporate Governance and Nominating Committee

The Corporate Governance and Nominating Committee is responsible for considering and making recommendations to the Board with respect to matters relating to the corporate governance of Toronto Hydro, including board and committee composition and mandates, and guidelines for assessing the effectiveness of the Board and its committees and procedures to ensure that the Board functions independently from management.

As part of its governance function, the Corporate Governance and Nominating Committee reviews a skills matrix for all potential director candidates, which is then forwarded to the Corporation's sole shareholder by the Board. The Corporate Governance and Nominating Committee also nominates independent candidates for appointment to the Board of Directors of LDC for approval by the Corporation's Board of Directors as required by the Affiliate Relationships Code. The Corporate Governance and Nominating Committee reviews and approves all orientation and education materials and programs for new and current directors undertaken by management. The Corporate Governance and Nominating Committee is also responsible for periodically reviewing reports on the activities of Toronto Hydro’s corporate compliance and customer advocate functions.

The Corporate Governance and Nominating Committee is comprised of Tamara Kronis (Chair), Brian Chu, Mary Ellen Richardson and Councillor Paul Ainslie. Ms. Kronis, Mr. Chu and Ms. Richardson are each independent within the meaning of applicable Canadian securities laws. Since the City is the sole shareholder of the Corporation, Councillor Ainslie is not independent within the meaning of applicable Canadian securities laws.

(c) Human Resources and Environment Committee

The Human Resources and Environment Committee is responsible for reviewing and assisting the Board in overseeing the recruitment and assessment of the CEO and the compensation of the CEO, reviewing and approving the compensation of the executive officers, reviewing and making recommendations to the Board concerning executive compensation disclosure under applicable securities laws, and reviewing and making recommendations to the Board regarding the compensation structure and benefit plans and programs of Toronto Hydro. The Human Resources and Environment Committee is also responsible for reviewing and approving the parameters of collective bargaining negotiations, the oversight of health and safety related matters and processes, and the oversight of environmental related matters and processes of Toronto Hydro. See section 12.1(a) under the heading "Human Resources and Environment Committee" for further information on the Human Resources and Environment Committee.

10.3 Directors

The following summaries set forth, for each of the directors of the Corporation, his or her name, province and country of residence, the date on which he or she became a director and the expiry date of his or her current term, his or her relevant education and experience, principal occupations within the five preceding years and board memberships with other reporting issuers. The following tables also summarize the attendance of individual directors at the Board and standing committee meetings held during 2017 and 2018 as of the date of this AIF.

David McFadden, Chair of the Board
Ontario, Canada

Director since: December 10, 2015
Expiry of current term: December 10, 2019, or effective date of appointment of a successor director

Mr. McFadden is a lawyer whose practice focuses on the energy, infrastructure, financial services and aerospace industries. He is currently Counsel at Gowling WLG, and a former member of the firm's Board of Trustees and Executive Committee. Mr. McFadden currently serves as Chair of the Board of Directors of 407 International Inc. and PCI Geomatics Inc. He also serves on the Board of Directors of Cricket Energy Holdings Inc. Mr. McFadden is currently a member of the Board of Directors of the Ontario Energy Association, having previously served as Chair of the Board. He is also a member of the Smart Grid Forum of the Independent Electricity System Operator and serves on the Advisory Board of the MaRS Advanced Energy Centre and on the Council for Clean & Reliable Electricity. Mr. McFadden was named the Energy Leader of the Year by the Ontario Energy Association in 2013. In the past, Mr. McFadden has served as co-chair of the Electricity Transition Committee of the Ontario Government, and also served on the Ontario Government's Electricity Distribution Sector Review Panel and the Ontario Government's Electricity Conservation and Supply Task Force. Mr. McFadden has also been active in the higher education sector. He served as Chair of the Ontario Centres of Excellence from 2004-2010 and currently is a member of the Board of Governors of York University. Mr. McFadden holds a Bachelor of Laws at Osgoode Hall Law School and a Bachelor of Arts at the University of Toronto, and is a member of the Law Society of Ontario.

Mr. McFadden currently serves as Chair of the Board of Directors. He is also an *ex-officio* member of the Audit Committee, Human Resources and Environment Committee, and Corporate Governance and Nominating Committee.

Principal Occupation:
Counsel, Gowling WLG

Board/Committee Membership	**2017 Attendance**	
Board	8 of 8	100.0%
	2018 Attendance(1)	
Board	1 of 1	100.0%

Board Memberships for other Reporting Issuers:
407 International Inc.

Note:

(1) 2018 attendance is for the period of January 1, 2018 to the date of this AIF.

Brian Chu, Vice-Chair of the Board
Ontario, Canada

Director since:	December 10, 2015
Expiry of current term:	December 10, 2019, or effective date of appointment of a successor director

Mr. Chu is a founding partner of the law firm of Bogart Robertson & Chu LLP, whose practice focuses on corporate and commercial real estate law. Mr. Chu currently serves on the Board of Directors of the Technical Standards & Safety Authority and is a member of its Safety and Regulatory Affairs Committee. He also served as Trustee and Chair of the Centennial Centre of Science and Technology (Ontario Science Centre). He was formerly President of Laidlaw Foundation, Chair of the Board of Governors of Ontario College of Arts and Design, and Vice-Chair of Centennial College. Mr. Chu has been a member of the Canadian Tax Foundation since 1986. Mr. Chu holds a Juris Doctor from the University of Toronto and is a member of the Law Society of Ontario. Mr. Chu has extensive experience in compensation practices and policies, including determining executive compensation and setting, as well as communicating and reviewing, chief executive officer performance objectives. In his role at the Ontario Science Centre, he was accountable to the Minister of Tourism, Culture and Sport on all matters related to the hiring and termination of the chief executive officer. Mr. Chu is also responsible for human resources matters, salary and compensation relating to all staff at Bogart Robertson & Chu LLP.

Mr. Chu currently serves as Vice-Chair of the Board of Directors, and is the Chair of the Human Resources and Environment Committee. Mr. Chu also served as a director of the Corporation from August 1, 2005 to April 14, 2013, during which time he served as a member of the Audit Committee and the Corporate Governance Committee, the Chair of the Corporate Governance Committee (from August 25, 2005 to November 30, 2008) and the Chair of the Audit Committee (from December 1, 2008 to April 14, 2013).

Principal Occupation:
Partner at Bogart Robertson & Chu LLP

Board/Committee Membership	**2017 Attendance**	
Board	7 of 8	87.5 %
Audit Committee[1]	3 of 3 [2]	100.0 %
Corporate Governance and Nominating Committee[1]	2 of 2 [2]	100.0 %
Human Resources and Environment Committee	5 of 5	100.0 %
	2018 Attendance[3]	
Board	1 of 1	100.0%
Corporate Governance and Nominating Committee	1 of 1	100.0%
Human Resources and Environment Committee	1 of 1	100.0%

Board Memberships for other Reporting Issuers:
None

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Notes:

(1) Mr. Chu ceased to be a member of the Audit Committee and was reappointed to the Corporate Governance and Nominating Committee on May 11, 2017.

(2) Three Audit Committee meetings occurred until date on which Mr. Chu ceased to be a member of that committee, and two Corporate Governance and Nominating Committee meetings occurred since date of Mr. Chu's appointment to that committee.

(3) 2018 attendance is for the period of January 1, 2018 to the date of this AIF.

Heather Zordel
Ontario, Canada

Director since: December 10, 2015
Expiry of current term: December 10, 2019, or effective date of appointment of a successor director

Ms. Zordel is a lawyer whose practice focuses on corporate finance, securities regulatory compliance and governance for listed companies and investment funds. Ms. Zordel is currently a partner in the Securities Group at Gardiner Roberts LLP. She is also a Co-Director and Course Director for Osgoode Hall Law School's Master of Laws program in Securities Law. In the past, Ms. Zordel has served as Chair of the OSC Securities Advisory Committee, a member of the Federal Expert Panel on Securities Regulation, a member of the Board of Directors of the Metro Toronto Convention Centre and a member of other corporate, non-profit and condominium boards. She is also an author and regular media commentator. Ms. Zordel holds a Bachelor of Commerce from University of Saskatchewan, and a Juris Doctor and Master of Laws (Securities Law) from Osgoode Hall Law School. She is a member and a Bencher of the Law Society of Ontario. She is a member of the Audit Committee and Government Relations Committee of the Law Society of Ontario.

Ms. Zordel currently serves as Chair of the Board of Directors of TH Energy.

Principal Occupation:
Partner and Securities Lawyer, Gardiner Roberts LLP
Former Partner at Cassels Brock and Blackwell LLP

Board/Committee Membership	**2017 Attendance**	
Board	8 of 8	100.0%
Audit Committee	5 of 5	100.0%
	2018 Attendance[(1)]	
Board	1 of 1	100.0%
Audit Committee	1 of 1	100.0%

Board Memberships for other Reporting Issuers:
None

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Note:

(1) 2018 attendance is for the period of January 1, 2018 to the date of this AIF.

The Honourable Howard Wetston, Senator
Ontario, Canada

Director since: December 10, 2015
Expiry of current term: December 10, 2019, or effective date of appointment of a successor director

The Honourable Mr. Wetston, Senator was appointed to the Senate of Canada and assumed office on November 10, 2016. Mr. Wetston also serves as counsel at Goodmans LLP. He is a distinguished lawyer with a breadth of experience and expertise in competition law and policy, securities regulation, energy regulation and administrative law. In 2016, Mr. Wetston was awarded the Order of Canada for his significant contributions as a public servant, jurist and regulator. Mr. Wetston has served as Chair and Chief Executive Officer of the OSC, as Vice-Chair of the OSC, and as Chair and Chief Executive Officer of the OEB. During his time as Chair and Chief Executive Officer of the OSC, Mr. Wetston played a significant role in Canadian and international securities regulatory bodies by serving as a senior member of the Canadian Securities Administrators and as a Vice Chair of the International Organization of Securities Commissions. Mr. Wetston has served as a Judge of the Federal Court of Canada, Trial Division, an ex-officio member of the Federal Court's Appeal Division, and Director of Investigations and Research at the Bureau of Competition Policy. Mr. Wetston is a Senior Fellow of the C.D. Howe Institute and has served on several Advisory Boards, including the Program on Ethics in Law and Business at the University of Toronto, and the Shannon School of Business at Cape Breton University. He is an Advisory Board member of Spark Power Corp. Mr. Wetston is also a Trustee of the International Valuations Standards Council and the C.D. Howe Institute's Competition Policy Counsel. Mr. Wetston holds a Bachelor of Laws from Dalhousie University and a Bachelor of Science from Mount Allison University, and holds an ICD.D designation from the Institute of Corporate Directors and he has also received special recognition as a Board Diversity Champion from Catalyst Canada Honours. Mr. Wetston holds honorary doctorate degrees from Cape Breton University and Dalhousie University and he is a recipient of the Queen Elizabeth II Diamond Jubilee Medal.

Mr. Wetston currently serves as Chair of the Board of Directors of LDC.

Principal Occupation:
Senator
Counsel, Goodmans LLP

Board/Committee Membership	**2017 Attendance**	
Board	6 of 8	75.0 %
Corporate Governance and Nominating Committee[(1)]	0 of 2[(2)]	0.0 %
	2018 Attendance[(3)]	
Board	1 of 1	100.0%

Board Memberships for other Reporting Issuers:
None

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Notes:

(1) The Honourable Mr. Wetston, Senator ceased to be a member of the Corporate Governance and Nominating Committee on May 11, 2017.

(2) Only two Corporate Governance and Nominating Committee meetings occurred until date on which the Honourable Mr. Wetston, Senator ceased to be a member that committee.

(3) 2018 attendance is for the period of January 1, 2018 to the date of this AIF.

Juliana Lam
Ontario, Canada

Director since: April 26, 2017
Expiry of current term: April 26, 2019, or effective date of appointment of a successor director

Ms. Lam has extensive senior level financial management experience in diverse industries including mining, manufacturing, services and distribution. She is currently serving as Executive Vice-President and Chief Operating Officer of Chartered Professional Accountants of Ontario. Prior to that, Ms. Lam was the Executive Vice-President and Chief Financial Officer of Uranium One Inc. Previously, Ms. Lam served as Senior Vice-President Finance at Kinross Gold Corporation, Chief Financial Officer of Nexans Canada Inc., and has held senior finance roles within other publicly traded companies. She holds a Bachelor of Arts from the University of Toronto, an MBA from the Richard Ivey School of Business, University of Western Ontario, is a Chartered Professional Accountant (CPA, CA), and holds the ICD.D designation from the Institute of Corporate Directors. In addition to being a member of the board and the board committees of Toronto Hydro Corporation, Ms. Lam serves the community on the boards and board committees of two not-for-profit organizations in the Greater Toronto Area.

Principal Occupation:
Executive Vice-President & Chief Operating Officer, Chartered Professional Accountants of Ontario
Former Executive Vice-President & Chief Financial Officer, Uranium One Inc.

Board/Committee Membership	**2017 Attendance (from date of appointment)**	
Board	5 of 5[2]	100.0 %
Audit Committee[1]	2 of 2[2]	100.0 %
Human Resources and Environment Committee[1]	3 of 3[2]	100.0 %
	2018 Attendance[3]	
Board	1 of 1	100.0%
Audit Committee	1 of 1	100.0%
Human Resources and Environment Committee	1 of 1	100.0%

Board Memberships for other Reporting Issuers:
None

Notes:

(1) Ms. Lam was appointed to the Audit Committee and the Human Resources and Environment Committee on May 11, 2017.

(2) Only five Board Meetings, two Audit Committee meetings and three Human Resources and Environment Committee occurred since date of appointment.

(3) 2018 attendance is for the period of January 1, 2018 to the date of this AIF.

Mary Ellen Richardson
Ontario, Canada

Director since:	December 11, 2016
Expiry of current term:	December 10, 2019, or effective date of appointment of a successor director

Ms. Richardson is an independent consultant to the energy sector, with extensive experience in the oil, natural gas and electricity industries. Ms. Richardson currently serves as a member of the Board of Directors, is a member of the Human Resources and Governance & Finance and Audit Committees, and Chair of the Government Relations Committee of Markham District Energy Inc. In the past, Ms. Richardson has served as President of the Canadian District Energy Association, Vice-President, Corporate Affairs and Vice-President, Conversation Programs and External Relations at the OPA, President of the Association of Major Power Consumers in Ontario, and was a member of the Board of Directors and Human Resources Committee of Guelph Municipal Holdings Inc. Ms. Richardson has also served on the management board of the Ontario Centre of Excellence in Energy, on the Board of Directors of Environmental Careers Organization of Canada, on the Ontario Government's Electricity Conservation and Supply Task Force, on the Executive of the Stakeholders' Alliance for Competition and Customer Choice, and on Hydro One's Customer Advisory Board. Ms. Richardson holds an Honours degree in Economics from the University of Calgary, and the ICD.D designation.

Principal Occupation:
President, Mary Ellen Richardson Inc.

Board/Committee Membership	**2017 Attendance**	
Board	8 of 8	100.0%
Corporate Governance and Nominating Committee	4 of 4	100.0%
	2018 Attendance(1)	
Board	1 of 1	100.0%
Corporate Governance and Nominating Committee	1 of 1	100.0%

Board Memberships for other Reporting Issuers:
None

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Note:

(1) 2018 attendance is for the period of January 1, 2018 to the date of this AIF.

Michael Nobrega
Ontario, Canada

Director since: May 10, 2016
Expiry of current term: December 10, 2019, or effective date of appointment of a successor director

Mr. Nobrega is a Chartered Accountant with extensive experience in finance and business. Mr. Nobrega has served as President & Chief Executive Officer of OMERS, Chief Investment Officer of OMERS, and as President & Chief Executive Officer of Borealis (OMERS) Infrastructure. Mr. Nobrega is currently Chair of Ontario Centres of Excellence and is a member of the Board of Directors of IBI Group Inc. In the past, Mr. Nobrega was also president of a merchant bank, a tax partner at Arthur Anderson, Chartered Accountants, and a member of the Board of Directors of the Global Risk Institute. Mr. Nobrega earned an Honours Bachelor of Arts (Economics and Mathematics) from the University of Toronto, where, in 2002, he was honoured with the Arbor Award for outstanding community service. He holds a chartered accountancy designation from the Institutes of Chartered Accountants of Ontario and Canada, and was named a Fellow of the Institute of Chartered Accountants of Ontario in 2009. Mr. Nobrega has considerable experience in executive compensation matters from his years as the Chief Executive Officer of OMERS and Borealis (OMERS) Infrastructure. He is familiar with the structure of compensation systems and related benefit programs, and is experienced in executive performance evaluation.

Principal Occupation:
Chair, Ontario Centres of Excellence
Former President & Chief Executive Officer of OMERS (from March 2007- March 2014)

Board/Committee Membership	**2017 Attendance**	
Board	7 of 8	87.5 %
Audit Committee	5 of 5	100.0 %
Human Resources and Environment Committee	4 of 5	80.0 %
	2018 Attendance(1)	
Board	1 of 1	100.0%
Audit Committee	1 of 1	100.0%
Human Resources and Environment Committee	1 of 1	100.0%

Board Memberships for other Reporting Issuers:
IBI Group Inc.

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Note:

(1) 2018 attendance is for the period of January 1, 2018 to the date of this AIF.

Tamara Kronis
Ontario, Canada

Director since: December 10, 2015
Expiry of current term: December 10, 2019, or effective date of appointment of a successor director

Ms. Kronis is a Toronto-based entrepreneur, goldsmith and lawyer. She is currently owner of Studio1098, a custom fine jewellery design studio, where she works as a goldsmith, gemmologist and jewellery designer. Prior to opening Studio1098, Ms. Kronis worked as a commercial lawyer whose practice included several transactions related to the Ontario energy market. Her past experience includes positions as Legal Counsel, Vertex Customer Management/Vertex Outsourcing, Associate Lawyer at Torys LLP, Director of Advocacy at EGALE Canada and Trial Assistant, United Nations (International Criminal Tribunal for the Former Yugoslavia). Ms. Kronis holds a Master of Arts in Political Science and a Bachelor of Laws from the University of Toronto, and a Bachelor of Arts in Politics and Economics from Brandeis University. She is a Fellow of the Canadian Gemmological Association and the Gemmological Association of Great Britain. Ms. Kronis is a member of the Law Society of Ontario.

Principal Occupation:
Owner, Chief Goldsmith, Gemmologist and Jewellery Designer, Studio1098

Board/Committee Membership	**2017 Attendance**	
Board	8 of 8	100.0 %
Human Resources and Environment Committee[1]	2 of 2[2]	100.0 %
Corporate Governance and Nominating Committee[1]	2 of 2[2]	100.0 %
	2018 Attendance[3]	
Board	1 of 1	100.0%
Corporate Governance and Nominating Committee	1 of 1	100.0%

Board Memberships for other Reporting Issuers:
None

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Notes:

(1) Ms. Kronis ceased to be a member of the Human Resources and Environment Committee and was reappointed to the Chair of the Corporate Governance and Nominating Committee on May 11, 2017.

(2) Two Human Resources and Environment Committee meetings occurred until date on which Ms. Kronis ceased to be a member of that committee, and two Corporate Governance and Nominating Committee meetings occurred since date of Ms. Kronis' appointment to that committee.

(3) 2018 attendance is for the period of January 1, 2018 to the date of this AIF.

Denzil Minnan-Wong
Ontario, Canada

Director since: December 3, 2014
Expiry of current term: November 30, 2018, or effective date of appointment of a successor director

Deputy Mayor Minnan-Wong has been the City Councillor for Ward 34 – Don Valley East since 1997. Deputy Mayor Minnan-Wong is currently serving as Chair of City Council's Civic Appointments Committee, Chair of City Council's Employee and Labour Relations Committee, Chair of City Council's Striking Committee, and Vice-Chair of City Council's Executive Committee. He also sits on City Council's Committee of Revision, North York Community Council, City Council's Debenture Committee, the Toronto Transit Commission Board, and City Council's Corporations Nominating Panel. Deputy Mayor Minnan-Wong is the Mayor's designate on the Board of Directors for Waterfront Toronto. Deputy Mayor Minnan-Wong's past experience includes serving as Chair of City Council's Public Works and Infrastructure Committee, Chair of City Council's Economic Development Committee, Chair of North York Community Council, and a member of City Council's Planning and Transportation Committee, City Council's Works and Emergency Services Committee, City Council's Audit Committee, and the Toronto Financial Service Advisory Committee. He was formerly on the Board of Directors for BUILD Toronto, and Invest Toronto. Deputy Mayor Minnan-Wong holds a Juris Doctor from Osgoode Hall Law School, and is a member of the Law Society of Ontario.

Principal Occupation:
Deputy Mayor and Councillor, City of Toronto

Board/Committee Membership	**2017 Attendance**	
Board	7 of 8	87.5%
	2018 Attendance(1)	
Board	1 of 1	100.0%

Board Memberships for other Reporting Issuers:
None

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Note:

(1) 2018 attendance is for the period of January 1, 2018 to the date of this AIF.

Paul Ainslie
Ontario, Canada

Director since: February 10, 2015
Expiry of current term: November 30, 2018, or effective date of appointment of a successor director

Councillor Ainslie has been the City Councillor for Ward 43 – Scarborough East since December 2006. Councillor Ainslie is currently serving as Chair of City Council's Government Management Committee and the Chair of the Toronto Zoo Board of Management, and also sits on City Council's Executive Committee, Scarborough Community Council, and the Toronto Public Library. Mr. Ainslie is a member of the Board of Directors of the Federation of Ontario Public Libraries, the Ontario Good Roads Association, the Canadian National Exhibition Association, Municipal Section, Toronto and Region Conservation Authority, and the Guild Renaissance Group. Councillor Ainslie's past experience includes serving as Co-Chair of the Rouge Valley Health System Centenary Buy A Bed fundraising campaign and Chair of the Board of Directors of Haliburton Club.

Principal Occupation:
Councillor, City of Toronto

Board/Committee Membership	**2017 Attendance**	
Board	5 of 8	62.5%
Corporate Governance and Nominating Committee	3 of 4	75.0%
	2018 Attendance(1)	
Board	1 of 1	100.0%
Corporate Governance and Nominating Committee	1 of 1	100.0%

Board Memberships for other Reporting Issuers:
None

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Note:

(1) 2018 attendance is for the period of January 1, 2018 to the date of this AIF.

Stephen Holyday
Ontario, Canada

Director since: December 3, 2014
Expiry of current term: November 30, 2018, or effective date of appointment of a successor director

Deputy Mayor Holyday is the Mayor's designate to the Board effective as of December 3, 2014. Deputy Mayor Holyday has been the City Councillor for Ward 3 - Etobicoke Centre since December 2014, and was appointed Deputy Mayor in September 2017 Deputy Mayor Holyday is currently serving as Chair of City Council's Audit Committee, Vice-Chair of City Council's Employee and Labour Relations Committee, and Vice-Chair of Public Works and Infrastructure Committee. He sits on the Etobicoke York Community Council and George Bell Arena Nominating Panel. Deputy Mayor Holyday is a Mayor's Designate on the Board of Directors of The Atmospheric Fund. Deputy Mayor Holyday is a member of the Board of Directors of the Hockey Hall of Fame, and a member of the Canadian National Exhibition Association - Municipal Section. Before being elected to public office, Deputy Mayor Stephen Holyday was Manager, Service Management at the Ontario Ministry of Energy. He holds a Bachelor of Technology in Architectural Science from Ryerson University. Through his experience as Vice-Chair of City Council's Employee and Labour Relations Committee, Mr. Holyday is familiar with compensation systems and related benefit programs at all levels.

Principal Occupation:
Deputy Mayor and Councillor, City of Toronto
Acting Manager and Manager, Service Management, Ontario Ministry of Energy (From May 2009 to November 2014)

Board/Committee Membership	**2017 Attendance**	
Board	8 of 8	100.0%
Human Resources and Environment Committee	5 of 5	100.0%
	2018 Attendance(1)	
Board	1 of 1	100.0%
Human Resources and Environment Committee	1 of 1	100.0%

Board Memberships for other Reporting Issuers:
None

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Note:

(1) 2018 attendance is for the period of January 1, 2018 to the date of this AIF.

10.4 Executive Officers

The following table sets forth the name, province and country of residence, office, and principal occupation for each of executive officers of the Corporation. 33.3% (1 out of 3) of the executive officers of the Corporation are female. 25.0% (2 out of 8) of the executive officers of LDC are female.

Name	Residence	Office	Principal Occupation
Anthony Haines[(1)]	Ontario, Canada	President and Chief Executive Officer	President and Chief Executive Officer, Toronto Hydro Corporation
Sean Bovingdon[(2)]	Ontario, Canada	Executive Vice-President, Chief Financial Officer	Executive Vice-President, Chief Financial Officer, Toronto Hydro Corporation
Amanda Klein[(3)]	Ontario, Canada	Executive Vice-President, Regulatory Affairs and General Counsel	Executive Vice-President, Regulatory Affairs and General Counsel, Toronto Hydro Corporation

Notes:

(1) Mr. Haines has been the President of LDC since September 2006. He was also appointed the CEO of the Corporation effective October 1, 2009.

(2) Sean Bovingdon was appointed as the Corporation's Executive Vice-President and Chief Financial Officer effective as of April 3, 2017. Prior to joining Toronto Hydro, Mr. Bovingdon was the Chief Financial Officer of Argent Energy Ltd from June 2011 until his appointment as the President of Argent Energy Ltd effective April 2015.

(3) Ms. Klein was Senior Regulatory Counsel (from June 20, 2011 to August 22, 2012) and then Director, Rates and Regulatory Affairs (from August 23, 2012 to December 31, 2014) until her appointment as Vice-President, Regulatory Affairs and General Counsel of the Corporation effective January 1, 2015. Ms. Klein was appointed Executive Vice-President, Regulatory Affairs and General Counsel of the Corporation effective September 1, 2016.

10.5 Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Mr. McFadden was a director of Atlantis Systems Corp. when its directors and officers were subject to a management cease trade order from April 1, 2008 and May 12, 2008 for their failure to file the corporation's annual audited financial statements, management's discussion and analysis and annual information form by the regulatory filing deadline. The cease trade order is no longer in effect.

Mr. Bovingdon served as the Chief Financial Officer of Argent Energy Ltd. (the "Administrator"), the administrator of Argent Energy Trust ("the Trust"), from June 2011 until August 2016 and he also served as President of the Administrator from April 2015 until August 2016. The units of the Trust were listed on the Toronto Stock Exchange ("TSX"). On February 17, 2016, the Trust sought and obtained protection under the *Companies' Creditors Arrangement Act* (Canada) (the "CCAA"). On August 30, 2016, the Court of Queen's Bench of Alberta entered an Order, among other things, terminating the CCAA proceeding for the Trust effective August 31, 2016. On August 31, 2016, the Trust made an assignment into bankruptcy, and on vesting of the Trust's assets with the bankruptcy trustee, the Trust was deemed to be terminated by operation of law. During the CCAA proceedings, certain securities commissions in Canada (including the Alberta Securities Commission, the British Columbia Securities Commission, the Manitoba Securities Commission, and the OSC) issued cease trade orders against the Trust for failing to file interim and annual financial statements. In addition, the Trust units and convertible debentures of the Trust were delisted from the TSX effective at the close of market on March 24, 2016 for failure of the Trust to meet the continued listing requirements of the TSX.

Except as noted above, no director or executive officer of the Corporation is, as at the date of this AIF, or has within ten years prior to the date of this AIF:

(a) been a director, chief executive officer or chief financial officer of any company (including the Corporation) that was the subject of a cease trade or similar order or an order that denied the company access to any exemption under securities legislation for a period of more than 30 consecutive days, where such order was

issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer;

(b) been a director, chief executive officer or chief financial officer of any company (including the Corporation) that was the subject of a cease trade or similar order or an order that denied the company access to any exemption under securities legislation for a period of more than 30 consecutive days, where such order was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer;

(c) been a director or executive officer of any company (including the Corporation) that, while that person was acting in that capacity or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or

(d) become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold the assets of such director or executive officer.

No director, executive officer, or to the Corporation's knowledge, the City, has been subject to:

(a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or

(b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

10.6 Independence

As at the date of this AIF, the Board consists of eleven directors, all of whom are appointed by the City in its capacity as sole shareholder of the Corporation. Three of the directors are Councillors of the City and are not considered independent because of their positions. None of the other directors have a direct or indirect material relationship with the Corporation and are independent within the meaning of applicable Canadian securities law.

No members of management sit on the Board. The Board meets regularly to discuss the management of the Corporation. A portion of each Board and Board committee meeting is reserved for Directors to meet without management present. Under its mandate, the Board is authorized to retain independent legal counsel and other advisors if it considers this appropriate. The mandate also provides that the Board shall have unrestricted access to the officers of the Corporation and is authorized to invite officers and employees of the Corporation and others to attend or participate in its meetings and proceedings if it considers this appropriate. The full text of the Board's written mandate is attached as Annex B.

The Corporation has developed a written position description for the Chair of the Board. The Chair is responsible for reporting to the Board, leading the directors and managing the day-to-day activities of the Board. The Chair is also responsible for engaging in discussions with the shareholder and its representatives as are necessary and desirable, maintaining an active and cooperative relationship with the CEO and other senior management of the Corporation, acting as the principal interface between the Board and the CEO of the Corporation, and providing advice and counsel to the CEO and other senior management of the Corporation.

The Board has also developed written position descriptions for the chair of each Board committee and the CEO.

10.7 Board Orientation and Continuing Education

Each new director, upon joining the Board, is given an orientation session with comprehensive set of materials designed to provide him/her with a summary of the key organizational, financial, regulatory, and operational aspects of Toronto Hydro. These materials also contain information on the various Toronto Hydro boards and their committees.

On an on-going basis, as part of regular and special board meetings, directors receive presentations, reports and training on topics related to Toronto Hydro's businesses and the obligations and responsibilities of directors. Topics covered are either suggested by management or requested by the directors. As well, directors receive information from management in response to any actions arising at a board meeting or otherwise. Educational programs through external service providers are also made available to the directors.

10.8 Board, Committee and Director Assessments

The Corporate Governance and Nominating Committee oversees a process used to evaluate the effectiveness of the Board as a whole, its committees and the individual directors. The process may be facilitated by an independent consultant with expertise in board assessments as selected by the Board. Alternatively, the Board may complete an internal assessment. The process may consist of an in-person interview and/or a written questionnaire evaluating the Board, its committees and the individual directors that are completed periodically by each director. The directors' responses to the questionnaire and/or interviews related to the operation of the Board and its committees are compiled into a summary report that is reviewed by the Corporate Governance and Nominating Committee. This report and recommended remedial actions are presented to the Board for review, consideration and implementation.

10.9 Board Oversight and Management of Risks

In accordance with its mandate, the Board is responsible for overseeing the identification of the principal risks of the business and implementation of appropriate systems to manage these risks. In 2009, Toronto Hydro adopted an ERM program to add value and improve the Corporation's operations through enabling the attainment of its strategic goals and objectives. The ERM program helps the Corporation achieve this by bringing a systematic and disciplined approach towards identifying, evaluating, treating, monitoring and reporting of risks applicable to Toronto Hydro. Accordingly, ERM is an integral part of the strategic management of the Corporation's business and is routinely considered in forecasting, planning and executing all aspects of Toronto Hydro’s operations. The ERM program follows industry best practice and adopts a rigorous top-down / bottom-up approach towards the management of risks.

See Part 8 under the heading "Risk Factors" above for further information on ERM.

10.10 Indebtedness of Directors and Executive Officers

No director, executive officer, employee, former director, former executive officer or former employee or associate of any director or executive officer of the Corporation or any of its subsidiaries had any outstanding indebtedness to the Corporation or any of its subsidiaries except routine indebtedness or had any indebtedness that was the subject of a guarantee, support agreement, letter of credit or other similar arrangement or understanding provided by the Corporation or any of its subsidiaries.

PART 11 - AUDIT COMMITTEE

11.1 Composition, Independence and Financial Literacy

The Audit Committee is comprised of Michael Nobrega (Chair), Juliana Lam and Heather Zordel, each of whom is independent and financially literate within the meaning of applicable Canadian securities laws. Prior to May 11, 2017, the Audit Committee was comprised of Michael Nobrega (Chair), Brian Chu and Heather Zordel. See section 10.3 under the heading "Directors" for more information about the relevant education and experience of each member.

11.2 Audit Committee Charter

Under the terms of its charter, the Audit Committee is responsible for: managing the relationship between Toronto Hydro and its external auditors; overseeing the external audit; overseeing the internal audit; reviewing and recommending to the Board for approval the financial statements, management's discussion and analysis and interim reports of the Corporation and its subsidiaries, the annual information form and other public disclosure of financial information extracted from the financial statements of the Corporation; overseeing internal financial control structure and financial risk management systems; establishing and reviewing certain procedures and policies; reviewing policy reporting; and reviewing and making recommendations to the Board with respect to the payment of dividends or distribution of capital by the Corporation.

The full text of Corporation's Audit Committee Charter is attached as Annex A.

11.3 Policy on the Provision of Services by the External Auditors

The Audit Committee has developed a Policy on the Provision of Services by the External Auditors. Under the terms of the Policy:

- the external auditors may not provide services to Toronto Hydro that impair or have the potential to impair the independence and objectivity of the external auditors in relation to the external audit function (generally, prohibited services include services where the external auditors participate in activities that are normally undertaken by management of Toronto Hydro, are remunerated through a "success fee" structure, act in an advocacy role for Toronto Hydro or may be required to audit their own work);

- the Audit Committee has pre-approved certain audit and permitted non-audit services as services that the auditors may provide to Toronto Hydro, including: services that constitute the agreed scope of the external audit or interim reviews of Toronto Hydro; services that are outside the agreed scope of, but are consistent with, the external audit or interim reviews of Toronto Hydro; tax services that do not compromise the independence and objectivity of the external auditors in relation to the external audit; and other services of an advisory nature that do not compromise the independence and objectivity of the external auditors in relation to the external audit work; and

- an authorization process has been established which provides, among other things: the Chief Financial Officer may authorize in advance all engagements of the external auditors to provide pre-approved services (other than audit services) to Toronto Hydro up to a maximum of $25,000 for any engagement and up to a maximum of $100,000 for all engagements in any fiscal quarter (the Chief Financial Officer must report all such authorized engagements to the Audit Committee at its next meeting); the Chair of the Audit Committee may authorize in advance all engagements of the external auditors to provide pre-approved services (other than audit services) to Toronto Hydro up to a maximum of $50,000 for any engagement and up to a maximum of $100,000 for all engagements in any fiscal quarter (the Chair must report all such authorized engagements to the Audit Committee at its next meeting); and the Audit Committee must authorize in advance all engagements of the external auditors to provide pre-approved services to Toronto Hydro above the prescribed thresholds and all engagements to provide services that are not pre-approved services regardless of the dollar value of the services.

Exceptions can be made to this Policy where the exceptions are in the interests of Toronto Hydro and appropriate arrangements are established to ensure the independence and objectivity of the external auditors in relation to the external audit. Any exception must be authorized by the Audit Committee and must be reported to the Board.

11.4 External Auditors Service Fees

The table below sets out the fees charged by Toronto Hydro's external auditor, KPMG LLP, on an accrual basis, for each of last two fiscal years in respect of the services noted below.

	Year ended December 31,	
	2017	**2016**
Audit fees[(1)]	$683,720	$707,241
Audit-related fees[(2)]	$32,000	$54,210
Tax fees[(3)]	-	-
All other fees	-	$10,000

Notes:

(1) Fees for audit services and interim reviews, excluding CPAB levy.

(2) Fees for assurance and related services that are reasonably related to the performance of the audit or review of the Corporation's financial statements and are not reported under (1) above, specifically French translation.

(3) Fees for tax advisory services.

PART 12 - EXECUTIVE COMPENSATION

12.1 Compensation Governance

(a) Human Resources and Environment Committee

(i) *Composition and Independence*

The Human Resources and Environment Committee, under the direction of the Board has oversight for Toronto Hydro's senior executive compensation program. The Human Resources and Environment Committee is comprised of Brian Chu (Chair), Juliana Lam, Michael Nobrega, and Deputy Mayor Stephen Holyday. Mr. Chu, Ms. Lam, and Mr. Nobrega are each independent within the meaning of applicable Canadian securities laws. Since the City is the sole shareholder of the Corporation, Deputy Mayor Holyday is not independent within the meaning of applicable Canadian securities laws. The appointment of one of the Corporation's City Councillor directors to the Human Resources and Environment Committee is a requirement under the Shareholder Direction. Prior to May 11, 2017, the Human Resources and Environment Committee was comprised of Brian Chu (Chair), Deputy Mayor Stephen Holyday, Michael Nobrega and Tamara Kronis. See section 10.3 under the heading "Directors" for more information about the relevant education and experience of each member.

(ii) *Human Resources and Environment Committee Charter*

The Human Resources and Environment Committee operates under a written charter adopted by the Board. One of the primary functions of the Human Resources and Environment Committee is to advise and assist the Board in overseeing Toronto Hydro's compensation program and assessing the performance and compensation of the CEO and the other senior executive officers of Toronto Hydro. Specifically, under the terms of its charter, the Human Resources and Environment Committee is responsible for assisting the Board in fulfilling its responsibilities with respect to: the recruitment and assessment of the performance of the CEO; the review and approval of the compensation of the CEO and the other senior executive officers of Toronto Hydro; the review and approval of senior executive compensation policies; the review and approval of senior executive compensation disclosure; the review of the alignment of compensation programs with Toronto Hydro's strategic plans and risk profile; and the general oversight of the compensation structure and benefit plans and programs for Toronto Hydro.

(b) Compensation Risk Oversight

Toronto Hydro has a rigorous risk management and governance structure in place to assist the Board with its oversight and management of all of Toronto Hydro's risks, including risks related to Toronto Hydro's compensation policies and practices. While the Board and the Human Resources and Environment Committee have not conducted a formal assessment of the implications of risks specifically associated with Toronto Hydro's compensation policies and practices, the Human Resources and Environment Committee has and continues to consider the Corporation's strategic objectives, plans and risk strategy in its review and recommendations regarding Toronto Hydro's compensation program. In addition to Toronto Hydro's ERM program, the practices, processes and systems in place to identify and mitigate compensation policies and practices that could encourage an executive officer to take inappropriate or excessive risks include: the periodic review and audit of Toronto Hydro's senior executive compensation program by Toronto Hydro's internal auditor; the development and application of a management control reporting system providing transparency and control to compensation measures; the use of a balanced scorecard of corporate, divisional and individual performance objectives; the periodic benchmarking of Toronto Hydro's compensation program; the review of Toronto Hydro's compensation program by an independent compensation consultant and, from time to time, the OEB; and the application of maximum payout amounts for achievement of individual performance goals. See sections 8 under the heading "Risk Oversight" and 10.9 under the heading "Board Oversight and Management of Risks" for more information on Toronto Hydro's ERM program, section 12.2(c)(ii) under the heading "Benchmarking" for more information on Toronto Hydro's benchmarking of its compensation program, section 12.2(c)(iii) under the heading "Compensation Consultants and Advisors" for more information on the Corporation's compensation consultant and section 12.2(d)(ii) under the heading "Performance-Based Incentive Compensation" for more information on Toronto Hydro's performance-based incentive compensation program.

12.2 Compensation Discussion and Analysis

(a) Named Executive Officers

This Compensation Discussion and Analysis describes and explains all significant elements of compensation awarded to, earned by, paid to, or payable to the NEOs for the financial year ended December 31, 2017. The NEOs are:

(i) **Anthony Haines**
President and Chief Executive Officer, Toronto Hydro Corporation

(ii) **Sean Bovingdon**(1)
Executive Vice-President and Chief Financial Officer, Toronto Hydro Corporation

(iii) **Laura Foster**(2)
Interim, Chief Financial Officer, Toronto Hydro Corporation

(iv) **Dino Priore**
Executive Vice-President and Chief Engineering and Construction Officer, Toronto Hydro-Electric System Limited

(v) **Ben La Pianta**(3)
Executive Vice-President and Chief Electric Operations and Procurement Officer, Toronto Hydro-Electric System Limited

(vi) **Ave Lethbridge**
Executive Vice-President and Chief Human Resources and Safety Officer, Toronto Hydro-Electric System Limited

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Notes:

(1) Effective April 3, 2017, Mr. Bovingdon began his role as Executive Vice-President and Chief Financial Officer.

(2) Effective April 3, 2017, Ms. Foster ceased her role as Interim, Chief Financial Officer and began her role as Vice-President Audit and Corporate Compliance.

(3) Effective January 1, 2018 Mr. La Pianta began his role as Executive Vice-President and Chief Customer Care and Electric Operations & Procurement Officer.

(b) General Objectives of Compensation Program

Toronto Hydro's senior executive compensation program is designed to attract and retain executives who have the skills and experience to help the Corporation achieve its strategic goals, to motivate executives to achieve such corporate goals and to reward senior executives for superior performance and achievement of corporate, divisional and individual objectives.

(c) Process for Establishing Compensation

(iii) *Policies and Practices*

Toronto Hydro's overall senior executive compensation policy, structure and program is developed and supervised by the Human Resources and Environment Committee with the assistance of a compensation consultant, and approved by the Board. See section 12.2(c)(iii) under the heading "Compensation Consultants and Advisors" for more information on the compensation consultant.

Pursuant to the terms of its charter, the Human Resources and Environment Committee has the responsibility to annually, and more frequently if appropriate, review and make recommendations to the Board with respect to the individual performance-based incentive compensation goals and objectives related to the compensation of the CEO and to assess the CEO's performance against those goals and objectives. The Human Resources and Environment Committee also makes recommendations to the Board with respect to the overall compensation and benefits of the CEO. The Board ultimately sets and approves the CEO's compensation.

The CEO has the responsibility to annually, and more frequently if appropriate, review and approve the individual performance-based incentive compensation goals and objectives related to the compensation of the other senior executive officers, including the NEOs, and assess the other senior executive officers' performance against those goals and objectives. The CEO proposes the other senior executive officers' performance-based incentive compensation and overall compensation, subject to the Human Resources and Environment Committee's review and approval.

(iv) *Benchmarking*

Toronto Hydro periodically benchmarks the compensation it provides to the NEOs to ensure reasonableness, competitiveness and effectiveness of Toronto Hydro's compensation program, including the level and type of compensation provided. The Human Resources and Environment Committee periodically engages a compensation consultant to conduct executive compensation benchmarking for the NEOs, to ensure that Toronto Hydro is able to attract, retain and motivate high-performing senior executives in the markets in which we compete for talent.

Toronto Hydro's objective is to pay competitively with other Canadian Utility and Energy Industry companies of comparable size and complexity. NEO compensation is generally benchmarked against:

- industry comparators in the public sector of like size: publicly owned utility/ energy companies in Canada with revenues of approximately ½ to 2x Toronto Hydro's distribution revenue and / or total revenue;
- publicly and privately owned (including publicly traded) utility/ energy companies in Canada with revenues of approximately ½ to 2x Toronto Hydro's distribution revenue and / or total revenue;
- industrial companies in the Greater Toronto Area ("GTA");
- industrial companies in Canada; and
- public sector organizations in Canada.

The benchmark data comes from proprietary compensation surveys, and publicly disclosed executive compensation information in Canada.

Toronto Hydro's flow-through revenue for electricity transmission and generation is excluded for purposes of identifying comparable general industry (i.e., non-local-distribution-company) peer companies, except in the case of the CFO, where the Toronto Hydro's full revenue is also considered because Toronto Hydro believes this role's accountability for cash management more closely matches organizations with similar total revenues. The senior executive compensation information derived from the benchmarking analysis is designed to assist the Human Resources and Environment Committee in establishing, over a reasonable period of time, total cash compensation for NEOs in the range of the median total cash compensation of the benchmark data. Total cash compensation to NEOs may exceed the median of the marketplace when corporate, divisional and individual performance significantly exceeds objectives.

(v) *Compensation Consultants and Advisors*

The Human Resources and Environment Committee began engaging the services of Willis Towers Watson for senior executive compensation consulting services in 2016 and previously engaged Mercer for these services. The consulting services provided to the Human Resources and Environment Committee include providing advice on the competitiveness and appropriateness of Toronto Hydro's senior executive compensation program, compensation benchmarking services, and other compensation related matters that may arise from time to time. The Corporation also engages Willis Towers Watson for actuarial services. The Human Resources and Environment Committee or the Board is required to pre-approve the actuarial services Willis Towers Watson provides to Toronto Hydro in accordance with the Corporation's Policy on the Provision of Services by Compensation Advisors. The actuarial services provided by Willis Towers Watson do not present any conflicts with the services provided as compensation advisor to the Human Resources and Environment Committee.

The table below sets out the fees billed by Mercer and Willis Towers Watson for each of last two fiscal years in respect of the services noted below.

	Year ended December 31,			
	2017		**2016**	
	Mercer	Willis Towers Watson	Mercer	Willis Towers Watson
Executive Compensation – Related Fees[(1)]	—	$94,906	$11,021	$94,514
All Other Fees[(2)]	—	$42,427	$39,060	$100,503

Notes:

(1) Aggregate fees billed by Mercer and Willis Towers Watson, or any of its affiliates, for services related to determining compensation for any of Toronto Hydro's directors and executive officers.

(2) Aggregate fees billed by Mercer and Willis Towers Watson, or any of its affiliates, for services related to employee compensation and benefits management consultation or actuarial services that are not reported under (1) above.

(d) Elements of Compensation

The principal components of compensation for NEOs are:

- base salary;
- performance-based incentive compensation;
- personal benefits and perquisites;
- pension plan;
- post-employment benefits;
- retirement allowances; and
- termination payments.

As the Corporation has a single shareholder that is the registered and beneficial owner of all of its issued and outstanding shares, the Corporation is not able to offer an equity incentive plan or other stock-based compensation to its NEOs.

(vi) *Base Salary*

In accordance with the general objectives and process for establishing compensation noted above, Toronto Hydro provides NEOs with a base salary to compensate them for services rendered during the fiscal year. Toronto Hydro provides reasonably competitive market-based base salaries to help attract, motivate, and retain NEOs who are critical to the Corporation's success.

Annually, adjustments to base salaries for NEOs are driven by market benchmarking data and the NEO's individual performance rating. The performance rating is determined, in the case of the CEO, by the Human Resources and Environment Committee and, in the case of the other NEOs, by the CEO, based on the achievement of performance-based incentive compensation objectives, knowledge, skills, and competencies related to day-to-day performance, as well as demonstration of desired corporate behaviours, subject to the Human Resources and Environment Committee's review and approval.

(vii) *Performance-Based Incentive Compensation*

All NEOs receive a portion of their annual compensation in the form of performance-based cash payments. The performance-based incentive compensation is designed to retain, motivate and reward NEOs for reaching corporate, divisional and individual performance objectives established at the beginning of each calendar year.

The annual performance-based incentive compensation is calculated as a percentage of the NEO's base salary for the year and, if earned, paid in one lump sum in the next fiscal year.

In order for a NEO to earn and receive the performance-based incentive compensation, the Corporation and the NEO must each achieve certain pre-determined performance objectives. Each NEO's performance-based incentive compensation is based on a weighting of corporate, divisional and individual performance objectives, whose weightings and objectives are determined at the start of each year and vary by role to reflect the performance focus of the role. The weighting and objectives are reviewed and set each year in order to reflect the Corporation's overall strategy and objectives.

Each year the board reviews and approves the Corporation's objectives. Each performance objective is weighted to reflect relative importance and includes threshold, target and outstanding expectations of performance. Specific performance targets are approved by the Board giving consideration to the Corporation's business plans and priorities for the upcoming year, the prior year's performance and a review of forecasted results based on a historical analysis of performance. Similarly divisional objectives are approved by the CEO and reviewed by the Human Resources and Environment Committee to recognize unique divisional priorities and ensure alignment with the Corporation's overall objectives.

The CEO's individual objectives are reviewed and approved by the Board. The individual objectives of the other NEOs are reviewed and approved by the CEO. Each NEO's individual objectives are based on areas of strategic and operational emphasis related to their respective responsibilities and portfolios.

The NEO's individual objectives are intended to be reasonably difficult to attain and to encourage success in the NEO's performance. Individual objectives are often but not always achieved by a NEO in any given year. NEOs review their objectives and measurements throughout the year, with one formal mid-year review with the Chair of the Board (in the case of the CEO), and with the CEO (in the case of the other NEOs), to track achievement to-date and revise performance goals as may be necessary to reflect any change in corporate strategy or priorities.

In the case of the CEO, an annual performance evaluation in respect of his individual performance goals is conducted by the Chair of the Board who provides a recommendation to the Human Resources and Environment Committee regarding the performance-based incentive compensation to be paid to the CEO. The amount paid to the CEO is approved by the Board after review of the recommendation of the Human Resources and Environment Committee.

In the case of each of the other NEOs, an annual performance evaluation in respect of the individual objectives for each individual is conducted by the CEO, who proposes the amount of performance-based incentive compensation to be paid to each other NEO. The Human Resources and Environment Committee reviews and approves the amounts of performance-based incentive compensation to be paid to each of the other NEOs.

The Human Resources and Environment Committee may exercise its discretion to increase or reduce the performance-based incentive compensation paid to the CEO or NEOs, as applicable, including in certain circumstances, absent attainment of a relevant performance goal or similar condition.

(viii) *Personal Benefits and Perquisites*

Toronto Hydro provides NEOs with other personal benefits and perquisites that Toronto Hydro believes are reasonable and consistent with its overall compensation program to better enable the Corporation to attract and retain superior employees for key positions. Benefits include group health, dental, group life insurance, short-term and long-term disability, accidental death & dismemberment, a gym subsidy, and educational reimbursements, all of which are generally available to all salaried employees.

(ix) *Pension Plan*

All full-time employees of Toronto Hydro, including the NEOs, are required to participate in the OMERS pension plan. Pursuant to the terms of the OMERS pension plan, NEOs are required to make equal plan contributions based on their eligible pensionable earnings. In 2017, Toronto Hydro and each NEO was required to contribute 9% equally of the first $55,300 of pensionable earnings and thereafter 14.6% equally on all earnings over $55,300 and up to $170,797. From $170,797 and up to a maximum of $387,100, contributions continue equally at 14.6% towards a Retirement Compensation Arrangement (RCA), which is governed separately under the Canadian Income Tax Act. The OMERS pension plan is generally available to all other salaried employees. See section 4.6 (a) under the heading "Employees" for more information on the OMERS pension plan.

(x) *Post-employment Benefits*

NEOs are eligible to receive post-employment health, dental and life insurance benefits after a minimum of five years of service with Toronto Hydro if they retire from Toronto Hydro and begin collecting under the OMERS pension plan upon retirement. The post-employment benefits provided to eligible NEOs are the same as are generally available to all other salaried employees. Post-employment benefits aid in attracting and retaining key executives to ensure the long-term success of Toronto Hydro.

(xi) *Retirement Allowances*

From time to time, in certain circumstances, Toronto Hydro enters into retirement allowance agreements with its NEOs. The retirement allowance agreements are designed to recognize service, and to promote retention, stability and continuity, of the NEOs. These agreements are made on a case-by-case basis based on a NEO's years of service and position. Any retirement allowance provided to the CEO is approved by the Board after review of the recommendation of the Human Resources and Environment Committee. In the case of each of the other NEOs, any retirement allowance agreement is proposed by the CEO and reviewed and amended or approved by the Human Resources and Environment Committee. Retirement allowance payments are typically paid in one or two lump sum instalments following termination or retirement of the NEO.

(xii) *Termination Payments*

From time to time, Toronto Hydro enters into agreements with NEOs which provide for payments upon termination. These agreements are made on a case-by-case basis based on the NEO's age, years of service and position. Any such agreement for the CEO is approved by the Board after review of the recommendation of the Human Resources and Environment Committee. In the case of each of the other NEOs, any such agreement is proposed by the CEO and reviewed and approved by the Human Resources and Environment Committee. Typically, termination payments are paid either as a lump sum or as salary continuation for an agreed period following termination.

12.3 Compensation of Named Executive Officers

(a) Summary Compensation Table

The following table provides a summary of the compensation earned during the years ended December 31, 2017, 2016 and 2015, by the NEOs:

Summary Compensation Table[1]

NEO Name and Principal Position[5]	Year	Salary[2] ($)	Non-Equity Incentive Plan Compensation[3] ($)	All Other Compensation[4] ($)	Total Compensation ($)
Anthony Haines President and Chief Executive Officer, Toronto Hydro Corporation	2017 2016 2015	$548,490 $522,286 $509,459	$528,138 $508,551 $488,301	$10,452 $10,301 $10,210	$1,087,080 $1,041,138 $1,007,970
Sean Bovingdon Executive Vice-President and Chief Financial Officer, Toronto Hydro Corporation	2017	$274,039 [6]	$166,500	$200,000	$640,539
Laura Foster[7] Interim, Chief Financial Officer, Toronto Hydro Corporation	2017 2016 2015	$209,808 $189,918 $157,997	$92,610 $89,285 $62,801	$1,560 $1,440 $1,835	$303,978 $280,643 $222,633
Dino Priore Executive Vice-President and Chief Engineering and Construction Officer, Toronto Hydro –Electric System Limited	2017 2016 2015	$338,019 $326,019 $311,120	$211,371 $192,889 $184,584	$4,108 $2,330 $1,931	$553,498 $521,238 $497,635
Ben La Pianta Executive Vice-President and Chief Electric Operations and Procurement Officer, Toronto Hydro –Electric System Limited	2017 2016 2015	$298,103 $287,100 $273,165	$195,137 $169,295 $161,120	$5,005 $3,823 $3,376	$498,245 $460,218 $437,661
Ave Lethbridge Executive Vice-President and Chief Human Resources and Safety Officer, Toronto Hydro –Electric System Limited	2017 2016 2015	$265,775 $254,833 $244,865	$158,145 $151,454 $142,614	$3,655 $9,132 $8,193	$427,575 $415,419 $395,672

Notes:

(1) Amounts shown in this table are in Canadian dollars and have been rounded to the nearest dollar.

(2) Amounts shown reflect actual amounts paid during the year.

(3) Each NEO's annual performance-based incentive compensation for a fiscal year is determined and paid in the next fiscal year. Accordingly, amounts reflected in respect of a particular year (i.e. 2016) represent the annual performance-based incentive compensation earned by the NEO for the achievement of performance objectives in respect of that fiscal year (i.e. 2016) but which amounts are paid in the following fiscal year (i.e. 2017).

(4) Amounts shown in this column reflect all other compensation earned by the NEO during the year. The amounts shown include the aggregate value of perquisites and other personal benefits provided to the NEO, where such perquisites and personal benefits are not generally available to all employees and have been calculated by using the actual cost. In 2017, 2016 and 2015, perquisites and personal benefits were not worth $50,000 or more for any NEO, nor were they worth 10% or more of any NEO's total salary for the year, with the exception of Mr. Bovingdon. Mr. Bovingdon received a one-time $200,000 relocation allowance when he joined the Corporation in 2017.

(5) Effective December 15, 2015, Jean-Sebastien Couillard ceased to be Executive Vice-President, Chief Financial Officer of the Corporation. See section 12.3(b)(vii) under the heading "Termination Payments" for a discussion regarding additional amounts respecting termination.

(6) Effective April 3, 2017, Mr. Bovingdon is the Executive Vice-President and Chief Financial Officer and his annual base salary was $375,000.

(7) Effective December 16, 2015, Ms. Foster began acting in the capacity of Interim, Chief Financial Officer of the Corporation until April 3, 2017 when she accepted the role of Vice-President, Audit and Corporate Compliance. As a result of Ms. Foster acting in the capacity of Interim, Chief Financial Officer, her annual base salary increased to $180,000 in 2015, $200,000 in 2016 and $210,000 in 2017. Ms. Foster's target performance-based incentive was 30% of salary for 2017.

(b) Compensation of NEOs in 2017 – Narrative Discussion

(xiii) *Base Salaries*

The NEOs' annual base salaries for 2017 were: $549,000 in the case of Mr. Haines, $375,000 in the case of Mr. Bovingdon, $210,000 in the case of Ms. Foster, $353,250 in the case of Mr. Priore, $328,315 in the case of Mr. La Pianta, and $265,987 in the case of Mrs. Lethbridge.

(xiv) *Performance-Based Incentive Compensation*

The targets and component weightings for the 2017 performance-based incentive compensation were as follows:

Position	Target Performance-Based Incentive (% of salary)	Individual Performance (% weighting)	Divisional Performance (% weighting)	Corporate Performance (% weighting)
CEO	65%	20%	—	80%
CFO	40%	20%	20%	60%
Other NEOs	40%	20%	20%	60%

The performance-based incentive compensation amount payable to each NEO may exceed the respective target % of base salary indicated above when results exceed corporate, divisional and individual objectives and may be below the respective target % of base salary indicated above when the corporate, divisional and individual objectives are not achieved. The component weightings outlined above have been unchanged since 2011.

The performance objectives of the Corporation for 2017 were as follows:

Corporate Key Performance Indicators	Measure	Target	Weight (%)
Net income after net movements in regulatory balances ($ millions)	Net Income after net movements in regulatory balances per the Corporation's Consolidated Financial Statements.	$145.0	45%
LDC Regulated Capital ($ millions) [(1)]	Achievement of LDC's capital work program.	$370.5	15%
System Average Interruption Duration Index (SAIDI) (in minutes) (Defective equipment only)	Measure of the annual system average interruption duration per customer served, not including Major Event Days.	29.71	10%
System Average Interruption Frequency Index (SAIFI) (number of interruptions) (Defective equipment only)	Measure of the frequency of service interruptions per customer served, not including Major Event Days.	0.56	10%
First Call Resolution	Percentage of telephone enquiries resolved within one call, within a 21-day time period.	83%	4%
Bill Accuracy	The percentage of issued bills that are considered accurate or inaccurate as defined by the Ontario Energy Board.	98.6%	4%
New Services Connected On Time	Percentage of connections for new low-voltage (<750 volts) service requests completed within five business days from the day on which all applicable service conditions are satisfied, or at such later date as agreed to by the customer	96%	2%
Safety	Number of recordable injuries x 200,000 / exposure hours.	1.50	10%

Note:
(1) This is a non-GAAP measure as it includes all eligible capital expenditures, net of capital contributions related to regulated operations excluding Copeland and the facilities consolidation program.

Corporate KPIs are cascaded down in the organization to create appropriate divisional performance objectives with strong line of sight. Divisional KPIs support operational, financial, customer and employee targets. Weightings for these KPIs ranged from 5% to 20% of divisional performance. All divisional KPIs support achievement in the four areas of focus i.e. Customer, People, Operations, and Financial. These measures are aimed at increasing customer satisfaction, improving reliability, accomplishing LDC's work program safely and meeting regulatory requirements. Prioritization of these KPI's is determined based on divisional accountabilities. Some examples of Divisional measures are Customer Connection Index, Safety Inspections per Leader, Distribution System Health Index & Operating Expenses.

Performance-based incentives also include individual performance objectives which are set annually and are tied to business priorities and each individual's particular accountabilities. The number and weighting of individual objectives vary by individual and from year to year. Examples of the 2017 individual performance objectives for the

NEOs include, but are not limited to, continuous improvement of operational processes to enhance performance and engagement.

In 2017, the Corporation exceeded all of its corporate targets represented by its KPIs. The NEOs exceeded the majority of their divisional and individual performance targets for 2017. Each of the corporate, divisional and individual performance targets were reasonably difficult to attain and served to encourage success in the NEOs performance and in the Corporation's overall results.

(iii) *Personal Benefits and Perquisites*

In 2017, the NEOs received personal benefits and perquisites as described in section 12.2(d)(iii) under the heading "Personal Benefits and Perquisites", and as quantified in the Summary Compensation Table in section 12.3(a) above.

(iv) *Pension Plan*

In 2017, each of the NEOs participated in the OMERS pension plan. The OMERS pension plan is a group pension plan that is generally available to all salaried employees. See section 4.6(a) under the heading "Employees" and section 12.2(d)(iv) under the heading "Pension Plan" for further information on the OMERS pension plan.

(v) *Post-employment Benefits*

As of December 31, 2017, Mr. Haines, Mr. Priore, Mr. La Pianta and Mrs. Lethbridge have each provided Toronto Hydro with more than five years of service and are therefore eligible for post-employment medical, dental, and life insurance benefits if they retire from Toronto Hydro and begin collecting under the OMERS pension plan upon retirement.

(vi) *Retirement Allowance*

Mr. Haines is the only NEO entitled to retirement allowances, which allowances are calculated based on completed years of service and are payable in the form of lump-sum cash payments following Mr. Haines' termination (without cause) or retirement from the Corporation.

Under the terms of Mr. Haines' existing retirement allowance (the "Existing Allowance"), if Mr. Haines is terminated (without cause) or retires from the Corporation during 2018, he will receive a $625,000 retirement allowance. The amount of the Existing Allowance payable to Mr. Haines will thereafter be increased by an additional $125,000 per year (from 2018 to 2020) for each full calendar year of service completed. The maximum Existing Allowance payable to Mr. Haines is $1,000,000, which Mr. Haines will earn if he remains in active service for the Corporation until December 31, 2020. In the event that Mr. Haines becomes permanently disabled while in active service for the Corporation, he will be deemed to remain in active service for the Corporation until December 31, 2020, at which point he will be considered to have retired and earned the maximum Existing Allowance of $1,000,000. In the event of the death of Mr. Haines while in active service for the Corporation, the Existing Allowance which Mr. Haines would have earned as of the date of his death will be paid to his designated beneficiary or to the legal representative of Mr. Haines' estate.

As part of his compensation package, Mr. Haines also participates in the OMERS defined benefit pension plan. See "Pension Plan" above in section 12.3(b)(iv). OMERS made significant unilateral changes to its defined benefit pension plan that significantly reduce the value of Mr. Haines' pension benefit under the OMERS pension plan. In order to mitigate the impact of these changes in a manner consistent with the terms of his existing employment relationship with the Corporation, the Corporation has awarded Mr. Haines a second retirement allowance (the "Second Allowance"). Under the terms of the Second Allowance, if Mr. Haines is terminated (without cause) or retires from the Corporation during 2018, he will receive a $750,000 retirement allowance. The amount of the Second Allowance payable to Mr. Haines will thereafter be increased by an additional $225,000 per year (from 2018 to 2021) for each full calendar year of service completed. The maximum Second Allowance payable to Mr. Haines is $1,650,000, which Mr. Haines will earn if he remains in active service for the Corporation until December 31, 2021. In the event that Mr. Haines becomes permanently disabled while in active service for the Corporation, he will be deemed to remain in active service for the Corporation until December 31, 2021, at which point he will be considered to have retired and earned the maximum Second Allowance of $1,650,000. The provisions relating to entitlement on death are identical to those established for the Existing Allowance.

(vii) *Termination Payments*

Mr. Haines has entered into an agreement with the Corporation which provides for certain payments upon termination.

If the employment of Mr. Haines is terminated without cause by the Corporation, then Mr. Haines is entitled to a payment equal to 24 months of base salary and performance pay that would have been paid had he continued to work for 24 months (approximately $2,114,660 as at December 31, 2017), with the performance pay calculated based on the average annual performance pay earned by Mr. Haines during the 3 years preceding the date of termination. Mr. Haines would also be entitled to continued group health and dental benefit coverage for a period of 24 months from the date of termination.

Mr. Bovingdon has entered into an agreement with the Corporation which provides for certain payments upon termination.

If the employment of Mr. Bovingdon is terminated without cause by the Corporation, then Mr. Bovingdon is entitled to 12 months of working notice of termination or pay in lieu thereof and would continue to be eligible for performance pay that would otherwise have been earned and/or paid during the 12 month period. Mr. Bovingdon would also be entitled, during the 12 month period, to any benefits to which he was entitled during employment.

In addition, and in connection with Mr. Couillard ceasing employment with the Corporation, Mr. Couillard was entitled to a termination payment in the aggregate amount of $708,852, representing 18 months of base salary and performance pay, with the performance pay calculated based on the average annual performance pay earned by Mr. Couillard during the three years preceding the date of termination. All amounts owing were paid as of December 31, 2017.

12.4 Compensation of Directors

(a) Director Compensation Table

Director Name	**Total[(1)] ($)**
David McFadden	$75,000
Brian Chu	$30,000
Heather Zordel	$25,500
Howard Wetston	$18,500
Juliana Lam[(2)]	$19,375
Mary Ellen Richardson	$24,500
Michael Nobrega	$29,500
Tamara Kronis	$26,500
Deputy Mayor Denzil Minnan-Wong	$Nil
Councillor Paul Ainslie	$Nil
Deputy Mayor Stephen Holyday	$Nil

Notes:

(1) There was no compensation paid to directors during 2017 other than in respect of director retainer fees and meeting attendance fees.

(2) Effective April 26, 2017, Juliana Lam was appointed as a director of the Corporation.

(b) Compensation of Directors – Narrative Discussion

Directors of the Corporation, other than Councillors of the City, are compensated for their services as directors through a combination of retainer fees and meeting attendance fees. These fees are set by the sole shareholder of the Corporation, the City. The annual retainer fees are as follows: chair of the Board – $75,000 and each of the other directors – $12,500. The meeting attendance fees are as follows: each meeting of the Board and the subsidiaries attended – $1,000 and each meeting of the Audit Committee, Corporate Governance and Nominating Committee, Human Resources and Environment Committee, or other Board committee attended – $1,000, subject to annual maximum fees per committee member of $5,000 for the Audit Committee, Corporate Governance Committee, Human Resources and Environment Committee or any other committee of the Board. The Board does, from time to time and in the normal course, strike ad hoc committees to streamline and expedite certain matters as they come before the Board. Any compensation Directors have earned from their attendance at these committees has been included in the table above. The Chair receives no meeting attendance fees. Councillors receive no remuneration for their services as directors of the Corporation. The other directors, other than the Chair, are subject to a maximum annual total retainer and attendance fees of $30,000.

PART 13 - LEGAL PROCEEDINGS

In the ordinary course of business, Toronto Hydro is subject to various legal actions and claims from customers, suppliers, former employees and other parties. On an ongoing basis, Toronto Hydro assesses the likelihood of any adverse judgments or outcomes as well as potential ranges of probable costs and losses. A determination of the provision required, if any, for these contingencies is made after an analysis of each individual issue. The provision may change in the future due to new developments in each matter or changes in approach, such as a change in settlement strategy. If damages were awarded under these actions, Toronto Hydro would make a claim under any applicable liability insurance policies which Toronto Hydro believes would cover any damages which may become payable by Toronto Hydro in connection with these actions, subject to such claim not being disputed by the insurers.

PART 14 - MATERIAL CONTRACTS

Except for the indenture and the supplemental indentures under which the Debentures were issued, Toronto Hydro has not entered into any material contract (other than contracts entered into in the ordinary course of business) in the most recently completed financial year, or before the most recently completed financial year, if such contract is still in effect.

Copies of these material contracts are available on the SEDAR website at www.sedar.com.

PART 15 - NAMED AND INTERESTS OF EXPERTS

The external auditor of the Corporation is KPMG LLP. KPMG LLP is independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Ontario.

PART 16 - TRANSFER AGENTS AND REGISTRARS

The trustee and registrar for the outstanding Debentures of the Corporation is BNY Trust Company of Canada, located in Toronto, Ontario.

PART 17 - ADDITIONAL INFORMATION

Additional information relating to the Corporation, including additional financial information provided in the Consolidated Financial Statements and Management's Discussion and Analysis, is available on the SEDAR website at www.sedar.com.

ANNEX A - CHARTER – AUDIT COMMITTEE

1. General

(1) The board of directors ***(Board)*** of Toronto Hydro Corporation ***(Corporation)*** has established the Audit Committee ***(Committee)*** to assist the Board in fulfilling its corporate governance and oversight responsibilities with respect to financial reporting, internal financial control structure, financial risk management systems, internal audit and external audit functions.

(2) The composition, responsibilities and authority of the Committee are set out in this Charter.

(3) This Charter and the by-laws of the Corporation and such other procedures, not inconsistent therewith, as the Committee may adopt from time to time shall govern the meetings and procedures of the Committee.

2. Composition

(1) The Committee shall be composed of at least three persons who are directors of the Corporation ***(Members)***:

(a) all Members must be *independent*, (as determined by the Board in accordance with the meaning of "independence", as the context requires, given to it in the Canadian Securities Administrators' National Instrument 52-110 Audit Committees, as the same may be amended and/or replaced from time to time); and

(b) at least one of whom, including the chair of the Committee (***Chair***) is *financially literate* (ie, have the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the accounting issues that can reasonably be expected to be raised by the financial statements of the Corporation).

(2) Members shall be appointed by the Board on the recommendation of the Chair of the Board and shall serve until they resign, cease to be a Director or are removed or replaced by the Board.

(3) The Board shall designate one of the Members as Chair. The Committee shall periodically review the position description of the Chair and make recommendations to the Board.

(4) The Secretary of the Corporation shall be secretary of the Committee ***(Secretary)***.

(5) The Chair of the Corporation's Board of Directors shall be an *ex-officio* Member of the Committee with all of the responsibilities and privileges thereof.

3. Responsibilities

The Committee shall assist the Board in fulfilling its corporate governance and oversight responsibilities with respect to financial reporting, internal financial control structure, financial risk management systems, internal audit functions, external audit functions, and the payment of dividends by the Corporation.

The Committee shall have the responsibilities set out below.

(1) ***Managing the Relationship between the Corporation and its External Auditors***

The Committee shall be responsible for managing the relationship between the Corporation and its external auditors, including:

(a) appointing and replacing the external auditors, subject to shareholder approval;

(b) setting the compensation of the external auditors subject to the approval of the board of directors or shareholder, as applicable;

(c) overseeing the work of the external auditors, including resolving disagreements between management and the external auditors with respect to financial reporting;

(d) pre-approving all audit services and permitted non-audit services to be provided to the Corporation and its subsidiary entities by the external auditors in accordance with the "Policy on the Provision of Services by the External Auditors";

(e) having the external auditors report to the Committee in a timely manner with respect to all required matters, including those set out in paragraph 3(2);

(f) ensuring the rotation of the audit partner having primary responsibility for the external audit of the Corporation, the audit partner responsible for reviewing the external audit and the external auditors at such intervals as may be required; and

(g) reviewing and assessing the performance, independence and objectivity of the external auditors.

(2) ***Overseeing the External Audit***

The Committee shall be responsible for overseeing the external audit of the Corporation, including:

(a) reviewing and approving the engagement letter and the audit plan, including financial risk areas identified by the external auditors and management;

(b) reviewing and assessing the accounting and reporting practices and principles used by the Corporation in preparing its financial statements, including:

(1) all significant accounting policies and practices used, including changes from preceding years and any proposed changes for future years;

(2) all significant financial reporting issues, estimates and judgments made;

(3) all alternative treatments of financial information discussed by the external auditors and management, the results of such discussions and the treatments preferred by the external auditors;

(4) any major issues identified by the external auditors with respect to the adequacy of internal control systems and procedures and any special audit steps adopted in light of material deficiencies and weaknesses;

(5) the effect of regulatory and accounting initiatives and off-balance sheet transactions or structures on the financial statements;

(6) any errors or omissions in, and any required restatement of, the financial statements for preceding years;

(7) all significant tax issues;

(8) the reporting of all material contingent liabilities; and

(9) any material written communications between the external auditors and management;

(c) reviewing and assessing the results of the external audit and the external auditors' opinion on the financial statements;

(d) reviewing and discussing with the external auditors and management any management or internal control letters issued or proposed to be issued by the external auditors;

(e) reviewing and discussing with the external auditors any problems or difficulties encountered by them in the course of their audit work and management's response (including any restrictions on the scope of activities or access to requested information and any significant disagreements with management); and

(f) reviewing and discussing with legal counsel any legal matters that may have a material impact on the financial statements, operations, assets or compliance policies of the Corporation and any material reports or enquiries received by the Corporation and its subsidiary entities from regulators or government agencies.

(3) ***Overseeing the Internal Audit***

The Committee shall be responsible for overseeing the internal audit of the Corporation, including:

(a) periodically reviewing the Internal Audit Charter and making recommendations to the Board;

(b) reviewing and approving the audit plan, including significant risk exposures identified by the internal auditor and management;

(c) reviewing and discussing with the internal auditor and management the results of any internal audits;

(d) reviewing and discussing with the internal auditors any problems or difficulties encountered by them in the course of their audit work and management's response (including any restrictions on the scope of activities or access to requested information and any significant disagreements with management);

(e) appointing and replacing the internal auditor;

(f) reviewing and assessing the performance of the internal auditor;

(g) ensuring the Committee is kept informed of emerging trends and successful practices in internal auditing; and

(h) confirming there is effective and efficient coordination of activities between internal and external auditors.

(4) ***Reviewing and Recommending to the Respective Boards for Approval the Financial Statements, MD&A and Interim Reports of the Corporation and its Subsidiaries***

The Committee shall review and recommend to the Board for approval, the financial statements, management's discussion and analysis of financial condition and results of operations ***(MD&A)*** and interim financial reports of the Corporation and its subsidiaries, annual information form **(*AIF*)** of the Corporation and other public disclosure of financial information extracted from the financial statements of the Corporation and its subsidiaries with particular focus on:

(a) the quality and appropriateness of accounting and reporting practices and principles and any changes thereto;

(b) major estimates or judgments, including alternative treatments of financial information discussed by management and the external auditors, the results of such discussions and the treatment preferred by the external auditors;

(c) material financial risks;

(d) material transactions;

(e) material adjustments;

(f) compliance with loan agreements;

(g) material off-balance sheet transactions and structures;

(h) compliance with accounting standards;

(i) compliance with legal and regulatory requirements; and

(j) disagreements with management.

(5) ***Overseeing Internal Financial Control Structure and Financial Risk Management Systems***

The Committee shall be responsible for overseeing the internal financial control structure and financial risk management systems of the Corporation, including:

(a) reviewing and discussing with management and the external auditors the quality and adequacy of internal control over financial reporting structures of the Corporation, including any major deficiencies or weakness and the steps taken by management to rectify these deficiencies or weaknesses;

(b) reviewing and discussing with management, the internal auditor and the external auditors the risk assessment and risk management policies of the Corporation, the major financial risk exposures of the Corporation and the steps taken by management to monitor and control these exposures;

(c) reviewing and discussing with the Chief Executive Officer and the Chief Financial Officer of the Corporation the procedures undertaken by them in connection with the certifications required to be given by them in connection with annual and other filings required to be made by the Corporation under applicable securities laws; and

(d) periodically reviewing the Treasury Policy and signing policies for the Corporation and its subsidiaries, making recommendations to the Board in respect of such policies and reviewing performance under those polices with Management.

(6) ***Establish and Review Certain Procedures and Policies***

The Committee shall establish adequate policies and procedures, or require that adequate policies and procedures are established, with respect to the following, and shall annually, or on such other schedule as stated herein, assess the adequacy of these procedures:

(a) the review of the public disclosure of financial information extracted from the financial statements of the Corporation;

(b) the receipt, retention and treatment of complaints received by the Corporation with respect to accounting, internal controls or auditing matters;

(c) the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters;

(d) the approval by the Committee of the hiring policies for any present or former partner or employee of the current and former external auditor into a position of senior management with the Corporation or its subsidiaries; and

(e) the periodic review of the Expense Reimbursement Policy, and provision of recommendations to the Board in respect of the same.

(7) ***Review of Policy Reporting***

(a) The Committee shall be responsible, on a quarterly basis, for reviewing and reporting to the Board in respect of the report of Internal Audit with respect to incidents regarding questionable accounting or auditing matters investigated under the Code of Business Conduct during the previous quarter.

(b) The Committee shall be responsible for reviewing, on a quarterly basis, the report of Internal Audit concerning executive and Board expense reimbursements made in accordance with the Corporation's Expense Reimbursement Policy for the immediately preceding quarter.

(8) ***Review and Recommendations for Dividend Payment***

(a) The Committee shall be responsible for reviewing and making recommendations to the Board with respect to the declaration of dividends or distribution of capital by the Corporation.

4. Authority

(1) The Committee is authorized to carry out its responsibilities as set out in this Charter and to make recommendations to the Board arising therefrom.

(2) The Committee may delegate by written policy to the Chair and the Chief Financial Officer of the Corporation ***(CFO)*** the authority, within specified limits, to authorize in advance all engagements of the external auditors to provide pre-approved services to the Corporation and its subsidiary entities. The Chair and the CFO shall report all engagements authorized by them to the Committee at its next meeting.

(3) The Committee shall have direct and unrestricted access to the external and internal auditors, officers and employees and information and records of the Corporation.

(4) The Committee is authorized to retain, and to set and pay the compensation of, independent legal counsel and other advisors if it considers this appropriate.

(5) The Committee is authorized to invite officers and employees of the Corporation and its subsidiaries and outsiders with relevant experience and expertise to attend or participate in its meetings and proceedings if it considers this appropriate.

(6) The external auditors shall have direct and unrestricted access to the Committee and shall report directly to the Committee.

(7) The Corporation shall pay directly or reimburse the Committee for the expenses incurred by the Committee in carrying out its responsibilities, in accordance with the Corporation's Expense Reimbursement Policy.

5. Meetings and Proceedings

(1) The Committee shall meet as frequently as required but not less frequently than four times each year.

(2) Any Member or the Secretary may call a meeting of the Committee. The external auditors or the CFO may ask a Member to call a meeting of the Committee.

(3) The Chair shall approve the agenda of each meeting of the Committee, including input from the officers and employees of the Corporation, external auditors, other Members and other directors of the Corporation as appropriate. Meetings will include presentations by management or professional advisors and consultants when appropriate and allow sufficient time to permit a full and open discussion of agenda items.

(4) Unless waived by all Members, a notice of each meeting of the Committee confirming the date, time, place and agenda of the meeting, together with any supporting materials, shall be forwarded, electronically or otherwise, to each Member at least three days before the date of the meeting.

(5) The quorum for each meeting of the Committee is at least 50% of the Members. In the absence of the Chair, the other Members may appoint one of their number as chair of a meeting. The Chair of a meeting shall not have a second or casting vote.

(6) The Chair or a delegate of the Chair shall report to the Board following each meeting of the Committee.

(7) The Secretary or a delegate of the Secretary shall keep minutes of all meetings of the Committee, including all resolutions passed by the Committee. Minutes of all meetings shall be distributed to the Members. The minutes shall be available for review by the other directors of the Corporation after approval thereof by the Committee.

(8) An individual who is not a Member may be invited to attend a meeting of the Committee for all or part of the meeting. A standing invitation to all meetings shall be given to the President and Chief Executive Officer of the Corporation and the CFO except where the meeting, or part of the meeting, is for Members only or a private session with the internal auditor or the external auditors. A standing invitation should be given to the internal auditor and the engagement partners of the external auditors for all meetings where financial information is reviewed and approved.

(9) The Committee shall meet regularly alone and in private sessions with the Director of Internal Audit, the external auditors and management of the Corporation to facilitate full communication.

6. Review

(1) This Charter shall be reviewed by the Corporate Governance and Nominating Committee of the Corporation every 2 years and any recommended changes shall be referred first to the Audit Committee for review and comment and second, after consideration of the input from the Audit Committee, to the Board of the Corporation for consideration and disposition.

(2) In addition to the biennial review, the Audit Committee may at any time review the Charter and make recommendations to the Corporate Governance and Nominating Committee for their review and recommendations to the Board with respect thereto.

ANNEX B - MANDATE – BOARD OF DIRECTORS

1. General

(1) The board of directors ***(Board)*** of *Toronto Hydro Corporation* ***(Corporation)*** is responsible for supervising the management of the business and affairs of the Corporation and its subsidiary entities ***(Group)***.

(2) The composition, responsibilities, and authority of the Board are set out in this Mandate.

(3) This Mandate, the Shareholder Direction issued by the City of Toronto ***(Shareholder)*** and the by-laws of the Corporation and such other procedures, not inconsistent therewith, as the Board may adopt from time to time shall govern the meetings and procedures of the Board.

2. Composition

(1) The directors of the Corporation ***(Directors)*** should have a mix of competencies and skills necessary to enable the Board and Board committees to properly discharge their responsibilities.

(2) All of the Directors shall be residents of Canada.

(3) The Shareholder shall appoint Directors every two years.

(4) In appointing Directors the Shareholder shall give due regard to the qualifications of the candidates including:

(a) experience on a public utility commission or board of a major corporation or other commercial enterprise and/or the completion of formal training in directorship / governance;

(b) experience in regulated electricity utility sector at a senior management level;

(c) experience at an executive level in resource and performance management / compensation, including ability to appoint and evaluate the performance of the CEO and senior executives; oversee strategic human resource management, including workforce planning, compensation models, and labour relations; and oversee large scale organizational change;

(d) educational background, including university degrees and professional designations;

(e) experience or knowledge with respect to:

i) strategic planning, including ability to identify and critically assess strategic opportunities and threats to the organization;

ii) risk management, including ability to assess key risks to the organization on an enterprise basis and monitor the risk management framework systems;

iii) corporate finance / accounting / audit / securities, including ability to analyze financial statements, assess financial viability, contribute to financial planning, oversee budgets, and oversee funding arrangements;

iv) corporate governance;

v) market development;

vi) large system operation and management;

vii) urban energy industries;

viii) public policy issues and laws relating to the Corporation and its subsidiary entities and the electricity industry;

ix) environmental matters, including experience in environmental management;

x) labour relations;

xi) occupational health and safety issues;

xii) information technology governance, including privacy, data management and security;

xiii) legal and regulatory compliance, including ability to monitor compliance of legal and regulatory requirements;

xiv) stakeholder engagement / advocacy / communications, including ability to effectively engage and communicate to industry stakeholders and advocate on behalf of the organization;

(f) the following interpersonal skills and attributes:

i) leadership, including ability to make, and take responsibility for, decisions and take necessary actions in the best interest of the organization, set appropriate Board and organizational culture and represent the organization favourably;

ii) personal integrity / ethics, including understanding and fulfilling the duties and responsibilities of a director, being transparent and declaring any activities or conduct that might be a potential conflict, and maintaining Board confidentiality;

iii) communications skills, including ability to listen constructively and appropriately debate others' viewpoints, develop and deliver cogent arguments, and communicate effectively with a broad range of stakeholders;

iv) constructive questioning, including preparedness to ask questions and challenge management and peer directors in a constructive and appropriate manner;

v) critical and innovative thinking / decision making, including ability to critically analyze complex and detailed information, readily distill key issues, and develop innovative approaches and solutions to problems;

vi) influencing and negotiating, including ability to negotiate outcomes and influence others to agree with those outcomes and gain stakeholder support for the Board's decisions;

vii) crisis management, including ability to constructively manage crises, provide leadership around solutions and contribute to communications strategy with stakeholders;

viii) individual and team contribution, including ability to work as part of a team, and demonstrate the passion and time to make a genuine and active contribution to the Board and the organization;

ix) commercial sensitivity and acumen; and

x) independence of judgement;

(g) at least three directors with financial management expertise.

(5) For the purposes of determining whether a Director is independent, the Board shall use the definition of independence within the meaning of National Instrument 52-110 *Audit Committee* adopted by the Canadian Securities Administrators.

(6) The Board shall appoint a Chair of the Board upon the nomination of the Shareholder from time to time.

(7) The Secretary of the Corporation shall be secretary of the Board ***(Secretary)***.

3. Responsibilities

(1) The Board is responsible for supervising the management of the business and affairs of the Group, including the following specific matters:

(a) establishing sound financial principles and performance objectives;

(b) approving any dividend payment or distribution of capital;

(c) appointing the officers of the Corporation;

(d) approving the overall business strategy and related business plan;

(e) approving the financing strategy, including the selection of financial institutions and related banking authorities;

(f) directing labour and employee relations matters; and

(g) approving the financial statements in accordance with the requirements of the Business Corporations Act (Ontario).

(2) In discharging their responsibilities, the Directors owe the following duties to the Corporation:

- a fiduciary duty: they must act honestly and in good faith with a view to the best interests of the Corporation; and

- a duty of care: they must exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances.

In discharging their responsibilities, the Directors are entitled to rely on the honesty and integrity of the senior officers of the Corporation and the auditors and other professional advisors of the Corporation.

In discharging their responsibilities, the Directors are also entitled to directors and officers liability insurance purchased by the Corporation and indemnification from the Corporation to the fullest extent permitted by law and the constating documents of the Corporation.

(3) The Board has specifically recognized its responsibilities for:

(a) to the extent feasible, satisfying itself as to the integrity of the Chief Executive Officer ***(CEO)*** and other senior officers of the Corporation and that the CEO and other senior officers of the Corporation create a culture of integrity throughout the Group;

(b) adopting a strategic planning process and approving annually (or more frequently if appropriate) a strategic plan which takes into account, among other things, the opportunities and risks of the business of the Group;

(c) overseeing the identification of the principal risks of the business of the Group and overseeing the implementation of appropriate systems to manage these risks;

(d) overseeing the integrity of the internal control and management information systems of the Group;

(e) succession planning (including appointing, training and monitoring the senior officers of the Corporation);

(f) recruiting and assessing the performance of the CEO, the compensation of the CEO and other officers of the Group, executive compensation disclosure and oversight of the compensation structure and benefit plans and programs of the Group;

(g) assessing the effectiveness of the Board;

(h) adopting a disclosure policy for the Group;

(i) developing and overseeing the orientation of new Directors, and the continuing education of existing Directors, of the Group; and

(j) developing the approach of the Corporation to corporate governance including a periodic review of the Code of Business Conduct and Whistleblower Procedure of the Group.

(4) In addition to those matters which must by law be approved by the Board, the Board oversees the development of, and reviews and approves, significant corporate plans and initiatives, including the annual business plan and budget, major acquisitions and dispositions and other significant matters of corporate strategy or policy, including the Environmental Policy, Occupational Health and Safety Policy, Code of Business Conduct and Whistleblower Procedure, Disclosure Policy, Signing Policy and Treasury Policy.

(5) The Board shall periodically review the Shareholder Direction and make recommendations to the Shareholder to facilitate and clarify interaction and communication between the Shareholder and the Board.

(6) The Board shall periodically review the performance of the Board against the Shareholder Direction.

(7) The Board shall periodically review the structure and mandate of each Board committee, the effectiveness of each committee, and the appointment and removal of committee members.

(8) The Board shall periodically review performance under the Environmental Policy with management.

(9) To assist the Directors in discharging their responsibilities, the Board expects management of the Corporation to:

(a) review and update annually (or more frequently if appropriate) the strategic plan and report regularly to the Board on the implementation of the strategic plan in light of evolving conditions;

(b) prepare and present to the Board annually (or more frequently if appropriate) a business plan and budget and report regularly to the Board on the Corporation's performance against the business plan and budget; and

(c) report regularly to the Board on the Corporation's business and affairs and on any matters of material consequence for the Corporation and its Shareholder.

Additional expectations are developed and communicated during the annual strategic planning and budgeting process and during regular Board and Board committee meetings.

(10) The Board considers that generally management should speak for the Corporation in its communications with securities holders and the public. The Corporation's investor relations personnel are required to respond to inquiries from securities holders and the public after review and discussion, as appropriate, by senior management and the Board and Board committees. The Corporation's investor relations personnel are available to the securities holders by telephone, fax and e-mail. The Corporation maintains an investor relations section on its website. Presentations at investor conferences are posted promptly on the Corporation's website. They are also available on request. The Board reviews the Corporation's major communications with securities holders and the public. All disclosures on behalf of the Corporation are to be made in compliance with the Corporation's disclosure policy.

(11) Directors are expected to attend Board meetings and meetings of Board committees of which they are members. Directors are also expected to spend the time needed, and to meet as frequently as necessary, to discharge their responsibilities.

(12) Directors are expected to undertake such activities as are required from them to remain current in their knowledge of issues relating to the business of the Group and matters relating to any Board committee of which they are members.

(13) Directors are expected to comply with the Code of Business Conduct and Whistleblower Procedure of the Group.

4. Authority

(1) The Board is authorized to carry out its responsibilities as set out in this Mandate.

(2) The Board is authorized to retain, and to set and pay the compensation of, independent legal counsel and other advisors if it considers this appropriate.

(3) The Board is authorized to invite officers and employees of the Corporation and others to attend or participate in its meetings and proceedings if it considers this appropriate.

(4) The Directors have unrestricted access to the officers of the Corporation. The Directors will use their judgment to ensure that any such contact is not disruptive to the operations of the Corporation and, except for the chair of any committee established by the Board advise the Chair and the Chief Executive Officer of the Corporation of any direct communications between them and the officers of the Corporation.

(5) The Board and the Directors have unrestricted access to the advice and services of the Secretary.

(6) The Board may delegate certain of its functions to Board committees, each of which will have its own charter.

5. Meetings and Proceedings

(1) The Board shall meet as frequently as is determined to be necessary but not less than four times each year.

(2) Any Director or the Secretary may call a meeting of the Board.

(3) The Chair is responsible for the agenda of each meeting of the Board, including input from other Directors and the officers and employees of the Corporation as appropriate. Meetings will include presentations by management and others when appropriate and allow sufficient time to permit a full and open discussion of agenda items.

(4) Unless waived by all Directors, a notice of each meeting of the Board confirming the date, time, place and agenda of the meeting, together with any supporting materials, shall be forwarded to each Director at least 48 hours before the date of the meeting.

(5) The quorum for each meeting of the Board is a majority of the number of Directors. In the absence of the Chair, the other Directors shall appoint one of their number as chair of a meeting. The chair of a meeting shall not have a second or casting vote.

(6) The Secretary or his delegate shall keep minutes of all meetings of the Board, including all resolutions passed by the Board. Minutes of meetings shall be distributed to the Directors.

(7) An individual who is not a Director may be invited to attend a meeting of the Board for all or part of the meeting.

(8) The Directors shall meet regularly alone to facilitate full communication.

6. Review

(1) This Mandate shall be reviewed by the Corporate Governance Committee of the Corporation every 2 years and any recommended changes shall be brought to the Board of the Corporation for consideration and disposition.

PUBLIC DEBT OFFERING

In accordance with s. 2.1.9 of the OEB's Filing Requirements,[1] this schedule provides Toronto Hydro-Electric System Limited's public debt offering information, as follows:

- Appendix A: Base Shelf Prospectus 2017
- Appendix B: 11th Supplemental Trust Indenture, Sep 2014
- Appendix C: 12th Supplemental Trust Indenture, Mar 2015
- Appendix D: 13th Supplemental Trust Indenture, Jun 2016
- Appendix E: 14th Supplemental Trust Indenture, Nov 2017

[1] Ontario Energy Board, Filing Requirements for Electricity Distributor Rate Applications, Chapter 2 (July 12, 2018).

No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

This short form prospectus is a base shelf prospectus which has been filed under legislation in each of the provinces of Canada that permits certain information about these securities to be determined after this prospectus has become final and that permits the omission from this prospectus of that information. The legislation requires the delivery to purchasers of a prospectus supplement containing the omitted information within a specified period of time after agreeing to purchase any of these securities.

This short form prospectus constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. These securities have not been and will not be registered under the United States Securities Act of 1933, as amended (the "U.S. Securities Act") or any state securities laws, and, subject to certain exceptions, may not be offered or sold within the United States or to, or for the account or benefit of, U.S. Persons (as such term is defined in Regulation S under the U.S. Securities Act). See "Plan of Distribution".

Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions or similar authorities in Canada. *Copies of the documents incorporated herein by reference may be obtained on request without charge from the* Corporate Secretary *of Toronto Hydro Corporation at 14 Carlton Street, Toronto, Ontario, M5B 1K5, (416) 542-3100 and are also available electronically at www.sedar.com.*

SHORT FORM BASE SHELF PROSPECTUS

New Issue May 8, 2017

TORONTO HYDRO CORPORATION

$1,000,000,000 DEBENTURES

(unsecured)

Toronto Hydro Corporation (the "Corporation") may offer and issue from time to time unsecured debentures (the "Debentures") in one or more series in an aggregate principal amount of up to $1,000,000,000 (or the equivalent thereof in foreign currencies or currency units based on the applicable exchange rate at the time of offering) during the twenty-five months from the date of issuance of the receipt for this prospectus.

The Debentures will be issued under a trust indenture dated May 7, 2003 (as supplemented from time to time by supplemental indentures), will be direct unsecured obligations of the Corporation and will rank *pari passu* (except as to sinking funds and to the extent prescribed by law) with all other unsecured and unsubordinated indebtedness of the Corporation. The Debentures will have a term to maturity of not less than one year and will be issuable in denominations of $1,000 and multiples thereof. The Debentures may be issued in Canadian dollars or any foreign currency or currency unit determined at the time of issue.

The specific terms of an offering of Debentures (including the aggregate principal amount of the Debentures being offered, the currency or currencies, the issue and delivery date, the form, the maturity date, the interest rate, the issue price, the interest payment date(s), any redemption or repayment provisions, any provisions entitling the Corporation to extend the maturity date of the Debentures, the name(s) of the dealer(s) offering the Debentures, the commission payable to such dealer(s), the method of distribution and the net proceeds to the Corporation) will be set forth in a pricing supplement which will be delivered to purchasers together with this prospectus. The Corporation reserves the right to set forth in a pricing supplement specific terms of Debentures which are not within the parameters set forth in this prospectus.

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The sole shareholder of the Corporation is the City of Toronto. The Debentures will not be obligations of, and will not be guaranteed in any manner by, the City of Toronto.

Investing in the Debentures involves risks. See "Risk Factors" in this prospectus, which may be amended or supplemented in any prospectus supplement or pricing supplement.

There is no market through which the Debentures may be sold and purchasers may not be able to resell Debentures purchased under this prospectus. This may affect the pricing of the Debentures in the secondary market, the transparency and availability of trading prices, the liquidity of the Debentures and the extent of issuer regulation. See "Risk Factors". Unless otherwise indicated in a pricing supplement, the Debentures will not be listed on any securities exchange.

RATES ON APPLICATION

Pursuant to the dealer agreement referred to under the heading "Plan of Distribution", the Debentures may be offered for sale severally and on a continuous basis by one or more of CIBC World Markets Inc., TD Securities Inc., BMO Nesbitt Burns Inc., RBC Dominion Securities Inc., National Bank Financial Inc. and Scotia Capital Inc. and such other dealers as may be selected from time to time by the Corporation (collectively, the "Dealers" and each a "Dealer"), in each case, acting as agent of the Corporation or as principal. Where the Debentures are offered by the Dealer(s) as agent(s), the commissions payable by the Corporation in connection with sales of such Debentures shall be agreed from time to time between the Corporation and any such Dealer(s). Where the Debentures are purchased by the Dealer(s) as principal, the Debentures shall be purchased at such prices and with such commissions as may be agreed from time to time between the Corporation and any such Dealer(s) for resale to the public at prices to be negotiated with each purchaser. Such resale prices may vary during the distribution period and as between purchasers. Each Dealer's compensation will increase or decrease by the amount by which the aggregate price paid for Debentures by purchasers exceeds or is less than the price paid by such Dealer, when purchasing as principal, to the Corporation. The commissions payable in connection with sales of Debentures will be set forth in a pricing supplement which will be delivered to purchasers together with this prospectus. In connection with any offering of Debentures, the Dealers may over-allot or effect transactions which stabilize or maintain the market price of the Debentures offered at a level above that which might otherwise prevail in the open market. Such transactions, if commenced, may be discontinued at any time. See "Plan of Distribution". The Corporation may also offer the Debentures directly to potential purchasers pursuant to applicable statutory exemptions at prices and upon terms negotiated between the purchaser and the Corporation, in which case no commissions will be paid to the Dealers. The Corporation and, if applicable, the Dealers, may reject any offer to purchase the Debentures in whole or in part. The Corporation also reserves the right to withdraw, cancel or modify the offering of the Debentures under this prospectus without notice.

The Corporation may be considered to be a connected issuer of CIBC World Markets Inc., TD Securities Inc., BMO Nesbitt Burns Inc., RBC Dominion Securities Inc., National Bank Financial Inc. and Scotia Capital Inc. within the meaning of Canadian securities legislation. CIBC World Markets Inc., TD Securities Inc., BMO Nesbitt Burns Inc., RBC Dominion Securities Inc., National Bank Financial Inc. and Scotia Capital Inc. are wholly-owned subsidiaries of banks which are currently lenders to the Corporation. See "Plan of Distribution".

The offering of the Debentures is subject to the approval of certain legal matters on behalf of the Corporation by Norton Rose Fulbright Canada LLP and on behalf of the Dealers by Blake, Cassels & Graydon LLP.

The registered and head office of the Corporation is located at 14 Carlton Street, Toronto, Ontario, M5B 1K5.

TABLE OF CONTENTS

Page

DOCUMENTS INCORPORATED BY REFERENCE 3
FORWARD-LOOKING INFORMATION 4
TORONTO HYDRO 6
USE OF PROCEEDS 6
PLAN OF DISTRIBUTION 6
RELATIONSHIP BETWEEN THE CORPORATION AND THE DEALERS 7
RATINGS 8
EARNINGS COVERAGE RATIOS 8
DESCRIPTION OF THE DEBENTURES 9
RISK FACTORS 20
ELIGIBILITY FOR INVESTMENT 22
LEGAL MATTERS 23
AUDITORS 23
PURCHASERS' STATUTORY RIGHTS 23
CERTIFICATE OF THE CORPORATION C-1
CERTIFICATE OF THE DEALERS C-2

DOCUMENTS INCORPORATED BY REFERENCE

The following documents of the Corporation filed with the provincial securities regulatory authorities in Canada are incorporated by reference in this prospectus for the purposes of the offering of Debentures hereunder:

(a) the annual information form (the "AIF") of the Corporation for the year ended December 31, 2016 dated March 31, 2017;

(b) the comparative audited consolidated financial statements of the Corporation together with the auditors' report thereon and the notes thereto as at December 31, 2016 and December 31, 2015, and for the years ended December 31, 2016 and December 31, 2015; and

(c) management's discussion and analysis of financial condition and results of operations ("MD&A") for the three months and years ended December 31, 2016 and December 31, 2015 (the "Annual MD&A").

Updated earnings coverage ratios will be filed quarterly with the provincial securities regulatory authorities in Canada, either as prospectus supplements or as exhibits to the Corporation's unaudited interim and audited consolidated financial statements, and will be deemed to be incorporated by reference in this prospectus for the purposes of the offering of Debentures hereunder.

Any documents of the type required by National Instrument 44-101 – *Short Form Prospectus Distributions* to be incorporated by reference in a short form prospectus, including the documents of the type referred to above, interim financial statements and related MD&A, material change reports (except confidential material change reports) and business acquisition reports filed by the Corporation with the provincial securities regulatory authorities in Canada after the date of this prospectus and prior to termination of any offering hereunder will be deemed to be incorporated by reference in this prospectus.

Upon a new AIF and new annual financial statements and related MD&A being filed by the Corporation with, and where required, accepted by, the applicable securities regulatory authorities during the currency of this prospectus, the previous AIF, the previous annual financial statements and related MD&A, all previous interim financial statements and related MD&A, previous material change reports and previous business acquisition reports filed by the Corporation prior to the end, and in case of business acquisition reports prior to the commencement, of the financial year of the Corporation in respect of which the new AIF is filed will be deemed no longer to be incorporated by reference into this prospectus for purposes of future

offers and sales of Debentures hereunder. Upon unaudited interim financial statements and the accompanying interim MD&A being filed by the Corporation with the applicable securities regulatory authorities during the currency of this prospectus, all unaudited interim financial statements and the accompanying interim MD&A filed prior to the new unaudited interim financial reports shall be deemed no longer to be incorporated by reference into this prospectus for purposes of future offers and sales of Debentures hereunder.

A pricing supplement containing the specific variable terms for an offering of Debentures will be delivered to purchasers of such Debentures together with this prospectus and will be deemed to be incorporated by reference in this prospectus as of the date of the pricing supplement, solely for the purposes of the Debentures offered under that pricing supplement.

Certain marketing materials (as that term is defined in applicable securities legislation) may be used in connection with a distribution of Debentures under this prospectus and any applicable pricing supplement. Any template version (as that term is defined in applicable securities legislation) of marketing materials pertaining to a distribution of Debentures, and filed by the Corporation after the date of the applicable pricing supplement for the offering and before termination of the distribution of such Debentures, will be deemed to be incorporated by reference in such pricing supplement for the purposes of the distribution of Debentures to which the pricing supplement pertains.

Any statement contained in this prospectus or in a document incorporated or deemed to be incorporated by reference herein will be deemed to be modified or superseded, for purposes of this prospectus, to the extent that a statement contained herein or in a document incorporated or deemed to be incorporated by reference herein modifies or supersedes such prior statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of a modifying or superseding statement will not be deemed an admission for any purposes that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it was made. Any statement so modified or superseded will not constitute a part of this prospectus, except as so modified or superseded.

FORWARD-LOOKING INFORMATION

Certain information included or incorporated by reference in this prospectus constitutes "forward-looking information" within the meaning of applicable securities legislation. The purpose of the forward-looking information is to provide the Corporation's current expectations regarding future results of operations, performance, business prospects and opportunities and may not be appropriate for other purposes. All information, other than statements of historical fact included or incorporated by reference in the prospectus, which address activities, events or developments that the Corporation expects or anticipates may or will occur in the future, are forward-looking information. The words "anticipates", "believes", "budgets", "committed", "can", "could", "estimates", "expects", "focus", "forecasts", "intends", "may", "might", "plans", "propose", "projects", "schedule", "should", "will", "would", "objective", "outlook" or the negative or other variations of these words or other comparable words or phrases, are intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects the Corporation's current beliefs and is based on information currently available to the Corporation.

Specific forward-looking information in this prospectus includes statements under the headings "Use of Proceeds" and "Plan of Distribution". Additional forward-looking information is identified in the various documents incorporated by reference in this prospectus, including, without limitation, the section entitled "Forward-Looking Information" in the Corporation's AIF and the section entitled "Forward-Looking Information" in the Corporation's MD&A.

The forward-looking information is based on estimates and assumptions made by the Corporation's management in light of past experience and perception of historical trends, current conditions and expected future developments, as well as other factors that management believes to be reasonable in the

circumstances, including, but not limited to, the completion of issuances of Debentures under this prospectus, the amount of indebtedness of the Corporation at such time, changes in funding requirements, the future course of the economy and financial markets, no unforeseen changes in the legislative and operating framework for electricity distribution in Ontario, the receipt of applicable regulatory approvals and requested rate orders, no unexpected delays in obtaining required approvals, the ability of the Corporation to obtain and retain qualified staff, equipment and services in a timely and cost efficient manner, the receipt of favourable judgments, no unforeseen changes in electricity distribution rate orders or rate setting methodologies, no unfavourable changes in environmental regulation, the level of interest rates and the Corporation's ability to borrow, and assumptions regarding general business and economic conditions.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information, which are discussed in more detail under "Risk Factors" in this prospectus and in any pricing supplement and in the comparable sections of the documents incorporated or deemed to be incorporated by reference in this prospectus (including the sections entitled "Forward-Looking Information" and "Risk Factors" in the Corporation's AIF and the sections entitled "Forward-Looking Information" and "Risk Management and Risk Factors" in the Corporation's MD&A). All of the forward-looking information included or incorporated by reference in this prospectus is qualified by the cautionary statements in this "Forward-Looking Information" section and the "Risk Factors" section of this prospectus and in the comparable sections of the documents incorporated or deemed to be incorporated by reference in this prospectus (including the sections entitled "Forward-Looking Information" and "Risk Factors" in the Corporation's AIF and the sections entitled "Forward-Looking Information" and "Risk Management and Risk Factors" in the Corporation's MD&A). These factors are not intended to represent a complete list of the factors that could affect the Corporation; however, these factors should be considered carefully and readers should not place undue reliance on forward-looking information made herein or in the documents incorporated by reference. Furthermore, the forward-looking information contained or incorporated by reference herein is dated as of the date of this prospectus or as of the date specified in the documents incorporated by reference into this prospectus, as the case may be, and the Corporation has no intention and undertakes no obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

Capitalized terms used in this section without definition, have the meanings given to them elsewhere in this prospectus. Unless otherwise specified, all references to dollars contained in this prospectus are to Canadian dollars.

TORONTO HYDRO

Toronto Hydro Corporation (the "Corporation" and, together with its subsidiaries, "Toronto Hydro") is a holding company which wholly-owns two subsidiaries:

- *Toronto Hydro-Electric System Limited* ("LDC") – distributes electricity and engages in conservation and demand management activities; and
- *Toronto Hydro Energy Services Inc.* – provides street lighting and expressway lighting services in the City of Toronto.

The principal business of Toronto Hydro is the distribution of electricity by LDC, which owns and operates the electricity distribution system for Canada's largest city. A leader in conservation and demand management, it has 761,000 customers located in the City of Toronto and distributes approximately 19% of the electricity consumed in Ontario.

The sole shareholder of the Corporation is the City of Toronto.

USE OF PROCEEDS

The Debentures will be issued from time to time at the discretion of the Corporation in an aggregate principal amount not to exceed $1,000,000,000 (or the equivalent thereof in foreign currencies or currency units based on the applicable exchange rate at the time of offering). Unless otherwise specified in a pricing supplement, the net proceeds from the sale of Debentures will be used by the Corporation to reduce certain indebtedness of the Corporation, including, but not limited to, indebtedness that the Corporation may have with the bank affiliates of one or more of the Dealers, to finance the Corporation's capital expenditure program and for general corporate purposes. The net proceeds from the sale of Debentures cannot be estimated at the date hereof since the amount thereof will depend on the terms and conditions of the Debentures and the extent to which the Debentures are issued under this prospectus. Any commissions payable to the Dealers relating to a particular offering of Debentures will be netted out of the proceeds thereof and all other expenses relating thereto will be paid out of the Corporation's general funds or netted out of the proceeds of such offering.

PLAN OF DISTRIBUTION

Pursuant to the terms of a dealer agreement dated May 8, 2017 (the "Dealer Agreement"), the Debentures may be offered for sale severally and on a continuous basis by one or more of the Dealers, in each case, acting as agent of the Corporation or as principal. Where the Debentures are offered by the Dealer(s) as agent(s), the commissions payable by the Corporation in connection with sales of such Debentures shall be agreed from time to time between the Corporation and any such Dealer(s). Where the Debentures are purchased by the Dealer(s) as principal, the Debentures shall be purchased at such prices and with such commissions as may be agreed from time to time between the Corporation and any such Dealer(s) for resale to the public at prices to be negotiated with each purchaser. Such resale prices may vary during the distribution period and as between purchasers. Each Dealer's compensation will increase or decrease by the amount by which the aggregate price paid for Debentures by purchasers exceeds or is less than the price paid by the Dealer, when purchasing as principal, to the Corporation. The commissions payable in connection with sales of Debentures will be set forth in a pricing supplement which will be delivered to purchasers together with this prospectus. The Corporation may also offer the Debentures directly to potential purchasers pursuant to applicable statutory exemptions at prices and upon terms negotiated between the purchaser and the Corporation, in which case no commissions will be paid to the Dealers.

The obligations of a Dealer under the Dealer Agreement to purchase any particular issue of Debentures as principal may be terminated at its discretion upon the occurrence of certain stated events. Such events are set out in detail in the Dealer Agreement and include, but are not limited to: (i) an event which prevents or restricts the trading in the Debentures or any other securities of the Corporation or the distribution of the Debentures; (ii) the occurrence of any material change in the business, affairs, operations,

assets, liabilities (contingent or otherwise), capital or ownership of Toronto Hydro taken as a whole; (iii) a public announcement by DBRS Limited ("DBRS") or Standard & Poor's ("S&P") that it has placed under surveillance or review, with possible negative or uncertain implications, its rating of any debt securities of the Corporation; and (iv) certain downgrades of the ratings assigned by S&P and DBRS to the long-term debt securities of the Corporation. In addition, the Corporation has agreed under the terms of the Dealer Agreement to reimburse the Dealers for certain expenses and to indemnify the Dealers against certain liabilities.

The Corporation and, if applicable, the Dealers, may reject any offer to purchase the Debentures in whole or in part. The Corporation also reserves the right to withdraw, cancel or modify the offering of the Debentures under this prospectus without notice.

In connection with any offering of Debentures, the Dealers may over-allot or effect transactions which stabilize or maintain the market price of the Debentures offered at a level above that which might otherwise prevail in the open market. Such transactions, if commenced, may be discontinued at any time. In addition, the Dealers may from time to time purchase and sell the Debentures in the secondary market but are not obliged to do so. There can be no assurance that there will be a secondary market for the Debentures. The offering price and other terms for such sales in the secondary market may, from time to time, be varied by the Dealers.

RELATIONSHIP BETWEEN THE CORPORATION AND THE DEALERS

The Dealers are wholly-owned subsidiaries of banks which are currently lenders to the Corporation under certain credit facilities, including an $800 million revolving credit facility (the "THC Revolving Credit Facility"), of which up to $210 million is available in the form of letters of credit, a $75 million demand facility for the purpose of issuing letters of credit mainly to support LDC's prudential obligations with the IESO (the "Prudential Facility") and a $20 million demand facility for the purpose of working capital management (the "Working Capital Facility"). As at December 31, 2016, no borrowings were outstanding under the THC Revolving Credit Facility, $7.1 million had been drawn under the Working Capital Facility and $33.4 million of letters of credit had been issued against the Prudential Facility. The Corporation also reserves capacity under the THC Revolving Credit Facility for amounts of commercial paper outstanding under its commercial paper program; hence, available borrowing under the THC Revolving Credit Facility is reduced by the amount of commercial paper outstanding at any point in time. As at December 31, 2016, the Corporation had $261 million of commercial paper outstanding. The Revolving Credit Facility, the Prudential Facility and the Working Capital Facility are unsecured and the Corporation is, and has been since the establishment of such facilities, in compliance with the terms of the respective agreements governing such facilities. As of the date hereof, the Corporation has not been required to obtain a waiver in respect of any breach under such facilities and the Corporation's financial position has not adversely changed in a material manner since such facilities were put in place. Proceeds from the sale of the Debentures may be used to repay indebtedness to the bank affiliates of CIBC World Markets Inc., TD Securities Inc., BMO Nesbitt Burns Inc., RBC Dominion Securities Inc., National Bank Financial Inc. and Scotia Capital Inc. under the THC Revolving Credit Facility, the Prudential Facility or the Working Capital Facility or other bank facilities. Accordingly, the Corporation may be considered to be a connected issuer of CIBC World Markets Inc., TD Securities Inc., BMO Nesbitt Burns Inc., RBC Dominion Securities Inc., National Bank Financial Inc. and Scotia Capital Inc. within the meaning of Canadian securities legislation. The decision to distribute the Debentures will be made by the Corporation and the terms and conditions of distribution will be determined through negotiations between the Corporation and the Dealers. The lenders will not have any involvement in such decision or determination. Other than payment of their portion of the commissions, if applicable, none of the proceeds of offerings of the Debentures will be applied, directly or indirectly, for the benefit of CIBC World Markets Inc., TD Securities Inc., BMO Nesbitt Burns Inc., RBC Dominion Securities Inc., National Bank Financial Inc. and Scotia Capital Inc.

The Debentures have not and will not be registered under the U.S. Securities Act, or any state securities laws, and may not be offered or sold within the United States or to U.S. Persons (as such term is defined in Regulation S under the U.S. Securities Act) unless registered under the U.S. Securities Act and applicable state securities laws or an exemption therefrom is available. Each of the Dealers will agree not to buy or offer to buy, to sell or offer to sell, or solicit any offer to buy any Debentures in the United States of America and its territories or possessions, or to, or for the account or benefit of, U.S. Persons, except to

"qualified institutional buyers" in accordance with Rule 144A under the U.S. Securities Act. Debentures issued to qualified institutional buyers pursuant to Rule 144A under the U.S. Securities Act will be represented by definitive certificates and will be subject to certain restrictions on transfer set forth therein and in the supplemental indenture and will bear a legend regarding such restrictions as set forth in the supplemental indenture. This prospectus does not constitute an offer to sell or a solicitation of an offer to buy any of the Debentures in the United States. In addition, until 40 days after the commencement of the offering of an issue of Debentures, an offer or sale of that issue within the United States by any Dealer (whether or not participating in the offering) may violate the registration requirements of the U.S. Securities Act if such offer or sale is made otherwise than in accordance with Rule 144A under the U.S. Securities Act or pursuant to an applicable exemption from the registration requirements of the U.S. Securities Act.

RATINGS

The outstanding senior unsecured debentures of the Corporation have been assigned a rating of "A" with a stable trend by DBRS and "A" by S&P.

DBRS rates long-term debt instruments by rating categories ranging from a high of "AAA" to a low of "D". All rating categories other than AAA and D also contain the subcategories "(high)" and "(low)" to indicate relative standing within the major rating categories. The absence of either a "(high)" or "(low)" designation indicates the rating is in the middle of the category. An "A" rating is the third highest of the ten rating categories. Long-term debt instruments which are rated in the "A" category by DBRS are considered to be of good credit quality, with substantial capacity for the payment of financial obligations. Entities in the "A" category, however, may be vulnerable to future events, but qualifying negative factors are considered manageable.

S&P rates long-term debt instruments by rating categories ranging from a high of "AAA" to a low of "D". Ratings from "AA" to "CCC" may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories. An "A" rating is the third highest of the ten rating categories. Long-term debt instruments which are rated in the "A" category by S&P are considered somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher-rated categories; however, the obligor's capacity to meet its financial commitment on the obligation is still strong.

Credit ratings are intended to provide investors with an independent measure of the credit quality of an issue of securities. A rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the rating agency.

The Corporation has made, and anticipates making, payments to each of DBRS and S&P pursuant to the ratings agency services agreements entered into with such credit rating organizations with respect to, among other things, the ratings assigned to the long-term debt of the Corporation, the Corporation's commercial paper rating, the Corporation's rating and ratings assigned to the Debentures of a particular series. There have been no other services provided by any of such credit rating organizations to the Corporation within the last two years.

EARNINGS COVERAGE RATIOS

For the twelve-month period ended December 31, 2016, the consolidated earnings of the Corporation before interest on the consolidated long-term debt of the Corporation and before income taxes was $256.1 million. Interest expense on the consolidated long-term debt of the Corporation for this period, without giving effect to the issue of any Debentures that may be distributed under this prospectus, was $81.6 million. The earnings coverage ratio for the Corporation for the twelve-month period ended December 31, 2016, based on audited information, without giving effect to the issue of any Debentures that may be distributed under this prospectus, was 3.14.

DESCRIPTION OF THE DEBENTURES

The Debentures will be issued in one or more series under a trust indenture dated May 7, 2003 between the Corporation and BNY Trust Company of Canada (the "Trustee" which term shall include, unless the context requires otherwise, its successors), as supplemented from time to time by supplemental indentures (together, the "Indenture"). The Indenture permits the issuance of an unlimited principal amount of debentures of the Corporation in one or more series. The terms of each series of debentures issued pursuant to the Indenture will be specified in a supplemental indenture to the Indenture. A copy of the Indenture is available electronically at www.sedar.com.

The specific terms of an offering of Debentures (including the aggregate principal amount of the Debentures being offered, the currency or currencies, the issue and delivery date, the form, the maturity date, the interest rate, the issue price, the interest payment date(s), any redemption or repayment provisions, any provisions entitling the Corporation to extend the maturity date of the Debentures, the name(s) of the Dealer(s) offering the Debentures, the commission payable to such Dealer(s), the method of distribution and the net proceeds to the Corporation) will be set forth in a pricing supplement which will be delivered to purchasers together with this prospectus. Unless otherwise indicated in a pricing supplement, the Debentures will not be listed on any securities exchange. The Corporation reserves the right to set forth in a pricing supplement specific terms of Debentures which are not within the parameters set forth in this prospectus.

The following is a summary of the material attributes of the Debentures. This summary does not purport to be complete. For a complete description of the Debentures, reference should be made to the Indenture. Certain capitalized terms used in this summary are defined below under "Definitions".

Term, Denomination and Currency

The Debentures will have a term to maturity of not less than one year and will be issuable in denominations of $1,000 and multiples thereof. The Debentures may be issued in Canadian dollars or any foreign currency or currency unit determined at the time of issue.

Interest

The Debentures will bear interest at fixed or floating rates as set out in the applicable pricing supplement to this prospectus.

Rank

The Debentures will be direct unsecured obligations of the Corporation and will rank *pari passu* with all other Debentures from time to time outstanding under the Indenture and, except as to sinking funds and to the extent prescribed by law, with all other unsecured and unsubordinated indebtedness of the Corporation from time to time outstanding, including, but not limited to, indebtedness of the Corporation under the THC Revolving Credit Facility, the Prudential Facility, the Working Capital Facility, its commercial paper program and debentures of every other series from time to time outstanding issued pursuant to the Indenture.

The Debentures will not be obligations of, and will not be guaranteed in any manner by, the City of Toronto.

Redemption

If so specified in the applicable pricing supplement, a series of Debentures may be redeemed, at the Corporation's option, in whole at any time or in part from time to time, prior to maturity, on not more than 60 and not less than 15 business days prior notice, at the redemption price or at par, together in each case with accrued and unpaid interest to, but not including, the date fixed for redemption. The applicable pricing supplement will specify the redemption price (or the manner of calculating the redemption price), if any, for the series of Debentures.

If less than all Debentures of any series of Debentures are to be redeemed, the Debentures to be redeemed will be selected by the Trustee on a *pro rata* basis or by lot or such other means as the Trustee may deem equitable and expedient.

Purchase for Cancellation

The Corporation may, at any time, purchase Debentures for cancellation, in the open market, by tender or by private contract, at any price.

Covenants

Negative Pledge

The Corporation will not, and will not permit any Designated Subsidiary to, create, assume or suffer to exist any Security Interest, other than Permitted Encumbrances, on or over any of its assets (present or future) to secure any Obligation, unless at the same time it shall secure equally and rateably therewith all the debentures issued pursuant to the Indenture then outstanding.

Limitation on Funded Indebtedness

The Corporation will not, and will not permit any Designated Subsidiary to, directly or indirectly, issue, incur, assume or otherwise become liable for or in respect of any Funded Indebtedness unless, after giving effect thereto, Consolidated Funded Indebtedness would not exceed 75% of Total Consolidated Capitalization. This covenant will not operate to prevent the Corporation or a Designated Subsidiary from issuing, incurring, assuming or otherwise becoming liable for or in respect of any Inter-Company Indebtedness and Non-Speculative Financial Instrument Obligations. This covenant will operate to prevent the Corporation or a Designated Subsidiary from assigning any Inter-Company Indebtedness to a person other than the Corporation or a Designated Subsidiary.

Limitation on Designated Subsidiary Indebtedness

The Corporation will not permit a Designated Subsidiary to, directly or indirectly, issue, incur, assume or otherwise become liable for or in respect of any Indebtedness except:

(a) Inter-Company Indebtedness of the Designated Subsidiary;

(b) Non-Recourse Debt of the Designated Subsidiary;

(c) Non-Speculative Financial Instrument Obligations of the Designated Subsidiary;

(d) Permitted Capital Lease Obligations of the Designated Subsidiary;

(e) Prudential and Bilateral Credit Support Obligations of the Designated Subsidiary;

(f) Purchase Money Obligations of the Designated Subsidiary; and

(g) any other Indebtedness of the Designated Subsidiary (in addition to the Indebtedness referred to in paragraphs (a) to (f)) if, after giving effect to the Indebtedness, the aggregate amount of all Indebtedness of all Designated Subsidiaries permitted by this paragraph (g) only would not exceed 5% of Consolidated Net Worth.

For the purposes of this covenant, the assignment by the Corporation to a third party of Inter-Company Indebtedness owing by a Designated Subsidiary will be considered to be an incurrence of Indebtedness by such Designated Subsidiary.

Designation of Subsidiaries as Designated Subsidiaries

LDC is a Designated Subsidiary. The board of directors of the Corporation may designate a subsidiary of the Corporation in addition to LDC as a Designated Subsidiary if:

(a) at the time of and after giving effect to the designation, no Event of Default or event that, with the passing of time or the giving of notice or both, would constitute an Event of Default has occurred and is continuing;

(b) after giving effect to the designation, the Corporation would be entitled under the Indenture to issue Funded Indebtedness in the amount of at least $1.00; and

(c) none of the shares of the subsidiary is owned by another subsidiary of the Corporation that is not a Designated Subsidiary.

The board of directors of the Corporation may terminate the designation of a subsidiary of the Corporation other than LDC as a Designated Subsidiary if:

(a) at the time of and after giving effect to the termination, no Event of Default or event that, with the passing of time or the giving of notice or both, would constitute an Event of Default has occurred and is continuing;

(b) after giving effect to the termination, the Corporation would be entitled under the Indenture to issue Funded Indebtedness in the amount of at least $1.00; and

(c) the subsidiary does not own any Funded Indebtedness of the Corporation or any shares or Funded Indebtedness of any other Designated Subsidiary.

Restriction on Mergers and Dispositions

The Corporation will not, directly or indirectly through a Designated Subsidiary, enter into a transaction or series of transactions in which all or substantially all of the undertaking, property and assets of the Corporation and its Designated Subsidiaries determined on a consolidated basis would become the property of any other person, whether by way of reorganization, consolidation, amalgamation, arrangement, merger, transfer, sale, lease or otherwise, unless:

(a) the person is a corporation organized and existing under the laws of Canada or a province or territory thereof and expressly assumes, by a supplemental indenture satisfactory in form to the Trustee and its counsel and executed and delivered to the Trustee, all of the covenants and obligations of the Corporation under the Indenture and all debentures issued pursuant to the Indenture; and

(b) at the time of and after giving effect to the reorganization, consolidation, amalgamation, arrangement, merger, transfer, sale, lease or other transaction, no Event of Default or event that, with the passing of time or the giving of notice or both, would constitute an Event of Default has occurred and is continuing.

Events of Default

The following are Events of Default applicable to all series of debentures, including each series of Debentures, issued pursuant to the Indenture:

(a) failure to pay principal or premium (if any) on the debentures when due;

(b) failure to pay interest on the debentures when due if such failure continues for a period of 30 days;

(c) the sale, transfer, lease or other disposition of all or substantially all of the property and assets of the Corporation and its Designated Subsidiaries determined on a consolidated basis other than in accordance with the covenants described above under " – Covenants – Restriction on Mergers and Dispositions";

(d) failure to observe or perform any other covenant or condition contained in the Indenture if such failure continues for a period of 60 days after written notice thereof has been given to the Corporation by the Trustee or the holders of at least 25% in principal amount of the debentures of any affected series then outstanding;

(e) failure by the Corporation or any Material Subsidiary to pay principal, premium (if any) or interest due on any Indebtedness, the principal amount of which is more than $50 million in the aggregate, beyond the applicable grace period;

(f) failure by the Corporation or any Material Subsidiary to observe or perform any provision of any agreement under which Indebtedness is created if such failure has the effect of causing more than $50 million of such Indebtedness in the aggregate to become due and payable or to be required to be redeemed or repurchased before its stated maturity;

(g) the rendering by a court of competent jurisdiction of one or more judgments against the Corporation or any Material Subsidiary in an aggregate amount of more than $50 million if the judgments remain undischarged or unstayed for more than 30 days; and

(h) specified events of bankruptcy, insolvency or reorganization affecting the Corporation or any Material Subsidiary.

Default

If an Event of Default described in paragraphs (a) to (g) above occurs and is continuing, the Trustee or the holders of not less than 25% of the principal amount of debentures of a series of debentures issued pursuant to the Indenture then outstanding may declare the principal amount of, and the premium (if any) and accrued and unpaid interest on all debentures of that series then outstanding to be due and payable immediately.

If an Event of Default described in paragraph (h) above occurs and is continuing, the principal amount of and the premium (if any) and accrued and unpaid interest on all debentures issued pursuant to the Indenture then outstanding shall be due and payable immediately without any declaration or other action by the Trustee or the holders of the debentures.

Protection of Trustee

Subject to the provisions of the Indenture relating to the duties of the Trustee, if an event of default applicable to a series of debentures issued pursuant to the Indenture occurs and is continuing, the Trustee will be under no obligation to exercise any of its rights or powers under the Indenture at the request or direction of any holders of such debentures unless the Trustee is sufficiently indemnified in accordance with the provisions of the Indenture. Subject to the provisions of the Indenture providing for the indemnification of the Trustee, the holders of the requisite principal amount of such debentures will have the right to direct the time, method and place of conducting any proceedings for any remedy available to the Trustee or exercising any rights or powers of the Trustee in respect of such debentures.

Modification

The Indenture provides that certain rights, privileges, restrictions and conditions of debentures issued and outstanding under the Indenture may be modified if such modifications are authorized by extraordinary resolution.

The term "extraordinary resolution" is defined in the Indenture to mean:

(a) in the case of modifications which affect a particular series of debentures issued pursuant to the Indenture, a resolution passed by the affirmative votes of the holders of not less than 66⅔% in principal amount of debentures of that series then outstanding represented and voting at a meeting or an instrument in writing signed by the holders of not less than 66⅔% in principal amount of debentures of that series then outstanding; and

(b) in the case of modifications which affect all debentures issued pursuant to the Indenture, a resolution passed by the affirmative votes of the holders of not less than 66⅔% in principal amount of all debentures then outstanding represented and voting at a meeting or an instrument in writing signed by the holders of not less than 66⅔% in principal amount of all debentures then outstanding, treated in each case as a single class.

Defeasance

The Indenture requires the Trustee to release the Corporation from its obligations in respect of a series of debentures issued pursuant to the Indenture if specified conditions are met, including the deposit by the Corporation of cash or certain cash-equivalent securities for the payment of all principal and interest and any other amounts on the debentures of such series and the payment of the expenses of the Trustee.

Form, Transfer and Payment Mechanics

Except as described under "Plan of Distribution" or as set out in a pricing supplement, the Debentures will be represented by one or more global Debentures (collectively, the "Global Debenture") registered in the name of CDS Clearing and Depository Services Inc. or a successor thereof (the "Depository") or its nominee and held by or on behalf of the Depository as custodian for institutions (including the Dealers) which participate directly or indirectly in the Depository's book-entry only registration system ("BEO Participants"). Interests in the Debentures represented by the Global Debenture will be evidenced by credits to book-entry accounts of BEO Participants maintained with the Depository. Interests of the owners of Debentures represented by the Global Debenture will be evidenced by credits to accounts maintained with such BEO Participants on behalf of such owners.

Except as described under "Plan of Distribution" and as described below or as set out in a pricing supplement, purchasers of Debentures represented by the Global Debenture will not be entitled to certificates or other instruments from the Corporation or the Depository evidencing their ownership of Debentures. Beneficial owners of Debentures represented by the Global Debenture will not be shown on the registers maintained by the Trustee or the records maintained by the Depository but will be shown through book-entry accounts of BEO Participants. The rights of beneficial owners of Debentures represented by the Global Debenture may be exercised only through the BEO Participants with which such book-entry accounts are maintained. Purchasers of Debentures represented by the Global Debenture will receive a customer confirmation of purchase from the selling Dealer.

Purchasers of Debentures represented by the Global Debenture will receive definitive Debentures registered in their name only:

(a) if the Corporation determines that the Depository is no longer willing, able or qualified to discharge properly its responsibilities as holder of the Global Debenture in connection with the Debentures and the Corporation is unable to locate a qualified successor;

(b) if the Corporation elects to terminate the book-entry only registration of Debentures through the Depository; or

(c) in certain other specified circumstances.

Transfers of interests in Debentures represented by the Global Debenture will be effected through records maintained by the Depository or its nominee (with respect to interests of BEO Participants) and on the records of BEO Participants (with respect to interests of persons other than BEO Participants).

Beneficial owners of Debentures represented by the Global Debenture who are not BEO Participants but who desire to transfer any interest in Debentures may do so only through BEO Participants.

Payments of interest and principal on the Global Debenture will be made to the Depository or its nominee as registered holder of the Global Debenture. As long as the Depository or its nominee is the registered owner of the Global Debenture, the Depository or its nominee will be considered the sole owner of the Global Debenture for the purposes of receiving payment on the Global Debenture and for all other purposes under the Indenture and the Global Debenture.

The Corporation expects that the Depository or its nominee, upon receipt of any payment of principal or interest in respect of the Global Debenture, will credit the accounts of BEO Participants, on the date principal or interest is payable, with payments in amounts proportionate to their respective interests in the principal amount of the Global Debenture as shown on the records of the Depository or its nominee. The Corporation also expects that payments of principal and interest by BEO Participants to the owners of interests in the Debentures represented by the Global Debenture held through accounts maintained with BEO Participants will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name", and will be the responsibility of BEO Participants. The responsibility and liability of the Corporation and the Trustee in respect of Debentures represented by the Global Debenture is limited to making payment of any principal and interest due on the Global Debenture to the Depository or its nominee.

Governing Law

The Indenture is and the Debentures will be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein.

Definitions

The following defined terms used in this section of the prospectus are defined in the Indenture substantially as set out below.

"**Capital Lease**" means, with respect to a person, a lease or other arrangement in respect of real or personal property that is required to be classified and accounted for as a capital lease on a balance sheet of the person in accordance with GAAP.

"**Capital Lease Obligation**" means, with respect to a person, the obligation of the person to pay rent or other amounts under a Capital Lease.

"**Consolidated Funded Indebtedness**" means the aggregate amount of all Funded Indebtedness of the Corporation and its Designated Subsidiaries determined on a consolidated basis in accordance with GAAP.

"**Consolidated Net Worth**" means the shareholder's equity of the Corporation and its Designated Subsidiaries determined on a consolidated basis in accordance with GAAP. For greater certainty, the shareholder's equity of a subsidiary of the Corporation that is not a Designated Subsidiary will not be included in making such determination.

"**Contingent Liability**" means, with respect to a person, any agreement, undertaking or arrangement by which the person guarantees, endorses or otherwise becomes or is contingently liable upon (by direct or indirect agreement, contingent or otherwise, to provide funds for payment, to supply funds to, or otherwise to invest in, a debtor, or otherwise to assure a creditor against loss) the obligation, debt or other liability of any other person (other than by endorsements of instruments in the course of collection), or guarantees the payment of dividends or other distributions upon the shares of any other person. The amount of any Contingent Liability will, subject to any limitation contained therein, be deemed to be the outstanding principal amount (or maximum principal amount, if larger) of the obligation, debt or other liability to which the Contingent Liability relates.

"**Deferred Purchase Price Obligation**" means, with respect to a person, an obligation issued, incurred or assumed by the person in connection with the acquisition by the person of an asset in respect of the deferred purchase price of the asset.

"**Designated Subsidiary**" means Toronto Hydro-Electric System Limited and, until such designation is terminated in accordance with the covenants described above under "– Covenants – Designation of Subsidiaries as Designated Subsidiaries", any other subsidiary of the Corporation designated as a Designated Subsidiary by the board of directors of the Corporation in accordance with the covenants described above under "– Covenants – Designation of Subsidiaries as Designated Subsidiaries".

"**Event of Default**" means an event of default under the Indenture.

"**Financial Instrument Obligations**" means, with respect to any person, obligations arising under:

(a) interest rate swap agreements, forward rate agreements, floor, cap or collar agreements, futures or options, insurance or other similar agreements or arrangements, or any combination thereof, entered into or guaranteed by the person where the subject matter thereof is interest rates or the price, value or amount payable thereunder is dependent or based upon interest rates or fluctuations in interest rates in effect from time to time (but excluding conventional floating rate indebtedness);

(b) currency swap agreements, cross-currency agreements, forward agreements, floor, cap or collar agreements, futures or options, insurance or other similar agreements or arrangements, or any combination thereof, entered into or guaranteed by the person where the subject matter thereof is currency exchange rates or the price, value or amount payable thereunder is dependent or based upon currency exchange rates or fluctuations in currency exchange rates in effect from time to time; and

(c) any agreement for the making or taking of any commodity (including coal, natural gas, oil and electricity), swap agreement, floor, cap or collar agreement or commodity future or option or other similar agreement or arrangement, or any combination thereof, entered into or guaranteed by the person where the subject matter thereof is any commodity or the price, value or amount payable thereunder is dependent or based upon the price or fluctuations in the price of any commodity;

or any other similar transaction, including any option to enter into any of the foregoing, or any combination of the foregoing, in each case to the extent of the net amount due or accruing due by the person under the obligations determined by marking the obligations to market in accordance with their terms.

"**Funded Indebtedness**" means Indebtedness (other than Subordinated Indebtedness) that, on the date of issue or assumption of liability, has a term to maturity (including any right of extension or renewal) greater than 18 months.

"**GAAP**" means, as at any date of determination:

(a) accounting principles which are generally recognized as being generally accepted in Canada, if the Corporation is then preparing its financial statements in accordance with such principles; or

(b) accounting principles which are generally recognized as being generally accepted in the United States, if the Corporation is then preparing its financial statements in accordance with such principles.

"**Indebtedness**" means, with respect to a person, without duplication:

(a) all obligations of the person for borrowed money, including obligations with respect to bankers' acceptances and contingent reimbursement obligations relating to letters of credit and other financial instruments;

(b) all Financial Instrument Obligations of the person;

(c) all Deferred Purchase Price Obligations of the person;

(d) all Capital Lease Obligations and Purchase Money Obligations of the person;

(e) all Prudential and Bilateral Credit Support Obligations of the person; and

(f) all Contingent Liabilities of the person with respect to obligations of another person if such obligations are of the type referred to in paragraphs (a) to (e).

"**Inter-Company Indebtedness**" means, with respect to the Corporation, indebtedness of the Corporation to a Designated Subsidiary and, with respect to a Designated Subsidiary, indebtedness of the Designated Subsidiary to the Corporation or to another Designated Subsidiary.

"**Material Subsidiary**" means a Designated Subsidiary and any other subsidiary of the Corporation:

(a) the total assets of which represent more than 10% of the total assets of the Corporation and its Designated Subsidiaries determined on a consolidated basis in accordance with GAAP; or

(b) the total revenues of which represent more than 10% of the total revenues of the Corporation and its Designated Subsidiaries determined on a consolidated basis in accordance with GAAP.

For greater certainty, the assets and revenues of a subsidiary of the Corporation that is not a Designated Subsidiary will not be included in making such determinations.

"**Non-Recourse Debt**" means, with respect to a person, any indebtedness incurred to finance the creation, development, construction or acquisition of an asset of the person (and any extensions, renewals or refunding of any such indebtedness) provided that the recourse of the obligee thereof against the person is limited in all circumstances (other than in respect of false or misleading representations or warranties) to the asset (including all rights and benefits related to or arising out of the asset).

"**Non-Speculative Financial Instrument Obligations**" means, with respect to a person, Financial Instrument Obligations of the person entered into by the person in the ordinary course of business for risk management purposes and not for speculative or capital raising purposes.

"**Obligations**" means, with respect to a person, without duplication, all items which, in accordance with GAAP, would be included as liabilities on the liability side of the balance sheet of the person and all Contingent Liabilities of the person.

"**Permitted Capital Lease Obligations**" means, with respect to a Designated Subsidiary, the obligation of the Designated Subsidiary to pay rent or other amounts under a Capital Lease, other than a Capital Lease entered into as part of a Sale and Leaseback Transaction unless:

(a) the property which is the subject matter of the Sale and Leaseback Transaction is owned by the Designated Subsidiary;

(b) the proceeds of sale of such property have been determined by the board of directors of the Designated Subsidiary to be at least equal to its fair value; and

(c) either of the following is applicable:

(1) at the time of the Sale and Leaseback Transaction, the cost of acquiring such property could have been financed pursuant to a Purchase Money Obligation; or

(2) within 120 days after completion of the Sale and Leaseback Transaction, the Designated Subsidiary reduces its Indebtedness, other than Indebtedness permitted pursuant to paragraphs (a) to (e) above under "– Covenants – Limitation on Designated Subsidiary Indebtedness", by an amount at least equal to the net proceeds from the Sale and Leaseback Transaction.

"**Permitted Encumbrances**" means:

(a) any Security Interest securing Obligations of a Designated Subsidiary that:

(1) exists before and at the time that the Designated Subsidiary becomes a Designated Subsidiary;

(2) was not created or assumed in contemplation or as a result of the Designated Subsidiary becoming a Designated Subsidiary; and

(3) immediately before and after the Designated Subsidiary becomes a Designated Subsidiary, does not attach to the assets or secure Obligations of the Corporation or any other Designated Subsidiary;

(b) any Purchase Money Mortgage or Capital Lease of the Corporation or a Designated Subsidiary;

(c) any Security Interest in an asset created or assumed by the Corporation or a Designated Subsidiary to secure Non-Recourse Debt of the Corporation or the Designated Subsidiary in respect of such asset;

(d) any Security Interest in cash, marketable debt securities or accounts receivable created or assumed by the Corporation or a Designated Subsidiary to or in favour of a bank or other lending institution to secure indebtedness of the Corporation or the Designated Subsidiary that is payable on demand or that, on the date of issue or assumption of liability, has a term to maturity (including any right of extension or renewal) of 18 months or less and that is incurred by the Corporation or the Designated Subsidiary in the ordinary course of business and for the purpose of carrying on the same;

(e) any Security Interest in cash or marketable debt securities created or assumed by the Corporation to secure Non-Speculative Financial Instrument Obligations of the Corporation if the aggregate value of such cash and marketable debt securities is not more than 105% of the aggregate amount of the Non-Speculative Financial Instrument Obligations;

(f) any Security Interest created or assumed by a Designated Subsidiary in favour of the Corporation or any Wholly-Owned Designated Subsidiary;

(g) any Security Interest in an asset acquired by the Corporation or a Designated Subsidiary that secures Obligations of any other person, whether or not such Obligations are assumed by the Corporation or the Designated Subsidiary provided that the Security Interest:

(1) exists before and at the time that the asset is acquired by the Corporation or the Designated Subsidiary;

(2) was not created or assumed in contemplation or as a result of the asset being acquired by the Corporation or the Designated Subsidiary; and

(3) immediately before and after the asset is acquired by the Corporation or the Designated Subsidiary, does not attach to the assets or secure Obligations of the Corporation or any other Designated Subsidiary;

(h) any Security Interest in cash or marketable debt securities in a sinking fund account established by the Corporation in support of a series of debentures issued pursuant to the Indenture;

(i) any Security Interest or deposit under workers' compensation, social security or similar legislation or in connection with bids, tenders, leases, contracts or expropriation proceedings or to secure public or statutory obligations, surety and appeal bonds or costs of litigation where required by law;

(j) any Security Interest or privilege imposed by law, such as builders', mechanics, material men's, carriers', warehousemen's and landlords' liens and privileges; or any Security Interest or privilege arising out of judgments or awards with respect to which the Corporation or a Designated Subsidiary at the time is prosecuting an appeal or proceedings for review and with respect to which it has secured a stay of execution pending such appeal or proceedings for review; or any Security Interest for taxes, assessments or governmental charges or levies not at the time due and delinquent or the validity of which is being contested at the time by the Corporation or a Designated Subsidiary in good faith; or any undetermined or inchoate Security Interest or privilege incidental to current operations that has not been filed pursuant to law against the Corporation or a Designated Subsidiary or that relates to obligations not due or delinquent; or the deposit of cash or securities in connection with any Security Interest or privilege referred to in this paragraph (j);

(k) any right reserved to or vested in any municipality or governmental or other public authority by the terms of any lease, licence, franchise, grant or permit held or acquired by the Corporation or a Designated Subsidiary, or by any statutory provision, to terminate the lease, licence, franchise, grant or permit or to purchase assets used in connection therewith or to require annual or other periodic payments as a condition of the continuance thereof;

(l) any Security Interest or right of distress reserved in or exercisable under any lease for rent to which the Corporation or a Designated Subsidiary is a party and for compliance with the terms of the lease;

(m) any Security Interest created or assumed by the Corporation or a Designated Subsidiary in favour of a public utility or any municipality or governmental or other public authority when required by the utility, municipality or other authority in connection with the operations of the Corporation or a Designated Subsidiary;

(n) any reservations, limitations, provisos and conditions expressed in original grants from the Crown;

(o) any minor encumbrances, such as easements, rights-of-way, servitudes or other similar rights in land granted to or reserved by other persons, rights-of-way for sewers, electric lines, telegraph and telephone lines, oil and natural gas pipelines and other similar purposes, or zoning or other restrictions applicable to the Corporation's or a Designated Subsidiary's use of real property, that do not in the aggregate materially detract from the value of the property or materially impair its use in the operation of the business of the Corporation or the Designated Subsidiary;

(p) any extension, renewal, alteration, substitution or replacement, in whole or in part, of a Security Interest referred to in paragraphs (a) to (o) provided that the Security Interest is limited to all or part of the same assets, the principal amount of the secured Obligations is not increased by that action, the term of the secured Obligations is not shortened and the terms and conditions of the Security Interest are no more restrictive in any material respect than the Security Interest so extended; and

(q) any other Security Interest created or assumed by the Corporation or a Designated Subsidiary (in addition to the Security Interests referred to in paragraphs (a) to (p)) if, after giving effect to the Security Interest, the aggregate amount of all Indebtedness secured by

Security Interests permitted by this paragraph only does not at that time exceed 5% of Consolidated Net Worth.

"**Prudential and Bilateral Credit Support Obligations**" means, without duplication, the following obligations:

(a) all contingent reimbursement obligations of the Corporation relating to letters of credit and other financial instruments and all Contingent Liabilities of the Corporation in respect of Obligations of a subsidiary of the Corporation for the purchase or sale of electricity or natural gas; and

(b) all obligations of a Designated Subsidiary for borrowed money, including contingent reimbursement obligations relating to letters of credit and other financial instruments under credit facilities established for participants in the wholesale market for electricity administered by the Independent Electricity System Operator ("IESO"), in respect of the Obligations of the Designated Subsidiary for the purchase or sale of electricity or natural gas;

if such obligations were incurred or assumed to satisfy:

(x) prescribed prudential requirements in the wholesale market for electricity administered by the IESO;

(y) credit support arrangements required by electricity distribution companies under the terms of the Retail Settlement Code established by the Ontario Energy Board; or

(z) credit support requirements of counterparties under bilateral contracts or customers under purchase contracts.

"**Purchase Money Mortgage**" means, with respect to a person, any Security Interest created or assumed by the person to secure a Purchase Money Obligation provided that such Security Interest is limited to the asset financed by such Purchase Money Obligation and is created or assumed not later than three months after such Purchase Money Obligation is issued, incurred or assumed.

"**Purchase Money Obligation**" means, with respect to a person, indebtedness of the person issued, incurred or assumed to finance all or part of the cost of acquiring any asset for the person, other than shares, bonds and other securities, or constructing, installing or improving any real property or fixtures of the person, provided that the indebtedness is issued, incurred or assumed within twelve months after such acquisition, construction, installation or improvement, and includes any extension, renewal or refunding of such indebtedness so long as the principal amount thereof outstanding on the date of such extension, renewal or refunding is not increased.

"**Sale and Leaseback Transaction**" means, with respect to a person, a transaction or series of transactions pursuant to which the person sells or transfers real or personal property owned by the person to a third party and subsequently leases such real or personal property.

"**Security Interest**" means any security interest, assignment by way of security, mortgage, charge (whether fixed or floating), hypothec, pledge, lien or other encumbrance on or interest in property or assets that secures the payment of Obligations.

"**Subordinated Indebtedness**" means all indebtedness of the Corporation in respect of which, upon any distribution of assets of the Corporation upon any dissolution, winding-up, liquidation or reorganization of the Corporation (whether in bankruptcy, insolvency or receivership proceedings or upon an assignment for the benefit of creditors, or any other marshalling of the assets and liabilities of the Corporation or otherwise), the payment of all indebtedness and liabilities of the Corporation in connection with all debentures issued pursuant to the Indenture including principal, interest, fees and expenses, must be satisfied in full prior to any amount being applied to such indebtedness.

"**Tax Act**" means, collectively, the *Income Tax Act* (Canada) and the *Income Tax Regulations*;

"**Total Consolidated Capitalization**" means, without duplication, the sum of:

(a) the principal amount of all Consolidated Funded Indebtedness;

(b) the principal amount of all Subordinated Indebtedness; and

(c) the Consolidated Net Worth;

in each case, as determined by the Corporation and its Designated Subsidiaries.

"**Wholly-Owned Designated Subsidiary**" means a Designated Subsidiary all of the outstanding shares in the capital of which are owned by the Corporation or one or more Wholly-Owned Designated Subsidiaries.

RISK FACTORS

An investment in the Debentures is subject to a variety of risks. Before deciding whether to invest in any Debentures, prospective purchasers of Debentures should consider carefully various risks, including the risk factors described below and contained in the documents incorporated or deemed to be incorporated by reference in this prospectus (including the sections entitled "Forward-Looking Information" and "Risk Factors" in the Corporation's AIF and the sections entitled "Forward-Looking Information" and "Risk Management and Risk Factors" in the Corporation's MD&A). This prospectus, including the documents incorporated or deemed to be incorporated by reference in this prospectus, does not describe all of the risks of an investment in the Debentures. Prospective purchasers should consult their own financial and legal advisors about the risks entailed by an investment in the Debentures and the suitability of such investment in light of their particular circumstances. Debentures will not be an appropriate investment for a prospective purchaser if the purchaser does not understand the terms of the Debentures or financial matters in general. A prospective purchaser should not purchase Debentures unless the prospective purchaser understands, and can bear, all of the investment risks related to the Debentures.

Rank of Debentures and Holding Company Structure

The Debentures will be direct unsecured obligations of the Corporation and will rank *pari passu* with all other unsecured and unsubordinated indebtedness of the Corporation from time to time outstanding, including, but not limited to, indebtedness of the Corporation under the THC Revolving Credit Facility, the Prudential Facility, the Working Capital Facility, its commercial paper program and debentures of every other series issued pursuant to the Indenture. A default by the Corporation under the Indenture will constitute an event of default under the THC Revolving Credit Facility and an event of default or repayment event under the Working Capital Facility and the Prudential Facility. There can be no assurance that sufficient funds would be available to the Corporation at the time of any such default to make any required payment under the Debentures.

The Corporation is a holding company and substantially all of its business activities are carried on by its subsidiaries. Therefore, the Corporation's ability to meet its financial obligations is dependent primarily upon the receipt of interest and principal, management fees, cash dividends and other payments from its subsidiaries, together with proceeds raised by the Corporation through the issuance of debt. The Corporation is wholly-owned by the City of Toronto and does not currently raise funds through the issuance of share capital. The payment of dividends and the making of loans, advances and other payments to the Corporation by its subsidiaries may be subject to statutory or contractual restrictions, will depend on the earnings of the subsidiaries and will be subject to various business and other considerations.

The Corporation's subsidiaries are separate legal entities and have no legal obligation, contingent or otherwise, to pay any amount due under the Debentures or to make any amounts available to the Corporation, whether by dividends, interest, loans or other payments. In addition, these subsidiaries have not guaranteed the Debentures. Therefore, the Debentures will be effectively subordinated to the current and future liabilities, including trade payables and other indebtedness, of the Corporation's subsidiaries. The creditors of those subsidiaries will have the right to be paid before payment on the Debentures from any cash

received or held by those subsidiaries. In the event of any bankruptcy, dissolution, liquidation or reorganization of one of those subsidiaries, following payment by the subsidiary of its liabilities, the subsidiary may not have sufficient assets to make payments to the Corporation in its capacity as an equityholder of such subsidiary.

Absence of Public Market for the Debentures

The Debentures will be newly issued securities for which there is no existing trading market. The Corporation does not intend to list the Debentures on any Canadian, U.S. or other securities exchange. This may affect the pricing of the Debentures in the secondary market, the transparency and availability of trading prices, the liquidity of the Debentures and the extent of issuer regulation. There can be no assurance that a secondary market will develop for the Debentures or that any secondary market that does develop will continue. Accordingly, purchasers may not be able to sell the Debentures. In addition, if a trading market develops for the Debentures, the Debentures could trade at prices that may be higher or lower than their initial offering prices, depending on many factors, including prevailing interest rates, general economic conditions, the Corporation's results of operations and financial position, the ratings assigned to the Debentures and the Corporation's other debt securities and the markets for similar debt securities.

Ratings

The Corporation's perceived creditworthiness and changes in ratings of the Debentures may affect the market price or value and the liquidity of the Debentures. There is no assurance that any rating assigned to the Debentures issued hereunder will remain in effect for any given period of time or that any rating will not be lowered or withdrawn entirely by the relevant rating agency. A lowering or withdrawal of such rating may have an adverse effect on the market value of the Debentures.

Ratings may not reflect all risks associated with an investment in the Debentures. The ratings applied to the Debentures are an assessment of the Corporation's ability to pay its obligations. The ratings, however, may not reflect the potential impact of risks related to structure, market or other factors discussed in this prospectus or documents incorporated or deemed to be incorporated by reference in this prospectus on the value of the Debentures.

Additional Debt Financing

The Corporation expects to borrow to repay the Debentures when required to do so under the terms of the Debentures and to fund capital expenditures, including the renewal of LDC's electricity distribution assets. The Corporation's ability to arrange sufficient and cost-effective debt financing could be adversely affected by a number of factors, including financial market conditions, the regulatory environment in Ontario, the Corporation's results of operations and financial condition, the ratings assigned to the Corporation and its debt securities by credit rating agencies, the current timing of debt maturities and general economic conditions.

Interest Rate Risks

Prevailing interest rates will affect the market price or value of the Debentures. Generally, the market price or value of the Debentures will decline as prevailing interest rates for comparable debt instruments rise and increase as prevailing interest rates for comparable debt instruments decline. Fluctuations in interest rates may also impact borrowing costs of the Corporation which may adversely affect its creditworthiness.

Risks Associated with Floating Rate Debentures

The Debentures will bear interest at fixed or floating rates as set out in the applicable pricing supplement to this prospectus. Investments in floating rate Debentures entail risks not associated with investments in fixed rate Debentures. The resetting of the applicable rate on a floating rate Debenture may result in a lower interest rate as compared to a fixed rate Debenture issued at the same time. The applicable rate on a floating rate Debenture will fluctuate in accordance with fluctuations in the instrument or obligation or other measure on which the applicable rate is based, which in turn may fluctuate and be affected by a

number of interrelated factors, including economic, financial and political events over which the Corporation has no control.

Foreign Currency Risks

An investment in Debentures that are denominated or payable in a currency other than Canadian dollars entails significant risks that are not associated with a similar investment in a security denominated in Canadian dollars. Such risks include, without limitation, the possibility of significant changes in rates of exchange between the Canadian dollar and the applicable foreign currency unit, the possibility of the imposition or modification of foreign exchange controls by either the Canadian or foreign governments and potential illiquidity in the secondary market. These risks generally depend on circumstances over which the Corporation has no control, including political events, government policy and macroeconomic conditions. These risks will vary depending upon the currency or currencies involved and, where appropriate, will be more fully described in a pricing supplement.

This prospectus does not describe all the risks of an investment in the Debentures denominated or payable other than in Canadian dollars and prospective investors should consult their own financial and legal advisor as to the risk entailed with respect thereto. Debentures denominated in other than Canadian dollars are not appropriate investments for investors who are unfamiliar with foreign currency transactions.

The Debentures will be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein. A judgment by a Canadian court relating to any Debenture may be awarded only in Canadian currency and such judgment may be based on a rate of exchange in existence on a day other than the day of payment.

Shareholder Direction

Council of the City of Toronto has adopted a shareholder direction (the "Shareholder Direction") which sets out certain corporate governance principles with respect to Toronto Hydro. The Shareholder Direction is summarized in the AIF under "Relationship with the City". The Shareholder Direction is not for the benefit of, or enforceable by, the holders of the Debentures.

ELIGIBILITY FOR INVESTMENT

In the opinion of Norton Rose Fulbright Canada LLP, counsel to the Corporation, and Blake, Cassels & Graydon LLP, counsel to the Dealers, unless otherwise specified in the applicable pricing supplement, the Debentures, if issued on the date hereof, would be, as at that date, qualified investments under the Tax Act for a trust governed by a registered retirement savings plan ("RRSP"), registered retirement income fund ("RRIF"), registered education savings plan ("RESP"), registered disability savings plan ("RDSP"), deferred profit sharing plan (other than a trust governed by a deferred profit sharing plan to which the Corporation or an employer with which the Corporation does not deal at arm's length within the meaning of the Tax Act, has made a contribution) or a tax-free savings account ("TFSA").

Notwithstanding that the Debentures may be a qualified investment for a trust governed by an RRSP, RRIF or TFSA, the annuitant under an RRSP or RRIF or the holder of a TFSA will be subject to a penalty tax if such Debentures are a "prohibited investment" for the RRSP, RRIF or TFSA within the meaning of the Tax Act. The Debentures will not be a prohibited investment for a trust governed by an RRSP, RRIF or TFSA provided that the annuitant of the RRSP or the RRIF or the holder of the TFSA, as the case may be, deals at "arm's length" (within the meaning of the Tax Act) with the Corporation and does not have a "significant interest" (within the meaning of the Tax Act) in the Corporation. Under tax proposals to amend the Tax Act contained in the federal budget released on March 22, 2017, the prohibited investment rules will also apply to a trust governed by a RESP or RDSP, effective after March 22, 2017. Prospective purchasers are advised to consult their own advisors in this regard.

LEGAL MATTERS

Certain legal matters in connection with any offering hereunder will be passed on for the Corporation by Norton Rose Fulbright Canada LLP and for the Dealers by Blake, Cassels & Graydon LLP. The partners and associates of Norton Rose Fulbright Canada LLP and Blake, Cassels & Graydon LLP, respectively, beneficially own, directly or indirectly, less than one per cent of the securities of the Corporation or any associate or affiliate of the Corporation.

AUDITORS

The auditors of the Corporation are KPMG LLP, Chartered Professional Accountants ("KPMG LLP"), at their office at Bay Adelaide Centre, 333 Bay Street, Suite 4600, Toronto, Ontario, M5H 2S5. KPMG LLP have been the auditors of the Corporation since April 12, 2011. KPMG LLP have confirmed they are independent with respect to the Corporation within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

PURCHASERS' STATUTORY RIGHTS

Securities legislation in certain provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus and any amendment. In several of the provinces, the securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, revisions of the price or damages if the prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that the remedies for rescission, revision of the price or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province for the particulars of these rights or consult with a legal advisor.

CERTIFICATE OF THE CORPORATION

Dated: May 8, 2017

This short form prospectus, together with the documents incorporated in this prospectus by reference, will, as of the date of the last supplement to this prospectus relating to the securities offered by this prospectus and the supplement(s), constitute full, true and plain disclosure of all material facts relating to the securities offered by this prospectus and the supplement(s) as required by the securities legislation of all the provinces of Canada.

(Signed) Anthony Haines
President and
Chief Executive Officer

(Signed) Sean Bovingdon
Executive Vice-President and
Chief Financial Officer

On behalf of the Board of Directors

(Signed) David McFadden
Director and
Chair of the Board of Directors

(Signed) Michael Nobrega
Director

CERTIFICATE OF THE DEALERS

Dated: May 8, 2017

To the best of our knowledge, information and belief, this short form prospectus, together with the documents incorporated in this prospectus by reference will, as of the date of the last supplement to this prospectus relating to the securities offered by this prospectus and the supplement(s), constitute full, true and plain disclosure of all material facts relating to the securities offered by this prospectus and the supplement(s) as required by the securities legislation of all the provinces of Canada.

CIBC WORLD MARKETS INC.

By: (Signed) Scott Burrows

TD SECURITIES INC.

By: (Signed) Patrick Scace

BMO NESBITT BURNS INC.

By: (Signed) Andrew Hainsworth

RBC DOMINION SECURITIES INC.

By: (Signed) Robert Brown

NATIONAL BANK FINANCIAL INC.

By: (Signed) John B. Carrique

SCOTIA CAPITAL INC.

By: (Signed) Murray Neal

ELEVENTH SUPPLEMENTAL TRUST INDENTURE

Made as of September 16, 2014

Between

TORONTO HYDRO CORPORATION
as issuer

and

BNY TRUST COMPANY OF CANADA
as trustee

Supplementing the Trust Indenture

made as of May 7, 2003

and

providing for the issue of

4.08% Senior Unsecured Debentures
due 2044 (Series 10)

TABLE OF CONTENTS

RECITALS 1

Section 1 INTERPRETATION 2

1.1 To Be Read With Trust Indenture 2

1.2 Headings etc. 2

1.3 Definitions 2

Section 2 SERIES 10 DEBENTURES 3

2.1 Creation and Designation 3

2.2 Limitation on Issue 3

2.3 Date of Issue and Maturity 3

2.4 Concerning Interest 3

2.5 Interest Payments 4

2.6 Payment of Amounts Due on Maturity 4

2.7 Redemption and Purchase of Series 10 Debentures 4

2.8 Form of Series 10 Debentures 4

2.9 Signatures on Series 10 Debentures 6

2.10 Certification 6

2.11 Location of Register 6

2.12 Additional Amounts 6

Section 3 MISCELLANEOUS 6

3.1 Acceptance of Trust 6

3.2 Confirmation of Trust Indenture 6

3.3 Counterparts 7

Schedule 1 – FORM OF GLOBAL DEBENTURE-SERIES 10

Schedule 2 –U.S. FORM OF DEFINITIVE DEBENTURE-SERIES 10

ELEVENTH SUPPLEMENTAL TRUST INDENTURE

THIS ELEVENTH SUPPLEMENTAL TRUST INDENTURE made as of September 16, 2014,

BETWEEN:

TORONTO HYDRO CORPORATION
a corporation incorporated under the laws of Ontario (the "**Corporation**")

and

BNY TRUST COMPANY OF CANADA
a trust company existing under the laws of Canada (the "**Trustee**")

RECITALS

(A) BNY Trust Company of Canada is the successor trustee of CIBC Mellon Trust Company;

(B) The Corporation has entered into a trust indenture with the Trustee made as of May 7, 2003, as amended, supplemented or restated from time to time (the "**Trust Indenture**") which provides for the issuance of one or more series of unsecured Debentures of the Corporation by way of Supplemental Indentures;

(C) The Corporation entered into a first supplemental trust indenture made as of May 7, 2003 for the purpose of providing for the issue of $225,000,000 aggregate principal amount of Series 1 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 1 Debentures;

(D) The Corporation entered into a second supplemental trust indenture made as of November 14, 2007 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 2 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 2 Debentures;

(E) The Corporation entered into a third supplemental trust indenture made as of November 12, 2009 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 3 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 3 Debentures;

(F) The City Note has been converted, in accordance with its terms, into the Series 4 Debentures and the Series 5 Debentures;

(G) The Corporation entered into a fourth supplemental trust indenture made as of April 1, 2010 for the purpose of providing for the issue of $245,057,000 aggregate principal amount of Series 4 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 4 Debentures;

(H) The Corporation entered into a fifth supplemental trust indenture made as of April 1, 2010 for the purpose of providing for the issue of $245,057,000 aggregate principal amount of Series 5 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 5 Debentures;

(I) The Corporation entered into a sixth supplemental trust indenture made as of May 20, 2010 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 6 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 6 Debentures;

(J) The Corporation entered into a seventh supplemental trust indenture made as of September 20, 2011 for the purpose of amending the definition of "GAAP" under the Trust Indenture;

(K) The Corporation entered into an eighth supplemental trust indenture made as of November 18, 2011 for the purpose of providing for the issue of $300,000,000 aggregate principal amount of Series 7 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 7 Debentures;

(L) The Corporation entered into a ninth supplemental trust indenture made as of April 9, 2013 for the purpose of providing for the issue of Series 8 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 8 Debentures;

(M) The Corporation entered into a tenth supplemental trust indenture made as of April 9, 2013 for the purpose of providing for the issue of Series 9 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 9 Debentures; and

(N) This Eleventh Supplemental Trust Indenture is entered into for the purpose of providing for the issue of Series 10 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 10 Debentures.

NOW THEREFORE THIS ELEVENTH SUPPLEMENTAL TRUST INDENTURE WITNESSES and it is hereby covenanted, agreed and declared as follows:

Section 1 INTERPRETATION

1.1 To Be Read With Trust Indenture

This Eleventh Supplemental Trust Indenture is a Supplemental Indenture as that term is used in the Trust Indenture. The Trust Indenture and this Eleventh Supplemental Trust Indenture shall be read together and shall have effect as though all the provisions of both indentures were contained in one instrument.

1.2 Headings etc.

The division of this Eleventh Supplemental Trust Indenture into Sections and clauses, the provision of a table of contents and the insertion of headings are for convenience of reference only and shall not affect the interpretation thereof. Unless the context otherwise requires, the expression "Section" and "Schedule" followed by a number, letter or combination of numbers and letters refer to the specified Section of or Schedule to this Eleventh Supplemental Trust Indenture.

1.3 Definitions

All terms which are defined in the Trust Indenture and used but not defined in this Eleventh Supplemental Trust Indenture shall have the meanings ascribed to them in the Trust Indenture, as such meanings may be amended or supplemented with respect to Series 10 Debentures by this Eleventh Supplemental Trust Indenture. In the event of any inconsistency between the meaning given to a term in the Trust Indenture and the meaning given to the same term in this Eleventh Supplemental Trust Indenture, the meaning given to the term in this Eleventh Supplemental Trust Indenture shall prevail to the extent of the inconsistency. Subject to the foregoing, in this Eleventh Supplemental Trust Indenture and in the Series 10 Debentures, the following terms have the following meanings:

(a) ***Canada Yield*** on any date means the yield to maturity on that date, compounded semi-annually, that a non-callable Government of Canada bond would carry if issued, in Canadian dollars in Canada, at 100% of its principal amount on that date with a term to maturity approximately equal to the remaining term to maturity of the Series 10

Debentures, such yield to maturity being the average of the yields provided by two major Canadian investment dealers specified by the Corporation.

(b) ***Canada Yield Price*** means the price equal to the net present value of all scheduled payments of interest (other than accrued and unpaid interest) and principal on the Series 10 Debentures, using a discount rate equal to the sum of the Canada Yield and 36 basis points, calculated at 10:00 a.m. (Toronto, Ontario time) three Business Days prior to the Redemption Date of the Series 10 Debentures.

(c) ***Series 10 Debentures*** means the 4.08% Senior Unsecured Debentures due 2044 (Series 10) referred to in Section 2.1.

(d) ***Series 10 Debentures Debt Account*** means the deposit account established in respect of the Series 10 Debentures pursuant to Section 8.2 of the Trust Indenture that is designated in writing by the Corporation to the Trustee as the "Series 10 Debentures Debt Account".

(e) ***Series 10 Debentures Interest Payment Date*** means March 16 and September 16 in each year that the Series 10 Debentures are outstanding.

(f) ***Series 10 Debentures Interest Period*** means the period commencing on and including the later of the date of issue of the Series 10 Debentures and the immediately preceding Series 10 Debentures Interest Payment Date and ending on and including the day immediately preceding the next Series 10 Debentures Interest Payment Date to occur in respect of which interest is payable.

(g) ***Trust Indenture*** means the trust indenture made as of May 7, 2003 between the Corporation and the Trustee, as amended, supplemented or restated from time to time.

Section 2 SERIES 10 DEBENTURES

2.1 Creation and Designation

The Corporation is authorized in accordance with the Trust Indenture to issue under this Eleventh Supplemental Trust Indenture, and hereby creates and issues, a series of debentures designated "4.08% Senior Unsecured Debentures due 2044 (Series 10)", having the terms set out in this Eleventh Supplemental Trust Indenture.

2.2 Limitation on Issue

The aggregate principal amount of Series 10 Debentures which may be issued under this Eleventh Supplemental Trust Indenture including any supplement hereto will be limited to $500,000,000.

2.3 Date of Issue and Maturity

The Series 10 Debentures shall be dated September 16, 2014 (being the applicable date of issue) and will become due and payable, together with all accrued interest and unpaid interest thereon, on September 16, 2044 (being the applicable Stated Maturity).

2.4 Concerning Interest

(a) The Series 10 Debentures shall be issued in $1,000 principal amount denominations or integral multiples thereof and shall bear interest on the unpaid principal amount thereof at a rate of 4.08% per annum from and including their date of issue, payable semi-annually in arrears, in equal instalments, on each Series 10 Debentures Interest Payment Date.

(b) Interest shall be payable in respect of each Series 10 Debentures Interest Period (after as well as before maturity, default and judgment, with interest on overdue interest at the same rate) on each Series 10 Debentures Interest Payment Date in accordance with Section 2.8 of the Trust Indenture.

2.5 Interest Payments

The Corporation shall make payments of interest on the Series 10 Debentures in accordance with the provisions of Section 2.8 of the Trust Indenture.

2.6 Payment of Amounts Due on Maturity

In accordance with Section 8.2 of the Trust Indenture, the Corporation will deposit to the Series 10 Debentures Debt Account all amounts required to be paid to the order of Holders of Series 10 Debentures on maturity, prior to 9:00 a.m. (Toronto, Ontario time), on the Stated Maturity of the Series 10 Debentures. The deposit of such funds will satisfy and discharge the liability of the Corporation for principal of, and any accrued and unpaid interest on, the Series 10 Debentures to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld).

2.7 Redemption and Purchase of Series 10 Debentures

(a) The Series 10 Debentures may be redeemed, at the Corporation's option when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to March 16, 2044, on not more than 60 Business Days and not less than 15 Business Days prior notice, at a price equal to the greater of the Canada Yield Price and par, together in each case with accrued and unpaid interest to (but excluding) the Redemption Date and in each case otherwise in accordance with Sections 5.1, 5.2, 5.3 and 5.4 of the Trust Indenture.

(b) The Series 10 Debentures may be redeemed, at the Corporation's option when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after March 16, 2044, on not more than 60 Business Days and not less than 15 Business Days prior notice, at a price equal to 100% of the principal amount of the Series 10 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the Redemption Date and otherwise in accordance with Sections 5.1, 5.2, 5.3 and 5.4 of the Trust Indenture.

(c) The Corporation will be entitled at any time when not in default under the Trust Indenture to purchase for cancellation all or any of the Series 10 Debentures in accordance with Section 5.5 of the Trust Indenture.

(d) The Series 10 Debentures will not be subject to repurchase pursuant to any sinking fund provisions.

2.8 Form of Series 10 Debentures

(a) Except as set out in 2.8(b) below, the Series 10 Debentures and the registration panel and the certificate of the Trustee endorsed thereon shall be issuable initially as one Global Debenture to be held by, or on behalf of, CDS as depository for its participants and registered in the name of CDS or its nominee The Global Debenture shall be substantially in the form set out in Schedule 1 hereto with such appropriate additions, deletions, substitutions and variations as the Directors shall by resolution determine prior to the time of issue thereof and as the Trustee may approve and with such distinguishing letters and numbers as the Trustee may approve, with such approval in each case to be conclusively evidenced by the Trustee's certification of such Global Debenture.

(b) The Trustee understands and acknowledges that the Series 10 Debentures have not been and will not be registered under the United States Securities Act of 1933, as amended (the "U.S. Securities Act"). Each Series 10 Debenture originally issued in the United States or to a U.S. Person will be represented by a definitive certificate in the form set out in Schedule 2 hereto which definitive certificate, and each Series 10 Debenture certificate issued in exchange therefor or in substitution thereof, shall bear the following legend:

"THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN AND WILL NOT BE REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE **"U.S. SECURITIES ACT**") OR UNDER ANY STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF THE CORPORATION THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE CORPORATION, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT, OR (C) INSIDE THE UNITED STATES IN ACCORDANCE WITH (1) RULE 144A UNDER THE U.S. SECURITIES ACT OR (2) RULE 144 UNDER THE U.S. SECURITIES ACT, IF AVAILABLE, OR (3) IN COMPLIANCE WITH CERTAIN OTHER PROCEDURES SATISFACTORY TO THE CORPORATION. A NEW CERTIFICATE, BEARING NO LEGEND, DELIVERY OF WHICH WILL CONSTITUTE "GOOD DELIVERY", MAY BE OBTAINED FROM BNY TRUST COMPANY OF CANADA UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO BNY TRUST COMPANY OF CANADA AND THE CORPORATION, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT."

If any Series 10 Debentures are being sold or transferred outside the United States in compliance with the requirements of Rule 904 of Regulation S under the U.S Securities Act, the legend may be removed by providing a declaration to the Trustee to the following effect (or as the Corporation may prescribe from time to time),

"The undersigned (A) acknowledges that the sale of the _____ Debentures, represented by certificate numbers _____ to which this declaration relates is being made in reliance on Rule 904 of Regulation S under the United States Securities Act of 1933, as amended (the "**U.S. Securities Act**") and (B) certifies that (1) it is not an "affiliate" (as defined in Rule 405 under the U.S. Securities Act) of Toronto Hydro Corporation, (2) the offer of such Debentures was not made to a person in the United States and at the time the buy order was originated, the buyer was outside the United States, or the seller and any person acting on its behalf reasonably believe that the buyer was outside the United States and (3) neither the seller, nor any affiliate of the seller, nor any person acting on its or their behalf engaged in any directed selling efforts in connection with the offer and sale of such Debentures. Terms used herein have the meanings given to them by Regulation S under the U.S. Securities Act."

If any Series 10 Debentures are being sold or transferred pursuant to Rule 144 of the U.S. Securities Act, the legend may be removed by delivery to the Trustee of a written opinion of Trustee Counsel (or counsel to the transferor satisfactory to the Trustee) to the effect that such legend is no longer required under applicable requirements of the U.S. Securities Act or state securities laws.

Prior to the issuance of Series 10 Debentures, the Corporation shall notify the Trustee, in writing, concerning which Series 10 Debentures are to be certificated and are to bear the legend described above. The Trustee will thereafter maintain a list of all registered holders from time to time of legended Series 10 Debentures.

2.9 Signatures on Series 10 Debentures

The Series 10 Debentures shall be signed in accordance with the provisions of Section 2.6 of the Trust Indenture.

2.10 Certification

(a) No Series 10 Debenture issued shall be obligatory or shall entitle the Holder of such Series 10 Debenture to the benefits of this Eleventh Supplemental Trust Indenture until it has been certified by manual signature by or on behalf of the Trustee by execution of the certificate of the Trustee appended thereto substantially in the form set out in Schedule 1 hereto, or in some other form approved by the Trustee, whose approval shall be conclusively evidenced by the Trustee's execution of the certificate. Such certificate on any Series 10 Debenture shall be conclusive evidence that such Series 10 Debenture is duly issued and is a valid and binding obligation of the Corporation and that the Holder of such Series 10 Debenture is entitled to the benefits of the Trust Indenture, as supplemented by this Eleventh Supplemental Trust Indenture, and such Series 10 Debenture.

(b) The certificate of the Trustee on any Series 10 Debenture shall not be construed as a representation or warranty by the Trustee as to the validity of this Eleventh Supplemental Trust Indenture or of the Series 10 Debentures (except the due certification thereof and any other warranties implied by law) and the Trustee shall in no respect be liable or answerable for the use made of the Series 10 Debentures or any of them or the proceeds thereof.

2.11 Location of Register

With respect to the Series 10 Debentures, initially the Register referred to in Section 3.1 of the Trust Indenture shall be kept by the Trustee at the Corporate Trust Office and may thereafter be kept by the Trustee in such other place as the Corporation, with the approval of the Trustee, may designate.

2.12 Additional Amounts

The Corporation will not be required to pay an additional amount on the Series 10 Debentures in respect of any tax, assessment or government charge that is required by law to be withheld or deducted by it.

2.13 Trustees, etc.

The Trustee will be the Paying Agent and the Registrar for the Series 10 Debentures.

Section 3 MISCELLANEOUS

3.1 Acceptance of Trust

The Trustee accepts the trusts in this Eleventh Supplemental Trust Indenture and agrees to carry out and discharge the same upon the terms and conditions set out in this Eleventh Supplemental Trust Indenture and in accordance with the Trust Indenture.

3.2 Confirmation of Trust Indenture

The Trust Indenture as amended and supplemented by this Eleventh Supplemental Trust Indenture is in all respects confirmed.

3.3 Counterparts

This Eleventh Supplemental Trust Indenture may be executed in counterparts, each of which so executed shall be deemed to be original and such counterparts together shall constitute one and the same instrument.

[SIGNATURE PAGE FOLLOWS]

IN WITNESS WHEREOF the parties hereto have executed this Eleventh Supplemental Trust Indenture under the hands of their proper signatories in that behalf:

TORONTO HYDRO CORPORATION

By: *"Anthony Haines"*

Name: Anthony Haines

Title: President and Chief Executive Officer

By: *"Jean-Sebastien Couillard"*

Name: Jean-Sebastien Couillard

Title: Executive Vice-President and Chief Financial Officer

BNY TRUST COMPANY OF CANADA

By: *"J. Steven Broude"*

Name: J. Steven Broude

Title: Authorized Signatory

Schedule 1 – FORM OF GLOBAL DEBENTURE-SERIES 10

This Debenture is a Global Debenture within the meaning of the Trust Indenture hereinafter referred to and is registered in the name of a Depository or a nominee thereof. Unless this Debenture is presented by an authorized representative of CDS Clearing and Depository Services Inc. ("CDS") to Toronto Hydro Corporation or its agent for registration of transfer, exchange or payment, and any debenture issued in respect thereof is registered in the name of CDS & CO., or in such other name as is requested by an authorized representative of CDS (and any payment is made to CDS & CO., or to such other entity as is requested by an authorized representative of CDS), ANY TRANSFER, PLEDGE OR OTHER USE HEREOF FOR VALUE OR OTHERWISE BY OR TO ANY PERSON IS WRONGFUL since the registered holder hereof, CDS & CO., has a property interest in the securities represented by this debenture herein and it is a violation of its rights for another person to hold, transfer or deal with this debenture.

No. 10-000

$●

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
●% SENIOR UNSECURED DEBENTURES DUE 2044 (SERIES 10)

ISIN CA89119ZAG87
CUSIP 89119ZAG8

Issue Date	September 16, 2014
Stated Maturity	September 16, 2044
Interest Rate Per Annum	●%
Interest Payment Dates	March 16 and September 16 in each year
Initial Interest Payment Date	March 16, 2015
Principal Amount	$●

TORONTO HYDRO CORPORATION (the "**Corporation**") for value received hereby promises to pay to the registered holder hereof on the Stated Maturity, or on such earlier date as the Principal Amount (or a portion thereof) may become due in accordance with the provisions of the Trust Indenture (as defined below), on presentation and surrender of this ●% Senior Unsecured Debenture due September 16, 2044 (Series 10) (the "**Series 10 Debenture**"), the Principal Amount in lawful money of Canada at the office of the Trustee (as defined below) at 11th Floor, 320 Bay Street, Toronto, Ontario M5H 4A6, and to pay interest on the Principal Amount at the Interest Rate Per Annum from and including the later of the Issue Date and the last Interest Payment Date on which interest has at that time most recently been paid on this Series 10 Debenture, at the address of the registered holder hereof appearing on the register of Series 10 Debentures maintained by or at the direction of the Trustee (the "**Register**"), in like money semi-annually in arrears, in equal instalments on the Interest Payment Dates in each year, and if the Corporation at any time defaults in the payment of any principal or interest, to pay interest on the amount in default at the same rate, in like money, on demand, at the address of the registered holder hereof appearing on the Register. The Corporation will (i) on the day that is

each Interest Payment Date, make payment by a wire transfer, or (ii) on the day that is two Business Days before each Interest Payment Date, forward or cause to be forwarded a cheque by same day delivery, to the address of the registered holder hereof appearing on the Register for interest due and payable to such holder on such Interest Payment Date, less any taxes required by law to be deducted or withheld, made payable to the order of such holder; provided, however that in case of payment of interest at maturity or redemption or as otherwise provided in the Trust Indenture, the time for payment of interest, less any such taxes, may at the option of the Corporation be determined based on the time that the certificate representing this Series 10 Debenture is presented and surrendered to the Trustee. The payment by such wire transfer or forwarding of such cheque (provided such cheque is paid on presentation) will satisfy and discharge the liability for interest upon such Series 10 Debenture to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld as aforesaid).

This Series 10 Debenture is one of an authorized issue of debentures designated as ●% Senior Unsecured Debentures due September 16, 2044 (Series 10) and forming the series of debentures created and issued under an eleventh supplemental trust indenture made as of ●, 2014 (the "**Eleventh Supplemental Trust Indenture**") to a trust indenture (the "**Indenture**") made as of May 7, 2003, between the Corporation and BNY Trust Company of Canada (successor trustee of CIBC Mellon Trust Company) (the "**Trustee**"), as Trustee (the first supplemental trust indenture to the Indenture made as of May 7, 2003 between the Corporation and the Trustee, the second supplemental trust indenture to the Indenture made as of November 14, 2007 between the Corporation and the Trustee, the third supplemental trust indenture to the Indenture made as of November 12, 2009 between the Corporation and the Trustee, the fourth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the fifth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the sixth supplemental trust indenture to the Indenture made as of May 20, 2010 between the Corporation and the Trustee, the seventh supplemental trust indenture to the Indenture made as of September 20, 2011 between the Corporation and the Trustee, the eighth supplemental trust indenture to the Indenture made as of November 18, 2011 between the Corporation and the Trustee, the ninth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the tenth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the Eleventh Supplemental Trust Indenture and the Indenture (as amended, supplemented or restated from time to time) are collectively referred to herein as the "**Trust Indenture**"). The Trust Indenture specifies the terms and conditions upon which the Series 10 Debentures are created and issued or may be created, issued and held and the rights of the registered holders of the Series 10 Debentures, the Corporation and the Trustee, all of which terms and conditions are incorporated by reference in this Series 10 Debenture and to each of which the registered holder of this Series 10 Debenture, by acceptance hereof, agrees.

The aggregate principal amount of Series 10 Debentures that may be created and issued under the Trust Indenture is limited to $500,000,000 in lawful money of Canada Series 10 Debentures are issuable as fully registered debentures in denominations of $1,000 and integral multiples thereof and, subject to the terms and conditions set forth in the Trust Indenture, are issued as book entry only debentures.

The Series 10 Debentures are direct unsecured obligations of the Corporation and will rank equally with each other and with all other debentures of every other series from time to time issued and outstanding pursuant to the Trust Indenture and, except to the extent prescribed by law, with all other unsecured and unsubordinated Indebtedness of the Corporation.

This Series 10 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to March 16, 2044, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to the greater of the Canada Yield Price (as defined in the Trust Indenture) and par, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

This Series 10 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after March 16, 2044, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to 100% of the Principal Amount of the Series 10 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

At any time when the Corporation is not in default under the Trust Indenture, the Corporation may, subject to the terms and conditions set forth in the Trust Indenture, purchase Series 10 Debentures in the open market, by tender or by private contract, at any price. Series 10 Debentures purchased by the Corporation shall be cancelled and not reissued.

The Principal Amount may become or be declared due before the Stated Maturity on the conditions, in the manner, with the effect and at the times set forth in the Trust Indenture.

The Trust Indenture contains provisions for the holding of meetings of registered holders of debentures issued by the Corporation pursuant to the Trust Indenture and the making of resolutions at such meetings and the creation of instruments in writing signed by the registered holders of a specified majority of debentures issued and outstanding pursuant to the Trust Indenture. Such resolutions and instruments will be binding on and may affect the rights and entitlements of all holders of debentures issued by the Corporation pursuant to the Trust Indenture, subject to the provisions of the Trust Indenture.

This Series 10 Debenture may be transferred only upon compliance with the conditions prescribed in the Trust Indenture relating to the transfer of a Global Debenture (as defined in the Trust Indenture), and upon compliance with such reasonable requirements as the Trustee or other registrar may prescribe, and such transfer shall be duly noted hereon by the Trustee or other registrar.

This Series 10 Debenture shall not become obligatory for any purpose until it shall have been certified by the manual signature of the Trustee in accordance with the Trust Indenture.

IN WITNESS WHEREOF TORONTO HYDRO CORPORATION has caused this Series 10 Debenture to be signed by its ● and its ●.

TORONTO HYDRO CORPORATION

By: _____

Name: ●

Title: ●

By: _____

Name: ●

Title: ●

(FORM OF TRUSTEE'S CERTIFICATE)

This Debenture is one of the Series 10 Debentures referred to in the Trust Indenture referred to above.

BNY TRUST COMPANY OF CANADA
Trustee

By: _____
Authorized Signatory

(FORM OF REGISTRATION PANEL)

(NO WRITING HEREON EXCEPT BY THE TRUSTEE OR OTHER REGISTRAR)

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
●% SENIOR UNSECURED DEBENTURES DUE 2044 (SERIES 10)

ISIN CA89119ZAG87
CUSIP 89119ZAG8

DATE OF REGISTRATION	IN WHOSE NAME REGISTERED	AMOUNT OF DECREASE	AMOUNT OF INCREASE	AMOUNT OF SERIES 10 DEBENTURES OUTSTANDING FOLLOWING CHANGE	SIGNATURE OF TRUSTEE OR OTHER REGISTRAR

Schedule 2 – U.S. FORM OF DEFINITIVE DEBENTURE-SERIES 10

*THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN AND WILL NOT BE REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE "**U.S. SECURITIES ACT**") OR UNDER ANY STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF THE CORPORATION THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE CORPORATION, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT, OR (C) INSIDE THE UNITED STATES IN ACCORDANCE WITH (1) RULE 144A UNDER THE U.S. SECURITIES ACT OR (2) RULE 144 UNDER THE U.S. SECURITIES ACT, IF AVAILABLE, OR (3) IN COMPLIANCE WITH CERTAIN OTHER PROCEDURES SATISFACTORY TO THE CORPORATION. A NEW CERTIFICATE, BEARING NO LEGEND, DELIVERY OF WHICH WILL CONSTITUTE "GOOD DELIVERY", MAY BE OBTAINED FROM BNY TRUST COMPANY OF CANADA UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO BNY TRUST COMPANY OF CANADA AND THE CORPORATION, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT.*

No. 10-000

$●

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
●% SENIOR UNSECURED DEBENTURES DUE 2044 (SERIES 10)

Issue Date	September 16, 2014
Stated Maturity	September 16, 2044
Interest Rate Per Annum	●%
Interest Payment Dates	March 16 and September 16 in each year
Initial Interest Payment Date	March 16, 2015
Principal Amount	$●

TORONTO HYDRO CORPORATION (the "**Corporation**") for value received hereby promises to pay to the registered holder hereof on the Stated Maturity, or on such earlier date as the Principal Amount (or a portion thereof) may become due in accordance with the provisions of the Trust Indenture (as defined below), on presentation and surrender of this ●% Senior Unsecured Debenture due September 16, 2044 (Series 10) (the "**Series 10 Debenture**"), the Principal Amount in lawful money of Canada at the office of the Trustee (as defined below) at 11th Floor, 320 Bay Street, Toronto, Ontario M5H 4A6, and to pay interest on the Principal Amount at the Interest Rate Per Annum from and including the later of the Issue Date and the last Interest Payment Date on which interest has at that time most recently been paid on this Series 10 Debenture, at the address of the registered holder hereof appearing on the register of Series 10 Debentures maintained by or at the direction of the Trustee (the "**Register**"), in like money semi-annually in arrears, in equal instalments on the Interest Payment Dates in each year, and if the Corporation at any time defaults in the payment of any principal or interest, to pay interest on the amount in default at the same rate, in like money, on demand, at the

address of the registered holder hereof appearing on the Register. The Corporation, on the day that is two Business Days before each Interest Payment Date, will forward or cause to be forwarded by same day delivery to the address of the registered holder hereof appearing on the Register a cheque for interest due and payable to such holder on such Interest Payment Date, less any taxes required by law to be deducted or withheld, made payable to the order of such holder; provided, however that in case of payment of interest at maturity or redemption or as otherwise provided in the Trust Indenture, the time for payment of interest, less any such taxes, may at the option of the Corporation be determined based on the time that the certificate representing this Series 10 Debenture is presented and surrendered to the Trustee. The forwarding of such cheque will satisfy and discharge the liability for interest upon such Series 10 Debenture to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld as aforesaid) unless such cheque is not paid on presentation.

This Series 10 Debenture is one of an authorized issue of debentures designated as ●% Senior Unsecured Debentures due September 16, 2044 (Series 10) and forming the series of debentures created and issued under an eleventh supplemental trust indenture made as of ●, 2014 (the "**Eleventh Supplemental Trust Indenture**") to a trust indenture (the "**Indenture**") made as of May 7, 2003, between the Corporation and BNY Trust Company of Canada (successor trustee of CIBC Mellon Trust Company) (the "**Trustee**"), as Trustee (the first supplemental trust indenture to the Indenture made as of May 7, 2003 between the Corporation and the Trustee, the second supplemental trust indenture to the Indenture made as of November 14, 2007 between the Corporation and the Trustee, the third supplemental trust indenture to the Indenture made as of November 12, 2009 between the Corporation and the Trustee, the fourth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the fifth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the sixth supplemental trust indenture to the Indenture made as of May 20, 2010 between the Corporation and the Trustee, the seventh supplemental trust indenture to the Indenture made as of September 20, 2011 between the Corporation and the Trustee, the eighth supplemental trust indenture to the Indenture made as of November 18, 2011 between the Corporation and the Trustee, the ninth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the tenth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the Eleventh Supplemental Trust Indenture and the Indenture (as amended, supplemented or restated from time to time) are collectively referred to herein as the "**Trust Indenture**"). The Trust Indenture specifies the terms and conditions upon which the Series 10 Debentures are created and issued or may be created, issued and held and the rights of the registered holders of the Series 10 Debentures, the Corporation and the Trustee, all of which terms and conditions are incorporated by reference in this Series 10 Debenture and to each of which the registered holder of this Series 10 Debenture, by acceptance hereof, agrees.

The aggregate principal amount of Series 10 Debentures that may be created and issued under the Trust Indenture is limited to $500,000,000 in lawful money of Canada. Series 10 Debentures are issuable as fully registered debentures in denominations of $1,000 and integral multiples thereof.

The Series 10 Debentures are direct unsecured obligations of the Corporation and will rank equally with each other and with all other debentures of every other series from time to time issued and outstanding pursuant to the Trust Indenture and, except to the extent prescribed by law, with all other unsecured and unsubordinated Indebtedness of the Corporation.

This Series 10 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to March 16, 2044, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to the greater of the Canada Yield Price (as defined in the Trust Indenture) and par, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

This Series 10 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after March 16, 2044, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to 100% of the Principal Amount of the Series 10 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

At any time when the Corporation is not in default under the Trust Indenture, the Corporation may, subject to the terms and conditions set forth in the Trust Indenture, purchase Series 10 Debentures in the open market, by tender or by private contract, at any price. Series 10 Debentures purchased by the Corporation shall be cancelled and not reissued.

The Principal Amount may become or be declared due before the Stated Maturity on the conditions, in the manner, with the effect and at the times set forth in the Trust Indenture.

The Trust Indenture contains provisions for the holding of meetings of registered holders of debentures issued by the Corporation pursuant to the Trust Indenture and the making of resolutions at such meetings and the creation of instruments in writing signed by the registered holders of a specified majority of debentures issued and outstanding pursuant to the Trust Indenture. Such resolutions and instruments will be binding on and may affect the rights and entitlements of all holders of debentures issued by the Corporation pursuant to the Trust Indenture, subject to the provisions of the Trust Indenture.

This Series 10 Debenture may be transferred only upon compliance with the conditions prescribed in the Trust Indenture by the registered holder hereof or the holder's legal representative or attorney duly appointed by an instrument in form and execution satisfactory to the Trustee, and upon compliance with such reasonable requirements as the Trustee or other registrar may prescribe, and such transfer shall be duly noted hereon by the Trustee or other registrar.

This Series 10 Debenture shall not become obligatory for any purpose until it shall have been certified by the manual signature of the Trustee in accordance with the Trust Indenture.

IN WITNESS WHEREOF TORONTO HYDRO CORPORATION has caused this Series 10 Debenture to be signed by its ● and its ●.

TORONTO HYDRO CORPORATION

By: _____

Name: ●

Title: ●

By: _____

Name: ●

Title: ●

(FORM OF TRUSTEE'S CERTIFICATE)

This Debenture is one of the Series 10 Debentures referred to in the Trust Indenture referred to above.

BNY TRUST COMPANY OF CANADA
Trustee

By: _____
Authorized Signatory

(FORM OF REGISTRATION PANEL)

(NO WRITING HEREON EXCEPT BY THE TRUSTEE OR OTHER REGISTRAR)

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
●% SENIOR UNSECURED DEBENTURES DUE 2044 (SERIES 10)

DATE OF REGISTRATION	IN WHOSE NAME REGISTERED	SIGNATURE OF TRUSTEE OR OTHER REGISTRAR

TWELFTH SUPPLEMENTAL TRUST INDENTURE

Made as of March 16, 2015

Between

TORONTO HYDRO CORPORATION
as issuer

and

BNY TRUST COMPANY OF CANADA
as trustee

Supplementing the Trust Indenture

made as of May 7, 2003

and

providing for the issue of

3.55% Senior Unsecured Debentures
due 2045 (Series 11)

TABLE OF CONTENTS

RECITALS 1

Section 1 INTERPRETATION 2

1.1 To Be Read With Trust Indenture 2

1.2 Headings etc. 2

1.3 Definitions 2

Section 2 SERIES 11 DEBENTURES 3

2.1 Creation and Designation 3

2.2 Limitation on Issue 3

2.3 Date of Issue and Maturity 3

2.4 Concerning Interest 3

2.5 Interest Payments 4

2.6 Payment of Amounts Due on Maturity 4

2.7 Redemption and Purchase of Series 11 Debentures 4

2.8 Form of Series 11 Debentures 4

2.9 Signatures on Series 11 Debentures 6

2.10 Certification 6

2.11 Location of Register 6

2.12 Additional Amounts 6

Section 3 MISCELLANEOUS 6

3.1 Acceptance of Trust 6

3.2 Confirmation of Trust Indenture 6

3.3 Counterparts 7

Schedule 1 – FORM OF GLOBAL DEBENTURE-SERIES 11

Schedule 2 –U.S. FORM OF DEFINITIVE DEBENTURE-SERIES 11

TWELFTH SUPPLEMENTAL TRUST INDENTURE

THIS TWELFTH SUPPLEMENTAL TRUST INDENTURE made as of March 16, 2015,

BETWEEN:

TORONTO HYDRO CORPORATION
a corporation incorporated under the laws of Ontario (the "**Corporation**")

and

BNY TRUST COMPANY OF CANADA
a trust company existing under the laws of Canada (the "**Trustee**")

RECITALS

(A) BNY Trust Company of Canada is the successor trustee of CIBC Mellon Trust Company;

(B) The Corporation has entered into a trust indenture with the Trustee made as of May 7, 2003, as amended, supplemented or restated from time to time (the "**Trust Indenture**") which provides for the issuance of one or more series of unsecured Debentures of the Corporation by way of Supplemental Indentures;

(C) The Corporation entered into a first supplemental trust indenture made as of May 7, 2003 for the purpose of providing for the issue of $225,000,000 aggregate principal amount of Series 1 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 1 Debentures;

(D) The Corporation entered into a second supplemental trust indenture made as of November 14, 2007 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 2 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 2 Debentures;

(E) The Corporation entered into a third supplemental trust indenture made as of November 12, 2009 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 3 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 3 Debentures;

(F) The City Note has been converted, in accordance with its terms, into the Series 4 Debentures and the Series 5 Debentures;

(G) The Corporation entered into a fourth supplemental trust indenture made as of April 1, 2010 for the purpose of providing for the issue of $245,057,000 aggregate principal amount of Series 4 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 4 Debentures;

(H) The Corporation entered into a fifth supplemental trust indenture made as of April 1, 2010 for the purpose of providing for the issue of $245,057,000 aggregate principal amount of Series 5 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 5 Debentures;

(I) The Corporation entered into a sixth supplemental trust indenture made as of May 20, 2010 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 6 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 6 Debentures;

(J) The Corporation entered into a seventh supplemental trust indenture made as of September 20, 2011 for the purpose of amending the definition of "GAAP" under the Trust Indenture;

(K) The Corporation entered into an eighth supplemental trust indenture made as of November 18, 2011 for the purpose of providing for the issue of $300,000,000 aggregate principal amount of Series 7 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 7 Debentures;

(L) The Corporation entered into a ninth supplemental trust indenture made as of April 9, 2013 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 8 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 8 Debentures;

(M) The Corporation entered into a tenth supplemental trust indenture made as of April 9, 2013 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 9 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 9 Debentures;

(N) The Corporation entered into an eleventh supplemental trust indenture made as of September 16, 2014 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 10 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 10 Debentures; and

(O) This Twelfth Supplemental Trust Indenture is entered into for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 11 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 11 Debentures.

NOW THEREFORE THIS TWELFTH SUPPLEMENTAL TRUST INDENTURE WITNESSES and it is hereby covenanted, agreed and declared as follows:

Section 1 INTERPRETATION

1.1 To Be Read With Trust Indenture

This Twelfth Supplemental Trust Indenture is a Supplemental Indenture as that term is used in the Trust Indenture. The Trust Indenture and this Twelfth Supplemental Trust Indenture shall be read together and shall have effect as though all the provisions of both indentures were contained in one instrument.

1.2 Headings etc.

The division of this Twelfth Supplemental Trust Indenture into Sections and clauses, the provision of a table of contents and the insertion of headings are for convenience of reference only and shall not affect the interpretation thereof. Unless the context otherwise requires, the expression "Section" and "Schedule" followed by a number, letter or combination of numbers and letters refer to the specified Section of or Schedule to this Twelfth Supplemental Trust Indenture.

1.3 Definitions

All terms which are defined in the Trust Indenture and used but not defined in this Twelfth Supplemental Trust Indenture shall have the meanings ascribed to them in the Trust Indenture, as such meanings may be amended or supplemented with respect to Series 11 Debentures by this Twelfth Supplemental Trust Indenture. In the event of any inconsistency between the meaning given to a term in the Trust Indenture and the meaning given to the same term in this Twelfth Supplemental Trust Indenture, the meaning given to the term in this Twelfth Supplemental Trust Indenture shall prevail to the extent of the inconsistency. Subject to the foregoing, in this Twelfth Supplemental Trust Indenture and in the Series 11 Debentures, the following terms have the following meanings:

(a) ***Canada Yield*** on any date means the yield to maturity on that date, compounded semi-annually, that a non-callable Government of Canada bond would carry if issued, in Canadian dollars in Canada, at 100% of its principal amount on that date with a term to maturity approximately equal to the remaining term to January 28, 2045 of the Series 11 Debentures, such yield to maturity being the average of the yields provided by two major Canadian investment dealers specified by the Corporation.

(b) ***Canada Yield Price*** means the price equal to the net present value of all scheduled payments of interest (other than accrued and unpaid interest) and principal on the Series 11 Debentures that would have been payable to January 28, 2045 if redemption had not been made, using a discount rate equal to the sum of the Canada Yield and 33.5 basis points, calculated at 10:00 a.m. (Toronto, Ontario time) three Business Days prior to the Redemption Date of the Series 11 Debentures.

(c) ***Series 11 Debentures*** means the 3.55% Senior Unsecured Debentures due 2045 (Series 11) referred to in Section 2.1.

(d) ***Series 11 Debentures Debt Account*** means the deposit account established in respect of the Series 11 Debentures pursuant to Section 8.2 of the Trust Indenture that is designated in writing by the Corporation to the Trustee as the "Series 11 Debentures Debt Account".

(e) ***Series 11 Debentures Interest Payment Date*** means January 28 and July 28 in each year that the Series 11 Debentures are outstanding.

(f) ***Series 11 Debentures Interest Period*** means the period commencing on and including the later of the date of issue of the Series 11 Debentures and the immediately preceding Series 11 Debentures Interest Payment Date and ending on and including the day immediately preceding the next Series 11 Debentures Interest Payment Date to occur in respect of which interest is payable.

(g) ***Trust Indenture*** means the trust indenture made as of May 7, 2003 between the Corporation and the Trustee, as amended, supplemented or restated from time to time.

Section 2 SERIES 11 DEBENTURES

2.1 Creation and Designation

The Corporation is authorized in accordance with the Trust Indenture to issue under this Twelfth Supplemental Trust Indenture, and hereby creates and issues, a series of debentures designated "3.55% Senior Unsecured Debentures due 2045 (Series 11)", having the terms set out in this Twelfth Supplemental Trust Indenture.

2.2 Limitation on Issue

The aggregate principal amount of Series 11 Debentures which may be issued under this Twelfth Supplemental Trust Indenture including any supplement hereto will be limited to $500,000,000.

2.3 Date of Issue and Maturity

The Series 11 Debentures shall be dated March 16, 2015 (being the applicable date of issue) and will become due and payable, together with all accrued interest and unpaid interest thereon, on July 28, 2045 (being the applicable Stated Maturity).

2.4 Concerning Interest

(a) The Series 11 Debentures shall be issued in $1,000 principal amount denominations or integral multiples thereof and shall bear interest on the unpaid principal amount thereof at a rate of 3.55% per annum from and including their date of issue, payable semi-annually in arrears, in equal instalments, on each Series 11 Debentures Interest Payment Date.

(b) Interest shall be payable in respect of each Series 11 Debentures Interest Period (after as well as before maturity, default and judgment, with interest on overdue interest at the same rate) on each Series 11 Debentures Interest Payment Date in accordance with Section 2.8 of the Trust Indenture.

2.5 Interest Payments

The Corporation shall make payments of interest on the Series 11 Debentures in accordance with the provisions of Section 2.8 of the Trust Indenture.

2.6 Payment of Amounts Due on Maturity

In accordance with Section 8.2 of the Trust Indenture, the Corporation will deposit to the Series 11 Debentures Debt Account all amounts required to be paid to the order of Holders of Series 11 Debentures on maturity, prior to 9:00 a.m. (Toronto, Ontario time), on the Stated Maturity of the Series 11 Debentures. The deposit of such funds will satisfy and discharge the liability of the Corporation for principal of, and any accrued and unpaid interest on, the Series 11 Debentures to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld).

2.7 Redemption and Purchase of Series 11 Debentures

(a) The Series 11 Debentures may be redeemed, at the Corporation's option when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to January 28, 2045, on not more than 60 Business Days and not less than 15 Business Days prior notice, at a price equal to the greater of the Canada Yield Price and par, together in each case with accrued and unpaid interest to (but excluding) the Redemption Date and in each case otherwise in accordance with Sections 5.1, 5.2, 5.3 and 5.4 of the Trust Indenture.

(b) The Series 11 Debentures may be redeemed, at the Corporation's option when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after January 28, 2045, on not more than 60 Business Days and not less than 15 Business Days prior notice, at a price equal to 100% of the principal amount of the Series 11 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the Redemption Date and otherwise in accordance with Sections 5.1, 5.2, 5.3 and 5.4 of the Trust Indenture.

(c) The Corporation will be entitled at any time when not in default under the Trust Indenture to purchase for cancellation all or any of the Series 11 Debentures in accordance with Section 5.5 of the Trust Indenture.

(d) The Series 11 Debentures will not be subject to repurchase pursuant to any sinking fund provisions.

2.8 Form of Series 11 Debentures

(a) Except as set out in 2.8(b) below, the Series 11 Debentures and the registration panel and the certificate of the Trustee endorsed thereon shall be issuable initially as one Global Debenture to be held by, or on behalf of, CDS as depository for its participants and registered in the name of CDS or its nominee. The Global Debenture shall be substantially in the form set out in Schedule 1 hereto with such appropriate additions, deletions, substitutions and variations as the Directors shall by resolution determine prior

to the time of issue thereof and as the Trustee may approve and with such distinguishing letters and numbers as the Trustee may approve, with such approval in each case to be conclusively evidenced by the Trustee's certification of such Global Debenture.

(b) The Trustee understands and acknowledges that the Series 11 Debentures have not been and will not be registered under the United States Securities Act of 1933, as amended (the "U.S. Securities Act"). Each Series 11 Debenture originally issued in the United States or to a U.S. Person will be represented by a definitive certificate in the form set out in Schedule 2 hereto which definitive certificate, and each Series 11 Debenture certificate issued in exchange therefor or in substitution thereof, shall bear the following legend:

"THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN AND WILL NOT BE REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE **"U.S. SECURITIES ACT**") OR UNDER ANY STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF THE CORPORATION THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE CORPORATION, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT, OR (C) INSIDE THE UNITED STATES IN ACCORDANCE WITH (1) RULE 144A UNDER THE U.S. SECURITIES ACT OR (2) RULE 144 UNDER THE U.S. SECURITIES ACT, IF AVAILABLE, OR (3) IN COMPLIANCE WITH CERTAIN OTHER PROCEDURES SATISFACTORY TO THE CORPORATION. A NEW CERTIFICATE, BEARING NO LEGEND, DELIVERY OF WHICH WILL CONSTITUTE "GOOD DELIVERY", MAY BE OBTAINED FROM BNY TRUST COMPANY OF CANADA UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO BNY TRUST COMPANY OF CANADA AND THE CORPORATION, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT."

If any Series 11 Debentures are being sold or transferred outside the United States in compliance with the requirements of Rule 904 of Regulation S under the U.S Securities Act, the legend may be removed by providing a declaration to the Trustee to the following effect (or as the Corporation may prescribe from time to time),

"The undersigned (A) acknowledges that the sale of the _____ Debentures, represented by certificate numbers _____ to which this declaration relates is being made in reliance on Rule 904 of Regulation S under the United States Securities Act of 1933, as amended (the "**U.S. Securities Act**") and (B) certifies that (1) it is not an "affiliate" (as defined in Rule 405 under the U.S. Securities Act) of Toronto Hydro Corporation, (2) the offer of such Debentures was not made to a person in the United States and at the time the buy order was originated, the buyer was outside the United States, or the seller and any person acting on its behalf reasonably believe that the buyer was outside the United States and (3) neither the seller, nor any affiliate of the seller, nor any person acting on its or their behalf engaged in any directed selling efforts in connection with the offer and sale of such Debentures. Terms used herein have the meanings given to them by Regulation S under the U.S. Securities Act."

If any Series 11 Debentures are being sold or transferred pursuant to Rule 144 of the U.S. Securities Act, the legend may be removed by delivery to the Trustee of a written opinion of Trustee Counsel (or counsel to the transferor satisfactory to the Trustee) to the effect that such legend is no longer required under applicable requirements of the U.S. Securities Act or state securities laws.

Prior to the issuance of Series 11 Debentures, the Corporation shall notify the Trustee, in writing, concerning which Series 11 Debentures are to be certificated and are to bear the legend described

above. The Trustee will thereafter maintain a list of all registered holders from time to time of legended Series 11 Debentures.

2.9 Signatures on Series 11 Debentures

The Series 11 Debentures shall be signed in accordance with the provisions of Section 2.6 of the Trust Indenture.

2.10 Certification

(a) No Series 11 Debenture issued shall be obligatory or shall entitle the Holder of such Series 11 Debenture to the benefits of this Twelfth Supplemental Trust Indenture until it has been certified by manual signature by or on behalf of the Trustee by execution of the certificate of the Trustee appended thereto substantially in the form set out in Schedule 1 hereto, or in some other form approved by the Trustee, whose approval shall be conclusively evidenced by the Trustee's execution of the certificate. Such certificate on any Series 11 Debenture shall be conclusive evidence that such Series 11 Debenture is duly issued and is a valid and binding obligation of the Corporation and that the Holder of such Series 11 Debenture is entitled to the benefits of the Trust Indenture, as supplemented by this Twelfth Supplemental Trust Indenture, and such Series 11 Debenture.

(b) The certificate of the Trustee on any Series 11 Debenture shall not be construed as a representation or warranty by the Trustee as to the validity of this Twelfth Supplemental Trust Indenture or of the Series 11 Debentures (except the due certification thereof and any other warranties implied by law) and the Trustee shall in no respect be liable or answerable for the use made of the Series 11 Debentures or any of them or the proceeds thereof.

2.11 Location of Register

With respect to the Series 11 Debentures, initially the Register referred to in Section 3.1 of the Trust Indenture shall be kept by the Trustee at the Corporate Trust Office and may thereafter be kept by the Trustee in such other place as the Corporation, with the approval of the Trustee, may designate.

2.12 Additional Amounts

The Corporation will not be required to pay an additional amount on the Series 11 Debentures in respect of any tax, assessment or government charge that is required by law to be withheld or deducted by it.

2.13 Trustees, etc.

The Trustee will be the Paying Agent and the Registrar for the Series 11 Debentures.

Section 3 MISCELLANEOUS

3.1 Acceptance of Trust

The Trustee accepts the trusts in this Twelfth Supplemental Trust Indenture and agrees to carry out and discharge the same upon the terms and conditions set out in this Twelfth Supplemental Trust Indenture and in accordance with the Trust Indenture.

3.2 Confirmation of Trust Indenture

The Trust Indenture as amended and supplemented by this Twelfth Supplemental Trust Indenture is in all respects confirmed.

3.3 Counterparts

This Twelfth Supplemental Trust Indenture may be executed in counterparts, each of which so executed shall be deemed to be original and such counterparts together shall constitute one and the same instrument.

[SIGNATURE PAGE FOLLOWS]

IN WITNESS WHEREOF the parties hereto have executed this Twelfth Supplemental Trust Indenture under the hands of their proper signatories in that behalf:

TORONTO HYDRO CORPORATION

By: *"Anthony Haines"*

Name: Anthony Haines

Title: President and Chief Executive Officer

By: *"Jean-Sebastien Couillard"*

Name: Jean-Sebastien Couillard

Title: Executive Vice-President and Chief Financial Officer

BNY TRUST COMPANY OF CANADA

By: *"Ismail Bawa"*

Name: Ismail Bawa

Title: Authorized Signatory

Schedule 1 – FORM OF GLOBAL DEBENTURE-SERIES 11

This Debenture is a Global Debenture within the meaning of the Trust Indenture hereinafter referred to and is registered in the name of a Depository or a nominee thereof. Unless this Certificate is presented by an authorized representative of CDS Clearing and Depository Services Inc. ("CDS") to Toronto Hydro Corporation or its agent for registration of transfer, exchange or payment, and any certificate issued in respect thereof is registered in the name of CDS & CO., or in such other name as is requested by an authorized representative of CDS (and any payment is made to CDS & CO., or to such other entity as is requested by an authorized representative of CDS), ANY TRANSFER, PLEDGE OR OTHER USE HEREOF FOR VALUE OR OTHERWISE BY OR TO ANY PERSON IS WRONGFUL since the registered holder hereof, CDS & CO., has a property interest in the securities represented by this certificate herein and it is a violation of its rights for another person to hold, transfer or deal with this certificate.

No. 11-000

$●

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
●% SENIOR UNSECURED DEBENTURES DUE 2045 (SERIES 11)

ISIN CA89119ZAH60
CUSIP 89119ZAH6

Issue Date	March 16, 2015
Stated Maturity	July 28, 2045
Interest Rate Per Annum	●%
Interest Payment Dates	January 28 and July 28 in each year
Initial Interest Payment Date	July 28, 2015
Principal Amount	$●

TORONTO HYDRO CORPORATION (the "**Corporation**") for value received hereby promises to pay to the registered holder hereof on the Stated Maturity, or on such earlier date as the Principal Amount (or a portion thereof) may become due in accordance with the provisions of the Trust Indenture (as defined below), on presentation and surrender of this ●% Senior Unsecured Debenture due July 28, 2045 (Series 11) (the "**Series 11 Debenture**"), the Principal Amount in lawful money of Canada at the office of the Trustee (as defined below) at 11th Floor, 320 Bay Street, Toronto, Ontario M5H 4A6, and to pay interest on the Principal Amount at the Interest Rate Per Annum from and including the later of the Issue Date and the last Interest Payment Date on which interest has at that time most recently been paid on this Series 11 Debenture, at the address of the registered holder hereof appearing on the register of Series 11 Debentures maintained by or at the direction of the Trustee (the "**Register**"), in like money semi-annually in arrears, in equal instalments on the Interest Payment Dates in each year, and if the Corporation at any time defaults in the payment of any principal or interest, to pay interest on the amount in default at the same rate, in like money, on demand, at the address of the registered holder hereof appearing on the Register. The Corporation will (i) on the day that is

each Interest Payment Date, make payment by a wire transfer, or (ii) on the day that is two Business Days before each Interest Payment Date, forward or cause to be forwarded a cheque by same day delivery, to the address of the registered holder hereof appearing on the Register for interest due and payable to such holder on such Interest Payment Date, less any taxes required by law to be deducted or withheld, made payable to the order of such holder; provided, however that in case of payment of interest at maturity or redemption or as otherwise provided in the Trust Indenture, the time for payment of interest, less any such taxes, may at the option of the Corporation be determined based on the time that the certificate representing this Series 11 Debenture is presented and surrendered to the Trustee. The payment by such wire transfer or forwarding of such cheque (provided such cheque is paid on presentation) will satisfy and discharge the liability for interest upon such Series 11 Debenture to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld as aforesaid).

This Series 11 Debenture is one of an authorized issue of debentures designated as ●% Senior Unsecured Debentures due July 28, 2045 (Series 11) and forming the series of debentures created and issued under a twelfth supplemental trust indenture made as of ●, 2015 (the "**Twelfth Supplemental Trust Indenture**") to a trust indenture (the "**Indenture**") made as of May 7, 2003, between the Corporation and BNY Trust Company of Canada (successor trustee of CIBC Mellon Trust Company) (the "**Trustee**"), as Trustee (the first supplemental trust indenture to the Indenture made as of May 7, 2003 between the Corporation and the Trustee, the second supplemental trust indenture to the Indenture made as of November 14, 2007 between the Corporation and the Trustee, the third supplemental trust indenture to the Indenture made as of November 12, 2009 between the Corporation and the Trustee, the fourth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the fifth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the sixth supplemental trust indenture to the Indenture made as of May 20, 2010 between the Corporation and the Trustee, the seventh supplemental trust indenture to the Indenture made as of September 20, 2011 between the Corporation and the Trustee, the eighth supplemental trust indenture to the Indenture made as of November 18, 2011 between the Corporation and the Trustee, the ninth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the tenth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the eleventh supplemental trust indenture to the Indenture made as of September 16, 2014 between the Corporation and the Trustee, and the Twelfth Supplemental Trust Indenture to the Indenture (as amended, supplemented or restated from time to time) are collectively referred to herein as the "**Trust Indenture**"). The Trust Indenture specifies the terms and conditions upon which the Series 11 Debentures are created and issued or may be created, issued and held and the rights of the registered holders of the Series 11 Debentures, the Corporation and the Trustee, all of which terms and conditions are incorporated by reference in this Series 11 Debenture and to each of which the registered holder of this Series 11 Debenture, by acceptance hereof, agrees.

The aggregate principal amount of Series 11 Debentures that may be created and issued under the Trust Indenture is limited to $500,000,000 in lawful money of Canada Series 11 Debentures are issuable as fully registered debentures in denominations of $1,000 and integral multiples thereof and, subject to the terms and conditions set forth in the Trust Indenture, are issued as book entry only debentures.

The Series 11 Debentures are direct unsecured obligations of the Corporation and will rank equally with each other and with all other debentures of every other series from time to time issued and outstanding pursuant to the Trust Indenture and, except to the extent prescribed by law, with all other unsecured and unsubordinated Indebtedness of the Corporation.

This Series 11 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to January 28, 2045, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to the greater of the Canada Yield Price (as defined in the Trust Indenture) and par, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

This Series 11 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after January 28, 2045, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to 100% of the Principal Amount of the

Series 11 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

At any time when the Corporation is not in default under the Trust Indenture, the Corporation may, subject to the terms and conditions set forth in the Trust Indenture, purchase Series 11 Debentures in the open market, by tender or by private contract, at any price. Series 11 Debentures purchased by the Corporation shall be cancelled and not reissued.

The Principal Amount may become or be declared due before the Stated Maturity on the conditions, in the manner, with the effect and at the times set forth in the Trust Indenture.

The Trust Indenture contains provisions for the holding of meetings of registered holders of debentures issued by the Corporation pursuant to the Trust Indenture and the making of resolutions at such meetings and the creation of instruments in writing signed by the registered holders of a specified majority of debentures issued and outstanding pursuant to the Trust Indenture. Such resolutions and instruments will be binding on and may affect the rights and entitlements of all holders of debentures issued by the Corporation pursuant to the Trust Indenture, subject to the provisions of the Trust Indenture.

This Series 11 Debenture may be transferred only upon compliance with the conditions prescribed in the Trust Indenture relating to the transfer of a Global Debenture (as defined in the Trust Indenture), and upon compliance with such reasonable requirements as the Trustee or other registrar may prescribe, and such transfer shall be duly noted hereon by the Trustee or other registrar.

This Series 11 Debenture shall not become obligatory for any purpose until it shall have been certified by the manual signature of the Trustee in accordance with the Trust Indenture.

IN WITNESS WHEREOF TORONTO HYDRO CORPORATION has caused this Series 11 Debenture to be signed by its ● and its ●.

TORONTO HYDRO CORPORATION

By: _____

Name: ●

Title: ●

By: _____

Name: ●

Title: ●

(FORM OF TRUSTEE'S CERTIFICATE)

This Debenture is one of the Series 11 Debentures referred to in the Trust Indenture referred to above.

BNY TRUST COMPANY OF CANADA
Trustee

By: _____
Authorized Signatory

(FORM OF REGISTRATION PANEL)

(NO WRITING HEREON EXCEPT BY THE TRUSTEE OR OTHER REGISTRAR)

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
●% SENIOR UNSECURED DEBENTURES DUE 2045 (SERIES 11)

ISIN CA89119ZAH60
CUSIP 89119ZAH6

DATE OF REGISTRATION	IN WHOSE NAME REGISTERED	AMOUNT OF DECREASE	AMOUNT OF INCREASE	AMOUNT OF SERIES 11 DEBENTURES OUTSTANDING FOLLOWING CHANGE	SIGNATURE OF TRUSTEE OR OTHER REGISTRAR

Schedule 2 – U.S. FORM OF DEFINITIVE DEBENTURE-SERIES 11

*THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN AND WILL NOT BE REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE "**U.S. SECURITIES ACT**") OR UNDER ANY STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF THE CORPORATION THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE CORPORATION, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT, OR (C) INSIDE THE UNITED STATES IN ACCORDANCE WITH (1) RULE 144A UNDER THE U.S. SECURITIES ACT OR (2) RULE 144 UNDER THE U.S. SECURITIES ACT, IF AVAILABLE, OR (3) IN COMPLIANCE WITH CERTAIN OTHER PROCEDURES SATISFACTORY TO THE CORPORATION. A NEW CERTIFICATE, BEARING NO LEGEND, DELIVERY OF WHICH WILL CONSTITUTE "GOOD DELIVERY", MAY BE OBTAINED FROM BNY TRUST COMPANY OF CANADA UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO BNY TRUST COMPANY OF CANADA AND THE CORPORATION, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT.*

No. 11-000

$●

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
●% SENIOR UNSECURED DEBENTURES DUE 2045 (SERIES 11)

Issue Date	March 16, 2015
Stated Maturity	July 28, 2045
Interest Rate Per Annum	●%
Interest Payment Dates	January 28 and July 28 in each year
Initial Interest Payment Date	July 28, 2015
Principal Amount	$●

TORONTO HYDRO CORPORATION (the "**Corporation**") for value received hereby promises to pay to the registered holder hereof on the Stated Maturity, or on such earlier date as the Principal Amount (or a portion thereof) may become due in accordance with the provisions of the Trust Indenture (as defined below), on presentation and surrender of this ●% Senior Unsecured Debenture due July 28, 2045 (Series 11) (the "**Series 11 Debenture**"), the Principal Amount in lawful money of Canada at the office of the Trustee (as defined below) at 11th Floor, 320 Bay Street, Toronto, Ontario M5H 4A6, and to pay interest on the Principal Amount at the Interest Rate Per Annum from and including the later of the Issue Date and the last Interest Payment Date on which interest has at that time most recently been paid on this Series 11 Debenture, at the address of the registered holder hereof appearing on the register of Series 11 Debentures maintained by or at the direction of the Trustee (the "**Register**"), in like money semi-annually in arrears, in equal instalments on the Interest Payment Dates in each year, and if the Corporation at any time defaults in the payment of any principal or interest, to pay interest on the amount in default at the same rate, in like money, on demand, at the address of the registered holder hereof appearing on the Register. The Corporation, on the day that is two

Business Days before each Interest Payment Date, will forward or cause to be forwarded by same day delivery to the address of the registered holder hereof appearing on the Register a cheque for interest due and payable to such holder on such Interest Payment Date, less any taxes required by law to be deducted or withheld, made payable to the order of such holder; provided, however that in case of payment of interest at maturity or redemption or as otherwise provided in the Trust Indenture, the time for payment of interest, less any such taxes, may at the option of the Corporation be determined based on the time that the certificate representing this Series 11 Debenture is presented and surrendered to the Trustee. The forwarding of such cheque will satisfy and discharge the liability for interest upon such Series 11 Debenture to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld as aforesaid) unless such cheque is not paid on presentation.

This Series 11 Debenture is one of an authorized issue of debentures designated as ●% Senior Unsecured Debentures due July 28, 2045 (Series 11) and forming the series of debentures created and issued under a twelfth supplemental trust indenture made as of ●, 2015 (the "**Twelfth Supplemental Trust Indenture**") to a trust indenture (the "**Indenture**") made as of May 7, 2003, between the Corporation and BNY Trust Company of Canada (successor trustee of CIBC Mellon Trust Company) (the "**Trustee**"), as Trustee (the first supplemental trust indenture to the Indenture made as of May 7, 2003 between the Corporation and the Trustee, the second supplemental trust indenture to the Indenture made as of November 14, 2007 between the Corporation and the Trustee, the third supplemental trust indenture to the Indenture made as of November 12, 2009 between the Corporation and the Trustee, the fourth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the fifth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the sixth supplemental trust indenture to the Indenture made as of May 20, 2010 between the Corporation and the Trustee, the seventh supplemental trust indenture to the Indenture made as of September 20, 2011 between the Corporation and the Trustee, the eighth supplemental trust indenture to the Indenture made as of November 18, 2011 between the Corporation and the Trustee, the ninth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the tenth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the eleventh supplemental trust indenture to the Indenture made as of September 16, 2014 between the Corporation and the Trustee, and the Twelfth Supplemental Trust Indenture to the Indenture (as amended, supplemented or restated from time to time) are collectively referred to herein as the "**Trust Indenture**"). The Trust Indenture specifies the terms and conditions upon which the Series 11 Debentures are created and issued or may be created, issued and held and the rights of the registered holders of the Series 11 Debentures, the Corporation and the Trustee, all of which terms and conditions are incorporated by reference in this Series 11 Debenture and to each of which the registered holder of this Series 11 Debenture, by acceptance hereof, agrees.

The aggregate principal amount of Series 11 Debentures that may be created and issued under the Trust Indenture is limited to $500,000,000 in lawful money of Canada. Series 11 Debentures are issuable as fully registered debentures in denominations of $1,000 and integral multiples thereof.

The Series 11 Debentures are direct unsecured obligations of the Corporation and will rank equally with each other and with all other debentures of every other series from time to time issued and outstanding pursuant to the Trust Indenture and, except to the extent prescribed by law, with all other unsecured and unsubordinated Indebtedness of the Corporation.

This Series 11 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to January 28, 2045, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to the greater of the Canada Yield Price (as defined in the Trust Indenture) and par, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

This Series 11 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after January 28, 2045, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to 100% of the Principal Amount of the Series 11 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

At any time when the Corporation is not in default under the Trust Indenture, the Corporation may, subject to the terms and conditions set forth in the Trust Indenture, purchase Series 11 Debentures in the open market, by tender or by private contract, at any price. Series 11 Debentures purchased by the Corporation shall be cancelled and not reissued.

The Principal Amount may become or be declared due before the Stated Maturity on the conditions, in the manner, with the effect and at the times set forth in the Trust Indenture.

The Trust Indenture contains provisions for the holding of meetings of registered holders of debentures issued by the Corporation pursuant to the Trust Indenture and the making of resolutions at such meetings and the creation of instruments in writing signed by the registered holders of a specified majority of debentures issued and outstanding pursuant to the Trust Indenture. Such resolutions and instruments will be binding on and may affect the rights and entitlements of all holders of debentures issued by the Corporation pursuant to the Trust Indenture, subject to the provisions of the Trust Indenture.

This Series 11 Debenture may be transferred only upon compliance with the conditions prescribed in the Trust Indenture by the registered holder hereof or the holder's legal representative or attorney duly appointed by an instrument in form and execution satisfactory to the Trustee, and upon compliance with such reasonable requirements as the Trustee or other registrar may prescribe, and such transfer shall be duly noted hereon by the Trustee or other registrar.

This Series 11 Debenture shall not become obligatory for any purpose until it shall have been certified by the manual signature of the Trustee in accordance with the Trust Indenture.

IN WITNESS WHEREOF TORONTO HYDRO CORPORATION has caused this Series 11 Debenture to be signed by its ● and its ●.

TORONTO HYDRO CORPORATION

By: _____

Name: ●

Title: ●

By: _____

Name: ●

Title: ●

(FORM OF TRUSTEE'S CERTIFICATE)

This Debenture is one of the Series 11 Debentures referred to in the Trust Indenture referred to above.

BNY TRUST COMPANY OF CANADA
Trustee

By: _____
Authorized Signatory

(FORM OF REGISTRATION PANEL)

(NO WRITING HEREON EXCEPT BY THE TRUSTEE OR OTHER REGISTRAR)

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
●% SENIOR UNSECURED DEBENTURES DUE 2045 (SERIES 11)

DATE OF REGISTRATION	IN WHOSE NAME REGISTERED	SIGNATURE OF TRUSTEE OR OTHER REGISTRAR

THIRTEENTH SUPPLEMENTAL TRUST INDENTURE

Made as of June 14, 2016

Between

TORONTO HYDRO CORPORATION
as issuer

and

BNY TRUST COMPANY OF CANADA
as trustee

Supplementing the Trust Indenture

made as of May 7, 2003

and

providing for the issue of

2.52% Senior Unsecured Debentures
due 2026 (Series 12)

TABLE OF CONTENTS

RECITALS 1

Section 1 INTERPRETATION 2

1.1 To Be Read With Trust Indenture 2

1.2 Headings etc 2

1.3 Definitions 3

Section 2 SERIES 12 DEBENTURES 3

2.1 Creation and Designation 3

2.2 Limitation on Issue 4

2.3 Date of Issue and Maturity 4

2.4 Concerning Interest 4

2.5 Interest Payments 4

2.6 Payment of Amounts Due on Maturity 4

2.7 Redemption and Purchase of Series 12 Debentures 4

2.8 Form of Series 12 Debentures 5

2.9 Signatures on Series 12 Debentures 6

2.10 Certification 6

2.11 Location of Register 6

2.12 Additional Amounts 6

Section 3 MISCELLANEOUS 7

3.1 Acceptance of Trust 7

3.2 Confirmation of Trust Indenture 7

3.3 Counterparts 7

Schedule 1 – FORM OF GLOBAL DEBENTURE-SERIES 12

Schedule 2 –U.S. FORM OF DEFINITIVE DEBENTURE-SERIES 12

THIRTEENTH SUPPLEMENTAL TRUST INDENTURE

THIS THIRTEENTH SUPPLEMENTAL TRUST INDENTURE made as of June 14, 2016,

BETWEEN:

TORONTO HYDRO CORPORATION
a corporation incorporated under the laws of Ontario (the "**Corporation**")

and

BNY TRUST COMPANY OF CANADA
a trust company existing under the laws of Canada (the "**Trustee**")

RECITALS

(A) BNY Trust Company of Canada is the successor trustee of CIBC Mellon Trust Company;

(B) The Corporation has entered into a trust indenture with the Trustee made as of May 7, 2003, as amended, supplemented or restated from time to time (the "**Trust Indenture**") which provides for the issuance of one or more series of unsecured Debentures of the Corporation by way of Supplemental Indentures;

(C) The Corporation entered into a first supplemental trust indenture made as of May 7, 2003 for the purpose of providing for the issue of $225,000,000 aggregate principal amount of Series 1 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 1 Debentures;

(D) The Corporation entered into a second supplemental trust indenture made as of November 14, 2007 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 2 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 2 Debentures;

(E) The Corporation entered into a third supplemental trust indenture made as of November 12, 2009 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 3 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 3 Debentures;

(F) The City Note has been converted, in accordance with its terms, into the Series 4 Debentures and the Series 5 Debentures;

(G) The Corporation entered into a fourth supplemental trust indenture made as of April 1, 2010 for the purpose of providing for the issue of $245,057,000 aggregate principal amount of Series 4 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 4 Debentures;

(H) The Corporation entered into a fifth supplemental trust indenture made as of April 1, 2010 for the purpose of providing for the issue of $245,057,000 aggregate principal amount of Series 5 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 5 Debentures;

(I) The Corporation entered into a sixth supplemental trust indenture made as of May 20, 2010 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 6 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 6 Debentures;

(J) The Corporation entered into a seventh supplemental trust indenture made as of September 20, 2011 for the purpose of amending the definition of "GAAP" under the Trust Indenture;

(K) The Corporation entered into an eighth supplemental trust indenture made as of November 18, 2011 for the purpose of providing for the issue of $300,000,000 aggregate principal amount of Series 7 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 7 Debentures;

(L) The Corporation entered into a ninth supplemental trust indenture made as of April 9, 2013 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 8 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 8 Debentures;

(M) The Corporation entered into a tenth supplemental trust indenture made as of April 9, 2013 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 9 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 9 Debentures;

(N) The Corporation entered into an eleventh supplemental trust indenture made as of September 16, 2014 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 10 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 10 Debentures;

(O) The Corporation entered into a twelfth supplemental trust indenture made as of March 16, 2015 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 11 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 11 Debentures;

(P) The Corporation entered into an amended and restated tenth supplemental trust indenture made as of September 2, 2015 for the purpose of making changes and corrections which were required for curing and correcting certain ambiguities and omissions in connection with an issue of $45,000,000 additional aggregate principal amount of Series 9 Debentures; and

(Q) This Thirteenth Supplemental Trust Indenture is entered into for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 12 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 12 Debentures.

NOW THEREFORE THIS THIRTEENTH SUPPLEMENTAL TRUST INDENTURE WITNESSES and it is hereby covenanted, agreed and declared as follows:

Section 1 INTERPRETATION

1.1 To Be Read With Trust Indenture

This Thirteenth Supplemental Trust Indenture is a Supplemental Indenture as that term is used in the Trust Indenture. The Trust Indenture and this Thirteenth Supplemental Trust Indenture shall be read together and shall have effect as though all the provisions of both indentures were contained in one instrument.

1.2 Headings etc.

The division of this Thirteenth Supplemental Trust Indenture into Sections and clauses, the provision of a table of contents and the insertion of headings are for convenience of reference only and shall not affect the interpretation thereof. Unless the context otherwise requires, the expression "Section" and "Schedule" followed by a number, letter or combination of numbers and letters refer to the specified Section of or Schedule to this Thirteenth Supplemental Trust Indenture.

1.3 Definitions

All terms which are defined in the Trust Indenture and used but not defined in this Thirteenth Supplemental Trust Indenture shall have the meanings ascribed to them in the Trust Indenture, as such meanings may be amended or supplemented with respect to Series 12 Debentures by this Thirteenth Supplemental Trust Indenture. In the event of any inconsistency between the meaning given to a term in the Trust Indenture and the meaning given to the same term in this Thirteenth Supplemental Trust Indenture, the meaning given to the term in this Thirteenth Supplemental Trust Indenture shall prevail to the extent of the inconsistency. Subject to the foregoing, in this Thirteenth Supplemental Trust Indenture and in the Series 12 Debentures, the following terms have the following meanings:

(a) ***Canada Yield*** on any date means the yield to maturity on that date, compounded semi-annually, that a non-callable Government of Canada bond would carry if issued, in Canadian dollars in Canada, at 100% of its principal amount on that date with a term to maturity approximately equal to the remaining term to May 25, 2026 of the Series 12 Debentures, such yield to maturity being the average of the yields provided by two major Canadian investment dealers specified by the Corporation.

(b) ***Canada Yield Price*** means the amount equal to the net present value of all scheduled payments of interest (other than accrued and unpaid interest) and principal on the Series 12 Debentures that would have been payable to May 25, 2026 if redemption had not been made, using a discount rate equal to the sum of the Canada Yield and 33 basis points, calculated at 10:00 a.m. (Toronto, Ontario time) three Business Days prior to the Redemption Date of the Series 12 Debentures.

(c) ***Series 12 Debentures*** means the 2.52% Senior Unsecured Debentures due 2026 (Series 12) referred to in Section 2.1.

(d) ***Series 12 Debentures Debt Account*** means the deposit account established in respect of the Series 12 Debentures pursuant to Section 8.2 of the Trust Indenture that is designated in writing by the Corporation to the Trustee as the "Series 12 Debentures Debt Account".

(e) ***Series 12 Debentures Interest Payment Date*** means February 25 and August 25 in each year that the Series 12 Debentures are outstanding.

(f) ***Series 12 Debentures Interest Period*** means the period commencing on and including the later of the date of issue of the Series 12 Debentures and the immediately preceding Series 12 Debentures Interest Payment Date and ending on and including the day immediately preceding the next Series 12 Debentures Interest Payment Date to occur in respect of which interest is payable.

(g) ***Trust Indenture*** means the trust indenture made as of May 7, 2003 between the Corporation and the Trustee, as amended, supplemented or restated from time to time.

Section 2 SERIES 12 DEBENTURES

2.1 Creation and Designation

The Corporation is authorized in accordance with the Trust Indenture to issue under this Thirteenth Supplemental Trust Indenture, and hereby creates and issues, a series of debentures designated "2.52% Senior Unsecured Debentures due 2026 (Series 12)", having the terms set out in this Thirteenth Supplemental Trust Indenture.

2.2 Limitation on Issue

The aggregate principal amount of Series 12 Debentures which may be issued under this Thirteenth Supplemental Trust Indenture including any supplement hereto will be limited to $500,000,000.

2.3 Date of Issue and Maturity

The Series 12 Debentures shall be dated June 14, 2016 (being the applicable date of issue) and will become due and payable, together with all accrued interest and unpaid interest thereon, on August 25, 2026 (being the applicable Stated Maturity).

2.4 Concerning Interest

(a) The Series 12 Debentures shall be issued in $1,000 principal amount denominations or integral multiples thereof and shall bear interest on the unpaid principal amount thereof at a rate of 2.52% per annum from and including their date of issue, payable semi-annually in arrears, in equal instalments, on each Series 12 Debentures Interest Payment Date.

(b) Interest shall be payable in respect of each Series 12 Debentures Interest Period (after as well as before maturity, default and judgment, with interest on overdue interest at the same rate) on each Series 12 Debentures Interest Payment Date in accordance with Section 2.8 of the Trust Indenture.

2.5 Interest Payments

The Corporation shall make payments of interest on the Series 12 Debentures in accordance with the provisions of Section 2.8 of the Trust Indenture.

2.6 Payment of Amounts Due on Maturity

In accordance with Section 8.2 of the Trust Indenture, the Corporation will deposit to the Series 12 Debentures Debt Account all amounts required to be paid to the order of Holders of Series 12 Debentures on maturity, prior to 9:00 a.m. (Toronto, Ontario time), on the Stated Maturity of the Series 12 Debentures. The deposit of such funds will satisfy and discharge the liability of the Corporation for principal of, and any accrued and unpaid interest on, the Series 12 Debentures to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld).

2.7 Redemption and Purchase of Series 12 Debentures

(a) The Series 12 Debentures may be redeemed, at the Corporation's option when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to May 25, 2026, on not more than 60 Business Days and not less than 15 Business Days prior notice, at a price equal to the greater of the Canada Yield Price and par, together in each case with accrued and unpaid interest to (but excluding) the Redemption Date and in each case otherwise in accordance with Sections 5.1, 5.2, 5.3 and 5.4 of the Trust Indenture.

(b) The Series 12 Debentures may be redeemed, at the Corporation's option when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after May 25, 2026, on not more than 60 Business Days and not less than 15 Business Days prior notice, at a price equal to 100% of the principal amount of the Series 12 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the Redemption Date and otherwise in accordance with Sections 5.1, 5.2, 5.3 and 5.4 of the Trust Indenture.

(c) The Corporation will be entitled at any time when not in default under the Trust Indenture to purchase for cancellation all or any of the Series 12 Debentures in accordance with Section 5.5 of the Trust Indenture.

(d) The Series 12 Debentures will not be subject to repurchase pursuant to any sinking fund provisions.

2.8 Form of Series 12 Debentures

(a) Except as set out in 2.8(b) below, the Series 12 Debentures and the registration panel and the certificate of the Trustee endorsed thereon shall be issuable initially as one Global Debenture to be held by, or on behalf of, CDS as depository for its participants and registered in the name of CDS or its nominee. The Global Debenture shall be substantially in the form set out in Schedule 1 hereto with such appropriate additions, deletions, substitutions and variations as the Directors shall by resolution determine prior to the time of issue thereof and as the Trustee may approve and with such distinguishing letters and numbers as the Trustee may approve, with such approval in each case to be conclusively evidenced by the Trustee's certification of such Global Debenture.

(b) The Trustee understands and acknowledges that the Series 12 Debentures have not been and will not be registered under the United States Securities Act of 1933, as amended (the "U.S. Securities Act"). Each Series 12 Debenture originally issued in the United States or to a U.S. Person will be represented by a definitive certificate in the form set out in Schedule 2 hereto which definitive certificate, and each Series 12 Debenture certificate issued in exchange therefor or in substitution thereof, shall bear the following legend:

"THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN AND WILL NOT BE REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE **"U.S. SECURITIES ACT**") OR UNDER ANY STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF THE CORPORATION THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE CORPORATION, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT, OR (C) INSIDE THE UNITED STATES IN ACCORDANCE WITH (1) RULE 144A UNDER THE U.S. SECURITIES ACT OR (2) RULE 144 UNDER THE U.S. SECURITIES ACT, IF AVAILABLE, OR (3) IN COMPLIANCE WITH CERTAIN OTHER PROCEDURES SATISFACTORY TO THE CORPORATION. A NEW CERTIFICATE, BEARING NO LEGEND, DELIVERY OF WHICH WILL CONSTITUTE "GOOD DELIVERY", MAY BE OBTAINED FROM BNY TRUST COMPANY OF CANADA UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO BNY TRUST COMPANY OF CANADA AND THE CORPORATION, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT."

If any Series 12 Debentures are being sold or transferred outside the United States in compliance with the requirements of Rule 904 of Regulation S under the U.S Securities Act, the legend may be removed by providing a declaration to the Trustee to the following effect (or as the Corporation may prescribe from time to time),

"The undersigned (A) acknowledges that the sale of the _____ Debentures, represented by certificate numbers _____ to which this declaration relates is being made in reliance on Rule 904 of Regulation S under the United States Securities Act of 1933, as amended (the "**U.S. Securities Ac**t") and (B) certifies that (1) it is not an "affiliate" (as defined in Rule 405 under the U.S. Securities Act) of Toronto Hydro Corporation, (2) the offer of such Debentures was not made to a person in the United

States and at the time the buy order was originated, the buyer was outside the United States, or the seller and any person acting on its behalf reasonably believe that the buyer was outside the United States and (3) neither the seller, nor any affiliate of the seller, nor any person acting on its or their behalf engaged in any directed selling efforts in connection with the offer and sale of such Debentures. Terms used herein have the meanings given to them by Regulation S under the U.S. Securities Act."

If any Series 12 Debentures are being sold or transferred pursuant to Rule 144 of the U.S. Securities Act, the legend may be removed by delivery to the Trustee of a written opinion of Trustee Counsel (or counsel to the transferor satisfactory to the Trustee) to the effect that such legend is no longer required under applicable requirements of the U.S. Securities Act or state securities laws.

Prior to the issuance of Series 12 Debentures, the Corporation shall notify the Trustee, in writing, concerning which Series 12 Debentures are to be certificated and are to bear the legend described above. The Trustee will thereafter maintain a list of all registered holders from time to time of legended Series 12 Debentures.

2.9 Signatures on Series 12 Debentures

The Series 12 Debentures shall be signed in accordance with the provisions of Section 2.6 of the Trust Indenture.

2.10 Certification

(a) No Series 12 Debenture issued shall be obligatory or shall entitle the Holder of such Series 12 Debenture to the benefits of this Thirteenth Supplemental Trust Indenture until it has been certified by manual signature by or on behalf of the Trustee by execution of the certificate of the Trustee appended thereto substantially in the form set out in Schedule 1 hereto, or in some other form approved by the Trustee, whose approval shall be conclusively evidenced by the Trustee's execution of the certificate. Such certificate on any Series 12 Debenture shall be conclusive evidence that such Series 12 Debenture is duly issued and is a valid and binding obligation of the Corporation and that the Holder of such Series 12 Debenture is entitled to the benefits of the Trust Indenture, as supplemented by this Thirteenth Supplemental Trust Indenture, and such Series 12 Debenture.

(b) The certificate of the Trustee on any Series 12 Debenture shall not be construed as a representation or warranty by the Trustee as to the validity of this Thirteenth Supplemental Trust Indenture or of the Series 12 Debentures (except the due certification thereof and any other warranties implied by law) and the Trustee shall in no respect be liable or answerable for the use made of the Series 12 Debentures or any of them or the proceeds thereof.

2.11 Location of Register

With respect to the Series 12 Debentures, initially the Register referred to in Section 3.1 of the Trust Indenture shall be kept by the Trustee at the Corporate Trust Office and may thereafter be kept by the Trustee in such other place as the Corporation, with the approval of the Trustee, may designate.

2.12 Additional Amounts

The Corporation will not be required to pay an additional amount on the Series 12 Debentures in respect of any tax, assessment or government charge that is required by law to be withheld or deducted by it.

2.13 Trustees, etc.

The Trustee will be the Paying Agent and the Registrar for the Series 12 Debentures.

Section 3 MISCELLANEOUS

3.1 Acceptance of Trust

The Trustee accepts the trusts in this Thirteenth Supplemental Trust Indenture and agrees to carry out and discharge the same upon the terms and conditions set out in this Thirteenth Supplemental Trust Indenture and in accordance with the Trust Indenture.

3.2 Confirmation of Trust Indenture

The Trust Indenture as amended and supplemented by this Thirteenth Supplemental Trust Indenture is in all respects confirmed.

3.3 Counterparts

This Thirteenth Supplemental Trust Indenture may be executed in counterparts, each of which so executed shall be deemed to be original and such counterparts together shall constitute one and the same instrument.

[SIGNATURE PAGE FOLLOWS]

IN WITNESS WHEREOF the parties hereto have executed this Thirteenth Supplemental Trust Indenture under the hands of their proper signatories in that behalf:

TORONTO HYDRO CORPORATION

By: _____

Name: Anthony Haines

Title: President and Chief Executive Officer

By: _____

Name: Laura Foster

Title: Interim, Chief Financial Officer

BNY TRUST COMPANY OF CANADA

By: _____

Name: Ismail Bawa

Title: Authorized Signatory

Schedule 1 – FORM OF GLOBAL DEBENTURE-SERIES 12

This Debenture is a Global Debenture within the meaning of the Trust Indenture hereinafter referred to and is registered in the name of a Depository or a nominee thereof. Unless this Certificate is presented by an authorized representative of CDS Clearing and Depository Services Inc. ("CDS") to Toronto Hydro Corporation or its agent for registration of transfer, exchange or payment, and any certificate issued in respect thereof is registered in the name of CDS & CO., or in such other name as is requested by an authorized representative of CDS (and any payment is made to CDS & CO., or to such other entity as is requested by an authorized representative of CDS), ANY TRANSFER, PLEDGE OR OTHER USE HEREOF FOR VALUE OR OTHERWISE BY OR TO ANY PERSON IS WRONGFUL since the registered holder hereof, CDS & CO., has a property interest in the securities represented by this certificate herein and it is a violation of its rights for another person to hold, transfer or deal with this certificate.

No. 12-000

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TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
2.52**% SENIOR UNSECURED DEBENTURES DUE 2026 (SERIES 12)**

ISIN CA 89119ZAJ27
CUSIP 89119ZAJ2

Issue Date	June 14, 2016
Stated Maturity	August 25, 2026
Interest Rate Per Annum	2.52%
Interest Payment Dates	February 25 and August 25 in each year
Initial Interest Payment Date	August 25, 2016
Principal Amount	$●

TORONTO HYDRO CORPORATION (the "**Corporation**") for value received hereby promises to pay to the registered holder hereof on the Stated Maturity, or on such earlier date as the Principal Amount (or a portion thereof) may become due in accordance with the provisions of the Trust Indenture (as defined below), on presentation and surrender of this 2.52% Senior Unsecured Debenture due August 25, 2026 (Series 12) (the "**Series 12 Debenture**"), the Principal Amount in lawful money of Canada at the office of the Trustee (as defined below) at 11th Floor, 320 Bay Street, Toronto, Ontario M5H 4A6, and to pay interest on the Principal Amount at the Interest Rate Per Annum from and including the later of the Issue Date and the last Interest Payment Date on which interest has at that time most recently been paid on this Series 12 Debenture, at the address of the registered holder hereof appearing on the register of Series 12 Debentures maintained by or at the direction of the Trustee (the "**Register**"), in like money semi-annually in arrears, in equal instalments on the Interest Payment Dates in each year, and if the Corporation at any time defaults in the payment of any principal or interest, to pay interest on the amount in default at the same rate, in like money, on demand, at the address of the registered holder hereof appearing on the Register. The Corporation will (i) on the day that is

each Interest Payment Date, make payment by a wire transfer, or (ii) on the day that is two Business Days before each Interest Payment Date, forward or cause to be forwarded a cheque by same day delivery, to the address of the registered holder hereof appearing on the Register for interest due and payable to such holder on such Interest Payment Date, less any taxes required by law to be deducted or withheld, made payable to the order of such holder; provided, however that in case of payment of interest at maturity or redemption or as otherwise provided in the Trust Indenture, the time for payment of interest, less any such taxes, may at the option of the Corporation be determined based on the time that the certificate representing this Series 12 Debenture is presented and surrendered to the Trustee. The payment by such wire transfer or forwarding of such cheque (provided such cheque is paid on presentation) will satisfy and discharge the liability for interest upon such Series 12 Debenture to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld as aforesaid).

This Series 12 Debenture is one of an authorized issue of debentures designated as 2.52% Senior Unsecured Debentures due August 25, 2026 (Series 12) and forming the series of debentures created and issued under a thirteenth supplemental trust indenture made as of June 14, 2016 (the "**Thirteenth Supplemental Trust Indenture**") to a trust indenture (the "**Indenture**") made as of May 7, 2003, between the Corporation and BNY Trust Company of Canada (successor trustee of CIBC Mellon Trust Company) (the "**Trustee**"), as Trustee (the first supplemental trust indenture to the Indenture made as of May 7, 2003 between the Corporation and the Trustee, the second supplemental trust indenture to the Indenture made as of November 14, 2007 between the Corporation and the Trustee, the third supplemental trust indenture to the Indenture made as of November 12, 2009 between the Corporation and the Trustee, the fourth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the fifth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the sixth supplemental trust indenture to the Indenture made as of May 20, 2010 between the Corporation and the Trustee, the seventh supplemental trust indenture to the Indenture made as of September 20, 2011 between the Corporation and the Trustee, the eighth supplemental trust indenture to the Indenture made as of November 18, 2011 between the Corporation and the Trustee, the ninth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the tenth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the amended and restated tenth supplemental trust indenture to the Indenture made as of September 2, 2015 between the Corporation and the Trustee, the eleventh supplemental trust indenture to the Indenture made as of September 16, 2014 between the Corporation and the Trustee, the twelfth supplemental trust indenture to the Indenture made as of March 16, 2015 between the Corporation and the Trustee, and the Thirteenth Supplemental Trust Indenture to the Indenture (as amended, supplemented or restated from time to time) are collectively referred to herein as the "**Trust Indenture**"). The Trust Indenture specifies the terms and conditions upon which the Series 12 Debentures are created and issued or may be created, issued and held and the rights of the registered holders of the Series 12 Debentures, the Corporation and the Trustee, all of which terms and conditions are incorporated by reference in this Series 12 Debenture and to each of which the registered holder of this Series 12 Debenture, by acceptance hereof, agrees.

The aggregate principal amount of Series 12 Debentures that may be created and issued under the Trust Indenture is limited to $500,000,000 in lawful money of Canada Series 12 Debentures are issuable as fully registered debentures in denominations of $1,000 and integral multiples thereof and, subject to the terms and conditions set forth in the Trust Indenture, are issued as book entry only debentures.

The Series 12 Debentures are direct unsecured obligations of the Corporation and will rank equally with each other and with all other debentures of every other series from time to time issued and outstanding pursuant to the Trust Indenture and, except to the extent prescribed by law, with all other unsecured and unsubordinated Indebtedness of the Corporation.

This Series 12 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to May 25, 2026, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to the greater of the Canada Yield Price (as defined in the Trust Indenture) and par, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

This Series 12 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after May 25, 2026, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to 100% of the Principal Amount of the Series 12 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

At any time when the Corporation is not in default under the Trust Indenture, the Corporation may, subject to the terms and conditions set forth in the Trust Indenture, purchase Series 12 Debentures in the open market, by tender or by private contract, at any price. Series 12 Debentures purchased by the Corporation shall be cancelled and not reissued.

The Principal Amount may become or be declared due before the Stated Maturity on the conditions, in the manner, with the effect and at the times set forth in the Trust Indenture.

The Trust Indenture contains provisions for the holding of meetings of registered holders of debentures issued by the Corporation pursuant to the Trust Indenture and the making of resolutions at such meetings and the creation of instruments in writing signed by the registered holders of a specified majority of debentures issued and outstanding pursuant to the Trust Indenture. Such resolutions and instruments will be binding on and may affect the rights and entitlements of all holders of debentures issued by the Corporation pursuant to the Trust Indenture, subject to the provisions of the Trust Indenture.

This Series 12 Debenture may be transferred only upon compliance with the conditions prescribed in the Trust Indenture relating to the transfer of a Global Debenture (as defined in the Trust Indenture), and upon compliance with such reasonable requirements as the Trustee or other registrar may prescribe, and such transfer shall be duly noted hereon by the Trustee or other registrar.

This Series 12 Debenture shall not become obligatory for any purpose until it shall have been certified by the manual signature of the Trustee in accordance with the Trust Indenture.

IN WITNESS WHEREOF TORONTO HYDRO CORPORATION has caused this Series 12 Debenture to be signed by its ● and its ●.

TORONTO HYDRO CORPORATION

By: _____

Name: ●

Title: ●

By: _____

Name: ●

Title: ●

(FORM OF TRUSTEE'S CERTIFICATE)

This Debenture is one of the Series 12 Debentures referred to in the Trust Indenture referred to above.

BNY TRUST COMPANY OF CANADA
Trustee

By: _____
Authorized Signatory

(FORM OF REGISTRATION PANEL)

(NO WRITING HEREON EXCEPT BY THE TRUSTEE OR OTHER REGISTRAR)

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
2.52**% SENIOR UNSECURED DEBENTURES DUE 2026 (SERIES 12)**

ISIN CA 89119ZAJ27
CUSIP 89119ZAJ2

DATE OF REGISTRATION	IN WHOSE NAME REGISTERED	AMOUNT OF DECREASE	AMOUNT OF INCREASE	AMOUNT OF SERIES 12 DEBENTURES OUTSTANDING FOLLOWING CHANGE	SIGNATURE OF TRUSTEE OR OTHER REGISTRAR

Schedule 2 – U.S. FORM OF DEFINITIVE DEBENTURE-SERIES 12

*THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN AND WILL NOT BE REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE "**U.S. SECURITIES ACT**") OR UNDER ANY STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF THE CORPORATION THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE CORPORATION, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT, OR (C) INSIDE THE UNITED STATES IN ACCORDANCE WITH (1) RULE 144A UNDER THE U.S. SECURITIES ACT OR (2) RULE 144 UNDER THE U.S. SECURITIES ACT, IF AVAILABLE, OR (3) IN COMPLIANCE WITH CERTAIN OTHER PROCEDURES SATISFACTORY TO THE CORPORATION. A NEW CERTIFICATE, BEARING NO LEGEND, DELIVERY OF WHICH WILL CONSTITUTE "GOOD DELIVERY", MAY BE OBTAINED FROM BNY TRUST COMPANY OF CANADA UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO BNY TRUST COMPANY OF CANADA AND THE CORPORATION, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT.*

No. 12-000

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TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
2.52**% SENIOR UNSECURED DEBENTURES DUE 2026 (SERIES 12)**

Issue Date	June 14, 2016
Stated Maturity	August 25, 2026
Interest Rate Per Annum	2.52%
Interest Payment Dates	February 25 and August 25 in each year
Initial Interest Payment Date	August 25, 2016
Principal Amount	$●

TORONTO HYDRO CORPORATION (the "**Corporation**") for value received hereby promises to pay to the registered holder hereof on the Stated Maturity, or on such earlier date as the Principal Amount (or a portion thereof) may become due in accordance with the provisions of the Trust Indenture (as defined below), on presentation and surrender of this 2.52% Senior Unsecured Debenture due August 25, 2026 (Series 12) (the "**Series 12 Debenture**"), the Principal Amount in lawful money of Canada at the office of the Trustee (as defined below) at 11th Floor, 320 Bay Street, Toronto, Ontario M5H 4A6, and to pay interest on the Principal Amount at the Interest Rate Per Annum from and including the later of the Issue Date and the last Interest Payment Date on which interest has at that time most recently been paid on this Series 12 Debenture, at the address of the registered holder hereof appearing on the register of Series 12 Debentures maintained by or at the direction of the Trustee (the "**Register**"), in like money semi-annually in arrears, in equal instalments on the Interest Payment Dates in each year, and if the Corporation at any time defaults in the payment of any principal or interest, to pay interest on the amount in default at the same rate, in like money, on demand, at the address of the registered holder hereof appearing on the Register. The Corporation, on the day that is two

Business Days before each Interest Payment Date, will forward or cause to be forwarded by same day delivery to the address of the registered holder hereof appearing on the Register a cheque for interest due and payable to such holder on such Interest Payment Date, less any taxes required by law to be deducted or withheld, made payable to the order of such holder; provided, however that in case of payment of interest at maturity or redemption or as otherwise provided in the Trust Indenture, the time for payment of interest, less any such taxes, may at the option of the Corporation be determined based on the time that the certificate representing this Series 12 Debenture is presented and surrendered to the Trustee. The forwarding of such cheque will satisfy and discharge the liability for interest upon such Series 12 Debenture to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld as aforesaid) unless such cheque is not paid on presentation.

This Series 12 Debenture is one of an authorized issue of debentures designated as 2.52% Senior Unsecured Debentures due August 25, 2026 (Series 12) and forming the series of debentures created and issued under a thirteenth supplemental trust indenture made as of June 14, 2016 (the "**Thirteenth Supplemental Trust Indenture**") to a trust indenture (the "**Indenture**") made as of May 7, 2003, between the Corporation and BNY Trust Company of Canada (successor trustee of CIBC Mellon Trust Company) (the "**Trustee**"), as Trustee (the first supplemental trust indenture to the Indenture made as of May 7, 2003 between the Corporation and the Trustee, the second supplemental trust indenture to the Indenture made as of November 14, 2007 between the Corporation and the Trustee, the third supplemental trust indenture to the Indenture made as of November 12, 2009 between the Corporation and the Trustee, the fourth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the fifth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the sixth supplemental trust indenture to the Indenture made as of May 20, 2010 between the Corporation and the Trustee, the seventh supplemental trust indenture to the Indenture made as of September 20, 2011 between the Corporation and the Trustee, the eighth supplemental trust indenture to the Indenture made as of November 18, 2011 between the Corporation and the Trustee, the ninth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the tenth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the amended and restated tenth supplemental trust indenture to the Indenture made as of September 2, 2015 between the Corporation and the Trustee, the eleventh supplemental trust indenture to the Indenture made as of September 16, 2014 between the Corporation and the Trustee, the twelfth supplemental trust indenture to the Indenture made as of March 16, 2015 between the Corporation and the Trustee, and the Thirteenth Supplemental Trust Indenture to the Indenture (as amended, supplemented or restated from time to time) are collectively referred to herein as the "**Trust Indenture**"). The Trust Indenture specifies the terms and conditions upon which the Series 12 Debentures are created and issued or may be created, issued and held and the rights of the registered holders of the Series 12 Debentures, the Corporation and the Trustee, all of which terms and conditions are incorporated by reference in this Series 12 Debenture and to each of which the registered holder of this Series 12 Debenture, by acceptance hereof, agrees.

The aggregate principal amount of Series 12 Debentures that may be created and issued under the Trust Indenture is limited to $500,000,000 in lawful money of Canada. Series 12 Debentures are issuable as fully registered debentures in denominations of $1,000 and integral multiples thereof.

The Series 12 Debentures are direct unsecured obligations of the Corporation and will rank equally with each other and with all other debentures of every other series from time to time issued and outstanding pursuant to the Trust Indenture and, except to the extent prescribed by law, with all other unsecured and unsubordinated Indebtedness of the Corporation.

This Series 12 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to May 25, 2026, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to the greater of the Canada Yield Price (as defined in the Trust Indenture) and par, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

This Series 12 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after May 25, 2026, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to 100% of the Principal Amount of the Series

12 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

At any time when the Corporation is not in default under the Trust Indenture, the Corporation may, subject to the terms and conditions set forth in the Trust Indenture, purchase Series 12 Debentures in the open market, by tender or by private contract, at any price. Series 12 Debentures purchased by the Corporation shall be cancelled and not reissued.

The Principal Amount may become or be declared due before the Stated Maturity on the conditions, in the manner, with the effect and at the times set forth in the Trust Indenture.

The Trust Indenture contains provisions for the holding of meetings of registered holders of debentures issued by the Corporation pursuant to the Trust Indenture and the making of resolutions at such meetings and the creation of instruments in writing signed by the registered holders of a specified majority of debentures issued and outstanding pursuant to the Trust Indenture. Such resolutions and instruments will be binding on and may affect the rights and entitlements of all holders of debentures issued by the Corporation pursuant to the Trust Indenture, subject to the provisions of the Trust Indenture.

This Series 12 Debenture may be transferred only upon compliance with the conditions prescribed in the Trust Indenture by the registered holder hereof or the holder's legal representative or attorney duly appointed by an instrument in form and execution satisfactory to the Trustee, and upon compliance with such reasonable requirements as the Trustee or other registrar may prescribe, and such transfer shall be duly noted hereon by the Trustee or other registrar.

This Series 12 Debenture shall not become obligatory for any purpose until it shall have been certified by the manual signature of the Trustee in accordance with the Trust Indenture.

IN WITNESS WHEREOF TORONTO HYDRO CORPORATION has caused this Series 12 Debenture to be signed by its ● and its ●.

TORONTO HYDRO CORPORATION

By: _____

Name: ●

Title: ●

By: _____

Name: ●

Title: ●

(FORM OF TRUSTEE'S CERTIFICATE)

This Debenture is one of the Series 12 Debentures referred to in the Trust Indenture referred to above.

BNY TRUST COMPANY OF CANADA
Trustee

By: _____
Authorized Signatory

(FORM OF REGISTRATION PANEL)

(NO WRITING HEREON EXCEPT BY THE TRUSTEE OR OTHER REGISTRAR)

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
2.52**% SENIOR UNSECURED DEBENTURES DUE 2026 (SERIES 12)**

DATE OF REGISTRATION	IN WHOSE NAME REGISTERED	SIGNATURE OF TRUSTEE OR OTHER REGISTRAR

FOURTEENTH SUPPLEMENTAL TRUST INDENTURE

Made as of November 14, 2017

Between

TORONTO HYDRO CORPORATION
as issuer

and

BNY TRUST COMPANY OF CANADA
as trustee

Supplementing the Trust Indenture

made as of May 7, 2003

and

providing for the issue of

3.485% Senior Unsecured Debentures
due 2048 (Series 13)

TABLE OF CONTENTS

RECITALS 1

Section 1 INTERPRETATION 2

1.1 To Be Read With Trust Indenture 2

1.2 Headings etc. 3

1.3 Definitions 3

Section 2 SERIES 13 DEBENTURES 4

2.1 Creation and Designation 4

2.2 No Limitation on Issue 4

2.3 Date of Issue and Maturity 4

2.4 Concerning Interest 4

2.5 Interest Payments 4

2.6 Payment of Amounts Due on Maturity 4

2.7 Redemption and Purchase of Series 13 Debentures 4

2.8 Form of Series 13 Debentures 5

2.9 Signatures on Series 13 Debentures 6

2.10 Certification 6

2.11 Location of Register 6

2.12 Additional Amounts 7

Section 3 MISCELLANEOUS 7

3.1 Acceptance of Trust 7

3.2 Confirmation of Trust Indenture 7

3.3 Counterparts 7

Schedule 1 – FORM OF GLOBAL DEBENTURE-SERIES 13

Schedule 2 – U.S. FORM OF DEFINITIVE DEBENTURE-SERIES 13

FOURTEENTH SUPPLEMENTAL TRUST INDENTURE

THIS FOURTEENTH SUPPLEMENTAL TRUST INDENTURE made as of November 14, 2017,

BETWEEN:

TORONTO HYDRO CORPORATION
a corporation incorporated under the laws of Ontario (the "**Corporation**")

and

BNY TRUST COMPANY OF CANADA
a trust company existing under the laws of Canada (the "**Trustee**")

RECITALS

(A) BNY Trust Company of Canada is the successor trustee of CIBC Mellon Trust Company;

(B) The Corporation has entered into a trust indenture with the Trustee made as of May 7, 2003, as amended, supplemented or restated from time to time (the "**Trust Indenture**") which provides for the issuance of one or more series of unsecured Debentures of the Corporation by way of Supplemental Indentures;

(C) The Corporation entered into a first supplemental trust indenture made as of May 7, 2003 for the purpose of providing for the issue of $225,000,000 aggregate principal amount of Series 1 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 1 Debentures;

(D) The Corporation entered into a second supplemental trust indenture made as of November 14, 2007 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 2 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 2 Debentures;

(E) The Corporation entered into a third supplemental trust indenture made as of November 12, 2009 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 3 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 3 Debentures;

(F) The City Note has been converted, in accordance with its terms, into the Series 4 Debentures and the Series 5 Debentures;

(G) The Corporation entered into a fourth supplemental trust indenture made as of April 1, 2010 for the purpose of providing for the issue of $245,057,000 aggregate principal amount of Series 4 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 4 Debentures;

(H) The Corporation entered into a fifth supplemental trust indenture made as of April 1, 2010 for the purpose of providing for the issue of $245,057,000 aggregate principal amount of Series 5 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 5 Debentures;

(I) The Corporation entered into a sixth supplemental trust indenture made as of May 20, 2010 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 6 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 6 Debentures;

(J) The Corporation entered into a seventh supplemental trust indenture made as of September 20, 2011 for the purpose of amending the definition of "GAAP" under the Trust Indenture;

(K) The Corporation entered into an eighth supplemental trust indenture made as of November 18, 2011 for the purpose of providing for the issue of $300,000,000 aggregate principal amount of Series 7 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 7 Debentures;

(L) The Corporation entered into a ninth supplemental trust indenture made as of April 9, 2013 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 8 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 8 Debentures;

(M) The Corporation entered into a tenth supplemental trust indenture made as of April 9, 2013 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 9 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 9 Debentures;

(N) The Corporation entered into an eleventh supplemental trust indenture made as of September 16, 2014 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 10 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 10 Debentures;

(O) The Corporation entered into a twelfth supplemental trust indenture made as of March 16, 2015 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 11 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 11 Debentures;

(P) The Corporation entered into an amended and restated tenth supplemental trust indenture made as of September 2, 2015 for the purpose of making changes and corrections which were required for curing and correcting certain ambiguities and omissions in connection with an issue of $45,000,000 additional aggregate principal amount of Series 9 Debentures;

(Q) The Corporation entered into a thirteenth supplemental trust indenture made as of June 14, 2016 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 12 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 12 Debentures; and

(R) This Fourteenth Supplemental Trust Indenture is entered into for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 13 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 13 Debentures.

NOW THEREFORE THIS FOURTEENTH SUPPLEMENTAL TRUST INDENTURE WITNESSES and it is hereby covenanted, agreed and declared as follows:

Section 1 INTERPRETATION

1.1 To Be Read With Trust Indenture

This Fourteenth Supplemental Trust Indenture is a Supplemental Indenture as that term is used in the Trust Indenture. The Trust Indenture and this Fourteenth Supplemental Trust Indenture shall be read together and shall have effect as though all the provisions of both indentures were contained in one instrument.

1.2 Headings etc.

The division of this Fourteenth Supplemental Trust Indenture into Sections and clauses, the provision of a table of contents and the insertion of headings are for convenience of reference only and shall not affect the interpretation thereof. Unless the context otherwise requires, the expression "Section" and "Schedule" followed by a number, letter or combination of numbers and letters refer to the specified Section of or Schedule to this Fourteenth Supplemental Trust Indenture.

1.3 Definitions

All terms which are defined in the Trust Indenture and used but not defined in this Fourteenth Supplemental Trust Indenture shall have the meanings ascribed to them in the Trust Indenture, as such meanings may be amended or supplemented with respect to Series 13 Debentures by this Fourteenth Supplemental Trust Indenture. In the event of any inconsistency between the meaning given to a term in the Trust Indenture and the meaning given to the same term in this Fourteenth Supplemental Trust Indenture, the meaning given to the term in this Fourteenth Supplemental Trust Indenture shall prevail to the extent of the inconsistency. Subject to the foregoing, in this Fourteenth Supplemental Trust Indenture and in the Series 13 Debentures, the following terms have the following meanings:

(a) ***Canada Yield*** on any date means the yield to maturity on that date, compounded semi-annually, that a non-callable Government of Canada bond would carry if issued, in Canadian dollars in Canada, at 100% of its principal amount on that date with a term to maturity approximately equal to the remaining term to August 28, 2047 of the Series 13 Debentures, such yield to maturity being the average of the yields provided by two major Canadian investment dealers specified by the Corporation.

(b) ***Canada Yield Price*** means the amount equal to the net present value of all scheduled payments of interest (other than accrued and unpaid interest) and principal on the Series 13 Debentures that would have been payable to August 28, 2047 if redemption had not been made, using a discount rate equal to the sum of the Canada Yield and 30 basis points, calculated at 10:00 a.m. (Toronto, Ontario time) three Business Days prior to the Redemption Date of the Series 13 Debentures.

(c) ***Series 13 Debentures*** means the 3.485% Senior Unsecured Debentures due 2048 (Series 13) referred to in Section 2.1.

(d) ***Series 13 Debentures Debt Account*** means the deposit account established in respect of the Series 13 Debentures pursuant to Section 8.2 of the Trust Indenture that is designated in writing by the Corporation to the Trustee as the "Series 13 Debentures Debt Account".

(e) ***Series 13 Debentures Interest Payment Date*** means February 28 and August 28 in each year that the Series 13 Debentures are outstanding.

(f) ***Series 13 Debentures Interest Period*** means the period commencing on and including the later of the date of issue of the Series 13 Debentures and the immediately preceding Series 13 Debentures Interest Payment Date and ending on and including the day immediately preceding the next Series 13 Debentures Interest Payment Date to occur in respect of which interest is payable.

(g) ***Trust Indenture*** means the trust indenture made as of May 7, 2003 between the Corporation and the Trustee, as amended, supplemented or restated from time to time.

Section 2 SERIES 13 DEBENTURES

2.1 Creation and Designation

The Corporation is authorized in accordance with the Trust Indenture to issue under this Fourteenth Supplemental Trust Indenture, and hereby creates and issues, a series of debentures designated "3.485% Senior Unsecured Debentures due 2048 (Series 13)", having the terms set out in this Fourteenth Supplemental Trust Indenture.

2.2 No Limitation on Issue

The aggregate principal amount of Series 13 Debentures which may be issued under this Fourteenth Supplemental Trust Indenture including any supplement hereto is unlimited.

2.3 Date of Issue and Maturity

The Series 13 Debentures shall be dated November 14, 2017 (being the applicable date of issue) and will become due and payable, together with all accrued interest and unpaid interest thereon, on February 28, 2048 (being the applicable Stated Maturity).

2.4 Concerning Interest

(a) The Series 13 Debentures shall be issued in $1,000 principal amount denominations or integral multiples thereof and shall bear interest on the unpaid principal amount thereof at a rate of 3.485% per annum from and including their date of issue, payable semi-annually in arrears, in equal instalments, on each Series 13 Debentures Interest Payment Date.

(b) Interest shall be payable in respect of each Series 13 Debentures Interest Period (after as well as before maturity, default and judgment, with interest on overdue interest at the same rate) on each Series 13 Debentures Interest Payment Date in accordance with Section 2.8 of the Trust Indenture.

2.5 Interest Payments

The Corporation shall make payments of interest on the Series 13 Debentures in accordance with the provisions of Section 2.8 of the Trust Indenture.

2.6 Payment of Amounts Due on Maturity

In accordance with Section 8.2 of the Trust Indenture, the Corporation will deposit to the Series 13 Debentures Debt Account all amounts required to be paid to the order of Holders of Series 13 Debentures on maturity, prior to 9:00 a.m. (Toronto, Ontario time), on the Stated Maturity of the Series 13 Debentures. The deposit of such funds will satisfy and discharge the liability of the Corporation for principal of, and any accrued and unpaid interest on, the Series 13 Debentures to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld).

2.7 Redemption and Purchase of Series 13 Debentures

(a) The Series 13 Debentures may be redeemed, at the Corporation's option when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to August 28, 2047, on not more than 60 Business Days and not less than 15 Business Days prior notice, at a price equal to the greater of the Canada Yield Price and par, together in each case with accrued and unpaid interest to (but excluding) the Redemption Date and in each case otherwise in accordance with Sections 5.1, 5.2, 5.3 and 5.4 of the Trust Indenture.

(b) The Series 13 Debentures may be redeemed, at the Corporation's option when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after August 28, 2047, on not more than 60 Business Days and not less than 15 Business Days prior notice, at a price equal to 100% of the principal amount of the Series 13 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the Redemption Date and otherwise in accordance with Sections 5.1, 5.2, 5.3 and 5.4 of the Trust Indenture.

(c) The Corporation will be entitled at any time when not in default under the Trust Indenture to purchase for cancellation all or any of the Series 13 Debentures in accordance with Section 5.5 of the Trust Indenture.

(d) The Series 13 Debentures will not be subject to repurchase pursuant to any sinking fund provisions.

2.8 Form of Series 13 Debentures

(a) Except as set out in 2.8(b) below, the Series 13 Debentures and the registration panel and the certificate of the Trustee endorsed thereon shall be issuable initially as one Global Debenture to be held by, or on behalf of, CDS as depository for its participants and registered in the name of CDS or its nominee. The Global Debenture shall be substantially in the form set out in Schedule 1 hereto with such appropriate additions, deletions, substitutions and variations as the Directors shall by resolution determine prior to the time of issue thereof and as the Trustee may approve and with such distinguishing letters and numbers as the Trustee may approve, with such approval in each case to be conclusively evidenced by the Trustee's certification of such Global Debenture.

(b) The Trustee understands and acknowledges that the Series 13 Debentures have not been and will not be registered under the United States Securities Act of 1933, as amended (the "U.S. Securities Act"). Each Series 13 Debenture originally issued in the United States or to a U.S. Person will be represented by a definitive certificate in the form set out in Schedule 2 hereto which definitive certificate, and each Series 13 Debenture certificate issued in exchange therefor or in substitution thereof, shall bear the following legend:

"THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN AND WILL NOT BE REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE **"U.S. SECURITIES ACT"**) OR UNDER ANY STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF THE CORPORATION THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE CORPORATION, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT, OR (C) INSIDE THE UNITED STATES IN ACCORDANCE WITH (1) RULE 144A UNDER THE U.S. SECURITIES ACT OR (2) RULE 144 UNDER THE U.S. SECURITIES ACT, IF AVAILABLE, OR (3) IN COMPLIANCE WITH CERTAIN OTHER PROCEDURES SATISFACTORY TO THE CORPORATION. A NEW CERTIFICATE, BEARING NO LEGEND, DELIVERY OF WHICH WILL CONSTITUTE "GOOD DELIVERY", MAY BE OBTAINED FROM BNY TRUST COMPANY OF CANADA UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO BNY TRUST COMPANY OF CANADA AND THE CORPORATION, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT."

If any Series 13 Debentures are being sold or transferred outside the United States in compliance with the requirements of Rule 904 of Regulation S under the U.S Securities Act, the legend may be removed

by providing a declaration to the Trustee to the following effect (or as the Corporation may prescribe from time to time),

> "The undersigned (A) acknowledges that the sale of the _____ Debentures, represented by certificate numbers _____ to which this declaration relates is being made in reliance on Rule 904 of Regulation S under the United States Securities Act of 1933, as amended (the "**U.S. Securities Act**") and (B) certifies that (1) it is not an "affiliate" (as defined in Rule 405 under the U.S. Securities Act) of Toronto Hydro Corporation, (2) the offer of such Debentures was not made to a person in the United States and at the time the buy order was originated, the buyer was outside the United States, or the seller and any person acting on its behalf reasonably believe that the buyer was outside the United States and (3) neither the seller, nor any affiliate of the seller, nor any person acting on its or their behalf engaged in any directed selling efforts in connection with the offer and sale of such Debentures. Terms used herein have the meanings given to them by Regulation S under the U.S. Securities Act."

If any Series 13 Debentures are being sold or transferred pursuant to Rule 144 of the U.S. Securities Act, the legend may be removed by delivery to the Trustee of a written opinion of Trustee Counsel (or counsel to the transferor satisfactory to the Trustee) to the effect that such legend is no longer required under applicable requirements of the U.S. Securities Act or state securities laws.

Prior to the issuance of Series 13 Debentures, the Corporation shall notify the Trustee, in writing, concerning which Series 13 Debentures are to be certificated and are to bear the legend described above. The Trustee will thereafter maintain a list of all registered holders from time to time of legended Series 13 Debentures.

2.9 Signatures on Series 13 Debentures

The Series 13 Debentures shall be signed in accordance with the provisions of Section 2.6 of the Trust Indenture.

2.10 Certification

(a) No Series 13 Debenture issued shall be obligatory or shall entitle the Holder of such Series 13 Debenture to the benefits of this Fourteenth Supplemental Trust Indenture until it has been certified by manual signature by or on behalf of the Trustee by execution of the certificate of the Trustee appended thereto substantially in the form set out in Schedule 1 hereto, or in some other form approved by the Trustee, whose approval shall be conclusively evidenced by the Trustee's execution of the certificate. Such certificate on any Series 13 Debenture shall be conclusive evidence that such Series 13 Debenture is duly issued and is a valid and binding obligation of the Corporation and that the Holder of such Series 13 Debenture is entitled to the benefits of the Trust Indenture, as supplemented by this Fourteenth Supplemental Trust Indenture, and such Series 13 Debenture.

(b) The certificate of the Trustee on any Series 13 Debenture shall not be construed as a representation or warranty by the Trustee as to the validity of this Fourteenth Supplemental Trust Indenture or of the Series 13 Debentures (except the due certification thereof and any other warranties implied by law) and the Trustee shall in no respect be liable or answerable for the use made of the Series 13 Debentures or any of them or the proceeds thereof.

2.11 Location of Register

With respect to the Series 13 Debentures, initially the Register referred to in Section 3.1 of the Trust Indenture shall be kept by the Trustee at the Corporate Trust Office and may thereafter be kept by the Trustee in such other place as the Corporation, with the approval of the Trustee, may designate.

2.12 Additional Amounts

The Corporation will not be required to pay an additional amount on the Series 13 Debentures in respect of any tax, assessment or government charge that is required by law to be withheld or deducted by it.

2.13 Trustees, etc.

The Trustee will be the Paying Agent and the Registrar for the Series 13 Debentures.

Section 3 MISCELLANEOUS

3.1 Acceptance of Trust

The Trustee accepts the trusts in this Fourteenth Supplemental Trust Indenture and agrees to carry out and discharge the same upon the terms and conditions set out in this Fourteenth Supplemental Trust Indenture and in accordance with the Trust Indenture.

3.2 Confirmation of Trust Indenture

The Trust Indenture as amended and supplemented by this Fourteenth Supplemental Trust Indenture is in all respects confirmed.

3.3 Counterparts

This Fourteenth Supplemental Trust Indenture may be executed in counterparts, each of which so executed shall be deemed to be original and such counterparts together shall constitute one and the same instrument.

[SIGNATURE PAGE FOLLOWS]

IN WITNESS WHEREOF the parties hereto have executed this Fourteenth Supplemental Trust Indenture under the hands of their proper signatories in that behalf:

TORONTO HYDRO CORPORATION

By: *"Anthony Haines"*

Name: Anthony Haines

Title: President and Chief Executive Officer

By: *"Sean Bovingdon"*

Name: Sean Bovingdon

Title: Executive Vice-President and Chief Financial Officer

BNY TRUST COMPANY OF CANADA

By: *"Pierre Tremblay"*

Name: Pierre Tremblay

Title: Authorized Signatory

Schedule 1 – FORM OF GLOBAL DEBENTURE-SERIES 13

This Debenture is a Global Debenture within the meaning of the Trust Indenture hereinafter referred to and is registered in the name of a Depository or a nominee thereof. Unless this certificate is presented by an authorized representative of CDS Clearing and Depository Services Inc. ("CDS") to Toronto Hydro Corporation or its agent for registration of transfer, exchange or payment, and any certificate issued in respect thereof is registered in the name of CDS & CO., or in such other name as is requested by an authorized representative of CDS (and any payment is made to CDS & CO., or to such other entity as is requested by an authorized representative of CDS), ANY TRANSFER, PLEDGE OR OTHER USE HEREOF FOR VALUE OR OTHERWISE BY OR TO ANY PERSON IS WRONGFUL since the registered holder hereof, CDS & CO., has a property interest in the securities represented by this certificate herein and it is a violation of its rights for another person to hold, transfer or deal with this certificate.

[No. 13-000]

$●

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
3.485% SENIOR UNSECURED DEBENTURES DUE 2048 (SERIES 13)

ISIN CA 89119ZAK99
CUSIP 89119ZAK9

Issue Date	November 14, 2017
Stated Maturity	February 28, 2048
Interest Rate Per Annum	3.485%
Interest Payment Dates	February 28 and August 28 in each year
Initial Interest Payment Date	February 28, 2018
Principal Amount	$●

TORONTO HYDRO CORPORATION (the "**Corporation**") for value received hereby promises to pay to the registered holder hereof on the Stated Maturity, or on such earlier date as the Principal Amount (or a portion thereof) may become due in accordance with the provisions of the Trust Indenture (as defined below), on presentation and surrender of this 3.485% Senior Unsecured Debenture due February 28, 2048 (Series 13) (the "**Series 13 Debenture**"), the Principal Amount in lawful money of Canada at the office of the Trustee (as defined below) at 11th Floor, 320 Bay Street, Toronto, Ontario M5H 4A6, and to pay interest on the Principal Amount at the Interest Rate Per Annum from and including the later of the Issue Date and the last Interest Payment Date on which interest has at that time most recently been paid on this Series 13 Debenture, at the address of the registered holder hereof appearing on the register of Series 13 Debentures maintained by or at the direction of the Trustee (the "**Register**"), in like money semi-annually in arrears, in equal instalments on the Interest Payment Dates in each year, and if the Corporation at any time defaults in the payment of any principal or interest, to pay interest on the amount in default at the same rate, in like money, on demand, at the address of the registered holder hereof appearing on the Register. The Corporation will (i) on the day that is

each Interest Payment Date, make payment by a wire transfer, or (ii) on the day that is two Business Days before each Interest Payment Date, forward or cause to be forwarded a cheque by same day delivery, to the address of the registered holder hereof appearing on the Register for interest due and payable to such holder on such Interest Payment Date, less any taxes required by law to be deducted or withheld, made payable to the order of such holder; provided, however that in case of payment of interest at maturity or redemption or as otherwise provided in the Trust Indenture, the time for payment of interest, less any such taxes, may at the option of the Corporation be determined based on the time that the certificate representing this Series 13 Debenture is presented and surrendered to the Trustee. The payment by such wire transfer or forwarding of such cheque (provided such cheque is paid on presentation) will satisfy and discharge the liability for interest upon such Series 13 Debenture to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld as aforesaid).

This Series 13 Debenture is one of an authorized issue of debentures designated as 3.485% Senior Unsecured Debentures due February 28, 2048 (Series 13) and forming the series of debentures created and issued under a fourteenth supplemental trust indenture made as of November 14, 2017 (the "**Fourteenth Supplemental Trust Indenture**") to a trust indenture (the "**Indenture**") made as of May 7, 2003, between the Corporation and BNY Trust Company of Canada (successor trustee of CIBC Mellon Trust Company) (the "**Trustee**"), as Trustee (the first supplemental trust indenture to the Indenture made as of May 7, 2003 between the Corporation and the Trustee, the second supplemental trust indenture to the Indenture made as of November 14, 2007 between the Corporation and the Trustee, the third supplemental trust indenture to the Indenture made as of November 12, 2009 between the Corporation and the Trustee, the fourth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the fifth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the sixth supplemental trust indenture to the Indenture made as of May 20, 2010 between the Corporation and the Trustee, the seventh supplemental trust indenture to the Indenture made as of September 20, 2011 between the Corporation and the Trustee, the eighth supplemental trust indenture to the Indenture made as of November 18, 2011 between the Corporation and the Trustee, the ninth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the tenth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the amended and restated tenth supplemental trust indenture to the Indenture made as of September 2, 2015 between the Corporation and the Trustee, the eleventh supplemental trust indenture to the Indenture made as of September 16, 2014 between the Corporation and the Trustee, the twelfth supplemental trust indenture to the Indenture made as of March 16, 2015 between the Corporation and the Trustee, the thirteenth supplemental trust indenture to the Indenture made as of June 14, 2016 between the Corporation and the Trustee, and the Fourteenth Supplemental Trust Indenture to the Indenture (as amended, supplemented or restated from time to time) are collectively referred to herein as the "**Trust Indenture**"). The Trust Indenture specifies the terms and conditions upon which the Series 13 Debentures are created and issued or may be created, issued and held and the rights of the registered holders of the Series 13 Debentures, the Corporation and the Trustee, all of which terms and conditions are incorporated by reference in this Series 13 Debenture and to each of which the registered holder of this Series 13 Debenture, by acceptance hereof, agrees.

The aggregate principal amount of Series 13 Debentures that may be created and issued under the Trust Indenture is unlimited. Series 13 Debentures are issuable as fully registered debentures in denominations of $1,000 and integral multiples thereof and, subject to the terms and conditions set forth in the Trust Indenture, are issued as book entry only debentures.

The Series 13 Debentures are direct unsecured obligations of the Corporation and will rank equally with each other and with all other debentures of every other series from time to time issued and outstanding pursuant to the Trust Indenture and, except to the extent prescribed by law, with all other unsecured and unsubordinated Indebtedness of the Corporation.

This Series 13 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to August 28, 2047, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to the greater of the Canada Yield Price (as defined in the Trust Indenture) and par, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

This Series 13 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after August 28, 2047, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to 100% of the Principal Amount of the Series 13 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

At any time when the Corporation is not in default under the Trust Indenture, the Corporation may, subject to the terms and conditions set forth in the Trust Indenture, purchase Series 13 Debentures in the open market, by tender or by private contract, at any price. Series 13 Debentures purchased by the Corporation shall be cancelled and not reissued.

The Principal Amount may become or be declared due before the Stated Maturity on the conditions, in the manner, with the effect and at the times set forth in the Trust Indenture.

The Trust Indenture contains provisions for the holding of meetings of registered holders of debentures issued by the Corporation pursuant to the Trust Indenture and the making of resolutions at such meetings and the creation of instruments in writing signed by the registered holders of a specified majority of debentures issued and outstanding pursuant to the Trust Indenture. Such resolutions and instruments will be binding on and may affect the rights and entitlements of all holders of debentures issued by the Corporation pursuant to the Trust Indenture, subject to the provisions of the Trust Indenture.

This Series 13 Debenture may be transferred only upon compliance with the conditions prescribed in the Trust Indenture relating to the transfer of a Global Debenture (as defined in the Trust Indenture), and upon compliance with such reasonable requirements as the Trustee or other registrar may prescribe, and such transfer shall be duly noted hereon by the Trustee or other registrar.

This Series 13 Debenture shall not become obligatory for any purpose until it shall have been certified by the manual signature of the Trustee in accordance with the Trust Indenture.

IN WITNESS WHEREOF TORONTO HYDRO CORPORATION has caused this Series 13 Debenture to be signed by its • and its •.

TORONTO HYDRO CORPORATION

Per: _____

Name: •

Title: •

Per: _____

Name: •

Title: •

(FORM OF TRUSTEE'S CERTIFICATE)

This Debenture is one of the Series 13 Debentures referred to in the Trust Indenture referred to above.

BNY TRUST COMPANY OF CANADA
Trustee

By: _____
Authorized Signatory

(FORM OF REGISTRATION PANEL)

(NO WRITING HEREON EXCEPT BY THE TRUSTEE OR OTHER REGISTRAR)

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
3.485% SENIOR UNSECURED DEBENTURES DUE 2048 (SERIES 13)

ISIN CA 89119ZAK99
CUSIP 89119ZAK9

DATE OF REGISTRATION	IN WHOSE NAME REGISTERED	AMOUNT OF DECREASE	AMOUNT OF INCREASE	AMOUNT OF SERIES 13 DEBENTURES OUTSTANDING FOLLOWING CHANGE	SIGNATURE OF TRUSTEE OR OTHER REGISTRAR

Schedule 2 – U.S. FORM OF DEFINITIVE DEBENTURE-SERIES 13

*THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN AND WILL NOT BE REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE "**U.S. SECURITIES ACT**") OR UNDER ANY STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF THE CORPORATION THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE CORPORATION, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT, OR (C) INSIDE THE UNITED STATES IN ACCORDANCE WITH (1) RULE 144A UNDER THE U.S. SECURITIES ACT OR (2) RULE 144 UNDER THE U.S. SECURITIES ACT, IF AVAILABLE, OR (3) IN COMPLIANCE WITH CERTAIN OTHER PROCEDURES SATISFACTORY TO THE CORPORATION. A NEW CERTIFICATE, BEARING NO LEGEND, DELIVERY OF WHICH WILL CONSTITUTE "GOOD DELIVERY", MAY BE OBTAINED FROM BNY TRUST COMPANY OF CANADA UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO BNY TRUST COMPANY OF CANADA AND THE CORPORATION, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT.*

[No. 13-000]

$•

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
3.485% SENIOR UNSECURED DEBENTURES DUE 2048 (SERIES 13)

Issue Date	November 14, 2017
Stated Maturity	February 28, 2048
Interest Rate Per Annum	3.485%
Interest Payment Dates	February 28 and August 28 in each year
Initial Interest Payment Date	February 28, 2018
Principal Amount	$•

TORONTO HYDRO CORPORATION (the "**Corporation**") for value received hereby promises to pay to the registered holder hereof on the Stated Maturity, or on such earlier date as the Principal Amount (or a portion thereof) may become due in accordance with the provisions of the Trust Indenture (as defined below), on presentation and surrender of this 3.485% Senior Unsecured Debenture due February 28, 2048 (Series 13) (the "**Series 13 Debenture**"), the Principal Amount in lawful money of Canada at the office of the Trustee (as defined below) at 11th Floor, 320 Bay Street, Toronto, Ontario M5H 4A6, and to pay interest on the Principal Amount at the Interest Rate Per Annum from and including the later of the Issue Date and the last Interest Payment Date on which interest has at that time most recently been paid on this Series 13 Debenture, at the address of the registered holder hereof appearing on the register of Series 13 Debentures maintained by or at the direction of the Trustee (the "**Register**"), in like money semi-annually in arrears, in equal instalments on the Interest Payment Dates in each year, and if the Corporation at any time defaults in the payment of any principal or interest, to pay interest on the amount in default at the same rate, in like money, on demand, at the address of the registered holder hereof appearing on the Register. The Corporation, on the day that is two

Business Days before each Interest Payment Date, will forward or cause to be forwarded by same day delivery to the address of the registered holder hereof appearing on the Register a cheque for interest due and payable to such holder on such Interest Payment Date, less any taxes required by law to be deducted or withheld, made payable to the order of such holder; provided, however that in case of payment of interest at maturity or redemption or as otherwise provided in the Trust Indenture, the time for payment of interest, less any such taxes, may at the option of the Corporation be determined based on the time that the certificate representing this Series 13 Debenture is presented and surrendered to the Trustee. The forwarding of such cheque will satisfy and discharge the liability for interest upon such Series 13 Debenture to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld as aforesaid) unless such cheque is not paid on presentation.

This Series 13 Debenture is one of an authorized issue of debentures designated as 3.485% Senior Unsecured Debentures due February 28, 2048 (Series 13) and forming the series of debentures created and issued under a fourteenth supplemental trust indenture made as of November 14, 2017 (the "**Fourteenth Supplemental Trust Indenture**") to a trust indenture (the "**Indenture**") made as of May 7, 2003, between the Corporation and BNY Trust Company of Canada (successor trustee of CIBC Mellon Trust Company) (the "**Trustee**"), as Trustee (the first supplemental trust indenture to the Indenture made as of May 7, 2003 between the Corporation and the Trustee, the second supplemental trust indenture to the Indenture made as of November 14, 2007 between the Corporation and the Trustee, the third supplemental trust indenture to the Indenture made as of November 12, 2009 between the Corporation and the Trustee, the fourth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the fifth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the sixth supplemental trust indenture to the Indenture made as of May 20, 2010 between the Corporation and the Trustee, the seventh supplemental trust indenture to the Indenture made as of September 20, 2011 between the Corporation and the Trustee, the eighth supplemental trust indenture to the Indenture made as of November 18, 2011 between the Corporation and the Trustee, the ninth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the tenth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the amended and restated tenth supplemental trust indenture to the Indenture made as of September 2, 2015 between the Corporation and the Trustee, the eleventh supplemental trust indenture to the Indenture made as of September 16, 2014 between the Corporation and the Trustee, the twelfth supplemental trust indenture to the Indenture made as of March 16, 2015 between the Corporation and the Trustee, the thirteenth supplemental trust indenture to the Indenture made as of June 14, 2016 between the Corporation and the Trustee, and the Fourteenth Supplemental Trust Indenture to the Indenture (as amended, supplemented or restated from time to time) are collectively referred to herein as the "**Trust Indenture**"). The Trust Indenture specifies the terms and conditions upon which the Series 13 Debentures are created and issued or may be created, issued and held and the rights of the registered holders of the Series 13 Debentures, the Corporation and the Trustee, all of which terms and conditions are incorporated by reference in this Series 13 Debenture and to each of which the registered holder of this Series 13 Debenture, by acceptance hereof, agrees.

The aggregate principal amount of Series 13 Debentures that may be created and issued under the Trust Indenture is unlimited. Series 13 Debentures are issuable as fully registered debentures in denominations of $1,000 and integral multiples thereof.

The Series 13 Debentures are direct unsecured obligations of the Corporation and will rank equally with each other and with all other debentures of every other series from time to time issued and outstanding pursuant to the Trust Indenture and, except to the extent prescribed by law, with all other unsecured and unsubordinated Indebtedness of the Corporation.

This Series 13 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to August 28, 2047, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to the greater of the Canada Yield Price (as defined in the Trust Indenture) and par, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

This Series 13 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after August 28, 2047, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to 100% of the Principal Amount of the

Series 13 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

At any time when the Corporation is not in default under the Trust Indenture, the Corporation may, subject to the terms and conditions set forth in the Trust Indenture, purchase Series 13 Debentures in the open market, by tender or by private contract, at any price. Series 13 Debentures purchased by the Corporation shall be cancelled and not reissued.

The Principal Amount may become or be declared due before the Stated Maturity on the conditions, in the manner, with the effect and at the times set forth in the Trust Indenture.

The Trust Indenture contains provisions for the holding of meetings of registered holders of debentures issued by the Corporation pursuant to the Trust Indenture and the making of resolutions at such meetings and the creation of instruments in writing signed by the registered holders of a specified majority of debentures issued and outstanding pursuant to the Trust Indenture. Such resolutions and instruments will be binding on and may affect the rights and entitlements of all holders of debentures issued by the Corporation pursuant to the Trust Indenture, subject to the provisions of the Trust Indenture.

This Series 13 Debenture may be transferred only upon compliance with the conditions prescribed in the Trust Indenture by the registered holder hereof or the holder's legal representative or attorney duly appointed by an instrument in form and execution satisfactory to the Trustee, and upon compliance with such reasonable requirements as the Trustee or other registrar may prescribe, and such transfer shall be duly noted hereon by the Trustee or other registrar.

This Series 13 Debenture shall not become obligatory for any purpose until it shall have been certified by the manual signature of the Trustee in accordance with the Trust Indenture.

IN WITNESS WHEREOF TORONTO HYDRO CORPORATION has caused this Series 13 Debenture to be signed by its • and its •.

TORONTO HYDRO CORPORATION

Per: _____

Name: •

Title: •

Per: _____

Name: •

Title: •

(FORM OF TRUSTEE'S CERTIFICATE)

This Debenture is one of the Series 13 Debentures referred to in the Trust Indenture referred to above.

BNY TRUST COMPANY OF CANADA
Trustee

By: _____
Authorized Signatory

(FORM OF REGISTRATION PANEL)

(NO WRITING HEREON EXCEPT BY THE TRUSTEE OR OTHER REGISTRAR)

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
3.485% SENIOR UNSECURED DEBENTURES DUE 2048 (SERIES 13)

DATE OF REGISTRATION	IN WHOSE NAME REGISTERED	SIGNATURE OF TRUSTEE OR OTHER REGISTRAR

RATING AGENCY REPORTS

In accordance with s. 2.1.9 of the OEB's Filing Requirements,[1] this schedule provides Toronto Hydro-Electric System Limited's rating agency reports, as follows:

- Appendix A: Standard and Poor's, 30 April 2018
- Appendix B: DBRS, 27 April 2018

[1] Ontario Energy Board, Filing Requirements for Electricity Distributor Rate Applications, Chapter 2 (July 12, 2018).

S&P Global
Ratings

RatingsDirect®

Summary:

Toronto Hydro Corp.

Primary Credit Analyst:
Andrew Ng, Toronto + 1 (416) 507 2545; andrew.ng@spglobal.com

Secondary Contact:
Vinod Makkar, CFA, Toronto + (416) 507-3271; vinod.makkar@spglobal.com

Table Of Contents

Rationale

Outlook

Our Base-Case Scenario

Company Description

Business Risk

Financial Risk

Liquidity

Government Influence

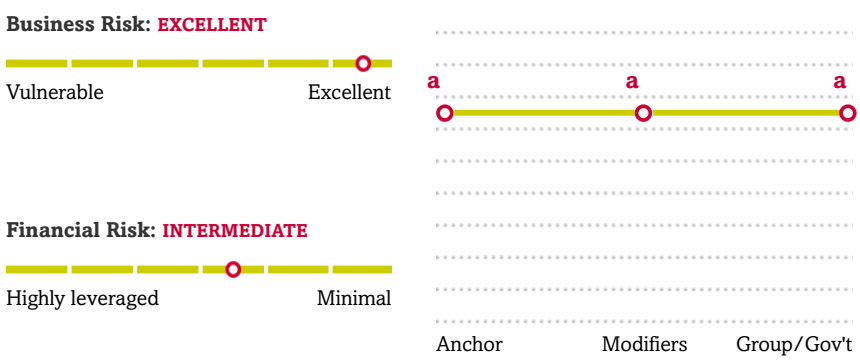
Ratings Score Snapshot

Issue Ratings--Subordination Risk Analysis

Related Criteria

Summary:

Toronto Hydro Corp.



CORPORATE CREDIT RATING
A/Stable/--

Rationale

Business Risk: Excellent	Financial Risk: Intermediate
• A strong regulatory structure that is transparent, predictable, consistent, and independent, supporting the regulated electricity distribution business' stable cash flows • Minimal exposure to unregulated businesses • A diverse customer base and economic activity within the service territory, with no meaningful concentration risk • No exposure to commodity cost risk because tariffs allow the pass-through of electricity costs to customers • Lack of geographical and regulatory diversity	• Steady and stable regulated cash flow • Large capital programs related to expansion and replacement of aging infrastructure

Outlook: Stable

The stable outlook reflects S&P Global Ratings' view that Toronto Hydro Corp. will continue to focus on its regulated electricity distribution operation and generate stable and predictable cash flow. For 2018, we expect adjusted funds from operations (AFFO)-to-debt to be low at about 12%-13%, primarily due to the settlement of variance account related to refund of the over-collection of energy costs from 2016. We expect AFFO-to-debt in 2019-2020 will normalize and improve to 15%-16%.

Downside scenario

We could take a negative rating action on Toronto Hydro if the company's credit metrics were to deteriorate materially, with AFFO-to-debt approaches 10% with no prospect for improvement, a two-notch downgrade to the utility's stand-alone credit profile (SACP). This could happen if there are significant cost overruns with capital programs or if Toronto Hydro experiences adverse regulatory decisions, including material cost disallowance or materially lower return on equity (ROE) and equity thickness.

Given our current view of the moderate likelihood that the utility to receive extraordinary support from its government owner, a one-notch downgrade either to the City of Toronto or a one-notch revision to the company's SACP on its own would have no rating impact.

Upside scenario

We could take a positive rating action on Toronto Hydro if the company sustainably improves its financial position, with sustained AFFO-to-debt approaching 20%. However, we believe this is unlikely during our two-year outlook period given that rates are regulated and that the company is going through a period of intense capital spending. Alternatively, a positive rating action to Toronto would also result in one on Toronto Hydro based on our view of the likelihood of government support the utility would receive from the city.

Our Base-Case Scenario

Assumptions	Key Metrics

- Electricity distribution rates for 2018 and 2019 will be set under the custom incentive ratemaking mechanism
- The regulatory regime will be relatively stable and Toronto Hydro will not experience any material, adverse regulatory decisions
- The company will earn an expected ROE of about 9.3% per the Ontario Energy Board's (OEB) directive in 2016 based on the deemed capital structure with 60% debt and 40% equity
- Capital expenditures of about C$500 million on average in 2018-2019
- Dividend payments of about C$90 million in 2018

	2017A	2018E	2019E
AFFO/debt	15.9%	12%-13%	15%-16%
Debt-to-capital	58.3%	60%-61%	60%-61%

AFFO--Adjusted funds from operations. A--Actual. E--Estimate.

Company Description

Toronto Hydro is a utility holding company. Its primary operation is Toronto Hydro-Electric System Ltd.'s (THESL) monopoly electricity distribution business, which delivers electricity throughout Toronto. THESL represented virtually all of Toronto Hydro's revenue (net of commodity pass-through) in 2017. It is one of Ontario's largest local distribution companies serving approximately 768,000 customers in the city and delivers approximately 19% of the electricity consumed in the Province of Ontario.

Business Risk: Excellent

Our view of Toronto Hydro's business risk has not changed. The utility continues to operate under a supportive regulatory regime. The OEB, the provincial regulator, continues to provide a transparent, consistent, and independently operated regulatory framework that supports a stable and predictable cash flow model, which we view as a key credit strength. Toronto Hydro has limited exposure to commodity risk because electricity cost is flow through to ratepayers. The tariff structure also allows the operator to recover prudently spent operating cost, capital expenditures, or other unexpected material losses in a timely manner.

Further supporting our assessment of the excellent business risk profile is Toronto Hydro's large and diverse customer base, with no meaningful concentration risk. The utility's largest customer is the City of Toronto (AA/Stable/A-1+), an investment-grade counterparty. Residential and small businesses account for more than 90% of customers. In our view, this customer profile is less sensitive to macroeconomic stress and business cycles. Nevertheless, the residential customer base has some sensitivity to volume fluctuations, primarily weather-driven, although we do not believe the fluctuations would stress credit metrics enough to affect the rating, especially given that residential distribution rates

are moving to a fixed rate structure thereby mitigating associating volume risk. We do not expect the utility's customer composition to change materially over the next two years.

Overall, we assess Toronto Hydro's business risk profile at the lower half of the business risk profile category, reflecting the relatively limited geographic footprint of the utility's operations and its exposure to only a single regulatory regime.

Financial Risk: Intermediate

We assess Toronto Hydro's financial measures against our most relaxed benchmarks because virtually all of the utility's cash flow is from the low end of the utility risk spectrum in electricity distribution under a supportive regulatory framework. We expect the company's large capital programs will continue to pressure credit metrics and that the utility will continue to rely on both internal generated funds and external funds to finance its capital programs.

For 2018, we expect Toronto Hydro's credit metrics to be lower than expected with adjusted funds from operations (AFFO)-to-debt of 12%-13%. This is primarily due to refund of about C$90 million related to over-collection of energy cost from 2016. The OEB has approved the return of this amount to rate-payers in 2018. As a result, FFO will fall by a similar amount resulting in lower cash flow and credit metrics. In 2019-2020, we forecast AFFO-to-debt to return to 15%-16%.

Liquidity: Adequate

We consider Toronto Hydro's liquidity adequate. We expect liquidity sources will exceed uses by more than 1.1x over the next 12 months. In the event of a 10% drop in EBITDA, we believe the utility has sufficient liquidity sources to cover uses. In our view, Toronto Hydro has sound relationships with banks and generally satisfactory standing in the credit markets. In the event of unexpected financial stress, we expect the utility would scale back on its capital expenditures and has the flexibility to suspend dividend payments to preserve credit metrics.

In our view, Toronto Hydro has manageable long-term debt maturities in the next three years, with C$250 million of senior unsecured debt maturing in 2019. We believe the company maintains good access to capital markets to refinance its debt maturities.

Principal Liquidity Sources	Principal Liquidity Uses
• Projected FFO of C$380 million-C$400 million in 2018 • Committed credit facility of C$800 million of which about C$640 million is available as of Dec 31, 2017. The credit facility matures in October 2022	• Debt maturities, including commercial paper, of about C$160 million • Capital spending of about C$500 million in 2018 • Dividends of approximately C$90 million in 2018

Government Influence

We continue to believe there is a moderate likelihood that the utility's owner, the City of Toronto, would provide timely and sufficient extraordinary support in the event of financial distress. This is evident with the cash injection by the city in 2017, which demonstrates Toronto is willing to provide financial support to the utility during financial stress.

Ratings Score Snapshot

Corporate Credit Rating

A/Stable/--

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Excellent

Financial risk: Intermediate

- **Cash flow/Leverage:** Intermediate

Anchor: a

Modifiers

- **Diversification/Portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : a

- **Likelihood of government support:** Moderate (no impact)

Issue Ratings--Subordination Risk Analysis

Capital structure

As of Dec. 31, 2017, Toronto Hydro had total consolidated long-term debt of about C$2 billion at holding company level.

Analytical conclusions

All debt is at the holding company level, so we do not consider Toronto Hydro's senior unsecured debt as structurally subordinated. As a result, we equalize our issue-level rating on the senior unsecured debt with our 'A' long-term issuer

credit rating on the utility.

Related Criteria

- Criteria - Corporates - General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- General Criteria: Rating Government-Related Entities: Methodology And Assumptions, March 25, 2015
- Criteria - Corporates - General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Group Rating Methodology, Nov. 19, 2013
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	**Intermediate**	Significant	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	**a+/a**	a-	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

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Rating Report

Toronto Hydro Corporation

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Insight beyond the rating.

Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Senior Unsecured Debentures & MTNs	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating Update

On April 23, 2018, DBRS Limited (DBRS) confirmed Toronto Hydro Corporation's (THC or the Company) Issuer Rating and Senior Unsecured Debentures & MTNs rating at "A" and the Commercial Paper (CP) rating at R-1 (low). All trends are Stable. The ratings reflect THC's low-risk electricity distribution business, underpinned by a transparent and supportive regulatory framework that serves an economically strong franchise area, and provides relatively predictable earnings.

DBRS expects the regulatory regime in Ontario to remain transparent and supportive, allowing the Company to recover prudently incurred costs in a timely manner and to earn an adequate return on equity (ROE; 9.30% for 2015 to 2019). The Company is in the fourth year of a five-year Custom Incentive Rate-Setting (CIR) model approved by the Ontario Energy Board (OEB), which has provided THC with funding certainty for its ongoing large capital program. THC is expected to file a CIR application for the 2020–2024 period in mid-2018. In June 2017, the Company received a $250 million equity contribution from its sole shareholder, the City of Toronto (the City; rated AA with a Stable trend by DBRS). In response to the equity contribution, THC amended its dividend policy to pay the City $75 million for 2017, up from $25 million, and 60% of THC's previous year's consolidated net income for subsequent years. DBRS views the capital contribution by the City as a positive outcome as it has alleviated the pressure on THC's credit metrics in the near term. However, the new dividend policy to pay 60% of the Company's previous year's net income is expected to offset the benefit of the equity contribution in the medium term. (Please refer to DBRS's press release, *DBRS Comments on Toronto Hydro Receiving Equity from the City of Toronto*, dated June 29, 2017.)

The Company's key credit metrics as at December 31, 2017, remained reasonable for the current rating. THC's significant capital expenditure (capex) program, however, continues to pressure its credit metrics. The Company's capital program is largely non-discretionary as it is focused on meeting growing customer demand and maintaining the reliability of the distribution grid. DBRS expects annual capex to to remain consistent with 2017 levels (gross capex of $553 million) over the next several years and result in a steady growth in the rate base. Although THC's operating cash flow is expected to grow modestly, the significant capital program and the dividend policy is expected to result in free cash flow deficits that are likely to be funded with debt. DBRS notes that while a rating upgrade for THC is unlikely in the near term, the ratings could be adversely affected should the Company fail to maintain cash flow-to-debt and debt-to-capital at or near 15% and 60%, respectively, in the medium term.

Financial Information

	For the year ended December 31 [2]				
(CAD millions where applicable)	**2017**	**2016**	**2015**	**2014**	**2013**
Cash flow/Total debt [1]	16.7%	15.9%	15.2%	14.9%	18.4%
Total debt in capital structure [1]	55.6%	62.4%	62.8%	61.1%	57.6%
EBIT gross interest coverage (times) [1]	2.78	2.70	2.37	2.62	2.45

1 Including operating leases. **2** 2014 to 2017 based on IFRS; 2013 based on USGAAP.

Issuer Description

THC is a holding company with the following subsidiaries: Toronto Hydro-Electric System Limited (THESL), which distributes electricity and engages in Conservation and Demand Management activities and Toronto Hydro Energy Services Inc., which provides street lighting services. The Company's sole shareholder is the City of Toronto (the City).

Rating Considerations

Strengths

1. Reasonable regulatory environment

Nearly all of THC's earnings are contributed by its low-risk distribution business that operates under a reasonable and supportive regulatory environment. The Company operates under a five-year CIR framework with an approved ROE of 9.30% (2015–2019) that allows THC to generate relatively stable earnings and cash flow. The Company's deemed capital structure (debt-to-equity of 60%:40%) has remained unchanged for several years. DBRS views the regulatory framework in Ontario as consistent and supportive for regulated distribution operators.

2. Strong and growing franchise area

THC operates in Toronto, which is one of the largest metropolitan cities in North America and has a reasonable growth in population. The Company is one of the largest municipally owned local distribution companies (LDCs) in Canada, providing approximately 19% of the electricity consumed in Ontario and serves a customer base of approximately 768,000 customers. THC's customer base grew marginally by 0.9% in 2017. The Company's electricity throughput is predominantly distributed to residential and general service customers, who account for 93% of THC's revenue. This reduces the Company's exposure to cyclicality.

3. Reasonable financial profile

THC's credit metrics, including DBRS-adjusted cash flow-to-total debt at 16.7%, total debt-to-capital at 55.6% and EBIT interest coverage at 2.8x for 2017, have remained reasonable for the "A" rating category.

Challenges

1. Balance sheet pressure as a result of high capex

The Company has a substantial capex program of approximately $2.2 billion for the 2015 to 2019 period to replace its aging electricity infrastructure, which is expected to result in consistent free cash flow deficits in the medium term. Historically, THC has depended entirely on debt to fund its cash flow deficits, causing leverage to rise to 62.4% for 2016, from 57.6% for 2013. Although the equity contribution from the City has alleviated the pressure on leverage in 2017, DBRS expects credit metrics to weaken over the next two to three years after factoring in the higher dividend policy implemented in 2017. DBRS expects the Company to maintain leverage in line with the regulated capital structure (60% debt to 40% equity), consistent with the current rating category.

2. Limited access to equity market

The Company's ownership structure (100% owned by the City) limits its ability to access the equity markets. As a result, THC's cash flow deficits are funded largely through debt.

3. Earnings sensitive to volume

Earnings and cash flow for electricity distribution companies are partially dependent on the volume of electricity sold, given that rates typically include a variable charge component. Seasonality, economic cyclicality and weather variability have a direct impact on the volume of electricity sold and, therefore, on revenue earned from electricity sales. However, this sensitivity is expected to be reduced through the introduction of a fixed charge for residential customers that will reduce weather sensitivities and volume risk for all Ontario-based LDCs. The Company is phasing in a higher fixed monthly rate and lower volumetric rate for its residential customers over the 2017 to 2020 period.

Earnings and Outlook

	For the year ended December 31 [1]				
(CAD millions where applicable)	**2017**	**2016**	**2015**	**2014**	**2013**
Net Revenue	761	726	665	639	578
EBITDA	468	449	390	371	323
EBIT	244	237	196	186	179
Gross interest expense	88	87	81	70	72
Earning before taxes	166	163	125	124	113
Net income before non-recurring items	140	142	124	111	112
Non-recurring items	16	9	3	1	9
Reported net income	157	151	127	112	121
Return on equity	8.80%	10.28%	9.46%	8.71%	9.49%
Allowed ROE	9.30%	9.30%	9.30%	9.58%	9.58%
Rate Base [2]	3,890	3,574	3,232	2,298	2,298

1 2014 to 2017 financials based on IFRS; 2013 based on USGAAP. **2** 2017 Rate base has not been approved by the OEB.

2017 Summary

- THC continued to generate stable and predictable earnings that are supported by its stable regulated operations.
- Increase in EBIT compared with 2016 was primarily due to higher electricity distribution rates, partially offset by higher operating expenses in connection with system maintenance, and higher depreciation and amortization related to new in-service asset additions.

2018 Outlook

- EBIT for 2018 is expected to grow modestly in line with annual rate adjustments, largely for growth in rate base.

Financial Profile

	For the year ended December 31 2				
(CAD millions where applicable)	2017	2016	2015	2014	2013
Net income before non-recurring items	140	142	124	111	112
Depreciation & amortization	224	212	194	185	173
Deferred income taxes and other	3	20	22	(3)	16
Cash Flow From Operations	**368**	**374**	**340**	**292**	**301**
Dividends paid	(75)	(63)	(56)	(61)	(43)
Capital expenditures	(483)	(507)	(539)	(544)	(413)
Free Cash Flow (Bef. Working Cap. Changes)	**(190)**	**(196)**	**(255)**	**(313)**	**(156)**
Changes in non-cash work. cap. items	62	(15)	24	38	(45)
Changes in regulatory assets & liabilities	13	77	(52)	(67)	(20)
Net Free Cash Flow	**(115)**	**(134)**	**(283)**	**(341)**	**(220)**
Acquisitions & long-term investments	0	0	0	0	0
Short-term investments	0	0	0	0	0
Proceeds on asset sales	13	2	14	2	2
Net equity change	250	0	0	0	0
Net debt change	(151)	127	266	343	147
Other	3	5	2	(3)	(5)
Change in Cash	**0**	**(0)**	**0**	**(0)**	**(77)**
Total debt	2,205	2,353	2,223	1,955	1,618
Cash and cash equivalents	0	0	0	0	0
Total debt in capital structure 1	55.6%	62.4%	62.8%	61.1%	57.6%
Cash flow/Total debt 1	16.7%	15.9%	15.2%	14.9%	18.4%
EBIT gross interest coverage (times) 1	2.78	2.70	2.37	2.62	2.45
Dividend payout ratio	53.4%	44.6%	45.6%	54.8%	38.4%

1 Including operating leases. 2 2014 to 2017 based on IFRS; 2013 based on USGAAP.

2017 Summary

- THC's financial profile and key credit metrics remained reasonable with the current rating category. The debt-to-capital ratio strengthened in 2017 following the equity contribution from the City.
- Cash flow from operations was slightly lower compared with 2016 primarily because of lower electricity consumption, rebate of settlement variances through rates and higher taxes, partially offset by higher electricity distribution rates and conservation and demand management incentives received.
- Capex moderated compared with the last several years in line with OEB approvals. The Company continues to replace its aging electricity infrastructure to maintain and improve the electricity distribution system.
- THC continued to generate free cash flow deficits, which were funded by a $250 million equity contribution from the City.
- DBRS views the equity contribution by the City as a positive outcome as it alleviated pressure on credit metrics in 2017. However, the benefit is expected to be offset by higher dividend payouts in 2017 and future years.

2018 Outlook

- Operating cash flow is expected to be lower compared with 2017 because of higher cash taxes and settlement variances.
- DBRS expects annual capex to remain consistent with 2017 levels (gross capex of $553 million) over the next several years.
- Dividends are expected to be higher as the Company's policy beginning 2018 is to pay out 60% of the previous year's net income after net movements in regulatory balances.
- THC's high capex needs and dividends are expected to generate cash flow deficits that are likely to be funded by debt. Leverage is likely to be modestly higher than 2017 levels; however, it is expected to remain within the regulatory capital structure (60% debt: 40% equity).

Liquidity and Long-Term Debt Maturities

Liquidity

For the year ended December 31, 2017 (CAD millions)	Amount	Drawn/CPs/LOCs	Available	Expiry
Cash & Cash Equivalents	-	-	-	-
Revolving Credit Facility	800.0	159.0	641.0	Oct 10, 2022
Prudential Facility	75.0	38.4	36.6	Demand
Working Capital Facility	20.0	11.7	8.3	Demand
Total			**685.9**	

- The Company's liquidity profile remains adequate to cover near- to medium-term obligations, with approximately $686 million of available facilities.
- THC has a $600 million CP program. The CP program is backstopped by the $800 million revolving credit facility with a maturity date of October 10, 2022. As at December 31, 2017, $159 million was drawn under this facility for CP issuance.
- The Company also has a $75 million Prudential Facility (demand facility) for the purpose of issuing letters of credit mainly to support prudential requirements with the Independent Electricity System Operator (rated A (high) with a Stable trend by DBRS) and a $20 million Working Capital Facility.

Debentures

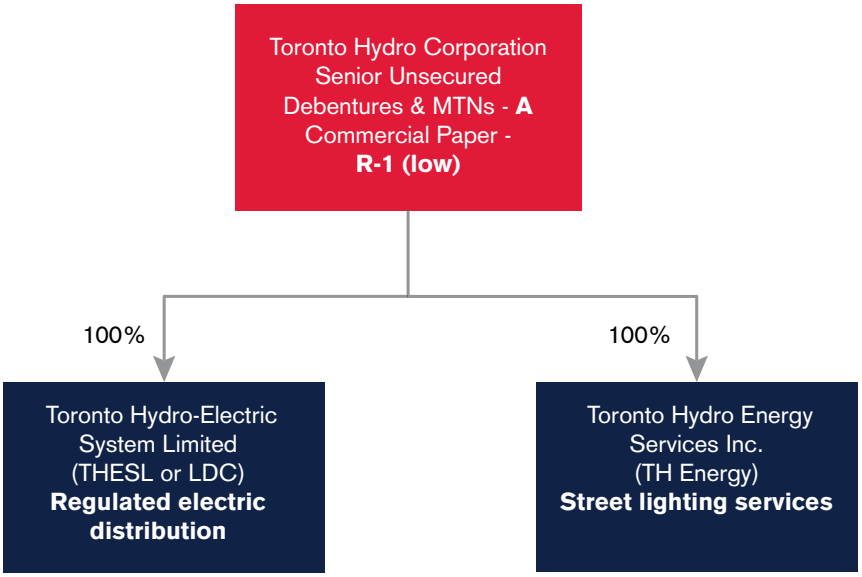
	Maturity	Outstanding (CAD millions)
Series 3 - 4.49%	Nov. 12, 2019	250
Series 6 - 5.54%	May 21, 2040	200
Series 7 - 3.54%	Nov. 18, 2021	300
Series 8 - 2.91%	Apr. 10, 2023	250
Series 9 - 3.96%	Apr. 9, 2063	245
Series 10 - 4.08%	Sep. 16, 2044	200
Series 11 - 3.55%	Jul. 28, 2045	200
Series 12 - 2.52%	Aug. 25, 2026	200
Series 13 - 3.485%	Feb. 28, 2048	200
Total Debentures		**2,045**
Less: Unamortized debt issuance costs		(11)
Long-Term Portion of Debentures		**2,034**

Debentures Maturities

	2018	2019	2020	2021	2022	2022+	Total
Debentures (CAD millions)	-	250	-	300	-	1,495	2,045
% of Total	0%	12%	0%	15%	0%	73%	100%

- Debt maturities are reasonably staggered and manageable, and THC continues to have adequate access to debt capital markets.
- The Company filed a base shelf prospectus on May 8, 2017, for issue of debentures up to $1.0 billion.
- On November 14, 2017, $250.0 million of THC's Series 2 debentures matured and were repaid with proceeds from the issue of $200 million of 3.485% senior unsecured debentures due February 28, 2048.

Corporate Structure



- THC is a holding company with the following subsidiaries operating in the Toronto area:
  - THESL is one of the largest municipal electricity distribution utilities in Canada (99% of revenue).
  - Toronto Hydro Energy Services Inc., which has a contractual relationship with the City, owns and operates street lighting services (1% of revenue).
- The Company serves approximately 768,000 customers.
- A large portion of the energy produced in Ontario is generated by Ontario Power Generation Inc. (rated A (low) and R-1 (low) with Stable trends by DBRS), then transmitted to THC's networks by Hydro One Inc. (rated A (high) and R-1 (low) with Stable trends by DBRS). THC distributes the power to its customers via overhead and underground power lines, has a peak load of approximately 4,400 megawatts and distributes 19% of the electricity distributed in Ontario.

Regulation

- THESL is regulated by the OEB and operates under a supportive regulatory environment (Please refer to page 7). The Company has a good track record of prudently managing its regulatory risk.
- THESL operates with a deemed capital structure of 60% debt (56% long term and 4% short term), 40% equity and an allowed ROE of 9.30% from 2015 to 2019.
- The CIR framework approved by the OEB for THESL is a hybrid between cost of service (COS) and an incentive rate mechanism (IRM) for a five-year term. The rate setting for the term is based on THESL's forecasts and OEB's incentive rate analysis using productivity benchmarking. CIR is suited to distributors with large, broad, multi-year investment needs over a five-year period or more and to distributors who require certainty of funding several years in advance.
- THESL filed a rate application with the OEB under CIR in July 2014, seeking approval of its 2015 test-year revenue requirement and corresponding electricity distribution rates effective May 1, 2015, and subsequent annual rate adjustments based on a custom index for the period January 1, 2016, to December 31, 2019.
- On December 29, 2015, the OEB approved THESL's application and issued a final rate order on March 1, 2016, as follows:
  1. THESL's rates set on a five-year CIR basis effective May 1, 2015, to December 31, 2019.
  2. Total capex funding of approximately $2.2 billion approved for the 2015–2019 period, an approximate 10% reduction from the $2.5 billion applied for by THESL.
  3. OEB also approved an annual rate adjustment based on a custom index (2017 inflation of 1.9% and a stretch factor of 0.6%), allowing for rates to rise by approximately 1.3% in 2017, in addition to a capital factor mechanism for enhanced incremental capex funding.
  4. THESL is required to share non-capital-related earnings in excess of 100 basis points (bps) over the allowed ROE (9.3%) equally between the Company and its customers.
  5. THESL can request a regulatory review (off ramp) should actual ROE vary from the allowed ROE by 300 bps (either positive or negative).

Regulation (CONTINUED)

Criteria	Score	Analysis
Deemed Equity	Excellent Good **Satisfactory** Below Average Poor	The OEB allows THESL's distribution business to have a deemed equity of 40%, which has been consistent historically.
Allowed ROE	Excellent **Good** Satisfactory Below Average Poor	The OEB has approved the ROE at 9.3% from 2015 to 2019.
Energy Cost Recovery	**Excellent** Good Satisfactory Below Average Poor	There is no power price risk, as THESL is not responsible for purchasing power from generation facilities or the wholesale market. Power costs are passed on to ratepayers, and THESL collects the payments from its customers on a monthly basis effective Jan 2017.
Capital Cost Recovery	Excellent **Good** Satisfactory Below Average Poor	Major capital costs are pre-approved for a five-year period by the OEB and recoveried through distribution rates.
COS vs. IRM	Excellent Good **Satisfactory** Below Average Poor	THESL operates under the CIR (hybrid of COS and IRM) from 2015 to 2019. Productivity and inflation factors are reasonable.
Political Interference	Excellent Good **Satisfactory** Below Average Poor	The government of Ontario plays a significant role in the electricity sector in Ontario, given that the majority of the utilities are government owned (THC is owned by City). Furthermore, stakeholders such as independent Electricity System Operator is also government owned. As a result, the government has direct and indirect influence on Ontario's electricity industry.
Stranded Cost Recovery	Excellent **Good** Satisfactory Below Average Poor	THC has a limited history of stranded costs. Most prudently incurred or budgeted capital expenditures are approved by the OEB. DBRS notes that there can be some regulatory lag in the approval of capital expenditures.
Rate Freeze	Excellent Good **Satisfactory** Below Average Poor	From 2002 to 2005, as a result of rising rates during Ontario's experimental utility deregulation phase, a province-wide distribution rate freeze was imposed. There have been no subsequent province-wide rate freezes.

Toronto Hydro Corporation

Balance Sheet

(CAD millions)	December 31 2017	2016	2015
Assets			
Cash & equivalents	0	0	0
Accounts receivable	218	230	192
Inventories	9	10	10
Unbilled revenue	278	321	320
Prepaid expenses & other	21	14	20
Total Current Assets	**527**	**574**	**542**
Net fixed assets	4,143	3,907	3,589
Future income tax assets	57	64	114
Goodwill & intangibles	296	218	199
Regulatory assets	173	173	232
Investments & others	30	19	11
Total Assets	**5,226**	**4,954**	**4,687**

	December 31 2017	2016	2015
Liabilities & Equity			
Bank indebtedness	171	268	338
Accounts payable	516	504	474
Current portion L.T.D.	0	250	0
Customer advanced deposits	49	39	38
Deferred revenue	11	5	5
Other current liab.	24	17	21
Total Current Liab.	**771**	**1,083**	**876**
Long-term debt	2,034	1,835	1,885
Deferred income taxes	68	83	141
Provisions	313	281	297
Regulatory liabilities	51	65	12
Other L.T. liab.	229	179	136
Shareholders' equity	1,760	1,429	1,341
Total Liab. & SE	**5,226**	**4,954**	**4,687**

	For the year ended December 31 [2] 2017	2016	2015	2014	2013
Liquidity & Capital Ratios					
Current ratio	0.68	0.53	0.62	0.62	0.80
Total debt in capital structure	55.6%	62.2%	62.4%	60.6%	57.0%
Total debt in capital structure [1]	55.6%	62.4%	62.8%	61.1%	57.6%
Cash flow/Total debt	16.7%	15.9%	15.3%	14.9%	18.6%
Cash flow/Total debt [1]	16.7%	15.9%	15.2%	14.9%	18.4%
(Cash flow-dividends)/Capex (times)	0.61	0.61	0.53	0.43	0.62
Dividend payout ratio	53.4%	44.6%	45.6%	54.8%	38.4%
Coverage Ratios (times)					
EBIT gross interest coverage	2.78	2.72	2.40	2.67	2.50
EBITDA gross interest coverage	5.34	5.16	4.79	5.33	4.51
Fixed-charges coverage	2.78	2.70	2.37	2.62	2.45
EBIT gross interest coverage [1]	2.78	2.70	2.37	2.62	2.45
Profitability Ratios					
EBITDA margin	61.5%	61.8%	58.7%	58.0%	55.9%
EBIT margin	32.0%	32.6%	29.4%	29.1%	31.0%
Profit margin	18.4%	19.6%	18.6%	17.3%	19.4%
Return on equity	8.8%	10.3%	9.5%	8.7%	9.5%
Return on capital	6.3%	6.4%	5.7%	5.7%	6.5%

1 Including operating leases. **2** 2014 to 2017 based on IFRS; 2013 based on USGAAP.

Rating History

	Current	2017	2016	2015	2014	2013	2012
Issuer Rating	A	A	A	A	A (high)	A (high)	A (high)
Senior Unsecured Debentures & MTNs	A	A	A	A	A (high)	A (high)	A (high)
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	NR

Previous Action

- "DBRS Confirms Ratings of Toronto Hydro Corporation with Stable Trends," April 23, 2018.

Related Research

- "DBRS Comments on Toronto Hydro Receiving Equity from the City of Toronto," June 29, 2017.

Commercial Paper Limit

- CAD 600 million.

Previous Report

- Toronto Hydro Corporation: Rating Report, April 27, 2017.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on www.dbrs.com.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

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EXISTING ACCOUNTING ORDERS AND DEPARTURES FROM USoA

Toronto Hydro confirms that it has, to the best of its knowledge, materially complied with the Uniform System of Accounts ("USoA") as set out in the OEB's Accounting Procedures Handbook ("APH"), and with the following utility-specific accounting orders:

- Impact for USGAAP Deferral Account, effective January 1, 2012, to record the financial impacts resulting from the transition to and implementation of USGAAP;[1]
- Sub-Accounts to Account 1508 – Other Regulatory Assets, effective June 1, 2013, relating to Incremental Capital Module ("ICM") amounts;[2]
- Sub-Accounts to Account 1508 – Other Regulatory Assets, to record the costs and revenues associated with wireless pole attachments;[3]
- Sub-Accounts to Account 1508 – Other Regulatory Assets, to record the variance between actual and approved revenue requirement related to third party initiated relocation and expansion projects;[4]
- Sub-Accounts to Account 1508 – Other Regulatory Assets, to record the variance between actual and approved amounts related to derecognition of assets;[4]
- Sub-Accounts to Account 1508 – Other Regulatory Assets, to record the incremental costs and savings related to the transition of Residential and General Service customers to monthly billing;[4]
- Sub-Accounts to Account 1508 – Other Regulatory Assets, to record the variance between actual and forecasted gains net of tax with the gross up for the PILs tax savings related to the sale of 5800 Yonge and 28 Underwriters properties;[4]

[1] EB-2012-0079, Decision and Order (June 7, 2012).
[2] EB-2012-0064, Rate Order (May 9, 2013).
[3] EB-2012-0234, Decision and Accounting Order (June 5, 2014).
[4] EB-2014-0116, Decision and Order (December 29, 2015).

- Sub-Accounts to Account 1508 – Other Regulatory Assets, to record the revenue requirement impact relating to the ICM true-up process;[4]
- Sub-Accounts to Account 1508 – Other Regulatory Assets, to record the variance between actual and approved cumulative 2015 – 2019 capital in-service additions related revenue requirement included in rates;[4]
- Sub-Accounts to Account 1508 – Other Regulatory Assets, to record the difference between the forecasted other post-employment benefit costs calculated using the accounting accrual method versus actual cash payments made;[4] and
- Sub-Accounts to Account 1508 – Other Regulatory Assets, to record any earnings outside of Toronto Hydro's approved annual return on equity exceeding a +/- 100 basis-point dead band.[4]

Toronto Hydro-Electric System Limited
EB-2018-0165
Exhibit 1C
Tab 3
Schedule 10
ORIGINAL
(120 pages)

ENERGIZING GROWTH AND INNOVATION

2017 ANNUAL REPORT







TORONTO HYDRO® Corporation



MESSAGE

FROM THE CHAIR OF THE BOARD, AND PRESIDENT AND CHIEF EXECUTIVE OFFICER

We're pleased to present Toronto Hydro's 2017 Annual Report, which we've titled *Energizing Growth and Innovation*. The title reflects the corporation's commitment to effectively and sustainably power the growth of Toronto, and to employ innovative approaches across our business to meet the city's evolving needs. In 2017, we continued to invest in and maintain the city's electricity system, while also focusing on new ways to safely store and distribute power to Canada's largest city.

PRIORITIZING EMPLOYEE AND PUBLIC SAFETY – Ensuring the safety of our employees and the public is our number one priority. In 2017, we were recognized again as one of Canada's safest employers, receiving the 2017 Canadian Electricity Association President's Award of Excellence for Employee Safety. We also continued with our efforts to increase the electrical safety knowledge of our customers to help keep them safe.

Our commitment to safety extends to emergency preparedness. Internally, we continued to implement our Grid Emergency Management program established in 2014 to help improve our response to extreme weather events. As part of our commitment to mutual assistance, we also deployed mutual aid resources to four American utilities following severe weather events.

DELIVERING CUSTOMER VALUE – Customer service and delivering customer value is a core part of how we do business, and we believe that openness and transparency is an important part of serving our customers better. To that end, we launched a Customer Value Scorecard that we publicly release on our website every quarter, and introduced Customer Advisory Panels to help align our approach with the needs and preferences of our customers. We also offered our customers enhanced tools and services to help make doing business with us simple, easy and convenient. This included the launch of ***Power****Lens*®, a new platform that shows customers how their homes use electricity so they can take steps towards saving. In recognition of our customer service initiatives, we were awarded the 2017 Customer Service award by the Ontario Energy Association.

Helping our customers save electricity and better manage their bills remains one of our biggest priorities. In 2017, our CDM programs led to an estimated energy savings of 353,000 MWh and reduced summer peak demand by 43 MW. We also assisted the government by implementing its Fair Hydro Plan developed to reduce electricity costs through a number of initiatives. For our most vulnerable residents, we continued to promote assistance programs such as the Low-Income Energy Assistance Program, the Home Assistance Program and the Ontario Electricity Support Program.

ENERGIZING GROWTH AND INNOVATION

PROGRESSIVE AND SUSTAINABLE SOLUTIONS – To meet the challenge of growing electricity demand, we're focusing on innovative, integrated energy solutions to help us build the grid of the future. In 2017, we continued to monitor the world's first grid-scale pole-mounted energy storage system, which is showing promising results in the early stages of a pilot program. We also announced a collaboration with Metrolinx to build a battery energy storage system capable of providing backup and emergency power for the Eglinton Crosstown light rail transit (LRT) line.

AS TORONTO CONTINUES TO GROW, WE'RE WORKING HARD TO ENSURE THAT WE'RE PREPARED TO MEET OUR CITY'S EVOLVING NEEDS.

We've been recognized as a Sustainable Electricity Company™ by the Canadian Electricity Association (CEA) since 2014, and we continue to pursue strategic projects to promote a sustainable future for Toronto. In order to encourage our employees to transition to electric vehicles (EVs), in 2017, we installed four charging stations at our location at 500 Commissioners Street. We also sponsored Plug'n Drive, a non-profit organization helping to accelerate the adoption of EVs, and powered two charging stations at the Plug'n Drive Electric Vehicle Discovery Centre in Toronto.

INVESTING IN INFRASTRUCTURE RENEWAL – We invested $552.9 million primarily to renew our aging infrastructure to address service reliability, safety and customer service requirements. In addition, we invested approximately $60 million in an upgrade to Hydro One's transmission grid serving the west end of the city, which is expected to benefit thousands of residents and businesses in Toronto. We also supported major capital investment projects across the city, including Metrolinx's Light Rail Transit (LRT) expansion and the City of Toronto's revitalization and relocation projects.

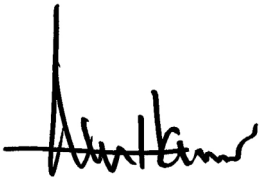
STRONG FINANCIAL RESULTS – Once again, Toronto Hydro had a highly successful year, resulting in a $156.5 million net income after net movements in regulatory balances. Our strong 2017 results were a reflection of our commitment to customer service and operational excellence. We also received a $250 million equity investment from the City of Toronto, and in connection with that investment, we declared the following dividends payable to the City and approved amendments to our Dividend Policy: an aggregate amount of $75 million in respect of fiscal 2017, and in respect of fiscal 2018 and subsequent fiscal years, 60% of Toronto Hydro's immediately previous year's annual consolidated net income after net movements in regulatory balances.

We're proud of the advancements we made in 2017, and encourage you to read more about our accomplishments in the Progress section of this report.

On behalf of the Board of Directors and the senior management team, we thank our customers and stakeholders for their continued support of Toronto Hydro. We would especially like to thank all of our employees for their hard work over the past year. Toronto Hydro's accomplishments are a result of your determination, perseverance and dedication to this organization.



David McFadden
Chair



Anthony Haines
President and Chief Executive Officer



Toronto Hydro Corporation Board of Directors

GOVERNANCE

Corporate Governance

The Corporation has developed sound corporate governance practices. The Corporation's Board of Directors and management believe that strong corporate governance is essential for creating shareholder value and maintaining investor confidence.

Board of Directors

The Board of Directors of the Corporation is responsible for supervising the management of the business and affairs of the Corporation and, along with the subsidiary boards of directors, its subsidiary entities. The Board of Directors of the Corporation is composed of eight independent directors and three city councillors. All directors are appointed by the sole shareholder of the Corporation. The Board of Directors has four regularly scheduled meetings each year but meets as often as is necessary to fulfill its responsibilities to the Corporation.

The Board of Directors has put in place a system of corporate governance that meets the requirements of applicable provincial legislation and Canadian securities rules. As part of its ongoing commitment to good corporate governance, the Board of Directors operates in accordance with a board mandate, and its committees operate in accordance with committee charters, which are all reviewed and approved by the Board of Directors.

The members of the Corporation's Board of Directors as of December 31, 2017 are introduced here. The description indicates committee and subsidiary Boards of Directors' participation.

Effective January 1, 2017, the City, as the sole shareholder of the Corporation, re-appointed Councillor Paul Ainslie, Deputy Mayor Stephen Holyday (as the Mayor's designate), and Deputy Mayor Denzil Minnan-Wong to the Board of Directors for a term ending November 30, 2018, or until their successors are appointed.

Effective April 26, 2017, the City appointed Juliana Lam to the Board of Directors. The appointment is effective for a term ending April 26, 2019, or until her successor is appointed.

Effective December 10, 2017, the City re-appointed David McFadden, Brian Chu, Heather Zordel, the Honourable Howard Wetston, Senator, Mary Ellen Richardson, Michael Nobrega and Tamara Kronis to the Board of Directors for a term ending December 10, 2019, or until their successors are appointed.

Code of Business Conduct and Whistleblower Procedure

All employees, officers and directors of the Corporation and its subsidiaries are required to comply with the principles set out in the Code of Business Conduct and Whistleblower Procedure (the Code), which was implemented by the Corporation in 2003, and is reviewed, revised and approved by the Board from time to time. The Code provides guidance to all employees in situations of perceived conflict of interest. All employees, officers and directors of the Corporation and its subsidiaries are required to complete training in respect of the Code and attest to compliance with the Code upon commencement of employment and every three years thereafter. The Code provides for the appointment of an Ethics Officer and establishes a direct hotline to the Ethics Officer by which perceived violations of the principles set out in the Code may be reported, anonymously or otherwise. The Ethics Officer reports quarterly to the Human Resources and Environment Committee of the Board of Directors on the nature of complaints received and the Vice-President, Audit and Corporate Compliance, reports quarterly to the Audit Committee of the Board of Directors on matters related to audit and accounting. Where the complaint involves the conduct of a director or officer of the Corporation, the Ethics Officer is required to report it to the Chair of the Human Resources and Environment Committee, or, where such conduct relates to questionable auditing or accounting matters, to the Chair of the Audit Committee, who oversees the investigation of that complaint. A copy of the Corporation's Code of Business Conduct and Whistleblower Procedure is available on our website.

Disclosure Policy

The Board of Directors recognizes the importance of ensuring that communications to the public about the Corporation and its subsidiaries are timely, factual, accurate and are broadly disseminated in accordance with all applicable legal and regulatory requirements. To ensure consistent and appropriate disclosure practices, the Corporation has adopted a Disclosure Policy to govern the disclosure by its employees, officers and directors, and those specifically authorized to speak on Toronto Hydro's behalf. The Corporation has also established a Disclosure Policy Committee composed of senior executives to assist the Chair, the President and Chief Executive Officer, and other authorized spokespersons in making accurate, complete and timely disclosure. The composition and operation of the Disclosure Policy Committee, and its functional subcommittee, are established in the Disclosure Policy.

Committees of the Board of Directors

The Board of Directors believes that its ability to discharge its responsibilities is enhanced by the active participation of committees in the corporate governance process. Currently, there are three standing committees of the Board of Directors: Audit Committee, Corporate Governance and Nominating Committee, and Human Resources and Environment Committee. Each committee meets regularly throughout the year and provides a report at meetings of the Board of Directors on material matters considered by the committee.

Audit Committee

The Audit Committee is responsible for overseeing the adequacy and effectiveness of financial reporting, accounting systems, internal financial control structures and financial risk management systems. The Audit Committee reviews the Corporation's and each of its subsidiaries' quarterly and annual financial statements, as well as financial statements prepared in connection with the requirements of applicable regulatory authorities, reviews the audit plans of the external auditors, oversees the internal audit of the Corporation, reviews and makes recommendations to the Board with respect to the payment of dividends or distribution of capital by the Corporation, and recommends the external auditor to the Board for appointment by the Corporation's sole shareholder.

Corporate Governance and Nominating Committee

The Corporate Governance and Nominating Committee is responsible for considering and making recommendations to the Board of Directors with respect to matters relating to the corporate governance of the Corporation and its subsidiaries, including board and committee composition and mandates, guidelines for assessing the effectiveness of the Board and its committees, and procedures to ensure that the Board of Directors functions independently from management.

As part of its governance function, the Corporate Governance and Nominating Committee reviews a skills matrix for all potential director candidates, which is then forwarded to the Corporation's sole shareholder by the Board of Directors. The Corporate Governance and Nominating Committee also nominates independent candidates for appointment to the Board of Directors of Toronto Hydro-Electric System Limited for approval by the Corporation's Board of Directors as required by the Affiliate Relationships Code. The Corporate Governance and Nominating Committee reviews and approves all orientation and education materials and programs for new and current directors undertaken by management. The Corporate Governance and Nominating Committee is also responsible for periodically reviewing reports on the activities of Toronto Hydro's corporate compliance and policy functions.

Human Resources and Environment Committee

The Human Resources and Environment Committee is responsible for reviewing and assisting the Board of Directors in overseeing the recruitment and assessment of the CEO and the compensation of the CEO, reviewing and approving the compensation of executive officers, reviewing and approving executive compensation disclosure under applicable securities laws, and reviewing and making recommendations to the Board of Directors regarding the compensation structure and benefit plans and programs of the Corporation and its subsidiaries. The Human Resources and Environment Committee is also responsible for reviewing and approving the parameters of collective bargaining negotiations, the oversight of health and safety related matters and processes, and the oversight of environmental related matters and processes of the Corporation and its subsidiaries.

BOARD OF DIRECTORS



David McFadden, Chair

- Counsel, Gowling WLG
- Former Member, Board of Trustees and Executive Committee, Gowling WLG
- Chair, 407 International Inc.
- Chair, PCI Geomatics Inc.
- Director and Former Chair, Ontario Energy Association
- Director, Cricket Energy Holdings Inc.
- Member, Energy Transformation Network of Ontario, Independent Electricity System Operator
- Member, Advisory Board of the MaRS Advanced Energy Centre
- Member, Board of Governors, York University
- Member, Council for Clean and Reliable Electricity
- Member, Law Society of Ontario
- Former Member, Ontario Government's Electricity Distribution Sector Review Panel
- Former Member, Ontario Government's Electricity Conservation and Supply Task Force
- Former Co-Chair, Electricity Transition Committee of the Ontario Government
- Former Chair, Ontario Centres of Excellence

Committee Memberships

- *Ex-Officio* Member, Audit Commitee
- *Ex-Officio* Member, Human Resources and Environment Committee
- *Ex-Officio* Member, Corporate Governance and Nominating Committee



Brian Chu, Vice-Chair

- Partner, Bogart Robertson & Chu LLP
- Director, and Member of Safety Regulatory Affairs Committee, Technical Standards & Safety Authority
- Member, Canadian Tax Foundation
- Member, Law Society of Ontario
- Former Trustee and Chair, Centennial Centre of Science and Technology (Ontario Science Centre)
- Former Vice-Chair, Centennial College
- Former Chair, Board of Governors, Ontario College of Art and Design
- Former President, Laidlaw Foundation

Committee Memberships

- Human Resources and Environment Committee (Chair)
- Corporate Governance and Nominating Committee



Councillor Paul Ainslie

- City of Toronto Councillor, Ward 43 - Scarborough East
- Chair, City of Toronto - Government Management Committee
- Chair, City of Toronto - Toronto Zoo Board of Management
- Member, City of Toronto - Executive Committee
- Member, City of Toronto - Scarborough Community Council
- Member, City of Toronto - Toronto Public Library
- Member, Board of Directors of the Federation of Ontario Public Libraries
- Member, Canadian National Exhibition Association, Municipal Section
- Member, Board of Directors of Guild Renaissance Group
- Member, Board of Directors of the Ontario Good Roads Association
- Member, Toronto and Region Conservation Authority
- Former Co-Chair, Rouge Valley Health System Centenary Buy a Bed Fundraising Campaign
- Past Chair, Board of Directors of Haliburton Club

Committee Membership

- Corporate Governance and Nominating Committee



Deputy Mayor Stephen Holyday, Mayor's Designate

- Deputy Mayor, City of Toronto
- City of Toronto Councillor, Ward 3 - Etobicoke Centre
- Chair, City of Toronto - Audit Committee
- Vice-Chair, City of Toronto - Employee and Labour Relations Committee
- Vice-Chair, City of Toronto - Public Works and Infrastructure Committee
- Member, City of Toronto - Etobicoke York Community Council
- Member, City of Toronto, George Bell Arena Nominating Panel
- Mayor's Designate, Board of Directors, Toronto Atmospheric Fund
- Member, Canadian National Exhibition Association, Municipal Section
- Member, Board of Directors, Hockey Hall of Fame
- Former Acting Manager and Manager, Service Management, Ontario Ministry of Energy

Committee Membership

- Human Resources and Environment Committee

ENERGIZING GROWTH AND INNOVATION



Tamara Kronis

- Member of the Board of Directors, Toronto Hydro Energy Services Inc.
- Owner, Chief Goldsmith, Gemmologist and Jewellery Designer, Studio1098
- Member, Law Society of Ontario
- Former Legal Counsel, Vertex Customer Management/Vertex Outsourcing
- Former Associate Lawyer, Torys LLP
- Former Director of Advocacy, EGALE Canada
- Former Trial Assistant, United Nations (International Criminal Tribunal for the former Yugoslavia)
- Fellow, Canadian Gemmological Association
- Fellow, Gemmological Association of Great Britain

Committee Membership

- Corporate Governance and Nominating Committee (Chair)



Juliana Lam

- Executive Vice-President and Chief Operating Officer, Chartered Professional Accountants of Ontario
- Former Executive Vice-President & CFO, Uranium One Inc.
- Former Senior Vice-President, Finance, Kinross Gold Corporation
- Former Chief Financial Officer, Nexans Canada Inc.
- MBA, CPA, CA and ICD.D designations

Committee Memberships

- Audit Committee
- Human Resources and Environment Committee



Deputy Mayor Denzil Minnan-Wong

- City of Toronto Deputy Mayor
- City of Toronto Councillor, Ward 34 - Don Valley East
- Chair, City of Toronto - Civic Appointments Committee
- Chair, City of Toronto - Striking Committee
- Chair, City of Toronto - Employee and Labour Relations Committee
- Vice-Chair, City of Toronto - Executive Committee
- Mayor's Designate, Waterfront Toronto Board
- Member, Toronto Transit Commission Board
- Member, City of Toronto - Committee of Revision
- Member, North York Community Council
- Member, City of Toronto - Debenture Committee
- Member, City of Toronto – Corporations Nominating Panel
- Member, Law Society of Ontario
- Former Chair, City of Toronto – Public Works and Infrastructure Committee
- Former Chair, City of Toronto, Economic Development Committee
- Former Chair, North York Community Council
- Former Member, City of Toronto – Planning and Transportation Committee
- Former Member, City of Toronto – Works and Emergency Services Committee
- Former Member, City of Toronto Audit Committee
- Former Member, Toronto Financial Service Advisory Committee
- Former Mayor's Designate, BUILD Toronto Board
- Former Mayor's Designate, Invest Toronto Board



Michael Nobrega

- Chair, Ontario Centres of Excellence
- Member, Board of Directors, IBI Group Inc.
- Former President and CEO, Ontario Municipal Employees Retirement System (OMERS)
- Former Chief Investment Officer, OMERS
- Former President and CEO, Borealis (OMERS) Infrastructure
- Former Partner, Arthur Andersen, Chartered Accountants
- Former Member, Board of Directors, Global Risk Institute
- Recipient, University of Toronto Arbor Award
- Fellow, Institute of Chartered Accountants of Ontario

Committee Memberships

- Audit Committee (Chair)
- Human Resources and Environment Committee



Mary Ellen Richardson

- Member of the Board of Directors, Toronto Hydro Energy Services Inc.
- Member, Board of Directors, Human Resources and Governance and Finance and Audit Committees, and Chair, Government Relations Committee, Markham District Energy Inc.
- Former President, Canadian District Energy Association
- Former Vice-President, Corporate Affairs, and Vice-President, Conservation Programs and External Relations, Ontario Power Authority
- Former President, Association of Major Power Consumers in Ontario
- Former Member, Board of Directors, and Human Resources Committee, Guelph Municipal Holdings Inc.
- Former Member, Management Board, Ontario Centres of Excellence in Energy
- Former Member, Board of Directors, Environmental Careers Organization of Canada
- Former Member, Ontario Government's Electricity Conservation and Supply Task Force
- Former Member, Executive of the Stakeholders' Alliance for Competition and Customer Choice
- Former Member, Customer Advisory Board, Hydro One

Committee Membership

- Corporate Governance and Nominating Committee



The Honourable Howard Wetston, Senator

- Chair of the Board of Directors, Toronto Hydro-Electric System Limited
- Senator, Senate of Canada
- Counsel, Goodmans LLP
- Member, Advisory Board, Spark Power Corp.
- Former Member, Advisory Board, Program on Ethics in Law and Business, University of Toronto
- Former Member, Advisory Board, Shannon School of Business, Cape Breton University
- Former Chair and Chief Executive Officer, Ontario Securities Commission
- Former Vice-Chair, Ontario Securities Commission
- Former Chair and Chief Executive Officer, Ontario Energy Board
- Former Judge, Federal Court of Canada, Trial Division
- Former Ex-officio Judge of the Federal Court of Canada's Appeal Division
- Former Senior Member, Canadian Securities Administrators
- Former Vice-Chair, International Organization of Securities Commissions
- Former Director, Investigations and Research, Bureau of Competition Policy (Commissioner of Competition)
- Trustee, International Valuations Standards Council
- Competition Policy Council, C.D. Howe Institute
- Senior Fellow, C.D. Howe Institute
- Awarded Member, Order of Canada
- Board Diversity Champion, Catalyst Canada Honours
- Recipient, Queen Elizabeth II Diamond Jubilee Medal



Heather Zordel

- Chair of the Board of Directors, Toronto Hydro Energy Services Inc.
- Partner, Securities Group, Gardiner Roberts LLP
- Co-Director and Course Director, Osgoode Hall Law School's Master of Laws program in Securities Law
- Member and Bencher, Law Society of Ontario
- Former Chair, Securities Advisory Committee, Ontario Securities Commission
- Former Member, Federal Expert Panel on Securities Regulation
- Former Member, Board of Directors, Metro Toronto Convention Centre

Committee Membership

- Audit Committee



David D. Hay*

- Managing Director, Delgatie Incorporated
- Director, EPCOR Utilities Inc.
- Chair, SHAD Valley International
- Member, Council for Clean and Reliable Energy
- Chair, Beaverbrook Art Gallery Acquisition Committee
- Former Vice-Chair and Managing Director, CIBC World Markets
- Former President and CEO, New Brunswick Power
- Former Director, Associated Electric & Gas Insurance Services AEGIS (USA)
- Former Co-Chair, New Brunswick Special Task Force "Electricity in New Brunswick and options for its future"
- Former Chair, Beaverbrook Art Gallery
- Former Senior Vice-President, Merrill Lynch Canada Inc.
- Former Managing Director, M&A, Merrill Lynch &Co., Inc. (London, England)
- Former Associate, Osler Hoskin & Harcourt
- Former Law Clerk to the Chief Justice of the High Court of the Supreme Court of Ontario
- Former Lecturer on Law and Finance, University of Toronto and University of New Brunswick
- Former Director, Star Choice Communications Inc.
- Former Director, EMR Microwave Technology Corporation



Case Ootes*

- Former Member of the Board of Governors, Seneca College
- Former Chair of Mayor Ford's Transition Team
- Former Chair of Mayor Tory's Transition Team
- Former Managing Director, Toronto Community Housing
- Former Deputy Mayor of the City of Toronto
- Former Chair of Labour Relations for the City of Toronto
- Former Chair, Toronto Financial Service Alliance
- Former Member, Toronto Police Services Board
- Former Member, Toronto Transit Commission
- Former Director, Municipal Property Assessment Corporation
- Former Director, GO Transit Board
- Former Director, Greater Toronto Marketing Alliance Board
- Former Director, Business Development Corp. Board
- Former Director, Toronto East General Hospital Board
- Former Director, Toronto Hydro Board
- Former Director, Toronto Region Conservation Board
- Former Seneca College Executive in Residence
- Former President of East York Kiwanis
- Former Corporate Credit Manager, Imperial Oil
- Former Manager of Accounting Service, Imperial Oil



Mario Silva*

- Published Author and International Legal Scholar
- Distinguished Visiting Professor at Ryerson University
- Non-Resident Fellow, Montreal Institute for Genocide and Human Rights Studies at Concordia University
- Professional Fellow of the Privacy and Cyber Crime Institute at Ted Rogers School of Management at Ryerson University
- Professional Fellow at Institute for the Study of Corporate Social Responsibility at Ted Rogers School of Management at Ryerson University
- Chair, Corporate Social Responsibility Advisory Council – Superior Medical
- Former Visiting Scholar, Faculty of Law at McGill University
- Former Member of Parliament
- Former Toronto City Councillor
- Former Chair, International Holocaust Remembrance Alliance (IHRA)
- Former Director, Toronto Hydro
- Former Director, Toronto Transit Commission
- Former Director, Exhibition Place
- Former Director, Mount Sinai Hospital
- Former Director, Canadian Opera Company
- Commander of the Order of Merit, Portugal
- Commander of the Order of Rio Branco, Brazil
- Knight, Ordre national de la Légion d'honneur, France
- Recipient, Insignia of the Autonomous Region of the Azores
- Recipient, Bridge Builder Award by the Parliament of Canada All Party Interfaith Friendship Group

*Member of the Board of Directors for Toronto Hydro-Electric System Limited only



SENIOR MANAGEMENT TEAM

The Toronto Hydro senior management team is comprised of:

Anthony Haines
President and Chief Executive Officer [1, 2]

Sean Bovingdon
Executive Vice-President and Chief Financial Officer [1, 2]

Amanda Klein
Executive Vice-President, Regulatory Affairs and General Counsel [1, 2]

Ben LaPianta
Executive Vice-President and Chief Customer Care, Electric Operations and Procurement Officer [2]

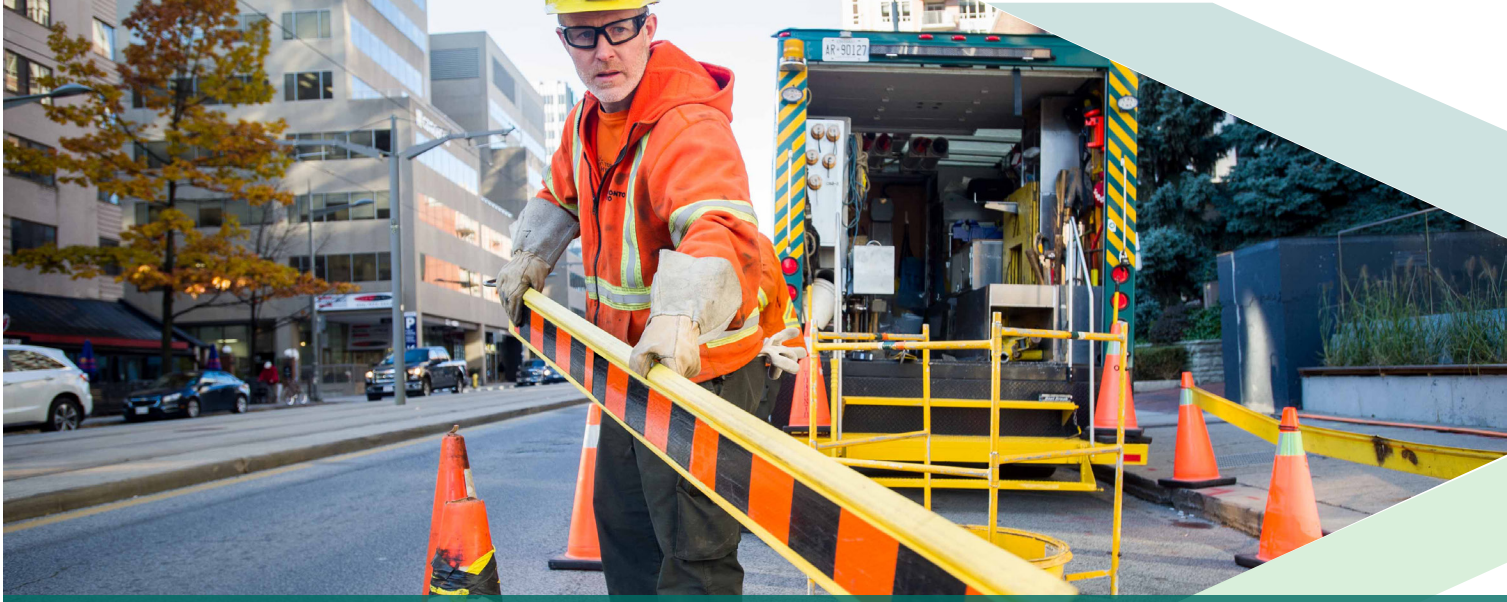
Ave Lethbridge
Executive Vice-President and Chief Human Resources and Safety Officer [2]

Dino Priore
Executive Vice-President and Chief Engineering and Construction Officer [2]

Chris Tyrrell
Executive Vice-President of Utility Innovation and Chief Conservation Officer [2]

Robert Wong
Executive Vice-President and Chief Information Officer [2]

[1] Toronto Hydro Corporation
[2] Toronto Hydro-Electric System Limited



TORONTO HYDRO CORPORATION OVERVIEW

Toronto Hydro Corporation (the Corporation) is a holding company which wholly-owns two subsidiaries:

Toronto Hydro-Electric System Limited – distributes electricity and engages in conservation and demand management (CDM) activities

Toronto Hydro Energy Services Inc. – provides street lighting and expressway lighting services in the city of Toronto

Services

- Supervises the operations of its subsidiaries
- Provides corporate, management services and strategic direction to its subsidiaries

2017 Achievements

- Invested $552.9 million primarily in the renewal of aging infrastructure to address service reliability, safety and customer service requirements
- Raised $800,000 at the company's fourth annual golf tournament in support of Sunnybrook's renowned Ross Tilley Burn Centre
- Raised more than $153,000 for United Way Toronto and York Region and was recognized with a United Way Spirit Award
- Received an equity investment of $250 million from the City of Toronto and issued the City an additional 200 common shares
- On November 14, 2017, the Corporation issued $200.0 million of 3.485% senior unsecured debentures at a price of $999.29 per $1,000 principal amount due February 28, 2048
- As at December 31, 2017, the debentures issued under the Corporation's medium-term note program were rated "A" by DBRS Limited and "A" by Standard & Poor's. The commercial paper issued under the Corporation's commercial paper program was rated "R-1 (low)" by DBRS Limited

2018 Objectives

The Corporation aims to:

- Provide customers value for money
- Maintain an engaged, safe and healthy workforce that meets changing business requirements
- Improve reliability through optimal and sustainable system management
- Meet the financial objectives of its Shareholder



BALANCED SCORECARD

The Corporation measures performance in relation to the achievement of strategic objectives by using a balanced scorecard approach. Key Performance Indicators (KPIs) are monitored throughout the year and appropriate actions are taken as required.

The performance objectives of the Corporation in 2017 were as follows:

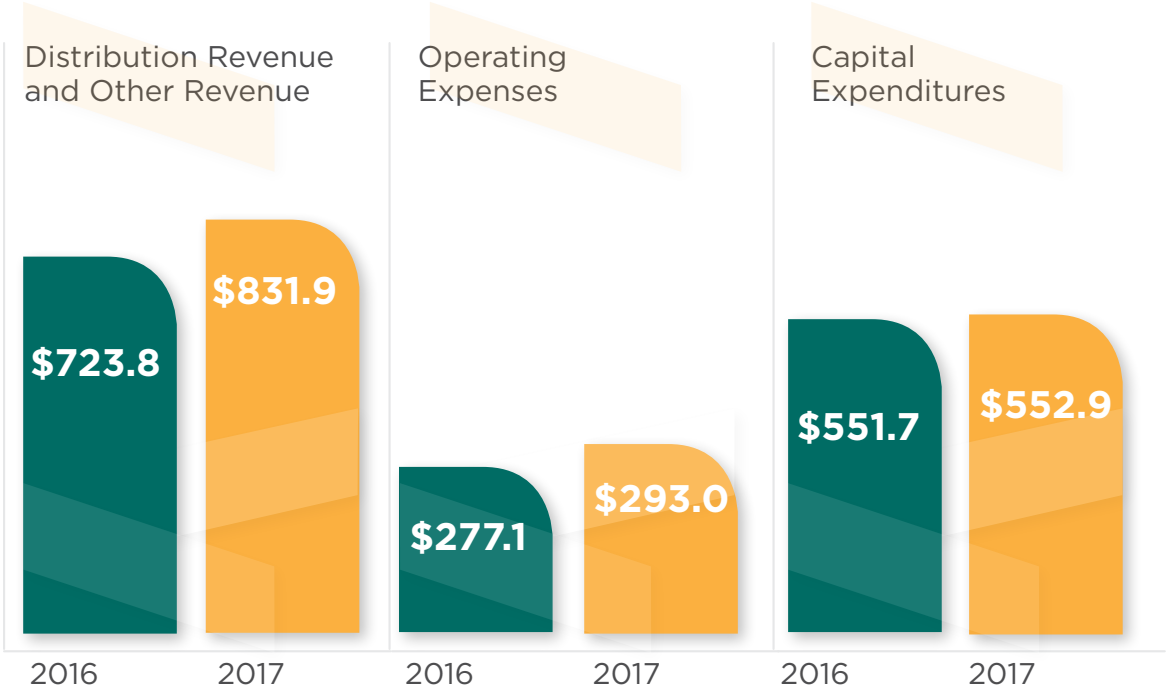
CORPORATE KEY PERFORMANCE INDICATORS	MEASURE	2017 TARGET
Net income after net movements in regulatory balances ($ millions)	Net Income after net movements in regulatory balances per the Corporation's Consolidated Financial Statements	$145.0
Local Distribution Company (LDC) Regulated Capital ($ millions)[1]	Achievement of LDC's capital work program	$370.5
System Average Interruption Duration Index (SAIDI) (in minutes) (Defective equipment only)	Measure of the annual system average interruption duration per customer served, not including Major Event Days	29.71
System Average Interruption Frequency Index (SAIFI) (Number of interruptions) (Defective equipment only)	Measure of the frequency of service interruptions per customer served, not including Major Event Days	0.56
First Call Resolution	Percentage of telephone enquiries resolved within one call, within a 21-day time period	83.0%
Bill Accuracy	The percentage of issued bills that are considered accurate or inaccurate as defined by the Ontario Energy Board	98.6%
New Services Connected On Time	Percentage of connections for new low-voltage (<750 volts) service requests completed within five business days from the day on which all applicable service conditions are satisfied, or at such later date as agreed to by the customer	96.0%
Safety	Number of recordable injuries x 200,000/exposure hours	1.50

[1] *This is a non-GAAP measure as it includes all eligible capital expenditures, net of capital contributions related to regulated operations excluding Copeland Station and the facilities consolidation program.*



FACTS & FIGURES

Toronto Hydro Corporation (in millions of Canadian dollars)



1,440 (APPROXIMATE)

Number of Employees

as at December 31, 2017

Toronto Hydro-Electric System Limited

0.99 HOURS

System Average Interruption Duration Index

1.43 INTERRUPTIONS

System Average Interruption Frequency Index

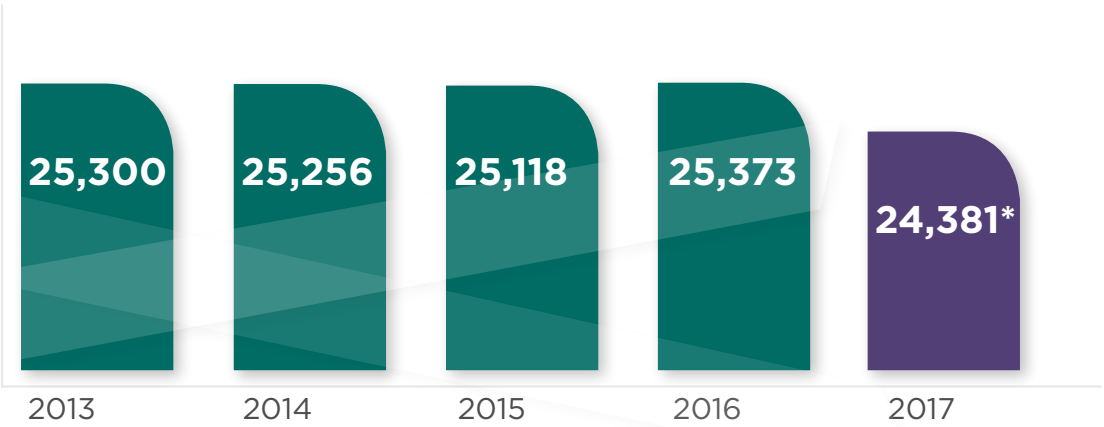
0.69 HOURS

Customer Average Interruption Duration Index

4,316 MEGAWATTS

Peak Load on September 26, 2017

Electricity Delivered (GWh)



* Note: Lower electricity consumption due to cooler than expected summer.

ENERGIZING GROWTH AND INNOVATION

Number of Customers



768,000
(APPROXIMATE)

685,292
RESIDENTIAL SERVICE

82,233 GENERAL SERVICE
with monthly peak demand of 5,000 kW or less averaged over a twelve-month period

44 LARGE USERS
with monthly peak demand of more than 5,000 kW averaged over a twelve-month period

Electricity Distribution by Class (GWh)



4,933
RESIDENTIAL SERVICE

17,277
GENERAL SERVICE

2,171
LARGE USERS

Electricity Distribution by Class (%)



20% RESIDENTIAL SERVICE

71% GENERAL SERVICE

9% LARGE USERS

Toronto Hydro Corporation 2017 Capital Expenditures (in millions of Canadian dollars)

Regulated Local Distribution Company [1]	
Distribution System	
Planned [2]	$373.0
Reactive	48.1
Copeland Station	23.2
Facilities Consolidation	35.2
Technology assets	54.9
Other [3]	10.5
Regulated capital expenditures	$544.9
Unregulated capital expenditures [4]	8.0
TOTAL	$552.9

[1] Refers to Toronto Hydro-Electric System Limited
[2] Includes, among other initiatives, the replacement of underground and overhead infrastructure, station programs, and the delivery of customer connections
[3] Includes fleet capital and buildings
[4] Primarily relates to streetlighting and generation equipment

Electricity Distribution System is serviced from:

(approximate)

34	terminal stations
1	transmission system terminal station
17,350	primary switches
60,540	distribution transformers
153	in-service municipal substations
15,540	kilometres of overhead wires supported by
178,800	poles and approximately
13,220	kilometres of underground wires
1	Control Centre
5	Operations Centres



2017 ANNUAL REPORT GLOSSARY

Customer Average Interruption Duration Index (CAIDI)	A measure (in hours) of the average duration of interruptions experienced by customers, not including Major Event Days (MED). CAIDI represents the quotient obtained by dividing the System Average Interruption Duration Index (SAIDI) by the System Average Interruption Frequency Index (SAIFI). See below for more explanation.
Gigawatt-Hour (GWh)	A standard unit for measuring electrical energy produced or consumed over time. One GWh is equal to one million kilowatt-hours.
Kilowatt (kW)	A common measure of electrical power equal to 1,000 watts.
Kilowatt-Hour (kWh)	A standard unit for measuring electrical energy produced or consumed over time. One kWh is the amount of electricity consumed by ten 100-watt light bulbs burning for one hour.
Major Event Days (MED)	Refers to major event days as defined by IEEE Standard 1366-2012, IEEE Guide for Electric Power Distribution Reliability Indices.
Megawatt (MW)	A common measure of electrical power equal to one million watts.
Megawatt-Hour (MWh)	A standard unit for measuring electrical energy produced or consumed over time. One MWh is the amount of electricity consumed by 10,000 100-watt light bulbs burning for one hour.
Peak Load	The maximum demand for power, measured in megawatts, that occurs within a stated period of time. Toronto Hydro's peak system load (or peak demand) normally occurs in the summer because of power demands from air conditioning.
System Average Interruption Duration Index (SAIDI)	A measure (in hours) of the annual system average interruption duration for customers served, not including MED. SAIDI represents the quotient obtained by dividing the total customer hours of interruptions longer than one minute by the number of customers served.
System Average Interruption Frequency Index (SAIFI)	A measure of the frequency of service interruptions for customers served, not including MED. SAIFI represents the quotient obtained by dividing the total number of customer interruptions longer than one minute by the number of customers served.



TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

Toronto Hydro-Electric System Limited owns and operates $4.4 billion of capital assets comprised primarily of an electricity distribution system that delivers electricity to approximately 768,000 customers located in the city of Toronto. It serves the largest city in Canada and distributes approximately 19% of the electricity consumed in the province of Ontario.

Services

- Committed to delivering safe and reliable electrical power to approximately 768,000 residential, commercial and industrial customers in the City of Toronto, which has a population base of approximately 2.8 million
- Plans, maintains and aims to operate its electricity distribution infrastructure efficiently and in an environmentally responsible manner
- Strives to provide consistent, high-quality customer service
- Designs and delivers CDM programs

2017 Achievements

- Among the leading local distribution companies in the delivery of CDM programs to help customers conserve energy, save money and help the environment
- Recognized as a Sustainable Electricity Company™, a designation by the Canadian Electricity Association
- Continued work on Copeland transformer station, the first transformer station built in downtown Toronto since the 1960s, and the second underground transformer station in Canada
- Supported major capital investment projects across the city, including: Metrolinx's Light Rail Transit (LRT) expansion and GO Regional Electrification of Rail Program, Toronto Transit Commission's Scarborough Subway Extension project and Easier Access Program, the City of Toronto's revitalization and relocation projects and the Ministry of Transportation's Bridge Rehabilitation projects

ENERGIZING GROWTH AND INNOVATION

- Collaborated with Metrolinx on plans to build a battery energy storage system that will provide backup and emergency power for the Eglinton Crosstown LRT
- Invested approximately $60 million to upgrade electricity infrastructure in the city's west end
- Continued to monitor the world's first grid-scale pole-mounted energy storage system, which is showing promising results in the early stages of a pilot program
- Recognized again as one of Canada's safest employers, receiving Canada's Safest Employers Gold Safety Award in the Utilities and Electrical Category, and the 2017 Canadian Electricity Association President's Award of Excellence for Employee Safety
- Continued to improve digital communication channels with more enhancements to online tools, including the launch of the ***Power****Lens*® portal, a new platform that shows customers how their homes use electricity so they can take steps towards saving
- Deployed Mutual Aid resources to four American utilities following severe weather events
- Continued annual safety campaign to remind the public of electrical safety hazards on the street and at home
- Supported Georgian College's engineering facility to help train future electrical utility workers and fund curriculum development
- Participated in the Centre for Urban Energy at Ryerson University, an academic-industry collaboration that explores and develops sustainable solutions to urban energy challenges
- Sponsored Plug'n Drive, a non-profit organization committed to accelerating the adoption of electric vehicles, and powered two public charging stations at its Electric Vehicle Discovery Centre in northern Toronto



PROGRESS

Supporting the unprecedented growth in our city requires coming up with innovative solutions to new challenges. We continue to apply that spirit of innovation across our business to further our progress in customer service, grid investment, sustainability and emergency preparedness.

In 2017, we engaged our customers through multiple channels to help them save energy and improve their electrical safety knowledge. To meet growing electricity demand, we invested in innovative energy solutions to support a reliable and resilient grid. We also continued to promote a sustainable future for our city and promoted emergency preparedness to help Torontonians be prepared for any situation.

The progress we made in 2017 will help to energize the growth and innovation driving our grid, our people and our city, now and for years to come. The sections that follow highlight some of the notable accomplishments and advancements.



Customer Service

For us, customer service and delivering customer value are what's important. How do we benefit our customers and how can we make things easier for them? To answer these questions, we place an emphasis on understanding evolving customer needs and expectations, and to hear them directly from our customers, we introduced Customer Advisory Panels. The Panels are designed to regularly engage a diverse group of customers to obtain valuable feedback on ideas, initiatives and programs, and to help align our approach with their needs and preferences.

With this in mind, in 2017, we made further improvements to make doing business with us simple, easy and convenient. At the same time, we promoted and introduced programs to help customers better manage their bills. Also, to help keep the public safe, we continued with our efforts to increase the electrical safety knowledge of our customers.

- Being open, transparent, and accountable to our customers is also important to us. In order to do this publicly, we launched our Customer Value Scorecard, which includes many of the customer value performance measures from our annual business plan
- We improved digital communication tools, including the launch of the ***Power****Lens*® portal, a platform that shows customers how their homes use electricity so they can take steps towards saving. ***Power****Lens*® provides a breakdown of electricity use by hour, day or month, electricity consumption by device and appliance type, and custom action plans tailored to a customer's home and habits. Customers can set usage and cost alerts, find contractor and rebate information, as well as create annual electricity reduction goals, track progress, take action, win prizes and earn points towards e-gift cards



- We launched three new programs for our commercial and business customers:
  - **Business Refrigeration Incentive** offers a rebate of up to $2,500 to upgrade eligible refrigeration systems. The program also includes a free on-site refrigeration energy audit, a personalized action plan and free professional installation
  - **RTUsaver** includes the installation of a free Wi-Fi enabled programmable thermostat, following a free rooftop air conditioner unit (RTU) checkup to ensure it's in good working order
  - **OPsaver** is designed for larger commercial, institutional and industrial customers, and encourages continuous energy improvement through operational and behavioural change
- In 2016, we worked with nearby distribution companies to pilot an instant rebate retail program for energy-efficient products. The success of this pilot led to the 2017 launch of Deal Days, a province-wide program based on the same instant rebate concept. Deal Days eliminate the need for paper vouchers and supports sustainability efforts, while also improving the customer retail experience



- We worked with the Ontario government to implement its Fair Hydro Plan, which was developed to help reduce electricity costs through a number of initiatives
- We continue to serve our vulnerable customers though community outreach by building awareness and promoting a variety of programs including the Ontario Electricity Support Program (OESP), Low-Income Energy Assistance Program (LEAP) and Home Assistance Program (HAP), which can help customers reduce and manage electricity costs. In 2017, we promoted these programs at more than 140 events, which included over 7,400 customer interactions
- Once again, we exceeded the Ontario Energy Board's bill accuracy threshold of 98%
- We continued to encourage our customers to move to paperless billing as a more convenient, sustainable and cost-effective way to receive bills. As a result, 30% of our customers are now receiving eBills – that's an increase of 400% since 2011
- Our call centre resolved customer concerns in the first call 88% of the time, which is 2% higher than in 2016. The number of issues escalated beyond the first call decreased by 33%
- Our key account team managed the relationships with our largest business customers by providing customized energy-saving opportunities and offering specific solutions to meet their business needs

ENERGIZING GROWTH AND INNOVATION

- We introduced a new video series featuring the Bombillas – an animated family intended to reflect Toronto's diversity. Each month, the videos used stories to convey important information about electrical safety, customer care, conservation and capital infrastructure investments



- To help prevent contact with underground electrical cables, we encouraged customers to call Ontario One Call – a free service that lets homeowners and contractors know what's located underground – before starting any work that involves digging. This was in response to approximately 60 claims of homeowners or contractors hitting underground electrical equipment in Toronto in 2016
- We promoted electrical safety throughout the year via newsletters and bill inserts, social media and at events to increase the electrical safety knowledge of our customers
- We warned customers about text, email and phone-based scams, and provided tips to help them recognize and protect themselves from fraudulent behaviour
- We were awarded the 2017 Customer Service award by the Ontario Energy Association for demonstrating excellence in customer service, specifically for sustaining high levels of customer satisfaction and the design and delivery of new, innovative programs to help customers manage their electricity costs

Learn more about our customer care initiatives.



Grid Investment

Electricity infrastructure is the trusted backbone of Toronto's economic and social life. With the city continuing to experience unprecedented growth, keeping up with growing demand remains a pressing challenge. To meet this challenge, we're focused on improving, innovating and investing in our grid to serve our customers now and into the future.

In addition to replacing aging electrical infrastructure as part of a long-term infrastructure renewal investment program, we're also developing smart grid technology to help reduce outage restoration times and increase the responsiveness of our distribution system. This is expected to help improve reliability and enhance the overall customer service experience. That work includes investing in the kinds of innovative, integrated energy solutions we need to create the grid of the future.



- In 2017, we invested $552.9 million primarily in the renewal of aging infrastructure to address safety, reliability and customer service requirements
- Since 2010, the average number of service interruptions has improved by approximately 19%, and the average duration of interruptions has improved by approximately 24%
- We invested approximately $60 million in an upgrade to Hydro One's transmission grid serving the west end of the city. It's expected that thousands of residents and businesses in Toronto will benefit from the upgrades through greater capacity for growth, better reliability and resiliency against outages on the distribution system. As the power grid in Toronto is interconnected, the work being done in the west end will help electricity flow to the entire city
- To help support Toronto's renewable energy goals, we continued to support renewable generation through enabling infrastructure and direct project investments. In 2017, we interconnected 198 solar projects representing approximately 10 MW, the equivalent of removing 1,100 homes off the grid

ENERGIZING GROWTH AND INNOVATION

- We continued work on the Clare R. Copeland Transformer Station, only the second underground transformer station of its kind in Canada. In 2017, we installed, tested and commissioned major electrical equipment including power transformers and high and medium voltage switchgear. We also installed and energized the electric station service equipment, and completed the installation and landscaping of the machine shop. When completed, Copeland Station will provide electricity to buildings and neighbourhoods in the central-southwest area of Toronto
- We continued to monitor the world's first grid-scale pole-mounted energy storage system, which showed positive results in the early stages of a pilot program. Developed by Ryerson University and piloted by Toronto Hydro using eCAMION battery technology, this unique energy storage system is mounted to the top of an existing hydro pole. The system stores energy during off-peak hours and releases power as needed. From initial results, the energy storage system has demonstrated an ability to reduce strain on the local transformer. (If successful, the system could become a standard that's introduced with new installations on over 175,000 poles across the city)



- We collaborated with Metrolinx on plans to build a battery energy storage system for the Eglinton Crosstown light rail transit (LRT) line, which will increase reliability of the line, lower operating costs and reduce emissions. The power system will be capable of providing backup and emergency power to the LRT line in the event of a widespread power outage, and will also benefit local residents by providing additional reliability to customers in the area. The system will have the power capacity of 10 MW – enough to power the equivalent of approximately 11,000 homes – making it the largest battery energy storage project we've been involved with to date
- We continued to work with the Independent Electricity System Operator (IESO) Central Toronto Working Group for its Integrated Regional Resource Plan (IRRP), which looks at where the demand for electricity is growing and how this can be managed over the next 25 years. As a member, we regularly participate in IRRP meetings and provide advice on the development of plan options, including innovative solutions to address Toronto's future electricity needs

Learn more about our grid.



Sustainability Initiatives

Sustainability is a key part of our corporate culture—it's embedded in our business strategy and daily operations. Since 2014, we've been recognized as a Sustainable Electricity Company™ by the Canadian Electricity Association (CEA), making us one of four electrical utilities in Canada to be awarded this prestigious designation. While we're humbled to be recognized for our sustainability efforts, we know that it's simply the right thing to do for our customers, our city and our planet.

Sustainable Electricity Company™ | Canadian Electricity Association

In our 2016 Annual Report, we began sharing an annual comparison of our sustainability results to demonstrate our progress. We're continuing to share this information with you and plan to do so each year. We regularly monitor and assess our energy consumption, waste streams and procurement practices to reduce our environmental footprint and improve organizational efficiency. We also encourage our customers to be part of the shift to a sustainable economy by encouraging the use of electrified transportation, offering online billing to reduce paper consumption, and promoting a variety of conservation and home energy-efficiency programs.

- We've continued to work with residential, small business, industrial and commercial customers to implement energy-efficiency projects through our Conservation and Demand Management (CDM) programs. In 2017, our CDM programs led to an estimated energy savings of 353,000 MWh*, reduced summer peak demand by 43 MW and helped to reduce GHG emissions in the city by 14,120 tCO_2e
- Our total GHG emissions were 34,792 tCO_2e – a decrease of 7% relative to 2016
- In November 2017, we underwent and passed an external audit to upgrade our existing Environmental Management System certification from the International Organization for Standardization's 2004 Environmental Management Systems Standard (ISO 14001:2004) to the 2015 version of the standard (ISO 14001:2015). Additionally, the audit confirmed that Toronto Hydro has continued to maintain its Occupational Health and Safety Assessment Series

ENERGIZING GROWTH AND INNOVATION

Standard for Occupational Health and Safety Management Systems (OHSAS 18001:2007) certificate. The auditor, Intertek, declared the management element of Toronto Hydro's Environmental, Health and Safety Management System to be of benchmark status

- We earned the top spot on *Corporate Knights'* fourth annual Future 40 Responsible Corporate Leaders in Canada list, in recognition of our sustainability achievements. This marked the third time we've been named to the list. The Future 40 ranking is a prestigious annual ranking that's recognized internationally and designed to showcase Canada's emerging sustainability leaders
- Our President and CEO, Anthony Haines, was recognized as a Responsible CEO of the Year Award by *Corporate Responsibility (CR) Magazine,* which marked the first time a Canadian CEO has been given this prestigious award. The award is presented to CEOs who visibly exceed standards in the areas of employee relations, environmental impact, sustainability, human rights, philanthropy and corporate responsibility practices
- Anthony Haines also received the 2017 Individual Leadership on Sustainability Award from the CEA for outstanding leadership on sustainability issues within the electricity sector
- We completed construction of a Toronto Hydro-owned building at 715 Milner Avenue as part of our Facilities Consolidation program, aimed at making better use of space at existing work centres. As a result, we moved out of a leased building at 601 Milner. As part of the construction, we reused 35 tonnes of existing furniture, recycled 38 tonnes of furniture and resold or donated 24 tonnes of furniture. The donated furniture was given to organizations such as Toronto Furniture Bank and Habitat for Humanity. In total, 88% of the furniture from the building at 601 Milner was diverted from landfill
- In addition to recycling solid non-hazardous waste from our facilities, we've been recycling wood poles removed from service, fluorescent lights, batteries and electronic waste. In 2017, we diverted 535 metric tonnes of wood poles from landfill compared to 490 tonnes diverted in 2016
- We developed a Corporate Waste Recycling Rate – that accounts for a broader pool of waste streams – to provide a more comprehensive picture of our waste diversion efforts. In 2017, our Corporate Waste Diversion Rate was 93%
- We continued to use and install the Governor to Reduce Idle and Pollution (GRIP) technology on our vehicles, and downsized our fleet by 12 vehicles. We also implemented a pilot project in collaboration with Centennial College and eCamion to test the effectiveness of lithium ion batteries in vehicles, and trialed the use of electric power take-off for our bucket trucks. The cumulative 2017 savings, relative to 2013, associated with our fleet-related initiatives are: 36% reduction in total fuel consumed; 35% reduction in GHG emissions; 0.4% reduction in kilometres travelled; and 43% reduction in total non-PTO idling hours**





- In order to encourage our employees to transition to electric vehicles (EVs), we installed four charging stations at our 500 Commissions Street location in 2017, and there are plans to install charging stations at 71 Rexdale Boulevard and 715 Milner Avenue in 2018. We also initiated a project to replace small cars in our fleet with fully-electric vehicles
- We sponsored Plug'n Drive, a non-profit organization committed to accelerating the adoption of EVs. We also powered two charging stations in the test drive zone at the Plug'n Drive Electric Vehicle Discovery Centre in Toronto, the world's first experiential learning facility dedicated to EV education and awareness
- We contributed to advancing the transition to EVs through participation in various working groups and associations, including the City of Toronto's EV Working Group and the Canadian Urban Transit Research & Innovation Consortium
- We implemented the use of secure pull printing, which requires employees to use their access cards at our printers. This ensures that all printed documents are collected from the printer, thereby reducing wasted paper. We also implemented the use of tablets for issuing and completing facilities-related work orders. Previously, work orders were issued on paper and submitted for filing once completed. When combined with similar initiatives carried out in earlier years, we have reduced our annual paper consumption by approximately 3,073,000 sheets of paper, which equates to a savings of approximately 39 tCO_2e of associated GHG emissions in 2017, when compared to 2013
- For the fourth consecutive year, we hosted our annual charity golf tournament, raising $800,000 through our partners and sponsors for Sunnybrook's Ross Tilley Burn Centre – the largest, most advanced adult burn centre in Canada – for a total of $2.6 million raised in four years

ENERGIZING GROWTH AND INNOVATION



- Our employees, along with their friends and families, planted 300 trees and shrubs at Earl Bales Park for our annual Tree Planting Event, which we hosted in collaboration with Local Enhancement & Appreciation of Forests (LEAF) and the Parks, Forestry & Recreation division of the City of Toronto. Since 2004, we've planted more than 4,300 trees across the city
- Our employees raised more than $153,000 for United Way Toronto and York Region, surpassing last year's total by almost $10,000, and we received a 2017 United Way Spirit award in recognition of our employee campaign
- To raise awareness and increase participation in our conservation programs and online services, we participated in almost 200 event days, including 46 community events, 72 retail Deal Days events, 36 business events and 34 councillor-hosted Environment Days, generating approximately 52,000 interactions in total. These events give us the opportunity to build close ties with the communities we serve on a regular basis and educate our customers about energy conservation
- To help support local organizations committed to a sustainable future, we continued to sponsor several community groups and events, including: LEAF, Cycle TO, the Toronto Light Festival, CityFest, Cavalcade of Lights, the Kids' World of Energy Festival and Amici's Canoe Heads for Kids
- We hosted two Brighter Nights™ community events, where we replaced old, burnt-out or inefficient porch lights with more energy-efficient bulbs to help make the community safer. The Brighter Nights™ program is a joint effort with the City of Toronto's Community Crisis Response Program, Toronto Community Housing, Toronto Police Service, and local community groups and volunteers

SUSTAINABILITY INITIATIVES CONTINUED

We're proud of our progress. Below we share our performance for some of our sustainability initiatives by highlighting results from the past two years:

CATEGORY	METRIC	RESULTS 2017	RESULTS 2016	OUR PERFORMANCE
Conservation and Demand Management (CDM)	Energy saved through CDM programs	353.0 GWh	273.2 GWh	29% increase
Paper Purchased	Annual amount of paper purchased, including all paper sizes, but excluding speciality paper (e.g. plotter paper, business cards, etc.)	4,276,850 sheets of paper	4,724,450 sheets of paper	9% decrease
Kilometres (km) Travelled	Based on GPS data obtained from Fleet Assets & Maintenance Department	3,137,617 km	3,407,236 km	8% decrease
Fuel Usage (consumption)	Annual fuel consumption obtained from 4Refuel truck-to-truck fueling, use of 500 Commissioners pumps and TChek gas cards. This includes all types of fuel used by Toronto Hydro vehicles	1,013,115 litres	1,119,575 litres	10% decrease
Non-PTO Idling Time	Calculations are based on data gathered through vehicles' GPS system	59,768 hours	74,342 hours	20% decrease

Learn more about our sustainability efforts.

**2017 CDM energy and peak demand savings have not yet been verified by the Independent Electricity System Operator (IESO). Final results expected to be available in July 2018 following an IESO evaluation.*

*** Some of our vehicles (e.g. bucket trucks) require engines to be kept on (idling) in order to charge and operate the vehicle hydraulics. This is referred to as PTO idling time .*



Emergency Preparedness

Emergencies – such as those caused by extreme weather – have the potential to significantly impact our ability to deliver power to our customers. To help guard against this, we continue to implement a new emergency management program to help improve our emergency response. We also remind our customers throughout the year about the importance of emergency preparedness. When an emergency situation does occur, we want to be prepared so that we're able to help ourselves and our neighbours – whether they happen to be across the street or across the border.

- We continued to implement our Grid Emergency Management program, established in 2014, to help improve our response to extreme weather events. In 2017, we developed and incorporated: playbooks containing emergency management plans for high-risk capital projects; an awareness program for our staff to help familiarize them with our emergency management program; and seminars, training and tabletop exercises with senior management. We also hosted a functional exercise for the first time, which included almost 90 employees and tested 38 emergency roles over an 11-hour simulation period
- We encouraged Torontonians to create or check their 72-hour emergency kit throughout the year through tips we shared at community events, in our newsletters, on social media and through weather-triggered content on The Weather Network
- We supplied close to 1,600 emergency kits to vulnerable residents at over 140 community events
- We received a Silver Award of Excellence from the Canadian Public Relations Society for our Emergency Preparedness Hacks video series



EMERGENCY PREPAREDNESS CONTINUED



- To help us build a strong local network of support for responding to emergencies, we continued to work with critical infrastructure and public safety groups from the public sector, utilities, transportation and public health, including: the City of Toronto, the Office of the Fire Marshal, Ontario Power Generation, Toronto Transit Commission, Greater Toronto Airports Authority, Metrolinx, and Scarborough and Rouge Hospital
- We continued to maintain a strong, proactive role as a member of the North Atlantic Mutual Assistance Group (NAMAG), which brings together utilities from provinces and states along the northeast that have formally agreed to provide assistance to each other during emergencies. In October, members of our emergency management team attended the NAMAG Fall Conference, where NAMAG members worked on strengthening mutual aid processes through panel discussions, presentations and reviews
- We're also members of the Canadian Mutual Assistance Group (CanMAG), coordinated through the Canadian Electricity Association
- As part of our ongoing commitment to mutual assistance, in 2017, we deployed mutual aid resources to four American utilities following severe weather events

Learn more about emergency preparedness.



FINANCIAL REPORT
DECEMBER 31, 2017

TORONTO HYDRO CORPORATION

TABLE OF CONTENTS

Glossary	3
Management's Discussion and Analysis	4
Executive Summary	5
Introduction	5
Business of Toronto Hydro Corporation	6
Electricity Distribution – Industry Overview	7
Results of Operations	8
Summary of Quarterly Results of Operations	15
Financial Position	16
Liquidity and Capital Resources	17
Corporate Developments	22
Legal Proceedings	24
Share Capital	24
Transactions with Related Parties	25
Controls and Procedures	25
Risk Management and Risk Factors	26
Critical Accounting Estimates	32
Significant Accounting Policies	32
Changes in Accounting Policies	32
Future Accounting Pronouncements	32
Forward-Looking Information	33
Selected Annual Information	36
Additional Information	36
Consolidated Financial Statements	37
Notes to the Consolidated Financial Statements	44

GLOSSARY

CDM – Conservation and demand management

CGU – Cash generating unit

CIR – Custom Incentive Rate-setting

City – City of Toronto

Copeland Station – The Clare R. Copeland transformer station, formerly called "Bremner Station".

Corporation – Toronto Hydro Corporation

Electricity Act – *Electricity Act, 1998* (Ontario), as amended

ERM – Enterprise risk management

ERP – Enterprise resource planning

GAAP – Generally Accepted Accounting Principles

GWh – Gigawatt hour

HONI – Hydro One Networks Inc.

IAS – International Accounting Standard

IASB – International Accounting Standards Board

ICM – Incremental Capital Module

IESO – Independent Electricity System Operator. The IESO and the Ontario Power Authority were merged under the name Independent Electricity System Operator on January 1, 2015

IFRIC – International Financial Reporting Interpretations Committee

IFRS – International Financial Reporting Standards

IRM – Incentive Regulation Mechanism

ITA – *Income Tax Act* (Canada), as amended

kW – Kilowatt

LDC – Toronto Hydro-Electric System Limited

LRAM – Lost revenue adjustment mechanism

MD&A – Management's Discussion and Analysis

MEU – Municipal electricity utility

OCI – Other comprehensive income

OEB – Ontario Energy Board

OEB Act – *Ontario Energy Board Act, 1998* (Ontario), as amended

OFHP – Ontario's Fair Hydro Plan

OFHA – *Fair Hydro Act, 2017* (Ontario)

OMERS – Ontario Municipal Employees Retirement System

OPA – Ontario Power Authority. The IESO and the OPA were merged under the name Independent Electricity System Operator on January 1, 2015

OPEB – Other post-employment benefits

OREC – *Ontario Rebate for Electricity Consumers Act*, 2016 (Ontario).

PILs – Payments in lieu of corporate taxes

PP&E – Property, plant and equipment

TA – *Taxation Act, 2007* (Ontario), as amended

TH Energy – Toronto Hydro Energy Services Inc.

US GAAP – United States Generally Accepted Accounting Principles

WMS – Wholesale Market Service



MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE YEARS ENDED DECEMBER 31, 2017 AND 2016

Executive Summary

- Net income after net movements in regulatory balances for the three months and year ended December 31, 2017 was $35.1 million and $156.5 million, respectively, compared to $23.4 million and $151.4 million for the comparable periods in 2016;
- Capital expenditures were primarily related to the renewal of the electricity infrastructure of LDC and were $148.9 million and $552.9 million for the three months and year ended December 31, 2017, respectively, compared to $149.2 million and $551.7 million for the comparable periods in 2016;
- On June 28, 2017, the Corporation issued 200 common shares to the City for total proceeds of $250.0 million, net of share issue costs and expenses;
- On August 23, 2017, LDC filed its 2018 rate application seeking OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2018 and ending on December 31, 2018. On December 14, 2017, the OEB issued a decision and rate order approving LDC's 2018 rates and the disposition of certain deferral and variance accounts;
- On November 14, 2017, the Corporation issued $200.0 million of 3.485% senior unsecured debentures due February 28, 2048;
- The Corporation's Series 2 debentures in the amount of $250.0 million, matured and were repaid on November 14, 2017; and
- Under the terms of the energy conservation agreement with the IESO for the delivery of CDM programs over the 2015 – 2020 period, the Corporation is entitled to a performance incentive if the verified mid-term electricity savings target is achieved by December 31, 2017. The Corporation exceeded the mid-term energy savings target and recognized a performance incentive of $12.2 million.

Introduction

This MD&A should be read in conjunction with the Corporation's audited consolidated financial statements and accompanying notes as at and for the years ended December 31, 2017 and 2016, which were prepared in accordance with IFRS (the "Consolidated Financial Statements").

Copies of these documents are available on the System for Electronic Document Analysis and Retrieval website at www.sedar.com.

Business of Toronto Hydro Corporation

The Corporation is a holding company which wholly owns two subsidiaries:

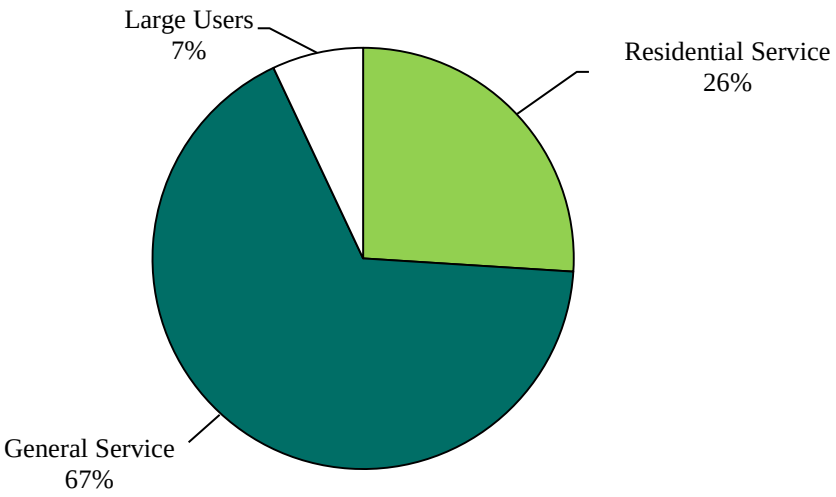
- LDC - distributes electricity and engages in CDM activities; and
- TH Energy - provides street lighting and expressway lighting services in the City.

The Corporation supervises the operations of, and provides corporate, management services and strategic direction to its subsidiaries.

The principal business of the Corporation and its subsidiaries is the distribution of electricity by LDC. LDC owns and operates an electricity distribution system, delivering electricity to approximately 768,000 customers located in the City. The City is the sole shareholder of the Corporation. LDC serves the largest city in Canada and distributes approximately 19% of the electricity consumed in Ontario. The business of LDC and other electricity distributors is regulated by the OEB, which has broad powers relating to licensing, standards of conduct and service, and the regulation of electricity distribution rates charged by LDC and other electricity distributors in Ontario. For the year ended December 31, 2017, LDC earned energy sales and distribution revenues of $3,742.0 million from general service users[1], residential service users[2] and large users[3].

LDC Energy Sales and Distribution Revenues by Class

Year ended December 31, 2017



[1] "general service" means a service supplied to premises other than those receiving "residential service" and "large users" and typically includes small businesses and bulk-metered multi-unit residential establishments. This service is provided to customers with a monthly peak demand of 5,000 kW or less averaged over a twelve-month period.

[2] "residential service" means a service that is for domestic or household purposes, including single family or individually metered multi-family units and seasonal occupancy.

[3] "large users" means a service provided to a customer with a monthly peak demand of more than 5,000 kW averaged over a twelve-month period.

Electricity Distribution – Industry Overview

In April 1999, the Government of Ontario began restructuring the province's electricity industry. Under regulations passed pursuant to the restructuring, LDC and other electricity distributors purchase electricity from the wholesale market administered by the IESO and recover the costs of electricity and certain other costs from customers in accordance with rate-setting procedures mandated by the OEB.

The OEB has regulatory oversight of electricity matters in Ontario. The OEB Act sets out the OEB's authority to issue a distribution licence that must be obtained by owners or operators of an electricity distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, separation of accounts for distribution and other activities, and requirements for rate-setting and other legal filings.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to approve the amounts paid to non-contracted generators, the responsibility to provide rate protection for rural or remote electricity customers, and the responsibility for ensuring that electricity distribution companies fulfill their obligations to connect and service customers.

LDC is required to charge its customers for the following amounts (all of which, other than distribution rates, represent a pass-through of amounts payable to third parties):

- *Commodity Charge* – The commodity charge represents the market price of electricity consumed by customers and is passed through the IESO back to operators of generating stations. It includes the global adjustment, which represents the difference between the market price of electricity and the rates paid to regulated and contracted generators.

- *Retail Transmission Rate* – The retail transmission rate represents the costs incurred in respect of the transmission of electricity from generating stations to local distribution networks. Retail transmission rates are passed through back to operators of transmission facilities.

- *WMS Charge* – The WMS charge represents various wholesale market support costs, such as the cost of the IESO to administer the wholesale electricity system, operate the electricity market, and maintain reliable operation of the provincial grid. Wholesale charges are passed through back to the IESO.

- *Distribution Rate* – The distribution rate is designed to recover the costs incurred by LDC in delivering electricity to customers, including the OEB-allowed cost of capital. Distribution rates are regulated by the OEB and include fixed and variable (usage-based) components, based on a forecast of LDC's customers and load.

LDC is required to satisfy and maintain prudential requirements with the IESO, which include credit support with respect to outstanding market obligations in the form of letters of credit, cash deposits or guarantees from third parties with prescribed credit ratings.

The Corporation is exempt from tax under the ITA if not less than 90% of the capital of the Corporation is owned by the City and not more than 10% of the income of the Corporation is derived from activities carried on outside the municipal geographical boundaries of the City. In addition, the Corporation's subsidiaries are also exempt from tax under the ITA provided that all of their capital is owned by the Corporation and not more than 10% of their respective income is from activities carried on outside the municipal geographical boundaries of the City. A corporation exempt from tax under the ITA is also exempt from tax under the TA.

The Corporation and each of its subsidiaries are MEUs for purposes of the PILs regime contained in the Electricity Act. The Electricity Act provides that a MEU that is exempt from tax under the ITA and the TA is required to make, for each taxation year, a PILs payment to the Ontario Electricity Financial Corporation in an amount equal to the tax that it would be liable to pay under the ITA and the TA if it were not exempt from tax. The PILs regime came into effect on October 1, 2001, at which time the Corporation and each of its subsidiaries were deemed to have commenced a new taxation year for purposes of determining their respective liabilities for PILs payments.

Results of Operations

Net Income after Net Movements in Regulatory Balances

Interim Consolidated Statements of Income
Three months ended December 31
(in millions of Canadian dollars)

	2017 $	2016 $	Change $
Revenues			
Energy sales	728.9	813.3	(84.4)
Distribution revenue	181.7	159.0	22.7
Other	27.7	22.0	5.7
	938.3	994.3	(56.0)
Expenses			
Energy purchases	750.7	782.6	31.9
Operating expenses	77.8	78.6	0.8
Depreciation and amortization	62.0	59.6	(2.4)
	890.5	920.8	30.3
Finance costs	(18.9)	(19.5)	0.6
Gain on disposals of PP&E	0.2	2.1	(1.9)
Income before income taxes	29.1	56.1	(27.0)
Income tax expense	(11.1)	(28.0)	16.9
Net income	18.0	28.1	(10.1)
Net movements in regulatory balances	10.9	(30.6)	41.5
Net movements in regulatory balances arising from deferred tax assets	6.2	25.9	(19.7)
Net income after net movements in regulatory balances	35.1	23.4	11.7

The increase in net income after net movements in regulatory balances for the three months ended December 31, 2017 was primarily due to higher 2017 electricity distribution rates, higher electricity consumption, and higher other revenue related to the recognition of the CDM mid-term incentive and pole and duct rentals. These variances were partially offset by amounts being deferred into capital related regulatory accounts for future refunds to customers, higher income taxes (including regulatory balances arising from deferred tax assets), and higher depreciation and amortization related to new in-service asset additions.

Consolidated Statements of Income
Year ended December 31
(in millions of Canadian dollars)

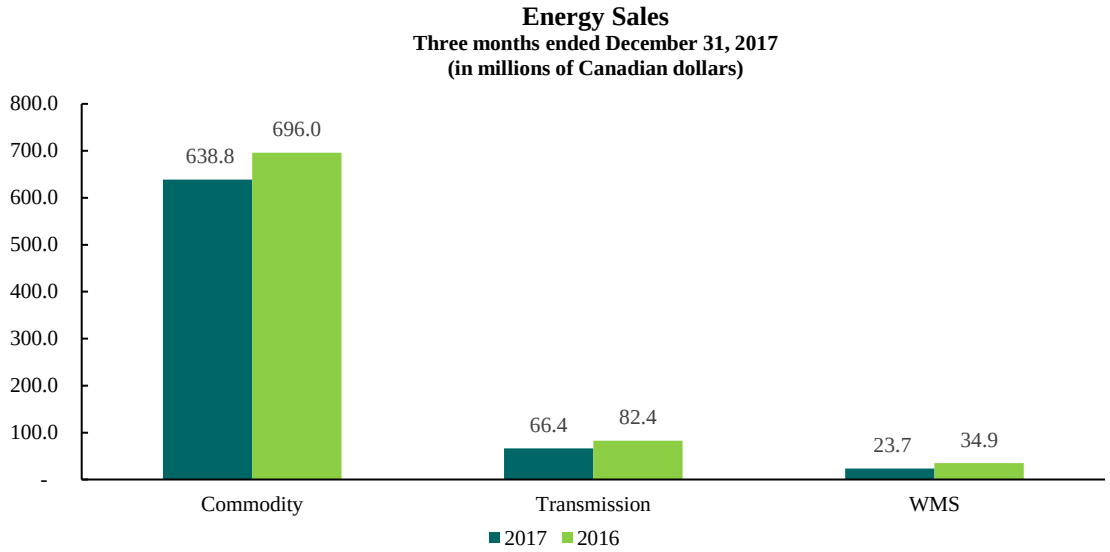
	2017 $	2016 $	Change $
Revenues			
Energy sales	3,017.8	3,306.2	(288.4)
Distribution revenue	724.2	647.9	76.3
Other	107.7	75.9	31.8
	3,849.7	4,030.0	(180.3)
Expenses			
Energy purchases	3,063.5	3,216.9	153.4
Operating expenses	293.0	277.1	(15.9)
Depreciation and amortization	224.2	212.2	(12.0)
	3,580.7	3,706.2	125.5
Finance costs	(77.7)	(74.2)	(3.5)
Gain on disposals of PP&E	9.8	2.1	7.7
Income before income taxes	201.1	251.7	(50.6)
Income tax expense	(44.7)	(67.1)	22.4
Net income	156.4	184.6	(28.2)
Net movements in regulatory balances	(13.1)	(77.2)	64.1
Net movements in regulatory balances arising from deferred tax assets	13.2	44.0	(30.8)
Net income after net movements in regulatory balances	156.5	151.4	5.1

The increase in net income after net movements in regulatory balances for the year ended December 31, 2017 was primarily due to higher 2017 electricity distribution rates and higher other revenue related to the recognition of the CDM mid-term incentive and pole and duct rentals. These variances were partially offset by lower electricity consumption, higher operating expenses in connection with system maintenance, higher depreciation and amortization related to new in-service asset additions, higher income taxes (including regulatory balances arising from deferred tax assets), amounts being deferred into capital related regulatory accounts for future refunds to customers, and a one-time residual ICM balance recorded as an increase in equity through net movements in regulatory balances in 2016. The 2016 first quarter implementation of the new electricity distribution rates also resulted in $19.2 million of foregone revenue being recorded in net movements in regulatory balances for the comparable period, instead of distribution revenue given IFRS 14 - *Regulatory Deferral Accounts* ("IFRS 14") treatment.

Energy Sales

LDC's energy sales arise from charges to customers for electricity consumed, based on regulated rates. Energy sales include amounts billed or billable to customers for commodity charges, retail transmission charges, and WMS charges at current rates. These charges are passed through to customers over time and are considered revenue by LDC. During the same period, energy sales should be equal to the cost of energy purchased. However, a difference between energy sales and energy purchases arises when there is a timing difference between the amounts charged by LDC to customers, based on regulated rates, and the electricity and non-competitive electricity service costs billed monthly by the IESO to LDC. This difference is recorded as a settlement variance, representing amounts to be recovered from or refunded to customers through future rates approved by the OEB. In accordance with IFRS 14, this settlement variance is presented within regulatory balances on the consolidated balance sheets ("Consolidated Balance Sheets")

and within net movements in regulatory balances on the consolidated statements of income and comprehensive income ("Consolidated Statements of Income").



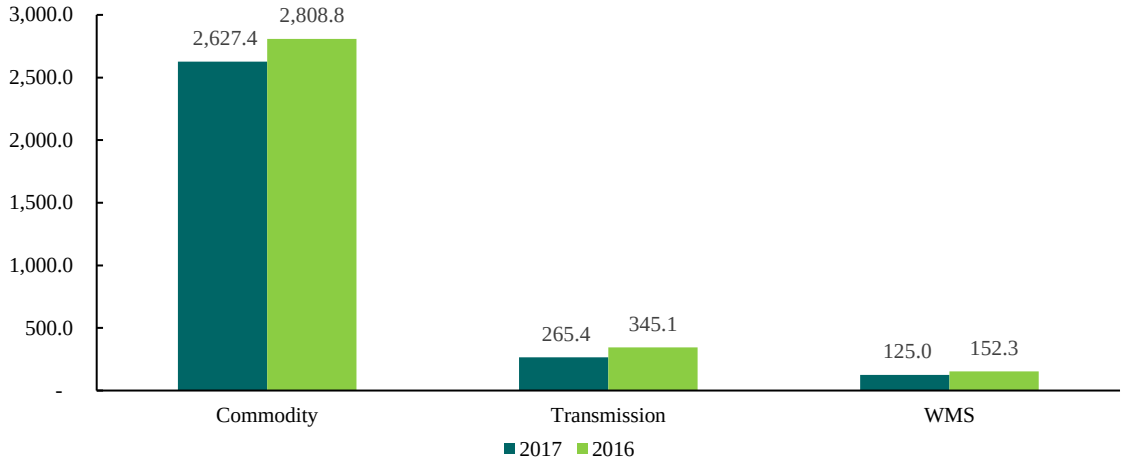
Energy sales for the three months ended December 31, 2017 were $728.9 million compared to $813.3 million for the comparable period in 2016. The decrease was primarily due to lower commodity charges ($57.2 million) and lower retail transmission charges ($16.0 million). The decrease in commodity and retail transmission charges was primarily due to lower pass-through electricity costs.

Energy Purchases , Energy Sales, and Settlement Variances
Three months ended December 31, 2017
(in millions of Canadian dollars)

	Energy Purchases $	Energy Sales $	Settlement Variances $
Commodity Charges	673.1	638.8	34.3
Retail Transmission Charges	65.2	66.4	(1.2)
WMS Charges	12.4	23.7	(11.3)
Total	750.7	728.9	21.8

For the three months ended December 31, 2017, LDC recognized $728.9 million in energy sales to customers and was billed $750.7 million for energy purchases from the IESO. The difference between energy sales and energy purchases represents a $21.8 million settlement variance for the period. The settlement variance was recorded as a decrease to the regulatory credit balance ($21.8 million including carrying charges on the accumulated settlement variance balance) on the Consolidated Balance Sheets, and presented within net movements in regulatory balances on the Consolidated Statements of Income.

Energy Sales
Year ended December 31, 2017
(in millions of Canadian dollars)



Energy sales for the year ended December 31, 2017 were $3,017.8 million compared to $3,306.2 million for the comparable period in 2016. The decrease was primarily due to lower commodity charges ($181.4 million) and lower retail transmission charges ($79.7 million). The decrease in commodity and retail transmission charges was primarily due to lower electricity consumption and lower pass-through electricity costs.

Energy Purchases, Energy Sales, and Settlement Variances
Year ended December 31, 2017
(in millions of Canadian dollars)

	Energy Purchases $	Energy Sales $	Settlement Variances $
Commodity Charges	2,681.4	2,627.4	54.0
Retail Transmission Charges	281.8	265.4	16.4
WMS Charges	100.3	125.0	(24.7)
Total	3,063.5	3,017.8	45.7

For the year ended December 31, 2017, LDC recognized $3,017.8 million in energy sales to customers and was billed $3,063.5 million for energy purchases from the IESO. The difference between energy sales and energy purchases represents a $45.7 million settlement variance for the year. The settlement variance was recorded as a decrease to the regulatory credit balance ($45.2 million including carrying charges on the accumulated settlement variance balance, see the regulatory credit balance table in note 9 to the Consolidated Financial Statements) on the Consolidated Balance Sheets, and presented within net movements in regulatory balances on the Consolidated Statements of Income.

Distribution Revenue

Distribution revenue is recorded based on OEB-approved distribution rates to recover the costs incurred by LDC in delivering electricity to customers, and includes revenue collected through OEB-approved rate riders.

Distribution revenue for the three months and year ended December 31, 2017 was $181.7 million and $724.2 million, respectively, compared to $159.0 million and $647.9 million for the comparable periods in 2016.

The increase in distribution revenue for the three months ended December 31, 2017 was primarily due to higher electricity distribution rates ($11.7 million), higher electricity consumption ($5.6 million), and additional revenue collected through OEB-approved rate riders ($5.5 million).

The increase in distribution revenue for the year ended December 31, 2017 was primarily due to higher electricity distribution rates ($48.8 million) and additional revenue collected through OEB-approved rate riders ($22.6 million), partially offset by lower electricity consumption in 2017 ($14.9 million). The remaining increase was related to the recognition of 2016 foregone revenue ($19.2 million) from the implementation of the new electricity distribution rates effective March 1, 2016, which was recorded in net movements in regulatory balances for the year ended December 31, 2016 given the IFRS 14 treatment, instead of distribution revenue.

Other Revenue

Other revenue includes revenue from services ancillary to electricity distribution, delivery of street lighting services, pole and duct rentals, amortization of deferred revenue related to capital contributions from customers, and CDM cost efficiency incentives.

Other revenue for the three months and year ended December 31, 2017 was $27.7 million and $107.7 million, respectively, compared to $22.0 million and $75.9 million for the comparable periods in 2016.

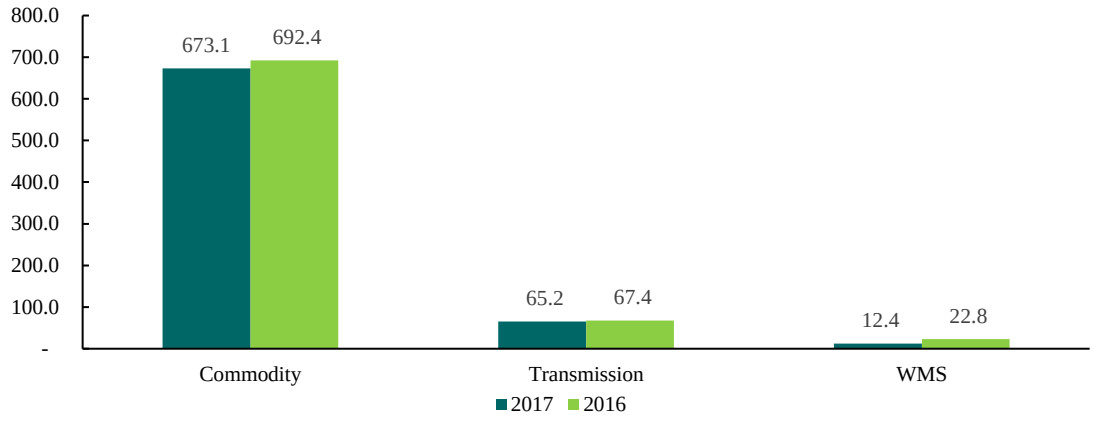
The increase was primarily due to higher revenue in connection with ancillary services, street lighting services, pole and duct rentals, recognition of the CDM mid-term incentive, and deferral of development charges. The development charges are excess expansion deposits retained by LDC where the requested number of connections or demand were not met by the connecting customer (see development charges in note 9(o) to the Consolidated Financial Statements).

The development charges were recorded as a regulatory balance on the Consolidated Balance Sheets, with a corresponding offset in net movements in regulatory balances on the Consolidated Statements of Income. This regulatory balance is expected to offset future electricity distribution rates for customers, although application has yet to be made to dispose of the balance.

Energy Purchases

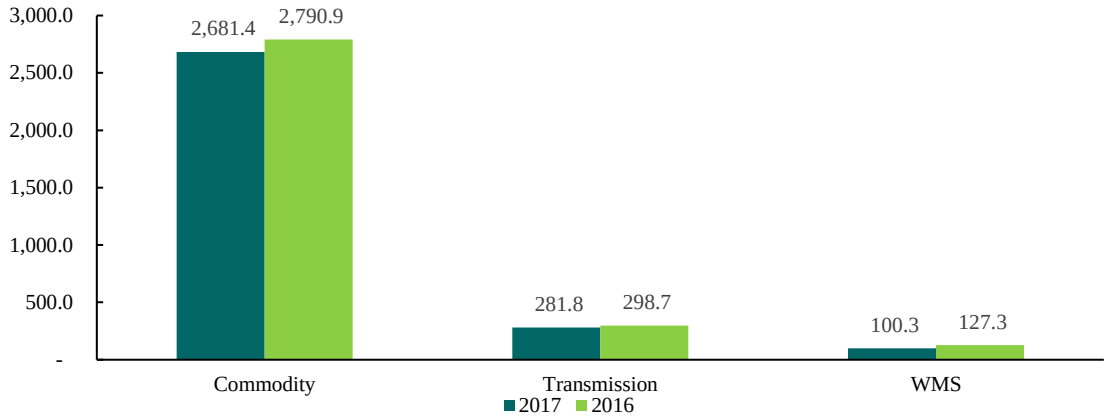
LDC's energy purchases consist of actual charges for electricity generated by third parties, which are passed through to customers over time in the form of energy sales. Energy purchases are billed monthly by the IESO and include commodity charges, retail transmission charges and WMS charges.

LDC Energy Purchases
Three months ended December 31, 2017
(in millions of Canadian dollars)



Energy purchases for the three months ended December 31, 2017 were $750.7 million compared to $782.6 million for the comparable period in 2016. The decrease was primarily due to lower commodity charges ($19.3 million) and lower WMS charges ($10.4 million). The decrease in commodity and WMS charges was primarily due to lower rates.

LDC Energy Purchases
Year ended December 31, 2017
(in millions of Canadian dollars)



Energy purchases for the year ended December 31, 2017 were $3,063.5 million compared to $3,216.9 million for the comparable period in 2016. The decrease was primarily due to lower commodity charges ($109.5 million) and lower WMS charges ($27.0 million). The decrease in commodity and WMS charges was primarily due to lower electricity consumption and lower rates.

Operating Expenses

Operating expenses for the three months and year ended December 31, 2017 were $77.8 million and $293.0 million, respectively, compared to $78.6 million and $277.1 million for the comparable periods in 2016.

The decrease in operating expenses for the three months ended December 31, 2017 was primarily due to lower street lighting maintenance costs, lower rental expenses due to expiration of rental agreements, and lower service fees for third party warehouse costs, partially offset by higher ancillary service costs.

The increase in operating expenses for the year ended December 31, 2017 was primarily due to higher costs in connection with ancillary services and system maintenance programs, partially offset by lower rental expenses due to expiration of rental agreements and lower street lighting maintenance costs.

Depreciation and Amortization

Depreciation and amortization expense for the three months and year ended December 31, 2017 was $62.0 million and $224.2 million, respectively, compared to $59.6 million and $212.2 million for the comparable periods in 2016.

The increase in depreciation and amortization expense for the three months and year ended December 31, 2017 was primarily due to new in-service asset additions in 2017, partially offset by certain assets being fully depreciated, and lower derecognition of assets removed from service.

Finance Costs

Finance costs for the three months and year ended December 31, 2017 were $18.9 million and $77.7 million, respectively, compared to $19.5 million and $74.2 million for the comparable periods in 2016.

The decrease in finance costs for the three months ended December 31, 2017 was primarily due to a lower average amount of outstanding long-term debt ($2,058.6 million) in the fourth quarter of 2017 compared with the same period in 2016 ($2,084.6 million) (see "Liquidity and Capital Resources" below).

The increase in finance costs for the year ended December 31, 2017 was primarily due to a higher average amount of outstanding long-term debt ($2,078.4 million) during 2017 compared with the same period in 2016 ($2,001.4 million) and lower capitalized borrowing costs (see "Liquidity and Capital Resources" below).

Gain on Disposals of PP&E

Gain on disposals of PP&E for the three months and year ended December 31, 2017 were $0.2 million and $9.8 million, respectively, compared to $2.1 million for the comparable periods in 2016. The increase in gain on disposals of PP&E for the year ended December 31, 2017 was primarily due to the gain realized on disposal of a surplus property in the second quarter of 2017 ($9.3 million), offset by lower gain realized on other disposals. The gain on disposal of a surplus property, net of tax of $8.0 million was recorded as a regulatory balance on the Consolidated Balance Sheets to reduce future electricity distribution rates for customers, with a corresponding offset in net movements in regulatory balances on the Consolidated Statements of Income.

Income Tax Expense and Income Tax Recorded in Net Movements in Regulatory Balances

Income tax expense and income tax recorded in net movements in regulatory balances for the three months and year ended December 31, 2017 were $4.9 million and $31.5 million, respectively, compared to $2.1 million and $23.1 million for the comparable periods in 2016.

The unfavourable variance in income tax expense and income tax recorded in net movements in regulatory balances for the three months ended December 31, 2017 was primarily due to higher income before taxes (including net movements in regulatory balances), offset by higher net deductions for permanent and temporary differences between accounting and tax treatments.

The unfavourable variance in income tax expense and income tax recorded in net movements in regulatory balances for the year ended December 31, 2017 was primarily due to higher income before taxes (including net movements in regulatory balances) and lower net deductions for permanent and temporary differences between accounting and tax treatments.

Net Movements in Regulatory Balances

In accordance with IFRS 14, the Corporation separately presents regulatory balances and related net movements on the Consolidated Balance Sheets and Consolidated Statements of Income.

The increase in the regulatory debit ($9.1 million) and the decrease in the regulatory credit ($9.4 million) balances for the year ended December 31, 2017 equals the sum ($18.5 million) of net movements in regulatory balances, net movements in regulatory balances arising from deferred tax assets, and net movements in regulatory balances related to OCI, net of tax for the relevant period (see "Financial Position" below).

Energy purchases record the actual cost of power purchased which varies from month to month. Since the selling price of power within energy sales is fixed for set periods of time, a gain or loss usually results, and is part of the calculation of net income. However, per OEB regulations, such gains or losses on energy sales are deferred within balance sheet regulatory variance accounts for later disposition to or from rate payers via rate riders after approval by the OEB. Deferrals of gains or losses on energy sales (see discussion on "settlement variance" under "Results of Operations" above), or disposition of past deferrals in electricity rates will usually represent the largest single element of the net movements in regulatory balances for a period.

Net movements in regulatory balances for the three months ended December 31, 2017 were a recovery of $10.9 million compared to a charge of $30.6 million for the comparable period in 2016. The recovery of $10.9 million for the three months ended December 31, 2017 was primarily due to the timing difference between the electricity costs billed monthly by the IESO and LDC's billing to customers, partially offset by amounts disposed through OEB approved rate riders and amounts being deferred into capital-related regulatory accounts for future refunds to customers. The charge of $30.6 million for the three months ended December 31, 2016 was primarily due to the timing difference between the electricity costs billed monthly by the IESO and LDC's billing to customers.

Net movements in regulatory balances for the year ended December 31, 2017 were a charge of $13.1 million compared to a charge of $77.2 million for the comparable period in 2016. The charge of $13.1 million for the year ended December 31, 2017 was primarily due to the timing difference between the electricity costs billed monthly by the IESO and LDC's billing to customers, partially offset by amounts disposed through OEB approved rate riders and amounts being deferred into capital-related regulatory accounts for future refunds to customers. The charge of $77.2 million for the year ended December 31, 2016 was primarily due to the timing difference between the electricity costs billed monthly by the IESO and LDC's billing to customers, partially offset by the recognition of the 2016 approved foregone revenue per the OEB's CIR decision and rate order.

Net movements in regulatory balances related to OCI, net of tax for the three months and year ended December 31, 2017 were a recovery of $18.4 million, compared to a charge of $15.5 million for the comparable periods in 2016. The recovery of $18.4 million for the three months and year ended December 31, 2017 was due to the actuarial loss recognized for post-employment benefits. The charge of $15.5 million for the three months and year ended December 31, 2016 was due to the actuarial gain recognized for post-employment benefits.

Summary of Quarterly Results of Operations

The table below presents a summary of the Corporation's results of operations for eight quarters including and immediately preceding December 31, 2017.

Summary of Quarterly Results of Operations
(in millions of Canadian dollars)

	December 31 2017 $	September 30 2017 $	June 30 2017 $	March 31 2017 $
Energy sales	728.9	817.9	721.8	749.2
Distribution revenue	181.7	186.1	178.2	178.2
Other	27.7	36.6	23.0	20.4
Revenues	938.3	1,040.6	923.0	947.8
Net income after net movements in regulatory balances	35.1	46.8	35.0	39.6
	December 31 2016 $	**September 30 2016 $**	**June 30 2016 $**	**March 31 2016 $**
Energy sales	813.3	899.9	801.1	791.9
Distribution revenue	159.0	183.3	158.8	146.8
Other	22.0	21.2	16.8	15.9
Revenues	994.3	1,104.4	976.7	954.6
Net income after net movements in regulatory balances	23.4	52.5	31.2	44.3

The Corporation's revenues, all other things being equal, are impacted by temperature fluctuations and unexpected weather conditions. Revenues would tend to be higher in the first quarter as a result of higher energy consumption for winter heating, and in the third quarter due to air conditioning/cooling. The Corporation's revenues are also impacted by fluctuations in electricity prices and the timing and recognition of regulatory decisions and rate orders.

Financial Position

The following table outlines the significant changes in the consolidated balance sheets as at December 31, 2017 as compared to the consolidated balance sheets as at December 31, 2016.

Consolidated Balance Sheet Data
(in millions of Canadian dollars)

Balance Sheet Account	Increase (Decrease) $	Explanation of Significant Change
Assets		
Accounts receivable and unbilled revenue	(54.3)	The decrease was primarily due to lower pass-through electricity costs, partially offset by the recognition of the CDM mid-term incentive receivable.
Assets held for sale	8.7	In 2017, LDC commenced the process to sell a property to a third party and subsequently entered into a sales agreement. Accordingly, the carrying amount of the property of $8.7 million was reclassified from PP&E to Assets held for sale.
PP&E and intangible assets	314.6	The increase was primarily due to capital expenditures, partially offset by depreciation and derecognition, and reclassification of assets held for sale during the year.
Deferred tax assets	(6.8)	The decrease was primarily due to lower net deductible temporary differences between tax and accounting values of PP&E and intangible assets.
Liabilities and Equity		
Commercial paper	(102.0)	The decrease was primarily due to repayment using the proceeds from the equity investment received from the City in June 2017 ($250.0 million), offset by issuances required for general corporate purposes (see "Liquidity and Capital Resources" below).
Debentures	(50.6)	The decrease was primarily due to the repayment of the Series 2 debentures ($250.0 million), partially offset by the issuance of Series 13 debentures ($200.0 million) in the fourth quarter of 2017 (see "Liquidity and Capital Resources" below).
Accounts payable and accrued liabilities	11.9	The increase was primarily due to timing differences in payments, partially offset by lower electricity costs payable to the IESO.
Deferred revenue	44.5	The increase was primarily due to capital contributions received in 2017.

Consolidated Balance Sheet Data
(in millions of Canadian dollars)

Balance Sheet Account	Increase (Decrease) $	Explanation of Significant Change
Post-employment benefits	32.5	The increase was primarily due to the recognized actuarial loss driven by the annually updated actuarial assumptions.
Retained earnings	81.5	The increase was due to net income after net movements in regulatory balances ($156.5 million) offset by dividends paid ($75.0 million).
Regulatory Balances		
Regulatory debit balances	9.1	The increase was primarily due to the OPEB actuarial loss recorded as regulatory debit balance, partially offset by amounts disposed through OEB-approved rate riders primarily related to foregone revenue.
Regulatory credit balances	(9.4)	The decrease was primarily due to balances arising in the period related to settlement variances, partially offset by amounts being deferred into capital related regulatory accounts for future refunds to customers and amounts disposed through OEB-approved rate riders.

Liquidity and Capital Resources

The Corporation's current assets and current liabilities amounted to $526.7 million and $770.5 million, respectively, as at December 31, 2017, resulting in a working capital deficit of $243.8 million. The deficit is attributable to the Corporation's preference for utilizing its Commercial Paper Program and Working Capital Facility (both defined below) before issuing additional debentures to fulfill the Corporation's ongoing liquidity requirements, including funding of significant capital spending in the current year. The Corporation seeks to maintain an optimal mix of short-term and long-term debt in order to lower overall financing costs and to enhance borrowing flexibility.

The Corporation's primary sources of liquidity and capital resources are cash provided by operating activities, issuances of commercial paper, amounts available to be drawn against its credit facilities, and borrowings from debt capital markets. The Corporation's liquidity and capital resource requirements are mainly for capital expenditures to maintain and improve the electricity distribution system of LDC, for energy purchases and to meet financing obligations. See "Liquidity Risk" under note 16 to the Consolidated Financial Statements.

The amount available under the Revolving Credit Facility and the outstanding borrowings under the Revolving Credit Facility and Commercial Paper Program are as follows:

(in millions of Canadian dollars)	Revolving Credit Facility Limit $	Revolving Credit Facility Borrowings $	Commercial Paper Outstanding $	Revolving Credit Facility Availability $
December 31, 2017	800.0	-	159.0	641.0
December 31, 2016	800.0	-	261.0	539.0

The Corporation is a party to a $20.0 million demand facility with a Canadian chartered bank for the purpose of working capital management ("Working Capital Facility"). As at December 31, 2017, $11.7 million had been drawn under the Working Capital Facility compared to $7.1 million as at December 31, 2016.

Consolidated Statements of Cash Flow Data
(in millions of Canadian dollars)

	Three months ended December 31		Year ended December 31	
	2017 $	2016 $	2017 $	2016 $
Working capital facility beginning of period	(10.1)	(9.1)	(7.1)	(14.2)
Net cash provided by operating activities	211.4	191.7	584.7	571.3
Net cash used in investing activities	(132.3)	(138.2)	(520.9)	(549.4)
Net cash used in financing activities	(80.7)	(51.5)	(68.4)	(14.8)
Working capital facility, end of period	(11.7)	(7.1)	(11.7)	(7.1)

Operating Activities

Net cash provided by operating activities for the three months and year ended December 31, 2017 was $211.4 million and $584.7 million, respectively, compared to $191.7 million and $571.3 million for the comparable periods in 2016.

The increase in net cash provided by operating activities for the three months and year ended December 31, 2017 was primarily due to improved working capital mainly related to timing differences in the settlement of receivable and payables (see note 22 to the Consolidated Financial Statements), and lower net movements in regulatory balances arising from deferred tax assets, partially offset by lower collection from energy sales in excess of energy purchases, which were deferred as a settlement variance and timing of income tax instalments paid.

Investing Activities

Net cash used in investing activities for the three months and year ended December 31, 2017 was $132.3 million and $520.9 million, respectively, compared to $138.2 million and $549.4 million for the comparable periods in 2016.

The decrease in net cash used in investing activities for the three months ended December 31, 2017 was due to lower cash spending on capital projects, partially offset by lower proceeds on disposals of PP&E in the fourth quarter of 2017.

The decrease in net cash used in investing activities for the year ended December 31, 2017 was due to lower cash spending on capital projects and higher proceeds on disposals.

Electricity distribution is a capital-intensive business. As the municipal electricity distribution company serving the largest city in Canada, LDC continues to invest in the renewal of existing aging infrastructure to address safety, reliability and customer service requirements.

The following table summarizes the Corporation's capital expenditures, both PP&E and intangible assets, which are inclusive of capital accruals, for the periods indicated.

Capital Expenditures
(in millions of Canadian dollars)

	Three months ended December 31		Year ended December 31	
	2017 $	2016 $	2017 $	2016 $
Regulated LDC				
Distribution system				
Planned [1]	103.1	85.1	373.0	365.3
Reactive	12.8	16.9	48.1	47.6
Copeland Station	4.9	7.8	23.2	22.6
Facilities consolidation	-	16.1	35.2	50.6
Technology assets	20.3	17.0	54.9	49.1
Other [2]	5.3	3.8	10.5	10.8
Regulated capital expenditures	146.4	146.7	544.9	546.0
Unregulated capital expenditures [3]	2.5	2.5	8.0	5.7
Total capital expenditures	148.9	149.2	552.9	551.7

[1] Includes, among other initiatives, the replacement of underground and overhead infrastructures, station programs, and the delivery of customer connections.

[2] Includes fleet capital and buildings.

[3] Primarily relates to street lighting and generation equipment.

The total regulated capital expenditures for the three months and year ended December 31, 2017 were $146.4 million and $544.9 million, respectively, compared to $146.7 million and $546.0 million for the comparable periods in 2016.

For the three months ended December 31, 2017, spending on regulated capital expenditure year over year was relatively consistent. Changes were primarily related to lower spending on the facilities consolidation program ($16.1 million), partially offset by higher spending on the implementation of an SAP ERP project ($8.1 million), station programs related to the renewal of aging station infrastructure ($4.7 million), network infrastructure ($1.8 million), and metering ($1.7 million).

For the year ended December 31, 2017, the decrease in regulated capital expenditures was primarily related to lower spending on overhead infrastructure ($19.1 million), the radio project ($16.0 million), and the facilities consolidation program ($15.4 million). These variances were partially offset by higher spending on station programs related to the renewal of aging station infrastructure ($26.2 million), the implementation of an SAP ERP project ($19.9 million), and metering ($7.3 million).

The largest capital initiatives in 2017 include the replacement of underground and overhead infrastructures, station programs, delivery of customer connections, the facilities consolidation program, and the construction of Copeland Station in response to the growing need for distribution options in the downtown core of the City.

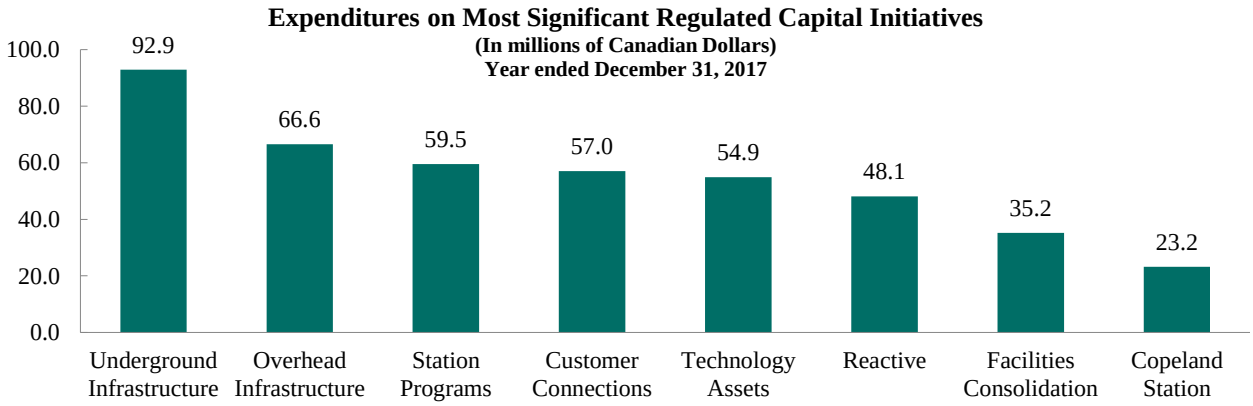
The replacement of underground infrastructure includes replacing direct buried cables, transformer switches, handwells and other aging underground infrastructure. The replacement of overhead infrastructure includes replacing poles, overhead transformers, conductors, overhead switches and other aging overhead infrastructure and equipment. Both initiatives will allow LDC to continue to provide ongoing safe and reliable service to its customers. For the year ended December 31, 2017, capital expenditures for the underground and overhead infrastructures were $92.9 million and $66.6 million, respectively.

The station programs relate to the lifecycle management of electrical equipment installed at each of the Corporation's active Municipal and transformer stations, while ensuring that adequate capacity is available to serve customers. For the year ended December 31, 2017, capital expenditures for the station programs were $59.5 million.

The delivery of customer connections includes spending related to new services and upgrades to existing services for specific commercial customers. For the year ended December 31, 2017, capital expenditures for the delivery of customer connections were $57.0 million.

The facilities consolidation program relates to the consolidation of operating centres to lower operating centre costs and simplify long-term planning. In the year ended December 31, 2017, the Corporation continued relocating staff, equipment and operations as well as performing the required capital investment on specific properties and incurred costs of $35.2 million.

Copeland Station will be the first transformer station built in downtown Toronto since the 1960's and will be the second underground transformer station in Canada. When in service, it will provide electricity to buildings and neighbourhoods in the central-southwest area of Toronto. During 2017, major electrical equipment including power transformers and high and medium voltage switchgear, medium voltage cable, control wiring and DC systems was installed, tested and commissioned, and the high voltage cable was completed. The electric station service equipment was installed and energized. Protection and control equipment was installed and testing and commissioning commenced. In addition, the machine shop installation and landscaping were completed and sidewalks and roadway were paved. HONI, the electricity transmission provider, commenced the installation of their transmission equipment, including high voltage switchgear and protection and control equipment. As at December 31, 2017, the cumulative capital expenditures on the Copeland Station project amounted to $195.1 million, plus capitalized borrowing costs. All capital expenditures related to Copeland Station are recorded to PP&E. Copeland Station is one of the most complex projects ever undertaken by the Corporation and the expected completion date is 2018. The total capital expenditure required to complete the project is approximately $200.0 million, plus capitalized borrowing costs. There may be additional unforeseen delays and expenditures prior to completion of the project. See "Risk Management and Risk Factors" below for further information on the Copeland Station project.



Financing Activities

Net cash used in financing activities for the three months and year ended December 31, 2017 was $80.7 million and $68.4 million, respectively, compared to $51.5 million and $14.8 million for the comparable periods in 2016. The change for the year was primarily due to the repayment of the Corporation's Series 2 debentures and commercial paper and an increase in dividends paid, partially offset by the equity investment received from the City in June 2017.

The Corporation is a party to a credit agreement with a syndicate of Canadian chartered banks which established a revolving credit facility expiring on October 10, 2022 ("Revolving Credit Facility"), pursuant to which it may borrow up to $800.0 million, of which up to $210.0 million is available in the form of letters of credit. On August 1, 2017, the maturity date of the Revolving Credit Facility was extended by one year from October 10, 2021 to October 10, 2022. As at December 31, 2017, the Corporation was in compliance with all covenants included in its Revolving Credit Facility agreement.

The Corporation has a commercial paper program allowing up to $600.0 million of unsecured short-term promissory notes ("Commercial Paper Program") to be issued in various maturities of no more than one year. The Commercial Paper Program is supported by liquidity facilities available under the Revolving Credit Facility; hence, available borrowing under the Revolving Credit Facility is reduced by the amount of commercial paper outstanding at any point in time. Proceeds from the Commercial Paper Program are used for general corporate purposes.

For the three months and year ended December 31, 2017, the average aggregate outstanding borrowings under the Corporation's Revolving Credit Facility, Working Capital Facility and Commercial Paper Program were $140.2 million and $210.3 million respectively, with a weighted average interest rate of 1.21% and 0.93% (compared to $253.2 million and $348.7 million with a weighted average interest rate of 0.83% and 0.89% for the three months and year ended December 31, 2016).

Additionally, the Corporation is a party to a $75.0 million demand facility with a Canadian chartered bank for the purpose of issuing letters of credit mainly to support LDC's prudential requirements with the IESO ("Prudential Facility"). As at December 31, 2017, $38.4 million of letters of credit were issued against the Prudential Facility.

The Corporation filed a base shelf prospectus dated May 8, 2017 with the securities commissions or similar regulatory authorities in each of the provinces of Canada. These filings allow the Corporation to make offerings of unsecured debt securities of up to $1.0 billion during the 25-month period following the date of the prospectus.

On November 14, 2017, the Corporation issued $200.0 million senior unsecured debentures at a rate of 3.485% ("Series 13"). The Series 13 debentures due on February 28, 2048 were priced at $999.29 per $1,000 principal amount and bear interest payable semi-annually in arrears. The net proceeds were used to repay certain existing indebtedness and for general corporate purposes. Debt issuance costs of $1.4 million relating to the Series 13 debentures were recorded against the carrying amount of the debentures in the fourth quarter of 2017 and are amortized to finance costs using the effective interest method.

The Corporation's Series 2 debentures matured and were repaid on November 14, 2017.

As at December 31, 2017, the Corporation had debentures outstanding in the principal amount of $2.0 billion. These debentures will mature between 2019 and 2063. As at December 31, 2017, the Corporation was in compliance with all covenants included in its trust indenture and supplemental trust indentures.

The following table sets out the current credit ratings of the Corporation:

Credit Ratings
As at December 31, 2017

	DBRS		Standard & Poor's	
	Credit Rating	Trend	Credit Rating	Outlook
Issuer rating	A	Stable	A	Stable
Senior unsecured debentures	A	Stable	A	-
Commercial paper	R-1 (low)	Stable	-	-

The Corporation believes that it has sufficient available sources of liquidity and capital to satisfy working capital requirements for the next twelve months.

On March 2, 2017, the Board of Directors of the Corporation declared dividends in the amount of $6.25 million with respect to the first quarter of 2017 (March 31, 2016 – $44.6 million), which was paid to the City on March 31, 2017.

On May 11, 2017, the Board of Directors of the Corporation declared dividends in the amount of $6.25 million with respect to the second quarter of 2017 (June 30, 2016 – $6.25 million), which was paid to the City on June 30, 2017.

In connection with receipt of the equity investment from the City, the Board of Directors of the Corporation declared dividends payable to the City and approved amendments to the Corporation's Dividend Policy, as follows:

- In respect of fiscal 2017, an aggregate amount of $75.0 million shall be paid to the City, consisting of the two previously declared and paid instalments of $6.25 million each and a further $62.5 million. The $62.5 million was paid to the City on July 7, 2017.

- In respect of fiscal 2018 and subsequent fiscal years, 60% of the Corporation's consolidated net income after net movements in regulatory balances for the prior fiscal year shall be declared separately in four equal quarterly instalments, with each instalment payable to the City on the last business day of each fiscal quarter.

On March 7, 2018, the Board of Directors of the Corporation declared a quarterly dividend in the amount of $23.5 million, payable to the City by March 31, 2018.

Summary of Contractual Obligations and Other Commitments

The following table presents a summary of the Corporation's debentures, major contractual obligations and other commitments.

Summary of Contractual Obligations and Other Commitments
As at December 31, 2017
(in millions of Canadian dollars)

	Total $	2018 $	2019/2020 $	2021/2022 $	After 2022 $
Working Capital Facility	11.7	11.7	-	-	-
Commercial paper [1]	159.0	159.0	-	-	-
Debentures – principal repayment	2,045.0	-	250.0	300.0	1,495.0
Debentures – interest payments	1,471.3	75.7	143.1	121.3	1,131.2
Operating leases	1.4	0.3	0.6	0.5	-
Capital projects [2] and other	46.0	17.5	27.5	1.0	-
Finances leases	1.5	1.5	-	-	-
Total contractual obligations and other commitments	3,735.9	265.7	421.2	422.8	2,626.2

[1] The notes under the Commercial Paper Program were issued at a discount and are repaid at their principal amount.
[2] Primarily commitments for construction services and estimated capital contributions.

Corporate Developments

Changes to the Corporation's Board of Directors and Audit Committee

Effective January 1, 2017, the City, as the sole shareholder of the Corporation, re-appointed Councillor Paul Ainslie, Deputy Mayor Stephen Holyday (as the Mayor's designate), and Deputy Mayor Denzil Minnan-Wong to the Board of Directors for a term ending November 30, 2018, or until their successors are appointed.

On March 2, 2017, the Board of Directors of the Corporation confirmed the Chair of the Corporation, David McFadden, as an ex officio member of each of its Audit, Corporate Governance and Nominating, and Human Resources and Environment Committees, with all the responsibilities and privileges of the regular members of each committee.

Effective April 26, 2017, the City appointed Juliana Lam to the Board of Directors. The appointment is effective for a term ending April 26, 2019, or until her successor is appointed. Juliana Lam was appointed by the Board of Directors to the Audit Committee to replace Brian Chu who retired from the Audit Committee, effective May 11, 2017.

Effective December 10, 2017, the City re-appointed David McFadden, Brian Chu, Heather Zordel, the Honourable Howard Weston, Senator, Mary Ellen Richardson, Michael Nobrega and Tamara Kronis to the Board of Directors for a term ending December 10, 2019, or until their successors are appointed.

Electricity Distribution Rates

The OEB's regulatory framework for electricity distributors is designed to support the cost-effective planning and operation of the electricity distribution network and to provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price.

The OEB typically regulates the electricity rates for distributors using a combination of detailed cost of service reviews and IRM adjustments. Under the OEB's rate-setting methods, actual operating conditions may vary from forecasts such that actual returns achieved can differ from approved returns. Approved electricity rates are generally not adjusted as a result of actual costs or revenues being different from forecasted amounts, other than for certain prescribed costs that are eligible for deferral for future collection from, or refund to, customers.

On March 1, 2016 pursuant to LDC's 2015 – 2019 CIR application, the OEB set 2018 distribution rates on an interim basis. On August 23, 2017, LDC filed its 2018 rate application seeking OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2018 and ending on December 31, 2018. On December 14, 2017, the OEB issued a decision and rate order approving LDC's 2018 rates, with an effective date of January 1, 2018, and the disposition of certain deferral and variance accounts.

Ontario's Fair Hydro Plan

On March 2, 2017, the Government of Ontario announced the OFHP, which includes a number of initiatives, some of which affect LDC or its customers.

OFHP includes the OREC, which came into effect on January 1, 2017. The OREC provides eligible customers with financial assistance in the form of an 8% rebate of the pre-tax cost of their electricity. The OREC rebates are administered by LDC and paid by the IESO in the month following customer billing. Current accounts receivable and unbilled revenue include the amount owing by the IESO to LDC. No effect on revenue or expense is recognized by LDC in respect of the OREC rebates.

OFHP also includes the OFHA, which enacted the Ontario Fair Hydro Plan Act, 2017 and amended the Electricity Act, 1998 and the Ontario Energy Board Act, 1998. The OFHA came into effect on June 1, 2017 and its impact is reflected in the Consolidated Financial Statements. The OFHA provides eligible customers with financial assistance through various changes to commodity pricing, new or amended programs, and eliminating or reducing certain provincial charges on the electricity bill. The OFHP reduces electricity bills by 25% on average for eligible customers, which includes the 8% OREC rebate. The OFHA reduces the total electricity bill for eligible customers and, accordingly, reduces current accounts receivable, unbilled revenue, accounts payable and accrued liabilities for LDC. No effect on distribution revenue or expense is recognized by LDC in respect of the OFHA.

CDM Activities

On March 26, 2014, the Minister of Energy of Ontario, under the guidance of sections 27.1 and 27.2 of the OEB Act, directed the OEB to amend the licence of each licensed electricity distributor to require the electricity distributor, as a condition of its licence, to make CDM programs available to its customers and to do so in relation to each customer segment in its service area, over the period beginning January 1, 2015 through December 31, 2020. On March 31, 2014, the Minister of Energy of Ontario issued a direction to require the OPA to coordinate, support and fund the delivery of CDM programs through electricity distributors. The objective of the CDM efforts is to reduce electricity consumption in the Province of Ontario by a total of 7 terawatt hours between January 1, 2015 and December 31, 2020, of which LDC's share is approximately 1,576 GWh of energy savings.

On November 13, 2014, LDC entered into an energy conservation agreement with the OPA for the delivery of CDM programs over the 2015-2020 period. The IESO and the OPA were merged under the name IESO starting on January 1, 2015.

Under the energy conservation agreement with the IESO, LDC has a joint CDM plan with Oakville Hydro Electricity Distribution Inc. ("Oakville Hydro") for the delivery of CDM programs over the 2015-2020 period. LDC can choose between full cost recovery funding, pay-for-performance funding, or a combination of both, on a CDM program by program basis. Under the full cost recovery funding method, the IESO reimburses LDC for all adequately documented incurred costs, with an option to receive a portion of its funding in advance. Cost efficiency incentives may be awarded

if LDC's electricity savings meet or exceed certain CDM plan targets for programs under the full cost recovery funding method, with a mid-term review to be performed by the IESO for the 2015-2017 period. Under the pay-for-performance funding method, LDC receives payment in arrears based on verified electricity savings achieved with various options for frequency of payment. The programs under the joint CDM plan with Oakville Hydro are only being offered under the full cost recovery funding method.

The joint CDM plan provides combined funding of approximately $425.0 million, including participant incentives and program administration costs to achieve an aggregate energy savings target of approximately 1,668 GWh. Oakville Hydro's programs under the joint CDM plan started on January 1, 2016. LDC received $44.9 million as at December 31, 2016 and $57.4 million in the year ended December 31, 2017 from the IESO for the delivery of CDM programs. Amounts received but not yet spent are presented on the consolidated balance sheets under current liabilities as deferred conservation credit. As at December 31, 2017, LDC estimated that approximately $12.9 million qualified as a joint mid-term incentive, of which $12.2 million represents LDC's portion and is included within accounts receivable.

Effective October 16, 2017, LDC entered into an agreement to transfer $4.0 million of funding and a corresponding 20 GWh of its energy savings target to another local distribution company. This agreement will decrease the joint CDM plan funding with Oakville Hydro to $421.0 million, with a revised energy savings target of 1,648 GWh. The revised CDM plan was approved by the IESO on December 14, 2017.

Legal Proceedings

In the ordinary course of business, the Corporation is subject to various legal actions and claims from customers, suppliers, former employees and other parties. On an ongoing basis, the Corporation assesses the likelihood of any adverse judgments or outcomes as well as potential ranges of probable costs and losses. A determination of the provision required, if any, for these contingencies is made after an analysis of each individual issue. The provision may change in the future due to new developments in each matter or changes in approach, such as a change in settlement strategy. If damages were awarded under these actions, the Corporation and its subsidiaries would make a claim under any applicable liability insurance policies which the Corporation believes would cover any damages which may become payable by the Corporation and its subsidiaries in connection with these actions, subject to such claim not being disputed by the insurers. There have been no material changes in legal proceedings as disclosed in note 25 to the Consolidated Financial Statements.

Share Capital

Share capital consists of the following:

	Number of Shares	$
Authorized The authorized share capital of the Corporation consists of an unlimited number of common shares without par value. All shares issued were fully paid.		
Issued and outstanding		
Common shares, beginning of the year	1,000	567.8
Common shares issued [1]	200	250.0
Common shares issued and outstanding, end of the year	1,200	817.8

[1] On June 28, 2017, the Corporation issued 200 common shares to the City for total proceeds of $250.0 million, net of share issue costs and expenses.

Transactions with Related Parties

As the City is the sole shareholder of the Corporation, the Corporation and the City are considered related parties. The Corporation provides electricity, street lighting and ancillary services to the City. All transactions with the City are conducted on terms similar to those offered to unrelated parties.

Summary of Transactions with Related Parties
(in millions of Canadian dollars)

	Year ended December 31	
	2017 **$**	**2016** **$**
Revenues	**283.3**	275.3
Operating expenses and capital expenditures	**22.2**	26.9
Dividends	**75.0**	63.4

Summary of Amounts Due to/from Related Parties
(in millions of Canadian dollars)

	As at December 31	
	2017 **$**	**2016** **$**
Accounts receivable	**13.8**	12.7
Unbilled revenue	**26.3**	23.2
Accounts payable and accrued liabilities	**40.1**	41.0
Customer deposits	**15.7**	14.1
Deferred revenue	**1.9**	3.5

Revenues represent amounts charged to the City primarily for electricity, street lighting and ancillary services. Operating expenses and capital expenditures represent amounts charged by the City for purchased road cut repairs, property taxes and other services. Dividends are paid to the City.

Accounts receivable represents receivables from the City primarily for electricity, street lighting and ancillary services. Unbilled revenue represents receivables from the City mainly related to electricity provided and not yet billed. Accounts payable and accrued liabilities represent amounts payable to the City related to road cut repairs and other services. Customer deposits represent amounts received from the City for future expansion projects. Deferred revenue represents amounts received from the City primarily for the construction of electricity distribution assets.

Controls and Procedures

For purposes of certain Canadian securities regulations, the Corporation is a "Venture Issuer". As such, it is exempt from certain requirements of National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings. Accordingly, the Chief Executive Officer and Chief Financial Officer have reviewed the Consolidated Financial Statements and the MD&A for the year ended December 31, 2017 and 2016. Based on their knowledge and exercise of reasonable diligence, they have concluded that these documents fairly present in all material respects the financial condition, financial performance and cash flows of the Corporation as at the date of and for the period presented.

Risk Management and Risk Factors

The Corporation faces various risks that could impact the achievement of its strategic objectives. It adopts an enterprise wide approach to risk management, achieved through a process of consolidating and aligning the various views of risk across the enterprise via a risk governance structure. The Corporation executes its ERM activities via an ERM framework that is aligned to industry best practices and international guidelines. The Corporation views ERM as a management activity undertaken to add value and improve overall operations. It helps the Corporation by enabling the attainment of its strategic goals and objectives through a systematic, disciplined approach towards identifying, evaluating, treating, monitoring and reporting of risks. Accordingly, ERM is an integral part of the strategic management of the Corporation and is routinely considered in forecasting, planning and executing all aspects of the business.

The ERM framework is operationalized by a consistent, disciplined methodology that clearly defines the risk management process which incorporates subjective elements, risk quantification and risk interdependencies.

While the Corporation's philosophy is that ERM is the responsibility of all business units, at all levels, in strategic and operational matters, the ERM governance structure is comprised of three key levels.

At the top level is the Board, which works to maintain a general understanding of the Corporation's risk profile, the risk categories, the types of risks to which the Corporation may be exposed and the practices used to identify, assess, measure and manage those risks. The risk profile is a list of key risks that represent the greatest threats to achieving the Corporation's strategic objectives.

The second level is the executive team, the lead body to ensure systems are in place to identify, manage, and monitor risks. Through its review of reports from the business and other areas, the executive team assesses the appropriateness and consistent application of systems to manage risks within the Corporation. The executive team also ensures that key risks are brought forward to the attention of the Board for discussion and action, as required.

Finally, the third level is the senior leadership team. The senior leadership team supports the executive team and is a collection of subject matter experts from across the Corporation who actively engage in the day-to-day management of risks. Working with the executive team, this group oversees the Corporation's risk profile, its performance against the defined risk appetite and determines appropriate risk responses. They also work to ensure effective, efficient, complete and transparent risk reporting to the executive team.

The Corporation's business is subject to a variety of risks including those described in the following sections. There can be no assurance that any steps the Corporation may take to manage risks will avoid future loss resulting from the occurrence of such risks.

Risks from External Influences

Ownership by the City and Inconsistent Policy Risk

The Corporation is subject to the risk that its shareholder can potentially limit the Corporation's ability to meet its business objectives as laid out in the Shareholder Direction principles. Under the Shareholder Direction, the City also has the power to direct the Corporation and its subsidiaries to conduct their affairs and govern their operations in accordance with such rules, policies, directives or objectives as are directed by City Council from time to time. These council approved directions can be inconsistent and/or divergent with the Shareholder Direction principles and could materially adversely affect the Corporation's business, operations, financial condition or prospects if the Corporation is required to comply with such directions.

Regulatory Risk

The Corporation is subject to the risk that its business activities may be impeded by the OEB (includes both traditional regulated Cost of Service work and non-traditional new ancillary service model work). There is a risk that future changes to Ontario's regulatory model, manner of regulation and/or broader government policy framework does not align with the Corporation's business direction and could materially adversely affect the Corporation's strategic goals and financial results.

Ontario's electricity industry regulatory developments may affect the electricity distribution rates charged by LDC and the costs LDC is permitted to recover. This may in turn have a material adverse effect on the financial performance of the Corporation and/or LDC's ability to deliver effective and efficient operations and reliable service to its customers, and as well as create barriers to LDC achieving its strategic objectives. Among other things, there can be no assurance that:

- the OEB will approve LDC's electricity distribution rates, at levels that will permit LDC to carry out its planned capital expenditures required to maintain safe and reliable service to its customers and earn the allowed rate of return on the investment in the business;
- all capital expenditures incurred by LDC will be approved by the OEB. In particular, capital cost overruns due to project delays or increased costs may not be recoverable in distribution rates;
- the regulatory instruments that are made available to LDC will be sufficient to address LDC's operations, needs and circumstances in respect of future applications for electricity distribution rates;
- the OEB will not set a lower recovery for LDC's cost of capital;
- the full cost of providing service to distribution customers will be permitted to be recovered through LDC's electricity distribution rates;
- the OEB will not permit competitors to provide distribution services in LDC's licensed area, or permit loads within LDC's service area to become electrically served by a means other than through LDC's electricity distribution system;
- the OEB will allow recovery for revenue lost as a consequence of unanticipated effects of CDM;
- parts of LDC's services will not be separated from LDC and opened to competition; or
- regulatory or other changes will not be made to the PILs regime.

Any future regulatory decision to disallow or limit the recovery of costs could lead to potential asset impairment and charges to results from operations, which could have a material adverse effect on the Corporation.

Political and Legislative Risk

The Corporation is subject to the risk that government bodies and policy priorities of government may impact the Corporation's ability to deliver effective and efficient operations and meet business objectives. Changes to any of the laws, rules, regulations and policies applicable to the businesses carried on by the Corporation could materially adversely affect the Corporation. There can be no assurance that the Corporation will be able to comply with applicable future laws, rules, regulations and policies. Failure by the Corporation to comply with applicable laws, rules, regulations and policies may subject the Corporation to civil or regulatory proceedings that could have a material adverse effect on the Corporation. The OEB may not allow recovery for the costs of coming into or maintaining compliance with these laws, rules, regulations and policies.

Risks to Maintaining Operations

Human Capital Risk

The Corporation is subject to the risk that human resources may not be available with the necessary knowledge, skills and education to support the Corporation's future talent requirements. All retirements pose risks for knowledge management and business continuity, both at the Corporation and the industry. Development and retention of talent to meet the evolving needs of the business requires LDC to focus on a series of proactive activities and programs to mitigate these risks, such as strategic workforce planning, promotion of apprenticeship programs, investments in colleges and universities, succession planning, knowledge transfer and a robust training program.

The Corporation's ability to operate successfully in the electricity industry in Ontario will continue to depend in part on its ability to make changes to existing work processes and conditions in order to adapt to changing circumstances. The Corporation's ability to make such changes, in turn, will continue to depend in part on its relationship with its

labour unions including reaching a new collective bargaining agreement with Power Workers' Union. There can be no assurance that the Corporation will be able to secure the support of its labour unions.

Strategy and Business Model Risk

The Corporation is subject to the risk that it may fail to monitor the external environment and or develop and pursue strategies through appropriate business models, thus failing to gain a strategic advantage, which could materially adversely affect the Corporation. The OEB distribution licence issued to LDC stipulates a service area that reflects the territory within the City. By law, only the OEB can grant such a licence for a service area and only an entity with such a licence can provide licenced services to the public-at-large within a service area. The OEB has not granted any other distribution licence that permits distribution within LDC's service area. In addition to this regulatory barrier to entry, there are other barriers to entry, including the cost of constructing an electricity distribution system, physical space limitations within and legal access to the right-of-way, the specialized skills associated with the distribution business, the level of expertise required to achieve operational and regulatory compliance, and LDC's relationships with its customers. There can be no assurance that these barriers will continue to be sufficient to prevent this type of competition. Other regulated and unregulated entities have always competed with LDC and its predecessors to provide customers with other sources of energy, including electricity. The pervasiveness of this competition and its effects on LDC's distribution business have varied over time and continue to vary based on many factors, including the relative price of energy source (e.g., natural gas, grid-supplied electricity, behind-the-meter generation) and technology advancements (e.g., multi-unit building sub-metering, micro-grids, electricity storage).

There can be no assurance that the future nature, prevalence, or effects of these forms of competition will be comparable to current or historic experience. Failure to effectively scan our external and internal environment could lead to missed business opportunities and loss of competitive advantage (see "Customer Risk" section for additional details).

Asset Integrity Risk

The Corporation is subject to the risk that it may be unable to maintain continuous supply due to failure of the existing distribution infrastructure and assets which could materially adversely affect the Corporation. Electricity distribution is a capital-intensive business. As the municipal electricity distribution company serving the largest city in Canada, LDC continues to invest in the renewal of existing aging infrastructure and in the development of new infrastructure (such as the Copeland Station project) to address safety, reliability and customer service requirements.

LDC estimates that approximately one-third of its electricity distribution assets have already exceeded or will reach the end of their expected useful lives within the next 5-year period. At the same time, Toronto is a growing city, and LDC must make system upgrades to expand its capacity to keep pace with urban intensification and electrification. In addition, as the City, Ontario and the Government of Canada implement policies and programs to respond to climate change, the pressures on the Corporation's system will only increase. Widespread adoption of electric vehicles, fuel switching and changing emissions standards make electricity the comparatively clean energy choice. This drives the need for significant capital expenditures for system upgrades so that the grid can handle such increased load. LDC's ability to continue to provide a safe work environment for its employees and a reliable and safe distribution service to its customers and the general public will depend on, among other things, the ability of the Corporation to fund additional infrastructure, and the OEB allowing recovery of costs in respect of LDC's maintenance program and capital expenditure requirements for distribution plant refurbishment and replacement.

One of LDC's largest capital initiatives currently in progress is the construction of Copeland Station, which is also one of the most complex projects ever undertaken by the Corporation. Due to unforeseen delays, the expected completion date for the Copeland Station project has been extended to 2018 and it is currently anticipated that the total expenditure required to complete the project will increase from $195.0 million to approximately $200.0 million, plus capitalized borrowing costs as applicable. There may be additional unforeseen delays and expenditures prior to the completion of the project. On January 25, 2017, the Corporation was informed that Carillion Construction Inc., the general contractor for the Copeland Station Project, filed for creditor protection under the Companies' Creditors Arrangement Act after its affiliate, Carillion plc, went into compulsory liquidation in the United Kingdom.

All capital projects for new and replacement infrastructure have risks related to delays or increased costs due to many factors, including: necessary modifications to project plans; the availability, scheduling and cost of materials,

equipment and qualified personnel; LDC's ability to obtain necessary environmental and other regulatory and governmental approvals; and the impact of weather conditions, site conditions and contractor performance.

LDC is focused on overcoming the above challenges and executing its capital and maintenance programs. However, if LDC is unable to carry out these plans in a timely and optimal manner or becomes subject to significant unforeseen equipment failures, equipment performance will degrade. Such degradation may compromise the reliability of distribution assets, the ability to deliver sufficient electricity and/or customer supply security and increase the costs of operating and maintaining these assets.

Occupational Health and Safety Risk

The Corporation is subject to the risk that employees may be exposed to serious or fatal injuries or illness as a result of the work environment in which they operate. Due to the nature of the Corporation's business and business activities, occupational safety is an integral part of our corporate culture. Employees could be exposed to hazards when performing their work duties. This includes hazards such as electrical contact, working in confined spaces, fires and explosions, slips, trips and falls and motor vehicle accidents. The Corporation is subject to compliance with provincial Health and Safety legislation. The Corporation's management approach to occupational safety is to meet or excel on legal compliance and eliminate or safeguard known occupational hazards and risks. There are processes in place to develop and nurture good leadership practices through recruitment, education, training and performance management practices that encourage the application of our corporate values, including safety. LDC received OHSAS 18001 certification in 2013 and conducts annual third party audits to maintain certification, in addition occupational health and safety legal compliance audits are conducted every two years.

Customer Risk

The Corporation is subject to the risk that it may fail to identify and meet its customers' needs and expectations, within approved OEB funding levels, and consequently customers leave the Corporation's distribution area or opt for alternative sources of electricity. This includes all customer classes, but is primarily related to general service and large users. This may lead to erosion of the Corporation's revenue base and monopoly position. It is important that the Corporation maintains its relationship with its customers to better understand the specific needs and expectations of each class. The political environment and government policy regarding the energy sector may impact customer satisfaction and perception of value, especially with concerns around hydro costs. The Corporation is taking steps to help its customers through cost saving CDM programs. Service interruptions due to increasing weather events, or unexpected events could further impact customer satisfaction and service quality (see "Business Interruption Risk" section for additional details).

Advances in technology may compete with the Corporation by affecting energy consumption levels and, as a result, customer demand for the Corporation's services could be negatively impacted in a material way. As customers increasingly prioritize energy efficiency and awareness of energy costs, and governments increasingly provide subsidies to encourage energy efficiency, primarily in response to climate change concerns, there will be a corresponding increase in the demand for technologies that enable customers to better monitor and minimize their energy consumption and otherwise exercise greater control over their electricity supply and demand. For example, distributed generation technologies draw on renewable sources of energy, such as solar power and wind, allowing customers to generate their own supply of electricity. The effect of such technologies may be reduced reliance on larger-scale utilities such as the Corporation. Likewise, energy-efficient homes and improvements to energy storage technologies like batteries may further affect consumption levels and the demand for the Corporation's services. Although OEB's current policy is moving residential customers to fixed delivery charges as opposed to consumption-based delivery charges, as technologies continue to advance and become more widely adopted, the Corporation may be required to make changes to its business and operations, which may present additional risks and challenges for the Corporation.

The Corporation is affected by energy demand which may change as a result of technology change, available customer choice and CDM programs, as well as general economic conditions, energy prices, disposable income and population growth, among other things. Reduced or increased energy demand could have a material adverse effect on the Corporation's business, operations, financial condition or prospects, as well as on the Corporation's need for, and ability to, fund future capital expenditures.

Information Technology and Cybersecurity Risk

The Corporation is subject to the risk that it may be unable to preserve the confidentiality, integrity, authenticity, availability, accountability and non-repudiation of information assets. The Corporation's ability to operate effectively is in part dependent on the development, maintenance and management of complex information technology systems. Computer systems are employed to operate LDC's electricity distribution system, and the Corporation's financial, billing and business systems to capture data and to produce timely and accurate information. Failures of any one of the financial, business and operating systems could have a material adverse effect on the Corporation's business, operations, financial condition or prospects. The Corporation mitigates this risk through various methods including the implementation of high availability and redundancy in its core infrastructure and application components. Operational technology systems are isolated from business systems and operate independently.

LDC's electricity distribution infrastructure and technology systems are also potentially vulnerable to damage or interruption from cyber-attacks, breaches or other compromises, which could result in business interruption, service disruptions, theft of intellectual property and confidential information (about customers, suppliers, counterparties and employees), additional regulatory scrutiny, litigation and reputational damage. The Corporation has implemented security controls aligned with industry best practices and standards including the National Institute of Standards and Technology Cybersecurity Framework, and maintains cyber insurance. Cyber-attacks, breaches or other compromises of electricity distribution infrastructure and technology systems could result in service disruptions and system failures, including as a result of a failure to provide electricity to customers, property damage, corruption or unavailability of critical data or confidential employee or customer information. A significant breach could materially adversely affect the financial performance of the Corporation or its reputation and standing with customers, regulators and in the financial markets. It could also expose the Corporation to third-party claims.

LDC must also comply with legislative and licence requirements relating to the collection, use and disclosure of personal information (including the personal information of customers), as well as information provided by suppliers, contractors, employees, counterparties, and others. Such information could be exposed in the event of a cybersecurity incident or other unauthorized access, which could materially adversely affect the Corporation and also result in third-party claims against the Corporation.

Preventative controls are employed to protect information and technology assets against cyber-attacks and mitigate their effects. Detective controls are employed to continuously monitor information systems so that the Corporation can respond appropriately to minimize the damage in the event of a cyber-attack. Even with these measures in place, since the techniques used to obtain unauthorized access, disable or degrade service, or sabotage systems change frequently and often are not recognized until launched against a target, the Corporation may be unable to anticipate these techniques or to implement adequate preventative measures. As such, there can be no assurance that such measures will be effective in protecting LDC's electricity distribution infrastructure or assets, or the personal information of its customers, from a cyber-attack or the effects therefrom.

Brand and Reputation Risk

The Corporation is subject to the risk that an action or inaction by it or its representatives will impair the Corporation's image in the community, public confidence or brand. The Corporation is committed to delivering safe and reliable electricity to its customers in an environmentally responsible manner at optimal costs. Failure to deliver on our commitment could impact the public's perception of the Corporation. In addition, events and/or external factors that draw negative media attention to the Corporation could cause reputational damages and impact the Corporation's business and relationship with its stakeholders.

Business Interruption Risk

The Corporation is subject to the risk that it may be unable to maintain continuing and sustainable business operations, or recover from business interruption, in an effective manner. The Corporation's operations are exposed to the effects of natural and other unexpected occurrences such as extreme storm and other weather conditions and natural disasters, as well as terrorism and pandemics. Although the Corporation's facilities and operations are constructed, operated and maintained to withstand such occurrences, there can be no assurance that they will successfully do so in all circumstances. Any major damage to the Corporation's facilities or interruption of the Corporation's operations arising from these occurrences could result in lost revenues and repair costs that can be substantial. Although the Corporation has insurance which it considers to be consistent with industry practice, if it sustained a large uninsured loss caused

by natural or other unexpected occurrences, LDC may apply to the OEB for the recovery of the loss related to the electricity distribution system. There can be no assurance that the OEB would approve, in whole or in part, such an application.

Risks to Maintaining Financial Condition

Capital Structure Risk

The Corporation is subject to the risk that it may not be able to optimize its debt to equity ratio or access capital markets at effective rates. There can be no assurance that debt or equity financing will be available or sufficient to meet the Corporation's requirements, objectives, or strategic opportunities. If and when financing is available, there can be no assurance that it will be on acceptable terms to the Corporation.

The Corporation relies on debt financing through its MTN Program, CP Program or existing credit facilities to finance the Corporation's daily operations, repay existing indebtedness, and fund capital expenditures. The Corporation's ability to arrange sufficient and cost-effective debt financing could be materially adversely affected by a number of factors, including financial market conditions and activity in the global capital markets, the regulatory environment in Ontario, the Corporation's business, operations, financial condition or prospects, compliance with covenants, the ratings assigned to the Corporation or the debentures issued under the Corporation's MTN Program by credit rating agencies, the rating assigned to short-term borrowings under the CP Program by a credit rating agency, and the availability of the commercial paper market.

In the event the Corporation is unable to maintain an R-1 (low) credit rating for its CP Program, the Corporation has sufficient liquidity through its Revolving Credit Facility to repay its commercial paper obligations as they become due.

Market and Credit Risk

The Corporation is directly and indirectly subject to various market and credit fluctuations which could materially adversely affect the Corporation. For example, LDC is exposed to credit risk with respect to customer non-payment of electricity bills. LDC is permitted, at certain times of the year, to mitigate the risk of customer non-payment using any means permitted by law, including security deposits (i.e. letters of credit, surety bonds, cash deposits or lock-box arrangements, under terms prescribed by the OEB), late payment penalties, pre-payment, pre-authorized payment, load limiters or disconnection. While LDC would be liable for the full amount of the default, there can be no assurance that the OEB would allow recovery of the bad debt expense. Established practice in such cases is that the OEB would examine any electricity distributor's application for recovery of extraordinary bad debt expenses on a case-by-case basis. LDC's security interest or other measures, if any, may also not provide sufficient protection. Additionally, security interests and other measures taken by, or in favour of, LDC, if any, may not provide sufficient protection.

The Corporation is exposed to fluctuations in interest rates for the valuation of its post-employment benefit obligations. The Corporation estimates that a 1% (100 basis point) increase in the discount rate used to value these obligations would decrease the accrued benefit obligation of the Corporation, as at December 31, 2017, by $46.8 million, and a 1% (100 basis point) decrease in the discount rate would increase the accrued benefit obligation, as at December 31, 2017, by $60.2 million.

The Corporation is exposed to short-term interest rate risk on the short-term borrowings under its CP Program and Working Capital Facility, and customer deposits, while most of its remaining obligations were either non-interest bearing or bear fixed interest rates, and its financial assets were predominately short-term in nature and mostly non-interest bearing. The Corporation manages interest rate risk by monitoring its mix of fixed and floating rate instruments, and taking action as necessary to maintain an appropriate balance. The Corporation estimates that a 100 basis point increase (decrease) in short-term interest rates, with all other variables held constant, would result in an increase (decrease) of approximately $2.3 million to annual finance costs.

The Corporation had limited exposure to the changing values of foreign currencies. While the Corporation purchases goods and services which are payable in US dollars, and purchases US currency to meet the related commitments when required, the impact of these transactions as at December 31, 2017 was not material.

Critical Accounting Estimates

The preparation of the Corporation's Consolidated Financial Statements in accordance with IFRS requires management to make judgments, estimates and assumptions which affect the application of accounting policies, reported assets, liabilities and regulatory balances, and the disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements, and the reported revenues and expenses for the year. The estimates are based on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities as well as for identifying and assessing the accounting treatment with respect to commitments and contingencies. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the IESO, the Ontario Ministry of Energy or the Ontario Ministry of Finance.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to estimates are recognized prospectively. Assumptions and estimates with a significant risk of resulting in a material adjustment within the next financial year are used in the following:

- Note 26(b) – Recognition and measurement of regulatory balances;
- Note 26(j) – Revenue recognition – measurement of unbilled revenue, determination of the CDM incentive;
- Notes 26(f) and 26(g) – Determination of useful lives of depreciable assets;
- Notes 26(m) and 14 – Measurement of post-employment benefits – key actuarial assumptions;
- Notes 26(o) and 21 – Recognition of deferred tax assets – availability of future taxable income against which deductible temporary differences and tax loss carryforwards can be used; and
- Note 25 – Recognition and measurement of provisions and contingencies.

Significant Accounting Policies

The Corporation's Consolidated Financial Statements have been prepared in accordance with IFRS with respect to the preparation of financial information. The Consolidated Financial Statements are presented in Canadian dollars, which is the Corporation's functional currency. The significant accounting policies of the Corporation are summarized in notes 2 and 26 to the Consolidated Financial Statements.

Changes in Accounting Policies

In January 2016, the IASB issued amendments to IAS 7 *Statement of Cash Flows* as part of the IASB's Disclosure Initiative. These amendments require entities to provide disclosures that enable users of financial statements to evaluate changes in liabilities arising from financing activities, including changes from cash flows and non-cash changes. These amendments are effective for annual periods beginning on or after January 1, 2017. The additional disclosures relating to changes in liabilities arising from financing activities are included in note 22 to the Consolidated Financial Statements and have no impact to the Corporation's financial position or results of operations.

Future Accounting Pronouncements

A number of new standards, amendments and interpretations are not yet effective for the year ended December 31, 2017, and have not yet been applied in preparing the Consolidated Financial Statements.

Revenue from Contracts with Customers

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers* ("IFRS 15"), which replaces existing revenue recognition guidance, including IAS 18 *Revenue* and IFRIC 18 *Transfers of Assets from Customers*. IFRS 15 contains a single model that applies to contracts with customers with two methods for recognizing revenue: at a point in time or over time. IFRS 15 is effective for annual periods beginning on or after January 1, 2018.

The Corporation will adopt IFRS 15 on January 1, 2018 using the modified retrospective approach. The Corporation has completed its assessment of the key revenue streams. The majority of the Corporation's revenue (energy sales and distribution revenue) is generated from electricity distribution at regulated prices. The Corporation concluded that IFRS 15 will not have a material impact on the accounting for these revenue streams. Upon adoption of IFRS 15, there will be a $167.6 million income statement reclassification between Energy Sales and Energy Purchases for the comparative year ended December 31, 2017 and no impact to opening retained earnings as at January 1, 2018. The

Corporation is currently finalizing its assessment on capital contributions. The Corporation has determined that IFRS 15 will also increase its required disclosure on revenue streams.

Financial Instruments

In July 2014, the IASB issued the final version of IFRS 9 *Financial Instruments* ("IFRS 9"), which replaces IAS 39 *Financial Instruments: Recognition and Measurement* ("IAS 39"). IFRS 9 includes revised guidance on the classification and measurement of financial instruments, including a new expected credit loss model for measuring impairment on financial assets, and new general hedge accounting requirements. It also carries forward the guidance on recognition and derecognition of financial instruments from IAS 39. The standard is effective for annual periods beginning on or after January 1, 2018, and will be applied retrospectively with some exceptions. The Corporation has assessed the impact of adopting IFRS 9, and concluded that the new classification under IFRS 9 will not have a material impact on the consolidated financial statements. Management is currently evaluating the impact of adopting the new expected credit loss model for measuring impairment.

Leases

In January 2016, the IASB issued IFRS 16 *Leases* ("IFRS 16"), which replaces IAS 17 *Leases* ("IAS 17") and related interpretations. IFRS 16 introduces a single lessee accounting model eliminating the current distinction between finance and operating leases. It requires the recognition of lease-related assets and liabilities on the balance sheet, except for short-term leases and leases of low value underlying assets. In addition, the nature and timing of expenses related to leases will change, as IFRS 16 replaces the straight-line operating leases expense with the depreciation expense for the assets and interest expense on the lease liabilities. Lessor accounting remains substantially unchanged. The standard is effective for annual periods beginning on or after January 1, 2019, and may be applied either retrospectively or using a modified retrospective approach. Early adoption is permitted if IFRS 15 is also adopted.

The Corporation intends to early adopt IFRS 16 on January 1, 2018. The Corporation has completed its assessment of existing operating leases. IFRS 16 will not have a significant impact on the Corporation's consolidated financial statements and the Corporation has assessed the quantitative impact of adopting IFRS 16 to be $nil in opening retained earnings, and an increase of $1.6 million in total assets and total liabilities for the right-of-use assets and the lease liabilities, respectively, as at January 1, 2018.

Forward-Looking Information

Certain information included in this MD&A constitutes "forward-looking information" within the meaning of applicable securities legislation. The purpose of the forward-looking information is to provide the Corporation's current expectations regarding future results of operations, performance, business prospects and opportunities and may not be appropriate for other purposes. All information, other than statements of historical fact, which address activities, events or developments that we expect or anticipate may or will occur in the future, are forward-looking information. The words "anticipates", "believes", "budgets", "committed", "can", "could", "estimates", "expects", "focus", "forecasts", "future", "intends", "may", "might", "plans", "propose", "projects", "schedule", "seek", "should", "trend", "will", "would", "objective", "outlook" or the negative or other variations of these words or other comparable words or phrases, are intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects the Corporation's current beliefs and is based on information currently available to the Corporation.

Specific forward-looking information in the MD&A includes, but is not limited to, the statements regarding the settlement variance and other regulatory balance variances as described in the section entitled "Results of Operations"; the effect of changes in energy consumption on future revenue as described in the sections entitled "Summary of Quarterly Results of Operations" and "Risk Management and Risk Factors"; the Corporation's plans to finance the investment in LDC's infrastructure and, the Corporation's available sources of liquidity and capital resources and the sufficiency thereof to satisfy working capital requirements for the next twelve months as described in the section entitled "Liquidity and Capital Resources"; the planned and proposed capital initiatives and the expected results of such initiatives as described in the section entitled "Liquidity and Capital Resources"; the expected capital expenditures required to complete Copeland Station and the anticipated completion date for Copeland Station as described in the section entitled "Liquidity and Capital Resources" and "Risk Management and Risk Factors"; the anticipated contractual obligations and other commitments of the Corporation over the next five years as set out in the section entitled "Liquidity and Capital Resources"; the payment of dividends as described in the section entitled

"Liquidity and Capital Resources"; plans to meet CDM targets as described in the section entitled "Corporate Developments"; the Corporation's expectation that cash generated from operations, after the payment of dividends, is not expected to be sufficient to repay existing indebtedness, fund capital expenditures and meet other liquidity requirements over the next 12 months as described in the section entitled "Risk Management and Risk Factors"; the ability to claim under applicable liability insurance policies and/or pay any damages with respect to legal actions and claims as described in the section entitled "Legal Proceedings"; the Corporation's reliance on debt financing through its medium-term note program, Commercial Paper Program or existing credit facilities to finance the Corporation's daily operations, repay existing indebtedness, and fund capital expenditures as described in the section entitled "Risk Management and Risk Factors"; the effect of changes in interest rates and discount rates on future revenue requirements and future post-employment benefit obligations, respectively, as described in the section entitled "Risk Management and Risk Factors"; the Corporation's plans to attract, train and retain skilled employees and mitigate risks from retiring employees as described in the section entitled "Risk Management and Risk Factors"; the possibility that advances in technology may compete with the Corporation by affecting energy consumption levels and, as a result, customer demand for the Corporation's services as described in the section entitled "Risk Management and Risk Factors"; the expectation that one-third of the Corporation's electricity distribution assets have already exceeded or will reach the end of their expected useful lives within the next 5-year period as described in the section entitled "Risk Management and Risk Factors";; and the adoption and impact of new standards, amendments and interpretations on the Corporation's consolidated financial statements in the section entitled "Future Accounting Pronouncements".

The forward-looking information is based on estimates and assumptions made by the Corporation's management in light of past experience and perception of historical trends, current conditions and expected future developments, as well as other factors that management believes to be reasonable in the circumstances, including, but not limited to, the amount of indebtedness of the Corporation, changes in funding requirements, the future course of the economy and financial markets, no unforeseen delays and costs in the Corporation's capital projects (including Copeland Station), no unforeseen changes in the legislative and operating framework for Ontario's electricity market, the receipt of applicable regulatory approvals and requested rate orders, no unexpected delays in obtaining required approvals, the receipt of applicable IESO approvals for mid-term CDM incentives, the ability of the Corporation to obtain and retain qualified staff, equipment and services in a timely and cost efficient manner, the receipt of favourable judgments, no unforeseen changes in rate orders or rate setting methodologies, no unfavourable changes in environmental regulation, the level of interest rates and the Corporation's ability to borrow, and assumptions regarding general business and economic conditions.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to, risks associated with the execution of the Corporation's capital and maintenance programs necessary to maintain the performance of our aging distribution assets and make required infrastructure improvements; risks associated with capital projects, including Copeland Station; risks associated with electricity industry regulatory developments and other governmental policy changes; risks associated with the timing and results of regulatory decisions regarding the Corporation's revenue requirements, cost recovery and rates; risks associated with information system security and with maintaining complex information technology systems; risk to the Corporation's facilities and operations posed by unexpected weather conditions caused by climate change and other factors, terrorism and pandemics and the Corporation's limited insurance coverage for losses resulting from these events; risks associated with being controlled by the City, including the risk that the City could introduce rules, policies or directives that can potentially limit the Corporation's ability to meet its business objectives as laid out in the Shareholder Direction principles; risks related to the Corporation's work force demographic and its potential inability to attract, train and retain skilled employees; risks associated with possible labour disputes and the Corporation's ability to negotiate appropriate collective agreements; risk that the Corporation may fail to monitor the external environment and or develop and pursue strategies through appropriate business models, thus failing to gain a strategic advantage; risk that the Corporation is not able to arrange sufficient and cost-effective debt financing to repay maturing debt and to fund capital expenditures and other obligations; risk of downgrades to the Corporation's credit rating; risks related to the timing and extent of changes in prevailing interest rates and discounts rates and their effect on future revenue requirements and future post-employment benefit obligations; risk of substantial and currently undetermined or underestimated environmental costs and liabilities; risk that assumptions that form the basis of the Corporation's recorded environmental liabilities and related regulatory balances may change; risk that the presence or release of hazardous or harmful substances could lead to claims by third parties and/or governmental orders and other factors which are discussed in more detail under the section entitled "Risk Management and Risk Factors" in this MD&A. Please review this section – "Risk Management and Risk Factors" in detail. All of the forward-looking information included in this MD&A is qualified by the cautionary

statements in this "Forward-Looking Information" section and the "Risk Management and Risk Factors" section of this MD&A. These factors are not intended to represent a complete list of the factors that could affect the Corporation; however, these factors should be considered carefully and readers should not place undue reliance on forward-looking information made herein. Furthermore, the forward-looking information contained herein is dated as of the date of this MD&A or as of the date specified in this MD&A, as the case may be, and the Corporation has no intention and undertakes no obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

Selected Annual Information

The following table sets forth selected annual financial information of the Corporation for the three years ended December 31, 2017, 2016 and 2015. This information has been derived from the Corporation's consolidated financial statements.

Selected Annual Consolidated Financial Information
(in millions of Canadian dollars)

	2017 $	2016 $	2015 $
Year Ended December 31			
Total Revenues [1]	3,849.7	4,030.0	3,539.9
Net income after net movements in regulatory balances [1]	156.5	151.4	126.7
As at December 31			
Total assets and regulatory balances [2]	5,226.2	4,954.4	4,686.9
Total debentures [2,3]	2,034.0	2,084.6	1,885.1
Other non-current financial liabilities [4]	9.1	17.3	16.6
Total equity [2]	1,760.4	1,428.9	1,340.9
Dividends [5]	75.0	63.4	56.3

[1] See "Results of Operations" for further details on distribution revenue, other revenue, and net income after net movements in regulatory balances.

[2] See "Financial Position" for further details of significant changes in assets, debentures and shareholder's equity.

[3] Total debentures include current and long-term debentures.

[4] Other non-current financial liabilities include primarily non-current obligations under capital lease and non-current customer deposits. Under IFRS, deposits that are due or will be due on demand within one year from the end of the reporting period have been reclassified to other current financial liabilities.

[5] See "Liquidity and Capital Resources" for further details on dividends.

Additional Information

Additional information with respect to the Corporation (including its annual information form) is available on the System for Electronic Document Analysis and Retrieval website at www.sedar.com.

Toronto, Canada

March 7, 2018



CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2017 AND 2016

See Financial Report for abbreviations and defined terms
used in the audited consolidated financial statements.

MANAGEMENT'S REPORT

The accompanying Consolidated Financial Statements have been prepared by management of Toronto Hydro Corporation (the "Corporation"), who are responsible for the integrity, consistency and reliability of the information presented. The Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards and applicable securities legislation.

The preparation of the Consolidated Financial Statements necessarily involves the use of estimates and assumptions based on management's judgments, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Corporation as described in Note 26 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements includes information regarding the estimated impact of future events and transactions. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected. The Consolidated Financial Statements have been prepared within reasonable limits of materiality in light of information available up to March 7, 2018.

In meeting its responsibility for the reliability of financial information, management maintains and relies on a comprehensive system of internal controls and internal audit, which is designed to provide reasonable assurance that the financial information is relevant, reliable and accurate, and that the Corporation's assets are safeguarded and transactions are properly authorized and executed. The system includes formal policies and procedures and appropriate delegation of authority and segregation of responsibilities within the organization. An internal audit function evaluates the effectiveness of these internal controls and reports its findings to management and the Audit Committee of the Corporation, as required.

The Board of Directors, through its Audit Committee, is responsible for overseeing management in the performance of its financial reporting and internal controls. The Audit Committee is composed of independent directors and meets periodically with management, the internal auditors and the external auditors to discuss internal controls over the financial reporting process, auditing matters and financial reporting issues, to satisfy itself that each group has properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The Audit Committee also considers, for review by the Board of Directors and approval by the shareholder, the appointment of the external auditors. The external auditors have direct and full access to the Audit Committee, with and without the presence of management, to discuss their audit and their findings as to the integrity of the financial reporting and the effectiveness of the system of internal controls.

The Consolidated Financial Statements were reviewed by the Audit Committee, and on their recommendation, were approved by the Board of Directors. The Consolidated Financial Statements have been examined by KPMG LLP, independent external auditors appointed by the Corporation's shareholder. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with International Financial Reporting Standards. The attached Independent Auditors' Report outlines the scope of their examination and their opinion.

On behalf of Toronto Hydro Corporation's management:

"Anthony Haines"
Anthony Haines
President and Chief Executive Officer

"Sean Bovingdon"
Sean Bovingdon
Executive Vice-President and Chief Financial Officer

KPMG LLP
Chartered Professional Accountants
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INDEPENDENT AUDITORS' REPORT

To the Shareholder of Toronto Hydro Corporation

We have audited the accompanying consolidated financial statements of Toronto Hydro Corporation, which comprise the consolidated balance sheets as at December 31, 2017 and December 31, 2016, the consolidated statements of income, comprehensive income, changes in equity and cash flows for the years ended December 31, 2017 and December 31, 2016, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Toronto Hydro Corporation as at December 31, 2017 and December 31, 2016, and its consolidated financial performance and its consolidated cash flows for the years ended December 31, 2017 and December 31, 2016 in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants
March 7, 2018
Toronto, Canada

KPMG LLP is a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International Cooperative ("KPMG International"), a Swiss entity. KPMG Canada provides services to KPMG LLP.

CONSOLIDATED BALANCE SHEETS

[in millions of Canadian dollars]

As at December 31	2017 $	2016 $
ASSETS		
Current		
Accounts receivable *[notes 4 and 16[b]]*	**217.7**	229.8
Unbilled revenue *[note 16[b]]*	**278.3**	320.5
Materials and supplies	**9.3**	9.7
Other assets *[note 5]*	**12.7**	13.5
Assets held for sale *[note 8]*	**8.7**	-
Total current assets	**526.7**	573.5
Property, plant and equipment *[note 6]*	**4,143.4**	3,907.2
Intangible assets *[note 7]*	**296.2**	217.8
Deferred tax assets *[note 21]*	**57.0**	63.8
Other assets *[note 5]*	**3.0**	1.3
Total assets	**5,026.3**	4,763.6
Regulatory balances *[note 9]*	**199.9**	190.8
Total assets and regulatory balances	**5,226.2**	4,954.4
LIABILITIES AND EQUITY		
Current		
Working capital facility *[note 10]*	**11.7**	7.1
Commercial paper *[note 10]*	**159.0**	261.0
Accounts payable and accrued liabilities *[note 11]*	**516.3**	504.4
Income tax payable	**12.8**	8.1
Customer deposits	**49.2**	39.1
Deferred revenue *[note 12]*	**10.7**	5.1
Deferred conservation credit *[note 3[c]]*	**9.3**	5.5
Debentures *[note 13]*	**-**	249.8
Other liabilities *[note 24]*	**1.5**	3.1
Total current liabilities	**770.5**	1,083.2
Debentures *[note 13]*	**2,034.0**	1,834.8
Customer deposits	**8.9**	15.0
Deferred revenue *[note 12]*	**179.2**	140.3
Post-employment benefits *[note 14]*	**313.0**	280.5
Other liabilities *[note 24]*	**0.2**	2.3
Total liabilities	**3,305.8**	3,356.1
Commitments, contingencies and subsequent events *[notes 2, 24 and 25]*		
Equity		
Share capital *[note 17]*	**817.8**	567.8
Retained earnings	**942.6**	861.1
Total equity	**1,760.4**	1,428.9
Total liabilities and equity	**5,066.2**	4,785.0
Regulatory balances *[note 9]*	**160.0**	169.4
Total liabilities, equity and regulatory balances	**5,226.2**	4,954.4

ON BEHALF OF THE BOARD:

"David McFadden"
David McFadden, Director

"Michael Nobrega"
Michael Nobrega, Director

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF INCOME

[in millions of Canadian dollars]

Year ended December 31	2017 $	2016 $
Revenues		
Energy sales	**3,017.8**	3,306.2
Distribution revenue	**724.2**	647.9
Other *[note 18]*	**107.7**	75.9
	3,849.7	4,030.0
Expenses		
Energy purchases	**3,063.5**	3,216.9
Operating expenses *[note 19]*	**293.0**	277.1
Depreciation and amortization *[notes 6 and 7]*	**224.2**	212.2
	3,580.7	3,706.2
Finance costs *[note 20]*	**(77.7)**	(74.2)
Gain on disposals of property, plant and equipment	**9.8**	2.1
Income before income taxes	**201.1**	251.7
Income tax expense *[note 21]*	**(44.7)**	(67.1)
Net income	**156.4**	184.6
Net movements in regulatory balances *[note 9]*	**(13.1)**	(77.2)
Net movements in regulatory balances arising from deferred tax assets *[note 9]*	**13.2**	44.0
Net income after net movements in regulatory balances	**156.5**	151.4

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

[in millions of Canadian dollars]

Year ended December 31	2017 $	2016 $
Net income after net movements in regulatory balances	**156.5**	151.4
Other comprehensive income		
Items that will not be reclassified to income or loss		
Remeasurements of post-employment benefits, net of tax (2017 - $6.7, 2016 - $5.5) *[note 14]*	(18.4)	15.5
Net movements in regulatory balances related to OCI, net of tax (2017 - $6.7, 2016 - $5.5) *[note 14]*	18.4	(15.5)
Other comprehensive income, net of tax	**-**	-
Total comprehensive income	**156.5**	151.4

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

[in millions of Canadian dollars]

Year ended December 31	2017 $	2016 $
Share capital ***[note 17]***	**817.8**	567.8
Retained earnings, beginning of year	**861.1**	773.1
Net income after net movements in regulatory balances	**156.5**	151.4
Dividends *[notes 17 and 23]*	**(75.0)**	(63.4)
Retained earnings, end of year	**942.6**	861.1
Total equity	**1,760.4**	1,428.9

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

[in millions of Canadian dollars]

Year ended December 31	2017 $	2016 $
OPERATING ACTIVITIES		
Net income after net movements in regulatory balances	**156.5**	151.4
Net movements in regulatory balances *[note 9]*	**13.1**	77.2
Net movements in regulatory balances arising from deferred tax assets *[note 9]*	**(13.2)**	(44.0)
Adjustments		
Depreciation and amortization *[notes 6 and 7]*	**224.2**	212.2
Amortization of deferred revenue *[note 12]*	**(4.7)**	(3.8)
Finance costs	**77.7**	74.2
Income tax expense	**44.7**	67.1
Post-employment benefits	**7.4**	5.0
Gain on disposals of property, plant and equipment	**(9.8)**	(2.1)
Other	**1.0**	0.7
Capital contributions received *[note 12]*	**50.8**	44.7
Net change in other non-current assets and liabilities	**(6.9)**	(1.8)
Increase in customers deposits	**4.0**	6.7
Changes in non-cash working capital balances *[note 22]*	**62.0**	(15.3)
Income tax paid	**(22.1)**	(0.9)
Net cash provided by operating activities	**584.7**	571.3
INVESTING ACTIVITIES		
Purchase of property, plant and equipment *[note 22]*	**(440.0)**	(511.7)
Purchase of intangible assets *[note 22]*	**(93.4)**	(39.9)
Proceeds on disposals of property, plant and equipment	**12.5**	2.2
Net cash used in investing activities	**(520.9)**	(549.4)
FINANCING ACTIVITIES		
Decrease in commercial paper, net of issuances *[note 10]*	**(102.0)**	(63.0)
Common shares issued *[note 17]*	**250.0**	-
Dividends paid *[note 17]*	**(75.0)**	(63.4)
Proceeds from issuance of debentures *[note 13]*	**199.9**	200.0
Debt issuance costs paid *[note 13]*	**(1.4)**	(1.3)
Repayment of debentures *[note 13]*	**(250.0)**	-
Repayment of finance lease liability	**(3.0)**	(3.1)
Interest paid	**(86.9)**	(84.0)
Net cash used in financing activities	**(68.4)**	(14.8)
Net decrease (increase) in working capital facility during the year	**(4.6)**	7.1
Working capital facility, beginning of year	**(7.1)**	(14.2)
Working capital facility, end of year	**(11.7)**	(7.1)

See accompanying notes to the consolidated financial statements.

1. NATURE OF BUSINESS

The Corporation was incorporated on June 23, 1999 under the *Business Corporations Act* (Ontario) in accordance with the Electricity Act. The Corporation is wholly owned by the City and is domiciled in Canada, with its registered office located at 14 Carlton Street, Toronto, Ontario, M5B 1K5. The Corporation and its subsidiaries distribute electricity to customers and provide street lighting and expressway lighting services in the City.

2. BASIS OF PRESENTATION

The Corporation's audited consolidated financial statements for the years ended December 31, 2017 and 2016 ["Consolidated Financial Statements"] have been prepared in accordance with IFRS with respect to the preparation of annual financial information.

These Consolidated Financial Statements are presented in Canadian dollars, the Corporation's functional currency, and have been prepared on the historical cost basis, except for post-employment benefits which are recorded at actuarial value.

The Corporation has evaluated the events and transactions occurring after the consolidated balance sheet date through March 7, 2018 when the Corporation's Consolidated Financial Statements were authorized for issue by the Corporation's Board of Directors, and identified the events and transactions which required recognition in the Consolidated Financial Statements and/or disclosure in these notes to the Consolidated Financial Statements *[notes 8 and 17]*.

The summary of significant accounting policies has been disclosed in note 26.

3. REGULATION

The OEB has regulatory oversight of electricity matters in Ontario. The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to approve the amounts paid to non-contracted generators, the responsibility to provide rate protection for rural or remote electricity customers, and the responsibility for ensuring that electricity distribution companies fulfill their obligations to connect and service customers.

LDC is required to charge its customers for the following amounts (all of which, other than distribution rates, represent a pass-through of amounts payable to third parties):

- *Commodity Charge* – The commodity charge represents the market price of electricity consumed by customers and is passed through the IESO back to operators of generating stations. It includes the global adjustment, which represents the difference between the market price of electricity and the rates paid to regulated and contracted generators.

- *Retail Transmission Rate* – The retail transmission rate represents the costs incurred in respect of the transmission of electricity from generating stations to local distribution networks. Retail transmission rates are passed through back to operators of transmission facilities.

- *WMS Charge* – The WMS charge represents various wholesale market support costs, such as the cost of the IESO to administer the wholesale electricity system, operate the electricity market, and maintain reliable operation of the provincial grid. Wholesale charges are passed through back to the IESO.

- *Distribution Rate* – The distribution rate is designed to recover the costs incurred by LDC in delivering electricity to customers, including the OEB-allowed cost of capital. Distribution rates are regulated by the OEB and include fixed and variable (usage-based) components, based on a forecast of LDC's customers and load.

a) Electricity Distribution Rates

The OEB's regulatory framework for electricity distributors is designed to support the cost-effective planning and operation of the electricity distribution network and to provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price.

The OEB typically regulates the electricity rates for distributors using a combination of detailed cost of service reviews and IRM adjustments. Under the OEB's rate-setting methods, actual operating conditions may vary from forecasts such that actual returns achieved can differ from approved returns. Approved electricity rates are generally not adjusted as a result of actual costs or revenues being different from forecasted amounts, other than for certain prescribed costs that are eligible for deferral for future collection from, or refund to, customers.

On March 1, 2016 pursuant to LDC's 2015 – 2019 CIR application, the OEB set 2018 distribution rates on an interim basis. On August 23, 2017, LDC filed its 2018 rate application seeking OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2018 and ending on December 31, 2018. On December 14, 2017, the OEB issued a decision and rate order approving LDC's 2018 rates, with an effective date of January 1, 2018, and the disposition of certain deferral and variance accounts.

b) Ontario's Fair Hydro Plan

On March 2, 2017, the Government of Ontario announced the OFHP, which includes a number of initiatives, some of which affect LDC or its customers.

OFHP includes the OREC, which came into effect on January 1, 2017. The OREC provides eligible customers with financial assistance in the form of an 8% rebate of the pre-tax cost of their electricity. The OREC rebates are administered by LDC and paid by the IESO in the month following customer billing. Current accounts receivable and unbilled revenue include the amount owing by the IESO to LDC. No effect on revenue or expense is recognized by LDC in respect of the OREC rebates.

OFHP also includes the OFHA, which enacted the Ontario Fair Hydro Plan Act, 2017 and amended the Electricity Act, 1998 and the Ontario Energy Board Act, 1998. The OFHA came into effect on June 1, 2017 and its impact is reflected in the Consolidated Financial Statements. The OFHA provides eligible customers with financial assistance through various changes to commodity pricing, new or amended programs, and eliminating or reducing certain provincial charges on the electricity bill. The OFHA reduces the total electricity bill for eligible customers and, accordingly, reduces current accounts receivable, unbilled revenue, accounts payable and accrued liabilities for LDC. No effect on distribution revenue or expense is recognized by LDC in respect of the OFHA.

c) CDM Activities

On March 26, 2014, the Minister of Energy of Ontario, under the guidance of sections 27.1 and 27.2 of the OEB Act, directed the OEB to amend the licence of each licensed electricity distributor to require the electricity distributor, as a condition of its licence, to make CDM programs available to its customers and to do so in relation to each customer segment in its service area, over the period beginning January 1, 2015 through December 31, 2020. On March 31, 2014, the Minister of Energy of Ontario issued a direction to require the OPA to coordinate, support and fund the delivery of CDM programs through electricity distributors. The objective of the CDM efforts is to reduce electricity consumption in the Province of Ontario by a total of 7 terawatt hours between January 1, 2015 and December 31, 2020, of which LDC's share is approximately 1,576 GWh of energy savings.

On November 13, 2014, LDC entered into an energy conservation agreement with the OPA for the delivery of CDM programs over the 2015-2020 period. The IESO and the OPA were merged under the name IESO starting on January 1, 2015.

Under the energy conservation agreement with the IESO, LDC has a joint CDM plan with Oakville Hydro Electricity Distribution Inc. ["Oakville Hydro"] for the delivery of CDM programs over the 2015-2020 period. LDC can choose between full cost recovery funding, pay-for-performance funding, or a combination of both, on a CDM program by program basis. Under the full cost recovery funding method, the IESO reimburses LDC for all adequately documented incurred costs, with an option to receive a portion of its funding in advance. Cost efficiency incentives may be awarded if LDC's electricity savings meet or exceed certain CDM plan targets for programs under the full cost recovery funding method, with a mid-term review to be performed by the IESO for the 2015-2017 period. Under the pay-for-performance funding method, LDC receives payment in arrears based on verified electricity savings achieved with various options for frequency of payment. The programs under the joint CDM plan with Oakville Hydro are only being offered under the full cost recovery funding method.

The joint CDM plan provides combined funding of approximately $425.0 million, including participant incentives and program administration costs to achieve an aggregate energy savings target of approximately 1,668 GWh. Oakville Hydro's programs under the joint CDM plan started on January 1, 2016. LDC received $44.9 million as at December 31, 2016 and $57.4 million in the year ended December 31, 2017 from the IESO for the delivery of CDM programs. Amounts received but not yet spent are presented on the consolidated balance sheets under current liabilities as deferred conservation credit. As at December 31, 2017, LDC estimated that approximately $12.9 million qualified as a joint mid-term incentive, of which $12.2 million represents LDC's portion and is included within accounts receivable.

Effective October 16, 2017, LDC entered into an agreement to transfer $4.0 million of funding and a corresponding 20 GWh of its energy savings target to another local distribution company. This agreement will decrease the joint CDM plan funding with Oakville Hydro to $421.0 million, with a revised energy savings target of 1,648 GWh. The revised CDM plan was approved by the IESO on December 14, 2017.

4. ACCOUNTS RECEIVABLE

Accounts receivable consists of the following:

	2017 $	2016 $
Trade receivables	**189.9**	215.4
Due from related parties *[note 23]*	**13.8**	12.7
CDM mid-term incentive *[note 3[c]]*	**12.2**	—
Other	**1.8**	1.7
	217.7	229.8

5. OTHER ASSETS

Other assets consist of the following:

	2017 $	2016 $
Prepaid expenses	**11.3**	12.3
Deferred financing costs	**1.6**	1.6
Other	**2.8**	0.9
Total other assets	**15.7**	14.8
Less: Current portion of other assets relating to:		
Prepaid expenses	**11.3**	12.3
Deferred financing costs	**0.4**	0.4
Other	**1.0**	0.8
Current portion of other assets	**12.7**	13.5
Non-current portion of other assets	**3.0**	1.3

6. PROPERTY, PLANT AND EQUIPMENT

PP&E consist of the following:

	Distribution assets $	Land and buildings $	Equipment and other $	Construction in progress $	Total $
Cost					
Balance as at January 1, 2016	3,027.2	203.1	175.7	498.7	3,904.7
Additions/(Transfers)	381.2	111.3	67.0	(47.7)	511.8
Disposals and retirements	(32.1)	(0.1)	(0.3)	—	(32.5)
Balance as at December 31, 2016	3,376.3	314.3	242.4	451.0	4,384.0
Additions/(Transfers)	**404.4**	**84.8**	**38.4**	**(76.1)**	**451.5**
Assets held for sale *[note 8]*	**—**	**(21.2)**	**—**	—	**(21.2)**
Disposals and retirements	**(31.5)**	**(3.2)**	**(0.4)**	**—**	**(35.1)**
Balance as at December 31, 2017	**3,749.2**	**374.7**	**280.4**	**374.9**	**4,779.2**
Accumulated depreciation					
Balance as at January 1, 2016	222.6	15.7	77.7	—	316.0
Depreciation	129.3	10.3	25.9	—	165.5
Disposals and retirements	(4.6)	—	(0.1)	—	(4.7)
Balance as at December 31, 2016	347.3	26.0	103.5	—	476.8
Depreciation	**138.1**	**13.5**	**26.7**	—	**178.3**
Assets held for sale *[note 8]*	—	**(12.5)**	—	—	**(12.5)**
Disposals and retirements	**(5.9)**	**(0.5)**	**(0.4)**	—	**(6.8)**
Balance as at December 31, 2017	**479.5**	**26.5**	**129.8**	**—**	**635.8**
Carrying amount					
Balance as at December 31, 2016	3,029.0	288.3	138.9	451.0	3,907.2
Balance as at December 31, 2017	**3,269.7**	**348.2**	**150.6**	**374.9**	**4,143.4**

As at December 31, 2017, "Equipment and other" included assets under finance lease with cost of $18.2 million [December 31, 2016 - $18.2 million] and accumulated depreciation of $10.4 million [December 31, 2016 - $8.3 million]. For the year ended December 31, 2017, the Corporation recorded depreciation expense of $2.1 million [2016 - $2.3 million] related to assets under finance lease.

For the year ended December 31, 2017, borrowing costs in the amount of $6.2 million [2016 - $9.5 million] were capitalized to PP&E and credited to finance costs, with an average capitalization rate of 3.73% [2016 - 3.61%].

"Construction in progress" additions are net of transfers to the other PP&E categories.

7. INTANGIBLE ASSETS

Intangible assets consist of the following:

	Computer software	Contributions	Software in development	Contributions for work in progress	Total
	$	$	$	$	$
Cost					
Balance as at January 1, 2016	101.6	21.7	11.8	104.3	239.4
Additions/(Transfers)	11.9	53.8	8.4	(34.2)	39.9
Balance as at December 31, 2016	113.5	75.5	20.2	70.1	279.3
Additions/(Transfers)	**23.4**	**—**	**34.0**	**44.0**	**101.4**
Balance as at December 31, 2017	**136.9**	**75.5**	**54.2**	**114.1**	**380.7**
Accumulated amortization					
Balance as at January 1, 2016	38.1	2.0	—	—	40.1
Amortization	19.3	2.1	—	—	21.4
Balance as at December 31, 2016	57.4	4.1	—	—	61.5
Amortization	**20.0**	**3.0**	**—**	**—**	**23.0**
Balance as at December 31, 2017	**77.4**	**7.1**	**—**	**—**	**84.5**
Carrying amount					
Balance as at December 31, 2016	56.1	71.4	20.2	70.1	217.8
Balance as at December 31, 2017	**59.5**	**68.4**	**54.2**	**114.1**	**296.2**

For the year ended December 31, 2017, borrowing costs in the amount of $3.6 million [2016 - $3.0 million] were capitalized to intangible assets and credited to finance costs, with an average capitalization rate of 3.73% [2016 - 3.61%].

"Software in development" and "Contributions for work in progress" additions are net of transfers to the other intangible asset categories.

"Computer software" is externally acquired. The remaining amortization periods for computer software and contributions range from less than one year to 5 years, and from 11 to 25 years, respectively.

8. ASSETS HELD FOR SALE

In 2017, LDC commenced the process to sell a property including land and buildings to a third party. Accordingly, the carrying amount of the identified assets of $8.7 million was transferred from PP&E to assets held for sale as at December 31, 2017. Upon reclassification as assets held for sale, no further depreciation was recorded by LDC on the related assets. On January 16, 2018, LDC entered into an agreement to sell the property, which is expected to close on April 16, 2018. Upon completion of the sale, the net gain including the future tax savings will be deferred as a regulatory credit balance *[note 9[c]]*.

9. REGULATORY BALANCES

Debit balances consist of the following:

	January 1, 2017	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2017	Remaining recovery/ reversal period (months)	Carrying charges applicable
	$	$	$	$	$		
OPEB actuarial net loss	**60.2**	**25.1**	**—**	**—**	**85.3**	note 9[a]	—
Foregone revenue	**64.3**	**—**	**(20.3)**	**—**	**44.0**	24	—
Gain on disposal	**8.6**	**(8.1)**	**18.6**	**—**	**19.1**	note 9[c]	*
LRAM	**10.5**	**11.0**	**(4.8)**	**—**	**16.7**	note 9[d]	*
IFRS transitional adjustments	**22.8**	**—**	**(7.8)**	**—**	**15.0**	24	—
Stranded meters	**11.4**	**—**	**(3.9)**	**—**	**7.5**	24	*
OPEB cash versus accrual	**2.9**	**1.3**	**—**	**—**	**4.2**	note 9[g]	—
Named properties	**4.6**	**—**	**(1.5)**	**—**	**3.1**	24	—
Capital contributions	**1.5**	**—**	**(0.5)**	**—**	**1.0**	24	—
Smart meters	**2.1**	**—**	**(3.1)**	**1.0**	**—**	—	—
Other	**1.9**	**2.1**	**—**	**—**	**4.0**	—	*
	190.8	**31.4**	**(23.3)**	**1.0**	**199.9**		

	January 1, 2016	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2016	Remaining recovery/ reversal period (months)	Carrying charges applicable
	$	$	$	$	$		
OPEB actuarial net loss	81.2	(21.0)	—	—	60.2	note 9[a]	—
Foregone revenue	61.1	19.2	(16.0)	—	64.3	36	—
Gain on disposal	—	—	14.5	(5.9)	8.6	note 9[c]	*
LRAM	9.1	4.7	(3.3)	—	10.5	note 9[d]	*
IFRS transitional adjustments	28.9	—	(6.1)	—	22.8	36	—
Stranded meters	14.4	—	(3.0)	—	11.4	36	*
OPEB cash versus accrual	1.8	1.1	—	—	2.9	note 9[g]	—
Named properties	5.8	—	(1.2)	—	4.6	36	—
Capital contributions	1.9	—	(0.4)	—	1.5	36	—
Smart meters	10.0	—	(7.9)	—	2.1	4	—
Settlement variances	25.3	—	—	(25.3)	—	—	*
Other	2.2	1.6	—	(1.9)	1.9	—	*
	241.7	5.6	(23.4)	(33.1)	190.8		

* In accordance with the OEB's direction, carrying charges were accrued to certain regulatory balances at a rate of 1.10% for January 1, 2017 to September 30, 2017 and 1.50% for October 1, 2017 to December 31, 2017 [2016 - 1.10%].

Credit balances consist of the following:

	January 1, 2017	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2017	Remaining recovery/ reversal period (months)	Carrying charges applicable
	$	$	$	$	$		
Deferred taxes	**65.3**	**(6.5)**	**—**	**—**	**58.8**	note 9[j]	—
Settlement variances	**62.8**	**(45.2)**	**23.4**	**—**	**41.0**	note 9[k]	*
Capital-related revenue requirement	**8.8**	**16.2**	**—**	**—**	**25.0**	note 9[l]	*
Derecognition	**12.8**	**3.1**	**—**	**—**	**15.9**	note 9[m]	*
Tax-related variances	**17.5**	**—**	**(8.2)**	**—**	**9.3**	12	*
Development charges	**—**	**5.3**	**—**	**—**	**5.3**	note 9[o]	*
Smart meters	**—**	**—**	**(0.7)**	**1.0**	**0.3**	—	—
Other	**2.2**	**2.7**	**(0.5)**	**—**	**4.4**	—	*
	169.4	**(24.4)**	**14.0**	**1.0**	**160.0**		

	January 1, 2016	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2016	Remaining recovery/ reversal period (months)	Carrying charges applicable
	$	$	$	$	$		
Deferred taxes	114.8	(49.5)	—	—	65.3	note 9[j]	—
Settlement variances	—	89.3	1.2	(27.7)	62.8	note 9[k]	*
Capital-related revenue requirement	2.8	6.0	—	—	8.8	note 9[l]	*
Derecognition	9.9	2.9	—	—	12.8	note 9[m]	*
Tax-related variances	26.5	—	(8.5)	(0.5)	17.5	24	*
ICM	9.7	0.1	(9.8)	—	—	—	*
Gain on disposal	5.9	—	—	(5.9)	—	—	*
Other	2.0	1.2	(2.0)	1.0	2.2	—	*
	171.6	50.0	(19.1)	(33.1)	169.4		

* In accordance with the OEB's direction, carrying charges were accrued to certain regulatory balances at a rate of 1.10% for January 1, 2017 to September 30, 2017 and 1.50% for October 1, 2017 to December 31, 2017 [2016 - 1.10%].

The "Balances arising in the period" column consists of new additions to regulatory balances (for both debits and credits). The "Recovery/reversal" column consists of amounts disposed through OEB-approved rate riders or transactions reversing an existing regulatory balance. The "Other movements" column consists of impairment and reclassification between the regulatory debit and credit balances. In addition, the "Other movements" column includes reclassification of regulatory deferral accounts considered to be insignificant into the "Other" categories. During 2016, residual regulatory balances approved by the OEB for disposition over a 10-month period commencing on March 1, 2016 were reclassified from "Other" regulatory debit balance, settlement variances and tax-related variances into "Other" regulatory credit balance. There was no impairment recorded for the year ended December 31, 2017.

Reconciliation between the net movements in regulatory balances shown above and the net movements presented on the consolidated statements of income and the consolidated statements of comprehensive income is as follows:

	2017 $	2016 $
Total movements per regulatory debit balances table	**9.1**	(50.9)
Total movements per regulatory credit balances table	**9.4**	2.2
Total net movements	**18.5**	(48.7)
Net movements per financial statements:		
Net movements in regulatory balances	**(13.1)**	(77.2)
Net movements in regulatory balances arising from deferred tax assets	**13.2**	44.0
Net movements in regulatory balances related to OCI, net of tax	**18.4**	(15.5)
Total net movements per financial statements	**18.5**	(48.7)

Regulatory developments in Ontario's electricity industry and other governmental policy changes may affect the electricity distribution rates charged by LDC and the costs LDC is permitted to recover. There is a risk that the OEB may disallow the recovery of a portion of certain costs incurred in the current period through future rates or disagree with the proposed recovery period. In the event that the disposition of these balances is assessed to no longer be probable based on management's judgment, any impairment will be recorded in the period when the assessment is made.

The regulatory balances of the Corporation consist of the following:

a) OPEB Actuarial Net Loss

This regulatory balance accumulates the actuarial gains and losses arising from changes in actuarial assumptions and experience adjustments recognized in OCI. The balance arising during the year ended December 31, 2017 of $25.1 million is related to the actuarial loss recorded for the year [2016 - $21.0 million actuarial gain] *[note 14[a]]*. The net position is an actuarial loss that is recoverable in future rates. LDC has not sought recovery to date from the OEB as changes in underlying assumptions may reduce the balance in the account. LDC expects to recover this regulatory balance as per OEB direction, in a future rate application.

b) Foregone Revenue

This regulatory balance relates to the revenue that LDC would have recovered in 2015 and 2016 if new OEB-approved rates were implemented as of May 1, 2015 and January 1, 2016, respectively. In the CIR decision and rate order, the OEB approved foregone revenue rate riders over 46 months commencing on March 1, 2016 for May 1, 2015 to December 31, 2015 based on approved 2015 rates and for January 1, 2016 to February 29, 2016 based on approved 2016 rates.

c) Gain on Disposal

This regulatory balance consists of the net of amounts disposed through the OEB-approved rate riders offset by the related tax savings (debits), and the after-tax gain realized on two significant LDC properties (credits). As part of the CIR decision and rate order, LDC agreed to a rate rider that would pass the total forecasted net gains along with future tax savings on both properties back to ratepayers, effective from March 1, 2016 to December 31, 2018. During 2015, the gain on one of the properties was realized by LDC resulting in a net credit balance at December 31, 2015. As at December 31, 2016, the amount disposed through the rate riders exceeded the gain realized on the first property as the second property was still not sold, resulting in a net debit balance. Upon the sale of the second property, the account

would revert to a credit balance if actual net gains and tax savings exceed the total amount of the approved rate riders *[note 8]*. In the second quarter of 2017, LDC realized a gain in connection with the disposal of a third property. LDC expects to seek disposition for any residual balance in a future rate application.

d) Lost Revenue Adjustment Mechanism

This regulatory balance relates to the difference between the level of CDM program activities included in LDC's load forecast used to set approved rates and the actual impact of CDM activities achieved. New variances are accrued based on current CDM activities. Approved variances up to 2014 were disposed through OEB-approved rate riders over 12 months commencing on January 1, 2017 and approved variances for 2015 and 2016 will be disposed through OEB-approved rate riders over 12 months commencing on January 1, 2018. Variances pertaining to years subsequent to 2016 have yet to be applied for disposition.

e) IFRS Transitional Adjustments

This regulatory balance relates to the differences arising from accounting policy changes for PP&E and intangible assets due to the transition from US GAAP to IFRS in 2014, primarily related to derecognition of certain assets and additional capitalized borrowing costs. In the CIR decision and rate order, the OEB approved disposition of the balance over 46 months commencing on March 1, 2016.

f) Stranded Meters and Smart Meters

These regulatory balances relate to the provincial government's decision to install smart meters throughout Ontario.

The net book value of stranded meters related to the deployment of smart meters was reclassified from PP&E to a new regulatory balance as at December 31, 2013. In the CIR decision and rate order, the OEB approved LDC's request for recovery of the forecasted net book value of the stranded meters as at December 31, 2014 over 46 months commencing on March 1, 2016.

On January 16, 2014, the OEB approved LDC's request for incremental revenue and disposition of the smart meter regulatory balances to be recovered through rates over 36 months commencing on May 1, 2014. The OEB ruling on smart meters also permitted the recovery in principle of LDC's allowed cost of capital on smart meters since 2008, with a rate order issued to this effect. This allows LDC to recover the incremental revenue requirement associated with these assets for the period during which they remained outside of rate base.

g) OPEB Cash versus Accrual

This regulatory balance relates to the difference between LDC's forecasted OPEB costs determined on an accrual basis and the cash payments made under the OPEB plans. The OEB directed LDC to track the difference as a temporary arrangement, pending the OEB's conclusion on the sector-wide policy consultation it initiated on the regulatory treatment of pension and OPEB costs. On September 14, 2017, the OEB issued its final report on the consultation and established the use of the accrual accounting method as the default method on which to set rates for OPEB costs. LDC will continue to track the cash versus accrual difference until its next rate application when the disposition of this regulatory balance will be considered. The timing of disposition of the balance is currently unknown.

h) Named Properties

As part of 2010 rates, LDC had forecasted net gains on certain properties which were planned for sale between 2007 and 2011. This regulatory balance relates to the excess of those forecasted net gains over the actual net gains realized

upon the sale of the named properties. In the CIR decision and rate order, the OEB approved disposition of this variance over 46 months commencing on March 1, 2016.

i) Capital Contributions

This regulatory balance relates to the difference between amounts included in rates for HONI capital contributions and actual contributions made in 2010 and 2011. In the CIR decision and rate order, the OEB approved disposition of this variance over 46 months commencing on March 1, 2016.

j) Deferred Taxes

This regulatory credit balance relates to both deferred tax amounts reclassified under IFRS 14 *[note 26[b]]* and the expected future electricity distribution rate reduction for customers arising from timing differences in the recognition of deferred tax assets. LDC did not apply for disposition of the balance since it is reversed through timing differences in the recognition of deferred tax assets.

The amounts reclassified under IFRS 14 include the deferred tax liability related to regulatory balances of $34.9 million as at December 31, 2017 [December 31, 2016 - $36.4 million], offset by the recognition of a regulatory balance in respect of additional temporary differences for which a deferred tax amount was recognized of $8.5 million as at December 31, 2017 [December 31, 2016 - $10.4 million].

The deferred tax amount related to the expected future electricity distribution rate reduction for customers was $32.4 million as at December 31, 2017 [December 31, 2016 - $39.3 million].

k) Settlement Variances

This account includes the variances between amounts charged by LDC to customers, based on regulated rates, and the corresponding cost of electricity and non-competitive electricity service costs incurred by LDC. LDC has deferred the variances between the costs incurred and the related recoveries in accordance with the criteria set out in the accounting principles prescribed by the OEB. New variances are accrued based on current charges while approved variances up to 2016, including carrying charges forecasted to the end of 2017, will be disposed through OEB-approved rate riders over 12 months commencing on January 1, 2018. Settlement variances pertaining to years subsequent to 2016 have yet to be applied for disposition.

l) Capital-related Revenue Requirement

This regulatory balance relates to the asymmetrical variance between the cumulative 2015 to 2019 capital-related revenue requirement included in rates and the actual capital-related revenue requirement over the same period. If the cumulative 2015 to 2019 capital-related revenue requirement included in rates exceeds the actual capital-related revenue requirement over the same rate period, LDC must apply for disposition of this account in order to clear the balance to ratepayers through a rate rider. This account was approved by the OEB in the CIR decision and rate order. The timing of disposition of the balance is currently unknown.

m) Derecognition

This regulatory balance relates to the difference between the revenue requirement on derecognition of PP&E and intangible assets included in the OEB-approved rates and the actual amounts of derecognition. This account was approved by the OEB in the CIR decision and rate order. The timing of disposition of the balance is currently unknown.

n) Tax-related Variance Accounts

This regulatory credit balance arose from favourable income tax reassessments on certain prior year tax positions received, which differed from those assumed in previous applications for electricity distribution rates. In the CIR decision and rate order, the OEB approved disposition of the balance over 10-34 months commencing on March 1, 2016.

o) Development charges

This regulatory balance relates to excess expansion deposits retained by LDC where the requested number of connections or electricity demand were not met by the connecting customer. Pursuant to the OEB's Distribution System Code, LDC may collect expansion deposits on offers to connect from specific customers to guarantee the payment of additional costs relating to expansion projects. During the customer connection horizon, LDC has an obligation to annually return the expansion deposit to the connecting customer in proportion to the actual connections or electricity demand that occurred in that year. If the number of connections or electricity demand requested by the customer do not materialize by the end of the specified customer connection horizon, LDC retained the excess expansion deposit not otherwise returned to the connecting customer.

The excess expansion deposits were recorded as a regulatory balance on the Consolidated Balance Sheets, with a corresponding offset in net movements in regulatory balances. This regulatory balance is expected to offset future electricity distribution rates for customers, although application has yet to be made to dispose of the balance.

p) Incremental Capital Module

This regulatory balance related to the ICM application approved by the OEB and the associated rate riders, which became effective June 1, 2013. The balance of $9.8 million represented the net of amounts collected through the ICM rate riders from 2013 to 2014 and amounts recognized in profit or loss in relation to the eligible in-service capital expenditures. Further to the OEB's decision on July 28, 2016, the entire balance of $9.8 million was recorded as an increase in equity through net movements in regulatory balances in 2016.

10. SHORT-TERM BORROWINGS

The Corporation is a party to a credit agreement with a syndicate of Canadian chartered banks which established a revolving credit facility ["Revolving Credit Facility"], pursuant to which it may borrow up to $800.0 million, of which up to $210.0 million is available in the form of letters of credit. On August 1, 2017, the maturity date of the Revolving Credit Facility was extended by one year from October 10, 2021 to October 10, 2022. Borrowings under the Revolving Credit Facility bear interest at short-term floating rates plus a fixed spread, which varies in accordance with the Corporation's credit rating.

The Corporation has a commercial paper program allowing up to $600.0 million of unsecured short-term promissory notes ["Commercial Paper Program"] to be issued in various maturities of no more than one year. The Commercial Paper Program is supported by liquidity facilities available under the Revolving Credit Facility; hence, available borrowing under the Revolving Credit Facility is reduced by the amount of commercial paper outstanding at any point in time. Proceeds from the Commercial Paper Program are used for general corporate purposes. Borrowings under the Commercial Paper Program bear interest based on the prevailing market conditions at the time of issuance.

Additionally, the Corporation is a party to:

- a $75.0 million demand facility with a Canadian chartered bank for the purpose of issuing letters of credit mainly to support LDC's prudential requirements with the IESO ["Prudential Facility"]; and
- a $20.0 million demand facility with a second Canadian chartered bank for the purpose of working capital management ["Working Capital Facility"].

The available amount under the Revolving Credit Facility as well as outstanding borrowings under the Revolving Credit Facility and Commercial Paper Program are as follows:

	Revolving Credit Facility Limit $	Revolving Credit Facility Borrowings $	Commercial Paper Outstanding $	Revolving Credit Facility Availability $
December 31, 2017	800.0	—	159.0	641.0
December 31, 2016	800.0	—	261.0	539.0

For the year ended December 31, 2017, the average aggregate outstanding borrowings under the Corporation's Revolving Credit Facility, Working Capital Facility and Commercial Paper Program were $210.3 million [2016 - $348.7 million] with a weighted average interest rate of 0.93% [2016 - 0.89%].

As at December 31, 2017, $11.7 million had been drawn under the Working Capital Facility [December 31, 2016 - $7.1 million] and $38.4 million of letters of credit had been issued against the Prudential Facility [December 31, 2016 - $33.4 million].

11. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

Accounts payable and accrued liabilities consist of the following:

	2017 $	2016 $
Trade payables	**325.1**	328.6
Accrued liabilities	**133.2**	116.3
Due to related parties *[note 23]*	**40.1**	41.0
Accrued interest	**15.9**	16.6
Other	**2.0**	1.9
	516.3	504.4

12. DEFERRED REVENUE

Deferred revenue consists of capital contributions received from electricity customers to construct or acquire PP&E which have not yet been recognized into other revenue, and revenue not yet recognized from ancillary services *[note 26[j]]*.

	2017 $	2016 $
Capital contributions, beginning of year	**143.6**	103.0
Capital contributions received	**50.8**	44.7
Amortization	**(4.7)**	(3.8)
Other	**(1.5)**	(0.3)
Capital contributions, end of year	**188.2**	143.6
Other	**1.7**	1.8
Total deferred revenue	**189.9**	145.4
Less: Current portion of deferred revenue relating to:		
Capital contributions	**9.0**	3.3
Other	**1.7**	1.8
Current portion of deferred revenue	**10.7**	5.1
Non-current portion of deferred revenue	**179.2**	140.3

13. DEBENTURES

Debentures consist of the following:

	2017 $	2016 $
Senior unsecured debentures		
Series 2 – 5.15% due November 14, 2017	**—**	250.0
Series 3 – 4.49% due November 12, 2019	**250.0**	250.0
Series 6 – 5.54% due May 21, 2040	**200.0**	200.0
Series 7 – 3.54% due November 18, 2021	**300.0**	300.0
Series 8 – 2.91% due April 10, 2023	**250.0**	250.0
Series 9 – 3.96% due April 9, 2063	**245.0**	245.0
Series 10 – 4.08% due September 16, 2044	**200.0**	200.0
Series 11 – 3.55% due July 28, 2045	**200.0**	200.0
Series 12 – 2.52% due August 25, 2026	**200.0**	200.0
Series 13 – 3.485% due February 28, 2048	**200.0**	—
Total debentures	**2,045.0**	2,095.0
Less: Unamortized debt issuance costs	**10.2**	9.7
Unamortized discount/premium	**0.8**	0.7
Current portion of debentures	**—**	249.8
Long-term portion of debentures	**2,034.0**	1,834.8

All debentures of the Corporation rank equally.

The Corporation filed a base shelf prospectus dated May 8, 2017 with the securities commissions or similar regulatory authorities in each of the provinces of Canada. These filings allow the Corporation to make offerings of unsecured debt securities of up to $1.0 billion during the 25-month period following the date of the prospectus.

On June 14, 2016, the Corporation issued $200.0 million senior unsecured debentures at a rate of 2.52% [“Series 12”]. The Series 12 debentures due on August 25, 2026 were priced at $999.84 per $1,000 principal amount and bear interest payable semi-annually in arrears. The net proceeds were used to repay certain existing indebtedness and for general corporate purposes. Debt issuance costs of $1.3 million relating to the Series 12 debentures were recorded against the carrying amount of the debentures in the second quarter of 2016 and are amortized to finance costs using the effective interest method.

On November 14, 2017, the Corporation issued $200.0 million senior unsecured debentures at a rate of 3.485% [“Series 13”]. The Series 13 debentures due on February 28, 2048 were priced at $999.29 per $1,000 principal amount and bear interest payable semi-annually in arrears. The net proceeds were used to repay certain existing indebtedness and for general corporate purposes. Debt issuance costs of $1.4 million relating to the Series 13 debentures were recorded against the carrying amount of the debentures in the fourth quarter of 2017 and are amortized to finance costs using the effective interest method.

The Corporation’s Series 2 debentures matured and were repaid on November 14, 2017.

The Corporation may redeem all or part of its outstanding debentures at any time prior to maturity at a price equal to the greater of the Canada Yield Price (determined in accordance with the terms of the debentures) and par, plus accrued and unpaid interest up to and excluding the date fixed for redemption. Also, the Corporation may, at any time and from time to time, purchase debentures for cancellation, in the open market, by tender or by private contract, at any

price agreed upon with the holder of the debentures being purchased. The debentures contain certain covenants which, subject to certain exceptions, restrict the ability of the Corporation and LDC to create security interests, incur additional indebtedness or dispose of all or substantially all of their assets.

14. EMPLOYEE FUTURE BENEFITS

Pension

The Corporation's eligible employees participate in a defined benefit pension plan through OMERS. As at December 31, 2017, the OMERS plan was 94.0% funded [December 31, 2016 - 93.4%]. OMERS has a strategy to return the plan to a fully funded position. The Corporation is not able to assess the implications, if any, of this strategy or of the withdrawal of other participating entities from the OMERS plan on its future contributions. For the year ended December 31, 2017, the Corporation's contributions were $17.6 million [2016 - $17.6 million], representing less than five percent of total contributions to the OMERS plan. The Corporation expects to contribute approximately $19.0 million to the OMERS plan in 2018.

Post-employment benefits other than pension

a) Benefit obligation

	2017 $	2016 $
Balance, beginning of year	**280.5**	296.5
Current service cost	**4.1**	6.2
Interest cost	**11.2**	12.0
Benefits paid	**(11.0)**	(10.9)
Experience loss (gain) [(1)]	**1.9**	(4.2)
Actuarial gain arising from changes in demographic assumptions [(1)]	**—**	(17.5)
Actuarial loss (gain) arising from changes in financial assumptions [(1)]	**26.3**	(1.6)
Balance, end of year	**313.0**	280.5

[(1)] Actuarial loss (gain) on accumulated sick leave credits of $3.1 million [2016 - ($2.3) million] is recognized in benefit cost *[note 14[c]]* and actuarial loss (gain) on medical, dental and life insurance benefits of $25.1 million [2016 - ($21.0) million] is recognized in OCI *[note 14[d]]*.

The weighted average duration of the benefit obligation as at December 31, 2017 is 16.7 years [2016 - 16.7 years].

b) Amounts recognized in regulatory balances

As at December 31, 2017, the amount recognized in regulatory balances related to net actuarial loss was $85.3 million [December 31, 2016 - $60.2 million] *[note 9[a]]*.

c) Benefit cost recognized

	2017 $	2016 $
Current service cost	**4.1**	6.2
Interest cost	**11.2**	12.0
Actuarial loss (gain) on other employee benefits *[note 14[a]]*	**3.1**	(2.3)
Benefit cost	**18.4**	15.9
Capitalized to PP&E and intangible assets	**8.1**	6.4
Charged to operating expenses	**10.3**	9.5

d) Amounts recognized in OCI

	2017 $	2016 $
Actuarial loss (gain) *[note 14[a]]*	**25.1**	(21.0)
Income tax expense (recovery) in OCI *[note 21]*	**(6.7)**	5.5
Remeasurements of post-employment benefits, net of tax	**18.4**	(15.5)
Net movements in regulatory balances related to OCI, net of tax	**(18.4)**	15.5
OCI, net of tax	—	—

e) Significant assumptions

	2017	2016
Discount rate (%) used in the calculation of:		
Benefit obligation as at December 31	**3.50**	4.00
Assumed medical and dental cost trend rates (%) as at December 31:		
Rate of increase in dental costs assumed for next year	**4.00**	4.00
Rate of increase in medical costs assumed for next year		
For pre July 2000 retirements	**5.00**	5.00
For other retirements	**5.50**	5.50
Rate that medical cost trend rate gradually declines to		
For pre July 2000 retirements	**5.00**	5.00
For other retirements	**5.00**	5.00
Year that the medical cost trend rate reaches the ultimate trend rate		
For pre July 2000 retirements	**2015**	2015
For other retirements	**2018**	2018

f) Sensitivity analysis

Significant actuarial assumptions for benefit obligation measurement purposes are discount rate and assumed medical and dental cost trend rates. The sensitivity analysis below has been determined based on reasonably possible changes of the assumptions, in isolation of one another, occurring at the end of the reporting period. This analysis may not be representative of the actual change since it is unlikely that changes in the assumptions would occur in isolation of one another as some of the assumptions may be correlated.

Changes in key assumptions would have had the following effect on the benefit obligation:

	Change in assumption	2017 $	2016 $
Benefit obligation		**313.0**	280.5
Discount rate	1% -	**(46.8)**	(42.0)
	1%	**60.2**	54.0
Medical and dental cost trend rate	1% -	**40.2**	36.1
	1%	**(36.0)**	(32.3)

15. CAPITAL MANAGEMENT

The Corporation's main objectives when managing capital are to:

- ensure ongoing access to funding to maintain, refurbish and expand the electricity distribution system of LDC;
- ensure sufficient liquidity is available (either through cash and cash equivalents, investments or committed credit facilities) to meet the needs of the business;
- ensure compliance with covenants related to its credit facilities and senior unsecured debentures; and
- minimize finance costs while taking into consideration current and future industry, market and economic risks and conditions.

The Corporation monitors forecasted cash flows, capital expenditures, debt repayment and key credit ratios similar to those used by key rating agencies. The Corporation manages capital by preparing short-term and long-term cash flow forecasts. In addition, the Corporation accesses capital debt markets as required to help fund some of the periodic net cash outflows and to maintain available liquidity. There have been no changes in the Corporation's approach to capital management during the year. As at December 31, 2017, the Corporation's definition of capital included equity, borrowings under its Working Capital Facility, Commercial Paper Program and Revolving Credit Facility, long-term debt and obligations under finance leases, including the current portion thereof, and had remained unchanged from the definition as at December 31, 2016. As at December 31, 2017, equity amounted to $1,760.4 million [December 31, 2016 - $1,428.9 million], and borrowings under its Working Capital Facility, Commercial Paper Program and Revolving Credit Facility, long-term debt and obligations under finance leases, including the current portion thereof, amounted to $2,206.2 million [December 31, 2016 - $2,357.8 million].

The Corporation is subject to debt agreements that contain various covenants. The Corporation's unsecured debentures limit consolidated funded indebtedness to a maximum of 75% of total consolidated capitalization as defined in the agreements. The Corporation's Revolving Credit Facility limits the debt to capitalization ratio to a maximum of 75%.

The Corporation's debt agreements also include restrictive covenants such as limitations on designated subsidiary indebtedness, and restrictions on mergers and dispositions of designated subsidiaries. As at December 31, 2017 and December 31, 2016, the Corporation was in compliance with all covenants included in its trust indenture, supplemental trust indentures and Revolving Credit Facility agreement.

16. FINANCIAL INSTRUMENTS

a) Recognition and measurement

As at December 31, 2017 and December 31, 2016, the fair values of accounts receivable, unbilled revenue, Working Capital Facility, commercial paper, and accounts payable and accrued liabilities approximated their carrying amounts due to the short maturity of these instruments *[note 26[k]]*. The fair value of customer deposits approximates their carrying amounts taking into account interest accrued on the outstanding balance. Obligations under finance leases are measured based on a discounted cash flow analysis and approximate the carrying amounts as management believes that the fixed interest rates are representative of current market rates.

The carrying amounts and fair values of the Corporation's debentures consist of the following:

	2017 $		2016 $	
	Carrying amount	**Fair value (1)**	**Carrying amount**	**Fair value (1)**
Senior unsecured debentures				
Series 2 – 5.15% due November 14, 2017	—	—	249.8	258.7
Series 3 – 4.49% due November 12, 2019	**249.6**	**260.6**	249.5	270.8
Series 6 – 5.54% due May 21, 2040	**198.7**	**264.2**	198.7	253.5
Series 7 – 3.54% due November 18, 2021	**299.1**	**313.9**	298.9	322.8
Series 8 – 2.91% due April 10, 2023	**249.2**	**255.5**	249.0	259.3
Series 9 – 3.96% due April 9, 2063	**243.3**	**266.4**	243.3	246.4
Series 10 – 4.08% due September 16, 2044	**198.4**	**221.0**	198.3	209.4
Series 11 – 3.55% due July 28, 2045	**198.3**	**202.9**	198.3	191.3
Series 12 – 2.52% due August 25, 2026	**198.9**	**196.2**	198.8	195.5
Series 13 – 3.485% due February 28, 2048	**198.5**	**200.7**	—	—
	2,034.0	**2,181.4**	2,084.6	2,207.7

(1) The fair value measurement of financial instruments for which the fair value has been disclosed is included in Level 2 of the fair value hierarchy *[note 26[k]]*.

b) Financial risks

The following is a discussion of financial risks and related mitigation strategies that have been identified by the Corporation for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks listed.

Credit risk

The Corporation is exposed to credit risk as a result of the risk of counterparties defaulting on their obligations. The Corporation's exposure to credit risk primarily relates to accounts receivable and unbilled revenue. The Corporation monitors and limits its exposure to credit risk on a continuous basis.

The Corporation is subject to credit risk with respect to customer non-payment of electricity bills. LDC obtains security instruments from certain customers in accordance with direction provided by the OEB. As at December 31, 2017, LDC held security deposits in the amount of $58.2 million [December 31, 2016 - $54.1 million], of which $29.8 million [December 31, 2016 - $30.0 million] was related to security deposits on offers to connect to guarantee the payment of additional costs related to expansion projects. The Corporation's security instruments may not provide sufficient protection from counterparties defaulting on their obligations. As at December 31, 2017, there were no significant concentrations of credit risk with respect to any customer. The credit risk and mitigation strategies with respect to unbilled revenue are the same as those for accounts receivable. The credit risk related to cash, cash equivalents and investments is mitigated by the Corporation's treasury policies on assessing and monitoring the credit exposures of counterparties.

The Corporation did not have any single customer that generated more than 10% of total consolidated revenue for the years ended December 31, 2017 and December 31, 2016.

Credit risk associated with accounts receivable and unbilled revenue is as follows:

	2017 $	2016 $
Accounts receivable (net of allowance for doubtful accounts)		
Outstanding for not more than 30 days	**178.6**	197.9
Outstanding for more than 30 days and not more than 120 days	**33.8**	27.3
Outstanding for more than 120 days	**5.3**	4.6
Total accounts receivable	**217.7**	229.8
Unbilled revenue	**278.3**	320.5
Total accounts receivable and unbilled revenue	**496.0**	550.3

The Corporation has a broad base of customers. As at December 31, 2017 and December 31, 2016, the Corporation's accounts receivable and unbilled revenue which were not past due or impaired were assessed by management to have no significant collection risk and no additional allowance for doubtful accounts was required for these balances.

Reconciliation between the opening and closing allowance for doubtful accounts balances is as follows:

	2017 $	2016 $
Balance, beginning of year	**(9.8)**	(11.5)
Provision for doubtful accounts	**(6.2)**	(4.0)
Write-offs	**6.0**	6.0
Recoveries	**(0.2)**	(0.3)
Balance, end of year	**(10.2)**	(9.8)

Unbilled revenue represents amounts for which the Corporation has a contractual right to receive cash through future billings and are unbilled at period-end. Unbilled revenue is considered current and no allowance for doubtful accounts was provided as at December 31, 2017 and December 31, 2016.

Interest rate risk

The Corporation is exposed to fluctuations in interest rates for the valuation of its post-employment benefit obligations *[note 14[f]]*. The Corporation is also exposed to short-term interest rate risk on the net of cash and cash equivalents, short-term borrowings under its Revolving Credit Facility, Working Capital Facility and Commercial Paper Program *[note 10]* and customer deposits. The Corporation manages interest rate risk by monitoring its mix of fixed and floating rate instruments, and taking action as necessary to maintain an appropriate balance.

As at December 31, 2017, aside from the valuation of its post-employment benefit obligations, the Corporation was exposed to interest rate risk predominately from short-term borrowings under its Commercial Paper Program and customer deposits, while most of its remaining obligations were either non-interest bearing or bear fixed interest rates, and its financial assets were predominately short-term in nature and mostly non-interest bearing. The Corporation estimates that a 100 basis point increase (decrease) in short-term interest rates, with all other variables held constant, would result in an increase (decrease) of approximately $2.3 million to annual finance costs.

Liquidity risk

The Corporation is exposed to liquidity risk related to its ability to fund its obligations as they become due. The Corporation monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and financial requirements. The Corporation has access to credit facilities and debt capital markets and monitors cash balances daily. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing finance costs.

Liquidity risks associated with financial commitments are as follows:

2017	Due within 1 year $	Due within 2 years $	Due within 3 years $	Due within 4 years $	Due within 5 years $	Due after 5 years $
Working Capital Facility	**11.7**	—	—	—	—	—
Commercial paper [1]	**159.0**	—	—	—	—	—
Accounts payable and accrued liabilities [2]	**500.4**	—	—	—	—	—
Obligations under finance leases	**1.5**	—	—	—	—	—
Senior unsecured debentures						
Series 3 – 4.49% due November 12, 2019	—	**250.0**	—	—	—	—
Series 6 – 5.54% due May 21, 2040	—	—	—	—	—	**200.0**
Series 7 – 3.54% due November 18, 2021	—	—	—	**300.0**	—	—
Series 8 – 2.91% due April 10, 2023	—	—	—	—	—	**250.0**
Series 9 – 3.96% due April 9, 2063	—	—	—	—	—	**245.0**
Series 10 – 4.08% due September 16, 2044	—	—	—	—	—	**200.0**
Series 11 – 3.55% due July 28, 2045	—	—	—	—	—	**200.0**
Series 12 – 2.52% due August 25, 2026	—	—	—	—	—	**200.0**
Series 13 – 3.485% due February 28, 2048	—	—	—	—	—	**200.0**
Interest payments on debentures	**75.7**	**77.1**	**66.0**	**66.0**	**55.3**	**1,131.2**
	748.3	**327.1**	**66.0**	**366.0**	**55.3**	**2,626.2**

[1] The notes under the Commercial Paper Program were issued at a discount and are repaid at their principal amount.
[2] Accounts payable and accrued liabilities exclude $15.9 million of accrued interest on debentures included within "Interest payments on debentures".

Foreign exchange risk

As at December 31, 2017, the Corporation had limited exposure to the changing values of foreign currencies. While the Corporation purchases goods and services which are payable in US dollars, and purchases US currency to meet the related commitments when required, the impact of these transactions is not material to the Consolidated Financial Statements.

17. SHARE CAPITAL

Share capital consists of the following:

	Number of Shares	$
Authorized The authorized share capital of the Corporation consists of an unlimited number of common shares without par value. All shares issued were fully paid.		
Issued and outstanding		
Common shares, beginning of the year	1,000	567.8
Common shares issued [(1)]	200	250.0
Common shares issued and outstanding, end of the year	**1,200**	**817.8**

[(1)] On June 28, 2017, the Corporation issued 200 common shares to the City for total proceeds of $250.0 million, net of share issue costs and expenses.

Dividends

The Shareholder Direction adopted by the City with respect to the Corporation provides that the Board of Directors of the Corporation will use its best efforts to ensure that the Corporation meets certain financial performance standards, including those relating to credit rating and dividends.

On March 2, 2017, the Board of Directors of the Corporation declared dividends in the amount of $6.25 million with respect to the first quarter of 2017 [March 31, 2016 – $44.6 million], which was paid to the City on March 31, 2017.

On May 11, 2017, the Board of Directors of the Corporation declared dividends in the amount of $6.25 million with respect to the second quarter of 2017 [June 30, 2016 – $6.25 million], which was paid to the City on June 30, 2017. In connection with receipt of the equity investment from the City, the Board of Directors of the Corporation declared dividends payable to the City and approved amendments to the Corporation's Dividend Policy, as follows:

[i] In respect of fiscal 2017, an aggregate amount of $75.0 million shall be paid to the City, consisting of the two previously declared and paid instalments of $6.25 million each and a further $62.5 million. The $62.5 million was paid to the City on July 7, 2017.

[ii] In respect of fiscal 2018 and subsequent fiscal years, 60% of the Corporation's consolidated net income after net movements in regulatory balances for the prior fiscal year shall be declared separately in four equal quarterly instalments, with each instalment payable to the City on the last business day of each fiscal quarter.

On March 7, 2018, the Board of Directors of the Corporation declared a quarterly dividend in the amount of $23.5 million, payable to the City by March 31, 2018.

18. OTHER REVENUE

Other revenue consists of the following:

	2017 $	2016 $
Ancillary services	**22.3**	16.4
Street lighting service fee	**18.9**	16.6
Pole and duct rentals	**15.8**	12.0
Other regulatory service charges	**13.3**	16.7
CDM mid-term incentive *[note 3[c]]*	**12.2**	—
Development charges *[note 9[o]]*	**5.1**	—
Amortization of deferred revenue *[note 12]*	**4.7**	3.8
Miscellaneous	**15.4**	10.4
	107.7	75.9

19. OPERATING EXPENSES

Operating expenses consist of the following:

	2017 $	2016 $
Salaries and benefits	**226.5**	223.6
External services	**138.6**	112.9
Other support costs [(1)]	**22.3**	32.7
Materials and supplies	**21.6**	16.7
Less: Capitalized costs	**(116.0)**	(108.8)
	293.0	277.1

[(1)] Includes taxes other than income taxes, utilities, rental, communication, insurance, and other general and administrative expenses.

For the year ended December 31, 2017, the Corporation recognized operating expenses of $13.0 million related to materials and supplies used to service electricity distribution assets [2016 - $7.6 million].

20. FINANCE COSTS

Finance costs consist of the following:

	2017 $	2016 $
Interest income	**(0.2)**	(0.2)
Interest expense		
Interest on long-term debt [1]	**83.2**	81.6
Interest on short-term debt	**3.7**	4.9
Other interest	**0.8**	0.5
Capitalized borrowing costs	**(9.8)**	(12.6)
	77.7	74.2

[1] Includes amortization of debt issuance costs, discounts and premiums.

21. INCOME TAXES

Income tax expense differs from the amount that would have been recorded using the combined statutory Canadian federal and provincial income tax rate. Reconciliation of income tax expense computed at the statutory income tax rate to the income tax provision is set out below:

	2017 $	2016 $
Rate reconciliation before net movements in regulatory balances		
Income before income taxes	**201.1**	251.7
Statutory Canadian federal and provincial income tax rate	**26.5%**	26.5%
Expected income tax expense	**53.3**	66.7
Non-taxable amounts	**(8.7)**	0.4
Other	**0.1**	—
Income tax expense	**44.7**	67.1
Effective tax rate	**22.2%**	26.7%
Rate reconciliation after net movements in regulatory balances		
Net income after net movements in regulatory balances, before income tax [1]	**188.0**	174.5
Statutory Canadian federal and provincial income tax rate	**26.5%**	26.5%
Expected income tax expense	**49.8**	46.2
Temporary differences recoverable in future rates	**(15.5)**	(22.7)
Other	**(2.8)**	(0.4)
Income tax expense and income tax recorded in net movements in regulatory balances	**31.5**	23.1
Effective tax rate	**16.8%**	13.2%

[1] Income tax includes income tax expense and income tax recorded in net movements in regulatory balances.

Income tax expense as presented in the consolidated statements of income and OCI are as follows:

	2017 $	2016 $
Income tax expense	**44.7**	67.1
Income tax recorded in net movements in regulatory balances	**(13.2)**	(44.0)
Income tax expense and income tax recorded in net movements in regulatory balances	**31.5**	23.1
Income tax expense (recovery) in OCI *[note 14[d]]*	**(6.7)**	5.5
Income tax expense (recovery) in OCI recorded in net movements in regulatory balances	**6.7**	(5.5)
Income tax expense in OCI	**—**	—

Components of income tax expense and income tax recorded in net movements in regulatory balances are as follows:

	2017 $	2016 $
Current tax expense		
Current year	**32.5**	24.3
Adjustment for tax positions taken in prior periods	**(1.1)**	(2.2)
	31.4	22.1
Deferred tax expense		
Origination and reversal of temporary differences	**0.1**	1.0
Income tax expense and income tax recorded in net movements in regulatory balances	**31.5**	23.1

Deferred tax assets consist of the following:

	Net balance, January 1 2017 $	Recognized in net income $	Recognized in OCI $	Net balance, December 31 2017 $
PP&E and intangible assets	**11.7**	**(26.6)**	**—**	**(14.9)**
Post-employment benefits	**74.3**	**1.9**	**6.7**	**82.9**
Other taxable temporary differences	**(22.2)**	**11.2**	**—**	**(11.0)**
	63.8	**(13.5)**	**6.7**	**57.0**

	Net balance, January 1 2016 $	Recognized in net income $	Recognized in OCI $	Net balance, December 31 2016 $
PP&E and intangible assets	34.5	(22.8)	—	11.7
Post-employment benefits	78.6	1.2	(5.5)	74.3
Other taxable temporary differences	1.2	(23.4)	—	(22.2)
	114.3	(45.0)	(5.5)	63.8

As at December 31, 2017, the Corporation had accumulated net capital losses of $18.7 million [December 31, 2016 - $18.7 million], which are available to offset capital gains in future years. As at December 31, 2017, the Corporation had $1.7 million accumulated non-capital losses for income tax purposes [December 31, 2016 - $2.6 million], which are available to offset net income in future years before expiring [$1.4 million expires in 2035 and $0.3 million expires in 2036].

Deferred tax assets have not been recognized in respect of the following items because it is not probable that future taxable income will be available against which the Corporation can utilize the benefits therefrom.

	2017 $	2016 $
Deductible temporary differences	**7.4**	7.7
Net capital losses	**5.0**	5.0
Non-capital losses	**0.4**	0.7
	12.8	13.4

22. CONSOLIDATED STATEMENTS OF CASH FLOWS

Changes in non-cash working capital provided/(used) cash as follows:

	2017 $	2016 $
Accounts receivable	**12.1**	(38.1)
Unbilled revenue	**42.2**	(0.1)
Income tax receivable	**—**	9.9
Materials and supplies	**0.4**	0.1
Other current assets	**0.8**	(3.6)
Accounts payable and accrued liabilities	**(6.0)**	20.6
Income tax payable	**4.7**	8.1
Deferred revenue	**5.6**	0.3
Deferred conservation credit	**3.8**	(12.4)
Other current liabilities	**(1.6)**	(0.1)
	62.0	(15.3)

Reconciliation between the amount presented on the consolidated statements of cash flows and total additions to PP&E and intangible assets is as follows:

	2017 $	2016 $
Purchase of PP&E, cash basis	**440.0**	511.7
Net change in accruals related to PP&E	**9.9**	(1.7)
Other	**1.6**	1.8
Total additions to PP&E	**451.5**	511.8
Purchase of intangible assets, cash basis	**93.4**	39.9
Net change in accruals related to intangible assets	**8.0**	—
Total additions to intangible assets	**101.4**	39.9

Summary of changes in liabilities arising from financing activities:

	2016 $	Cash flows [1] $	Non-cash changes $		2017 $
			Foreign exchange	Other	
Year ended December 31					
Commercial paper	**261.0**	**(102.0)**	—	—	**159.0**
Dividends payable	—	**(75.0)**	—	**75.0**	—
Debentures *[note 13]*	**2,084.6**	**(51.5)**	—	**0.9**	**2,034.0**
Accrued interest [2]	**16.6**	**(86.9)**	—	**86.2**	**15.9**
Lease liability [3]	**4.6**	**(3.0)**	**(0.1)**	—	**1.5**
	2,366.8	**(318.4)**	**(0.1)**	**162.1**	**2,210.4**

	2015 $	Cash flows [1] $	Non-cash changes $		2016 $
			Foreign exchange	Other	
Year ended December 31					
Commercial paper	324.0	(63.0)	—	—	261.0
Dividends payable	—	(63.4)	—	63.4	—
Debentures *[note 13]*	1,885.0	198.7	—	0.9	2,084.6
Accrued interest [2]	14.9	(84.0)	—	85.7	16.6
Lease liability [3]	8.0	(3.1)	(0.3)	—	4.6
	2,231.9	(14.8)	(0.3)	150.0	2,366.8

(1) Cash inflows and cash outflows arising from commercial paper borrowings and debentures are presented on a net basis
(2) Included within accounts payable and accrued liabilities *[note 16[b]]*
(3) Included within other liabilities

23. RELATED PARTY TRANSACTIONS

As the City is the sole shareholder of the Corporation, the Corporation and the City are considered related parties.

Summary of Transactions with Related Parties	2017 $	2016 $
Revenues	**283.3**	275.3
Operating expenses and capital expenditures	**22.2**	26.9
Dividends	**75.0**	63.4

Summary of Amounts Due to/from Related Parties	2017 $	2016 $
Accounts receivable	**13.8**	12.7
Unbilled revenue	**26.3**	23.2
Accounts payable and accrued liabilities	**40.1**	41.0
Customer deposits	**15.7**	14.1
Deferred revenue	**1.9**	3.5

Revenues represent amounts charged to the City primarily for electricity, street lighting and ancillary services. Operating expenses and capital expenditures represent amounts charged by the City for purchased road cut repairs, property taxes and other services. Dividends are paid to the City *[note 17]*.

Accounts receivable represents receivables from the City primarily for electricity, street lighting and ancillary services. Unbilled revenue represents receivables from the City mainly related to electricity provided and not yet billed. Accounts payable and accrued liabilities represent amounts payable to the City related to road cut repairs and other services. Customer deposits represent amounts received from the City for future expansion projects. Deferred revenue represents amounts received from the City primarily for the construction of electricity distribution assets.

Key management personnel include the Corporation's senior executive officers and members of the Board of Directors. The compensation costs associated with the key management personnel are as follows:

	2017 $	2016 $
Short-term employee benefits	**4.6**	4.1
Post-employment benefits	**1.1**	1.0
	5.7	5.1

24. COMMITMENTS

Operating leases and capital projects

As at December 31, 2017, the future minimum payments under property operating leases, capital projects and other commitments were as follows:

	Operating leases $	Capital projects [1] and other $
Less than one year	**0.3**	**17.5**
Between one and five years	**1.1**	**28.5**
Total amount of future minimum payments [2]	**1.4**	**46.0**

[1] Mainly commitments for construction services and estimated capital contributions.
[2] Refer to note 16 for financial commitments excluded from the table above.

Operating lease expense for the year ended December 31, 2017 was $0.8 million [2016 - $2.8 million].

Finance leases

As at December 31, 2017 and December 31, 2016, reconciliation between the future minimum lease payments and their present value was as follows:

	2017 $			2016 $		
	Future minimum lease payments	Interest	Present value of minimum lease payments	Future minimum lease payments	Interest	Present value of minimum lease payments
Less than one year	**1.5**	—	**1.5**	3.2	0.2	3.0
Between one and five years	—	—	—	1.6	—	1.6
More than five years	—	—	—	—	—	—
	1.5	—	**1.5**	4.8	0.2	4.6
Current portion included within Other liabilities			**1.5**			3.0
Non-current portion included within Other liabilities			—			1.6

25. CONTINGENCIES

Legal Proceedings

In the ordinary course of business, the Corporation is subject to various legal actions and claims from customers, suppliers, former employees and other parties. On an ongoing basis, the Corporation assesses the likelihood of any adverse judgments or outcomes as well as potential ranges of probable costs and losses. A determination of the provision required, if any, for these contingencies is made after an analysis of each individual issue. The provision may change in the future due to new developments in each matter or changes in approach, such as a change in settlement strategy. If damages were awarded under these actions, the Corporation and its subsidiaries would make a claim under any applicable liability insurance policies which the Corporation believes would cover any damages which may become payable by the Corporation and its subsidiaries in connection with these actions, subject to such claim not being disputed by the insurers.

26. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

a) Basis of consolidation

The Consolidated Financial Statements include the accounts of the Corporation and its wholly-owned subsidiaries. All intercompany balances and transactions have been eliminated.

b) Regulation

The following regulatory treatments have resulted in accounting treatments which differ from those prescribed by IFRS for enterprises operating in an unregulated environment and regulated entities that did not adopt IFRS 14 *Regulatory Deferral Accounts* ["IFRS 14"]:

Regulatory Balances

In January 2014, the IASB issued IFRS 14 as an interim standard giving entities conducting rate-regulated activities the option of continuing to recognize regulatory balances according to their previous GAAP. Regulatory balances provide useful information about the Corporation's financial position, financial performance and cash flows. IFRS 14 is restricted to first-time adopters of IFRS and remains in force until either repealed or replaced by permanent guidance on rate-regulated accounting from the IASB.

The Corporation has determined that certain debit and credit balances arising from rate-regulated activities qualify for the application of regulatory accounting treatment in accordance with IFRS 14 and the accounting principles prescribed by the OEB in the "Accounting Procedures Handbook for Electricity Distributors". Under rate-regulated accounting, the timing and recognition of certain expenses and revenues may differ from those otherwise expected under other IFRS in order to appropriately reflect the economic impact of regulatory decisions regarding the Corporation's regulated revenues and expenditures. These amounts arising from timing differences are recorded as regulatory debit and credit balances on the Corporation's consolidated balance sheets, and represent existing rights and obligations regarding cash flows expected to be recovered from or refunded to customers, based on decisions and approvals by the OEB. Regulatory balances can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment or if future OEB direction is determined by management to be probable. In the event that the disposition of these balances is assessed to no longer be probable based on management's judgment, the balances are recorded in the Corporation's consolidated statements of income in the period when the assessment is made. Regulatory balances, which do not meet the definition of an asset or liability under any other IFRS, are segregated on the consolidated balance sheets and are presented on the consolidated statements of income and the consolidated statements of comprehensive income as net movements in regulatory balances and net movements in regulatory balances related to OCI, net of tax. The netting of regulatory debit and

credit balances is not permitted. The measurement of regulatory balances is subject to certain estimates and assumptions, including assumptions made in the interpretation of the OEB's regulations and decisions.

c) Cash and cash equivalents

Cash and cash equivalents include cash in bank accounts and short-term investments with terms to maturity of 90 days or less from their date of acquisition. On the consolidated statements of cash flows, cash and cash equivalents (working capital facility) include bank overdrafts that are repayable on demand and form an integral part of the Corporation's cash management.

d) Accounts receivable and unbilled revenue

Accounts receivable is recorded at the invoiced amount and overdue amounts bear interest at OEB-approved rates. Unbilled revenue is recorded based on an estimated amount for electricity delivered and for other services provided and not yet billed. The estimate is primarily based on the customers' previous billings with adjustments mainly for assumptions related to seasonality and weighted average price. The carrying amount of accounts receivable and unbilled revenue is reduced through an allowance for doubtful accounts, if applicable, and the amount of the related impairment loss is recognized in the consolidated statements of income. The impairment loss is the difference between an asset's carrying amount and the estimated future cash flows. When the Corporation considers that there are no realistic prospects of recovery of the financial assets, the relevant amounts are written off. If the amount of impairment loss subsequently decreases due to an event occurring after the impairment was recognized, then the previously recognized impairment loss is reversed through net income.

Accounts receivable and unbilled revenue are assessed at each reporting date to determine whether there is objective evidence of impairment, which includes default or delinquency by a debtor, indications that a debtor or issuer will enter bankruptcy, and adverse changes in the payment status of borrowers or issuers. Accounts receivable and unbilled revenue that are not individually assessed for impairment are collectively assessed for impairment by grouping together receivables with similar risk characteristics, and the Corporation considers historical trends on the timing of recoveries and the amount of loss incurred, as well as current economic and credit conditions.

e) Materials and supplies

Materials and supplies consist primarily of small consumable materials mainly related to the maintenance of the electricity distribution infrastructure. The Corporation classifies all major construction related components of its electricity distribution infrastructure to PP&E. Materials and supplies are carried at the lower of cost and net realizable value, with cost determined on a weighted average cost basis net of a provision for obsolescence.

f) Property, plant and equipment

PP&E are measured at cost less accumulated depreciation and any accumulated impairment losses, if applicable. The cost of PP&E represents the original cost, consisting of direct materials and labour, contracted services, borrowing costs, and directly attributable overhead. Subsequent costs are capitalized only if it is probable that the future economic benefits associated with the expenditure will flow to the Corporation and the costs can be measured reliably. If significant parts of an item of PP&E have different useful lives, then they are accounted for as separate major components of PP&E. The carrying amount of an item of PP&E is derecognized on disposal of the asset or when no future economic benefits are expected to accrue to the Corporation from its continued use. Any gain or loss arising on derecognition is recorded in the consolidated statements of income in the period in which the asset is derecognized. The gain or loss on disposal of an item of PP&E is determined as the sale proceeds less the carrying amount of the asset and costs of removal and is recognized in the consolidated statements of income.

Depreciation begins when an asset becomes available for use. Depreciation is provided on a straight-line basis over the estimated useful lives at the following annual rates:

Distribution assets:	
Distribution lines	1.7% to 5.0%
Transformers	3.3% to 5.0%
Meters	2.5% to 6.7%
Stations	2.0% to 10.0%
Buildings	1.3% to 5.0%
Equipment and other:	
Street lighting assets	1.7% to 5.0%
Assets under finance lease	1.0% to 14.3%
Other capital assets	4.0% to 25.0%

Leased assets are depreciated over the shorter of the lease term and their useful lives unless it is reasonably certain that the Corporation will obtain ownership by the end of the lease term. Assets under finance lease included a 99-year land lease. Construction in progress relates to assets not currently available for use and therefore is not depreciated. The depreciation method and useful lives are reviewed at each financial year-end and adjusted if appropriate. There are no residual values for items of PP&E.

g) Intangible assets

Intangible assets are measured at cost less accumulated amortization and any accumulated impairment losses, if applicable.

Amortization begins when an asset becomes available for use. Amortization is provided on a straight-line basis over the estimated useful lives at the following annual rates:

Computer software	10.0% to 25.0%
Contributions	4.0%

Software in development and contributions for work in progress relate to assets not currently available for use and therefore are not amortized. Contributions represent payments made to HONI for dedicated infrastructure in order to receive connections to transmission facilities. The amortization method and useful lives are reviewed at each financial year-end and adjusted if appropriate.

h) Impairment of non-financial assets

The Corporation reviews the carrying amounts of its non-financial assets other than materials and supplies and deferred tax assets at each reporting date to determine whether there is any indication of impairment, in which case the assets' recoverable amounts are estimated. For impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent on the cash inflows of other assets or CGUs. The Corporation has determined that its CGUs are at the individual entity level due to interdependencies of each entity's group of assets to generate cash flows. An impairment loss is recognized if the carrying amount of an asset or CGU exceeds its recoverable amount. Impairment losses are recognized in the consolidated statements of income, and are allocated to reduce the carrying amounts of assets in the CGU on a pro rata basis. An impairment loss recognized in prior periods is reversed when an asset's recoverable amount has increased, but not exceeding the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior years.

i) Capitalized borrowing costs

Borrowing costs directly attributable to the acquisition, construction or development of qualifying assets that necessarily take a substantial period of time to get ready for their intended use are capitalized, until such time as the assets are substantially ready for their intended use. The interest rate for capitalization is the Corporation's weighted average cost of borrowing, and is applied to the carrying amount of the construction-in-progress assets or assets under development including borrowing costs previously capitalized, net of capital contributions received. Capitalization commences immediately as the expenditure on a qualifying asset is incurred. Borrowing costs are included in PP&E and intangible assets for financial reporting purposes, and charged to operations through depreciation and amortization expense over the useful lives of the related assets.

j) Revenue recognition

Revenues from energy sales and electricity distribution are recorded on the basis of cyclical billings and include an estimated amount for electricity delivered and not yet billed. These revenues are impacted by energy demand primarily driven by outside temperature, and customer class usage patterns and composition.

Energy sales arise from charges to customers for electricity consumed, based on regulated rates. Energy sales include amounts billed or billable to customers for commodity charges, retail transmission charges, and WMS charges at current rates. These charges are passed through to customers over time and are considered revenue by LDC due to the collection risk of the related balances. The Corporation applies judgment to determine whether revenues are recorded on a gross or net basis. The Corporation has primary responsibility for the delivery of electricity to the customer. During the same period, energy sales should be equal to the cost of energy purchased. However, a difference between energy sales and energy purchases arises when there is a timing difference between the amounts charged by LDC to customers, based on regulated rates, and the electricity and non-competitive electricity service costs billed monthly by the IESO to LDC. This difference is recorded as a settlement variance, representing future amounts to be recovered from or refunded to customers through future billing rates approved by the OEB. In accordance with IFRS 14, this settlement variance is presented within regulatory balances on the consolidated balance sheets and within net movements in regulatory balances on the consolidated statements of income.

Distribution revenue is recorded based on OEB-approved distribution rates to recover the costs incurred by LDC in delivering electricity to customers. Distribution revenue also includes revenue related to the collection of OEB-approved rate riders.

Other revenue, which includes revenue from services ancillary to the electricity distribution, delivery of street lighting services, and pole and duct rentals, is recognized as the services are rendered. When services are made up of different components which are not separately identifiable, the related other revenues are recognized on a straight-line basis over the term of the contract. Capital contributions received from electricity customers to construct or acquire PP&E for the purpose of connecting a customer to a network are recorded as deferred revenue and amortized into other revenue at an equivalent rate to that used for the depreciation of the related PP&E. Revenue from ancillary services not yet recognized is also included within deferred revenue.

Revenues and costs associated with CDM programs are presented using the net basis of accounting. Cost efficiency incentives related to the CDM programs, included as part of other revenue, are recognized when it is probable that future economic benefits will flow to the entity and the amount can be reasonably measured.

k) Financial instruments

All financial assets are classified as "Loans and Receivables" and all financial liabilities are classified as "Other Financial Liabilities". These financial instruments are recognized initially at fair value adjusted for any directly attributable transaction costs. Subsequently, they are measured at amortized cost using the effective interest method less any impairment for the financial assets. The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's length transaction between willing parties.

The Corporation uses the following methods and assumptions to estimate the fair value of each class of financial instruments for which carrying amounts are included in the consolidated balance sheets:

- Cash, cash equivalents and short-term investments are classified as "Loans and Receivables" and are measured at fair value. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Accounts receivable and unbilled revenue are classified as "Loans and Receivables" and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Working capital facility, revolving credit facility and commercial paper are classified as "Other Financial Liabilities" and are initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value due to the short maturity of these instruments. Transaction costs incurred in connection with the Corporation's revolving credit facility are capitalized within other assets on the consolidated balance sheets and are amortized on a straight-line basis over the term of the facility, and are included in finance costs.

- Accounts payable and accrued liabilities are classified as "Other Financial Liabilities" and are initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value because of the short maturity of these instruments.

- Customer deposits are classified as "Other Financial Liabilities" and are initially measured at fair value. Subsequent measurements are recorded at cost plus accrued interest. The carrying amounts approximate fair value taking into account interest accrued on the outstanding balance.

- Obligations under finance leases are classified as "Other Financial Liabilities" and are initially measured at fair value, or the present value of the minimum lease payments if lower. Subsequent measurements are based on a discounted cash flow analysis and approximate the carrying amount as management believes that the fixed interest rates are representative of current market rates.

- Debentures are classified as "Other Financial Liabilities" and are initially measured at fair value. The carrying amounts of the debentures are carried at amortized cost, based on the fair value of the debentures at issuance, which was the fair value of the consideration received adjusted for transaction costs. The fair values of the debentures are based on the present value of contractual cash flows, discounted at the Corporation's current borrowing rate for similar debt instruments *[note 16[a]]*. Debt issuance costs incurred in connection with the Corporation's debenture offerings are capitalized as part of the carrying amount of the debentures and amortized over the term of the related debentures, using the effective interest method, and the amortization is included in finance costs.

l) Fair value measurements

The Corporation utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. A fair value hierarchy exists that prioritizes observable and unobservable inputs used to measure fair value. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect the Corporation's assumptions with respect to how market participants would price an asset or liability. The fair value hierarchy includes three levels of inputs that may be used to measure fair value:

- Level 1: Unadjusted quoted prices in active markets for identical assets or liabilities. An active market for the asset or liability is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis;
- Level 2: Other than quoted prices included within Level 1 that are observable for the assets or liabilities, either directly or indirectly; and
- Level 3: Unobservable inputs, supported by little or no market activity, used to measure the fair value of the assets or liabilities to the extent that observable inputs are not available.

m) Employee benefits

(i) Short-term employee benefits

Short-term employee benefit obligations that are due to be settled wholly within twelve months after the end of the annual reporting period in which the employees render the related service are measured on an undiscounted basis and are expensed as the related service is provided. A liability is recognized for the amount expected to be paid if the Corporation has a present legal or constructive obligation to pay this amount as a result of past service provided by the employee and the obligation can be estimated reliably.

(ii) Multi-employer pension plan

The Corporation's full-time employees participate in a pension plan through OMERS. The OMERS plan is a jointly sponsored, multi-employer defined benefit pension plan established in 1962 by the province of Ontario for employees of municipalities, local boards and school boards. Both participating employers and employees are required to make plan contributions equally based on participating employees' contributory earnings, and share equally in funding gains or losses. The plan assets and pension obligations are not segregated in separate accounts for each member entity. The OMERS plan is accounted for as a defined contribution plan and the contribution payable is recognized as an employee benefit expense in the consolidated statements of income in the period when the service is rendered by the employee, since it is not practicable to determine the Corporation's portion of pension obligations or of the fair value of plan assets.

(iii) Post-employment benefits other than pension

The Corporation has a number of unfunded benefit plans providing post-employment benefits (other than pension) to its employees. The Corporation pays certain medical, dental and life insurance benefits under unfunded defined benefit plans on behalf of its retired employees. The Corporation also pays accumulated sick leave credits, up to certain established limits based on service, in the event of retirement, termination or death of certain employees.

The cost of providing benefits under the benefit plans is actuarially determined using the projected unit credit method, which incorporates management's best estimate of future salary levels, retirement ages of employees, health care costs, and other actuarial factors. Changes in actuarial assumptions and experience adjustments give rise to actuarial gains and losses. Actuarial gains and losses on medical, dental and life insurance benefits are recognized in OCI as

they arise. Actuarial gains and losses related to rate-regulated activities are subsequently reclassified from OCI to a regulatory balance on the consolidated balance sheets. Actuarial gains and losses on accumulated sick leave credits are recognized in the consolidated statements of income in the period in which they arise.

The measurement date used to determine the present value of the benefit obligation is December 31 of the applicable year. The latest actuarial valuation was performed as at January 1, 2016.

n) Customer deposits

Security deposits from electricity customers are cash collections to guarantee the payment of electricity bills. This liability includes related interest amounts owed to the customers with a corresponding amount charged to finance costs. Deposits that are refundable upon demand are classified as a current liability.

Security deposits on offers to connect are cash collections from specific customers to guarantee the payment of additional costs relating to expansion projects. This liability includes related interest amounts owed to the customers with a corresponding amount charged to finance costs. Deposits are classified as a current liability when the Corporation no longer has an unconditional right to defer payment of the liability for at least 12 months after the reporting period.

o) Income taxes

Under the Electricity Act, the Corporation is required to make PILs to the Ontario Electricity Financial Corporation. These payments are calculated in accordance with the ITA and the TA as modified by regulations made under the Electricity Act and related regulations. This effectively results in the Corporation paying income taxes equivalent to what would be imposed under the Federal and Ontario Tax Acts.

The Corporation uses the liability method of accounting for income taxes. Under the liability method, current income taxes payable are recorded based on taxable income. The Corporation recognizes deferred tax assets and liabilities for the future tax consequences of events that have been included in the Consolidated Financial Statements or income tax returns. Deferred tax assets and liabilities are determined based on the difference between the carrying value of assets and liabilities on the consolidated balance sheets and their respective tax basis, using the tax rates enacted or substantively enacted by the consolidated balance sheet date that are in effect for the year in which the differences are expected to reverse. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when it is probable that they will be realized, and are measured at the best estimate of the tax amount expected to be paid to or recovered from the taxation authorities. Deferred tax assets are reviewed at each reporting date and reduced to the extent that it is no longer probable that the related tax benefits will be realized. The calculation of current and deferred taxes requires management to make certain judgments with respect to changes in tax interpretations, regulations and legislation, and to estimate probable outcomes on the timing and reversal of temporary differences and tax authority audits of income tax.

Rate-regulated accounting requires the recognition of regulatory balances and related deferred tax assets and liabilities for the amount of deferred taxes expected to be refunded to or recovered from customers through future electricity distribution rates. A gross up to reflect the income tax benefits associated with reduced revenues resulting from the realization of deferred tax assets is recorded within regulatory credit balances. Deferred taxes that are not included in the rate-setting process are charged or credited to the consolidated statements of income.

The benefits of the refundable and non-refundable apprenticeship and other ITCs are credited against the related expense in the consolidated statements of income.

p) Use of judgments and estimates

The preparation of the Corporation's Consolidated Financial Statements in accordance with IFRS requires management to make judgments, estimates and assumptions which affect the application of accounting policies, reported assets, liabilities and regulatory balances, and the disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements, and the reported revenues and expenses for the year. The estimates are based on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities as well as for identifying and assessing the accounting treatment with respect to commitments and contingencies. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the IESO, the Ontario Ministry of Energy or the Ontario Ministry of Finance.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to estimates are recognized prospectively. Assumptions and estimates with a significant risk of resulting in a material adjustment within the next financial year are used in the following:

- Note 26[b] – Recognition and measurement of regulatory balances;
- Note 26[j] – Revenue recognition – measurement of unbilled revenue, determination of the CDM incentive;
- Notes 26[f] and 26[g] – Determination of useful lives of depreciable assets;
- Notes 26[m] and 14 – Measurement of post-employment benefits – key actuarial assumptions;
- Notes 26[o] and 21 – Recognition of deferred tax assets – availability of future taxable income against which deductible temporary differences and tax loss carryforwards can be used; and
- Note 25 – Recognition and measurement of provisions and contingencies.

q) Changes in accounting policies

In January 2016, the IASB issued amendments to IAS 7 *Statement of Cash Flows* as part of the IASB's Disclosure Initiative. These amendments require entities to provide disclosures that enable users of financial statements to evaluate changes in liabilities arising from financing activities, including changes from cash flows and non-cash changes. These amendments are effective for annual periods beginning on or after January 1, 2017. The additional disclosures relating to changes in liabilities arising from financing activities are included in note 22 and have no impact to the Corporation's financial position or results of operations.

r) Future accounting pronouncements

A number of new standards, amendments and interpretations are not yet effective for the year ended December 31, 2017, and have not yet been applied in preparing these Consolidated Financial Statements.

Revenue from Contracts with Customers

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers* ["IFRS 15"], which replaces existing revenue recognition guidance, including IAS 18 *Revenue* and IFRIC 18 *Transfers of Assets from Customers*. IFRS 15 contains a single model that applies to contracts with customers with two methods for recognizing revenue: at a point in time or over time. IFRS 15 is effective for annual periods beginning on or after January 1, 2018.

The Corporation will adopt IFRS 15 on January 1, 2018 using the modified retrospective approach. The Corporation has completed its assessment of the key revenue streams. The majority of the Corporation's revenue (energy sales and

distribution revenue) is generated from electricity distribution at regulated prices. The Corporation concluded that IFRS 15 will not have a material impact on the accounting for these revenue streams. Upon adoption of IFRS 15, there will be a $167.6 million income statement reclassification between Energy Sales and Energy Purchases for the comparative year ended December 31, 2017 and no impact to opening retained earnings as at January 1, 2018. The Corporation is currently finalizing its assessment on capital contributions. The Corporation has determined that IFRS 15 will also increase its required disclosure on revenue streams.

Financial Instruments

In July 2014, the IASB issued the final version of IFRS 9 *Financial Instruments* ["IFRS 9"], which replaces IAS 39 *Financial Instruments: Recognition and Measurement* ["IAS 39"]. IFRS 9 includes revised guidance on the classification and measurement of financial instruments, including a new expected credit loss model for measuring impairment on financial assets, and new general hedge accounting requirements. It also carries forward the guidance on recognition and derecognition of financial instruments from IAS 39. The standard is effective for annual periods beginning on or after January 1, 2018, and will be applied retrospectively with some exceptions. The Corporation has assessed the impact of adopting IFRS 9, and concluded that the new classification under IFRS 9 will not have a material impact on the consolidated financial statements. Management is currently evaluating the impact of adopting the new expected credit loss model for measuring impairment.

Leases

In January 2016, the IASB issued IFRS 16 *Leases* ["IFRS 16"], which replaces IAS 17 *Leases* ["IAS 17"] and related interpretations. IFRS 16 introduces a single lessee accounting model eliminating the current distinction between finance and operating leases. It requires the recognition of lease-related assets and liabilities on the balance sheet, except for short-term leases and leases of low value underlying assets. In addition, the nature and timing of expenses related to leases will change, as IFRS 16 replaces the straight-line operating leases expense with the depreciation expense for the assets and interest expense on the lease liabilities. Lessor accounting remains substantially unchanged. The standard is effective for annual periods beginning on or after January 1, 2019, and may be applied either retrospectively or using a modified retrospective approach. Early adoption is permitted if IFRS 15 is also adopted.

The Corporation intends to early adopt IFRS 16 on January 1, 2018. The Corporation has completed its assessment of existing operating leases. IFRS 16 will not have a significant impact on the Corporation's consolidated financial statements and the Corporation has assessed the quantitative impact of adopting IFRS 16 to be $nil in opening retained earnings, and an increase of $1.6 million in total assets and total liabilities for the right-of-use assets and the lease liabilities, respectively, as at January 1, 2018.

RATE BASE OVERVIEW

In accordance with s. 2.2.1 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (July 12, 2018) (the "Filing Requirements"), this schedule provides an overview of Toronto Hydro's rate base and year-over-year variance analysis of rate base and distribution assets (also referred to as Property, Plant & Equipment ("PP&E")). Continuity statements for Toronto Hydro's fixed assets, including interest during construction and overhead costs, are filed at Exhibit 2A, Tab 1, Schedule 2.

Through previous applications, the OEB has approved planned investments in certain assets that meet the OEB's definition for high voltage assets. This includes qualifying assets at the Copeland TS and contributions paid to HONI for work conducted on the transmission system. Toronto Hydro also proposes investments in high voltage assets in its 2020-2024 application. Once incurred, actual costs of such assets are separately reported in the utility's RRR (section 2.1.5.2).

1. RATE BASE

Table 1 summarizes Toronto Hydro's rate base values for the Historical (2015 to 2017), Bridge (2018 and 2019), and Forecast (2020) years, including opening and closing PP&E net book values ("NBV"), the average of opening and closing NBV, and the working capital allowance ("WCA"). The difference between 2019 closing PP&E NBV and 2020 opening PP&E NBV is due to the addition of monthly billing asset balances.

Table 1: Rate Base Summary ($ Millions)

	OEB Approved[1]	Actual			Bridge		Forecast
	2015	2015	2016	2017	2018	2019	2020
Opening PP&E NBV	2,849.0	2,843.2	3,085.4	3,462.0	3,744.7	4,120.6	4,270.4
Closing PP&E NBV	3,134.7	3,085.4	3,462.0	3,744.7	4,120.6	4,269.0	4,489.8
Average PP&E NBV	**2,991.8**	**2,964.3**	**3,273.7**	**3,603.4**	**3,932.7**	**4,194.8**	**4,380.1**
Working Capital Allowance	240.2	247.9	275.8	247.4	273.6	287.2	235.2
Rate Base	**3,232.0**	**3,212.2**	**3,549.5**	**3,850.8**	**4,206.3**	**4,482.0**	**4,615.3**

For the forecast year revenue requirement (Exhibit 6, Tab 1, Schedule 1), rate base includes the average of the opening and closing PP&E NBV, and WCA. The NBV of PP&E includes all assets in PP&E, excluding construction work-in-progress ("CWIP"). WCA is based on the cost of power and controllable expenses such as operations and maintenance, billing, collections and administration expenses.

1.1 Fixed Asset Continuity Statements

The continuity statements are filed at Exhibit 2A, Tab 1, Schedule 2. Toronto Hydro confirms that:

- The continuity statements provide year-end balance and include interest during construction, and all overheads;
- The opening and closing balances of gross assets and accumulated depreciation that are used to calculate the fixed asset component of rate base correspond to the respective balances in the fixed asset continuity statements; and
- The continuity statements reconcile to calculated depreciation expenses (Exhibit 4B, Tab 1, Schedule 1) and are presented by asset account.

[1] OEB-approved as per EB-2014-0116.

1.2 Working Capital Allowance ("WCA")

As presented in Table 1, WCA increases from $247.9 million in 2015 to $287.2 million in 2019, primarily due to cost of power expenses. In 2020, Toronto Hydro's forecast WCA of $235.2 million is less than historical amounts due to a reduction in the allowance rates resulting from the utility's latest Lead/Lag Study performed by Navigant Consulting Inc. Further details on WCA are provided at Exhibit 2A, Tab 3, Schedule 1.

2. RATE BASE VARIANCE ANALYSIS

2.1 2015 OEB-Approved versus 2015 Historical

Actual rate base in 2015 was $19.8 million less than the OEB-approved amount. Average NBV of PP&E in 2015 was $27.5 million less than the OEB-approved level, primarily due to lower in-service additions than forecasted. Toronto Hydro's actual WCA was $7.7 million more than approved because of higher than forecast cost of power expenses, mostly due to commodity cost increases.

2.2 2015 Historical versus 2016 Historical

Rate base increased by $337.4 million from 2015 to 2016. The increase in average PP&E NBV of $309.4 million was primarily due to assets coming into service. WCA increased by $27.9 million primarily due to rising commodity costs.

2.3 2016 Historical versus 2017 Historical

Rate base increased by $301.2 million from 2016 to 2017. The increase in average PP&E NBV of $329.7 million was primarily due to assets coming into service. WCA decreased by $28.4 million primarily due to lower cost of power expenses stemming from declining commodity costs.

2.4 2017 Historical versus 2018 Bridge Year

Rate base is forecasted to increase by $355.6 million from 2017 to 2018. The $329.3 million increase in average PP&E NBV is primarily due to assets coming into service. WCA is expected to increase by $26.2 million primarily due to projected increases in commodity costs.

2.5 2018 Bridge versus 2019 Bridge Year

Rate base is forecasted to increase by $275.6 million from 2018 to 2019. The increase in average PP&E NBV of $262.1 million is primarily due to assets coming into service. WCA is expected to increase by $13.5 million primarily due to projected increases in commodity costs.

2.6 2019 Bridge Year versus 2020 Test Year

Rate base is forecasted to increase by $133.3 million from 2019 to 2020. The $185.3 million increase in average PP&E NBV is primarily due to assets coming into service. WCA is expected to decrease by $52.0 million primarily due to a lower WCA rate resulting from the utility's latest lead-lag study, which is partially offset by a projected increase in commodity costs.

3. PROPERTY, PLANT AND EQUIPMENT

Table 2 below presents a summary of Toronto Hydro's distribution asset (also referred to as PP&E below) balances, before and after accumulated depreciation and excluding CWIP, for the Historical (2015 to 2017), Bridge (2018 to 2019), and Forecast (2020) years.

Table 2: Gross and Net PP&E – Years Ending December 31 ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Forecast
Land and Buildings	76.2	129.9	141.4	165.4	166.8	169.8
Other Distribution Assets	170.0	238.5	267.3	482.2	529.7	612.7
General Plant	127.7	185.2	247.5	239.5	240.5	243.0
TS Primary Above 50	5.8	6.0	36.9	38.9	39.0	39.1
Distribution System	149.9	156.8	184.5	228.8	251.0	277.9
Poles, Wires	2,172.2	2,430.6	2,663.8	2,902.8	3,151.0	3,426.9
Contributions and Grants	(58.2)	(90.5)	(118.0)	(182.1)	(254.4)	(329.2)
Line Transformers	412.4	465.3	515.4	574.4	645.6	714.2
Services and Meters	262.0	290.0	321.8	362.6	403.9	451.0
Equipment	61.5	100.4	120.8	129.7	135.7	152.5
IT Assets	27.3	47.2	58.7	70.2	77.9	89.0
Gross Assets	**3,406.8**	**3,959.4**	**4,440.1**	**5,012.4**	**5,386.6**	**5,846.8**
Accumulated Depreciation	(320.6)	(496.8)	(684.3)	(889.7)	(1,116.2)	(1,357.0)
Closing PP&E NBV (MIFRS)	**3,086.2**	**3,462.6**	**3,755.8**	**4,122.7**	**4,270.4**	**4,489.8**

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Note: Variances due to rounding may exist.

The PP&E NBV reported by Toronto Hydro pursuant to the OEB's Reporting and Record-keeping Requirements ("RRR") and determined for rate base purposes are aligned, with the exception of one difference: in 2015 to 2017, assets related to the monthly billing program[2] were included in PP&E for RRR purposes but excluded in the determination of rate base as these amounts are reported in the approved regulatory account.[3]

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[2] See Exhibit 9.
[3] *Ibid*.

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The major drivers of the changes from 2015 to 2020 include:

- Continued investment in distribution assets;
- Completion of the Copeland TS - Phase 1 project;
- Completion of the Operating Centre Consolidation Plan ("OCCP");
- Completion of the Enterprise Resource Planning ("ERP") application project; and
- Completion of the Hydro One Runnymede Station Expansion.

3.1 2015 OEB-Approved versus 2015 Historical

At the end of 2015, Toronto Hydro received the decision related to its last rebasing application (EB-2014-0116), which resulted in OEB-approved rates and resulting revenue requirement.[5] Toronto Hydro therefore provides its variance analysis between 2015 OEB-approved and historical PP&E NBV on an aggregate basis.

OEB-approved NBV for 2015 was $3,134.7 million compared to an actual of $3,086.2 million. The variance of $48.5 million was primarily due to lower in-service additions than forecasted, partially offset by less derecognition and dispositions than forecasted.

For the reasons discussed in Exhibit 4B, Tab 1, Schedule 2, Toronto Hydro expected volatility in asset derecognition over the 2015-2019 period. In its EB-2014-0116 decision, the OEB approved a variance account to track the differences in actual and forecasted derecognition. Toronto Hydro tracks the consequences of lower than expected derecognition in this account.

Actual asset dispositions were less than forecasted primarily due to the delayed disposition of the operating centre located at 5800 Yonge Street (Exhibit 2B, Section E4).

[5] EB-2014-0116, Decision and Order (February 29, 2016), page 4.

3.2 2015 Historical versus 2016 Historical

Actual asset NBV for 2016 was $3,462.6 million compared to $3,086.2 million in 2015. The increase of $376.5 million is primarily due to assets coming into service.

Table 3: 2015 Historical versus 2016 Historical ($ Millions)[6]

	2015 Actual	2016 Actual	Variance ($)	Variance (%)
Land and Buildings	76.2	129.9	53.7	70.4%
Other Distribution Assets	170.0	238.5	68.5	40.3%
General Plant	127.7	185.2	57.5	45.1%
TS Primary Above 50	5.8	6.0	0.2	2.6%
Distribution System	149.9	156.8	6.9	4.6%
Poles, Wires	2,172.2	2,430.6	258.4	11.9%
Contributions and Grants	(58.2)	(90.5)	(32.3)	55.5%
Line Transformers	412.4	465.3	52.9	12.8%
Services and Meters	262.0	290.0	28.0	10.7%
Equipment	61.5	100.4	38.9	63.4%
IT Assets	27.3	47.2	19.9	72.9%
Gross Assets	**3,406.8**	**3,959.4**	**552.6**	**16.2%**
Accumulated Depreciation	(320.6)	(496.8)	(176.2)	54.9%
Closing PP&E NBV (MIFRS)	**3,086.2**	**3,462.6**	**376.5**	**12.2%**

3.3 2016 Historical versus 2017 Historical

Actual asset NBV for 2017 was $3,755.8 million compared to $3,462.6 million in 2016. The increase of $293.2 million is primarily due to assets coming into service.

[6] Further breakdown of the categories and amounts presented in Tables 3 to 7 is provided in fixed asset continuity schedules provided in Exhibit 2A, Tab 1, Schedule 2, Appendix 2-BA.

Table 4: 2016 Historical versus 2017 Historical ($ Millions)

	2016 Actual	2017 Actual	Variance ($)	Variance (%)
Land and Buildings	129.9	141.4	11.5	8.8%
Other Distribution Assets	238.5	267.3	28.8	12.1%
General Plant	185.2	247.5	62.3	33.6%
TS Primary Above 50	6.0	36.9	30.9	516.1%
Distribution System	156.8	184.5	27.7	17.7%
Poles, Wires	2,430.6	2,663.8	233.2	9.6%
Contributions and Grants	(90.5)	(118.0)	(27.5)	30.3%
Line Transformers	465.3	515.4	50.0	10.8%
Services and Meters	290.0	321.8	31.8	11.0%
Equipment	100.4	120.8	20.4	20.3%
IT Assets	47.2	58.7	11.4	24.2%
Gross Assets	**3,959.4**	**4,440.1**	**480.7**	**12.1%**
Accumulated Depreciation	(496.8)	(684.3)	(187.5)	37.7%
Closing PP&E NBV (MIFRS)	**3,462.6**	**3,755.8**	**293.2**	**8.5%**

3.4 2017 Historical versus 2018 Bridge

Forecasted asset NBV for 2018 is $4,122.7 million compared to $3,755.8 million in 2017. The increase of $366.9 million is primarily due to assets coming into service.

Table 5: 2017 Historical versus 2018 Bridge ($ Millions)

	2017 Actual	2018 Bridge	Variance ($)	Variance (%)
Land and Buildings	141.4	165.4	24.0	17.0%
Other Distribution Assets	267.3	482.2	214.9	80.4%
General Plant	247.5	239.5	(8.0)	-3.2%
TS Primary Above 50	36.9	38.9	2.0	5.3%
Distribution System	184.5	228.8	44.2	24.0%
Poles, Wires	2,663.8	2,902.8	239.0	9.0%
Contributions and Grants	(118.0)	(182.1)	(64.1)	54.3%
Line Transformers	515.4	574.4	59.1	11.5%
Services and Meters	321.8	362.6	40.8	12.7%
Equipment	120.8	129.7	8.9	7.4%
IT Assets	58.7	70.2	11.5	19.7%
Gross Assets	**4,440.1**	**5,012.4**	**572.3**	**12.9%**
Accumulated Depreciation	(684.3)	(889.7)	(205.4)	30.0%
Closing PP&E NBV (MIFRS)	**3,755.8**	**4,122.7**	**366.9**	**9.8%**

3.5 2018 Bridge versus 2019 Bridge

Forecasted asset NBV for 2019 is $4,270.4 million compared to $4,122.7 million in 2018. The increase of $147.7 million is primarily due to assets coming into service.

Table 6: 2018 Bridge versus 2019 Bridge ($ Millions)

	2018 Bridge	2019 Bridge	Variance ($)	Variance (%)
Land and Buildings	165.4	166.8	1.4	0.8%
Other Distribution Assets	482.2	529.7	47.5	9.9%
General Plant	239.5	240.5	1.0	0.4%
TS Primary Above 50	38.9	39.0	0.1	0.3%
Distribution System	228.8	251.0	22.3	9.7%
Poles, Wires	2,902.8	3,151.0	248.1	8.5%
Contributions and Grants	(182.1)	(254.4)	(72.3)	39.7%
Line Transformers	574.4	645.6	71.2	12.4%
Services and Meters	362.6	403.9	41.2	11.4%
Equipment	129.7	135.7	6.0	4.6%
IT Assets	70.2	77.9	7.7	10.9%
Gross Assets	**5,012.4**	**5,386.6**	**374.2**	**7.5%**
Accumulated Depreciation	(889.7)	(1,116.2)	(226.5)	25.5%
Closing PP&E NBV (MIFRS)	**4,122.7**	**4,270.4**	**147.7**	**3.6%**

3.6 2019 Bridge versus 2020 Forecast Year

Forecasted asset NBV in 2020 is $4,489.8 million compared to $4,270.4 million in 2019. The increase of $219.4 million is primarily due to assets coming into service. The 2020 NBV opening balance includes an adjustment of $1.4 million for the addition of the assets resulting from the monthly billing program,[7] as approved by the OEB.

[7] See Exhibit 9.

Table 7: 2019 Bridge versus 2020 Forecast ($ Millions)

	2019 Bridge	2020 Forecast	Variance ($)	Variance (%)
Land and Buildings	166.8	169.8	3.0	1.8%
Other Distribution Assets	529.7	612.7	83.0	15.7%
General Plant	240.5	243.0	2.5	1.0%
TS Primary Above 50	39.0	39.1	0.1	0.3%
Distribution System	251.0	277.9	26.8	10.7%
Poles, Wires	3,151.0	3,426.9	275.9	8.8%
Contributions and Grants	(254.4)	(329.2)	(74.8)	29.4%
Line Transformers	645.6	714.2	68.6	10.6%
Services and Meters	403.9	451.0	47.1	11.7%
Equipment	135.7	152.5	16.8	12.4%
IT Assets	77.9	89.0	11.1	14.2%
Gross Assets	**5,386.6**	**5,846.8**	**460.2**	**8.5%**
Accumulated Depreciation	(1,116.2)	(1,357.0)	(240.8)	21.6%
Closing PP&E NBV (MIFRS)	**4,270.4**	**4,489.8**	**219.4**	**5.1%**

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From 2019 to 2020, "other distribution assets" are expected to increase by $83.0 million or 15.7 percent, primarily due to the in-service amount for Hydro One Contributions (see Exhibit 2B, Section E7.4) and IT software additions (see Exhibit 2B, Section E8.4).

General Plant assets are expected to increase by $2.5 million or 1.0 percent primarily due to the in-service amounts for facilities-related assets. Refer to the Facilities Management and Security program (Exhibit 2B, Section E8.2) for more information.

Distribution system assets are expected to increase by $26.8 million or 10.7 percent, primarily due to the forecasted completion of stations projects. Refer to the Stations Renewal program (Exhibit 2B, Section E6.6) for details.

Capital investment in poles and wires is expected to increase by $275.9 million or 8.8 percent and investment in line transformer assets are expected to increase by $68.6

million or 10.6 percent. The increase in these major plant categories is primarily attributed to the Underground System Renewal – Horseshoe (Exhibit 2B, Section E6.2), Underground System Renewal – Downtown (Exhibit 2B, Section E6.3), Overhead System Renewal (Exhibit 2B, Section E6.5), Reactive and Corrective Capital (Exhibit 2B, Section E6.7) and Customer Connections (Exhibit 2B, Section E5.1) programs.

Contributions and grants are expected to increase by $74.8 million or 29.4 percent on account of realized contributions related to in-service assets, resulting in a reduction to NBV. **/C**

Services and meter assets are expected to increase by $47.1 million or 11.7 percent. The increase in services and meter assets is primarily related to the Metering program (Exhibit 2B, Section E5.4).

Equipment assets are expected to increase by $16.8 million or 12.4 percent, primarily due to investment in fleet and facilities-related assets. Refer to the Fleet and Equipment Services program (Exhibit 2B, Section E8.3) for details. **/C**

IT assets are expected to increase by $11.1 million or 14.2 percent, primarily due to investment in computer hardware equipment. Refer to the IT/OT Systems program (Exhibit 2B, Section E8.4) for more information.

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year 2020

			Cost (Forecast)				Accumulated Depreciation (Forecast)				
CCA Class	OEB Account	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 267,602,967	$ 30,655,579	$ -	$ 298,258,546	($ 133,790,497)	($ 36,099,942)	$ -	($ 169,890,439)	$ 128,368,107
N/A	1612	Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 7,001,832	$ -	$ -	$ 7,001,832	$ -	$ -	$ -	$ -	$ 7,001,832
1	1808	Buildings	$ 142,417,844	$ 2,986,710	$ -	$ 145,404,554	($ 16,453,350)	($ 3,720,102)	$ -	($ 20,173,452)	$ 125,231,102
47	1815	Transformer Station Equipment >50 kV	$ 38,971,341	$ 112,337	$ -	$ 39,083,678	($ 4,476,217)	($ 1,325,172)	$ -	($ 5,801,389)	$ 33,282,289
47	1820	Distribution Station Equipment <50 kV	$ 251,030,850	$ 27,166,846	($ 326,796)	$ 277,870,899	($ 47,736,208)	($ 11,273,000)	$ 95,923	($ 58,913,285)	$ 218,957,614
47	1830	Poles, Towers & Fixtures	$ 408,235,757	$ 34,478,688	($ 6,898,194)	$ 435,816,251	($ 56,927,928)	($ 11,739,346)	$ 927,888	($ 67,739,387)	$ 368,076,864
47	1835	Overhead Conductors & Devices	$ 470,630,605	$ 47,031,817	($ 2,629,678)	$ 515,032,744	($ 55,177,206)	($ 12,364,683)	$ 283,889	($ 67,258,000)	$ 447,774,745
47	1840	Underground Conduit	$ 1,321,929,677	$ 111,087,570	($ 668,559)	$ 1,432,348,688	($ 246,721,584)	($ 50,257,599)	$ 98,099	($ 296,881,084)	$ 1,135,467,604
47	1845	Underground Conductors & Devices	$ 950,155,945	$ 99,413,968	($ 5,903,043)	$ 1,043,666,871	($ 128,104,051)	($ 29,225,810)	$ 560,001	($ 156,769,861)	$ 886,897,010
47	1850	Line Transformers	$ 645,603,131	$ 79,659,607	($ 11,048,456)	$ 714,214,282	($ 125,011,987)	($ 28,236,015)	$ 1,545,228	($ 151,702,773)	$ 562,511,508
47	1855	Services (Overhead & Underground)	$ 155,842,896	$ 19,867,315	($ 398,088)	$ 175,312,122	($ 15,123,088)	($ 3,818,256)	$ 22,965	($ 18,918,379)	$ 156,393,743
47	1860	Meters	$ 114,917,588	$ 20,046,264	($ 1,022,851)	$ 133,941,001	($ 22,879,514)	($ 6,389,230)	$ 140,733	($ 29,128,011)	$ 104,812,991
47	1860	Meters (Smart Meters)	$ 133,105,598	$ 9,339,433	($ 713,141)	$ 141,731,890	($ 61,457,036)	($ 12,222,117)	$ 163,557	($ 73,515,596)	$ 68,216,295
N/A	1905	Land	$ 17,356,057	$ -	$ -	$ 17,356,057	$ -	$ -	$ -	$ -	$ 17,356,057
1	1908	Buildings & Fixtures	$ 239,739,712	$ 2,499,408	$ -	$ 242,239,120	($ 48,920,103)	($ 11,382,932)	$ -	($ 60,303,035)	$ 181,936,086
13	1910	Leasehold Improvements	$ 753,840	$ -	$ -	$ 753,840	($ 753,840)	$ -	$ -	($ 753,840)	$ -
8	1915	Office Furniture & Equipment	$ 20,231,295	$ 896,014	$ -	$ 21,127,310	($ 11,505,619)	($ 1,905,523)	$ -	($ 13,411,142)	$ 7,716,167
50	1920	Computer Equipment - Hardware	$ 77,902,724	$ 11,081,696	$ -	$ 88,984,420	($ 52,064,292)	($ 11,692,222)	$ -	($ 63,756,513)	$ 25,227,907
10	1930	Transportation Equipment	$ 41,495,087	$ 4,654,924	$ -	$ 46,150,010	($ 28,580,408)	($ 3,045,967)	$ -	($ 31,626,375)	$ 14,523,635
8	1935	Stores Equipment	$ 7,066	$ -	$ -	$ 7,066	($ 7,066)	$ -	$ -	($ 7,066)	$ -
8	1940	Tools, Shop & Garage Equipment	$ 33,583,396	$ 9,772,286	$ -	$ 43,355,682	($ 13,827,242)	($ 3,095,774)	$ -	($ 16,923,016)	$ 26,432,666
8	1945	Measurement & Testing Equipment	$ 481,035	$ 2,661	$ -	$ 483,695	($ 394,236)	($ 44,522)	$ -	($ 438,758)	$ 44,937
8	1950	Service Equipment	$ 1,114,955	$ 59,523	$ -	$ 1,174,478	($ 691,091)	($ 84,739)	$ -	($ 775,830)	$ 398,647
8	1955	Communications Equipment	$ 46,633,950	$ 1,711,630	$ -	$ 48,345,580	($ 18,758,557)	($ 3,827,071)	$ -	($ 22,585,628)	$ 25,759,953
8	1960	Miscellaneous Equipment	$ 275,770	$ -	$ -	$ 275,770	($ 223,448)	($ 34,673)	$ -	($ 258,121)	$ 17,649
47	1970	Load Management Controls Customer Premises	$ 3,022,834	$ -	$ -	$ 3,022,834	($ 3,022,834)	$ -	$ -	($ 3,022,834)	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 61,907,132	$ 9,907,190	($ 627,898)	$ 71,186,424	($ 15,107,184)	($ 4,128,590)	$ 67,859	($ 19,167,914)	$ 52,018,509
47	2440	Contributions & Grants (Formally known as Account 1995)	($ 254,372,738)	($ 75,354,275)	$ 565,896	($ 329,161,117)	$ 22,701,606	$ 8,995,336	($ 28,847)	$ 31,668,095	($ 297,493,021)
N/A	1609	Capital Contributions Paid	$ 191,774,015	$ 46,229,405	$ -	$ 238,003,420	($ 20,491,327)	($ 8,780,891)	$ -	($ 29,272,218)	$ 208,731,202
N/A	2005	Property Under Capital Leases	$ 18,170,834	$ -	$ -	$ 18,170,834	($ 11,516,281)	($ 89,423)	$ -	($ 11,605,704)	$ 6,565,130
		Sub-Total	**$ 5,407,522,996**	**$ 493,306,595**	**($ 29,670,808)**	**$ 5,871,158,783**	**($ 1,117,020,588)**	**($ 245,788,261)**	**$ 3,877,295**	**($ 1,358,931,554)**	**$ 4,512,227,229**
		Less Socialized Renewable Energy Generation Investments (input as negative)	($ 8,138,769)	($ 263,784)	$ -	($ 8,402,553)	$ 119,756	$ 570,353	$ -	$ 690,109	($ 7,712,444)
		Less Other Non Rate-Regulated Utility Assets (input as negative)	($ 12,762,660)	($ 3,195,791)	$ -	($ 15,958,451)	$ 674,182	$ 587,711	$ -	$ 1,261,893	($ 14,696,558)
		Total PP&E	**$ 5,386,621,566**	**$ 489,847,020**	**($ 29,670,808)**	**$ 5,846,797,779**	**($ 1,116,226,651)**	**($ 244,630,196)**	**$ 3,877,295**	**($ 1,356,979,552)**	**$ 4,489,818,227**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)						$ -			
		Total						**($ 244,630,196)**			

10		Transportation
		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	($ 1,759,521)
Stores Equipment	$ -
Net Depreciation	($ 242,870,675)

Notes:
Fixed Asset Continuity Schedule includes monthly billing
Socialized Renewable Energy Generation Investments include Energy Storage program
Other Non Rate-Regulated Utility Assets includes Generation Protection, Monitoring and Control program

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year **2021**

			Cost (Forecast)				Accumulated Depreciation (Forecast)				
CCA Class	**OEB Account**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 298,258,546	$ 37,311,502	$ -	$ 335,570,048	($ 169,890,439)	($ 37,671,581)	$ -	($ 207,562,019)	$ 128,008,028
N/A	1612	Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 7,001,832	$ -	$ -	$ 7,001,832	$ -	$ -	$ -	$ -	$ 7,001,832
1	1808	Buildings	$ 145,404,554	$ 5,876,387	$ -	$ 151,280,941	($ 20,173,452)	($ 3,909,446)	$ -	($ 24,082,897)	$ 127,198,043
47	1815	Transformer Station Equipment >50 kV	$ 39,083,678	$ 313,154	$ -	$ 39,396,833	($ 5,801,389)	($ 1,338,360)	$ -	($ 7,139,750)	$ 32,257,083
47	1820	Distribution Station Equipment <50 kV	$ 277,870,899	$ 25,156,550	($ 341,165)	$ 302,686,284	($ 58,913,285)	($ 12,153,144)	$ 100,136	($ 70,966,293)	$ 231,719,991
47	1830	Poles, Towers & Fixtures	$ 435,816,251	$ 35,434,611	($ 7,314,181)	$ 463,936,681	($ 67,739,387)	($ 12,283,987)	$ 967,637	($ 79,055,737)	$ 384,880,944
47	1835	Overhead Conductors & Devices	$ 515,032,744	$ 46,953,586	($ 2,787,782)	$ 559,198,548	($ 67,258,000)	($ 13,294,311)	$ 297,886	($ 80,254,425)	$ 478,944,124
47	1840	Underground Conduit	$ 1,432,348,688	$ 111,484,762	($ 703,712)	$ 1,543,129,738	($ 296,881,084)	($ 53,597,463)	$ 102,019	($ 350,376,528)	$ 1,192,753,210
47	1845	Underground Conductors & Devices	$ 1,043,666,871	$ 105,249,928	($ 6,282,985)	$ 1,142,633,815	($ 156,769,861)	($ 31,687,080)	$ 594,838	($ 187,862,102)	$ 954,771,713
47	1850	Line Transformers	$ 714,214,282	$ 82,839,451	($ 11,603,645)	$ 785,450,087	($ 151,702,773)	($ 30,409,996)	$ 1,621,305	($ 180,491,464)	$ 604,958,623
47	1855	Services (Overhead & Underground)	$ 175,312,122	$ 20,530,921	($ 425,950)	$ 195,417,093	($ 18,918,379)	($ 4,253,260)	$ 24,571	($ 23,147,068)	$ 172,270,025
47	1860	Meters	$ 133,941,001	$ 16,359,888	($ 1,017,640)	$ 149,283,249	($ 29,128,011)	($ 7,297,256)	$ 140,016	($ 36,285,251)	$ 112,997,998
47	1860	Meters (Smart Meters)	$ 141,731,890	$ 8,026,261	($ 428,284)	$ 149,329,867	($ 73,515,596)	($ 12,088,423)	$ 98,156	($ 85,505,863)	$ 63,824,003
N/A	1905	Land	$ 17,356,057	$ -	$ -	$ 17,356,057	$ -	$ -	$ -	$ -	$ 17,356,057
1	1908	Buildings & Fixtures	$ 242,239,120	$ 4,375,711	$ -	$ 246,614,831	($ 60,303,035)	($ 11,392,360)	$ -	($ 71,695,394)	$ 174,919,437
13	1910	Leasehold Improvements	$ 753,840	$ -	$ -	$ 753,840	($ 753,840)	$ -	$ -	($ 753,840)	$ -
8	1915	Office Furniture & Equipment	$ 21,127,310	$ 1,568,651	$ -	$ 22,695,961	($ 13,411,142)	($ 1,526,032)	$ -	($ 14,937,174)	$ 7,758,787
50	1920	Computer Equipment - Hardware	$ 88,984,420	$ 10,567,673	$ -	$ 99,552,093	($ 63,756,513)	($ 11,643,137)	$ -	($ 75,399,650)	$ 24,152,443
10	1930	Transportation Equipment	$ 46,150,010	$ 8,116,801	$ -	$ 54,266,811	($ 31,626,375)	($ 3,492,699)	$ -	($ 35,119,074)	$ 19,147,737
8	1935	Stores Equipment	$ 7,066	$ -	$ -	$ 7,066	($ 7,066)	$ -	$ -	($ 7,066)	$ -
8	1940	Tools, Shop & Garage Equipment	$ 43,355,682	$ 19,796,068	$ -	$ 63,151,750	($ 16,923,016)	($ 3,903,645)	$ -	($ 20,826,661)	$ 42,325,089
8	1945	Measurement & Testing Equipment	$ 483,695	$ 3,739	$ -	$ 487,435	($ 438,758)	($ 26,979)	$ -	($ 465,737)	$ 21,698
8	1950	Service Equipment	$ 1,174,478	$ 88,984	$ -	$ 1,263,461	($ 775,830)	($ 77,693)	$ -	($ 853,524)	$ 409,938
8	1955	Communications Equipment	$ 48,345,580	$ 1,836,338	$ -	$ 50,181,919	($ 22,585,628)	($ 3,607,264)	$ -	($ 26,192,892)	$ 23,989,027
8	1960	Miscellaneous Equipment	$ 275,770	$ -	$ -	$ 275,770	($ 258,121)	($ 12,468)	$ -	($ 270,588)	$ 5,182
47	1970	Load Management Controls Customer Premises	$ 3,022,834	$ -	$ -	$ 3,022,834	($ 3,022,834)	$ -	$ -	($ 3,022,834)	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 71,186,424	$ 9,339,034	($ 668,673)	$ 79,856,785	($ 19,167,914)	($ 4,551,218)	$ 72,264	($ 23,646,868)	$ 56,209,917
47	2440	Contributions & Grants (Formally known as Account 1995)	($ 329,161,117)	($ 66,749,789)	$ 579,154	($ 395,331,751)	$ 31,668,095	$ 11,381,397	($ 29,523)	$ 43,019,970	($ 352,311,782)
N/A	1609	Capital Contributions Paid	$ 238,003,420	$ 2,325,724	$ -	$ 240,329,144	($ 29,272,218)	($ 9,072,914)	$ -	($ 38,345,133)	$ 201,984,011
N/A	2005	Property Under Capital Leases	$ 18,170,834	$ -	$ -	$ 18,170,834	($ 11,605,704)	($ 89,423)	$ -	($ 11,695,127)	$ 6,475,707
		Sub-Total	**$ 5,871,158,783**	**$ 486,805,934**	**($ 30,994,864)**	**$ 6,326,969,853**	**($ 1,358,931,554)**	**($ 257,998,740)**	**$ 3,989,305**	**($ 1,612,940,989)**	**$ 4,714,028,864**
		Less Socialized Renewable Energy Generation Investments (input as negative)	($ 8,402,553)	($ 868,193)	$ -	($ 9,270,746)	$ 690,109	$ 632,411	$ -	$ 1,322,520	($ 7,948,226)
		Less Other Non Rate-Regulated Utility Assets (input as negative)	($ 15,958,451)	($ 2,121,225)	$ -	($ 18,079,676)	$ 1,261,893	$ 682,756	$ -	$ 1,944,649	($ 16,135,026)
		Total PP&E	**$ 5,846,797,779**	**$ 483,816,517**	**($ 30,994,864)**	**$ 6,299,619,432**	**($ 1,356,979,552)**	**($ 256,683,572)**	**$ 3,989,305**	**($ 1,609,673,820)**	**$ 4,689,945,612**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)						$ -			
		Total						**($ 256,683,572)**			

10		Transportation
		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	($ 1,759,521)
Stores Equipment	$ -
Net Depreciation	($ 254,924,052)

Notes:
Fixed Asset Continuity Schedule includes monthly billing
Socialized Renewable Energy Generation Investments include Energy Storage program
Other Non Rate-Regulated Utility Assets includes Generation Protection, Monitoring and Control program

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year 2022

			Cost (Forecast)				Accumulated Depreciation (Forecast)				
CCA Class	OEB Account	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 335,570,048	$ 64,289,180	$ -	$ 399,859,228	($ 207,562,019)	($ 40,290,306)	$ -	($ 247,852,326)	$ 152,006,902
N/A	1612	Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 7,001,832	$ -	$ -	$ 7,001,832	$ -	$ -	$ -	$ -	$ 7,001,832
1	1808	Buildings	$ 151,280,941	$ 37,970,525	$ -	$ 189,251,466	($ 24,082,897)	($ 4,410,932)	$ -	($ 28,493,829)	$ 160,757,636
47	1815	Transformer Station Equipment >50 kV	$ 39,396,833	$ 3,881,789	$ -	$ 43,278,622	($ 7,139,750)	($ 1,393,044)	$ -	($ 8,532,794)	$ 34,745,828
47	1820	Distribution Station Equipment <50 kV	$ 302,686,284	$ 29,125,614	($ 343,626)	$ 331,468,271	($ 70,966,293)	($ 12,850,100)	$ 100,860	($ 83,715,532)	$ 247,752,739
47	1830	Poles, Towers & Fixtures	$ 463,936,681	$ 34,995,145	($ 7,317,218)	$ 491,614,608	($ 79,055,737)	($ 12,832,992)	$ 974,920	($ 90,913,809)	$ 400,700,799
47	1835	Overhead Conductors & Devices	$ 559,198,548	$ 45,723,045	($ 2,789,199)	$ 602,132,394	($ 80,254,425)	($ 14,187,705)	$ 299,349	($ 94,142,780)	$ 507,989,614
47	1840	Underground Conduit	$ 1,543,129,738	$ 111,801,320	($ 706,308)	$ 1,654,224,750	($ 350,376,528)	($ 56,046,909)	$ 102,918	($ 406,320,519)	$ 1,247,904,231
47	1845	Underground Conductors & Devices	$ 1,142,633,815	$ 106,662,165	($ 6,276,298)	$ 1,243,019,681	($ 187,862,102)	($ 34,255,520)	$ 594,725	($ 221,522,897)	$ 1,021,496,784
47	1850	Line Transformers	$ 785,450,087	$ 83,727,352	($ 11,655,663)	$ 857,521,776	($ 180,491,464)	($ 32,788,733)	$ 1,629,292	($ 211,650,905)	$ 645,870,871
47	1855	Services (Overhead & Underground)	$ 195,417,093	$ 20,290,191	($ 424,454)	$ 215,282,831	($ 23,147,068)	($ 4,698,141)	$ 24,486	($ 27,820,723)	$ 187,462,108
47	1860	Meters	$ 149,283,249	$ 17,137,458	($ 1,003,870)	$ 165,416,836	($ 36,285,251)	($ 8,106,701)	$ 138,121	($ 44,253,831)	$ 121,163,005
47	1860	Meters (Smart Meters)	$ 149,329,867	$ 8,279,065	($ 260,287)	$ 157,348,645	($ 85,505,863)	($ 10,199,124)	$ 59,557	($ 95,645,430)	$ 61,703,215
N/A	1905	Land	$ 17,356,057	$ -	$ -	$ 17,356,057	$ -	$ -	$ -	$ -	$ 17,356,057
1	1908	Buildings & Fixtures	$ 246,614,831	$ 21,654,357	$ -	$ 268,269,188	($ 71,695,394)	($ 11,512,353)	$ -	($ 83,207,747)	$ 185,061,441
13	1910	Leasehold Improvements	$ 753,840	$ -	$ -	$ 753,840	($ 753,840)	$ -	$ -	($ 753,840)	$ -
8	1915	Office Furniture & Equipment	$ 22,695,961	$ 7,762,883	$ -	$ 30,458,843	($ 14,937,174)	($ 1,492,271)	$ -	($ 16,429,445)	$ 14,029,398
50	1920	Computer Equipment - Hardware	$ 99,552,093	$ 13,055,636	$ -	$ 112,607,729	($ 75,399,650)	($ 11,310,339)	$ -	($ 86,709,989)	$ 25,897,740
10	1930	Transportation Equipment	$ 54,266,811	$ 7,707,722	$ -	$ 61,974,533	($ 35,119,074)	($ 4,282,381)	$ -	($ 39,401,456)	$ 22,573,077
8	1935	Stores Equipment	$ 7,066	$ -	$ -	$ 7,066	($ 7,066)	$ -	$ -	($ 7,066)	$ -
8	1940	Tools, Shop & Garage Equipment	$ 63,151,750	$ 29,060,707	$ -	$ 92,212,456	($ 20,826,661)	($ 5,440,415)	$ -	($ 26,267,076)	$ 65,945,380
8	1945	Measurement & Testing Equipment	$ 487,435	$ 177	$ -	$ 487,612	($ 465,737)	($ 15,847)	$ -	($ 481,584)	$ 6,028
8	1950	Service Equipment	$ 1,263,461	$ 84,499	$ -	$ 1,347,960	($ 853,524)	($ 79,709)	$ -	($ 933,232)	$ 414,728
8	1955	Communications Equipment	$ 50,181,919	$ 1,819,906	$ -	$ 52,001,825	($ 26,192,892)	($ 2,946,910)	$ -	($ 29,139,802)	$ 22,862,023
8	1960	Miscellaneous Equipment	$ 275,770	$ 1,579,433	$ -	$ 1,855,203	($ 270,588)	($ 11,083)	$ -	($ 281,671)	$ 1,573,532
47	1970	Load Management Controls Customer Premises	$ 3,022,834	$ -	$ -	$ 3,022,834	($ 3,022,834)	$ -	$ -	($ 3,022,834)	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 79,856,785	$ 9,886,266	($ 667,846)	$ 89,075,205	($ 23,646,868)	($ 4,940,531)	$ 72,176	($ 28,515,224)	$ 60,559,981
47	2440	Contributions & Grants (Formally known as Account 1995)	($ 395,331,751)	($ 67,219,101)	$ 597,344	($ 461,953,509)	$ 43,019,970	$ 13,965,086	($ 30,450)	$ 56,954,606	($ 404,998,903)
N/A	1609	Capital Contributions Paid	$ 240,329,144	$ 5,596,422	$ -	$ 245,925,566	($ 38,345,133)	($ 9,237,696)	$ -	($ 47,582,829)	$ 198,342,737
N/A	2005	Property Under Capital Leases	$ 18,170,834	$ -	$ -	$ 18,170,834	($ 11,695,127)	($ 89,423)	$ -	($ 11,784,550)	$ 6,386,284
		Sub-Total	**$ 6,326,969,853**	**$ 594,871,754**	**($ 30,847,427)**	**$ 6,890,994,181**	**($ 1,612,940,989)**	**($ 269,454,078)**	**$ 3,965,954**	**($ 1,878,429,114)**	**$ 5,012,565,067**
		Less Socialized Renewable Energy Generation Investments (input as negative)	($ 9,270,746)	($ 1,694,024)	$ -	($ 10,964,769)	$ 1,322,520	$ 737,590	$ -	$ 2,060,110	($ 8,904,659)
		Less Other Non Rate-Regulated Utility Assets (input as negative)	($ 18,079,676)	($ 2,219,756)	$ -	($ 20,299,432)	$ 1,944,649	$ 761,833	$ -	$ 2,706,482	($ 17,592,950)
		Total PP&E	**$ 6,299,619,432**	**$ 590,957,975**	**($ 30,847,427)**	**$ 6,859,729,980**	**($ 1,609,673,820)**	**($ 267,954,656)**	**$ 3,965,954**	**($ 1,873,662,522)**	**$ 4,986,067,458**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)						$ -			
		Total						**($ 267,954,656)**			

10		Transportation
		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	($ 1,759,521)
Stores Equipment	$ -
Net Depreciation	($ 266,195,135)

Notes:
Fixed Asset Continuity Schedule includes monthly billing
Socialized Renewable Energy Generation Investments include Energy Storage program
Other Non Rate-Regulated Utility Assets includes Generation Protection, Monitoring and Control program

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year 2023

			Cost (Forecast)				Accumulated Depreciation (Forecast)				
CCA Class	OEB Account	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 399,859,228	$ 41,936,722	$ -	$ 441,795,950	($ 247,852,326)	($ 42,323,474)	$ -	($ 290,175,800)	$ 151,620,150
N/A	1612	Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 7,001,832	$ -	$ -	$ 7,001,832	$ -	$ -	$ -	$ -	$ 7,001,832
1	1808	Buildings	$ 189,251,466	$ 24,862,013	$ -	$ 214,113,478	($ 28,493,829)	($ 5,886,992)	$ -	($ 34,380,822)	$ 179,732,657
47	1815	Transformer Station Equipment >50 kV	$ 43,278,622	$ 4,663,767	$ -	$ 47,942,389	($ 8,532,794)	($ 1,543,305)	$ -	($ 10,076,099)	$ 37,866,290
47	1820	Distribution Station Equipment <50 kV	$ 331,468,271	$ 30,034,149	($ 358,450)	$ 361,143,970	($ 83,715,532)	($ 13,787,587)	$ 105,205	($ 97,397,914)	$ 263,746,056
47	1830	Poles, Towers & Fixtures	$ 491,614,608	$ 36,474,413	($ 7,769,068)	$ 520,319,953	($ 90,913,809)	($ 13,387,282)	$ 1,020,341	($ 103,280,750)	$ 417,039,203
47	1835	Overhead Conductors & Devices	$ 602,132,394	$ 47,002,240	($ 2,959,674)	$ 646,174,960	($ 94,142,780)	($ 14,977,861)	$ 314,872	($ 108,805,769)	$ 537,369,192
47	1840	Underground Conduit	$ 1,654,224,750	$ 117,197,293	($ 744,311)	$ 1,770,677,732	($ 406,320,519)	($ 58,697,608)	$ 107,359	($ 464,910,769)	$ 1,305,766,964
47	1845	Underground Conductors & Devices	$ 1,243,019,681	$ 113,889,863	($ 6,689,225)	$ 1,350,220,319	($ 221,522,897)	($ 36,586,924)	$ 632,475	($ 257,477,345)	$ 1,092,742,974
47	1850	Line Transformers	$ 857,521,776	$ 87,904,740	($ 12,233,907)	$ 933,192,608	($ 211,650,905)	($ 35,274,498)	$ 1,708,443	($ 245,216,960)	$ 687,975,648
47	1855	Services (Overhead & Underground)	$ 215,282,831	$ 21,002,880	($ 454,636)	$ 235,831,075	($ 27,820,723)	($ 5,146,705)	$ 26,227	($ 32,941,201)	$ 202,889,874
47	1860	Meters	$ 165,416,836	$ 21,096,001	($ 981,543)	$ 185,531,295	($ 44,253,831)	($ 9,044,328)	$ 135,049	($ 53,163,110)	$ 132,368,185
47	1860	Meters (Smart Meters)	$ 157,348,645	$ 9,675,324	($ 116,284)	$ 166,907,685	($ 95,645,430)	($ 8,975,671)	$ 26,487	($ 104,594,614)	$ 62,313,072
N/A	1905	Land	$ 17,356,057	$ -	$ -	$ 17,356,057	$ -	$ -	$ -	$ -	$ 17,356,057
1	1908	Buildings & Fixtures	$ 268,269,188	$ 5,387,713	$ -	$ 273,656,901	($ 83,207,747)	($ 12,134,798)	$ -	($ 95,342,545)	$ 178,314,356
13	1910	Leasehold Improvements	$ 753,840	$ -	$ -	$ 753,840	($ 753,840)	$ -	$ -	($ 753,840)	$ -
8	1915	Office Furniture & Equipment	$ 30,458,843	$ 1,931,444	$ -	$ 32,390,288	($ 16,429,445)	($ 2,084,719)	$ -	($ 18,514,164)	$ 13,876,124
50	1920	Computer Equipment - Hardware	$ 112,607,729	$ 13,760,863	$ -	$ 126,368,592	($ 86,709,989)	($ 11,597,216)	$ -	($ 98,307,205)	$ 28,061,388
10	1930	Transportation Equipment	$ 61,974,533	$ 8,291,568	$ -	$ 70,266,101	($ 39,401,456)	($ 5,261,264)	$ -	($ 44,662,719)	$ 25,603,382
8	1935	Stores Equipment	$ 7,066	$ -	$ -	$ 7,066	($ 7,066)	$ -	$ -	($ 7,066)	$ -
8	1940	Tools, Shop & Garage Equipment	$ 92,212,456	$ 2,195,808	$ -	$ 94,408,264	($ 26,267,076)	($ 6,299,506)	$ -	($ 32,566,582)	$ 61,841,682
8	1945	Measurement & Testing Equipment	$ 487,612	$ 234	$ -	$ 487,847	($ 481,584)	($ 700)	$ -	($ 482,284)	$ 5,562
8	1950	Service Equipment	$ 1,347,960	$ 90,900	$ -	$ 1,438,860	($ 933,232)	($ 88,888)	$ -	($ 1,022,120)	$ 416,740
8	1955	Communications Equipment	$ 52,001,825	$ 1,961,339	$ -	$ 53,963,164	($ 29,139,802)	($ 3,066,257)	$ -	($ 32,206,059)	$ 21,757,105
8	1960	Miscellaneous Equipment	$ 1,855,203	$ -	$ -	$ 1,855,203	($ 281,671)	($ 124,277)	$ -	($ 405,948)	$ 1,449,255
47	1970	Load Management Controls Customer Premises	$ 3,022,834	$ -	$ -	$ 3,022,834	($ 3,022,834)	$ -	$ -	($ 3,022,834)	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 89,075,205	$ 10,387,589	($ 712,351)	$ 98,750,443	($ 28,515,224)	($ 5,259,164)	$ 76,983	($ 33,697,405)	$ 65,053,038
47	2440	Contributions & Grants (Formally known as Account 1995)	($ 461,953,509)	($ 45,072,071)	$ 643,931	($ 506,381,648)	$ 56,954,606	$ 15,926,556	($ 32,825)	$ 72,848,337	($ 433,533,311)
N/A	1609	Capital Contributions Paid	$ 245,925,566	$ 40,711,097	$ -	$ 286,636,663	($ 47,582,829)	($ 10,223,081)	$ -	($ 57,805,910)	$ 228,830,753
N/A	2005	Property Under Capital Leases	$ 18,170,834	$ -	$ -	$ 18,170,834	($ 11,784,550)	($ 89,423)	$ -	($ 11,873,973)	$ 6,296,861
		Sub-Total	**$ 6,890,994,181**	**$ 595,385,892**	**($ 32,375,518)**	**$ 7,454,004,556**	**($ 1,878,429,114)**	**($ 285,934,972)**	**$ 4,120,617**	**($ 2,160,243,469)**	**$ 5,293,761,087**
		Less Socialized Renewable Energy Generation Investments (input as negative)	($ 10,964,769)	$ -	$ -	($ 10,964,769)	$ 2,060,110	$ 730,985	$ -	$ 2,791,095	($ 8,173,674)
		Less Other Non Rate-Regulated Utility Assets (input as negative)	($ 20,299,432)	($ 2,364,569)	$ -	($ 22,664,001)	$ 2,706,482	$ 845,403	$ -	$ 3,551,885	($ 19,112,116)
		Total PP&E	**$ 6,859,729,980**	**$ 593,021,323**	**($ 32,375,518)**	**$ 7,420,375,785**	**($ 1,873,662,522)**	**($ 284,358,584)**	**$ 4,120,617**	**($ 2,153,900,489)**	**$ 5,266,475,297**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)						$ -			
		Total						**($ 284,358,584)**			

10		Transportation
		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	($ 1,759,521)
Stores Equipment	$ -
Net Depreciation	($ 282,599,064)

Notes:
Fixed Asset Continuity Schedule includes monthly billing
Socialized Renewable Energy Generation Investments include Energy Storage program
Other Non Rate-Regulated Utility Assets includes Generation Protection, Monitoring and Control program

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year **2024**

			Cost (Forecast)				Accumulated Depreciation (Forecast)				
CCA Class	**OEB Account**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 441,795,950	$ 42,240,621	$ -	$ 484,036,571	($ 290,175,800)	($ 44,166,890)	$ -	($ 334,342,690)	$ 149,693,881
N/A	1612	Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 7,001,832	$ -	$ -	$ 7,001,832	$ -	$ -	$ -	$ -	$ 7,001,832
1	1808	Buildings	$ 214,113,478	$ 26,798,264	$ -	$ 240,911,742	($ 34,380,822)	($ 6,789,310)	$ -	($ 41,170,132)	$ 199,741,610
47	1815	Transformer Station Equipment >50 kV	$ 47,942,389	$ 5,082,632	$ -	$ 53,025,021	($ 10,076,099)	($ 1,693,709)	$ -	($ 11,769,808)	$ 41,255,214
47	1820	Distribution Station Equipment <50 kV	$ 361,143,970	$ 39,693,730	($ 363,939)	$ 400,473,761	($ 97,397,914)	($ 14,682,155)	$ 106,818	($ 111,973,251)	$ 288,500,510
47	1830	Poles, Towers & Fixtures	$ 520,319,953	$ 51,616,068	($ 7,846,443)	$ 564,089,579	($ 103,280,750)	($ 13,931,532)	$ 1,028,747	($ 116,183,535)	$ 447,906,044
47	1835	Overhead Conductors & Devices	$ 646,174,960	$ 66,835,914	($ 2,991,329)	$ 710,019,545	($ 108,805,769)	($ 15,943,965)	$ 317,902	($ 124,431,831)	$ 585,587,714
47	1840	Underground Conduit	$ 1,770,677,732	$ 160,732,739	($ 753,024)	$ 1,930,657,447	($ 464,910,769)	($ 61,448,629)	$ 108,392	($ 526,251,005)	$ 1,404,406,442
47	1845	Underground Conductors & Devices	$ 1,350,220,319	$ 160,174,347	($ 6,757,459)	$ 1,503,637,207	($ 257,477,345)	($ 39,174,881)	$ 639,251	($ 296,012,975)	$ 1,207,624,232
47	1850	Line Transformers	$ 933,192,608	$ 120,041,479	($ 12,403,105)	$ 1,040,830,982	($ 245,216,960)	($ 37,722,957)	$ 1,732,472	($ 281,207,445)	$ 759,623,537
47	1855	Services (Overhead & Underground)	$ 235,831,075	$ 28,610,882	($ 458,743)	$ 263,983,214	($ 32,941,201)	($ 5,614,902)	$ 26,464	($ 38,529,638)	$ 225,453,576
47	1860	Meters	$ 185,531,295	$ 34,448,189	($ 950,656)	$ 219,028,827	($ 53,163,110)	($ 10,280,739)	$ 130,800	($ 63,313,050)	$ 155,715,778
47	1860	Meters (Smart Meters)	$ 166,907,685	$ 15,315,450	($ 13,248)	$ 182,209,887	($ 104,594,614)	($ 8,220,112)	$ 2,855	($ 112,811,870)	$ 69,398,017
N/A	1905	Land	$ 17,356,057	$ -	$ -	$ 17,356,057	$ -	$ -	$ -	$ -	$ 17,356,057
1	1908	Buildings & Fixtures	$ 273,656,901	$ 5,669,199	$ -	$ 279,326,100	($ 95,342,545)	($ 10,206,842)	$ -	($ 105,549,387)	$ 173,776,713
13	1910	Leasehold Improvements	$ 753,840	$ -	$ -	$ 753,840	($ 753,840)	$ -	$ -	($ 753,840)	$ -
8	1915	Office Furniture & Equipment	$ 32,390,288	$ 2,032,354	$ -	$ 34,422,642	($ 18,514,164)	($ 2,236,894)	$ -	($ 20,751,058)	$ 13,671,584
50	1920	Computer Equipment - Hardware	$ 126,368,592	$ 14,693,358	$ -	$ 141,061,951	($ 98,307,205)	($ 12,730,837)	$ -	($ 111,038,042)	$ 30,023,909
10	1930	Transportation Equipment	$ 70,266,101	$ 8,603,573	$ -	$ 78,869,674	($ 44,662,719)	($ 6,206,575)	$ -	($ 50,869,294)	$ 28,000,380
8	1935	Stores Equipment	$ 7,066	$ -	$ -	$ 7,066	($ 7,066)	$ -	$ -	($ 7,066)	$ -
8	1940	Tools, Shop & Garage Equipment	$ 94,408,264	$ 2,993,952	$ -	$ 97,402,216	($ 32,566,582)	($ 6,324,522)	$ -	($ 38,891,104)	$ 58,511,112
8	1945	Measurement & Testing Equipment	$ 487,847	$ 402	$ -	$ 488,249	($ 482,284)	($ 727)	$ -	($ 483,011)	$ 5,238
8	1950	Service Equipment	$ 1,438,860	$ 94,320	$ -	$ 1,533,180	($ 1,022,120)	($ 98,866)	$ -	($ 1,120,986)	$ 412,194
8	1955	Communications Equipment	$ 53,963,164	$ 3,943,679	$ -	$ 57,906,843	($ 32,206,059)	($ 3,264,598)	$ -	($ 35,470,657)	$ 22,436,186
8	1960	Miscellaneous Equipment	$ 1,855,203	$ -	$ -	$ 1,855,203	($ 405,948)	($ 124,277)	$ -	($ 530,224)	$ 1,324,978
47	1970	Load Management Controls Customer Premises	$ 3,022,834	$ -	$ -	$ 3,022,834	($ 3,022,834)	$ -	$ -	($ 3,022,834)	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 98,750,443	$ 13,749,513	($ 719,484)	$ 111,780,473	($ 33,697,405)	($ 5,806,970)	$ 77,754	($ 39,426,621)	$ 72,353,852
47	2440	Contributions & Grants (Formally known as Account 1995)	($ 506,381,648)	($ 224,655,139)	$ 648,701	($ 730,388,086)	$ 72,848,337	$ 17,625,548	($ 33,068)	$ 90,440,817	($ 639,947,269)
N/A	1609	Capital Contributions Paid	$ 286,636,663	$ 9,979,192	$ -	$ 296,615,855	($ 57,805,910)	($ 11,185,667)	$ -	($ 68,991,576)	$ 227,624,279
N/A	2005	Property Under Capital Leases	$ 18,170,834	$ -	$ -	$ 18,170,834	($ 11,873,973)	($ 89,423)	$ -	($ 11,963,396)	$ 6,207,439
		Sub-Total	**$ 7,454,004,556**	**$ 588,694,720**	**($ 32,608,729)**	**$ 8,010,090,546**	**($ 2,160,243,469)**	**($ 300,320,428)**	**$ 4,138,387**	**($ 2,456,425,510)**	**$ 5,553,665,036**
		Less Socialized Renewable Energy Generation Investments (input as negative)	($ 10,964,769)	$ -	$ -	($ 10,964,769)	$ 2,791,095	$ 730,985	$ -	$ 3,522,080	($ 7,442,690)
		Less Other Non Rate-Regulated Utility Assets (input as negative)	($ 22,664,001)	($ 2,515,682)	$ -	($ 25,179,683)	$ 3,551,885	$ 934,364	$ -	$ 4,486,249	($ 20,693,434)
		Total PP&E	**$ 7,420,375,785**	**$ 586,179,038**	**($ 32,608,729)**	**$ 7,973,946,094**	**($ 2,153,900,489)**	**($ 298,655,079)**	**$ 4,138,387**	**($ 2,448,417,181)**	**$ 5,525,528,913**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)						$ -			
		Total						**($ 298,655,079)**			

10		Transportation
		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	($ 1,759,521)
Stores Equipment	$ -
Net Depreciation	($ 296,895,559)

Notes:
Fixed Asset Continuity Schedule includes monthly billing
Socialized Renewable Energy Generation Investments include Energy Storage program
Other Non Rate-Regulated Utility Assets includes Generation Protection, Monitoring and Control program

GROSS ASSETS

1. BREAKDOWN BY FUNCTION

In accordance with Section 2.2.1.2 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (July 12, 2018) (the "Filing Requirements"), Table 1 below provides a breakdown of Toronto Hydro's gross assets by function for the historical (2015-2017), bridge (2017-2018), and forecast (2020) years. The amounts for construction work-in-progress ("CWIP"), which is not included in rate base, have also been provided.

Table 1: Breakdown of Ending Balance of Gross Assets by Function ($ Millions)

Gross Assets	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Forecast
High Voltage Plant	5.8	6.0	36.9	38.9	39.0	39.1
Distribution Plant	3,047.0	3,471.1	3,803.4	4,265.9	4,590.4	4,996.0
General Plant	354.0	482.3	599.8	707.6	757.2	811.7
Gross Fixed Assets Before CWIP	**3,406.8**	**3,959.4**	**4,440.1**	**5,012.4**	**5,386.6**	**5,846.8**
CWIP	577.7	502.9	485.8	311.5	343.5	367.7
Total Including CWIP	**3,984.5**	**4,462.3**	**4,925.9**	**5,323.9**	**5,730.2**	**6,214.5**

Note: Variances due to rounding may exist

2. BREAKDOWN BY MAJOR PLANT ACCOUNT

Also, in accordance with the Filing Requirements, Appendix A to this schedule provides a detailed breakdown of gross assets by major plant account and Uniform System of Accounts.

Appendix A. Table 2 - Gross Assets Breakdown by Major Plant Account - Detailed by Uniform System of Account

	Description	2015 Actuals MIFRS	2016 Actuals MIFRS	2017 Actuals MIFRS	2018 Bridge MIFRS	2019 Bridge MIFRS	2020 Forecast MIFRS
1815	Transformer Station Equipment	5.8	6.0	36.9	38.9	39.0	39.1
	Subtotal High Voltage Plant	5.8	6.0	36.9	38.9	39.0	39.1
1805	Land	7.1	7.1	7.0	7.0	7.0	7.0
1808	Buildings and Fixtures	51.4	105.1	116.6	141.0	142.4	145.4
1810	Leasehold Improvements	-	-	-	-	-	-
1820	Distribution Station Equipment	149.9	156.8	184.5	228.8	251.0	277.9
1830	Poles, Towers and Fixtures	311.0	339.5	362.5	386.5	408.2	435.8
1835	O/H Conductors and Devices	299.4	349.5	390.5	432.2	470.6	515.0
1840	U/G Conduit	952.0	1,051.0	1,127.9	1,225.7	1,321.9	1,432.3
1845	U/G Conductors and Devices	609.9	690.6	782.8	858.3	950.2	1,043.7
1850	Line Transformers	412.4	465.3	515.4	574.4	645.6	714.2
1855	Services	93.3	109.1	122.1	139.6	155.8	175.3
1860	Meters (includes Smart Meters)	168.7	180.9	199.7	223.0	248.0	275.7
1970	Load Management-Customer	3.0	3.0	3.0	3.0	3.0	3.0
1975	Load Management-Utility	-	-	-	-	-	-
1980	System Supervisory Equipment	25.4	28.2	33.6	42.1	49.1	55.2
1609	Capital Contributions Paid	21.7	75.6	75.6	186.2	191.8	238.0
2440	Contributed Capital	(58.2)	(90.5)	(118.0)	(182.1)	(254.4)	(329.2)
	Subtotal Distribution Plant	3,047.0	3,471.1	3,803.4	4,265.9	4,590.4	4,989.4
1611	Computer Software	101.6	113.6	137.0	232.7	267.6	298.3
1905	Land	17.7	17.7	17.7	17.4	17.4	17.4
1908	Buildings and Fixtures	126.9	184.5	246.7	238.7	239.7	242.2
1910	Leasehold Improvements	0.8	0.8	0.8	0.8	0.8	0.8
1915	Office Furniture and Equipment	10.8	15.4	19.0	19.9	20.2	21.1
1920	Computer Equipment	27.3	47.2	58.7	70.2	77.9	89.0
1930	Transportation Equipment	26.6	29.9	33.7	38.4	41.5	46.2
1935	Stores Equipment	0.0	0.0	0.0	0.0	0.0	0.0
1940	Tools, Shop and Garage Equipment	14.7	17.8	21.2	23.7	25.4	35.0
1945	Measurement & Test Equipment	0.5	0.5	0.5	0.5	0.5	0.5
1950	Power Operated Equipment	0.6	0.7	0.8	1.0	1.1	1.2
1955	Communication Equipment	8.0	35.9	45.4	46.0	46.6	48.3
1960	Miscellaneous Equipment	0.3	0.3	0.3	0.3	0.3	0.3
2005	Property Under Capital Leases	18.2	18.2	18.2	18.2	18.2	18.2
	Subtotal General Plant	354.0	482.3	599.8	707.6	757.2	818.3
1610	Miscellaneous Intangible Plant	-	-	-	-	-	-
	GROSS FIXED ASSETS BEFORE CWIP	3,406.8	3,959.4	4,440.1	5,012.4	5,386.6	5,846.8
2055	Construction Work-in-Process	577.7	502.9	485.8	311.5	343.5	367.7
	TOTAL INCLUDING CWIP	3,984.5	4,462.3	4,925.9	5,323.9	5,730.2	6,214.5

WORKING CAPITAL ALLOWANCE ("WCA")

Toronto Hydro has determined the Working Capital Allowance ("WCA") included in its 2020 rate base based on an updated Lead-Lag Study performed by Navigant Consulting Inc. ("Navigant"), which is filed as Exhibit 2A, Tab 3, Schedule 2.

Navigant used a full year of Toronto Hydro's financial information to determine the revenue lead and expense lag for various detailed revenue and cost components. The time periods chosen were intended to provide the most recent actual data available at the time of analysis. Navigant's methodology is generally the same as that employed in the last two Lead-Lag studies performed for Toronto Hydro.[1] Toronto Hydro confirms that for the purposes of the Lead-Lag Study, leads and lags were measured in days, and were dollar weighted.

The current Lead-Lag Study demonstrates a decrease in the WCA rate approved in the utility's last rebasing application from 8.0 percent of controllable expenses plus cost of power to 6.21 percent. Applying the lead/lag days to Toronto Hydro's forecast revenues and expenses produces a WCA percentage of 6.42 percent for the 2020 test year. The reduction was achieved primarily as a result of:

1) The OEB's requirement for utilities to transition to monthly billing in late 2016;[2] plus
2) The expiration of the Debt Retirement Charge as of April 1, 2018; minus
3) The impact of the OEB's Winter Disconnection Moratorium.

[1] EB-2007-0680 and EB-2014-0116
[2] Please refer to Exhibit 9, Tab 1 for Toronto Hydro's Deferral and Variance Account evidence which includes the discussion of the transition to monthly billing.

Table 1 below presents a detailed calculation of the WCA for 2020. To calculate the WCA, the Cost of Power is determined by using the split between RPP and non-RPP customers, the 2020 forecast RPP, HOEP, and the most recent OEB approved UTRs. Details of the Cost of Power calculation are provided in Appendix A. Toronto Hydro has used the same methodology as used in its EB-2014-0116 application, and reflects the implementation of the Fair Hydro Plan.

Table 1: Working Capital Allowance Calculation

	2020 Expenses ($ Millions)	Working Capital Factor		Expenses times Working Capital Factor ($ Millions)
Cost of Power	3,384.0	5.0%		169.2
OM&A	277.5	4.29%		11.9
Interest on Long Term Debt	89.2	6.99%		6.2
Income and Capital Taxes	34.7	16.69%		5.8
Sub-Total Working Capital Requirement				**193.1**
HST at 13%		**Net Lag Days**	**Expenses * Net Lag Days/365 * 13% HST**	
Revenue	4,182.0	-10.07	-15.0	
Cost of Power	3,384.0	46.03	55.5	
Eligible OM&A Expenses	106.3	41.58	1.6	
HST Working Capital Requirement				**42.1**
Total Working Capital				**235.2**
Working Capital as % of Cost of Power and Controllable Expenses				**6.42%**

Table 2 below provides a comparison of the WCA requirements for the 2020 test year included in the utility's rate base calculations (Exhibit 2A, Tab 1, Schedule 1), and the last OEB-approved WCA in 2015.

Table 2: Working Capital Allowance ($ Millions)

	2015 OEB Approved	2020 Test Year
Working Capital Allowance	240.2	235.2

Cost of Power 2018-2020

	2018	2019	2020	Notes & Assumptions
Quantities				
Total Purchased Energy (kWh)	24,378,163,944	24,123,762,642	24,036,018,049	From Final CIR Load Forecast
RPP	10,450,785,029	10,156,104,072	10,119,163,599	
Non-RPP	13,927,378,915	13,967,658,570	13,916,854,451	
System Network (kW)	44,537,292	44,120,546	43,836,438	From Final CIR Load Forecast
Line Connection (kW)	45,679,633	44,073,209	43,788,978	From Final CIR Load Forecast
Transformer Connection (kW)	20,698,744	45,203,542	44,912,009	From Final CIR Load Forecast
Own Use kWh	20,698,744	20,698,744	20,698,744	Equal to April 2017-March 2018 Annual Amount
Prices				
HOEP ($/kWh)	$ 0.01954	$ 0.01974	$ 0.01895	Based on Navigant Apr 2018 Report for 2018/2019, weighted average. 2020 escalated at factor of 0.96
GA ($/kWh)	$ 0.09847	$ 0.10597	$ 0.10989	Based on Navigant Apr 2017 Report, 3.7% increase annually in 2019-20
Network Rate ($/kW)	$ 3.52	$ 3.63	$ 3.74	Based on most recent 2018 actuals, assumes 3% annual increase 2019-20
Line Connection Rate ($/kW)	$ 0.88	$ 0.91	$ 0.94	Based on most recent 2018 actuals, assumes 3% annual increase 2019-20
Transformer Connection Rate ($/kW)	$ 2.13	$ 2.19	$ 2.26	Based on most recent 2018 actuals, assumes 3% annual increase 2019-20
Wholesale Market Services Rate ($/kWh)	$ 0.0036	$ 0.0036	$ 0.0036	Assumed constant at most recent actual amount
Ontario Electricity Support Program Charge	$ -	$ -	$ -	Assumed constant at most recent actual amount
Rural Rate Protection Charge ($/kWh)	$ 0.0003	$ 0.0003	$ 0.0003	Assumed constant at most recent actual amount
Other				
Switch Gear Credit ($)	$ (10,913,609.04)	$ (10,913,609.04)	$ (10,913,609.04)	Assumed constant at 2018 forecast amount, based on most recent actuals
Hydro One Low Voltage ($)	$ 328,146.44	$ 328,146.44	$ 328,146.44	Assumed constant at 2018 forecast amount, based on most recent actuals
Agincourt Shortfall Load Transfer ($)	$ 1,165,983.97	$ 1,165,983.97	$ 1,165,983.97	Assumed constant at 2018 forecast amount, based on most recent actuals
Hydro One MSP costs ($)	$ 434,250.00	$ 434,250.00	$ 434,250.00	Assumed constant at 2018 forecast amount, based on most recent actuals
RPP % of Total Purchased Energy kWh	42.87%	42.10%	42.10%	2018 uses 3 months actuals. Remainder of forecast is average of 12 months actuals April 17 - March 18.
Class A % of total GA amount	12.35%	15.50%	15.50%	2018 uses 3 months actuals. Remainder of forecast is average of months actuals Jul 17 - March 18.
Cost of Power				
Energy (HOEP)	**2,876,844,040**	**3,032,598,202**	**3,096,810,180**	
RPP	1,229,907,408	1,276,723,843	1,303,757,086	
(a) HOEP - EE 2001	205,736,637	200,481,494	191,762,198	
(b) GA - EE 2003	1,024,170,771	1,076,242,349	1,111,994,888	
Non-RPP :	1,646,936,632	1,755,874,359	1,793,053,094	
(a) HOEP - EE 2005	270,689,339	275,721,580	263,729,959	
(b) GA - EE 2095	1,376,247,293	1,480,152,779	1,529,323,136	
GA - Class A	169,949,437	229,423,681	237,045,086	
GA - Class B	1,206,297,856	1,250,729,098	1,292,278,050	
GA Modifier	-108,190,292	-107,061,259	-106,671,848	
Transmission	284,446,121	290,274,731	297,625,829	
Smart Metering Entity Charge	5,195,067	5,236,050	5,286,155	
Wholesale Market Services	87,761,390	86,845,546	86,529,665	
Rural Rate Protection Charge	7,313,449	7,237,129	7,210,805	
THESL Own Use Deduction	-2,530,174	-2,682,764	-2,747,560	
Total Cost of Power Expense	**3,150,839,602**	**3,312,447,633**	**3,384,043,227**	

Working Capital Requirements of Toronto Hydro Electric System Limited's Distribution Business

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TABLE OF CONTENTS

Section I: Executive Summary 1

Summary 1

Organization of the Report 1

Section II: Working Capital Methodology 2

Key Concepts 2

Mid-Point Method 2

Statutory Approach 2

Expense Lead Components 3

Dollar Weighting 3

Methodology 3

Section III: Revenue Lags 4

Retail Customer Revenue Lag 4

Service Lag 5

Billing Lag 5

Collections Lag 5

Payment Processing Lag 6

Section IV: Expense Leads 7

Cost of Power 7

IESO Cost of Power 8

Hydro One Low Voltage Expense 9

Payments to Non-Utility Generators 10

Payments to DG 10

OM&A Expenses 11

Payroll and Benefits 12

Property Taxes 12

Non-Resident Withholding Taxes 13

Corporate Procurement Card 14

Lease Payments 15

Consulting and Contract Staff 16

Miscellaneous OM&A 17

Interest Expenses 18

Payments in Lieu of Taxes ("PILs") 18

Harmonized Sales Tax 19

Section V: Toronto Hydro – Working Capital Requirements 20

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Section VI: Appendix – Detailed Data Tables 21

IESO Credits 21
Other External Revenues 21
Payroll 22
Withholdings 23
Pensions 24
Benefits – Health and Dental 25
Benefits – Group Life Insurance 26
Benefits – WSIB 27
Benefits – Employee Health Tax 28
Other Benefits – Long-term Disability 29
Other Benefits – Accidental Death and Dismemberment 29
Other Benefits – Employee Assistance Program 30
Lease Payments – Islington Monogram Holdings 30
Lease Payments – Davpart Inc 31
Lease Payments – Other Annual Leases 31

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LIST OF TABLES

Table 1: Summary of Working Capital Requirements....1
Table 2: Summary of Revenue Lag....4
Table 3: Retail Customer Revenue Lag....5
Table 4: Summary of Cost of Power Expenses....7
Table 5: Summary of IESO Cost of Power Expenses....8
Table 6: Summary of Hydro One Low Voltage Expenses....9
Table 7: Summary of Non-Utility Generator Expenses....10
Table 8: Summary of DG Cost of Power Expenses....10
Table 9: Summary of OM&A Expenses....11
Table 10: Summary of Payroll and Benefits Expenses....12
Table 11: Summary of Property Tax Expenses....12
Table 12: Summary of Non-Resident Withholding Tax Expenses....13
Table 13: Summary of Corporate Procurement Card Expenses....14
Table 14: Summary of Lease Payment Expenses....15
Table 15: Summary of Consulting and Contract Staff Expenses....16
Table 16: Summary of Miscellaneous OM&A Expenses....17
Table 17: Summary of Interest Expenses....18
Table 18: Summary of Payments in Lieu of Taxes Expenses....18
Table 19: Summary of HST Working Capital Amounts....19
Table 20: THESL Distribution Working Capital Requirements....20
Table 21: Summary of IESO Credits....21
Table 22: Summary of Other External Revenues....21
Table 23: Summary of Payroll Expenses....22
Table 24: Summary of Withholdings Expenses....23
Table 25: Summary of Pension Expenses....24
Table 26: Summary of Benefits, Health and Dental Expenses....25
Table 27: Summary of Benefits, Group Life Insurance Expenses....26
Table 28: Summary of Benefits, WSIB Expenses....27
Table 29: Summary of Benefits, Employee Health Tax Expenses....28
Table 30: Summary of Other Benefits, Long-term Disability Expenses....29
Table 31: Summary of Other Benefits, Accidental Death and Dismemberment Expenses....29
Table 32: Summary of Other Benefits, Employee Assistance Program Expenses....30
Table 33: Summary of Lease Payments, Islington Monogram Holdings....30
Table 34: Summary of Lease Payments, Davpart Inc....31
Table 35: Summary of Lease Payments, Other Annual Leases....31

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SECTION I: EXECUTIVE SUMMARY

Summary

In preparation for an upcoming rate filing before the OEB, THESL retained Navigant to prepare an update to its prior working capital study. This report provides the results of the update and the working capital requirements of THESL's distribution business.

Listed below are key findings and conclusions from this study:

1. In terms of lead-lag days, the results from this study are generally comparable with THESL's previous working capital study (EB-2014-0116);
2. The approach and methods used in this study are generally consistent with THESL's prior lead-lag study as well as studies performed by other local distribution companies in Ontario; and,
3. Results from the lead-lag study identify the following working capital amounts.

Table 1: Summary of Working Capital Requirements

Year	
Percentage of OMA	**6.21%**
Working Capital Requirement $(M)	**$211.54**

Organization of the Report

Section II of this report discusses the methodology used within this working capital lead-lag study.

Section III of this report discusses the lag times associated with THESL's collections of revenues. This includes a description of the sources of revenues and how an overall revenue lag is derived.

Section IV presents the lead times associated with THESL's expenses. This includes a description of the types of expenses incurred by THESL's distribution operations and how expenses are treated for the purposes of deriving an overall expenses lead. This includes the working capital requirement associated with the Harmonized Sales Tax ("HST").

Section V presents the working capital requirements of THESL's distribution business.

Section VI presents a supporting appendix for this study that includes detailed data tables.

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SECTION II: WORKING CAPITAL METHODOLOGY

Working capital is the amount of funds that are required to finance the day-to-day operations of a regulated utility and which are included as part of a rate base for ratemaking purposes. A lead-lag study is the most accurate basis for the determination of working capital and was used by Navigant for this purpose.

A lead-lag study analyzes the time between the date customers receive service and the date that customers' payments are available to THESL (or "lag") together with the time between which THESL receives goods and services from its vendors and pays for them at a later date (or "lead")[1]. "Leads" and "Lags" are both measured in days and are dollar-weighted where appropriate. The dollar-weighted net lag (lag minus lead) days is then divided by 365 (or 366 for leap years) and then multiplied by the annual test year expenses to determine the amount of working capital required. The resulting amount of working capital is then included in THESL's rate base for the purpose of deriving revenue requirement.

Key Concepts

Mid-Point Method

When a service is provided to (or by) THESL over a period of time, the service is deemed to have been provided (or received) evenly over the midpoint of the period, unless specific information regarding the provision (or receipt) of that service indicates otherwise. If both the service end date ("Y") and the service start date ("X") are known, the mid-point of a service period can be calculated using the formula:

$$\text{Mid-Point} = \frac{([Y-X]+1)}{2}$$

When specific start and end dates are unknown, but it is known that a service is evenly distributed over the mid-point of a period, an alternative formula that is generally used is shown below. The formula uses the number of days in a year ("A") and the number of periods in a year ("B"):

$$\text{Mid-Point} = \frac{A/B}{2}$$

Statutory Approach

In conjunction with the mid-point method, it is important to note that not all areas of this study may utilize dates on which actual payments were made to (or by) THESL. In some instances, the due dates for payments are established by statute or by regulation. In these instances, the due date established by statute has been used in lieu of when payments were made.

[1] A positive lag (or lead) indicates that payments are received (or paid for) after the provision of a good or service.

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Expense Lead Components

As used in this study, expense leads are defined to consist of two components:

1. Service Lead component (services are assumed to be provided to THESL evenly around the mid-point of the service period); and,
2. Payment Lead component (the time period from the end of the service period to the time payment was made and when funds have left THESL's possession).

Dollar Weighting

Both leads and lags should be dollar-weighted where appropriate and where data is available to accurately reflect the flow of dollars. For example, suppose that a particular transaction has a lead time of 100 days and has a dollar value of $100. Further, suppose that another transaction has a lead time of 30 days with a dollar value of $1 Million. A simple un-weighted average of the two transactions would give us a lead time of 65 days ([100+30]/2). However, when these two transactions are dollar weighted, the resulting lead time would be closer to 30 days which is more representative of how the dollars flow.

Methodology

Performing a lead-lag study requires two key undertakings:

1. Developing an understanding of how the regulated distribution business operates in terms of products and services sold to customers/purchased from vendors, and the policies and procedures that govern such transactions; and,
2. Modeling such operations using data from a relevant period of time and a representative data set. It is important to ascertain and factor into the study whether (or not) there are known changes to existing business policies and procedures going forward. Where such changes are known and material, they should be factored into the study.

To develop an understanding of THESL's operations, interviews with personnel within THESL's Accounts Payable, Customer Service, Wholesale Market Operations, Human Resources, Payroll, Treasury, and Tax Departments were conducted. Key questions that were addressed during the course of the interviews included:

1. What is being sold (or purchased)? If a service is being provided to (or by) THESL, over what time period was this service provided;
2. Who are the buyers (or sellers);
3. What are the terms for payment? Are the terms for payment driven by industry norms or by company policy? Is there flexibility in the terms for payment;
4. Are any changes to the terms for payment expected? Are these terms driven by industry or internally? What is the basis for any such changes;
5. Are there any new rules or regulations governing transactions relating to distribution operations that are expected to materialize over the time frame considered in this report; and,
6. How are payments made (or received)? Payment types have different payment lead times (i.e., internet payments have shorter deposit times than cheque deposit times)

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SECTION III: REVENUE LAGS

A distribution utility providing service to its customers generally derives its revenue from bills paid for service by its customers. A revenue lag represents the number of days from the date service is rendered by THESL until the date payments are received from customers and funds are available to THESL.

Interviews with THESL personnel indicate that its distribution business receives funds from the following funding streams:

1. Retail Customers;
2. IESO Credits (i.e., Ontario Electricity Support Program, Ontario Rebate for Electricity Consumers); and,
3. Other External Revenues (i.e., Hydro One Substation Monitoring, Demand Billables, Distributed Generation claims).

The lag times associated with the funding streams above were weighted and combined to calculate an overall revenue lag time as shown below. Additional details regarding IESO Credits and Other External Revenues can be found in the Appendix.

Table 2: Summary of Revenue Lag

Description	Lag Days	Revenues ($M)	Weighting (%)	Weighted Lag
Retail Customer Revenues	50.90	$4,077.72	93.81%	47.75
IESO Credits	62.82	$157.74	3.63%	2.28
Other External Revenues	32.54	$111.10	2.56%	0.83
Total		**$4,346.55**	**100.00%**	**50.87**

Retail Customer Revenue Lag

Retail customer revenue lag consists of the following components:

1. Service Lag;
2. Billing Lag;
3. Collections Lag; and,
4. Payment Processing Lag.

The lag times for each of the above components, when added together, results in the retail customer revenue lag for the purpose of calculating the working capital requirements for THESL's distribution business. The components are intended to represent a continuous process from the end date of the customer's previous billing cycle to the date in which the payment is available to THESL. Table 3 below provides a summary of THESL's retail customer revenue lag along with a description for each component. Based upon discussions with THESL, it has also been noted that the Ontario Fair Hydro plan, which came into effect in July 1, 2017, is expected to have an impact on the retail customer revenue lag and consequently the working capital calculation, however at the time of this study there is insufficient data to make an estimate of the impact and hence the impacts have not been quantified. The intent is to update the study when THESL data reflecting the Ontario Fair Hydro Plan is available.

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Table 3: Retail Customer Revenue Lag

Revenue Lag Component	Description	Lag Days
Service Lag	The average time from the provision of electricity to a customer until the meter is read	15.21
Billing Lag	The average time from the meter read until the bill is generated and provided to the customer	12.49
Collections Lag	The average time from when a bill is provided to the customer until the customer initiate payment to the utility	21.86
Payment Lag	The average time from when the customer provides payment to the utility until when the payment is made liquid and available to the utility	1.34
Total		**50.90**

The estimation of each component of the retail customer revenue lag is described below.

Service Lag

The service lag is the time from THESL's provision of electricity to a customer, to the time the customer's service period ends, which is typically defined as when the meter is read. Customer service staff at THESL provided data which documented that all customer have been moved to monthly billing. As such the service lag was estimated to be 15.21, which is a departure from what was calculated in the prior study which had a combination of monthly and bi-monthly customers.

Billing Lag

The billing lag is the time period from when the customer's service period ends, which is typically defined as when the meter is read, and the time that the customer's bill is generated in the customer information system. Interviews with billing staff at THESL and analysis of meter billing data indicated that THESL customers have an average billing lag of 12.49 days, which is similar to what was calculated in the prior study indicating no significant changes to billing operations and practices.

Collections Lag

The collections lag is the time period from when the bill is generated in the customer information system, until the time when the customer provides a payment to THESL. The collections lag is measured by analyzing the receivables aging data provided by THESL. THESL's collection lag was calculated to be 21.86 days, which is shorter than what was calculated in the prior study.

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Payment Processing Lag

The payment processing lag is the time period from when the customer provides a payment to THESL until such time as the funds associated with that payment are liquid and available to the utility. The payment processing lag is measured by analyzing the payment methods used by THESL customers. Some examples of the payment methods used include credit card, pre-authorized payment and branch payment. THESL provided the processing time associated with each method of payment and the number of customers using each method of payment. Using such data provided by THESL, a customer-weighted average payment processing lag of 1.34 days was determined for THESL's distribution operations. This number is very similar to that from the prior study indicating that there are no significant changes to the way that customers opt to pay for their electricity bills.

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SECTION IV: EXPENSE LEADS

The determination of working capital requires both a measurement of the lag in the collection of revenues for services provided by THESL's distribution business, and the lead times associated with payments for services provided to THESL. Therefore, in conjunction with the calculation of the revenue lag, expense lead times were calculated for the following items:

1. Cost of Power;
2. Operating, Maintenance and Administration ("OM&A") Expenses;
3. Payments in Lieu of Taxes;
4. Interest on Long Term Debt; and,
5. Harmonized Sales Tax.

The expense lead calculation in this study does not take into account the Debt Retirement Charge, which was incorporated into the prior study. The Debt Retirement Charge was not included as it is expected to completely expire by April 1, 2018[2].

Cost of Power

For the purpose of the distribution lead-lag study, cost of power expenses were considered to consist of payments made by THESL to its vendors in the following categories:

1. Independent Electricity System Operator ("IESO") Cost of Power Expenses;
2. Hydro One Low Voltage Charges;
3. Payments to Non-Utility Generators; and,
4. Payments to Distributed Generators ("DG") such as Residential Standard Offer Program ("RESOP"), Feed-in Tariff ("FIT"), and micro Feed-in Tariff ("mFIT") generators.

Expense lead times were calculated individually for each of the items listed above and then dollar-weighted to derive a composite cost of power expense lead time of 32.63 days.

Table 4: Summary of Cost of Power Expenses

Description	Lag Days	Expenses ($M)	Weighting (%)	Weighted Lag
IESO Cost of Power	32.73	$3,000.26	98.06%	32.10
Hydro One Low Voltage Expense	32.79	$0.35	0.01%	0.00
Payments to Non-Utility Generators	32.89	$0.03	0.00%	0.00
Payments to DG	27.51	$58.88	1.92%	0.53
Total		**$3,059.51**	**100.00%**	**32.63**

[2] https://www.fin.gov.on.ca/en/guides/drc/101.html

IESO Cost of Power

THESL purchases its power supply requirements on a monthly basis from the IESO and pays for such supplies on a schedule defined by the IESO's billing and settlement procedures. Taking the information on actual payments made by THESL, a dollar-weighted cost of power expense lead time of 32.73 days was calculated. Table 5 below summarizes the components of the IESO cost of power expense lead calculation.

Table 5: Summary of IESO Cost of Power Expenses

Delivery Period	Costs ($M)	Weighting (%)	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead
Jan-16	$254.69	8.49%	2/17/2016	15.50	17.00	32.50	2.76
Feb-16	$240.10	8.00%	3/16/2016	14.50	16.00	30.50	2.44
Mar-16	$250.83	8.36%	4/18/2016	15.50	18.00	33.50	2.80
Apr-16	$239.57	7.99%	5/17/2016	15.00	17.00	32.00	2.56
May-16	$238.44	7.95%	6/16/2016	15.50	16.00	31.50	2.50
Jun-16	$253.99	8.47%	7/19/2016	15.00	19.00	34.00	2.88
Jul-16	$217.24	7.24%	8/17/2016	15.50	17.00	32.50	2.35
Aug-16	$298.28	9.94%	9/19/2016	15.50	19.00	34.50	3.43
Sept-16	$260.03	8.67%	10/19/2016	15.00	19.00	34.00	2.95
Oct-16	$240.53	8.02%	11/17/2016	15.50	17.00	32.50	2.61
Nov-16	$236.64	7.89%	12/16/2016	15.00	16.00	31.00	2.45
Dec-16	$269.91	9.00%	1/18/2017	15.50	18.00	33.50	3.01
Total	**$3,000.26**	**100.00%**					**32.73**

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Hydro One Low Voltage Expense

THESL provides payment to Hydro One for low voltage expenses on a monthly basis. Based upon information on payments made by THESL, a dollar-weighted Hydro One low voltage expense lead time of 32.79 days was calculated. Table 6 below summarizes the components of the Hydro One low voltage expense lead calculation.

Table 6: Summary of Hydro One Low Voltage Expenses

Delivery Period	Costs ($M)	Weighting (%)	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead
Jan-16	$0.03	8.64%	2/17/2016	15.50	17.00	32.50	2.81
Feb-16	$0.02	6.79%	3/16/2016	14.50	16.00	30.50	2.07
Mar-16	$0.02	6.66%	4/18/2016	15.50	18.00	33.50	2.23
Apr-16	$0.02	6.77%	5/17/2016	15.00	17.00	32.00	2.17
May-16	$0.02	6.33%	6/16/2016	15.50	16.00	31.50	1.99
Jun-16	$0.03	8.35%	7/19/2016	15.00	19.00	34.00	2.84
Jul-16	$0.03	8.78%	8/17/2016	15.50	17.00	32.50	2.85
Aug-16	$0.03	9.74%	9/19/2016	15.50	19.00	34.50	3.36
Sept-16	$0.04	10.96%	10/19/2016	15.00	19.00	34.00	3.72
Oct-16	$0.03	8.60%	11/17/2016	15.50	17.00	32.50	2.79
Nov-16	$0.03	8.53%	12/16/2016	15.00	16.00	31.00	2.65
Dec-16	$0.03	9.84%	1/18/2017	15.50	18.00	33.50	3.30
Total	**$0.35**	**100.00%**					**32.79**

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Payments to Non-Utility Generators

THESL purchases power supply from non-utility generators on a monthly basis and pays for such supplies on a monthly basis. A dollar-weighted expense lead time of 32.89 days was calculated. Table 7 below summarizes the components of the non-utility generator expense lead calculation.

Table 7: Summary of Non-Utility Generator Expenses

Delivery Period	Costs ($M)	Weighting (%)	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead
Jan-16	$0.001	3.98%	2/17/2016	15.50	17.00	32.50	1.29
Feb-16	$0.001	5.29%	3/16/2016	14.50	16.00	30.50	1.61
Mar-16	$0.000	1.84%	4/18/2016	15.50	18.00	33.50	0.62
Apr-16	$0.000	1.86%	5/17/2016	15.00	17.00	32.00	0.60
May-16	$0.001	5.43%	6/16/2016	15.50	16.00	31.50	1.71
Jun-16	$0.002	7.01%	7/19/2016	15.00	19.00	34.00	2.38
Jul-16	$0.003	10.26%	8/17/2016	15.50	17.00	32.50	3.34
Aug-16	$0.005	19.51%	9/19/2016	15.50	19.00	34.50	6.73
Sept-16	$0.002	8.03%	10/19/2016	15.00	19.00	34.00	2.73
Oct-16	$0.001	4.83%	11/17/2016	15.50	17.00	32.50	1.57
Nov-16	$0.004	15.91%	12/16/2016	15.00	16.00	31.00	4.93
Dec-16	$0.004	16.04%	1/18/2017	15.50	18.00	33.50	5.37
Total	**$0.026**	**100.00%**					**32.89**

Payments to DG

THESL purchases power supply from RESOP, FIT and mFIT customers. A dollar-weighted expense lead time of 27.51 days was calculated. Table 8 below summarizes the components of the DG expense lead calculation.

Table 8: Summary of DG Cost of Power Expenses

Description	Lag Days	Revenues ($M)	Weighting (%)	Weighted Lag
RESOP	35.97	$0.18	0.31%	0.11
FIT	27.86	$54.87	93.20%	25.97
mFIT	22.03	$3.83	6.50%	1.43
Total		**$58.88**	**100.00%**	**27.51**

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OM&A Expenses

For the purpose of this distribution lead-lag study, OM&A expenses were considered to consist of payments made by THESL to its vendors in the following categories:

1. Payroll & Benefits;
2. Property Taxes;
3. Payments-in-lieu of Property Taxes;
4. Non-Resident Withholding Tax;
5. Corporate Procurement Card;
6. Lease Payments;
7. Consulting and Contract Staff; and,
8. Miscellaneous OM&A.

Expense lead times were calculated individually for each of the items listed above and then dollar-weighted to derive a composite expense lead time of 35.19 days for OM&A expenses.

Table 9: Summary of OM&A Expenses

Description	Amounts ($M)	Weighting (%)	Expense Lead Time	Weighted Lead Time
Payroll & Benefits	$205.09	59.46%	32.73	19.46
Property Tax	$5.85	1.70%	-30.39	-0.52
Non-Resident Withholding Tax	$0.08	0.02%	29.60	0.01
Corporate Procurement Card	$0.15	0.04%	32.76	0.01
Lease Payments	$2.83	0.82%	34.74	0.28
Consulting and Contract Staff	$83.27	24.14%	48.06	11.60
Miscellaneous OM&A	$47.63	13.81%	31.41	4.34
Total	**$344.90**	**100.00%**		**35.19**

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Payroll and Benefits

The following items were considered to be expenses related to the payroll and benefits of THESL's distribution business:

1. Two types of Payroll including Basic and Management payroll;
2. Three types of Payroll Withholdings including the Canada Pension Plan, Employment Insurance, and Income Tax withholdings;
3. Pension related expenses which include contributions made by THESL to the THESL Pension Plan;
4. Group Health, Dental, and Life Insurance related administrative fees and claims, payments made by THESL to the Workplace Safety and Insurance Board ("WSIB") and payments made by THESL on account of the Employer Health Tax ("EHT"); and,
5. Other Benefits such as Long-term Disability ("LTD"), Accidental Death and Dismemberment ("AD&D"), and the Employee Assistance Program ("EAP").

When all the above expenses were dollar-weighted using actual payment data, the weighted average expense lead time associated with payroll and benefits was determined to be 32.73 days as shown in Table 10, below. Additional detail can be found in the Appendix.

Table 10: Summary of Payroll and Benefits Expenses

Description	Amounts ($M)	Weighting (%)	Expense Lead Time	Weighted Lead Time
Payroll	$100.90	49.20%	21.39	10.52
Payroll Withholdings	$50.07	24.42%	38.24	9.34
Pensions	$33.34	16.26%	71.89	11.69
Benefits	$18.99	9.26%	11.44	1.06
Other Benefits	$1.78	0.87%	13.89	0.12
Total	**$205.09**	**100.00%**		**32.73**

Property Taxes

THESL makes property tax payments to the City of Toronto and taxing authorities in the Province of Ontario. These payments are made in the current year for the current year and are typically made in installments. Using the payment dates and amounts associated with THESL's distribution business, a dollar-weighted expense lead (-lag) time of negative 30.39 days was determined. Table 11, below summarizes the components of the property tax expense lead calculation. Additional detail can be found in the Appendix.

Table 11: Summary of Property Tax Expenses

Description	Amounts ($M)	Weighting (%)	Expense Lead Time	Weighted Lead Time
Property Taxes	$5.81	99.30%	-30.67	-30.46
Payments in Lieu of Property Taxes	$0.04	0.70%	9.23	0.06
Total	**$5.85**	**100.00%**		**-30.39**

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Non-Resident Withholding Taxes

THESL makes non-resident withholding tax payments to the relevant taxing authority. These payments are made on a monthly basis. Using actual payment dates and amounts provided by THESL, a dollar-weighted expense lead time of 29.60 days was determined. Table 12 below summarizes the components of the non-resident withholding tax expense lead calculation.

Table 12: Summary of Non-Resident Withholding Tax Expenses

Delivery Period	Costs ($M)	Weighting (%)	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead
Jan-16	$0.005	6.68%	1/15/2016	15.50	15.00	30.50	2.04
Feb-16	$0.012	14.41%	2/12/2016	15.50	12.00	27.50	3.96
Mar-16	$0.006	7.00%	3/15/2016	14.50	15.00	29.50	2.06
Apr-16	$0.001	1.58%	4/15/2016	15.50	15.00	30.50	0.48
May-16	$0.001	1.50%	5/13/2016	15.00	13.00	28.00	0.42
Jun-16	$0.019	23.14%	6/14/2016	15.50	14.00	29.50	6.83
Jul-16	$0.008	9.63%	7/15/2016	15.00	15.00	30.00	2.89
Aug-16	$0.022	26.45%	8/15/2016	15.50	15.00	30.50	8.07
Sept-16	$0.001	1.51%	9/15/2016	15.50	15.00	30.50	0.46
Oct-16	$0.002	1.96%	10/14/2016	15.00	14.00	29.00	0.57
Nov-16	$0.003	3.46%	11/14/2016	15.50	14.00	29.50	1.02
Dec-16	$0.002	2.69%	12/15/2016	15.00	15.00	30.00	0.81
Total	**$0.082**	**100.00%**					**29.60**

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Corporate Procurement Card

Procurement (or charge) cards are used by the THESL's employees for a variety of company related reasons including, and not limited to, purchases of materials in the field, incidental expenses, and to settle charges for travel and accommodation. Based on invoice and payment information provided by THESL, a dollar-weighted expense lead time of 32.76 days was determined. Table 13 below summarizes the components of the corporate procurement card expense lead calculation.

Table 13: Summary of Corporate Procurement Card Expenses

Delivery Period	Costs ($M)	Weighting (%)	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead
Jan-16	$0.010	6.63%	2/7/2016	15.50	18.00	33.50	2.22
Feb-16	$0.009	6.32%	3/7/2016	15.50	16.00	31.50	1.99
Mar-16	$0.016	10.88%	4/7/2016	14.50	18.00	32.50	3.54
Apr-16	$0.007	4.66%	5/7/2016	15.50	17.00	32.50	1.51
May-16	$0.009	5.98%	6/7/2016	15.00	18.00	33.00	1.97
Jun-16	$0.012	8.52%	7/7/2016	15.50	17.00	32.50	2.77
Jul-16	$0.009	6.30%	8/7/2016	15.00	18.00	33.00	2.08
Aug-16	$0.011	7.71%	9/7/2016	15.50	18.00	33.50	2.58
Sept-16	$0.009	5.93%	10/7/2016	15.50	17.00	32.50	1.93
Oct-16	$0.017	11.68%	11/7/2016	15.00	18.00	33.00	3.86
Nov-16	$0.019	12.97%	12/7/2016	15.50	17.00	32.50	4.22
Dec-16	$0.018	12.41%	1/7/2017	15.00	18.00	33.00	4.10
Total	**$0.146**	**100.00%**					**32.76**

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Lease Payments

THESL makes lease payments to various entities for use of land related to its distribution business. Based upon discussions with THESL subject matter experts, THESL will no longer be using operating leases and primarily hold capital leases in the future and as such only operating and maintenance costs associated with these capital leases should be included in this working capital study. Since the operating and maintenance costs related to these future capital leases cannot be determined presently, THESL's current operating and maintenance costs for leases were used as a proxy for future operating and maintenance costs. Using the payment dates and amounts associated with THESL's distribution business, a dollar-weighted expense lead time of 34.74 days was determined. Table 14, below summarizes the components of the lease payment lead calculation. Additional detail can be found in the Appendix.

Table 14: Summary of Lease Payment Expenses

Description	Amounts ($M)	Weighting (%)	Expense Lead Time	Weighted Lead Time
Islington Monogram Holdings	$1.33	47.11%	-16.68	-7.86
Davpart Inc	$1.12	39.43%	-16.75	-6.60
Other Annual Leases	$0.38	13.46%	365.50	49.20
Total	**$2.83**	**100.00%**		**34.74**

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Consulting and Contract Staff

THESL engages consulting and contract staff to provide assistance in the areas such as engineering, receivables management, accounting, and general consulting.
A dollar-weighted expense lead time of 48.06 days was determined based on a review of invoices rendered and payments made by THESL, as shown in Table 15 below.

Table 15: Summary of Consulting and Contract Staff Expenses

Delivery Period	Costs ($M)	Weighting (%)	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead
Jan-16	$6.42	7.71%	16.00	32.80	48.80	3.76
Feb-16	$5.27	6.32%	15.00	33.23	48.23	3.05
Mar-16	$8.28	9.95%	15.75	30.63	46.37	4.61
Apr-16	$6.54	7.85%	15.50	29.26	44.76	3.51
May-16	$7.23	8.69%	15.99	31.21	47.21	4.10
Jun-16	$6.03	7.24%	15.50	30.93	46.43	3.36
Jul-16	$7.21	8.66%	15.98	34.37	50.35	4.36
Aug-16	$6.84	8.22%	16.00	34.17	50.17	4.12
Sept-16	$7.04	8.46%	15.50	33.69	49.19	4.16
Oct-16	$11.98	14.39%	15.98	31.62	47.60	6.85
Nov-16	$10.18	12.22%	15.50	33.60	49.10	6.00
Dec-16	$0.24	0.29%	15.50	41.12	56.62	0.16
Total	**$83.27**	**100.00%**				**48.06**

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Miscellaneous OM&A

The Miscellaneous OM&A category includes items such as product purchases, equipment rentals, and provision of general services to THESL. Based on transactions in THESL's accounts payable system under the Miscellaneous OM&A category, a dollar-weighted expense lead time of 31.41 days was derived. Table 16, below summarizes the components of the Miscellaneous OM&A expense lead calculation.

Table 16: Summary of Miscellaneous OM&A Expenses

Delivery Period	Costs ($M)	Weighting (%)	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead
Jan-16	$2.85	5.98%	57.28	-102.76	-45.48	-2.72
Feb-16	$6.08	12.76%	107.69	-16.01	91.68	11.70
Mar-16	$3.07	6.45%	14.58	15.31	29.88	1.93
Apr-16	$4.39	9.21%	56.46	-70.31	-13.84	-1.27
May-16	$4.13	8.68%	42.35	34.55	76.90	6.67
Jun-16	$3.94	8.28%	25.79	2.23	28.02	2.32
Jul-16	$4.77	10.01%	36.39	-16.87	19.52	1.95
Aug-16	$3.34	7.01%	19.73	2.70	22.43	1.57
Sept-16	$2.85	5.97%	24.37	11.11	35.49	2.12
Oct-16	$3.06	6.43%	34.67	47.84	82.51	5.31
Nov-16	$4.38	9.19%	20.92	8.21	29.13	2.68
Dec-16	$4.78	10.04%	43.48	-51.93	-8.45	-0.85
Total	**$47.63**	**100.00%**				**31.41**

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Interest Expenses

THESL makes interest payments on long-term and short-term debt. Payments on long-term debt are generally made twice a year whereas payments on short-term debt are generally made monthly. Table 17 below summarizes the components of the interest expense lead calculation. Taking into account the various long-term and short-term debt instruments, a dollar-weighted expense lead time of 25.34 days was determined.

Table 17: Summary of Interest Expenses

Description	Amounts ($M)	Weighting (%)	Expense Lead Time	Weighted Lead Time
Long-term Debt	$75.58	96.05%	25.18	24.19
Short-term Debt	$3.11	3.95%	29.30	1.16
Total	**$78.68**	**100.00%**		**25.34**

Payments in Lieu of Taxes ("PILs")

THESL makes payments in lieu of taxes in installments to the relevant taxing authorities. As payment data for the calendar year 2016 was not reflective of historical or forward-looking payment frequencies for PILs, payment amounts that were made in calendar year 2017 were used. Taking this into account, a dollar-weighted expense lead (-lag) time of negative 10.05 days was determined for PILs. Table 18, below summarizes the components of the PILS expense lead calculation.

Table 18: Summary of Payments in Lieu of Taxes Expenses

Delivery Period	Costs ($M)	Weighting (%)	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead
Jan-17	$0.27	2.56%	182.50	-334.00	-151.50	-3.87
Feb-17	$0.27	2.56%	182.50	-306.00	-123.50	-3.16
Mar-17	$2.00	19.15%	182.50	-275.00	-92.50	-17.71
Apr-17	$2.00	19.15%	182.50	-244.00	-61.50	-11.78
May-17	$1.14	10.94%	182.50	-214.00	-31.50	-3.45
Jun-17	$0.00	0.00%	182.50	-184.00	-1.50	0.00
Jul-17	$1.11	10.65%	182.50	-153.00	29.50	3.14
Aug-17	$1.83	17.50%	182.50	-122.00	60.50	10.59
Sept-17	$1.83	17.50%	182.50	-90.00	92.50	16.19
Total	**$10.45**	**100.00%**				**-10.05**

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Harmonized Sales Tax

The expense lead times associated with the following items that attract HST were considered in THESL's distribution lead-lag study:

1. Revenues;
2. Cost of Power; and,
3. OM&A[3].

A summary of the expense lead times and working capital amounts associated with each of the above items is provided in Table 19. Note that the statutory approach described at the outset was used to determine the expense lead times associated with THESL's remittances and disbursements of HST (i.e., both remittances and collections are generally on the last day of the month following the date of the applicable invoice). Expense lead times for HST is shown below.

Table 19: Summary of HST Working Capital Amounts

Description	HST Lead Time	HST Working Capital Amount ($M)
Revenues	-10.07	-$15.59
Cost of Power	46.03	$50.16
OM&A	41.58	$2.07
Total		**$36.64**

[3] Costs within OM&A that attract HST include Corporate Procurement Card, Lease Payments, Consulting and Contract Staff, and Miscellaneous OM&A.

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SECTION V: TORONTO HYDRO – WORKING CAPITAL REQUIREMENTS

Using the results described under the discussion of revenue lags and expense leads, and applying them to THESL's distribution expenses, THESL's working capital requirements were determined and are shown in the tables below.

Table 20: THESL Distribution Working Capital Requirements

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital Requirements ($M)
Cost of Power	50.87	32.63	18.24	5.00%	$3,059.51	$152.85
OM&A Expenses	50.87	35.19	15.68	4.29%	$344.90	$14.81
PILS	50.87	-10.05	60.91	16.69%	$10.45	$1.74
Interest Expense	50.87	25.34	25.52	6.99%	$78.68	$5.50
Total					**$3,493.53**	**$174.91**
HST						$36.64
Total - Including HST						**$211.54**
Working Capital as a Percent of OM&A incl. Cost of Power						**6.21%**

The results of the study indicate a lower working capital requirement as compared to THESL's EB-2014-0116 distribution lead-lag study. The primary reasons for the difference is driven by:

1. The decrease in retail revenue lag days due to the move of all customers to a monthly billing frequency – the retail revenue lag days have decreased by approximately 7%; and,
2. The removal of the Debt Retirement Charge component has decreased working capital for THESL – had the debt retirement charge still been an expense, the working capital amount would be approximately 0.15% higher for each year of the filing period.

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SECTION VI: APPENDIX – DETAILED DATA TABLES

IESO Credits

Table 21: Summary of IESO Credits

Description	Lag Days	Revenues ($M)	Weighting (%)	Weighted Lag
Ontario Electricity Support Program	62.84	$14.04	8.90%	5.59
Ontario Rebate for Electricity Consumers ("OREC")	62.91	$123.37	78.21%	49.20
OREC Global Adjustment Modifier	62.24	$20.33	12.89%	8.02
Total		**$157.74**	**100.00%**	**62.82**

Other External Revenues

Table 22: Summary of Other External Revenues

Description	Lag Days	Revenues ($M)	Weighting (%)	Weighted Lag
Hydro One Sub-Station	273.00	$0.63	0.57%	1.55
Demand Billables	29.52	$53.95	48.56%	14.33
RESOP	32.03	$0.13	0.12%	0.04
FIT	32.73	$52.95	47.66%	15.60
mFIT	32.77	$3.44	3.09%	1.01
Total		**$111.10**	**100.00%**	**32.54**

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Payroll

Table 23: Summary of Payroll Expenses

Delivery Period	Costs ($M)	Weighting (%)	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead
12/27/2015	$3.33	3.30%	1/13/2016	7.00	4.00	11.00	0.36
1/10/2016	$3.41	3.38%	1/27/2016	7.00	4.00	11.00	0.37
1/24/2016	$3.59	3.56%	2/10/2016	7.00	4.00	11.00	0.39
2/7/2016	$3.51	3.47%	2/24/2016	7.00	4.00	11.00	0.38
2/21/2016	$3.67	3.63%	3/9/2016	7.00	4.00	11.00	0.40
3/6/2016	$3.16	3.13%	3/23/2016	7.00	4.00	11.00	0.34
3/20/2016	$3.78	3.75%	4/6/2016	7.00	4.00	11.00	0.41
4/3/2016	$3.51	3.48%	4/20/2016	7.00	4.00	11.00	0.38
4/17/2016	$3.71	3.68%	5/4/2016	7.00	4.00	11.00	0.40
5/1/2016	$3.59	3.56%	5/18/2016	7.00	4.00	11.00	0.39
5/15/2016	$3.65	3.61%	6/1/2016	7.00	4.00	11.00	0.40
5/29/2016	$3.81	3.77%	6/15/2016	7.00	4.00	11.00	0.42
6/12/2016	$3.79	3.76%	6/29/2016	7.00	4.00	11.00	0.41
6/26/2016	$3.77	3.74%	7/13/2016	7.00	4.00	11.00	0.41
7/10/2016	$3.73	3.70%	7/27/2016	7.00	4.00	11.00	0.41
7/24/2016	$3.82	3.78%	8/10/2016	7.00	4.00	11.00	0.42
8/7/2016	$3.79	3.76%	8/24/2016	7.00	4.00	11.00	0.41
8/21/2016	$3.80	3.77%	9/7/2016	7.00	4.00	11.00	0.41
9/4/2016	$3.83	3.79%	9/21/2016	7.00	4.00	11.00	0.42
9/18/2016	$3.81	3.77%	10/5/2016	7.00	4.00	11.00	0.42
10/2/2016	$3.77	3.74%	10/19/2016	7.00	4.00	11.00	0.41
10/16/2016	$3.87	3.84%	11/2/2016	7.00	4.00	11.00	0.42
10/30/2016	$3.90	3.86%	11/16/2016	7.00	4.00	11.00	0.43
11/13/2016	$4.04	4.00%	11/30/2016	7.00	4.00	11.00	0.44
11/27/2016	$4.05	4.01%	12/14/2016	7.00	4.00	11.00	0.44
12/11/2016	$4.10	4.07%	12/28/2016	7.00	4.00	11.00	0.45
1/1/2015	$4.12	4.08%	3/23/2016	182.50	83.00	265.50	10.84
Total	**$100.90**	**100.00%**					**21.39**

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Withholdings

Table 24: Summary of Withholdings Expenses

Delivery Period	Costs ($M)	Weighting (%)	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead
12/27/2015	$2.02	4.04%	1/19/2016	7.00	10.00	17.00	0.69
1/10/2016	$2.07	4.14%	2/3/2016	7.00	11.00	18.00	0.74
1/24/2016	$2.20	4.39%	2/18/2016	7.00	12.00	19.00	0.83
2/7/2016	$2.19	4.38%	3/3/2016	7.00	12.00	19.00	0.83
2/21/2016	$2.22	4.44%	3/17/2016	7.00	12.00	19.00	0.84
3/6/2016	$2.77	5.52%	4/5/2016	7.00	17.00	24.00	1.33
3/20/2016	$2.21	4.41%	4/12/2016	7.00	10.00	17.00	0.75
4/3/2016	$2.04	4.08%	4/26/2016	7.00	10.00	17.00	0.69
4/17/2016	$2.07	4.13%	5/11/2016	7.00	11.00	18.00	0.74
5/1/2016	$1.91	3.82%	5/26/2016	7.00	12.00	19.00	0.73
5/15/2016	$1.86	3.71%	6/10/2016	7.00	13.00	20.00	0.74
5/29/2016	$1.87	3.74%	6/24/2016	7.00	13.00	20.00	0.75
6/12/2016	$1.77	3.53%	7/6/2016	7.00	11.00	18.00	0.64
6/26/2016	$1.65	3.30%	7/19/2016	7.00	10.00	17.00	0.56
7/10/2016	$1.55	3.10%	8/3/2016	7.00	11.00	18.00	0.56
7/24/2016	$1.51	3.01%	8/17/2016	7.00	11.00	18.00	0.54
8/7/2016	$1.48	2.96%	9/6/2016	7.00	17.00	24.00	0.71
8/21/2016	$1.42	2.84%	9/19/2016	7.00	16.00	23.00	0.65
9/4/2016	$1.45	2.89%	10/5/2016	7.00	18.00	25.00	0.72
9/18/2016	$1.41	2.82%	10/13/2016	7.00	12.00	19.00	0.54
10/2/2016	$1.38	2.76%	10/26/2016	7.00	11.00	18.00	0.50
10/16/2016	$1.43	2.86%	11/10/2016	7.00	12.00	19.00	0.54
10/30/2016	$1.44	2.87%	11/24/2016	7.00	12.00	19.00	0.55
11/13/2016	$1.52	3.03%	12/12/2016	7.00	16.00	23.00	0.70
11/27/2016	$1.51	3.01%	12/28/2016	7.00	18.00	25.00	0.75
12/11/2016	$1.51	3.02%	1/5/2017	7.00	12.00	19.00	0.57
1/1/2015	$3.60	7.20%	4/5/2016	182.50	96.00	278.50	20.04
Total	**$50.07**	**100.00%**					**38.24**

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Pensions

Table 25: Summary of Pension Expenses

Delivery Period	Costs ($M)	Weighting (%)	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead
Dec-15	$1.19	3.56%	2/29/2016	7.00	51.00	58.00	2.06
Jan-16	$1.19	3.58%	2/29/2016	7.00	37.00	44.00	1.58
Jan-16	$1.19	3.56%	3/31/2016	7.00	54.00	61.00	2.17
Feb-16	$1.21	3.63%	3/31/2016	7.00	40.00	47.00	1.71
Feb-16	$1.19	3.58%	4/29/2016	7.00	55.00	62.00	2.22
Mar-16	$1.58	4.74%	4/29/2016	7.00	41.00	48.00	2.27
Mar-16	$1.20	3.61%	5/31/2016	7.00	59.00	66.00	2.38
Apr-16	$1.19	3.58%	5/31/2016	7.00	45.00	52.00	1.86
Apr-16	$1.19	3.57%	6/30/2016	7.00	61.00	68.00	2.43
May-16	$1.19	3.57%	6/30/2016	7.00	47.00	54.00	1.93
May-16	$1.19	3.58%	7/29/2016	7.00	62.00	69.00	2.47
May-16	$1.19	3.56%	7/29/2016	7.00	48.00	55.00	1.96
Jun-16	$1.18	3.55%	7/29/2016	7.00	34.00	41.00	1.46
Jun-16	$1.19	3.56%	8/31/2016	7.00	53.00	60.00	2.14
Jul-16	$1.20	3.58%	8/31/2016	7.00	39.00	46.00	1.65
Jul-16	$1.18	3.55%	9/30/2016	7.00	55.00	62.00	2.20
Aug-16	$1.19	3.56%	9/30/2016	7.00	41.00	48.00	1.71
Aug-16	$1.17	3.50%	10/31/2016	7.00	58.00	65.00	2.27
Sep-16	$1.18	3.54%	10/31/2016	7.00	44.00	51.00	1.80
Sep-16	$1.18	3.55%	11/30/2016	7.00	60.00	67.00	2.38
Oct-16	$1.19	3.57%	11/30/2016	7.00	46.00	53.00	1.89
Oct-16	$1.18	3.55%	12/30/2016	7.00	62.00	69.00	2.45
Oct-16	$1.19	3.56%	12/30/2016	7.00	48.00	55.00	1.96
Nov-16	$1.19	3.56%	1/31/2017	7.00	66.00	73.00	2.60
Nov-16	$1.17	3.50%	1/31/2017	7.00	52.00	59.00	2.07
Dec-16	$1.19	3.57%	1/31/2017	7.00	38.00	45.00	1.61
Jan-15	$2.06	6.17%	4/29/2016	182.50	120.00	302.50	18.67
Total	**$33.34**	**100.00%**					**71.89**

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Benefits – Health and Dental

Table 26: Summary of Benefits, Health and Dental Expenses

Delivery Period	Costs ($M)	Weighting (%)	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead
Dec-15	$0.51	3.94%	1/1/2016	7.00	-8.00	-1.00	-0.04
Jan-16	$0.51	3.94%	1/1/2016	7.00	-22.00	-15.00	-0.59
Jan-16	$0.55	4.26%	2/1/2016	7.00	-5.00	2.00	0.09
Feb-16	$0.55	4.26%	2/1/2016	7.00	-19.00	-12.00	-0.51
Feb-16	$0.54	4.21%	3/1/2016	7.00	-4.00	3.00	0.13
Mar-16	$0.54	4.21%	3/1/2016	7.00	-18.00	-11.00	-0.46
Mar-16	$0.58	4.54%	4/1/2016	7.00	-1.00	6.00	0.27
Apr-16	$0.58	4.54%	4/1/2016	7.00	-15.00	-8.00	-0.36
Apr-16	$0.56	4.35%	5/1/2016	7.00	1.00	8.00	0.35
May-16	$0.56	4.35%	5/1/2016	7.00	-13.00	-6.00	-0.26
May-16	$0.39	3.06%	6/1/2016	7.00	4.00	11.00	0.34
May-16	$0.39	3.06%	6/1/2016	7.00	-10.00	-3.00	-0.09
Jun-16	$0.39	3.06%	6/1/2016	7.00	-24.00	-17.00	-0.52
Jun-16	$0.50	3.91%	7/1/2016	7.00	-8.00	-1.00	-0.04
Jul-16	$0.50	3.91%	7/1/2016	7.00	-22.00	-15.00	-0.59
Jul-16	$0.52	4.02%	8/1/2016	7.00	-5.00	2.00	0.08
Aug-16	$0.52	4.02%	8/1/2016	7.00	-19.00	-12.00	-0.48
Aug-16	$0.51	3.97%	9/1/2016	7.00	-2.00	5.00	0.20
Sep-16	$0.51	3.97%	9/1/2016	7.00	-16.00	-9.00	-0.36
Sep-16	$0.49	3.82%	10/1/2016	7.00	0.00	7.00	0.27
Oct-16	$0.49	3.82%	10/1/2016	7.00	-14.00	-7.00	-0.27
Oct-16	$0.52	4.07%	11/1/2016	7.00	3.00	10.00	0.41
Oct-16	$0.52	4.07%	11/1/2016	7.00	-11.00	-4.00	-0.16
Nov-16	$0.37	2.89%	12/1/2016	7.00	5.00	12.00	0.35
Nov-16	$0.37	2.89%	12/1/2016	7.00	-9.00	-2.00	-0.06
Dec-16	$0.37	2.89%	12/1/2016	7.00	-23.00	-16.00	-0.46
Total	**$12.85**	**100.00%**					**-2.79**

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Benefits – Group Life Insurance

Table 27: Summary of Benefits, Group Life Insurance Expenses

Delivery Period	Costs ($M)	Weighting (%)	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead
Dec-15	$0.06	3.92%	1/1/2016	7.00	-8.00	-1.00	-0.04
Jan-16	$0.06	3.92%	1/1/2016	7.00	-22.00	-15.00	-0.59
Jan-16	$0.06	3.91%	2/1/2016	7.00	-5.00	2.00	0.08
Feb-16	$0.06	3.91%	2/1/2016	7.00	-19.00	-12.00	-0.47
Feb-16	$0.06	3.96%	3/1/2016	7.00	-4.00	3.00	0.12
Mar-16	$0.06	3.96%	3/1/2016	7.00	-18.00	-11.00	-0.44
Mar-16	$0.06	4.31%	4/1/2016	7.00	-1.00	6.00	0.26
Apr-16	$0.06	4.31%	4/1/2016	7.00	-15.00	-8.00	-0.35
Apr-16	$0.06	4.21%	5/1/2016	7.00	1.00	8.00	0.34
May-16	$0.06	4.21%	5/1/2016	7.00	-13.00	-6.00	-0.25
May-16	$0.04	2.77%	6/1/2016	7.00	4.00	11.00	0.31
May-16	$0.04	2.77%	6/1/2016	7.00	-10.00	-3.00	-0.08
Jun-16	$0.04	2.77%	6/1/2016	7.00	-24.00	-17.00	-0.47
Jun-16	$0.06	4.23%	7/1/2016	7.00	-8.00	-1.00	-0.04
Jul-16	$0.06	4.23%	7/1/2016	7.00	-22.00	-15.00	-0.63
Jul-16	$0.06	4.21%	8/1/2016	7.00	-5.00	2.00	0.08
Aug-16	$0.06	4.21%	8/1/2016	7.00	-19.00	-12.00	-0.51
Aug-16	$0.06	4.30%	9/1/2016	7.00	-2.00	5.00	0.21
Sep-16	$0.06	4.30%	9/1/2016	7.00	-16.00	-9.00	-0.39
Sep-16	$0.06	4.28%	10/1/2016	7.00	0.00	7.00	0.30
Oct-16	$0.06	4.28%	10/1/2016	7.00	-14.00	-7.00	-0.30
Oct-16	$0.06	4.23%	11/1/2016	7.00	3.00	10.00	0.42
Oct-16	$0.06	4.23%	11/1/2016	7.00	-11.00	-4.00	-0.17
Nov-16	$0.04	2.85%	12/1/2016	7.00	5.00	12.00	0.34
Nov-16	$0.04	2.85%	12/1/2016	7.00	-9.00	-2.00	-0.06
Dec-16	$0.04	2.85%	12/1/2016	7.00	-23.00	-16.00	-0.46
Total	**$1.47**	**100.00%**					**-2.77**

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Benefits – WSIB

Table 28: Summary of Benefits, WSIB Expenses

Delivery Period	Costs ($M)	Weighting (%)	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead
Dec-15	$0.06	4.42%	2/29/2016	7.00	51.00	58.00	2.57
Jan-16	$0.06	4.42%	2/29/2016	7.00	37.00	44.00	1.95
Jan-16	$0.06	4.61%	3/31/2016	7.00	54.00	61.00	2.81
Feb-16	$0.06	4.61%	3/31/2016	7.00	40.00	47.00	2.17
Feb-16	$0.10	7.51%	4/30/2016	7.00	56.00	63.00	4.73
Mar-16	$0.10	7.51%	4/30/2016	7.00	42.00	49.00	3.68
Mar-16	$0.06	4.45%	5/31/2016	7.00	59.00	66.00	2.94
Apr-16	$0.06	4.45%	5/31/2016	7.00	45.00	52.00	2.32
Apr-16	$0.06	4.38%	6/30/2016	7.00	61.00	68.00	2.98
May-16	$0.06	4.38%	6/30/2016	7.00	47.00	54.00	2.37
May-16	$0.06	4.32%	7/31/2016	7.00	64.00	71.00	3.07
May-16	$0.06	4.32%	7/31/2016	7.00	50.00	57.00	2.46
Jun-16	$0.06	4.32%	7/31/2016	7.00	36.00	43.00	1.86
Jun-16	$0.06	4.07%	8/31/2016	7.00	53.00	60.00	2.44
Jul-16	$0.06	4.07%	8/31/2016	7.00	39.00	46.00	1.87
Jul-16	$0.05	3.71%	9/30/2016	7.00	55.00	62.00	2.30
Aug-16	$0.05	3.71%	9/30/2016	7.00	41.00	48.00	1.78
Aug-16	$0.04	3.21%	10/31/2016	7.00	58.00	65.00	2.09
Sep-16	$0.04	3.21%	10/31/2016	7.00	44.00	51.00	1.64
Sep-16	$0.04	2.63%	11/30/2016	7.00	60.00	67.00	1.76
Oct-16	$0.04	2.63%	11/30/2016	7.00	46.00	53.00	1.40
Oct-16	$0.03	2.18%	12/31/2016	7.00	63.00	70.00	1.52
Oct-16	$0.03	2.18%	12/31/2016	7.00	49.00	56.00	1.22
Nov-16	$0.02	1.57%	1/31/2017	7.00	66.00	73.00	1.14
Nov-16	$0.02	1.57%	1/31/2017	7.00	52.00	59.00	0.92
Dec-16	$0.02	1.57%	1/31/2017	7.00	38.00	45.00	0.70
Total	**$1.38**	**100.00%**					**56.67**

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Benefits – Employee Health Tax

Table 29: Summary of Benefits, Employee Health Tax Expenses

Delivery Period	Costs ($M)	Weighting (%)	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead
Dec-15	$0.11	3.48%	2/15/2016	7.00	37.00	44.00	1.53
Jan-16	$0.12	3.55%	2/15/2016	7.00	23.00	30.00	1.07
Jan-16	$0.12	3.65%	3/15/2016	7.00	38.00	45.00	1.64
Feb-16	$0.12	3.69%	3/15/2016	7.00	24.00	31.00	1.14
Feb-16	$0.12	3.65%	4/15/2016	7.00	41.00	48.00	1.75
Mar-16	$0.13	3.85%	4/15/2016	7.00	27.00	34.00	1.31
Mar-16	$0.12	3.69%	5/16/2016	7.00	44.00	51.00	1.88
Apr-16	$0.12	3.62%	5/16/2016	7.00	30.00	37.00	1.34
Apr-16	$0.12	3.67%	6/15/2016	7.00	46.00	53.00	1.94
May-16	$0.12	3.61%	6/15/2016	7.00	32.00	39.00	1.41
May-16	$0.12	3.63%	7/15/2016	7.00	48.00	55.00	1.99
May-16	$0.12	3.70%	7/15/2016	7.00	34.00	41.00	1.52
Jun-16	$0.12	3.68%	7/15/2016	7.00	20.00	27.00	0.99
Jun-16	$0.12	3.64%	8/15/2016	7.00	37.00	44.00	1.60
Jul-16	$0.12	3.61%	8/15/2016	7.00	23.00	30.00	1.08
Jul-16	$0.12	3.60%	9/15/2016	7.00	40.00	47.00	1.69
Aug-16	$0.12	3.61%	9/15/2016	7.00	26.00	33.00	1.19
Aug-16	$0.12	3.57%	10/17/2016	7.00	44.00	51.00	1.82
Sep-16	$0.12	3.66%	10/17/2016	7.00	30.00	37.00	1.35
Sep-16	$0.12	3.60%	11/15/2016	7.00	45.00	52.00	1.87
Oct-16	$0.12	3.58%	11/15/2016	7.00	31.00	38.00	1.36
Oct-16	$0.12	3.65%	12/15/2016	7.00	47.00	54.00	1.97
Oct-16	$0.12	3.67%	12/15/2016	7.00	33.00	40.00	1.47
Nov-16	$0.12	3.78%	1/16/2017	7.00	51.00	58.00	2.19
Nov-16	$0.12	3.78%	1/16/2017	7.00	37.00	44.00	1.66
Dec-16	$0.12	3.79%	1/16/2017	7.00	23.00	30.00	1.14
Jan-15	$0.16	5.01%	4/15/2016	182.50	106.00	288.50	14.46
Total	**$3.29**	**100.00%**					**54.38**

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Other Benefits – Long-term Disability

Table 30: Summary of Other Benefits, Long-term Disability Expenses

Delivery Period	Costs ($M)	Weighting (%)	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead
Jan-16	$0.140	8.36%	15.50	-2.00	13.50	1.13
Feb-16	$0.141	8.42%	14.00	-2.00	12.00	1.01
Mar-16	$0.140	8.38%	15.50	-1.00	14.50	1.21
Apr-16	$0.140	8.34%	15.00	-1.00	14.00	1.17
May-16	$0.138	8.27%	15.50	-4.00	11.50	0.95
Jun-16	$0.139	8.32%	15.00	-1.00	14.00	1.17
Jul-16	$0.139	8.31%	15.50	-2.00	13.50	1.12
Aug-16	$0.139	8.30%	15.50	-5.00	10.50	0.87
Sept-16	$0.139	8.30%	15.00	0.00	15.00	1.25
Oct-16	$0.139	8.28%	15.50	-3.00	12.50	1.04
Nov-16	$0.139	8.32%	15.00	0.00	15.00	1.25
Dec-16	$0.140	8.39%	15.50	-1.00	14.50	1.22
Total	**$1.674**	**100.00%**				**13.38**

Other Benefits – Accidental Death and Dismemberment

Table 31: Summary of Other Benefits, Accidental Death and Dismemberment Expenses

Delivery Period	Costs ($M)	Weighting (%)	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead
Jan-16	$0.003	8.01%	15.50	-2.00	13.50	1.08
Feb-16	$0.003	8.18%	14.00	-2.00	12.00	0.98
Mar-16	$0.003	8.22%	15.50	-1.00	14.50	1.19
Apr-16	$0.003	8.28%	15.00	-1.00	14.00	1.16
May-16	$0.003	8.25%	15.50	-4.00	11.50	0.95
Jun-16	$0.003	8.39%	15.00	-1.00	14.00	1.17
Jul-16	$0.003	8.41%	15.50	-2.00	13.50	1.14
Aug-16	$0.003	8.43%	15.50	-5.00	10.50	0.88
Sept-16	$0.003	8.47%	15.00	0.00	15.00	1.27
Oct-16	$0.003	8.43%	15.50	-3.00	12.50	1.05
Nov-16	$0.003	8.44%	15.00	0.00	15.00	1.27
Dec-16	$0.003	8.49%	15.50	-1.00	14.50	1.23
Total	**$0.036**	**100.00%**				**13.38**

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Other Benefits – Employee Assistance Program

Table 32: Summary of Other Benefits, Employee Assistance Program Expenses

Delivery Period	Costs ($M)	Weighting (%)	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead
Jan-16	$0.006	8.33%	15.50	12.00	27.50	2.29
Feb-16	$0.006	8.34%	14.00	12.00	26.00	2.17
Mar-16	$0.006	8.34%	15.50	28.00	43.50	3.63
Apr-16	$0.006	8.34%	15.00	12.00	27.00	2.25
May-16	$0.006	8.33%	15.50	9.00	24.50	2.04
Jun-16	$0.006	8.32%	15.00	14.00	29.00	2.41
Jul-16	$0.006	8.32%	15.50	11.00	26.50	2.20
Aug-16	$0.006	8.33%	15.50	8.00	23.50	1.96
Sept-16	$0.006	8.33%	15.00	13.00	28.00	2.33
Oct-16	$0.006	8.33%	15.50	10.00	25.50	2.13
Nov-16	$0.006	8.34%	15.00	15.00	30.00	2.50
Dec-16	$0.006	8.34%	15.50	12.00	27.50	2.29
Total	**$0.073**	**100.00%**				**25.91**

Lease Payments – Islington Monogram Holdings

Table 33: Summary of Lease Payments, Islington Monogram Holdings

Delivery Period	Costs ($M)	Weighting (%)	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead
Jan-16	$0.12	9.09%	15.50	-25.00	-9.50	-0.86
Feb-16	$0.12	9.09%	14.50	-31.00	-16.50	-1.50
Mar-16	$0.12	9.09%	15.50	-34.00	-18.50	-1.68
Apr-16	$0.12	9.09%	15.00	-31.00	-16.00	-1.45
May-16	$0.12	9.09%	15.50	-32.00	-16.50	-1.50
Jun-16	$0.12	9.09%	15.00	-34.00	-19.00	-1.73
Jul-16	$0.12	9.09%	15.50	-32.00	-16.50	-1.50
Aug-16	$0.12	9.09%	15.50	-33.00	-17.50	-1.59
Sept-16	$0.12	9.09%	15.00	-35.00	-20.00	-1.82
Oct-16	$0.12	9.09%	15.50	-31.00	-15.50	-1.41
Nov-16	$0.12	9.09%	15.00	-33.00	-18.00	-1.64
Total	**$1.33**	**100.00%**				**-16.68**

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Lease Payments – Davpart Inc

Table 34: Summary of Lease Payments, Davpart Inc

Delivery Period	Costs ($M)	Weighting (%)	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead
Feb-16	$0.09	8.35%	14.50	-31.00	-16.50	-1.38
Mar-16	$0.09	8.35%	15.50	-34.00	-18.50	-1.55
Apr-16	$0.09	8.35%	15.00	-31.00	-16.00	-1.34
May-16	$0.09	8.35%	15.50	-32.00	-16.50	-1.38
Jun-16	$0.09	8.35%	15.00	-34.00	-19.00	-1.59
Jul-16	$0.09	8.35%	15.50	-32.00	-16.50	-1.38
Aug-16	$0.09	8.35%	15.50	-33.00	-17.50	-1.46
Sep-16	$0.09	8.35%	15.00	-30.00	-15.00	-1.25
Oct-16	$0.09	8.35%	15.50	-31.00	-15.50	-1.29
Nov-16	$0.09	8.35%	15.00	-33.00	-18.00	-1.50
Dec-16	$0.09	8.35%	15.50	-31.00	-15.50	-1.29
Jan-17	$0.09	8.13%	15.50	-32.00	-16.50	-1.34
Total	**$1.12**	**100.00%**				**-16.75**

Lease Payments – Other Annual Leases

Table 35: Summary of Lease Payments, Other Annual Leases

Delivery Period	Costs ($M)	Weighting (%)	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead
2015	$0.38	100%	182.50	183.00	365.50	365.50
Total	**$0.38**	**100%**				**365.50**

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CAPITAL EXPENDITURES

In accordance with the Chapter 5 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (July 12, 2018) ("Filing Requirements"), Toronto Hydro has filed a consolidated Distribution System Plan ("DSP") in Exhibit 2B. In this schedule, Toronto Hydro files OEB's Appendix 2-AA (Capital Projects Table) and Appendix 2-AB (Capital Expenditures Summary), as required by Chapter 2, s. 2.2.2.2 of the Filing Requirements. In accordance with the Filing Requirements, this schedule also provides:

- A description of the proposed accounting treatment for projects that have a life cycle greater than one year, including the treatment of the cost of funds for construction work-in-progress ("CWIP");
- The components of other capital expenditures, including a reconciliation of all capital components to the total capital budget; and
- The components of CWIP.

Toronto Hydro makes capital contributions to Hydro One Networks Inc. ("HONI"), as required, to complete certain capital work such as Stations Renewal and Stations Expansion (see Exhibit 2B, Sections E6.6 and E7.4, respectively). These contributions are recognized as intangible assets and amortized on a straight line basis over 25 years.

1. OEB-REQUIRED APPENDICES (2-AA AND 2-AB)

Appendices 2-AA and 2-AB, which are filed at Exhibit 2A, Tab 4, Schedules 2 and 3, provide an overview of Toronto Hydro's capital expenditures from 2015 to 2024 by program and investment category, respectively.

To maximize the usefulness of these appendices, Toronto Hydro mapped its historical and future capital expenditures to the investment categories and programs presented in the DSP, at Exhibit 2B. Variance explanations related to Toronto Hydro's capital expenditures are provided in Exhibit 2B, Section E4.

Toronto Hydro confirms that no non-distribution activities are included in the plan presented in this application.

2. ACCOUNTING TREATMENT FOR CWIP

Some of Toronto Hydro's capital projects may be in progress at the reporting cut-off date. In such cases, capital costs are recorded in a CWIP account until the project work is completed. Under Modified International Financial Reporting Standards ("MIFRS"), a financing charge, referred to as Allowance for Funds Used During Construction ("AFUDC"), is added to capital projects that necessarily take a substantial period of time (exceeding six months) to get ready for their intended use. Further information follows.

3. COMPONENTS OF CAPITAL EXPENDITURES

Toronto Hydro's capital expenditures under the Other Capital Expenditures category (in Appendix 2-AB) includes AFUDC and miscellaneous capital, which are described below.

3.1 Allowance for Funds Used During Construction (AFUDC)

The OEB's Accounting Procedures Handbook, Article 410, directs utilities to capitalize AFUDC. The AFUDC rate applied by Toronto Hydro under MIFRS for 2015 to 2017 actuals, 2018 to 2019 bridge, and 2020 forecast years is based on Toronto Hydro Corporation's weighted average cost of borrowing.

3.2 Miscellaneous Capital

Miscellaneous capital primarily consists of pre-capitalized inventory and major tools. The value of pre-capitalized inventory[1] results from the change in capitalized inventory levels between years. The utility purchases major tools in the normal course of operations and on an ongoing basis to replace worn or broken tools, as required, and to install, commission and otherwise complete capital activities.

The 2015 to 2019 capital plan presented in EB-2014-0116 ("CIR Filing Plan") included the annual inflationary increases within the 'Other' category. To improve comparability to actuals, Toronto Hydro has included the inflationary component for the CIR Filing Plan in the System Access, System Renewal, System Service, and General Plant categories in Appendix 2-AB.

4. CONSTRUCTION WORK IN PROGRESS

At any point in time, Toronto Hydro will have a balance in the CWIP account. Initial capital expenditures are recorded into CWIP until the project is complete, and capitalized in accordance with MIFRS.

Table 1: Historical, Bridge and Forecasted Construction Work In Progress ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Forecast
Opening CWIP	522.1	577.7	502.9	485.8	311.5	343.5
Additions (CAPEX)	490.6	508.4	496.6	434.7	425.7	514.0
Deductions (In Service Additions)	(435.3)	(584.3)	(520.3)	(608.9)	(397.8)	(489.8)
Other	0.3	1.1	6.5	-	4.2	-
Closing CWIP	577.7	502.9	485.8	311.5	343.5	367.7

Note
Variances due to rounding may exist

[1] See Article 410 of the Accounting Procedures Handbook for Electricity Distributors.

Other includes amounts related to monthly billing and externally driven capital deferral accounts (see Exhibit 9) and accounting presentation changes.

OEB Appendix 2-AA
Capital Programs Table

Programs ($M)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Customer Connections	31.7	40.1	21.9	44.8	37.6	42.9	43.9	44.8	45.6	46.3
Externally Initiated Plant Relocations & Expansion	2.2	2.6	2.6	7.5	8.3	11.4	20.8	4.6	4.7	4.5
Generation Protection, Monitoring, and Control	-	2.1	0.0	8.0	3.4	3.7	2.3	2.4	2.5	2.7
Load Demand	9.9	16.8	16.2	17.3	21.6	11.3	11.4	18.5	22.6	23.6
Metering	14.5	17.4	24.8	23.0	26.1	22.6	14.8	23.6	30.6	39.2
System Access Total	**58.3**	**79.0**	**65.5**	**100.8**	**97.1**	**91.8**	**93.3**	**93.9**	**106.0**	**116.4**
Area Conversions	46.3	28.2	26.9	40.0	44.4	41.4	47.2	46.3	50.4	35.6
Network System Renewal	10.2	16.8	14.7	18.9	29.8	18.6	19.3	18.5	17.7	18.3
Reactive and Corrective Capital	42.0	54.3	55.5	58.4	57.1	61.2	62.4	63.5	64.4	65.8
Stations Renewal	11.3	11.6	19.0	19.7	23.7	27.5	35.3	29.4	27.0	22.4
Underground System Renewal - Downtown	-	-	-	-	-	15.1	22.5	23.9	30.0	30.6
Underground System Renewal - Horseshoe	115.5	80.7	83.1	70.0	71.4	93.0	88.7	90.3	93.1	95.2
Overhead Infrastructure Relocation	0.9	3.1	2.6	0.2	-	-	-	-	-	-
SCADAMATE R1 Renewal	3.5	4.9	2.1	1.4	2.7	-	-	-	-	-
PILC Piece Outs & Leakers	6.0	5.7	1.8	0.1	1.5	-	-	-	-	-
Underground Legacy Infrastructure	7.4	9.9	9.0	2.3	5.0	-	-	-	-	-
Overhead System Renewal	61.0	51.0	35.7	18.4	17.8	49.8	50.4	51.3	56.5	57.7
System Renewal Total	**304.1**	**266.1**	**250.3**	**229.4**	**253.4**	**306.6**	**325.7**	**323.1**	**339.0**	**325.5**
Energy Storage Systems	-	-	-	5.9	2.0	1.0	3.7	3.8	1.0	1.0
Network Condition Monitoring and Control	-	-	-	-	-	7.6	10.2	12.6	15.3	17.4
Overhead Momentary Reduction	0.0	-	-	0.3	0.3	-	-	-	-	-
Stations Expansion	23.0	34.5	59.4	30.6	32.8	19.5	40.0	49.3	12.5	15.2
System Enhancements	7.1	17.2	12.2	4.0	6.7	6.2	6.2	5.6	4.8	4.9
Handwell Upgrades	4.7	0.8	0.8	-	-	-	-	-	-	-
Polymer SMD-20 Renewal	3.0	0.3	0.0	0.6	-	-	-	-	-	-
Design Enhancement	0.0	0.6	(0.0)	-	-	-	-	-	-	-
System Service Total	**37.9**	**53.3**	**72.4**	**41.4**	**41.8**	**34.2**	**60.1**	**71.3**	**33.6**	**38.5**
Facilities Management and Security	15.4	9.0	6.3	2.1	2.5	11.6	11.8	12.1	12.3	12.6
Fleet and Equipment	4.1	3.7	4.7	3.3	3.3	8.6	8.9	8.5	8.7	7.8
IT/OT Systems	28.4	48.6	55.4	64.6	34.4	54.8	55.7	49.5	56.6	64.8
Control Operations Reinforcement	-	-	-	-	-	3.9	17.4	18.9	-	-
Operating Centers Consolidation Plan	31.6	48.3	32.2	-	-	-	-	-	-	-
Program Support	-	0.0	0.4	-	-	-	-	-	-	-
General Plant Total	**79.4**	**109.5**	**98.9**	**70.0**	**40.2**	**78.8**	**93.7**	**89.0**	**77.7**	**85.2**
AFUDC	10.8	12.5	9.8	6.0	4.0	6.0	8.2	8.7	8.9	7.7
Miscellaneous	0.8	(8.8)	0.9	0.3	(1.6)	1.0	0.8	1.2	0.6	1.0
Other Total	**11.6**	**3.7**	**10.7**	**6.3**	**2.4**	**7.0**	**9.0**	**9.8**	**9.5**	**8.7**
Subtotal	**491.4**	**511.6**	**497.8**	**447.8**	**434.9**	**518.4**	**581.8**	**587.1**	**565.7**	**574.4**
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets (input as negative)	(0.8)	(3.2)	(1.2)	(13.1)	(9.3)	(4.4)	(3.1)	(3.2)	(3.3)	(3.5)
Total	**490.6**	**508.4**	**496.6**	**434.7**	**425.7**	**514.0**	**578.8**	**583.9**	**562.4**	**570.9**

OEB Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated

First year of Forecast Period:

2020

CATEGORY	2015			2016			2017			2018			2019			Forecast Period (planned)				
	CIR Filing Plan	Actual	Var	CIR Filing Plan	Actual	Var	CIR Filing Plan	Actual	Var	CIR Filing Plan	Bridge	Var	CIR Filing Plan	Bridge[2]	Var	2020	2021	2022	2023	2024
	In millions of dollars		%	*In millions of dollars*		%	*In millions of dollars*		%	*In millions of dollars*		%	*In millions of dollars*		%	*In millions of dollars*				
System Access	86.1	58.3	-32.3%	95.3	79.0	-17.2%	104.9	65.5	-37.6%	95.8	100.8	5.2%	92.3	97.1	5.2%	91.8	93.3	93.9	106.0	116.4
System Renewal	251.7	304.1	20.8%	239.6	266.1	11.0%	256.2	250.3	-2.3%	275.9	229.4	-16.9%	287.3	253.4	-11.8%	306.6	325.7	323.1	339.0	325.5
System Service	76.5	37.9	-50.4%	70.7	53.3	-24.6%	65.1	72.4	11.3%	52.6	41.4	-21.4%	80.2	41.8	-47.9%	34.2	60.1	71.3	33.6	38.5
General Plant	104.6	79.4	-24.1%	101.5	109.5	7.9%	30.3	98.9	226.4%	34.2	70.0	104.6%	30.3	40.2	32.7%	78.8	93.7	89.0	77.7	85.2
Other	12.2	11.6	-4.8%	11.6	3.7	-67.9%	10.8	10.7	-1.4%	11.5	6.3	-45.6%	12.1	2.4	-80.2%	7.0	9.0	9.8	9.5	8.7
TOTAL EXPENDITURE	531.1	491.4	-7.5%	518.8	511.6	-1.4%	467.4	497.8	6.5%	470.0	447.8	-4.7%	502.2	434.9	-13.4%	518.4	581.8	587.1	565.7	574.4
Capital Contributions	- 6.6	- 4.0	-40.0%	- 29.1	- 16.6	-42.9%	- 48.2	- 37.4	-22.5%	- 32.1	- 22.9	-28.6%	- 30.5	- 28.1	-8.0%	- 12.8	- 16.1	- 15.2	- 16.8	- 14.6
Net Capital Expenditures	524.5	487.5	-7.1%	489.7	495.0	1.1%	419.2	460.5	9.9%	438.0	424.9	-3.0%	471.6	406.8	-13.7%	505.6	565.7	571.9	548.9	559.8
System O&M	128.8	116.1	-9.9%		126.5	--		126.3	--		126.9	--		131.0	--	130.4				

Note: Variances due to rounding may exist

Notes to the Table:

1. Historical “previous plan” data is not required unless a plan has previously been filed. However, use the last Board-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including the Bridge Year.
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year): 12

Explanatory Notes on Variances (complete only if applicable)
Notes on shifts in forecast vs. historical budgets by category
Refer to Section E4 for analysis of shifts in forecast vs. historical expenditures by category
Notes on year over year Plan vs. Actual variances for Total Expenditures
Refer to Section E4 on Variance analysis for between Plan vs Actuals.
Notes on Plan vs. Actual variance trends for individual expenditure categories
Refer to Section E4 on Variance analysis for between Plan vs Actuals.

CAPITALIZATION POLICY

This schedule addresses s. 2.2.2.5 of the Ontario Energy Board's ("OEB") Filing Requirements for Electricity Distribution Rate Applications (July 12, 2018) ("Filing Requirements"), which requires each applicant to file a copy of its capitalization policy and identify changes to that capitalization policy since filing its last rebasing application.

1. BACKGROUND

Consistent with the OEB's expectations, Toronto Hydro converted to International Financial Reporting Standards ("IFRS") effective January 1, 2015.[1] This application represents Toronto Hydro's second rebasing application under Modified IFRS ("MIFRS").

Although Toronto Hydro updated and implemented its IFRS-compliant capitalization policy in time for IFRS reporting for the year ended December 2015, Toronto Hydro filed its USGAAP capitalization policy in the 2015-2019 CIR application (refer to EB-2014-0116, Exhibit 2A, Tab 7, Appendix A) as the utility's IFRS policy was not approved at that time.

2. CAPITALIZATION POLICY

A copy of Toronto Hydro's current and IFRS-compliant capitalization policy is filed in Appendix A to this schedule.

Toronto Hydro confirms that, for purposes of calculating the 2020-2024 rates (Exhibit 2A, Tab 1, Schedule 1), its capitalization practices conform to MIFRS.

[1] Filing Requirements, s. 2.0.9 - "Accounting Matters".

3. CHANGES TO CAPITALIZATION POLICY

There have been no changes to Toronto Hydro's IFRS-compliant capitalization policy applied to rates resulting from the last application. As part of a continuous review process, Toronto Hydro evaluates its policies and practices to incorporate new IFRS pronouncements.

POLICY

CAPITALIZATION	**Policy Owner:** Executive Vice-President and Chief Financial Officer
	Policy Approver: Policy Administration Steering Committee
	Version Approval Date: V6.0 2017-10-16
	Last Review by PASC: V6.0 2017-10-16
The most recent version of this policy can be obtained from http://pluggedin.torontohydro.com/policy/Pages/FinancePolicies.aspx	
The distribution of this policy is not restricted.	

Anthony Haines
President and CEO, Toronto Hydro Corporation

Dec 6, 2017
Date

TABLE OF CONTENTS

1 DOCUMENT REVIEW & REVISION HISTORY 2
2 DISTRIBUTION HISTORY 2
3 POLICY OVERVIEW 3
4 DEFINITIONS AND ABBREVIATIONS 3
5 SCOPE 4
6 OBJECTIVE 4
7 CRITERIA FOR CAPITALIZATION 4
8 ASSET COST 5
9 IN-SERVICE ADDITIONS 9
10 DERECOGNITION 9
11 POLICY ADMINISTRATION OWNERSHIP, APPROVAL AND RESPONSIBILITIES 9
12 POLICY COMMUNICATION 10
13 POLICY COMPLIANCE AND VIOLATIONS 10
14 RELATED LAWS, REGULATIONS AND DOCUMENTATION 10

1 DOCUMENT REVIEW & REVISION HISTORY

This policy is reviewed annually.

Version Number	Date of Review	Reviewed By	Brief Description of Change
V1.0	2008-06-27	PASC	V1.0 approved by PASC
V2.0	2010-07-29	PASC	V2.0 approved by PASC
V3.0	2011-06-30	PASC	V3.0 approved by PASC
V4.0	2013-09-24	PASC	V4.0 approved by PASC
V5.0	2015-12-14	PASC	Reflect accounting policies in accordance with IFRS, revisions to policy administration and responsibilities, addition of compliance monitoring
V6.0	2017-10-16	PASC	Added clarifying guidance including additional intangible asset treatment, updated roles and responsibilities, added OEB AP Handbook related excerpts and other minor wording changes

2 DISTRIBUTION HISTORY

Version Number	Date of Issue	Recipients
V1.0	2008-06-27	Toronto Hydro @ Home Employee Extranet
V2.0	2010-08-30	Toronto Hydro @ Home Employee Extranet
V3.0	2011-09-16	http://pluggedin.torontohydro.com/policy/Pages/FinancePolicies.aspx
V4.0	2013-09-30	http://pluggedin.torontohydro.com/policy/Pages/FinancePolicies.aspx
V5.0	2015-12-14	http://pluggedin.torontohydro.com/policy/Pages/FinancePolicies.aspx
V6.0	2017-10-16	http://pluggedin.torontohydro.com/policy/Pages/FinancePolicies.aspx

3 POLICY OVERVIEW

This document describes the accounting policy and specific criteria used to determine the appropriate classification of expenditures, in particular, whether expenditures should be capitalized on the balance sheet (capital assets) or expensed to operations in the period incurred (expense), and the conditions for derecognition.

The purpose of recording expenditures as capital assets is to provide for an equitable allocation of costs among current and future periods. As capital assets are expected to provide future economic benefits for more than a year, expenditures incurred for the acquisition, construction or development of capital assets should be capitalized and allocated over the estimated useful lives[1] of the associated capital assets in the form of amortization/depreciation expense. All other expenditures should be expensed in the accounting period incurred.

4 DEFINITIONS AND ABBREVIATIONS

TERM or ACRONYM	DESCRIPTION
AP Handbook	Accounting Procedures Handbook for Electricity Distributors issued by the OEB
Borrowing Costs	Interest and other costs incurred in connection with the borrowing of funds
CWIP	Construction Work In Progress
Corporation	Toronto Hydro Corporation and its subsidiaries
IFRS	International Financial Reporting Standards
ISA	In-Service Additions
Qualifying asset	An asset that necessarily takes a substantial period of time to get ready for its intended use
OEB	Ontario Energy Board
On-cost	Materials handling costs
PASC	Policy Administration Steering Committee
PP&E	Property, Plant and Equipment
SLR	Standard Labour Rate
VHR	Vehicle Hire Rate

[1] Estimates of useful life are reviewed annually and whenever events or changes in circumstances indicate that the current estimates or depreciation method are no longer appropriate. Changes in estimates are accounted for on a prospective basis.

5 SCOPE

5.1 This policy applies to the capitalization of assets for the Corporation.

5.2 This policy is designed to augment other corporate policies and is not intended to replace or preclude them. Should an overlap arise between the application of this policy and any other policy, the policy most specific to the situation will apply.

6 OBJECTIVE

6.1 To ensure proper classification of the Corporation's expenditures in accordance with IFRS and the regulatory reporting standards included in the AP Handbook.

7 CRITERIA FOR CAPITALIZATION

7.1 Initial Recognition – Capitalization versus Expensing

Subject to the threshold levels outlined in **Appendix A**, expenditures will be capitalized only if:

i) It is probable that future economic benefits will flow to the entity; and
ii) The cost can be measured reliably.

Capital assets comprise of PP&E and intangible assets, and are expected to be used during more than one year. PP&E consists typically of long-lived tangible assets used in the production or supply of goods or services, for rental to others, or for administrative purposes, such as distribution assets, equipment, land and buildings. Intangible assets are assets that lack physical substance, such as computer software and capital contributions paid.

For additional guidance, **Appendix B – Decision Tree** illustrates the criteria that must be met in order for expenditures to be capitalized. Expenditures not meeting the criteria will be expensed in the period incurred. Additionally, **Appendix C** includes excerpts from the OEB AP Handbook outlining capital asset and expense account definitions. A review of these definitions provides practical references and examples to assist in the classification of various expenditures.

For complex transactions, when capital/operating decisions may be ambiguous and/or estimates of useful lives are not known, the Business Units should consult with the Finance group.

7.2 Subsequent recognition - Capitalization versus Expensing

When expenditures are incurred relating to existing capital assets, they should be evaluated against the recognition criteria (i.e., it is probable that future economic benefits will flow to the entity and the cost can be measured reliably). Subsequent costs should be capitalized only if they meet the recognition criteria. Otherwise, costs should be expensed.

Costs to be capitalized are costs incurred to enhance the service potential of an existing capital asset. The service potential of an existing capital asset may be enhanced when:

i) there is an increase in the previously assessed physical output or service capacity;
ii) associated operating costs are lowered;
iii) the life or useful life is extended; or
iv) the quality of output is improved.

Costs to be expensed are costs incurred in the maintenance of the service potential of a capital asset. Frequently referred to as repair and maintenance expenses, they are costs incurred more or less on a continuous basis to keep the capital asset in normal operating condition, but do not improve the value of the asset, nor prolong its life appreciably. They are the result of an activity that encompasses actions of a detective, preventive, and/or monitoring nature. They are normally planned or scheduled. They can also be reactionary, in response to an unscheduled breakdown in service function.

For those instances when professional judgement has to be exercised to determine the proper classification of the Corporation's expenditures, the Business Units should confirm the classification with the Finance group.

8 ASSET COST

Capital asset cost is the amount of consideration given to acquire, construct, or develop a capital asset and includes all costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.

The "directly attributable" criteria should not be interpreted as "directly attributable to an asset". It means "directly attributable to getting the asset ready to operate as intended". Further, the directly attributable costs for a self-constructed asset is determined using the same principles as an acquired asset.

8.1 Cost

For purchased capital assets, cost should include the purchase price and other acquisition costs, such as brokers' commissions, and all the costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management, such as: costs of employee benefits arising directly from the acquisition of the asset; installation costs, including architectural, design and engineering fees; legal fees; survey costs; site preparation costs; freight charges; transportation insurance costs; duties; the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located; and testing and preparation charges.

For an electrical plant that is constructed, construction costs should include where applicable: the cost of directly attributable labour; materials and supplies; transportation; work done by others for the utility; damages incurred in the construction work; privileges and permits; special machinery services; borrowing costs applied to construction work in progress; the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located; and such portion of directly attributable general engineering, salaries and expenses, insurance, taxes and other similar items as may be properly included in construction. The cost of abnormal amounts of wasted material, labour, or other resources incurred in self-constructing an asset is not included in the cost of the asset.

For information technology ("IT") projects related to computer software, costs should include only the expenditures incurred in the development phase of a project.

Software development involves two stages:

i) the research phase. Examples of activities which might be incurred in this stage are conceptual formulation of alternatives, evaluation of alternatives, determination of existence of needed technologies, and final selection of alternatives. All costs incurred during this phase should be expensed as they are incurred.

ii) the development phase. Examples of activities which might be incurred in this stage are design of chosen alternative, including software configuration and interfaces, coding, installation on computer hardware, and testing. Costs incurred during this phase should start being capitalized only after the IT group demonstrates all of the following:
   a. the technical feasibility of completing the software so that it will be available for use;
   b. the intention to complete the software and use it (i.e., commit resources for the project in the budget);
   c. the ability to use the software;
   d. how the software will generate probable future economic benefits (i.e., demonstrate the usefulness of the software);
   e. the availability of adequate technical, financial and other resources to complete the development and to use the software (i.e., a business plan showing the technical, financial and other resources needed and how they will be secured);
   f. the ability to measure reliably the expenditure attributable to the software during its development (i.e., use of time sheets).

If the research phase of an internal project to create/modify a software cannot be distinguished from the development phase, the expenditure for that project should be treated as if it were incurred in the research phase only.

Capitalization should cease no later than when substantial testing is complete and the software is capable of operating in the manner intended by management, or when it is no longer probable that the computer software project will be completed and placed in service.

For cloud computing arrangements with third party service providers to use their software applications over the internet, the costs should be assessed against the general capitalization criteria set out in **Appendix B – Decision Tree**. The service provider hosts the hardware, software, servers, storage and other components. The Corporation incurs costs to build a customized user interface which is housed on its premises in order to access the software application. If the definition of an asset is met, the Corporation should consider the nature of asset that has been acquired in order to determine the appropriate accounting treatment (e.g., prepaid, other asset, or intangible asset). Otherwise, the costs should be expensed as a service fee. Each arrangement should be analysed on a case-by-case basis.

As there is often no asset that the Corporation controls on its own premises in these types of arrangements, the capitalization criteria would need to be applied to the rights provided through the individual contractual arrangement with the third party service provider. As each arrangement may be unique, each individual contract should be assessed separately. Any development costs related to the cloud solution should be assessed using the same criteria as the IT projects related to computer software above.

Other costs that are not costs of an item of PP&E or intangible asset:

i) costs incurred while an item capable of operating in the manner intended by

management has yet to be brought into use or is operated at less than full capacity;
ii) initial operating losses, such as those incurred while demand for the item's output builds up;
iii) costs of relocating or redeploying the item to a new location;
iv) administration and other general overhead costs; and
v) training costs.

8.2 Borrowing costs

Borrowing costs eligible for capitalization are determined by applying the weighted average cost of borrowing to the carrying amount of eligible CWIP during a period, including borrowing costs previously capitalized. Capitalization of borrowing costs will commence as soon as the expenditure on a qualifying asset is incurred and will cease when substantially all the activities necessary to prepare the qualifying asset for its intended use are complete.

8.3 Burdens

Four burden rates are specifically analyzed below with respect to the asset cost:

1. Time-sheeting of Indirect Labour

   One of the methods of capitalizing labour costs is to allocate employee labour costs through the process of time-sheeting of indirect labour. Field crews are supported, supervised and guided by those employees whose personnel costs are included in indirect labour.

   The process of capitalizing costs of indirect labour includes labour costing (i.e. time-sheeting) which differentiates the time spent between capital, operating, and "blended" activities (i.e. a mix of capital and operating), in order to appropriately allocate costs across projects based on identified cost drivers.

   Once time-sheeted hours are applied to specific activities, the calculated cost will be allocated to capital expenditures, operating expenses, or a blend of both based on the nature of the activity. Costs identified as capital or costs that are designated as capital in nature within a blend activity will be mapped to CWIP, while costs identified as operating or costs that are designated as operating in nature within a blend activity will be mapped to operating expense.

2. Standard labour rate

   Another method of capitalizing labour costs is to track direct labour costs for various employees and apply a SLR to time recorded to various jobs. There are three broad direct labour categories within the group of employees who currently submit time-sheets for direct labour and for whom SLR's are calculated: inside workers, outside shift workers and outside hourly workers.

   The SLRs are calculated by dividing the total employee burden (i.e. employee's total remuneration, including various types of benefits) by the total available hours (i.e. hours available for work during the course of the year on capital projects) for each SLR category. The total available hours consist of: a) the total working days in a year less b) leaves (such as vacation and statutory holidays) as well as c) various unproductive time (such as safety training, inclement weather, etc.).

3. On-cost

An on-cost charge is applied to material issuances from the warehouse. Examples include transformers, poles, cables, etc. If the items issued from the warehouse are associated with capital projects, the on-cost charge is capitalized, whereas if the items issued are associated with operating projects, the on-cost charge is expensed in the period in which it is incurred.

The on-cost charge associates the cost of warehousing and handling to the items themselves. The on-cost rate is calculated as the sum of budgeted expenses in the specific material handling responsibility centers divided by the budgeted dollar value of materials moving through the warehouse in a given year. This rate is then applied to the dollar value of all materials when issued to capital and operating projects. Some of the budgeted expenses within the material handling responsibility centers are not capitalizable, thus should not be included in the on-cost calculation. The disallowed costs include:

- Payroll related to administrative staff supporting the procurement and warehousing functions;
- Inventory and direct purchases of materials used in the warehouse for internal purposes – i.e. not used for capital projects;
- Utilities and communications related expenses;
- Office supplies used in procurement and warehousing;
- Employee expenses (i.e. reimbursed expenses for employee purchases); and
- Allocated IT charges related to telephone and computing equipment used by the procurement and warehousing departments.

4. Vehicle Hire Rate

Vehicles used in the construction of capital assets can be capitalized into the item of PP&E. This capitalization is applied to projects based on time-sheets for the use of each vehicle. A VHR is calculated for each vehicle class and applied to the hours time-sheeted to determine the amount capitalized to each project.

The VHRs are calculated by taking the sum of the total operating charges, fuel costs and depreciation, and dividing by the total available vehicle hours for each vehicle class. The total available vehicle hours are based on the number of working days in a year less a factor for vehicle repairs and maintenance. Some of the budgeted expenses are not capitalizable, thus should not be included in the VHR calculation.

8.4 Decommissioning cost

The Corporation recognizes a liability, known as a decommissioning provision, for future removal and handling costs for contamination in distribution equipment and for the future environmental remediation of certain properties, as assessed on a case-by-case basis. A decommissioning provision shall be recognized when there is a present legal or constructive obligation as a result of a past event and it is probable that there will be a future economic outflow that can be reliably measured. The liability is measured at present value and an offsetting amount is added to the carrying amount of the related asset. This cost is depreciated over the useful life of the related asset. Changes to an existing decommissioning provision are added to or deducted from the cost of the related asset and depreciated prospectively over the remaining useful life of the asset.

9 IN-SERVICE ADDITIONS

9.1 Once it has been established that an expenditure is part of the cost of a capital asset, it is recorded as CWIP until the asset is capable of operating in the manner intended by management (i.e., the capital asset is energized or connected to the distribution system), at which point it is recorded as an item of PP&E or intangible asset and depreciation begins.

10 DERECOGNITION

10.1 Derecognition occurs when an item of PP&E or intangible asset no longer generate future economic benefits or when the item is disposed of.

10.2 When an item of PP&E or intangible asset no longer generates future economic benefits, the loss arising from derecognition equals its carrying amount and is recorded in the period in which the item is derecognized as depreciation or amortization expense.

10.3 When an item of PP&E or intangible asset is disposed of, the gain or loss arising from derecognition equals the difference between the net disposal proceeds (if any) and its carrying amount and is recorded in the period in which the item is derecognized as a gain or loss on disposal.

11 POLICY ADMINISTRATION OWNERSHIP, APPROVAL AND RESPONSIBILITIES

Policy Owner

11.1 This policy is owned by the *Executive Vice-President and Chief Financial Officer,* who is responsible for:

- Ensuring that this policy is comprehensive, clear and current.
- Approving any exceptions to this policy, as required.
- Reviewing this policy annually.

Policy Approver

11.2 This policy is approved by the *Policy Administration Steering Committee,* which is responsible for:

- Considering the impact of this policy to the associated risk.
- Approving this policy annually.

Designated Responsible Person

11.3 This policy is managed by the *Manager, External Financial Reporting*, who is responsible for:

- Ensuring that this policy is in accordance with IFRS and OEB Accounting Procedures Handbook guidance.
- Ensuring consistency between referenced appendices and this document.
- Reviewing and updating this policy annually, as necessary.

11.4 This policy is implemented by the *Manager, Capital Planning and Reporting*, who is responsible for:

- Ensuring that this policy is communicated to all staff impacted.

- Ensuring on-going compliance with this policy.
- Immediately communicating any exceptions or violations of this policy to the *Controller* and the *Executive Vice-President and Chief Financial Officer*.

12 POLICY COMMUNICATION

COMMUNICATION TRIGGER	TYPE OF COMMUNICATION	PARTY RESPONSIBLE FOR POLICY COMMUNICATION	AUDIENCE	ACKNOWLEDGEMENT
Policy Update	E-Mail, Posted on Intranet	Controller	All affected employees	No
New Hire in Finance	Discussion, E-mail	Immediate Supervisor/Manager	New hire	No

13 POLICY COMPLIANCE AND VIOLATIONS

13.1 All of the Corporation's employees, officers and directors are required to comply with this policy.

13.2 Any employee who fails to comply with this policy could be subject to disciplinary action, up to and including dismissal.

13.3 Failure to comply with this policy could lead to a material misstatement of the Corporation's expenditures on the financial statements and inaccurate submissions to regulatory agencies. This can have legal, regulatory and reputational ramifications.

13.4 Compliance Monitoring

At the direction of the Corporation's General Counsel, the Controller is responsible for tracking and collecting applicable data measuring compliance and reporting upon the same to the General Counsel in such format as he/she may require.

14 RELATED LAWS, REGULATIONS AND DOCUMENTATION

14.1 Refer to IAS 16 *Property, Plant and Equipment* and IAS 38 *Intangible Assets* for additional definitions and accounting principles. These standards are available from the Finance group.

14.2 The following appendices were referenced in this policy:

- Appendix A - Minimum threshold dollar amounts for capitalization
- Appendix B - Decision Tree - Classification of an expenditure
- Appendix C - Capital asset and repair and maintenance expense definitions - Excerpts from the OEB AP Handbook

These appendices can be found on the Toronto Hydro Plugged In intranet site at http://pluggedin.torontohydro.com/policy/Pages/FinancePolicies.aspx.

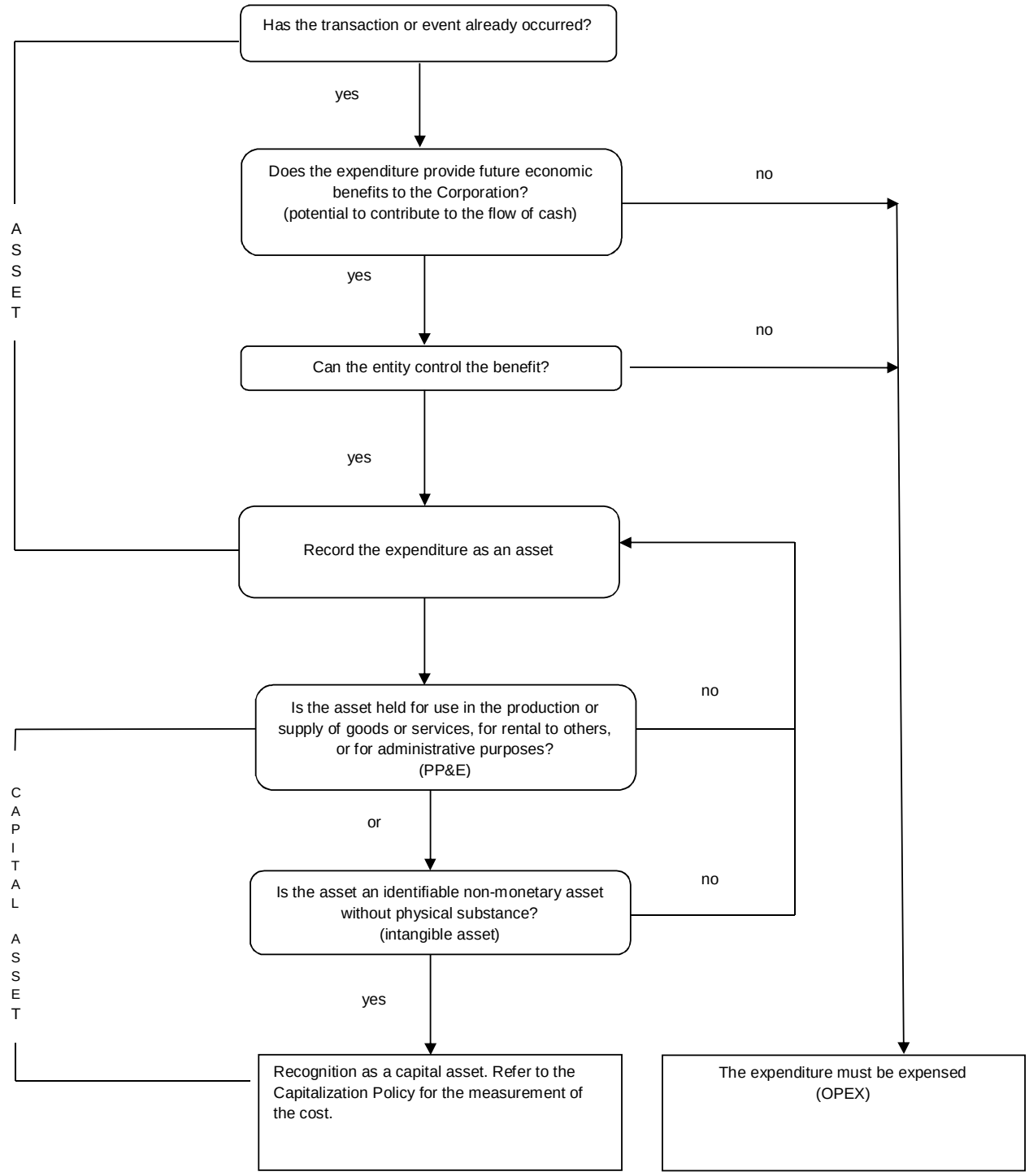
CAPITALIZATION POLICY
APPENDIX A – MINIMUM THRESHOLD DOLLAR AMOUNT FOR CAPITALIZATION

This appendix is governed by the Capitalization Policy.

Once it has been established that an expenditure has the characteristics of a capital asset, for practical purposes, only those expenditures exceeding the prescribed threshold $ amount outlined below will be recorded as a capital asset. Expenditures below the threshold $ amount will be recorded as an expense. Note that for expenditures related to "major" projects, such as overhauls, major renovations, etc., it may not be appropriate to look at threshold $ amounts on an itemized basis (i.e. per project, per expenditure/item). For those instances, the expenditure will be reviewed on a case by case basis in order to assess capitalization.

Asset Category	Comment	Threshold Amount ($)
Land	All purchases treated as a capital asset	n/a
Buildings	Per project	5,000
Leasehold Improvements	Per project	2,000
Fixtures	Per project	5,000
Stations – Major Equipment	Per project	5,000
Distribution Systems	Per project	5,000
OH Conductors	Per project	5,000
UG Conduit and Conductors	Per project	5,000
Poles, towers, fixtures	Per project	5,000
Transformers	Per project	5,000
Meters	Per project	2,000
Office furniture and equipment	Per expenditure/item	2,000
Computer Equipment-Hardware (Mainframe and software)	Per expenditure/item	2,000
Computer software	Per expenditure/item	2,000
Tools, shop, garage and store equipment	Per expenditure/item	1,000
Measuring and testing equipment	Per expenditure/item	1,000
Communication equipment	Per expenditure/item	1,000
Rolling stock/transportation equipment	Per expenditure/item	1,000
Work and service equipment	Per expenditure/item	2,000
Capital contributions (intangible assets)	Per project	n/a
CWIP	Includes assets not currently available for use	n/a

CAPITALIZATION POLICY
APPENDIX B – DECISION TREE – CLASSIFICATION OF AN EXPENDITURE



CAPITALIZATION POLICY
APPENDIX C – CAPITAL ASSET AND REPAIR AND MAINTENANCE EXPENSE DEFINITIONS – EXCERPT FROM OEB AP HANDBOOK (Issued: December 2011; Effective: January 1, 2012; Updates issued in March 2015 for new accounts)
(APPLICABLE TO THESL)

This appendix is governed by the Capitalization Policy.

Article 220 – Uniform System of Accounts
Electric Plant in Service - Detailed Accounts
D. Distribution Plant

1805 Land
This account shall include the cost of land used in connection with power distribution. (See Article 230, Definitions and Instructions No. 8 for detail guidance).
Note: Do not include in this account the cost of permits to erect poles, towers, etc., or to trim trees. See Account 1830, Poles, Towers and Fixtures, and Account 1835, Overhead Conductors and Devices.

1808 Buildings and Fixtures
This account shall include the cost in place of buildings and fixtures used in connection with distribution operations. (See Article 230 *Definitions and Instructions* No. 9.)

1810 Leasehold Improvements
This account shall include the cost of additions, improvements or alterations made to premises the utility leases from others. The cost of the leasehold improvements shall be amortized over the term of the lease or the service life of the improvement, whichever is shorter. Renewal provisions in the lease agreement shall be disregarded in amortizing leasehold improvements.
This account shall be subdivided into as many classifications as are required.

1815 Transformer Station Equipment - Normally Primary Above 50 kV
This account shall include the installed cost of transforming and switching equipment used for the purpose of stepping down from transmission voltages to subtransmission voltages and/or distribution voltages.
The account shall include all equipment used in the above operation from the high voltage feeder through to the delivery point outside the station or the connections within the confines of the station area. Included in the cost shall be all transformer equipment, control equipment, switching equipment, station metering equipment and the compartments or cubicles used to house such equipment, as well as general equipment such as cranes, hoists, test equipment, motors and the like. Moveable mountings or settings specially constructed for the particular equipment mounted therein shall also be included.
The detail of separate stations shall be entered in such a manner that an accurate record of their age, cost, location, and voltage characteristics will be evident.

1820 Distribution Station Equipment - Normally Primary Below 50 kV
This account shall include the installed cost of transforming and switching equipment used for the purpose of stepping down to distribution voltages.
The account shall include all equipment used in the above operation from the high voltage feeder through to the low voltage connection outside the station within the confines of the station area. Included in the cost shall be all transformer equipment, control equipment, switching equipment, station metering equipment and the compartments or cubicles used to house such equipment, as well as general equipment such as cranes, hoists, test equipment, motors and the like. Moveable

mountings or settings specially constructed for the particular equipment mounted therein shall also be included.
The detail of separate stations shall be entered in such a manner that an accurate record of their age, cost, location, and voltage characteristics will be evident.

1825 Storage Battery Equipment
This account shall include the cost installed of storage battery equipment used for the purpose of supplying electricity to meet emergency or peak demands.

Example items:

- Batteries, including elements, tanks, tank insulators, etc
- Battery room connections, including cable or bus runs and connections
- Battery room flooring, when specially laid for supporting batteries
- Charging equipment, including motor generator sets and other charging equipment and connections, and cable runs from generator or station bus to battery room connections
- Miscellaneous equipment, including instruments, water stills, etc
- Switching equipment, including endcell switches and connections, boards and panels, used exclusively for battery control, not part of general station switchboard
- Ventilating equipment, including fans and motors, louvers, and ducts not part of building

Note: Storage batteries used for control and general station purposes shall not be included in this account but in the account appropriate for their use.

1830 Poles, Towers, and Fixtures
This account shall include the cost installed of poles, towers, and appurtenant fixtures used for supporting overhead distribution conductors and service wires.

Example items:

- Anchors, head arm, and other guys, including guy guards, guy clamps, strain insulators, pole plates, etc
- Brackets
- Crossarms and braces
- Excavation and backfill, including disposal of excess excavated material
- Extension arms
- Foundations
- Guards
- Insulator pins and suspension bolts
- Paving
- Permits for construction
- Pole steps and ladders
- Poles, wood, steel, concrete, or other material
- Racks complete with insulators
- Railings
- Reinforcing and stubbing
- Settings
- Shaving, painting, gaining, roofing, stenciling, and tagging
- Towers
- Transformer racks and platforms

Note: Sub-accounts should be used for sub-transmission Poles, Towers and Fixtures.

1835 Overhead Conductors and Devices
This account shall include the cost installed of overhead conductors and devices used for distribution purposes.

Example items:

- Circuit breakers
- Conductors, including insulated and bare wires and cables
- Ground wires, clamps, etc
- Insulators, including pin, suspension, and other types, and tie wire or clamps
- Lightning arresters
- Railroad and highway crossing guards
- Splices
- Switches
- Initial cost of tree trimming, including the cost of permits
- Other line devices

Note: The cost of conductors used solely for street lighting or signal systems shall not be included in this account but in account 1875, Street Lighting and Signal Systems.

1840 Underground Conduit

This account shall include the cost installed of underground conduit and tunnels used for housing distribution cables or wires.

Example items:

- Conduit, concrete, brick and tile, including iron pipe, fiber pipe, Murray duct, and standpipe on pole or tower
- Excavation, including shoring, bracing, bridging, backfill, and disposal of excess excavated material
- Foundations and settings specially constructed for and not expected to outlast the apparatus for which constructed
- Lighting systems
- Manholes, concrete or brick, including iron or steel frames and covers, hatchways, gratings, ladders, cable racks and hangers, etc., permanently attached to manholes
- Municipal inspection
- Pavement disturbed, including cutting and replacing pavement, pavement base, and sidewalks
- Permits
- Protection of street openings
- Removal and relocation of subsurface obstructions
- Sewer connections, including drains, traps, tide valves, check valves, etc.
- Sumps, including pumps
- Ventilating equipment

Note: The cost of underground conduit used solely for street lighting or signal systems shall be included in Account 1875, Street Lighting and Signal Systems.

1845 Underground Conductors and Devices

This account shall include the cost installed of underground conductors and devices used for distribution purposes.

Example items:

- Armored conductors, buried, including insulators, insulating materials, splices, potheads, trenching, etc
- Armored conductors, submarine, including insulators, insulating materials, splices in terminal chamber, potheads, etc
- Cables in standpipe, including pothead and connection from terminal chamber or manhole to insulators on pole
- Circuit breakers
- Fireproofing, in connection with any items listed herein

- Hollow core oil filled cable, including straight or stop joints, pressure tanks, auxiliary air tanks, feeding tanks, terminals, potheads and connections, etc
- Lead and fabric covered conductors, including insulators, compound filled, oil filled or vacuum splices, potheads, etc
- Lightning arresters
- Municipal inspection and Permits
- Protection of street openings
- Racking of cables
- Switches
- Other line devices

Note: The cost of underground conductors and devices used solely for street lighting or signal systems shall be included in Account 1875, Street Lighting and Signal Systems.

1850 Line Transformers

A. This account shall include the cost installed of overhead and underground distribution line transformers and poletype and underground voltage regulators owned by the utility, for use in transforming electricity to the voltage at which it is to be used by the customer, whether actually in service or held in reserve.

B. The records covering line transformers shall be so kept that the utility can furnish the number of transformers of various capacities in service and those in reserve by:
a) type (underground or overhead);
b) capacity;
c) function.

Example items:

- Transformers
- Transformer cutouts
- Grounding equipment
- Other material and labour necessary for installation (first installation only)
- Transformer lightning arresters
- Transformers, line and network
- Capacitors
- Network protectors

Note: The cost of removing and resetting line transformers shall not be charged to this account but to Account 5035, Overhead Distribution Transformers - Operations or Accounts 5055**,** Underground Distribution Transformers - Operations. The cost of line transformers used solely for street lighting or signal systems shall be included in Account 1875, Street Lighting and Signal Systems.

1855 Services

This account shall include the cost installed of overhead and underground conductors leading from a point where wires leave the last pole of the overhead system or the transformers or manhole, or the top of the pole of the distribution line, to the point of connection with the customer's electrical panel. Conduit used for underground service conductors shall be included herein.

Example items:

- Brackets
- Cables and wires
- Conduit
- Insulators
- Municipal inspection
- Overhead to underground, including conduit or standpipe and conductor from last splice on pole to connection with customer's wiring

- Pavement disturbed, including cutting and replacing pavement, pavement base, and sidewalks
- Permits
- Protection of street openings
- Service switch
- Suspension wire

Records shall be maintained providing information on underground and overhead services separately and by capacity and function.

1860 Meters

A. This account shall include the cost installed of meters or devices and appurtenances thereto, for use in measuring the electricity delivered to its users, whether actually in service or held in reserve.

B. The records covering meters shall be so kept that the utility can furnish information as to the number of meters of various capacities in service and in reserve by:
a) type (underground or overhead);
b) capacity;
c) function.

Example items:

- Labour and expense of first installation
- Inspection fees
- Alternating current, watt hour meters
- Current limiting devices
- Demand indicators
- Demand meters
- Direct current watt hour meters
- Graphic demand meters
- Instrument transformers
- Maximum demand meters
- Meter badges and their attachments
- Meter boards and boxes
- Meter fittings, connections, and shelves (first set)
- Meter switches and cutouts
- Prepayment meters
- Protective devices
- Testing new meters
- Interval Meters
- Smart Meters

Note A: This account shall not include meters for recording output of a generating station, substation meters, etc. Generation station high voltage meters shall be recorded in Account 1815, Transformer Station Equipment - Normally Primary Above 50 kV and substation meters shall be recorded in Account 1820, Distribution Station Equipment - Normally Primary Below 50 kV.
Note B: Generation related meter costs for renewable energy standard offer program, Feed-in Tariff (—FITǁ) and microFIT generation activities shall be recorded in a separate sub-account by meter type under this account. The revenues collected for the recovery of the generator connection costs including the meter costs shall be treated as capital contributions and recorded in Account 2440, Deferred Revenues. The meter cost is offset by the capital contribution (recorded in Account 2440, Deferred Revenues) and the depreciation expense is offset by the amortized deferred revenue (recorded in Account 4245, Government and Other Assistance Directly Credited to Income) in profit or loss. (See Article 430 *Contributions in Aid of Construction.*)
Note C: The cost of removing and resetting meters shall be charged to Account 5065, Meter Expenses.

1865 Other Installations on Customer Premises
This account shall include the cost installed of equipment on the customer's side of a meter when the utility incurs such cost and when the utility retains title to and assumes full responsibility for maintenance and replacement of such property. This account shall not include expenses related to leased equipment (see Account 1870, Leased Property on Customer Premises).

Example items:

- Cable vaults
- Commercial lamp equipment
- Foundations and settings specially provided for equipment included herein
- Frequency changer sets
- Motor generator sets
- Motors
- Switchboard panels, high or low tension
- Wire and cable connections to incoming cables

Note A: Do not include in this account any costs incurred in connection with merchandising or contract work activities. (See Account 4330).
Note B: It is intended that only equipment used in furnishing special service or service of a character different from that normally supplied shall be included in this account.
Note C: Maintenance costs relating the items in this account are to be charged to Account 5195, Maintenance of Other Installations on Customer Premises.

1870 Leased Property on Customer Premises
This account shall include the cost of electric motors, transformers, and other equipment on customers' premises (including municipal corporations), leased or loaned to customers, but not including property held for sale.
Note A: The cost of setting and connecting such appliances or equipment on the premises of customers and the cost of resetting or removal shall not be charged to this account but to operating expenses, Account 5178, Customer Installations Expenses - Leased Property.
Note B: Do not include in this account any costs incurred in connection with merchandising. (See Account 4330).

1875 Street Lighting and Signal Systems
If street lighting and signal systems are authorized by the Board for ratemaking, this account shall include the cost installed of equipment used wholly for public street and highway lighting or traffic, fire alarm, police, and other signal systems.

Example items:

- Armored conductors, buried or submarine, including insulators, insulating materials, splices, trenching, etc
- Automatic control equipment
- Conductors, overhead or underground
- Lamps, incandescent, or other types, including glassware, suspension fixtures, brackets, etc
- Municipal inspection
- Ornamental lamp posts
- Pavement disturbed, including cutting and replacing pavement, pavement base, and sidewalks
- Permits
- Posts and standards
- Protection of street openings
- Relays or time clocks
- Series contactors
- Switches
- Transformers, pole or underground

Article 220 - Uniform System of Accounts
Balance Sheet Accounts
Electric Plant in Service - Detailed Accounts
E. General Plant

1905 Land
This account shall include the cost of land used for utility purposes, the cost of which is not properly included in other land account. (See Article 230 *Definitions and Instructions* No. 8 for detail guidance.)

1908 Buildings and Fixtures
This account shall include the cost in place of buildings and fixtures used for utility purposes, the cost of which is not properly included in other Buildings and Fixtures accounts. (See Article 230 *Definitions and Instructions* No. 9.)

1910 Leasehold Improvements
This account shall include the cost of additions, improvements or alterations made to premises the utility leases from others. The cost of the leasehold improvements shall be amortized over the term of the lease or the service life of the improvement, whichever is shorter. Renewal provisions in the lease agreement shall be disregarded in amortizing leasehold improvements.
This account shall be subdivided into as many classifications as are required.

1915 Office Furniture and Equipment
This account shall include the cost of the general office furniture and equipment.
Articles of low value and/or relatively short life should be charged to the appropriate operating account when purchased.
The account shall be maintained in such a manner as to provide the cost of each piece of equipment, and be subdivided into as many classifications as are required.

1920 Computer Equipment - Hardware
This account shall include the costs of acquiring computer hardware. Hardware includes all physical equipment associated with input, processing, storage and output functions, also word processing equipment.
This account shall be subdivided as considered necessary.

1930 Transportation Equipment
These accounts shall include the cost of automobiles, small trucks, truck chassis, special truck bodies, aerial ladders, trailers and other mobile equipment.

These accounts shall be subdivided into the following:

- Automobiles
- Trucks - Under 3 tons
- Trucks - 3 tons and over.

The accounts shall be maintained in such a manner as to provide the cost of each piece of equipment.
Note: Work and service equipment is to be included in Account 1950, Power Operated Equipment.

1935 Stores Equipment
This account shall include the cost of equipment used for the receiving, shipping, handling, and storage of materials and supplies.

Example items:

- Chain falls

- Counters
- Cranes (portable)
- Elevating and stacking equipment (portable)
- Hoists
- Lockers
- Scales
- Shelving
- Storage bins
- Trucks, hand and power driven
- Wheelbarrows

1940 Tools, Shop and Garage Equipment
This account shall include the cost of tools, implements, and equipment used in construction, repair work, general shops and garages and not specifically provided for or included in other accounts.

Example items:
- Air compressors
- Anvils
- Automobile repair shop equipment
- Battery charging equipment
- Belts, shafts and countershafts
- Boilers
- Cable pulling equipment
- Concrete mixers
- Drill presses
- Derricks
- Electric equipment
- Engines
- Forges
- Furnaces
- Foundations and settings specially constructed
- Gas producers
- Greasing tools and equipment
- Hoists
- Ladders
- Lathes
- Machine tools
- Motor-driven tools
- Pneumatic tools
- Pumps
- Riveters
- Smithing equipment
- Tool racks
- Vises
- Welding apparatus
- Work benches
- Line belt and harness for line crews
- Chain saws

1945 Measurement and Testing Equipment
This account shall include the cost installed of laboratory equipment used for general laboratory purposes and not specifically provided for or included in other departmental or functional plant accounts.

Example items:

- Ammeters
- Current batteries
- Frequency changers
- Galvanometers
- Inductometers
- Laboratory standard millivolt meters and volt meters
- Meter testing equipment
- Millivolt meters
- Motor generator sets
- Panels
- Phantom loads
- Portable graphic ammeters, voltmeters, and wattmeters
- Portable loading devices
- Potential batteries
- Potentiometers
- Rotating standards
- Standard cell, reactance, resistor, and shunt
- Switchboards
- Synchronous timers
- Testing panels
- Testing resistors
- Transformers
- Voltmeters
- Other testing, laboratory, or research equipment not provided for elsewhere
- Telescopic guns

1950 Power Operated Equipment
This account shall include the cost of power operated equipment used in construction, repair and service work exclusive of equipment included in other accounts. Include, also, the tools and accessories acquired for use with such equipment and the vehicle on which such equipment is mounted.

Example items:

- Air compressors, including driving unit and vehicle
- Backhoe machines
- Boring machines
- Bulldozers
- Cranes and hoists
- Pipe cleaning machines
- Pipe coating or wrapping machines
- Tractors Crawler type
- Trenchers
- Other power operated equipment

Note: It is intended that this account include only such large units as are generally self-propelled or mounted on movable equipment.

1955 Communication Equipment
This account shall include the cost installed of telephone and wireless equipment for general use in connection with utility operations.

1960 Miscellaneous Equipment
This account shall include the cost of equipment, apparatus, etc., used in the utility operations, which is not included in any other account of this Uniform System of Accounts.

Example items:

- Kitchen equipment
- Employees' recreation equipment
- Operators' cottage furnishings
- Other miscellaneous equipment

Note: Miscellaneous equipment of the nature indicated above wherever practicable shall be included in the utility plant accounts on a functional basis.

1970 Load Management Controls - Customer Premises
This account shall include the cost of control equipment on customer premises in connection with the remote control of water heaters, and other customer equipment.

1975 Load-Management Controls - Utility Premises
This account shall include the cost of all control devices situated on utility premises, used for the purpose of controlling equipment in Account 1970 above.

1980 System Supervisory Equipment
This account shall include the costs of all control equipment used for the purposes of remote operation and control of utility transformer stations and distribution equipment.

1985 Sentinel Lighting Rental Units
These accounts shall include the installed cost of all Sentinel Lighting Rental Units. The accounts shall be subdivided into as many classifications as are required.

1990 Other Tangible Property
This account shall include the cost of tangible utility plant not provided for elsewhere.

1995 Contributions and Grants - Credit
Effective until December 31, 2011, (or date of IFRS adoption, if early adoption was elected) this account shall include amounts relating to contributions or grants in cash, services or property from governments or government agencies, corporations, individuals and others received in aid of construction or for acquisition of fixed assets.
This account shall be maintained so that the company can supply information as to the purpose of each contribution or grant, the conditions, if any, on which it was made, the amount of contributions or grants from governments or government agencies, corporations, individuals and others and the amount applicable to each Electric Plant in Service detail Account (i.e. Accounts 1606 to 1990).

Note A: Effective on January 1, 2012, (or date of IFRS adoption, if early adoption was elected) customer contributors will be recorded in Account 2440, Deferred Revenues.
Note B**:** Effective on the date of IFRS adoption on January 1, 2012, (or date of IFRS adoption, if early adoption was elected by the utility), the balance in this account should be adjusted to zero in accordance with the guidance in Article 510 *Transitional Issues Relating to the Adoption of IFRS.*
Note C**:** After the adoption of IFRS, the utility shall continue to maintain detail records as evidence in support of the amounts recorded in this account as at December 31, 2011 (or date of IFRS adoption, if early adoption was elected) relating to contributions or grants in cash, services or property from governments or government agencies, corporations, individuals and others received in aid of construction or for acquisition of fixed assets.

Article 220 - Uniform System of Accounts
Balance Sheet Accounts
Electric Plant in Service - Detailed Accounts
Other Capital Assets

2005 Property Under Capital Leases

A. This account shall include the amount recorded under capital leases for plant leased from others and used by the utility in its utility operations.

B. The electric property included in this account shall be classified separately according to the detailed Accounts (1606 to 1990) prescribed for Electric Plant in Service.

C. Records shall be maintained with respect to each capital lease reflecting: (1) name of leaser, (2) basic details of lease, (3) termination date, (4) original cost or fair market value of property leased, (5) future minimum lease payments, (6) executor costs, (7) present value of minimum lease payments, (8) the amount representing interest and the interest rate used, and (9) expenses paid.

Note: The related obligations shall be recorded in Account 2285, Obligations Under Capital Leases - Current and Account 2325, Obligations Under Capital Leases - Non-current.

2010 Electric Plant Purchased or Sold

A. This account shall be charged with the cost of electric plant acquired as an operating unit or system by purchase, merger, consolidation liquidation, or otherwise, and shall be credited with the selling price of like property transferred to others pending the distribution to appropriate accounts in accordance with Article 230 *Definitions and Instructions* No. 7.

B. Within six months from the date of acquisition or sale of property recorded herein, the utility shall file with the Board the proposed journal entries to clear from this account the amounts recorded herein.

2020 Experimental Electric Plant Unclassified

A. This account shall include the cost of electric plant which was constructed as a development plant under the provisions of paragraph C, Account 2055, Construction Work in Progress Electric, and due to the nature of the plant it is desirable to operate it for a period of time in an experimental status.

B. Amounts in this account shall be transferred to Electric Plant in Service Accounts 1606 to 1990, or Account 2075, Non Rate-Regulated Property Owned or Under Capital Leases as appropriate when the project is no longer considered as experimental.

C. The amortization of property in this account shall be charged to Account 5705, Amortization Expense, and credited to Account 2105, Accumulated Amortization of Electric Utility Plant. The amounts herein shall be amortized over a period which would correspond to the estimated useful life of the relevant project considering the characteristics involved. However, when projects are transferred to relevant Electric Plant in Service accounts, the projects shall be reviewed and a new amortization rate based on the revised service life and unamortized amounts will be established as required.

D. Records shall be maintained with respect to each unit of experiment so that full details may be obtained as to the cost, amortization and the experimental status.

E. Should it be determined that experimental plant recorded in this account will fail to satisfactorily perform its function, the costs thereof shall be accounted for as directed or authorized by the Board.

2030 Electric Plant and Equipment Leased to Others

A. This account shall include the original cost of electric plant and equipment owned by the utility, but leased to others as operating units or systems, where the lessee has exclusive possession.

B. The property included in this account shall be classified according to the detailed Accounts (1606 to 1990) prescribed for Electric Plant in Service and this account shall be maintained in such detail as though the property were used by the owner in its utility operations.

2040 Electric Plant Held For Future Use

A. This account shall include the original cost of electric plant (for land and land rights see B below) owned and held for future use in electric service under a definite plan for such use, to include: (1) Property acquired (for land and land rights see B below) but never used by the utility in electric service, but held for such service in the future under a definite plan, and (2) property (for land and land rights see B below) previously used by the utility in service, but retired from such service and held pending its reuse in the future, under a definite plan, in electric service.

B. This account shall also include the original cost of land and land rights owned and held for future use in electric service under a plan for such use, to include land and land rights: (1) Acquired but never used by the utility in electric service, but held for such service in the future under a plan, and (2) previously held by the utility in service, but retired from such service and held pending its reuse in the future under a plan, in electric service. See Article 230 *Definitions and Instructions* No. 8 for detailed guidance.)

C. In the event that property recorded in this account shall no longer be needed or appropriate for future utility operations, the company shall request Board approval of journal entries to remove such property from this account when the gain realized from the sale or other disposition of the property is material, prior to their being recorded. Such filings shall include the description and original cost of individual properties removed from this account, the accounts charged upon removal, and any associated gains realized upon disposition of such property.

D. Gains or losses from the sale of land and land rights or other disposition of such property previously recorded in this account and not placed in utility service shall be recorded directly in Accounts 4345 or 4350, as appropriate, except when determined to be significant by the Board. Upon such a determination, the amounts shall be transferred to Account 2410, Deferred Gains from Disposition of Utility Plant, or Account 1530, Deferred Losses from Disposition of Utility Plant, and amortized to Accounts 4345, Gains from Disposition of Utility Plant, or 4350**,** Losses from Disposition of Utility Plant, as appropriate.

E. The property included in this account shall be classified according to the detail Accounts (1606 to 1990) prescribed for Electric Plant in Service and the account shall be maintained in such detail as though the property were in service.

2050 Completed Construction Not Classified–Electric

At the end of the year or such other date as a balance sheet may be required by the Board, this account shall include the total of the balances of work orders for electric plant which has been completed and placed in service but which work orders have not been classified for transfer to the detailed electric plant accounts.

Note: For the purpose of reporting to the Board the classification of Electric Plant in Service by Accounts (1606 to 1990), the utility shall also report the balance in this account tentatively classified as accurately as practicable according to prescribed account classifications. The purpose of this provision is to avoid any significant omissions in reported amounts of Electric Plant in Service.

2055 Construction Work in Progress–Electric

A. This account shall include the total of the balances of work orders for electric plant in process of construction.

B. Work orders shall be cleared from this account as soon as practicable after completion of the job. Further, if a project, such as a hydroelectric project, a steam station or a transmission line, is designed to consist of two or more units or circuits which may be placed in service at different dates, any expenditures which are common to and which will be used in the operation of the project as a whole shall be included in Electric Plant in Service upon the completion and the readiness for service of the first unit. All expenditures which are identified exclusively with units of property not yet in service shall be included in this account.

C. Expenditures on development projects for construction of utility facilities are to be included in a separate subdivision in this account. Records must be maintained to show separately each project along with complete detail of the nature and purpose of the development project together with the related costs.

2060 Electric Plant Acquisition Adjustments

A. This account shall include the difference between (1) the cost to the accounting utility of electric plant acquired as an operating unit or system by purchase, merger, consolidation, liquidation, or otherwise, and (2) the original cost, estimated, if not known, of such property, less the amount or amounts credited by the accounting utility at the time of acquisition to accumulated provisions for amortization and contributions in aid of construction with respect to such property. The goodwill shall be recorded as a debit in this account and the credit is to Account 3030, Miscellaneous Paid-in Capital in the case of goodwill resulting from pushdown accounting by the parent to its subsidiary.

B. This account shall be subdivided so as to show the amounts included for each property acquisition and to Electric Plant in Service, Electric Plant Held for Future Use and Electric Plant Leased to Others. (See Article 230 *Definitions and Instructions* No. 7.)

C. Amounts recorded in this account related to an operating unit or system acquisition may be amortized to Account 5720, Amortization of Electric Plant Acquisition Adjustments, pursuant to an approval or order of the Board, over a period not longer than the estimated remaining life of the properties to which such amounts relate.

D. Amounts included in this account shall be disposed subject to Board approval.

Note: The provisions of this account shall not be construed as approving or authorizing the recording of appreciation of electric plant.

2065 Other Electric Plant Adjustments

A. This account shall include the difference between the original cost, estimated if not known, and the book cost of electric plant to the extent that such difference is not included in Account 2060, Electric Plant Acquisition Adjustments (See Article 230 *Definitions and Instructions* No. 7 under —General classification of electric plant.)

B. Amounts included in this account shall be classified in such manner as to show the origin of each amount and shall be disposed of as the Board may approve or direct. Note**:** The provisions of this account shall not be construed as approving or authorizing the recording of appreciation of electric plant.

2070 Other Utility Plant
This account shall include the cost of land, structures, equipment and other tangible and intangible plant assets owned by the utility, but not used in its utility operations and not included in Accounts 2030, Electric Plant and Equipment Leased to Others, 2040, Electric Plant Held for Future Use, and 2055, Construction Work in Progress - Electric.
Non rate-regulated utility assets shall not be included in this account but in Account 2075.

2075 Non Rate-Regulated Utility Property Owned or Under Finance Leases
A. This account shall include the book cost of land, structures, equipment, or other tangible or intangible property owned by the utility or under a finance lease, but not used in utility service and not included in Account 2040, Electric Plant Held for Future Use.

B. This account shall also include the amount recorded under finance leases for property leased from others and used by the utility in its non rate-regulated utility operations. Records shall be maintained with respect to each lease reflecting: (1) name of lessor, (2) basic details of lease, (3) terminal date, (4) original cost or fair market value of property leased, (5) future minimum lease payments, (6) executory costs, (7) present value of minimum lessee payments, (8) the amount representing interest and the interest rate used, and (9) expenses paid.

C. This account shall be subdivided so as to show the amount of property used in operations which are non-utility in character but nevertheless constitute a distinct operating activity of the company and the amount of miscellaneous property not used in operations. The records in support of each sub-account shall be maintained so as to show an appropriate classification of the property.

Note A**:** The gain from the sale or other disposition of property included in this account which had been previously recorded in Account 2040, Electric Plant Held for Future Use, shall be accounted for in accordance with paragraph C of Account 2040.
Note B**:** The related obligations shall be recorded in Account 2285, Obligations Under Capital Leases - Current and Account 2325, Obligations Under Capital Leases - Non-current.

2075 Non Rate-Regulated Utility Property Owned or Under Finance Leases, Sub-account Generation Facility Assets
A. This account shall include the book cost of qualifying generation facilities or assets owned by the utility or under a finance lease, but not used in utility service and not included in Account 2040, Electric Plant Held for Future Use.

B. This account shall also include the amount recorded under finance leases for generation property leased from others and used by the utility in its non rate-regulated utility operations. Records shall be maintained with respect to each lease reflecting: (1) name of lessor, (2) basic details of lease, (3) terminal date, (4) original cost or fair market value of property leased, (5) future minimum lease payments, (6) executory costs, (7) present value of minimum lessee payments, (8) the amount representing interest and the interest rate used, and (9) expenses paid.

C. This account shall be subdivided so as to show the amount of property used in operations which are non-utility in character but nevertheless constitute a distinct operating activity of the company and the amount of miscellaneous property not used in operations. The records in support of each sub-account shall be maintained so as to show an appropriate classification of the generation property.

2105 Accumulated Depreciation of Electric Utility Plant – Property Plant and Equipment, Sub-account Accumulated Depreciation for Specifically Identified Asset Accounts
This sub-account will record the total amount of accumulated depreciation or accumulated amortization related to the below detailed asset accounts.
Electric Plant in Service – Detailed Accounts
Distribution Plant
1805 Land
1806 Land Rights (if applicable)
1808 Buildings and Fixtures
1810 Leasehold Improvements

Article 220 - Uniform System of Accounts
Income Statement
Distribution Expenses - Operations

5005 Operation Supervision and Engineering
This account shall include the cost of labour and expenses incurred in the general supervision and direction of the operation of the distribution system. Direct supervision of specific activities, such as station operation, line operation, meter department operation, etc., shall be charged to the appropriate operations account in the 5000 series based on the nature of the activity in relation to the account descriptions . (See Article 230 *Definitions and Instructions* No. 4.)

5010 Load Dispatching
This account shall include the cost of labour, materials used and expenses incurred in load dispatching operations pertaining to the distribution of electricity.

Example items:
Labour:
- Directing switching
- Arranging and controlling clearances for construction, maintenance, test and emergency purposes
- Controlling system voltages
- Preparing operating reports
- Obtaining reports on the weather and special events

Expenses:
- Communication service provided for system control purposes
- System record and report forms
- Meals, traveling and incidental expenses
- SCADA equipment related expenses

5012 Station Buildings and Fixtures Expenses
This account shall include the cost of labour, materials used and expenses incurred in operating distribution station building and fixtures recorded in Account 1808 Buildings and Fixtures and Account 1810 Leasehold Improvements.

Example items:
Labour:
- Standing watch, guarding and patrolling station and station yard
- Sweeping, mopping and tidying station
- Care of grounds, including snow removal, cutting grass, etc

Station Supplies and Expenses:

- Taxes (e.g. property taxes), light, heat, telephone
- Building service expenses
- Tool expenses
- Transportation expenses
- Meals, traveling and incidental expenses

The accounts shall be sub-divided to show the cost of operating individual stations.

5014 Transformer Station Equipment - Operating Labour

These accounts shall include labour with payroll burden incurred in operating the transformer station equipment recorded in Account 1815. The accounts shall be subdivided to obtain the cost of operating individual stations. General supervision shall be recorded in Account 5005.

Example items:

- Supervision specific to transformer station equipment operation
- Adjusting station equipment where such adjustment primarily affects performance, such as regulating the flow of cooling water, adjusting current in fields of a machine or changing voltage of regulators, changing station transformer taps
- Inspecting, testing and calibrating station equipment for the purpose of checking its performance
- Keeping station log and records and preparing reports on station equipment operation
- Operating switching and other station equipment

5015 Transformer Station Equipment - Operating Supplies and Expenses

These accounts shall include the cost of material, trucking and other expenses incurred in operating the transformer station equipment recorded in Account 1815.

Example items:

- Operating supplies, such as lubricants, commutator brushes, water, and rubber goods
- Station meter and instrument supplies, such as ink and charts
- Station record and report forms
- Small hand tools
- Transportation expenses
- Meals, traveling, and incidental expenses

5016 Distribution Station Equipment - Operating Labour

These accounts shall include labour with payroll burden incurred in operating the transformer station equipment recorded in Account 1820. The accounts shall be subdivided to obtain the cost of operating individual stations. General supervision shall be recorded in Account 5005.

Example items:

- Supervision specific to transformer station equipment operation
- Adjusting station equipment where such adjustment primarily affects performance, such as regulating the flow of cooling water, adjusting current in fields of a machine or changing voltage of regulators, changing station transformer taps
- Inspecting, testing and calibrating station equipment for the purpose of checking its performance
- Keeping station log and records and preparing reports on station equipment operation
- Operating switching and other station equipment

Note: If the utility owns storage battery equipment used for supplying electricity to customers in periods of emergency, the cost of operating labour should be recorded in this account and the cost of supplies, such as acid, gloves, hydrometers, thermometers, soda, automatic cell fillers, acid

proof shoes, etc., shall be included in Account 5017. If significant in amount, a separate subdivision in each account shall be maintained for such expenses.

5017 Distribution Station Equipment - Operating Supplies and Expenses
These accounts shall include the cost of material, trucking and other expenses incurred in operating the transformer station equipment recorded in Account 1820.

Example items:

- Operating supplies, such as lubricants, commutator brushes, water, and rubber goods
- Station meter and instrument supplies, such as ink and charts
- Station record and report forms
- Small hand tools
- Transportation expenses
- Meals, traveling, and incidental expenses

5020 Overhead Distribution Lines and Feeders - Operation Labour
This account shall include labour with payroll burden incurred in operating overhead lines from the low voltage connection in the distribution station to the customers' premises but not operating labour incurred in relation to customer premises (Account 5070).

Example items

- Supervision specific to line operation
- Changing line transformer taps
- Inspecting and testing lightning arresters, line circuit breakers, switches and grounds
- Inspecting and testing line transformers for the purpose of determining load, temperature or operating performance
- Patrolling lines
- Load tests and voltages surveys of feeders and circuits

5025 Overhead Distribution Lines and Feeders - Operation Supplies and Expenses
These accounts shall include the cost of material, trucking and other expenses incurred in operating overhead lines from the low voltage connection in the distribution station to the customer's premises but not operating supplies and expenses incurred in relation to customer premises (Account 5075).

Line Supplies and Expenses examples:

- Voltage surveys, either routine or upon request of customers, including voltage tests at customers' main switch
- Transferring loads, switching and reconnecting circuits and equipment for operation purposes
- Electrolysis surveys
- Inspecting and adjusting line testing equipment
- Tool expenses
- Transportation expenses
- Meals, traveling and incidental expense
- Operating supplies, such as instrument charts, rubber goods, etc

5030 Overhead Subtransmission Feeders - Operation
These accounts shall include labour with payroll burden, material, trucking and other expenses incurred in inspecting, patrolling and testing the overhead sub transmission feeder system.

5035 Overhead Distribution Transformers - Operation
This account shall include labour with payroll burden, material, trucking and other expenses incurred in removing and resetting overhead transformers and devices and also the inspection and testing while in service. The account shall be subdivided as necessary.
Note: The cost of the original setting shall be charged to Account 1850, Line Transformers.

5040 Underground Distribution Lines and Feeders - Operation Labour
These accounts shall include labour with payroll burden incurred in operating underground distribution lines from the low voltage connection in the municipal distribution station to the customers' premises but not operating labour incurred in relation to customer premises (Account 5070).

Line Labour examples:

- Supervision specific to line operation
- Changing line transformer taps
- Inspecting and testing lightning arresters, line circuit breakers, switches and grounds
- Inspecting and testing line transformers for the purpose of determining load, temperature or operating performance
- Patrolling lines
- Load tests and voltages surveys of feeders and circuits

5045 Underground Distribution Lines and Feeders - Operation Supplies and Expenses
These accounts shall include the cost of material, trucking and other expenses incurred in operating underground distribution lines from the low voltage connection in the municipal distribution station to the customers' premises but not operating supplies and expenses incurred in relation to customer premises (Account 5070).

Example items

- Voltage surveys, either routine or upon request of customers, including voltage tests at customers' main switch
- Transferring loads, switching and reconnecting circuits and equipment for operation purposes
- Electrolysis surveys
- Inspecting and adjusting line testing equipment
- Tool expenses
- Transportation expenses
- Meals, traveling and incidental expense
- Operating supplies, such as instrument charts, rubber goods, etc

5050 Underground Subtransmission Feeders - Operation
These accounts shall include labour with payroll burden, material, trucking and other expenses incurred in inspecting, patrolling and testing the underground subtransmission feeder system.

5055 Underground Distribution Transformers - Operation
This account shall include labour with payroll burden, material, trucking and other expenses incurred in removing and resetting underground transformers and devices and also the inspection and testing while in service. The account shall be subdivided as necessary.
Note: The cost of the original setting shall be charged to Account 1850, Line Transformers.

5060 Street Lighting and Signal System Expenses
This account shall include the cost of labour, materials used and expenses incurred in the operation of such plant owned by the utility, if authorized by the Board and where such work is done regularly as a part of the street lighting and signal system service.

Example items:

Labour:

- Supervision specific to street lighting and signal systems operation
- Replacing lamps and consequential cleaning of glassware and fixtures
- Routine patrolling for lamp outages, extraneous nuisances or encroachments, etc
- Testing lines and equipment including voltage and current measurement
- Winding and inspection of time switch and other controls

Materials and Expenses:

- Street lamp renewals
- Transportation and tool expense
- Meals, traveling, and incidental expenses

Note: Where the utility does not own the street lighting assets, the revenues and expenses from the provision or maintenance of street lighting services should be recorded in Account 4375, Revenues from Non-Utility Operations and 4380, Expenses from Non-Utility Operations, respectively.

5065 Meter Expenses

This account shall include the cost of labour, materials used and expenses incurred in the operation of customer meters and associated equipment.

Example items:

Labour:

- Supervision specific to meter operation
- Clerical work on meter history and associated equipment record cards, test cards, and reports
- Disconnecting and reconnecting, removing and reinstalling, sealing and unsealing meters and other metering equipment in connection with initiating or terminating services including the cost of obtaining meter readings, if incidental to such operation
- Consolidating meter installations due to elimination of separate meters for different rates of service
- Changing or relocating meters, instrument transformers, time switches, and other metering equipment
- Resetting time controls, checking operation of demand meters and other metering equipment, when done as an independent operation
- Inspecting and adjusting meter testing equipment
- Inspecting and testing meters, instrument transformers, time switches, and other metering equipment on premises or in shops excluding inspecting and testing incidental to maintenance
- Replacing or removing broken meters

Materials and Expenses:

- Meter seals and miscellaneous meter supplies
- Transportation expenses
- Meals, traveling, and incidental expenses
- Tool expenses
- Replacing or removing broken meters

Note: The cost of the first setting, including the government inspection fee, and testing of a meter is chargeable to utility plant Account 1860, Meters. The cost of removing and resetting for government inspection, including the fees, shall be a charge to this account.

5070 Customer Premises - Operating Labour

This account shall include labour with payroll burden related to providing service on assets on customers' premises which are included in Account 1855, Services.

Example items:

- Inspecting premises, including check of wiring for code compliance
- Investigating, locating, and clearing grounds on customers' wiring
- Investigating service complaints, including load tests of motors and lighting and power circuits on customers' premises; field investigations of complaints on bills or of voltage
- Radio, television and similar interference work including erection of new aerials on customers' premises and patrolling of lines, testing of lightning arresters, inspection of pole hardware, etc., and examination of customers' wiring to locate cause of interference
- Investigation of current diversion including setting and removal of check meters discovery and settlement of current diversion
- Changes in customer wiring and any other labour cost identifiable as caused by current diversion

Note A: Amounts billed customers for any work, the cost of which is charged to this account, shall be transferred to Account 4235, Miscellaneous Service Revenues.
Note B: Do not include in this account expenses incurred in connection with merchandising.

5075 Customer Premises - Materials and Expenses
This account shall include trucking, materials and other expenses related to providing services to assets on customers' premises which are included in Account 1855, Services.

Examples of services include inspection, voltages tests and the like related to labour examples listed in 5070, Customer Premises - Operating Labour.

Example items:
Materials and Expenses:

- Lamp and fuse renewals
- Materials used in the course of performing inspection, voltage tests, etc
- Tool expense
- Transportation expense, including pickup and delivery charges
- Meals, traveling and incidental expenses
- Rewards paid for discovery of current diversion

Note A: Amounts billed customers for any work, the cost of which is charged to this account, shall be transferred to Account 4235, Miscellaneous Service Revenues.
Note B: Do not include in this account expenses incurred in connection with merchandising and contract work.

5085 Miscellaneous Distribution Expenses
This account shall include the cost of labour, materials used and expenses incurred in distribution system operation not provided for elsewhere.

Example items:
Labour:

- General records of physical characteristics of lines and substations, such as capacities, etc
- Ground resistance records
- Joint pole maps and records
- Distribution system voltage and load records
- Preparing maps and prints
- Service interruption and trouble records
- General clerical and stenographic work except that chargeable to account 5065, Meter expenses

Material and Expenses:

- Operating records covering poles, transformers, manholes, cables, and other distribution facilities. Exclude meter records chargeable to Account 5065, Meter Expenses and station records chargeable to Account 5012, Station Building and Fixtures Expenses
- Janitorial work at distribution office buildings including snow removal, cutting grass, etc
- Communication service
- Building service expenses
- Miscellaneous office supplies and expenses, printing, and stationery, maps and records and first aid supplies
- Research, development, and demonstration expenses

5090 Underground Distribution Lines and Feeders - Rental Paid
This account shall include rents of property of others used, occupied, or operated in connection with the distribution system, including payments to the government authorities and others for the use and occupancy of public lands and reservations for underground distribution line rights of way. (See Article 230 *Definitions and Instructions* No. 5.) Records should permit identification of payments and parties to whom they were made.

5095 Overhead Distribution Lines and Feeders - Rental Paid
This account shall include rents of property of others used, occupied, or operated in connection with the distribution system, including payments to the government authorities and others for the use and occupancy of public lands and reservations for overhead distribution line rights of way. (See Article 230 *Definitions and Instructions* No. 5.) Records should permit identification of payments and parties to whom they were made.

5096 Other Rent
This account shall include rents for property of others used, occupied or operated in connection with the operation of the distribution system. Include rentals paid for railroad crossings, rights of ways, payments to government bodies and others for use of public or private land, etc., not otherwise included in Accounts 5090, Underground Distribution Lines and Feeders Rental Paid or 5095, Overhead Distribution Lines and Feeders - Rental Paid.

5105 Maintenance Supervision and Engineering
This account shall include the cost of labour and expenses incurred in the general supervision and direction of maintenance of the distribution system that cannot be directly allocated to any particular job/project. Direct field supervision of specific jobs shall be charged to the appropriate maintenance account in the 5100 series based on the nature of the activity in relation to the account descriptions. (See Article 230 *Definitions and Instructions* No. 4.)

5110 Maintenance of Buildings and Fixtures - Distribution Stations
This account shall include the cost of labour, materials used and expenses incurred in maintenance of structures, the book cost of which is included in Account 1808, Buildings and Fixtures, and 1810, Leasehold Improvements.

5112 Maintenance of Transformer Station Equipment
This account shall include the cost of labour, materials used and expenses incurred in maintenance of plant, the book cost of which is included in Account 1815, Transformer Station Equipment - Normally Primary above 50kV.

5114 Maintenance of Distribution Station Equipment
This account shall include the cost of labour, materials used and expenses incurred in maintenance of plant, the book cost of which is included in Account 1820, Distribution Station Equipment - Normally Primary below 50kV, and Account 1825, Storage Battery Equipment.

Records should permit the identification of expenses relating to each type of equipment listed above.

5120 Maintenance of Poles, Towers and Fixtures
This account shall include the cost of labour, materials used and expenses incurred in the maintenance of overhead distribution line facilities, the book cost of which is included in Account 1830, Poles, Towers and Fixtures.

Example items:

Work of the following character on poles, towers, and fixtures:

- Installing additional clamps or removing clamps or strain insulators on guys in place.
- Moving line or guy pole in relocation of pole or section of line.
- Painting poles, towers, cross arms, or pole extensions.
- Readjusting and changing position of guys or braces.
- Realigning and straightening poles, cross arms, braces, pins, racks, brackets, and other pole fixtures.
- Reconditioning reclaimed pole fixtures.
- Relocating crossarms, racks, brackets, and other fixtures on poles.
- Repairing pole supported platform.
- Repairs by others to jointly owned poles.
- Shaving, cutting rot, or treating poles or crossarms in use or salvaged for reuse.
- Stubbing poles already in service.
- Supporting conductors, transformers, and other fixtures and transferring them to new poles during pole replacements.
- Maintaining pole signs, stencils, tags, etc.

The accounts shall be subdivided to show costs for subtransmission feeders and distribution lines and feeders separately.

5125 Maintenance of Overhead Conductors and Devices
This account shall include the cost of labour, materials used and expenses incurred in the maintenance of overhead distribution line facilities, the book cost of which is included in Account 1835, Overhead Conductors and Devices.

Example items:

Work of the following character on overhead conductors and devices:

- Overhauling and repairing line cutouts, line switches, line breakers, and capacitor installations
- Cleaning insulators and bushings
- Refusing line cutouts
- Repairing line oil circuit breakers and associated relays and control wiring. Repairing grounds
- Resagging, retying, or rearranging position or spacing of conductors
- Standing by phones, going to calls, cutting faulty lines clear or similar activities at times of emergency
- Sampling, testing, changing, purifying, and replenishing insulating oil
- Transferring loads, switching, and reconnecting circuits and equipment for maintenance purposes
- Repairing line testing equipment

The accounts shall be subdivided to show costs for subtransmission feeders and distribution lines and feeders separately.

5130 Maintenance of Overhead Services
This account shall include the cost of labour, materials used and expenses incurred in the maintenance of overhead distribution line facilities, the book cost of which is included in Account 1855, Services.

Example items:
Work of the following character on overhead services:

- Moving position of service either on pole or on customers' premises
- Pulling slack in service wire
- Retying service wire
- Refastening or tightening service bracket

5135 Overhead Distribution Lines and Feeders - Right of Way
These accounts shall include labour with payroll burden, material, trucking, and other expenses incurred in connection with tree trimming, etc. and other costs incurred in maintaining right of way subsequent to construction of a line.

These accounts may be further subdivided as follows:

- Labour and Payroll Burden
- Material
- Truck Expense
- Other Expense

5145 Maintenance of Underground Conduit
This account shall include the cost of labour, materials used and expenses incurred in the maintenance of underground distribution line facilities, the book cost of which is included in account 1840, Underground Conduit.

Example items

- Cleaning ducts, manholes, and sewer connections
- Moving or changing position of conduit or pipe
- Minor alterations of hand holes, manholes, or vaults
- Refastening, repairing, or moving racks, ladders, or hangers in manholes or vaults
- Plugging and shelving ducts
- Repairs to sewers, drains, walls, and floors, rings and covers

The accounts shall be subdivided to show costs for sub transmission feeders and distribution lines and feeders separately.

5150 Maintenance of Underground Conductors and Devices
This account shall include the cost of labour, materials used and expenses incurred in the maintenance of underground distribution line facilities, the book cost of which is included in Account 1845, Underground Conductors and Devices.

Example items:
Work of the following character on underground conductors and devices:

- Repairing circuit breakers, switches, cutouts, network protectors, and associated relays and control wiring
- Repairing grounds
- Retraining and reconnecting cables in manholes including transfer of cables from one duct to another
- Repairing conductors and splices
- Repairing or moving junction boxes and potheads
- Refireproofing cables and repairing supports

- Repairing electrolysis preventive devices for cables
- Repairing cable bonding systems
- Sampling, testing, changing, purifying and replenishing insulating oil
- Transferring loads, switching and reconnecting circuits and equipment for maintenance purposes
- Repairing line testing equipment
- Repairing oil or gas equipment in high voltage cable systems and replacement of oil or gas

The accounts shall be subdivided to show costs for sub transmission feeders and distribution lines and feeders separately.

5155 Maintenance of Underground Services

This account shall include the cost of labour, materials used and expenses incurred in the maintenance of underground distribution line facilities, the book cost of which is included in the underground portion of Account 1855, Services.

Example items:

Work of the following character on underground services:

- Cleaning ducts
- Repairing any underground service plant

5160 Maintenance of Line Transformers

This account shall include the cost of labour, materials used and expenses incurred in maintenance of distribution line transformers, the book cost of which is included in Account 1850, Line Transformers. The cost shall include renewing oil, painting and the like, necessary to keep the equipment in service.

Note: All lightning arresters on the distribution system, excluding pothead arresters, are considered to be transformer equipment or devices and the maintenance thereof is chargeable to this account. Records shall be kept to separately show costs related to overhead and underground transformers.

5165 Maintenance of Street Lighting and Signal Systems

This account shall include the cost of labour, materials used and expenses incurred in maintenance of plant, the book cost of which is included in Account 1875, Street Lighting and Signal Systems.

5170 Sentinel Lights - Labour

This account shall include labour related to servicing rental sentinel lights.

5172 Sentinel Lights - Materials and Expenses

This account shall include trucking, materials and other expenses related to servicing rental sentinel lights.

5175 Maintenance of Meters

This account shall include the cost of labour, materials used and expenses incurred in the maintenance of meters and meter testing equipment, the book cost of which is included in Account 1860, Meters, and Account 1945, Measurement and Testing Equipment, respectively.

The cost shall include cleaning and painting and other work necessary to keep the equipment in service. The labour and expenses incident to the operation of the meter repair department shall be a charge to these accounts.

5178 Customer Installations Expenses - Leased Property

This account shall include the cost of labour, materials used and expenses incurred in work on customer installations of leased property included in account 1870, Leased Property on Customer Premises and in rendering services to customers of the nature of those indicated by the list of items hereunder.

Example items:
Labour:

- Supervision specific to customer installations work
- Installing, connecting, reinstalling, or removing leased property on customers' premises
- Testing, adjusting, and repairing customers' fixtures and appliances in shop or on premises
- Cost of changing customers' equipment due to changes in service characteristics

Materials and Expenses:

- Materials used in servicing customers' fixtures, appliances and equipment
- Power, light, heat, telephone, and other expenses of appliance repair department
- Tool expense
- Transportation expense, including pickup and delivery charges
- Meals, traveling and incidental expenses

5195 Maintenance of Other Installations on Customer Premises
This account shall include the cost of labour, materials used and expenses incurred in maintenance of plant the book cost of which is included in Account 1865, Other Installations on Customer Premises.

5205 Purchase of Transmission and System Services
This account will be used to record expenses related to purchase of transmission and system services.

5210 Transmission Charges
This account will be used to record Transmission Charges incurred.

5215 Transmission Charges Recovered
This account will be used to record Transmission Charges recovered from customers. Records shall be maintained so that the quantity of electricity supplied each party and the related revenues shall be readily available.

Article 220 – Uniform System of Accounts
Electric Plant in Service - Detailed Accounts
A. Intangible Plant

1606 Organization
This account shall include all fees paid to federal or provincial governments for the privilege of incorporation and expenditures incident to organizing the corporation, and putting it into readiness to do business.

Example items
- Cost of obtaining certificates authorizing an enterprise to engage in the public utility business
- Fees and expenses for incorporation
- Fees and expenses for mergers or consolidations
- Office expenses incident to organizing the utility
- Stock and minute books and corporate seal.

Note A: This account shall not include any discounts upon securities issued or assumed; nor shall it include any costs incident to negotiating loans, selling bonds or other evidences of debt or expenses in connection with the authorization, issuance or sale of capital stock.
Note B: When charges are made to this account for expenses incurred in mergers, consolidations, or reorganizations, etc. amounts previously included herein or in similar accounts in the books of the entities concerned shall be excluded from this account.
Note C: This account shall include amounts related to transfer by-laws.

1608 Franchises and Consents
A. This account shall include amounts paid to the federal, provincial, or other government in consideration for franchises, consents, water power licenses, or certificates, running in perpetuity or for a specified term of more than one year, together with necessary and reasonable expenses incident to procuring such franchises, consents, water power licenses, or certificates of permission and approval.
B. If a franchise, consent, water power license or certificate is acquired by assignment, the charge to this account shall not exceed the amount paid by the utility.
C. The amortization related to any item in this account shall be recorded in Account 2120, Accumulated Amortization of Electric Utility Plant - Intangibles.
D. Records supporting this account shall be kept so as to show separately the book cost of each franchise or consent.
Note: Annual or other periodic payments under franchises shall not be included herein but in the appropriate operating expense account.

1609 Capital Contributions Paid
This account shall include capital contributions paid by a distributor to a host distributor, a transmitter or a generator for capital expenditures (e.g., under a Connection and Cost Recovery Agreement) that meet the IAS 38 Intangible Assets requirements for classification as an intangible asset. The amortization related to any item in this account shall be recorded in Account 2120, Accumulated Amortization of Electric Utility Plant – Intangibles.

1610 Miscellaneous Intangible Plant
A. This account shall include the cost of patent rights, licenses, privileges, capitalizable load profile development costs and other intangible property necessary or valuable in the conduct of utility operations and not specifically chargeable to any other account.

B. The amortization related to any item in this account shall be recorded in Account 2120, Accumulated Provision for Amortization of Electric Utility Plant - Intangibles.
C. This account shall be maintained in such a manner that the utility can furnish full information with respect to the amounts included herein.

1611 Computer Software
This account shall include the cost of developed or purchased computer operating and application software that is material in amount.

Example items:

- Accounting packages
- Customer Information System (CIS)
- Groupware packages (e.g. e-mail, scheduling & conferencing programs, etc.)
- Database management system packages
- Software development tools.
- Primary development tools.

1612 Land Rights
This account(s) shall include the cost of rights, interests and privileges held by the utility in land owned by others. See Article 230 Definitions and Instructions No. 8 for detail guidance.
Note: Do not include in this account the cost of permits to erect poles, towers, etc., or to trim trees. See Account 1830, Poles, Towers and Fixtures, and Account 5135, Overhead Distribution Lines and Feeders - Tree Trimming.

OVERHEAD COSTS

Overhead capitalization is a function of the overall type and nature of the capital work being executed by Toronto Hydro. There have been no changes in the utility's overhead expense capitalization policy since its last rebasing application. In accordance with section 2.2.2.4 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (July 12, 2018), OEB Appendix 2-D has been filed at Exhibit 2A, Tab 5, Schedule 2, Appendix A.

1. BACKGROUND

Consistent with the OEB's expectations, Toronto Hydro converted to International Financial Reporting Standards ("IFRS") effective January 1, 2015.[1] This application represents Toronto Hydro's second rebasing application under Modified International Financial Reporting Standards ("MIFRS").

[1] Filing Requirements, s. 2.0.9 - "Accounting Matters".

OEB Appendix 2-D
Overhead Expense

Applicants are to provide a breakdown of OM&A before capitalization in the below table. OM&A before capitalization may be broken down by cost center, program, drivers or another format best suited to focus on capitalized vs. uncapitalized OM&A.

OM&A Before Capitalization	2015 Historical Year	2016 Historical Year	2017 Historical Year	2018 Bridge Year	2019 Bridge Year	2020 Test Year
Operations	146.9	155.1	153.6	159.7	166.7	169.0
Maintenance	73.6	65.1	68.5	69.1	71.2	72.0
Billing and Collecting	36.8	34.0	35.9	40.8	41.5	45.8
Community Relations	3.5	2.5	2.4	2.6	2.7	2.8
Administrative and General	90.4	98.2	104.5	103.4	104.9	109.4
Taxes Other Than Income Taxes	5.2	4.6	5.3	5.6	5.4	5.5
Donations	1.0	1.0	1.0	0.9	0.9	1.0
Total OM&A Before Capitalization (B)	$ 357.4	$ 360.6	$ 371.1	$ 382.0	$ 393.4	$ 405.6

Applicants are to provide a breakdown of capitalized OM&A in the below table. Capitalized OM&A may be broken down using the categories listed in the table below if possible. Otherwise, applicants are to provide its own break down of capitalized OM&A.

Capitalized OM&A	2015 Historical Year	2016 Historical Year	2017 Historical Year	2018 Bridge Year	2019 Bridge Year	2020 Test Year	Directly Attributable? (Yes/No)	Explanation for Change in Overhead Capitalized
Labour Capitalization	(99.1)	(95.6)	(101.1)	(105.4)	(109.8)	(112.5)	Yes	
Vehicle Capitalization	(4.2)	(4.3)	(4.5)	(3.8)	(3.9)	(4.1)	Yes	
Material Handling On-cost	(10.2)	(10.8)	(10.3)	(11.6)	(11.6)	(11.5)	Yes	
Total Capitalized OM&A (A)	(113.4)	(110.8)	(115.9)	(120.8)	(125.2)	(128.1)		
% of Capitalized OM&A (=A/B)	-32%	-31%	-31%	-32%	-32%	-32%		

COST OF ELIGIBLE INVESTMENTS FOR THE CONNECTION OF QUALIFYING GENERATION FACILITIES

Section 2.2.2.7 of the OEB's Filing Requirements for Electricity Distributor Rate Applications[1] contemplates that a distributor will file for provincial rate protection associated with any costs incurred to make eligible investments.[2]

In accordance with the cost responsibility rules in the OEB's Distribution System Code ("DSC"), costs incurred by a distributor for the purpose of connecting or enabling the connection of a Renewable Energy Generation ("REG") facility to its distribution system are considered eligible investments for the purpose of provincial rate recovery under s. 79.1 of the *Ontario Energy Board Act, 1998*.[3]

1. REG CONNECTIONS

Significant renewable generation activity exists across Toronto Hydro's distribution system. As of December 31, 2017, Toronto Hydro connected 1,750 REG projects representing over 96 MW of capacity, and has undertaken approximately 540 MW of pre-assessment capacity reviews. Toronto Hydro anticipates 1,312 new REG connections during the 2018 through 2024 period, with a corresponding capacity of 116 MW. By the end of 2024, Toronto Hydro anticipates that approximately 212 MW of REG capacity will be connected to its distribution system.[4]

[1] Ontario Energy Board, Filing Requirements for Electricity Distributor Rate Applications, Chapter 2 (July 12, 2018).
[2] As described in section 79.1 of the *Ontario Energy Board Act, 1998* (the "Act") and O. Reg. 330/09 made under the Act.
[3] O. Reg. 330/09, at s. 1(2).
[4] For further information, please refer to Customer Connections (Exhibit 2B, Section E5.1).

Some REG projects are currently unable to connect to Toronto Hydro's system due to short-circuit limits on station equipment, feeder thermal limits, fault current, anti-islanding, and limited ability to transfer loads between feeders in the event of a contingency. The primary constraint at this time is short circuit capacity at the station bus.

2. ELIGIBLE INVESTMENTS SUMMARY

To address interconnection constraints at the distribution level, Toronto Hydro proposes to undertake a number of Renewable Enabling Improvement ("REI") investments as part of its 2020-2024 Distribution System Plan ("DSP"), which is filed at Exhibit 2B.

2.1 Generation Protection, Monitoring, and Control

Installation of Bus-Tie Reactors: Bus-tie reactors lower the short circuit current on the station bus and distribution system by insertion of an impedance at the bus-tie point. This method of fault mitigation has been successfully applied by PowerStream, Guelph Hydro, and Hydro One Networks Inc. ("Hydro One"). Toronto Hydro proposes to work with Hydro One to install bus-tie reactors at Ellesmere, Esplanade, Fairbank, Horner, and Sheppard TS to eliminate the existing fault current constraint, which will enable REG connections. For additional details, please refer to the Generation Protection, Monitoring, and Control Program (Exhibit 2B, Section E5.5).

Remote Monitoring and Control of Generation (SCADA): During the 2015-2019 plan period, Toronto Hydro has been installing monitoring and control systems for all new distributed generation ("DG") connections. This has provided system planners and operators with the visibility required to monitor generation to load ratios in real time to ensure all DG sites are de-energized in the event of a system fault. With the continued

implementation of the Generation Protection, Monitoring, and Control program (Exhibit 2B, E5.5), Toronto Hydro will be able to actively monitor and control DGs in real time to ensure these ratios are within tolerable levels and the anti-islanding feature of DG facilities can properly operate in the event of a distribution system fault. These real-time monitoring and control systems communicate with REG resources via communication networks connected to the utility's supervisory control and data acquisition ("SCADA") system to enable safe operation of the distribution system and feeder management of bi-directional distribution grid flows. The system has the ability to forecast resources and coordinate with Toronto Hydro's distribution outage management system, thereby enabling greater REG penetration providing real-time visibility. Toronto Hydro's requirement for monitoring and control is modelled after requirements developed by the IESO. Consistent with the DSC, the costs associated with this investment program pertains only to renewable generation resources, as conventional generation projects bear the cost of monitoring and control requirements. For additional details, please refer to the Generation Protection, Monitoring, and Control program (Exhibit 2B, Section E5.5).

2.2 Energy Storage

Toronto Hydro plans to install five energy storage systems on three distribution feeders that are forecast to have high generator to minimum load ratios over the 2020-2024 period. These energy storage systems represent a total aggregated peak capacity of 2.5 MW and aggregated energy capacity of 10 MWh. Toronto Hydro's infrastructure was not designed to accommodate two-way, variable REG resources. These energy storage systems will balance energy flows in specific areas, allowing renewable generation connections to proceed and helping defer the need for conventional infrastructure

upgrades. For additional details, please refer to the Energy Storage Systems program (Exhibit 2B, Section E7.2).

The IESO reviewed Toronto Hydro's plans for REG investments and found that: (i) the utility's plans are substantially consistent with that of IESO; and (ii) although specific REG investments are not included in the most recent Integrated Regional Resource Plan ("IRRP"), addressing barriers to connecting additional DG within Toronto Hydro's service area is consistent with regional planning principles. IESO concurs that removing technical barriers to new DG connections can provide lasting benefits. For more information, please refer to the IESO Comment Letter filed at Exhibit 2B, Section B, Appendix F.

3. ELIGIBLE INVESTMENTS COSTS

Table 1, below, summarizes the costs associated with Toronto Hydro's planned REI investments over the 2020 to 2024 plan period. Toronto Hydro is not proposing any specific Renewable Expansion[5] ("RE") investments during 2020-2024. However, certain demand response investments in the Station Expansion program (Exhibit 2B, Section E7.4) are expected to improve the utility's ability to connect REG facilities.

Table 1: Renewable Enabling Improvements ("REI") from 2020-2024 ($ Millions)

Capital Program	2020	2021	2022	2023	2024	Total
Generation, Protection, Monitoring, and Control	3.7	2.3	2.4	2.5	2.7	8.6
Energy Storage	1.0	1.0	1.0	1.0	1.0	5.0
Totals	**4.7**	**3.3**	**3.4**	**3.5**	**3.7**	**13.6**

[5] As defined in Section 3.2.30 of the Distribution System Code.

4. PROVINCIAL RATE PROTECTION

Toronto Hydro applied the six percent direct benefit percentage provided by the OEB with respect to REI investments to calculate the provincial rate protection amounts. The detailed breakdown is provided in the OEB Appendices 2-FA and 2-FB at Exhibit 2A, Tab 8, Schedules 2 and 3.[6]

Two versions of the OEB Appendices 2-FA and 2-FB are filed: one for Energy Storage and one for Generation, Protection, Monitoring, and Control systems. This is necessary as the life spans of these assets are different.

Further, the OEB Appendices reflect opening balances, which arise from the REI investments approved by the OEB in the utility's 2015-2019 Rate Application.[7] The opening balances reflect the current forecast for those programs previously approved by the OEB.

[6] Appendix 2-FC provided in Schedule 4 is not applicable.
[7] EB-2014-0116, Toronto Hydro-Electric System Limited Decision and Order (December 29, 2015).

OEB Appendix 2-FA
Renewable Generation Connection Investment Summary (past investments or over the future rate setting period) - Energy Storage

Enter the details of the Renewable Generation Connection projects as described in the appropriate section of the Filing Requirements.
All costs entered on this page will be transferred to the appropriate cells in the appendices that follow.

For Part A, Renewable Enabling Improvements (REI), these amounts will be transferred to Appendix 2 - FB
For Part B, Expansions, these amounts will be transferred to Appendix 2 - FC

If there are more than **five** projects proposed to be in-service in a certain year, please amend the tables below and ensure that the formulae for the Total Amounts in any given rate year are updated.
Based on the current methodology and allocation, amounts allocated represent 6% for REI Connection Investments and 17% for Expansion Investments. (EB-2009-0349, 6-10-2010, p. 15, note 9)

There are two scenarios described below. Separate sets of spreadsheets (2-FA, 2-FB, 2-FC) should be submited for each scenario as required.

Scenario 1: **Past Investments with No Recovery.** The distributor has made investments in the past (during the IRM Years), but has not received approval for these projects and therefore did not receive revenue from the IESO under Regulation 330/09 and did not receive ratepayer revenue for the direct benefit portion of the investment.
The WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage should correspond to the distributor's last Cost of Service approval.
The Direct Benefit portion of the calculated Revenue Requirement for each year should be summed and can be applied for recovery from the distributor's ratepayers through a rate rider.
The Provincial Recovery portion of the calculated Revenue Requirement for each year should be summed and can be applied for recovery from the IESO through a separate order.

Scenario 2: **Investments in the Test Year and Beyond.** Distributor plans to make investments in 2017 and/or beyond. These investments should be added to 2-FA in the appropriate year.
The WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage should correspond to the distributor's current application.

Part A

REI Investments (Direct Benefit at 6%)	2020	2021	2022	2023	Test Year 2024
Project 1					
REI Investments (Direct Benefit at 6%)					
Capital Costs	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,000,000
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 2					
Name: REI Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 3					
Name: REI Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 4					
Name: REI Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 5					
Name: REI Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Total Capital Costs	**$ 1,000,000**	**$ 1,000,000**	**$ 1,000,000**	**$ 1,000,000**	**$ 1,000,000**
Total OM&A (Start-Up)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Ongoing)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

OEB Appendix 2-FA
Renewable Generation Connection Investment Summary (past investments or over the future rate setting period) - Energy Storage

Part B

Expansion Investments (Direct Benefit at 17%)	2016	2017	2018	2019	Test Year 2020
Project 1					
Name: Expansion Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 2					
Name: Expansion Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 3					
Name: Expansion Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 4					
Name: Expansion Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 5					
Name: Expansion Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Total Capital Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Start-Up)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Ongoing)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

OEB Appendix 2-FB
Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Enabling Improvement Investments
Energy Storage

This table will calculate the distributor/provincial shares of the investments entered in Part A of Appendix 2-FA.
Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage.
For historical investments, enter these variables for your last cost of service test year. For 2020 and beyond, enter variables as in the application.
Rate Riders are not calculated for the Test Year as these assets and costs are already in the distributor's rate base/revenue requirement.

		2020			2021			2022			2023			2024		
			Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
		Total	6%	94%	Total	6%	94%	Total	6%	94%	Total	6%	94%	Total	6%	94%
Net Fixed Assets (average)		$ 8,507,196	$ 510,432	$ 7,996,765	$ 8,863,312	$ 531,799	$ 8,331,513	$ 9,152,761	$ 549,166	$ 8,603,595	$ 9,375,543	$ 562,533	$ 8,813,011	$ 9,531,659	$ 571,900	$ 8,959,760
Incremental OM&A (on-going, N/A for Provincial Recovery)		$0	$ -		$0	$ -		$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recovery)		$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA	6.4%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base			$ 510,432	$ 7,996,765		$ 531,799	$ 8,331,513		$ 549,166	$ 8,603,595		$ 562,533	$ 8,813,011		$ 571,900	$ 8,959,760
Deemed ST Debt	4%		$ 20,417	$ 319,871		$ 21,272	$ 333,261		$ 21,967	$ 344,144		$ 22,501	$ 352,520		$ 22,876	$ 358,390
Deemed LT Debt	56%		$ 285,842	$ 4,478,188		$ 297,807	$ 4,665,647		$ 307,533	$ 4,818,013		$ 315,018	$ 4,935,286		$ 320,264	$ 5,017,465
Deemed Equity	40%		$ 204,173	$ 3,198,706		$ 212,719	$ 3,332,605		$ 219,666	$ 3,441,438		$ 225,013	$ 3,525,204		$ 228,760	$ 3,583,904
ST Interest	2.61%		$ 533	$ 8,349		$ 555	$ 8,698		$ 573	$ 8,982		$ 587	$ 9,201		$ 597	$ 9,354
LT Interest	3.71%		$ 10,605	$ 166,141		$ 11,049	$ 173,096		$ 11,409	$ 178,748		$ 11,687	$ 183,099		$ 11,882	$ 186,148
ROE	8.82%		$ 18,008	$ 282,126		$ 18,762	$ 293,936		$ 19,375	$ 303,535		$ 19,846	$ 310,923		$ 20,177	$ 316,100
Cost of Capital Total			$ 29,146	$ 456,615		$ 30,366	$ 475,729		$ 31,357	$ 491,265		$ 32,121	$ 503,223		$ 32,655	$ 511,602
OM&A			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Amortization		$ 610,551	$ 36,633	$ 573,918	$ 677,218	$ 40,633	$ 636,585	$ 743,884	$ 44,633	$ 699,251	$ 810,551	$ 48,633	$ 761,918	$ 877,218	$ 52,633	$ 824,585
Grossed-up PILs			-$ 15,509	-$ 242,974		-$ 11,080	-$ 173,581		-$ 7,244	-$ 113,493		-$ 3,894	-$ 61,009		-$ 943	-$ 14,768
Revenue Requirement			$ 50,270	$ 787,560		$ 59,919	$ 938,733		$ 68,746	$ 1,077,023		$ 76,859	$ 1,204,132		$ 84,346	$ 1,321,419
Provincial Rate Protection				$ 787,560			$ 938,733			$ 1,077,023			$ 1,204,132			$ 1,321,419
Monthly Amount Paid by IESO				$ 65,630			$ 78,228			$ 89,752			$ 100,344			$ 110,118

Note 1: The difference between the actual costs of approved eligible investments and revenue received from the IESO should be recorded in a variance account. The Board may provide regulatory accounting guidance regarding a variance account either in an individual proceeding or on a generic basis.
Note 2: For the 2016 Test Year, Costs and Revenues of the Direct Benefit are to be included in the test year applicant Rate Base and Revenues.

PILs Calculation

Income Tax	2020		2021		2022		2023		2024	
	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial
Net Income - ROE on Rate Base	$ 18,008	$ 282,126	$ 18,762	$ 293,936	$ 19,375	$ 303,535	$ 19,846	$ 310,923	$ 20,177	$ 316,100
Amortization (6% DB and 94% P)	$ 36,633	$ 573,918	$ 40,633	$ 636,585	$ 44,633	$ 699,251	$ 48,633	$ 761,918	$ 52,633	$ 824,585
CCA (6% DB and 94% P)	-$ 97,656	-$ 1,529,952	-$ 90,125	-$ 1,411,961	-$ 84,100	-$ 1,317,569	-$ 79,280	-$ 1,242,055	-$ 75,424	-$ 1,181,644
Taxable income	-$ 43,015	-$ 673,908	-$ 30,730	-$ 481,441	-$ 20,093	-$ 314,783	-$ 10,801	-$ 169,214	-$ 2,614	-$ 40,959
Tax Rate (to be entered)	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Income Taxes Payable	-$ 11,399.08	-$ 178,585.59	-$ 8,143.52	-$ 127,581.85	-$ 5,324.52	-$ 83,417.48	-$ 2,862.24	-$ 44,841.79	-$ 692.82	-$ 10,854.21
Gross Up										
Income Taxes Payable	-$ 15,508.95	-$ 242,973.60	-$ 11,079.62	-$ 173,580.75	-$ 7,244.25	-$ 113,493.18	-$ 3,894.21	-$ 61,009.24	-$ 942.61	-$ 14,767.63
Grossed Up PILs	**-$ 15,509**	**-$ 242,974**	**-$ 11,080**	**-$ 173,581**	**-$ 7,244**	**-$ 113,493**	**-$ 3,894**	**-$ 61,009**	**-$ 943**	**-$ 14,768**

OEB Appendix 2-FB
Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Enabling Improvement Investments
Energy Storage

		2020	2021	2022	2023	2024
Net Fixed Assets						
Enter applicable amortization in years:	15					
Opening Gross Fixed Assets		$ 8,658,265	$ 9,658,265	$ 10,658,265	$ 11,658,265	$ 12,658,265
Gross Capital Additions		$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000
Closing Gross Fixed Assets		$ 9,658,265	$ 10,658,265	$ 11,658,265	$ 12,658,265	$ 13,658,265
Opening Accumulated Amortization		$ 345,793	$ 956,344	$ 1,633,562	$ 2,377,446	$ 3,187,997
Current Year Amortization (before additions)		$ 577,218	$ 643,884	$ 710,551	$ 777,218	$ 843,884
Additions (half-year)		$ 33,333	$ 33,333	$ 33,333	$ 33,333	$ 33,333
Closing Accumulated Amortization		$ 956,344	$ 1,633,562	$ 2,377,446	$ 3,187,997	$ 4,065,215
Opening Net Fixed Assets		$ 8,312,472	$ 8,701,921	$ 9,024,703	$ 9,280,819	$ 9,470,268
Closing Net Fixed Assets		$ 8,701,921	$ 9,024,703	$ 9,280,819	$ 9,470,268	$ 9,593,050
Average Net Fixed Assets		$ 8,507,196	$ 8,863,312	$ 9,152,761	$ 9,375,543	$ 9,531,659

UCC for PILs Calculation

		2020	2021	2022	2023	2024
Opening UCC		$ 7,638,041	$ 7,010,433	$ 6,508,346	$ 6,106,677	$ 5,785,342
Capital Additions (from Appendix 2-FA)		$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000
UCC Before Half Year Rule		$ 8,638,041	$ 8,010,433	$ 7,508,346	$ 7,106,677	$ 6,785,342
Half Year Rule (1/2 Additions - Disposals)		$ 500,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000
Reduced UCC		$ 8,138,041	$ 7,510,433	$ 7,008,346	$ 6,606,677	$ 6,285,342
CCA Rate Class (to be entered)	8	8	8	8	8	8
CCA Rate (to be entered)	20%	20%	20%	20%	20%	20%
CCA		$ 1,627,608	$ 1,502,087	$ 1,401,669	$ 1,321,335	$ 1,257,068
Closing UCC		$ 7,010,433	$ 6,508,346	$ 6,106,677	$ 5,785,342	$ 5,528,273

OEB Appendix 2-FA

Renewable Generation Connection Investment Summary (past investments or over the future rate setting period) - Generation Protection Monitoring and Control

Enter the details of the Renewable Generation Connection projects as described in the appropriate section of the Filing Requirements.
All costs entered on this page will be transferred to the appropriate cells in the appendices that follow.

For Part A, Renewable Enabling Improvements (REI), these amounts will be transferred to Appendix 2 - FB
For Part B, Expansions, these amounts will be transferred to Appendix 2 - FC

If there are more than **five** projects proposed to be in-service in a certain year, please amend the tables below and ensure that the formulae for the Total Amounts in any given rate year are updated.

Based on the current methodology and allocation, amounts allocated represent 6% for REI Connection Investments and 17% for Expansion Investments. (EB-2009-0349, 6-10-2010, p. 15, note 9)

There are two scenarios described below. Separate sets of spreadsheets (2-FA, 2-FB, 2-FC) should be submited for each scenario as required.

Scenario 1: **Past Investments with No Recovery.** The distributor has made investments in the past (during the IRM Years), but has not received approval for these projects and therefore did not receive revenue from the IESO under Regulation 330/09 and did not receive ratepayer revenue for the direct benefit portion of the investment.
The WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage should correspond to the distributor's last Cost of Service approval.
The Direct Benefit portion of the calculated Revenue Requirement for each year should be summed and can be applied for recovery from the distributor's ratepayers through a rate rider.
The Provincial Recovery portion of the calculated Revenue Requirement for each year should be summed and can be applied for recovery from the IESO through a separate order.

Scenario 2: **Investments in the Test Year and Beyond.** Distributor plans to make investments in 2017 and/or beyond. These investments should be added to 2-FA in the appropriate year.
The WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage should correspond to the distributor's current application.

Part A

REI Investments (Direct Benefit at 6%)	2020	2021	2022	2023	Test Year 2024
Project 1					
Generation Protection (Bus Tie Reactors)					
Capital Costs	$720,000	$989,000	$1,041,000	$1,115,750	$1,134,250
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 2					
Monitoring and Control Systems					
Capital Costs	$2,973,750	$1,267,500	$1,332,500	$1,413,750	$1,543,750
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 3					
Name: REI Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 4					
Name: REI Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 5					
Name: REI Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Total Capital Costs	**$ 3,693,750**	**$ 2,256,500**	**$ 2,373,500**	**$ 2,529,500**	**$ 2,678,000**
Total OM&A (Start-Up)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Ongoing)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

OEB Appendix 2-FA

Renewable Generation Connection Investment Summary (past investments or over the future rate setting period) - Generation Protection Monitoring and Control

Part B

Expansion Investments (Direct Benefit at 17%)	2016	2017	2018	2019	Test Year 2020
Project 1					
Name: Expansion Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 2					
Name: Expansion Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 3					
Name: Expansion Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 4					
Name: Expansion Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 5					
Name: Expansion Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Total Capital Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Start-Up)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Ongoing)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

OEB Appendix 2-FB
Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Enabling Improvement Investments
Generation Protection, Monitoring, and Control

This table will calculate the distributor/provincial shares of the investments entered in Part A of Appendix 2-FA.
Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage.
For historical investments, enter these variables for your last cost of service test year. For 2020 and beyond, enter variables as in the application.
Rate Riders are not calculated for the Test Year as these assets and costs are already in the distributor's rate base/revenue requirement.

		2020			2021			2022			2023			2024		
		Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%
Net Fixed Assets (average)		$ 13,646,667	$ 818,800	$ 12,827,867	$ 16,006,820	$ 960,409	$ 15,046,411	$ 17,610,664	$ 1,056,640	$ 16,554,024	$ 19,264,344	$ 1,155,861	$ 18,108,483	$ 20,978,360	$ 1,258,702	$ 19,719,658
Incremental OM&A (on-going, N/A for Provincial Recovery)		$0	$ -		$0	$ -		$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recovery)		$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA	6.4%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base			$ 818,800	$ 12,827,867		$ 960,409	$ 15,046,411		$ 1,056,640	$ 16,554,024		$ 1,155,861	$ 18,108,483		$ 1,258,702	$ 19,719,658
Deemed ST Debt	4%		$ 32,752	$ 513,115		$ 38,416	$ 601,856		$ 42,266	$ 662,161		$ 46,234	$ 724,339		$ 50,348	$ 788,786
Deemed LT Debt	56%		$ 458,528	$ 7,183,606		$ 537,829	$ 8,425,990		$ 591,718	$ 9,270,253		$ 647,282	$ 10,140,750		$ 704,873	$ 11,043,009
Deemed Equity	40%		$ 327,520	$ 5,131,147		$ 384,164	$ 6,018,564		$ 422,656	$ 6,621,610		$ 462,344	$ 7,243,393		$ 503,481	$ 7,887,863
ST Interest	2.61%		$ 855	$ 13,392		$ 1,003	$ 15,708		$ 1,103	$ 17,282		$ 1,207	$ 18,905		$ 1,314	$ 20,587
LT Interest	3.71%		$ 17,011	$ 266,512		$ 19,953	$ 312,604		$ 21,953	$ 343,926		$ 24,014	$ 376,222		$ 26,151	$ 409,696
ROE	8.82%		$ 28,887	$ 452,567		$ 33,883	$ 530,837		$ 37,278	$ 584,026		$ 40,779	$ 638,867		$ 44,407	$ 695,710
Cost of Capital Total			$ 46,753	$ 732,471		$ 54,839	$ 859,150		$ 60,334	$ 945,235		$ 66,000	$ 1,033,994		$ 71,872	$ 1,125,992
OM&A			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Amortization		$ 560,879	$ 33,653	$ 527,226	$ 669,065	$ 40,144	$ 628,921	$ 753,247	$ 45,195	$ 708,052	$ 842,393	$ 50,544	$ 791,849	$ 937,074	$ 56,224	$ 880,850
Grossed-up PILs			-$ 1,745	-$ 27,340		-$ 809	-$ 12,671		$ 430	$ 6,735		$ 1,722	$ 26,982		$ 3,069	$ 48,078
Revenue Requirement			$ 78,661	$ 1,232,357		$ 94,174	$ 1,475,400		$ 105,959	$ 1,660,022		$ 118,265	$ 1,852,825		$ 131,165	$ 2,054,920
Provincial Rate Protection				$ 1,232,357			$ 1,475,400			$ 1,660,022			$ 1,852,825			$ 2,054,920
Monthly Amount Paid by IESO				$ 102,696			$ 122,950			$ 138,335			$ 154,402			$ 171,243

Note 1: The difference between the actual costs of approved eligible investments and revenue received from the IESO should be recorded in a variance account. The Board may provide regulatory accounting guidance regarding a variance account either in an individual proceeding or on a generic basis.
Note 2: For the 2016 Test Year, Costs and Revenues of the Direct Benefit are to be included in the test year applicant Rate Base and Revenues.

PILs Calculation

Income Tax	2020 Direct Benefit	2020 Provincial	2021 Direct Benefit	2021 Provincial	2022 Direct Benefit	2022 Provincial	2023 Direct Benefit	2023 Provincial	2024 Direct Benefit	2024 Provincial
Net Income - ROE on Rate Base	$ 28,887	$ 452,567	$ 33,883	$ 530,837	$ 37,278	$ 584,026	$ 40,779	$ 638,867	$ 44,407	$ 695,710
Amortization (6% DB and 94% P)	$ 33,653	$ 527,226	$ 40,144	$ 628,921	$ 45,195	$ 708,052	$ 50,544	$ 791,849	$ 56,224	$ 880,850
CCA (6% DB and 94% P)	-$ 67,380	-$ 1,055,624	-$ 76,270	-$ 1,194,904	-$ 81,281	-$ 1,273,399	-$ 86,546	-$ 1,355,880	-$ 92,120	-$ 1,443,212
Taxable income	-$ 4,840	-$ 75,831	-$ 2,243	-$ 35,145	$ 1,192	$ 18,679	$ 4,777	$ 74,836	$ 8,512	$ 133,348
Tax Rate (to be entered)	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Income Taxes Payable	-$ 1,282.67	-$ 20,095.16	-$ 594.47	-$ 9,313.39	$ 315.95	$ 4,949.92	$ 1,265.85	$ 19,831.58	$ 2,255.56	$ 35,337.15
Gross Up										
Income Taxes Payable	-$ 1,745.13	-$ 27,340.35	-$ 808.80	-$ 12,671.27	$ 429.87	$ 6,734.59	$ 1,722.24	$ 26,981.74	$ 3,068.79	$ 48,077.76
Grossed Up PILs	**-$ 1,745**	**-$ 27,340**	**-$ 809**	**-$ 12,671**	**$ 430**	**$ 6,735**	**$ 1,722**	**$ 26,982**	**$ 3,069**	**$ 48,078**

OEB Appendix 2-FB
Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Enabling Improvement Investments
Generation Protection, Monitoring, and Control

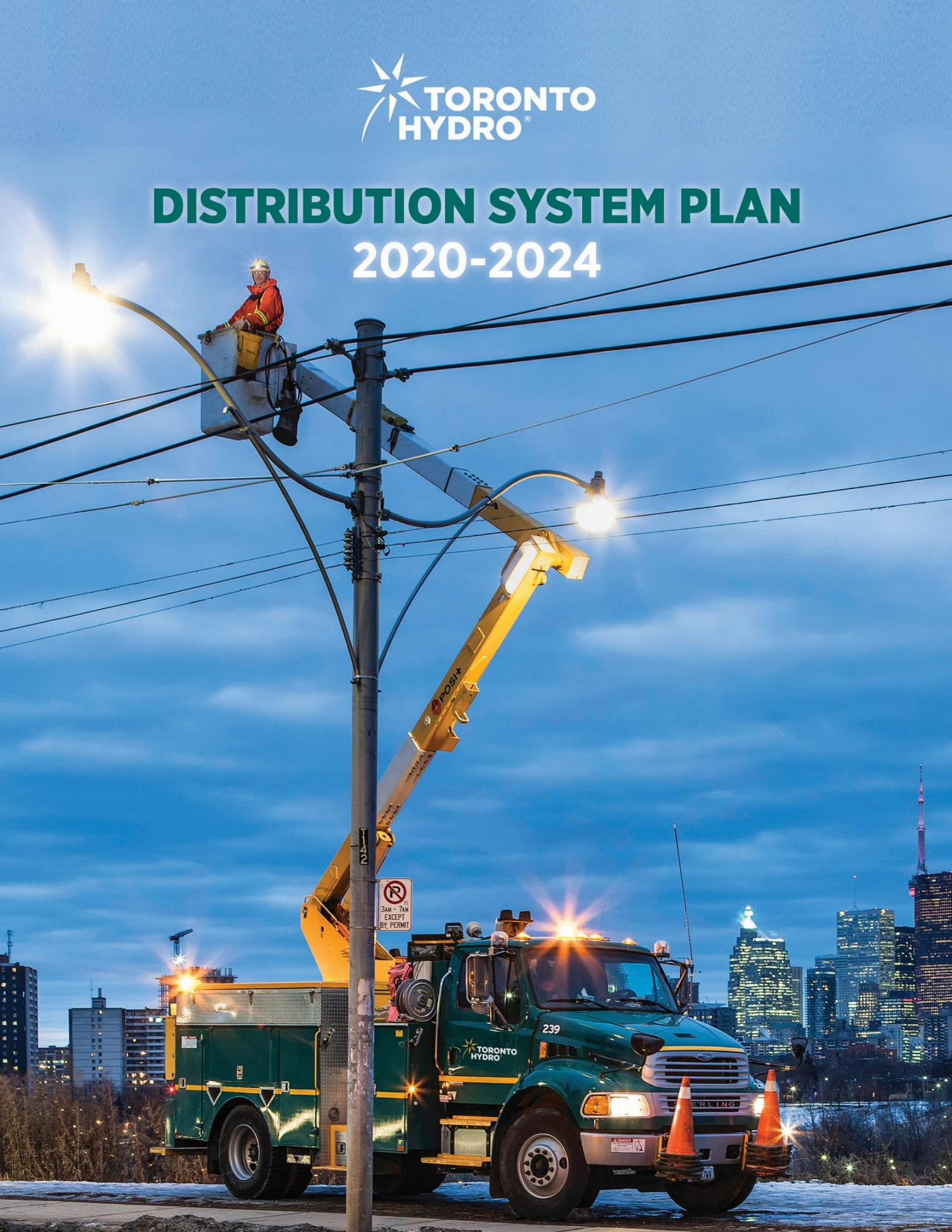
		2020	2021	2022	2023	2024
Net Fixed Assets						
Enter applicable amortization in years:	27.5					
Opening Gross Fixed Assets		13,577,298	$ 17,271,048	$ 19,527,548	$ 21,901,048	$ 24,430,548
Gross Capital Additions		$ 3,693,750	$ 2,256,500	$ 2,373,500	$ 2,529,500	$ 2,678,000
Closing Gross Fixed Assets		$ 17,271,048	$ 19,527,548	$ 21,901,048	$ 24,430,548	$ 27,108,548
Opening Accumulated Amortization		$ 1,497,066	$ 2,057,945	$ 2,727,011	$ 3,480,258	$ 4,322,651
Current Year Amortization (before additions)		$ 493,720	$ 628,038	$ 710,093	$ 796,402	$ 888,384
Additions (half-year)		$ 67,159	$ 41,027	$ 43,155	$ 45,991	$ 48,691
Closing Accumulated Amortization		$ 2,057,945	$ 2,727,011	$ 3,480,258	$ 4,322,651	$ 5,259,725
Opening Net Fixed Assets		$ 12,080,232	$ 15,213,103	$ 16,800,537	$ 18,420,790	$ 20,107,897
Closing Net Fixed Assets		$ 15,213,103	$ 16,800,537	$ 18,420,790	$ 20,107,897	$ 21,848,823
Average Net Fixed Assets		$ 13,646,667	$ 16,006,820	$ 17,610,664	$ 19,264,344	$ 20,978,360

UCC for PILs Calculation

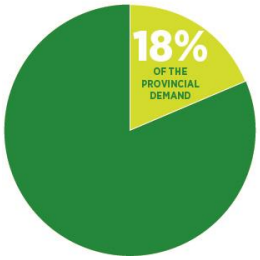
		2020	2021	2022	2023	2024
Opening UCC		$ 12,190,681	$ 14,761,427	$ 15,746,752	$ 16,765,572	$ 17,852,646
Capital Additions (from Appendix 2-FA)		$ 3,693,750	$ 2,256,500	$ 2,373,500	$ 2,529,500	$ 2,678,000
UCC Before Half Year Rule		$ 15,884,431	$ 17,017,927	$ 18,120,252	$ 19,295,072	$ 20,530,646
Half Year Rule (1/2 Additions - Disposals)		$ 1,846,875	$ 1,128,250	$ 1,186,750	$ 1,264,750	$ 1,339,000
Reduced UCC		$ 14,037,556	$ 15,889,677	$ 16,933,502	$ 18,030,322	$ 19,191,646
CCA Rate Class (to be entered)	47	47	47	47	47	47
CCA Rate (to be entered)	8%	8%	8%	8%	8%	8%
CCA		$ 1,123,004	$ 1,271,174	$ 1,354,680	$ 1,442,426	$ 1,535,332
Closing UCC		$ 14,761,427	$ 15,746,752	$ 16,765,572	$ 17,852,646	$ 18,995,315

TORONTO HYDRO®

DISTRIBUTION SYSTEM PLAN 2020-2024







HEAD OFFICE
14 CARLTON STREET
TORONTO, ONTARIO
M5B 1K5

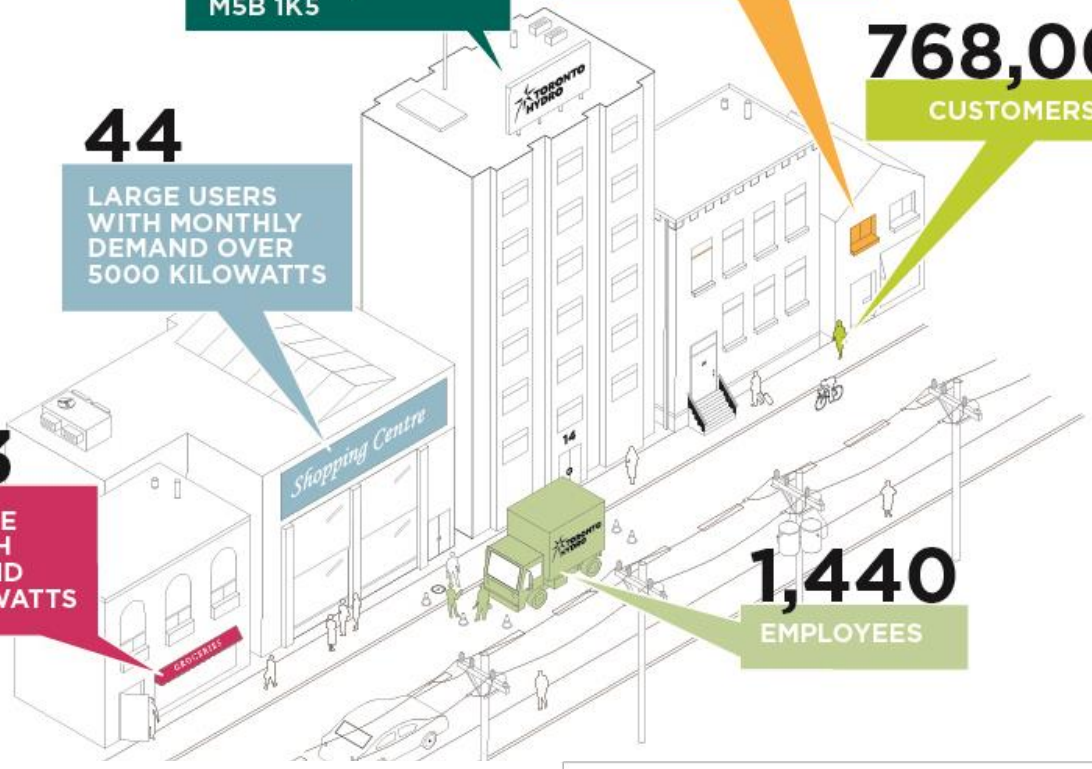
685,292
RESIDENTIAL CUSTOMERS

768,000
CUSTOMERS

44
LARGE USERS WITH MONTHLY DEMAND OVER 5000 KILOWATTS

82,233
GENERAL SERVICE CUSTOMERS WITH MONTHLY DEMAND OF 0-5000 KILOWATTS

1,440
EMPLOYEES





1
CONTROL CENTRE

15,540
KILOMETRES OF OVERHEAD WIRES

153
MUNICIPAL SUBSTATIONS

17,350
PRIMARY SWITCHES

60,540
DISTRIBUTION TRANSFORMERS

178,800
POLES

13,220
KILOMETRES OF UNDERGROUND WIRES

Table of Contents



A	Distribution System Plan Overview
B	Coordinated Planning with Third Parties
C	Performance Measurement for Continuous Improvement
D	Asset Management Process
E	Capital Expenditure Plan

Table of Contents – Detailed

A Distribution System Plan Overview

A1 Introduction

A2 DSP Organization

A2.1 Concordance with the Chapter 5 Filing Requirements

A2.2 Capital Programs and Drivers

A3 Asset Management Process

A4 Coordinated Planning with Third Parties

A4.1 Capital Investment Needs

A4.2 Addressing Customer Needs and Preferences

A4.3 Outcomes and Performance Measurement

A4.4 Expected Sources of Cost Savings during the Plan Period

A4.5 Third-Party Studies and Reports

A5 Grid Modernization

B Coordinated Planning with Third Parties

B1 Overview of Coordinated Planning Approach

B1.1 Coordinated Planning Approach

B1.2 Customer Consultations

B1.3 Transmitter Consultations

B1.4 Other Distributor Consultations

B1.5 IESO Consultations

B2 Regional Planning Process

B2.1 Toronto Integrated Regional Resource Plan

B2.2 Metro Toronto Regional Infrastructure Plan

B2.3 GTA North Regional Infrastructure Plan

B3 IESO Comments on Renewable Generation

B3.1 IESO Comment Letter
B3.2 Toronto Hydro's Response to the IESO Letter

Appendix A – Needs Assessment Report (Toronto)
Appendix B – Needs Assessment Report (GTA North)
Appendix C – Regional Infrastructure Plan (Metro Toronto)
Appendix D – Regional Infrastructure Plan (GTA North)
Appendix E – Integrated Regional Resource Plan (Central Toronto)
Appendix F – IESO Letter of Comment

C Performance Measurement

C1 Customer Preferences and the Outcomes Framework
C2 Toronto Hydro's 2020-2024 Custom Performance Measures

C2.1 Customer Service
C2.2 Safety
C2.3 Reliability
C2.4 Financial
C2.5 Environment

D Asset Management Process

D1 Asset Management Process Overview

D1.1 Asset Management Objectives and Outcomes
D1.2 Asset Management Process Overview
D1.3 Asset Management Process Enhancements

D2 Overview of Distribution Assets

D2.1 Distribution Service Area and Trends
D2.2 System Demographics and Characteristics
D2.3 System Utilization

D3 Asset Lifecycle Optimization

D3.1 Asset Lifecycle Optimization Practices
D3.2 Asset Lifecycle Risk Management Policies and Practices
D3.3 Asset Utilization Policies and Practices
D3.4 Program Planning Approach and Project Development

D4 Facilities Asset Management Strategy

D4.1 Asset Management Process
D4.2 Asset Renewal Process
D4.3 Investment Planning and Forecasting
D4.4 Summary

D5 Information Technology Asset Management Strategy

D5.1 IT Asset Management
D5.2 IT Investment Planning
D5.3 Five-Year Investment Plan

Appendix A – UMS Asset Management Review
Appendix B – PSE Standards Review
Appendix C – Toronto Hydro Asset Condition Assessment Methodology
Appendix D – Climate Change Vulnerability Assessment

E Capital Expenditure Plan

E1 Capital Expenditure plan Introduction

E1.1 Introduction
E1.2 2020-2024 Capital Expenditures

E2 Capital Expenditure planning Process Overview

E2.1 Capital Planning in Business Planning
E2.2 Asset Management in Capital Planning
E2.3 Customer Priorities, Needs, and Preferences in Capital Planning

E3 System Capability Assessment for Renewable Energy and Conventional Generation

E3.1 Applications
E3.2 Forecasted Generation Connections

E3.3 Capacity and Constraints to Connect Distributed Generation (DG)

E4 Capital Expenditure Summary

E4.1 Plan versus Actual Variances for 2015-2019
E4.2 Forecast (2020-2024) versus Historical (2015-2019) Expenditures

E5 System Access Investments

E5.1 Customer Connections
E5.2 Externally Initiated Plant Relocations and Expansions
E5.3 Load Demand
E5.4 Metering
E5.5 Generation Protection, Monitoring, and Control

E6 System Renewal Investments

E6.1 Area Conversions
E6.2 Underground System Renewal – Horseshoe
E6.3 Underground System Renewal – Downtown
E6.4 Network System Renewal
E6.5 Overhead System Renewal
E6.6 Stations Renewal
E6.7 Reactive and Corrective Capital

E7 System Service Investments

E7.1 System Enhancements
E7.2 Energy Storage Systems
E7.3 Network Condition Monitoring & Control
E7.4 Stations Expansion

E8 General Plant Investments

E8.1 Control Operations Reinforcement
E8.2 Facilities, Management, and Security
E8.3 Fleet and Equipment Services
E8.4 Information Technology and Operational Technology Systems

A Distribution System Plan Overview



A1 Introduction

A2 DSP Organization

A3 Asset Management Process

A4 Coordinated Planning with Third Parties

A5 Grid Modernization

A1 Introduction

Toronto Hydro's Distribution System Plan ("DSP") provides a detailed and comprehensive view of the utility's capital investment plans and supporting information for the 2020-2024 period. The capital programs described and justified in this plan address urgent and necessary work related to the distribution system assets that safely power the City of Toronto, as well as the general plant assets that keep the utility's "24/7" operations running and responsive to customer needs and requests.

This plan continues the utility's effort to renew a significant backlog of deteriorated and obsolete assets at risk of failure, and to adapt to the continuously evolving challenge of serving, and operating within a dense, mature, and growing major city. Toronto Hydro is on track to successfully complete its previous plan for 2015-2019, with adjustments for typical changes and evolving circumstances, including the final rates approved by the Ontario Energy Board ("OEB") for that period. Efforts to date have resulted in gradual improvements to reliability, the overall age of the system, and other performance indicators.

Despite these initial signs of progress, reinvesting in the short-term performance and long-term viability of an aged, deteriorated, and highly utilized system remains an urgent priority for the utility. Recent extreme weather events, accompanied by growing evidence of the impact of climate change on weather patterns in Toronto, have amplified this need, underscoring the challenge to build a resilient system for the long-term. At the same time, technology and innovation are driving a more dynamic system that is transitioning away from the usual patterns of supply and demand, adding additional complexity and urgency to the challenge of modernizing the grid, which in turn is driving investment needs in information technology and cyber security solutions.

The 2020-2024 DSP strikes a balance between these pressing needs and customer preferences for (i) keeping prices as low as possible, (ii) maintaining average reliability, (iii) improving reliability for customers experiencing below-average service, and (iv) balancing other priorities (e.g. customer service) with the need to contain rate increases. The resulting five-year capital expenditure plan represents the minimum level of investment needed to ensure this balance is achieved, while avoiding the accumulation of asset risk and associated declines in performance over the long-term.

Toronto Hydro developed the DSP in full accordance with Chapter 5 of the OEB's Filing Requirements for Electricity Distribution Rate Applications, and in alignment with the principles and objectives of the OEB's *Renewed Regulatory Framework* ("RRF"), including the updated guidance in the OEB's

Handbook for Utility Rate Applications (2016). In additional to the expenditure plan and forecast information for 2020-2024, the DSP provides historical and bridge year information for 2015-2017 and 2018-2019 respectively, including information on expenditures and accomplishments, material variances, and measured performance during the previous 2015-2019 plan period. In developing this DSP, Toronto Hydro built upon the experience of its first five-year DSP (covering the 2015-2019 period) and the OEB's findings in the 2015 Custom IR Application, refining successful elements (e.g. detailed investment program justifications) and making substantial enhancements to certain fundamental elements (e.g. the quality and role of Customer Engagement in planning).

A2 DSP Organization

The 2020-2024 DSP consists of the following five major sections:

- **Section A – Distribution System Plan Overview:** Provides an overview of the key elements of the 2020-2024 DSP, including brief summaries of the 2020-2024 Capital Expenditure Plan and its drivers and outcomes; the Asset Management principles, processes, and methodologies that underpin the plan; and the Customer Engagement results that informed the plan.
- **Section B – Coordinated Planning with Third Parties:** Describes how Toronto Hydro's DSP aligns with broader regional planning efforts, including information regarding the applicable consultation processes.
- **Section C – Performance Measurement for Continuous Improvement:** Provides information with respect to the selected measures that will be adopted by Toronto Hydro to track performance of the DSP over the course of the planning horizon.
- **Section D – Asset Management Process:** Describes Toronto Hydro's asset management processes, the current state of the assets and system performance challenges, and the utility's asset lifecycle optimization and risk management practices and methodologies. The processes, tools, and information in this section were used to derive the 2020-2024 Capital Expenditure Plan.
- **Section E – Capital Expenditure Plan:** Describes how Toronto Hydro leveraged various substantive inputs – including Customer Engagement findings – to develop the 2020-2024 Capital Expenditure Plan and its customer-focused objectives. This section also contains detailed justifications and business cases for the 20 capital programs that constitute the plan.[1]

A2.1 Concordance with the Chapter 5 Filing Requirements

The structure of Toronto Hydro's DSP generally concords with the headings of the OEB's Chapter 5 Filing Requirements. This concordance is summarized in Table 1 below.

[1] The vintage of asset data and station load forecasts used within the DSP are from mid-late 2017, with the exception of Asset Condition data that was updated as of January 2018.

Table 1: Concordance between DSP Sections and Chapter 5 Headings

DSP Sections	Filing Requirement Headings
Section A	5.2.1 – Distribution System Plan Overview
Section B	5.2.2 – Coordinated Planning with Third parties
Section C	5.2.3 – Performance Measurement for Continuous Improvement
Section D	5.3 – Asset Management Process
Section E	5.4 – Capital Expenditure Plan

Minor exceptions to the concordance between the Chapter 5 filing requirements and DSP headings are as follows:

- In the latest Chapter 5 requirements, issued in July 2018, the OEB relocated its filing requirements for detailed historical period data on interruptions and MEDs from Chapter 2 to Chapter 5 (section 5.2.3). Due to the timing of these updates, Toronto Hydro's direct response to these requirements remains outside the DSP in Exhibit 1B, Tab 2, Schedule 4. In addition to this stand-alone schedule, salient observations about historical reliability performance are integrated throughout the DSP, including in Section C, and are relied upon to justify forecast expenditures.
- Toronto Hydro addresses the requirements in section 5.2.4 of Chapter 5 (i.e. "Realized efficiencies due to smart meters") within the Metering capital program (Section E5.4 of the DSP).
- In the latest Chapter 5 requirements, the OEB relocated the "System capability assessment for renewable energy generation" requirements from 5.4 to 5.3. Due to the timing of these updates, Toronto Hydro's response to these requirements remains in the Capital Expenditure Plan section of the DSP (Section E3).

A2.2 Capital Programs and Drivers

The 2020-2024 Capital Expenditure Plan in the DSP consists of 20 unique capital programs. These program are allocated to each of the OEB's four major investment categories, as defined in Table 2, based on their trigger drivers, which represent the primary reason a program must be carried out.

Table 2: Capital Investment Categories

System Access	• Modifications (including asset relocation) the utility is obligated to perform to provide a customer (including a generator) or group of customers with access to electricity services via the distribution system.
System Renewal	• The replacement and/or refurbishment of system assets to extend the original serviceable life of the assets and thereby maintain the ability of the distribution system to provide customers with electricity services.
System Service	• Modifications to the system to ensure that it continues to meet operational objectives while addressing anticipated future customer electricity service requirements.
General Plant	• Modification, replacements, or additions to assets that are not part of the distribution system, including land and buildings, tools and equipment, rolling stock and electronic devices and software used to support day to day business and operations activities.

Each capital program is defined by a single trigger driver and a number of secondary drivers. The trigger drivers for Toronto Hydro's 2020-2024 DSP programs are summarized in Table 3, below. Although safety is not listed as a trigger driver, it is a significant secondary driver for many programs – especially those that are triggered by asset Failure or Failure Risk in the System Renewal category. Secondary drivers may be as, or more, consequential than the trigger drivers. Details on the trigger and secondary drivers for each program are provided in the detailed program justifications in Sections E5 through E8 of the DSP.

Table 3: Investment Category Trigger Drivers

Category	Driver	Description
System Access	***Customer Service Requests***	• The fulfilment of Toronto Hydro's obligation to connect a customer to its system. This includes both traditional demand customers and distributed generation ("DG") customers. The obligation to connect holds as long as there are no safety concerns for the public or employees and there is no adverse effect on the reliability of the distribution system. The utility undertakes expansion or enhancements to the system when a connection cannot be made with existing infrastructure.

Category	Driver	Description
	Mandated Service Obligation	• Compliance with all legal and regulatory requirements and government directives.
System Renewal	***Functional Obsolescence***	• The asset and/or its installation is no longer aligned to Toronto Hydro's processes and practices such that it can no longer be maintained (e.g. lack of vendor support) or utilized as intended to support the utility's operations.
	Failure	• Asset or critical component failure has taken place and Toronto Hydro must respond reactively as part of its capital investment activities.
	Failure Risk	• There is imminent risk of failure due to age or condition deterioration. The potential failures will result in significant reliability impacts to customers as well as potential safety risks to crew workers or to the public.
System Service	***Reliability***	• Maintain or improve reliability at a local, feeder-wide, or system-wide level.
	Capacity Constraints	• Expected changes in load will constrain the ability of the system to provide consistent service delivery and handle demand requirements.
General Plant	***Operational Resilience***	• The ability to mitigate and recover from disruptions to core business functions.
	System Maintenance and Capital Investment Support	• Required investments to support day to day business operational activities; sustaining operations by providing its employees with a safer environment to operate in an efficient and reliable manner.

A3 Development of the 2020-2024 DSP

Toronto Hydro's 2020-2024 DSP, including the 2020-2024 Capital Expenditure Plan, was an output of its outcomes-oriented, customer-focused business planning activities. The plan was derived from the utility's distribution system asset management ("AM") processes and other operational planning activities, discussed in detail in Section D of the DSP. A high-level view of business planning as it relates to the Capital Expenditure Plan is shown in Figure 1, below.

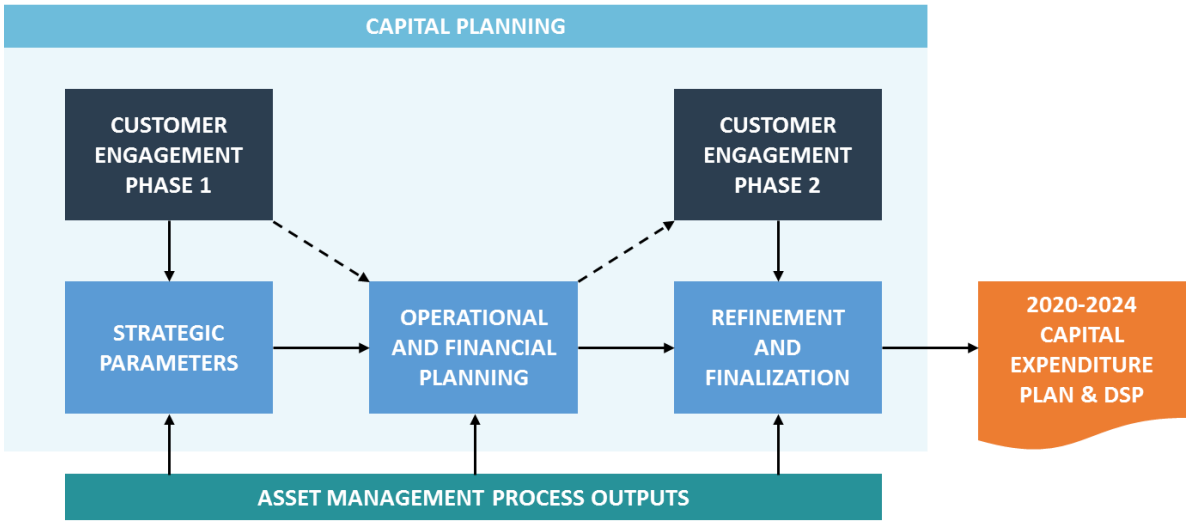


Figure 1: Capital Planning in Business Planning

Toronto Hydro began business planning by engaging customers (i.e. Phase 1 of Customer Engagement) and using the feedback received and various other qualitative and quantitative inputs to set the initial strategic parameters for the business planning horizon. These parameters included an upper price limit – reflecting most customers' preference for keeping rates as low as possible – an upper capital budget limit – approximating a minimum sustainment level of capital investment – and an Outcomes Framework that aligns with customers' priorities, the utility's corporate strategic pillars and the *Renewed Regulatory Framework*. The specifics of these parameters are discussed in detail in Section E2.

The strategic parameters guided the operational and financial planning activities that produced the Capital Expenditure Plan for 2020-2024. Over the course of these iterative planning activities, the utility worked to develop and optimize its program-level capital (and OM&A) expenditure plans to align with its short- and long-term AM objectives, while remaining within the financial constraints

and considerations set-out in the strategic parameters. This exercise led to a $75 million per year reduction between the initial plan proposals and the penultimate plan.

Toronto Hydro took its penultimate plan back to customers for feedback on how effective the utility was in interpreting the Customer Engagement results and using them to inform the proposed plan. Overall, a majority of customers expressed support for either the proposed plan or doing more. Customers were particularly supportive of two programs related to preventing network vault floods and fires. The utility took this feedback into account as it made its final refinements and adjustments to the DSP.

In the result, Toronto Hydro produced an optimized and customer-aligned Capital Expenditure Plan with an average investment of $562 million[2] per year over the 2020-2024 period. The final plan produced an average annual bill impact (base rates, without riders) for residential customers of 3.0 percent for distribution, below the limit set in the strategic parameters and communicated to customers in the second phase of Customer Engagement. The program outcomes in Sections E5 through E8, as well as the Custom Performance Measures and AM objectives for the plan as whole (discussed in Sections C and E2), have been developed and calibrated to reflect customer feedback, ensuring the performance and accomplishments of the DSP are tracked over the 2020-2024 period in relation to outcomes that are meaningful to customers.

[2] This figure includes inflation and other allocations, and excludes Renewable Enabling Improvement ("REI") expenditures funded through provincial rate relief.

A4 Key Elements and Objectives of the DSP

This section provides a high-level overview of the key elements driving the level and mix of capital investment in the 2020-2024 DSP, including major system challenges, and customer needs and preferences. It also includes an overview of the outcome objectives for the 2020-2024 DSP and how Toronto Hydro intends to measure its performance in relation to these outcomes.

Figure 2 illustrates the overall level of capital expenditures planned for the 2020-2024 period, grouped by the OEB's specified investment categories. As illustrated, the largest need for capital investment continues to be in the System Renewal category, which is driven by asset failure and failure risk related to age, condition, and obsolescence.

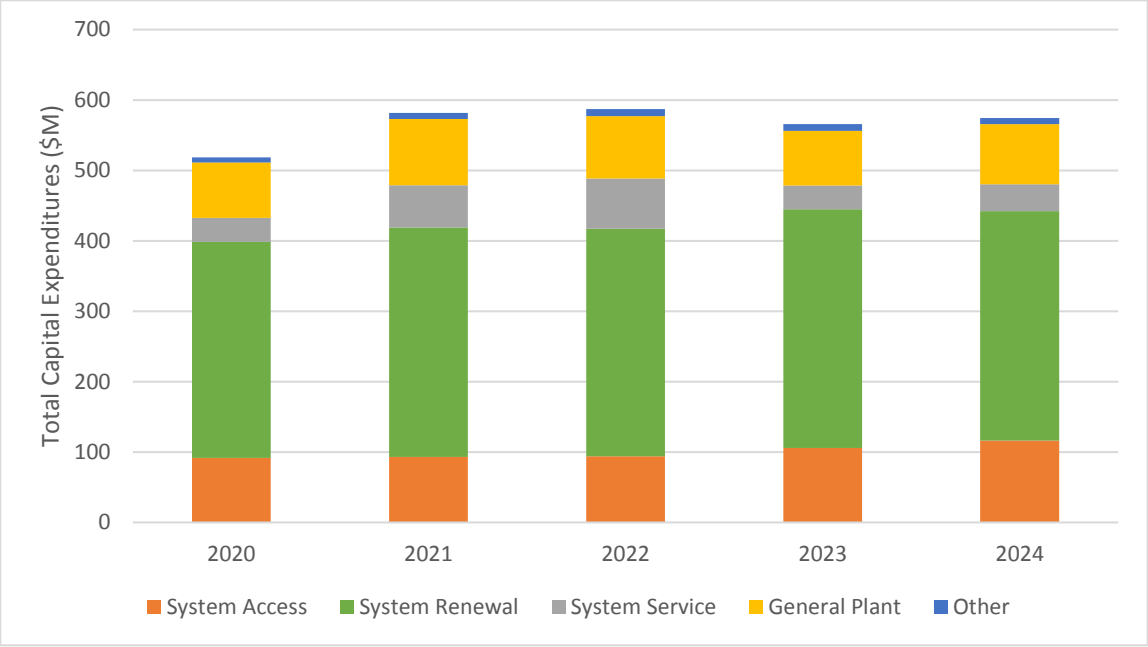


Figure 2: 2020-2024 Capital Expenditure Plan by Investment Category

A4.1 Capital Investment Needs

This section provides an overview of the system and operational investment needs facing Toronto Hydro during the 2020-2024 forecast period. For a comprehensive discussion of Toronto's existing distribution system assets, configurations, climate, and utilization please refer to Section D2.

A4.1.1 System Challenges: Deteriorating and Obsolete Assets

The most significant driver of investment in Toronto Hydro's DSP is asset failure and failure risk due to a continuing backlog of deteriorating and obsolete assets. A key system-wide indicator of the magnitude of this challenge is the percentage of Assets Past Useful Life ("APUL"). As seen in Figure 3, below, approximately a quarter of the utility's asset base is operating beyond useful life, and an estimated 9 percent will reach that point by 2025, indicating that a significant proactive renewal program is necessary to prevent this backlog from increasing. An increase in the APUL backlog would likely result in a corresponding deterioration in reliability, safety and other outcomes driven by asset failure and failure risk.

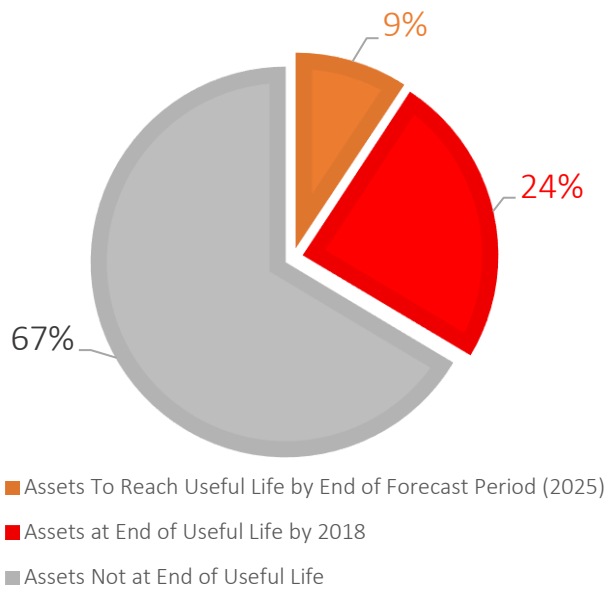


Figure 3: Percentage of Assets Past Useful Life

Asset Condition Assessment ("ACA") demographic results also indicate substantial asset investment needs for a number of critical asset classes over the plan period. Among the subset of asset classes analyzed using Toronto Hydro's ACA methodology, major civil assets like poles and vaults, which are the backbone of a safe and viable distribution system, and major stations electrical assets, which have the highest potential reliability impact on the system, are showing the greatest signs of material deterioration.

As explained in the System Renewal program justifications in Section E6, Toronto hydro is proposing a pace of renewal investment in a number of core programs that is the minimum required to prevent these age and condition-related risks from worsening over the 2020-2024 period. For instance, without the proposed proactive intervention in the overhead asset class, Toronto Hydro projects that the percentage of pole top transformers having reached or exceeded useful life will increase from 14 percent as of 2017 to approximately 40 percent by 2024, and the number of poles with material deterioration could nearly triple to over 30,000.

The utility also continues to face challenges related to higher-risk, obsolete, legacy assets, and asset configurations such as rear lot plant, box construction, non-submersible network equipment, and direct-buried cable. Legacy assets are specific asset types, configurations, or sub-systems that do not meet current Toronto Hydro standards, often featuring obsolete components with limited or no suppliers or skilled labour to support maintenance, repair, or replacement. Due to asset-specific defects or deficiencies, these assets typically carry elevated reliability, safety, or environmental risks. For example, direct-buried cable and non-submersible network protectors are highly susceptible to moisture-related damage and continue to be significant contributors to reliability and safety risk. Another example is transformers at risk of spilling PCB-contaminated oil. Toronto Hydro's pole-top and underground transformer replacement strategies for 2020-2024 are driven in part by the utility's efforts to effectively eliminate this critical environmental risk over the period.

Toronto Hydro has seen improvements in the frequency and duration of outages caused by defective equipment. However, defective equipment continues to be, by far, the largest contributor to outage frequency (i.e. SAIFI), at 36 percent, and outage duration (i.e. SAIDI), at 44 percent. In light of the age, condition, and legacy asset risks discussed above, Toronto Hydro concludes that a shift to a more reactive renewal approach would result in a decline in reliability over the short- and long-term, with potentially significant impacts for customers in areas served by legacy assets such as direct-buried cable and rear-lot plant. A reactive renewal approach would also be more costly over the long-term.

A4.1.2 System Challenges: Climate Change and Adverse Weather

On top of the reliability challenges posed by a backlog of deteriorating and obsolete equipment, Toronto Hydro anticipates that increasingly frequent adverse and extreme weather events will put additional reliability pressures on the system, making the resiliency of the system and the utility's operations a greater concern over the medium- to long-term than in past planning cycles.

Climate change is a significant factor influencing Toronto Hydro's planning and operations. By the year 2050, Toronto's climate is forecast to be significantly different than the already changing climate seen today. For example, in Toronto, daily maximum temperatures over 25°C are expected to occur 106 times per year as opposed to 66 times per year currently. Daily maximum temperatures over 40°C, which have historically been an anomaly, are projected to occur up to seven times per year by 2050.[3] A warmer climate will also allow the atmosphere to hold more moisture, which is expected to lead to more frequent and severe extreme weather events such as ice storms and extreme rainfall events. These extreme events can cause major disruptions to Toronto Hydro's distribution system.

Not only are these weather conditions projected to occur more frequently and with greater severity in the future due to climate change, but trends from the past 20 years suggest that these changes are already affecting the system. Figure 4 below depicts cumulative rainfall and the number of high wind days in Toronto over the past 20 years. With respect to rainfall, seven of the 10 highest rain fall years have occurred in the last 10 years. Similarly, six of the 10 years with the greatest number of days of wind gusts above 70 kilometres per hour have also occurred in the last 10 years.

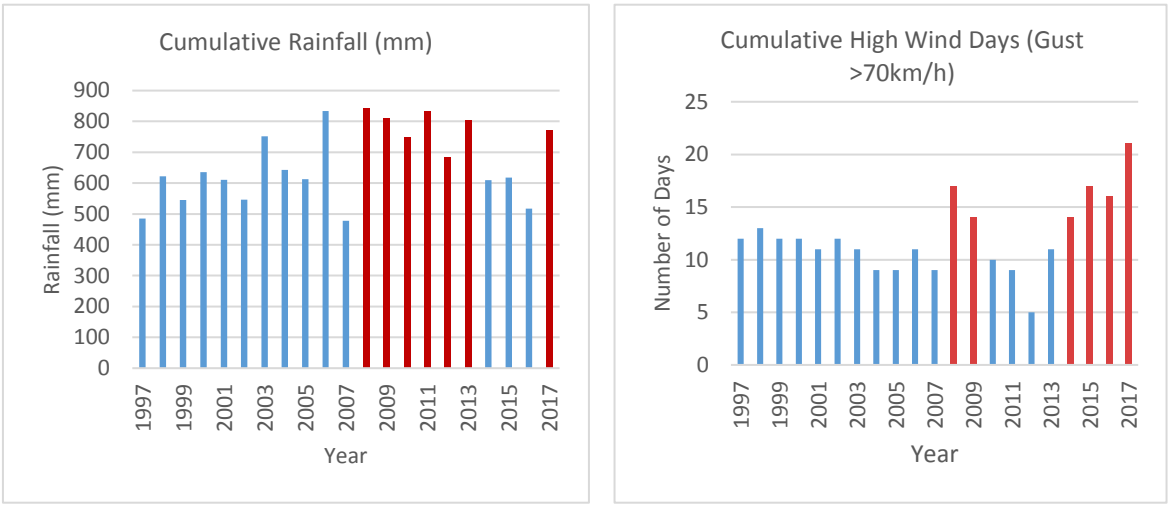


Figure 4: Cumulative Rainfall (left) and Number of High Wind Days (right) in Toronto[4]

[3] See Appendix D to Section D – Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment by AECOM (June 2015)

[4] Weather data compiled using Toronto Lester B. Pearson INTL A for January 1997 to June 2013 and Toronto INTL A for July 2013 to December 2017. Available from: Government of Canada, Weather, Climate and Hazard Historical Data online: <http://climate.weather.gc.ca/historical_data/search_historic_data_e.html>

Recent extreme weather events (see Table 4, below) have repeatedly and pervasively affected Toronto Hydro's customers. Extreme weather events in 2017 resulted in a 72 percent increase in the number of customer interruptions attributed to tree contacts compared to the average of the previous five years. Similarly, in 2018, Toronto Hydro experienced four extreme storms during the first half of the year.

These circumstances drive Toronto Hydro to continue emphasizing plans and programs that facilitate and improve its system resiliency and ability to respond to these events. This is reflected in the fact that all of the utility's investment categories include at least some investments that support this objective. System Renewal work – and especially the renewal of legacy asset types – will contribute to system hardening by improving asset health and introducing updated equipment design and construction standards that are better suited to the changing operating environment. Grid modernization efforts in the System Access,[5] System Renewal, [6] System Service,[7] and General Plant[8] categories will help the utility respond to major events more effectively. Neglecting to make these investments during the 2020-2024 period could leave the utility ill-prepared for the effects of climate change, leading to a potential decline in service and higher costs related to reactive and emergency scenarios.

Table 4: Extreme Weather Events since the Beginning of 2017

Event	Description
Freezing Rain (February 2017)	• Approximately 2-6 mm of freezing rain followed by additional heavy rain. • Estimated 9,200 customers out at peak; all customers restored within 24 hours of the start of the freezing rain event.
High-water/flooding (May - June 2017)	• Heavy rainfall in southern Ontario exceeded the yearly average for an entire summer. • Numerous incidents of high-water/flooding reported across Toronto. • No customers were directly impacted during this 55-day incident due to the utility's proactive damage assessment and DPM mitigation measures, including flood mitigation efforts.

[5] For example, replacing end-of-life meters with next-generation smart meters.
[6] For example, replacing end-of-life stations assets with assets equipped with modern SCADA-enabled remote monitoring and control capabilities.
[7] For example, installing remote sensing capabilities in network vaults to detect floods before they damage equipment.
[8] For example, creating a fully functional dual control centre (refer to Section E8.1).

Event	Description
Wind Storm (October 2017)	• Strong wind gusts approaching 100 km/h in some areas and lasting approximately 3 hours. • Estimated 43,000 customers out at peak. • 90 percent of customers restored within 11 hours of event; all customers restored within 48 hours of the end of the event.
Wind storm (April 2018)	• Sustained 65km/h winds, with gusts approaching 90km/h. • Estimated 24,000 customers out at peak; all customers restored within 48 hours of the end of the event.
Ice Storm (April 2018)	• Approximately 10-20 mm of freezing rain, 20-25 mm rain, sustained winds of 70 km/h with gusts up to 110 km/h. • Estimated 51,000 customers out at peak. • 99 percent of customers restored within first two days of response; all impacted customers restored within 5 days of the start of the event.
Wind Storm (May 2018)	• High winds reported throughout service territory with gusts reaching approximately 120 km/h. • Estimated 68,000 customers out at peak. • 96 percent of customers restored within 48 hours of the start of the event.
Flash Storm (June 2018)	• High winds reported throughout service territory with gusts reaching approximately 90-100/h. • Estimated 16,500 customers out at peak. • 86 percent of customers restored within the first 12 hours and 97 percent of customers restored within the first 24 hours of the event.

A4.1.3 System Challenges: City Growth and Capacity Constraints

By 2020, Toronto Hydro expects to be distributing electricity to approximately 768,000 customers with a peak load of 4,316 MW. This continues a steady trajectory of customer growth and it is expected to continue. Despite this growth, overall system peak load (which is temperature-dependent) has remained relatively steady in recent years at approximately 5,000 MVA. Meanwhile, Toronto continues to experience concentrated load growth in certain areas of the City, primarily due to the high number of large condominium developments. Figure 5 illustrates how this type of growth continues to outpace nearly all North American cities. This concentrated growth is mainly observed

in the downtown area, but also along major transit corridors such as Yonge Street and Sheppard Avenue (and in the near future other corridors, such as Eglinton Avenue and Finch Avenue).

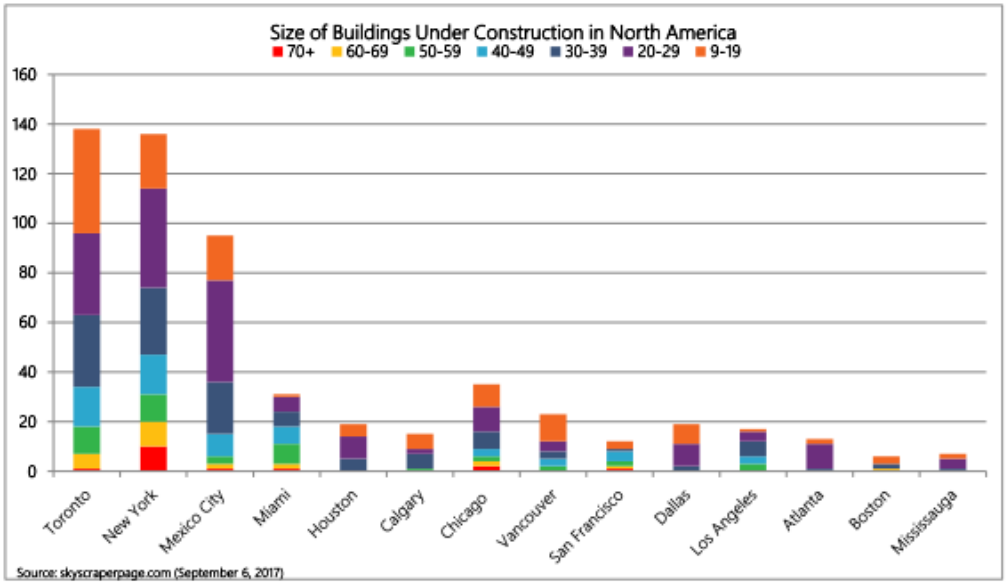


Figure 5: Number of Floors for High-Rise & Mid-Rise Buildings under Construction[9]

This growth is pushing certain distribution equipment to capacity. Infrastructure renewal and upgrades are urgently required to support that growth while maintaining reliability and safety outcomes. Investments in the System Access and System Service categories are driven by this projected level of demand. For example, Toronto Hydro projects increases in the costs associated with connecting customers and upgrading customer connections during the 2020-2024 period. Toronto Hydro must also continue investing proactively in its Load Demand (Section E5.3) and Stations Expansion (Section E7.4) programs to ensure adequate station bus capacity and feeder positions is available on the system. Failure to make these investments could have a detrimental effect on the utility's ability to connect future customers cost-effectively, without affecting reliability performance for existing customers. Furthermore, the failure to maintain and improve system operational flexibility will hamper the utility's ability to efficiently execute capital and maintenance work. Toronto Hydro's planned capacity-related investments for the 2020-2024 period are fully

[9] Toronto Economic Bulletin (September 26, 2017) : <https://www.toronto.ca/legdocs/mmis/2017/ed/bgrd/backgroundfile-107204.pdf>.

aligned with the regional plans developed in coordination with the IESO and Hydro One as summarized in Section B, Coordinated Planning with Third Parties.

Another relevant aspect of economic growth in the City of Toronto is the number of large, third-party infrastructure renewal and expansion projects that require Toronto Hydro to relocate its existing infrastructure. Toronto Hydro is obligated by the *Public Service Works on Highways Act*[10] ("PSWHA") and section 3.4 of the Distribution System Code ("DSC") to accommodate these third-party requests in a fair and reasonable manner. For the 2020-2024 period, the utility is expecting greater needs in this area due to a larger number of committed relocation and expansion projects by Metrolinx, the Toronto Transit Commission, and the City of Toronto.

A4.1.4 System Challenges: Technology Advancement

Technology advancements are a major challenge in the electricity distribution sector globally. The challenge is in many ways greater for distributors in major urban centres. The most prominent example of that challenge may be the complexity of integrating distributed energy resources on heavily loaded feeders in dense built-out areas that serve customers sensitive to power quality.

Interest in generation projects within Toronto Hydro's service territory has been steady in recent years, and is anticipated to continue into the future. Toronto Hydro has connected approximately 1,800 distributed generation connections. The utility is regularly approached by its customers to discuss utility options for or capacity to facilitate net metering and battery energy storage. Inquiries regarding conventional generators have also increased as micro-turbine based installations become more economically viable and commercial and industrial customers attempt to increase site reliability and operational cost savings.

Toronto Hydro is obligated to facilitate the safe, timely, and cost-efficient connection of distributed energy resources to its grid, and the connection of renewable energy generation projections remains a key public policy-aligned objective. The utility's Generation Capacity and Capability Assessment (described in Section E3.3) has identified a number of potential barriers to connecting the forecasted 581 MW of incremental distributed generation anticipated by 2024, including short-circuit capacity constraints, islanding risks, and system thermal limits. Toronto Hydro's Customer Connections (E5.1), Generation Protection, Monitoring, and Control (E5.5), and Energy Storage Systems (E7.2) programs all contain necessary investments specifically targeted at connecting and facilitating distributed

[10] R.S.O. 1990, c. P-49.

energy resources. Furthermore, the utility's grid modernization efforts (e.g. proliferation of modern SCADA-enabled equipment and creation of a dual control centre), which permeate all investment categories, will help prepare the utility to manage the increasingly complex interactions and inputs in electricity generated and consumed.

While smart grid systems, infrastructure automation, and other technological advancements by Toronto Hydro and its customers offer significant opportunities, they also increase the exposure of the grid and those connected to it to greater risk of attack by hostile actors. This global challenge is particularly acute in major economic centres, such as Toronto.[11] Mitigating these technology-driven security risks is a critical and urgent challenge for Toronto Hydro in the 2020-2024 period and drives material investment in the General Plant category, including contributing to an overall increase in IT investment needs.[12]

A4.1.5 Customer Billing and Business Operations Needs

In addition to stations and feeder-level investments, Toronto Hydro must maintain its metering and non-distribution system assets to ensure accurate and timely customer billing and to keep the utility's "24/7" operations running and responsive to customer needs and requests.

Both front- and back-end assets related to customer billing are reaching end-of-life and will require replacement during the 2020-2024 period. On the front-end, this includes a necessary ramp-up in the utility's Residential and Small C&I Meter Replacement activities to address end-of-life meters with expiring seals.[13] Toronto Hydro cannot, as a matter of law, bill customers using meters with expired seals. The bulk of these meters will have their seals expire in 2024, and by 2025, 90 percent of these meters will be operating beyond their expected useful life, resulting in unacceptably high risks to billing accuracy, customer satisfaction and financial stability. To prevent these risks from materializing, Toronto Hydro must replace these meters in a staged manner beginning in 2022. Besides being a compliance-driven investment, the replacement of first generation smart meters with next generation technology will allow Toronto Hydro to capture the benefits of grid

[11] The OEB recently issued a regulatory response through its Cyber Security Framework (December 6, 2017) : <https://www.oeb.ca/sites/default/files/Ontario-Cyber-Security-Framework-20171206.pdf>.
[12] For more information on Toronto Hydro's proposed investments to assist with cyber security, please refer to Exhibit 2B, Section E8.2, Exhibit 2B Section E8.4, and Exhibit 4A, Tab 2, Schedule 17.
[13] Refer to the Metering program (System Access) in Section E5.4 for more information and a full options analysis.

modernization capabilities such as "last gasp" functionality, which will support outage restoration, communication, and the development of customer-specific reliability measures.

On the back-end, Toronto Hydro's Customer Information System ("CIS") has been out of vendor support for over two years. The CIS is the foundation of a range of customer service functions and business processes including billing. Without vendor support, the application is increasingly exposed to reliability and cybersecurity risks, and customizations (e.g. the provision of self-service options through *mytorontohydro.com*) will continue to be challenging to administer and maintain. For these reasons, Toronto Hydro must upgrade to a fully supported CIS during the 2020-2024 period.

Beyond billing-related investments, Toronto Hydro must maintain business continuity by investing in the operational assets that allow the utility to carry-out its day-to-day business, execute work in the field, and remain responsive to customers. General Plant expenditures for 2020-2024 are largely related to routine, asset lifecycle, and condition driven investments that are necessary to ensure the safe and reliable operation of the utility's fleet, facilities, and IT infrastructure.[14]

A4.2 Addressing Customer Needs and Preferences

Toronto Hydro undertook extensive Customer Engagement as part of business planning for this application. The utility augmented its routine, ongoing customer engagement by engaging Innovative Research Group ("Innovative") to design and implement a planning-specific Customer Engagement process, which was structured in two phases.[15]

In **Phase 1**, Innovative used a range of techniques to assess customers' needs and preferred outcomes. The results of this phase directly informed the strategic parameters for the business plan and informed decision-making throughout the planning process that produced the penultimate Capital Expenditure Plan. Innovative initially identified the following customer priorities, which were foundational to the development of the utility's Outcomes Framework (described in the A4.3 below):

1) Delivering reasonable electricity prices;
2) Ensuring reliable electrical service;
3) Ensuring the safety of electrical infrastructure;
4) Providing quality customer service;

[14] Refer to Facilities Management and Security (E8.2), Fleet and Equipment (E8.3) and Information Technology and Operational Technology Systems (E8.4) programs for more information.
[15] Innovative's final report can be found at Exhibit 1B, Tab 3, Schedule 1, Appendix A

5) Helping customers with electricity conservation and efficient usage; and
6) Enabling the electrical system to support the reduction of Greenhouse gases.

After identifying and categorizing the priorities above, Innovative gathered feedback on how customers ranked these priorities. Feedback from customers was that price, reliability, and safety were their top three priorities, with lower volume and mid-size customers clearly ranking "reasonable electricity prices" as the top priority, and larger customers ranking reliability as the top concern. In Innovative's view, the overall feedback could be characterized by the following common issues:

1) Keeping distribution price increases as low as possible;
2) Maintaining long-term performance for customers experiencing average or better service;
3) Improving service levels for customers experiencing below average service or who have special reliability needs; and
4) Balancing other customer priorities (e.g. customer service) with the need to contain rate increases.

In response to this feedback, and as mentioned in Section A3 above, the utility sought to minimize rate increases by establishing an upper price limit and an upper capital budget limit that approximated the minimum sustainment level of capital investment required. Toronto Hydro used these strategic parameters and the full breadth of customer feedback to develop program-level expenditure plans that addressed customers' priorities.

Perhaps the most important example of this is how Toronto Hydro has restrained the pace of System Renewal investment to a minimum level. Customers are generally satisfied with the service they receive from Toronto Hydro, and the utility's objective for the 2020-2024 is not to deliver a step-change improvement in system-wide reliability. The utility expects that its renewal plan, in conjunction with supporting investments in other categories, can maintain current levels of system average reliability for current customers and future customers, while allowing the utility to make targeted improvements in critical performance areas such as PCB oil spill risks and worst performing feeders. Each of Toronto Hydro's System Renewal programs in Section E6 describes how this pacing has been set in relation to leading indicators of performance such as asset condition.

Toronto Hydro's plans are also responsive to other needs and preferences identified by customers, such as the power quality concerns of large customers, and the preference of most customers for

improved access to usage and billing information online. For a detailed discussion of how Toronto Hydro's 2020-2024 DSP addresses customer needs and preferences, see Section E2.3.

In **Phase 2** of Customer Engagement, Innovative found that a majority of customers across all classes either supported sticking with the plan Toronto Hydro had developed or improving service (even if it cost more). Customers were asked to provide feedback on the pacing and prioritization of programs in areas where Toronto Hydro felt it could adjust pacing to achieve greater benefits. For core investments addressing safety and reliability, customers were generally supportive of the proposed pace or an accelerated approach. Customers were generally less supportive of doing more than planned when it came to more innovative investments, with the exception of investing in monitoring and control capabilities.

The utility took customers' support for the overall plan and the Customer Engagement process as confirmation that the plan achieves an appropriate balance between addressing long-term system needs and risks, delivering the outcomes that customers need and prefer, and keeping price increases as low as possible. Given the particularly strong support across customer classes for programs that address the risk of network vault floods and fires (i.e. Network Unit Renewal and Network Condition Monitoring & Control), Toronto Hydro made minor adjustments to the pace of these programs to address these issues at an accelerated pace over the 2020-2024 period.

A4.3 Outcomes and Performance Measurement

Toronto Hydro used the list of customer priorities identified in Phase 1 of Customer Engagement (summarized in A4.2 above) to develop a customer-focused Outcomes Framework for this Application and the 2020-2024 DSP. This framework aligns with both the utility's corporate strategic pillars and the outcomes and performance categories of the *Renewed Regulatory Framework* ("RRF"). The resulting framework is focused on six key outcomes: Customer Service, Reliability, Safety, Environment, Public Policy (which includes enabling the system to support the reduction of greenhouse gases), and Financial (which includes delivering reasonable electricity prices).[16]

This framework transitioned into the lens through which Toronto Hydro developed its business plan, and is reflected in the investment planning decisions made by the utility. Some of these decisions

[16] Refer to Exhibit 1B, Tab 2, Schedule 1 for more details on the structure of this framework and its alignment with the RRF and Toronto Hydro's strategic pillars.

translated into measures in Toronto Hydro's Custom Performance Scorecard for the 2020-2024 period, while others appear as priorities at the investment program level.

Toronto Hydro is proposing 15 custom measures for the 2020-2024 plan period with associated targets. These measures are shown in Table 5, below. These measures are incremental to the measures contained in the Electricity Distributor Scorecard ("EDS") and the Electricity Service Quality Requirements ("ESQR"), for a total of 44 unique measures to be reported to the OEB annually.

Table 5: 2020-2024 Custom Performance Scorecard Measures

Toronto Hydro Outcome	OEB Reporting Category	Toronto Hydro's Custom Measures	Target
Customer Service	Customer Satisfaction	Customers on eBills	Improve
Safety	Safety	Total Recorded Injury Frequency	Maintain
		Box Construction Conversion	Improve
		Network Units Modernization	Improve
Reliability	System Reliability	SAIDI - Defective Equipment	Maintain
		SAIFI - Defective Equipment	Maintain
		FESI 7 System	Improve
		FESI-6 Large Customers	Maintain
	Asset Management	System Capacity	Maintain
		System Health (Asset Condition) – Wood Poles	Monitor
		Direct Buried Cable Replacement	Improve
Financial	Cost Control	Average Wood Pole Replacement Cost	Monitor
		Vegetation Management Cost per Km	Monitor
Environment	Environment	Oil Spills Containing PCBs	Improve
		Waste Diversion	Monitor

The utility's forecasted measures and targets related to the Custom Performance Scorecard have been developed on the basis of the proposals, plans and associated rates contained in this Application. The utility selected these specific custom measures as they are strongly representative of the key drivers of expenditures during the period and customers' preferred outcomes. For example, the choice of adding SAIDI and SAIFI metrics for outages caused by Defective Equipment reflects the materiality of asset failure and failure risk as drivers of the utility's substantial System Renewal program. The target of "maintain" for these metrics reflects customers' reliability preferences for short- and long-term. Further complimenting these measures are the Feeders

Experiencing Sustained Interruptions ("FESI") measures, which have been added reflect the need to deliver targeted reliability improvements to customers experiencing below-average reliability. For a complete discussion of the utility's Custom Performance Scorecard measures, please refer to Section C of the DSP.

A4.4 Expected Sources of Cost Savings during the Plan Period

Throughout the plan period, and in the course of executing its DSP, Toronto Hydro will continue to evaluate its operational efficiencies and seek ways to reduce and avoid costs, while increasing value for ratepayers. The capital program narratives in Sections E5 through E8, and the OM&A narratives in Exhibit 4A, Tab 2, provide several examples of the investments and initiatives that will support the utility's efforts to control costs and increase productivity. The following list highlights some of these activities.

- **Grid Modernization:** Many of Toronto Hydro's planned investments in the 2020-2024 period will support the ongoing modernization of the grid, through the introduction of technologies that support remote monitoring, sensing, protection, and control. A key example of this is the Network Condition Monitoring and Control program (Section E7.3). Like all of the capital programs that introduce remote switching and monitoring capabilities, this program is expected to improve the productivity of field employees and system controllers when operating the system and responding to outages (for example, by allowing system controllers to perform switching operations remotely instead of relying on field crews for manual switching). In this program specifically, Toronto Hydro also anticipates cost savings related to network system maintenance, as the need for inspections will be reduced by the ability to monitor network vault condition remotely. The modernization of the network will also support more cost-effective customer connections by providing real-time load monitoring that will allow the utility to lift some of the connection capacity limitations on existing secondary networks. Further information on grid modernization benefits can be found throughout all investment categories, including the Metering program (Section E5.4), Stations Renewal (Section E6.6), System Enhancements (Section E7.1), and IT/OT Systems (Section E8.4).

- **Capacity Improvements:** Capacity improvements from the utility's Load Demand (Section E5.3) and Stations Expansion (Section E7.4) programs are expected to allow for more

flexibility in scheduling planned outages for maintenance at the affected stations and for the delivery of Toronto Hydro's capital plans generally.

- **Standardization:** By eliminating obsolete asset types across the system through programs such as Area Conversions (Section E6.1) and Stations Renewal (Section E6.6), Toronto Hydro expects to improve operational efficiency in a number of ways, including by improving safe and efficient employee access to the system, reducing costs associated with refurbishing and supporting non-standard assets, optimizing procurement and supply chain by reducing the number of different equipment standards on the system, and reducing line losses on 4 kV feeders. Upgrading feeders from 4 kV to 13.8 kV or 27.6 kV feeders is also expected to improve the capacity to connect customers, resulting in more cost-efficient connections.

- **Area Rebuilds:** When planning projects, Toronto Hydro uses cost-benefit and risk evaluation principles to identify opportunities to bundle multiple assets of different types into area rebuild projects. This approach reduces the risk of needing to travel and set-up in a project area on multiple occasions in a short timeframe, thereby reducing the overall cost of replacing the relevant assets and the frequency of disruption to customers. By taking this approach in programs such as Overhead System Renewal (Section E6.5) and Underground System Renewal – Horseshoe (E6.1), the utility aims to mitigate the overall cost of its System Renewal program over time.

- **Conservation First:** In addition to traditional expansion investments, the Stations Expansion (Section E7.4) program includes a continuation of Toronto Hydro's Local Demand Response activities introduced in the 2015-2019 DSP. These investments involve installing battery storage and implementing targeted demand response incentive programs to reduce peak demand by 10 MW, allowing the utility to defer an estimated $135 million of expansion investments at Cecil TS and Basin TS.

- **Safety and Environmental Costs:** Employee and public safety is paramount for Toronto Hydro and a significant driver of capital investment during the 2020-2024 period. By investing in the sustainment and improvement of safety outcomes, the utility supports secondary financial benefits, such as a decrease in Workplace Safety Insurance Board premiums resulting from the utility's safety record. For further details, please refer to Exhibit 4A, Tab 2, Schedule 15. Similarly, by endeavouring to eliminate the risk of PCB-contaminated

oil spills, Toronto Hydro reduces the risk of potentially material costs associated with non-compliance with Federal and Provincial environmental legislation and City bylaws.

- **Enhanced Work Coordination:** Some maintenance activities require an outage to be taken to create a safe work zone in accordance with Toronto Hydro's Work Protection Code. Initiatives undertaken in 2016 included the development of an annual feeder scheduling program and enhanced work coordination to allow crews to carry out more maintenance work per outage. For maintenance activities that require an outage (e.g. overhead switch maintenance), this initiative entails cost control benefits given the need for fewer switching and isolation operations overall.

- **Facilities Asset Management System:** Toronto Hydro has introduced a robust facilities management system that records assessments and maintenance plans for all assets located in Toronto Hydro's work centres and stations. This repository system identifies the condition of all facilities-related assets (e.g. poor, fair, good) owned by Toronto Hydro, ensuring that the utility is only replacing assets that are at end-of-life and in poor condition.

- **Procurement:** Toronto Hydro continues to rely on a mix of internal and external resources to carry-out its large capital and maintenance programs. The majority of the costs associated with the utility's capital work program are determined through a competitive procurement process. While labour market pressures and increasing congestion in the City of Toronto are expected to result in higher construction cost escalation during the coming years, the utility's competitive procurement strategy nonetheless helps to ensure that Toronto Hydro can secure the necessary resources to execute its capital plan at reasonable costs.

In addition to the above initiatives, Toronto Hydro's overall risk-based approach to system renewal and enhancement is expected to drive value, including cost savings, over the long-term by ensuring that decisions on when to replace assets are informed by quantitative analysis and measurement. For example, by using tools like the Feeder Investment Model ("FIM"), which provides a probabilistic, total lifecycle assessment of costs and risks, the utility is able to balance the benefits of deferring capital investments as long as possible and the additional costs (including customer interruption costs) associated with asset failure and reactive replacement. In the context of Toronto Hydro's large asset renewal backlog, economic risk-based approaches allow the utility to target assets that carry the greatest amount of risk cost based on age, condition, configuration, loading, and other considerations, ensuring that priorities are set in a manner that maximizes value-for-money over the

long-term. For more information on Toronto Hydro's asset management lifecycle optimization and risk management approaches, please see Section D3.

A4.5 Third-Party Studies and Reports

The 2020-2024 DSP is supported by a several expert studies and reports.

Table 6: Third-Party Studies Filed in Support of the 2020-2024 DSP

Study	Vendor	Description/Reference
Distribution System Plan Asset Management Review	UMS Group	UMS Group was retained to review and evaluate the maturity of Toronto Hydro's asset management processes and capabilities as they relate to the formulation of the DSP. UMS Group found that Toronto Hydro "exceeds the North American average level of maturity in all areas, reaching into "Best Practice" for some." The study can be found at appendix A to Exhibit 2B, Section D.
Econometric Benchmarking of Historical and Projected Total Cost and Reliability	Power System Engineering Inc. ("PSE")	PSE was retained to apply econometric modelling to benchmark the utility's historical and projected costs and reliability. The purpose of this review was to assess the reasonableness of Toronto Hydro's revenue forecasts and inform the appropriate stretch factor in the utility's Application. PSE compared Toronto Hydro's historical and projected total costs against its benchmark costs i.e. the Toronto Hydro's expected costs in any given year based on the econometric model. PSE's results indicated that (i) the historical average total costs for the utility, from 2015 to 2017, are 18.6 percent below benchmark expectations. Specifically, Toronto Hydro's total annual costs were approximately $157 million below benchmark values in 2017; and (ii) the projected total cost levels during the 2020-2024 period are 6.0 percent below benchmark expectations. Toronto Hydro's total annual costs are expected to be approximately $32 million below benchmark values in 2024. Based on their findings, PSE states that Toronto Hydro is not a poor total cost performer and recommends a stretch factor of 0.3 percent. The study can be found at Exhibit 2A, Tab 4, Schedule 2.

Study	Vendor	Description/Reference
Unit Costs Benchmarking Study	UMS Group	UMS Group was retained to perform a capital and maintenance unit cost benchmarking exercise. The utility provided UMS with actual, all-in capitalized unit costs for major asset classes for the 2014-2016 period. UMS performed a normalized comparison of these results to those of peer utilities across North America. Overall, UMS found that Toronto Hydro performed well relative to unit cost distribution of its peers, with one asset class in the third quartile and the remainder of the asset class unit costs in the second quartile. The study can be found at Appendix B to Exhibit 1B, Tab 2, Schedule 1.
Climate Change Vulnerability Assessment	AECOM Consultants Inc.	To better understand the risks related to increases in extreme and severe weather due to climate change, in June 2015, Toronto Hydro completed a vulnerability assessment following Engineers Canada's Public Infrastructure Engineering Vulnerability Committee ("PIEVC") protocol. The assessment identified areas of vulnerability to Toronto Hydro's infrastructure as a result of climate change. Following this study, a climate change adaptation road map was developed, along with initiatives relating to climate data validation, review of equipment specifications, and review of the load forecasting model. This information informed the development of Toronto Hydro's 2020-2024 DSP. The study can be found at Appendix D to Exhibit 2B, Section D.
Standards Review – 2018 Update	Power System Engineering, Inc.	Toronto Hydro retained PSE to update its 2014 Independent Review of the utility's standard design and construction practices, major material specifications, and procedural standards processes. Toronto Hydro's revised Standards were found by PSE to be thorough, well documented, and consistent with what is seen in the industry. The study can be found at Appendix B to Exhibit 2B, Section D.

Study	Vendor	Description/Reference
IT Cost Benchmarking	Gartner Inc.	To assess the reasonableness of the utility's level of overall IT/OT expenditures, Toronto Hydro procured an independent benchmarking study by Gartner Consulting concluded that the utility's total IT expenditures per user in both 2017 and 2020 benchmark competitively against industry peers. Gartner also concluded that, in both years, the distribution of Toronto Hydro's IT investments "by cost category, investment category, and functional area are all comparable to the peer group, with some variation but no significant issues identified." The study can be found at Appendix A to Exhibit 2B, Section E8.4.
Jurisdictional review and economic case for a dual distribution control center in Toronto Hydro territory	London Economics International LLC	To assess Toronto Hydro's investment in a dual control centre, the utility retained London Economics International ("LEI") to undertake a review of comparator utilities (see Section E8.1, Appendix A). LEI completed a review of various utilities in North America that have distribution operations with more than one control centre. These facilities were fully functional and were able to take over full operational functions from the primary control centre. The review confirmed that utilities serving a critical load in North America invest in more than one fully functioning control centre to support resiliency, increase reliability, and ensure quick recovery from terrorist threats and natural disasters, for example earthquakes and floods. The study can be found at Appendix A to Exhibit 2B, Section E8.1.

A5 Asset Management Process and Enhancements

Toronto Hydro's distribution system AM Process, explained in detail in Section D and depicted in Figure 6 below. The objective of Toronto Hydro's AM Process is to realize sustainable value from the organization's assets for the benefit of customers and stakeholders, while meeting all of the utility's mandated service and compliance obligations. This requires continuously balancing near-term customer preferences with the need to ensure predictable performance and costs over the long-term for both current and future customers.

The AM Process consists of the following five major elements which support everything from strategy and planning to construction and performance measurement.

The **Investment Planning & Portfolio Process ("IPPR")** is Toronto Hydro's system investment planning cycle, which includes both long-term and short-term planning horizons. Toronto Hydro's 2020-2024 Capital Expenditure Plan is derived from this process, which is itself built on the application of the utility's robust asset lifecycle optimization and risk management practices, described in detail in Section D3. This process produces an optimized mix of capital programs for the planning horizon, including the forecast program expenditure levels and associated volumes of work and performance objectives. The IPPR includes annual maintenance planning to support the mutual optimization of capital investment and system maintenance expenditures.

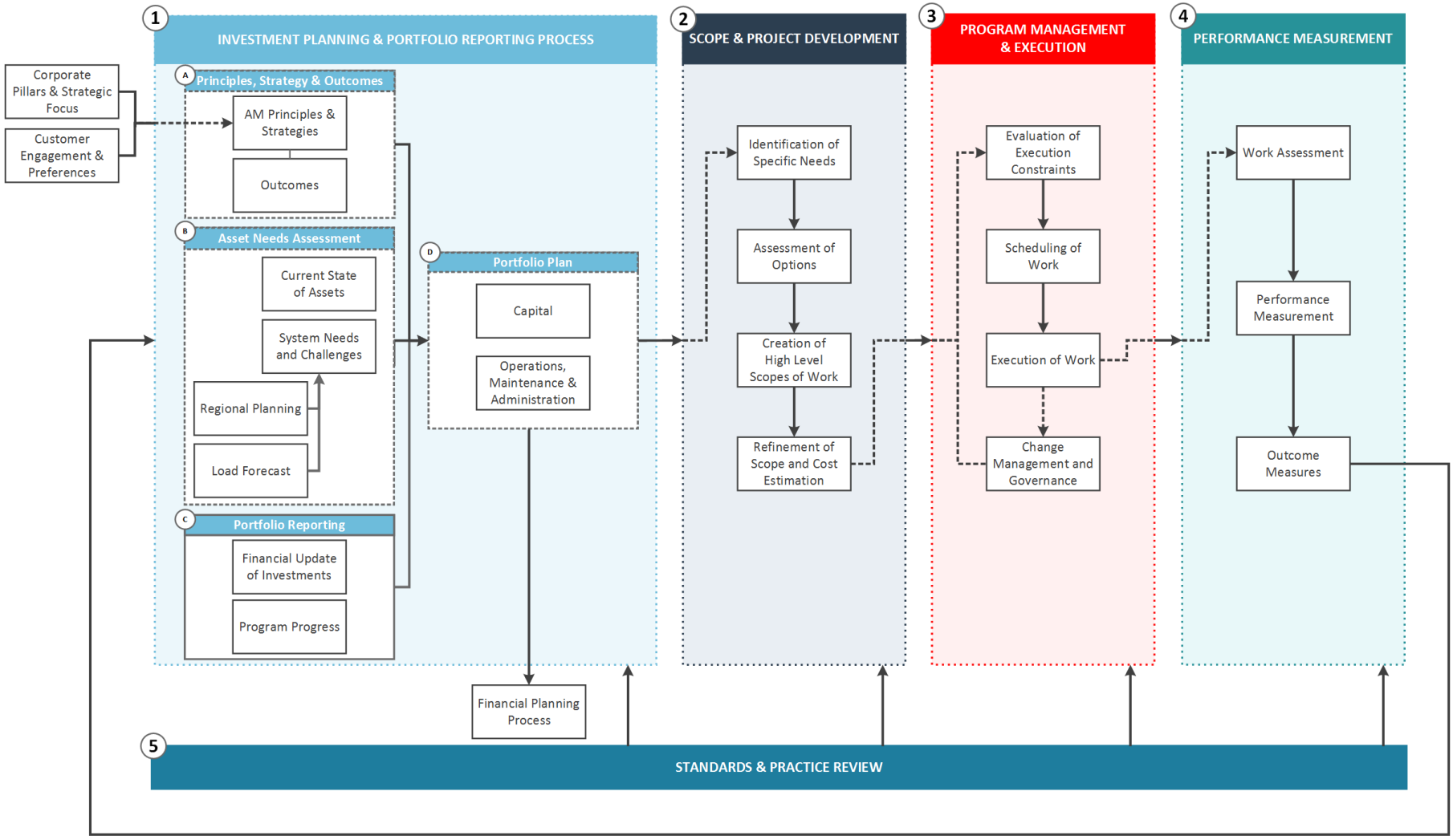


Figure 6: Asset Management Process Overview

As of 2016, the utility performs all of the activities in the IPPR on an annual basis. Toronto Hydro made this enhancement to further strengthen the alignment between: (i) the projects selected for execution within an annual capital plan; and (ii) the utility's overall five-year expenditure plan and outcome objectives. It will also help improve the sensitivity of the planning process to new and evolving information, including ongoing customer and stakeholder engagement, changes in system performance, public policy developments, and other dynamic factors.

The **Scope and Project Development** component of the AM Process involves the development of discrete projects within each investment program. This process involves four components: identification of specific needs, assessment of options, development of high-level project scopes of work ("scopes"), and refinement of scopes and cost estimates. This phase of the AM Process also relies on the application of Toronto Hydro's asset lifecycle optimization and risk management practices to ensure the development of high value projects that support the utility's outcome objectives.

The **Program Management and Execution** stage of the AM Process involves creating, delivering, and governing an executable work program. The major processes include evaluation of execution constraints, scheduling of work, execution of work, and the change management process that accounts for any required project changes.

Performance Measurement is the final stage of the AM Process. This stage monitors the performance of the investment program, to determine to what extent projects have contributed to expected outcomes. These results feedback into the annual IPPR process so that Toronto Hydro can modify programs and refine objectives if necessary.

The **Standards and Practice Review** is an ongoing activity that influences the other stages of the AM Process. It is driven by the need to evaluate particular standards and products to improve work execution. The review encompasses the necessary specifications and processes related to: (i) introducing standards and assets into the system; (ii) installation requirements; (iii) replacement considerations; (iv) identifying new assets to better meet system needs and customer preferences; (v) carrying out work in a consistent manner; and (vi) supporting improved safety on the system.

Toronto Hydro is continually monitoring and improving AM decision-support systems, enterprise systems and various inputs that support effective asset management. Recent Improvements to Toronto Hydro's AM Process over the 2015-2019 period are highlighted in Figure 7 below. For more information on these improvements, please refer to Section D of the DSP.

In addition to the distribution system AM Process, Toronto Hydro has similar robust AM processes for facilities, fleet, and IT assets. The AM approach for facilities and IT are summarized in Sections D4 and D5, while the AM strategy for fleet can found in the Fleet and Equipment capital program in Section E8.3.



Figure 7: Recent Enhancements of the AM Process (2015-2019)

A6 Capital Expenditure Plan

Table 7 shows the level of spending for the System Access, System Renewal, System Service, and General Plant investment categories, as well as the System O&M expenditures over the historical period from 2015 to 2019 and over the forecast period from 2020 to 2024. A detailed discussed of expenditure variances and trends over the 10-year 2015-2024 period is provided in Section E4.

Table 7: Historical (2015 to 2019) and Forecast (2020 to 2024) Expenditures ($ Millions)

Category	Actuals			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
System Access	58.3	79.0	65.5	100.8	97.1	91.8	93.3	93.9	106.0	116.4
System Renewal	304.1	266.1	250.3	229.4	253.4	306.6	325.7	323.1	339.0	325.5
System Service	37.9	53.3	72.4	41.4	41.8	34.2	60.1	71.3	33.6	38.5
General Plant	79.4	109.5	98.9	70.0	40.2	78.8	93.7	89.0	77.7	85.2
Other	11.6	3.7	10.7	6.3	2.4	7.0	9.0	9.8	9.5	8.7
Total Capex	**491.4**	**511.6**	**497.8**	**447.8**	**434.9**	**518.4**	**581.8**	**587.1**	**565.7**	**574.4**
System O&M	116.1	126.5	126.3	126.9	131.0	130.4				

Tables 8 through 11, below, provide a high-level summary of the 20 capital programs that constitute the 2020-2024 DSP by investment category. Detailed analysis for each program is included in Sections E5 through E8 of the DSP, including analysis of historical expenditures and accomplishments, justifications for 2020-2024 expenditures, and options analysis.

Table 8: System Access Program Summaries

Program Index and Name		2020-2024 Cost ($M)	Summary
E5.1	***Customer Connections***	**223.4**	**Description**: Investments the utility must make to provide load and generation customers with access to its distribution system. **Objectives**: Meet mandated service obligations for customer service requests by providing new and existing customers with timely, cost-efficient, reliable, and safe access to the distribution system. **Forecast/Pacing**: Forecasted expenditures based on gross cost and customer contribution trends. Growth in residential and commercial development within the City of Toronto is expected to continue.

Program Index and Name		2020-2024 Cost ($M)	Summary
E5.2	***Externally Initiated Plant Relocations and Expansion***	**46.1**	**Description**: Work the utility must undertake to relocate its infrastructure in order to accommodate construction by third parties. In some instances, the program includes work that increases feeder capacity where efficiencies can be achieved by pairing expansion work with the required relocation work. **Objectives**: Resolve third-party relocation requests in a fair and reasonable manner. **Forecast/Pacing**: Only committed projects are included in the forecast. The utility proposes to continue the variance account for externally driven capital during 2020-2024.
E5.3	***Load Demand***	**87.5**	**Description**: Expansions, enhancements and other work to alleviate emerging connection constraints, operational constraints, and reliability risks in areas of high load demand. **Objectives**: Reduce the number of highly loaded feeders in high-growth areas to support the utility's reliability and customer service objectives and to support efficient delivery of other capital and maintenance programs. **Forecast/Pacing**: The expenditure plan reflects specific needs identified through Toronto Hydro's Distribution Capacity and Capability Assessments. See Section E5.3 for more details.
E5.4	***Metering***	**130.8**	**Description**: Various investments in customer metering infrastructure driven by legal and regulatory metering requirements and to facilitate accurate customer billing. **Objectives**: Maintain compliance with legal and regulatory metering requirements under the *Electricity and Gas Inspection Act*, the *Weights and Measures Act*, and the IESO's Market Rules. **Forecast/Pacing**: Increases in this program are mainly driven by a ramp-up in 2022 of low-volume customer meter replacement, which is required to address the end-of-life meter population.

Program Index and Name		2020-2024 Cost ($M)	Summary
E5.5	***Generation Protection, Monitoring, and Control***	**13.6**	**Description**: Eliminating connection constraints and installing monitoring and control equipment to enable the connection of forecasted distributed generation projects. **Objectives**: Enable the safe and reliable connection of all forecasted distributed generation facilities to the system (including renewable energy generation) in support of provincial public policy objectives and in alignment with mandated service obligations. **Forecast/Pacing**: Planned expenditures are based on an assessment of the enhancement investments required to safely accommodate projected distributed generation projects during the 2020-2024 period.

1 **Table 9: System Renewal Program Summaries**

Program Index and Name		2020-2024 Costs ($M)	Summary
E6.1	***Area Conversions***	**220.8**	**Description**: Conversion of two unique legacy 4.16 kV designs known as rear lot construction and box construction to updated standard 13.8 kV and 27.6 kV lines. **Objectives**: Maintain reliability, reduce the risk of long-duration outages, mitigate safety risks for employees and the public, and alleviate other customer service and operational deficiencies related to these obsolete assets through a proactive replacement strategy. **Forecast/Pacing**: Toronto Hydro has paced the program to remove all box construction by 2026, and plans to maintain the current historical pace of rear lot conversion over the 2020-2024 period by converting an estimated 2,350 customers to front lot.

Program Index and Name		2020-2024 Costs ($M)	Summary
E6.2	***Underground System Renewal - Horseshoe***	**460.3**	**Description**: (1) Neighborhood rebuilds of underground circuits consisting of high-risk direct-buried cable and other assets at risk of failure. (2) Targeted removal of transformers at risk of spilling PCB-contaminated oil. **Objectives**: Maintain reliability, continue reducing the population of high-risk direct-buried cable, and continue reducing the risk of PCB-contaminated oil spills. **Forecast/Pacing**: To meet its objectives, including maintaining pace with the rate of cable aging, the utility plans to replace approximately 215 circuit-km of the highest risk direct-buried cable, and replace transformers at-risk of spilling PCB-contaminated oil in conjunction with cable-driven rebuild projects and through spot replacements.
E6.3	***Underground System Renewal - Downtown***	**122.0**	**Description**: Proactive renewal of obsolete lead cable at risk of failure, deteriorating cable chambers, and poor performing Underground Residential Distribution equipment. **Objectives**: Maintain reliability, while preventing asset-related public and employee safety risks from accumulating, by proactively addressing the highest-risk underground assets in congested, high-traffic urban areas. **Forecast/Pacing**: To meet its objectives, the utility plans to replace the highest risk 2 percent of existing paper-insulated lead covered cable, 20 percent of asbestos-insulated lead covered cable, and an estimated 185 cable chambers or chamber roofs in deteriorating condition.
E6.4	***Network System Renewal***	**92.4**	**Description**: (1) Continue the proactive renewal of high-risk, obsolete, Automatic Transfer Switches ("ATS") and Reverse Power Breakers ("RPB"), non-submersible network units prone to flooding, and vaults in deteriorated condition. (2) Reconfigure and re-cable sub-optimal grid networks. **Objectives**: Maintain reliability, reduce the risk of catastrophic equipment failure, support environmental objectives, and mitigate public and employee safety risks by proactively replacing deteriorating and functionally obsolete underground network system assets in highly congested urban areas. **Forecast/Pacing**: To meet its objectives, the utility plans to (1) replace all remaining ATS and RPB units in the 2020-2024 period, and (2) reduce the risk of network vault fires and flooding by replacing approximately 240 non-submersible network units by 2024.

Program Index and Name		2020-2024 Costs ($M)	Summary
E6.5	***Overhead System Renewal***	**265.7**	**Description**: (1) Neighborhood rebuilds of overheard circuits driven largely by pole condition, pole-top transformer age, feeder performance, and overall risk analysis. (2) Targeted removal of transformers at risk of spilling PCB-contaminated oil. **Objectives**: Maintain reliability, prevent asset-related failure risk from increasing, and reduce the risk of PCB contaminated-oil spills. **Forecast/Pacing**: Upwards of 34,000 poles are projected to have at least material condition by 2024. Pole-top transformers past useful life are projected to increase from 14 percent to 40 percent. The utility plans to meet its objectives by replacing approximately 13,000 poles in this program between 2018 and 2024 and by targeting transformers at risk of spilling oil with PCB.
E6.6	***Stations Renewal***	**141.5**	**Description**: Proactive replacement of critical transformer station ("TS") and municipal station ("MS") assets at risk of failure. **Objectives**: Maintain reliability, improve system resiliency, and reduce safety and environmental risks by addressing the increasing backlog of critical stations assets that are in deteriorating condition, beyond useful life, and otherwise at risk of failure. **Forecast/Pacing**: The program addresses a variety of major stations assets at a pace intended to maintain or improve the level of failure risk associated with each asset type population, as indicated by condition scores and observations, age, criticality, obsolescence, and other considerations.
E6.7	***Reactive and Corrective Capital***	**317.2**	**Description**: (1) The urgent and non-discretionary replacement of failed assets and assets with high-risk deficiencies. (2) Targeted, corrective interventions on worst performing feeders. **Objectives**: (1) Maintain reliability and mitigate immediate safety and environmental risks by addressing failed and critically defective assets in a timely manner. (2) Prevent increases in the number of feeders experiencing especially poor reliability by monitoring and executing short-term improvements on worst performing feeders where feasible. **Forecast/Pacing**: Due to the continuing backlog of aging, poor condition and obsolete assets, and the increasing frequency and intensity of adverse weather events and conditions, Toronto Hydro is forecasting moderate increases in the expenditures in this program in 2020-2024.

1 **Table 10: System Service Program Summaries**

Program Index and Name		2020-2024 Costs ($M)	Summary
E7.1	***System Enhancements***	**27.7**	**Description**: Targeted contingency enhancements to reduce the impact of asset failures and other outage causes, including adding tie-points to feeders, installing remote switching points, and installing protection equipment upstream from customer-owned stations equipment. **Objectives**: Maintain current levels of reliability while improving system resiliency in the face of increasingly frequent adverse weather events. **Forecast/Pacing**: Toronto Hydro is scaling back on the pace of investment in this area in 2020-2024 in light of progress already made in 2015-2019 and to reflect customer preferences for maintaining current levels of reliability.
E7.**2**	***Energy Storage Systems***	**10.5**	**Description**: Installing battery storage systems in targeted locations to enable renewable generation connections, support grid performance, and facilitate customer-specific battery solutions. **Objectives**: Support the utility's objectives of connecting renewable generation projects and improving grid performance (e.g. power quality) in poor performing areas. **Forecast/Pacing**: Forecast renewable enabling energy storage projects are based on anticipated connection constraints in the 2020-2024 period. A modest grid performance energy storage plan will be prioritized based on a needs and benefits analysis of specific feeder segments. Toronto Hydro is also planning to offer customer-specific battery storage solutions in accordance with "beneficiary pays" principles.

Program Index and Name		2020-2024 Costs ($M)	Summary
E7.3	***Network Condition Monitoring and Control***	**63.0**	**Description**: Modernizing the network system by installing SCADA-enabled monitoring and control technology throughout the network system. **Objectives**: Supports multiple objectives, including maintaining reliability, improving the resiliency of the network system in the face of increasing flooding risk, preventing vault fires and related safety and environmental risks, improving outage restoration capabilities, reducing network maintenance costs, and improving the utility's ability to connect new customers to the network system. **Forecast/Pacing**: Toronto Hydro forecasts 90 percent coverage of the network system with SCADA enabled monitoring and control capabilities by 2024 – an objective that received strong support from customers in Customer Engagement.
E7.4	***Stations Expansion***	**136.4**	**Description**: Expansion and demand response investments to mitigate capacity constraints at the station level. **Objectives**: Ensure sufficient system capacity is available to maintain reliability, connect customers, and support efficient operations, while deferring expansion investments through demand response initiatives where appropriate. **Forecast/Pacing**: The 2020-2024 proposed investments are informed by, and fully align with, Integrated Regional Resource Plan (IRRP) activities conducted in coordination with the IESO and Hydro One. Overall, Toronto Hydro is investing what is necessary prevent system capacity from deteriorating over the 2020-2024 period.

1 **Table 11: General Plant Program Summaries**

Program Index and Name		2020-2024 Costs ($M)	Summary
E8.1	***Control Operations Reinforcement***	**40.2**	**Description**: Create a fully functional dual control centre at a separate physical location from the existing primary control centre. **Objectives**: Improve Toronto Hydro's operational resiliency, including the utility's ability to safely operate the distribution grid in emergency scenarios, in line with industry practices for utilities serving a critical load. **Forecast/Pacing**: Toronto Hydro plans to install and operationalize this dual control centre during the 2020-2024 period.

Program Index and Name		2020-2024 Costs ($M)	Summary
E8.2	***Facilities Management and Security***	**60.4**	**Description**: Condition-based investments and improvements to physical security at critical operating centres and stations buildings. **Objectives**: Support all DSP outcomes by maintaining infrastructure that supports critical operations of the distribution system and ensuring safety and business continuity by improving security at operation centres. **Forecast/Pacing:** 2020-2024 investments in this program are largely driven by lifecycle cost and risk minimization principles informed by asset condition information and studies. Increases in this program are driven by required investments in deteriorating stations buildings and necessary upgrades to security systems.
E8.3	***Fleet and Equipment Services***	**42.5**	**Description**: Routine investment in the utility's fleet of vehicles to maintain safe and reliable operation in accordance with lifecycle cost optimization principles. **Objective**: Minimize vehicle downtime, repairs, and safety risks by cost-effectively investing in a reliable fleet of vehicles. **Forecast/Pacing**: The program is paced to address light and heavy duty vehicles that will be due for replacement during the 2020-2024 plan period in accordance with lifecycle optimization analysis. Toronto Hydro will assess vehicle condition before taking any vehicle out of service. Over the 2020-2024 period, Toronto Hydro will replace a higher number of heavy duty vehicles, as compared to the 2015-2019 period, due to their age and condition.

Program Index and Name		2020-2024 Costs ($M)	Summary
E8.4	***IT/OT Systems***	**281.4**	**Description**: Replacing and upgrading information and operational technology in accordance with the utility's IT Asset Management strategy and methodologies. **Objectives**: Support Toronto Hydro's business functions and priorities, including effective and reliable service to customers, safe and efficient management and operation of the distribution system, compliance with legal and regulatory requirements, and sustainment of the utility's long-term financial viability, by making necessary and targeted investments in core IT/OT infrastructure, while keeping related costs in alignment with industry norms. **Forecast/Plan**: Increased investment in the 2020-2024 period is driven by overall hardware and software needs, including replacement of end-of-life and unsupported assets, and enhancements necessary to adapt to evolving risks, regulatory requirements, and customer needs and preferences. A study performed by Gartner confirmed that the utility's overall IT costs, including by category and function, are competitive and comparable its peer group.

B Coordinated Planning with Third Parties



B1	Distribution System Plan Overview
B2	Coordinated Planning with Third Parties
B3	IESO Comments on Renewable Generation
App A	Needs Assessment Report (Toronto
App B	Needs Assessment Report (GTA North)
App C	Regional Infrastructure Plan (Metro Toronto)
App D	Regional Infrastructure Plan (GTA North)
App E	Integrated Regional Resource Plan (Central Toronto)
App F	IESO Letter of Comment

B1 Overview of Coordinated Planning Approach

Toronto Hydro participates in infrastructure planning on a regional basis to ensure regional issues and requirements are effectively integrated into the utility's planning processes. Toronto Hydro participates in the planning processes that produce the Toronto Region Integrated Regional Resource Plan ("IRRP"), led by the Independent Electricity System Operator ("IESO"), and in the Regional Infrastructure Plans ("RIP") for the Metro Toronto Region and Greater Toronto Area ("GTA") North Region, led by Hydro One Networks Inc. ("Hydro One"). Toronto Hydro's Distribution System Plan ("DSP") has been informed by the results of the completed regional plans and continues to coordinate with the aforementioned parties with respect plans that are under development. The following sections describe the coordinated planning approach, results from the ongoing Regional Planning Process, and the IESO's comments on the DSP's proposed renewable energy generation ("REG") investments.

B1.1 Coordinated Planning Approach

Planning for the electricity system in Ontario is generally done at three levels:

- Bulk system planning;
- Regional system planning; and
- Distribution system planning.

These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Bulk system planning typically looks at the broader power system. The bulk power system transfers large quantities both within Ontario (as between major generation sources and load centres) as well as between the provincial grid and neighbouring power systems external to the province via the interconnections. The IESO has accountability for the integrated planning of the bulk power system.

Regional planning looks at supply and reliability issues at regional and local levels, largely considering portions of the power system that supply various parts of the province. There are portions of the power system which can be electrically grouped together due to their bulk supply points and their electrical inter-relationships whereby common facilities may impact many connected customers.

Regional planning focuses on the facilities that provide electricity to transmission connected customers such as distributors and large directly-connected customers. This typically includes the transformer stations supplying the load and the transmission supply circuits to these stations. It also includes the 115/230 kV auto-transformers and their associated switchyards. From a resource perspective, regional planning considers local generation and Conservation and Demand Management ("CDM") that could be developed to address supply and reliability issues in a region or local area.

Local Distribution Companies ("LDCs") conduct wires (and resource) planning at the distribution level and coordinate with the Transmitter and the IESO mainly on transmission supply facilities. Toronto Hydro has coordinated new or enhanced transmission supply facilities for some of its stations. These are discussed in more detail in Section B2.

Regional planning can overlap with bulk system planning and distribution system planning. Overlaps with distribution system planning occur largely at the transformer load stations which deliver power to distributors, and at large directly-connected customers. Planning for the construction of transformer load stations, can sometimes take place at the distribution level. Another example where regional planning may require coordination with distribution planning occurs when a distribution solution may address the needs of the broader local area or region, for example, by providing load transfer capability between transformer stations.

Toronto Hydro consults with various stakeholders as part of the Regional Planning Process. Sections B1.2 to B1.5 describe the key stakeholder consultations within this process. Section B2 describes the process itself.

B1.2 Customer Consultations

The Regional Planning Process includes the formation of a Local Advisory Committee ("LAC"), led by the IESO. The IESO invited the City of Toronto, First Nations, and Métis communities, stakeholders, community groups and the general public to provide input on the development of the plan. In all, there are 18 members of the Toronto LAC. The inaugural meeting occurred in January 2016, and as of December 2017, six meetings have been held. Details, including meeting summaries, can be found at the following IESO link:

- http://www.ieso.ca/get-involved/regional-planning/gta-and-central-ontario/central-toronto-engagement

B1.3 Transmitter Consultations

Toronto Hydro consults with Hydro One through IRRP and RIP; the latter is led by Hydro One.

The Metro Toronto RIP, that covers Toronto Hydro's service area, was completed in January 2016 and is discussed in section B2.2 below. The GTA North RIP, that covers a neighbouring region important to Toronto Hydro's operations, was completed in February 2016 and is discussed in Section B2.3 below.

Hydro One launched a new RIP cycle in June 2017, starting with a Needs Assessment update. The Toronto Region Needs Assessment Report was completed in October 2017, and is provided as Appendix A.[1]

B1.4 Other Distributor Consultations

Toronto Hydro is not an embedded LDC, and does not supply any embedded LDCs. Therefore, the utility's planning consultations with other LDCs typically occur in the context of regional planning.

B1.5 IESO Consultations

Toronto Hydro actively consults with the IESO as part of Integrated Regional Resource Plan ("IRRP"). The most recent IRRP was published in 2015 and updated in 2017. The status of this plan is discussed in Section B2.1 below. The IESO launched a new IRRP process for the Toronto Region in the spring of 2018. Toronto Hydro is the host distributor for that IRRP and is actively consulting with the IESO, Hydro One and the public.

[1] The GTA North Region Needs Assessment was completed in March 2018 and is provided in Appendix B, and discussed in Section B2.3.

B2 Regional Planning Processes

The regional planning process is an important input to distribution system planning and the regional planning process is informed by Toronto Hydro's plans. The regional planning process for Toronto is characterized by:

- a large load that is dynamic in the city area;
- a significant number and density of transmission lines and stations;
- the presence of large generation; and
- a customer base that has experienced, and is sensitive to, major events that disrupt continuity of service.

To facilitate infrastructure planning, the IESO divides Ontario into planning regions. As planning considerations change, the boundaries of these regions are revised. In recent years, Toronto Hydro's service area was split between Central Toronto and Northern Toronto. Metro Toronto was also a descriptor of the planning region. More recently, regional planning considers Toronto Hydro Service area, the City of Toronto on a consolidated basis: the Toronto Region. Planning documents and reports that have been developed, issued, and relied upon during the 2015-2018 period, and that inform the utility's plans, make refer to the region using these various names.

B2.1 Toronto Integrated Regional Resource Plan

The Toronto Region used to be divided into two sub-regions for ease of planning: Central Toronto and the Northern sub-regions. The IRRP currently in development pertains to the Toronto Region. The IESO is the lead, working with Hydro One (the transmitter and Toronto Hydro (the sole LDC).

The purpose of the IRRP is to ensure that the electricity service requirements of the central Toronto community are served by an appropriate combination of demand and supply options that reflect the priorities of the community. Planning activities include forecasting the expected growth in electricity demand for 25 years, investigating the costs and benefits of conservation, distributed generation, and transmission and distribution options in meeting the future electricity needs of customers in the central Toronto area**.** The result of the planning process is an integrated plan, with a long-term perspective, which recommends a balance of options that account for costs, reliable electricity service, and mitigation of environmental impacts. The plan was completed in April 2015, and an

Addendum to the IRRP was completed in February 2017. The impact of the regional plan on the DSP is discussed in Section E2.2.3.3. An IESO link to the IRRP is provided below:

- http://www.ieso.ca/en/get-involved/regional-planning/gta-and-central-ontario/central-toronto-sub-region

The regional planning cycle is underway for the Toronto Region and an IRRP is expected to be posted in the fall of 2019.

B2.2 Metro Toronto Regional Infrastructure Plan

The Metro Toronto RIP was completed in January 2016. The plan is provided as Appendix C.[2]

The plan was the final phase of the regional planning process following the completion on the Central Toronto Sub-Region's IRRP by the IESO in April 2015 and the Metro Toronto Northern Sub-Region Needs Assessment Study by Hydro One in June 2014.

The Metro Toronto RIP provides a consolidated summary of needs and recommendations for Toronto over the near- and mid-term (five to ten years). The impact of the Metro Toronto RIP on the DSP is discussed in Section E2.2.3.3.

In response to the IRRP process that restarted earlier that year, in June 2017, Hydro One began the process of updating with the Needs Assessment, which will support the next IRRP and RIP. The Needs Assessment Report was completed in October 2017 and can be seen at the following link:

- https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/metrotoronto/Documents/Needs%20Assessment%20-%20Toronto%20Region%20-%20Final.pdf

B2.3 GTA North Regional Infrastructure Plan

The GTA North Regional Infrastructure Plan (RIP) was completed in February 2016. The plan is attached as Appendix D.[3]

[2] https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/metrotoronto/Documents/RIP%20Report%20Metro%20Toronto.pdf
[3] https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/gtanorth/Documents/Needs%20Assessment%20Report%20-%20GTA%20North%20Region.pdf

The RIP was the final phase of the regional planning process for the GTA North Region which consists of the York Sub-Region and the Western Sub-Region. It followed the completion of the York Sub-Region Integrated Regional Resource Plan by the IESO in April 2015 and the Western Sub-Region Needs Assessment Study by Hydro One in June 2014. Because Toronto Hydro also receives supply from GTA North Region, Toronto Hydro is a participant of the process.

Participants of the RIP included:

- Enersource Hydro Mississauga Inc.;
- Hydro One Brampton Networks Inc.;
- Hydro One Networks Inc. (Distribution);
- Independent Electricity System Operator;
- Newmarket-Tay Power Distribution Ltd.;
- PowerStream Inc.; and
- Toronto Hydro.

Toronto Hydro provided input to the GTA North Western Sub-Region Needs Assessment. The purpose of the Needs Assessment report is to assess if there were regional needs that would lead to coordinated regional planning. Where regional coordination is not required and a "wires" only solution is necessary, such needs will be addressed between the relevant LDCs and Hydro One and other parties as required. No need for coordinated regional planning was identified. Impacts to the DSP are described in Section E2.2.3.3.

Hydro One launched a new GTA North regional planning cycle in December 2017, starting with a Needs Assessment update. The Needs Assessment Report for the GTA North Region was finalized in March of 2018, is provided in Appendix B, and is available at the link below:

- https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/gtanorth/Documents/Needs%20Assessment%20Report%20-%20GTA%20North%20Region.pdf

B3 IESO Comments on Renewable Energy Generation

B3.1 IESO Comment Letter

In compliance with section 5.2.2 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (2018),[4] Toronto Hydro formally requested a letter of comment from the IESO with respect to the utility's planned renewable energy generation ("REG") investments. Toronto Hydro received the IESO Letter of Comment on July 20, 2018. This letter can be found in Appendix E to Section B.

B3.2 Toronto Hydro's Response to IESO Letter

The IESO found that Toronto Hydro's REG investment plan is substantially consistent with the IESO's information regarding REG applications to date and that the investments in Toronto Hydro's plan support and enable the connection of additional REG.

The IESO also confirmed that an IRRP is currently underway for the Toronto Region to be completed in 2019, and that following the IRRP completion, Hydro One is expected to conduct an RIP.

The IESO also found that although Toronto Hydro's plans are not included within the most recent RIP, the utility's plans to address barriers to connect additional DG within Toronto Hydro's service area is consistent with regional planning principles; and that the IESO does not foresee a need for coordination with other parties other than Hydro One.

[4] Previously, section 5.1.4.2 of the OEB's *Filing Requirements for Electricity Transmission and Distribution Applications (2013).*

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483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

Toronto Region

Date: October 18, 2017

Prepared by: Toronto Region Study Team

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Toronto Region and to recommend which needs may require further assessment and/or regional coordination to develop wires options. The results reported in this Needs Assessment are based on the input and information provided by the Study Team.

The Study Team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") shall not, under any circumstances whatsoever, be liable each other, to any third party for whom the Needs Assessment Report was prepared ("the Intended Third Parties") or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"). The Authors, Intended Third Parties and Other Third Parties acknowledge and agree that: (a) the Authors make no representations or warranties (express, implied, statutory or otherwise) as to this document or its contents, including, without limitation, the accuracy or completeness of the information therein; (b) the Authors, Intended Third Parties and Other Third Parties and their respective employees, directors and agents (the "Representatives") shall be responsible for their respective use of the document and any conclusions derived from its contents; (c) and the Authors will not be liable for any damages resulting from or in any way related to the reliance on, acceptance or use of the document or its contents by the Authors, Intended Third Parties or Other Third Parties or their respective Representatives.

Executive Summary

REGION	Toronto (formerly Metro Toronto)		
LEAD	Hydro One Networks Inc. ("HONI")		
START DATE	June 26, 2017	**END DATE**	October 18, 2017

1. INTRODUCTION

The first cycle of the Regional Planning process for the Toronto Region was initiated in Q2 2014 and completed with the publication of the Regional Infrastructure Plan ("RIP") on January 12, 2016. The RIP provided a description of needs and recommendations of preferred wires plans to address near-term and mid-term needs that may emerge over the next ten years. The RIP also identified some long-term needs that will be reviewed during this planning cycle.

The purpose of this Needs Assessment is to identify any new needs and reaffirm needs identified in the previous Toronto Region RIP.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the regional planning cycle should be triggered at least every five years. The trigger for this NA was several new needs emerging in the Toronto Region as discussed in this report.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the Toronto Region and includes:

- New needs identified by Study Team members; and,
- Review and reaffirm needs/plans identified in the previous RIP

The Study Team may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), Integrated Regional Resource Plan ("IRRP") and RIP, based on updated information available at that time.

An updated load forecast for the region was provided by Toronto Hydro-Electric System Limited ("THESL") for the purposes of this NA. In addition, THESL is currently undertaking a study to develop a new load forecast, expected to be completed by Q4 2017. The updated load forecast will be taken into account during the next phases of regional planning, i.e. IRRP and/or RIP. Hydro One Distribution, Alectra Utilities, and Veridian reaffirmed their load forecast developed during the RIP phase and the Study Team deemed this to be adequate for this NA.

4. INPUTS/DATA

The Study Team representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One provided input and relevant information for the Toronto Region regarding capacity needs, system reliability, operational issues, and major assets/facilities approaching end-of-life ("EOL").

5. ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical infrastructure needs in the Region over the study period. The assessment reviewed available information including load forecasts, system reliability and operation issues, and major high voltage equipment identified to be at the end of their useful life and requiring replacement/refurbishment.

A technical assessment of needs was undertaken based on:

- Station capacity and transmission adequacy;
- System reliability and operation; and,
- Major high voltage equipment reaching the end of its useful life with respect to replacing it with similar type equipment versus other options to determine the most optimal, resilient, and economic outcome.

6. RESULTS

I. Aging Infrastructure

In the Toronto Region, high voltage equipment at 13 stations and 3 transmission line sections have been identified to be at the end of their useful life and require replacement/refurbishment in the near and medium term. Refer to section 7.1.1 for more details.

II. 115kV Connection Capacity

A transformation capacity need to serve the potential load growth in the East Harbor / Port Lands area has been identified in the medium term. A transformation capacity need for Basin TS was also identified in the medium term. It is forecasted to slightly exceed its LTR in 2027. Refer to section 7.1.2 for more details.

III. System Reliability & Operation

Load restoration needs for the loss of circuits, C14L+C17L, C5E+C7E, and K3W+K1W have been identified. Refer to section 7.1.3 for more details.

IV. Needs Identified in Previous Toronto Region RIP

The study team reaffirms that the needs and their respective plans identified in the previous Toronto Region RIP (which are not yet underway) are still valid. Updates to the plans have been provided where relevant. Refer to sections 7.2.1 to 7.2.9 for more details.

7. RECOMMENDATIONS

The Study Team's recommendations are as follows:

a) Hydro One and THESL will coordinate a plan to address the following needs (further regional coordination is not required):

- EOL assets discussed in section 7.1.1.1 and 7.1.1.2

b) Further regional coordination is required for the following needs:

- EOL assets discussed in section 7.1.1.3 (EOL equipment replacement at Bermondsey TS, John TS, Main TS, and Manby TS) and 7.1.1.4 (EOL equipment replacement for C5E/C7E, H1L/H3L/H6LC/H8LC, and L9C/L12C)
- Additional transformation capacity need in the East Harbor / Port Lands area and Basin TS transformation capacity need discussed in section 7.1.2
- Load restoration need for the loss of circuits C14L+C17L, C5E+C7E, and K3W+K1W, discussed in section 7.1.3.
- Needs identified in previous Toronto RIP/IRRP (mostly the long term needs), discussed in sections 7.2.5 to 7.2.9 (transformation capacity need for 230/115kV Leaside autotransformers and voltage collapse of 115kV Leaside subsystem; line capacity need for 115kV Leaside TS x Wiltshire TS corridor; transformation capacity need for 230/115kV Manby TS autotransformers; line capacity need for 115kV Manby West x Riverside Junction; and, line capacity need for 115kV Don Fleet JCT x Esplanade TS)

c) The Study Team reaffirms the remaining needs that were identified in the previous RIP, discussed in sections 7.2.1 to 7.2.4. Their associated plans are valid and are in progress.

TABLE OF CONTENTS

1 Introduction 7
2 Regional Issue/Trigger 7
3 Scope of Needs Assessment 7
4 Regional Description and Connection Configuration 8
5 Inputs and Data 10
6 Assessment Methodology 10
7 Needs 11
8 Recommendations 27
9 References 30
Appendix A: Non-Coincident Summer Peak Load Forecast (2016 to 2027) 31
Appendix B: Acronyms 32

List of Tables and Figures

Table 1: Toronto Region Technical Study Team Participants 7
Table 2: New Needs 11
Table 3: Needs Identified in Previous RIP and IRRP (1) 11
Table 4: End-of-Life Assets – Toronto Region 12
Table 5: End-of-Life Lines 22
Table 6: Summary of Recommendations 28

Figure 1: Toronto Regional and Sub-Regional Boundaries 9
Figure 2: Toronto Region – Single Line Diagram 9

1 INTRODUCTION

The first cycle of the Regional Planning process for the Toronto Region (formerly Metro Toronto) was completed in January 2016 with the publication of the Regional Infrastructure Plan ("RIP"). The RIP provided a description of needs and recommendations of preferred wires plans to address near and medium term needs. The long term needs were recommended for further review during the next regional planning cycle.

The purpose of this Needs Assessment ("NA") is to identify new needs and reconfirm the needs identified in the previous Toronto Region regional planning cycle. Since the first regional planning cycle, several new needs in the region have been identified. The majority of these needs are a result of aging infrastructure which need to be replaced within the near to medium term.

This report was prepared by the Toronto Region Technical Study Team ("Study Team"), led by Hydro One Networks Inc. Participants of the Study Team are listed below in Table 1. The report captures the results of the assessment based on information provided by the lead transmitter, Local Distribution Companies ("LDC") and the Independent Electricity System Operator ("IESO").

Table 1: Toronto Region Technical Study Team Participants

Company
Alectra Utilities Corporation (formerly Enersource Hydro Mississauga, PowerStream Inc.)
Hydro One Networks Inc. (Distribution)
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator ("IESO")
Toronto Hydro-Electric System Limited ("THESL")
Veridian Connections Inc. ("Veridian")

2 REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. The NA was triggered due to several new needs in the Toronto Region as discussed in this report.

3 SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the Toronto Region and includes:

- New needs identified by the Study Team; and
- Needs already identified in the RIP report or IRRP report

The Study Team may identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), Local Planning ("LP"), Integrated Regional Resource Plan ("IRRP"), and/or RIP.

An updated load forecast for the region was provided by Toronto Hydro-Electric System Limited ("THESL") for the purposes of this NA. In addition, THESL is currently undertaking a study to develop a new load forecast, expected to be completed by Q4 2017. The updated load forecast will be taken into account during the next phases of regional planning, i.e. IRRP and/or RIP. Hydro One Distribution, Alectra Utilities, and Veridian reaffirmed their load forecast developed during the RIP phase and the Study Team deemed this to be adequate for this NA.

4 REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The Toronto Region includes the area roughly bordered geographically by Lake Ontario on the south, Steeles Avenue on the north, Highway 427 on the west and Regional Road 30 on the east. It consists of the City of Toronto, which is the largest City in Canada and the fourth largest in North America. Please see Figure 1 for the map.

The Toronto Region is comprised of the City of Toronto. Electrical supply to the Region is provided by thirty-five 230kV and 115kV transmission and step-down stations as shown in Figure 2. The eastern, northern and western parts of the Region are supplied by eighteen 230/27.6kV step-down transformer stations. The central area is supplied by two 230/115kV autotransformer stations (Leaside TS and Manby TS) and fifteen 115/13.8kV and two 115/27.6kV step-down transformer stations.

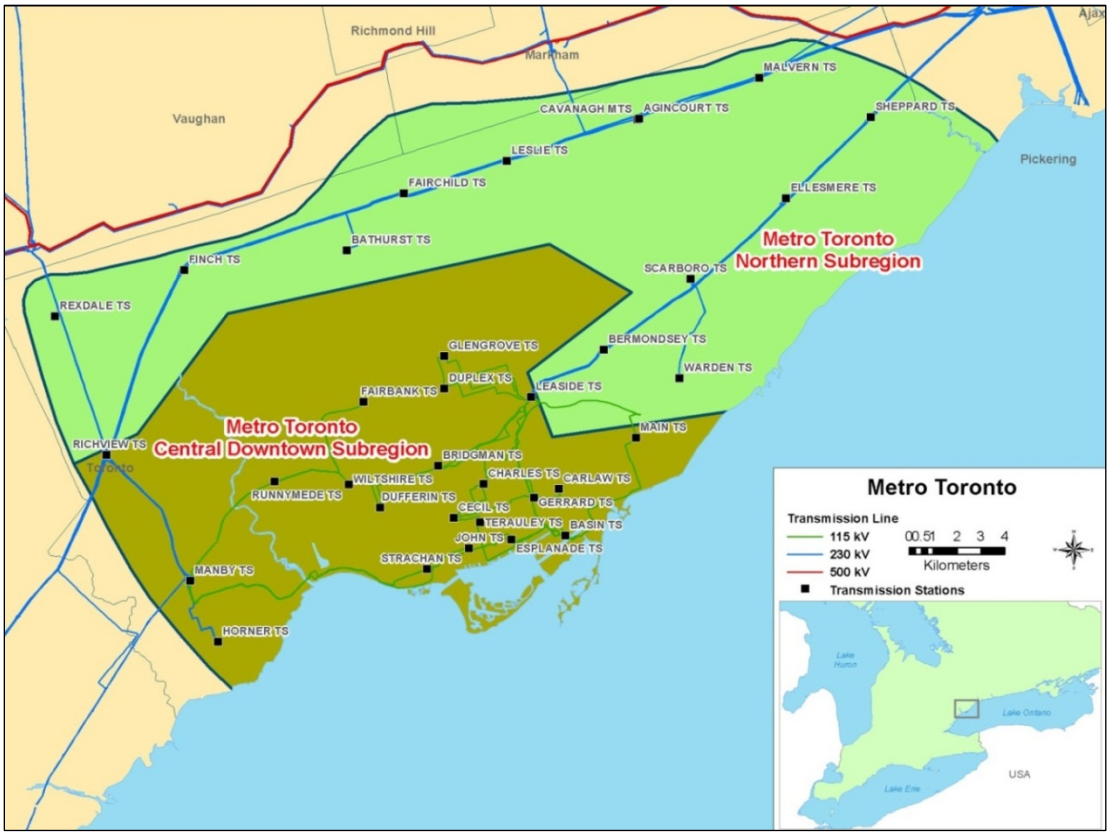

Figure 1: Toronto Regional and Sub-Regional Boundaries

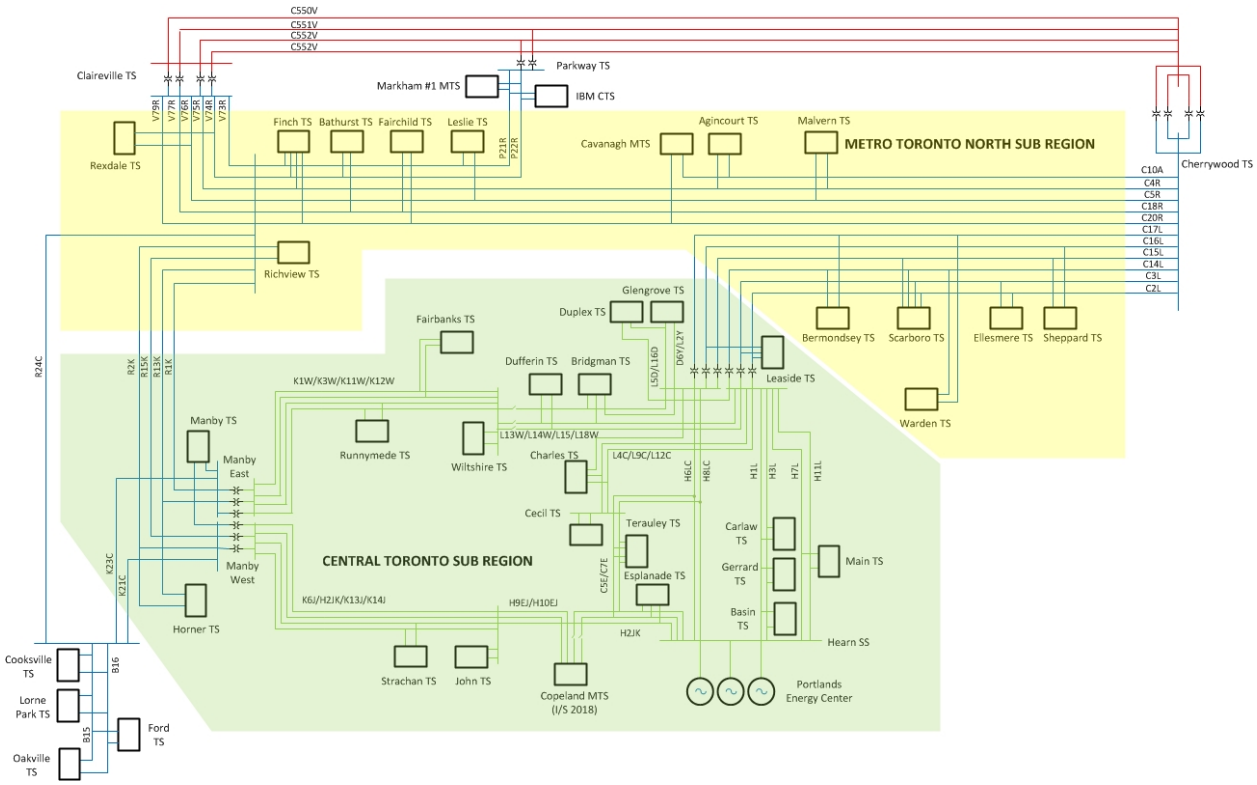

Figure 2: Toronto Region – Single Line Diagram

5 INPUTS AND DATA

Study Team participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the Toronto Region NA. The information provided includes the following:

- Load Forecast updates and/or reaffirmed from previous Toronto RIP;
- Any known capacity and reliability needs, operating issues, and/or major assets approaching the end of their useful life ("EOL"); and,
- Planned/foreseen transmission and distribution investments that are relevant to regional planning for the Toronto Region

6 ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in this Needs Assessment:

Information gathering included:

i. Load forecast: THESL provided an updated load forecast. Hydro One Distribution, Alectra Utilities, and Veridian reaffirmed their load forecast developed during the RIP phase and the Study Team deemed this to be adequate for this NA (for more details on the RIP load forecast, please refer to Section 5 of the RIP report). The LDC's load forecast is translated into load growth rates and is applied onto the 2016 actual summer station peak load, adjusted for extreme weather conditions (according to Hydro One's methodology). It should be noted that the actual versus forecasted year to year demand can vary due to factors such as weather, economic development, etc.

   In addition, THESL is currently undertaking a study to develop a new load forecast, expected to be completed by Q4 2017. This updated load forecast will be taken into account during the next phases of regional planning, i.e. IRRP and/or RIP.

ii. Relevant information regarding system reliability and operational issues in the region;

iii. List of major HV transmission equipment a) recently replaced b) planned and/or identified to be refurbished due to the end of their useful life which is relevant for regional planning purposes. This includes HV transformers, autotransformers, HV Breakers, HV underground cables and overhead lines.

Technical assessment of needs was based on:

i. Station capacity and Transmission Adequacy assessment

ii. System reliability and operation assessment

iii. End-of-life equipment: Major high voltage equipment reaching the end of its useful life with respect to replacing it with similar type equipment versus other options to determine the most optimal, resilient, and economic outcome.

Note that the Region is summer peaking so the assessment is based on summer peak loads.

7 NEEDS

This section describes emerging needs that have been identified in the Toronto Region since the previous regional planning cycle and reaffirms the near, medium, and long-term needs already identified in the previous RIP. The needs are summarized in Tables 2 and 3 below:

Table 2: New Needs

New Needs	Discussed in Section
End-of-Life Assets	7.1.1
East Harbor / Port Lands Area and Basin TS – Transformation Capacity	7.1.2
Load Restoration – C14L+C17L, C5E+C7E, K3W+K1W	7.1.3

Table 3: Needs Identified in Previous RIP and IRRP (1)

Needs Identified in Previous RIP	Discussed in Section	RIP Report Section
Southwest Toronto – Station Capacity	7.2.1	7.2
Downtown District – Station Capacity	7.2.2	7.3
230 kV Richview x Manby Corridor – Line Capacity	7.2.3	7.4
Supply Security – Breaker Failure at Manby West & East TS	7.2.4	7.6
230/115kV Leaside Autotransformers – Transformation Capacity	7.2.5	7.10
Voltage Instability of 115kV Leaside Subsystem	7.2.5	Identified in Central Toronto Area IRRP report – Appendix E
115 kV Leaside x Wiltshire Corridor – Line Capacity	7.2.6	7.10
230/115kV Manby Autotransformers – Transformation Capacity	7.2.7	7.10
115kV Manby West x Riverside Junction – Line Capacity	7.2.8	7.10
115kV Don Fleet JCT x Esplanade TS – Line Capacity	7.2.9	Identified in Central Toronto Area IRRP report – Appendix E

(1) Includes needs identified in the previous RIP and IRRP that do not have plans underway yet

7.1 New Needs

7.1.1 End-Of-Life (EOL) Asset Needs

Hydro One has identified the following major high voltage equipment and transmission lines to be reaching the end of their useful life over the next 10 years. Based on the equipment condition assessment including relevant tests, these EOL assets have been identified to be in poor condition. Replacement plans for EOL assets are summarized below in Table 4 with exceptions where implementation plans were developed and projects are already underway.

Table 4: End-of-Life Assets – Toronto Region

EOL Asset[(1)]	Replacement/ Refurbishment Timing[(2)]	Details
Fairbank TS: T1/T3, T2/T4 Transformers	2022-2023	EOL Transformers and other HV equipment are identified at these stations for replacement with similar type equipment with same ratings, and are discussed further in Section 7.1.1.1.
Fairchild TS: T1/T2 Transformers	2023-2024	
Leslie TS: T1 Transformer	2023-2024	
Runnymede TS: T3/T4 Transformers	2021-2022	
Sheppard TS: T3/T4 Transformers	2019-2020	
Bridgman TS: T11/T12/T13 Transformers	2022-2023	EOL Transformers and other HV equipment are identified at these stations for replacement with higher rated equipment, and are discussed further in Section 7.1.1.2
Charles TS T3/T4 Transformers	2024-2025	
Duplex TS: T1/T2	2023-2024	
Strachan TS: T12 Transformer	2020-2021	
Bermondsey TS: T3/T4 Transformers	2023-2024	EOL Transformers and other HV equipment are identified at these stations where scope for replacement is to be further assessed, and are discussed further in Section 7.1.1.3
John TS: T1, T2, T3, T4, T6 Transformers and 115 kV Breakers	2025-2026	
Main TS: T3/T4 Transformers and 115 kV line disconnect switches	2021-2022	
Manby TS: T7, T9, T12 Autotransformers, T13 Step-Down Transformer and rebuild 230kV yard	2024-2025	
115kV C5E/C7E Underground Cable: Esplanade TS to Terauley TS	TBD	EOL Line sections are identified for replacement where scope for replacement is to be further assessed, and are discussed further in Section 7.1.1.4
115kV H1L/H3L/H6LC/H8LC: Bloor Street JCT to Leaside JCT	TBD	
115kV L9C/L12C: Leaside TS to Balfour JCT	TBD	

(1) No other lines or stations in the Toronto region have been identified for major replacement/refurbishment at this time
(2) The replacement/refurbishment scope, timing, and prioritization are under review/development and are subject to change

The end-of-life equipment assessment for the above assets considered the following options:

1. Maintaining the status quo
2. Downsizing equipment with lower ratings and built to current standards by transferring load to underutilized facilities within a station or between stations
3. Eliminating equipment by transferring load to underutilized facilities within a station or between stations
4. Replacing equipment with similar equipment with same ratings and built to current standards
5. Replacing equipment with similar equipment with higher ratings and built to current standards

The study team agreed that non-wire options were not a viable option in cases where it has been recommended to replace EOL transformers with a similar transformer with the same or higher ratings (refer to section 7.1.1.1 and 7.1.1.2). With respect to (1), the EOL assets listed in Table 4 are in poor condition so maintaining the status quo for these assets is not an option due to the risk of equipment failure, customer outages and increased maintenance cost.

With respect to (2) and (3), it should be noted that the City of Toronto (within Toronto Region) is one of the most populous and congested cities in Canada where there is continued development, population and economic growth resulting in greater electricity demand. Efficient and effective/maximum use of land and station facilities includes planning ahead for long-term electricity needs, reliability and system resiliency. The majority of stations in the Toronto Region are above and forecasted to be over 75% of their Limited Time Rating ("LTR"). Accordingly, eliminating transformation capacity is not an option because total loads cannot be permanently transferred to neighboring stations. In addition, it is worth noting that:

- Upgrading equipment with higher capacity has very little incremental cost compared to replacing the equipment with similar equipment of the same or lower ratings. For example, it may cost $200-$300 thousand extra for the larger transformers rather than replacing them with similar transformers of the same or lower ratings now and then having to upgrade it later (due to eventual load growth) within the lifetime of the transformer for an additional cost of $5-$10M.
- Maintaining or upgrading capacity to the maximum at the station is the most effective and efficient use of maximizing land and infrastructure for little incremental cost, if any. The higher capacity at very low cost also provides operational flexibility, high resiliency during emergency and extreme weather conditions.
- There is no expectation and/or plan to downsize upstream facilities and therefore downsizing existing station capacity is not prudent.

Therefore, in many cases options (4) and (5) are considered better options. Further rationale for these options is provided in sections 7.1.1.1 to 7.1.1.4.

7.1.1.1 EOL Transformers: Replace with Similar Equipment with Same Ratings

This section describes EOL transformers which are recommended to be replaced with similar type of equipment with same ratings and built to current standards. This was determined to be the preferred option for the reasons listed below:

- Based on historical loading, future electricity needs, and the need for greater resiliency, it is not prudent to reduce the capacity of or eliminate the station, while still maintaining the capacity to reliably supply the demand.
- Hydro One has standardized transformer sizes in order to save costs on procurement, engineering, spares management, maintenance etc. For sustainment purposes the appropriate sized standard transformer is installed, which in some cases may be larger than what the load would currently require, but it is financially prudent.
- The cost savings of replacing EOL transformers with similar units of lower ratings (as opposed to similar units with the same ratings) is not significant compared to the cost of upgrading the

transformers in the future when needed. For example, it may cost $200-$300 thousand extra for the same size transformers as opposed to the smaller ones with lower ratings whereas upgrading them later (due to eventual load growth) within the lifetime of the transformer may cost an additional $5-$10 million. Such changes may also require reconfiguration of LV facilities resulting in additional cost.

- Customer determined that they do not require upgraded transformer(s) because:
  - current load forecast for electricity needs and existing configuration at station does not warrant an upgrade in capacity; or,
  - other measures, where feasible, are being taken to accommodate load growth (e.g. load transfers, new station being built, conservation and demand management programs)
- There is a need for the existing feeders to maintain distribution connections/reliability
- Non-wires options are not a viable option to address the need for these specific EOL transformers

Additional comments and further rationale for the Study Team's recommendations are provided below.

Fairbank TS

Fairbank TS comprises two DESN units, T1/T3 (50/83 MVA) and T2/T4 (50/83 MVA), having a summer 10-Day LTR of 182 MW. The station's 2016 actual non-coincident summer peak load (adjusted for extreme weather) was about 169 MW and is forecasted to be approximately 173 MW and 188 MW in 2017 and 2027 respectively. Transformers T1/T3 and T2/T4 are currently about 46 years old and have been identified to be at their EOL.

The load at Fairbank TS is forecasted to exceed its LTR in the medium term. As per the IRRP and RIP recommendations, a new Runnymede TS T1/T2 DESN will be built and is expected to be in-service in 2018. Currently, two feeders from Fairbank TS are planned to be moved to the new Runnymede TS T1/T2 DESN to keep Fairbank TS load under its LTR. The other two closest stations, Duplex TS and Glengrove TS, are 13.8kV stations so permanent load transfer from Fairbank TS, which is a 27.6kV station, is not a viable option. Further, the load at Duplex TS is forecasted to be over 90% of its LTR in the medium term. For these reasons, downsizing T1/T3 and T2/T4 to 42MVA transformers (the lower rated standard transformer size for 115/27.6kV) is not prudent. Moreover, downsizing capacity today and then later upgrading within the lifetime of the transformer due to eventual load growth will be significantly more costly. For example it may cost an additional $5-$10 million for the replacement of the transformers plus the incremental cost for the LDC to reconfigure feeders. It should also be noted that maintaining capacity, as opposed to downsizing, is a more resilient option as it provides additional flexibility during emergency conditions through load transfers.

Based on the above, the study team recommends that this need be addressed by Hydro One and THESL to coordinate the replacement plan. The timing of replacement for the EOL equipment is 2022-2023.

Fairchild TS

Fairchild TS comprises two DESN units, T1/T2 (75/125 MVA) and T3/T4 (75/125 MVA), having a summer 10-Day LTR of 346 MW. The station's 2016 actual non-coincident summer peak load (adjusted

for extreme weather) was about 272 MW and is forecasted to be approximately 275 MW and 296 MW in 2017 and 2027 respectively. Transformers T1 is 43 years old and has been identified to be at its EOL. The companion DESN transformer T2 failed and was replaced under emergency this year with a similar 75/125 MVA unit.

The load at Fairchild TS is forecasted to be over 85% of its LTR in the medium term. The load at the two closest stations, Bathurst TS and Leslie TS, is also forecasted to be over 85% and 90% of their respective LTR's in the medium term. Therefore, downsizing T1 and consolidating load within the station and/or with area stations is not a prudent or viable option given medium term load growth at these stations. It is also important to note that the station is configured as a dual secondary yard (230/27.6-27.6kV) and the standard lower rated unit has only one secondary and would have different impedance than the companion T2 transformer. Consequently, replacing T1 with a lower rated unit could cause significant operational and configuration issues. Moreover, downsizing capacity today and then later upgrading within the lifetime of the transformer due to eventual load growth will be significantly more costly. For example it may cost an additional $5-$10 million for the replacement of the transformers plus the incremental cost for the LDC to reconfigure feeders. It should also be noted that maintaining capacity, as opposed to downsizing, is a more resilient option as it provides additional flexibility during emergency conditions through load transfers. Upgrading T1 is also not an option since it's already at the maximum standard size.

Based on the above, the study team recommends that this need be addressed by Hydro One and THESL to coordinate the replacement plan. The timing of replacement for the EOL equipment is 2023-2024.

Leslie TS

Leslie TS comprises two DESN units, T1/T2 (75/125 MVA) and T3/T4 (75/125 MVA), having a summer 10-Day LTR of 325 MW. The station's 2016 actual non-coincident summer peak load (adjusted for extreme weather) was about 237 MW and is forecasted to be approximately 249 MW and 294 MW in 2017 and 2027 respectively. Transformer T1 is currently about 54 years old and has been identified to be at its EOL. The companion DESN transformer T2 is currently 19 years old and is not close to its EOL.

The load at Leslie TS is forecasted to be 90% of its LTR in the medium term. The load at the three closest stations, Fairchild TS, Cavanagh MTS, and Agincourt TS, is also forecasted to be over 85%, 65%, and 65% respectively of their LTR's in the medium term. Although Agincourt TS and Cavanagh MTS have available station capacity, they do not have spare feeder positions to potentially accommodate a permanent load transfer from Leslie TS as more than one feeder would have to be transferred to make downsizing T1 to 83MVA feasible. Adding new feeder positions would be much more costly as opposed to replacing the transformer with a similar unit. Therefore, downsizing T1 and consolidating load within the station and/or with Fairchild TS is not prudent given medium term load growth at these stations and because permanent load transfer to Agincourt TS and Cavanagh MTS is not a viable or economical option. Moreover, downsizing capacity today and then later upgrading within the lifetime of the transformer due to eventual load growth will be significantly more costly. For example it may cost an additional $5-$10 million for the replacement of the transformers plus the incremental cost for the LDC to reconfigure feeders. It should also be noted that maintaining capacity, as opposed to downsizing, is a

more resilient option as it provides additional flexibility during emergency conditions through load transfers. Upgrading T1 is also not an option since it's already at the maximum standard size.

Based on the above, the study team recommends that this need be addressed by Hydro One and THESL to coordinate the replacement plan. The timing of replacement for the EOL equipment is 2023-2024.

Runnymede TS

Runnymede TS comprises one DESN unit, T3/T4 (58/93 MVA), having a summer 10-Day LTR of 111 MW. The station's 2016 actual non-coincident summer peak load (adjusted for extreme weather) was about 119 MW and is forecasted to be approximately 121 MW and 185 MW in 2017 and 2027 respectively. Transformers T3/T4 are currently about 45 years old and have been identified to be at their EOL.

As per the previous IRRP and RIP report, building a new Runnymede TS T1/T2 DESN (50/83 MVA) was recommended and is expected to be in service in 2018-2019 to supply the load growth in this area and will keep the Runnymede TS T3/T4 DESN under its LTR. The neighbouring station, Fairbank TS, is also forecasted to exceed its capacity in the near term and currently two of its feeders are planned to be moved to the new Runnymede TS T1/T2 DESN to keep its load under its LTR. Further, the other closest station, Wiltshire TS, is a 13.8kV station so permanent load transfer from Runnymede T3/T4, which is a 27.6kV DESN, is not a viable or economical option. For these reasons, downsizing T3/T4 to 42MVA transformers (the lower rated standard transformer size for 115/27.6kV) is not prudent. Moreover, downsizing capacity today and then later upgrading within the lifetime of the transformer due to eventual load growth will be significantly more costly. For example it may cost an additional $5-$10 million for the replacement of the transformers plus the incremental cost for the LDC to reconfigure feeders. It should also be noted that maintaining capacity, as opposed to downsizing, is a more resilient option as it provides additional flexibility during emergency conditions through load transfers.

Based on the above, the study team recommends that this need be addressed by Hydro One and THESL to coordinate the replacement plan. The timing of replacement for the EOL equipment is 2021-2022

Sheppard TS

Sheppard TS comprises two DESN units, T1/T2 (75/125 MVA) and T3/T4 (50/83 MVA), having a summer 10-Day LTR of 204 MW. The station's 2016 actual non-coincident summer peak load (adjusted for extreme weather) was about 170 MW and is forecasted to be approximately 171 MW and 192 MW in 2017 and 2027 respectively. Transformers T3/T4 are currently 55 years old and have been identified to be at their EOL.

The load at Sheppard TS is forecasted to be over 90% of its LTR in the medium term. However, the Sheppard TS T1/T2 DESN is more lightly loaded than the T3/T4 DESN (T3/T4 is approximately 60% of total station loading in the past three years). Given the potential for load transfers from the T3/T4 DESN to the T1/T2 DESN, upgrading T3/T4 is not prudent. Downsizing T3/T4 is also not an option since the transformers are already at the smallest standard size for a 230/27.6kV DESN.

Based on the above, the study team recommends that this need be addressed by Hydro One and THESL to coordinate the replacement plan. The timing of replacement for the EOL equipment is 2019-2020.

7.1.1.2 EOL Transformers: Replace with Similar Equipment with Higher Ratings

This section describes EOL transformers which are recommended to be replaced with similar type units with higher ratings (60/100 MVA units) and built to current standards. As stated earlier, maintaining or upgrading capacity to the maximum at the station is the most effective and efficient use of maximizing land and infrastructure. Upgrading equipment with higher capacity has little incremental cost compared to replacing the equipment with similar equipment of the same or lower ratings. For example, it may cost $200-$300 thousand extra for the larger transformers rather than replacing them with similar transformers of the same or lower ratings now and having to upgrade it later (due to eventual load growth) within the lifetime of the transformer for an additional $5-$10M. Upgrading equipment also provides additional flexibility and reliable supply in emergency situations. This was also determined to be the preferred option for the reasons listed below:

- Load transfer is not viable because:
  - Capability to transfer load does not currently exist or is not cost effective at the distribution level
  - Insufficient proximity of neighbouring stations that have capacity to accommodate load transfer
- Hydro One has standardized transformer sizes in order to save costs on procurement, engineering, spares management, maintenance etc. For sustainment purposes the appropriate sized standard transformer is installed, which in some cases may be larger than what the load would currently require, but it is financially prudent.
- Customer does not require an upgrade of transformer(s) to accommodate load growth in area;
- Non-wire options are not a viable option to address the need for these specific EOL transformers

Bridgman TS

Bridgman TS comprises of five transformers, T11, T12, T13, T14, and T15, having a summer 10-Day LTR of 183 MW. The station's 2016 actual non-coincident summer peak load (adjusted for extreme weather) was about 159 MW and is forecasted to be approximately 162 MW and 175 MW in 2017 and 2027 respectively. Transformers T11, T12 and T13 (46/67 MVA) are currently about 50 years old and have been identified to be at their EOL.

The load at Bridgman TS is forecasted to be over 95% of its LTR in the medium term. The load at four of the closest stations, Cecil TS, Charles TS, Duplex TS, and Dufferin TS, is also forecasted to be over 80% of their respective LTR's in the medium term. Therefore, downsizing T11, T12, and T13 and consolidating load within the station and/or with area stations is not a prudent or viable option given long term load growth at these stations. It should also be noted that by upgrading T11, T12, and T13 to 100MVA units (the higher rated standard transformer size for 115/13.8-13.8kV), similar to the T15 unit, T14 can ultimately be removed while still increasing capacity and at a lower cost compared to replacing all the transformers with similar units with the same ratings. Moreover, downsizing capacity today and

then later upgrading within the lifetime of the transformer due to eventual load growth will be significantly more costly. For example it may cost an additional $5-$10 million for the replacement of the transformers plus the incremental cost for the LDC to reconfigure feeders. It should also be noted that maintaining capacity, as opposed to downsizing, is a more resilient option as it provides additional flexibility during emergency conditions through load transfers.

Based on the above, the study team recommends that this need be addressed by Hydro One and THESL to coordinate the replacement plan. The EOL transformers will be replaced with 60/100MVA units and the timing of replacement is 2022-2023.

Charles TS

Charles TS comprises two DESN units, T1/T2 (60/100 MVA) and T3/T4 (45/75 MVA), having a summer 10-Day LTR of 200 MW. The station's 2016 actual non-coincident summer peak load (adjusted for extreme weather) was about 139 MW and is forecasted to be approximately 146 MW and 174 MW in 2017 and 2027 respectively. Transformers T3/T4 are currently about 50 years old and have been identified to be at their EOL.

The load at Charles TS is forecasted to be over 85% of its LTR in the medium term. The load at three of the closest stations, Bridgman TS, Cecil TS and Terauley TS, is also forecasted to be approaching their respective LTR's in the medium term. Therefore, downsizing T3/T4 and consolidating load within the station and/or with area stations is not a prudent or viable option given medium term load growth at these stations. Moreover, downsizing capacity today and then later upgrading within the lifetime of the transformer due to eventual load growth will be significantly more costly. For example it may cost an additional $5-$10 million for the replacement of the transformers plus the incremental cost for the LDC to reconfigure feeders. It should also be noted that maintaining capacity, as opposed to downsizing, is a more resilient option as it provides additional flexibility during emergency conditions through load transfers.

Based on the above, the study team recommends that this need be addressed by Hydro One and THESL to coordinate the replacement plan. The EOL transformers will be replaced with 60/100MVA units and the timing of replacement is 2024-2025.

Duplex TS

Duplex TS comprises two DESN units, T1/T2 (45/75 MVA) and T3/T4 (45/75 MVA), having a summer 10-Day LTR of 121 MW. The station's 2016 actual non-coincident summer peak load (adjusted for extreme weather) was about 97 MW and is forecasted to be approximately 101 MW and 109 MW in 2017 and 2027 respectively. Transformers T1/T2 are currently about 49 years old and have been identified to be at their EOL.

The load at Duplex TS is forecasted to be 90% of its LTR in the medium term. The load at two of the closest stations, Bridgman TS and Glengrove TS, is also forecasted to be over 95% and 65% respectively of their LTR's in the medium term. Although Glengrove TS has capacity in the medium term,

maximizing use of existing land and station facilities at Duplex TS (as opposed to downsizing or eliminating) allows for effective planning for long-term electricity needs, reliability and system resiliency. The third neighbouring station, Fairbank TS, is a 27.6kV station so permanent load transfer from Duplex TS, which is a 13.8kV station, is not a viable or economical option. Further, the load at Fairbank TS will be close to its LTR following the transfer of its two feeders to the new Runnymede T1/T2 DESN). For these reasons downsizing T1/ T2 is not prudent. Moreover, downsizing capacity today and then later upgrading within the lifetime of the transformer due to eventual load growth will be significantly more costly. For example it may cost an additional $5-$10 million for the replacement of the transformers plus the incremental cost for the LDC to reconfigure feeders. It should also be noted that maintaining capacity, as opposed to downsizing, is a more resilient option as it provides additional flexibility during emergency conditions through load transfers.

Based on the above, the study team recommends that this need be addressed by Hydro One and THESL to coordinate the replacement plan. The EOL transformers will be replaced with 60/100MVA units and the timing of replacement is 2023-2024.

Strachan TS

Strachan TS comprises two DESN units, T12/T14 (T12: 40/67 MVA; T14: 45/75 MVA) and T13/T15 (45/75 MVA), having a summer 10-Day LTR of 161 MW. The station's 2016 actual non-coincident summer peak load (adjusted for extreme weather) was about 142 MW and is forecasted to be approximately 148 MW and 166 MW in 2017 and 2027 respectively. Transformer T12 is currently about 60 years old and has been identified to be at its EOL. The companion DESN transformer T14 is currently 42 years old and is not at its EOL.

The load at Strachan TS is forecasted to approach capacity in the medium term. The load at the closest station, John TS, is also forecasted to be 85% of its LTR's in the medium term. Therefore, downsizing T12 and consolidating load within the station and/or with area stations is not a viable option given medium term load growth at these stations. Moreover, downsizing capacity today and then later upgrading within the lifetime of the transformer due to eventual load growth will be significantly more costly. For example it may cost an additional $5-$10 million for the replacement of the transformers plus the incremental cost for the LDC to reconfigure feeders. It should also be noted that maintaining capacity, as opposed to downsizing, is a more resilient option as it provides additional flexibility during emergency conditions through load transfers.

Apart from the above transformer replacement options, the Study Team suggested evaluating the option of replacing T12 with a 115/230kV dual winding transformer (versus 115kV) since the 115kV cables, K6J and H2JK, between Strachan TS and Riverside JCT were recently replaced with cables built to 230kV (but currently operating at 115kV). It was determined that this option is not viable as there is insufficient space at the Strachan TS site to accommodate this and the associated station reconfiguration that would be required. Moreover, these dual winding transformers are not standard and would have to be custom built (if possible) which would result in a significant incremental cost, including the additional operating and maintenance costs, compared to replacing the transformer with a similar standard unit.

Based on the above, the study team recommends that this need be addressed by Hydro One and THESL to coordinate the replacement plan. The EOL transformer will be replaced with a 60/100MVA unit and the timing of replacement is 2020-2021. The preliminary plan also includes the upgrade of 115kV strain bus and replacement of 115kVdisconnect switches.

7.1.1.3 EOL Station Equipment: Replacement Plan to be Further Assessed

This section describes EOL station equipment where the replacement plan requires further assessment and regional coordination.

Bermondsey TS

Bermondsey TS comprises two DESN units, T1/T2 (75/125MVA) and T3/T4 (75/125 MVA), having a summer 10-Day LTR of 348 MW. The station's 2016 actual non-coincident summer peak load (adjusted for extreme weather) was about 179 MW and is forecasted to be approximately 185 MW and 200 MW in 2017 and 2027 respectively. Transformers T3 and T4 are currently about 51 years old and have been identified to be at their EOL.

The load at Bermondsey TS is forecasted to be 57% of its LTR in the medium term. The Bermondsey T1/T2 DESN is more lightly loaded than the T3/T4 DESN (T3/T4 is approximately 70% of total station loading over the last 3 years).The load at the three closest stations, Scarboro TS, Warden TS, and Leaside TS is forecasted to be over 75%, 85%, and over 95% respectively of their LTR's in the medium term.

A review of options such as the feasibility of downsizing T3/T4 and partially consolidating with T1/T2 DESN and/or with area stations should be assessed. Hence, further regional coordination in the IRRP and/or RIP phase is required to identify a preferred replacement plan. The timing of replacement for EOL equipment is 2023-2024.

John TS

John TS is connected to the 115kV Manby West system and jointly supplies Toronto's downtown district. Station facilities include six 115/13.8kV step-down transformers (T1, T2, T3, T4, T5, T6) and a 115kV switchyard. The summer 10-Day LTR is 262 MW. The station's 2016 actual non-coincident summer peak load (adjusted for extreme weather) was about 282 MW and is forecasted to be approximately 285 MW in 2017 and 224 MW in 2027 due to load transfers to the new Copeland MTS scheduled to be in service in 2018 (Phase 1).

John TS was built in the 1950's and THESL's switchgear at the station has reached the end of its useful life. It is expected to be replaced with new metalclad line-ups in the near term around 2022-2023. In addition, five step-down transformers at John TS, T1, T2, T3, T4, and T6, as well as the 115 kV breakers have been identified to be at the end of their useful life and require replacement within the near to medium term. The new equipment is currently expected to be in service by 2025-2026.

Since John TS requires a significant rebuild including the replacement of all EOL assets, options and an implementation plan need to be further assessed as part of the IRRP and RIP phase to develop a comprehensive plan. In addition, coordination of this work with Copeland MTS will be important because Copeland MTS' added capacity will be needed in order to improve execution of the replacement plan at John TS to maintain reliable supply in Toronto's downtown district. Therefore, it is recommended that the replacement plan for EOL equipment at John TS be further assessed as part of the IRRP and RIP phase.

Main TS

Main TS comprises one DESN unit, T3/T4 (45/75 MVA), having a summer 10-Day LTR of 74 MW. The station's 2016 actual non-coincident summer peak load (adjusted for extreme weather) was about 64 MW and is forecasted to be approximately 65 MW and 70 MW in 2017 and 2027 respectively. Transformers T3/T4 are currently about 49 years old and have been identified to be at their EOL.

The load at Main TS is forecasted to be 95% of its LTR in the medium term. The load at two of the closest stations, Carlaw TS and Warden TS, is forecasted to be at capacity, and 85% of LTR respectively in the medium term. Main TS is a 115/13.8 kV station that is supplied by the Leaside 115 kV system. There is a need to relieve Leaside autotransformers (described in section 7.2.5) in the long term (beyond 2027[1]). Moving over 60 MW of load (2016 actual non-coincident summer peak load) from Main TS off of the Leaside 115kV supply and onto the upstream 230 kV supply (CxL circuits) could potentially defer the need for Leaside autotransformer upgrades (or a new transmission supply point) by 4-5 years. This deferral could represent a significant value to ratepayers.

Accordingly, the Study Team will further assess the option of adding a 230/13.8 kV DESN at Warden TS with express 13.8 kV feeders running to Main TS along with other potential options. Hence, further regional coordination in the IRRP and/or RIP phase is required to identify a preferred replacement plan. The timing of replacement for EOL equipment is 2021-2022.

Manby TS

Manby TS is a major switching and autotransformer station in the Toronto region. Station facilities include six 230/115kV autotransformers (T1, T2, T7, T8, T9, T12), a 230 kV switchyard, a 115kV switchyard, and six 230/27.6kV step-down transformers (T3, T4, T5, T6, T13, T14). The total summer 10-Day LTR of the six step-down transformers is 226 MW. The station's 2016 actual non-coincident summer peak load (adjusted for extreme weather) was about 206 MW and is forecasted to be approximately 208 MW and 252 MW in 2017 and 2027 respectively. Three of the autotransformers, T7, T9, and T12, and one of the step-down transformers, T13, are close to 50 years old and have been identified to be at the end of their useful life. The 230 kV oil breakers have also been identified to be at EOL and require replacement. The timing of replacement for EOL equipment is 2024-2025.

[1] The need date assumes that two of the three units at Portland Energy Centre are out and total plant generation is 160MW and a high demand growth scenario. Under a low demand growth scenario, the need was identified in the IRRP to occur in the post 2035 timeframe, which was outside of the IRRP study timeframe. The need for Leaside autotransformer relief will be re-assessed as part of the next IRRP.

In addition to the EOL asset needs at Manby TS, there are also needs for: additional step down transformation capacity to relieve Manby TS loading discussed in section 7.2.1; transmission line capacity on the 230kV Richview TS to Manby TS corridor discussed in section 7.2.3; addressing potential violation of ORTAC load rejection limit of 150 MW discussed in section 7.2.4; and, transformation capacity to relieve Manby TS 230/115kV autotransformers in the long term discussed in section 7.2.7. Since the EOL equipment need may impact these additional needs it is recommended that the replacement plan for EOL equipment at Manby TS be further assessed as part of the IRRP and RIP phase.

7.1.1.4 EOL Transmission Lines

The table below lists sections of HV overhead lines and underground cables in the Toronto Region that are at the end of their useful life and require replacement in the near term.

Table 5: End-of-Life Lines

EOL Lines	Voltage Level (kV)	Est. Conductor Replacement (route length, km)	Asset Age (years)	Description
C5E/C7E (UG Cable)	115	3.6	58	Replacement of deteriorated cable from Esplanade TS to Terauley TS
H1L/H3L/H6LC/H8LC	115	2.05	64	Replacement of deteriorated overhead line from Bloor St. JCT to Leaside JCT
L9C/L12C	115	3.55	88	Replacement of deteriorated overhead line from Leaside TS to Balfour JCT

C5E/C7E Cable

Circuits C5E and C7E provide critical 115kV supply to Toronto's downtown core. The underground cables from Esplanade TS to Terauley TS (about 3.6 route km) are paper-insulated low pressure oil filled and are 58 years old and partially routed along Lake Ontario. These cables are in poor condition and deemed to be at the end of their useful life, and hence require replacement in the near-term. Due to their deteriorated condition, the risk of cable failure and oil leaks resulting in loss of supply and adverse environmental impact will only increase with age.

The preliminary scope of work involves replacement of the 115kV low pressure oil filled underground transmission cable with XLPE cable between Esplanade TS to Terauley TS with a 1200A continuous summer rating and an option for insulation for 230kV, although the cable would be operated at 115kV. The need and cost for a higher rated cable will also be assessed. Various routes will be identified and evaluated such as the existing route, utilizing the John x Esplanade TS tunnel, etc. The route investigation will assess existing easements and right-of-ways, cost, and other technical and environmental considerations. OEB Leave to Construct approval may be required.

Further regional coordination in the IRRP and RIP phase is required to review options and identify a preferred replacement plan.

H1L/H3L/H6LC/H8LC

Circuits H1L, H3L, H6LC, and H8LC provide 115kV supply to the eastern part of central Toronto from Hearn TS to Leaside TS. The line section between Bloor St. JCT to Leaside JCT (about 2 route km), is 64 years old and its conductors have been identified as reaching the end of their useful life and require replacement for safety, reliability and maintainability purposes.

The preliminary scope of work involves refurbishing the circuits between Bloor St. JCT to Leaside JCT to like-new conditions and built to current standards. Options for upgrading the circuits to 230kV will also be assessed.

Further regional coordination in the IRRP and RIP phase is required to review options and identify a preferred replacement plan.

L9C/L12C

Circuits L9C and L12C provide 115kV supply to central Toronto from Leaside TS to Cecil TS. The line section between Leaside TS and Balfour JCT (about 3.6 route km), are over 80 years old and their conductors have been identified as reaching the end of their useful life and require replacement for safety, reliability and maintainability purposes.

The preliminary scope of work involves refurbishing the circuits between Leaside TS and Balfour JCT to like-new conditions and built to current standards.

Further regional coordination in the IRRP and RIP phase is required to review options and identify a preferred replacement plan.

7.1.2 East Harbor / Port Lands Area – Transformation Capacity

THESL has identified an emerging area of load growth in the East Harbor and Port Lands in Toronto. The current load in the area is supplied from Esplanade TS and Basin TS. The area currently consists of prime land for future development. Among recent proposals in the East Harbor includes re-development of a former 60-acre Unilever factory site as a new master-planned district consisting of commercial and residential towers. Nearby, the Port Lands have also been in the City of Toronto’s plans for renewed development. In addition to these, the potential expansion of Ashbridges Bay Wastewater treatment plant and the future construction of the Toronto Transit Commission’s (TTC) downtown relief subway line may also impact load growth in the area. Recently THESL has been in discussions with Toronto Water for the tentative connection of about 14MVA of new electrical load.

Transformation capacity in the area is sufficient with present day loading however, due to the area's load growth potential there may be a need for increased capacity around 2025+. The infrastructure planning for this expansion could be complex due to urban vicinity and municipal plans/needs and should be undertaken for broader coordination as soon as possible. The existing Basin TS and Esplanade TS load

forecasts do not include the impact of this major undertaking. Furthermore, based on the existing Basin TS forecast, it may reach capacity by 2026 and slightly exceed its LTR by 2027.

Further regional coordination in the IRRP and RIP phase is required to review options and identify a preferred plan.

7.1.3 Load Restoration – C14L+C17L, C5E+C7E, and K3W+K1W

For the loss of 230kV circuits C14L and C17L (stations connected are Warden TS and Bermondsey TS), the load interrupted by configuration can exceed 150 MW and 250 MW and are required to be restored within the prescribed time periods as stated in the ORTAC.

For the loss of 115kV circuits C5E and C7E (station connected is Terauley TS), the load interrupted by configuration can exceed 150 MW over the study period and are required to be restored within the prescribed time periods as stated in the ORTAC.

For the loss of 115kV circuits K3W and K1W (stations connected are Fairbank TS and Wilshire TS), the load interrupted by configuration can exceed 150 MW and 250 MW and are required to be restored within the prescribed time periods as stated in the ORTAC.

Further regional coordination in the IRRP and RIP phase is required to review options and identify a preferred restoration plan.

7.2 Needs Identified in Previous RIP

The following section summarizes the needs and their respective plans identified in the previous RIP report which are not yet underway. The Study Team reaffirms these needs and an update with respect to their plans is provided below.

7.2.1 Southwest Toronto – Station Capacity

To address the station capacity need at Manby TS and Horner TS, the RIP recommended adding two 230/27.6 kV, 75/125MVA transformers and a new 27.6kV switchyard at the existing Horner TS site. New distribution feeder ties are required to be built between Manby TS and Horner TS by THESL to accommodate load transfer out of Manby TS to Horner TS as the loading at Manby TS exceeds its capacity. The need date is 2021. For more details, refer to section 7.2 of the RIP report.

The Study Team reaffirms this need. Hydro One is continuing the development and estimate work for this project. The planned in service date is 2020.

7.2.2 Downtown District – Station Capacity

The Toronto Downtown District is mainly supplied by the three existing 115/13.8 kV stations: John TS, Esplanade TS, and Terauley TS. THESL is building a new 115/13.8kV owned transformer station,

Copeland MTS, in the Downtown District near John TS with normal supply from the 115 kV Manby West system. Copeland MTS Phase 1 is currently under construction with a planned in service date of 2018. It will provide a new source of supply to the area customers.

As identified in the RIP report (refer to section 7.3 of the RIP report), a number of factors including additional transformation capacity, but also feeder positions would drive the need for Copeland MTS Phase 2 – a second 115/13.8kV DESN[2] at the Copeland MTS site. THESL anticipates that the need for a new transformation facility is more advanced due to: significant load transfers required to facilitate the refurbishment work at John TS (as discussed in section 7.1.1.3); and, limited spare feeder positions at existing stations for new customer connections and to maintain n-1 contingencies for dual radial feeders. THESL foresees substantial load additions due to new developments to the east of the station, which are not included in the existing Copeland MTS forecast.

Based on the station capacity consideration alone for the Downtown District stations, the need date for Copeland MTS Phase 2 is 2027+. However, based on the other considerations identified by THESL such as their requirements for spare feeder positions, the need date may be earlier around 2023-2024.

The Study Team reaffirms this need and recommends that the need and timing for Phase 2 be further refined by THESL through their distribution planning process and included in updates to the next IRRP and/or RIP.

7.2.3 230kV Richview TS x Manby TS Corridor – Line Capacity

Various alternatives were assessed to address the line capacity need for the two double circuit 230kV lines, R1K/R2K and R13K/R15K, along the Richview TS to Manby TS corridor. The RIP recommended that Hydro One proceed with the development and estimate work on the alternatives. With the effect of the proposed Metrolinx Mimico Traction Power Station ("TPS") load, the need date for relief may be 2020 at the earliest. For more details, refer to section 7.4 of the RIP report.

The Study Team reaffirms this need and has determined a recommended plan. This plan is staged as follows:

- Stage 1: Rebuild existing 115kV idle line to 230kV and reconfigure two existing circuits R2K and R15K into "Super-circuits"
- Stage 2: Terminate the new conductors on V73R and V79R circuits and Manby TS (3 new breakers) and complete station work coincident with Manby TS EOL replacement work planned in 2023-2024 (discussed in section 7.1.1.3)

Hydro One is continuing the development and estimate work on this plan with an in service date of 2021. Updates will be included in the next IRRP and RIP.

[2] A third 60/100 MVA transformer will also be installed, which under normal operation will remain on potential, but off-load. This transformer will only be loaded in the event of a contingency at Copeland MTS or at Windsor TS/John TS (following the replacement of the THESL switchgear after which inter-station support capability will have been installed). The site and the HV switching facilities required to accommodate Phase 2 are already included as part of the Copeland MTS Phase 1 project.

7.2.4 Breaker Failure at Manby TS

To address the risk of breaker failure at Manby TS causing the outage of any two of the three 230/115kV autotransformers at either the west or east yard of Manby TS and resulting in the remaining transformer exceeding its Short Term Emergency (STE) rating, the RIP recommended the installation of a Special Protection Scheme (SPS). The need date is summer 2018 and summer 2021 for Manby West and Manby East respectively. For more details refer to section 7.6 of the RIP report.

The Study Team reaffirms this need. Hydro One is continuing the development and estimate work for this project. The planned in service date is Q2 2018.

Since the RIP, IESO completed a System Impact Assessment (SIA) for the Manby SPS and it found that based on the coincident load forecast in order to respect post contingency thermal ratings of Manby T12 and T7 for the loss of two companion autotransformers, the ORTAC load rejection limit of 150 MW may be exceeded in the long term (around 2028+). This need and associated plan should be coordinated with the 230/115kV Manby TS transformer capacity need discussed in section 7.2.7 and the Manby TS EOL equipment need discussed in section 7.1.1.3. Hence further regional coordination in the IRRP and RIP is required.

7.2.5 230/115 kV Leaside Autotransformers Transformation Capacity and Voltage Collapse

Based on the load forecast, the Leaside TS autotransformers will require relief in the long term, beyond 2027. The need date assumes that two of the three units at Portland Energy Centre (PEC) are out and total plant generation is 160MW.

Following the loss of 230 kV circuits, C16L and C17L, while all three units at PEC are out of service pre-contingency, voltage collapse in the Leaside TS 115kV subsystem may be caused. This becomes a credible contingency once the current PEC contract expires. This need was identified in the Central Toronto Area IRRP report.

The Study Team reaffirms these needs and recommends that they be further assessed in the IRRP and/or RIP phase. For more details, refer to section 6.2.1 of RIP report and Appendix E of the IRRP report.

7.2.6 115 kV Leaside TS x Wiltshire TS Corridor – Line Capacity

Based on the RIP coincident load forecast, the Leaside TS x Wiltshire TS circuits will require relief in the long term (2034). For more details, refer to section 7.10 of the RIP report.

The Study Team reaffirms this need and recommends that it be further assessed in the next phases of the regional planning process, i.e. IRRP and/or RIP.

7.2.7 230/115 kV Manby Autotransformers – Transformation Capacity

Based on the RIP coincident load forecast, the Manby TS autotransformers will exceed their LTE and require relief in the long term (2035+).

As noted in section 7.1.1.3, three of the autotransformers at Manby TS, T7, T9, and T12, are at EOL and require replacement in 2023-2024. Currently, T7 and T9 in the Manby East switchyard are rated about 65 MVA and 40 MVA less than their third companion autotransformer, while T12 in the Manby West switchyard is rated about 52 MVA and 92 MVA less than its two companion autotransformers.

The Study Team reaffirms this need. Since the 230/115kV Manby transformer capacity need impacts the Manby TS EOL plans and the need to address the potential violation of the ORTAC 150 MW load rejection limit (discussed in section 7.2.4), there are benefits to coordinating the plans to address all these needs. Therefore, further regional planning in the IRRP and RIP is required. For more details, refer to section 7.10 of the RIP report.

7.2.8 115 kV Manby West x Riverside Junction – Line Capacity

Based on the RIP coincident load forecast, the Manby West x Riverside Junction circuits will require relief in the long term (2035+). For more details, refer to section 7.10 of the RIP report.

The Study Team reaffirms this need and recommends that it be further assessed in the next phases of the regional planning process, i.e. IRRP and/or RIP.

7.2.9 115 kV Don Fleet Junction x Esplanade TS – Line Capacity

The 115kV circuit H2JK between Don Fleet Junction and Esplanade TS is forecast to exceed its Long Term Emergency (LTE) rating in 2026 following the loss of 115 kV circuit H9EJ. This need was identified in the Central Toronto Area IRRP report.

The Study Team reaffirms this need and recommends that it be further assessed in the next phases of the regional planning process, i.e. IRRP and/or RIP. For more details, refer to Appendix E of the IRRP report.

It should also be noted that Metrolinx is planning to expand their Don Yard in downtown Toronto. The expansion will require the relocation of 115 kV overhead line section, H9EJ and H10EJ between Cherry St. and Don Fleet Junction (approximately 0.6 km) and 115 kV underground cable section, H2JK between Don Fleet Junction and Esplanade TS (approximately 1.8 km).

Further regional coordination in the IRRP and/or RIP phase is required to review options (including upgrading H2JK and converting it to an overhead line) and identify the preferred relocation plan.

8 RECOMMENDATIONS

The Study Team's recommendations to address the needs identified are as follows:

a) The equipment discussed in sections 7.1.1.1 and 7.1.1.2 is 40-60 years old. It has been determined that these assets are at the end of their useful life. From a cost, loading, timing, and customer connection needs perspective, none of these assets should be eliminated or have their capacity reduced. The study team recommends that these EOL needs be addressed by Hydro One and THESL to coordinate the replacement plan.

b) The Study Team will further assess the following needs discussed in sections: 7.1.1.3 (EOL station equipment needs); 7.1.1.4 (EOL line equipment needs); 7.1.2 (transformation capacity needs); 7.1.3. (load restoration need); 7.2.5 to 7.2.9 (needs identified in previous RIP/IRRP, mostly long-term); as part of the next phases of regional planning, i.e. IRRP and RIP, to develop a preferred plan.

c) The Study Team reaffirms the remaining needs that were identified in the previous RIP, discussed in sections 7.2.1 to 7.2.4 of this report. Updates (where relevant) to the associated plans are provided and implementation of these plans should be continued.

The table below summarizes the above recommendations.

Table 6: Summary of Recommendations

Further Regional Coordination Not Required	Further Regional Coordination Required
EOL Station Equipment: • Bridgman TS: T11/T12/T13 • Charles TS: T3/T4 • Duplex TS: T1/T2 • Fairbank TS: T1/T3, T2/T4 • Fairchild TS: T1/T2 • Leslie TS: T1 • Runnymede TS: T3/T4, 115 kV line grounding switches • Sheppard TS: T3/T4 • Strachan TS: T12	**EOL Station Equipment:** • Bermondsey TS: T3/T4 • John TS: T1, T2, T3, T4, T6, 115 kV breakers • Main TS: T3/T4, 115 kV line disconnect switches, installation of 115 kV CVTs • Manby TS: T7, T9, T12 autotransformers, T13 step-down transformer, rebuild 230kV yard **EOL Lines:** • 115kV C5E/C7E Underground Cable: Esplanade TS to Terauley TS • 115 kV H1L/H3L/H6LC/H8LC Overhead Line: Bloor St. JCT to Leaside JCT • 115kV L9C/L12C Overhead Line: Leaside TS to Balfour JCT **Transformation Capacity Need:** • East Harbor / Port Lands Area and Basin TS **Load Restoration Need:** • C14L+C17L (Warden TS and Bermondsey TS)

Further Regional Coordination Not Required	Further Regional Coordination Required
	• C5E+C7E (Terauley TS) • K3W+K1W (Fairbank TS and Wiltshire TS) **Needs identified in Previous RIP/IRRP:** <u>Medium Term</u> • 115kV Don Fleet JCT x Esplanade TS – Line Capacity <u>Long-Term</u> • 230/115kV Leaside TS autotransformers – Transformation Capacity and Voltage Collapse of 115kV Leaside Subsystem • 115kV Leaside TS to Wiltshire TS Corridor – Line Capacity • 230/115kV Manby autotransformers – Transformation Capacity • 115kV Manby West x Riverside Junction – Line Capacity

9 REFERENCES

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Appendix A: Non-Coincident Summer Peak Load Forecast (2016 to 2027)

			LTR (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Central 115kV	Lea115kV	BASIN TS	85	52	61	69	76	81	82	83	83	83	84	85	86
		BRIDGMAN TS	183	159	162	164	164	165	166	169	170	171	172	173	175
		CARLAW TS	70	56	56	65	66	68	68	68	69	69	70	70	70
		CECIL TS	204	173	177	182	190	194	197	198	200	200	202	203	204
		CHARLES TS	200	139	146	155	161	164	166	166	167	169	170	172	174
		DUFFERIN TS	161	132	132	138	124	126	127	127	128	129	131	132	132
		DUPLEX TS	121	97	101	109	113	112	110	108	105	106	107	108	109
		ESPLANADE TS	177	167	169	179	157	160	162	163	163	166	166	168	170
		GERRARD TS	94	38	40	36	46	48	50	50	51	51	51	52	53
		GLENGROVE TS	84	54	54	51	52	54	54	54	56	56	56	56	56
		MAIN TS	74	64	65	66	66	66	67	68	68	68	70	70	70
		TERAULEY TS	205	174	181	188	200	206	199	203	204	204	205	205	205
	ManbyE-115-27.6	FAIRBANK TS	182	169	173	180	162	169	174	178	183	183	185	186	188
		RUNNYMEDE TS	111	119	121	123	169	176	178	178	181	182	183	184	185
	ManbyE-115-13.8	WILTSHIRE TS	126	61	65	63	79	79	80	81	81	83	83	83	83
	ManbyW-115	COPELAND MTS	111	0	0	0	0	54	101	102	103	103	107	107	107
		STRACHAN TS	161	137	143	147	150	154	154	156	156	158	160	160	160
		WINDSOR TS (John TS)	262	282	285	283	286	235	214	217	218	219	222	223	224
Central 115kV Total			2611	2073	2130	2198	2259	2309	2351	2371	2387	2400	2424	2436	2450
Eastern 230kV	CxL230	BERMONDSEY TS	348	179	184	179	184	187	188	192	193	194	196	198	200
		ELLESMERE TS	189	139	141	143	145	147	148	149	150	151	152	153	154
		LEASIDE TS	210	157	164	180	185	190	192	193	194	196	197	199	201
		SCARBORO TS	341	230	235	239	243	245	246	248	249	251	253	254	255
		Metrolinx - Scarboro	0	0	0	0	0	0	0	78	78	78	78	78	78
		SHEPPARD TS	204	170	171	175	178	181	183	185	185	187	188	190	192
		WARDEN TS	183	138	139	144	147	148	149	150	151	152	153	155	156
Eastern 230kV Total			1474	1013	1034	1061	1082	1098	1105	1194	1200	1209	1218	1227	1236
Northern 230kV	CxR	AGINCOURT TS	174	101	101	102	105	108	111	112	113	114	114	114	114
		BATHURST TS	334	232	237	253	264	271	275	276	278	280	282	284	286
		CAVANAGH MTS	157	93	95	95	96	97	97	98	99	100	100	101	102
		FAIRCHILD TS	346	272	275	278	282	284	286	288	290	292	294	295	296
		FINCH TS	363	278	285	293	298	302	304	306	308	310	312	314	316
		LESLIE TS	325	237	249	262	273	277	280	283	286	287	290	292	293
		MALVERN TS	176	95	100	102	105	106	106	107	108	108	109	110	111
Northern 230kV Total			1701	1308	1342	1385	1421	1444	1458	1469	1481	1491	1502	1511	1519
Western 230kV	Manby230	HORNER TS	183	146	155	160	163	165	167	168	169	171	172	173	174
		MANBY TS	226	206	208	218	229	232	241	242	243	245	246	249	252
	Metrolinx	Metrolinx - Cityview	0	0	0	0	0	59	59	59	59	59	59	59	59
		Metrolinx - Mimico	0	0	0	0	0	28	28	28	28	28	28	28	28
	Rich230	REXDALE TS	187	140	142	145	147	148	150	150	152	152	154	154	154
		RICHVIEW TS	454	248	250	256	243	246	248	250	250	252	255	256	257
Western 230kV Total			1049	740	755	779	782	877	892	896	901	908	914	919	924
Grand Total			**6834**	**5134**	**5262**	**5422**	**5545**	**5729**	**5806**	**5930**	**5970**	**6008**	**6057**	**6093**	**6129**

Appendix B: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DCF	Discounted Cash Flow
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GATR	Guelph Area Transmission Reinforcement
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PEC	Portland Energy Centre
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TPS	Traction Power Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

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NEEDS ASSESSMENT REPORT

GTA North Region

Date: March 20, 2018

Prepared by: GTA North Region Study Team

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the GTA North Region and to recommend which needs may require further assessment and/or regional coordination to develop a preferred plan. The results reported in this Needs Assessment are based on the input and information provided by the Study Team.

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Executive Summary

REGION	GTA North		
LEAD	Hydro One Networks Inc. ("HONI")		
START DATE	December 1, 2017	**END DATE**	March 20, 2018

1. INTRODUCTION

The first cycle of the Regional Planning process for the GTA North Region was initiated in Q2 2014 and completed with the publication of the Regional Infrastructure Plan ("RIP") in February 2016. The RIP provided a description of needs and recommendations of preferred wires plans to address near-term needs. The RIP also identified some mid- and long-term needs that will be reviewed during this planning cycle.

The purpose of this Needs Assessment is to identify any new needs and reaffirm needs identified in the previous GTA North Region RIP.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the regional planning cycle should be triggered at least every five years. Due to the timing of the mid-term needs identified in the previous Integrated Regional Resource Plan ("IRRP") and RIP reports as well as new needs in the GTA North Region, the NA was triggered in advance of the regular 5-year review schedule.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the GTA North Region and includes:

- New needs identified by Study Team members; and,
- Review and reaffirm needs/plans identified in the previous RIP

The Study Team may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), IRRP and RIP, based on updated information available at that time.

4. INPUTS/DATA

The Study Team representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One provided input and relevant information for the GTA North Region regarding capacity needs, system reliability, operational issues, and major assets/facilities approaching end-of-life ("EOL").

5. ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical infrastructure needs in the Region over the study period. The assessment reviewed available information including load forecasts, conservation and demand management (CDM) and distributed generation (DG) forecasts, system reliability and operation issues, and major high voltage equipment identified to be at or near the end of their useful life and requiring replacement/refurbishment.

A technical assessment of needs was undertaken based on:

- Station capacity and transmission adequacy;
- System reliability and operation; and,
- Major high voltage equipment reaching the end of its useful life with respect to replacing it with similar type equipment versus other options to determine the most technically feasible, resilient, and cost effective outcome.

6. RESULTS

I. Aging Infrastructure

In the GTA North Region, high voltage equipment at Woodbridge TS (T5 transformer) was identified to be approaching the end of its useful life and requires replacement in the near-term. Refer to section 7.1.1 for more details.

II. 230kV Connection Capacity

- A transformation capacity need for the Vaughan area was reaffirmed. Based on current extreme summer weather non-coincident peak net load forecast, the need for additional transformation capacity is beyond 2027. If CDM savings are not achieved as forecasted, the need date may be as early as 2027. Refer to section 7.2.3 for more details.

- A transformation capacity need for the Northern York Area was reaffirmed. Based on current extreme summer weather non-coincident peak net load forecast, the need for additional transformation capacity is beyond 2027. If CDM savings are not achieved as forecasted, the need date may be as early as 2024. Refer to section 7.2.6 for more details.

III. 230kV Transmission Supply Capacity

Transmission Supply Capacity needs were reaffirmed to connect new transformation capacity in Vaughan and Northern York Areas in the long term. Refer to sections 7.2.3 and 7.2.6 for more details.

IV. System Reliability & Operation

- A load restoration need for the loss of circuits V43+V44 (supplies Woodbridge TS, Vaughan #3 MTS, and Kleinburg TS), was identified during the previous NA for the GTA North Western Sub-Region and the Northwest GTA IRRP. The study team reaffirmed this need. Refer to section 7.2.1 for more details.
- A load restoration need for the loss of circuits, P45+P46 (supplies Buttonville TS, Markham #4 MTS, and future Markham #5 MTS), has been identified in the near term. Refer to section 7.1.2 for more details.
- A load security need was previously identified on the Parkway to Claireville corridor and was reassessed during this NA. The load on this corridor is slightly lower than it was when the previous assessment was completed, although it continues to exceed the 600MW limit. Refer to section 7.2.2 for more details.

V. Station Service Supply to York Energy Centre

A need for addressing station service supply to York Energy Centre was reaffirmed for the near to medium term. Refer to section 7.2.5 for more details.

7. RECOMMENDATIONS

The Study Team's recommendations are as follows:

a) Further regional coordination is not required to address the following needs:
   - EOL Woodbridge TS T5 transformer (discussed in section 7.1.1). The study team recommends that this EOL need be addressed by Hydro One and affected LDCs to coordinate the replacement plan. Hydro One will keep the study team informed of the status of the plan if any major changes occur.

b) As per the IESO's letter of support in April 2017, Hydro One will proceed with development and estimate work to connect a new 230/27.6kV DESN in the Markham-Richmond Hill area in coordination with Alectra (discussed in section 7.2.4). Further updates will be included in the next IRRP and RIP.

c) Further assessment and regional coordination is required in the IRRP and/or RIP, to develop a preferred plan for the following needs:
   - Load Restoration – P45+P46 (discussed in Section 7.1.2)
   - Load Restoration – V43+V44 (discussed in Section 7.2.1)
   - Load Security on V71P/V75P – Parkway to Claireville (discussed in Section 7.2.2)
   - Vaughan Transformation Capacity (discussed in Section 7.2.3)
   - Station Service Supply to York Energy Centre (discussed in Section 7.2.5)
   - Northern York Area Transformation Capacity (discussed in Section 7.2.6)
   - Transmission Supply Capacity in Vaughan and Northern York Area in long term (discussed in sections 7.2.3 and 7.2.6)

TABLE OF CONTENTS

1 Introduction 7
2 Regional Issue/Trigger 7
3 Scope of Needs Assessment 7
4 Regional Description and Connection Configuration 8
5 Inputs and Data 10
6 Assessment Methodology 10
7 Needs 11
8 Recommendations 16
9 References 18
Appendix A: GTA North Region Load Forecast (2017 to 2027) 19
Appendix B: Acronyms 21

List of Tables and Figures

Table 1: GTA North Region Study Team Participants 7
Table 2: New Needs 11
Table 3: Needs Identified in Previous RIP and IRRP(1) 11
Table 4: End-of-Life Equipment – GTA North Region 12
Table 6: Summary of Recommendations 16

Figure 1: GTA North Region – Supply Areas 9
Figure 2: GTA North Transmission Single Line Diagram 10

1 INTRODUCTION

The first cycle of the Regional Planning process for the GTA North Region was completed in February 2016 with the publication of the Regional Infrastructure Plan ("RIP"). The RIP provided a description of needs and recommendations of preferred wires plans to address near and medium term needs. Additional medium and long term needs were recommended for further review during the next regional planning cycle.

The purpose of this Needs Assessment ("NA") is to identify new needs and reconfirm the needs identified in the previous GTA North regional planning cycle. Since the first regional planning cycle, some new needs in the region have been identified.

This report was prepared by the GTA North Region Study Team ("Study Team"), led by Hydro One Networks Inc. Participants of the Study Team are listed below in Table 1. The report captures the results of the assessment based on information provided by the lead transmitter, Local Distribution Companies ("LDC") and the Independent Electricity System Operator ("IESO").

Table 1: GTA North Region Study Team Participants

Company
Alectra Utilities Corporation (formerly Enersource Hydro Mississauga, PowerStream Inc., Hydro One Brampton)
Hydro One Networks Inc. (Distribution)
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator ("IESO")
Newmarket-Tay Power Distribution Ltd. ("Newmarket-Tay")
Toronto Hydro-Electric System Limited ("THESL")
Veridian Connections Inc. ("Veridian")

2 REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. Due to the timing of the mid-term needs identified in the previous IRRP and RIP reports as well as new needs in the GTA North Region, the study team recommended to trigger the next cycle in advance of the regular 5-year review schedule.

3 SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the GTA North Region and includes:

- Identification of new needs based on latest information provided by the Study Team; and,
- Confirmation/updates of existing needs and/or plans identified in the previous planning cycle.

The Study Team may identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), Local Planning ("LP"), IRRP, and/or RIP.

4 REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The GTA North Region is approximately bounded by the Regional Municipality of York, and also includes parts of the City of Toronto, Brampton, and Mississauga. The region is divided into two sub-regions:

- York Sub-Region: This area includes Southern York area (the Municipalities of Vaughan, Markham, and Richmond Hill) and Northern York area (the Municipalities of Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville, Georgina, and some parts of Durham and Simcoe regions are supplied from the same electricity infrastructure).
- Western Sub-Region: This area comprises the western portion of the City of Vaughan.

Electrical supply to the GTA North Region is primarily provided from three major 500/230 kV autotransformer stations, namely Claireville TS, Parkway TS, and Cherrywood TS, and a 230 kV transmission network supplying the various step-down transformation stations in the region. Local generation in the Region consists of the 393 MW York Energy Centre connected to the 230 kV circuits B82V/B83V in King Township.

Please see Figure 1 and Figure 2 for a map and single line diagram of the Sub-Region facilities.

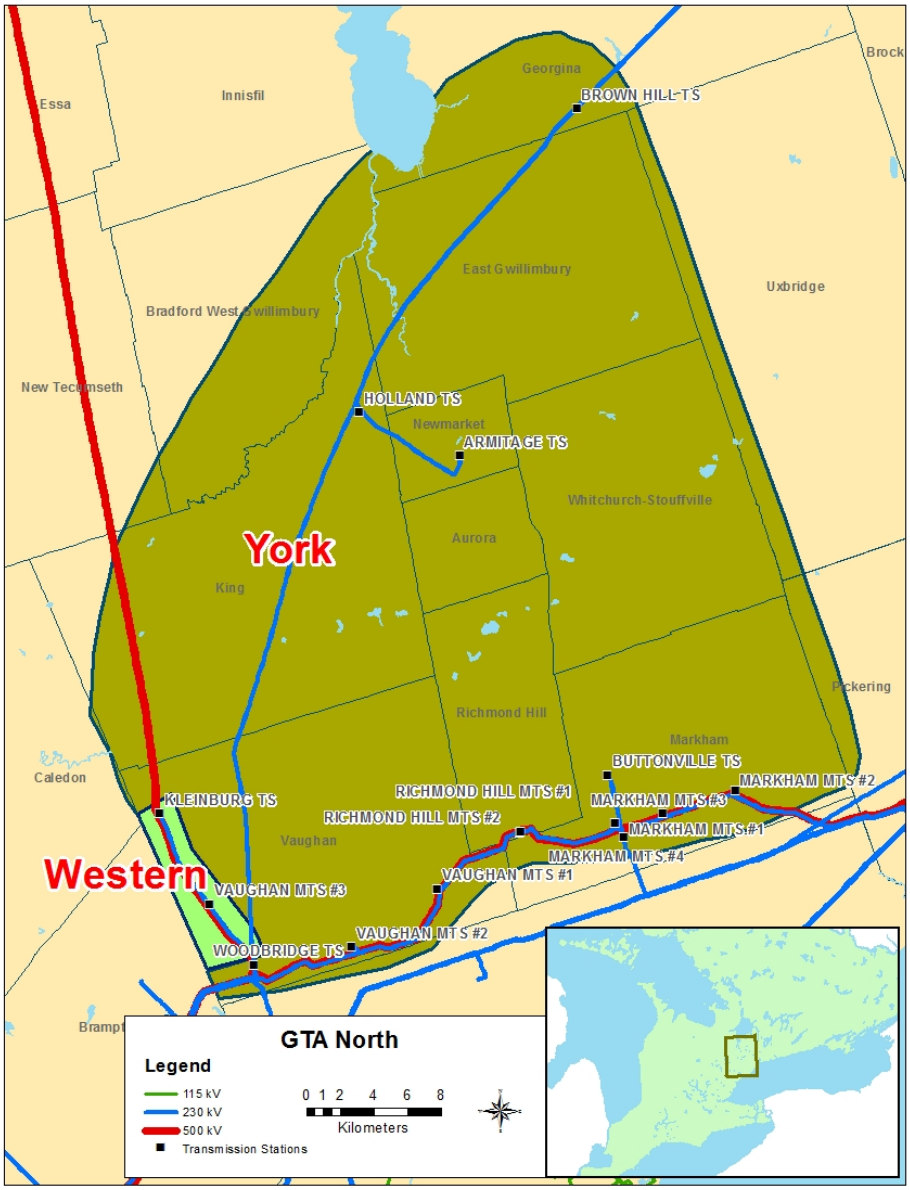

Figure 1: GTA North Region – Supply Areas

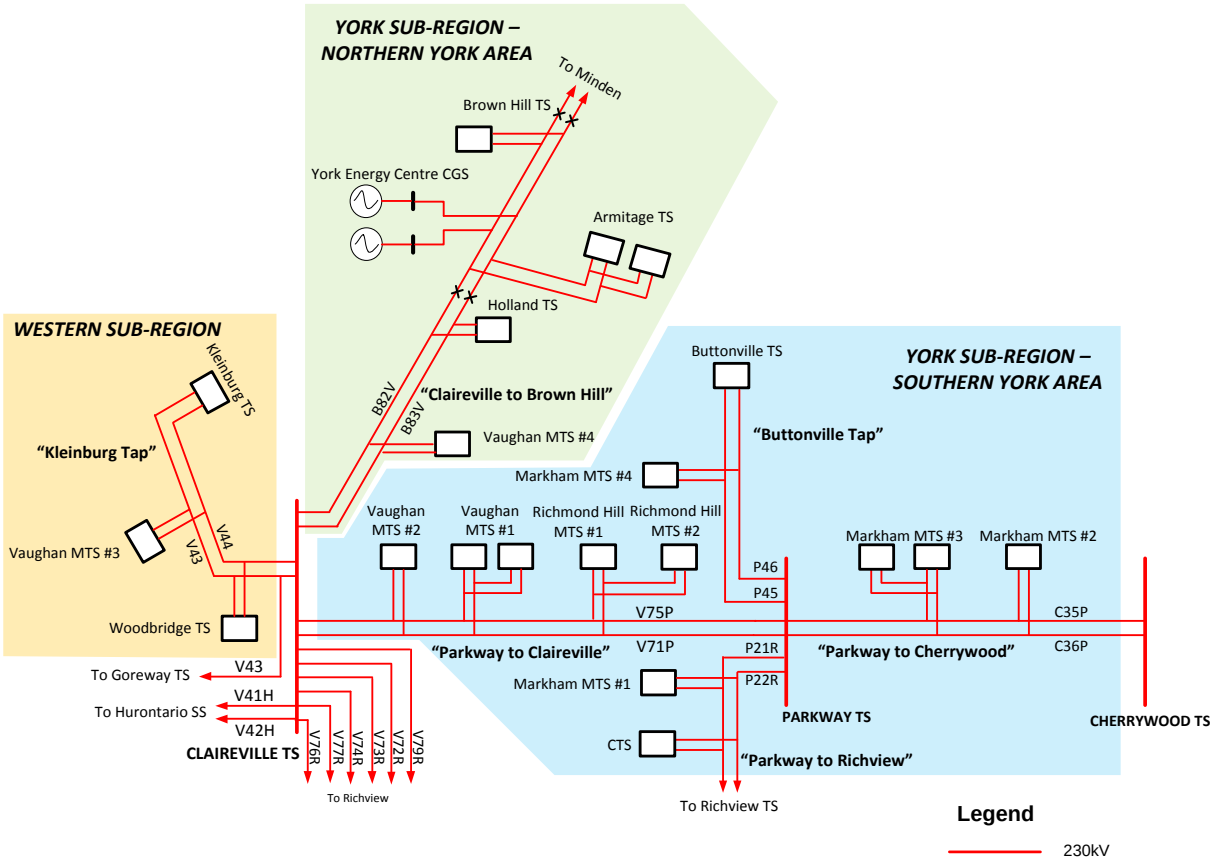

Figure 2: GTA North Transmission Single Line Diagram

5 INPUTS AND DATA

Study Team participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the GTA North Region NA. The information provided includes the following:

- Load Forecast;
- Known capacity and reliability needs, operating issues, and/or major assets approaching the end of their useful life ("EOL"); and,
- Planned/foreseen transmission and distribution investments that are relevant to regional planning for the GTA North Region

6 ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in this Needs Assessment:

Information gathering included:

i. Load forecast: The LDCs provided a load forecast for the region. The IESO provided a simplified Conservation and Demand Management ("CDM") and Distributed Generation ("DG") assumptions to determine their high-level impact on needs in the region. A GTA North Region

extreme summer weather coincident peak gross load forecast was produced by translating the LDC load forecast into load growth rates and applying onto the 2017 actual summer station coincident peak load, adjusted for extreme weather conditions (according to Hydro One's methodology). The CDM and DG assumptions were applied to this gross forecast to produce the net forecast. The extreme summer weather coincident peak net load forecast for the individual stations in the GTA North Region is given in Appendix A. A similar approach was used to develop the GTA North Region extreme summer weather non-coincident peak gross and net load forecast. It should be noted that the actual versus forecasted year to year demand can vary due to factors such as weather, economic development, etc.

ii. Relevant information regarding system reliability and operational issues in the region;

iii. List of major HV transmission equipment planned and/or identified to be refurbished and/or replaced due to the end of their useful life which is relevant for regional planning purposes. This includes HV transformers, autotransformers, HV Breakers, HV underground cables and overhead lines.

Technical assessment of needs was based on:

i. Station capacity and Transmission Adequacy assessment

ii. System reliability and operation assessment

iii. End-of-life equipment: Major high voltage equipment reaching the end of its useful life with respect to replacing it with similar type equipment versus other options to determine the most optimal, resilient, and economic outcome.

Note that the Region is summer peaking so the assessment is based on summer peak loads.

7 NEEDS

This section describes emerging needs that have been identified in the GTA North Region since the previous regional planning cycle and reaffirms the near, mid, and long-term needs already identified in the previous RIP and IRRP. The needs are summarized in Tables 2 and 3 below:

Table 2: New Needs

New Needs	Discussed in Section
End-of-Life Equipment – Woodbridge TS T5 transformer	7.1.1
Load Restoration – P45+P46 ("Buttonville Tap")	7.1.2

Table 3: Needs Identified in Previous RIP and IRRP(1)

Needs Identified in Previous RIP and IRRP	Discussed in Section	RIP Report Section
Load Restoration – V43+V44 ("Kleinburg Tap")	7.2.1	7.3.1
Load Security on V71P/V75P – Parkway to Claireville	7.2.2	7.1.2
Vaughan Transformation Capacity	7.2.3	7.1.3
Markham Transformation Capacity	7.2.4	7.1.4
Station Service Supply to York Energy Centre (YEC)	7.2.5	7.2.1
Northern York Area Transformation Capacity	7.2.6	7.2.2

(1) Includes needs identified in the previous RIP and IRRP that do not have final plans underway yet

7.1 New Needs

7.1.1 End-Of-Life (EOL) Equipment Needs

Hydro One has identified the following major high voltage equipment to be reaching the end of their useful life over the next 10 years. Based on the equipment condition assessment, this asset has been identified to be in poor condition and approaching the end of its useful life.

Table 4: End-of-Life Equipment – GTA North Region

EOL Equipment[(1)]	Replacement Timing[(2)]
Woodbridge TS: T5 Transformer	2022-2023

(1) No other major HV station equipment or lines in the GTA North region have been identified for replacement/refurbishment at this time
(2) The replacement/refurbishment timing and prioritization are subject to change

The end-of-life equipment assessment for the above asset considered the following options:

1. Maintaining the status quo
2. Replacing equipment with similar equipment with *lower* ratings and built to current standards
3. Replacing equipment with similar equipment with *lower* ratings and built to current standards by transferring some load to other existing facilities
4. Eliminating equipment by transferring all of the load to other existing facilities
5. Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement)
6. Replacing equipment with *higher* ratings and built to current standards

Woodbridge TS

Woodbridge TS comprises one DESN unit, T3/T5 (75/125 MVA), with two secondary winding voltages at 44 kV and 28 kV, each with a summer 10-Day LTR of 80 MW. The station's 2017 actual non-coincident summer peak load (adjusted for extreme weather) was 156 MW. Transformer T5 is currently about 45 years old and has been identified to be at its EOL. The companion DESN transformer, T3, is about 29 years old and is not at its EOL. Woodbridge TS supplies both Alectra and THESL.

The 44kV and 28kV load at Woodbridge TS is forecasted to be over 80% and 90% of their respective LTRs in the near and medium term. The closest station is Vaughan MTS #3 (owned by Alectra) and its load is forecasted to be over 95% of its LTR in the medium term. Therefore, downsizing T5 and consolidating load within the station and/or with area stations is not a prudent or viable option given medium term load growth at these stations and based on its historical loading. It is also important to note that the station is configured as a dual secondary yard (230/44-28kV) and the standard lower rated unit has only one secondary. Consequently, replacing T5 with a lower rated unit would result in significant re-configuration of the station and greater cost compared to replacing the EOL transformer with a similar unit of same ratings. Moreover, downsizing capacity today and then later upgrading within the lifetime of the transformer due to eventual load growth will also be significantly more costly. For example it may

cost an additional $5-$10 million for the replacement of the transformer plus the incremental cost for the LDC to reconfigure feeders at a later stage. It should also be noted that maintaining capacity, as opposed to downsizing, is a more resilient option as it provides additional flexibility during emergency conditions through load transfers.

With respect to maintaining status quo, the T5 transformer is in poor condition so this is not an option due to the risk of equipment failure, customer outages, increased maintenance cost, and environmental impact. Upgrading T5 is also not an option since it's already at the maximum size.

Based on the above, the study team recommends that this need be addressed by Hydro One and affected LDCs to coordinate the replacement plan. Hydro One will keep the study team informed of the status of the plan if any major changes occur. The timing of replacement for the EOL equipment is 2022-2023.

7.1.2 Load Restoration – P45+P46 ("Buttonville Tap")

This load restoration need is based on the ORTAC load restoration criteria that requires any load loss exceeding 250 MW to be restorable within 30 minutes. Based on the extreme summer weather coincident peak net load forecast, for the loss of 230kV circuits, P45 and P46 (stations connected are Buttonville TS and Markham #4 MTS), the load interrupted by configuration is expected to exceed 250 MW beginning in 2021 and restoration within 30 minutes needs to be assessed.

It should also be noted that a new station, Markham #5 MTS, is being planned for connection to circuits P45 and P46, with a projected need date in the 2025-2026[1] timeframe and an initial load of 26 MW based on the extreme summer weather coincident peak net load forecast (see Section 7.2.4 for more details). This load should also be taken into account for the load restoration need analysis.

The study team recommends that further assessment and regional coordination in the IRRP and RIP phase is required to review options and identify a preferred restoration plan.

7.2 Needs Identified in Previous RIP and/or IRRP

The following section summarizes the needs identified in the previous 2016 GTA North RIP report and 2015 York Region IRRP that do not have final plans underway yet. The Study Team reaffirms these needs and an update is provided below.

7.2.1 Load Restoration – V43+V44 ("Kleinburg Tap")

The load restoration need for 230 kV radial circuits, V43 and V44 (supplying Woodbridge TS, Vaughan #3 MTS, and Kleinburg TS), was identified during the previous NA for the GTA North Western Sub-Region and also in the Northwest GTA IRRP as load restoration times as per the ORTAC may not be met

[1] The need date will be further refined by Hydro One and Alectra through the project development process. Refer to section 7.2.4 for more details.

for the loss of V43 and V44. The study team recommended that this need be addressed in IESO's GTA West bulk system planning initiative.

The subsequent GTA West bulk system study did not address the restoration need. As a result, the study team recommends that the need be revisited as part of the next GTA North IRRP.

7.2.2 Load Security on V71P/V75P – Parkway to Claireville

In the previous York Region IRRP, the study team recommended the installation of inline switches at the Vaughan MTS #1 junction in order to improve the capability of the system to restore load in the event that both 230 kV circuits V71P/V75P are lost. While the installation of these switches will improve the load restoration capabilities and overall reliability on the Parkway to Claireville corridor, it does not address the load security need on V71P/V75P.

Since the previous GTA North RIP, the IESO completed an addendum to its expedited SIA for the in-line switches at Grainger Junction project. The addendum indicated that an exemption for this project with respect to the 600 MW load security limit would not be required. However, it advised that the load security issue on the Parkway to Claireville corridor must be re-assessed as part of the next regional planning cycle.

The Study Team reassessed the load security issue during this regional planning cycle. Based on the extreme summer weather coincident peak net load forecast, the load on the Parkway to Claireville corridor is around 695 MW, which is lower than the previous RIP forecast (refer to RIP report, Appendix D), however continues to exceed the 600 MW limit. As a result, the study team reaffirms this need and recommends further assessment and regional coordination in the next IRRP and RIP phase to review options and develop a preferred plan.

7.2.3 Vaughan Transformation Capacity

In the previous RIP, the study team recommended that the need for additional transformation capacity in Vaughan, along with associated transmission capacity[2], be further assessed in the next regional planning cycle and to refine the need timing as Alectra advised they were updating their load forecast and the need date may change (for more details, refer to section 7.1.3 of the RIP report). Based on the current extreme summer weather non-coincident peak net load forecast, the need for additional transformation capacity is beyond 2027. If CDM savings are not achieved as forecasted, then the need date can be as early as 2027.

The Study Team reaffirms this need and recommends further assessment and regional coordination in the IRRP and RIP phase to review options and develop a preferred plan.

7.2.4 Markham Transformation Capacity

[2] There are long-term transmission supply needs associated with new transformation capacity

In the previous RIP, the study team recommended to continue the assessment of wires and non-wires options to address the need for additional transformation capacity in the Markham-Richmond Hill area and to refine the need timing. During the RIP, Alectra advised that they were updating their load forecast and the need date may change (for more details, refer to section 7.1.4 of the RIP report). In April 2017, the IESO issued a letter of support to Hydro One Transmission and Alectra to proceed with wires planning for a new 230/27.6kV DESN and the associated distribution and/or transmission lines to connect the new transformer station. In the hand-off letter, the IESO concluded that it is not feasible to rely entirely on distributed energy resources to defer the near-term supply need in the area and that a new station and associated connection lines would be required by 2023 to meet the growth projections in the Markham-Richmond Hill area. Based on the current extreme summer weather non-coincident peak net load forecast, the need for additional transformation capacity is projected to be in the 2025-2026[3] timeframe. If CDM savings are not achieved as forecasted, then the need date can be as early as 2024.

The Study Team reaffirms this need and Hydro One and Alectra are currently in the process of selecting a preferred location to connect to 230 kV circuits P45/P46. Following this, Hydro One will proceed with development and estimate work to meet the need date. Further updates will be included in the next IRRP and RIP.

7.2.5 Station Service Supply to York Energy Centre

In the previous RIP, a need for addressing station service supply to York Energy Centre (currently supplied from Holland TS) in the event of a (i) low-voltage breaker failure at Holland TS or (ii) double circuit 230 kV contingency was identified (for more details, refer to section 7.2.1 of the RIP report). These events can result in an interruption to the station service supply to York Energy Centre and therefore the loss of all generation output until the station service can be restored from the alternate source.

Since the RIP, the IESO completed a System Impact Assessment (SIA) for the new 230 kV in-line breakers at Holland TS and it found that the use of load rejection will no longer be a suitable means to address (i) and (ii) in the near to medium term as the amount of load rejection required to address overloads and voltage collapse will exceed the permissible amount of 150 MW allowed by ORTAC load security criteria.

The Study Team reaffirms this need and recommends further assessment and regional coordination in the IRRP and RIP phase to review options and develop a preferred plan.

7.2.6 Northern York Area Transformation Capacity

In the previous RIP, the study team recommended that the need for additional transformation capacity in the Northern York Area, along with associated transmission capacity[4], be further assessed in the next regional planning cycle (for more details, refer to section 7.2.2 of the RIP report). Based on the current

[3] The need date will be further refined by Hydro One and Alectra through the project development process
[4] There are long-term transmission supply needs associated with new transformation capacity

extreme summer weather non-coincident peak net load forecast, the combined loading on Armitage TS and Holland TS will not exceed their combined summer 10-Day LTR during the study period (combined load is over 97% of its combined LTR in 2027). There is 44 kV transfer capability between these stations on the distribution system so the timing of the need is based on the combined capability of both stations. However, if CDM savings are not achieved as forecasted, then the need date may be as early as 2024.

The Study Team reaffirms this need and recommends further assessment and regional coordination in the IRRP and RIP phase to review options and develop a preferred plan.

8 RECOMMENDATIONS

The Study Team's recommendations to address the needs identified are as follows:

a) Further regional coordination is not required to address the EOL Woodbridge TS T5 transformer (discussed in sections 7.1.1). From a cost, loading, station configuration, and customer connection needs perspective, this asset should not be eliminated or have its capacity reduced. The study team recommends that this EOL need be addressed by Hydro One and affected LDCs to coordinate the replacement plan. Hydro One will keep the study team informed of the status of the plan if any major changes occur.

b) As per the IESO's letter of support in April 2017, Alectra and Hydro One will continue to develop a new 230/27.6kV DESN in the Markham-Richmond Hill area (discussed in section 7.2.4). Further updates will be included in the next IRRP and RIP.

c) Further assessment and regional coordination is required in the IRRP and/or RIP, to develop a preferred plan for the following needs:

- Load Restoration – P45+P46 (discussed in Section 7.1.2)
- Load Restoration – V43+V44 (discussed in Section 7.2.1)
- Load Security on V71P/V75P – Parkway to Claireville (discussed in Section 7.2.2)
- Vaughan Transformation Capacity (discussed in Section 7.2.3)
- Station Service Supply to York Energy Centre (discussed in Section 7.2.5)
- Northern York Area Transformation Capacity (discussed in Section 7.2.6)
- Transmission Supply Capacity in Vaughan and Northern York Area in long term (discussed in sections 7.2.3 and 7.2.6)

The table below summarizes the above recommendations.

Table 5: Summary of Recommendations

Further Regional Coordination Not Required	Further Regional Coordination Required
EOL Station Equipment: • Woodbridge TS: T5	**Load Restoration:** • P45+P46 (Buttonville TS, Markham #4 MTS,

Further Regional Coordination Not Required	Further Regional Coordination Required
IESO Letter of Support: • Markham Transformation Capacity (Markham #5 MTS)	and future Markham #5 MTS) • V43+V44 (Woodbridge TS, Vaughan #3 MTS, and Kleinburg TS) **Load Security:** • V71P/V75P (Parkway to Claireville) **Transformation Capacity:** • Vaughan #5 MTS • Northern York Area **Station Service Supply:** • York Energy Centre **Transmission Supply Capacity (long term)** • Vaughan #5 MTS • Northern York Area

9 REFERENCES

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Appendix A: GTA North Region Load Forecast (2017 to 2027)

Stations Net Coincident Peak Load Forecast (MW)

Station Name	LTR*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Kleinburg TS (28kV)	97	55	51	52	52	52	52	52	52	52	52	51
Kleinburg TS (44kV)	99	87	83	83	84	84	84	85	84	84	84	83
Vaughan MTS #3 (28kV)	153	162	124	140	147	147	146	146	145	144	142	147
Woodbridge TS (44kV)	80	45	46	47	47	47	47	47	47	46	46	45
Woodbridge TS (28kV)	80	85	71	70	69	69	69	70	69	68	68	67
Holland TS (44kV)	168	126	123	128	132	136	137	139	140	141	140	141
Armitage TS (44kV)	317	265	262	266	270	274	278	282	285	287	288	291
Brown Hill TS (44kV)	184	49	47	47	48	48	49	50	50	50	50	50
Richmond Hill MTS (28kV)	254	256	232	229	236	244	243	242	249	254	254	254
Vaughan MTS #1 (28kV)	306	302	257	254	253	270	276	291	289	287	284	294
Vaughan MTS #2 (28kV)	153	113	124	131	139	147	146	146	145	144	142	147
Vaughan MTS #4 (28kV)	153	0	44	52	69	78	110	127	145	144	142	147
Vaughan MTS #5 (28kV)**	153	0	0	0	0	0	0	0	0	0	0	0
Buttonville TS (28kV)	166	126	123	136	136	141	141	140	139	138	137	136
Markham MTS #1 (28kV)	81	78	80	79	78	78	78	77	80	81	81	81
Markham MTS #2 (28kV)	101	114	92	98	97	97	96	96	99	101	101	101
Markham MTS #3 (28kV)	202	154	197	196	194	193	193	192	198	202	202	202
Markham MTS #4 (28kV)	153	70	89	91	104	112	129	146	150	153	153	153
Markham MTS #5 (28kV)	153	0	0	0	0	0	0	0	0	26	86	77

* LTR based on 0.9 power factor

** Based on the non-coincident net forecast, the need date for Vaughan MTS #5 is beyond 2027.

Stations Net Non-Coincident Peak Load Forecast (MW)

Station Name	LTR*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Kleinburg TS (28kV)	97	62	59	59	59	59	59	59	59	59	59	58
Kleinburg TS (44kV)	99	87	83	83	84	84	84	85	84	84	84	83
Vaughan MTS #3 (28kV)	153	162	124	140	147	147	146	146	145	144	142	147
Woodbridge TS (44kV)	80	64	66	68	67	67	67	67	66	66	65	65
Woodbridge TS (28kV)	80	92	77	76	75	75	75	76	75	74	74	73
Holland TS (44kV)	168	132	128	134	138	142	144	145	146	147	147	147
Armitage TS (44kV)	317	295	291	296	300	304	309	313	316	318	319	323
Brown Hill TS (44kV)	184	78	75	75	77	77	78	80	80	80	80	80
Richmond Hill MTS (28kV)	254	256	232	229	236	244	243	242	249	254	254	254
Vaughan MTS #1 (28kV)	306	302	257	254	253	270	276	291	289	287	284	294
Vaughan MTS #2 (28kV)	153	113	124	131	139	147	146	146	145	144	142	147
Vaughan MTS #4 (28kV)	153	0	44	52	69	78	110	127	145	144	142	147
Vaughan MTS #5 (28kV)**	153	0	0	0	0	0	0	0	0	0	0	0
Buttonville TS (28kV)	166	135	132	146	146	152	151	151	150	148	147	145
Markham MTS #1 (28kV)	81	78	80	79	78	78	78	77	80	81	81	81
Markham MTS #2 (28kV)	101	114	92	98	97	97	96	96	99	101	101	101
Markham MTS #3 (28kV)	202	154	197	196	194	193	193	192	198	202	202	202
Markham MTS #4 (28kV)	153	70	89	91	104	112	129	146	150	153	153	153
Markham MTS #5 (28kV)	153	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26	86	77

* LTR based on 0.9 power factor

** Based on the non-coincident net forecast, the need date for Vaughan MTS #5 is beyond 2027.

Appendix B: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DCF	Discounted Cash Flow
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GATR	Guelph Area Transmission Reinforcement
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TPS	Traction Power Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme
YEC	York Energy Centre



Metro Toronto

REGIONAL INFRASTRUCTURE PLAN

January 12, 2016

hydro one

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Prepared by:
Hydro One Networks Inc. (Lead Transmitter)

With support from:

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Veridian Connections Inc.

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DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address electrical supply needs identified in previous planning phases and also any additional needs identified based on new and/or updated information provided by the RIP Working Group.

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Working Group.

Working Group participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the RIP report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the RIP report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the RIP report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE WITH SUPPORT FROM THE WORKING GROUP IN ACCORDANCE TO THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE METRO TORONTO REGION.

The participants of the RIP Working Group included members from the following organizations:

- Enersource Hydro Mississauga
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator ("IESO")
- PowerStream Inc.
- Toronto Hydro-Electric System Limited ("THESL")
- Veridian Connections Inc.
- Hydro One Networks Inc. (Transmission)

This RIP is the final phase of the regional planning process and it follows the completion of the Central Toronto Sub-Region's Integrated Regional Resource Plan ("IRRP") by the IESO in April 2015 and the and Metro Toronto Northern Sub-Region's Needs Assessment ("NA") Study by Hydro One in June 2014.

This RIP provides a consolidated summary of needs and recommended plans for both the Central Toronto Sub-Region and Metro Toronto Northern Sub-Region that make up the Metro Toronto Region.

The Central Toronto IRRP has identified longer term needs beyond 2025. These longer term needs are also reviewed and discussed in this report. However, as the need dates are beyond 2025, adequate time is available to develop a preferred alternative in the next planning cycle expected to be started in 2018.

The major infrastructure investments planned for the Metro Toronto Region over the near and mid-term, identified in the various phases of the regional planning process, are given in the Table below.

No.	Project	I/S date	Cost ($M)
1	Manby Autotransformer Overload Protection Scheme	2018	$2
2	Runnymede TS Expansion & Manby x Wiltshire Corridor Upgrade	2019	$90
3	Horner TS Expansion	2020	$53
4	Richview x Manby Corridor Upgrade	2020	$20-40
5	Copeland MTS Phase 2	2020+	$46

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. As mentioned above, the next planning cycle is expected to be started in 2018. However, the Region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the regional planning cycle will be started earlier to address the need.

TABLE OF CONTENTS

Disclaimer 5
Executive Summary 7
Table of Contents 9
List of Figures 11
List of Tables 11
1. Introduction 13
    1.1 Scope and Objectives 14
    1.2 Structure 14
2. Regional Planning Process 15
    2.1 Overview 15
    2.2 Regional Planning Process 15
    2.3 RIP Methodology 18
3. Regional Characteristics 19
    3.1 Central Toronto Sub-Region 19
    3.2 Metro Toronto Northern Sub-Region 20
4. Transmission Facilities Completed and/or Underway over the Last Ten Years 23
5. Forecast and Other Study Assumptions 24
    5.1 Load Forecast 24
    5.2 Other Study Assumptions 26
6. Adequacy of Existing Facilities 27
    6.1 Metro Toronto Northern Sub-Region 29
        6.1.1 230kV Transmission Facilities 29
        6.1.2 Step-Down Transformer Station Facilities 29
    6.2 Central Toronto Sub-Region 30
        6.2.1 230kV Transmission Facilities 30
        6.2.2 115kV Transmission Facilities 30
        6.2.3 Step-Down Transformer Facilities 31
7. Regional Needs and Plans 33
    7.1 West Toronto Area 33
        7.1.1 Station Capacity - Runnymede TS & Fairbank TS 33
        7.1.2 Line Capacity - Manby TS x Wiltshire TS 115kV circuits 33
        7.1.3 Recommended Plan and Current Status 34
    7.2 Southwest Toronto Area 35
        7.2.1 Station Capacity – Southwest Toronto (Manby TS & Horner TS) 35
        7.2.2 Recommended Plan and Current Status 35
    7.3 Downtown District 36
        7.3.1 Station Capacity – JETC Area 36
        7.3.2 Recommended Plan and Current Status 37
    7.4 Transmission Line Capacity – 230 kV Richview TS to Manby TS Corridor 38
        7.4.1 Description 38
        7.4.2 Alternatives Considered 39
        7.4.3 Recommended Plan and Current Status 40

7.5 Transmission Line Capacity – Circuit C10A (Duffin Jct. to Agincourt Jct) 40
7.6 Breaker Failure at Manby TS 41
7.6.1 Description 41
7.6.2 Recommended Plan and Current Status 41
7.7 Breaker Failure at Leaside TS 41
7.8 Cherrywood to Leaside (CxL) Double Circuit Contingencies 42
7.9 Load Restoration – Northern Sub-Region (Bathurst TS, Fairchild TS, Leslie TS) 42
7.10 Long Term Needs 43
- Transmission Line Capacity – 115 kV Manby West To Riverside Junction 43
- Transformation Capacity – 230/115 kV Manby TS 43
- Transformation Capacity – 230/115 kV Leaside TS 43
- Leaside TS x Wiltshire TS 115kV circuits 43

8. Conclusions and Next Steps 44
9. References 46
Appendix A. Stations in the Metro Toronto Region 47
Appendix B. Transmission Lines in the Metro Toronto Region 50
Appendix C. Distributors in the Metro Toronto Region 51
Appendix D. Metro Toronto Regional Load Forecast (2015-2035) 53
Appendix E. List of Acronyms 55

LIST OF FIGURES

Figure 1-1 Map of Metro Toronto Region 13
Figure 2-1 Regional Planning Process Flowchart 17
Figure 2-2 RIP Methodology 18
Figure 3-1 Metro Toronto Region – Supply Areas 21
Figure 3-2 Metro Toronto Region – Single Line Diagram 22
Figure 5-1 Metro Toronto Region Summer Extreme Weather Peak Forecast 24
Figure 5-2 Effect of Metrolinx Electrification on the Metro Toronto Region Summer Peak Load 25
Figure 7-1 West Toronto Area - Fairbank TS and Runnymede TS 34
Figure 7-2 Horner TS and Manby TS Supply Area 35
Figure 7-3 Toronto Downtown Supply Area 36
Figure 7-4 Richview x Manby Supply Area Map 38

LIST OF TABLES

Table 6-1 Needs identified in Previous Stages of the Regional Planning Process 28
Table 6-2 Adequacy of 230kV Transmission Facilities 30
Table 6-3 Overloaded Sections of 115kV circuits 31
Table 6-4 Adequacy of Step-Down Transformer Stations - Areas Requiring Relief 32
Table 7-1 Manby x Wiltshire Corridor Capability 33
Table 7-2 Coincident RIP MW Load Forecast for Richview TS x Manby TS Area 39
Table 7-3 Maximum Load Loss during Two Circuit Contingencies 42
Table 8-1 Regional Plans – Needs Identified in the Regional Planning Process 44
Table 8-2 Regional Plans – Next Steps, Lead Responsibility and Plan In-Service Dates 44

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE METRO TORONTO REGION.

The report was prepared by Hydro One Networks Inc. ("Hydro One") on behalf of the Working Group that consists of Hydro One, Enersource Hydro Mississauga, Hydro One Networks Inc. Distribution, the Independent Electricity System Operator ("IESO"), PowerStream Inc., Toronto Hydro-Electric System ("THESL"), and Veridian Connections Inc. in accordance with the new Regional Planning process established by the Ontario Energy Board in 2013.

The Metro Toronto Region is comprised of the City of Toronto. Electrical supply to the Region is provided by thirty five 230kV and 115kV transmission and step-down stations as shown in Figure 1-1. The eastern, northern and western parts of the Region are supplied by eighteen 230/27.6kV step-down transformer stations. The central area is supplied by two 230/115kV autotransformer stations (Leaside TS and Manby TS) and fifteen 115/13.8kV and two 115/27.6kV step-down transformer stations. The summer 2015 area load of the Metro Toronto region was about 4700MW.

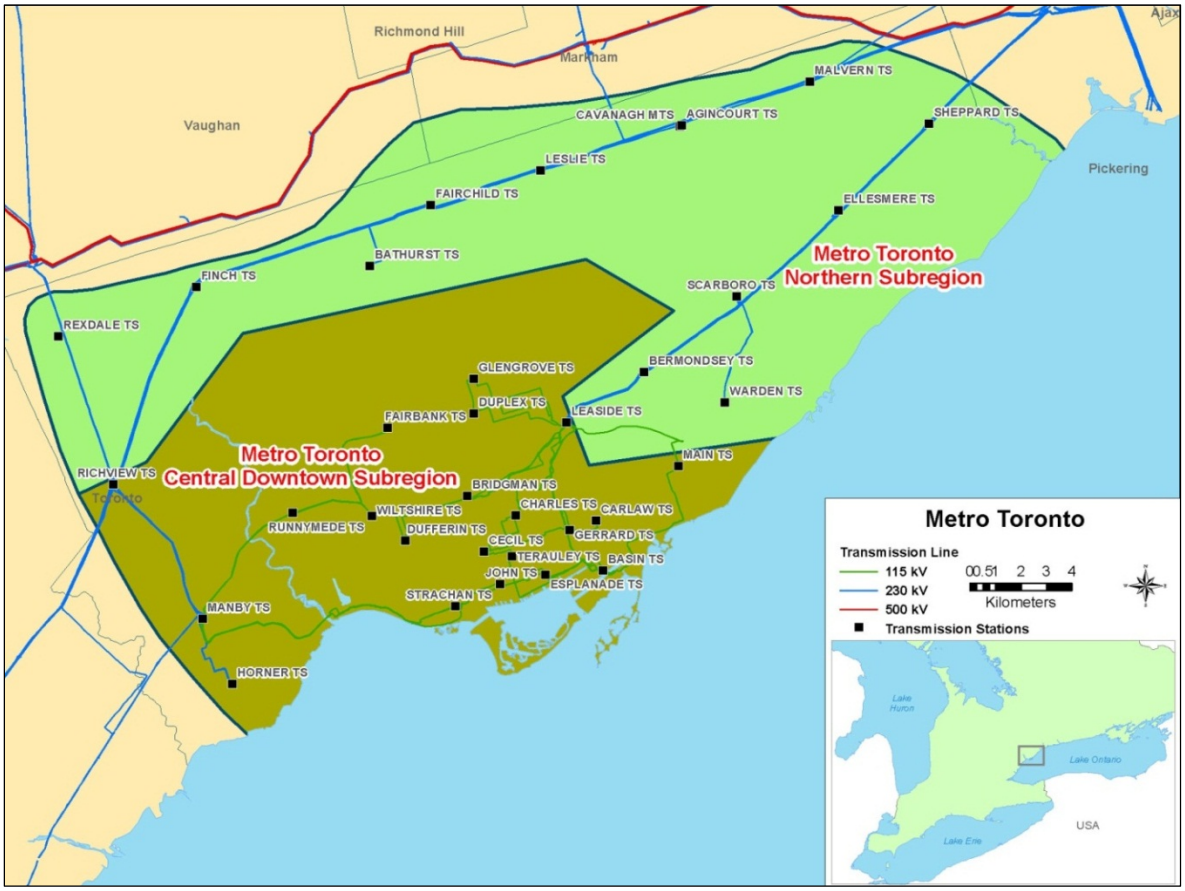

Figure 1-1 Map of Metro Toronto Region

1.1 Scope and Objectives

This RIP report examines the needs in the Metro Toronto Region. Its objectives are to:

- Identify new supply needs that may have emerged since previous planning phases (e.g., Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan);
- Assess and develop a wires plan to address these needs;
- Provide the status of wires planning currently underway or completed for specific needs;
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviews factors such as the load forecast, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management ("CDM"), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs (2015-2025) identified in previous planning phases (Needs Assessment, Local Plan or Integrated Regional Resource Plan);
- Identification of any new needs over the 2015-2025 period and a wires plan to address these needs based on new and/or updated information;
- Develop a plan to address any longer term needs identified by the Working Group.

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process;
- Section 3 describes the region;
- Section 4 describes the transmission work completed over the last ten years;
- Section 5 describes the load forecast used in this assessment;
- Section 6 describes the results of the adequacy assessment of the transmission facilities and identifies the needs;
- Section 7 discusses the needs and provides the alternatives and preferred solutions;
- Section 8 provides the conclusion and next steps.

2. REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at essentially three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment [1] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend

[1] Also referred to as Needs Screening.

a preferred wires solution. Similarly, resource options which the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee (LAC) in the region or sub-region. For the Metro Toronto Region, community engagement through a formal LAC is on-going.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timelines provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect;
- The NA, SA, and LP phases of regional planning;
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region.

Figure 2-1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

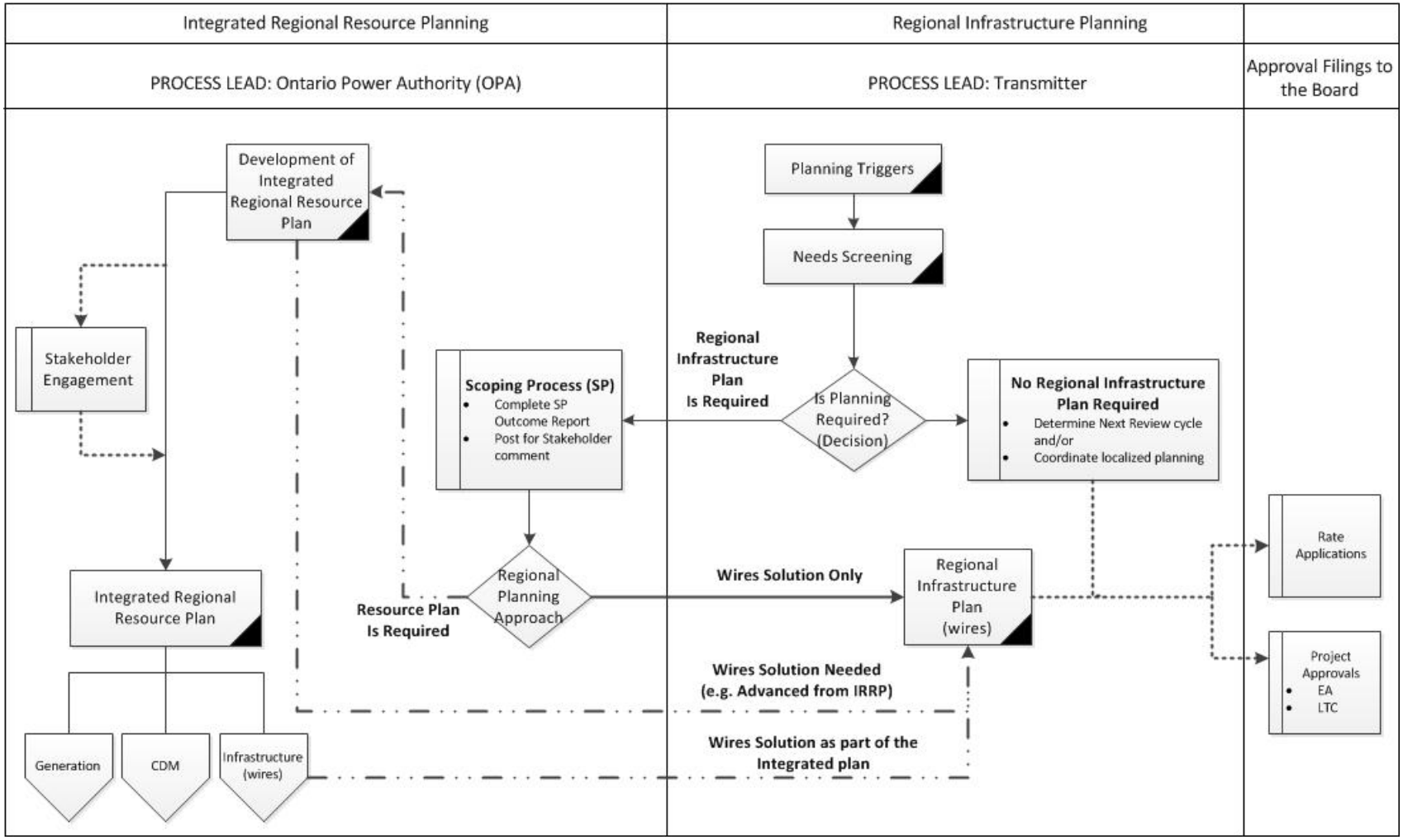

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of four steps (see Figure 2-2) as follows:

1) Data Gathering: The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2) Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.
3) Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4) Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

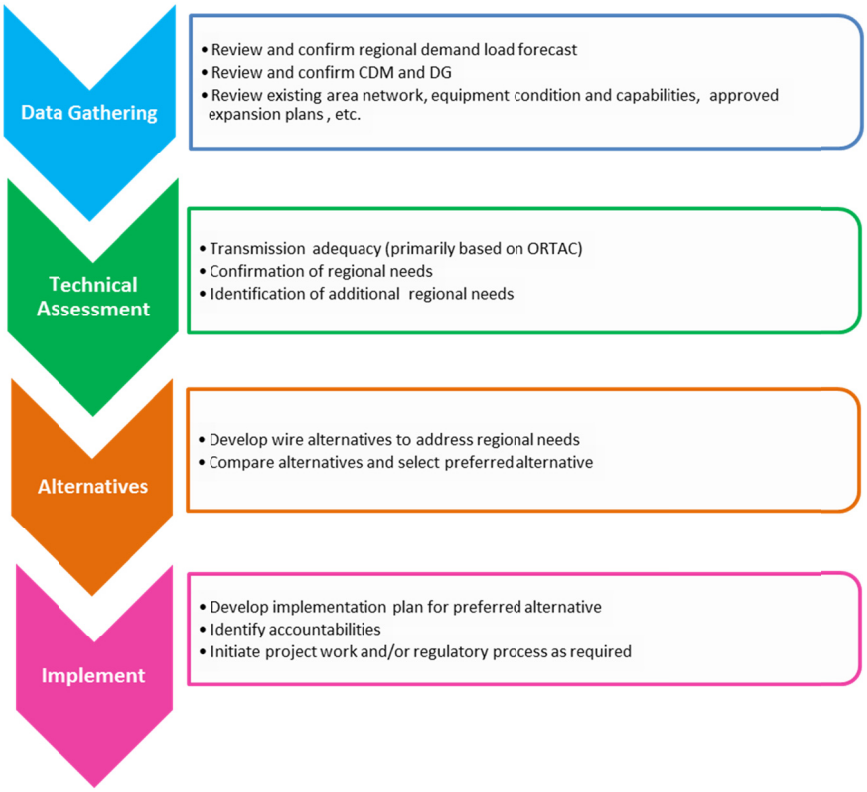

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE METRO TORONTO REGION INCLUDES THE AREA ROUGHLY BORDERED GEOGRAPHICALLY BY LAKE ONTARIO ON THE SOUTH, STEELES AVENUE ON THE NORTH, HIGHWAY 427 ON THE WEST AND REGIONAL ROAD 30 ON THE EAST. IT CONSISTS OF THE CITY OF TORONTO, WHICH IS THE LARGEST CITY IN CANADA AND THE FOURTH LARGEST IN NORTH AMERICA.

Bulk electrical supply to the Metro Toronto Region is provided through three 500/230 kV transformers stations - Claireville TS, Cherrywood TS and Parkway TS and a network of 230 kV and 115 kV transmission lines and step-down transformation facilities. Local generation in the area consists of the 550 MW Portlands Energy Centre located near downtown area and connected to the 115 kV network at Hearn Switching Station. The Metro Toronto Region 2015 peak summer demand was about 4700MW which represents about 20% of the gross electrical demand in the province.

Toronto Hydro-Electric System Limited ("THESL") is the Local Distribution Company ("LDC") that serves the electricity demands for the city of Toronto. Other LDCs supplied from electrical facilities in the Metro Toronto Region are Hydro One Networks Inc. Distribution, PowerStream Inc., Veridian Connections Inc., and Enersource Hydro Mississauga. The LDCs receive power at the step down transformer stations and distribute it to the end users – industrial, commercial and residential customers.

The April 2015 Integrated Regional Integrated Regional Resource Plan ("IRRP") report, prepared by the IESO in conjunction with Hydro One and the LDC, focused on the Central Toronto Area which included the 115kV network and the 230kV facilities in the western part of Region. The June 2014 Metro Toronto Northern Sub-Region Needs Assessment report, prepared by Hydro One, considered the remainder of the Metro Toronto region. A map and a single line diagram showing the electrical facilities of the Metro Toronto Region, consisting of the two sub-regions, is shown in Figure 3-1 and Figure 3-2 respectively. Please note that the facilities shown include the new Leaside TS to Bridgman TS 115kV circuit L18W and the new Copeland MTS. The L18W circuit is being built as part of the Midtown Transmission Reinforcement Project and Copeland MTS is a new THESL owned transformer station to serve the downtown area. Work on these projects is in the advanced stage and both are expected to come into service in 2016.

3.1 Central Toronto Sub-Region

The Central Toronto Sub-Region includes the area extending northward from Lake Ontario to roughly Highway 401, westward to Highway 427 and Etobicoke Creek, and eastward to Victoria Park Avenue.

The Central Toronto Sub-Region was identified as a "transitional" region, as planning activities in the region were already underway before the new regional planning process was introduced. The NA and SA phases were deemed to be complete, and the regional planning process was considered to be in the IRRP phase. An IRRP for the region was completed in April 2015.

The Central Toronto Sub-region is further subdivided into two areas:

- The Richview Manby 230kV area: This includes the former borough of Etobicoke and is served by the Richview TS to Manby TS 230kV circuits. The area has two 230/27.6kV step-down transformer stations. The coincident peak summer 2015 area load was about 320 MW.
  The Richview TS to Manby 230kV circuits together with the Richview TS to Cooksville TS circuit R24C supply a number of stations in the GTA West Southern Sub-Region. These stations while outside the Metro Toronto Region have therefore been included in Figure 3-2.

- The Central 115kV Area: The central area is supplied by two 230/115kV autotransformer stations (Leaside TS and Manby TS), fifteen 115/13.8kV and two 115/27.6kV step-down transformer stations. The area includes the downtown core including the financial, entertainment and educational districts. The 2015 summer coincident area load was about 1900MW.

Please see Figure 3-1 and 3-2 for a map and single line diagram of the Sub-Region facilities.

3.2 Metro Toronto Northern Sub-Region

The Metro Toronto Northern Sub-Region comprises the remainder of the Metro Toronto region. It includes the area roughly bordered geographically by Highway 401 on the south, Steeles Avenue on the north, Highway 427 on the west and Regional Road 30 on the east in addition to the area east of the Don Valley Parkway and north of O'Connor Dr.

Electrical supply to the Metro Toronto Northern Sub-Region is provided through 230 kV transmission lines and step-down transformation facilities. Supply to this sub-region is provided from a 230 kV transmission system consisting of the Richview TS to Parkway TS, the Richview TS to Cherrywood TS, the Richview TS to Claireville TS, as well as the Cherrywood TS to Leaside TS 230kV transmission system. The area is served primarily at 27.6kV by fifteen step-down transformer stations with a pocket of 13.8kV load supplied from Leaside TS and Leslie TS. The 2015 summer coincident area load was about 2500 MW.

Please see Figure 3-1 and 3-2 for a map and single line diagram of the Sub-Region facilities.

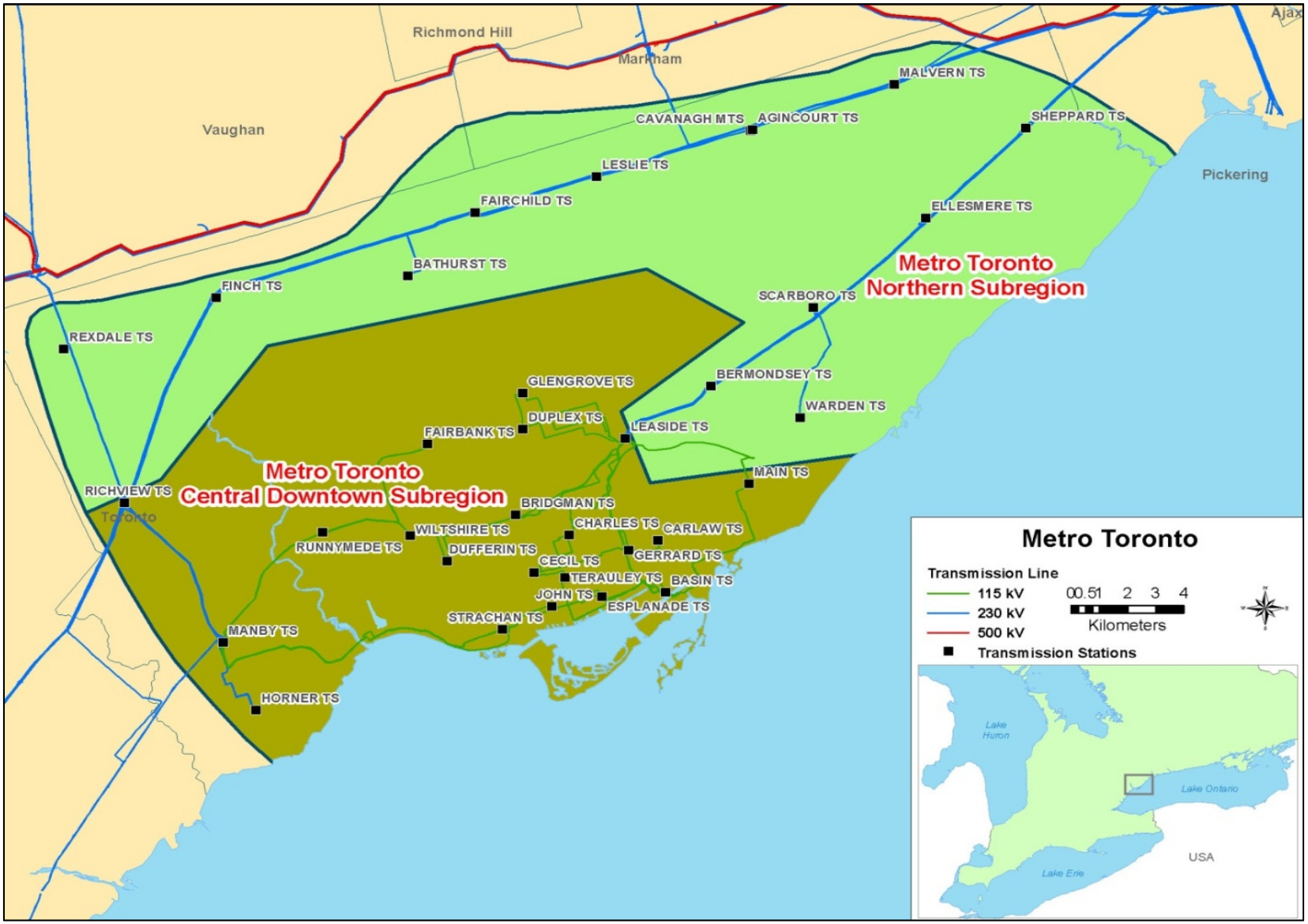

Figure 3-1 Metro Toronto Region – Supply Areas

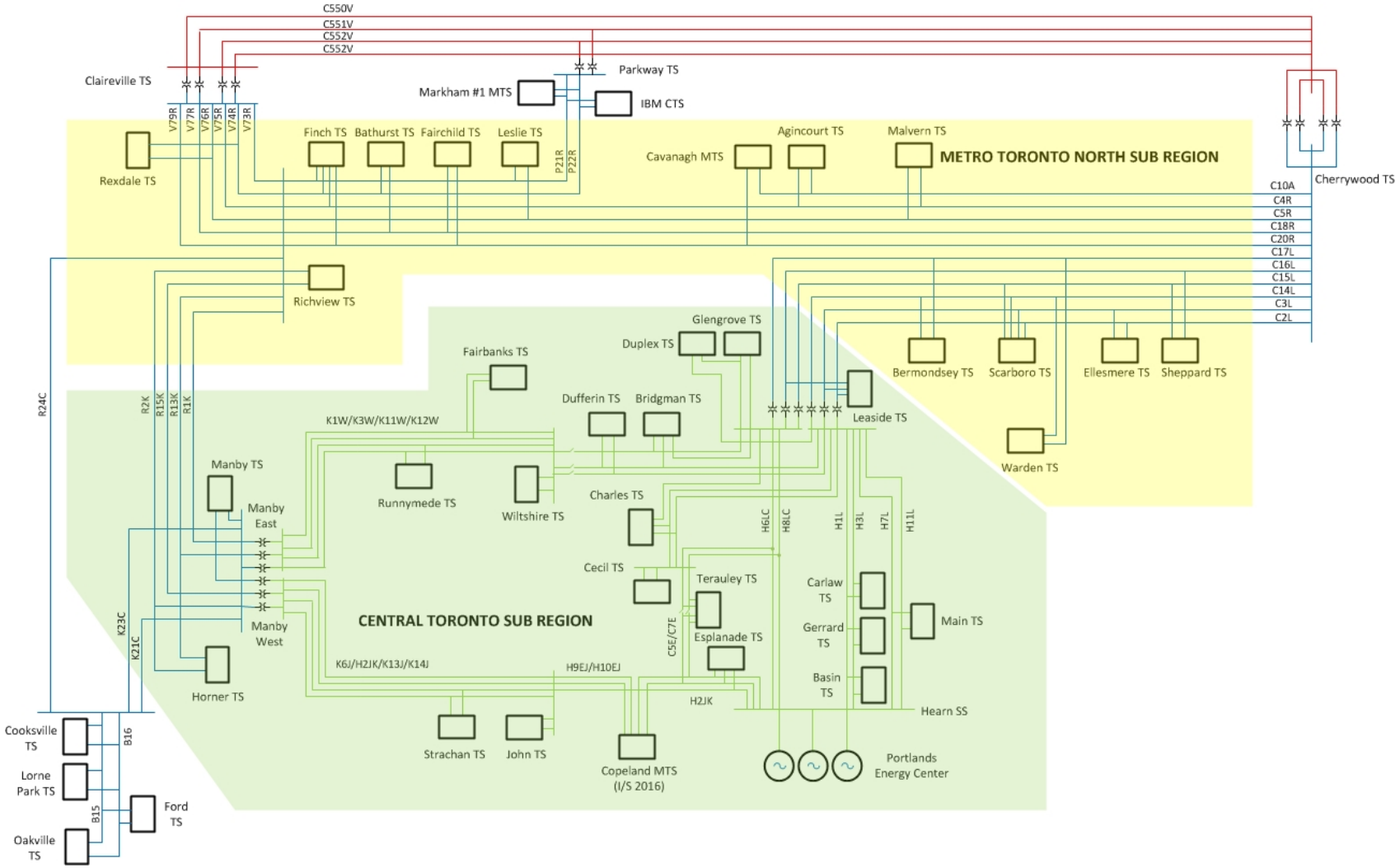

Figure 3-2 Metro Toronto Region – Single Line Diagram

4. TRANSMISSION FACILITIES COMPLETED AND/OR UNDERWAY OVER THE LAST TEN YEARS

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND COMPLETED BY HYDRO ONE, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY TO THE METRO TORONTO REGION IN GENERAL AND THE TORONTO 115 KV NETWORK IN PARTICULAR.

These projects together with the new 550 MW Portlands Energy Centre that went into service in 2009 have ensured that the City continues to receive adequate and reliable supply. A brief listing of these projects is given below:

- Parkway 500/230 kV TS (2005) – built to provide adequate 500/230 kV transformation capacity following the retirement of Lakeview GS. The station while just outside the Metro Toronto Region is a key contributor in ensuring supply adequacy to the Region.

- John TS to Esplanade TS underground cable circuits (2008) – built to provide transfer capability between the Leaside TS and the Manby TS 115 kV areas.

- Incorporation of the 550 MW Portlands Energy Centre (2009) – covered modification to the Hearn 115kV switchyard to connect the new generation.

- 115 kV Switchyard Work at Hearn SS, Leaside TS & Manby TS (2013 & 2014) – covered replacement of the aging 115 kV switchyard at Hearn SS with a new GIS switchyard and replacement of all 115 kV breakers at Leaside TS and Manby TS.

- Manby 230 kV Reconfiguration (2014) – re-tapped Horner TS from the circuit R15K to R13K at Manby TS to balance / improve the distribution of loading on the 230 kV Richview TS to Manby TS system.

- Lakeshore Cable Refurbishment project (2015) – covered replacement of the aging K6J/H2JK 115 kV circuits between Riverside Jct. and Strachan TS.

- Midtown Transmission Reinforcement Project (expected completion by 2016) – covered replacement of the aging L14W underground cable and building an additional fourth 115 kV circuit between Leaside TS and Bridgman TS.

- Clare R. Copeland 115kV switching station (expected completion by 2016) – built to connect a new THESL owned 115/13.8 kV step-down transformer station in the downtown district.

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the Metro Toronto Region is forecast to increase at an average rate of approximately 0.9% annually up to 2020, at 0.67% between 2020 and 2025 and at 0.61% beyond 2025. The growth rate varies across the region – from about 0.35% in the Northern Sub-Region to 1.07% in the City's downtown area over the 20 years.

Figure 5-1 shows the Metro Toronto Region's planning load forecast (summer net, non-coincident and regional-coincident extreme weather peak) under the IRRP high growth scenario. The regional-coincident (at the same time) forecast represents the total peak load of the 35 step-down transformer stations in the Metro Toronto. The coincident regional peak load is forecast to increase from 5176 MW in 2015 to 6196 MW by 2035.

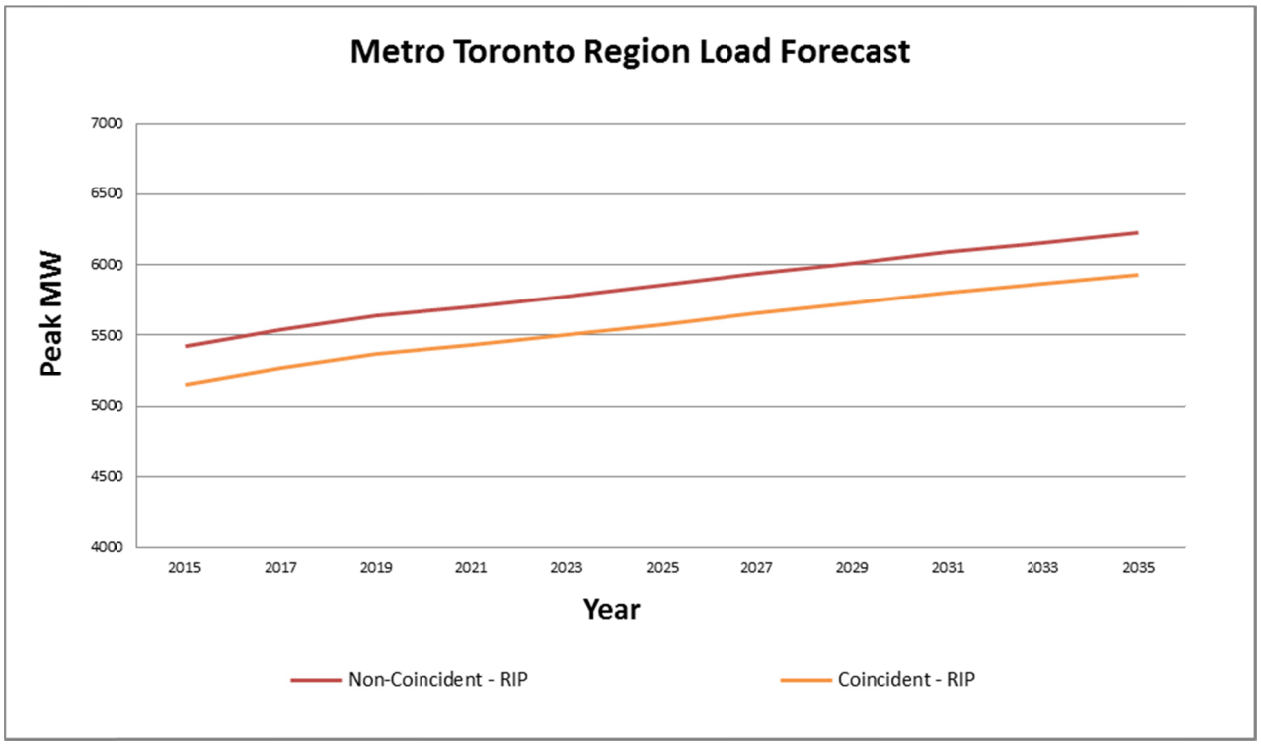

Figure 5-1 Metro Toronto Region Summer Extreme Weather Peak Forecast

The coincident and non-coincident extreme weather peak load forecast for the individual stations in the Metro Toronto Region is given in Appendix D. The coincident forecast represents the sum of the area stations peak load at the time of Metro Toronto Region peak demand and represents loads that would be seen by transmission lines and autotransformer stations and is used to determine the need for additional line and auto-transformation capacity. The non-coincident forecast represents the sum of the individual stations peak load and is used to determine the need for station capacity.

The individual station forecasts were developed by projecting 2015 summer peak loads, corrected for extreme weather, using the area stations growth rates as per the 2015 IESO's IRRP study (High Demand Scenario) for the Central Toronto Sub-Region [1] and as per the 2014 Hydro One's Need Assessment study [2] for the Metro Toronto Northern Sub-Region. The growth rates from [1] only account for existing Distributed Generation ("DG"), and do not include any new CDM and DG. The growth rates from [2] are the net growth rates seen by station equipment and account for CDM measures and connected DG. Details on the CDM and connected DG are provided in [1] and [2] and are not repeated here.

Impact of Metrolinx Go Transit Electrification

In June 2015, Metrolinx advised Hydro One that they are planning to proceed with the electrification of the Go transit rail system. This information was provided after the IRRP was completed in April 2015. Under their plan three Traction Power Stations (TPS) are proposed to be built in the Metro Toronto Region. These stations are as follows:

- Mimico TPS – For the Lakeshore West Go Transit Line (2020)
- Cityview TPS – For the Pearson Airport and Kitchener Go Transit lines (2020)
- Warden TPS – For the Lakeshore East Go Transit Line (2020)

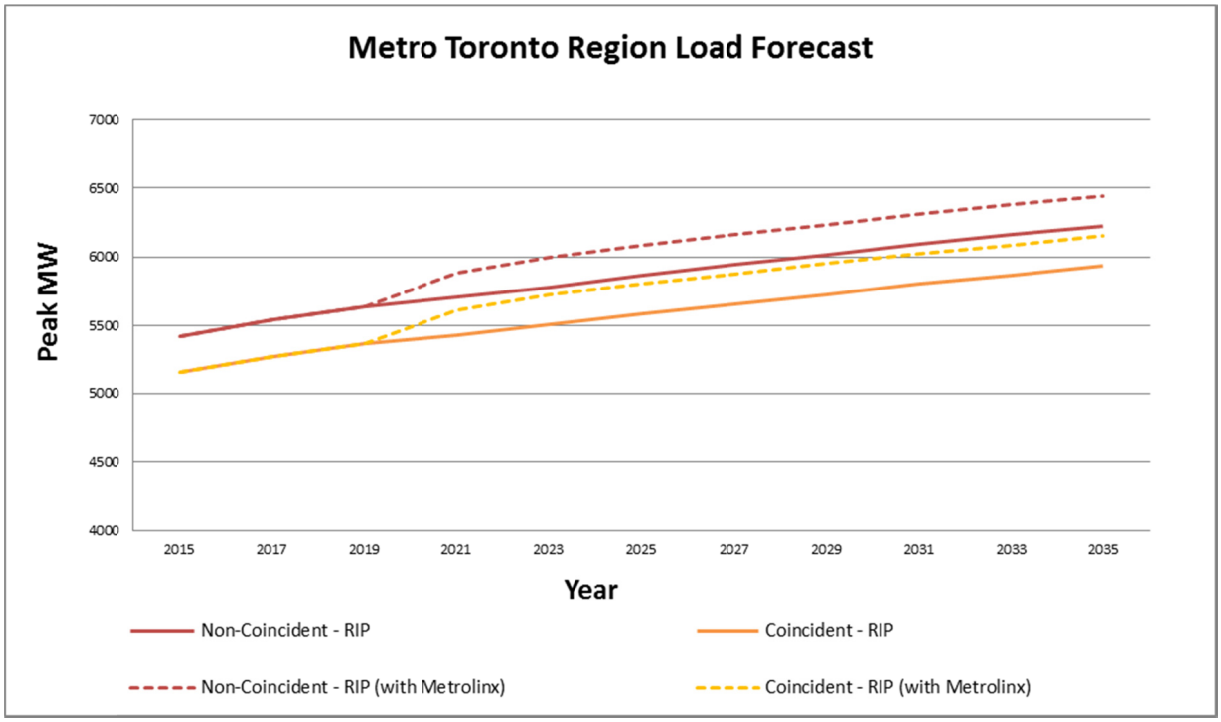

Figure 5-2 Effect of Metrolinx Electrification on the Metro Toronto Region Summer Peak Load

The impact of the Metrolinx load on the regional forecast is shown in Figure 5-2. Each of the three Metro area stations is expected to have an initial load of 40MW increasing to 80MW in 4 years. The net result is to increase the Region peak load by 240MW.

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP Assessments is 2015-2035.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low voltage capacitor banks. Normal planning supply capacity for transformer stations in this Sub-Region is determined by the summer 10-Day Limited Time Rating (LTR).
- For THESL 13.8kV stations, an additional 95% factor is applied to the normal planning supply capacity in this study. This is to reflect the fact that all the capacity cannot be effectively utilized due to the large relative size of the individual customer loads.

6. ADEQUACY OF EXISTING FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND DELIVERY STATION FACILITIES SUPPLYING THE METRO TORONTO REGION OVER THE 2015-2035 PERIOD. IT ASSUMES THAT ALL PROJECTS CURRENTLY UNDER WAY ARE IN SERVICE.

Within the current regional planning cycle two regional assessments have been conducted for the Metro Toronto Region. The findings of these studies are input to the RIP. The studies are:

1) IESO's Central Toronto Integrated Regional Resource Plan – dated April 28, 2015[1]
2) Hydro One's Needs Assessment Report – Metro Toronto – Northern Sub-Region – June 11, 2014[2]

The IRRP and NA planning assessments identified a number of regional needs to meet the area forecast load demands. These regional needs are summarized in Table 6-1 and include needs for which work is already underway and/or being addressed by a LP study. A detailed description and status of work initiated or planned to meet these needs is given in Section 7.

A review of the loading on the transmission lines and stations in the Metro Toronto Region was also carried out as part of the RIP report using the latest Regional Forecast based on the IRRP high load growth scenario and as given in Section 5. The impact of Metrolinx Electrification on the regional infrastructure has been included.

For cases where a need was identified in the near or mid-term by the high growth scenario, a sensitivity analysis was done using the IRRP low growth scenario to get a range on the need date. Sections 6.1 to 6.2 present the results of this review. Additional needs identified as a result of the review are also listed in Table 6-1.

Table 6-1 Needs identified in Previous Stages of the Regional Planning Process

Type	Section	Needs	Timing
Station Capacity	7.1	West Toronto (Runnymede TS & Fairbank TS)	Today
	7.2	Southwest Toronto (Manby TS & Horner TS)	2020-2027
	7.3	Downtown District (JETC[1] Area)	2020+[2]
Transmission Line Capacity	7.4	230 kV Richview TS to Manby TS Corridor	2020-2023
	7.5	Circuit C10A (Duffin Jct. to Agincourt Jct.)	Completed
Supply Security, Reliability and Restoration	7.6	Breaker failure contingencies at Manby W and Manby E TS	2018/2021
	7.7	Breaker failure contingency at Leaside TS	Today
	7.8	Double circuit contingencies C2L/C3L or C16L/C17L (Cherrywood TS to Leaside TS)	2021
	7.9	Load Restoration – Northern Sub-Region (Bathurst TS, Fairchild TS, Leslie TS)	Today
Long-Term	7.10	115 kV Manby West To Riverside Jct. Lines	2035+
		230/115 kV Manby TS transformer capacity	2035+
		230/115 kV Leaside TS transformer capacity	2026+
Additional Long-Term Need Identified in RIP	7.10	Leaside TS x Wiltshire TS circuits	2034

[1] JETC denotes John TS, Esplanade TS, Terauley TS, and Copeland MTS which jointly supply the Downtown District.

[2] The need date will be around 2027 based on the station capacity consideration alone for the Downtown District stations. However, a need date of 2020+ was established by the WG based upon other considerations, such as requirements for spare feeder position. More details are given in Section 7.3.

6.1 Metro Toronto Northern Sub-Region

6.1.1 230kV Transmission Facilities

The Northern 230kV facilities consist of the following 230kV transmission circuits (Please refer to Figure 3-2):

a) Claireville TS to Richview TS 230kV circuits: V72R, V73R, V74R, V76R, V77R and V79R.
b) Cherrywood TS to Richview TS 230kV circuits: C4R, C5R, C18R and C20R.
c) Parkway TS to Richview 230kV circuits: P21R and P22R
d) Cherrywood TS to Agincourt TS 230kV circuit C10A.
e) Cherrywood TS to Leaside TS 230kV circuits: C2L, C3L C14L, C15L, C16L and C17L.

The Claireville TS to Richview TS circuits, the Cherrywood TS to Richview TS circuits and the Parkway TS circuits to Richview TS circuits carry bulk transmission flows as well as serve local area station loads within the Sub-Region. These circuits are adequate over the study period.

The Cherrywood TS to Agincourt TS circuit C10A is a radial circuit that supplies Agincourt TS and Cavanagh TS. The Need Assessment for the Metro Toronto Northern Sub-Region had identified that line capacity was restricted due to inadequate clearance from underbuilt street lighting and distribution line. Field surveys carried out by Hydro One have confirmed that the limiting underbuilds have been removed. The circuit is adequate over the study period.

The Cherrywood TS to Leaside TS 230kV circuits supply the Leaside TS 230/115kV autotransformers as well as serve local area load. Loading on these circuits is adequate over the study period.

6.1.2 Step-Down Transformer Station Facilities

The Sub-Region has the following step down transformer stations:

Agincourt TS	Leaside TS
Bathurst TS	Leslie TS
Bermondsey TS	Malvern TS
Cavanagh MTS	Rexdale TS
Ellesmere TS	Scarboro TS
Fairchild TS	Sheppard TS
Finch TS	Warden TS

The Metro Toronto Northern Sub-Region Needs Assessment Report had identified that the gross load was approaching station capacity at Cavanagh MTS and the Leslie TS (T1/T2, 27.6kV windings) and the Sheppard TS (T3/T4) DESN units. No action was recommended as the net load after considering the CDM and DG program is within ratings. The RIP report has reviewed the station loading and confirms that station capacity is adequate over the study period. However, the station loads will be monitored to ensure facility ratings are not exceeded.

6.2 Central Toronto Sub-Region

6.2.1 230kV Transmission Facilities

The 230kV transmission facilities in the Central Toronto Sub-Region are as follows (Please refer to Figure 3-2):

a) Richview TS x Manby TS 230kV circuits: R1K, R2K, R13K and R15K
b) Cooksville TS x Manby TS 230kV circuits: K21C/K23C
c) Manby TS 230/115kV autotransformers
d) Leaside TS 230kV/115kV autotransformers

The Richview TS to Manby TS circuits and the Cooksville TS to Manby TS circuits supply the Manby 230/115kV autotransformer station as well as Horner TS. Please note that the K21C and K23C circuits connect back to Richview TS through Cooksville TS and 230kV circuit R24C.

Table 6-2 summarizes the result of adequacy studies and gives the need date for transmission reinforcement for each of the above facilities.

Table 6-2 Adequacy of 230kV Transmission Facilities

Facilities	2015 MW Load(1)	MW Load Meeting Capability (LMC)	Limiting Contingency	Need Date
Richview x Manby 230kV Corridor	1456	1540	R2K	2020-2023(2)
Manby E. 230/115kV autos	330	560	T2	2035+
Manby W. 230/115kV autos	397	612	T9	2035+
Leaside 230/115kV autos + Portlands GS(1)	1340	1525-1915(3)	None	2026+(4)

(1) The loads shown have been adjusted for extreme weather.

(2) The 2020 and 2023 need dates correspond to the high growth and low growth rate scenarios without considering Metrolinx Mimico TPS. Assuming Metrolinx Mimico TPS comes into service in 2020, the need date will become 2020 under both scenarios.

(3) The Leaside 115kV area is supplied by the Leaside TS 230/115kV autotransformers and the 550MW Portlands GS. Load Meeting capability is dependent on the generation from Portlands GS which backs up the flow through the Leaside autotransformers. The 1525MW LMC assumes only 160MW generation at Portland GS while the 1915MW LMC assumes the full 550MW generation at Portland GS.

(4) The need date is based on the 1525MW LMC which assumes that two of the three units are out at Portlands GS and total plant generation is 160MW.

6.2.2 115kV Transmission Facilities

The 115kV facilities in the Metro Toronto Region (see Figure 3-2) can be divided into five main corridors:

1. Manby TS East x Wiltshire TS – Four circuits K1W, K3W, K11, K12W. Forecast loading can exceed corridor rating under certain conditions. More details are provided in Section 7.1.2.
2. Manby TS West x John TS – Four circuits H2JK, K6J, K13J and K14J. These circuits are adequate over the study period.
3. Leaside TS x Hearn TS – Six circuits H6LC, H8LC, H1L, H3L, H7L and H11L. These circuits are expected to be adequate over the study period. .
4. Leaside TS x Cecil TS – Three circuits L4C, L9C, and L12C. These are expected to be adequate over the study period.
5. Leaside TS x Wiltshire TS – Four circuits L13W/L14W/L15/L18W. The L18W circuit is expected to go into service in summer 2016. Loading will exceed corridor rating by 2034 for loss of the L18W circuit. More details are provided in Section 7.10.4.

The loading on the limiting sections is summarized in Table 6-3.

Table 6-3 Overloaded Sections of 115kV circuits

Facilities	2015 MW Load	MW Load Meeting Capability	Limiting Contingency	Need Date
Manby TS x Wiltshire TS 115kV Corridor	330	348/410(1)	K11W	2019-2023(1)
Leaside TS x Wiltshire TS	310	350	L18W	2034

(1) The Manby x Wiltshire corridor provides emergency backup for Dufferin TS load under Leaside area contingencies. Assuming that a 100MW of back up capability is provided, the maximum load that can be supplied in the Fairbanks/Runnymede area is 348MW and the need date for upgrading the corridor is 2019. If 75MW of back up capability is required, the need date will become 2023. However, if back up capability during peak is not considered, maximum load meeting capability is 410MW. The need in this case would be beyond 2035.

6.2.3 Step-Down Transformer Facilities

There are a total of 20 step-down transformers stations in the Central Toronto Sub Region.as follows:

Basin TS	Esplanade TS	Fairbank TS
Bridgman TS	Gerrard TS	Copeland MTS
Carlaw TS	Glengrove TS	John TS
Cecil TS	Main TS	Strachan TS
Charles TS	Terauley TS	Horner TS
Dufferin TS	Wiltshire TS	Manby TS
Duplex TS	Runnymede TS	

The stations non-coincident loads are given in Appendix D Table D-1. The areas and the stations requiring relief are given in Table 6-4.

Table 6-4 Adequacy of Step-Down Transformer Stations - Areas Requiring Relief

Area/Supply	Capacity (MW)	2015 Loading (MW)	Need Date
West Toronto: Fairbanks TS and Runnymede TS	285	291	Now
Southwest Toronto : Manby TS and Horner TS area	400	376	2020-2027 (1)
Downtown Toronto: John TS, Esplanade TS, Terauley TS and Copeland MTS (JETC)	739	632	2020+ (2)

(1) The need dates are based on high and low demand growth rates scenario

(2) The need date will be around 2027 based on the station capacity consideration alone for the Downtown District stations. However, a need date of 2020+ was established by the WG based upon other considerations, such as requirements for spare feeder position. More details are given in Section 7.3.

7. REGIONAL NEEDS AND PLANS

THIS SECTION DISCUSSES THE ELECTRICAL SUPPLY NEEDS FOR THE METRO TORONTO REGION AND SUMMARIZES THE REGIONAL PLANS FOR ADDRESSING THE NEEDS. THESE NEEDS ARE LISTED IN TABLE 6-1 AND INCLUDE NEEDS PREVIOUSLY IDENTIFIED IN THE IRRP FOR THE CENTRAL TORONTO SUB-REGION [1] AND THE NA FOR THE METRO TORONTO NORTHERN SUB-REGION [2] AS WELL AS THE ADEQUACY ASSESSMENT CARRIED OUT AS PART OF THE CURRENT RIP REPORT.

7.1 West Toronto Area

7.1.1 Station Capacity - Runnymede TS & Fairbank TS

Runnymede TS and Fairbank TS are 115/27.6 kV transformer stations that supply the load demand in the west end of Toronto. The two stations are connected to the 115 kV Manby East transmission system and have been operating at or near their capacity limits for the last five years. THESL has managed growth by transferring loads to adjacent area stations.

The area 2015 extreme weather peak load was 291 MW and exceeded the stations capacity of 285MW. The area is experiencing some re-development and the proposed Eglinton Crosstown Light Railway Transit ("LRT") project by MetroLinx will add an additional 14 MW of load to Runnymede TS in 2021. Additional step down transformation capacity is required now to provide relief and be able to meet the forecast load demand.

7.1.2 Line Capacity - Manby TS x Wiltshire TS 115kV circuits

The Manby TS x Wiltshire TS four circuit 115kV tower line carries circuits K1W, K3W, K11W and K12W. These circuits supply Fairbanks TS, Runnymede TS and well as Wiltshire TS. Under Leaside area outage conditions, these circuits are also used to pick up all or parts of Dufferin TS and/or Bridgman TS loads. The total corridor capability is dependent on the Fairbanks TS and Runnymede TS load and the load picked up and is given in table below:

Table 7-1 Manby x Wiltshire Corridor Capability

Year	Fairbanks TS, Runnymede TS, and Wiltshire TS Load Forecast (MW)	Amount of Dufferin TS and Bridgman TS Load that can be picked up (MW)	Total Corridor Capability (MW)
2015	330	120	450
2019	349	97	446
2023	375	68	443
2027	390	46	436
2031	399	25	424
2035	406	10	416

The timing of the Manby TS x Wiltshire TS circuits upgrade is dependent on the backup capability desired. If backup capability is not considered, the upgrade can be deferred to beyond 2035. However, if at least 70MW of back up capability - equal to about half of Dufferin TS load - is deemed appropriate, the upgrade would be deferred to about 2023.



Figure 7-1 West Toronto Area - Fairbank TS and Runnymede TS

7.1.3 Recommended Plan and Current Status

The Working Group has considered and reviewed several options to provide additional transformation capacity in West Toronto area as part of the Central Toronto IRRP. Based upon the review, and consistent with the IRRP Working Group recommendation is to expand Runnymede TS by adding two 115/27.6 kV 50/83 MVA transformers and a 27.6kV switchyard with six feeders. This work is required to be completed as early as possible.

The Working Group also recommends that the Manby TS to Wiltshire TS tower line carrying circuits K1W/K3W/K11W/K12W be also upgraded at the same time. This option would maintain the load transfer capability between Leaside TS and the Manby TS under emergency or outage conditions in addition to supplying future load growth in the West Toronto Area.

The estimated total cost of the work is approximately $90 M, which includes $34 M for the station work at Runnymede TS, $16 M for the upgrade of four 9.5 km long circuits between Manby TS and Wiltshire TS and $40 M for distribution facilities by THESL. The transmission cost of $50M is expected to be recovered in accordance with the TSC.

Hydro One has initiated development work on the project covering preparation of estimates and obtaining of EA approvals. The estimate is expected to be completed by the end of Q2 2016. It will also confirm if

the targeted in-service date of May 2019 for this project is achievable. A Section 92 application will be submitted in 2016.

7.2 Southwest Toronto Area

7.2.1 Station Capacity – Southwest Toronto (Manby TS & Horner TS)

Manby TS and Horner TS are two 230/27.6 kV transformer stations supplying the load demand in the southwest end of Toronto (see Figure 7-2). Based on the current RIP forecast the 400MW combined station capacity of the stations is forecast to be exceeded by summer 2020. Additional step down transformation is required to provide relief.

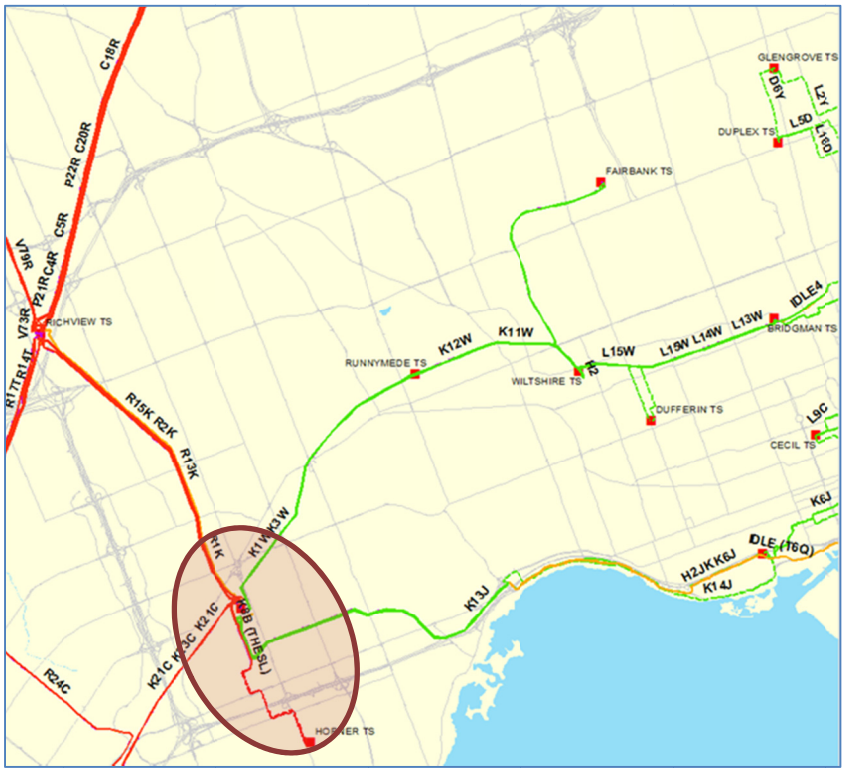

Figure 7-2 Horner TS and Manby TS Supply Area

7.2.2 Recommended Plan and Current Status.

To address the need for additional step down transformation capacity in the Southwest Toronto area, the Working Group's recommended building a second 230/27.6 kV DESN at the existing Horner TS site. Two 75/125MVA transformers will be installed at the station along with a new 27.6kV switchyard. Load transfer out of Manby TS to Horner TS is required to relieve Manby TS as the loading at that station exceeds its capacity. New distribution feeder ties are required to be built between Manby TS and Horner TS by THESL.

The estimated total cost of the work is about $53M, which includes $34 M for the station work at Horner TS and $19M for THESL distribution facilities. The transmission cost of $34M is expected to be recovered in accordance with the TSC.

Hydro One has initiated development work on the project covering preparation of estimates and obtaining of EA approvals at the request of THESL. The current in-service date for the project is expected to be May 2020.

7.3 Downtown District

7.3.1 Station Capacity – JETC[2] Area

The Toronto Downtown Core area is mainly supplied by the three existing 115/13.8 kV stations: John TS, Esplanade TS, and Terauley TS. John TS is connected to the Manby West system while Esplanade TS and Terauley TS are fed from the 115 kV Leaside / Hearn system. (see Figure 7-3)

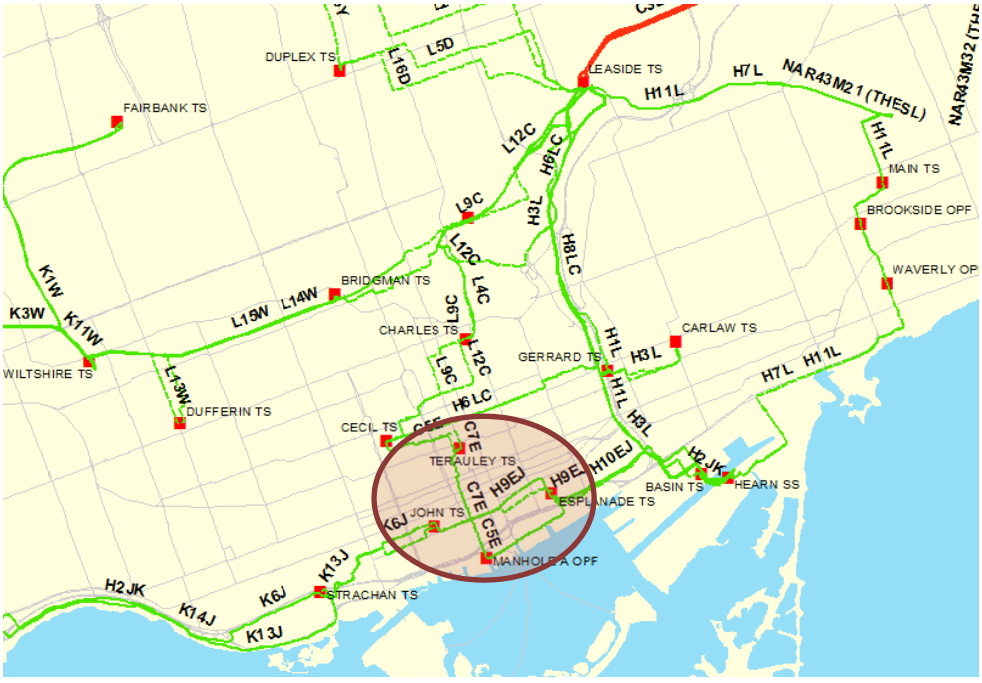

Figure 7-3 Toronto Downtown Supply Area

John TS was built in the 1950's and the THESL switchgear at the station is approaching end of life. THESL is building a new 115/13.8kV owned transformer station, Copeland MTS in the Downtown

[2] JETC denotes John TS, Esplanade TS, Terauley TS, and Copeland MTS which jointly supply the Downtown District.

District near John TS with normal supplied from the 115 kV Manby West system. The station first phase capacity will be around 130 MVA and it is expected to be in service in 2016. Copeland MTS will provide a new source of supply to the area customers and facilitate the replacement of end of life switchgear at John TS.

With the new Copeland MTS in-service in 2016, adequate transformation capacity will be available in the Downtown District till 2027. However, most of this capacity will be at John TS as 13.8kV buses at both Terauley TS and Esplanade TS are at or approaching capacity limits. THESL anticipates that the need for new transformation facility is more advanced due to limited spare feeder positions available at John TS for new customer connection and load transfer required to facilitate the refurbishment work at John TS. At the current pace of development in these areas, both bus and feeder position in the Downtown Core area are expected to be at or near capacity within five to ten years[3]. Specific issues identified by THESL Hydro are as follows:

- By 2019 THESL forecasts that two busses will be overloaded (ie. loaded beyond 10 Day LTR) at George and Duke MS and two busses overloaded at John/Windsor TS.
- By 2025 THESL forecasts that one bus will be overloaded at Copeland TS, two busses overloaded at George and Duke MS and three busses overloaded at John/Windsor TS.
- At John/Windsor TS, four out of six busses have no spare feeder positions to connect new customers. One bus has a single spare feeder position and one bus has two spare feeder positions.
- At George and Duke MS, one bus has no spare feeder positions and one bus has six spare feeder positions.
- At Esplanade TS, there is only one bus with three spare feeder positions.
- Once in service, Copeland TS is forecasted to have six and three spare positions on each its two busses, respectively.

7.3.2 Recommended Plan and Current Status

Based on the current information, the need to relieve the stations in Downtown District is expected to be beyond 2020. However, the need date may get delayed or brought forward if the load growth in this area is slower or faster than currently anticipated. The Working Group recommends that this need and timing should be further refined by THESL through their distribution planning process and included in updates to the IRRP and RIP. The uptake of CDM and DG should be preserved and re-assessed.

In the case where CDM and DG are deemed insufficient, building Copeland Phase 2 and installing additional transformers and two new buses at Copeland MTS site is the most cost effective way to meet the required THESL needs. The site and the high voltage switching facilities required to accommodate this expansion (Copeland Phase 2) are already included as part of the Copeland MTS Phase 1 project.Copeland MTS is an underground station and is not located adjacent to residential land uses. The THESL estimated cost for Copeland MTS Phase 2 to be approximately $46 M.

[3] Further information may be found in THESL's rate application EB-2014-0116 to the Ontario Energy Board

7.4 Transmission Line Capacity – 230 kV Richview TS to Manby TS Corridor

7.4.1 Description

The 230 kV transmission corridor between Richview TS and Manby TS is the main supply path for the Western Sector of Central Toronto Sub-Region. It also supplies the load in the southern Mississauga and Oakville areas via Manby TS. Along this Corridor there are two double circuit 230kV lines R1K/R2K and R13K/R15K. In addition the corridor contains an idle double circuit 115kV line. Figure 7-4 shows the area supplied by Richview TS x Manby TS circuits.

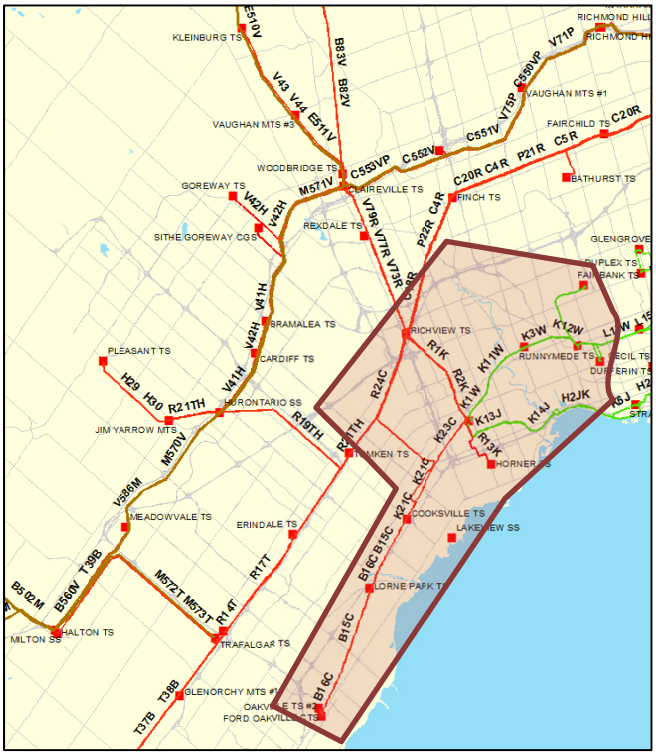

Figure 7-4 Richview x Manby Supply Area Map

The forecast loading on the Richview TS to Manby TS circuits is given in Table 7-2 below for both the high growth and low growth scenarios. The loads include the 115 kV Manby East, 115 kV Manby West, 230 kV Manby, and 230 kV Oakville-Cooksville loads. The need date for providing relief is 2020 for the high growth scenario and 2023 for the low growth scenario.

Table 7-2 also shows the effect of Metrolinx Mimico TPS on the need date for relief. In both scenarios, relief is required by 2020. The magnitude of Metrolinx load is large enough to trigger the reinforcement.

Again, due to the large incremental load from Mimico TPS, CDM will not be sufficient to help eliminate or even defer the need date for the transmission reinforcement. Transmission reinforcement is required to be implemented before the Mimico TPS can be connected.

Table 7-2 Coincident RIP MW Load Forecast for Richview TS x Manby TS Area

	Limit	2015	2017	2019	2021	2023	2025	2027	2029	2031	2033	2035
Base - Without Metrolinx Mimico TPS load												
High Growth	1540	1456	1488	1536	**1580**	1617	1646	1674	1698	1722	1742	1763
Low Growth	1540	1456	1481	1503	1530	**1544**	1557	1566	1572	1577	1597	1617
With Metrolinx Mimico TPS load												
High Growth	1540	1456	1488	1536	**1640**	1697	1726	1754	1778	1802	1822	1843
Low Growth	1540	1456	1481	1503	**1590**	1624	1637	1646	1652	1657	1677	1697

7.4.2 Alternatives Considered

The following alternatives are currently under consideration:

Upgrade four existing 230kV Richview TS x Manby TS circuits: Re-conductor with higher-capacity conductors on existing towers. Hydro One will check the feasibility of this option without major tower modifications and also in terms of outages arrangement. The estimated total cost of this option is about $16M, assuming that no major tower modifications and no bypass lines during re-conductoring are required.

Rebuild existing 115kV Richview TS x Manby TS line: Rebuild the existing idle 115 kV double-circuit line as a 230kV double-circuit line. The new 230 kV line is to share the existing terminations for circuits R2K and R15K at Richview TS and Manby TS. The ampacity of the new conductors are to be equal to or better than that of the existing circuits, effectively doubling the ampacity of R2K and R15K. This alternative requires the replacement of all the existing 115 kV towers with 230 kV towers. The estimated total cost of this option is about $19.5M.

Build two new 230 kV Richview TS x Manby TS circuits: Similar to the second alternative above, rebuild the two existing idle 115 kV double-circuit line as a 230kV double-circuit line. New terminations for these circuits are required at Richview TS and Manby TS. The ampacity of the new conductors are to be equal to or better than that of the existing circuits. This alternative not only provides higher transmission capacity but also increases the supply reliability to the Central Downtown and Southwest GTA area. The estimated total cost of this option is around $39.5M due to the extra station work required at the Richview TS and Manby TS.

Extend the Cooksville TS x Oakville TS line to Trafalgar TS: Extend the Cooksville TS x Oakville TS 230kV double circuit line B15C/B16C about 8km to Trafalgar TS where new 230kV switching facilties are also required. This alternative increases supply capacity and reliability to Southwest GTA area from Trafalgar TS, and thus alleviates the loading on the Richview x Manby corridor. The total estimated cost of this line and station work is around $54M.

CDM & DG: According to Central Toronto IRRP report, the potential DG development, targeted demand response and the potential incremental demand response in these areas supplied by Manby TS may defer the need for this transmission reinforcement by several years, depending on the load growth rate. However, with Mimico TPS connected near Horner TS, these targeted and potential incremental demand response will not be adequate due to the size of the extra load added by the TPS.

The Maintain Status Quo or Do Nothing alternative was not considered as it does not provide relief for the Richview x Manby transmission lines.

7.4.3 Recommended Plan and Current Status

The Metrolinx Mimico TPS information is new and was provided as part of the RIP after the IRRP was completed in April 2015. If this TPS is going to be in-service as planned in 2020, CDM initiatives will not effectively defer the need date for this transmission corridor because of the size of the additional load. Therefore, upgrading the existing Richview x Manby corridor or new supply path for the areas served by Manby TS will be required before the Metrolinx Mimico TPS can be connected.

The Trafalgar x Oakville line alternative, at $54M, is the highest cost alternative ($14.5M higher than the next most expensive alternative) and there is a risk that it may not be able to be completed in time to connect the the Metrolinx Mimico TPS in 2020. This alternative may also trigger the need for additional transformation facilities and thus would incur additional costs.

As a result, Working Group recommends that Hydro One proceed with the development and estimate work on the first three alternatives listed in Section 7.4.2 in 2016. Both EA and Section 92 approvals will be required and it is expected to take at least 3-4 years for the implementation of a wire solution. The Working Group will select the preferred alternative by December 2016. Hydro One will then plan to initiate project execution by summer 2018 in order to enable the connection of MetroLinx Mimico TPS by summer 2020.

7.5 Transmission Line Capacity – Circuit C10A (Duffin Jct. to Agincourt Jct)

C10A is a 20 km long radial circuit in Metro Toronto Northern Sub-Region from Cherrywood TS supplying Agincourt TS and Cavanagh MTS. The Metro Toronto Northern Sub-Region NA identified that the capacity of this circuit was thermally limited by a section approximately 4 km long between Duffin Jct. and Agincourt Jct. The flow on this section of the circuit might exceed its long-term emergency (LTE) rating under summer peak load conditions following certain contingencies.

A preliminary study based on the old field survey data was done in July 2015. The old record showed that the LTE rating was limited by some underbuilds along the line section. A new field survey was then carried out in October 2015. It was discovered that the aforementioned underbuilds had been previously removed, and the LTE rating of this line section should be 840A. The record is being updated. No further action is required.

7.6 Breaker Failure at Manby TS

7.6.1 Description

The failure of any of the Manby TS breakers A1H4 and H1H4 in the Manby West 230kV yard and the breaker H2H3 in the Manby east 230kV yard can cause the outage of any two of the three 230/115kV autotransformers at either the west or east yard of Manby TS. This may result in the overload of the remaining autotransformer. Based on the Coincident RIP Forecast the need date for the work is summer 2018 and summer 2021 for Manby West and Manby East respectively.

7.6.2 Recommended Plan and Current Status

The Working Group has recommended that installation of a Special Protection Scheme (SPS) is the most cost effective means to mitigate the breaker failure risk.

Hydro One is working on the development and estimate work for the SPS at Manby TS. The preliminary estimate for this work is approximately $2M and this will be updated when the development work is complete by summer 2016. The planned in-service of this work is summer 2018.

7.7 Breaker Failure at Leaside TS

The failure of breaker L14L15 at Leaside TS can cause the outage of two of the Leaside TS to Bridgman TS circuits. This may result in the loss of Transformers T11, T12, T14 and T15 at Bridgman TS. Under this scenario, two of the four LV buses will be lost by configuration. Only transformer T13 remains in service and supplies buses HLA1 and HLA7.

The 15 minute LTR for the X and Y windings of Transformer T13 is 55MVA. Therefore, as long as the loading on the HLA1 and HLA7 does not exceed the 15 minutes LTR, the operator can take action to reduce load to within transformer LTE ratings.

A new normally open switch is being installed at Bridgman TS as part of the Leaside-Bridgman Transmission Reinforcement project. This new switch can be closed remotely following the loss of the circuit L15W to resupply the two Bridgman transformers from the circuit L13W. This will alleviate the loading of the transformer T13 and the circuit L18W. and any possible voltage issue at Bridgman TS. Therefore, no investment is recommended.

7.8 Cherrywood to Leaside (CxL) Double Circuit Contingencies

Double circuit contingencies involving the lines C2L/C3L or C16L/C17L from Cherrywood TS to Leaside TS (CxL) can result in the loss of two of the three 230/115kV autotransformers on the same half of Leaside TS. The long-term emergency rating of the remaining autotransformer may be exceeded if only a single combustion unit at the Portland Energy Centre (PEC) is available, coincident with either of the abovementioned double contingencies during peak load condition.

The Working Group recommends that no further work is required in the near- and mid-term as there is already an existing operating instruction in place to cover the overload issue of the remaining Leaside autotransformer by closing the 115kV bus-tie at Leaside TS.

7.9 Load Restoration – Northern Sub-Region (Bathurst TS, Fairchild TS, Leslie TS)

Bathurst TS, Fairchild TS, and Leslie TS are supplied by the 230 kV Richview x Cherrywood x Parkway system in the Metro Toronto Northern Sub-Region. Following two circuit contingencies, approximately 240-300 MW of load during summer peak time could be lost during each contingency scenario, as follows:

Table 7-3 Maximum Load Loss during Two Circuit Contingencies

Double Element Contingency	Station Connected	Non-Coincident Load Forecast (MW)	
		2015	2025
P22R + C18R	Bathurst TS	271	279
C18R + C20R	Fairchild TS	292	301
P21R + C5R	Leslie TS	239	249

There are currently no existing transmission switching facilities to allow load restoration immediately. Partial load could be restored via distribution transfer to the nearby stations.

For Bathurst and Leslie cases, the stations are supplied by circuits on separate transmission lines for all or most sections. The probability of occurrence of overlapping outages on circuits on different tower lines is extremely low. The supplied circuits for Fairchild TS are on common tower for two-third of the line (approximately 32km).

Based on the outage records in the past 25 years there has been no incidence of any double contingencies described above.

A single transformer station would require four motorized disconnect switches to be useful. Typical cost for installing these transmission switching facilities per station would be between $8-10M.

Based on the low probability of frequency of such events versus the high mitigation cost, the Working Group recommendation is that no further action is required.

7.10 Long Term Needs

Four longer term needs had been identified in the Central Toronto IRRP as follows:

- Transmission Line Capacity – 115 kV Manby West To Riverside Junction
- Transformation Capacity – 230/115 kV Manby TS
- Transformation Capacity – 230/115 kV Leaside TS
- Leaside TS x Wiltshire TS 115kV circuits

Loading on Manby TS and the Manby TS x Riverside Junction circuit are within ratings over the study period under the Coincident RIP forecast. The Working Group recommendation is that no further action is required.

The Leaside TS transformer and the Leaside TS x Wiltshire circuits will require relief in the long term. This issue will be considered in the next planning cycle. The Working Group recommendation is that no further action is required. However, Hydro One and IESO will continue to monitor loads and initiate necessary relief measures, if required.

8. CONCLUSIONS AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE METRO TORONTO REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

This RIP report addresses regional needs identified in the earlier phases of the Regional Planning process and any new needs identified during the RIP phase. These needs are summarized in the Table 8-1 below.

Table 8-1 Regional Plans – Needs Identified in the Regional Planning Process

No.	Need Description
I	Supply Security – Breaker Failure at Manby West & East TS
II	West Toronto Area - Station Capacity and Line Capacity
III	Southwest Toronto - Station Capacity
IV	Downtown District - Station Capacity
V	230 kV Richview x Manby Corridor– Line Capacity
VI	Leaside Autotransformers
VII	Line Capacity – 115 kV Leaside x Wiltshire Corridor

Next Steps, Lead Responsibility, and Timeframes for implementing the wires solutions for the near-term and mid-term needs are summarized in the Table 8-2 below. Investments to address the long-term needs where there is time to make a decision (Need No. VI & VII), will be reviewed and finalized in the next regional planning cycle.

Table 8-2 Regional Plans – Next Steps, Lead Responsibility and Plan In-Service Dates

Id	Project	Next Steps	Lead Responsibility	I/S Date	Est. Cost	Needs Mitigated
1	Manby SPS	Transmitter to carry out the work	Hydro One	2018	$2M	I
2	Runnymede Expansion & 115 kV Manby x Wiltshire Corridor Upgrade	Transmitter to carry out the work	Hydro One	2019	$90M	II
3	Horner Expansion	Transmitter to carry out the work	Hydro One	2020	$53M	III
4	230 kV Richview x Manby Corridor Upgrade	Transmitter to carry out the work	Hydro One	2020	$20-40M	V
5	Copeland Phase 2	LDC to carry out work & monitor growth	THESL	2020+	$46M	IV

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered every five years. The next planning cycle for the Metro Toronto Region is expected to be started in 2018. However, the Region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the regional planning cycle will be started earlier to address the need.

9. REFERENCES

[1]. Independent Electricity System Operator, "Central Toronto Integrated Regional Resource Plan", 28 April 2015. http://www.ieso.ca/Documents/Regional-Planning/Metro_Toronto/2015-Central-Toronto-IRRP-Report.pdf

[2]. Hydro One, "Needs Screening Report, Metro Toronto Region – Northern Sub-Region", 11 June 2014. http://www.hydroone.com/RegionalPlanning/Toronto/Documents/Needs%20Assessment%20Report%20-%20Metro%20Toronto%20-%20Northern%20Subregion.pdf

Appendix A. Stations in the Metro Toronto Region

Station (DESN)	Voltage (kV)	Supply Circuits
Agincourt TS T5/T6	230/27.6	C4R/C10A
Basin TS T3/T5	115/13.8	H3L/H1L
Bathurst TS T1/T2	230/27.6	P22R/C18R
Bathurst TS T3/T4	230/27.6	P22R/C18R
Bermondsey TS T1/T2	230/27.6	C17L/C14L
Bermondsey TS T3/T4	230/27.6	C17L/C14L
Bridgman TS T11/T12/T13/T14/T15	115/13.8	L13W/L15W/L14W
Carlaw TS T1/T2	115/13.8	H1L/H3L
Cecil TS T1/T2	115/13.8	Cecil Buses H & P
Cecil TS T3/T4	115/13.8	Cecil Buses P & H
Charles TS T1/T2	115/13.8	L4C/L9C
Charles TS T3/T4	115/13.8	L12C/L4C
Dufferin TS T1/T3	115/13.8	L13W/L15W
Dufferin TS T2/T4	115/13.8	L13W/L15W
Duplex TS T1/T2	115/13.8	L16D/L5D
Duplex TS T3/T4	115/13.8	L5D/L16D
Ellesmere TS T3/T4	230/27.6	C2L/C3L
Esplanade TS T11/T12/T13	115/13.8	H2JK/H10EJ(C5E)/H9EJ(C7E)
Fairbank TS T1/T3	115/27.6	K3W/K1W
Fairbank TS T2/T4	115/27.6	K3W/K1W
Fairchild TS T1/T2	230/27.6	C18R/C20R

Station (DESN)	Voltage (kV)	Supply Circuits
Fairchild TS T3/T4	230/27.6	C18R/C20R
Finch TS T1/T2	230/27.6	C20R/P22R
Finch TS T3/T4	230/27.6	P21R/C4R
Gerrard TS T1/T3/T4	115/13.8	H3L/H1L
Glengrove TS T1/T3	115/13.8	D6Y/L2Y
Glengrove TS T2/T4	115/13.8	D6Y/L2Y
Horner TS T3/T4	230/27.6	R13K/R2K
John TS T1/T2/T3/T4	115/13.8	John Buses K1 & K2 & K3 & K4
John TS T5/T6	115/13.8	John Buses K1 & K4
Leaside TS T19/T20/T21 13.8	230/13.8	C2L/C3L/C16L
Leaside TS T19/T20/T21 27.6	230/27.6	C2L/C3L/C16L
Leslie TS T1/T2 13.8	230/13.8	P21R/C5R
Leslie TS T1/T2 27.6	230/27.6	P21R/C5R
Leslie TS T3/T4	230/27.6	P21R/C5R
Main TS T3/T4	115/13.8	H7L/H11L
Malvern TS T3/T4	230/27.6	C4R/C5R
Manby TS T13/T14	230/27.6	Manby W Buses A1 & H1
Manby TS T3/T4	230/27.6	Manby W Buses A1 & H1
Manby TS T5/T6	230/27.6	Manby E Buses H2 & A2
Rexdale TS T1/T2	230/27.6	V74R/V76R
Richview TS T1/T2	230/27.6	Richview Buses H1 & A1
Richview TS T5/T6	230/27.6	V74R/V72R
Richview TS T7/T8	230/27.6	Richview Buses H2 & A2
Runnymede TS T3/T4	115/27.6	K12W/K11W

Station (DESN)	Voltage (kV)	Supply Circuits
Scarboro TS T21/T22	230/27.6	C14L/C2L
Scarboro TS T23/T24	230/27.6	C15L/C3L
Sheppard TS T1/T2	230/27.6	C16L/C15L
Sheppard TS T3/T4	230/27.6	C15L/C16L
Strachan TS T12/T14	115/13.8	H2JK/K6J
Strachan TS T13/T15	115/13.8	K6J/H2JK
Terauley TS T1/T4	115/13.8	C7E/C5E
Terauley TS T2/T3	115/13.8	C7E/C5E
Warden TS T3/T4	230/27.6	C14L/C17L
Wiltshire TS T1/T6	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)
Wiltshire TS T2/T5	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)
Wiltshire TS T3/T4	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)
Cavanagh MTS T1/T2	230/27.6	C20R/C10A
IBM Markham CTS T1/T2	230/13.8	P21R/P22R
Markham MTS #1 T1/T2	230/27.6	P21R/P22R
Copeland MTS T1/T3 (Future)	115/13.8	D11J/D12J

Appendix B. Transmission Lines in the Metro Toronto Region

Location	Circuit Designations	Voltage (kV)
Richview x Manby	R1K, R2K, R13K, R15K	230
Richview x Cooksville	R24C	230
Manby x Cooksville	K21C, K23C	230
Cherrywood x Leaside	C2L, C3L, C14L, C15L, C16L, C17L	230
Cherrywood x Richview	C4R, C5R, C18R, C20R	230
Cherrywood x Agincourt	C10A	230
Parkway x Richview	P21R, P22R	230
Claireville x Richview	V72R, V73R, V74R, V76R, V77R, V79R	230
Manby East x Wiltshire	K1W, K3W, K11W, K12W	115
Manby West x John	K6J, K13J, K14J	115
Manby West x John x Hearn	H2JK	115
John x Esplanade x Hearn	H9EJ, H10EJ	115
Esplanade x Cecil	C5E, C7E	115
Hearn x Cecil x Leaside	H6LC, H8LC	115
Hearn x Leaside	H1L, H3L, H7L, H11L	115
Leaside x Charles	L4C	115
Leaside x Cecil	L9C, L12C	115
Leaside x Duplex	L5D, L16D	115
Leaside x Glengrove	L2Y	115
Duplex x Glengrove	D6Y	115

Appendix C. Distributors in the Metro Toronto Region

Distributor Name	Station Name	Connection Type
Toronto Hydro-Electric System Limited	Agincourt TS	Tx
	Basin TS	Tx
	Bathurst TS	Tx
	Bermondsey TS	Tx
	Bridgman TS	Tx
	Carlaw TS	Tx
	Cecil TS	Tx
	Charles TS	Tx
	Dufferin TS	Tx
	Duplex TS	Tx
	Ellesmere TS	Tx
	Esplanade TS	Tx
	Fairbank TS	Tx
	Fairchild TS	Tx
	Finch TS	Tx
	Gerrard TS	Tx
	Glengrove TS	Tx
	Horner TS	Tx
	John TS	Tx
	Leaside TS	Tx
	Leslie TS	Tx
	Main TS	Tx
	Malvern TS	Tx
	Manby TS	Tx
	Rexdale TS	Tx
	Richview TS	Tx
	Runnymede TS	Tx
	Scarboro TS	Tx
	Sheppard TS	Tx
	Strachan TS	Tx
	Terauley TS	Tx
	Warden TS	Tx
	Wiltshire TS	Tx
	Cavanagh MTS	Tx
	Copeland MTS (Future)	Tx

Distributor Name	Station Name	Connection Type
Hydro One Networks Inc. (Dx)	Agincourt TS	Tx
	Fairchild TS	Tx
	Finch TS	Tx
	Leslie TS	Tx
	Malvern TS	Tx
	Richview TS	Tx
	Sheppard TS	Tx
	Warden TS	Tx
PowerStream Inc.	Agincourt TS	Dx
	Fairchild TS	Dx
	Finch TS	Dx
	Leslie TS	Dx
Veridian Connections Inc.	Malvern TS	Dx
	Sheppard TS	Dx
Enersource Hydro Mississauga Inc.	Richview TS	Dx

Appendix D. Metro Toronto Regional Load Forecast (2015-2035)

Table D-1 Non-Coincident RIP Forecast (High Demand Growth)

			LTR	2015	2016	2017	2018	2019	2020	2021	2023	2025	2027	2029	2031	2033	2035
Central 115kV	Lea115	Basin	84	57	60	64	67	68	69	70	71	73	75	77	79	81	83
		Bridgman	179	174	177	179	181	182	183	184	185	187	189	191	193	195	198
		Carlaw	131	65	66	68	70	71	73	74	72	71	72	75	78	80	82
		Cecil	204	168	169	171	173	175	177	178	181	183	186	190	193	196	199
		Charles	200	151	153	156	158	159	161	162	165	167	170	172	173	177	181
		Dufferin	161	141	144	147	149	150	150	150	152	154	156	158	159	161	163
		Duplex	121	103	105	107	109	110	111	112	114	116	118	121	123	125	127
		Esplanade	177	169	170	172	173	176	178	180	185	190	196	201	206	210	215
		Gerrard	62	44	45	46	48	49	50	51	63	78	88	90	92	93	94
		Glengrove	84	55	57	58	59	60	60	61	62	63	64	66	67	68	69
		Main	72	65	64	63	62	63	64	66	65	65	66	69	72	75	77
		Terauley	205	187	191	196	201	205	209	213	217	220	224	230	236	240	245
	ManbyE115-13.8	Wiltshire	113	67	68	69	70	70	71	72	72	72	72	73	74	75	76
	ManbyE115-27.6	Runnymede	109	116	118	120	122	122	123	123	125	126	128	129	131	132	133
		Runnymede -LRT	0	0	0	0	0	0	0	14	18	23	26	26	26	26	26
		Fairbank	176	175	178	181	184	186	187	188	190	193	195	197	199	201	203
	ManbyW115	Copeland	111	0	0	86	102	102	102	102	106	111	113	113	113	113	113
		John	246	276	276	189	189	192	195	198	202	206	209	213	218	221	225
		Strachan	161	130	133	135	138	139	141	143	145	146	149	152	154	156	157
Central 115kV Total			2595	2143	2175	2206	2255	2279	2303	2341	2390	2444	2495	2540	2587	2626	2666
Eastern 230kV	CxL230	Bermondsey	348	194	196	198	200	200	200	200	202	203	204	206	207	209	210
		Ellesmere	189	169	171	173	175	175	175	175	176	177	178	180	181	182	183
		Leaside	210	156	158	159	161	161	161	161	163	165	166	168	170	172	174
		Scarboro	340	222	225	227	230	230	230	230	231	233	234	236	238	239	241
		Sheppard	204	170	170	171	171	171	171	171	173	174	175	176	178	179	180
		Warden	183	126	128	129	130	130	130	130	131	132	133	134	135	136	137
	Metrolinx	Metrolinx - Warden	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
Eastern 230kV Total			1474	1037	1047	1057	1067	1067	1107	1127	1155	1164	1172	1180	1189	1197	1206
Northern 230kV	CxR	Agincourt	174	95	97	99	101	102	103	104	104	105	106	107	107	108	109
		Bathurst	334	271	272	274	275	275	275	275	277	279	281	283	285	287	289
		Cavanagh	157	141	141	141	142	142	142	142	143	144	145	146	147	148	149
		Fairchild	357	292	293	295	297	297	297	297	299	301	303	306	308	310	312
		Finch	363	289	292	295	298	298	298	298	300	302	304	306	309	311	313
		Leslie	325	239	241	244	246	246	246	246	248	249	251	253	255	256	258
		Malvern	176	106	106	107	107	107	107	107	108	109	109	110	111	112	113
Northern 230kV Total			1885	1433	1444	1455	1466	1467	1468	1469	1479	1490	1500	1511	1521	1532	1543
Western 230kV	Manby230	Horner	179	144	146	148	150	151	152	153	155	157	157	156	155	157	159
		Manby	221	232	236	240	244	246	249	251	255	259	265	273	282	286	290
	Metrolinx	Metrolinx - Cityview	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
		Metrolinx - Mimico	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
	Rich230	Rexdale	187	135	135	135	135	134	133	132	133	134	135	136	137	138	139
		Richview T1T2EZ	154	130	131	131	131	130	129	128	129	130	131	132	133	134	135
		Richview T5T6JQ	188	109	110	110	110	109	108	108	108	109	110	111	111	112	113
		Richview T7T8BY	113	54	54	54	54	54	54	53	54	54	54	55	55	56	56
Western 230kV Total			1042	805	811	818	825	825	905	945	994	1003	1013	1023	1034	1043	1052
Grand Total			6995	5419	5477	5537	5613	5638	5783	5883	6019	6100	6180	6254	6331	6398	6466

Table D-2 Coincident RIP Forecast (High Demand Growth)

			LTR	2015	2016	2017	2018	2019	2020	2021	2023	2025	2027	2029	2031	2033	2035
Central 115kV	Lea115	Basin	84	52	55	58	61	62	63	63	65	66	68	70	72	73	75
		Bridgman	179	171	173	175	177	179	180	181	182	183	185	187	189	192	194
		Carlaw	131	61	63	65	67	68	69	70	69	68	68	71	74	76	78
		Cecil	204	152	154	156	158	159	161	162	165	167	170	173	176	178	181
		Charles	200	150	152	155	157	159	160	161	164	166	169	171	172	176	180
		Dufferin	161	139	142	144	147	147	148	148	150	152	153	155	157	159	160
		Duplex	121	103	105	107	109	110	111	112	114	116	118	121	123	125	127
		Esplanade	177	169	170	172	173	176	178	180	185	190	195	200	206	210	215
		Gerrard	62	44	45	46	47	48	49	50	62	77	87	89	91	92	93
		Glengrove	84	52	53	55	56	57	57	58	59	60	61	62	64	64	65
		Main	72	59	59	58	57	58	59	60	60	60	61	64	67	69	71
		Terauley	205	187	191	196	201	205	209	213	217	220	224	230	236	240	245
	ManbyE115-13.8	Wiltshire	113	61	61	62	63	64	64	65	65	65	65	66	67	68	69
	ManbyE115-27.6	Runnymede	109	96	98	99	101	101	102	102	103	105	106	107	109	110	110
		Runnymede -LRT	0	0	0	0	0	0	0	14	18	23	26	26	26	26	26
		Fairbank	176	174	177	179	183	184	185	186	188	191	193	195	197	199	201
	ManbyW115	Copeland	111	0	0	86	102	102	102	102	106	111	113	113	113	113	113
		John	246	267	266	179	179	182	185	188	191	195	199	202	206	210	213
		Strachan	161	130	133	135	138	139	141	143	145	146	149	152	154	156	157
Central 115kV Total			2595	2067	2097	2128	2176	2198	2222	2259	2307	2359	2409	2453	2498	2536	2575
Eastern 230kV	CxL230	Bermondsey	348	194	196	198	200	200	200	200	202	203	204	206	207	209	210
		Ellesmere	189	154	155	157	159	159	159	159	160	161	162	163	164	166	167
		Leaside	210	154	156	158	159	159	159	159	161	163	165	167	168	170	172
		Scarboro	340	220	222	225	227	227	227	227	229	230	232	234	235	237	239
		Sheppard	204	164	164	165	165	165	165	165	166	168	169	170	171	172	174
		Warden	183	125	126	127	129	129	129	129	130	130	131	132	133	134	135
	Metrolinx	Metrolinx - Warden	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
Eastern 230kV Total			1474	1010	1020	1030	1040	1040	1080	1100	1128	1136	1144	1152	1160	1168	1176
Northern 230kV	CxR	Agincourt	174	95	97	99	101	102	103	104	104	105	106	107	107	108	109
		Bathurst	334	245	247	248	249	249	249	249	251	253	255	257	258	260	262
		Cavanagh	157	119	119	119	120	120	120	120	120	121	122	123	124	125	126
		Fairchild	357	256	257	259	260	260	260	260	262	264	266	268	270	272	273
		Finch	363	273	276	278	281	281	281	281	283	285	287	289	291	293	295
		Leslie	325	223	225	227	229	229	229	229	231	233	234	236	238	239	241
		Malvern	176	106	106	106	107	107	107	107	108	108	109	110	111	111	112
Northern 230kV Total			1885	1317	1327	1337	1347	1348	1349	1351	1360	1370	1379	1389	1399	1408	1418
Western 230kV	Manby230	Horner	179	129	131	133	135	136	137	138	140	141	142	141	139	141	143
		Manby	221	232	236	240	244	246	249	251	255	259	265	273	282	286	290
	Metrolinx	Metrolinx - Cityview	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
		Metrolinx - Mimico	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
	Rich230	Rexdale	187	133	133	133	133	132	131	130	131	132	133	134	135	136	137
		Richview T1T2EZ	154	128	128	129	129	128	127	126	127	128	129	130	131	131	132
		Richview T5T6JQ	188	107	107	108	108	107	106	106	106	107	108	109	109	110	111
		Richview T7T8BY	113	52	52	52	52	52	51	51	51	52	52	53	53	53	54
Western 230kV Total			1042	782	788	794	801	801	881	921	970	979	988	998	1009	1018	1027
Grand Total			6995	5176	5232	5289	5363	5388	5532	5631	5765	5843	5920	5992	6066	6131	6196

Appendix E. List of Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme



GTA North

Regional Infrastructure Plan

February 5, 2016

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Prepared by:
Hydro One Networks Inc. (Lead Transmitter)

With support from:

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Independent Electricity System Operator
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PowerStream Inc.
Toronto Hydro Electric System Ltd.

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DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address all near and mid-term needs identified in previous planning phases and also any additional needs identified based on new and/or updated information provided by the RIP Working Group.

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Working Group.

Working Group participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the RIP report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the RIP report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the RIP report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE NETWORKS INC. ("HYDRO ONE") AND THE WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE ("TSC") REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN FACILITIES THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS OF THE GTA NORTH REGION.

The participants of the RIP Working Group included members from the following organizations:

- Enersource Hydro Mississauga Inc.
- Hydro One Brampton Networks Inc.
- Hydro One Networks Inc. (Distribution)Independent Electricity System Operator
- Newmarket-Tay Power Distribution Ltd.
- PowerStream Inc.
- Toronto Hydro-Electric System Limited
- Hydro One Networks Inc. (Transmission)

This RIP is the final phase of the OEB's mandated regional planning process for the GTA North Region which consists of the York Sub-Region and the Western Sub-Region. It follows the completion of the York Sub-Region's Integrated Regional Resource Planning ("IRRP") by the IESO in April 2015 and the Western Sub-Region's Needs Assessment ("NA") Study by Hydro One in June 2014.

This RIP provides a consolidated summary of needs and recommended plans for the York Sub-Region over the near-term (up to 5 years) and the mid-term (5 to 10 years). The York Region IRRP has identified the need for additional transformation capacity in Markham, Northern York Region and Vaughan in the mid-term. These mid-term needs are linked to long-term (beyond 10 years) transmission capacity needs.

No needs have been identified over the near-term and mid-term for the Western Sub-Region except for load restoration for the loss of double circuit 230 kV line V43/V44. It is recommended that this need be assessed as part of the IESO led GTA West bulk system planning initiative and as a result is not addressed in this RIP.

The major infrastructure investments planned for the GTA North Region over the near-term, identified in the various phases of the regional planning process, are given in the Table below.

No.	Project	I/S date	Cost
1	Vaughan #4 MTS	Q1 2017	$25M*
2	Holland breakers, disconnect switches and special protection scheme	Q4 2017	$32M
3	Parkway belt switches	Q4 2018	$4-6M

* PowerStream's station cost. Hydro One line connection cost is currently being estimated

The planning is continuing for the mid-term and long-term needs. These needs, and the options to address these them, are being reviewed by the Working Group as part of the community engagement activities currently being led by the IESO and LDCs through the Local Advisory Committee process. The Working Group expects to finalize recommendations to address these and associated long-term transmission needs in an IRRP update currently scheduled for 2017.

TABLE OF CONTENTS

Executive Summary 6
Table of Contents 8
List of Figures 10
List of Tables 10
1 Introduction 11
1.1 Scope and Objectives 12
1.2 Structure 12
2 Regional planning process 13
2.1 Overview 13
2.2 Regional Planning Process 13
2.3 RIP Methodology 16
3 Regional Characteristics 17
3.1 York Sub-Region 17
3.2 Western Sub-Region 18
4 Transmission Facilities Completed Over the Last Ten Years or Currently Underway 21
5 Forecast and other study assumptions 22
5.1 Load Forecast 22
5.2 Other Study Assumptions 23
6 Adequacy of Facilities and Regional Needs over the 2015-2025 period 24
6.1 Adequacy of York Sub-Region Facilities 25
6.1.1 500 and 230 kV Transmission Facilities 25
6.1.2 Step down Transformer Station Facilities 26
6.2 Adequacy of Western Sub-Region Facilities 27
6.2.1 Step down Transformation Facilities 27
6.3 Other Items Identified During Regional Planning 27
6.3.1 Load Security and Restoration in the Southern York Area 27
6.3.2 Load Restoration in Western Sub-Region 27
6.4 Long-Term Regional Needs 28
7 Regional Plans 29
7.1 Southern York Area 29
7.1.1 Increase Transformation Capacity in Vaughan 29
7.1.2 Improve Load Restoration Capability on the Parkway to Claireville Line 30
7.1.3 Mid-Term Need to Increase Transformation Capacity in Vaughan 31
7.1.4 Mid-Term Need to Increase Step-Down Transformation Capacity in Markham 31
7.2 Northern York Area 33
7.2.1 Increase Capacity and Load Restoration Capability on Claireville to Brown Hill Line 33
7.2.2 Mid-Term Need to Increase Transformation Capacity 33
7.3 Western Sub-Region 34
7.3.1 Load Restoration Need for the Claireville to Kleinburg Line 34
7.4 Long Term Future Transmission Corridor to the GTA North Region 34
8 Conclusions and next steps 35

References 36
Appendix A: Stations in the GTA North Region 37
Appendix B: Transmission Lines in the GTA North Region 38
Appendix C: Distributors in the GTA north Region 39
Appendix D: GTA North Region Load Forecast 2015-2025 40
Appendix E: List of Acronyms 41

LIST OF FIGURES

Figure 1-1 GTA North Region 11
Figure 2-1 Regional Planning Process Flowchart 15
Figure 2-2 RIP Methodology 16
Figure 3-1 GTA North Region – Supply Areas 19
Figure 3-2 GTA North Transmission Single Line Diagram 20
Figure 5-1 GTA North Region Extreme Summer Weather Coincident Peak Net Load Forecast 22
Figure 7-1 Vaughan MTS #4 30

LIST OF TABLES

Table 6-1 Near and Mid-Term Needs in the GTA North Region 25
Table 6-2 Step-Down Transformer Stations in the York Sub-Region 26
Table 6-3 Adequacy of the Step-Down Transformation Facilities in the York Sub-Region 26
Table 6-4 Step-Down Transformer Stations in the Western Sub-Region 27
Table 6-5 Adequacy of Step-Down Transformation Facilities – Western Sub-Region 27
Table 8-1: Regional Plans – Needs Identified in the Regional Planning Process 35
Table 8-2: Regional Plans – Next Steps, Lead Responsibility and Planned In-Service Dates 35

1 INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE GTA NORTH REGION.

The report was prepared by Hydro One Networks Inc. ("Hydro One") and documents the results of the study with input and consultation with Enersource Hydro Mississauga Inc. ("Enersource"), Hydro One Brampton Networks Inc. ("Hydro One Brampton"), Hydro One Distribution, Newmarket-Tay Power Distribution Ltd. ("NTPDL"), PowerStream Inc. ("PowerStream"), Toronto Hydro-Electric System Limited ("THESL"), and the Independent Electricity System Operator ("IESO") in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

The GTA North Region includes most of the Regional Municipality of York and parts of the City of Toronto, Brampton, and Mississauga (see Figure 1-1). Electrical supply to the Region is provided through 230 kV transmission circuits, fifteen step-down transformer stations ("TS"), and the York Energy Centre ("YEC") generating station ("GS").

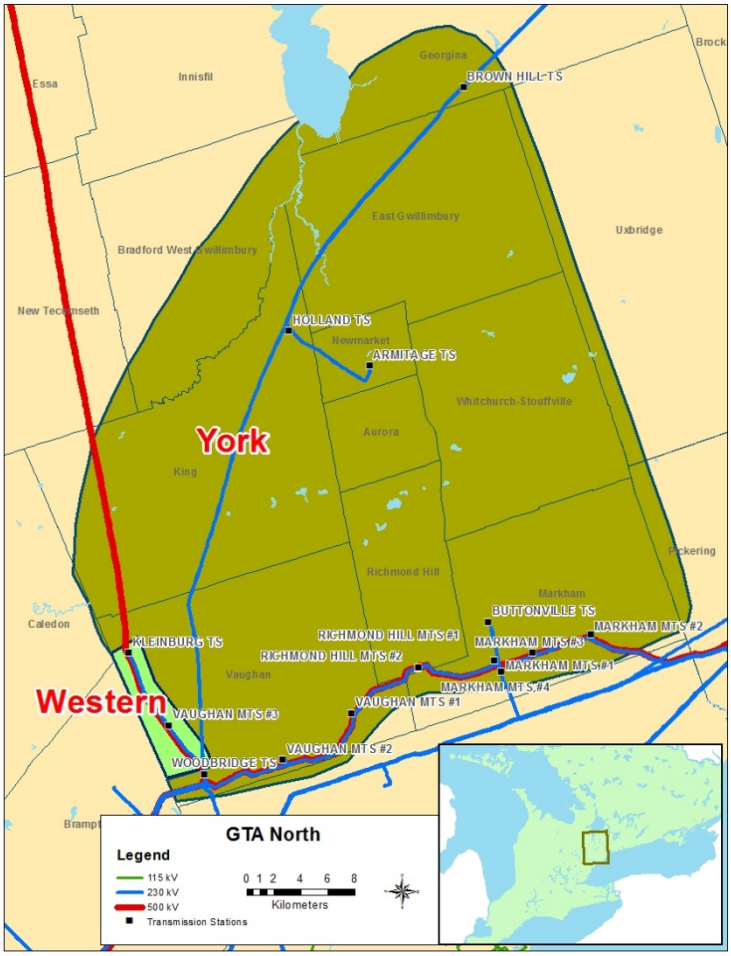

Figure 1-1 GTA North Region

1.1 Scope and Objectives

This RIP report examines the needs in the GTA North Region. Its objectives are to:

- Identify new supply needs that may have emerged since previous planning phases (e.g., Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan);
- Assess and develop a wires plan to address these needs;
- Provide the status of wires planning currently underway or completed for specific needs;
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviews factors such as the load forecast, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management ("CDM"), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of all the needs and relevant plans to address near and mid-term needs (2015 to 2025) identified in previous planning phases (Needs Assessment and Integrated Regional Resource Plan)
- Identification of any new needs over the 2015-2025 period and a wires plan to address them.
- Consideration of long-term needs identified in the York Region IRRP

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process.
- Section 3 describes the regional characteristics.
- Section 4 describes the transmission work completed over the last ten years.
- Section 5 describes the load forecast and study assumptions used in this assessment.
- Section 6 describes the results of the adequacy assessment of the transmission facilities and identifies the regional needs.
- Section 7 describes the needs and provides alternatives and preferred solutions.
- Section 8 provides the conclusion and next steps.

2 REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at essentially three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board ("OEB") in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment[1] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend a preferred wires solution. Similarly, resource options which the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led

[1] Also referred to as Needs Screening.

stakeholder engagement with municipalities and establishes a Local Advisory Committee in the region or sub-region.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timelines provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect;
- NA, SA, and LP phases of regional planning; and,
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region.

Figure 2-1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

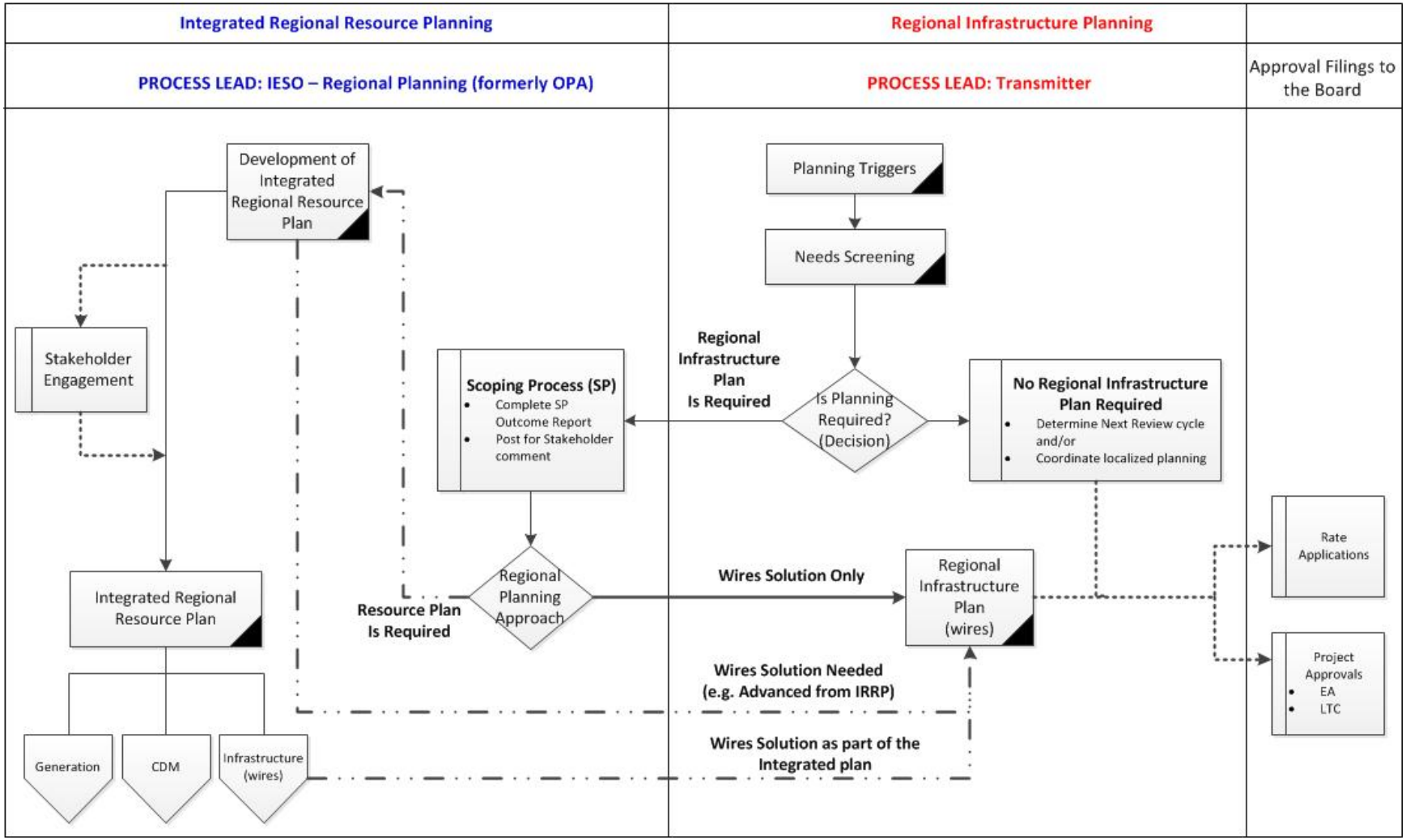

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of a four step process (see Figure 2-2) as follows:

1. Data Gathering: The first step of the process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any DG or CDM programs.
   - Existing area network and capabilities including any bulk system power flow assumptions; and,
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.

2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.

3. Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact, and costs.

4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

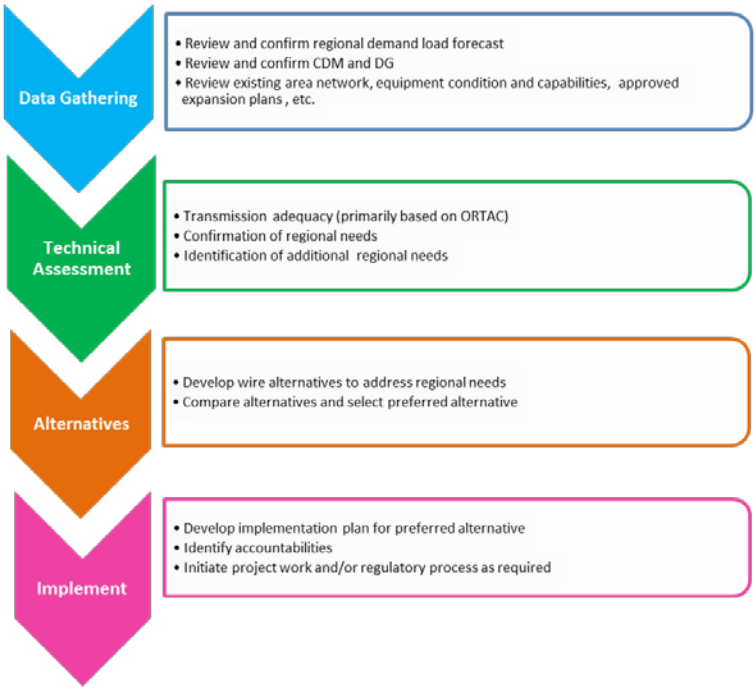

Figure 2-2 RIP Methodology

3 REGIONAL CHARACTERISTICS

THE GTA NORTH REGION IS COMPRISED OF THE YORK SUB-REGION AND THE WESTERN SUB-REGION. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM FIFTEEN 230 KV STEP-DOWN TRANSFORMER STATIONS. THE 2015 SUMMER PEAK AREA LOAD OF THE REGION WAS APPROXIMATELY 1900MW.

Electrical supply to the GTA North Region is primarily provided from three major 500/230 kV autotransformer stations, namely Claireville TS, Parkway TS, and Cherrywood TS, and a 230 kV transmission network supplying the various step-down transformation stations in the region. Local generation in the Region consists of the 393 MW York Energy Centre connected to the 230 kV circuits B82V/B83V in King Township.

The April 2015 York Region Integrated Regional Resource Plan ("IRRP"), prepared by the IESO in conjunction with Hydro One, PowerStream and Newmarket-Tay Power, focused solely on the York Sub-Region. The June 2014 GTA North Western Sub-Region Needs Assessment report, prepared by Hydro One, considered the Western Sub-Region. A map of the GTA North Region is shown in Figure 3-1 and a single line diagram of the transmission system is shown in Figure 3-2.

3.1 York Sub-Region

The York Sub-Region was identified as a "transitional" region, as planning activities in the region were already underway before the new regional planning process was introduced. The NA and SA phases were deemed to be complete, and the regional planning process was considered to be in the IRRP phase. An IRRP for the region was completed in April 2015.

For regional planning purposes, the York Sub-Region is further classified into Northern York Area and Southern York Area to reflect the layout of the region's electricity infrastructure. The Northern York Area encompasses the municipalities of Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville and Georgina, as well as some load in Simcoe County that is supplied from the same electricity infrastructure. It is supplied by Claireville TS, a 500/230 kV autotransformer station, and three 230 kV transformer stations stepping down the voltage to 44 kV. The York Energy Centre provides a local supply source in Northern York Area. The LDCs supplied in the Northern York Area are Hydro One Distribution, Newmarket-Tay Power Distribution, and PowerStream.

The Southern York Area includes the municipalities of Vaughan, Markham and Richmond Hill. It is supplied by three 500/230 kV autotransformer stations (Claireville TS, Parkway TS, and Cherrywood TS), nine 230 kV transformer stations (includes eight municipal transformer stations) stepping down the voltage to 27.6 kV, and one other direct transmission connected load customer. The LDC supplied in the Southern York Area is PowerStream.

Please see Figure 3-1 and Figure 3-2 for a map and single line diagram of the Sub-Region facilities.

3.2 Western Sub-Region

The Western Sub-Region comprises the Western portion of the municipality of Vaughan. Electrical supply to the sub-region is provided through Claireville TS, a 500/230 kV autotransformer station, and a 230 kV tap (namely, the "Kleinburg tap") that supplies three 230 kV transformer stations (including one municipal transformer station) stepping down the voltage to 44 kV and 27.6 kV. The LDCs directly supplied in the sub-region are PowerStream and Hydro One Distribution. Embedded LDCs supplied in the sub-region include Enersource, Hydro One Brampton and Toronto Hydro.
During the Needs Assessment phase for the Western Sub-Region, a load restoration need for the loss of V43/V44 was identified. It was recommended that a plan to address this need be included in the IESO led GTA West bulk system planning initiative and therefore this need is not addressed in this RIP.

Please see Figure 3-1 and Figure 3-2 for a map and single line diagram of the Sub-Region facilities.

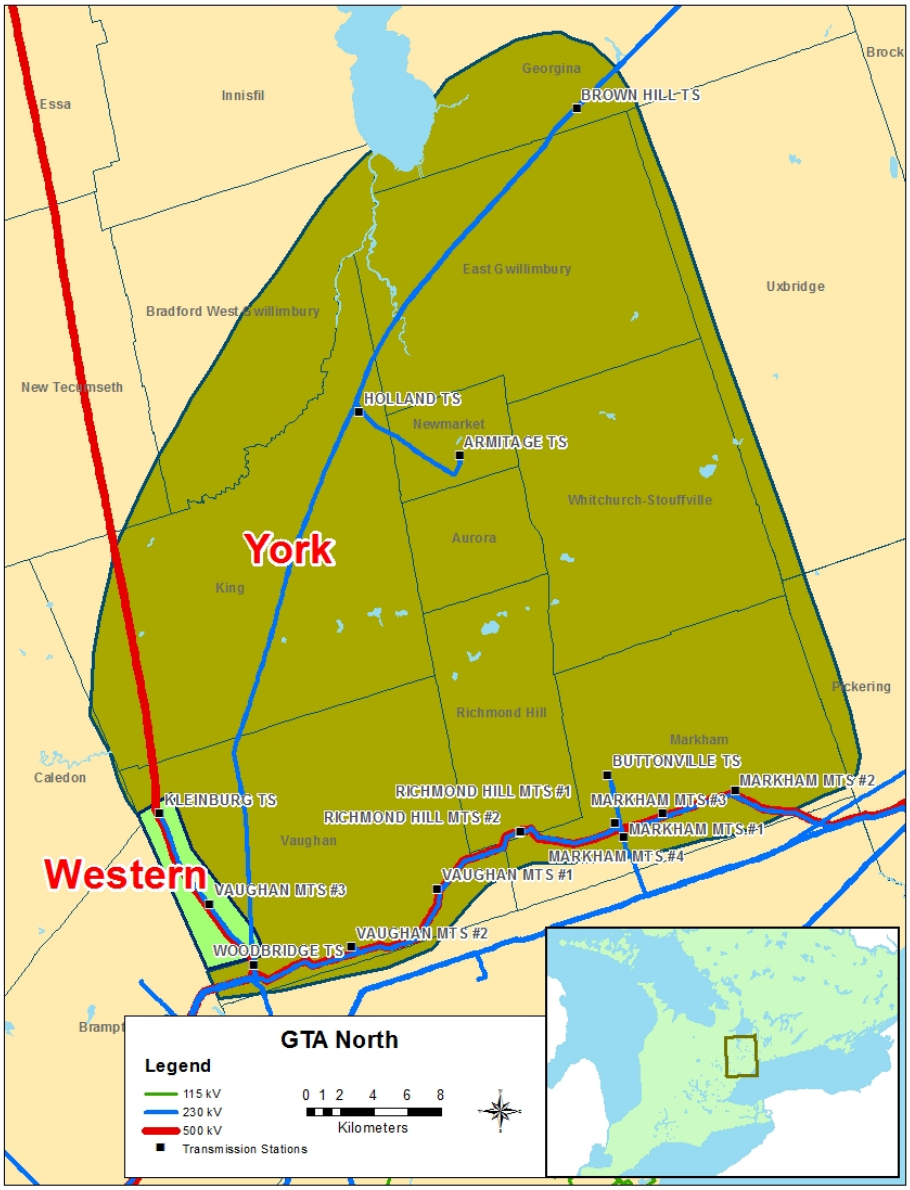

Figure 3-1 GTA North Region – Supply Areas

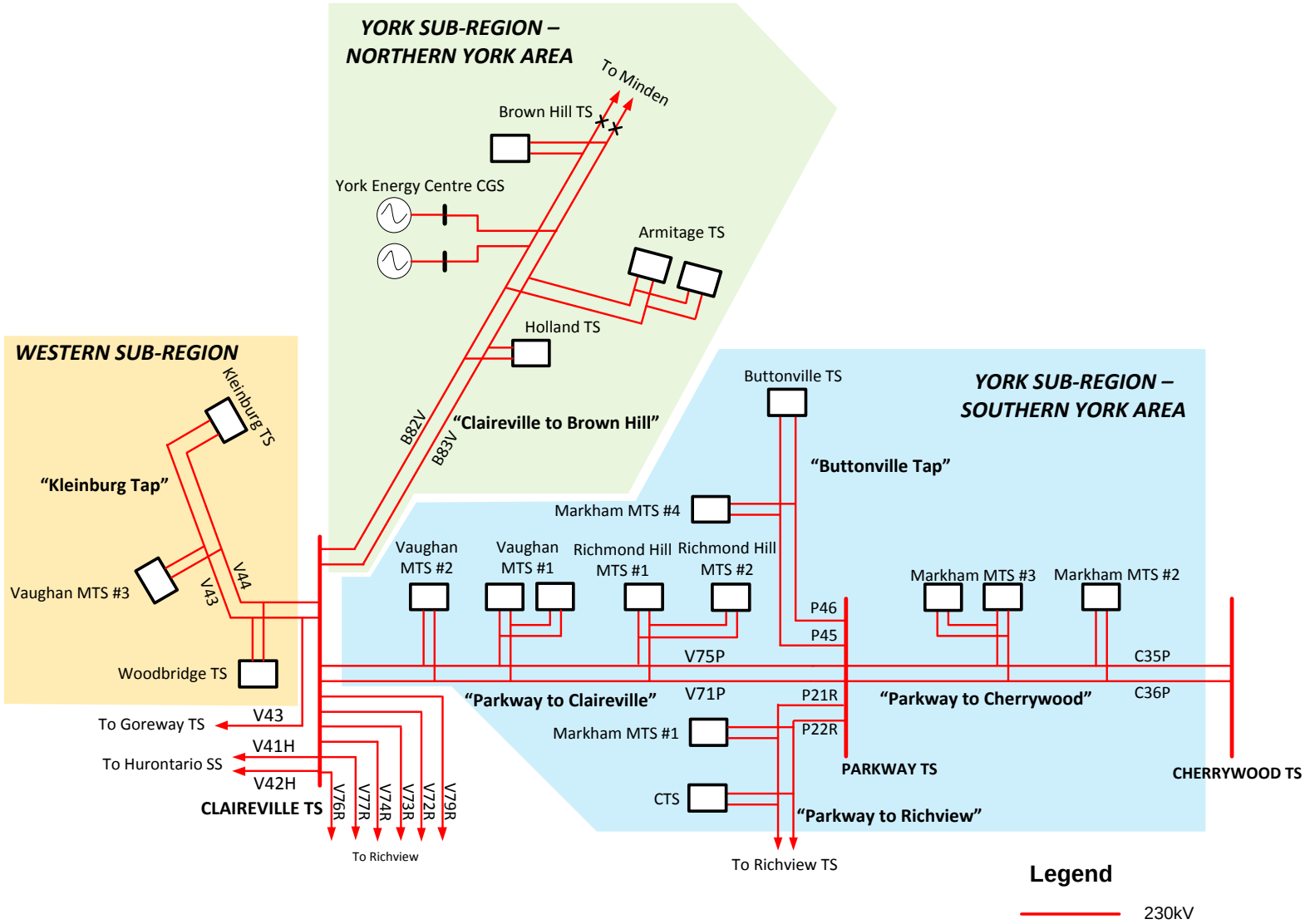

Figure 3-2 GTA North Transmission Single Line Diagram

4 TRANSMISSION FACILITIES COMPLETED OVER THE LAST TEN YEARS OR CURRENTLY UNDERWAY

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY TO THE GTA NORTH REGION.

A brief listing of the completed development projects along with their in-service dates over the last 10 years is given below:

- Holland TS and low voltage capacitor banks (2009) – to increase transformation capacity for the Northern York Area.
- Parkway 500-230kV autotransformer station (2006) – to increase transmission supply capacity to GTA North
- Parkway x Richmond Hill 230kV double circuit line (2006) – to improve reliability of supply to Southern York Area
- Connect Markham #4 MTS (2009) – to increase transformation capacity for the Southern York Area.
- Increased the size of the capacitor banks at Armitage TS (2006) – to improve reliability of supply to the Northern York Area.
- Connect the York Energy Centre generation facility (2012) – to provide a local source of supply for the Northern York Area.

The following development projects are currently underway:

- Vaughan MTS #4 (2017) – to increase transformation capacity for the Southern York Area.
- Holland breakers, disconnect switches and special protection scheme (2017) – to increase the transmission supply capacity and load restoration capability of the York Sub-Region.

5 FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the GTA North Region is forecast to increase at an average rate of approximately 2.1% annually up 2020, and 1.8% between 2020 and 2025. The growth rate varies across the Region.

Figure 5-1 shows the GTA North Region extreme summer weather coincident peak net load forecast. The coincident peak net load forecast for the individual stations in the GTA North Region is given in Appendix D. The net load forecast takes into account the expected impacts of conservation programs and distributed generation resources.

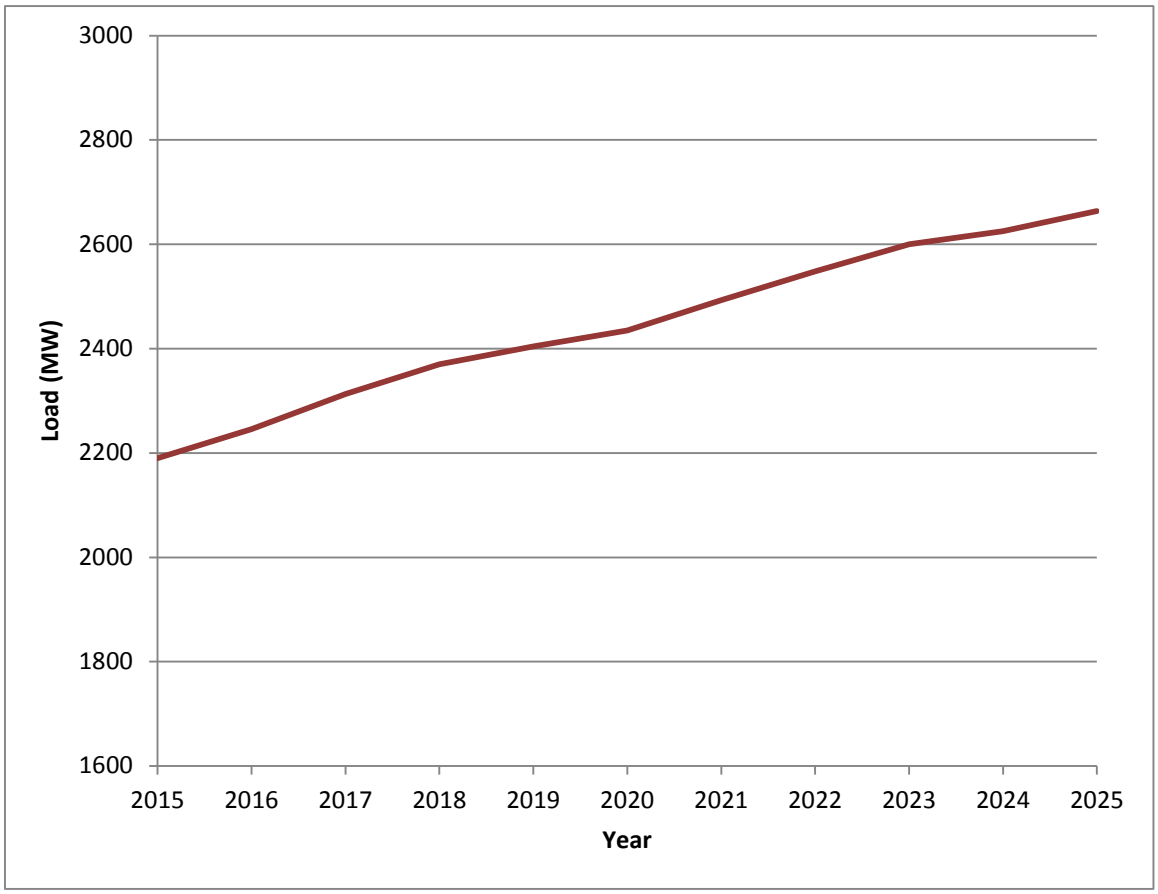

Figure 5-1 GTA North Region Extreme Summer Weather Coincident Peak Net Load Forecast

The station coincident peak net loads used in the RIP are as given in the York Region IRRP for the York Sub-Region[1] and the NA for the Western Sub-Region[2]. RIP Working Group participants confirmed that the load forecast, CDM, and DG information used in the IRRP and NA for the Western Sub-Region was still valid.

5.2 Other Study Assumptions

Further assumptions are as follows:

- The study period for the RIP Assessments is 2015-2025.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor which is consistent with ORTAC[4]. Normal planning supply capacity for transformer stations in this region is determined by the summer 10-Day Limited Time Rating ("LTR").

6 ADEQUACY OF FACILITIES AND REGIONAL NEEDS OVER THE 2015-2025 PERIOD

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND STEP DOWN TRANSFORMATION STATION FACILITIES SUPPLYING THE GTA NORTH REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM.

Within the current regional planning cycle two regional assessments have been conducted for the GTA North Region; the findings of these studies are input to the RIP:

1) IESO's York Region Integrated Regional Resource Plan – dated April 28, 2015[1]
2) Hydro One's Needs Assessment Report – GTA North – Western Sub-Region – June 27, 2014[2]

The York region IRRP identified a number of regional needs to meet the forecast load demand over the near to mid-term. Due to the immediate nature of the needs the Holland TS Breakers project and the Vaughan #4 MTS project were initiated to provide adequate load supply capability for the York Sub-Region while the York Region IRRP study was still underway. A detailed description and status of the Holland TS Breakers project and other work initiated or planned to meet these needs is given in Section 7.

This RIP reviewed the loading on transmission lines and stations in the GTA North Region assuming the Holland TS Breakers project is in-service using the latest Regional Forecast based on the IRRP load growth scenario as given in Section 5. Sections 6.1- 6.4 present the results of this review and Table 6-1 lists the Region's needs identified in both the IRRP and RIP phases.

Table 6-1 Near and Mid-Term Needs in the GTA North Region

Type	Section	Needs	Timing
Step-down Transformation Capacity	7.1.1	Additional transformation capacity in Vaughan (new Vaughan MTS #4 on circuits B82V/B83V)	2017
	7.1.4	Additional transformation capacity in Markham	2022(3)
	7.1.3	Additional transformation capacity in Vaughan(1)	2023(3)
	7.2.2	Additional transformation capacity in Northern York Area(1)	2023
Transmission Capacity	7.2.1	Capacity of the Claireville to Brown Hill (B82V/B83V) transmission line exceeded	2021
Load Security	7.2.1	Claireville to Brown Hill line (B82V/B83V)	2018
	7.1.2	Parkway to Claireville line (V71P/V75P)	Today
Load Restoration	7.2.1	Claireville to Brown Hill line (B82V/B83V)	Today
	7.1.2	Parkway to Claireville line (V71P/V75P)	Today
	7.3.1	Claireville to Kleinburg line (V43/V44) – restoration need only(2)	Today

(1) There are long-term transmission supply needs associated with new transformation capacity
(2) Restoration need to be assessed as part of the IESO led GTA West bulk system planning initiative
(3) PowerStream is currently reviewing their forecast and has advised that the need date for Markham may change to 2023 and the need date for Vaughan may change to 2026.

6.1 Adequacy of York Sub-Region Facilities

6.1.1 500 and 230 kV Transmission Facilities

All 500 and 230 kV transmission circuits in the GTA North are classified as part of the Bulk Electricity System ("BES"). The 230 kV circuits also serve local area stations within the region. The York Sub-Region is comprised of the following 230 kV circuits. Refer to Figure 3-2.

Southern York Area:

a) Parkway TS to Cherrywood TS 230 kV circuits: C35P and C36P.
b) Parkway TS to Claireville TS 230 kV circuits: V71P and V75P.
c) Parkway TS to Buttonville TS **(**"Buttonville Tap") 230 kV circuits: P45 and P46.
d) Parkway TS to Richview TS 230 kV circuits: P21R and P22R.

Northern York Area:

- Claireville TS to Brown Hill TS 230 kV circuits: B82V and B83V.

The RIP review shows that based on current forecast station loadings and bulk transfers, all 230 kV circuits are expected to be adequate over the study period.

6.1.2 Step down Transformer Station Facilities

There are a total of twelve step-down transformers stations in the York Sub-Region as follows:

Table 6-2 Step-Down Transformer Stations in the York Sub-Region

Northern York Area		
Armitage TS	Brown Hill TS	Holland TS
Southern York Area		
Buttonville TS	Markham MTS#1*	Markham MTS#2*
Markham MTS#3*	Markham MTS#4*	Richmond Hill MTS*
Vaughan MTS#1*	Vaughan MTS#2*	Industrial Customer

*Stations owned by PowerStream

Based on the LTR of these load stations, additional capacity is required in Vaughan in 2017 which will be addressed by Vaughan MTS #4. Based on the forecast in Appendix D, additional capacity is required in Markham as early as 2022, and additional capacity will be needed in both Vaughan and Northern York Area as early as 2023. However, PowerStream has advised that their forecast for Markham and Vaughan is currently under review, and that these need dates may change to 2023 and 2026 respectively.

The station loading in each area and the associated station capacity and need dates are summarized in Table 6-3.

Table 6-3 Adequacy of the Step-Down Transformation Facilities in the York Sub-Region

Area/Supply	Capacity (MW)	2015 Summer Loading (MW)*	Need Date
Northern York Area (Armitage, Holland)	485	430	2023
Northern York Area (Brown Hill)	184	74	-
Southern York Area (Markham/Richmond Hill)	956	833	2022
Southern York Area (Vaughan)	612**	459	2023

* Weather adjusted summer peak as per York Region IRRP

** Includes future capacity provided by Vaughan #4 MTS. It does not include Vaughan MTS #3 which is in the Western Sub-Region

6.2 Adequacy of Western Sub-Region Facilities

The Western Sub-Region is comprised of one 230 kV double circuit line V43/V44 between Claireville TS and Kleinburg TS. Refer to Figure 3-2. The line supplies Kleinburg TS, Vaughan MTS #3, and Woodbridge TS. Loading on the V43/V44 line is adequate over the study period.

6.2.1 Step down Transformation Facilities

There are three step-down transmission connected transformation stations in the York Sub-Region as follows:

Table 6-4 Step-Down Transformer Stations in the Western Sub-Region

Kleinburg TS
Woodbridge TS
Vaughan MTS#3*

*Station owned by PowerStream

The forecast individual station forecast loads are given in Appendix D. Based on the forecast loads these transformer stations are adequate over the study period. The total station capacity and 2015 loads in Western Sub-Region are given in Table 6-5.

Table 6-5 Adequacy of Step-Down Transformation Facilities – Western Sub-Region

Area/Supply	Capacity (MW)	2015 Summer Loading (MW)	2025 Summer Loading (MW)
Western Sub-Region (Vaughan/Kleinburg)	509	394	409

6.3 Other Items Identified During Regional Planning

6.3.1 Load Security and Restoration in the Southern York Area

The York Region IRRP report had identified load security and restoration needs for loss of the Claireville TS to Parkway TS 230 kV double circuit line V71P/V75P. Loading on the Claireville TS to Parkway TS 230 kV double circuit line V71P/V75P exceeds the 600 MW limit as per ORTAC security criteria. Loads in excess of 250 MW cannot be restored in less than 30 minutes as per the ORTAC restoration criteria. The needs and the Working Group recommendations to address the needs are discussed in more detail in Section 7.1.2.

6.3.2 Load Restoration in Western Sub-Region

The Needs Assessment report for the Western Sub-Region had identified a load restoration need for the loss of the Claireville TS to Kleinburg TS 230 kV double circuit line V43/V44. Loads in excess of 250 MW cannot be restored in less than 30 minutes as per the ORTAC restoration criteria. The Working Group has reviewed the need and reaffirmed the NA recommendation that this need be considered as part of the IESO led GTA West bulk system planning initiative.

6.4 Long-Term Regional Needs

As shown in Section 6.1.2 additional transformation capacity is required in the mid-term. With continued demand growth, the transmission system supplying these stations is also expected to reach its limits. The York Region IRRP had identified the need to coordinate the long term transmission needs with plans to address the station capacity needs.

The GO Rail Electrification Project is an initiative by Metrolinx to convert several rail corridors from a diesel to an electric-based system. GO's Barrie and Stouffville corridors are part of this plan and it is expected that parts of these rail corridors will be supplied by transmission infrastructure in the GTA North Region. At the time of this RIP the electrification project is still in the planning phase, but the impact of this project on the electrical infrastructure in the GTA North Region will need to be monitored as the plans are developed.

The options to address the transformation capacity needs are being reviewed by the Working Group as part of the community engagement activities currently being led by the IESO and LDCs through a Local Advisory Committee process. The Working Group expects to finalize recommendations to address these and associated long-term transmission needs in an IRRP update currently scheduled for 2017.

7 REGIONAL PLANS

This section discusses the needs, wires alternatives and the current preferred wires solution for addressing the electrical supply needs in the GTA North Region. These needs are listed in Table 6-1 and include needs previously identified in the IRRP for the York Sub-Region[1] and the NA for the Western Sub-Region.[2] Needs for which work is already underway are also included.

The near-term needs include needs that arise over the first five years of the study period (2015 to 2020) and the mid-term needs cover the second half of the study period (2020-2025).

7.1 Southern York Area

7.1.1 Increase Transformation Capacity in Vaughan

7.1.1.1 Description

The load forecast reflects substantial growth around the City of Vaughan, mainly around the northern boundaries, as new developments are being made in the area. As a result, based on the net demand forecast a new transformer station is needed by 2017 to ensure adequate transformation capacity is available. This need was also identified as a near-term need in the 2015 York Region IRRP.

7.1.1.2 Recommended Plan and Current Status

Due to the need to provide transformation capacity by 2017, work on building a new station was initiated by PowerStream while the York Region IRRP was still under way. The IRRP Working Group recommended that the new station connect to the Claireville to Brown Hill lines (230 kV circuits B82V/B83V) approximately 12 km north of Claireville TS.[5] Refer to Figure 7.1.

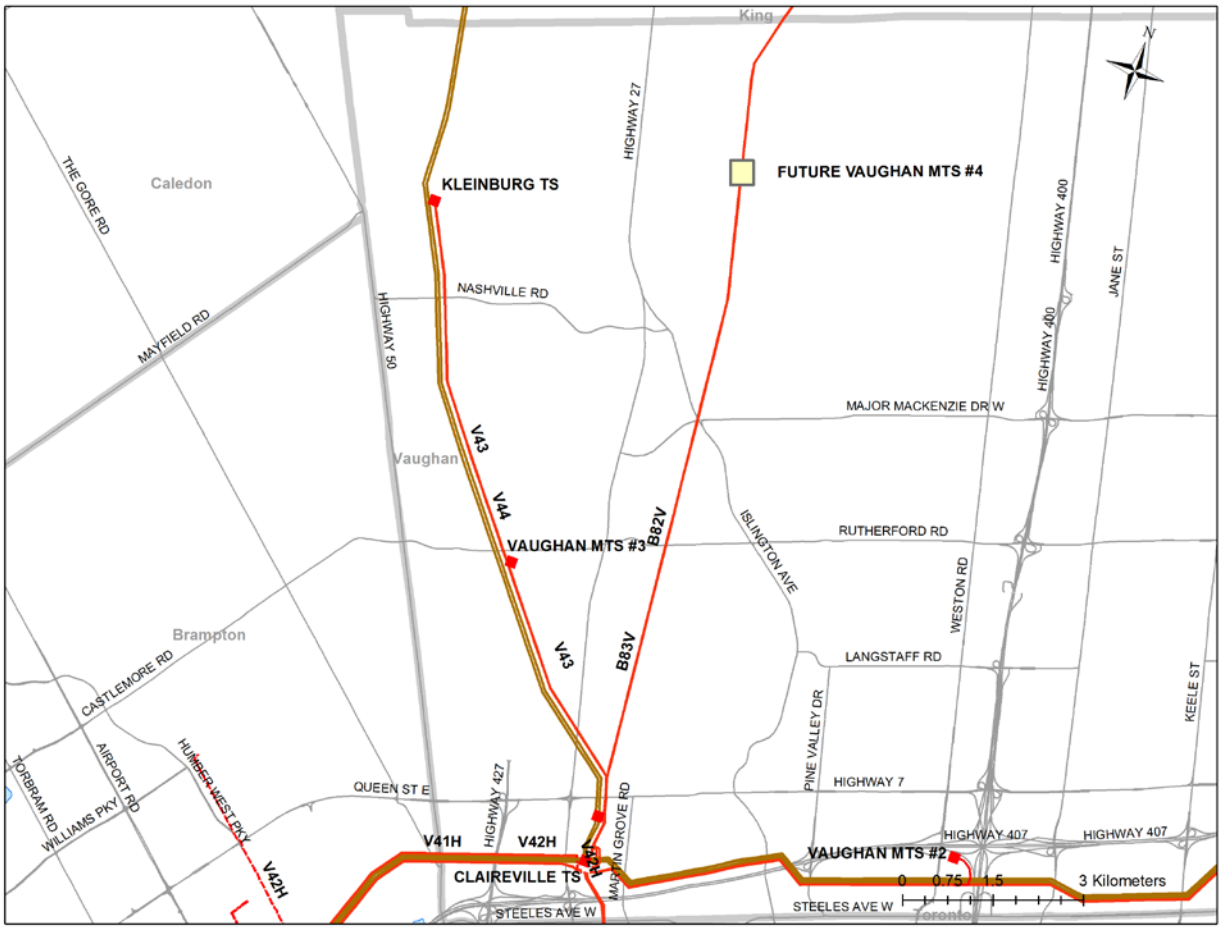

Figure 7-1 Vaughan MTS #4

The new station, Vaughan MTS #4, will provide 153 MW of 27.6 kV transformation capacity and is expected to be in-service by May 2017. Hydro One will construct the line tap to connect the new station to the B82V/B83V circuits.

PowerStream's estimated cost for the station is $25M. The Hydro One line connection cost is currently being estimated. The Hydro One line connection cost will be recovered from rate revenue in accordance with the TSC.

7.1.2 Improve Load Restoration Capability on the Parkway to Claireville Line

7.1.2.1 Description

The Parkway to Claireville line (V71P/V75P) is located on the Parkway Belt and supplies five load stations with a combined load of approximately 700 MW under current summer peak loading conditions. There are two needs identified for this system:

- The load security criteria in ORTAC[4] limits the amount of load that can be interrupted due to the loss of two elements (e.g.: a double circuit line outage) to 600 MW under peak load. On the Parkway to Claireville line, that limit is exceeded.
- The load restoration criteria requires that any load that is interrupted that exceeds 250 MW must be restorable within 30 minutes. At present, this may not be possible on the Parkway to Claireville line under certain operating conditions.

7.1.2.2 Recommended Plan and Current Status

The York Region IRRP recommended the installation of inline switches at the Vaughan MTS #1 junction in order to improve the capability of the system to restore load in the event that both 230 kV circuits V71P/V75P are lost. The switches will not reduce the amount of load that is interrupted, however they will enable Hydro One to quickly isolate the problem and allow the resupply of load to occur expeditiously. This work is covered under the V71P/V75P - Install 230 kV In-line Switches project.

Hydro One has established a project to install the two 230 kV in-line switches onto the V71P/V75P double circuit line with one switch installed on each circuit. The project is currently in the detailed design and estimation phase. The cost of this project is approximately $4-6 million and it is anticipated to be a transmission pool investment. The planned in-service date is May 2018.

7.1.3 Mid-Term Need to Increase Transformation Capacity in Vaughan

7.1.3.1 Description

The planned Vaughan MTS #4 will provide near term transformation capacity for Vaughan beginning in 2017. However, the load forecast shows that additional transformation capacity will be needed in Vaughan as early as 2023. There isn't sufficient transmission capacity available to supply another transformation station on the Claireville to Brown Hill line. Therefore a plan to increase transmission capacity to the area will be required before a plan for a new transformation station can be committed.

7.1.3.2 Recommended Plan and Current Status

Given the time required to build new transmission facilities, the York Region IRRP[1] had advised that it was necessary to identify a preferred alternative no later than 2018 to address both the transformation capacity need as well as the transmission capacity need. However, PowerStream is currently reviewing their load forecast for Vaughan and has advised that the need date for new transformation capacity may change to 2026. An update to the York Region IRRP is currently scheduled for 2017 to review the need date and develop a preferred plan for building and connecting additional transformation capacity in Vaughan.

7.1.4 Mid-Term Need to Increase Step-Down Transformation Capacity in Markham

7.1.4.1 Description

The step-down transformation capacity in Markham will be exceeded as early as 2022. The York Region IRRP has identified that additional transmission facilities will be required to supply the new station. It is

expected that the IESO will continue to explore non-wires options, in addition to wires options, through the IRRP process.

New developments attributable to forecasted load growth in the area are generally further north, away from existing transmission facilities. The ORTAC's[4] load restoration criteria will need to be considered in the further development of any detailed wires options. Non-wires options are beyond the scope of this RIP, but there are two main wires options for supplying a new Markham transformer station.

Option 1 - Connect to 230kV circuits C35P/C36P between Parkway TS and Cherrywood TS
The Parkway to Cherrywood line (C35P/C36P) connects two major bulk transmission stations, Parkway TS and Cherrywood TS, and also supplies load stations Markham MTS #3 (2 stations) and Markham MTS #2. There is transmission capacity available on these circuits to connect another transformer station.

Option 2 – Connect to 230kV double circuit line P45/P46 between Parkway TS and Buttonville TS
The Buttonville Tap (P45/P46) currently supplies two stations, Markham MTS #4 and Buttonville TS radially from Parkway TS. The transmission capacity on these circuits is thermally limited by a section less than 1 km long, so it would be necessary to increase the thermal capacity of these circuits in order to fully supply another station.

Extending the transmission circuits discussed would allow the point of supply to be nearer to the area of expected load growth and therefore reduce the amount of distribution facilities that would be needed.

7.1.4.2 Recommended Plan and Current Status

The existing transmission lines are not near the areas of expected load growth so the additional transmission costs to supply a new station nearer to the load need to be considered alongside the distribution costs. PowerStream estimates the incremental distribution costs for a station supplied by existing transmission lines to be on the order of $10-$50M higher than would be required for a station located nearer to the load.

Given that this need is a mid-term need, the York Region IRRP[1] identified a number of non-wires approaches that may address or defer the need for further transformation capacity. Such alternatives include CDM, DG, large generation and other local community initiatives and further monitoring of the load growth was recommended. In order to have facilities in-service to meet a summer 2022 need, it is recommended to continue wires planning, in addition to other non-wires alternatives, to meet this need and to identify a preferred solution by the end of 2017. This timeline allows approximately 4.5 years for detailed estimating, engineering, approvals, construction and commissioning if a wires option is identified as the preferred alternative. However, PowerStream is currently reviewing their load forecast for Markham and has advised that the need date for new transformation capacity may change to 2023. It is expected that the need date will be reviewed and a preferred solution will be identified in the York Region IRRP update process which is currently scheduled for 2017.

7.2 Northern York Area

7.2.1 Increase Capacity and Load Restoration Capability on Claireville to Brown Hill Line

The transmission capacity, load security and load restoration requirements are near-term needs for the Claireville to Brown Hill line (circuits B82V/B83V). These needs were identified in the 2015 York Region IRRP[1]. The Claireville to Brown Hill transmission line and local generation (York Energy Centre) combined are capable of supplying 600 MW of load. This limit is based on the ORTAC[4] load security criteria, which limits the amount of load that can be lost for two elements out of service to 600 MW. This is the most restrictive limit in this system and therefore defines the amount of load that can be supplied. With continued load growth at the stations supplied by this line as well as the future Vaughan #4 MTS (described in section 7.1), it is expected that load security criteria will be exceeded by 2018 based on the net demand forecast.

The load restoration need is based on the ORTAC[4] load restoration criteria that requires any load lost exceeding 250 MW to be restorable within 30 minutes. Based on the current net peak demand forecast, the loss of the Claireville to Brown Hill line will exceed this threshold and there are insufficient transmission and distribution facilities to restore sufficient load within 30 minutes in order to respect the criteria.

7.2.1.1 Recommended Plan and Current Status

Hydro One is expanding the Holland TS station to include two, 230kV inline circuit breakers and six motorized disconnect switches to increase the transmission capacity as well as the load restoration capability of this system. The project includes a load rejection and generation rejection special protection scheme (“SPS”). The purpose of the SPS is to ensure that the transmission system does not get overloaded following respected contingencies. The IESO (formerly the Ontario Power Authority) stated their support for this project in a letter to Hydro One dated June 14, 2013.[5] The planned in-service date for this project is Q4 2017 at an estimated cost of $32 million. This is anticipated to be a transmission pool cost and LDCs are not expected to pay any contribution.

The station service supply to the York Energy Centre is currently supplied from Holland TS. However, a low-voltage breaker failure event at Holland TS or a double circuit 230 kV contingency can result in an interruption to the station service supply to York Energy Centre and therefore the loss of all generation output until the station service can be restored from the alternate source. The IESO intends to develop a plan to address this issue in the York Region IRRP update currently scheduled for 2017.

7.2.2 Mid-Term Need to Increase Transformation Capacity

Based on the growth forecast for the Northern York Area, the combined loading on Armitage TS and Holland TS will exceed their combined summer 10-Day LTR as early as 2023. There is 44 kV transfer capability between these stations on the distribution system so the timing of the need is based on the combined capability of both stations. The IRRP indicated that the Claireville to Brown Hill circuits do not have sufficient capacity to fully supply another transformation station in Northern York Area after the Vaughan #4 MTS connection and Holland breakers project and therefore there is a long-term need to increase transmission capability to supply a new station. However, as noted in the York Region IRRP,

under a low growth scenario in the long term, the demand in Northern York Area will stabilize to within the capacity of existing stations to beyond 2033.

7.2.2.1 Recommended Plan and Current Status

The York Region IRRP[1] identified a number of non-wires alternatives that may address or defer the need for further transformation capacity in Northern York Area. Such alternatives include CDM, DG, large generation and other local community initiatives. However, given that the need date for this area may be as early as 2023, it is necessary to identify a preferred alternative by 2018 that addresses both the transformation capacity need as well as the transmission capacity need. The working group expects to finalize a plan and recommendations to address these needs in an IRRP update currently scheduled for 2017.

7.3 Western Sub-Region

7.3.1 Load Restoration Need for the Claireville to Kleinburg Line

The three stations in this sub-region, Woodbridge TS, Vaughan #3 MTS and Kleinburg TS, are supplied by two radial 230kV circuits, V43 and V44, originating from Claireville TS. Inherent to radial configuration, the loss of these two circuits will interrupt supply to loads and consequently load restoration times as per the ORTAC[4] may not be met. This need was identified during the NA for this sub-region and also in the Northwest GTA IRRP[6] and it was subsequently recommended that this need be addressed in the IESO's GTA West bulk system planning initiative.

7.4 Long Term Future Transmission Corridor to the GTA North Region

The GTA West RIP recommended the establishment of a future-use transmission corridor, to address growth-related needs in the GTA West region. In addition to addressing needs in the GTA West region, development of an eastern portion of this corridor through the City of Vaughan is also a possible option that could address the long-term supply needs identified for York Region. It is therefore recommended that, in the development of the long-term plans for the GTA West and GTA North regions, consideration be given to coordinating solutions to meet the needs of both regions when assessing options for each region individually.

8 CONCLUSIONS AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GTA NORTH REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

This RIP report addresses regional needs identified in the earlier phases of the Regional Planning process and any new needs identified during the RIP phase. These needs are summarized in Table 8-1.

Table 8-1: Regional Plans – Needs Identified in the Regional Planning Process

No.	Need Description
I	Vaughan Transformation Capacity (Near Term)
II	Northern York Area Load Security on B82V/B83V
III	Northern York Area Load Restoration on B82V/B83V
IV	Parkway to Claireville – Load Security on V71P/V75P
V	Parkway to Claireville – Load Restoration on V71P/V75P
VI	Markham Transformation Capacity (Mid-term)
VII	Vaughan Transformation Capacity (Mid-term)
VIII	Northern York Area Transformation Capacity (Mid-term)
IX	Kleinburg Tap – Load Restoration on V43/V44

Next Steps, Lead Responsibility, and Timeframes for implementing the wires solutions for the needs are summarized in Table 8-2 below. Investments to address the needs where there is time to make a decision (Needs No. VI, VII, and VIII), will be reviewed and finalized in the next regional planning cycle. Need No. IX will be addressed in the IESO GTA West bulk system planning initiative.

Table 8-2: Regional Plans – Next Steps, Lead Responsibility and Planned In-Service Dates

Id	Project	Next Steps	Lead Responsibility	I/S Date	Estimated Cost	Needs Mitigated
1	Vaughan #4 MTS	LDC to carry out the work	PowerStream	2017	$25M	I
2	Holland Breakers and SPS	Transmitter to carry out the work	Hydro One	2017	$32M	II, III
3	Parkway Belt Switches	Transmitter to carry out the work	Hydro One	2018	$4-6M	V

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. Due to the timing of the mid-term needs, the IRRP proposed that the process be updated in advance of the regular 5-year review schedule. The York Region IRRP is currently scheduled to be updated in 2017.

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[4]. Independent Electricity System Operator, "Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0"
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http://www.hydroone.com/RegionalPlanning/GTANorth/Documents/OPA%20Letter%20to%20Hydro%20One%20%20Regarding%20%20York%20Subregion.pdf

[6]. Independent Electricity System Operator, "Northwest Greater Toronto Area Integrated Regional Resource Plan", 28 April 2015
http://www.ieso.ca/Documents/Regional-Planning/GTA_West/2015-Northwest-GTA-IRRP-Report.pdf

APPENDIX A: STATIONS IN THE GTA NORTH REGION

Station (DESN)	Voltage (kV)	Supply Circuits
Kleinburg TS T1/T2 27.6 Kleinburg TS T1/T2 44	230/27.6 230/44	V43/V44
Vaughan MTS #3	230/27.6	V43/V44
Woodbridge TS T3/T5 27.6 Woodbridge TS T3/T5 44	230/27.6 230/44	V43/V44
Armitage TS T1/T2/T3/T4	230/44	B82V/B83V
Brown Hill TS T1/T2	230/44	B82V/B83V
Holland TS T1/T2	230/44	B82V/B83V
Buttonville TS T3/T4	230/27.6	P45/P46
Markham MTS #1	230/27.6	P21R/P22R
Markham MTS #2	230/27.6	C35P/C36P
Markham MTS #3 T1/T2/T3/T4	230/27.6	C35P/C36P
Markham MTS #4	230/27.6	P45/P46
Richmond Hill MTS #1	230/27.6	V71P/V75P
Richmond Hill MTS #2	230/27.6	V71P/V75P
Vaughan MTS #1 T1/T2/T3/T4	230/27.6	V71P/V75P
Vaughan MTS #2	230/27.6	V71P/V75P

APPENDIX B: TRANSMISSION LINES IN THE GTA NORTH REGION

Location	Circuit Designations	Voltage (kV)
Claireville TS to Brown Hill TS, Armitage TS and Holland TS	B82V/B83V	230
Claireville TS to Kleinburg TS, Vaughan MTS #3 and Woodbridge TS	V43/V44	230
Claireville TS to Vaughan MTS #1, Vaughan MTS #2, Richmond Hill MTS #1, Richmond Hill MTS #2, Parkway TS	V71P/V75P	230
Parkway TS to Markham MTS #1 and CTS	P21R/P22R	230
Parkway TS to Buttonville TS and Markham MTS #4	P45/P46	230
Parkway TS to Markham MTS #2, Markham MTS #3, Cherrywood TS	C35P/C36P	230

APPENDIX C: DISTRIBUTORS IN THE GTA NORTH REGION

Distributor Name	Station Name	Connection Type	Area/Region
Enersource Hydro Mississauga Inc.	Woodbridge TS	Dx	Western Sub-Region
Hydro One Brampton Networks Inc.	Woodbridge TS	Dx	Western Sub-Region
Hydro One Networks Inc. (Distribution)	Armitage TS	Tx	Northern York Area
	Brown Hill TS	Tx	Northern York Area
	Holland TS	Tx	Northern York Area
	Kleinburg TS	Tx	Western Sub-Region
	Woodbridge TS	Tx	Western Sub-Region
Newmarket-Tay Power Distribution Ltd.	Armitage TS	Tx	Northern York Area
	Holland TS	Tx	Northern York Area
PowerStream Inc.	Armitage TS	Dx	Northern York Area
		Tx	Northern York Area
	Buttonville TS	Tx	Southern York Area
	Holland TS	Dx	Northern York Area
	Kleinburg TS	Tx	Western Sub-Region
	Markham MTS #1	Tx	Southern York Area
	Markham MTS #2	Tx	Southern York Area
	Markham MTS #3	Tx	Southern York Area
	Markham MTS #4	Tx	Southern York Area
	Richmond Hill MTS #1	Tx	Southern York Area
	Richmond Hill MTS #2	Tx	Southern York Area
	Vaughan MTS #1	Tx	Southern York Area
	Vaughan MTS #2	Tx	Southern York Area
	Vaughan MTS #3	Tx	Western Sub-Region
	Woodbridge TS	Dx	Western Sub-Region
		Tx	Western Sub-Region
PowerStream Inc.[Barrie]	Holland TS	Dx	Northern York Area
Toronto Hydro Electric System Limited	Woodbridge TS	Dx	Western Sub-Region
Veridian Connections Inc.	Armitage TS	Dx	Northern York Area

APPENDIX D: GTA NORTH REGION LOAD FORECAST 2015-2025

Stations Net Coincident Peak Load Forecast (MW)

Station Name	LTR*	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Kleinburg 28 kV (BY)	97	54	56	58	59	63	64	66	69	70	70	70
Kleinburg 44 kV (EQ)	99	62	63	64	65	65	65	65	66	66	66	66
Vaughan 3 MTS 28 kV	153	153	153	153	153	153	153	153	153	153	153	153
Woodbridge 44 kV (EQ)	80	53	54	54	54	53	52	52	52	52	52	52
Woodbridge 28 kV (BY)	80	72	71	71	71	70	69	69	68	68	68	68
Holland TS 44 kV	168	136	138	142	144	145	146	149	152	154	156	158
Armitage TS 44 kV	317	294	299	306	312	314	317	324	330	336	338	344
Brown Hill TS 44 kV	184	74	76	79	81	83	85	88	90	93	95	98
Richmond Hill MTS 28 kV	254	254	254	254	254	254	254	254	254	254	254	254
Vaughan 1 MTS 28 kV	306	306	306	306	306	306	306	306	306	306	306	306
Vaughan 2 MTS 28 kV	153	153	153	153	153	153	153	153	153	153	153	153
Vaughan 4 MTS	153	0	24	47	69	83	97	119	140	160	170	185
Buttonville TS 28 kV	166	153	153	153	153	153	153	153	153	153	153	153
Markham 1 MTS 28 kV	81	81	81	81	81	81	81	81	81	81	81	81
Markham 2 MTS 28 kV	101	101	101	101	101	101	101	101	101	101	101	101
Markham 3 MTS 28 kV	202	202	202	202	202	202	202	202	202	202	202	202
Markham 4 MTS 28 kV	153	42	62	89	112	125	137	158	178	198	207	220

* LTR based on 0.9 power factor

APPENDIX E: LIST OF ACRONYMS

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

Toronto Hydro-Electric System Limited
EB-2018-0165
Exhibit 2B
Section B
Appendix E
ORIGINAL
(105 pages)

CENTRAL TORONTO AREA INTEGRATED REGIONAL RESOURCE PLAN

Part of the Metro Toronto Planning Region | April 28, 2015



ieso
Independent Electricity System Operator

Integrated Regional Resource Plan

Central Toronto Area

The Integrated Regional Resource Plan ("IRRP") was prepared by the IESO pursuant to the terms of its Ontario Energy Board licence, EI-2013-0066

This IRRP was prepared on behalf of the Central Toronto Area Working Group, which included the following members:

- Independent Electricity System Operator
- Toronto Hydro-Electric System Limited
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)

The Central Toronto Working Group assessed the adequacy of electricity supply to customers in the Central Toronto Area over a 25-year period; developed a flexible, comprehensive, integrated plan that considers opportunities for coordination in anticipation of potential demand growth scenarios and varying supply conditions in the Central Toronto Area; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key assumptions over time.

Central Toronto Working Group members agree with the IRRP's recommendations and support implementation of the plan through the recommended actions. Central Toronto Working Group members do not commit to any capital expenditures and must still obtain all necessary regulatory and other approvals to implement recommended actions.

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Table of Contents

1. Introduction 1

2. The Integrated Regional Resource Plan 3

2.1 Near- and Medium-Term Plan 3

2.2 Long-Term Plan 4

3. Development of the IRRP 6

3.1 The Regional Planning Process 6

3.2 The IESO's Approach to Integrated Regional Resource Planning 9

3.3 Central Toronto Working Group and IRRP Development 10

4. Background and Study Scope 12

4.1 Study Scope 12

4.2 Recent, Planned and Committed Resources 15

4.2.1 Conservation 15

4.2.2 Generation Resources 21

4.2.3 Transmission and Distribution Facilities 22

5. Demand Forecast 25

5.1 Historical Demand 25

5.2 Demand Forecast Methodology 26

5.3 Gross Demand Forecast 28

5.4 Conservation Resources Assumed in the Forecast 29

5.5 Distributed Generation Assumed in the Forecast 30

5.6 Planning Forecasts 30

6. Needs 33

6.1 Need Assessment Methodology 33

6.1.1 Ontario Resource Transmission Assessment Criteria 33

6.2 Near-Term and Medium-Term System Needs 36

6.2.1 Improving Supply Security for Low Probability Breaker Failures at Manby TS and Leaside TS 38

6.2.2 Manby TS Needs 38

6.2.3 Leaside TS Needs 40

6.2.4 Capacity Relief to Supply Points in the Manby TS Sector 42

6.2.5 Capacity Relief at Step-down Transformer Stations in West Toronto Area ... 42
6.2.6 Capacity Relief for Richview x Manby 230 kV Transmission Corridor 48
6.3 Medium-Term Needs 50
6.3.1 Capacity Relief to Supply Points Serving the Eastern (Leaside TS) Sector 50
6.3.2 Capacity Relief at Step-down Transformer Stations in the Downtown Area . 50
6.4 Other Observations for Addressing the Quality of Electricity Service 52
6.4.1 Probabilistic Reliability Assessment of Performance in Central Toronto 52
6.4.2 Assessment of Impact of Extreme Contingencies (Low Probability – High Impact Events) 54
6.4.3 Consideration of Plans for Transmission Infrastructure Renewal 54
7. Near-Term and Medium-Term Needs and Alternatives 56
7.1 Alternatives Considered for Meeting Near- and Medium-Term Needs 56
7.2 Near-Term Alternatives 56
7.2.1 Addressing Supply Security Risk at Manby TS and Leaside TS 56
7.2.2 Addressing Capacity Relief at Runnymede TS and Fairbank TS 60
7.2.3 Addressing Capacity Relief at Manby TS and Horner TS 63
7.2.4 Providing Capacity Relief for the Richview x Manby 230 kV Transmission Corridor 67
7.3 Medium-Term Alternatives 72
7.3.1 Providing Capacity Relief for Step-down Stations in the Downtown Area 72
7.3.2 Maintaining Reliability/Security Performance Levels Above Standards 75
7.3.3 Other Alternatives for Improving System Resiliency for Extreme Contingencies 76
7.4 Recommended Near and Medium-Term Plan 76
8. Long-Term Needs and Options 81
8.1 Approaches to Meeting Long-Term Needs 85
8.1.1 Delivering Provincial Resources 87
8.1.2 Large, Localized Generation 88
8.1.3 Community Self-Sufficiency 89
8.2 Recommended Long-Term Plan 91
9. Community Aboriginal and Stakeholder Engagement Process 92
10. Conclusion 97

List of Figures

Figure 3-1: Levels of Electricity System Planning 8
Figure 3-2: Steps in the IRRP Process 10
Figure 4-1: Central Toronto IRRP Study Area 13
Figure 4-2: Electrical Supply in Central Toronto by Sub-sector 14
Figure 5-1: Historical Electricity Peak Demand for Central Toronto 115 kV System 26
Figure 5-2: Development of Demand Forecasts 27
Figure 5-3: Concentrations of Growth in Central Toronto 29
Figure 5-4: Electricity Peak Demand Forecast for Central Toronto (115 kV System) 32
Figure 6-1: Map Showing Need Locations in Central Toronto 38
Figure 6-2: Manby TS Equipment and Affected Areas 39
Figure 6-3: Forecast of Customer Load at Risk Following Manby TS Breaker Failure Events 40
Figure 6-4: Leaside TS Equipment and Affected Areas 41
Figure 6-5: Forecast of Customer Load at Risk Following Leaside TS Breaker Failure Event 42
Figure 6-6: Station Capacity Needs in Central Toronto in the Near-Term 43
Figure 6-7: Runnymede TS and Fairbank TS Historical Peak Station Loadings 44
Figure 6-8: Eglinton LRT Project Location in Relation to Supply Points in West Toronto 45
Figure 6-9: Runnymede TS and Fairbank TS Peak Demand Forecast 45
Figure 6-10: Manby TS and Horner TS Historical Peak Station Loadings 46
Figure 6-11: Manby TS and Horner TS Supply Points in West Toronto 47
Figure 6-12: Manby TS and Horner TS Peak Demand Forecast 48
Figure 6-13: Richview – Manby 230 kV Transmission Capacity Needs 49
Figure 6-14: Forecast for Richview – Manby 230 kV Transmission Corridor 50
Figure 6-15: Station Capacity Needs in Downtown Toronto in the Medium-Term 51
Figure 8-1: Forecast Capacity Constraints in the Manby TS Sector in the Long-Term Period 82
Figure 8-2: Forecast Capacity Constraints at Leaside TS in the Long-Term Period 83
Figure 8-3: Approaches to Meeting Long-Term Needs 85
Figure 8-4: Potential Transmission Supply Sources to Meet Long-Term Needs 88
Figure 9-1: Summary of Central Toronto IRRP Community Engagement Process 93

List of Tables

Table 4-1: 2006-2014 Conservation Programs in the City of Toronto 17

Table 4-2: City of Toronto Energy Saving Policies and Programs 18

Table 4-3: Conservation Pilot Initiatives in the City of Toronto 20

Table 5-1: Peak Demand Savings Assumed from the 2013 LTEP Conservation Targets in Central Toronto (Megawatts) 30

Table 6-1: Summary of Near and Medium-Term Needs in Central Toronto 37

Table 7-1: Summary of Alternatives for Improving Supply Security Risks 59

Table 7-2: Summary of Alternatives for Providing Capacity Relief at Runnymede and Fairbank TS 63

Table 7-3: Summary of Alternatives for Providing Capacity Relief at Manby and Horner TS ... 66

Table 7-4: Summary of Alternatives for Providing Capacity Relief for Richview – Manby 230 kV Corridor 71

Table 7-5: Summary of Alternatives for Providing Capacity Relief for Downtown Transformer Stations 75

List of Appendices

Appendix A: Single Line Diagram of the Central Toronto Transmission System

Appendix B: Toronto Hydro Spatial Load Forecast Methodology

Appendix C: Conservation and Demand Management and Distributed Generation Forecast

Appendix D: Detailed Load Forecast and Forecast Scenarios

Appendix E: Technical Results – Deterministic and Probabilistic Assessments

Appendix F: Review of Power System Reliability Standards in Major Metropolitan Areas

Appendix G: Summary of Asset Condition and Sustainment Plans

Appendix H: Estimates of Conservation Achievable Potential

Appendix I: Letter to Toronto Hydro on Load Stations Planning

Appendix J: Stakeholder Engagement Summary Reports

List of Abbreviations

Abbreviation	Description
BES	Bulk Electric System
CDM	Conservation and Demand Management
CEMLC	Commercial Energy Management and Load Control
CEP	Community Energy Plan
CHP	Combined Heat and Power
DE	District Energy
DG	Distributed Generation
EM&V	Evaluation, Measurement and Verification
EUE	Expected Unserved Energy
EV	Electric Vehicle
FIT	Feed-in Tariff
GEA	Green Energy Act, 2009
GFA	Gross Floor Area
GHG	Green House Gas
GTA	Greater Toronto Area
GWh	Gigawatt hour
HONI	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IPSP	Integrated Power System Plan (2007)
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
kW	Kilowatt
LAC	Local Advisory Committee
LDC	Local Distribution Company
LTEP	Long-Term Energy Plan (2013)
LTR	Limited Time Rating
MPAC	Municipal Property Assessment Corporation
MVA	Megavolt-ampere
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB or Board	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PEC	Portlands Energy Centre
PPWG	Planning Process Working Group
PRA	Probabilistic Reliability Assessment

PSS®E	Power System Simulator for Engineering
PV	Photovoltaic (Solar)
RIP	Regional Infrastructure Plan
SCGT	Single-Cycle Gas Combustion Turbine
TGS	Toronto Green Building Standard
THESL	Toronto Hydro-Electric System Limited
TS	Transformer Station
Working Group	Central Toronto Area Working Group

1. Introduction

This Integrated Regional Resource Plan ("IRRP") addresses the electricity needs of Central Toronto. The report was prepared by the Independent Electricity System Operator ("IESO") on behalf of a Technical Working Group (the "Working Group") composed of the IESO, Toronto Hydro-Electric System ("Toronto Hydro" or "THESL") and Hydro One Networks Inc. ("Hydro One" or "HONI").

The Central Toronto Area has been undergoing extensive redevelopment, which has resulted in electricity demand growth that is placing pressure on parts of the electricity system serving the area. The City of Toronto's expectation is that the area will experience substantial continued population and economic growth in the coming decade. Therefore, there is a need for integrated regional electricity planning to ensure that the electricity system can support the pace of development over the long term.

In Ontario, planning to meet the electrical supply and reliability needs of a large area or region is done through regional electricity planning, a process that was formalized by the Ontario Energy Board ("OEB" or "Board") in 2013. In accordance with the OEB regional planning process, transmitters, distributors and the IESO are required to carry out regional planning activities for the 21 electricity planning regions across the province at least once every five years.

The area covered by the Central Toronto IRRP is a sub-region of the "Metro Toronto" region established through the Ontario Energy Board's ("OEB" or "Board") regional planning process. This report contributes to fulfilling the requirements for the Metro Toronto region as required by the IESO's OEB licence. Hydro One completed a Needs Screening for the remainder of Metro Toronto ("Metro Toronto Northern sub-region") in 2014 and found that no regionally coordinated planning was required for the remainder of the region.

This IRRP for Central Toronto identifies and co-ordinates the many different options to meet customer needs in Central Toronto over the next 25 years.[1] Specifically, this IRRP identifies investments for immediate implementation necessary to meet near and medium-term needs. This IRRP also identifies a number of options to meet longer-term needs, but given forecast

[1] The long-term planning horizon for a Regional Plan is typically 20 years. In the case of Central Toronto, Toronto Hydro provided a forecast covering a 25 year period. The Working Group agreed to assess needs based on the 25 year forecast.

uncertainty, the potential for technological change, and the longer development lead time, the plan maintains flexibility for longer-term options and does not recommend specific projects at this time. Instead, the long-term plan identifies near-term actions to develop alternatives and engage with the community, to gather information and lay the groundwork for future options. These actions are intended to be completed before the next IRRP cycle, scheduled for 2020 or sooner, depending on demand growth, so that the results of these actions can inform a decision, should one be needed at that time.

This report is organized as follows:

- A summary of the recommended plan for Central Toronto is provided in Section 2;
- The process used to develop the plan is discussed in Section 3;
- The context for electricity planning in the Central Toronto Area and study scope is discussed in Section 4;
- Demand forecast scenarios, and conservation and distributed generation ("DG") assumptions are described in Section 5;
- Near-term and medium-term electricity needs are presented in Section 6;
- Alternatives and recommendations for meeting near- and medium-term needs are addressed in Section 7;
- Options for meeting long-term needs are provided in Section 8;
- A summary of community, aboriginal and stakeholder engagement to date in developing this IRRP and going forward is provided in Section 9; and
- A conclusion is provided in Section 10;

2. The Integrated Regional Resource Plan

Near/Medium-Term Needs

- Meeting standards / improving supply security at Manby TS and Leaside TS – **today to 2018**
- Ensuring sufficient capacity to supply near term growth in west Toronto **– 2018**
- Ensuring sufficient supply capacity on the 230 kV transmission system between Richview TS and Manby TS **– 2018**
- Ensuring sufficient capacity to supply near term growth in downtown Toronto **– 2021**

The Central Toronto IRRP addresses the sub-region's electricity needs over the next 25 years, based on the application of the IESO's Resource and Transmission Assessment Criteria ("ORTAC"). The IRRP identifies needs that are forecast to arise in the near term (0-5 years), medium term (5-10 years) and long term (10-25+ years). These planning horizons are distinguished in the IRRP to reflect the different level of commitment required over these time horizons. The plans to address these timeframes are coordinated to ensure consistency. The IRRP was developed based on consideration of planning criteria, including reliability, cost and feasibility; and, in the near term, it seeks to maximize the use of the existing electricity system. For the near term, the IRRP identifies specific investments that need to be immediately implemented or that are already being implemented. This is necessary to ensure that they are in service in time to address the region's more urgent needs, respecting the lead time for their development.

For the medium and long term, the IRRP identifies a number of alternatives to meet needs. However, as these needs are forecast to rise further in the future, it is not necessary (nor would it be prudent given forecast uncertainty and the potential for technological change) to commit to specific projects at the present time. Instead, near-term actions are identified to develop alternatives and engage with the communities, to gather information and lay the groundwork for future options. These actions are intended to be completed before the next IRRP cycle, so that their results can inform a decision at that time.

The needs and recommended actions for the near/medium-term and long-term plans are summarized below.

2.1 Near- and Medium-Term Plan

The plan to meet Central Toronto's near- and medium-term electricity needs was developed with a view to economically maximizing the use of the existing system while ensuring adequate and reliable supply is in place to meet the growth needs of the region.

The core elements of the near- and medium-term plan include measures to meet the reliability standards and enhance supply security in the area, continuing with implementation of conservation, developing DG, and ensuring that infrastructure options are available to connect new customers and meet demand growth requirements in a timely manner.

Detailed recommendations are provided in Section 7. A summary of the plan's recommended actions is as follows:

1. Reconfigure the tap points of Horner TS on the Richview to Manby 230 kV lines to improve the distribution of loading on the 230 kV system by better balancing the loadings using existing infrastructure (completed by Hydro One in 2014).
2. Implement Special Protection Systems to address supply security and ensure that the reliability standards are met for breaker failure contingencies at the major transformer stations serving Central Toronto (Manby TS and Leaside TS).
3. Implement area-specific conservation options in order to defer 230 kV transmission line capacity needs.
4. Conduct further work to identify opportunities for distributed generation resources within the Central Toronto Area.
5. Proceed with work for increasing transformer station capacity in west Toronto by 2018, and in the downtown core by 2021.
6. Proceed with detailed investigation of the infrastructure options to provide capacity relief for the Richview – Manby 230 kV transmission corridor.
7. Investigate and implement cost-effective options for enhancing supply security and restoration capability following multiple element contingencies in Central Toronto.
8. Conduct further work to assess options for increasing system resiliency for extreme events.

2.2 Long-Term Plan

Long-Term Needs

- Ensuring sufficient capacity to supply long- term growth in Toronto

In the long term, Central Toronto's electricity system is expected to reach its capacity to supply growth at the two major transformer stations and at key transmission facilities supplying the area as early as the mid-2020s. Uncertainty in the long-term demand forecast, and the opportunity for conservation and DG resources to reduce the area's reliance on the delivery of provincial grid supply via the transmission system, could however defer these needs further into the future. The long-term plans for Central Toronto will be integrated and assessed with plans as a whole for the Metro Toronto Region.

The long-term plan sets out the near-term actions required to ensure that options remain available to address future needs if and when they arise. A number of alternatives are possible to meet the region's long-term needs. While specific solutions do not need to be committed today, it is appropriate to begin work now to gather information, monitor developments, engage the community, and develop alternatives, to support decision-making in the next iteration of the IRRP.

Detailed recommendations are provided in Section 8. A summary of the recommended actions to support the long-term plan are summarized as follows:

1. Establish a Local Advisory Committee to inform the long-term vision for electricity supply in the area.
2. Continue to engage with stakeholders and the community to develop community-based solutions.
3. Monitor demand growth, conservation achievement and DG uptake.
4. Initiate the next Regional Planning Cycle early, if needed.

3. Development of the IRRP

3.1 The Regional Planning Process

In Ontario, planning to meet the electricity needs of customers at a regional level is done through regional planning. Regional planning assesses the interrelated needs of a region – defined by common electricity supply infrastructure over the near, medium, and long term, and develops a plan to ensure cost-effective reliable electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs and recommend actions.

Regional planning has been conducted on an as needed basis in Ontario for many years. Most recently, the Ontario Power Authority ("OPA") carried out regional planning activities to address regional electricity supply needs. The OPA conducted joint regional planning studies distributors, transmitters, the IESO and other stakeholders in regions where a need for coordinated regional planning had been identified.

In 2012, the Ontario Energy Board convened a Planning Process Working Group ("PPWG") to develop a more structured, transparent, and systematic regional planning process. This group was composed of industry stakeholders including electricity agencies, utilities, and stakeholders. In May 2013, the PPWG released the Working Group Report to the Board, setting out the new regional planning process. Twenty-one electricity planning regions in the province were identified in the Working Group report and a phased schedule for completion of regional planning was outlined. The Board endorsed the Working Group Report and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013, as well as through changes to the OPA's licence in October 2013. The OPA licence changes required it to lead a number of aspects of regional planning including the completion of comprehensive IRRPs. Following the merger of the IESO and the OPA on January 1, 2015, the regional planning responsibilities identified in the OPA's licence became the responsibilities of the new IESO.

The regional planning process begins with a Needs Assessment process performed by the transmitter, which determines whether there are electricity needs requiring regional coordination. If regional planning is required, the IESO then conducts a Scoping Assessment process to determine whether a comprehensive IRRP is required, which considers conservation, generation, transmission and distribution solutions, or whether a straightforward "wires"

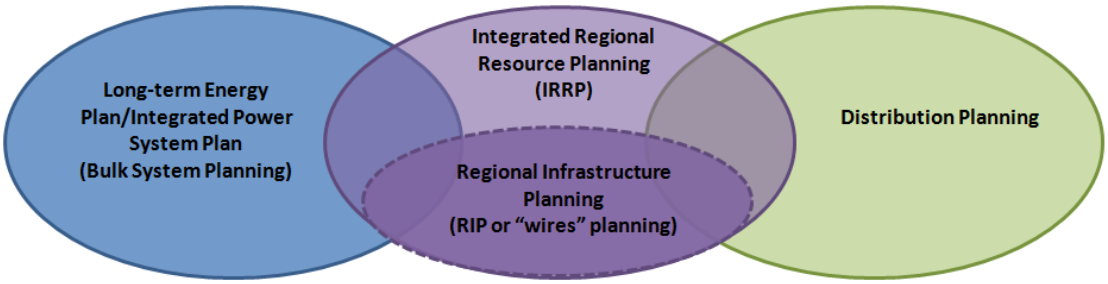
solution is the only option. If the latter applies, then a transmission and distribution focused Regional Infrastructure Plan ("RIP") is required. The Scoping Assessment process also identifies any sub-regions that require assessment. There may also be regions where infrastructure investments do not require regional coordination and can be planned directly by the distributor and transmitter, outside of the regional planning process. At the conclusion of the Scoping Assessment, the IESO produces a report that includes the results of the Needs Assessment process – identifying whether an IRRP, RIP, or no regional coordination is required – and a preliminary Terms of Reference. If an IRRP is the identified outcome, then the IESO is required to complete the IRRP within 18 months. If a RIP is required, the transmitter takes the lead and is required to complete the plan within six months. Both RIPs and IRRPs are to be updated at least every five years.

The final IRRPs and RIPs are to be posted on the IESO and the relevant transmitter websites, and can be used as supporting evidence in a rate hearing or Leave to Construct application for specific infrastructure investments. These documents may also be used by municipalities for planning purposes and other parties to better understand local electricity growth, conservation opportunities and infrastructure requirements.

Regional planning, as shown in Figure 3-1, is just one form of electricity planning that is undertaken in Ontario. There are three broad types of electricity planning in Ontario:

- Bulk system planning
- Regional system planning
- Distribution system planning

Figure 3-1: Levels of Electricity System Planning



Bulk System Planning

- 500 kV & 230 kV transmission
- Interconnections
- Inter-area network transfer capability
- System reliability (security and adequacy) to meet NERC, NPCC, ORTAC
- Congestion and system efficiency
- System supply and demand forecasts
- Incorporation of large generation
- Typically medium- and long-term focused

Regional Planning

- 230 kV & 115 kV transmission
- 115/230 kV autotransformers and associated switchyard facilities
- Customer connections
- Load supply stations
- Regional reliability (security and adequacy) to meet NERC, NPCC & ORTAC
- ORTAC local area reliability criteria
- Regional/local area generation & CDM resources
- Typically near- & medium-term focused

Distribution Network Planning

- Transformer stations to connect to the transmission system
- Distribution network planning (e.g. new & modified Dx facilities)
- Distribution system reliability (capacity & security)
- Distribution connected generation & CDM resources
- LDC demand forecasts
- Near- & medium-term focused

Planning at the bulk system level typically considers the 230 kV and 500 kV transmission network. Bulk system planning considers the major transmission facilities and assesses the resources needed to adequately supply the province. Bulk system planning is carried out by the IESO. Distribution planning, which is carried out by local distribution companies ("LDC"), looks at specific investments on the low voltage distribution system.

Regional planning can overlap with bulk system planning. For example, overlap can occur at interface points where regional resource options may also address a bulk system issue. Similarly, regional planning can overlap with the distribution planning of LDCs. An example of this is when a distribution solution addresses the needs of the broader local area or region. Therefore, to ensure efficiency and cost-effectiveness it is important for regional planning to be coordinated with both bulk and distribution system planning.

By recognizing the linkages with bulk and distribution system planning, and coordinating multiple needs identified within a given region over the long term, the regional planning process provides an integrated assessment of the needs. Regional planning aligns near- and long-term solutions and allows specific investments recommended in the plan to be understood as part of a larger context. Furthermore, regional planning optimizes ratepayer interests by avoiding piecemeal planning and asset duplication, and allows Ontario ratepayers' interests to be represented along with the interests of LDC ratepayers. Where IRRPs are undertaken, they

allow an evaluation of the multiple options available to meet needs, including conservation, generation, and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process, and by making plans available to the public.

3.2 The IESO's Approach to Integrated Regional Resource Planning

IRRPs assess electricity system needs for a region over a 20-year period, except in cases where the Working Group participants agree on a different planning horizon.[2] The outlook anticipates long-term trends so that near-term actions are developed within the context of a longer-term view. This enables coordination and consistency with the long-term plan, rather than simply reacting to immediate needs.

In developing an IRRP, a different approach is taken to developing the plan for the first 10 years of the plan—the near- and medium-term—than for the longer-term period, 10 to 20+ years. The plan for the first 10 years is developed based on best available information on demand, conservation, and other local developments. Given the long lead-time to develop electricity infrastructure, near-term electricity needs require prompt action to enable the specified solutions in a timely manner. By contrast, the long-term plan is characterized by greater forecast uncertainty and longer development lead-times; as such solutions do not need to be committed to immediately. Given the potential for changing conditions and technological development, the IRRP for the long term is more directional, focusing on developing and maintaining the viability of options for the future, and continuing to monitor demand forecast scenarios.

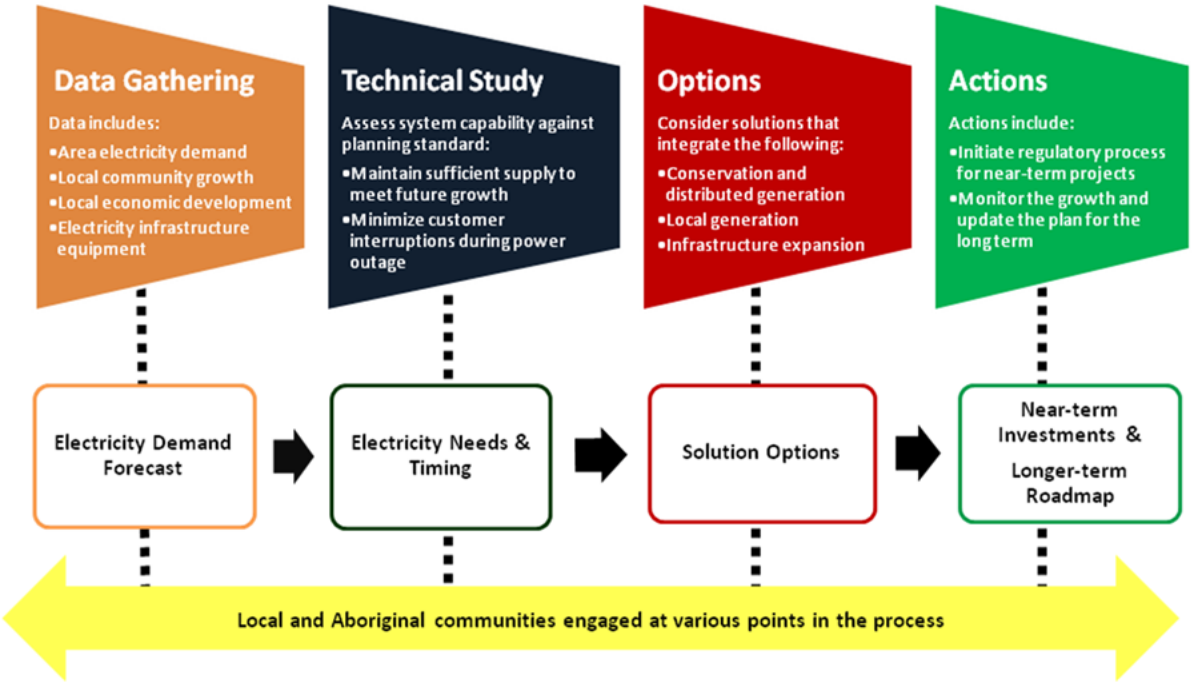
In developing an IRRP, the IESO and regional Working Group (see Section 3.3 below) carry out a number of steps. These steps include electricity demand forecasts; technical studies to determine electricity needs and the timing of these needs; the development of potential options; and, a recommended plan including actions for the near and long term. Throughout this process, engagement is carried out with stakeholders and First Nation and Métis communities, who may have an interest in the area. The steps of an IRRP are illustrated in Figure 3-2 below.

The IRRP report documents the inputs, findings and recommendations developed through the process described above, and provides recommended actions for the various entities that are

[2] In some cases, such as in this IRRP, the planning assessment was based on a 25-year forecast to account for longer-term growth potential and/or municipal plans. As planning for Central Toronto was initiated in 2011, the forecast period extends to 2036.

responsible for plan implementation. Where "wires" solutions are included in the plan recommendations, the completion of the IRRP report is the trigger for the transmitter to initiate an RIP process to develop those options. Other actions may involve development of conservation, local generation, or other solutions, community engagement, or information gathering to support future iterations of the regional planning process in the Region.

Figure 3-2: Steps in the IRRP Process



3.3 Central Toronto Working Group and IRRP Development

The Central Toronto IRRP process was commenced in 2011 by the Ontario Power Authority ("OPA"), in response to the significant rate of growth of new buildings and urban intensification in the downtown core and other areas within the central part of the city. It had been almost five years since the previous planning study for the area was done for the 2007 Integrated Power System Plan. The OPA proposed that a joint integrated planning study be undertaken which led to the establishment of the Working Group which as noted above included representatives of the former OPA, IESO, Toronto Hydro, and Hydro One.

The OPA developed a Terms of Reference that were signed by each of the participating organizations.[3] The Working Group gathered data, identified near term and potential long-term needs in the area, and recommended the near-term plan included in this IRRP. Implementation of elements of the near-term plan began in 2014 with the OPA issuing letters supporting near-term projects so that they could commence immediately in order to be in-service in time to address imminent needs.

This Central Toronto IRRP is therefore a "transitional" IRRP in that it began prior to the development of the OEB's regional planning process and much of the work was completed before the new process and its requirements were known. When the Regional Planning process was formalized by the OEB in 2013, the planning approach was adjusted to comply with the elements of the new process. This included the incorporation of formal input from electricity consumer groups in the city, municipal planners, other governments groups interested in electricity planning, industry stakeholders and interested community participants. This IRRP reflects this revised and updated information.

[3] The IRRP Terms of Reference can be found on the IESO website: http://www.ieso.ca/Documents/Regional-Planning/Metro_Toronto/Central-Toronto-IRRP-Terms-of-Reference.pdf

4. Background and Study Scope

The City of Toronto ("City"), the largest city in Canada by population and employment, has a very high land-use density of commercial and residential buildings, especially in the central parts of the city. Toronto is the largest electricity demand centre in Canada, at about 5,000 MW of peak summertime electricity demand, 40% of which (about 2,000 MW) is in the central area.[4] Extensive high density residential and commercial urban redevelopment has contributed to steady electricity demand growth in localized pockets, although the overall City of Toronto demand has been steady at around 5,000 MW for the last 10 years. This pace of growth in localized areas is expected to continue for the next several years. In recent years, more tall buildings have been under construction in Toronto than in any other major city in North America.[5]

To set the context for this IRRP, the scope of the IRRP and the existing electricity system serving the area are described in Section 4.1, and a summary of recent investments in the local electricity system is presented in Section 4.2.

4.1 Study Scope

The IRRP study area is shown in green shading in Figure 4-1. The study area is roughly bounded by Highway 401 to the north, Highway 427 and Etobicoke Creek to the west, Victoria Park Avenue to the east and Lake Ontario to the south. Most of this area operates at the 115 kV transmission level, whereas the surrounding Metro Toronto area is served at the 230 kV level. At the distribution level, most of the area operates at 13.8 kV, while the surrounding area is served by distribution at the 27.6 kV level.[6]

The 230 kV corridors supplying the two main 230kV/115kV transformer stations ("TS") in the east and the west are included within the scope of this IRRP. The individual supply stations along the 230 kV corridor in the east were included in the Metro Toronto Northern sub-region Needs Screening assessment completed by Hydro One in 2014.

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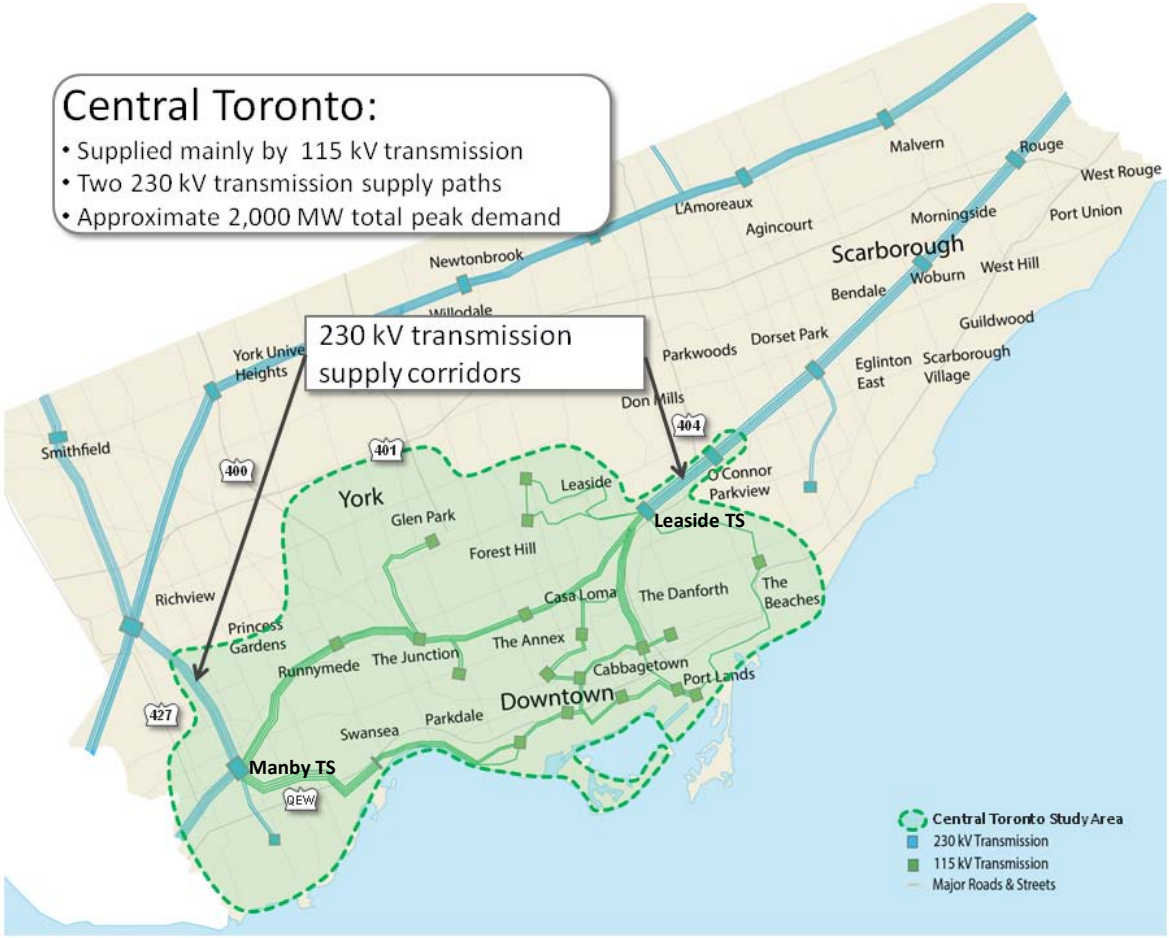
[4] The central area includes the downtown central business area.

[5] There are starting to be some signs of a slow-down in the construction of condominium buildings in Toronto, however, at least 55 tall buildings remain under construction, with many more approved by the City of Toronto for construction. Therefore, despite the possibility of a slower pace of growth in the future, electricity system infrastructure will still be required in the near term to supply the growth that is known with more certainty.

[6] Exceptions in the Central Toronto Area include four transformer stations in the study area that supply distribution system voltages at 27.6 kV. These stations include Manby, Leaside, Runnymede, Fairbank, and Horner transformer stations. These stations are shown in Appendix B.

Figure 4-1: Central Toronto IRRP Study Area

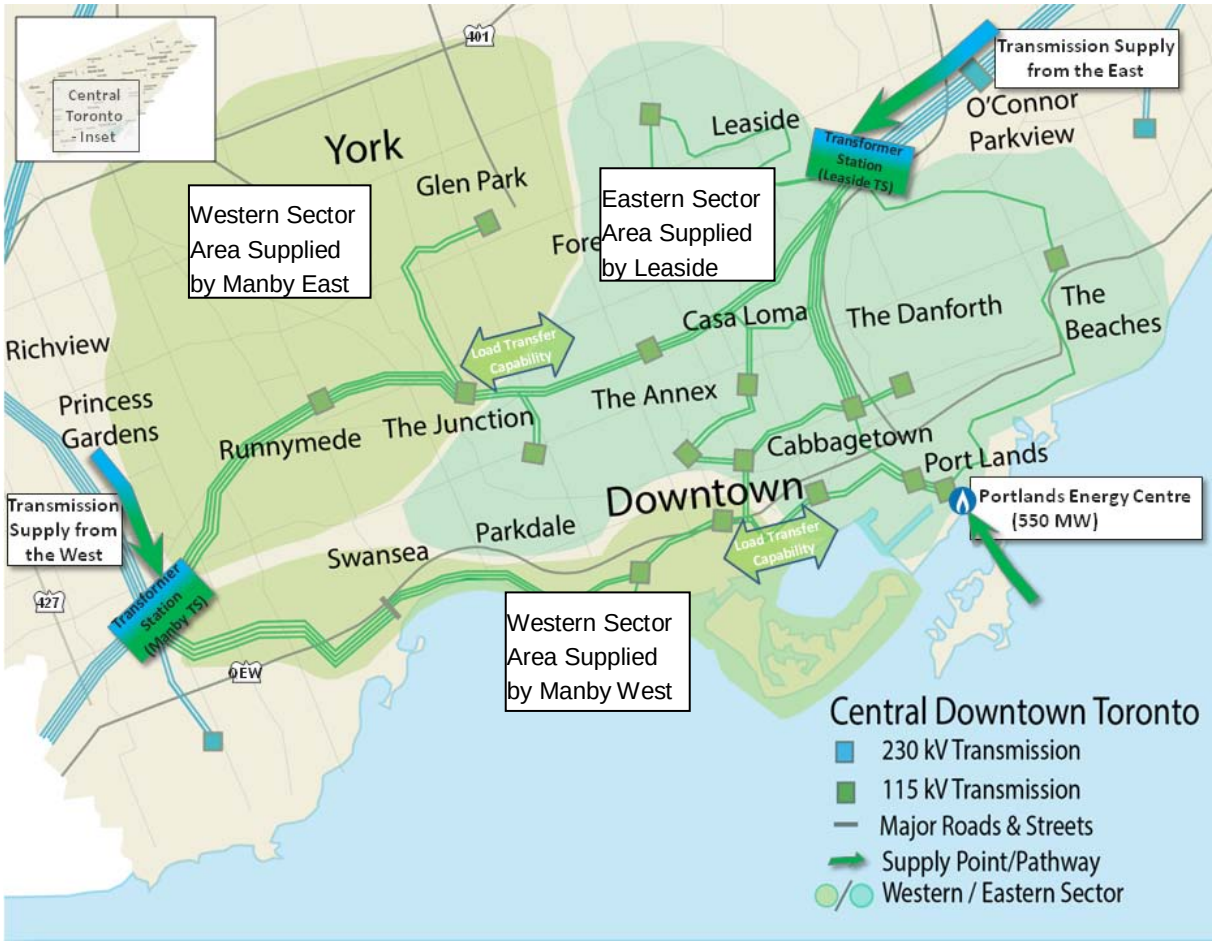


1. The study area boundaries, as shown, are the approximate service areas of the transmission and distribution facilities within the scope of the Central Toronto IRRP.
2. The study area also includes the service areas of Manby TS, Leaside TS and Horner TS, which are supplied by 230 kV transmission.

As shown in Figure 4-2, customers in the study area are served by two main electrical sectors, an eastern sector ("Eastern Sector") and a western sector ("Western Sector"). The Eastern Sector is supplied through a major 230 kV/115 kV TS in the Leaside area (Leaside TS) and the Western Sector is supplied through a major station near Islington City Centre – West in Etobicoke (Manby TS). The Portlands Energy Centre (PEC), a 550 MW natural gas fired combined cycle power plant near the downtown core, also feeds into the Eastern Sector. About 70% of the peak electrical demand (1,400 MW) is normally served by the power system facilities in the Eastern Sector and the remaining 30% of the peak electrical demand (600 MW) is normally served by the power system facilities in the Western Sector. The Western Sector is supplied by two independent busses at Manby TS: Manby West which supplies areas of the downtown core, and

Manby East which supplies areas to the northwest of downtown. A detailed diagram of the transmission system supplying the Central Toronto Area is provided in Appendix A. Further information about the electrical system in the study area can be found within a Central Toronto IRRP Discussion Workbook, available on the IESO website.[7]

Figure 4-2: Electrical Supply in Central Toronto by Sub-sector



Horner TS, to the south of Manby TS, is supplied by 230 kV facilities from Manby TS and is therefore inside the Central Toronto IRRP study area.

The transmission system in the study area has the capability of switching electrical demand between the Eastern and Western Sectors. There are switching facilities and cables that allow some of the load to be transferred back and forth between the Manby East and Leaside systems,

[7] The Discussion Workbook is available at: http://www.ieso.ca/Documents/Regional-Planning/Metro_Toronto/Central%20Toronto%20IRRP%20-%20Discussion%20Workbook.pdf

and between Manby West and Leaside systems, when required to maintain load supply during equipment outages or system emergencies.

In the event of a loss of supply in the Eastern (Leaside) Sector, the generation source at PEC will be initially lost. While PEC does not have black-start capability,[8] there is sufficient flexibility within the transmission system to restore generation at PEC from the West via switching, when emergencies occur in the Eastern Sector. Restarting PEC from the West is estimated to take about 1 hour to complete.[9]

The flexibility and redundancy built into the transmission system has enabled effective restoration of customers within the city under past extreme failure events. This flexibility also enables planned outages for routine maintenance and major refurbishments without materially impacting service to customers.

Transfer capability at the distribution system level is more limited. Some transfer capability is feasible from bus to bus within stations, but there is very little capability to transfer electrical demand between stations in the Central Toronto Area via the 13.8 kV distribution system.[10] This is a result of the legacy design of the distribution system that was originally built in Toronto.

4.2 Recent, Planned and Committed Resources

Since 2006, numerous projects, programs and initiatives in Central Toronto have addressed supply capacity, reliability, and equipment end-of-life. This has produced lasting improvements to the electricity supply situation in the area. These resources include conservation, local and distributed generation, and transmission and distribution investments.

4.2.1 Conservation

Considerable achievements in electricity conservation have been made in the City of Toronto. From 2006 through 2013, about 295 MW of peak demand reduction has been achieved in the

[8] Black-start is the capability to restore a power station to operation without relying on the external electric power transmission network, which is normally provided from the station's own generators.
[9] This time can vary depending on the sequence of events that had led to the initial isolation of the Leaside bus.
[10] Recent system investments will provide significant enhancements to the transfer capability in Central Toronto once in service. For example, the Midtown Reinforcement project will permit nearly all of the Manby East demand to be supplied via Leaside TS, and Clare R. Copeland TS, currently under construction in downtown Toronto, will eventually have the ability to transfer load to and from the other major stations around it.

city through programs and initiatives delivered by the OPA, Toronto Hydro and other participants, including the City of Toronto. Much of these savings are expected to persist for the next several years, although savings from conservation committed in the past may diminish over time.

The approach to conservation resource procurement that was taken up to 2015, involved designing and delivering conservation programs to customers province-wide. These programs were evaluated through the OPA's evaluation, measurement and verification (EM&V) process to determine both the provincial and LDC-specific impact of each program. The capability to conduct LDC-specific evaluation of savings for the conservation programs evolved with the ramping up of program offerings in the market. Impacts of conservation efforts were reported both at the provincial and LDC-level.

With the transition to more locally designed conservation programs (through the LDCs, for example), it is expected that conservation programs will be tailored to the local customer base, target specific customer groups in local or regional areas of need, and that results will be directly attributable to the local step-down station or bus level.

2006-2014 OPA Conservation Programs

At least 28 conservation programs were offered in the City of Toronto from 2006 to 2014. Eleven of these programs continue to be offered as the province transitions to the new conservation framework and Toronto Hydro's 2015-2020 Conservation Plans are implemented. Moving forward, under the Conservation First Framework, all Ontario LDCs are required to produce a conservation and demand management plan by May 1st, 2015 outlining how they intend to meet their mandated energy savings targets within their allocated conservation budget from 2015 to 2020.

The programs that have been offered to customers in Toronto are listed in Table 4-1. These are mostly province-wide programs delivered by Toronto Hydro or various delivery channel partners. Some initiatives were rolled out as pilots, and learnings from these initiatives were integrated into future programs or program redesign.

Table 4-1: 2006-2014 Conservation Programs in the City of Toronto

Program	Market Sector	Availability
Affordable Housing Pilot	Residential Low Income	2007
Cool & Hot Savings Rebate	Residential	2006-2010
Demand Response 1	Commercial & Institutional, Industrial	2006-2009
Demand Response 2	Commercial & Institutional, Industrial	2009-2010
Demand Response 3	Commercial & Institutional, Industrial	2008-Current
Energy Efficiency Assistance Pilot	Residential Low Income	2007
Every Kilowatt Counts	Residential	2006-2010
Great Refrigerator Roundup	Residential	2006-2010
High Performance New Construction	Commercial & Institutional	2008-Current
Toronto Hydro - Summer Challenge	Residential	2009
Loblaws Demand Response	Commercial & Institutional (Loblaw)	2006-2010
Multi-Family Energy Efficiency Rebates	Residential, Residential Low Income	2009-Current
***peaksaver*®** and ***peaksaver* Plus®**	Residential, Business	2007-Current
Power Savings Blitz	Commercial & Institutional	2008-2010
Social Housing Pilot	Residential Low Income	2007
Summer Savings	Residential	2007
Summer Sweepstakes	Residential	2008
Toronto Hydro Comprehensive	Residential, Commercial & Institutional, Residential Low-Income	2007-2010
Appliance Exchange	Residential	2011-Current
Appliance Retirement	Residential	2011-Current
Residential Coupons (Annual and Event Coupons)	Residential	2011-Current
HVAC Incentives	Residential	2011-Current
Retailer Co-op	Residential	2011-Current
Direct Install Lighting	Commercial & Institutional	2011-Current
Retrofit	Commercial & Institutional	2011-Current
Energy Audit	Commercial & Institutional	2011-Current
Home Assistance Program	Residential	2011-Current
Energy Manager	Industrial	2011-Current

City of Toronto Energy Saving Policies and Programs

In addition to the conservation programs listed in the preceding section, the City of Toronto has developed a number of innovative policies and programs that conserve energy. A summary of these policies and programs is presented in Table 4-2. This summary has been adapted from the City of Toronto Energy & Emissions Inventory and Mapping Report (2013).

Table 4-2: City of Toronto Energy Saving Policies and Programs

Policy	Description	Target Group
City Wide Energy Policies		
Toronto Green Standard (TGS)	The TGS is a two-tiered set of performance measures and guidelines used to achieve sustainable site and building design in new developments. New buildings are required to achieve a minimum energy performance of 25% better than the Model National Energy Code for Buildings/Ontario Building Code within Tier 1, and a voluntary energy performance of 35% energy savings within Tier 2. These minimum and voluntary targets are currently under review and are expected to increase in the future.	New planning applications (including Zoning By-law Amendment, Site Plan Control and Draft Plan of Subdivision) are required to comply with Tier 1 standards. Tier 2 measures are voluntary and applicants who wish to meet them may be eligible for a Development Charge Rebate.
Green Roof By-law	Sets green roof and cool roof coverage requirements for new developments as a way to reduce storm water runoff and building cooling demand.	Applies to new building permit applications for residential, commercial and institutional development made after January 31, 2010 with a minimum gross floor area (GFA) of 2,000 m2
Area Specific Energy Policies		
Waterfront Toronto Minimum Green Building Requirements	Waterfront Toronto Minimum Green Building Requirements	Waterfront Toronto Minimum Green Building Requirements
Secondary Plan Requirements for Energy Studies	Secondary Plan Requirements for Energy Studies	Secondary Plan Requirements for Energy Studies
Energy Programs		
Better Building Partnership	Better Building Partnership	Better Building Partnership
Home Energy Load Program	Home Energy Load Program	Home Energy Load Program

Conservation Pilot Initiatives in the City of Toronto

In addition, a number of innovative conservation pilot initiatives have either been completed or are underway in the City of Toronto. The IESO, Toronto Hydro, and the City of Toronto pilot initiatives are summarized in Table 4-3. Opportunities to scale these pilots to programs are being evaluated.

Table 4-3: Conservation Pilot Initiatives in the City of Toronto

Pilot	Description	Savings Opportunity
Pay for Performance (PFP): $/kWh (Loblaws Inc.)	• Pilot initiated in 2014 • Pay for Performance is a financial model in which savings from energy efficiency upgrades receive additional monetary compensation (beyond reduced operating costs) • If energy consumption increases penalties may be applied • Contracts may be offered in targeted areas	• To be evaluated
Municipal financial support through Local Improvement Charges (City of Toronto)	• Pilot initiated in 2014 • Local Improvement Charges (charged and collected by the city) will be used to create a fund, which will be available as a low-interest loan to individuals for investment in energy efficient upgrades • Pilot will include 200 homes and 200 apartment units • The City expects to make the fund available to all Toronto residents by 2015	• Maximum energy efficiency upgrades is expected to be 10% per building/unit
Multi-unit residential building demand response pilot (MURB DR) (Toronto Hydro)	• Pilot initiated in 2013 • Involves the installation of load control devices and programmable communicating thermostats in MURB units and common areas • Energy efficiency retrofits will also be conducted in building common areas	• Involves four condominium facilities for a total of 400 suites; the anticipated savings is 0.3 kW per suite and 77.9 kW per common area (with 100 suites, per building savings is 101 kW (ca. 10% of load) • A total of 20MW of demand reduction may be achieved if full program launch is enabled (ca. 200 buildings)
Local Demand Management Pilot Study (Toronto Hydro)	• Study initiated in fall 2013 • Aim is to assess the estimated demand savings from targeted demand reduction initiatives and to design and run pilots in constrained service areas	• If the initiative achieved 5% in demand savings, infrastructure investments could be offset for several years
Commercial Energy Management and Load Control (CEMLC) pilot (Toronto Hydro)	• Pilot involves the installation of load control devices and programmable communicating thermostats to be activated during peaksaver PLUS activation periods	• Pilot initiated in 2013 for the 50-250 kW commercial sector • Involves 12 facilities (3 in each of the office, retail, hospitality and institutional sectors); the average demand savings per site is expected to be 23.4 kW (280 kW total) • A total of 42 MW of demand reduction may be achieved if full program launch is enabled (1,800 sites)
HVAC load shifting technology pilot (Ice Energy- Ice Bear Energy Storage System)	• Piloted by Toronto Hydro 2010-2011 (supported by the OPA)	• Each unit reduces peak demand by 12 kW

Deep Lake Water Cooling

Downtown Toronto is home to the Deep Lake Water Cooling System that provides air conditioning to commercial, institutional, government and residential buildings by drawing cool lake water and circulating it to buildings to replace the need for electric air conditioning systems. It is estimated that deep lake water reduces electricity usage by 90% compared to conventional cooling systems. The Deep Lake Water Cooling System has been estimated to have reduced the downtown peak demand by as much as 61 MW.

4.2.2 Generation Resources

Since 2008, a number of new generation facilities have been installed in Central Toronto. The Portlands Energy Centre ("PEC") is an example of a large transmission connected generation facility sited within the load centre. Many new small renewable generation facilities have also come into service under the province's Feed-in Tariff program, as well as combined heat and power projects. These facilities are described further below.

Portlands Energy Centre 550 MW Gas-fired Generating Station

Phased in from 2008 to 2009, a major new generation supply resource was placed in-service and connected at the Hearn switching station in the Portlands area. This 550 MW combined cycle generation facility is an important source of generation providing capacity and supply security within the Central Toronto load area. The PEC restored some balance to the supply and demand situation in downtown Toronto, which had become imbalanced when the Hearn generating station was decommissioned in the 1980s.

Renewable Energy Generation

Since 2009, 13.75 MW of new renewable energy generation facilities have been contracted for in Central Toronto under the Feed-in Tariff program. Of these 120 projects, 13 MW are rooftop solar photovoltaic ("PV") projects, and one project is the 750 kW wind turbine installed at Exhibition Place. Another 731 microFIT solar PV projects, totaling approximately 4 MW of capacity, have been contracted for across the City of Toronto, a portion of which are located in the Central Toronto Area.

District Energy

The City of Toronto has identified and studied 27 areas, or "nodes," throughout the city where the density of development provides an opportunity to develop District Energy systems.[11] Of these 27 nodes, 10 were identified as having high potential to be developed, 7 of which are within the Central Toronto Area:

- East Bay Front (Jarvis and Queens Quay)
- Yonge and Dundas
- Yonge and Bloor
- West Don Lands (Eastern and Front)
- Fort York (Bathurst and Lakeshore)
- Etobicoke Civic Complex (West Mall and Civic Center Court)
- Lawrence Phase 2 (Allen and Lawrence)

A 1.6 MW District Energy system is currently under construction at Exhibition Place. Electrical energy generated will help meet local peak electricity demand needs of the area, and thermal energy will be sold to a new hotel under construction on the Exhibition Place grounds.

Other small District Energy systems in the City of Toronto make up a portion of the 21.5 MW of reliable peak electricity demand reduction that represents the full complement of DG resources within the Central Toronto Area.[12]

4.2.3 Transmission and Distribution Facilities

Since 2007, numerous transmission and distribution projects have been started or completed to address supply capability, reliability or equipment end-of-life issues in the Central Toronto Area. These projects include:

- John TS to Esplanade TS underground cables
- Midtown 115 kV transmission reinforcement
- Hearn switching station rebuild
- Breaker upgrades
- Lakeshore 115 kV cable refurbishment
- Clare R. Copeland 115 kV transformer station

[11] Report is available for download at the City of Toronto website: http://www1.toronto.ca/City%20Of%20Toronto/Environment%20and%20Energy/Programs%20for%20Businesses/BBP/PDFs/FINAL-GENIVAR-Report-City-of-Toronto-District-Energy-November-21-13.pdf

[12] 21.5 MW is the capacity of DG resources that can predictably generate during the peak demand period.

Many of these projects stemmed from previous integrated planning studies completed since the mid-1990s, and are discussed in more detail below. Over the last 10 years, investment in Central Toronto's electricity system has been approximately $1.3 billion.

John TS to Esplanade TS Underground Cables

Two new underground cables, 2.2 km in length, from the John TS to Esplanade TS were placed in-service in 2008 by Hydro One. These cables resulted in enhanced reliability and security between the Leaside and Manby systems and addressed the need for increased load transfer capability between the two 115 kV systems. This link was recognized as a common facility required for a future major new transmission supply to Central Toronto. The cables are capable of operation at 230 kV, but are currently being operated at 115 kV.

Midtown 115 kV Transmission Reinforcement

The Midtown transmission project, currently underway, is a multi-stage transmission refurbishment project that is replacing the underground cables between Bayview Junction and Birch Junction in the Leaside TS sector. This joint Hydro One – Toronto Hydro project will add a new 115 kV circuit between Leaside TS and Birch Junction, as well as installing new equipment at Leaside TS and the Bayview, Birch and Bridgman Junctions to provide additional electrical supply capacity to the area. In addition to addressing capacity issues for supplying Bridgman TS and Dufferin TS, the project provides additional capacity to transfer the Wiltshire TS load from the Manby TS sector to the Leaside TS sector under most normal operating conditions. This will provide more flexibility to address loading or equipment issues not only on the Manby TS system but also further upstream in the western parts of the GTA. This line upgrade will also enable nearly all of the electrical demand in the Manby East system to be supplied from Leaside TS under emergency conditions (up to 340 MW).

Hearn Switching Station Rebuild

Hydro One has completed a full rebuild of the Hearn switchyard in the Portlands area to address equipment end-of-life at this important switching station in downtown Toronto. The new Hearn station permits the Hearn 115 kV switchyard to operate as one bus rather than in split bus configuration, resulting in improved overall balancing of electrical demand on the transmission facilities out of Leaside TS.

Breaker Upgrades

Hydro One has replaced the 115 kV circuit breakers at both Leaside TS and Manby TS. These projects have resulted in the removal of fault current limitations that had affected the downtown area. They will also permit the connection of additional DG in the Central Toronto Area. In addition, the new equipment is more reliable and reduces the probability of an unexpected breaker failure contingency affecting supply to customers in the area.

Lakeshore 115 kV Cable Refurbishment

The Lakeshore Renewal Project is the second phase of the Lakeshore sustainment project first undertaken in the 1990s. The current project by Hydro One involves replacement of two 115 kV underground cables connecting Riverside Junction at Windermere Avenue and Lakeshore Boulevard to Strachan TS at Strachan Avenue and Manitoba Drive. Hydro One is installing two new 230 kV cables, but the cables will operate at 115 kV until more power is needed. The existing cables that were originally installed in the late 1950s will be decommissioned once the new cables are in service. The typical lifespan of a cable is 50 to 60 years.

Clare R. Copeland 115 kV Transformer Station (Phase 1)

Toronto Hydro is building the first new step-down transformer station in downtown Toronto in many years. In addition to providing additional supply capacity in the heart of the downtown business district, the Clare R. Copeland TS ("Copeland TS," formerly called Bremner TS) will provide additional flexibility to transfer downtown loads from Manby to Leaside and this additional load-shifting capability can reduce the amount of load at risk of being interrupted in the event of a contingency at Manby TS or John TS.

5. Demand Forecast

This section outlines the demand forecast for Central Toronto. The demand forecast estimates the future peak electricity demand within the area over the planning horizon, including the contribution of conservation and DG to reducing peak electricity demand requirements.

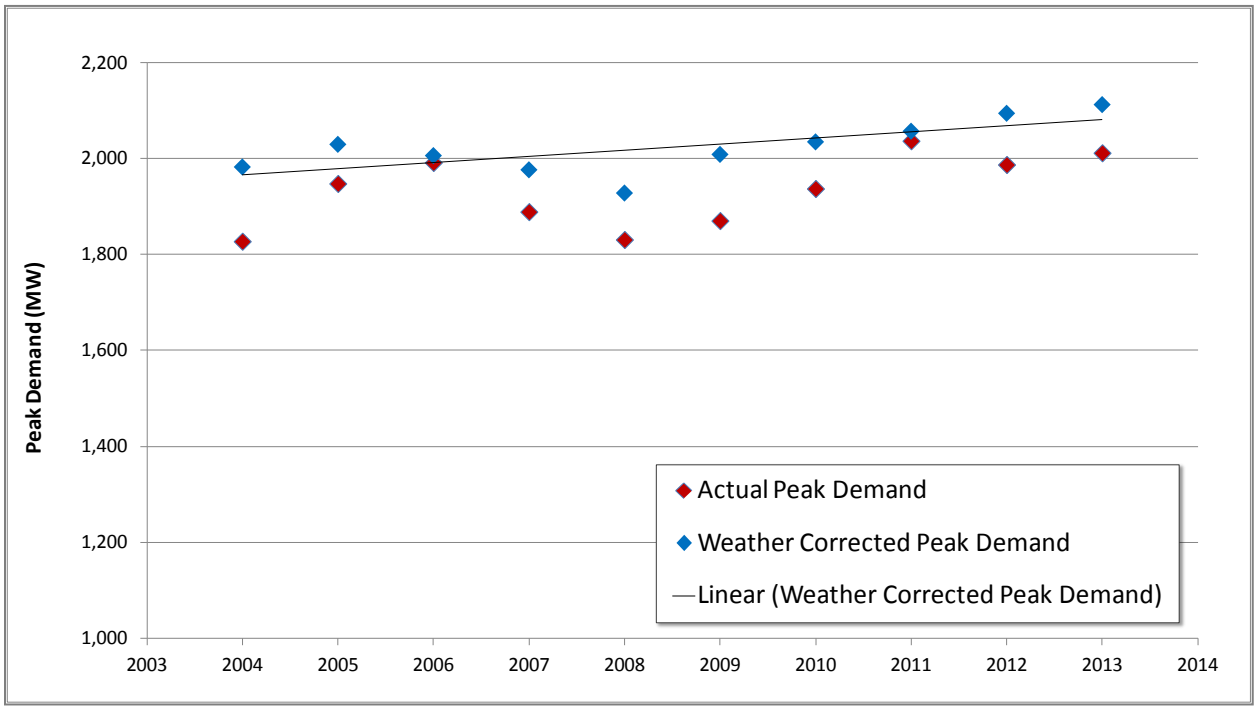
For the purposes of evaluating the adequacy of the electricity system, regional planning is concerned with the regional coincident peak demand. Coincident peak demand is the demand observed at the transformer stations for the hour of the year when overall demand in the study area is at its highest. This represents the moment when equipment is expected to be the most stressed, and resources the most constrained. Within Central Toronto, the peak loading hour for each year typically occurs in mid-afternoon of the hottest weekday during the summer, and is driven primarily by the weather sensitive air conditioning loads of commercial and residential customers. Within the past 10 years, the local peak occurred on the same day as the overall provincial peak in each year but one.

The following sections describe the historical demand trends in the area, followed by a description of the various forecast elements, including the gross forecast, conservation forecasts, and the net forecasts used for determining the electricity service requirements for the plan.

5.1 Historical Demand

Over the past five years, Central Toronto has experienced moderate overall growth in electricity demand. In 2007 and 2008, a decrease in electricity demand in the Central Toronto Area occurred, as conservation programs entered the market and the economy experienced a downturn. Since 2008, the demand in the area has returned to pre-recession levels and has been buoyed by strong growth in new building construction. Historical peak demand has averaged growth of 0.7% per year over the past decade, as shown in Figure 5-1.

Figure 5-1: Historical Electricity Peak Demand for Central Toronto 115 kV System



Within Central Toronto, there have been individual pockets of higher growth, and some areas that have experienced lower growth. In particular, the downtown core, consisting of five transformer stations (Cecil TS, Terauley TS, Esplanade TS, John TS and Strachan TS), has averaged growth of 1.2% per year over the same time period.

Factors that have influenced the historic peak demand from 2006 onwards have been the savings associated with conservation programs, and other initiatives such as the Deep Lake Water Cooling System Project that has been estimated to reduce the downtown peak demand by as much as 61 MW.

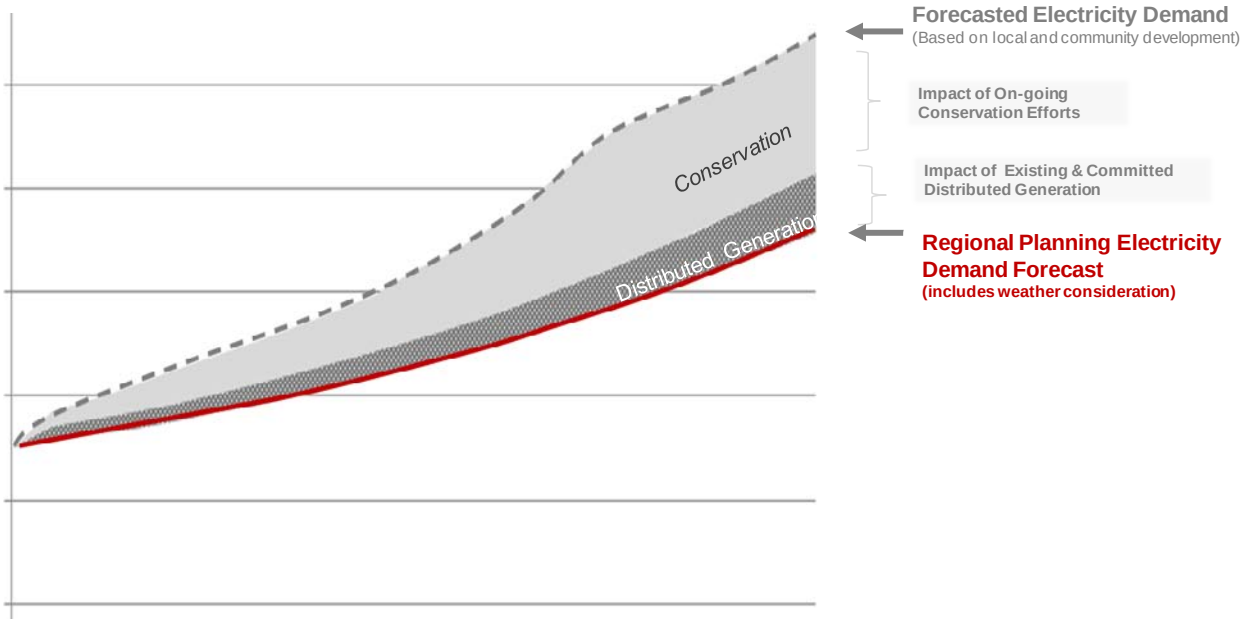
5.2 Demand Forecast Methodology

Regional electricity needs are driven by the limits of the infrastructure supplying an area, which is sized to meet peak demand requirements. Therefore, regional planning typically focuses on growth in regional-coincident peak demand. The Toronto region is a summer peaking area. The adequate supply of electricity, or energy adequacy, is usually not a concern, as the region can generally draw upon energy available from the provincial electricity grid and provincial energy adequacy for the province is planned through a separate process.

A regional peak demand forecast was developed as illustrated in Figure 5-2. A gross demand forecast, assuming extreme-weather conditions, was provided by Toronto Hydro. The gross demand forecast accounted for the growth projections provided by City of Toronto plans and projections for population, economic development, and intensification through plans for new building and urban development, and considered the impact of existing in-market conservation programs and existing DG. This forecast was then modified to reflect the peak demand impacts of future provincial conservation targets to produce a planning forecast. The planning forecast was then used to assess any growth-related electricity needs in the region.

Using a planning forecast that is net of provincial conservation targets is consistent with the Province's Conservation First policy. However, this planning forecast assumes that the energy targets will be met, and will produce the expected local peak demand impacts. An important aspect of plan implementation will be monitoring the actual peak demand impacts of conservation programs delivered by Toronto Hydro, and as necessary, revisiting and adapting the plan if assumptions change.

Figure 5-2: Development of Demand Forecasts



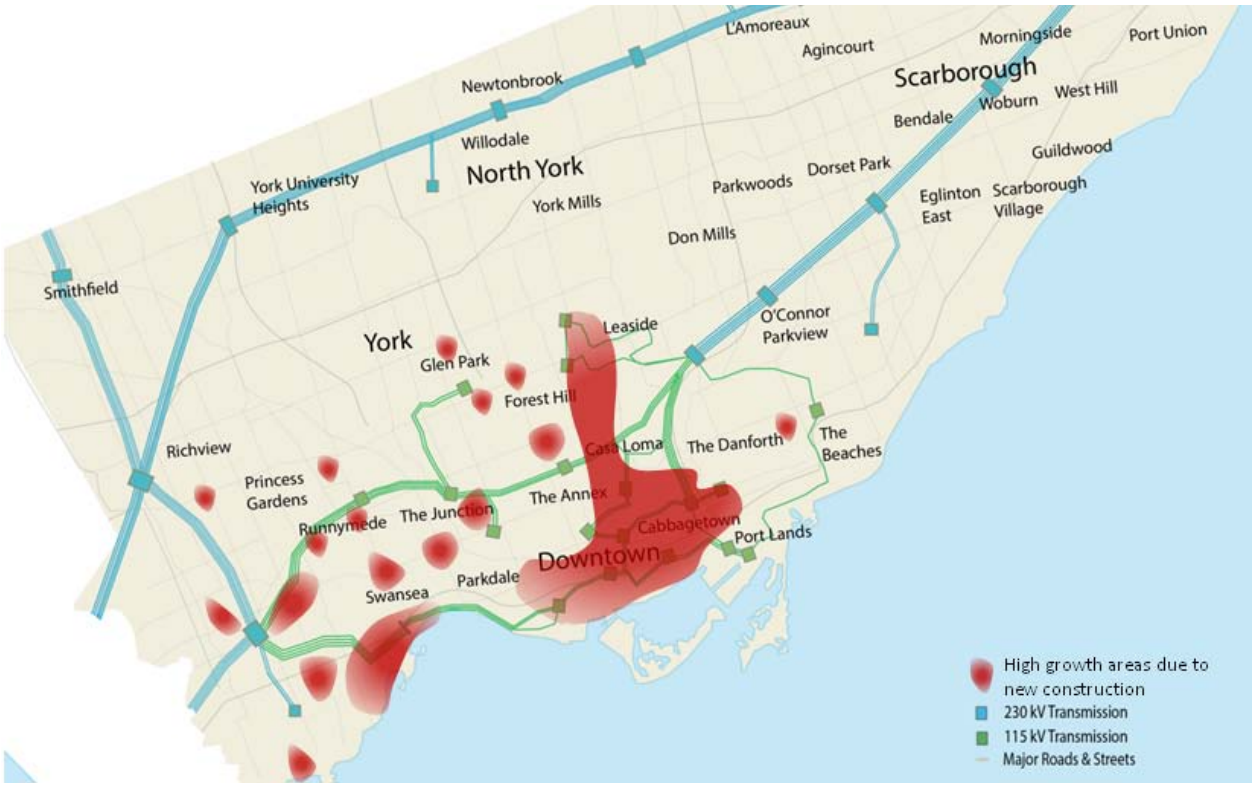
5.3 Gross Demand Forecast

For the purpose of this study, Toronto Hydro commissioned Navigant Consulting Inc. to develop a summer peak demand forecast covering a 25-year planning horizon. The forecast accounts for information on developments expected to contribute to demand growth in the area, including population and employment. The forecast provided by THESL was developed under coincident, extreme-weather assumptions, which accounts for the weather sensitive aspects of electricity demand such as space cooling in the summer months. Further detail about the methodology used to develop Toronto Hydro's gross forecast is provided in Appendix B.[13]

Overall, growth is expected to continue over much of the Central Toronto Area. The majority of growth is expected to be concentrated where significant pockets of new development are occurring, such as the central lakeshore area and the west end of the City. The growth in these areas is primarily due to high rise building development, and is shown in Figure 5-3.

[13] It is noted that Navigant produced separate forecasts termed "gross" and "net." The "gross" forecast excludes all conservation and DG past, present and future, and represents a forecast absent the impact of any conservation measures implemented in Toronto since 2006. This forecast is less useful for the purpose of determining electricity system needs. The "net" forecast includes historical conservation and the current conservation programs that were in-market in 2012 until 2014. After 2014, the THESL "net" forecast does not account for additional conservation programming. The references to THESL's "gross" demand forecast in this document actually refer to the "net" forecast as described in Appendix B.

Figure 5-3: Concentrations of Growth in Central Toronto



Source: City of Toronto

5.4 Conservation Resources Assumed in the Forecast

Conservation plays a key role in maximizing the useful life of existing infrastructure, and maintaining reliable supply. Conservation is achieved through a mix of program-related activities, including behavioral changes by customers and mandated efficiencies from building codes and equipment standards. These approaches complement each other to maximize conservation results. The conservation savings forecasts for Central Toronto have been applied to the gross peak demand forecast, along with existing DG resources, to determine the net peak demand for the region.

In December 2013 the Ministry of Energy released a revised Long-Term Energy Plan (LTEP), which outlined a provincial conservation target of 30 TWh of energy savings by 2032. To represent the effect of provincial targets within regional planning, the IESO developed forecast scenarios for peak demand savings based on varying levels of achievement of the provincial savings target. These conservation scenarios were applied to the gross demand forecast to

develop estimates of the peak demand impacts in Central Toronto. The conservation estimates are shown in Table 5-1. Additional conservation forecast details are provided in Appendix C.

Table 5-1: Peak Demand Savings Assumed from the 2013 LTEP Conservation Targets in Central Toronto (Megawatts)

Year	2014	2016	2018	2021	2026	2031	2036
High Demand Scenario	305	253	255	241	215	215	238
Low Demand Scenario	305	346	376	411	497	611	641
Median Demand Scenario	305	253	255	284	366	396	423

5.5 Distributed Generation Assumed in the Forecast

In addition to conservation resources, DG is also anticipated to offset peak demand requirements. The introduction of the *Green Energy Act, 2009* ("GEA"), and the associated development of Ontario's Feed-in Tariff ("FIT") program, has increased the significance of distributed renewable generation in Ontario. This generation, while intermittent in nature, contributes to meeting the electricity demands of the province.

In developing the planning forecast, the effects of DG in service at the time were included. Each project's capacity contribution was subtracted from the peak demand at the transformer station to which it was connected. The amount of DG assumed to have a peak demand impact was 21.5 MW.

Future DG uptake was not included in the forecast due to difficulties forecasting the uptake and location. This leaves DG potential as an option for meeting future needs.

Additional details of the demand reductions attributable to DG are provided in Appendix C.

5.6 Planning Forecasts

After taking into consideration the combined impacts of conservation and DG, planning forecast scenarios were produced based on the demand forecast submitted by Toronto Hydro to the Working Group.

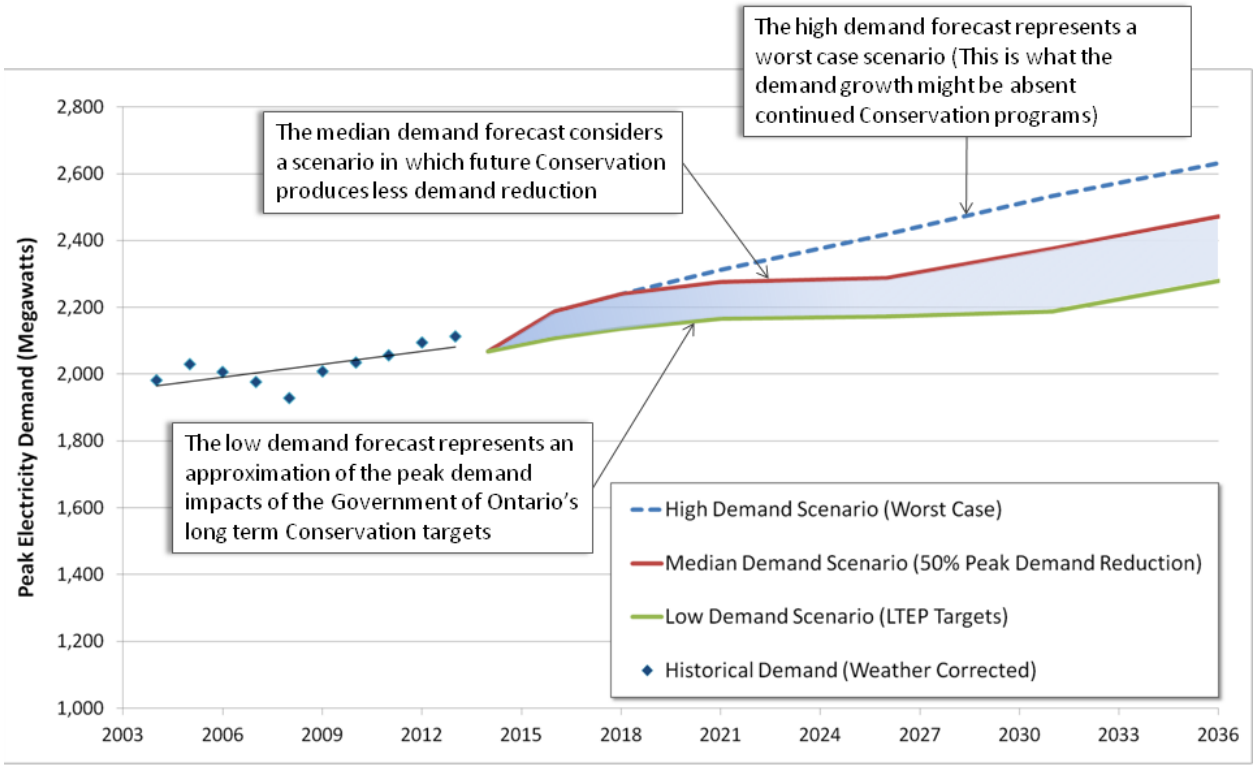
A "high demand" growth scenario was assessed to determine what the system needs would be under a worst-case, in which either conservation does not meet expectations, or new growth and development accelerate in the area. This forecast scenario assumes 238 MW of savings from conservation targets across the Central Toronto Area over the next 25 years. This scenario assumes that all historic and conservation initiatives to the end of 2014 continue to provide persistent savings, but no new conservation after 2015. The average annual growth rate under this scenario is 0.99% per year.

A "low demand" growth scenario was assessed which assumes that 60% of the new demand growth will be met through future conservation programs. The basis for this scenario was the provincial Long-Term Energy Plan targets ("LTEP targets"). This forecast scenario assumes 641 MW of new savings from conservation targets across the Central Toronto Area over the next 25 years. Combined with the effects of DG and existing conservation programs, the low demand scenario forecast assumes that the impact of future conservation programs to meet the long-term targets will reduce the average annual growth rate from 0.99% to 0.38% growth per year.

An additional planning scenario was developed to reflect the uncertainty associated with forecasting electricity demand and the possibility of varying levels of peak demand impact from future conservation. This "median demand" scenario was developed to test the impact on system needs if either future conservation produces less peak demand impact, or new customer growth is higher than forecast. This forecast scenario assumes 423 MW of new savings from conservation targets across the Central Toronto Area over the next 25 years, which considers 50% of the peak demand reduction compared to the low demand scenario. This represents a growth rate of 0.72% growth per year. This growth rate is closest to the historical rate of electricity demand growth in Central Toronto over the last ten years (0.71%).

The three demand scenarios are shown in Figure 5-4 for the 115 kV transmission system in Central Toronto. The raw demand forecast data for the entire study area is provided in Appendix D.

Figure 5-4: Electricity Peak Demand Forecast for Central Toronto (115 kV System)



6. Needs

This study assessed the capability of the existing high voltage power system to provide reliable electrical service over the near-term (0-5 years), medium-term (6-10 years) and longer-term (11-25 years) periods.[14] The assessment accounted for growth in electrical demand within the study area, the reliability standards established for power systems within Ontario, service quality expectations as expressed by customers, and other preferences indicated by the local community through the engagement process. The assessment as noted, also accounted for the implementation of expected conservation, given existing programs that are in the planning phases and targets established by the Province of Ontario.

6.1 Need Assessment Methodology

Provincial planning criteria were applied to assess the capability of the existing electricity system to supply forecast electricity demand growth in the Central Toronto are over the forecast period. Electrical system needs were determined through a series of tests as defined in the ORTAC, which establishes the planning criteria and assumptions to be used for assessing the adequacy and security of Ontario's electricity system.[15]

Technical assessments were conducted using industry-standard software-based modeling tools such as Power System Simulator for Engineering ("PSS®E") for conducting deterministic contingency analysis, and using the probabilistic assessment feature within PSS®E to estimate the risk related to certain contingencies that are beyond the stress tests as defined by the criteria in ORTAC. All system tests were performed assuming summertime peak demand conditions under the various demand forecast scenarios described in Section 5.

6.1.1 Ontario Resource Transmission Assessment Criteria

In accordance with the ORTAC, the transmission system must be able to provide continuous supply following defined transmission and generation outage scenarios, and limit the amount of load loss and restoration time following the occurrence of multiple element outages. The

[14] The long-term planning horizon for a Regional Plan is typically 20 years. In the case of Central Toronto, Toronto Hydro provided a forecast covering a 25-year period. The Working Group agreed to assess needs based on the 25-year forecast.

[15] The ORTAC document can be found on the IESO website:
http://www.ieso.ca/Documents/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

defined outage scenarios are referred to as "contingencies." These contingency-based tests are deterministic in that they are assessed independent of the probability of their occurrence.

Deterministic assessments are an established electricity industry practice for assessing the power system's ability to supply the demand under various possible states, including:

- all system elements in service (N-0),
- following the loss of any one transmission or generation element (N-1),
- following the loss of any one element while another element is on outage or planned maintenance (N-1-1), and
- In certain cases, following the loss of two elements simultaneously (N-2).[16]

In addition to the deterministic tests, the assessment accounted for the flexibility within ORTAC to rationalize higher (or lower) levels of reliability performance.[17] A probabilistic-based reliability assessment ("PRA") was conducted to test higher-order contingencies beyond those specified in ORTAC. Contingencies involving the loss of up to three independent power system elements (N-3) were tested with consideration of the frequency with which they might be expected to occur and the duration of the outages. The frequency and expected duration of an outage for each element was based on the historic levels of reliability and restoration service within the study area, as reported to the Working Group by Hydro One.

PRA provides an estimation of the amount of energy that is likely to go unsupplied in each year, as expressed by the Expected Unserved Energy ("EUE") metric,[18] giving an indication of "unreliability" related to the system design.

Types of Needs Uncovered in the Assessment

The assessment of the electricity system facilities serving Central Toronto uncovered a number of electricity power system needs. These needs generally fall into the following categories: (1) capacity-based needs relating to providing required infrastructure capacity to supply the peak

[16] Transmission facilities that provide Local Area supply are tested to N-1, or N-1-1 levels of security, whereas Bulk Power System facilities are tested to N-2 to account for the possible system impacts that could result from double contingencies.
[17] For example, Section 7.4 of ORTAC allows for transmission customers and transmitters to agree on higher or lower levels of reliability for technical, economic, safety and environmental reasons. The IRRP Working Group agreed that in the case of Central Toronto, that the assessment be supplemented by reviewing the impact of higher order contingencies on customers in the area.
[18] The EUE metric does not provide an absolute determination of the amount of energy that will not be supplied due to unreliability of the system. Rather, it is an indicator only and should not be interpreted as an accurate representation.

demand; (2) reliability-based needs relating to reducing the impact of supply interruptions; and (3) security-based needs relating to the ability to restore supply after major contingencies or unusual events such as extreme weather. These types of needs are described further below.

- **Capacity** is the ability to supply peak demand under normal conditions (i.e., all equipment in service) or under a contingency condition (e.g., one or more power system elements out of service). This ability includes the electrical and physical attributes of the power system to carry out its role.
- **Reliability**, in the context of interruptions of electricity supply to customers, involves two considerations. The first relates to the frequency of supply interruptions (or how often they occur). The second relates to the duration of supply interruptions, and the ability of the system to enable the restoration of service to customers within a specified period of time.
- **Security** involves ensuring that the power system is designed with enough flexibility to reasonably contain the interruption of electricity supply to customers when extraordinary failures occur, and to enable the restoration of supply to interrupted customers within a reasonable period of time. Security includes the ability of the system to cope during major events such as storms and other extreme weather events. The coincident or overlapping failure of several pieces of equipment, the failure of an entire transmission station, or more than two transmission circuits are considered as extraordinary failure events. Given the rare nature of these events, the cost of ensuring full redundancy is typically not justifiable. However, these rare failure events are given consideration in planning, as the power system should have the capability to limit the number of customers exposed and restore interrupted customers within a reasonable period of time.

As part of the security assessment, the IESO reviewed the system design under major power system failure events. A few of these events have occurred over the last several years and the Working Group agreed that proactively investigating the susceptibility of the local power system to these events should be a key component of this study. Although the occurrence of these types of failure events is statistically rare, they tend to have very high impacts on customers if the system and related operational procedures are not able to restore power to customers within a reasonable time period.

The needs identified through the assessment are summarized in the following sections for the near-term and medium-term periods and in Section 8 for the long term.

6.2 Near-Term and Medium-Term System Needs

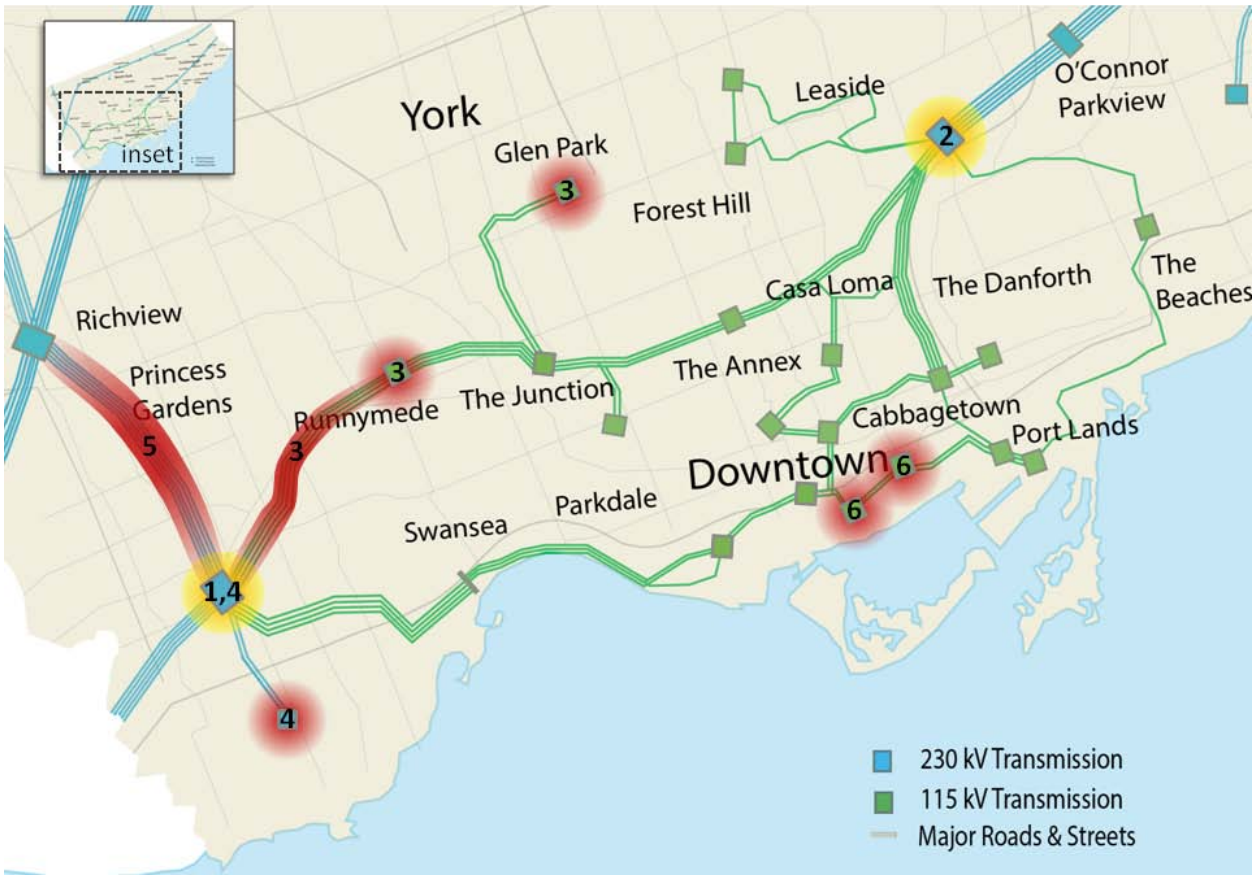
The technical assessment of the electricity system serving Central Toronto uncovered a number of system needs to be addressed by actions in the near term and medium term.

The near-term needs (0 to 5 years) and the medium-term needs (6 to 10 years), and the options and recommended actions for addressing these needs are summarized in Table 6-1 and are shown in Figure 6-1. Further details are provided in the following sections. Technical summaries of the assessment results are provided in Appendix E. Long-term needs and options are discussed in Section 8.

Table 6-1: Summary of Near and Medium-Term Needs in Central Toronto

Need	Description	Timing	Map Reference (Figure 6-1)	Section Reference
Supply security	Breaker failure contingency at Manby West and Manby East	Today at Manby West; 2018 at Manby East	1	6.2.2
Supply security	Breaker failure contingency at Leaside TS	Today	2	6.2.3
New transformation capacity	Demand growth in West Toronto is forecast to exceed the limits of Runnymede TS and Fairbank TS	2018	3	6.2.5
New transformation capacity	Demand growth in Southwest Toronto is forecast to exceed the limits of Manby TS and Horner TS	2018	4	6.2.5
Transmission line capacity	Demand growth in Central Toronto is forecast to exceed the limits of the 230 kV Richview TS to Manby TS corridor	2018	5	6.2.6
New transformation capacity	Demand growth in the downtown core is forecast to exceed the limits of Esplanade TS and Copeland TS	2021	6	6.3.2

Figure 6-1: Map Showing Need Locations in Central Toronto



6.2.1 Improving Supply Security for Low Probability Breaker Failures at Manby TS and Leaside TS

The IRRP assessment identified a need to reduce the impact of multiple element contingencies at the two major transformer stations that provide grid supply to the Central Toronto Area. These needs are related to the potential failure of a switching device (e.g., breaker) to perform the intended function of clearing an electrical fault. Such a failure could result in electricity service interruptions to customers in the Central Toronto Area.

6.2.2 Manby TS Needs

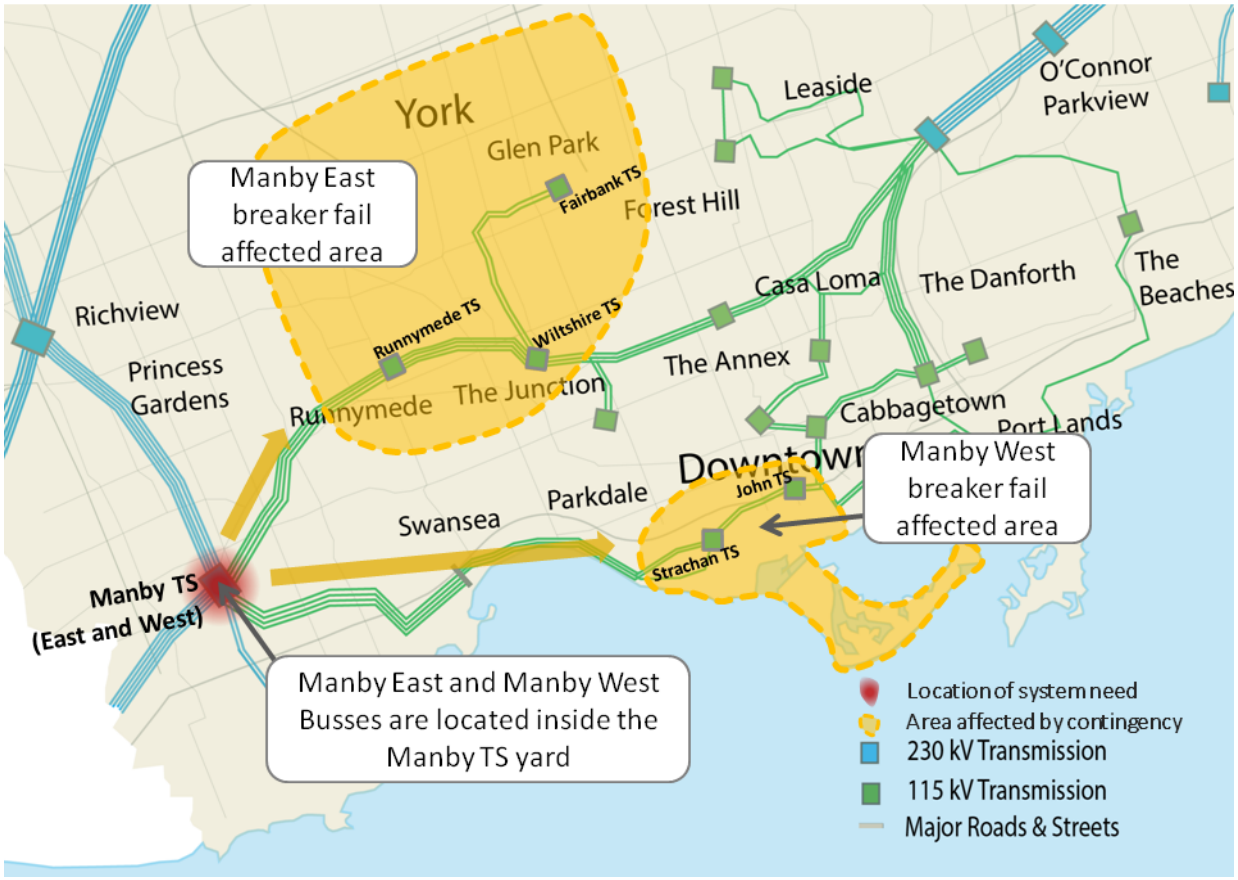
At Manby TS, this need stems from the reliability standards established for interconnected power systems in North America, as defined in the ORTAC. A breaker failure contingency at Manby TS would remove two transformers from service at the same time. The station has two independent delivery points to Central Toronto: a west bus and an east bus, each with three 230/115kV transformers to supply different parts of the Central Toronto Area, as shown in

Figure 6-2.[19] A breaker failure incident at either of these busses will result in only one of the three transformers remaining in service.

In the past, the summer peak station loads have been within the short time emergency rating of the transformer and would thereby still allow the system operator to take necessary action to reduce the transformer load in the event of the contingency. As the demand has increased in Central Toronto, there is a need to take action to ensure that the transformer loading can be reduced, and to minimize the possibility of cascading failures.

The location of the Manby TS and areas affected by the breaker failure are shown in Figure 10. Breaker failure could impact significant customer demand in the affected areas.

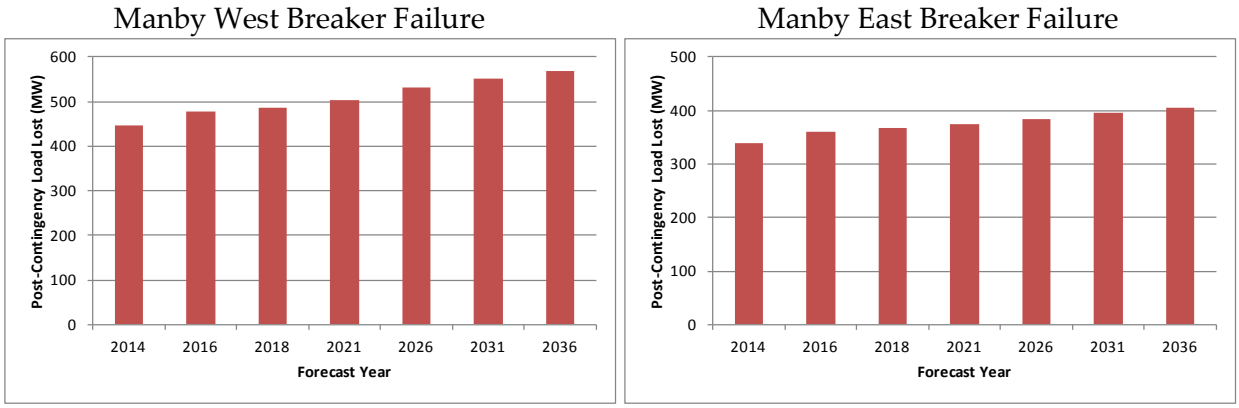
Figure 6-2: Manby TS Equipment and Affected Areas



[19] At Manby West, the failure of breaker H1H4 or A1H4 would activate breaker failure protection at the station resulting in only a single transformer to carry the full Manby West electrical demand. At Manby East, the failure of breaker H2H3 would activate breaker failure protection at the station resulting in only a single transformer to carry the full Manby East electrical demand.

As stated previously, this need occurs at each of the two independent east and west delivery points at Manby TS, affecting customers both in a large part of the downtown core and in the west Toronto area to the northwest of downtown. The severity of the need is reflected by the amount of load that would be at risk immediately following the breaker failure event. The estimated load at risk at both Manby TS busses is shown in Figure 6-3.

Figure 6-3: Forecast of Customer Load at Risk Following Manby TS Breaker Failure Events



6.2.3 Leaside TS Needs

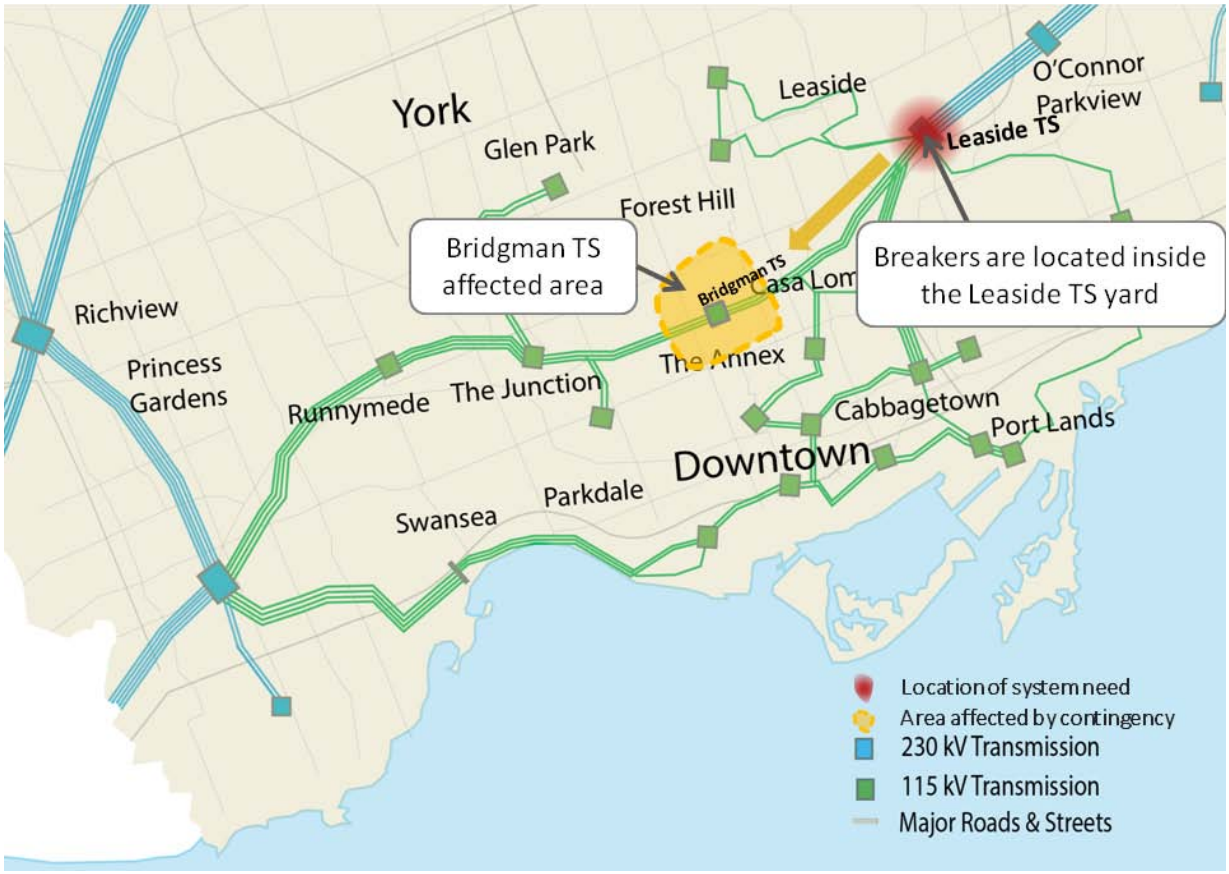
The need at Leaside TS is considered discretionary because the reliability standards (e.g., ORTAC) do not require action to be taken given system impacts and configuration, but because of the importance of security of supply in the Central Toronto Area and the important role that Leaside plays in backing up the Manby East system, the issue has been flagged in this plan.

A breaker failure contingency at Leaside TS would cause protection systems to activate and consequently remove from service two 115 kV circuits that supply the Bridgman TS to the north of downtown Toronto.[20] This would result in five of six step-down transformers at Bridgman TS being removed from service, leaving only one remaining transformer at Bridgman TS. This remaining transformer is not capable of supplying the full electrical demand of the station.

The location of the Leaside TS and the area affected by the breaker failure are shown in Figure 6-4. This breaker failure would lead to a significant outage to customers in the affected area shown.

[20] At Leaside TS, the failure of breaker L14L15, which is shared by the 115 kV circuits L14W and L15W supplying Bridgman TS, would remove both circuits from service. The cascading impact of outages at Bridgman TS would affect the supply to the area served by Bridgman TS.

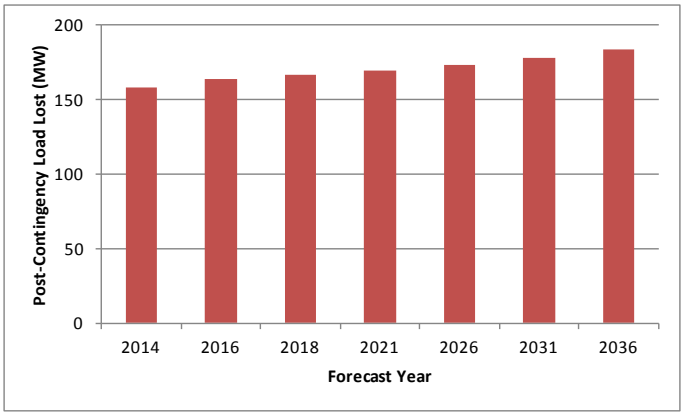
Figure 6-4: Leaside TS Equipment and Affected Areas



In contrast to the breaker events identified at Manby TS which must be addressed to satisfy the reliability standards, mitigating measures should be put in place at Leaside TS as a discretionary measure. These mitigating measures are appropriate given the number of customers potentially affected, the fact that the lines involved are also used to transfer loads from Manby during contingencies, and to improve the supply security in the area. The reliability standards require the testing of breaker failures within the Leaside TS, but since the consequence of the breaker failure do not affect the bulk electric system, the reliability standards do not require that mitigating measures be put in place.

The estimated load at risk immediately following the breaker failure event at Leaside TS is shown in Figure 6-5.

Figure 6-5: Forecast of Customer Load at Risk Following Leaside TS Breaker Failure Event



6.2.4 Capacity Relief to Supply Points in the Manby TS Sector

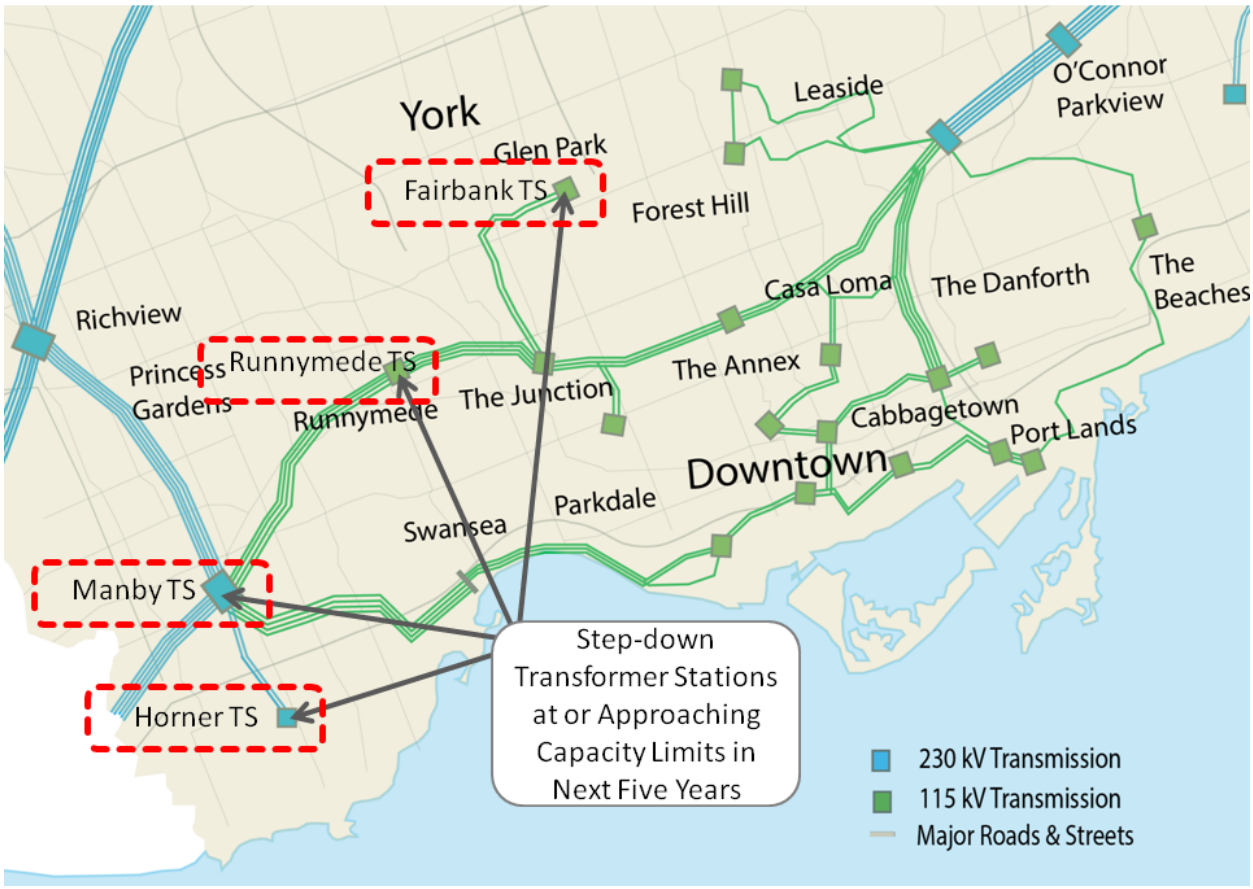
In the near term, there is a need to ensure that sufficient capacity is available to supply growing electricity demand in the west Toronto area. The capacity need occurs at the step-down transformer stations serving as electricity supply points for distribution customers in the Manby TS sector, and on the 230 kV transmission lines that supply the Manby TS from the provincial grid.

The local TS and line capacity needs are driven by continuing demand growth and by large new customer requests for connection to Toronto Hydro's distribution system. These individual TS and line needs are described separately in the following sub-sections.

6.2.5 Capacity Relief at Step-down Transformer Stations in West Toronto Area

There is a near-term need to provide capacity relief to existing step-down transformer stations serving distribution customers in the western sector. The specific distribution areas and neighbourhoods requiring the capacity relief are shown in Figure 6-6, and include the areas served by Runnymede TS, Fairbank TS, Manby TS, and Horner TS. These transformer stations provide energy transfer points between the high voltage transmission system and the distribution system, and the transmission facilities that provide supply to these stations. Runnymede TS and Fairbank TS are supplied by the 115 kV transmission system connected to the Manby East bus; and Manby TS and Horner TS are supplied by the 230 kV transmission network. The distribution voltage supplied by all four stations operates at 27.6 kV.

Figure 6-6: Station Capacity Needs in Central Toronto in the Near-Term



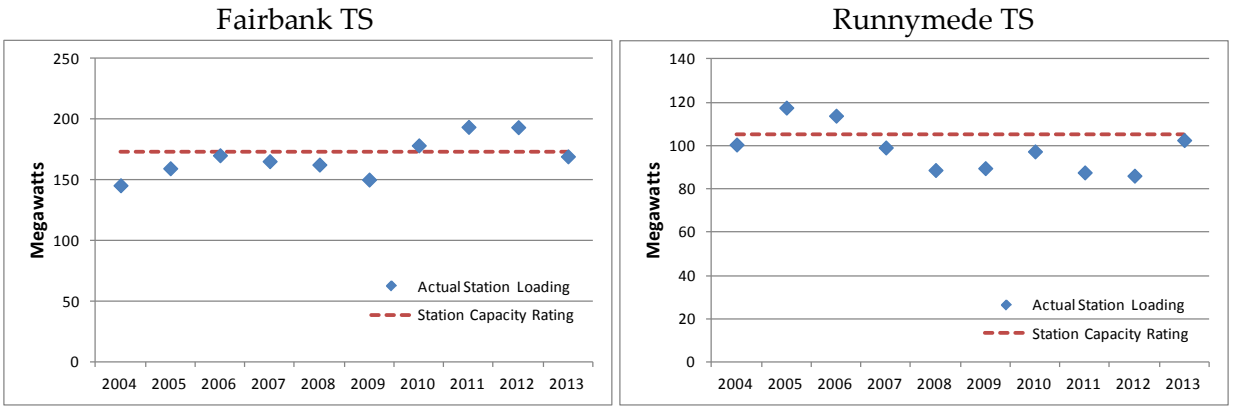
The needs in this area are being driven by the continued strong peak demand growth that has resulted in increasing new load connection request applications received by Toronto Hydro. In addition, other new large loads have signaled their intention to connect to the distribution system, such as the Eglinton Crosstown Light Rapid Transit ("LRT") ("Eglinton LRT") in the Runnymede/Fairbank area which is under construction and planned to be in service by 2019. Based on the geographic separation of the station areas, and the different growth drivers, the need for capacity relief in this area has been separated into two sub-areas: (1) Runnymede TS and Fairbank TS, and (2) Manby TS and Horner TS.

Runnymede TS and Fairbank TS

Both Runnymede TS and Fairbank TS are operating close to the station capacity during the peak demand period. A review of historical loadings at these stations shows that both Runnymede

TS and Fairbank TS have exceeded their 10-day limited time ratings (LTR) in the last 10 years, as shown in Figure 6-7.[21]

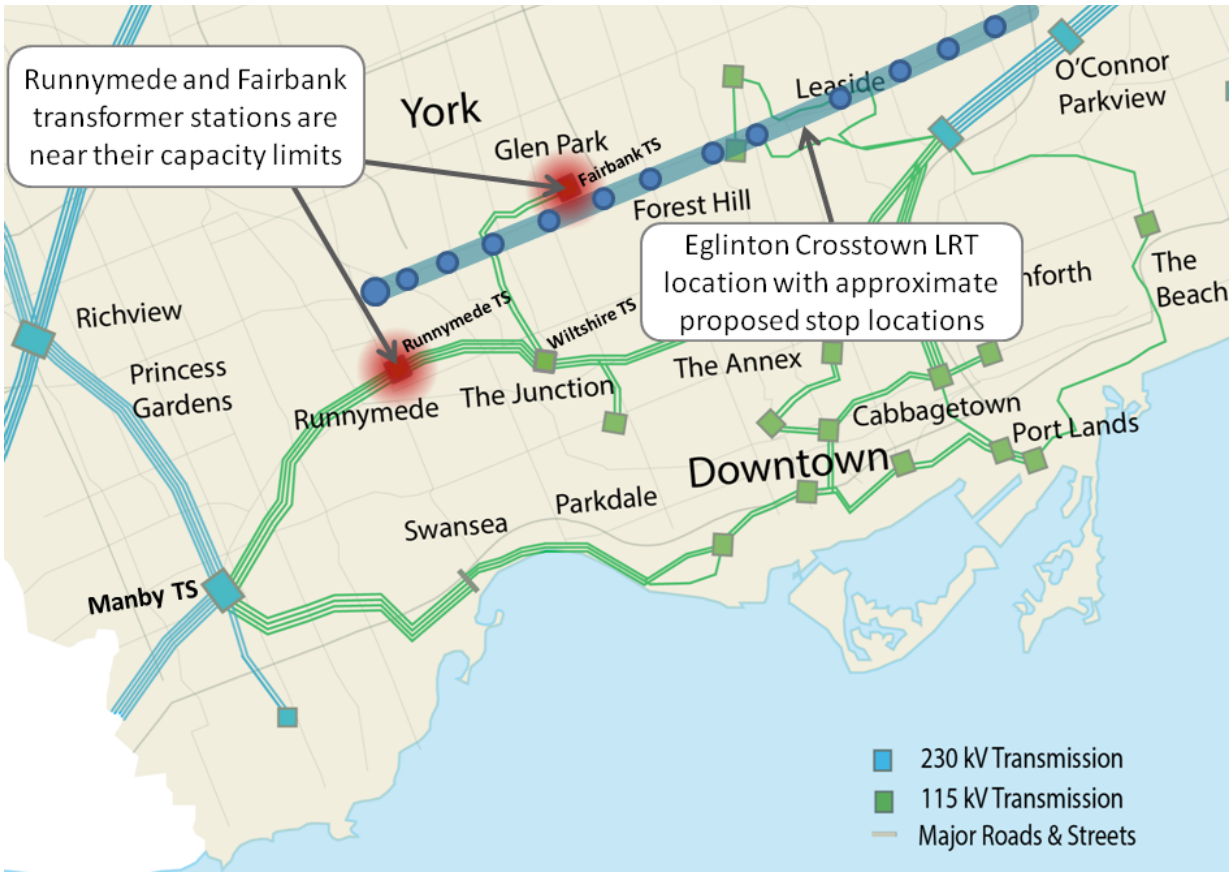
Figure 6-7: Runnymede TS and Fairbank TS Historical Peak Station Loadings



The service area of Runnymede TS and Fairbank TS is experiencing re-development, as well as being host to a portion of the Eglinton LRT project by MetroLinx. The Eglinton LRT project will add approximately 80 MVA (72 MW) of new load within Toronto, with over 20 MVA (18 MW) to be supplied from the west terminus of the line, near Runnymede TS. The location of the Eglinton LRT in relation to Runnymede TS and Fairbank TS is shown in Figure 6-8. As with other areas served by public transit facilities in Toronto, further land development and intensification due to the presence of new mass transit is expected to occur in the future.

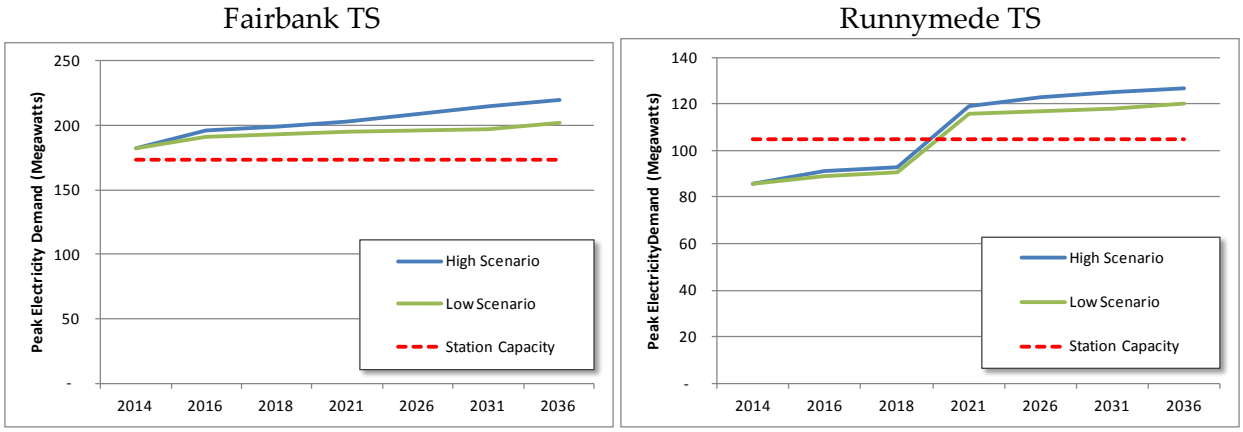
[21] The station capacity ratings were provided to the Working Group by Toronto Hydro and Hydro One.

Figure 6-8: Eglinton LRT Project Location in Relation to Supply Points in West Toronto



The demand forecast for Fairbank TS and Runnymede TS is shown in Figure 6-9. Both stations are forecast to require relief. The impact of the Eglinton LRT at the Runnymede TS will exceed the station's capacity to supply the load.

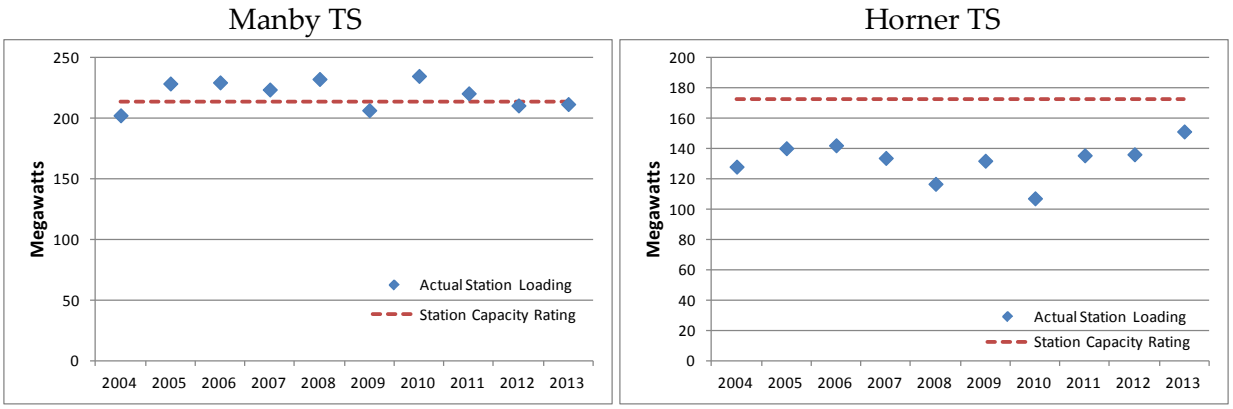
Figure 6-9: Runnymede TS and Fairbank TS Peak Demand Forecast



Manby TS and Horner TS

Both Manby TS[22] and Horner TS are operating close to the station capacity during the peak demand period. Manby TS is operating at its LTR and Horner TS was at 88% of its LTR in 2013, as shown in Figure 6-10. Manby TS has exceeded its capacity rating in past few years. Toronto Hydro has implemented several projects to relieve Manby TS in recent years through transfers to Horner TS, exhausting most, if not all, of the economic load transfer ability to Horner TS.

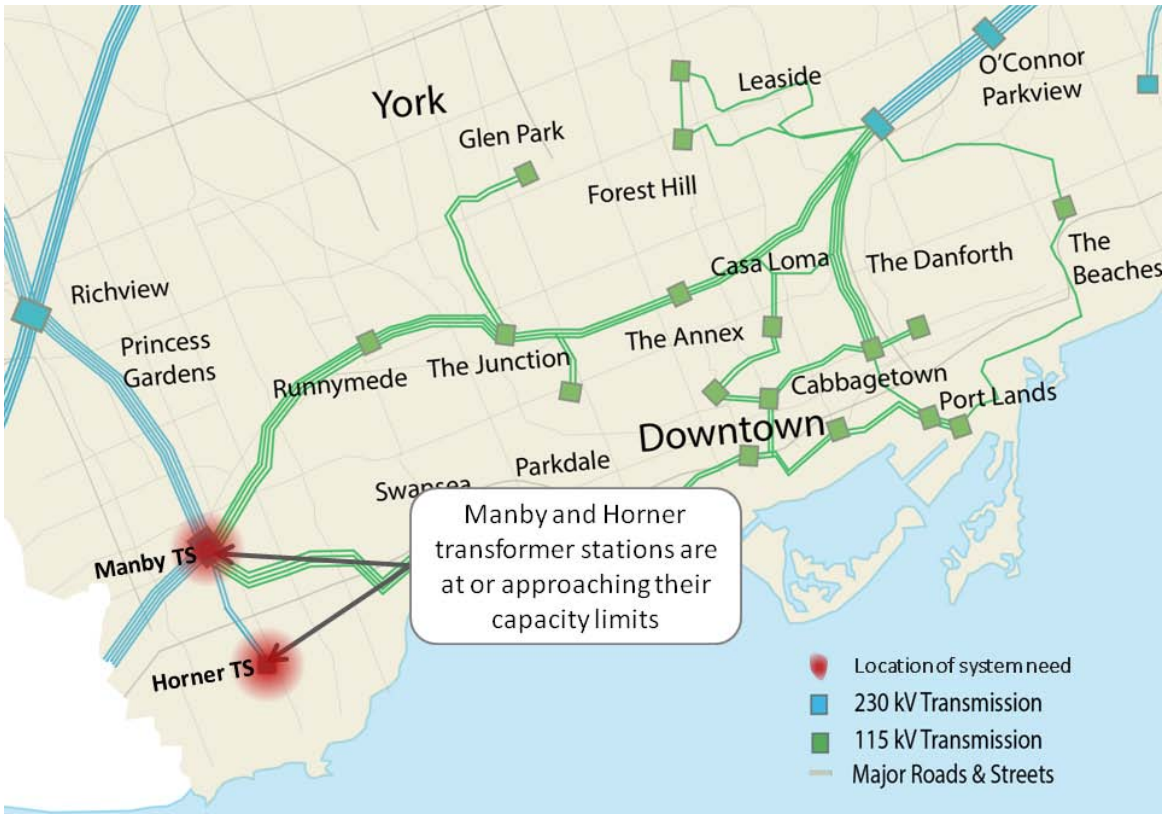
Figure 6-10: Manby TS and Horner TS Historical Peak Station Loadings



A consideration for Manby TS and Horner TS is continuing customer interest in connecting to the stations in this area. The location of Manby TS and Horner TS is shown in Figure 6-11.

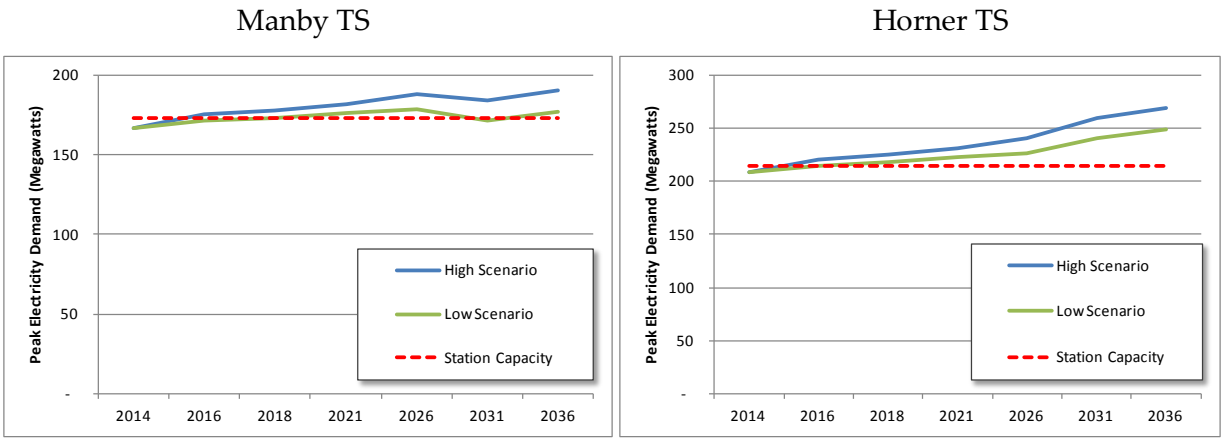
[22] This need refers to the capacity of the Manby TS step-down transformers that supply the local distribution network in the Islington City Centre area (230/27.6 kV), different from the 230/115 kV transformers that supply other parts of the Central Toronto Area via the 115 kV transmission system.

Figure 6-11: Manby TS and Horner TS Supply Points in West Toronto



The demand forecast for Manby TS and Horner TS is shown in Figure 6-12. Capacity relief at both stations is needed in the near-term period.

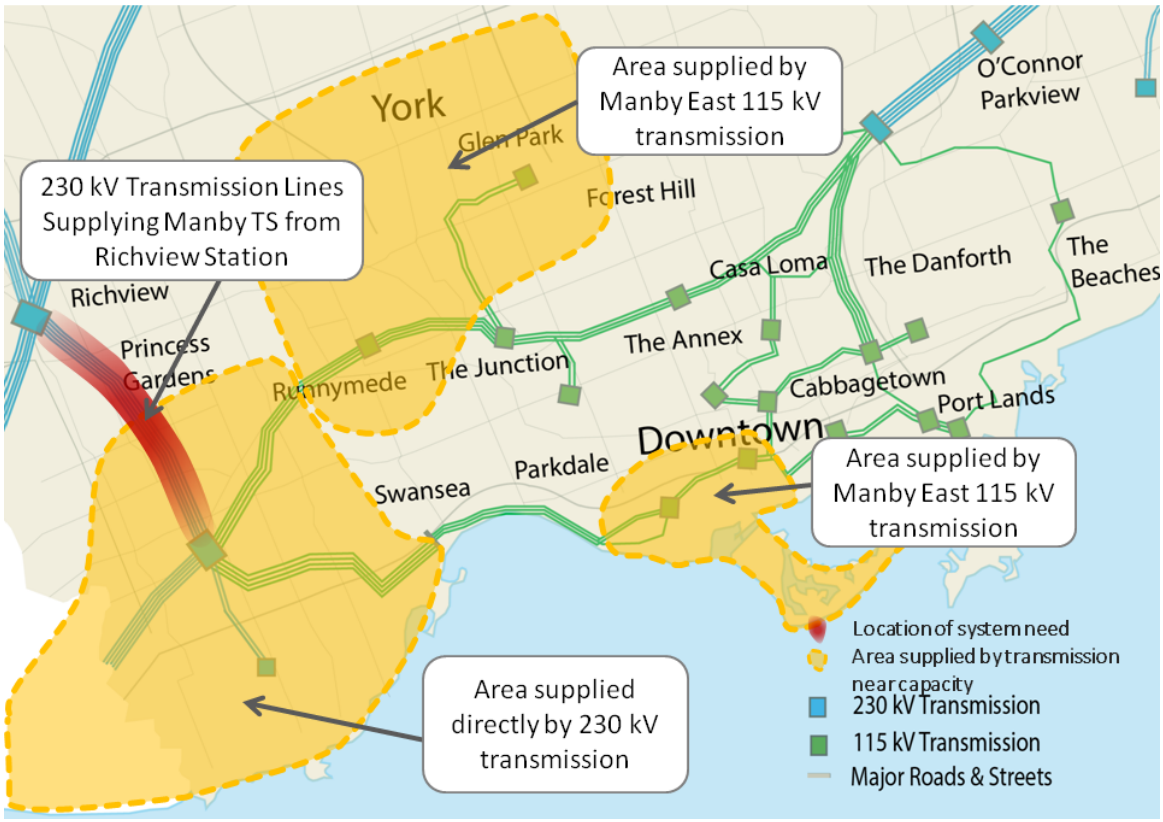
Figure 6-12: Manby TS and Horner TS Peak Demand Forecast



6.2.6 Capacity Relief for Richview x Manby 230 kV Transmission Corridor

At the end of the near-term period, there is a need for additional capacity on the 230 kV transmission lines that supply Manby TS from Richview TS. Richview TS is a major switching station and a main hub of supply from the provincial grid to customers in the western and northwest Greater Toronto Area. The Richview to Manby transmission corridor is the main supply path for a large part of the Central Toronto Area, including downtown Toronto, as well as southern Mississauga and Oakville. Manby TS is supplied by four 230 kV circuits from Richview TS along the corridor shown in red in Figure 6-13. The areas supplied by these transmission facilities are also shown in Figure 6-13 as orange shaded areas.

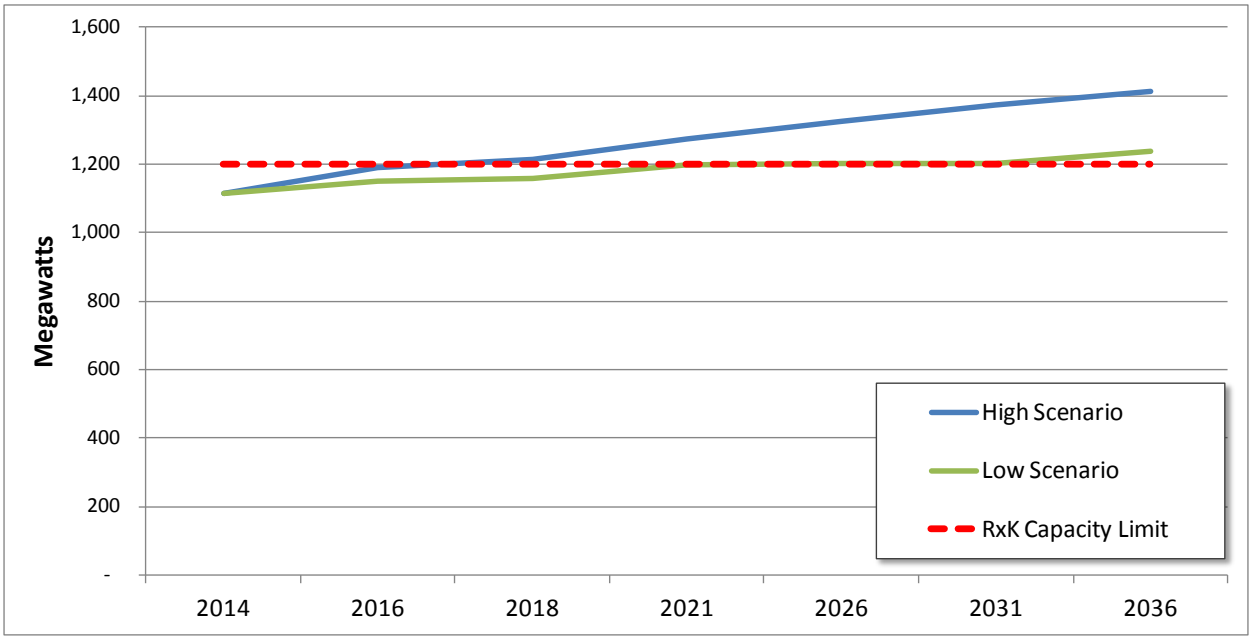
Figure 6-13: Richview – Manby 230 kV Transmission Capacity Needs



Note: The area supplied by Richview – Manby 230 kV transmission includes the Western Sector of the study area and the southern portion of Enersource and Oakville Hydro LDC franchise territory.

In 2014, Hydro One completed work to re-position the 230 kV tap points that supply Horner TS from the Richview – Manby transmission circuits. This project improves the load balancing of Horner TS supply across the Richview – Manby circuits, resulting in better utilization of existing facilities and providing some near-term capacity relief on the Richview – Manby corridor. Other new customers seeking connection to the power system in the Manby TS service area, such as the Eglinton LRT discussed in the previous section, will however add to the need for capacity relief by the end of this decade. The demand forecast for the Richview – Manby transmission corridor is shown in Figure 6-14. The forecast indicates that the capacity of this transmission corridor will be reached between 2018 and 2021, depending on the forecast scenario. Given the lead time for transmission, conservation and DG options, this need is considered urgent.

Figure 6-14: Forecast for Richview – Manby 230 kV Transmission Corridor



The electrical demand for transmission facilities in southern Mississauga and Oakville are excluded from the Richview – Manby ("RxK") corridor forecast and subtracted from the capacity limit shown above. The peak demand in these areas, also supplied via the Richview – Manby corridor is approximately 370 MW.

6.3 Medium-Term Needs

6.3.1 Capacity Relief to Supply Points Serving the Eastern (Leaside TS) Sector

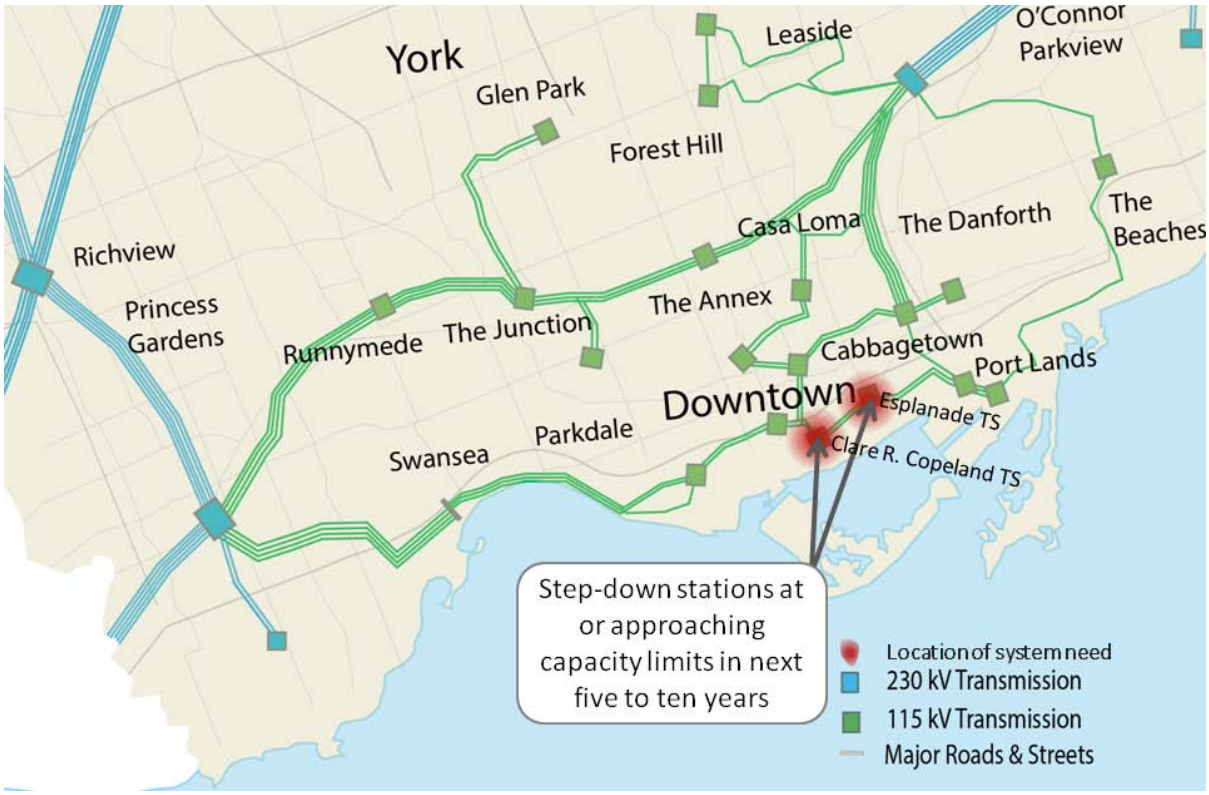
In the medium-term, there is a need to ensure that sufficient capacity is available to supply growing electricity demand in the downtown Toronto area, at the electricity supply points serving distribution customers in the downtown business district. This need is driven by continuing demand growth and by new customer connection requests.

6.3.2 Capacity Relief at Step-down Transformer Stations in the Downtown Area

There is a medium-term need (as early as 2021) to provide capacity relief to the Esplanade TS and Clare R. Copeland TS ("Copeland TS," phase one of which is currently under construction), which serve customers and supply growth in the downtown core. The stations requiring relief are shown in Figure 6-15.

Copeland TS will be used by Toronto Hydro to enable new customer connections, enable equipment renewal to address end-of-life issues at other downtown stations, and provide capacity relief. Once the first phase of Copeland TS is brought into service in 2016, Toronto Hydro expects that a combination of growth within the area and reconfiguration of adjacent station service areas will fully utilize the capacity by 2021, primarily because the station will pick up the growth from other adjacent, fully utilized downtown transformer stations, and connect new customers in the area.

Figure 6-15: Station Capacity Needs in Downtown Toronto in the Medium-Term



According to the load forecast, approximately 10 MW of relief will be required at Esplanade TS as early as 2016, with the amount of relief increasing to 30 MW by 2026. It is estimated that up to approximately 90 MW of additional customer load will be seeking connection in this area in the next five years. This estimate is based on recent information and is incremental to the load forecast provided for the IRRP. In addition, when Copeland TS is brought into service, the station will accept load from the nearby John TS and other transformer stations in the area, to free capacity to perform refurbishment work at John TS, as well as to provide relief to other downtown stations. Copeland TS is therefore expected to be at capacity very soon after

commissioning, and following the reconfiguration of existing station service areas. The need at Esplanade TS indicated in the load forecast will be deferred further into the future.

6.4 Other Observations for Addressing the Quality of Electricity Service

6.4.1 Probabilistic Reliability Assessment of Performance in Central Toronto

Electricity service reliability performance in the Central Toronto study area has typically exceeded reliability standards levels. The IRRP considered options for maintaining these high levels of service in the context of developing the plan. This approach was supported by stakeholder engagement feedback, which indicated that customers in the area expect very high electricity service reliability, including few interruptions and quick restoration of service when interruptions do occur.

To determine whether customers in Toronto should be provided with a higher level of electricity service, a review of utility practice in other jurisdictions containing major metropolitan areas was carried out. The review indicated that many utilities plan to meet higher levels of service reliability in central business areas as compared to outlying areas. About half of the utilities planned to achieve better reliability in central business areas or, in some cases, the capital region of their territory. Not all utilities planned or achieved higher reliability levels in the same manner. For example, some jurisdictions plan redundant transmission infrastructure, some have policies to ensure that greater amounts of generation are located within the load centre, some coordinate transmission and distribution planning more closely to enable one system to better back up the other, and several rely more heavily on special protection systems or operational schemes to provide higher levels of reliability in urban areas, rather than relying on more expensive infrastructure solutions. A summary of the review of planning standards in major metropolitan areas is provided as Appendix F.

A common practice in several jurisdictions is to employ probabilistic assessment tools to assess the reliability risk to customers, and to find solutions – the cost of which may correspond to the potential economic impact of the risk. For the Central Toronto IRRP, a probabilistic reliability assessment was conducted as a means of estimating the risk to customers inherent in the electricity system supplying the area, and to test the resiliency of the electricity system under outage contingency scenarios that are beyond the levels required by the reliability standards (e.g., ORTAC). The PRA took into account the probability of the outages, relying on historical

outage statistics of the various classes of equipment, including the frequency and the duration of historical outages.

The PRA results, provided in Appendix E, indicate that the transmission system serving the central part of the city has an inherent design that provides good flexibility for containing the impact of, and recovering from, such events. The design features of the local power system, coupled with the available operator control actions, result in the ability to restore service within a relatively short period of time, considering the magnitude of the types of outages assessed.

Actual experiences from recent major events confirm these findings. Root-cause analyses conducted subsequent to these major events have also incorporated system improvements that further mitigate the risk in the future. Given the low likelihood of occurrence associated with such incidents and the improvements which have been put in place to mitigate the known risks, the Working Group's view is that the cost of added transmission reinforcements to mitigate the residual risk is not justified. This was the case even when the economic impacts of customer outages were taken into account.

The annual monetized risk[23] of outages on the system is in the order of $6 million per year, reflecting the very low probability of multiple coincident transmission element failures. In addition, the risk of customer impact from outages is generally evenly distributed across the 115 kV system, with no one station or transmission service area being disproportionately vulnerable to outages as compared to any other. This finding indicates that there is no single transmission system fix that will substantially enhance supply security for the 115 kV transmission system area.

This PRA found that the greatest risk inherent within the 115 kV transmission system in Central Toronto is related to double transmission element contingencies at the individual step-down transformer station level. The coincident failure of two transformers or their transmission supply lines, on average, result in an annual monetized risk of just under $1 million per year. This indicates that the cost of mitigating solutions should be consistent with this benefit. Higher-order contingencies such as three elements failing at once (e.g., N-3) represent a very low risk to customers due to their very low probability of occurrence.

[23] Using assumptions for the value of customer reliability, the amount of expected unserved energy can be expressed as a monetary value. These assumptions are found in Appendix E.

6.4.2 Assessment of Impact of Extreme Contingencies (Low Probability – High Impact Events)

A number of specific "extreme contingencies" were assessed as part of the needs assessment, such as the loss of key transformer stations supplying the downtown Toronto 115 kV system and the loss of one or more multiple circuit structures (i.e., transmission towers). The contingencies assessed were selected by the Working Group based on a number of known possible scenarios that are beyond the scope of the normal planning criteria and more extreme than would be considered in the PRA discussed in the previous section, but for which an assessment was warranted due to the magnitude of the possible impact on customers.

The reliability standards[24] recognize the loss of a substation, transmission corridor and/or a major load centre as "extreme contingencies." While such extreme contingencies have a very low probability of occurring, the consequences can be high as the resulting interruptions can be widespread and/or take a long time to restore. While the design of the power system is not required to withstand such events without interruption of service, planning authorities assess extreme events for the potential impact and review if measures to mitigate the risk can be justified. Mitigation may include attempting to reduce the likelihood of load being interrupted, or more commonly reducing the extent and/or duration of unsupplied load following an extreme contingency. The ORTAC does not prescribe the degree of mitigation required and it is left to individual jurisdictions to assess the risk of extreme events and to determine if mitigation measures can be justified and incorporated in long-term plans.

The technical summary of the impact of extreme contingencies is not included with this IRRP due to security concerns.

6.4.3 Consideration of Plans for Transmission Infrastructure Renewal

Given the age of many of the transmission facilities in the area, the IRRP study assessed the potential impact on supply reliability of major facilities reaching end of life within the study period. Some facilities in the Central Toronto 115kV system are expected to require replacement or refurbishment over the next several years. The Hydro One report, "Summary of Asset Condition and Sustainment Plans for the Leaside and Manby 115kV System," included as Appendix G, identifies aging facilities in all major asset classes: overhead lines, underground cables, transformers, breakers and other switchgear equipment.

[24] Northeast Power Coordinating Council ("NPCC") criteria, as referenced in the ORTAC.

The refurbishment plans included in Hydro One's report were assessed using the demand forecast for the specific years representing the time periods:

- 1-5 years: 2016 forecast demand was assessed;
- 6-10 years: 2021 forecast demand was assessed; and
- 11-15 years: 2026 forecast demand was assessed.

The high demand forecast scenario was used for this assessment because this scenario represents the worst case loadings on the equipment supplying the area. The robustness of the transmission system, considering the planned outages that outlined in Hydro One's report, was tested by considering a contingency event in addition to the planned outage.

The assessment concluded that, given the process in Ontario for approving and taking equipment outages, it is expected that the local power system will have sufficient flexibility to accommodate the outages required to perform the planned refurbishment work.

The staging of certain refurbishment work, or strategies to keep existing facilities in service while replacement infrastructure is being built, and transferring customer supply to alternate sources, will help to mitigate risk of service interruptions during refurbishment periods.

7. Near-Term and Medium-Term Needs and Alternatives

The core elements of the near-term plan must include measures to enhance supply security and ensure that reliability standards continue to be met, and to ensure that sufficient infrastructure capacity is available to supply near-term growth. It is recommended that this be done by continuing with local conservation planning and implementation efforts, and proceeding with certain near-term infrastructure reinforcements to ensure that new customer demand can continue to be connected to the system. Finding opportunities for further DG resource development in the near and medium term is also recommended for improving the supply diversity and supporting system resilience.

This section describes the alternatives considered in developing the near and medium-term plan for Central Toronto and provides details of and rationale to support the recommended plan.

7.1 Alternatives Considered for Meeting Near- and Medium-Term Needs

In developing the near and medium-term plans, the Working Group considered a range of integrated alternatives. These alternatives balanced maximizing the use of the existing infrastructure with costs, and the need for enhancing the capacity, security and reliability of electricity service. A key objective in developing the plan was to ensure that longer-term infrastructure options are kept available and that the plan can adapt to a future in which the demand, resources and technology development are uncertain.

The following sections detail the alternatives that were considered, and comments on their performance in the context of the criteria described above.

7.2 Near-Term Alternatives

7.2.1 Addressing Supply Security Risk at Manby TS and Leaside TS

The supply security risks stemming from the possible breaker failure events at the Manby and Leaside transformer stations are generally recognized as having a low probability of occurring. However, should these events occur there would be significant electricity service interruptions to customers supplied downstream from these facilities. Given the high potential consequence

of these events, the number of technically feasible, cost-effective alternatives available for mitigating these risks is limited.

The alternatives that were considered for addressing these needs are discussed below.

Operational Measures (e.g., a Special Protection System, or "SPS")

A SPS can be designed to maintain the electrical demand within the capability of the transmission and distribution equipment that is remaining in service following a critical breaker failure event. These are operational measures that are automated, and do not typically involve major infrastructure upgrades.

The SPS is estimated to require one to two years for design and implementation, with a total cost in the order of $1 million to $3 million.

The use of an SPS is an acceptable solution for satisfying the ORTAC. SPSs are commonly used by utilities worldwide to enhance electricity service security for low probability, high consequence events. The SPS can be implemented quickly and more cost-effectively than other infrastructure based alternatives.

These types of automatic schemes are generally only triggered under very rare circumstances (although they may be "armed" and ready more often). When triggered, customer demand can be reduced in a strategic manner in order to maintain the equipment remaining in service below its emergency ratings and to prevent cascading failures and a wider customer impact. This also enables service to be restored more quickly. Specific customers that are interrupted can be selected based on criticality.

Another benefit of an SPS is that is can be designed and scoped to mitigate the impact of other rare equipment outage events, such as a partial or complete loss of Manby TS or Leaside TS or the loss of two circuits on a multi-circuit tower structure. These additional contingencies were assessed as per the analysis described in Section 6.4.2 and discussed with the Working Group in the context of the SPS alternative.

It is acknowledged that a SPS can introduce operational elements with associated risks that may need to be assessed and managed, such as the risk of failure on activation, inadvertent operation, as well as maintenance and coordination requirements between the transmitter, system operator, and the LDC.

Conservation and Distributed Generation

Conservation and DG are not technically feasible options for addressing these specific needs because there is not enough conservation achievable potential within the affected areas to address the risk within the timeframe required. A summary of each of the needs identified by the assessment, and the amount of conservation achievable potential within the affected areas is provided in Appendix H.

Furthermore, conservation is typically not used to address these types of security risks. However, conservation and DG resources that can be called upon to reduce the demand when needed can help to reduce overall equipment loadings, and thereby reduce the number of hours that a SPS needs to be armed, or to help manage equipment loadings while restoration of service is taking place following the contingency.

Reconfiguration of Station Facilities

An alternative option to address these security risks involves reconfiguring the bus work at the transformer station so that the breaker failure does not automatically remove multiple transmission system elements from service.

The reconfiguration requires significant capital work inside of a major transformer station that would take at least 2 to 3 years to design and implement, and with a cost that is several times more than a SPS.

This option is not precluded by the SPS alternative. It could be implemented coincident with other station refurbishment work as an incremental improvement at a later date, subject to a cost-benefit analysis at the time.

Status Quo

Doing nothing is not an option at Manby TS as this would not satisfy the applicable reliability standards. Doing nothing at Leaside TS would not contravene reliability standards; however, ORTAC Section 7.4 provides guidance for justifying this work based on the probability of the contingency, frequency of occurrence, length of repair time, the extent of hardship caused and cost.

Summary

Given the rare nature of the events discussed in Section 6.2.1, operational measures, such as an SPS, is the only alternative that is technically feasible to implement in the time required, and at a cost that is commensurate with the rarity that it is expected to be needed. The cost of implementing the SPS is estimated to be in the range of $1 million to $3 million, and could be implemented within one or two years.

The use of SPSs to limit the impact of failures of this nature is a common practice of utilities worldwide. These systems can minimize cascading equipment outages that result in the propagation of service interruptions to customers. By way of strategically maintaining electrical demand within equipment ratings, a SPS can reduce the extent of further equipment outages and the amount of customer load impacted. A SPS is especially useful to reduce the risk of rare equipment failures such as a breaker failure. Compared to additional redundant infrastructure, station or line work, a SPS can be implemented more quickly and at a lower cost.

A summary of the attributes of the alternatives considered is shown in Table 7-1.

Table 7-1: Summary of Alternatives for Improving Supply Security Risks

Alternative	Technically Feasible (YES/NO)	Meets Standards (YES/NO)	Time to Implement (YEARS)	COST ($M)	Comments
Operational measures (e.g., SPS)	YES	YES	1-2	1-3	Preferred approach based on least cost and time to implement for improving system resilience for breaker failures
Conservation / DG	NO	N/A	N/A	N/A	Insufficient potential within the area to mitigate the risk for a these low probability events
Reconfiguration of station facilities	YES	YES	2-3	10-30	Costs several times more than a SPS, but a potential medium to longer-term option if done in conjunction with other station refurbishment work
Status quo	NO	N/A	N/A	N/A	Not a feasible alternative

7.2.2 Addressing Capacity Relief at Runnymede TS and Fairbank TS

A number of alternatives for providing the capacity relief required to supply growing demand in the area were considered. Given that the transformer stations in the area are already near or at capacity, and the new Eglinton LRT load will be connecting to the distribution system in the near-term period, there are limited alternatives available that are able to meet the need within the time required. The need for capacity relief in the Runnymede TS and Fairbank TS area is urgent. Only Runnymede TS has the space needed to accommodate new transformation facilities.

The alternatives that were considered for capacity relief in the Runnymede TS and Fairbank TS area are discussed below.

Distribution Feeder Ties to Transfer the Load to Other Load Stations and Deferred New Transformation Capacity

This alternative involves building additional distribution feeder capacity by way of 27.6 kV interties between the overloaded stations and adjacent stations to enable permanent load transfers.

This allows for electrical demand to be transferred from Runnymede TS and Fairbank TS to adjacent stations with spare capacity (e.g., Richview TS and Bathurst TS), and to supply the Eglinton LRT using existing feeder positions from the existing stations. Achieving these transfers involves constructing several new 27.6 kV distribution voltage feeders between Runnymede TS and Richview TS, and Fairbank TS and Bathurst TS. The feeder tie routes are expected to be technically challenging due to the distances involved and the number of physical barriers in the area (e.g., highways, bridges, waterways, etc.). The distance from Runnymede TS to Richview TS is approximately 7.5 km, and from Fairbank TS to Bathurst TS is 7 km. These long feeders may have reliability performance and/or voltage quality issues due to their lengths.

The estimated cost of the distribution feeder ties is estimated to be $70 million to transfer loads and to supply the new growth. This alternative is subject to significant cost uncertainty due to the physical barriers in the area and the potential power quality challenges. Within about

10 years, transformation capacity will still be required at an additional cost of about $34 million.[25] Therefore, the total cost of this alternative is approximately $104 million.

Expanding the Existing Runnymede TS to Provide Relief to Fairbank TS and Supply New Customer Demand

This alternative involves installing an additional bus and transformation capacity at Runnymede TS, and upgrading the 115 kV lines between Manby East and Wiltshire TS, as well as building distribution feeder ties between Fairbank TS and Bathurst TS to transfer loads.

There is available space for the expansion at Runnymede TS and therefore, this alternative would not require additional property acquisition.

Increasing the load serving capability of Runnymede TS requires that other system impacts be considered. Runnymede TS is supplied from the 115 kV lines originating at Manby TS (circuits K11W and K12W that run from Manby TS to Wiltshire TS). Installation of new capacity at Runnymede TS would increase the power flow requirements on these 115 kV lines and therefore will require upgrades to the 115 kV lines between Manby TS and Wiltshire TS.

The estimated cost of this alternative is $90 million, which includes $34 million for Runnymede TS expansion, $16 million for upgrades to the 115 kV network, and $40 million for distribution feeders/service for supplying new growth.

Conservation

Conservation is not a technically feasible alternative for providing the capacity relief because there is not sufficient conservation achievable potential within the affected areas to address the capacity relief that is needed and to supply the new customers seeking to connect in the area by 2019.

The assessment of the amount of conservation achievable potential within the affected area is provided in Appendix H.

[25] This cost is the present value of the cost of expanding the Runnymede TS with additional transformation and bus capacity, and upgrading the 115 kV transmission lines between Manby TS and Wiltshire TS to enable the increased power flow requirements ($50 Million future cost expressed in present day dollars by applying a 4% discount rate).

Distributed Generation

The implementation of DG is not a technically feasible alternative to address this need because it would require strategically locating a sufficient amount of DG resources to relieve the specific TSs and feeders. Through recent procurement efforts and community outreach, the IESO is not aware of any such DG opportunities in the area that would defer or avoid this need.

Status Quo

Doing nothing is not a feasible alternative as it will not permit the connection of the new customer demand or provide relief to the stations already near or at capacity.

Summary

Based on the overall comparison of the costs, benefits and feasibility of the various alternatives, the expansion of the existing Runnymede TS is recommended as the preferred solution to address the need for capacity relief at the existing stations in the area and to supply new growth in the area, including the Eglinton LRT project.

Building distribution feeder ties defers the need date for incremental transformation capacity but carries significant cost due to the complexity of constructing new distribution feeders to transfer the electrical demand over long distances across a number of physical obstacles including major highways and waterways), and power quality concerns. This alternative requires an increase in transformation capacity in the area in about ten years to supply continued growth.

The upgrading of the 115 kV transmission service from Manby TS to Wiltshire TS associated with the Runnymede TS alternative will preserve the flexibility to transfer demand between Leaside TS and Manby TS in the event of system emergencies, and provides long-term capacity to supply demand growth and further expansion in the area.

A summary of the attributes of the alternatives considered is shown in Table 7-2.

Table 7-2: Summary of Alternatives for Providing Capacity Relief at Runnymede and Fairbank TS

Alternative	Technically Feasible (YES/NO)	Meets Standards (YES/NO)	Time to Implement (YEARS)	COST ($M)	Comments
Distribution load transfers and deferred new transformation	YES	YES	2-3	104	Technical feasibility uncertain due to distance and physical barriers; subject to high degree of cost uncertainty, and will still require additional transformation capacity and transmission upgrades in ten years' time
Expand existing Runnymede TS	YES	YES	2-3	90	Provides service for Metrolinx, relief for existing stations and capacity for future growth; no new sites required
Conservation	NO	N/A	N/A	N/A	Insufficient potential to provide relief for existing stations and permit connection of new customers
DG	NO	N/A	N/A	N/A	Insufficient potential to provide relief for existing stations and permit connection of new customers
Status quo	NO	N/A	N/A	N/A	Not a feasible alternative

7.2.3 Addressing Capacity Relief at Manby TS and Horner TS

A number of alternatives for providing the capacity relief required to supply growing demand in the area were considered. Given that the transformer stations in the area are already near or at capacity, there are limited options available that are able to meet the need within the time required. Capacity relief is required at both Manby TS and Horner TS in the near term. There is no available space at Manby TS to accommodate new transformation capacity or high-voltage

facilities. Horner TS has space available to accommodate the installation of a new bus and transformation capacity.

The alternatives that were considered for capacity relief at Manby are discussed below.

Distribution Feeder Ties to Transfer the Load to Other Load Stations

The distribution alternative involves building additional distribution feeder capacity between Manby TS and Richview TS to permanently transfer loads from Manby TS to Richview TS for relieving Manby TS. This includes constructing several new 27.6 kV feeders that tie existing feeders from the service area of Manby TS to Richview TS.

The estimated cost of this alternative is $77 million. This alternative carries a high level of cost uncertainty due to the distance and number of physical obstacles that require crossing, such as railway corridors, as these types of physical obstacles and barriers can substantially impact the project cost. Furthermore, distribution transfers can result in the demand being supplied by long distribution feeders which may have a reliability impact.

Although this alternative allows for spare capacity at Richview TS to be utilized, it does not provide any additional supply capacity in the area to support additional growth beyond the current near-term forecast.

Expanding the Horner TS and Transferring Load from Manby TS to Horner TS to Provide Relief to Manby TS

This alternative involves installing an additional bus and transformation capacity at Horner TS, as well as building distribution feeder ties between Manby TS and Horner TS to transfer loads.

There is available space for the expansion at Horner TS and this alternative would not require additional property acquisition. In addition, Horner TS is located in a commercial/industrial area with no residential land uses adjacent to the station.

The estimated cost of this alternative is $70 million, which includes $51 million for the Horner TS expansion plus $19 million for distribution transfers.

There are some challenges with respect to the distribution transfers from Manby TS to Horner TS, related to the crossing of Gardiner Expressway. It is expected that Toronto Hydro will address these challenges in the detailed design and routing of the distribution feeders.

This alternative provides additional supply capacity in the area, and will still enable the connection of new customer demand if it does materialize in the medium to longer term.

New Transformer Station near Manby TS and Distribution Feeder Capacity

This alternative involves building a new transformer station near Manby TS, supplied from the 230 kV transmission system, and new distribution feeder capacity to supply new customer growth and provide capacity relief for Manby TS.

Building a new transformer station will require acquisition of new property, and additional costs related to the high voltage connection to the Richview – Manby 230 kV transmission system.

The estimated cost of this alternative is $88 million, which includes $72 million for a new 100 MVA (90 MW) transformer station and $16 million for distribution load transfers to relieve the existing stations in the area.

Conservation Targeted at Customers in the Area to Provide Relief to Manby TS

Conservation is not considered a technically feasible alternative to provide the necessary relief in time to meet the need.

Conservation targeted at this area would take time to ramp up, but the relief is required today, as evidenced by the station exceeding its capacity rating in historical years.

The assessment of the amount of conservation achievable potential within the affected area is provided in Appendix H.

DG in the Area Supplied by Manby TS

DG is not considered a technically feasible alternative to provide the necessary relief in time to meet the need because the station relief is required today (the station has already exceeded its capacity rating in historical years). The Working Group is not aware of material potential or customer interest in developing DG resources within this area that can meet this need in time.

Status Quo

Doing nothing is not a feasible alternative as it does not provide the necessary relief for Manby TS.

Summary

The least cost alternative to provide capacity relief for Manby TS is to expand the Horner TS by adding a new bus and transformation capacity, and to use distribution feeder ties to transfer demand from Manby TS to Horner TS. This alternative provides additional supply capacity in the area of Horner TS to accommodate future demand growth, while not requiring any additional property. The Horner TS is located in an area that is not adjacent to residential land use and therefore, there is not likely to be local opposition to construction within the station.

A summary of the attributes of the alternatives considered is shown in Table 7-3.

Table 7-3: Summary of Alternatives for Providing Capacity Relief at Manby and Horner TS

Alternative	Technically Feasible (YES/NO)	Meets Standards (YES/NO)	Time to Implement (YEARS)	COST ($M)	Comments
Distribution feeder ties / load transfers	YES	YES	2-3	77	This alternative is subject to a high degree of cost uncertainty due to the distance and number of physical barriers between the stations in the area
Expand existing Horner TS	YES	YES	2-3	70	Provides relief for existing stations and capacity for future growth; no new sites required
New transformer station	YES	YES	3-5	88	Provides relief for existing stations and capacity for future growth; new site needed with longer implementation time
Conservation	NO	N/A	N/A	N/A	Insufficient potential identified to provide the relief required in time
DG	NO	N/A	N/A	N/A	Insufficient potential identified to provide the relief required in time
Status quo	NO	N/A	N/A	N/A	Not a feasible alternative

7.2.4 Providing Capacity Relief for the Richview x Manby 230 kV Transmission Corridor

The Richview x Manby 230 kV reinforcement will be needed by between 2018 and 2021, depending on the rate of demand growth in the coming years. Under a low demand scenario, the loading on these transmission lines remains flat at the capacity limit until 2026 (as shown in Figure 6-14).

The alternatives considered for providing the capacity relief are discussed below.

Building Two New Transmission Circuits between Richview TS and Manby TS

This alternative involves replacing a 115 kV double circuit line with a new 230 kV line on the existing transmission right-of-way between Richview TS and Manby TS (a distance of 6.5 km). The new 230 kV circuits can be arranged in two possible configurations:

- Reconfigure two of the existing Richview x Manby TS 230 kV circuits to "supercircuits" which would use existing line terminations at Richview TS and Manby TS and provide the higher capacity, or
- Separately terminate the new 230 kV circuits at both Richview TS and Manby TS to create a total of six 230 kV circuits between these stations. This provides the required higher capacity and increased reliability.

The existing right of way is 100 m wide, and can accommodate the replacement of the 115 kV line with a 230 kV line. The new 230 kV towers would be larger than the existing 115 kV towers. Most of the existing corridor is adjacent to residential land uses.

The estimated cost of this alternative is $19.5 million if the existing circuits are reconfigured as "supercircuits," and $39.5 million if separately terminating the new lines.

Upgrade the Existing Richview x Manby 230 kV Circuits with New Conductors

This alternative involves re-conductoring the existing Richview TS x Manby TS circuits using higher capacity conductors on the existing towers. This will allow the existing infrastructure to carry more power into Manby TS.

The estimated cost of this alternative is $16 million, including the re-conductoring of pairs of circuits at $8 million for each pair.

Since the existing towers can be used with upgraded conductors, this option will result in no visual difference along the transmission right-of way once it is completed.

This alternative does not result in any additional supply reliability to the area.

Installation of 70% Series Compensation

Installation of 70% series compensation at Cooksville TS was reviewed and deemed not technically feasible to meet the need due to the space limitations at Cooksville TS, and the proximity of residential homes to the station which limits the opportunity to expand the station.

The capacitor banks would require 0.6 to 1.5 acres of space which is not present at the station, so additional land would be required.

Conservation

A conservation alternative involves targeting peak demand savings in the areas supplied by Manby TS to reduce peak flows on the existing 230 kV lines. A conservation potential study has validated that sufficient potential exists in the areas supplied by Manby TS to defer the need. The conservation achievable potential for the areas supplied by the Richview x Manby circuits is provided in Appendix H.

Targeted demand response to provide peak demand savings up to 40 MW in the areas supplied by the Richview - Manby 230 kV lines could defer the need by several years, depending on the rate of demand growth in the near-term period and beyond. If the demand grows in line with a low demand scenario, no incremental demand response in addition to the ongoing conservation programs to meet the LTEP targets would be required until the mid-2020s (2026). If demand grows according to a high demand scenario, demand response will be required to curtail the peak demand flows on the Richview x Manby corridor by 2018.

The estimated cost of incremental demand response above the LTEP estimated savings under a low demand forecast scenario is about $7 million, which would result in a deferral of this need to the end of the study period (2036). If demand grows higher than expected, the cost of incremental demand response would be needed sooner, and would cost as much as $8 million to defer the transmission need by five years.

Conservation does not provide the additional security of the infrastructure upgrades.

Distributed Generation

DG can be developed in the areas served by Manby TS to supply part of the demand locally, and reduce the peak flows on the existing transmission lines serving the area. The IESO is aware of proponent interest in developing a district energy facility in downtown Toronto that could provide up to 90 MW of capacity relief for the Richview x Manby transmission corridor.

As an alternative to meet this transmission need, DG in the amount of 40 MW, connected to the Manby TS 115 kV sector (or in parts of southern Mississauga and Oakville also supplied by Richview x Manby transmission), could defer this transmission need until the end of the study period under a low demand forecast scenario. This incremental DG resource capacity would be in addition to the achievement of the LTEP conservation targets.

If the demand grows at a faster rate than expected in the near-term period, DG resources in the amount of 40 MW could defer this transmission need by five years (to 2020). Under this higher growth scenario, additional DG resources would need to be added each year to continue to defer the transmission.

The estimated cost to develop 40 MW of DG resources in Central Toronto is $110 million. There is a high degree of cost uncertainty for DG resources as it depends on the type, size and location of the facilities. It is likely that any such facility would incur higher development costs to meet emissions standards and to integrate the facility into the urban environment.

Smaller DG facilities are generally well accepted by communities. The community acceptance of larger DG facilities in Central Toronto is not known.

Status Quo

Doing nothing is not a feasible alternative as these lines are approaching capacity and action needs to be taken.

Summary

Concurrent with ongoing conservation programming to maintain forecast load levels, it is recommended that a targeted demand response program be implemented in the areas supplied downstream from the Richview x Manby 230 kV facilities, to reduce the loadings on these facilities during peak demand periods. In addition, it is recommended that Hydro One continue detailed design work on the infrastructure alternative to minimize the development

lead time required to implement the wires upgrades, in the event that planned conservation and targeted demand response activities do not result in the required capacity relief, or if the demand growths faster than expected.

In addition, opportunities to develop DG resources in the areas supplied by the Richview x Manby 230 kV facilities should be explored. The benefits of siting generation locally, in addition to providing transmission capacity relief, will need to be fully accounted for when making comparisons of cost and technical feasibility to transmission and other alternatives.

Upgrading the existing Richview x Manby corridor will increases the load meeting capability of this 230 kV corridor sufficient to supply the projected load growth in Toronto until beyond the IRRP study period. The detailed engineering design and specification of the transmission option should be completed concurrent to the development of conservation and DG opportunities, so that the infrastructure option is available for implementation with as short as possible of a lead time in the event that it is needed.

A summary of the attributes of the alternatives considered is shown in Table 7-4.

Table 7-4: Summary of Alternatives for Providing Capacity Relief for Richview – Manby 230 kV Corridor

Alternative	Technically Feasible (YES/NO)	Meets Standards (YES/NO)	Time to Implement (YEARS)	COST ($M)	Comments
Two new transmission circuits	YES	YES	5-7	19.5 - 39.5	The lower cost range is in combination with "supercircuiting" the existing circuits, and the higher cost is with new line terminations; this option involves installing larger towers on an existing right-of-way adjacent to homes
Upgrade existing transmission circuits	YES	YES	2-3	16	The feasibility of taking outages to complete this work needs to be determined in a detailed study by Hydro One
Series compensation	NO	N/A	N/A	N/A	Not a feasible alternative
Conservation	YES	YES	1-2	7-8+	Low cost range assumes low demand scenario (provides relief to end of study period), the high cost assumes a median demand scenario (provides five years of capacity relief)
DG	YES	YES	3-5	110	Estimated cost for 40 MW of combined heat and power DG, sufficient to provide relief to the end of the study period under a low demand scenario, and for five years of capacity relief under a median demand scenario
Status quo	NO	N/A	N/A	N/A	Not a feasible alternative

7.3 Medium-Term Alternatives

7.3.1 Providing Capacity Relief for Step-down Stations in the Downtown Area

The alternatives that were considered for capacity relief in the Esplanade TS and Copeland TS area are discussed below.

Completing Phase 2 of the Copeland TS

This alternative involves the installation of two additional transformers and load serving busses at Copeland TS, utilizing the space that is being built into phase 1 to accommodate the expansion.

Toronto Hydro's design for Copeland TS phase 2 includes an additional fifth (spare) transformer and a transfer bus to enable the utilization of the spare and station to station ties for additional security for downtown customers.

The bulk of the high voltage switching facilities are being constructed as part of phase 1 of the project.

The estimated cost for the additional transformers and load serving busses is $46 million.

This option does not require any additional property and the station is being built underground. It is not located adjacent to residential land uses.

Expanding the Esplanade TS

This alternative involves constructing a new building next to the existing Esplanade TS and installing two new transformers and load serving busses and high voltage connection facilities.

The estimated cost for this alternative is $48 million.

The Esplanade TS is located adjacent to residential customers and urban parkland.

Conservation

This alternative involves seeking conservation savings targeted at customers in the area to reduce peak demand.

The assessment of achievable conservation potential indicates that there is not technically enough potential in the area to defer or avoid these station needs, nor does conservation add the physical capability to connect new large customers to the distribution system.

The electricity service needs of a number of future developments in the downtown area, such as West Donlands, East Bayfront, lower Yonge Street, and the Portlands area, exceed any conservation savings potential as these developments represent potential large increases in demand that are not be fully reflected in the demand forecast. The total amount of peak demand savings needed includes the 10 MW reflected in the demand forecast, plus up to 90 MW of additional incremental customer demand due to new commercial and high-rise residential development applications. The 90 MW is in addition to the load forecast data as this estimate is based on more recent information regarding development in the downtown area of Toronto.

The assessment of the amount of conservation achievable potential within the affected area is provided in Appendix H.

Distributed Generation

Given the time required to implement DG resources, DG is not likely to avoid the need for additional station capacity.

Furthermore, DG resources do not add capability to connect new customers to the distribution system (e.g., available feeder positions at the station bus).

DG is therefore not considered a technically feasible option to address this capacity need.

Status Quo

Doing nothing is not a feasible alternative because it does not provide the necessary relief.

Summary

The Copeland TS phase 2 alternative is understood to be the most feasible and economic option because Copeland TS phase 1 is being designed to accommodate the expansion, and it is less costly than the Esplanade TS alternative and is not located adjacent to residential land uses.

Conservation resources, in addition to those being incorporated into Toronto Hydro's 2015-2020 Conservation and Demand Management plan, are not likely to produce sufficient savings in

time to meet this need; however, Conservation savings should be pursued on its own merits in downtown Toronto to meet provincial policy goals and to meet conservation targets. In addition, conservation achieved in the downtown core can provide relief for the Richview TS x Manby TS need described in Section 6.2.6.

DG resource development should still be encouraged in the area, but these resources cannot be relied upon to reduce the net demand requirements in the Copeland TS and Esplanade TS area, given the continued growth and high-density development planned to occur in the downtown core and surrounding areas in the coming years.

A summary of the attributes of the alternatives considered is shown in Table 7-5.

Table 7-5: Summary of Alternatives for Providing Capacity Relief for Downtown Transformer Stations

Alternative	Technically Feasible (YES/NO)	Meets Standards (YES/NO)	Time to Implement (YEARS)	COST ($M)	Comments
Copeland TS phase 2	YES	YES	3-5	46	Copeland TS phase 1 is being built with space to accommodate expansion, and is not located next to residential land uses
Expand existing Esplanade TS	YES	YES	3-5	48	Requires expansion of the existing site; cost subject to more uncertainty than Copeland TS
Conservation	NO	N/A	N/A	N/A	Requires demand response targeted within a small area in downtown Toronto; demand from new construction is likely to exceed savings from conservation
DG	NO	N/A	N/A	N/A	DG in sufficient amounts cannot be developed in time to meet the need
Status Quo	NO	N/A	N/A	N/A	Not a feasible alternative

7.3.2 Maintaining Reliability/Security Performance Levels Above Standards

Based on the results of the needs assessment and PRA, there are currently not expected to be any cost-effective transmission system options for improving system security in the Central Toronto Area. Transmission and distribution upgrades that have recently been completed, or are in progress, have already introduced additional redundancy and load transfer flexibility to mitigate reliability/security risks. Examples include the John TS to Esplanade TS cable connection, completed in 2008, and the Copeland TS which is under development. These two investments increase the amount of load that can be transferred in the downtown core to alternate supply sources. Other possible actions for maintaining a high level of reliability/security performance in an urban centre such as Central Toronto include:

- Continuing to increase distribution level station intertie capacity to transfer loads in the event of a loss of a transformer station.
    - Toronto Hydro has been systematically increasing the number of distribution station interties in the Central Toronto Area. This program has long-term reliability/security benefits and should continue.
- Developing DG resources for critical customers such as hospitals with the capability to allow these customers to continue operating in the event of power outages.
- Long-term options for additional transmission facilities into downtown Toronto that will provide additional capacity to supply long-term growth, and additional redundant transmission supply sources to the area.

7.3.3 Other Alternatives for Improving System Resiliency for Extreme Contingencies

The assessment of the impact of extreme contingencies indicated that while the existing transmission system supplying the Central Toronto Area is generally resilient in the event of low-probability, high-impact events, there are measures that can be explored to further improve system resilience in the area. Other possible actions to address the risk of extreme contingencies include:

- Special Protection Systems designed to anticipate and enhance the ability of the system operator to quickly respond to extreme contingencies and system emergencies.
- Continued conservation to reduce loadings on equipment and the amount of load that would need to be restored in the event of an extreme contingency.
- DG resources with the ability to provide grid support and operate as islanded micro-grids to continue to supply critical loads such as hospitals and provide critical services during system emergencies.
- Further coordinated study on extreme weather / climate change adaptation options.

7.4 Recommended Near and Medium-Term Plan

In summary, to address the needs expected to occur within the near-term and medium-term period, the IRRP recommends that the following actions be undertaken immediately:

1. **Reconfigure the tap points of Horner TS on the Richview to Manby 230 kV lines to improve the distribution of loading on the 230 kV system by better balancing the loadings using existing infrastructure (completed by Hydro One in 2014)**

2. Implement Special Protection Systems to address supply security and ensure that reliability standards are met for breaker failure contingencies at the major transformer stations serving Central Toronto (Manby TS and Leaside TS)

It is recommended that Hydro One proceed immediately with designing and implementing SPSs that will ensure that facilities at Manby TS satisfy the reliability standards established for the electric power system as demand continues to increase in the area.

It is also recommended that Hydro One review the feasibility of an SPS to enhance supply security in the event of a similar breaker failure contingency at Leaside TS which can affect load supply to Bridgman TS as a discretional security improvement.

- The SPSs will be designed to prevent the failure of breakers: H1H4/A1H4 at Manby West, H2H3 at Manby East, and optionally L14L15 at Leaside TS, from impacting multiple transmission elements that can propagate customer interruptions beyond a minimum level.
- Considering the immediacy of this need, the development of these options was communicated to Hydro One in a hand-off letter in December 2013.[26]
- The December 2013 letter also identified a number of additional observations for consideration in the design of the SPS to enhance the level of electricity service in the area.

3. Implement area-specific conservation options in order to defer 230 kV transmission line capacity needs

It is recommended that the IESO and Toronto Hydro proceed with planning and implementation of conservation initiatives focused on achieving peak demand savings in the parts of the study area supplied by the Richview – Manby 230 kV transmission facilities that are forecast to approach their capacity limits in the near to medium-term period.

Toronto Hydro's 2015-2020 CDM plan should ensure that the initiatives proposed in the Plan reflect the regional capacity needs identified in this IRRP.

Develop targeted demand response programs designed to reduce electrical demand in the area at peak demand periods. These programs should target small to large scale commercial and

[26] The letter to Hydro One is available at the IESO website: http://www.ieso.ca/Documents/Regional-Planning/Metro_Toronto/OPA-Letter-Hydro-One-Toronto.pdf

institutional customers, and multi-unit residential and small residential customers in the Central Toronto Area.

Develop a comprehensive evaluation, measurement and verification program to monitor the progress of the conservation savings and to estimate the impact of conservation in addressing the capacity needs identified in this IRRP.

4. Conduct further work to identify opportunities for DG resources within the Central Toronto Area

The IESO will work with stakeholders and DG proponents within the City of Toronto, Toronto Hydro and Hydro One to identify opportunities for implementation of DG resources, including district energy and combined heat and power projects, in the Central Toronto Area.

Procure cost-effective DG resources taking into account needs for provincial generation capacity, local capacity, reliability, system security benefits, and meeting government policy targets for clean and efficient generation.

The incorporation new DG in the Manby TS and/or Leaside TS supplied areas could be an economic solution to provide provincial, regional, and local benefits, given the additional generation capacity needed in the Province by the end of the decade.

5. Proceed with work for increasing transformer station capacity in west Toronto by 2018, and in the downtown core by 2021

It is recommended that Toronto Hydro and Hydro One finalize infrastructure options to provide near-term capacity relief in West Toronto for the Runnymede TS, Fairbank TS, Manby TS and Horner TS. This includes Hydro One developing detailed cost and feasibility assessments for upgrades to the 115 kV transmission lines necessary to support the Runnymede TS expansion. Considering the near-term nature of this need, the recommendation to continue with this work was communicated to Toronto Hydro in a letter in April 2014 (Appendix I).

It is also recommended that Toronto Hydro continue with procurement work on the station expansion in downtown Toronto in the medium-term.

The planning, development and procurement work includes:

- Completing the required Connection Impact Assessments and System Impact Assessments,
- Obtaining required regulatory and environmental approvals,
- Identifying detailed station and line work and associated costs to within a range of accuracy suitable for seeking project commitments; and
- Starting the procurement process for long lead time facilities.

6. Proceed with detailed investigation of the infrastructure options to provide capacity relief for the Richview – Manby 230 kV transmission corridor

To cover the risk of higher growth or lower conservation peak demand impacts related to Recommendation 3, the IESO and Hydro One will conduct detailed investigations of options for providing capacity relief for the Richview TS to Manby TS 230 kV transmission lines. This recommendation is to ensure that these options can be implemented in a timely manner, if or when the transmission is needed, and to keep the infrastructure lead time as short as possible.

In the event that Conservation and incremental demand response resources do not materialize to the extent necessary to defer the transmission alternative, the reinforcement of the Richview – Manby 230 kV corridor will be needed by about 2020.

7. Investigate and implement cost-effective options for enhancing supply security and restoration capability following multiple element contingencies in Central Toronto

It is recommended that Toronto Hydro continue to investigate opportunities for increasing capability on the distribution system to transfer station loads to adjacent stations using distribution inter-station ties.

The distribution ties should be able to transfer station loads to adjacent stations in the event of rare N-2 transmission contingencies that could impact service from 115 kV-supplied transformer stations. This should be part of a medium to long-term strategy of incrementally increasing distribution tie capability over time, for achieving higher supply resilience in response to risk of interruption of station service.

8. Conduct further work to assess options for increasing system resiliency for extreme events

It is recommended that the IESO, Toronto Hydro and Hydro One coordinate the assessment of options for increasing resiliency in preparation for possible widespread system outages resulting from low probability – high impact events, either caused by catastrophic failure of multiple critical system elements or extreme weather events such as ice storms and flooding.

Options for increasing system resiliency include Special Protection Systems, continued Conservation, and DG resources. It is also recommended that further work on the risk and impact of extreme weather events be conducted to enhance the capability to prepare for, and respond to these types of events.

8. Long-Term Needs and Options

In the long term, there is a need for additional transmission capacity to supply the Central Toronto Area from both Manby TS and Leaside TS. This need will arise when the demand growth exceeds the capability of the 115 kV transmission lines that supply the downtown core from Manby West, and the 230/115 kV transformers at both Manby TS and Leaside TS.

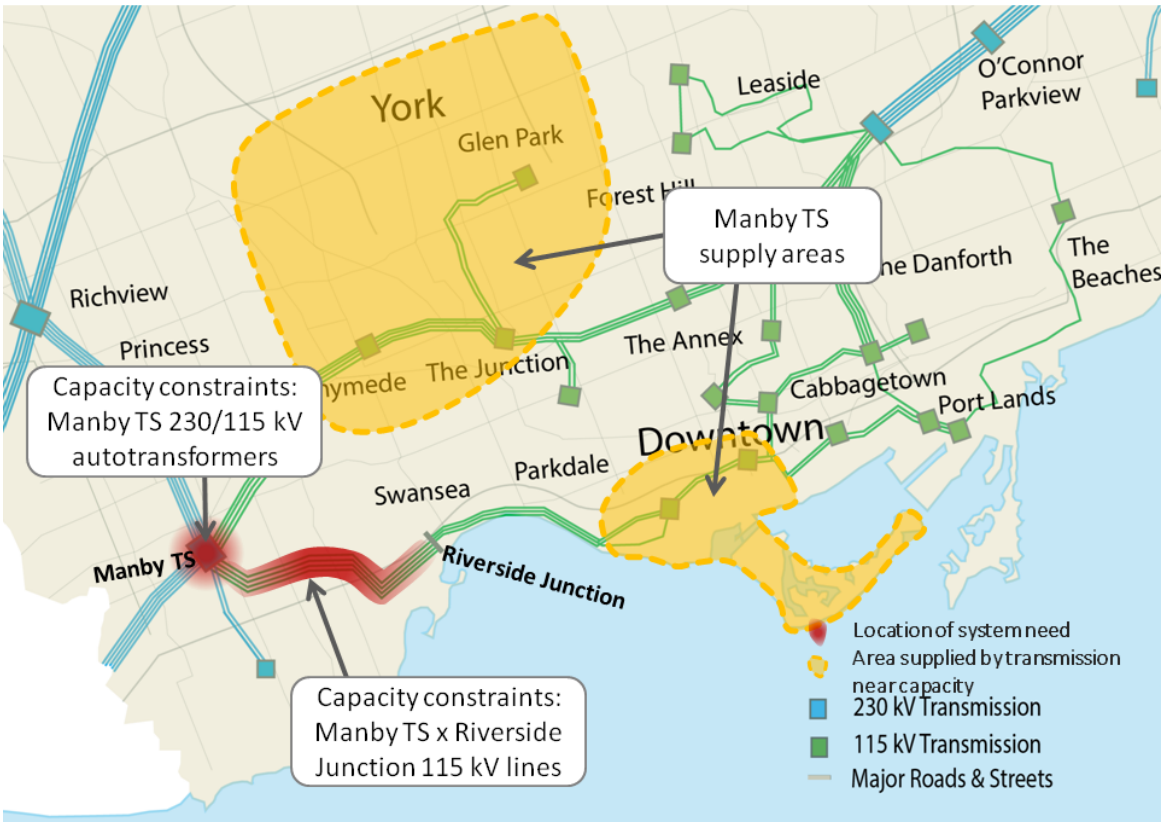
The capacity of the 115 kV transmission lines between Manby TS (Manby West) and the Riverside Junction into the downtown core is forecast to be exceeded as early as 2026 under a high demand scenario. These transmission circuits include the overhead section from Manby TS to Riverside Junction that supply Strachan TS and John TS in the downtown core. The underground section of this transmission corridor, from Riverside Junction to John TS, is being refurbished and upgraded to be capable of operating at 230 kV, although they will continue to operate at 115 kV. Under a forecast scenario that includes the impact of continued planned conservation to reduce electricity demand in the area (e.g., a low demand scenario that assumes achievement of the LTEP conservation targets), the capacity of this section of 115 kV transmission is not expected to be reached until 2031.

In addition to the 115 kV transmission lines, the 230/115 kV transformer capacity at Manby TS is forecast to be reached by 2031 under a high demand scenario. The total capacity shortfall at Manby TS by the end of the study period is forecast to be up to 50 MW. This shortfall is reduced or eliminated considering the achievement of conservation in managing the overall peak electrical demand in the area. Under a low demand scenario that considers the peak demand impact of achieving the LTEP conservation targets, this need is deferred to beyond the study period (after 2036).

A means of addressing this need is could be through the incorporation of an additional transmission supply point to the area that reduces the reliance on the Manby TS 230/115 kV transformers to meet the peak demand requirements of the area. The incorporation of additional electricity generation facilities in the areas supplied by Manby TS would also reduce the loadings on the Manby TS transformers if the generation could reliably operate during the peak demand period.

The constraints at Manby TS and on the 115 kV transmission described above are shown in Figure 8-1.

Figure 8-1: Forecast Capacity Constraints in the Manby TS Sector in the Long-Term Period



At Leaside TS, the ability to supply long-term load growth is limited by the ratings of 230/115 kV transformers, under a condition when all transmission elements are in service but one unit at PEC is out of service. Under such an N-1 outage at the PEC, both a gas turbine generator and the secondary cycle steam turbine generator will be out of service, and the generation output of the facility drops from 550 MW to 160 MW. This creates a situation, when the demand in the area is high enough (e.g., at peak), in which the Leaside transformers cannot supply the full electrical demand of the area.

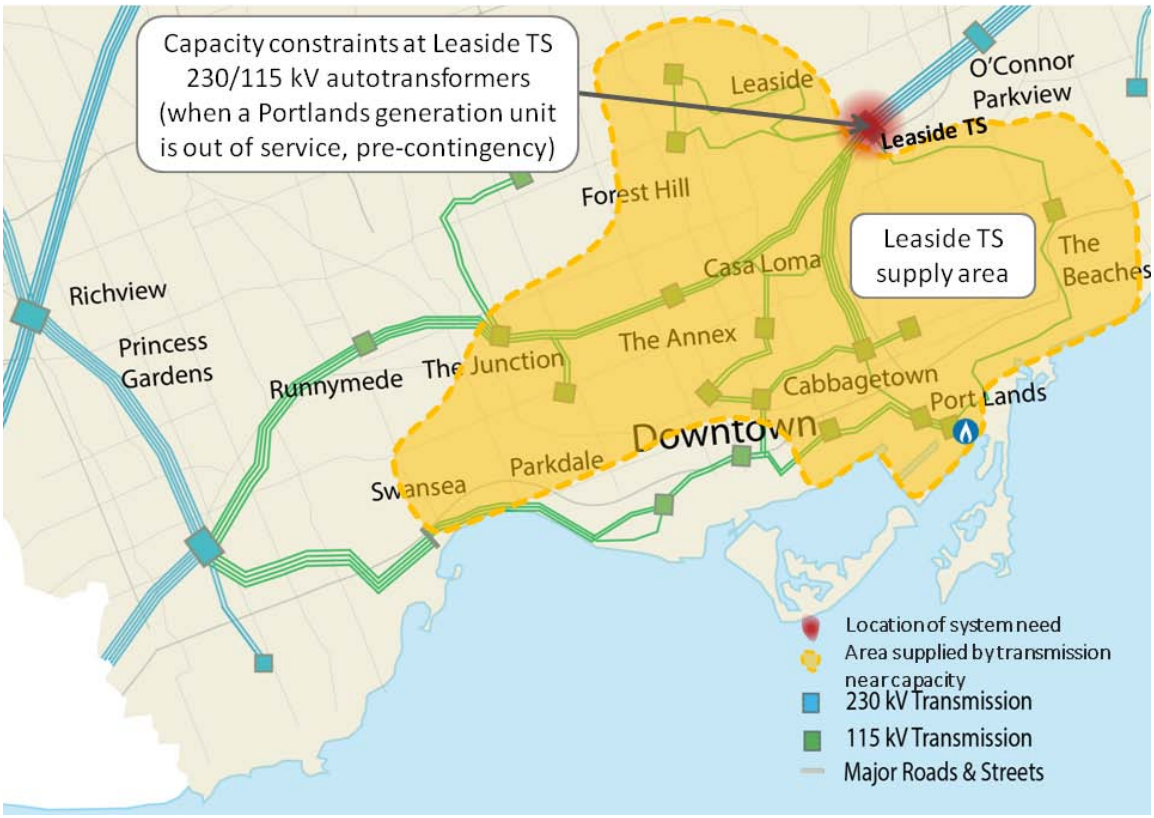
This capacity constraint could arise as soon as 2026 under a high demand scenario. The shortfall is forecast to be as high as 200 MW under this scenario. Under a low demand scenario, the shortfall is reduced such that the need is deferred until 2036.

A means of addressing this need could be through the incorporation of an additional transmission supply point to the area that reduces the reliance on the Leaside TS 230/115 kV transformers to meet the peak demand requirements of the area. The incorporation of additional electricity generation facilities in the area supplied by Leaside TS would also reduce

the loadings on the Leaside TS transformers if the generation could reliably operate during the peak demand period.

This constraint at Leaside TS described above is shown in Figure 8-2.

Figure 8-2: Forecast Capacity Constraints at Leaside TS in the Long-Term Period



For each of the needs described above, the capacity constraints could be deferred into the 2030s timeframe if the demand growth in the Central Toronto Area is managed through continued conservation achievement. The total amount of conservation peak demand savings under a low demand growth scenario is in the order of 640 MW of savings (550 MW in the 115 kV transmission service area) over the long-term period.

Given the uncertainty related to the timing of these needs, the approach for developing the long-term electricity plan is different than for the near-term plan. For needs arising in the near term, specific actions, programs or projects are recommended to ensure that the preferred solutions are available in time to meet the needs. For the longer term, potential options are identified, but no specific project commitments are made. There is time to explore and develop optional paths for regional electricity system development for the region. Instead of

committing specific projects, the focus is instead on identifying possible approaches for meeting long-term needs as they arise in the future.

The approach for the long term is designed to ensure community values and preferences are identified and given consideration in planning, to maintain flexibility with respect to plans, projects and programs, and avoid committing ratepayers to investments before they are needed. This provides additional time to gauge the success and potential of future conservation programs and initiatives, and to test, pilot and, if appropriate, scale up new and emerging technologies. Long-term plans will also need to coordinate with local energy planning activities. Collectively, these steps will lay a foundation for informed decisions in the future.

Another important consideration in developing long-term plans is recognizing the timeframe within which decisions will need to be committed. This involves integrating the projected timing of needs with the expected lead time to bring alternatives into service. To enable fair consideration of all possible alternatives, this latter consideration is driven by the longest lead time among all the possible alternatives. This is usually associated with new major transmission infrastructure, which typically requires five to seven years to bring into service, including conducting development work, seeking regulatory and other approvals, and construction.

Based on the expected timing of the long-term needs in Central Toronto, and the lead times required for infrastructure alternatives, it is expected that, if demand growth turns out higher than is forecast today, decisions on elements of the long-term plan could be required as early as 2019-2020. Current conservation planning targets may result in deferring the timing for these decisions until approximately 2029-2030 (10 years deferral). Additional DG resource integration into the Central Toronto Area could defer this date even further. Therefore, it is recommended that demand growth, impact of conservation, and integration of DG be monitored closely and regularly as part of the implementation of this IRRP. If necessary, the IRRP could be revisited ahead of the 5-year schedule mandated by the OEB's regional planning process.

The following sections describe three approaches for meeting the long-term electricity needs of the Region and lay out recommended actions to develop the longer-term plan. It is expected that the regional planning cycle for the Metro Toronto – Central and Northern sub-regions will be aligned for the next planning cycle, and the long-term options for electricity supply will be addressed for the whole Metro Toronto region. Therefore, in the following sections, a City-wide view is presented.

8.1 Approaches to Meeting Long-Term Needs

In recent years, a number of trends, including technology advances, policy changes supporting DG, greater emphasis on conservation as part of electricity system planning, and increased community interest in electricity planning and infrastructure siting, are changing the landscape for regional electricity planning. Traditional, "wires" based approaches to electricity planning may not be the best fit for all communities. New approaches that acknowledge and take advantage of these trends should also be considered.

To facilitate discussions about how a community might envision its future electricity supply, three conceptual approaches for meeting a region's long-term electricity needs provide a useful framework (Figure 8-3). Based on regional planning experience across the province over the last ten years, it is clear that different approaches are preferred in different regions, depending on local electricity needs and opportunities, and the desired level of involvement by customers and the community in planning and developing local energy systems.

Figure 8-3: Approaches to Meeting Long-Term Needs



The three approaches are as follows:

- **Delivering provincial resources**, or "wires" planning, is the traditional regional planning approach associated with the development of electric power systems over many decades. This approach involves using transmission and distribution infrastructure to supply a region's electricity needs, taking power from the provincial electricity system. This model takes advantage of generation that is planned at the provincial level, with generation sources typically located remotely from the region. In this approach, utilities (transmitters and distributors) play a lead role in development.
- The **Centralized local resources** approach involves developing one or a few large, local generation resources to supply a community. While this approach shares the goal of providing supply locally with the community self-sufficiency approach below, the emphasis is on large central-plant facilities rather than smaller, distributed resources.
- The **Community self-sufficiency** approach entails an emphasis on meeting community needs largely with local, distributed resources, which can include: aggressive conservation beyond provincial targets, demand response, local renewable, DG and storage, smart grid technologies for managing distributed generation resources; integrated heat/power/process systems and electric vehicles ("EV"). While many of these applications are not currently in widespread use, for regions with long-term needs (i.e., 10-20 years in the future) there is an opportunity to develop and test these options before commitment to specific projects is required. The success of this approach depends on early action to explore potential and develop options; it also requires the local community to take a lead role. This could be through a Community Energy Planning process, or a LDC or other local entity taking the initiative to pursue and develop options.

The intent of this discussion, going forward, is to identify which approach should be emphasized in a particular region. In practice, certain elements of electricity plans will be common to all three approaches, and there will necessarily be some overlap between them. For example, provincially mandated conservation policies will be an element in all regional electricity plans, regardless of which planning approach is adopted for a region. As well, it is likely that all plans will contain some combination of conservation, local generation, transmission, and distribution elements. Once the preferences of the community are made clear, a plan can be developed around the approach that makes the most sense, which will affect the relative balance of conservation, generation, and wires in the plan. Details of how these three approaches could be developed to meet the specific long-term needs of Central Toronto are provided in the following sections.

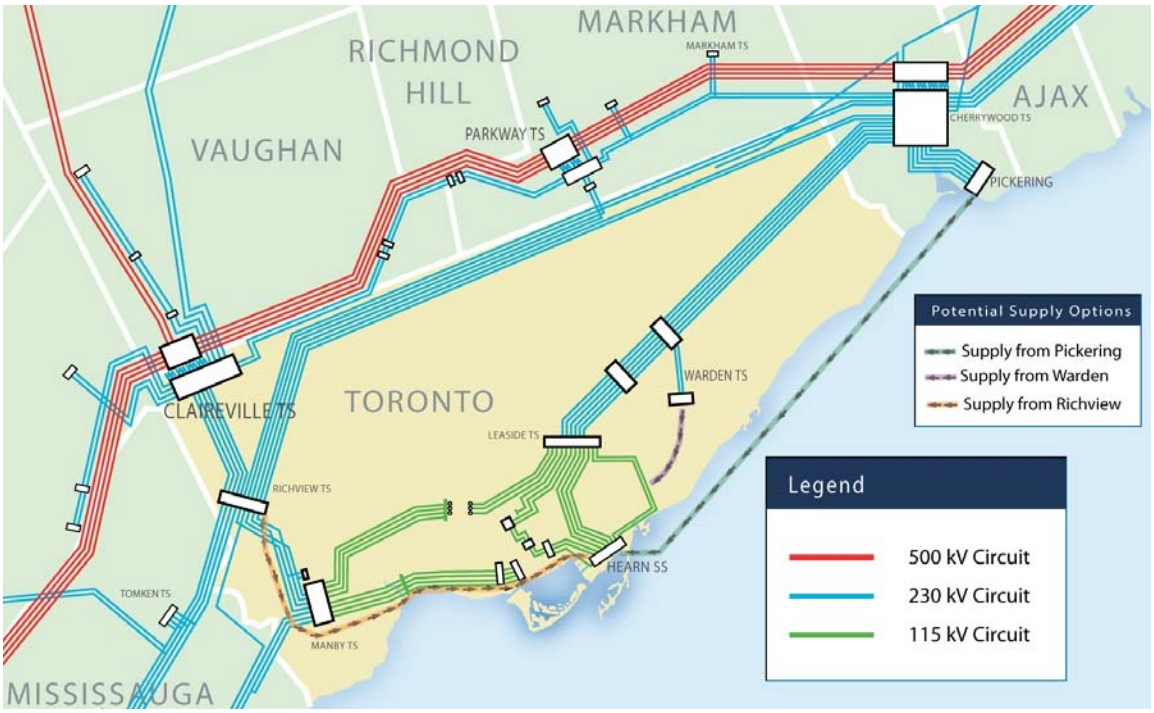
8.1.1 Delivering Provincial Resources

Under a "wires" based approach, the long-term forecast under a high growth scenario could necessitate major new transmission development to deliver power from other major provincial grid sources into the area. Options for other major transmission supply points from the north are limited, and thus a new supply source from the provincial grid under Lake Ontario should be considered as an alternative. Some potential long-term supply sources are shown in Figure 8-4.

Standard planning practices give preference to solutions that make use of existing utility corridors. A section of existing corridor in East Toronto, from Warden TS to the 115 kV system near Leaside TS, could provide the opportunity to upgrade the existing facilities along the right-of-way to diversify the transmission supply network in Toronto.

Another possible wires-based solution involves upgrading the 115 kV supply path from Manby TS into Central Toronto to 230 kV supply. Much of this work has already been completed in anticipation of a possible future switchover from 115 kV to 230 kV. For example, the transmission system from Riverside Junction to Strachan TS, and from John TS to Esplanade TS, is capable of operating at 230 kV. A remaining section, from Manby TS to Riverside Junction, if upgraded to 230 kV, would provide an additional 230 kV source of transmission supply into the area. Bypassing Manby TS en-route to downtown (as shown in Figure 8-4) also provides additional supply diversity into the area (effectively making Richview TS a third major supply point). This section of 115 kV line is identified as requiring a capacity upgrade in the long-term period, and so the opportunity exists to rebuild to 230 kV at that time.

Figure 8-4: Potential Transmission Supply Sources to Meet Long-Term Needs



8.1.2 Large, Localized Generation

Addressing Toronto's long-term needs primarily with large local generation would require that the size, location and characteristics of local generation facilities be consistent with the needs and values of the community. As the requirements are for additional capacity during times of peak demand, a large generation solution would need to be capable of being dispatched when needed, and to operate at an appropriate capacity factor. This would mean that peaking facilities, such as a single-cycle combustion turbine technology, could be more effective than technologies designed to operate over a wider range of hours, or that are optimized to a host facility's requirements.

Opportunities for siting large generation within the City of Toronto are extremely limited due to lack of appropriate land space.

In addition, because local generation would contribute to the overall generation capacity for the province, the generation capacity situation at the provincial level must be considered. Currently, the province has a surplus of generation capacity, and no new capacity is forecast to be needed until the end of the decade at the earliest. This was an additional consideration in ruling out local generation for meeting the near-term needs.

The cost of the generation would depend on the size and technology of the units chosen, as well as the degree to which they can contribute to a provincial capacity or energy need.

8.1.3 Community Self-Sufficiency

Addressing the long-term needs of Toronto under an approach that favours community self-sufficiency requires leadership from the community itself to identify opportunities and deploy solutions. As this approach relies to a great degree on new and emerging technologies, there will be a need to develop and test solutions to establish their potential and cost-effectiveness, so that they can be appropriately assessed in future regional plans.

In Toronto, there is strong community interest in this approach, as evidenced by the municipality taking the lead in identifying and developing energy-based opportunities within the city. Some of these initiatives are described below.

Community Energy Plans

A Community Energy Plan[27] ("CEP") is a comprehensive long-term plan to improve energy efficiency, reduce energy consumption and greenhouse gas ("GHG") emissions. A number of municipalities across the province are undertaking Community Energy Plans to better understand their local energy needs, identify opportunities for energy efficiency and clean energy, and develop plans that better align energy, infrastructure and land use planning within the community.

The City of Toronto has completed a number of Community Energy Plans and others are in progress. While these plans may, more typically, be conducted at the level of the municipality, the size and character of the City of Toronto has resulted in a number of plans being done across the City. The CEPs completed and underway in the City of Toronto include:

- Etobicoke Centre (completed 2008)
- North York (completed 2010)
- Etobicoke – Mimico (completed 2012)
- Scarborough Centre (completed 2014)
- Downtown – Lower Yonge Precinct (in-progress)
- Etobicoke Centre – Six Points Interchange Reconfiguration (in-progress)
- North York – York University (in-progress)

[27] These plans are sometimes referred to as "Municipal Energy Plans."

Integrated energy planning at the community level provides an opportunity for broader consideration of land-use, development and growth, infrastructure requirements and technology solutions that include:

- Advanced fuel cell technologies
- Energy storage technologies
- Demand response programs – particularly residential and small commercial demand response programs enabled by aggregators
- Aggressive conservation programs targeted at residential consumers and enabled by next-generation home area networks
- Battery electric vehicle storage capabilities, especially for load intensification cluster applications
- Enhanced renewable generation opportunities enabled by next-generation storage technologies
- Micro-grid and micro-generation technologies coupled with next-generation storage technologies
- Combined Heat and Power and district energy opportunities
- Renewed consideration of the Load Serving Entity/aggregator market model

The Working Group recognizes that there are risks associated with the community self-sufficiency approach, with the most crucial being the ability to successfully meet the electricity demand growth needs with new and unproven load management and storage technologies. Other key challenges include demonstrating consumer value, cost recovery certainty for innovative technologies and the risk of asset stranding, risk/reward incentives and technological obsolescence as a factor for asset replacement.

8.2 Recommended Long-Term Plan

The long-term plan sets out the near-term actions required to ensure that options remain available to address future needs if and when they arise. A number of alternatives are possible to meet the region's long-term needs. While specific solutions do not need to be committed today, it is appropriate to begin work now to support decision-making processes in the future.

To address the needs expected to occur in the long-term period, the IRRP recommends that the following actions be undertaken:

1. Establish a Local Advisory Committee to inform the long-term vision for electricity supply in the area

It is recommended that a Local Advisory Committee be established to assess the community values and preferences for the different long-term options, including:

- Delivering provincial resources
- Large, localized generation
- Community self-sufficiency

2. Continue to engage with stakeholders and the community to develop community-based solutions

The IESO will continue to engage with the City of Toronto, energy sector stakeholders, and proponents of community-based energy options to seek opportunities to promote testing, pilot projects and, if appropriate, scale up new and emerging technologies, and to coordinate electricity system planning activities with local energy planning activities

3. Monitor demand growth, conservation achievement and DG uptake

It is recommended that the IESO and Toronto Hydro closely and regularly monitor demand growth, impact of conservation, and integration of DG as part of the implementation of this IRRP.

4. Initiate the next Regional Planning Cycle early, if needed

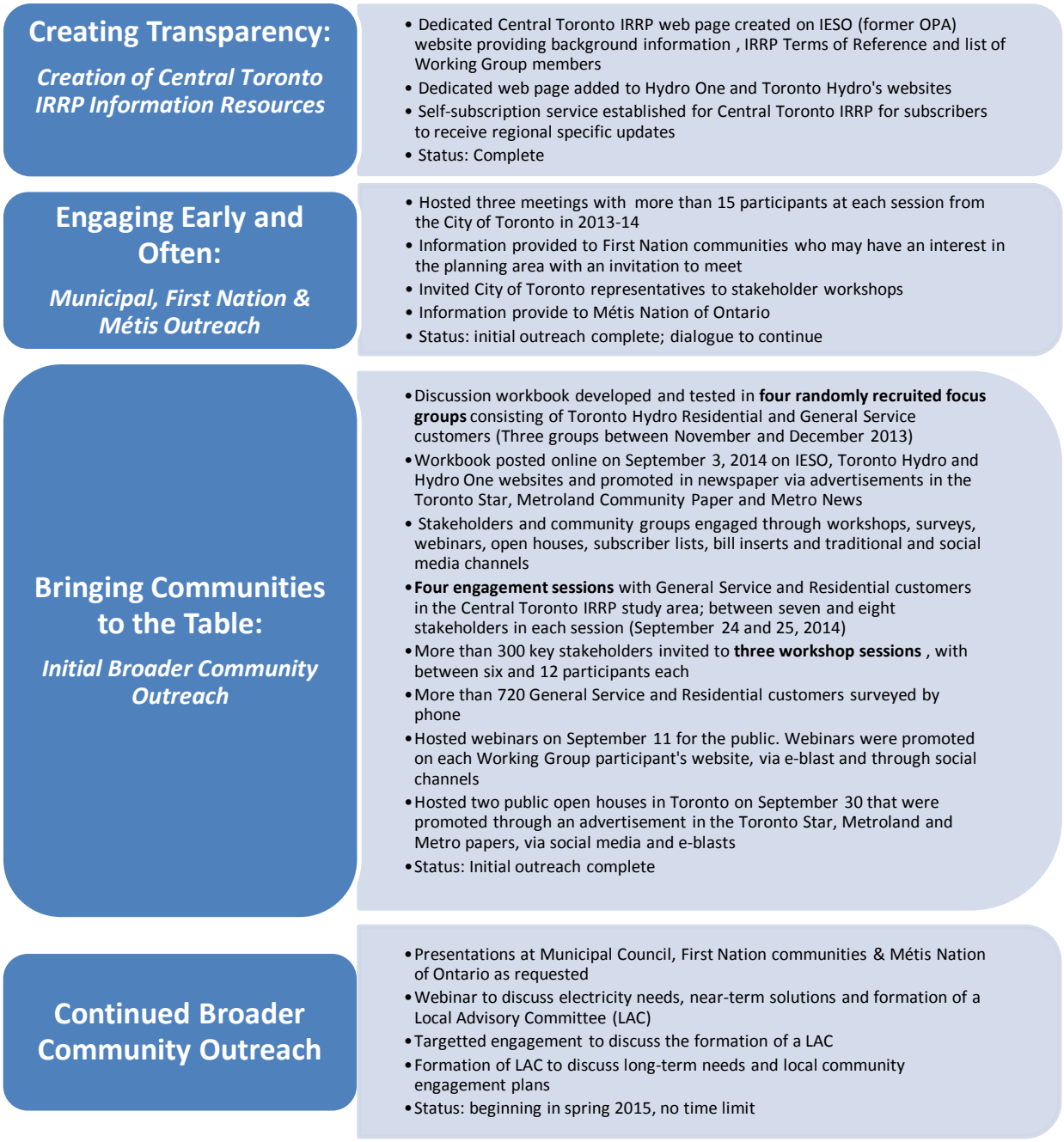
If changes to assumptions for demand, conservation or DG in the community change, then the IRRP should be revisited and revised ahead of the 5-year planning schedule.

9. Community Aboriginal and Stakeholder Engagement Process

Community engagement is an important aspect of the regional planning process. Providing opportunities for input in the regional planning process enables the views and preferences of the community to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles. It also activities undertaken to date for the Central Toronto IRRP, and those that will take place to discuss the long-term needs identified in the plan and to obtain input in the development of options.

A phased community engagement approach was developed for the Central Toronto IRRP based on the core principles of creating transparency, engaging early and often, and bringing communities to the table. These principles were established as a result of the IESO's outreach with Ontarians to determine how to improve the regional planning process, and they are now guiding the plan for further outreach with communities to ensure this dialogue continues and expands as the plan moves forward.

Figure 9-1: Summary of Central Toronto IRRP Community Engagement Process



Creating Transparency

To start the dialogue on the Central Toronto IRRP planning process, a number of information resources were created for the plan. A dedicated web page was created on the IESO (former OPA) website to provide an overview of the regional planning area, information on why the plan was being developed, the plan Terms of Reference, and a listing of the organizations involved was posted on the websites of the Working Group members. A dedicated email subscription service was established for the Central Toronto IRRP where stakeholders could subscribe to receive email updates.

Engaging Early and Often:

In 2011, when the Terms of Reference were signed by the four study partners, the Working Group engaged with Toronto Hydro's sole shareholder, the City of Toronto, and presentations were made on three separate occasions engaging more than 15 city staff members from various departments including Economic Development, Environment and Energy Office, Toronto Water, Parks, Forestry and Recreation, and the Toronto Transit Commission. The purpose of the meetings was to raise awareness about electricity planning needs in Central Toronto, and to discuss supply, the load forecast, specific growth centres, major weather events, long-term needs and stakeholder and community engagement. Key input from these discussions focused on achieving municipal targets for energy efficiency and reducing greenhouse gas emissions.

Bringing Communities to the Table

Due to the nature and size of the sub-region being studied, a multifaceted engagement program was developed. There were primarily three elements to developing and implementing the engagement: establishing background material (the workbook), customer engagement (qualitative research) and telephone surveys (quantitative research).

Key findings from the engagement:

- Most customers are familiar with the electricity system and satisfied with their level of service.
    - 84% of telephone survey respondents are satisfied with their current service
    - 58% of online workbook respondents were satisfied with service during major events
- Cost is a key issue - customers want lower electricity prices and better service
    - When asked "what can be done to improve service, paired with increased reliability," the leading answer to the question was to reduce rates. During the

last 12 months, half of Residential and General Service customers experienced an outage of some kind
    - The Focus Groups understood the need to replace aging infrastructure, but suggested that the system look within for savings before asking customers to pay more
- Cutting down the duration of outages is crucial
    - Much of the engagement focused on how reliability issues affected customers day-to-day – examining customer preference between cost and reliability, and frequency and duration
- The three capacity options presented were not well-known to customers
    - General awareness of Conservation, DG and Transmission and Distribution infrastructure is low, with DG least known
    - When asked about electricity generation in Toronto, solar photovoltaics and CHP are the two option respondents felt most appropriate for use in the Central Toronto Area. Bioenergy and emergency generators were seen as less viable options
    - Overall, customers are supportive of energy conservation and concerned about environmental issues
- Customers think that overall, they are getting good value for money
    - Given the difficult choice between increasing rates or reducing reliability, customers have shown that they will, reluctantly, accept paying marginally more for better service

To further continue the dialogue, a Local Advisory Committee (LAC) will be established as an advisory body to the Metro Toronto regional planning team.[28] The purpose of the committee is to establish a forum for members to be informed, and to advise on the regional planning process. Their input and recommendations, information on local priorities, and ideas on the design of community engagement strategies will be considered throughout the engagement and planning processes. LAC meetings will be open to the public and meeting information will be posted on the IESO website. Information on the formation of the LAC is available on the Metro Toronto Region IRRP main webpage.

Strengthened processes for early and sustained engagement with communities and the public were introduced following the 2013 engagement held with 1,250 Ontarians on how to enhance regional electricity planning. This feedback resulted in the development of a series of

[28] It is expected that future iterations of regional plans for Toronto will be addressed at the city-wide level, consistent with the Metro Toronto Regional Planning Area.

recommendations that were presented to, and subsequently adopted by the Minister of Energy. Further information can be found in the report entitled "Engaging Local Communities in Ontario's Electricity Planning Continuum" available on the IESO website.

Information on continuing outreach activities can be found on the IESO website and updates will be sent to all subscribers who have requested updates on the Central Toronto IRRP or for the Metro Toronto Region.

Copies of the community engagement materials are available on the IESO website, and engagement summary reports are provided in Appendix J.

10. Conclusion

This report documents an IRRP that has been carried out for Central Toronto, a sub-region of the Metro Toronto regional planning region, and fulfils the IESO's OEB licence requirement to conduct regional planning in the Metro Toronto region. The IRRP identifies electricity needs in the Region over the period from 2014 to 2036, recommends a plan to address near-term and medium-term needs, and identifies actions to develop alternatives for the longer term.

Implementation of the near-term plan is already underway, with Toronto Hydro developing conservation plans consistent with the Conservation First policy, and with infrastructure projects being developed by Toronto Hydro and Hydro One.

To support development of the long-term plan, a number of actions have been identified to develop alternatives, engage with the community, and monitor growth in the Region, and responsibility has been assigned to appropriate members of the Working Group for these actions. Information gathered and lessons learned as a result of these activities will inform development of the next iteration of the IRRP for the Metro Toronto Region.

The planning process does not end with the publishing of this IRRP. The community will be engaged in the development of the options for the long term. In addition, the Working Group will continue to meet regularly throughout the implementation of the plan to monitor progress and developments in the area, and will produce annual update reports that will be posted on the IESO website. Of particular importance, the Working Group will track closely the expected timing of the needs that are forecast to arise in the medium and long term. If demand grows as forecast, it may be necessary to revisit the plan as early as 2018-2019, in order to respect the lead time for development of alternatives. If demand growth slows or conservation achievement is higher than forecast, the plan may be revisited according to the OEB-mandated 5-year schedule. This outcome would allow more time to develop alternatives and to take advantage of advances in technology in the next planning cycle.

IESO Letter of Comment

Toronto Hydro-Electric System Limited

Renewable Energy Generation Investments Plan

July 20, 2018

ieso
Independent Electricity System Operator

Introduction

On March 28, 2013, the Ontario Energy Board ("the OEB" or "Board") issued its Filing Requirements for Electricity Transmission and Distribution Applications; Chapter 5 – Consolidated Distribution System Plan Filing Requirements (EB-2010-0377). Chapter 5 implements the Board's policy direction on 'an integrated approach to distribution network planning,' outlined in the Board's October 18, 2012 Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.

As outlined in the Chapter 5 filing requirements, the Board expects that the Ontario Power Authority[1] ("OPA") comment letter will include:

- the applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the Renewable Energy Generation ("REG") investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

Toronto Hydro-Electric System Limited - Distribution System Plan

On June 6, 2018, the IESO received Regional Planning and REG investments information ("Plan") from Toronto Hydro-Electric System Limited ("THESL") as part of their 2020-2024 Distribution System Plan. The IESO has reviewed the Plan and provides the following comments.

FIT/microFIT Applications Received

As of December 31, 2017, THESL's Plan indicates that it has 1087 microFIT projects, totalling 7.2 MW in capacity, and 568 FIT projects, totalling 80.2 MW in capacity, connected to its distribution system.

To date, the IESO's information shows 1161 microFIT projects, totalling 7.5 MW in capacity, and 636 FIT projects, totalling 90.9 MW in capacity. These figures only include FIT and microFIT contracts that are in-service or have received a Notice to Proceed. The renewable energy generation connections information for FIT and microFIT projects in THESL's Plan is therefore substantially consistent with that of the IESO with differences likely a result of when the data was collected.

[1] On January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization that will combine the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator.

Independent Electricity System Operator
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Consultation / Participation in Planning Meetings; Coordination with Distributors / Transmitters / Others; Consistency with Regional Plans

THESL is currently a member of a Working Group, with the IESO and Hydro One Networks Inc. ("Hydro One"), and has participated in planning meetings in the development of regional plans for the Toronto Region. The first regional planning cycle for Toronto (Central Toronto Sub-region) was concluded with the publishing of a Regional Infrastructure Plan ("RIP") in January 2016.

In the current regional planning cycle, a Needs Assessment and Scoping Assessment Outcomes Report are complete for the Toronto Region.

- The Needs Assessment was completed in October 2017 and can be found here: https://www.hydroone.com/about/corporate-information/regional-plans/metro-toronto
- A Scoping Assessment Outcome Report and Terms of Reference for the Toronto Region IRRP was finalized and posted in February 2018 and can be found here: http://www.ieso.ca/-/media/files/ieso/document-library/regional-planning/toronto/toronto-scoping-assessment-outcome-report-february-2018.pdf?la=en

An Integrated Regional Resource Plan ("IRRP") is currently underway for the Toronto Region and is expected to be completed in mid-2019. Following the completion of the IRRP, Hydro One is expected to conduct a RIP to complete this cycle of the regional planning process.

Based on a review of the investments proposed in THESL's Plan, the IESO does not foresee a need for co-ordination with other distributors, or transmitters other than Hydro One.

Although the specific investments described in THESL's Plan are not included within the most recent Regional Infrastructure Plan, addressing barriers to connect additional DG within THESL's service area is consistent with regional planning principles. Removing technical barriers to new DG connections can provide lasting benefits to the upstream transmission system by reducing the need, over time, for additional load meeting demands on the high voltage transmission serving the area.

The IESO looks forward to working with THESL on regional planning through the current cycle and appreciates this opportunity to comment on the REG investment information provided as part of its Distribution System Plan.

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C Performance Measurement for Continuous Improvement



C1 Customer Preferences and the Outcomes Framework

C2 Toronto Hydro's 2020-2024 Custom Performance Measures

C1 Customer Preferences and the Outcomes Framework

In developing its approach to performance measurement, Toronto Hydro considered the OEB's guidance, including the *Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach* (the "RRF").[1] A key theme of the OEB's guidance is that utilities should align their investment plans with customer needs, and adopt an outcomes-based approach to tracking their performance.

To remain responsive to customer needs and preferences, and demonstrate continuous improvement in its outcomes-based performance, Toronto Hydro has proposed 15 custom measures that are incremental to measures tracked and assessed by the OEB, for a total of 44 unique measures to be reported annually.[2] This section provides a comprehensive overview of these custom measures for the 2020-2024 plan period. Toronto Hydro's proposed custom measures reflect the utility's understanding of customer priorities and provide a means to demonstrate that value for money will be achieved through the utility's 2020-2024 Plan.

Toronto Hydro's Outcomes Framework is discussed in detail in Exhibit 1B, Tab 2, Schedule 1, and illustrated in Figure 1, below. This framework is aligned with Toronto Hydro's operations, and serves to translate Toronto Hydro's expenditure plan objectives into outcome categories that matter to the utility's customers: Customer Service, Reliability, Safety, Environment, Public Policy, and Financial.

Toronto Hydro's 2020-2024 customer-focused Outcomes Framework was derived through extensive customer engagement efforts (see Exhibit 1B, Tab 3). As discussed in detail in Exhibit 2B, Section E2, Toronto Hydro began business planning by engaging customers and using the feedback received from its customers to assist in shaping the strategic parameters for the planning period.[3]

[1] Ontario Energy Board, Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach (October 18, 2012).
[2] These proposed measures will monitor distribution system planning process performance.
[3] The results of Customer Engagement, Phase 1, are discussed in detail in Exhibit 2B, Section E2.3.

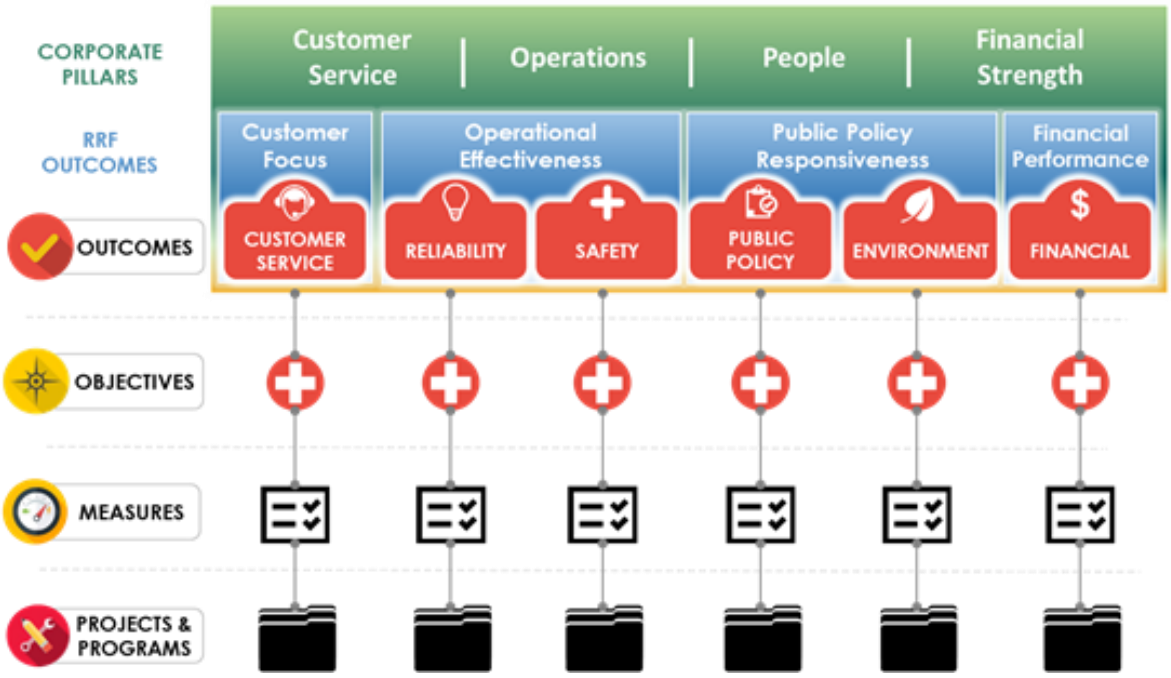


Figure 1: Toronto Hydro's Customer-Focused Outcomes Framework[4]

As detailed in Exhibit 1B, Tab 3, Schedule 1, Appendix A, customer feedback on Toronto Hydro's proposed application was collected in two phases. Phase I was used to develop a list of customer outcomes and identify customer priorities for the utility's planning process. Phase II was used to solicit customer feedback on the utility's proposed plans, and explore trade-offs in relation to specific programs and their associated bill impacts as well as the pacing of proposed investments. Customers were afforded the opportunity to view the cumulative bill impact of their choices and make adjustments, if necessary.[5]

Overall, customers across all rate classes ranked price, reliability, and safety as the top three priorities, with price being ranked higher for low-volume and medium sized customers.[6] Balancing reliability and cost was considered a core issue to be managed. Reliability, in particular, was seen as an asset management issue with a need to balance new investments to meet future demand and

[4] The RRF Outcomes are aligned alongside Toronto Hydro's Outcomes based on the definitions provided by the OEB in the Utility Rate Handbook. It should be noted that Toronto Hydro's Financial outcome includes cost-related components that the OEB would classify within the Operational Effectiveness outcome.
[5] Exhibit 1B, Tab 3, Schedule 1, Appendix A at p.2.
[6] Ibid at pp. 3, 6-7.

replacement of aging equipment to increase reliability.[7] Customers placed high value on safety, both within their homes and workplaces and externally, on the streets and/or in public.[8]

Environment and customer service also emerged as customer priorities. Customers identified concerns relating to the environment as an emerging issue,[9] and placed value on proactive usage and monitoring tools, including those alerting and informing on outages. For a detailed discussion of Toronto Hydro's customer engagement findings, please refer to Exhibit 1B, Tab 3, Schedule 1, Appendix A.

With insight into customers' priorities and preferences, Toronto Hydro developed a customer-focused Outcomes Framework (depicted in Figure 1, above) that aligned with the utility's corporate strategic pillars and the RRF. This transitioned into the lens through which Toronto Hydro developed its business plan, and is reflected in the investment planning decisions made by the utility. Some of these decisions translated into measures in Toronto Hydro's Custom Performance Scorecard, while others appear as priorities at the investment program level. For instance, as discussed in Exhibit 1B, Tab 3, Schedule 1, Appendix A, during an outage, customers value an estimated time of response ("ETOR"). Although Toronto hydro has not proposed ETOR as a custom measure, the utility is working on improving its response communication capabilities during outages through investments proposed as part of Metering (Exhibit 2B, Section E5.4), Control Operations Reinforcement program (Exhibit 2B, Section E8.1), Disaster Preparedness Management (Exhibit 4A, Tab 2, Schedule 6) and Control Centre Operations (Exhibit 4A, Tab 2, Schedule 7).

Overall, Toronto Hydro has developed its capital programs to maintain and improve reliability and safety, meet service and compliance obligations, address load capacity and growth needs, improve contingency constraints, or make necessary day-to-day operational investments. The choices made by the utility reflects a balance between customer preferences, affordability, and prioritized outcomes (as described in Exhibit 2B, Section E2), with the overriding objective of delivering value for money. The utility intends to continue using its Outcomes Framework to engage with customers and to assess and communicate the effectiveness of its plans in delivering value that aligns with evolving customer preferences over time.

[7] Supra note 5 at p. 11.
[8] Ibid.
[9] Supra note 5 at p. 12.

C2 Toronto Hydro's 2020-2024 Custom Performance Measures

Toronto Hydro is proposing 15 custom measures for the 2020-2024 plan period, see Table 1 below. These measures are incremental to the measures contained in the Electricity Distributor Scorecard ("EDS") and the Electricity Service Quality Requirements ("ESQR"), for a total of 44 unique measures to be reported to the OEB annually. This section provides a comprehensive overview of the outcome measures that are key trackers of the performance of Toronto Hydro's capital plan and supporting maintenance program for the 2020-2024 period.

These measures are reflective of an emphasis on output and results, and should be understood in accordance with their respective challenges. For instance, the Reliability measures should be transposed onto the challenges of operating in a densely populated urban core, using a multitude of complex equipment that is unique in its span and configuration when compared to other Ontario distributors. For a detailed discussion of Toronto Hydro's operating challenges, please see Exhibit 1B, Tab 1 and Exhibit 2B, Section D2.

Each of the 15 custom measures is assigned to an outcome category. Although this assignment means that the measure will be used to track performance under one specific outcome, measures are expected to impact performance in other outcome categories as well. In other words, the custom measures contribute to multiple outcomes. For example, while the Total Recordable Incident Frequency ("TRIF") measure appears in the Safety outcome, it also produces financial benefits (avoided costs), such as a decrease in Workplace Safety Insurance Board premiums, resulting from the utility's safety record. For further details, please refer to Exhibit 4A, Tab 2, Schedule 15. Similarly, the increase in adoption of eBilling measure, currently allotted to measure performance in the Customer Service outcome, also produces financial benefits (avoided costs) given the reduction in paper, printing and postage costs. For more information, please refer to Exhibit 4A, Tab 2, Schedule 14. Lastly, all seven measures under the Reliability outcome contribute to the Customer Service outcome as they are expected to address reliability and connection concerns valued by customers (see discussion above).

In developing targets for these 15 custom measures, Toronto Hydro used the most recent five-year historical data (2013-2017) to set the baseline target for performance during the 2020-2024 plan period. However, given that some of the proposed measures are new (e.g. System Health – Asset Condition (Wood Poles)), the requisite five-year historical data will not be available for 2020-2024 performance target-setting purposes. In such instances, Toronto Hydro will monitor and report its

results annually and consider this data in developing potential baseline target to measure future performance.[10]

Toronto Hydro's forecasted measures and targets related to the Custom Performance Scorecard, have been developed on the basis of the proposals, plans and associated rates contained in this Application. To the extent that Toronto Hydro's approvals differ from those it seeks in this Application, the utility would need to re-assess its forecasted performance target for the period. Further, there are risks outside of Toronto Hydro's control which may also affect its ability to achieve performance targets. For instance, the performance in the adoption of electronic billing measure (Customers on eBills) will likely plateau, at some point, due to fact that there will always be a certain demographic, e.g. the elderly with low computer literacy, who will prefer to receive a paper invoice. In such cases, Toronto Hydro's efforts to convert these customers will have a negligible effect on the improvement of its performance in this measure.

Table 1: 2020-2024 Custom Performance Scorecard Measures

Toronto Hydro Outcome	OEB Reporting Category	Toronto Hydro's Custom Measures	Target
Customer Service	**Customer Satisfaction**	Customers on eBills	Improve
Safety	**Safety**	Total Recorded Injury Frequency	Maintain
		Box Construction Conversion	Improve
		Network Units Modernization	Improve
Reliability	**System Reliability**	SAIDI - Defective Equipment	Maintain
		SAIFI - Defective Equipment	Maintain
		FESI 7 System	Improve
		FESI-6 Large Customers	Maintain
	Asset Management	System Capacity	Maintain
		System Health (Asset Condition) – Wood Poles	Monitor
		Direct Buried Cable Replacement	Improve
Financial	**Cost Control**	Average Wood Pole Replacement Cost	Monitor
		Vegetation Management Cost per Km	Monitor
Environment	**Environment**	Oil Spills Containing PCBs	Improve
		Waste Diversion Rate	Monitor

[10] This approach is consistent with the OEB's methodology in the annual Electricity Distributor Scorecard to utilize actual data in order to set baseline targets.

C2.1 Customer Service

Table 2: Customer Service Custom Performance Measure

OEB Reporting Category	2020-2024 Custom Performance Measures	Historical Performance (2013-2017)	Target (2020-2024)
Customer Satisfaction	Number of Customers Receiving Electronic Bills ("eBills")	224,420 (2017 year-end)	Improve

C2.1.1 Number of Customers on eBills

The Number of Customers Receiving eBills measure, within the Customer Service outcome, will track and report on the number of customers who opt-in to receive an eBill, as opposed to a paper bill. This is aligned with Toronto Hydro's efforts to increase the ease and accessibility of its customer billing and account information, consistent with preferences expressed by its customers.[11] For the 2020-2024 plan period, Toronto Hydro plans to increase the usage of eBills to approximately 347,000 customers.

Toronto Hydro prepares over nine million bills annually and offers its customers several delivery options, including standard paper-based bills, eBills, and ePost billing services. As shown in Figure 2, as of the end of 2017, over 224,000 Toronto Hydro customers opted to receive eBills, this is an increase of 250 percent in the last four years. The success of eBilling adoption is attributable to the utility's targeted marketing and education strategies that emphasize the benefits of paper-less billing. By the end of the 2020-2024 period, more than four of every 10 Toronto Hydro customers are expected to receive an eBill, up from 1.7 of every 10 in 2015.

[11] See Exhibit 1B, Tab 3, Schedule 1, Appendix A, at p.4.

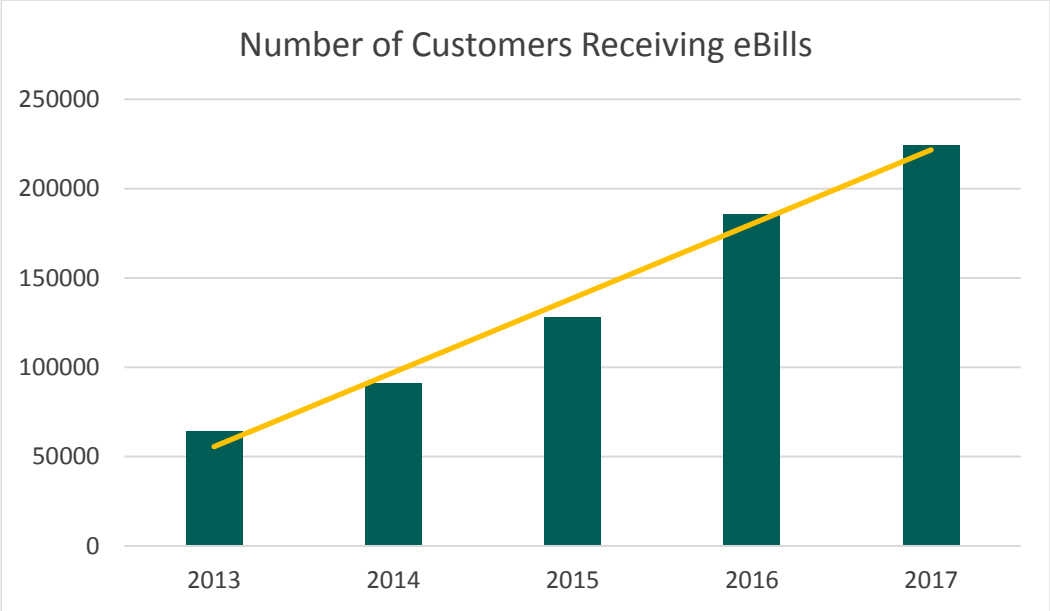


Figure 2: Number of Customers on eBills between 2013 – 2017

As mentioned in the section above, although the Number of Customers Receiving eBills measure is assigned to the Customer Service outcome category, the savings achievable through the success of this measure will contribute to the Financial outcome. This is because eBills are more cost-effective (almost a $1 less) than paper bills. For instance, in 2017, cost-savings amounted to approximately $9.52 per eBilled customer a year. Over the 2015-2024 period, Toronto Hydro expects to save approximately $15.3 million from customers opting into eBills.

In addition, the increase in customer adoption of eBills will also have a positive impact on Toronto Hydro's Environment outcome. Since 2015, Toronto Hydro has reduced its paper usage for billing purposes by approximately 12.4 percent.

Please refer to Metering (Exhibit 2B, Section E5.4), Information Technology (Exhibit 2B, Section E8.4), Preventative and Predictive Overhead Line Maintenance (Exhibit 4A, Tab 2, Schedule 1), and Customer Care (Exhibit 4A, Tab 2, Schedule 14) for discussion of investments that will contribute to the performance of this measure.

C2.2 Safety

Table 3: Safety Custom Performance Measure

OEB Reporting Category	2020-2024 Custom Performance Measures	Historical Performance (2013-2017)	Target (2020-2024)
Safety	Total Recordable Injury Frequency	1.3 recordable injuries per 100 workers	Maintain
	Box Construction Conversion	3,151 box construction poles on the system (2017 year-end)	Improve
	Network Units Modernization	56% with submersible protections (2017 year-end)	Improve

C2.2.1 Total Recordable Injury Frequency ("TRIF")

The TRIF measure tracks the proportion of recordable injuries to hours worked. A recordable injury is defined as any occupational injury or illness that results in an employee experiencing a fatality, lost-time injury, or any other type of injury or illness associated with a restricted work day. Measuring TRIF performance underlies the utility's commitment to health and safety.

The complicated nature and configuration of the utility's assets increase the likelihood of safety-related risks. Examples of operational risks inherent in the execution of Toronto Hydro's DSP are provided in several programs, including Underground System Renewal – Downtown (Exhibit 2A, Section E6.3), Network System Renewal (Exhibit 2B, Section E6.4), Overhead System Renewal (Exhibit 2A, Section E6.5), Corrective Maintenance (Exhibit 4A, Tab 2, Schedule 4), Control Centre Operations (Exhibit 4A, Tab 2, Schedule 7), and Human Resources and Safety (Exhibit 4A, Tab 2, Schedule 15). Mitigating these safety risks require investments in a number of areas, including grid investments addressing Box Conversion and Paper-Insulated Lead-Covered cable, technical training and development programs customized to address specific needs and challenges of Toronto Hydro's distribution system, [12] and a concerted emphasis on safety among Toronto Hydro's entire internal and external workforce. As discussed in the utility's last Rate Application, TRIF figures have decreased significantly since the utility implemented its comprehensive training program in 2006.[13]

[12] Please refer to Exhibit 4A, Tab 2, Schedule 15 for a detailed discussion of Toronto Hydro's internal training programs.
[13] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015), Exhibit 4A, Tab 2, Schedule 14, at p. 41.

Figure 3, below, illustrates Toronto Hydro's TRIF performance over the last five years.[14] The utility expects to maintain its safety record during the 2020-2024 plan period.

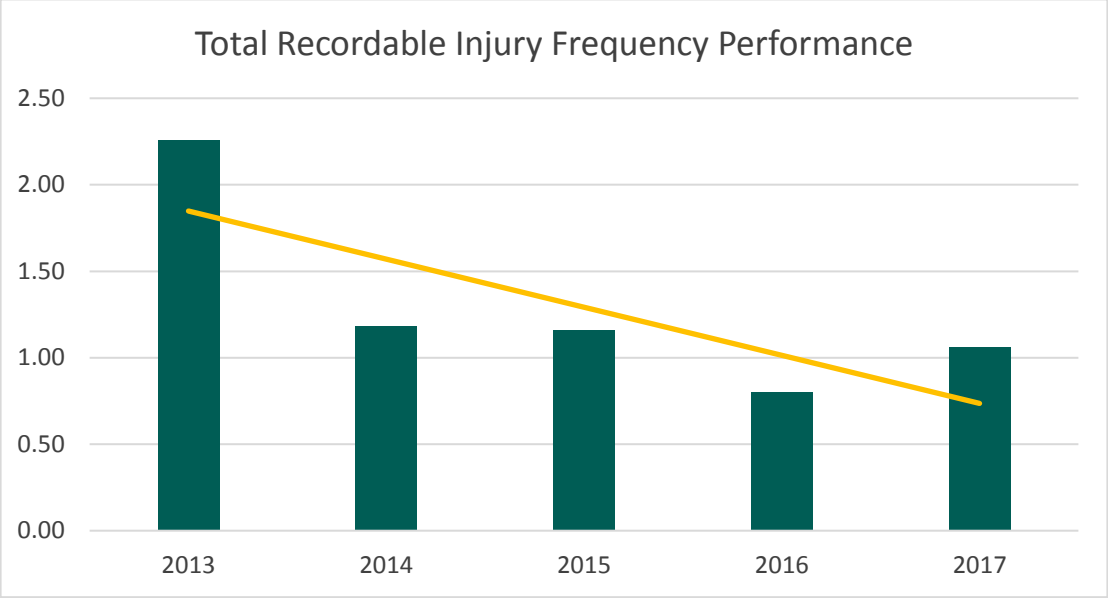


Figure 3: Total Recordable Injury Frequency Performance From 2013 – 2017

A substantial number of Toronto Hydro's capital and OM&A programs will contribute to the performance of this measure. For the proposed 2020-2024 investments driving TRIF performance, please see Area Conversions (Exhibit 2B, Section E6.1), Underground System Renewal – Horseshoe (Exhibit 2B, Section E6.2), Underground System Renewal – Downtown (Exhibit 2B, Section E6.3), System Enhancements (Exhibit 2B, Section E7.1), Network System Renewal (Exhibit 2B, Section E6.4), Fleet and Equipment Services (Exhibit 4A, Tab 2, Schedule 11), Work Program Execution (Exhibit 4A, Tab 2, Schedule 10), Control Centre Operations (Exhibit 4A, Tab 2, Schedule 7), and Human Resources and Safety (Exhibit 4A, Tab 2, Schedule 15).

C2.2.2 Box Construction Conversion

The Box Construction Conversion measure tracks Toronto Hydro's performance on the reduction in the number of box construction poles in its distribution system. As discussed in the Area Conversions program (Exhibit 2B, Section E6.1), Toronto Hydro currently maintains overhead pole lines with

[14] The TRIF is normalized to 200 hours- representing 100 workers working a 40-hour week for 50 weeks per year to allow for comparisons between companies utilizing this metric.

legacy framing, referred to as box construction. This type of framing presents several safety risks for employees resulting from the narrow distance between live conductors and inadequate clearances.[15] The congested legacy framing also contributes to poor reliability of the system.

Toronto Hydro has been working on converting feeders with box construction framing over the past five years. Between 2013 and 2017, the number of box construction poles were reduced from approximately 6,400 to approximately 3,200 as at the end of 2017. For 2020-2024, Toronto Hydro is proposing to convert 1,250 or approximately three quarters of the expected 1,600 remaining box construction poles.

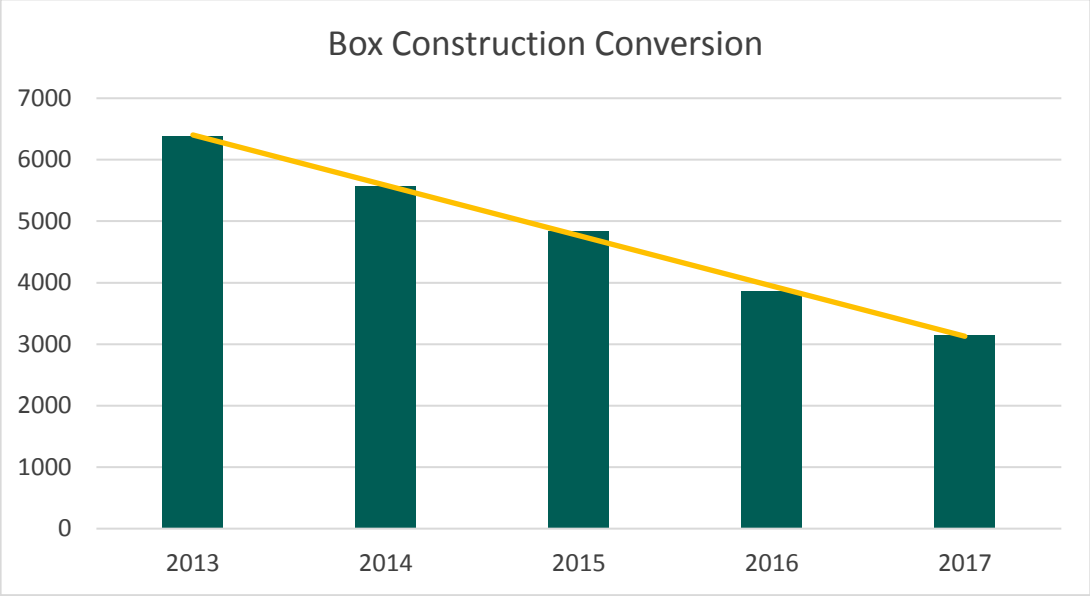


Figure 4: Box Construction Conversion Performance for 2013 - 2017

Replacing approximately three quarters of the remaining box construction poles by 2024 will reduce potential safety risks for crew members dealing with restricted working spaces and improve restoration times.

This measure will also assist in the attainment of Toronto Hydro's Customer Service outcome as the measure will assist in improved connection efficiency, mitigate costs relating to load capacity constraints when connecting new customers to the downtown area, and ensure reliable electricity

[15] Refer to Electric Utility Safety Rule ("EUSR") 129 - Safe Limits of Approach, Canadian Standards Association ("CSA"), and the clearance rules mandated by the Electrical Safety Authority ("ESA").

service. Specifically, the utility expects improvements in this measure will contribute to an increase in the average outage restoration time for 22,700 downtown residential and small business customers.

Please refer to Area Conversions, Exhibit 2B, Section E6.1, for discussion of investments that will contribute to the performance of this measure.

C2.2.3 Network Units Modernization

The Network Units Modernization measure tracks Toronto Hydro's progress on the installation of network units that have resilient submersible protectors. Toronto Hydro has approximately 1,800 network units in its downtown secondary distribution network. These network units are essential as they isolate faults from separate feeders within the network, which protects network equipment, and provides uninterrupted service to downtown load.

A subset of these units are not water tight and can lead to significant corrosion and rust following years of exposure to flooding.[16] Network units also have an outdated design that increase the risk of phase tracking, which can instigate costly and dangerous vault fires with corresponding public and employee safety risks. Toronto Hydro has been removing non-submersible protectors and replacing them with submersible protectors.

During the 2015-2019 period, Toronto Hydro expects to replace approximately 225 non-submersible protectors. Over the 2020-2024 period, Toronto Hydro plans to replace approximately 240 non-submersible protectors, thereby increasing the number of submersible protectors to approximately 75 percent by the end of 2024.

[16] Please refer to Exhibit 2B, Section E6.4 (Network System Renewal), and Exhibit 2B, Section E2 for a detailed discussion of legacy assets.

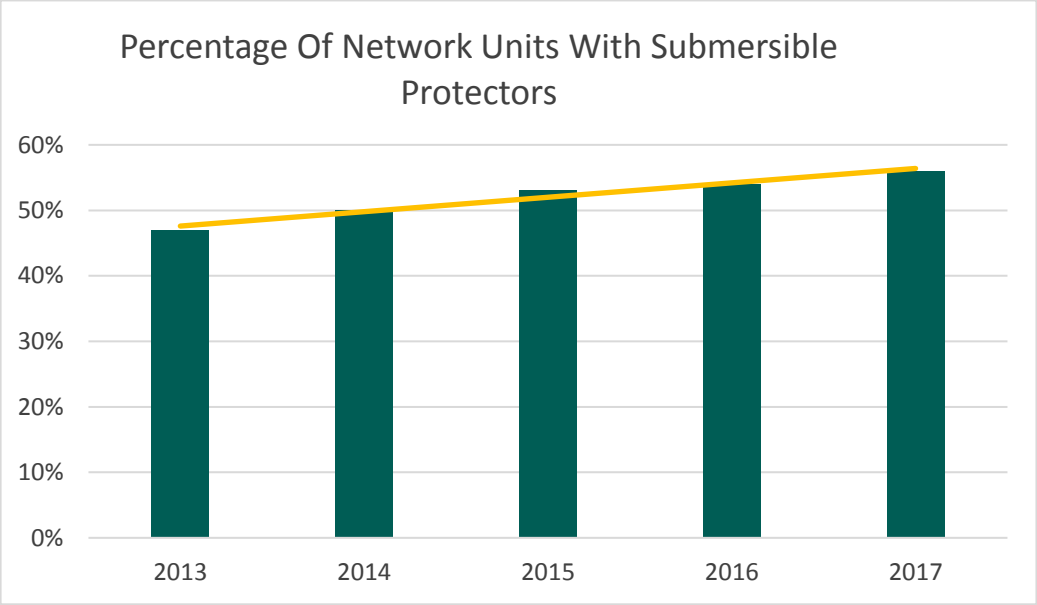


Figure 5: Network Unit Modernization: Percentage of Network Units with Submersible Protectors Performance for 2013-2017

Through this work, Toronto Hydro expects to mitigate public safety and catastrophic equipment failure risks, and help maintain network system reliability in the dense downtown core. Although the Network Units Measure is captured under the Safety outcome, the measure will also affect performance of Toronto Hydro's other outcomes. For instance, the metric will affect the Financial outcome through an expected decrease in costs associated with asset failures, including those resulting from customer interruptions, emergency repairs, and replacement.

Overall, Toronto Hydro anticipates that this program will increase service reliability, improve employee safety, and reduce environmental concerns by mitigated oil leaks. Please refer to Network System Renewal (Exhibit 2B, Section E6.4) for discussion of investments that will contribute to the performance of this measure.

C2.3 Reliability

Table 4: Reliability Custom Performance Measure

OEB Reporting Category	2020-2024 Custom Performance Measures	Historical Performance (2013-2017)	Target (2020-2024)
System Reliability	SAIDI- Defective Equipment	0.45 hours of interruption	Maintain
	SAIFI- Defective Equipment	0.52 hours of interruptions	Maintain
	FESI-7 System	26 feeders (avg.)	Improve
	FESI-6 Large Customers	18 feeders (avg.)	Maintain
Asset Management	System Capacity	17 in 2013 and 13 in 2017	Maintain
	System Health (Asset Condition)-Wood Poles	N/A	Monitor
	Direct Buried Cable Replacement	809 KM as of end of 2017	Improve

C2.3.1 System Average Interruption Duration Index ("SAIDI") & System Average Interruption Frequency Index ("SAIFI") Resulting from Defective Equipment

SAIDI is a measure in hours of the annual system average interruption duration for customers served, not including Major Event Days and Loss of Supply. SAIDI represents the quotient obtained by dividing the total customer hours of interruptions longer than one minute by the number of customers served.

SAIFI is a measure of the frequency of service interruptions for customers served, not including Major Event Days and Loss of Supply. SAIFI represents the quotient obtained by dividing the total number of customer interruptions longer than one minute by the number of customers served.

SAIDI and SAIFI Defective Equipment measures will assess the health performance of the system and highlight the impact of asset failures causing outages. These measures provide insight into the DSP performance as the health of assets is dependent, largely, on the utility's ability to execute its proposed capital and maintenance programs.[17]

[17] Toronto Hydro expects to upgrade its existing Outage Management System to a new Network Management System over the 2018-2022 period. This upgrade is expected to improve the utility's ability to capture interruptions across the distribution system. The utility will monitor the consequences of this upgrade on its reported reliability measures and provided the relevant information to the OEB as part of its annual reporting.

Between 2013 and 2017, outages caused by defective equipment was the main contributor to SAIDI and SAIFI performance.[18] As Figures 6 and 7, below, demonstrate, there was a slight improvement in the level of reliability in these years. This is directly attributable to Toronto Hydro's efforts to address aging and obsolete assets. For a comprehensive discussion of Toronto Hydro's historical system renewal efforts, please refer to Exhibit 2B, Section E2. For the 2020-2024 plan period, Toronto Hydro expects to maintain its performance for these measures.

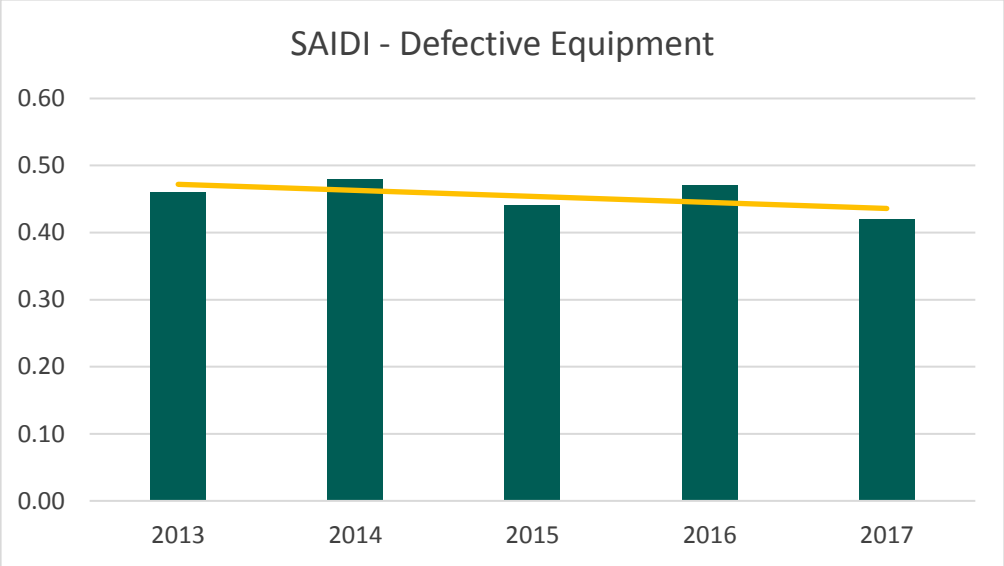


Figure 6: SAIDI (Defective Equipment) Performance between 2013-2017

[18] During this time, defective equipment contributed to 36.3 percent and 44.0 percent of the outages, respectively.

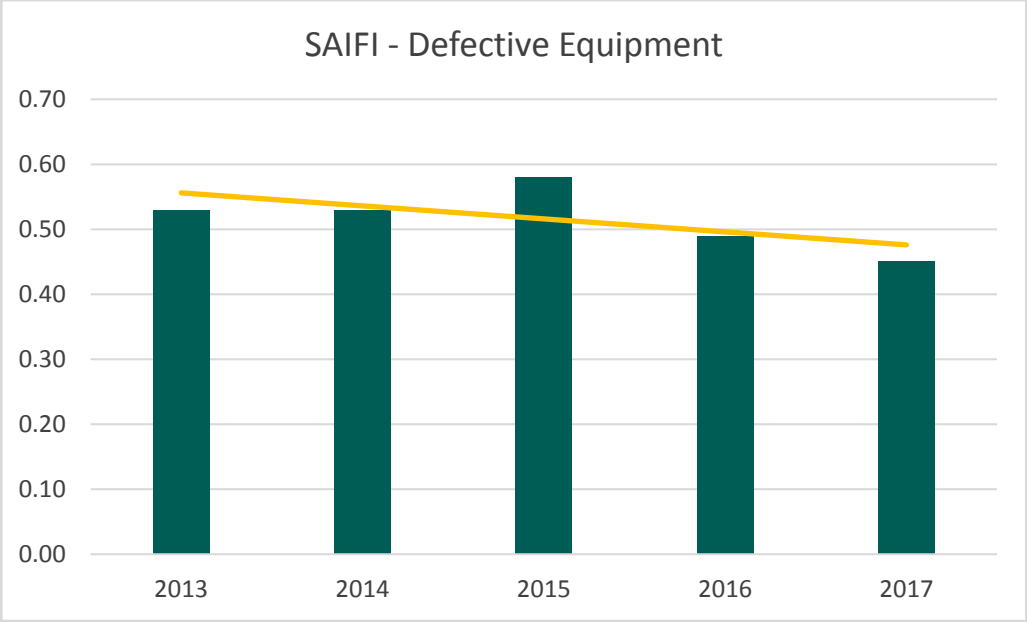


Figure 7: SAIFI (Defective Equipment) Performance between 2013-2017

Toronto Hydro's proposed investments during the 2020-2024 plan period are aimed at improving asset condition and demographics in order to mitigate reliability risks associated with defective equipment. Reliability results, as measured by SAIDI and SAIFI-Defective Equipment, are expected to decrease if the requisite investments are not made. For more information on system reliability performance and projection scenarios, please refer to Exhibit 2B, Section E2.

A substantial number of Toronto Hydro's capital programs will contribute to the performance of this measure. For instances of proposed 2020-2024 investments driving SAIDI and SAIFI-Defective Equipment performance, please refer to Load Demand (Exhibit 2B, Section E5.3), Area Conversions (Exhibit 2B, Section E6.1), Network System Renewal (Exhibit 2B, Section E6.4), Overhead System Renewal (Exhibit 2B, Section E6.5), Stations Renewal (Exhibit 2B, Section E6.6), Underground System Renewal – Downtown (Exhibit 2B, Section E6.3), Underground System Renewal – Horseshoe (Exhibit 2B, Section E6.2), System Enhancements (Exhibit 2B, Section E7.1), Stations Expansion (Exhibit 2B, Section E7.4), and the Predictive and Preventative Maintenance and Corrective Maintenance programs (Exhibit 4A, Tab 2, Schedules 1-4).

C2.3.2 Feeders Experiencing Sustained Interruptions (FESI-7/6) - Worst Performing Feeders

FESI-7 System and FESI-6 Large Customer measures track the performance of feeders that, on average, experience the highest number of customer interruptions as measured by Toronto Hydro's reliability metrics.[19] Toronto Hydro will track these measures on an annual system wide-basis, for those feeders experiencing seven or more interruptions (FESI-7 System) and large customers,[20] for those feeders experiencing six or more interruptions (FESI-6 Large Customers).

Between 2013 and 2017, FESI-7 System and FESI-6 Large Customers performance experienced a demonstrable improvement, see Figures 8 and 9, below.[21] For the 2020-2024 plan period, Toronto Hydro expects to improve performance for FESI-7- System measure, and maintain performance for FESI-6 Large Customers.

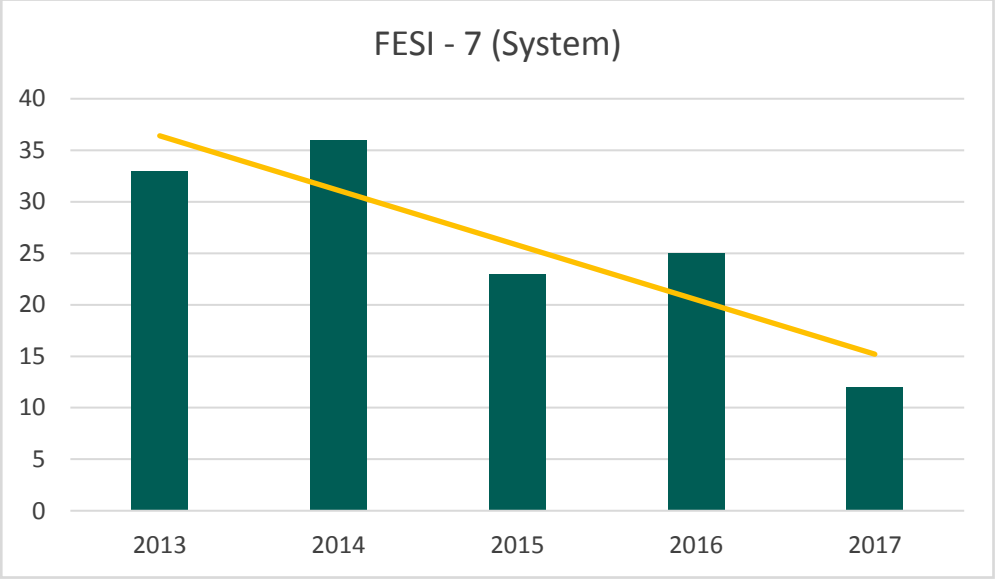


Figure 8: FESI-7 System Performance between 2013 and 2017

[19] These measures exclude interruptions caused by Major Event Days, Loss of Supply, scheduled outages, and station bus-level interruptions on the secondary side of the distribution transformer (e.g. on service wires or secondary bus).
[20] Defined as customers with average monthly peak demand greater than 1 megawatt.
[21] Toronto Hydro considers 2017 to be an outlier. Excluding 2017 results, the average performance for FESI-7- System and FESI-6 Large Customers is 29 and 21, respectively.

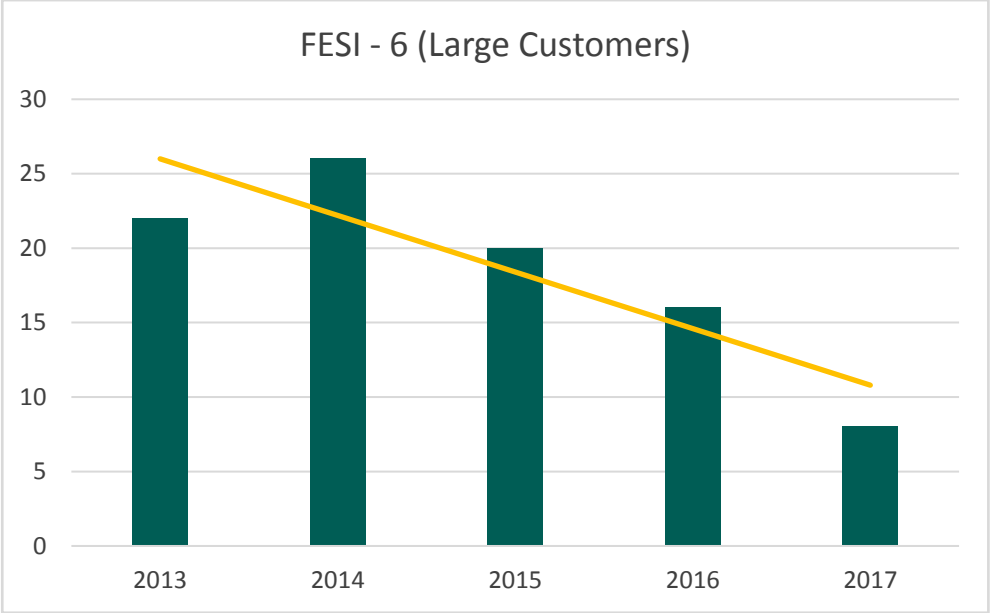


Figure 9: FESI-6 Large Customer Performance between 2013 and 2017

Toronto Hydro has proposed to measure feeders experiencing outages at these thresholds (FESI-7 and FESI-6) to account for customers with lower tolerance for interruptions. For instance, certain customers, such as hospitals, water treatment plants, and commercial manufacturers, have heightened reliability needs. The FESI-7 and FESI-6 measures will allow for the assessment of these nuanced needs and inform Toronto Hydro's planning decisions, targeting investments in areas where performance is substantially lower than the average levels of reliability experienced across the distribution system.

Similar to the improvements in SAIDI and SAIFI, the utility attributes its demonstrable improvement in FESI-7 System and FESI-6 Large Customers to its system renewal investments. For a comprehensive discussion of Toronto Hydro's historical investments, please refer to Exhibit 2B, Section E2.

A substantial number of Toronto Hydro's programs will contribute to the performance of this measure. For instances of proposed 2020-2024 investments driving FESI-7 System and FESI-6 Large Customers performance, please refer to Area Conversions (Exhibit 2B, Section E6.1), Network System Renewal (Exhibit 2B, Section E6.4), Overhead System Renewal (Exhibit 2B, Section E6.5), Stations Renewal (Exhibit 2B, Section E6.6), Underground System Renewal – Horseshoe (Exhibit 2B, Section E6.2), Underground System Renewal – Downtown (Exhibit 2B, Section E6.3), System Enhancements

(Exhibit 2B, Section E7.1), and the Predictive and Preventative Maintenance and Corrective Maintenance programs (Exhibit 4A, Tab 2, Schedules 1-4).

C2.3.3 System Capacity

The System Capacity measure tracks potential capacity constraints at the station level by measuring the ability of each station to connect at least one large customer.[22] This measure focuses on the 35 transformer stations that supply power to the City of Toronto. This measure is responsive to the continued City growth, leading to an increase in population density and urban development. For a comprehensive discussion on the state of the distribution system, including its operating challenges, please refer to Exhibit 2B, Section D2.

The System Capacity measure will consider a variety of factors that contribute to capacity concerns, including bus, transformer and feeder capacity and positions. If any of these factors create the inability to connect a large customer to a station, that particular station will be reported as part of this measure.

As seen in Figure 10, Toronto Hydro has reduced the number of stations with capacity constraints between 2013 and 2017. During this period, on average, there were 14 stations displaying capacity constraints. For the 2020-2024 plan period, Toronto Hydro plans to maintain the current levels of system capacity.

[22] Large customer for the purposes of this measure is defined as a customer with a peak load of approximately 10 MVA or higher.

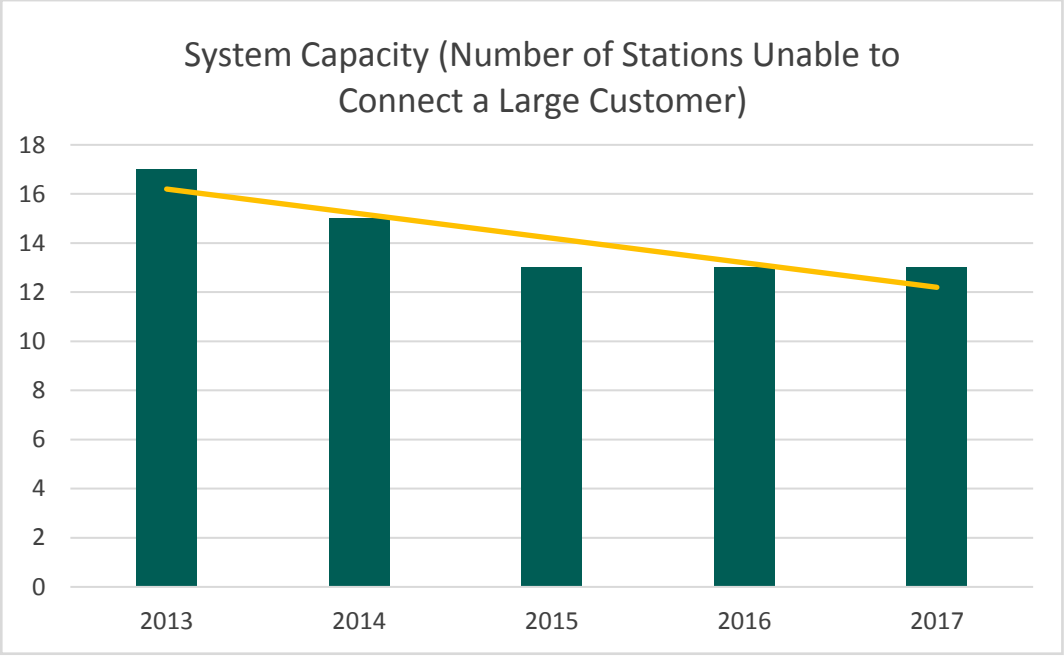


Figure 10: System Capacity (Number of Stations Unable To Connect a Large Customer) Performance for 2013 – 2017

Toronto Hydro's ability to connect customers on time is an existing measure under the OEB's performance tracking framework.[23] The ability to connect a customer to its system is significantly impacted by existing system capacity. Therefore, despite the fact that the System Capacity measure is included under the Reliability outcome, it will impact performance in the Customer Service outcome.

Please refer to Toronto Hydro's proposed investments in Stations Expansion (Exhibit 2B, Section E7.4) for discussion of targeted investments enabling continued and concentrated City growth. Other programs contributing to the performance of this measure include: Stations Expansion (Exhibit 2B, E7.4), Customer Connections (Exhibit 2B, Section E5.1), and Load Demand (Exhibit 2B, E5.3).

C2.3.4 System Health – Asset Condition (Wood Poles)

The System Health – Asset Condition (Wood Poles) measure will track the health of wood poles. Wood poles are critical assets and serve as an indication of overall distribution system health. These

[23] See the Electricity Distributor Scorecard and the Electricity Service Quality Requirements. See Exhibit 1B, Tab 2 for a discussion of how Toronto Hydro has performed on this measure.

assets form a sizeable portion of the utility's assets and are instrumental in ensuring reliability and safety. For instance, weak wood poles can tip over during severe weather events, impacting power supply in the area and posing significant safety risks.

Wood poles are one of two major asset classes for which Toronto Hydro performs an Asset Condition Assessment ("ACA"). ACA data shows that approximately 31 percent of the utility's wood poles have at least moderate deterioration as of 2017. With over 20,000 wood poles in HI3 condition (i.e. "moderate deterioration"), over 11,000 in HI4 condition (i.e. "material deterioration"), and approximately 1,100 in HI5 condition (i.e. "end of serviceable life"), pole replacement will continue to be a significant driver of both reactive and planned investment through 2024. For further details, please refer to Exhibit 2B, Section D2.

The System Health – Asset Condition (Wood Poles) is a new measure, and therefore Toronto Hydro does not have the requisite baseline data to set a target for the 2020-2024 period. The utility proposes to use actual annual data to measure its performance during this plan period.

A substantial number of Toronto Hydro's capital programs will contribute to the performance of this measure. For instances of proposed 2020-2024 investments driving System Health performance, please refer to Area Conversions (Exhibit 2B, Section E6.1), Overhead System Renewal (Exhibit 2B, Section E6.5), Reactive and Corrective Capital (Exhibit 2B, Section E6.7), and the Predictive and Preventative Maintenance and Corrective Maintenance programs (Exhibit 4A, Tab 2, Schedules 1-4).

C2.3.5 Direct Buried Cable Replacement

The Direct Buried Cable Replacement measure will track the number of kilometres of direct buried cable that remains in the distribution system during the 2020-2024 plan period. Customers supplied by feeders containing direct buried cable are more likely to experience lengthy interruptions resulting from increased difficulty in locating and replacing faulty segments. During 2020-2024, Toronto Hydro plans on reducing the presence of direct buried cable by approximately 27 percent.

As shown in Figure 11, as of 2018, Toronto Hydro's underground distribution system contains approximately 800 kilometres of direct buried cable. Of this, approximately 370 circuit-kilometres are of the highest-risk cross-linked polyethylene ("XLPE") type and approximately 70 percent of this cable is currently beyond its useful life. This is expected to escalate to 90 percent by 2024. To prevent reliability from degrading, the utility developed a plan to proactively replace approximately one quarter of the 800 circuit-kilometres (i.e. an estimated 215 circuit-kilometres) of this cable in the

Underground System Renewal – Horseshoe program during the 2020-2024 period, prioritizing the highest-risk neighbourhoods based on cable age, performance, criticality, and adjacency to other assets at risk of failure. For further information on Toronto Hydro's Direct Buried Cable Replacement Plan, please refer to Exhibit 2B, Section E2, and Exhibit 2B, Schedule E6.2.

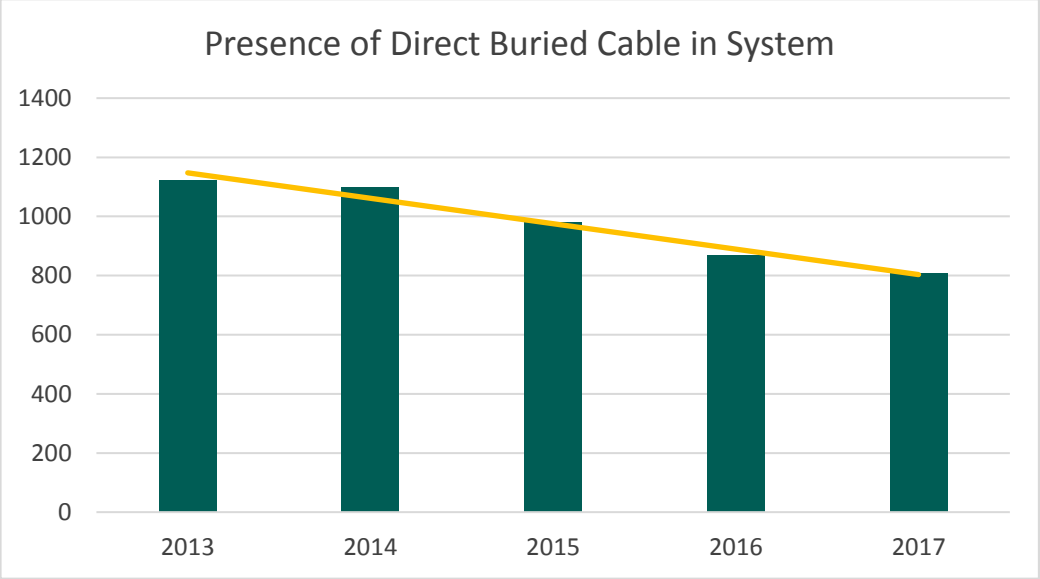


Figure 11: Presence of Direct Buried Cable between 2013-2017

Please refer to Toronto Hydro's Underground System Renewal – Horseshoe program (Exhibit 2B, Section E6.2) for a discussion of proposed investments driving the performance of this measure.

C2.4 Financial

Table 5: Financial Custom Performance Measure

OEB Reporting Category	2020-2024 Custom Performance Measures	Historical Performance (2013-2017)	Target (2020-2024)
Cost Control	Average Wood Pole Replacement Cost	N/A	Monitor
	Vegetation Management Cost Per KM	N/A	Monitor

C2.4.1 Average Wood Pole Replacement Cost

The Average Wood Replacement Cost measure will measure the unit cost of wooden poles installed in the distribution system. As mentioned in the System Health (Asset Condition)-Poles measure description, above, 11,000 wood poles are in HI4 condition (i.e. "material deterioration"), and approximately 1,100 in HI5 condition (i.e. "end of serviceable life"). Consequently, pole replacement will continue to be a significant driver cost driver through to 2024. For further details, please refer to Exhibit 2B, Section D2.

The Average Wood Pole Replacement Cost measure is a new measure and therefore, baseline data does not exist. Toronto Hydro will track performance of this measure using a three-year rolling average, consistent with the methodology applied in the UMS Group Unit Cost Benchmarking Study.[24] This methodology was selected to smooth out year-over-year fluctuations that are likely to occur in the course of utility operations.[25] By way of background, in 2018, UMS Group ("UMS") conducted a Unit Costs Benchmarking Study for Toronto Hydro that assessed its methodology for determining unit costs and benchmarked these costs against its peers.[26] For more information on unit cost metrics, please refer to Exhibit 1B, Tab 2.

A substantial number of Toronto Hydro's capital programs will contribute to the performance of this measure. For instances of proposed 2020-2024 investments driving Average Wood Pole Replacement Cost performance, please refer to Area Conversions (Exhibit 2B, Section E6.1), Overhead System Renewal (Exhibit 2B, Section E6.5), Reactive and Corrective Capital (Exhibit 2B,

[24] UMS Group, Toronto Hydro-Electric System Limited Unit Costs Benchmarking Study, filed as Appendix X to Exhibit 1B, Tab 2.
[25] Ibid at p. 12.
[26] Ibid at p. 8.

Section E6.7), and the Predictive and Preventative Maintenance and Corrective Maintenance programs (Exhibit 4A, Tab 2, Schedules 1-4).

C2.4.2 Vegetation Management Cost per Kilometre ("KM")

The Vegetation Management Cost per KM measure will track the costs of trimming and clearing of vegetation located near overhead feeders to minimize the risk of power interruptions. Vegetation-caused power interruptions are the second highest contributor (following defective equipment) to overall system reliability.

The unit costs for calculating this measure are on a per kilometre basis, determined by dividing the total actual expenditures of the Vegetation Management segment in Toronto Hydro's Preventative and Predictive Overhead Line Maintenance program (Exhibit 4A, Tab 2, Schedule 1) by the total kilometres trimmed.

Given the lack of historical data, Toronto Hydro will track performance of the Vegetation Management Cost per KM measure using a three-year rolling average, consistent with the methodology applied in the Average Wood Pole Replacement Cost measure, see discussion above.

Please refer to Preventative and Predictive Overhead Line Maintenance program (Exhibit 4A, Tab 2, Schedule 1) for a discussion of the proposed investments driving the performance of this measure.

C2.5 Environment

Table 6: Environment Custom Performance Measure

OEB Reporting Category	2020-2024 Custom Performance Measures	Historical Performance (2013-2017)	Target (2020-2024)
Environment	Oil Spills Containing PCBs	9 spills (avg.)	Improve
	Waste Diversion Rate	N/A	Monitor

C2.5.1 Oil Spills Containing Polychlorinated Biphenyl ('PCB")

The Oil Spills Containing PCBs measure tracks Toronto Hydro's progress towards reducing the risk of oil spills containing PCBs. Toronto Hydro has various types of underground transformers (e.g. submersible, padmounted, vault, network), all of which can potentially contain PCB contaminated oil. As of the end of 2017, approximately 3,800 are known to contain, or at risk of containing, PCB contaminated oil greater than 2 ppm. During the 2020-2024 period, Toronto Hydro endeavours to decrease the average PCB-contaminated oil spills by testing or replacing all of the PCB at-risk assets, which will be operating beyond useful life by 2025. For an overview of Toronto Hydro's efforts to reduce the number of PCB-contaminated oil spills, please refer to Exhibit 2B, Section D2.

Figure 12, below, displays the number of oil spills containing PCBs during 2013 and 2017. During this period, the utility experienced, on average, nine PCB-contaminated oil spills. For the 2020-2024 plan period, Toronto Hydro plans to improve its historical performance.

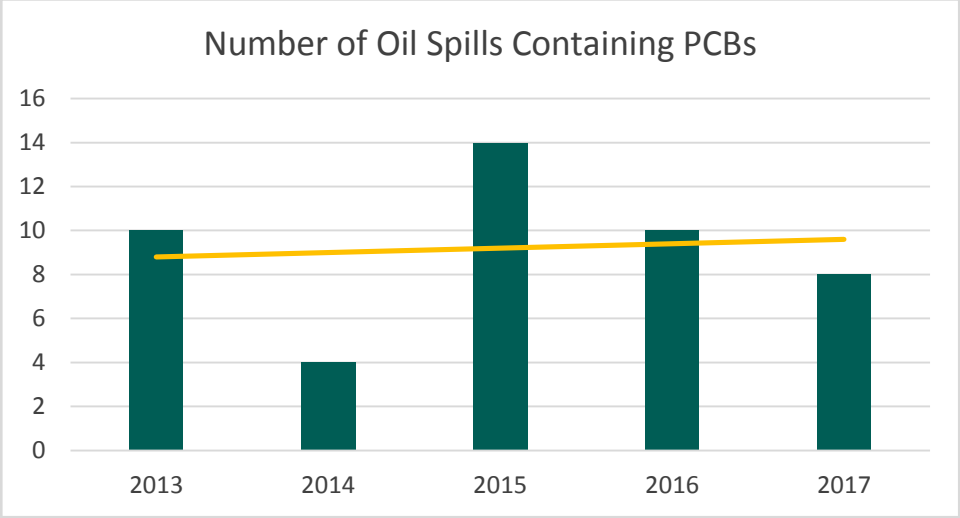


Figure 12: Oil Spills Containing PCBs between 2013-2017

Although a reduction in oil spills containing PCBs is allocated to the Environment outcome, there is a connection to the Public Policy reporting category as PCB-related usage and spills is regulated, in some form, by all levels of government.[27]

For details on the proposed investments driving the performance of this measure, please refer to Underground System Renewal – Horseshoe (Exhibit 2B, Section E6.2), Underground System Renewal – Downtown (Exhibit 2B, Section E6.3), Overhead System Renewal (Exhibit 2B, Section E6.5) and Reactive and Corrective Capital (Exhibit 2B E6.7).

C2.5.2 Waste Diversion Rate

The Waste Diversion Rate measures progress on Toronto Hydro's performance on office and work-site waste diverted from landfills. Waste diversion promotes recycling and reusing materials and presents a number of environmental benefits including reducing waste and lowering greenhouse gas emissions. Toronto Hydro's efforts to divert waste from landfills is a reflection of the utility's corporate leadership in reducing its environmental footprint.

Toronto Hydro has a significant presence in the City of Toronto, with four work centres, 207 stations, four warehouse locations,[28] and approximately 1,500 employees. Waste diversion efforts in the operations of a utility of Toronto Hydro's size can have a significant impact on the environment. The utility actively promotes waste diversion through the following initiatives: removal of employee desk-side garbage bins to encourage a decrease in waste, internal audits of waste collection areas, used furniture donations, and reduction in paper usage. In addition, Toronto Hydro consistently communicates waste and recycling sorting methods to its employees as well as provides an online recycling guide.

During the 2020-2024 plan period, Toronto Hydro plans to install additional organic bins, implement mobile applications to replace paper based forms, work with vendors to reduce packaging, and promote awareness of the recyclability of different types of waste produced in the field.

[27] For instance, the end use deadlines are provided under the federal PCB regulations, PCB Regulations, SOR/2008-273, spills are governed by the provincial Waste Management- PCBs, O. Reg. 232/11. On the municipal level, the Toronto Municipal Code, specifically chapter 681, Sewers, prohibits virtually any discharge of PCBs into the municipal sewages.

[28] One of the locations is managed by a third-party.

For further information on proposed investments driving the performance of this measure, please refer to Reactive and Corrective Capital (Exhibit 2A, Section E6.7), Facilities Management (Exhibit 4A, Tab 2, Schedule 12), and Supply Chain (Exhibit 4A, Tab 2, Schedule 13).

D Asset Management Process



D1	Asset Management Process Overview
D2	Coordinated Planning with Third Parties
D3	Overview of Distribution Assets
D4	Facilities Asset Management Strategy
D5	Information Technology Asset Management Strategy
App A	UMS Asset Management Review
App B	PSE Standards Review
App C	Toronto Hydro Asset Condition Assessment Methodology
App D	Climate Change Vulnerability Assessment

D1 Asset Management Process Overview

Section D of the Distribution System Plan ("DSP") details Toronto Hydro's asset management process, which is the systematic approach the utility uses to:

- Collect, organize, and assess information on its physical assets and current and future operating conditions;
- Assess the utility's business priorities and customer focused goals and objectives in relation to its assets; and
- Plan, prioritize, and optimize expenditures on system-related modifications, renewal, operations, and maintenance, and on general plant facilities, systems and apparatus.

Toronto Hydro's main asset management process is known as the Distribution System AM Process, referenced throughout the DSP as the "AM Process". The utility's processes for non-system (i.e. general plant) assets are fundamentally aligned with the AM Process, relying on many of the same principles, inputs, and evaluative frameworks. However, as there are subtle but relevant differences between the distribution system and general plant processes, Toronto Hydro has included separate, supplemental sections dedicated to the particulars of the asset management processes for general plant assets. Overall, Toronto Hydro has the following major asset management areas:

1) Distribution System AM Process;
2) Information and Operational Technology ("IT/OT") Asset Management; and
3) Facilities Asset Management.

The processes and details for each of these asset management areas are provided in the sections that follow:

- **Section D1** provides an overview of the elements that constitute the AM Process, including the relationship between corporate goals and asset management objectives, and describes Toronto Hydro's roadmap for continuous improvement in distribution system asset management, including enhancements and innovations that have been completed or commenced, with an emphasis on innovations in the period since the OEB's December 2015 decision on Toronto Hydro's 2015-2019 Custom IR application.
- **Section D2** describes the current state of the distribution system based on asset demographics, system configurations and various observable features of Toronto Hydro's

distribution service area, including expectations for the continuing evolution of these features over the forecast period and beyond.

- **Section D3** reviews the policies and practices through which Toronto Hydro optimizes distribution system asset risk, utilization, performance, and costs during the asset lifecycle.
- **Section D4** describes the asset management approach for facilities assets.
- **Section D5** describes the asset management approach for IT/OT assets.

In addition to the major areas listed above, the utility also utilizes a robust approach to the management of its fleet assets, described within the Fleet and Equipment capital program in Section E8.3 of this DSP.

The various asset management processes provide the architecture for long-term, short-term, and maintenance planning functions. Toronto Hydro applied these processes in developing the 2020-2024 Capital Expenditure Plan, described in Section E of the DSP, and the system maintenance plans, described in Exhibit 4A, Tab 2, Schedules 1-5.

Expert Review of Asset Management at Toronto Hydro

During the preparation of its 2020-2024 DSP, Toronto Hydro engaged UMS Group ("UMS") to perform an independent review of Toronto Hydro's asset management practices. UMS has "worked with utilities worldwide in developing and implementing Asset Management capabilities" and is an Institute of Asset Management ("IAM") Endorsed Assessor for ISO 55001 certification. UMS evaluated Toronto Hydro's asset management maturity through the lens of the ISO 55001 framework and UMS's own Strategic Asset Management Framework as they relate to the scope of the OEB's filing requirements for the DSP. UMS found that, across the ISO 55001 domains assessed, Toronto Hydro "exceeds the North American average level of maturity in all areas, reaching into "Best Practice" for some." The full report from UMS is included as Appendix A to Section D of the DSP.

D1.1 Asset Management Objectives and Outcomes

Toronto Hydro's asset management objectives are to a large extent driven by relevant legislative and regulatory obligations and guidance such as the OEB's Distribution System Code ("DSC") and the *Electricity Act, 1998*, including:

- Following good utility practices for system planning to ensure reliability and quality of electricity service on both a short-term and long-term basis;[1]
- "[Ensuring] the adequacy, safety, sustainability and reliability of electricity supply in Ontario through responsible planning and management of electricity resources, supply and demand";[2] and
- "[Protecting] the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service".[3]

Additionally, Toronto Hydro aligns its AM Process with other applicable legislative and regulatory requirements and principles, including the *Ontario Energy Board Act*, *1998*, Toronto Hydro's Distribution Licence, the Standard Supply Service Code, and relevant City of Toronto by-laws.

Beyond its mandated service and compliance obligations, the broader objective of Toronto Hydro's AM Process is to realize sustainable value from the organization's assets for the benefit of customers and stakeholders. This requires continuously balancing near-term customer preferences with the need to ensure predictable performance and costs over the long-term for both current and future customers.

For the purposes of setting strategic outcome objectives and measuring the extent to which those outcomes are met, Toronto Hydro has aligned its AM Process with:

- The utility's strategy for the regulated business, as described in Exhibits 1B, Tab 1 and Section E2 of the DSP; and
- The utility's Outcomes Framework, as detailed in Exhibit 1B, Tab 3, Schedule 1.

Toronto Hydro's corporate strategy and associated business planning processes, including the AM Process, are guided by a set of principles that align with the utility's four corporate pillars. As

[1] DSC, at section 4.4.1
[2] *Electricity Act*, *1998* at section 1.
[3] Ibid.

represented in Figure 1 below, the utility maintains a constant focus on these four pillars – Customer, Operations, People, and Financial – in a balanced way that promotes customer value and a sustainable business. These principles are an essential element in the determination and prioritization of outcomes.



Figure 1: Toronto Hydro's Corporate Pillars

D1.1.1 Introduction of an Enhanced Outcomes Framework

As discussed in Exhibit 2B, Section E2, Toronto Hydro leveraged its Phase 1 Customer Engagement results to develop an enhanced Outcomes Framework for the 2020-2024 planning horizon. This framework serves to translate Toronto Hydro's expenditure plan objectives into outcome categories that matter to the utility's customers. The framework is also aligned with Toronto Hydro's four corporate pillars and the OEB's *Renewed Regulatory Framework* ("RRF") Outcomes. The framework is depicted in Figure 2 in Section E2 and is structured around the following six outcome categories: Customer Service, Reliability, Safety, Environment, Public Policy, and Financial.

Section C of the DSP provides a comprehensive overview of the outcome measures that are most relevant for tracking the performance of Toronto Hydro's capital plan and supporting maintenance programs relative to the utility's customer-focused objectives for the 2020-2024 period.

Toronto Hydro used this Outcomes Framework to develop the strategy and results of its business planning process. The resulting 2020-2024 Capital Expenditure Plan includes measurable objectives that directly or indirectly relate the proposed level of spending in each program to the utility's strategic objective of continuous improvement in each of its six outcome categories (and by extension, each of the four RRF outcomes).

For example, one of the key reliability outcome objectives for Toronto Hydro's System Renewal expenditure plan is to maintain SAIDI and SAIFI at current levels over the 2020-2024 period. The programs in the System Renewal category demonstrate how the planned pace of spending relates to leading indicators of reliability (e.g. asset condition) in a manner that efficiently supports this objective.

The utility intends to continue using this framework to engage with customers and to assess and communicate the effectiveness of its asset management plans in delivering value that aligns with evolving customer preferences over time.

D1.2 Asset Management Process Overview

This section outlines the major elements of the AM Process for distribution system assets, their inter-relationships, and the key inputs and outputs between each element.

The corporate strategy and outcome objectives outlined in the previous section determine the overall direction for decision-making throughout the AM Process. At the same time, the information and performance results generated by the AM Process inform the continuous refinement of corporate objectives, in balance with other considerations such as Customer Engagement and benchmarking results.

Figure 2, below, illustrates the AM Process, consisting of five main components:

- Investment Planning and Portfolio Reporting ("IPPR") Process;
- Scope and Project Development;
- Program Management and Execution;
- Performance Measurement; and
- Standards and Practice Review.

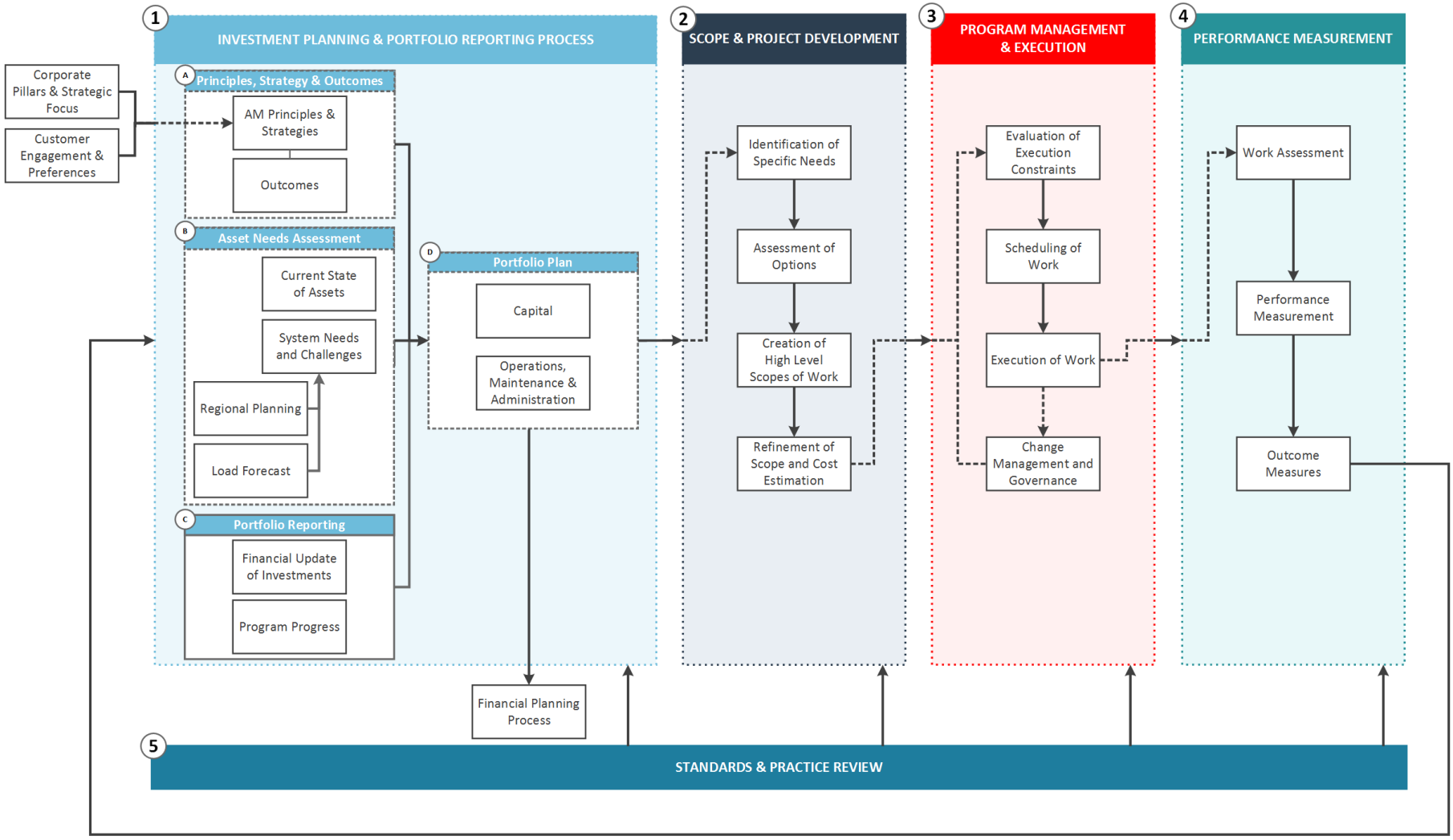


Figure 2: Asset Management Process Overview

The following sections outline each main component of the AM Process.

D1.2.1 Investment Planning and Portfolio Reporting ("IPPR") Process

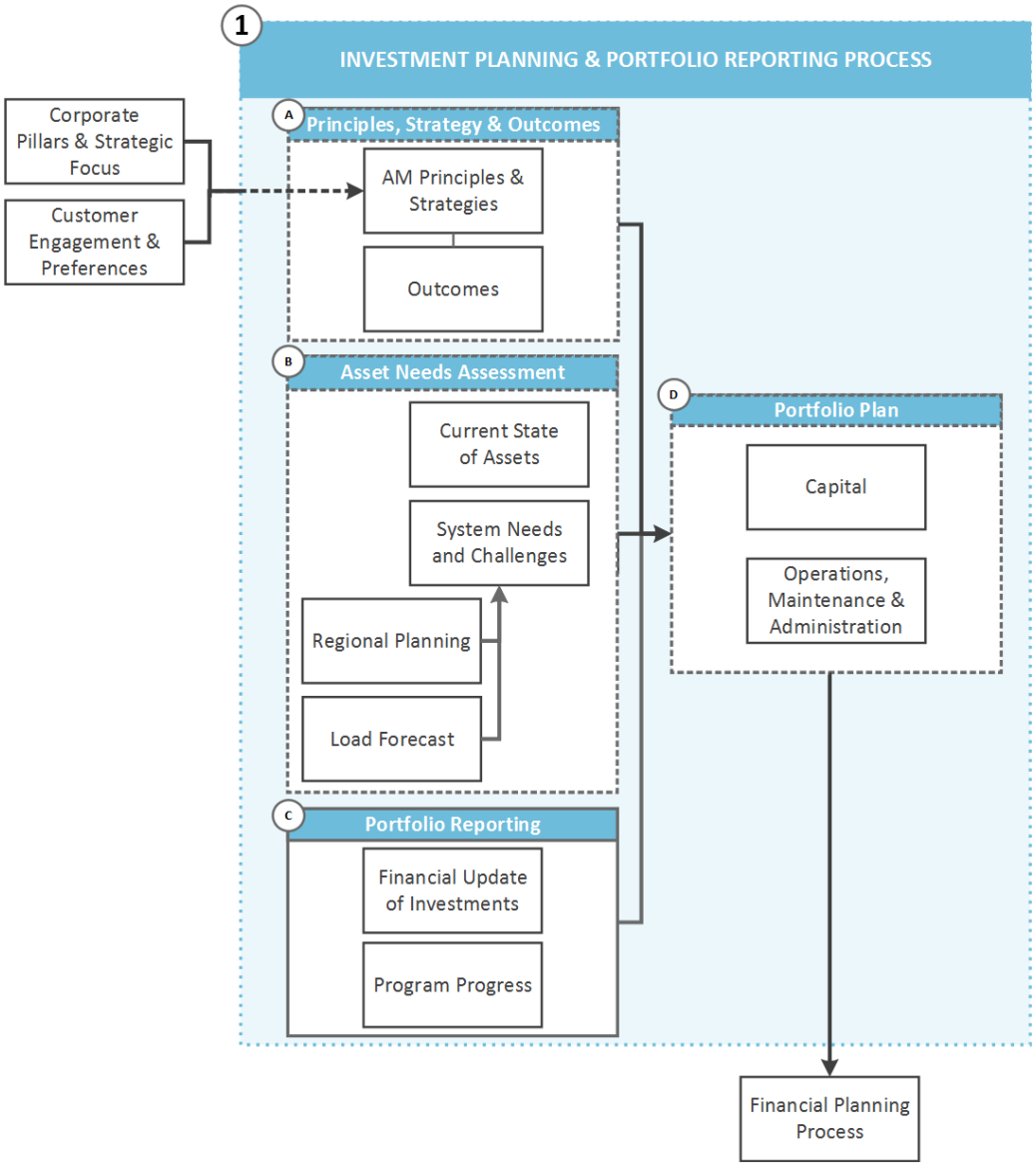


Figure 3: IPPR Process

The IPPR process is Toronto Hydro's system investment planning cycle, which includes both long-term and short-term planning horizons. It is composed of four sets of activities:

- **Principles, Strategies and Outcomes Development:** The IPPR process is guided by Toronto Hydro's asset management principles, strategies, and outcomes. The utility frequently reviews and updates these elements to ensure continuous alignment of asset management decision-making with corporate strategy and customer and stakeholder needs and preferences. These activities are discussed in detail in section D1.2.1.1 below.
- **Asset Needs Assessment:** To determine the types and level of asset investment needed, Toronto Hydro tracks and analyzes the current state of its assets, their performance relative to a wide variety of risk indicators (e.g. environmental, reliability, and safety indicators), and their ability to serve evolving demands from customers and external parties (e.g. bus-level load forecasts and evolving power quality needs). These activities are discussed in detail in section D1.2.1.2 below.
- **Portfolio Reporting:** Toronto Hydro monitors and assesses the progress of its system capital and maintenance programs against annual and longer-term budget, execution, and performance objectives. This helps ensure the utility is cost-effectively executing the DSP while making prudent adjustments in light of new information. These activities are discussed further in section D1.2.1.3 below.
- **Portfolio Planning**: Toronto Hydro uses the outputs of the above three activities to develop capital and maintenance investment plans. These plans are the result of the utility's asset management strategies and outcomes as applied to a combination of the current needs of the system and the current status of ongoing investment activities and accomplishments. Key aspects of the portfolio planning activity include the consideration of alternative investment strategies and the development of both short- and longer-term expenditure plans for each capital program. These activities are described in detail in section D1.2.1.4 below.

Over the last decade, due to the overall effort involved, Toronto Hydro has performed some of the above activities annually (e.g. asset needs assessment), while performing others (e.g. review of asset management strategies and longer-term expenditure plans) less frequently, often as part of a broader planning effort in the lead-up to a rate-setting application. In 2016, with the benefit of an extended five-year rate cycle, Toronto Hydro bundled all of the above activities into a single process that it now executes annually. This change is expected to further strengthen the alignment between: (i) the projects selected for execution within an annual capital plan; and (ii) the utility's overall five-year expenditure plan and outcome objectives. It will also help improve the sensitivity of the planning process to new and evolving information, including ongoing customer and stakeholder engagement, changes in system performance, public policy developments, and other dynamic factors.

The four major activities of the IPPR process are explained in further detail in the following sections.

D1.2.1.1 Principles, Strategies and Outcomes

Figure 4 provides a high-level summary of Toronto Hydro's asset management principles, strategies, and outcomes. The utility reviews and, if necessary, adjusts these components of the AM Process as part of the IPPR process.

Toronto Hydro's overarching asset management *principles* articulate the values that guide the utility's approach to managing its distribution system assets. These principles align with the components of the utility's corporate pillars (e.g. "strive for zero public and employee safety incidents" and "operate the system in a sustainable manner"), while also reflecting the balance between the utility's responsibility as the long-term steward of the system (i.e. system viability) and the needs and preferences of customers, including service quality needs and affordability.

Each of Toronto Hydro's asset management *strategies* is a high-level course of action meant to achieve an objective in relation to each guiding principle. These strategies are based on observed asset risk and performance and emerging challenges. The utility refines and recalibrates its asset management strategies over time to align with customer needs and preferences as identified through formal and informal Customer Engagement (e.g. "Plan investment and maintenance programs to help maintain system average reliability while improving reliability on worst performing feeders […]"). The strategies then serve to guide the utility's decision making with respect to the investment alternatives chosen and the pacing and prioritization of investments in specific programs over a given time period.

Asset management outcomes are the measurable, time-bound, and customer focused results of the utility's asset management strategies. The outcome categories for asset management are the same as those used in planning across all other functions of the utility. Toronto Hydro's 2020-2024 DSP is focused primarily on the outcomes the utility is projecting for the 2020-2024 rate period. Where appropriate, the DSP also includes information necessary to demonstrate the link between investments in the current period and delivery of outcomes over the longer-term (e.g. "Maintain and, where appropriate, reduce asset failure risk – as represented by leading indicators like asset condition – over the 2020-2024 period, supporting stable system reliability and safety outcomes for current and future customers").

PRINCIPLES	STRATEGIES	OUTCOMES
VIABILITY Ensure the long-term viability of the electricity distribution network and meet the customers' electricity supply needs by accommodating growth and evolving consumer and stakeholder needs	**RENEWAL** Ensure stable long-term performance and costs by investing at a pace that will, at a minimum, prevent growing asset performance risk over time **CAPACITY** Ensure station and feeder loading does not exceed specifications and that each station is capable of accommodating anticipated growth and development in Toronto	**RELIABILITY / SAFETY** Maintain and, where appropriate, reduce asset failure risk – as represented by leading indicators like asset condition – over the 2020-2024 period, supporting stable system reliability and safety outcomes for current and future customers **CUSTOMER SERVICE** Continue connecting customers of all types (including distributed energy resources) on time and cost-effectively, without harming system performance for existing customers
PERFORMANCE In alignment with customer and stakeholder needs and preferences, maintain and improve system performance and resiliency, with a focus on delivering performance improvements for customers experiencing poor service	**RELIABILITY** Plan investment and maintenance programs to help maintain system average reliability while improving reliability on worst performing feeders and for customers experiencing poor performance Modify and upgrade equipment standards where appropriate to improve system resiliency to adverse weather events **RENEWAL** Prioritize the replacement of assets with a high risk and consequence of failure **INNOVATION** Pursue innovative technologies that provide customer benefits, with a focus on technologies that can improve the resiliency of the system **POWER QUALITY** Develop solutions to the power quality issues faced by large commercial and industrial customers in Toronto	**RELIABILITY** Maintain system reliability at current levels over the 2020-2024 period while (1) improving the experience for customers with poor reliability and power quality and (2) improving the resiliency of the distribution system
ENVIRONMENT & SUSTAINABILITY Operate the system in a sustainable manner that continuously improves safety and environmental performance	**ENVIRONMENT & SUSTAINABILITY** Take all reasonable actions to mitigate the risk of equipment-related failures and incidents resulting in an adverse effect on the environment Take reasonable steps to gradually reduce greenhouse gas emissions from line losses	**ENVIRONMENT** Endeavour to eliminate the risk of PCB-contaminated oil spills by 2025 Reduce the system's impact on the environment caused by greenhouse gas emissions and oil leaks of all types
SAFETY Strive for zero public and employee safety incidents	**SAFETY** Eliminate all assets and asset configurations that present unacceptable safety risks to employees Develop investment and maintenance plans to reduce all types of public safety risks including those related to contact voltage, downed conductors, and cable chamber lid incidents	**SAFETY** Strive to target zero public and employee safety incidents over the 2020-2024 period Continue to reduce and eliminate public and employee safety risks, for example by removing higher-risk legacy assets from the system within a specific and reasonable timeframe
VALUE & AFFORDABILITY Strive to minimize the total lifecycle costs of the system while continuously delivering customer value	**VALUE-FOR-MONEY** Continuously improve the utility's risk-based approach to prioritizing and pacing investments, with the objective of directing spending to only the highest-value projects Mitigate increases in capital costs by continuously improving planning, estimating, procurement, and project management practices **INNOVATION** Leverage technological innovations that can improve customer value, including technologies that support the deferral of large capital projects	**FINANCIAL** Minimize average rate increases over the 2020-2024 period while continuously improving the value delivered to current and future customers
PUBLIC POLICY & COMPLIANCE Comply with all relevant legislation and regulations and support public policy objectives	**COMPLIANCE** Comply with applicable legislation and regulations **PUBLIC POLICY** Support and adapt to the implementation of public policy as it relates to Toronto Hydro's role in the electricity system (e.g. enabling distributed energy resources)	**SAFETY, ENVIRONMENT, ETC.** Comply with all safety, environmental and customer service regulations and standards over the 2020-2024 period **PUBLIC POLICY RESPONSIVENESS** Respond effectively to public policy during the 2020-2024 period, including by enabling the timely connection of all forecasted renewable generation projects and implementing a Conservation First approach wherever feasible

Figure 4: Summary of Principles, Strategies, and Outcomes

As mentioned above, Toronto Hydro's formal and informal Customer Engagement results influenced the development and refinement of the utility's asset management principles, strategies, and outcomes for the planning cycle that generated the 2020-2024 Capital Expenditure Plan. For further information on Toronto Hydro's Customer Engagement results and how they shaped the plan, please refer to Section E2.3.

The practical alignment of Toronto Hydro's asset lifecycle optimization and risk management practices with its asset management principles, strategies, and outcomes is discussed in detail in Section D3.

D1.2.1.2 Asset Needs Assessment

Toronto Hydro completes a needs assessment of its distribution system to determine the type of investments required. This includes determining the current state of assets, identifying system needs and challenges, and incorporating load forecasts and regional planning results. Further details on these focus areas and how they are used in developing the investment plans can be found in Section D3.2.

Toronto Hydro regularly performs a foundational analysis to understand the current state of the distribution system in terms of asset properties and quantities, asset performance risk (e.g. age, condition, and obsolescence), historical reliability, and asset utilization (e.g. capacity to connect customers and serve peak load).

1. *Asset Properties, Performance Risk, and Historical Reliability*

To assess the properties and quantities of assets and asset performance risk, Toronto Hydro gathers data such as nameplate and locational information from its enterprise systems, including the Geographic Information System ("GIS") and Enterprise Resource Planning ("ERP") system. This data is coupled with information from decision-support systems such as the Interruption Tracking Information System ("ITIS"), which stores historical reliability data, and the Asset Condition Assessment ("ACA"), which provides additional insight into the failure risk of assets based on observable conditions.

Both age and ACA data support Toronto Hydro's assessment of the probability that an asset will fail at a point in time. Asset age is strongly correlated with the probability of asset failure. Its simplicity and availability make it one of the important components of system-wide analysis (e.g. reliability forecasting), particularly for longer time horizons.

The ACA provides additional precision when assessing asset-specific failure risk for certain major asset types. The ACA combines observable asset condition variables (e.g. visible corrosion) with age to generate a health index ("HI") score that relates the overall asset condition to the asset's remaining useful life. This allows the utility to place assets along an asset health continuum, which is then divided into five HI bands (i.e. "HI1" to "HI5"). The bands are used to identify and track the progression of observable asset condition from new or good condition ("HI1") to end-of-serviceable life condition ("HI5"). As assets progress from HI1 to HI5, the risk of asset failure increases. The health of an asset helps Toronto Hydro optimize asset replacement plans by indicating whether an asset has a higher or lower probability of failure than age alone would indicate. The ACA model also allows the utility to project future asset condition at an aggregate population level, which supports effective investment program pacing during the planning process.

Age and ACA are leading indicators of failure and, by extension, the future reliability, safety, and environmental performance of Toronto Hydro's system. As noted above, Toronto Hydro also considers historical reliability – a lagging indicator of performance – in its asset needs assessment. Actual reliability helps to identify areas of poor or worsening performance and is a useful input in project prioritization. Historical reliability can also be a leading indicator of asset failure in specific circumstances. For example, a direct-buried cable that has failed and been repaired is more likely to fail in the future than a cable of the same age that has never failed.

Toronto Hydro also considers the potential consequences of failure when assessing asset needs. For example, a pole-top transformer that is known to use oil containing polychlorinated biphenyl ("PCB"), a prohibited toxic substance, has a heightened consequence of failure and is therefore a higher priority for replacement than an equivalent unit without PCBs.

2. Capacity and Connections

Toronto Hydro determines capacity and connection needs through load forecasting, connections forecasting, generation connections forecasting, and the Regional Planning process.

The load forecasting process enables Toronto Hydro to identify capacity availability and anticipated constraints at substations in relation to future load growth. This provides planners with a ten-year view of the system to aid in planning for future needs at the station bus and feeder levels. Further information on the load forecast can be found in Section D3.3.1.1.

The customer and generation connections forecasting processes enable Toronto Hydro to plan for the types and amounts of expenditures required to cost-effectively accommodate all anticipated load and generation customers. Toronto Hydro considers anticipated long-term trends and the number of actual connection applications received in developing these forecasts. See Exhibit 2B, Section D2 for more details.

The Regional Planning Process is an important input to distribution system planning and stations-level planning in particular. Toronto Hydro participates in infrastructure planning on a regional basis to ensure regional issues and requirements are effectively integrated into the utility's planning processes. Toronto Hydro participates in the Central Toronto Integrated Regional Resource Plan, led by the Independent Electricity System Operator, and in the Regional Infrastructure Plan for Metro Toronto Region and GTA North Region, led by Hydro One Networks Inc. Additional details on the Regional Planning process are discussed in Section B2.

3. Other Considerations

In addition to the above system-wide needs assessment considerations, Toronto Hydro assesses and plans for emerging needs and challenges as they arise. For example, the utility has a variety of obsolete legacy assets, such as rear lot distribution lines, that carry higher safety and reliability risks than their modern standard equivalents. These assets present unique risks and replacement challenges that Toronto Hydro addresses through dedicated programs.

For more information on the results of Toronto Hydro's asset needs assessment and a broader discussion of the utility's distribution system, refer to Section D2.

D1.2.1.3 Portfolio Reporting

As part of the IPPR process, Toronto Hydro monitors and reports on the progress of capital programs, which includes program level expenditures, project-specific execution status and project expenditures. The utility monitors changes in system-level outcomes (e.g. average reliability) and the effect of specific programs on specific outcomes (e.g. the reduction in the number of poles in end of serviceable life condition) during the Performance Measurement stage of the AM Process. This performance information is available to Toronto Hydro's planners to assess the benefits of the program to-date and identify necessary pacing and prioritization adjustments to meet objectives or emerging needs in future years.

D1.2.1.4 Portfolio Planning

The final piece of the annual IPPR Process is the development of the plan itself. Toronto Hydro planners use the information from the asset needs assessment and the portfolio reporting process to develop capital investment and maintenance plans that support the achievement of the utility's asset management strategies and outcomes in alignment with customer needs and preferences.

1. Capital Programs

Toronto Hydro develops capital programs that address the needs and challenges of the system in alignment with strategic focus areas and customer preferences. The utility develops the programs to maintain and improve reliability and safety, meet service and compliance obligations, address load capacity and growth needs, improve contingency constraints, and make necessary day-to-day operational investments. These programs are grouped into the following four investment categories based on the investment driver that triggers the work:

- System Access;
- System Renewal;
- System Service; and
- General Plant.

The details of these capital programs can be found in Section E of the DSP.

2. Maintenance Programs

Toronto Hydro's maintenance planning process is designed to assess the condition, extend the life, and maintain the reliability of distribution assets. The utility designs its maintenance programs to extract the maximum value from existing assets. Maintenance typically occurs on set frequencies derived from Reliability Centered Maintenance ("RCM") standards and the OEB's minimum inspection requirements in Appendix B of the DSC.

Toronto Hydro has four major categories of maintenance:

- **Preventative Maintenance:** Typically involves cyclical inspection and maintenance tasks, which emphasize assessing asset condition and preserving asset performance over the expected life of the asset, and maintaining public and employee safety.

- **Predictive Maintenance:** Involves testing or auditing equipment for a predetermined condition (or conditions) to anticipate failures, then undertaking the maintenance tasks necessary to prevent those failures.
- **Corrective Maintenance:** Involves repairing or replacing equipment after a deficiency has been reported, such as actions taken after Emergency Maintenance has restored power. Corrective Maintenance actions may also result from deficiencies discovered during the execution of Preventive or Predictive Maintenance tasks or other planned work.
- **Emergency Maintenance:** Involves the urgent repair or replacement of equipment when the equipment fails, often causing power disruptions to Toronto Hydro customers.

The details of the maintenance programs in these categories can be found in Exhibit 4A, Tab 2, Schedules 1-5.

Toronto Hydro ensures that capital and maintenance programs are coordinated by planning and reporting on both activities within the IPPR process. For example, maintenance programs account for changes associated with capital investment programs, such as new asset classes being introduced or existing asset classes being eliminated.

3. Pacing and Prioritization

Toronto Hydro paces its expenditure plans to support the achievement of multi-year outcome objectives (e.g. maintain or improve reliability over a number of years). Pacing decisions are informed by various leading and lagging indicators of risk and performance (e.g. asset condition demographics and reliability projections), and an assessment of various risk mitigation alternatives, as discussed in Section D3.2.

Program expenditures are reprioritized annually based on actual accomplishments and measured performance relative to the multi-year plan, as well as ongoing analysis of evolving system, customer, and stakeholder needs. Toronto Hydro prioritizes projects within and across programs in accordance with anticipated project benefits, estimated costs, and an assessment of execution capabilities and constraints. On this basis, the lowest priority projects are deferred to future years, and the projects that offer the greatest value-for-money relative to the utility's customer-focused objectives are scheduled for execution.

D1.2.2 Scope and Project Development

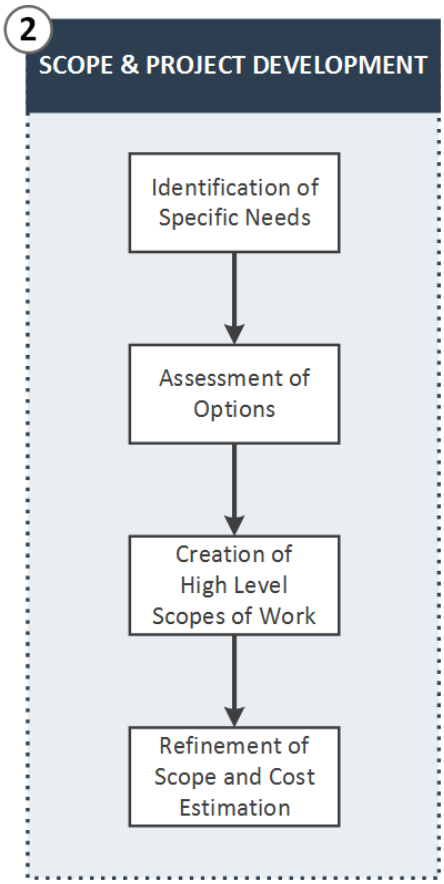


Figure 5: Scope and Development Stage

The scope and project development component of the AM Process involves the development of discrete projects within each investment program. This process involves four components: identification of specific needs, assessment of options, development of high-level project scopes of work ("scopes"), and refinement of scopes and cost estimates.

The investment proposals from IPPR identify and prioritize the assets or issues that require intervention within each capital program. As part of the early stages of scope development, Toronto Hydro prioritizes assets and identifies issues in discrete geographical locations through the use of decision support tools. The utility considers alternatives while developing a scope, which include various engineering options available to address an issue. The utility then evaluates the options with consideration for risks, required performance, customer preferences, effects on third parties, adjacent investment, and reconfiguration opportunities, and the overall costs versus benefits. Finally, the utility selects the preferred option for the specific area or issue being addressed, and collects and summarizes asset information for replacement or refurbishment along with high-level specifications for new assets to be installed as part of a conceptual design. This constitutes the initial scope of work.

The next step is the project development stage, during which a joint team of engineers and designers take the initial scope of work, assess feasibility and field conditions, and refine the cost estimates to achieve a more accurate class of estimate for annual and quarterly budgeting, scheduling, and resource balancing purposes. Toronto Hydro introduced this element of the process beginning in 2014 and 2015 to reduce the range of variances that it was experiencing as complex rebuild projects

progressed from high-level budget estimates to the detailed design stage, and to further strengthen the feedback loop between project execution learnings and high-level program planning.[4]

Where appropriate, the project development phase may break an original scope of work into smaller project phases for execution. This could be done for various reasons, including coordination with other work in the system, or to meet external constraints related to the location or the type of work. In the project development phase, the utility also undertakes initial project enabling tasks such as acquiring permits and coordinating with third parties prior to beginning final project design and construction. This helps to avoid design and scheduling uncertainty that can arise later in the process.

[4] Refer to Exhibit 4A, Tab 2, Schedule 9, Section 5 for more details on Toronto Hydro's project development efforts.

D1.2.3 Program Management and Execution

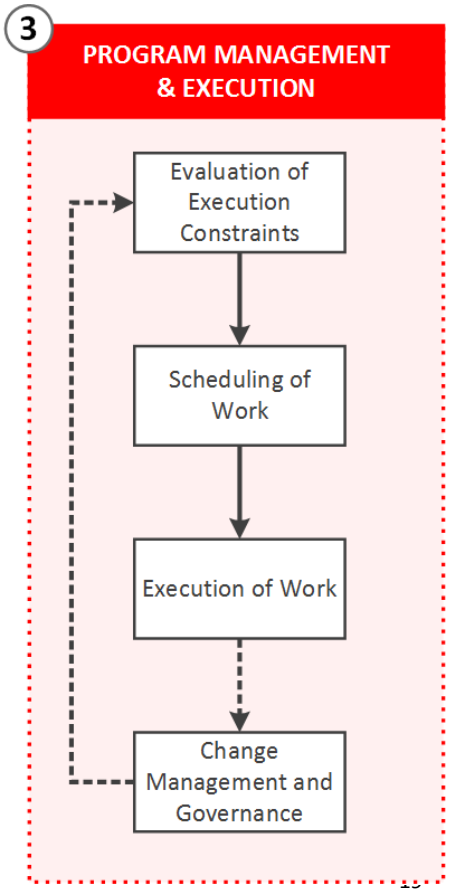


Figure 6: Program Management and Execution Stage

The program management and execution stage of the AM Process involves creating, delivering, and governing an executable work program. The major processes include evaluation of execution constraints, scheduling of work, execution of work, and the change management process that accounts for any required project changes.

The "evaluation of execution constraints" stage considers multiple factors such as available resources, road moratoriums, switching restrictions, and coordination opportunities. Program managers, in coordination with system planners and in alignment with strategic objectives, select a prioritized mix of projects to be executed in a given year. Some of these projects involve assets to be replaced or issues to be resolved that are of the most urgent nature. In order to balance renewal work while addressing emerging needs of the system, engineering staff prioritize projects accordingly.

Once Toronto Hydro develops an execution plan, the actual execution of work is monitored from the detailed design stage through the construction stage. Projects are closely tracked to proactively identify and manage risks that may impact the successful delivery of the planned work.

Toronto Hydro monitors changes to projects through a change management and governance process. This process provides visibility at different levels of the organization as appropriate for the size and strategic importance of a given project. Depending on the magnitude of a required change to a project's cost, schedule, or scope of work, the change may require a detailed assessment of alternatives and formal approval from senior management and the executive team before proceeding.

Exhibit 4A, Tab 2, Schedule 9, Section 5 provides further details about the processes utilized in the Program Management and Execution stage of the AM Process.

D1.2.4 Performance Measurement

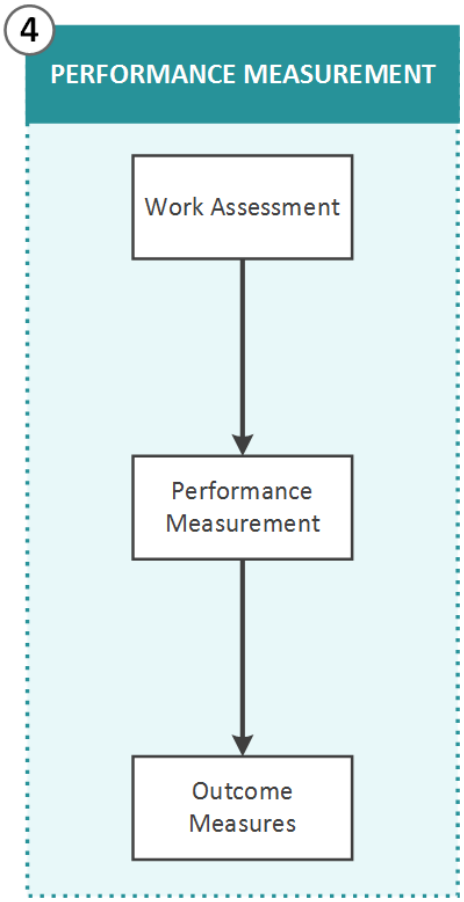


Figure 7: Performance Measurement Stage

The final stage of the AM Process is to monitor the performance of the investment program, to determine to what extent projects have contributed to expected outcomes. These results feedback into the annual IPPR process so that Toronto Hydro can modify programs and refine objectives if necessary.

Some key examples of outcome measures that Toronto Hydro tracks in relation to the capital and maintenance expenditure plans include:

- System Health;
- System Capacity;
- SAIDI and SAIFI for Defective Equipment; and
- FESI-7.

Further details on Toronto Hydro's performance measures for the 2020-2024 DSP are provided in Section C.

D1.2.5 Standards and Practice Review

The Standards and Practice Review is driven by the need to evaluate particular standards and products to improve work execution. This process influences all four stages of the AM Process as planners, designers, and crews rely on this process to identify what equipment is available to them and its appropriate use. The review encompasses the necessary specifications and processes related to: (i) introducing standards and assets into the system; (ii) installation requirements; (iii) replacement considerations; (iv) identifying new assets to better meet system needs and customer preferences; (v) carrying out work in a consistent manner; and (vi) supporting improved safety on the system.

1) **New and revised standards:** Toronto Hydro routinely introduces new standards and revises existing standards to ensure safe and effective work execution on the system. New standards are created in response to a number of drivers, including but not limited to: (i) weather impacts; (ii) process or productivity improvements; (iii) quality; and (iv) safety. When Toronto Hydro revises a standard, other documents, such as the standard design practices followed by project designers, are updated to align with changes made.
2) **New products:** Introducing new products enables more efficient, safe, and reliable service to customers. Product requests are reviewed to ensure alignment with business needs, that the appropriate stakeholders are engaged, and that the product satisfies Electrical Safety Authority ("ESA") requirements for major and minor equipment approval. The need for a new product can be initiated for a number of reasons, including: (i) safety; (ii) productivity; (iii) increased flexibility; (iv) ability to meet system requirements; and (v) better technology available. For example, Toronto Hydro has introduced new 600V network equipment to deliver reliable service to the increasingly taller buildings being developed in the City of Toronto.
3) **Refurbishment and replacement of equipment:** When major equipment, such as transformers, network protectors, and switches, is returned from the field, Toronto Hydro evaluates, inspects, and tests them to determine whether the asset can be reused (i.e. repaired or refurbished) or replaced (i.e. scrapped).
4) **Quality improvements:** When a product that is not near end-of-life is returned from the field because of failure, it is investigated to determine the root cause of the failure. Investigations are conducted in-house or equipment is sent back to the manufacturer. If a quality issue is discovered, the manufacturer is notified and requested to make modifications to address the

issue. If it cannot be fixed by the manufacturer, a quality alert will be issued notifying users of the issue and the product's use may be discontinued.

5) **Standard design practice:** The standards review process provides planning and design stakeholders with the framework for standard design practices. These practices instill safety by design, enforce construction standards, and ensure alignment with business strategies and consistency between projects. The design practice set outs general guidelines with respect to technical matters, and refers to construction standards for specific details.

6) **Industry standards**: Toronto Hydro seeks to align with industry standards and best practices wherever possible. This avoids unnecessary custom made products which can drive up costs and maintenance complexity. Toronto Hydro is also part of an Inter-Utility Standards Forum ("IUSF"), through which utilities collaborate on solutions to common problems and develop common equipment specification.

D1.3 Asset Management Process Enhancements

Toronto Hydro's AM process has evolved since its conception. The utility is continuously enhancing its approach to asset management to ensure the process and strategies remain aligned with the needs of its customers and the distribution system.

The recent progression of Toronto Hydro's AM process is described in the following two sections:

- Evolution of the AM process (2005-2014); and
- Enhancements during the current filing period (2015-2019).

D1.3.1 Evolution of the AM Process (2005-2014)

Toronto Hydro's AM Process, including the data and tools used as part of the process, has evolved and matured significantly since the mid-2000s. At that time, Toronto Hydro primarily looked to the Institute of Asset Management's Publicly Available Specification ("PAS 55"), which had been published by the British Standards Institution in 2004. That specification and its revision in 2008 (i.e. PAS 55:2008) provided guidance with respect to good asset management principles, including those pertaining to information management, risk management, life cycle management, performance and condition monitoring, and failure investigations. Based on that guidance, and as a result of its commitment to be a leader in effective asset management, Toronto Hydro pursued and achieved the following major milestones over a 10-year period as depicted in Figure 8.

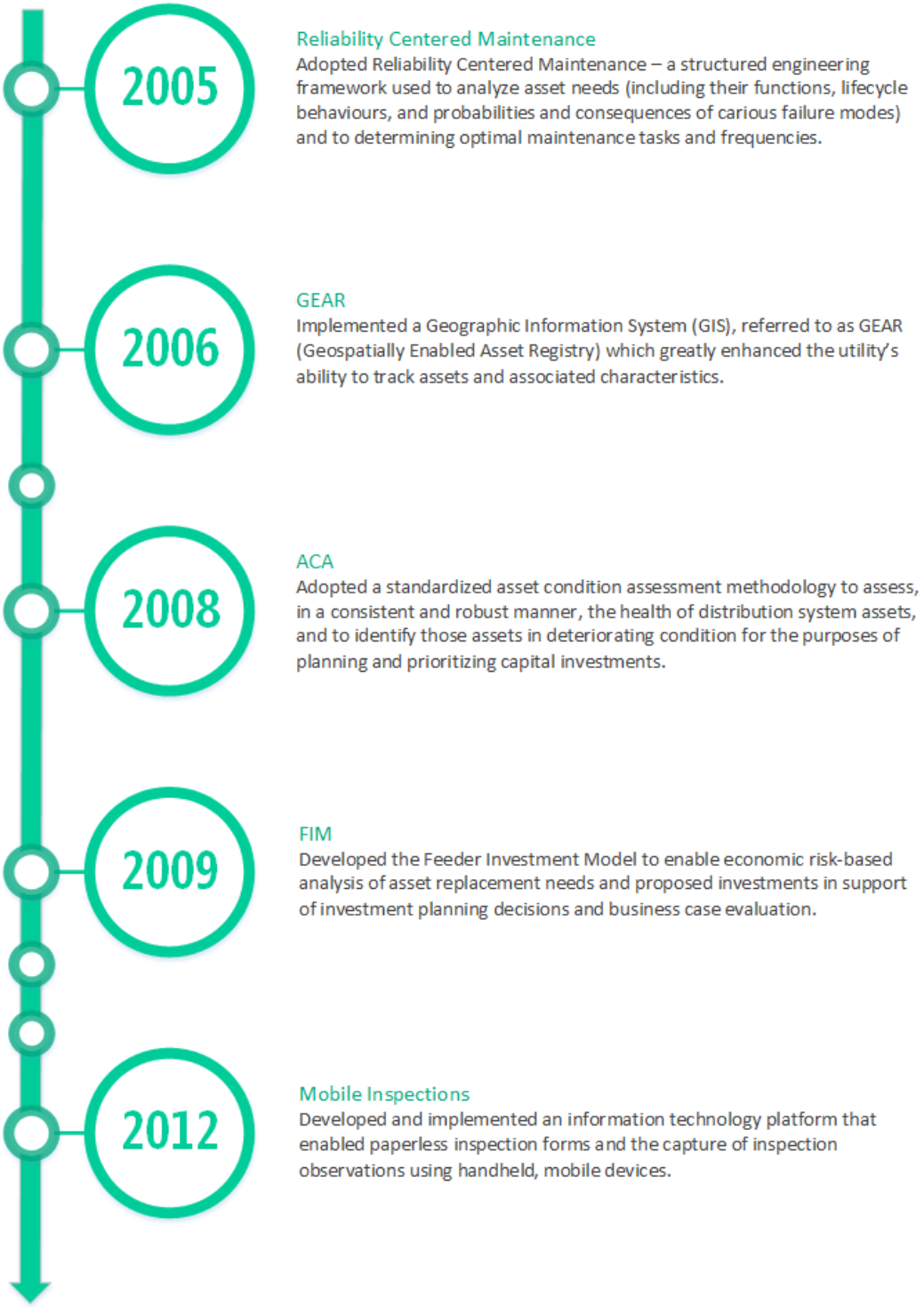


Figure 8: Evolution of the AM Process (2005-2014)

D1.3.2 Recent Enhancements (2015-2019)

Improvements to Toronto Hydro's AM Process over the 2015-2019 period are highlighted in Figure 9 below. The following section provides additional details on key process improvements.

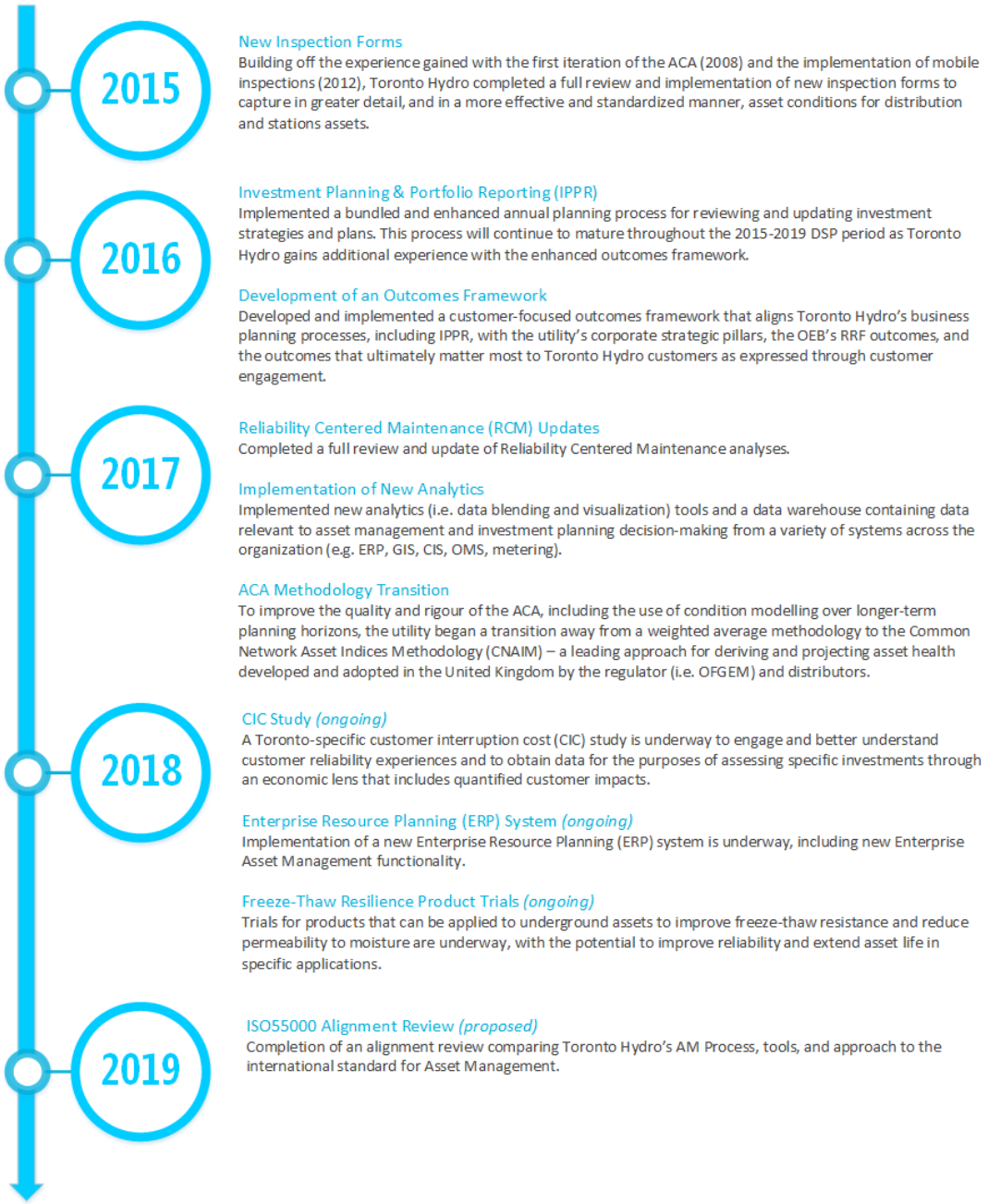


Figure 9: Recent Enhancements of the AM Process (2015-2019)

D1.3.2.1 Outcomes Framework

Toronto Hydro leveraged Customer Engagement results to develop an enhanced Outcomes Framework for the 2020-2024 planning horizon. Toronto Hydro used this Outcomes Framework to set the initial direction and result for the 2018-2024 Business Plan. The resulting 2020-2024 Capital Expenditure Plan includes measureable objectives that directly or indirectly relate the proposed level of spending in each program to the utility's strategic objective of continuous improvement in each of its six outcomes categories (and by extension, each of the four RRF outcomes): Reliability, Customer Service, Public Policy, Safety, Environment, and Financial.

Through these outcomes objectives, Toronto Hydro's capital programs aim to address the needs and challenges of the system in alignment with strategic focus areas and customer preferences. The utility developed its capital programs to maintain and improve reliability and safety, meet service and compliance obligations, address load capacity and growth needs, improve contingency constraints, and/or make necessary day-to-day operational investments. As a result, Toronto Hydro's DSP reflects a balance between customer preferences, affordability, and prioritized outcomes (as described in Section E2), with the overriding objective of delivering value for money.

D1.3.2.2 Asset Condition Assessment Update

Toronto Hydro has transitioned from the ACA methodology originally adopted in 2008 to an ACA model that provides more accurate and comprehensive condition-based analytics, and that better supports expenditure planning over longer time horizons. Toronto Hydro has long considered condition a key part of investment planning. With the emerging need to generate condition-based investment plans over horizons of five years or longer, and having encountered certain limitations in the existing weighted average condition assessment methodology, the utility decided to seek a more sophisticated condition methodology with projection modeling capabilities.

The model that Toronto Hydro has implemented is the Common Network Asset Indices Methodology ("CNAIM"). This methodology was developed and adopted by the major utilities in the United Kingdom – where utilities are expected to file eight-year business plans – in collaboration with the regulator (i.e. Ofgem). In terms of the functional outputs of the model, it is first and foremost a like-for-like upgrade on Toronto Hydro's existing model in the sense that it provides a more refined and reliable calculation of the condition score for an individual asset based on the most recently available inspection information for that asset. The new methodology also includes the ability to calculate

future health scores for assets, providing further information on asset demographics that can be used to evaluate proposed investment strategies over the longer-term.

This model provides incremental benefits at the strategic level by facilitating projections of asset condition demographics by asset class. This allows Toronto Hydro to assess the current and future condition profiles of an asset class to better calibrate the level of investment necessary to either maintain or improve the amount of failure risk associated with its aging asset base over time.

Appendix C to this section of the DSP provides a detailed discussion of the new model, how Toronto Hydro implemented it, and the condition results by major asset class.

D1.3.2.3 Data Consolidation: Data Warehousing for Engineering Analytics

Toronto Hydro is currently developing an engineering data warehouse to streamline data access and perform "big data" calculations that can support planning and system investment strategies. In parallel, the utility has been deploying new data blending and analytics software, and has integrated software into business processes to improve productivity and drive new insights.

D1.3.2.4 Enterprise Resource Planning ("ERP") System Implementation

The existing enterprise systems are to be consolidated into one system so that data integrity can be improved. This will provide teams across Toronto Hydro access to one system with accurate and up-to-date information. See Exhibit 2B, Section 8.4 for further details on the implementation of a new ERP system.

D2 Overview of Distribution Assets

D2.1 Distribution Service Area and Trends

Toronto Hydro is one of the largest municipal electrical distribution utilities in North America, serving the City of Toronto – Canada's largest city. The city is bounded by Lake Ontario to the South, Steeles Avenue to the North, Mississauga (mainly Highway 427) to the West, and Scarborough/Pickering Townline to the East. As shown in Figure 1 below, Toronto Hydro's service territory can be divided into two geographic areas: (i) an urban centre in downtown Toronto with a high customer density and a large financial and entertainment district; and (ii) a suburban area around downtown Toronto with a lower customer density, which is colloquially referred to as the "Horseshoe" area.



Figure 1: Areas of the Toronto Hydro Distribution System

The following subsections discuss the characteristics of Toronto Hydro's service territory, including its customers and load growth profiles, climate and weather, and economic profile. Section D2.2 provides a detailed description of the utility's asset demographics, system configurations, and asset condition, and Section D2.3 provides a summary of system utilization.

D2.1.1 Customer and Load Growth

Toronto Hydro's distribution system supplies approximately 768,000 customers with a peak load of 4,810 MVA as of 2017. Toronto Hydro has been experiencing steady population and customer growth for many years, as shown in Figure 2.

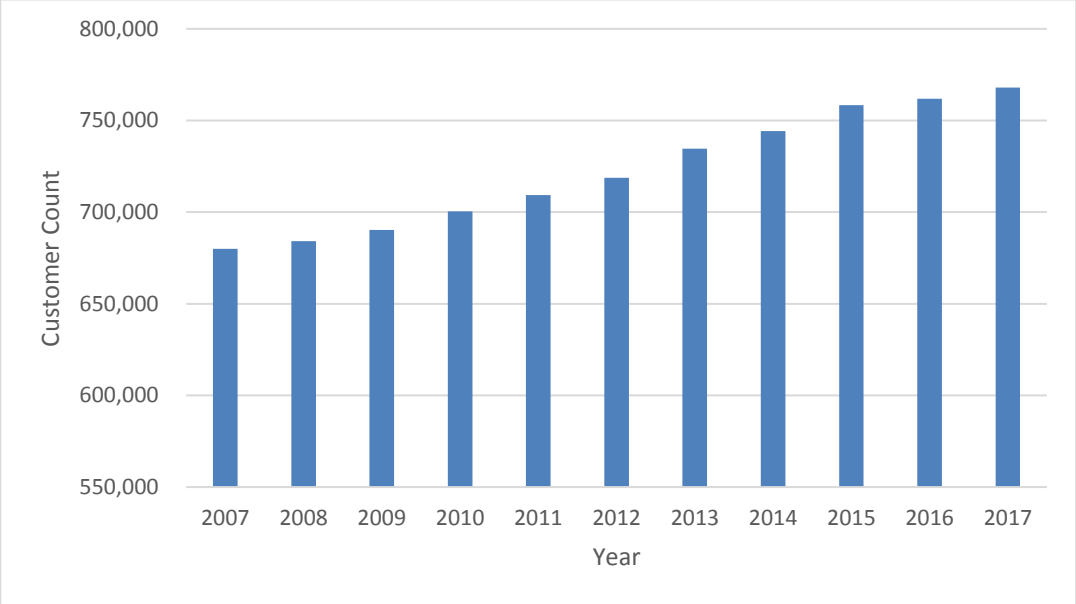


Figure 2: Historical Toronto Hydro Customer Counts

Despite steady customer and population growth, overall system peak load has remained relatively steady in recent years at approximately 5,000 MVA, as shown in Figure 3. It is important to note that system peak load varies with temperature.

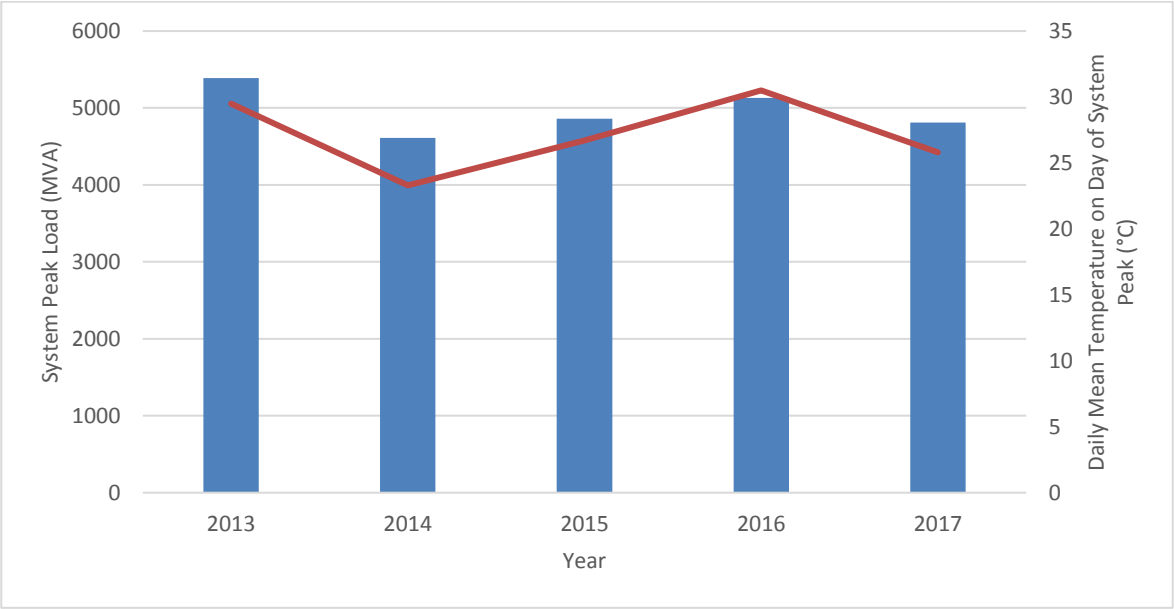


Figure 3: Historical Toronto Hydro System Peak Loading

However, Toronto continues to experience highly concentrated load growth in certain areas of the city primarily due to a high number of large condominium developments. Figures 4 and 5 show that Toronto has more buildings under construction than most North American cities, and a number of high-rise and mid-rise buildings under construction at a rate comparable to New York. This concentrated growth occurs mainly in the downtown area, but also along major transit corridors such as Yonge Street and Sheppard Avenue. The growth is pushing certain distribution and stations equipment to capacity. Infrastructure renewal and upgrades are required in these areas to support growth while maintaining satisfactory reliability and system resiliency.

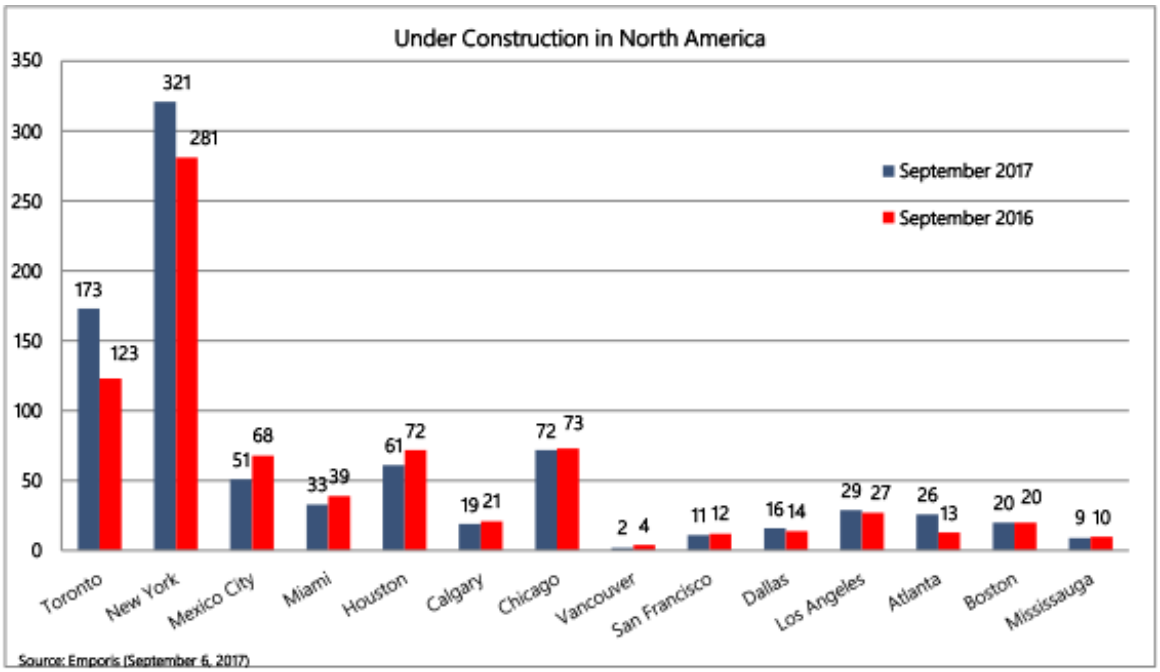


Figure 4: Number of High-Rise Buildings under Construction (Toronto Economic Update September 2017)

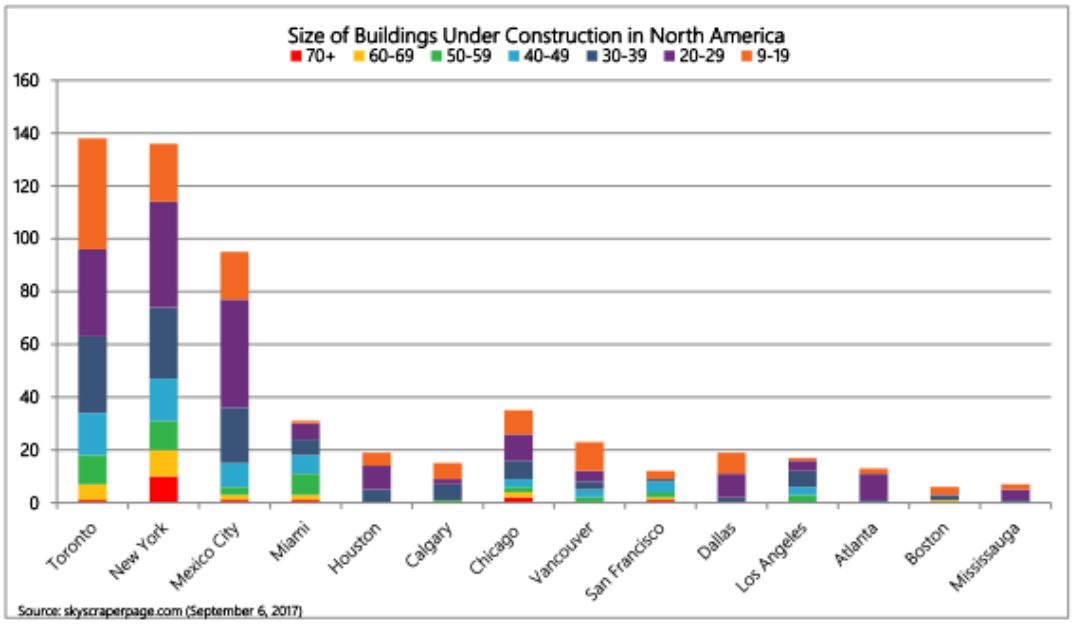


Figure 5: Number of Floors for High-Rise & Mid-Rise Buildings under Construction (Toronto Economic Update September 2017)

To keep pace with the growing city and ensure appropriate distribution system capacity, the utility plans to continue actively investing through the following programs, further described in Section E:

- Customer Connections (Section E5.1);
- Stations Expansion (Section E7.4);
- Load Demand (Section E5.3); and
- Generation Protection Monitoring & Control (Section E5.5).

D2.1.2 Climate and Weather

Climate change is a significant factor influencing Toronto Hydro's planning and operations. Scientists worldwide overwhelmingly agree that the planet is warming. By the year 2050, Toronto's climate is forecasted to be significantly different than the already changing climate seen today. For example, in Toronto, daily maximum temperatures of 25°C are expected to occur 106 times per year as opposed to 66 times per year currently. Daily maximum temperatures over 40°C, which have historically been an anomaly, are projected to occur up to seven times per year by 2050.[1] A warmer climate will also allow the atmosphere to hold more moisture, which is expected to lead to more frequent and severe extreme weather events such as ice storms and extreme rainfall events. These extreme events can cause major disruptions to Toronto Hydro's distribution system.

In addition to extreme weather events, Toronto experiences a wide range of weather conditions that may not be classified as extreme, but nevertheless have the potential to adversely affect the distribution system at various times during the year. Heat, high winds, heavy rainfall, freezing rain, and heavy snowfall have the potential to cause major system damage and extensive outages. Not only are these weather conditions projected to occur more frequently and with greater severity in the future due to climate change, trends from the past 20 years suggest that these changes are already affecting the system. Figure 6 below contains two charts depicting cumulative rainfall and the number of high wind days (i.e. with wind gusts exceeding 70 kilometres per hour) in Toronto over the past 20 years. With respect to rainfall, seven of the 10 highest rain fall years have occurred in the last 10 years. Similarly, six of the 10 years with the greatest number of days of wind gusts above 70 kilometres per hour have also occurred in the last 10 years (these years are highlighted in red).

[1] See Appendix D – Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment by AECOM (June 2015)

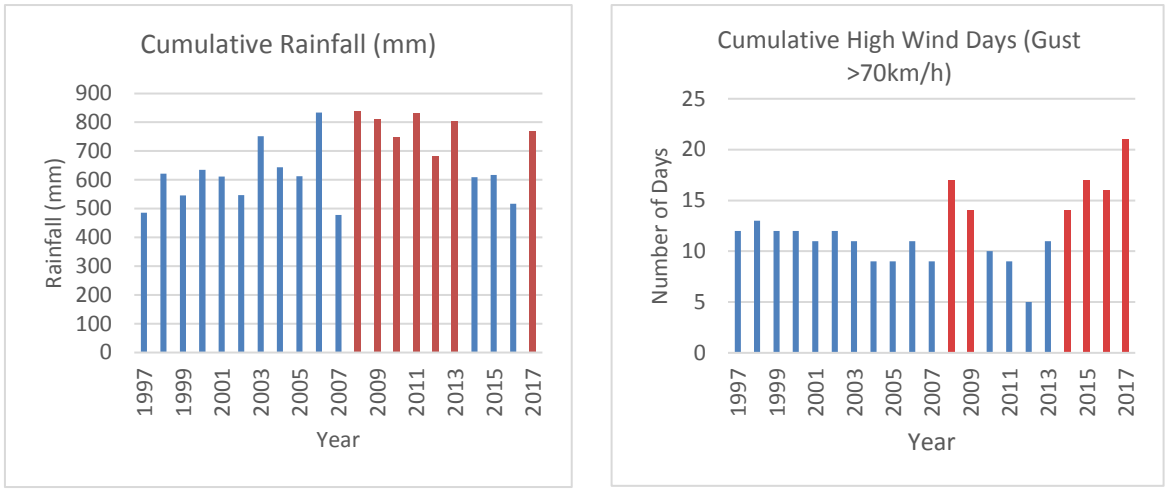


Figure 6: Cumulative Rainfall (left) and Number of High Wind Days (right) in Toronto[2]

These weather trends have increased reliability risks for Toronto Hydro's distribution system. Parts of the underground system are sensitive to significant rainfall, and in particular flooding, while the overhead system in general is sensitive to high winds, freezing rain and wet snow events resulting in damage and outages (e.g. from vegetation impact in proximity to overhead lines). In extreme cases, broken trees and the weight of ice and snow accretions bring lines, poles and associated equipment to the ground.

The aforementioned reliability risks are significant, as evidenced by examples of events that occurred in 2017. April and May of 2017 saw significant rainfall, causing a number of Toronto Hydro's vaults and cable chambers in the underground system to flood. From the perspective of the overhead system, high wind events in 2017 resulted in a 72 percent increase in the number of customer interruptions attributed to tree contacts compared to the average of the previous five years. Similarly, 2018 has seen significant storms and related damage, with four major events occurring during the first half of the year.

To better understand the risks related to increases in extreme and severe weather due to climate change, in June 2015, Toronto Hydro completed a vulnerability assessment following Engineers Canada's Public Infrastructure Engineering Vulnerability Committee ("PIEVC") protocol.[3] The

[2] Weather data compiled using Toronto Lester B. Pearson INTL A for January 1997 to June 2013 and Toronto INTL A for July 2013 to December 2017. Available from: Government of Canada, Weather, Climate and Hazard Historical Data online: <http://climate.weather.gc.ca/historical_data/search_historic_data_e.html>
[3] See Appendix D to Section D.

assessment identified areas of vulnerability to Toronto Hydro's infrastructure as a result of climate change. Following this study, a climate change adaptation road map was developed, along with initiatives relating to climate data validation, review of equipment specifications, and review of the load forecasting model.

Existing codes, standards, and regulations were developed with regard to historical weather data and do not always account for ongoing and future changes to the climate. In efforts to close this gap, Toronto Hydro now utilizes climate data projections for temperature, rainfall, and freezing rain in its equipment specifications and station load forecasting. Further, Toronto Hydro reviewed and updated major equipment specifications in 2016 to adapt to climate change, including:

- Revisions to submersible transformer specifications to require stainless steel construction and testing of the equipment's ability to withstand fully flooded conditions;
- Replacement of air-vented, padmounted switches with new standard SF_6 sealed-type, padmounted switches to remove risk of failure due to ingress of dirt and road contaminants on the live (i.e. energized) surface;
- Initiation of trials of solid dielectric transformers that do not contain oil and are designed to withstand extreme environmental conditions underground; and
- Adoption of breakaway links in tree-covered areas for residential customers with overhead service connections, intended to facilitate faster restoration after extreme weather and prevent damage to customer-owned service masts.

As part of the climate change adaptation roadmap, Toronto Hydro conducted analyses between 2016 and 2017 to better understand how assets and operational practices could be impacted by climate change:

1) An asset impact review that looked at how each type of asset is affected by the different aspects of climate change. Resulting recommendations for each type of asset were used to alter maintenance and asset management programs.
2) An industry review of climate adaptation best practices that included an evaluation of other major utilities as well as published papers. Vegetation management practices, system hardening practices, design criteria, and maintenance practices were areas identified as being affected by climate change.
3) An emergency restoration analysis to evaluate various strategies in the event of a failure in the underground electrical distribution infrastructure when load switching or re-routing is

not feasible. Restoration methods that utilities, specialized companies, and manufacturers have developed in this field were reviewed in order to restore the network as quickly and efficiently as possible. Evaluations and trials of the proposed methods will be investigated and tested prior to being implemented as a standard practice.

The following 2020-2024 program activities will contribute to Toronto Hydro's ongoing efforts to renew and enhance its system to increase resiliency to changes in the weather and climate, thereby supporting the continued delivery of outcomes expected by existing and future customers:

- As assets are replaced in the Overhead System Renewal program (Exhibit 2B, Section E6.5), Toronto Hydro will install taller poles with armless construction and tree-proof wire to reduce vegetation contact risks.
- Stainless steel submersible transformers will replace existing units as the utility carries out its Underground System Renewal – Horseshoe program (Exhibit 2B, Section E6.2).
- Underground System Renewal – Horseshoe program will also replace air-vented padmounted switches with SF_6 sealed-type padmounted switches to mitigate risk of failure due to ingress of dirt and road contaminants on the live surface.
- The Network System Renewal program (Exhibit 2B, Section E6.4) will replace non-submersible automatic transfer switches and remote power breakers with submersible equipment to tolerate flooding.
- The Network System Renewal program will also replace other end-of-life and deteriorated non-submersible protectors with submersible protectors to protect against flooding.
- The Network Condition Monitoring & Control program (Exhibit 2B, Section E7.3) will help the utility detect flooding in network vaults before it damages equipment.
- The Network Circuit Reconfiguration segment under the Network System Renewal program (Exhibit 2B, Section E6.4) will help the utility improve system restoration capabilities in the event of outages.
- Installation of flood mitigation systems at stations identified as being vulnerable to flooding will occur under the Stations Renewal program (Exhibit 2B, Section E6.6).
- New switchgear installed in the Stations Renewal or Station Expansion (Exhibit 2B, Section E6.6 and E7.4) programs will be specified to mitigate flood risk where appropriate (e.g. installing air-tight SF_6 switchgear or other engineered solutions).

- The Control Operations Reinforcement program (Exhibit 2B, Section E8.1) will improve Toronto Hydro's operational resiliency by developing a dual control centre at an existing work location.

Toronto Hydro is a partner of the City of Toronto in planning and preparing for the effects of climate change. The City's *ResilientTO* initiative includes a Resilient City Working Group that facilities collaboration between City divisions, agencies and corporations and external stakeholders on the topic of climate change resilience. Members share knowledge and technical information to facilitate the implementation of resilience actions within their operations.

D2.1.3 Economic Profile

The City of Toronto is Canada's economic and financial hub. It is home to the Toronto Stock Exchange, as well as the headquarters of five of the nation's largest banks. Toronto accounts for 10 percent of Canada's Gross Domestic Product ("GDP").[4] Its GDP growth has outperformed not only the national average, but also many of the most developed countries in the world in the past year, which is a trend that is expected to continue over the next year.[5]

Toronto also has a diverse industrial and commercial base comprised of 13 key sectors including aerospace, financial services, education, life sciences, technology, food, entertainment, and tourism.[6] The critical and growing importance of Toronto's economy underscores the necessity of continuing to invest sufficiently to ensure the delivery of value for current and future distribution customers and to prepare for technology driven change in this highly urbanized area.

D2.1.4 Toronto Hydro's Evolving Role in the City of Toronto

The role that Toronto Hydro plays in its service territory is evolving as new technologies emerge. In many cases, local and provincial policy imperatives aim to accelerate the uptake of new energy related technologies such as distributed generation and energy resources, and power quality, reliability and resiliency solutions.

[4] City of Toronto, Business and Economic Development facts, (2013), online: <http://www.toronto.ca/toronto_facts/business_econdev.html>. ["Toronto Business and Economic Development Facts"]
[5] City of Toronto, Toronto Economic Bulletin, Conference Board (December 2016 & September 2017) and OECD Economic Outlook – Interim Release, September 2017
[6] City of Toronto, Business & Economy, online: <https://www.toronto.ca/business-economy/industry-sector-support/>. ["Industry Sector Support"].

One example is the City of Toronto's climate change action plan and long-term vision. A key pillar of this plan is *TransformTO*,[7] which identifies how the City plans to reduce greenhouse gas emissions, improve health, grow the economy, and improve social equity. One of the major commitments of this plan is for 100 percent of vehicles in Toronto to use low-carbon energy by 2050. As part of achieving this goal, the Toronto Transit Commission ("TTC") is planning to convert its fleet of busses from diesel hybrid to electric, which will require upgrades to the distribution feeders supplying the TTC's Arrow Road Garage.[8]

Provincial and federal policy targeting greenhouse gas reductions is also a driver of technological change. Provincial energy policy actively supports and incentivizes the connection of renewable energy projects to the local distribution system. As of the end of 2017, Toronto Hydro has connected 1,750 renewable energy projects to its system, totaling 97 MW of generation capacity. As discussed in Section E3, Toronto Hydro anticipates steady growth in generation connections going forward and is planning to invest in necessary renewable enabling improvements, including monitoring and control technologies, and energy storage systems to facilitate this growth during the 2020-2024 period.

D2.2 System Demographics and Characteristics

Toronto Hydro's distribution system consists of a mix of overhead, underground, network, and stations infrastructure. This infrastructure operates at voltages of 27.6 kV, 13.8 kV, and 4.16 kV, and includes approximately 60,000 distribution transformers, 17,000 primary switches, 15,000 kilometres of overhead conductors, and 13,000 kilometres of underground cables as of 2017. Unless otherwise mentioned, asset demographic information provided herein is as of 2017.

The following sections provide details on these sub-systems and how each sub-system relates to Toronto Hydro's major asset management objectives. As discussed in Exhibit 2B, Section D3, Toronto Hydro manages its distribution infrastructure and plans capital investments and maintenance to achieve asset management objectives, specifically, the attainment of applicable outcomes. For further details on forecasted asset management measures for the 2020-2024 period, please see Exhibit 2B, Section C1.5.

[7] City of Toronto, TransformTO, (2017), online: <https://www.toronto.ca/services-payments/water-environment/environmentally-friendly-city-initiatives/transformto>. ["TransformTO"].
[8] See Section E

The following table and accompanying explanations provide an introduction to Toronto Hydro's sub-systems through the lens of a core subset of asset management performance measures, all of which relate directly or indirectly to Toronto Hydro's outcomes.

Table 1: Asset Management Performance Indicators by System Type

System	**Oil Deficiencies** (Number of assets)	**Priority Deficiencies** (Number assigned)	**Customer Hours of Interruption** due to Defective Equipment	**Customer Interruptions** due to Defective Equipment	**Condition** [9] (Percentage of Assets in HI4 or HI5)	**Oil Containing PCBs** (Number of assets with oil containing or at risk of containing PCB)	**Age** (Percentage of Assets past Useful Life)	**Legacy Assets**
	Lagging Indicator of Performance				**Leading Indicator of Performance**			
Overhead	12 *(2%)*	845 *(10%)*	108,258 *(33%)*	149,116 *(39%)*	11%	6,412 *(60%)*	17%	3151 Box Construction Poles 54 km of Rear Lot 31,000 poles with porcelain insulators
Underground	407 (*75%)*	5,388 *(66%)*	207,508 (*62%)*	217,833 *(57%)*	3%	3,799 *(35%)*	25%	809 km of Direct-Buried Cable 66 Transclosures 1,186 km of PILC[10] Cable 226 km AILC[11] Cables
Network	111 *(20%)*	1,281 (*16%)*	131 *(0%)*	146 *(0%)*	5%	114 *(1%)*	24%	753 Non-Submersible Network Units 985 vaults without communication
Stations	16 *(3%)*	678 *(8%)*	16,881 *(5%)*	12,600 *(3%)*	8%	452 *(4%)*	37%	364 legacy breakers at TSs[12] 592 legacy breakers at MSs[13]
Total	**546 *(100%)***	**8,192 *(100%)***	**332,778 *(100%)***	**379,695 *(100%)***	**9%**	**10,777 *(100%)***	**24%**	-

Notes: All figures are 2017 year-end actuals, unless otherwise noted.

[9] See Exhibit 2B, Section D, Appendix C for the Asset Condition Assessment description and classification details
[10] Paper Insulated Lead Covered ("PILC") cable
[11] Asbestos Insulated Lead-Covered ("AILC") cable
[12] Transformer Station ("TS")
[13] Municipal Station ("MS")

- **Oil Deficiencies:** An oil deficiency is any observation related to oil (e.g. dried oil, oil leak) made during planned asset inspections. These are reported by inspectors when inspecting equipment and components that are known to or intended to contain oil. Oil deficiencies are an indicator of the likelihood of oil spills. The primary driver for this metric is to protect the environment from oil spills and to adhere to federal, provincial, and municipal legislation, regulations, and by-laws pertaining to the release of oil in the environment. Toronto Hydro strives to achieve zero oil leaks into the environment. Programs that contribute to the management of this measure are Preventative and Predictive Maintenance programs for oil filled equipment (discussed in Exhibit 4A, Tab 2, Schedules 1, 2, and 3), and capital programs that replace deteriorating oil filled equipment, including Underground System Renewal (Sections E6.2 and E6.3) and Reactive and Corrective Capital (Section E6.7). While Toronto Hydro strives to reduce the risk of all oil spills, the utility plans to report specifically on the number of PCB-contaminated oil spills as an outcome in 2020-2024 as this is a critical priority for the period.
- **Priority Deficiencies**: Toronto Hydro defines "priority deficiencies" as the subset of all equipment deficiencies that require intervention on a reactive or corrective basis. Each year, Toronto Hydro identifies between 15,000 and 25,000 total deficiencies through planned inspections, responding to equipment failures and power interruptions, or through the course of day-to-day work. Priority deficiencies are deficiencies that pose a high risk to reliability, safety, or the environment and are assigned as a priority 1 (P1), priority 2 (P2), or priority 3 (P3) for the purposes of addressing the deficiency. Each category corresponds to a level of risk (with P1 being the highest risk) and a timeline for repairing the deficiency or replacing the asset. Toronto Hydro has various programs (including Reactive and Corrective Capital, Corrective Maintenance, and Emergency Response) to address asset deficiencies, some of which have already resulted in asset failure.[14] Given the risks, timely and effective responses to priority deficiencies are non-discretionary and must be taken over short time horizons (i.e. less than six months). Identifying and responding to priority deficiencies in a timely manner is critical to meeting the utility's performance objectives for key outcomes such as SAIDI and SAIFI, and the utility's safety and environmental objectives.
- **Customer Hours of Interruption ("CHI") and Customer Interruptions ("CI") (i.e. Outages)**: CHI and CI are measures of outage duration and frequency, scaled by the number of

[14] Exhibit 2B, Section E6.7 and Exhibit 4A, Tab 2, Schedule 4-5.

customers affected by each outage. Toronto Hydro uses this type of historical reliability data to identify priority project areas across all of its reliability-related programs, and to develop and pace investment program spending in order to improve key outcomes that the utility reports include SAIDI, SAIFI, and Feeders Experiencing Sustained Interruptions ("FESI").

- **Assets with Material Deterioration or at End of Serviceable Life**: As described in detail in Appendix C to Section D1, Toronto Hydro's asset condition assessment ("ACA") methodology assigns health index scores to assets based on observable condition variables, and categorizes these scores within five health index bands ("HI1" to "HI5"). Asset condition demographics are a strong predictor of future asset performance. Over the long-term, Toronto Hydro is focused on managing the number of assets in the HI3 ("moderate deterioration") to HI5 ("end of serviceable life") bands. Over the 2020-2024 period, in support of its objective of maintaining system performance, Toronto Hydro is proposing to monitor a new system health measure. Please see Section C for more details.
- **PCBs**: Toronto Hydro defines "PCB at-risk equipment" as an asset that: (i) is known to contain oil with greater than 2 ppm concentration of polychlorinated biphenyl ("PCB"); or (ii) has an unknown concentration of PCB and was manufactured in 1985 or earlier (and is therefore at a high risk of containing greater than 2 ppm PCB). This measure excludes cables. Due the toxic and persistent nature of PCBs, Environment Canada's *PCB Regulations*[15] prohibit the use of equipment that contains greater than 50 ppm PCBs, or the release of greater than one gram of PCBs, which could result from an oil leak with significantly less than 50 ppm. The City of Toronto also enforces its own PCB-related bylaws with a near-zero tolerance for the discharge of PCBs into the storm and sanitary sewer systems.[16]
- **Age**: Toronto Hydro monitors the percentage of its asset base that has passed its useful life or will pass that milestone by the end of the next planning horizon. As a key indicator of failure risk across the system, this information is used for long-term planning purposes. As of the end of 2017, approximately 24 percent of assets will be in-service past their useful life, as shown in Figure 7. By managing this measure over the long-term, the utility aims to provide predictability in the performance of key outcomes like reliability and safety for current and future customers.

[15] The *Canadian Environmental Protection Act*, PCB Regulations, SOR/2008-273
[16] Toronto Municipal Code, Chapter 681 – Sewers

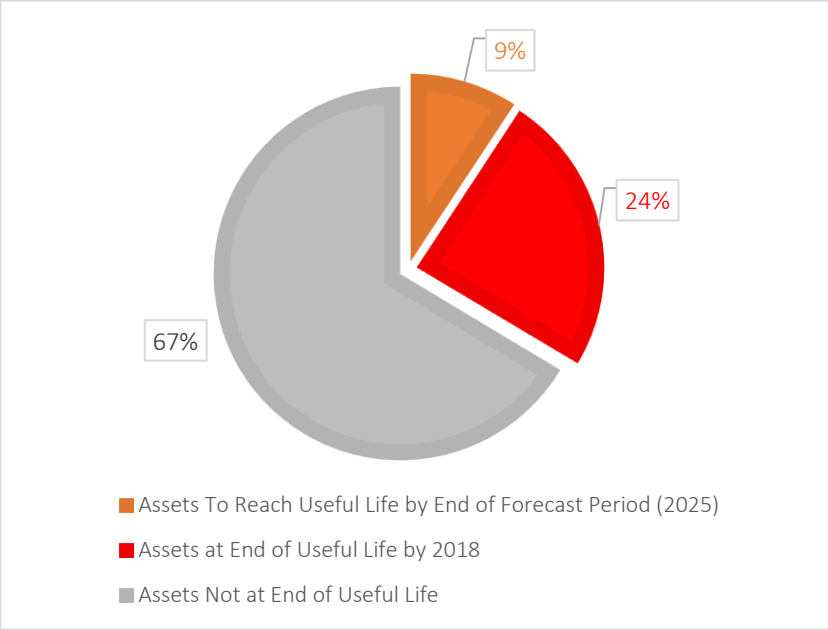


Figure 7: Assets Past Useful Life

- **Legacy Assets**: Legacy assets are specific asset types, configurations, or sub-systems that do not meet current Toronto Hydro standards, often feature obsolete components with limited or no supplier or skilled labour support to maintain, repair or replace these assets and result in elevated reliability, safety, or environmental risks. One of Toronto Hydro's asset management strategies is to eliminate all high risk legacy assets within a specific and reasonable timeframe. The specific legacy assets are discussed further in the following sections as part of the overhead, underground, network, and stations systems descriptions. Table 2 above provides an estimate of the remaining volumes of certain key legacy assets across Toronto Hydro's different subsystems. For further details on specific legacy asset replacement and pacing, please see Exhibit 2B, Section E2. Toronto Hydro plans to report reductions in legacy asset risk for specific types of legacy assets as safety and reliability outcomes during the 2020-2024 period. See Section C for more information.

The following sections provide a more detailed view of the overhead, underground, network, and stations sub-systems of Toronto Hydro's distribution system, including the age and condition demographics of the assets, and associated system challenges. Each section provides a further breakdown of how those sub-systems relate to Toronto Hydro's asset management indicators and measures discussed above and in Section C.

D2.2.1 Overhead Grid System

The overhead system consists of poles, overhead conductors, overhead transformers, overhead switches, and other equipment including lightning arrestors, guying hardware, and wires. All of these assets are placed above ground in areas with sufficient space and clearance from overhead obstructions (e.g. trees and buildings). Advantages of using an overhead system are that it is cost effective and allows for more expeditious fault identification and outage restoration, given that all assets are out in the open and visible to crews. Disadvantages of this system are that it is prone to foreign interference from vehicles, trees, animals, and weather-related outages (i.e. caused by high winds or freezing rain), and requires adequate clearances to operate and maintain.



Figure 8: Overhead Distribution Transformer

The majority of Toronto Hydro's overhead system is operated at 27.6 kV and 13.8 kV, but a subset of the overhead system operates at 4.16 kV. This system consists of approximately 135,000 poles, 7,619 overhead switches, 29,628 overhead transformers, 9,103 conductor-kilometres of overhead primary, and 11,450 circuit-kilometres of overhead secondary conductors as of 2017. The overhead system makes up approximately 57 percent of the total distribution system within the City of Toronto.

Asset management activities related to the overhead distribution system focus on mitigating environmental and safety risks, responding to system events and equipment deficiencies, managing

system performance with respect to reliability and power quality, and asset stewardship over the assets' lifespan.

Figure 9 provides the age demographic distribution of major overhead assets. As of 2017, over a quarter of poles are beyond their useful life of 45 years, and a significant percentage of pole top transformers are at or approaching their useful life of 35 years. Without proactive intervention, Toronto Hydro projects that the percentage of pole top transformers having reached or exceeded useful life will significantly increase from 14 percent as of 2017 to approximately 40 percent by 2024.

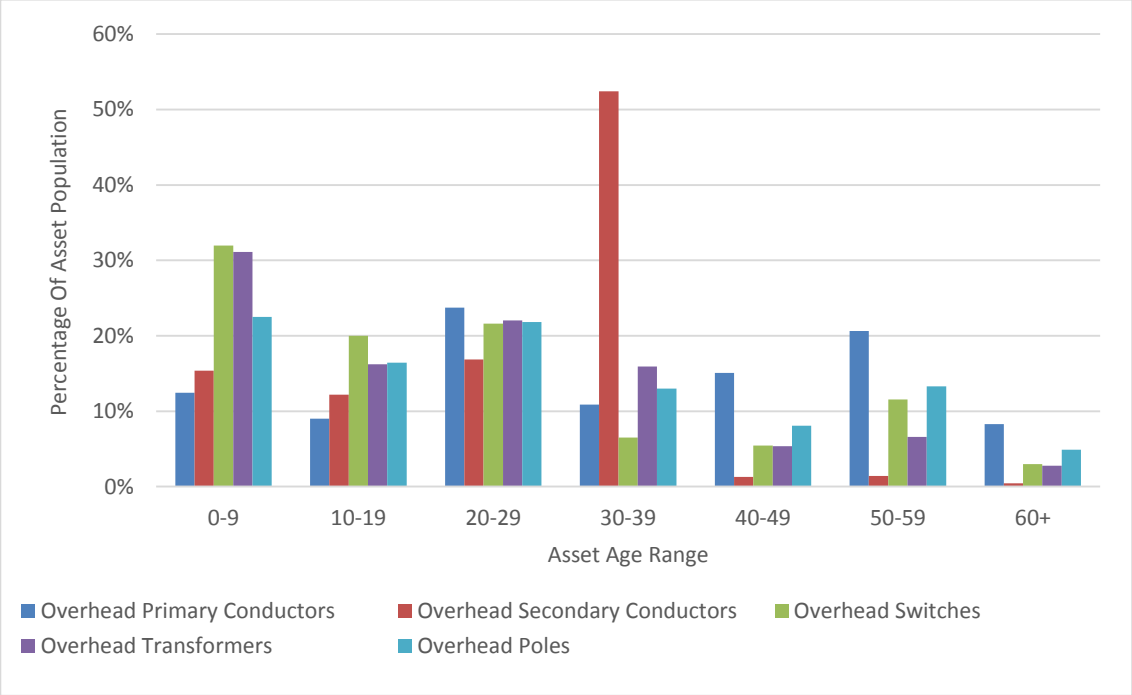


Figure 9: Overhead Assets Age Demographics as of 2017

Wood poles and overhead switches are the two major overhead asset classes for which Toronto Hydro performs an Asset Condition Assessment ("ACA"), as summarized in Figure 10. With respect to wood poles, the ACA showed that approximately 31 percent of Toronto Hydro's wood poles have at least moderate deterioration as of 2017. With over 20,000 wood poles in HI3 condition (i.e. "moderate deterioration"), over 11,000 in HI4 condition (i.e. "material deterioration"), and approximately 1,100 in HI5 condition (i.e. "end of serviceable life"), pole replacement will continue to be a significant driver of both reactive and planned investment through 2024. The need for a

continued pole replacement strategy and investment is underscored by the projected rate of deterioration across this asset class over the rate period, as discussed in Exhibit 2B, Section E6.5.

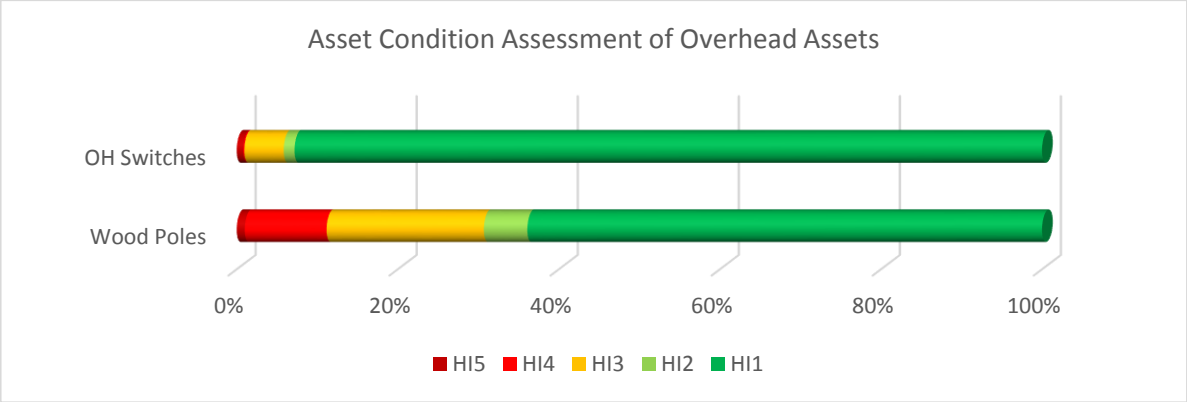


Figure 10: Asset Condition Assessment of Overhead Assets as of 2017

Other key asset management performance measures that are relevant to the overhead system include:

- **Oil Deficiencies**: Pole top transformers are the only asset type in the overhead system that may exhibit oil deficiencies. During the 2015-2017 period, Toronto Hydro found on average 27 pole-top transformers with oil deficiencies annually. The Overhead System Renewal program and Reactive and Corrective Capital program (Section E6.7) will continue to target pole top transformers exhibiting oil deficiencies.
- **Priority Deficiencies:** Overhead assets are susceptible to external interference from animals, insects, adverse weather, and vegetation contacts. These factors accelerate degradation processes and cause damage. From 2013 to 2017, Toronto Hydro issued more than 5,500 work requests to address deficiencies, predominantly for failing or failed overhead assets. In 2017 alone, Toronto Hydro classified 422 P1, 316 P2, and 107 P3 priority deficiencies on the overhead system.
- **PCBs**: Pole top transformers are the only asset type in the overhead system that are known to contain PCB contaminated oil. As of the end of 2017, about 6,400 PCB pole top transformers containing or at risk of containing PCBs remained on the system. By replacing these assets, which will be operating beyond useful life, by 2025, predominantly through the Overhead System Renewal program (Section E6.5), Toronto Hydro endeavours to eliminate the risk of PCB-contaminated oil spills.

D2.2.1.1 Overhead Legacy Equipment

On the overhead system, a major challenge facing Toronto Hydro stems from legacy overhead assets such as porcelain insulators and arrestors, non-standard animal guards, and legacy construction types such as rear lot and box construction. These challenges contribute to poor reliability performance, safety risks, and other undesirable outcomes. Capital investment programs that are planned to target and mitigate challenges within the overhead system include: Area Conversions (Section E6.1), Overhead System Renewal (Section E6.5), and Reactive and Corrective Capital (Section E6.7).

1. Obsolete and deteriorating overhead accessories

Overhead accessories include three major categories: insulator hardware, conductors, and animal guards. These assets are interconnected and integrated with transformers, poles, and switches and are vital components of the distribution system.

- **Legacy Insulator Hardware:** Toronto Hydro's legacy insulators are predominately porcelain, which is an insulation material that has been commonly used for switches, lightning arrestors, terminators, and line posts. The failure modes for assets with porcelain insulating material typically involve assets cracking and breaking apart. In some cases, discharge of fragments due to weakening structural integrity of the material could occur as a result of a failure. In general, porcelain material tends to have a high risk of failure due to its tendency for contamination build-up that leads to electrical tracking (i.e. the breakdown of insulation materials, which can lead to faults), and as such, will be replaced with polymeric material. Porcelain hardware has the potential to fail in a catastrophic manner, releasing porcelain shards which can damage nearby equipment and public property. For example, one porcelain insulator failure incident in Toronto sent shards of porcelain into the balcony of a nearby home, shattering the window of the family room and causing damage to the windshield of a nearby police car. The effects of this porcelain pothead failure can be seen in Figure 11.



Figure 11: Porcelain Pothead Failure

- **Animal Guards:** Existing legacy wildlife protection on Toronto Hydro's overhead distribution system consists of "Guthrie" guard animal protectors. Toronto Hydro is installing improved animal guards that use a cone shaped guard on the bushing with an accompanying insulated drop wire. This design provides an improved physical non-conductive barrier. Figure 12 below shows the difference between "Guthrie" and the new animal guards used by Toronto Hydro to guard against wildlife.

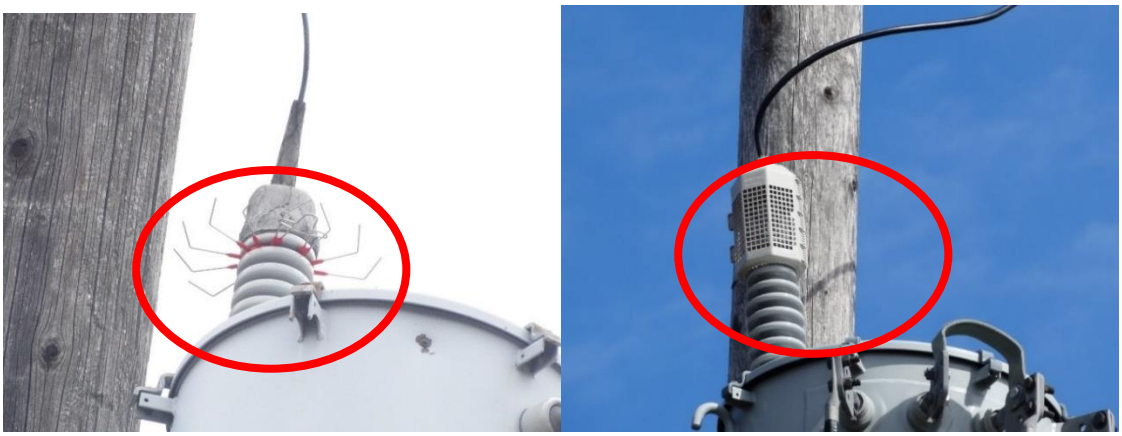


Figure 12: Animal Guards – Guthrie Guard (left), Newer Wildlife Guard (Right)

2. Legacy construction types

- **Rear Lot Construction:** This consists of overhead and underground assets that are installed in the backyard, or rear lot, and are generally operating near or beyond useful life. These assets were installed to serve residential customers in the Horseshoe region of Toronto. Due

to accessibility limitations, outages on the rear lot plant tend to be longer in duration. The location of the plant also presents safety risks to customers and employees. Toronto Hydro is continuing to replace rear lot plant with standard, front lot underground circuits as part of the Area Conversions program (Section E6.1).

- **Box Construction:** These overhead feeders are located along main streets in the downtown area and serve residential neighborhoods and small commercial customers. The congested, box-like framing of the circuits prevents crews from establishing safe limits of approach to live conductors, which in turn restricts operations and leads to longer power restoration times for customers when compared to modern overhead standards. Toronto Hydro is continuing to replace box construction plant with standard overhead circuits as part of the Area Conversions program (Section E6.1).

D2.2.1.2 Overhead Assets Failure Characteristics

Table 2 below highlights the failure modes and impacts of overhead asset failures.

Table 2: Overhead Asset Failure Modes

Asset	Failure Mode	Effects
Pole Top Transformer	a) Arc flash due to contamination of bushing. b) Corrosion of tank c) Winding Failure	a) Causes tracking and can lead to catastrophic failure (e.g. oil fire, spill). b) Causes oil leakage and potential environmental issues c) Causes outage to customers
Wood Poles & Auxiliary Equipment	a) Rotted pole (below ground and at ground level) b) Contamination of insulators c) Pest infestation	a) Pole and equipment on it could fall causing an outage, safety issues and environmental issues associated with oil leakage b) Pole can catch fire due to tracking c) Compromises pole strength; equipment can fall and drop; safety and environmental risks.
Overhead Switches	a) Burnt disconnect contacts due to contamination b) Corroded or loose connections	a) The switch would be damaged and require replacements b) Lead to a connection failure and a forced outage

D2.2.2 Underground Grid System

The underground system consists of cables, transformers, switches, and civil infrastructure. All of these assets are placed at grade, below grade, or inside building vaults. The underground system eliminates many non-asset risks that are present in the overhead system such as foreign interference and weather-related interruptions. However, this system also presents unique non-asset risks, such as flooding or faster deterioration due to moisture build-up. Although this system generally provides better reliability than the overhead system, the causes of outages are more difficult to identify and restoration may take longer because the assets are underground and not visible to crews.

The Horseshoe underground distribution system is operated at 27.6 kV, 13.8 kV, with a subset of the system operating at 4.16 kV. The downtown underground distribution system is operated at 13.8 kV, and 4.16 kV. The main underground configurations are either radial or looped, with radial being the predominant configuration in the downtown system.

System types and configurations are sometimes mixed to provide better reliability or flexibility when repairs are required, as is the case with Underground Residential Distribution ("URD"). URD is a distribution configuration in parts of the downtown area with primary cables, switches and distribution transformers placed underground while secondary voltage connections remain overhead. The primary feeders consist of a main-loop, sub-loop and branch circuits. Customers are supplied directly from either the sub-loops or branch circuits, which allow sectionalisation (i.e. the ability to use switching to segment a feeder into sections) within the feeder to minimize interruptions when work is required, or to allow partial restoration of the feeder under fault conditions. Figure 13 shows a picture of a typical installation.



Figure 13: Typical Layout of Underground Residential Distribution

Toronto Hydro's underground system consists of approximately 8,500 underground switches, 29,000 underground transformers, 11,000 cable chambers, and 12,697 circuit-kilometres of underground primary and 20,517 circuit-kilometres of underground secondary cables.

Asset management activities related to the underground distribution system focus on mitigating environmental and safety risks, responding to system events and equipment deficiencies, managing system performance with respect to reliability and power quality, and asset stewardship over the assets' lifespan.

Figure 14 provides the age demographic distribution of major underground assets. As of 2017, approximately 20 percent of underground transformers and over 20 percent of cable chambers are at or approaching their useful life of 35 years. Without proactive intervention, Toronto Hydro projects that the percentage of underground transformers and cable chambers having reached or exceeded useful life will increase from approximately 20 percent to 35 percent and 30 percent, respectively by 2024.

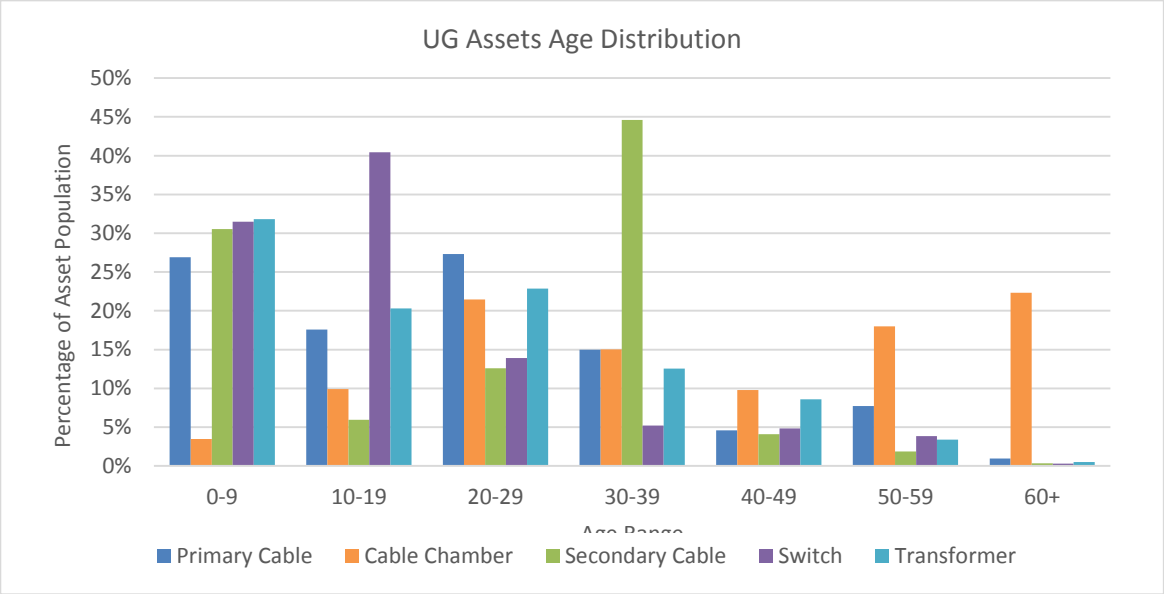


Figure 14: Underground Assets Age Demographic as of 2017

Underground switches and cable chambers are two major underground asset classes for which Toronto Hydro performs an ACA. As shown in Figure 15, approximately 14 percent of Toronto Hydro's underground switches and approximately 17 percent of cable chambers have at least moderate deterioration (i.e. HI3, HI4, and HI5) as of 2017. With over 1,300 cable chambers in HI3 condition, almost 400 in HI4 condition, and almost 100 in HI5 condition (i.e. "end of serviceable life"), cable chamber replacement will continue to be a significant driver of both reactive and planned investment through 2024 and beyond.

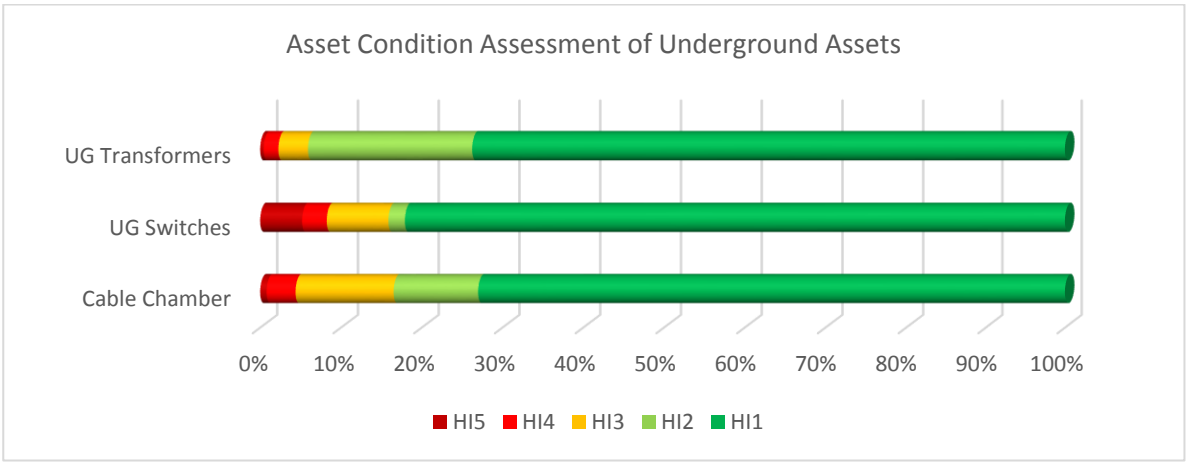


Figure 15: Asset Condition Assessment of Underground Assets as of 2017

Other key asset management performance measures that are relevant to the underground system include:

- **Oil Deficiencies:** During the 2015-2017 period, Toronto Hydro found, on average, 426 underground transformers with oil deficiencies per year. Assets replaced in the Underground System Renewal programs and Reactive Capital program will include assets exhibiting oil deficiencies found during inspections.
- **Priority Deficiencies:** The underground distribution system includes many below-grade vaults and cable chambers. The assets housed within them include cables, splices, joints, ducts, vents, hatchways, sump pumps, protectors, transformers, and switches. From 2013 to 2017, Toronto Hydro issued more than 24,000 work requests to address failing or failed underground assets. In 2017 alone, Toronto Hydro identified 1,445 P1, 1,440 P2, and 3,784 P3 priority deficiencies on the underground system.
- **PCBs:** Toronto Hydro has various types of underground transformers (e.g. submersible, padmounted, vault, and network), all of which can potentially contain PCB contaminated oil. As of the end of 2017, approximately 3,800 are known to contain, or at risk of containing, PCB contaminated oil greater than 2 ppm. Toronto Hydro endeavours to eliminate the risk of PCB-contaminated oil spills by testing or replacing all of these assets, which will be operating beyond useful life, by 2025, predominantly through the Underground System Renewal programs (Section E6.2 and E6.3). If sub-standard conditions are found during inspections, replacements may be done through the Reactive and Corrective Capital program.

D2.2.2.1 Underground Legacy Equipment

1. Direct-Buried XLPE Cable

Cables are the single greatest contributor to defective equipment caused outages on Toronto Hydro's system, contributing on average 140,000 CHIs annually. The underground system in the Horseshoe area consists of 809 circuit-kilometres that are of a legacy and obsolete installation type, namely direct-buried cross-linked polyethylene ("XLPE") cable (or duct). Over 70 percent of direct-buried cable has reached or passed its useful life as of 2017. Without investment, 90 percent will be at or beyond useful life by 2024. This would have a negative impact on reliability, which would erode and eventually reverse the recent improvements on the underground system. These cables are susceptible to outages due to direct exposure to environmental conditions. "Water treeing" is the

most significant degradation process for XLPE cable, and starts with moisture penetration into the cable insulation in the presence of an AC electric field. These "trees" are microscopic tears within the dielectric. Over time, continuous seepage of moisture into the insulation combined with electrical stress allows ions from the conductor to migrate into the microscopic tears. These tears then become carbonized and form electrical trees. Once this final stage of water treeing is reached, the cable quickly fails due to internal short circuits that occur between the primary conductor and the neutral shield on the outside of the cable insulation. Figure 16 depicts the internal short circuit that occurs once electrical trees are formed in the dielectric insulation. Figure 17 illustrates field and laboratory samples of microscopic voids bubbles) and damage to the insulation.

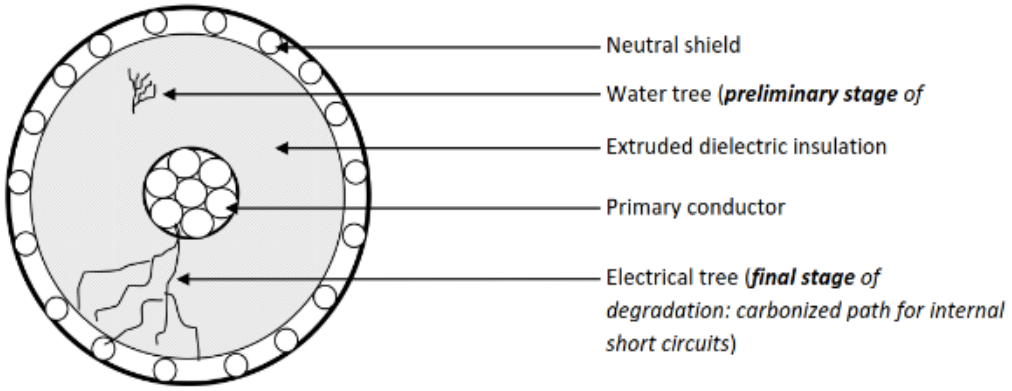


Figure 16: Cable Failure due to Electrical Treeing



Figure 17: Field and Laboratory Sample of Microscopic Voids and Damage XLPE Insulation

There is an immediate need to address the issues associated with direct-buried XLPE type cables so as to maintain system reliability for current and future customers in the Horseshoe area of Toronto. For further information, please see the Underground System Renewal – Horseshoe Program described in Exhibit 2B, Section E6.2.

2. Underground Lead Cable (PILC and AILC)

The majority of the cable in Toronto Hydro's downtown underground system is of two types: Paper-Insulated Lead-Covered ("PILC") and Asbestos-Insulated Lead-Covered ("AILC"). These cables are typically found at busy intersections beneath the sidewalks and roads of Toronto's downtown core. PILC cables are used as 13.8 kV primary cables, while AILC cables are used as secondary cables rated at 600 V. AILC cable is typically found on the secondary network 120/208 V and 240/416 V systems. Approximately 55 percent or 1,100 circuit-kilometres of Toronto Hydro's downtown primary system consists of PILC cable, whereas 30 percent or 220 circuit-kilometres of all cable in the downtown network system consists of AILC cable.

Historically, utilities installed lead cable to take advantage of its reliability and compact design. However, over time, many utilities encountered environmental and health and safety issues with these cables. The industry has moved away from using these cables and for a number of years, there has been only one supplier remaining in the market for PILC (with none for AILC). Due to the supply risk (and the aforementioned environmental and safety risks), Toronto Hydro has avoided installing new lead cable for a number of years. Other utilities have taken a similar approach. As time passes, the number of individuals in the industry with the expert skillset required to work on lead cable in the field continues to diminish. To date, Toronto Hydro has largely dealt with lead cable failures and congestion issues reactively. Due to the advancing age of the population of lead cables and increasing issues with reliability issues, Toronto Hydro is introducing a new program to begin the long-term replacement of all lead cable with modern standard underground cable. This is discussed further in the Cable Renewal segment of the Underground System Renewal – Downtown program (Section E6.3).

D2.2.2.2 Underground Assets Failure Characteristics

Table 3 provides a brief overview of the failure modes and impacts of underground asset failures.

Table 3: Underground Asset Failure Modes

Asset	Failure Mode	Effects
Underground Cable	a) Insulation failure (water trees, overvoltage). b) Carbon tracking in PILC cable paper insulation due to absence of oil medium (oil leak). c) Degradation due to age (cracked or degraded jacket)	a) Electrical stresses may lead to the cable failing at that position. b) Impregnating oil dries up, cable overheats, degrading the insulation. c) Water ingress, corrosion of the metallic shield, penetration into the insulation (potentially causing water trees).
Submersible Transformers	a) Oil Leaking b) Corrosion of tank c) Gasket deterioration with age d) Corroded secondary terminations (compression or bolted lugs).	a) Transformer cooling and insulating properties are diminished, flash over may occur. b) Oil leaks, transformer cooling and insulating properties are diminished. Internal components damage and flash over will occur. c) This failure mode can arise due to a flooding or contamination. Hotspots are detected and the secondary termination fails.
Padmounted Transformers	a) Corroded enclosure. b) Enclosure has been exposed to moisture (ground water, moisture ingress). c) Contaminated or damaged insulating barriers; d) Degradation due to age/contamination. e) Gasket deterioration with age.	a) Public or animal access to the transformer. Transformer could be damaged or cause injury to the public. b) Improper ventilation, inadequate air flow, tracking, and flashover. Safety risks heighten as the transformer is located next to sidewalks. c) Tracking on the insulators, and eventual flashover. d) Insulation material breakdown and build-up of sludge; flashover will occur. e) Small traces of oil leaking. Ingress of moisture may occur, transformer cooling and insulating properties are diminished.

Asset	Failure Mode	Effects
Underground Switches (Padmounted)	a) Loss of insulating properties due to contamination, moisture ingress, or humidity. b) Switch has been exposed to moisture (ground water, moisture ingress.	a) Flashover. b) Improper ventilation and inadequate air flow creates tracking and possible flashover and failure, presenting a safety concern as the switch is located next to sidewalks.
Cable Chambers	a) Collapsed duct. b) Excessive water leakage through ducts. c) Structural degradation at the neck; d) Cable racks and arms rust and deterioration; e) Wall or roof failure, with corrosion in rebars.	a) Hotspot depending on the extent of damage, cable damage. Worst case can involve damage to connected equipment, posing a safety risk to the public. b) Degradation of walls, floor, corrosion to the racks. c) Access is restricted. If chamber is on roadway, a sinkhole may occur, posing a safety risk. d) Racks fall off the wall causing the cable or joint to be unsupported and possibly cause damage to other cables, posing a potential safety risk. e) Cracks, spalling, delamination of concrete and chunks of concrete falling down, structural collapse, or fire, posing a safety risk.

D2.2.3 Secondary Network System

The secondary network system, which is predominantly found in the downtown Toronto area, was initially installed in the early-to-mid 1900s to improve reliability for critical loads. As the system evolved, it became recognized for its ability to efficiently serve medium sized loads in areas that have high density and small and narrow sidewalks. Such areas do not have sufficient space above grade for distribution infrastructure. The network system consists of interconnected low-voltage secondary cables, which are installed in a grid or mesh configuration. These grids are supplied by multiple network units housed in network vaults fed by different feeders, and offer additional redundancies that the typical overhead and underground distribution systems do not. Should a single primary feeder experience an outage, network connected customers will continue to be supplied from

alternate primary circuits, which continue to feed into the secondary grid or mesh. In this way, the secondary network system offers greater reliability than other underground or overhead systems.

At the heart of the network system are network units. The main difference between a network unit and a conventional radially-configured transformer is the addition of a network protector. The network protector prevents power from the secondary network grid from back feeding to the primary side. Should a fault occur on the primary side of the network unit, the network protector will automatically trip (i.e. open the switch to interrupt the current backfeeding into the fault). This protects the grid from the fault, and allows the remaining network units to keep the secondary network grid up and running.

Though the network system is better at handling normal failure scenarios, in the case of a catastrophic failure such as a vault fire, the entire secondary network grid that is connected to the vault must be dropped to allow emergency responders to extinguish the fire safely. In such a scenario, all connected customers are interrupted. To avoid these scenarios, network equipment must be kept in good condition to prevent vault fires or other failures from occurring. This is one of the reasons why Toronto Hydro takes a proactive approach to the maintenance and replacement of network units at risk of failure. Figure 18 below shows a typical submersible network unit.



Figure 18: Submersible Network Unit

The vaults that house network equipment are also an important component of the network system and must be maintained. If the integrity of a vault is compromised, the equipment inside the vault can be damaged, or the vault may become unsafe for employees. Unsafe conditions mean that crews are unable to complete any maintenance or repairs. As of 2017, Toronto Hydro has 575 vaults past their useful life. In addition, a number of vaults will need to be decommissioned as existing network areas redevelop into high rise areas, and some vaults that are otherwise in good structural condition, will require roof rebuilds.

Figure 19 provides the age demographic distribution of major network assets. As of 2017, approximately 16 percent of network units and approximately 1 percent of network vaults are at or approaching their useful life of 35 years and 60 years, respectively. Without intervention, Toronto Hydro projects that the percentage of network units having reached or exceeded useful life will increase from 16 percent to 25 percent, and the percentage of network vaults will balloon from 1 percent to 24 percent by 2024. Non-submersible network units are one asset type that Toronto Hydro plans to target specifically. These units are susceptible to water ingress and elevated failure risks even when in good condition. As such, they need to be replaced to reduce the failure risks on the network system. Replacements will occur on a prioritized basis considering factors such as condition, as discussed in Exhibit 2B, Section E6.4 (Network System Renewal).

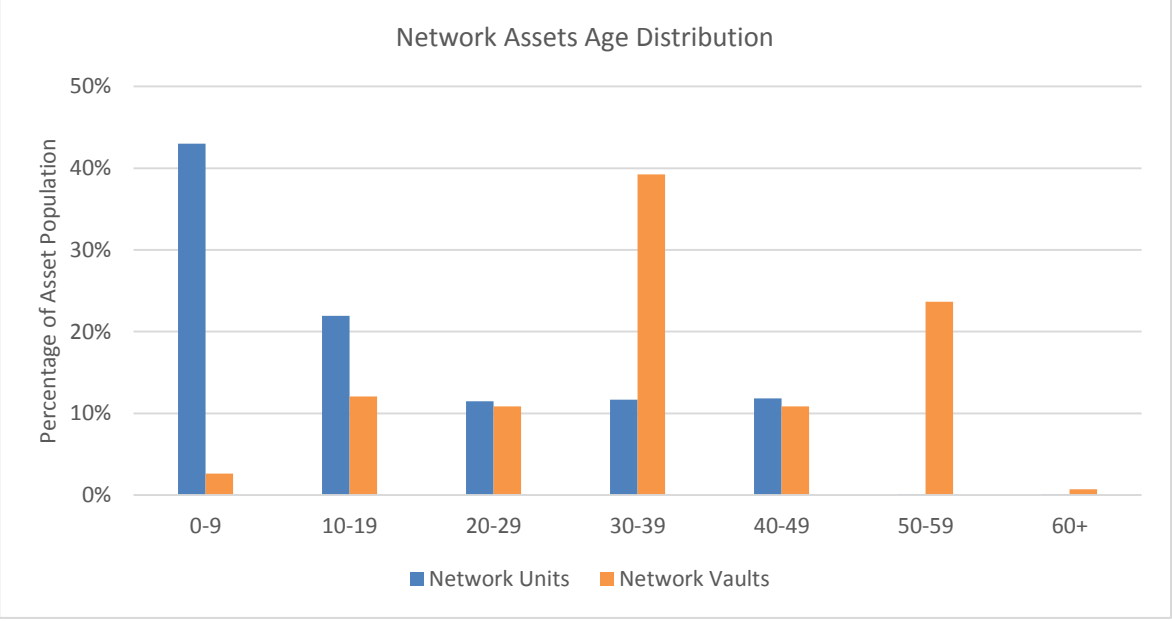


Figure 19: Network Assets Age Demographics as of 2017

Toronto Hydro performs an ACA for network transformers, network protectors, and network vault civil infrastructure. ACA results show that approximately 19 percent of Toronto Hydro's network vaults and 13 percent of network transformers have at least moderate deterioration as of 2017. With over 60 network vaults in HI3 condition, approximately 10 in HI4 condition, and approximately 30 in HI5 condition (i.e. "end of serviceable life"), Toronto Hydro expects network vault replacement will continue to be a significant driver of both reactive and planned investment through 2024.

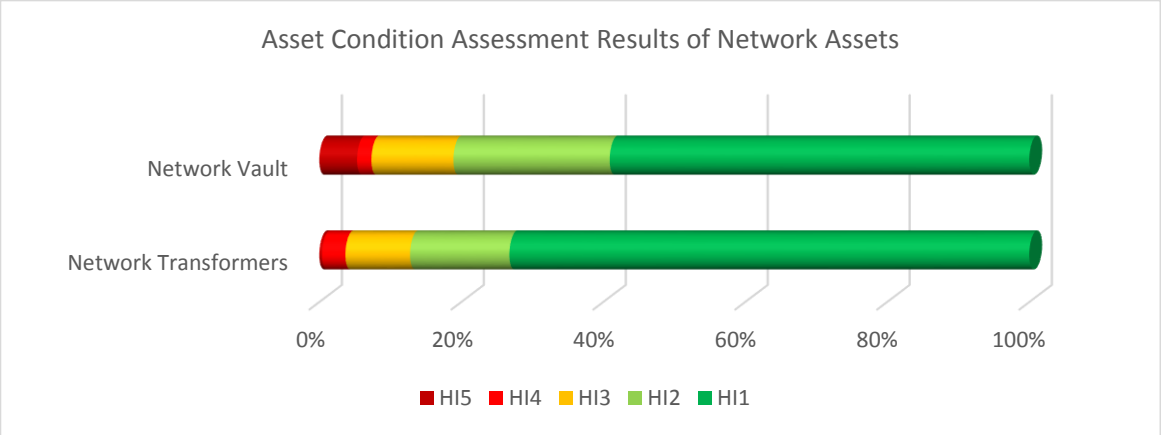


Figure 20: Asset Condition Assessment of Secondary Network Assets

Asset management activities related to the network focus on asset stewardship over asset life spans; mitigating environmental and safety risks, responding to system events and equipment deficiencies, and managing system performance with respect to reliability and power quality. The following summarizes what this means relative to the outcome measures for network assets, as set out in Table 2:

- **Oil Deficiencies**: Network transformers are the only asset group in the network system affected by this outcome. During the 2015-2017 period, Toronto Hydro found on average 114 oil deficiencies per year for network transformers. Assets replaced in the Network System Renewal Program and Reactive Capital Program will include assets exhibiting oil deficiencies found during inspections.
- **Priority Deficiencies**: Please see the discussion related to priority deficiencies under section D2.2.2 above as deficiencies related to the secondary network are generally tracked with all other underground deficiencies.
- **PCBs**: Network Transformers are the only asset group in the network system affected by this outcome. As of the end of 2017, Toronto Hydro has approximately 100 network transformers

that contain or are at risk of containing PCBs. Toronto Hydro endeavours to eliminate the risk of PCB-contaminated oil spills by 2025 by replacing end-of-life network units which include the aforementioned network transformers, which will be operating beyond useful life, through the Network Renewal Program (Exhibit 2B, Section E6.4).

D2.2.3.1 Network Legacy Equipment

On the network system, a major challenge facing Toronto Hydro stems from legacy network assets such as Automatic Transfer Switches ("ATS") and Reverse Power Breakers ("RPB"), and from non-submersible network protectors. These assets contribute to poor reliability performance, safety risks, and other undesirable outcomes. Capital investment programs that are planned to target and mitigate risks associated with these assets include: Network System Renewal (Section E6.4) and Reactive and Corrective Capital (Section E6.7).

1. Replacing obsolete and deteriorating network equipment

Legacy Network Equipment: The types of ATSs and RPBs used by Toronto Hydro are no longer produced or supported by the manufacturer, nor can they be properly maintained or replaced on a like-for-like basis. Failure can occur due to factors such as moisture penetration, or exposure to heavy debris and contamination, which results in equipment rusting and control electronics failure.

These assets can fail catastrophically, resulting in lengthy outages, vault fires, and damage to connected and adjacent equipment. The impact of an ATS failure can be seen in Figure 21 below. Toronto Hydro is continuing to replace ATS and RPB units with network transformer units and standalone network protectors, or 600A manual secondary switches.



Figure 21: Damage from a Vault Fire caused by Failure of an ATS Unit

Network Units with Non-submersible Protectors: Although network units are replaced based on condition, another consideration that informs investment decisions is the presence of "non-submersible" designs which are characterized by ventilated or semi-dust-tight protectors. The units are susceptible to water ingress and elevated failure risks even when in good condition. The failure modes for network units are flooding and internal transformer failure. Flooding can damage the protector mechanism, causing the unit to short, or fail to operate, whereas transformer failure can result from overloading, low oil, moisture ingress, or age-related insulation deterioration. Toronto Hydro is continuing to replace non-submersible protectors with submersible protectors that feature watertight cases to help address flooding risks as part of the Network System Renewal program (Section E6.4). Figure 22 below shows the difference between a ventilated network unit and a submersible network unit, where the black protector identified is of a submersible design to prevent water ingress.



Figure 22: A ventilated Network Unit (Left) and a Submersible Network Unit (Right)

D2.2.3.2 Network Assets Failure Characteristics

Low voltage secondary distribution networks are susceptible to similar failure modes as other underground distribution systems; however, the consequences of failure to operate and network customer service reliability are often different, as outlined in Table 4 below.

1 **Table 4: Network Asset Failure Modes**

Asset	Failure Mode	Effects
Underground Primary Cable	a) Internal arc occurs due to insulation degradation b) Internal arc occurs due to jacket damage c) Internal arc occurs due to mechanical stresses compromising geometry of cable	a) Station circuit breaker trips causing feeder outage b) Network vaults continue to operate under contingency, with possible equipment overloads. Network customers are not normally interrupted c) Dual radial customers supplied by faulted feeder are interrupted until switched to alternate feeder d) If multiple primary cable outages occur simultaneously, equipment overloads may force the Control Room to drop the entire network, resulting in widespread customer interruptions
Underground Secondary Cable	a) "Arcing" fault occurs due to insulation degradation b) "Solid" fault occurs when a failed cable conductor contacts another conductor	a) "Arcing" faults tend to self-clear without customer interruption. b) "Solid" faults may spread to adjacent cable junctions before self-clearing, resulting in interruptions to a small number of customers c) If self-cleared secondary cable faults are not identified, surrounding secondary cables may overload and eventually fault, resulting in interruptions to multiple customers
Network Transformer	a) Internal insulation failure caused by insulation degradation b) Corrosion of the steel tank or gasket failure results in insulating oil leakage	a) Internal network transformer faults tend to be cleared by the station feeder circuit breaker without breaching of the transformer tank. b) Oil leakage may cause contamination of the surrounding environment.

Asset	Failure Mode	Effects
Network Protector	a) Debris, salt, and moisture collect on the top of a network protector causing an electrical short b) Vault flooding allows water to enter the protector causing the mechanism to fail and possibly an electrical short.	a) Electrical shorts in protectors typically result in vault fires, with the possible destruction of all electrical equipment in the vault. The Fire Department normally requests interruption of electrical supplies to the vault b) Protector flooding normally only results in permanent damage to the mechanism, which must be replaced.

D2.2.4 Stations

Toronto Hydro's distribution system receives its transmission supply from Hydro One Networks Inc. ("Hydro One") at voltages of 230 kV, 115 kV, 27.6 kV, or 13.8 kV for use in the distribution system at Transformer Stations ("TS"). In general, Toronto Hydro owns all the medium voltage equipment up to the circuit breaker at a TS, subject to certain differences in ownership structures for each TS's equipment. Figure 23 below shows the ownership of station equipment and their associated demarcation point. In some areas, the voltage may be further stepped down to 13.8 kV or 4.16 kV at Municipal Stations ("MS") which are wholly-owned by Toronto Hydro.

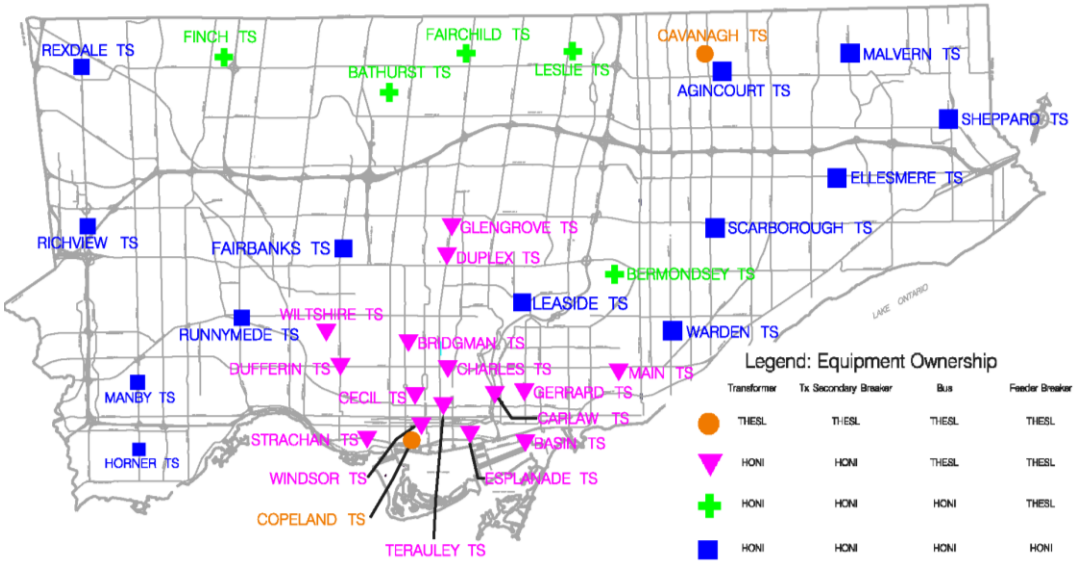


Figure 23: System Diagram of Station Components Ownership

Toronto Hydro is supplied by 36 TSs, including Copeland TS (as shown in Figure 23 above), and owns approximately 169 MSs.[17] Within these stations Toronto Hydro owns and operates approximately 209 switchgear, 215 power transformers, 90 outdoor circuit breakers, 201 remote terminal units ("RTUs"), and 187 direct-current ("DC") battery systems.

Feeders generally have at least one normally-open tie to another feeder to ensure there is a restoration option in case of an outage, or if planned work is required. [18] In the Horseshoe area, there are many normally open ties between feeders fed from the same bus or feeders fed from a different bus or station. This allows for increased operational flexibility and the ability to restore some load in the event of a bus or station outage. Feeders in the downtown area rely on a radial configuration with normally open ties to feeders supplied from the same bus, but never have ties with feeders fed from other stations. This configuration limits the restoration options for these feeders in case of a station outage. Toronto Hydro does look for opportunities to build contingency ties between different downtown stations where economical.

Asset management activities related to stations focus on mitigating environmental and safety risks, responding to system events and equipment deficiencies when they are identified, managing system performance with respect to reliability and power quality, and asset stewardship over the assets' life span.

Figure 24 provides the age demographic distribution of major station assets. As of 2017, 40 percent of Toronto Hydro's switchgear, 51 percent of power transformers, 13 percent of outdoor breakers, and 35 percent of DC battery systems are operating at or beyond their useful life. Without proactive intervention, the proportion of station assets operating beyond their useful life will continue to increase. Station asset renewal is complex and entails considerable operational constraints which limit the achievable level of renewal in a given year. Consistent investment and renewal work is needed to sustainably mitigate and control the failure risk presented by these assets.

[17] 15 of which are in the process of being decommissioned.
[18] Secondary network systems and pilot-wire/line-differential based systems operate with multiple supply points in parallel and do not require a normally open tie.

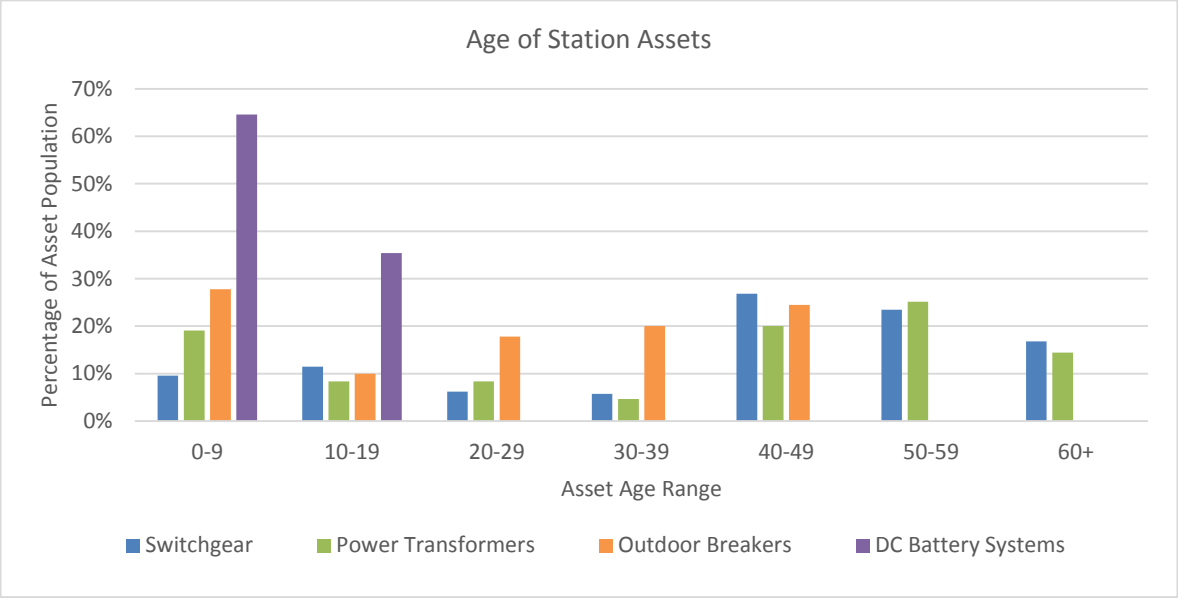


Figure 24: Stations Assets Demographics as of 2017

Within its stations asset classes, Toronto Hydro performs ACA analysis on its 215 power transformers as well as various types of its more than 1,600 circuit breakers. With the exception of 90 standalone outdoor circuit breakers, circuit breakers are contained inside one of Toronto Hydro's 209 switchgear and are considered components of their parent switchgear. Therefore, ACA performed on breakers helps serve as a proxy for switchgear condition.

Figure 25 shows that 90 percent of Toronto Hydro's air-blast circuit breakers, 66 percent of its oil circuit breakers, 58 percent of KSO oil circuit breakers, 56 percent of air-magnetic circuit breakers, 15 percent of SF_6 circuit breakers, and 6 percent of vacuum circuit breakers show signs of at least moderate deterioration. Accordingly, renewal of switchgear containing air-blast circuit breakers and oil circuit breakers are heavily targeted in the Stations Renewal Program (Exhibit 2B, Section E6.6). Similarly, standalone outdoor KSO circuit breakers are prioritized for renewal in the proposed program. Figure 25 shows that 33 percent of Toronto Hydro's station power transformers show signs of at least moderate deterioration. The need for transformer renewal is underscored by a recent surge in the number of units requiring reactive replacement.

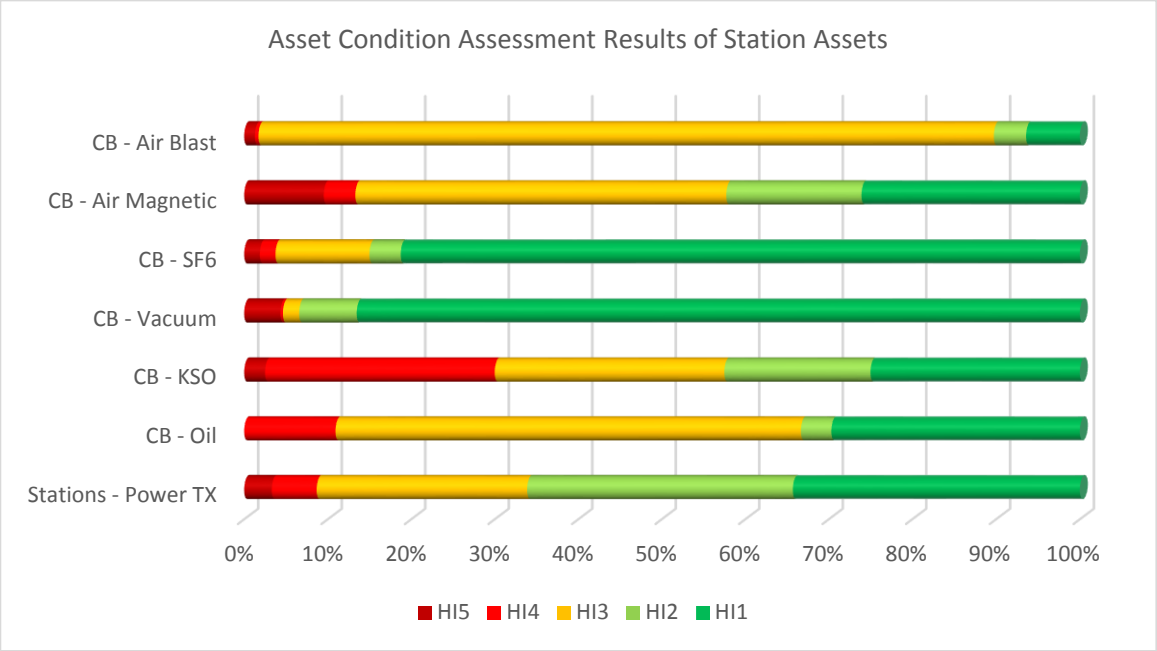


Figure 25: Asset Condition Assessment of Station Assets

Other key asset management performance measures that are relevant to the stations are include:

- **Oil Deficiencies**: During the 2015-2017 period, Toronto Hydro found on average 22 station transformers with oil deficiencies per year. Assets replaced in the Station Renewal program (Exhibit 2B, Section E6.6) and Reactive and Corrective Capital program (Exhibit 2B, Section E6.7) will include assets exhibiting oil deficiencies found during inspections.
- **Priority Deficiencies**: Station assets include power transformers, circuit breakers, switchgear, SCADA systems, relays, batteries and chargers, SCADA telemetry or control equipment, station alarms, DC panels, station heating, ventilation systems and sump pumps, which are installed across Toronto Hydro's 154 MSs[19] and 35 TSs (excluding Copeland TS). From 2013 to 2017, Toronto Hydro issued more than 4,000 work requests to address failing or failed station assets.
- **PCBs**: As of 2017, approximately 450 pieces of stations equipment, including power transformers and oil-filled breakers, contain or are at risk of containing PCBs. Through testing as part of the Preventative and Predictive Station Maintenance program (Exhibit 4A, Tab 2,

[19] Supra note 14.

Schedule 3), replacement under the Stations Renewal program (Exhibit 2B, Section E6.6) or decommissioning following voltage conversion and MS decommissioning, Toronto Hydro endeavours to eliminate the risk of PCB-contaminated oil spills by 2025. In certain instances, coordination with the Stations Expansion program (Exhibit 2B, Section 7.4) is required to remove station assets with oil containing PCBs.

D2.2.4.1 Stations Legacy Equipment

Toronto Hydro has many legacy station assets currently in operation, which are being phased out through capital renewal plans, as discussed in the Stations Renewal Program (Exhibit 2B, Section 6.6). Legacy assets include: (i) non-arc-resistant brick and metalclad switchgear; (ii) air-blast, oil, KSO oil, and air magnetic circuit breakers; (iii) DACSCAN MDO-11, D20 ME, D20M++, and MOSCAD RTUs; electromechanical pilot-wire relays; and (iv) copper communications cable.

Oil and KSO oil circuit breakers are legacy assets which also present several risks including a safety risk to Toronto Hydro personnel, risk of collateral damage to adjacent station equipment, and in some cases a safety risk to the public or an environmental risk. Both oil and KSO oil circuit breakers contain oil, which may catch fire or even explode upon failure of the asset. KSO oil circuit breakers can also contain PCBs.

D2.2.4.2 Stations Major Assets Failure Characteristics

Table 5 below provides a brief overview of the failure modes and impacts of station asset failures. Typically, failure of these assets results in power outages to all customers supplied by the affected station bus, or even the entire station. In addition to power outages, station asset failures can lead to extensive and irreparable damage.

Table 5: Station Assets Failure Modes

Asset	Failure Mode	Effects
Switchgear	a) Internal arcing occurs, due to a bus fault or circuit breaker failure.	a) Customers supplied by switchgear suffer a prolonged power outage. Arcing damages switchgear.

Asset	Failure Mode	Effects
Power Transformer	a) Oil insulation failure. b) Paper insulation failure. c) Bushing failure causes flashover.	a) Power outage to entire station. Potential internal arcing, which risks inducing fire or explosion. b) Power outage to entire station due to low or fluctuating voltage, or internal fault. c) Power outage to entire station, and flashover damages transformer.
KSO Circuit Breaker	a) Internal arcing occurs, due to internal fault or failure to interrupt fault current. b) Breaker fails to open on a fault, no internal arcing occurs. c) Bushing failure causes flashover. d) Breaker fails to close.	a) Power outage to entire station switchgear. Arcing damages breaker and risks inducing fire or explosion. b) Power outage to entire station switchgear. c) Power outage to entire station switchgear, and flashover damages breaker. d) Feeder cannot be supplied from the station switchgear. Distribtuion system is under contingency.
DC Battery System	a) DC charger system fails. b) DC battery fails.	a) All station protection and control capability is lost after 8 hours when the battery has depleted. Station is then rendered inoperable. b) Station is noncompliant with Section 10.7.1 of the Transmission System Code. Should either the DC charger system or station service supply be out of service, then the station is rendered inoperable.

D2.2.5 Metering

Toronto Hydro utilizes several different meter types in order to ensure the reliable measurement of electricity acquired by the utility through the provincial transmission system and distributed to its customers. These include: (i) Residential and Small Commercial & Industrial; (ii) Interval; (iii) Suite metered; and (iv) Wholesale applications.

- **Residential/Small Commercial & Industrial**: Toronto Hydro must continually upgrade its residential metering system to ensure that it continues to receive vendor support and is capable of enabling features on newer generation meters. Toronto Hydro plans to implement a new version upgrade of this system in 2021. To date, these meters represent 88 percent of Toronto Hydro's meter population.
- **Interval**: Toronto Hydro plans to upgrade the Interval Metering system, ITRON Enterprise Edition ("IEE") to continue to successfully meter Toronto Hydro's interval metered customers (those with a demand of 50 kW or above) over the 2020-2024 period. In 2011, Toronto Hydro had 3,300 Interval metered customers on IEE, which increased to 7,000 as of 2017. Continued growth in IEEE uptake is expected due to the decommissioning of the 2G network, and the consequent conversion of Toronto Hydro's own 2G network to 4G technology.
- **Suite Metering**: These meters represent the individually metered multi-residential buildings. The utility is legally obligated to provide suite meter installation services. Toronto Hydro offers this service in a competitive environment, and is also the provider of last resort in the event that the condominium chooses not to secure a third party meter service provide. Currently, there are approximately 79,000 suites that are individually metered by Toronto Hydro and about 3,000 multi-residential buildings that are metered by one bulk meter. Toronto Hydro plans to continue to offer its suite metering services to new customers along with retrofit upgrades over the 2020-2024 period.
- **Wholesale**: Toronto Hydro plans to upgrade its wholesale revenue meters at all applicable wholesale metering points to comply with the metering standards mandated by Measurement Canada and the Independent Electric System Operator ("IESO") Market Rules during the 2020-2024 period. These meters are installed at each of Toronto Hydro's transfer stations, and are used by Toronto Hydro to purchase power and to validate consumption with the IESO.

Toronto Hydro must maintain its fleet of meters in order to comply with both Measurement Canada and OEB mandates such as billing accuracy, estimated bills, and meter seals. In this regard, Toronto Hydro re-seals batches of meters to ensure accuracy and reactively replaces failed or non-communicating meters to ensure compliance. Toronto Hydro's meter population is aging with the majority of the residential and small C&I meter population reaching and exceeding 15 years of age during the 2020-2024 filing period.

D2.2.5.1 Metering Major Assets Failure Characteristics

Table 6 below provides a brief overview of the failure modes and impacts of metering asset failures.

Table 6: Metering assets failure mode

Asset	Failure Mode	Effects
Energy Meter	a) Communications Failure	a) Bills must be estimated or meter manualy read
Instrument Transformer	b) Device Failure	b) Meter reads would be incorrect due to failed instrument transformers

D2.3 System Utilization

Toronto Hydro completes an annual load forecast of station bus capacity to plan for short and long term load growth, additional capacity requirements to serve customers, and contingency scenarios such as planned work or loss of supply. This load forecasting process is further explained in Section D3.1.1. To prevent system overloading which may lead to asset failures, the peak utilization of a bus should not reach or exceed 100 percent of its rated capacity for extended periods of time.[20] Bus capacity rating is determined based on the ratings for all of its associated equipment and a Limited Time Rating[21] for upstream equipment provided by Hydro One. Forecasting is performed at the bus level.

[20] For planning purposes a 95 percent loading threshold is used for the downtown region, while a 100 percent bus loading threshold is used for the Horseshoe. This difference in the threshold is due to the fact that there is more load transfer capabilities in the Horseshoe area than the downtown area so more time is required to make plans for downtown capacity constraints, than for Horseshoe capacity constraints. Further details of the load forecasting can be found in Section D3.1.2.1 Decision Support Systems as well as E7.7 Stations Expansion.

[21] Limited Time Rating ("LTR"): With respect to transformers, a limited time rating is a set of 15-minute, 2-hour, and 10-day MVA ratings determined by Hydro One in order to accommodate shorter time interval loading periods without causing equipment damage. All of Toronto Hydro's buses are supplied via at minimum two transformers operating in parallel. For bus capacity planning purposes, Toronto Hydro utilizes the 10-day LTR rating provided by Hydro One which is the maximum MVA the most limiting transformer can supply for a 10-day period with the other transformer out-of-service.

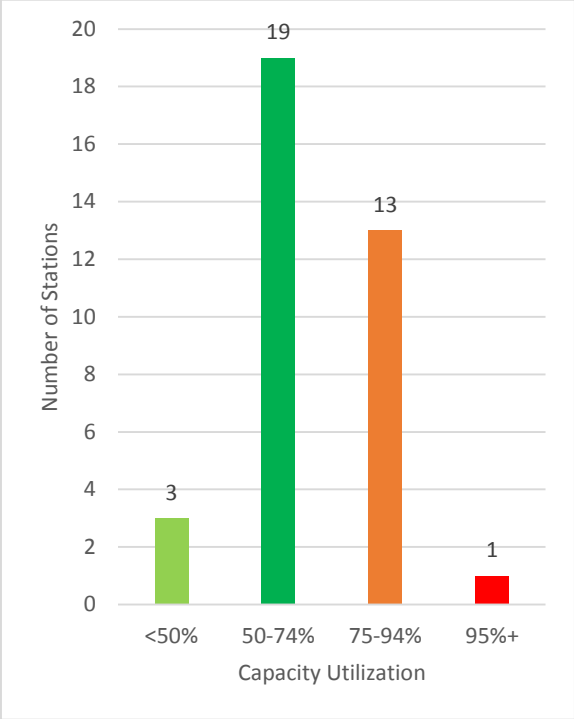


Figure 26: Forecasted Station Loading in 2020

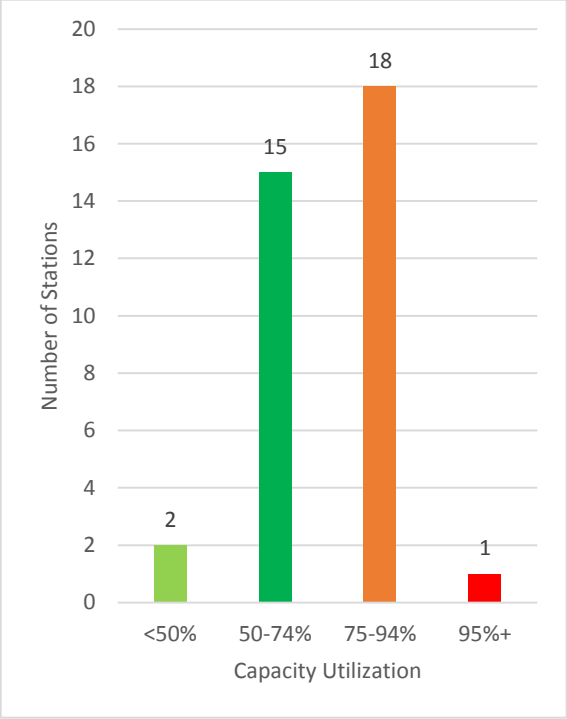


Figure 27: Forecasted Station Loading in 2025

From a station capacity standpoint, by 2020, 39 percent of Toronto Hydro stations will experience loading of 75 percent or higher, with one station that is forecast to be near capacity. By 2025, Toronto Hydro anticipates that the aforementioned percentage will increase to 53 percent, with one station expected to exceed its capacity. Operating stations at 100 percent capacity would severely limit the utility's flexibility to manage abnormal system states (planned or unplanned). In a worst case scenario, Toronto Hydro would be unable to maintain or replace a failing or failed asset.

More specifically, Toronto Hydro must also ensure that each of its stations has sufficient capacity to connect new or existing customers without sacrificing system reliability or operational flexibility for existing customers. Otherwise, extensive load transfers must be pursued through the Load Demand Program solely to free up the capacity needed to connect new customers without overloading a bus. Although this limit precedes station capacity, it is the primary driver for the need for extensive load transfers or station expansion projects so that new customer connections can be made. To this end, Toronto Hydro uses a second capacity metric, System Capacity (Exhibit 2B, Section C3.3), which forecasts that 13 to 14 of its stations will be unable to connect new large customers over 2020-2024,

unless the work proposed under its Station Expansion (Section 7.4) and Load Demand (Section 5.3) programs is completed.

To mitigate overloading at the stations and free up capacity to connect new large customers, Toronto Hydro analyzes each station's load forecast as well as available capacity in the area to resolve loading problems. Possible resolutions are to plan load transfers, upgrade existing components, or expand the station. A large number of limitations and considerations must be taken into account in implementing these solutions, including:

- incompatible system voltages (e.g. 27.6 kV vs. 13.8 kV);
- incompatible system types (e.g. radial versus looped, or overhead versus network);
- availability of civil infrastructure;
- availability of feeder positions;
- environmental or civil barriers (e.g. rivers, highways ravines); and
- relative cost between relief options.

Due to all these various considerations, every station must be individually analyzed to determine an appropriate resolution.

On the feeder level, Toronto Hydro typically plans new customer connections or customer load increases by analyzing the area where the additional load requirements are emerging. Similar limitations and considerations at both the feeder level and station level must be accounted for in the planning process. This process is largely reactive given the significant uncertainty in forecasting feeder loading, because it is difficult to predict exactly where new loads will materialize and there are multiple feeders which can potentially connect new loads.

On the asset level, Toronto Hydro frequently reviews the system in areas of high capacity utilization or areas of poor reliability to determine what work can be undertaken to improve the system. It is difficult to monitor every asset in the system to ensure it is optimally utilized. Nonetheless, Toronto Hydro has initiatives in place which will install new infrastructure and allow more assets to be closely monitored. Examples of such initiatives are network monitoring, stations control and monitoring replacements and new installations, and power transformer and switchgear replacements. These initiatives help prevent overloading which may cause premature equipment failure.

D3 Asset Lifecycle Optimization

Section D1 provided an end-to-end overview of Toronto Hydro's distribution system Asset Management Process ("AM Process"), from strategic planning to execution and reporting. Section D2 provided an overview of the current state of the major distribution assets that the utility manages.

- **Section D3** focuses on key factors that guide and influence investment pacing and prioritization decisions within the AM Process.
- **Section D3.1** provides an overview of the basic replacement, refurbishment, and maintenance approaches that Toronto Hydro applies to major asset classes to optimize the value derived from individual assets over their lifecycles. These asset lifecycle optimization practices are the fundamental building blocks for asset management and investment planning at Toronto Hydro.
- **Section D3.2** describes the ways in which the utility considers and manages failure risk in its AM process. Risk management takes various qualitative and quantitative forms and is fundamental to deriving expenditure plans that support the optimization of future outcomes within a constrained budget.
- **Section D3.3** describes the ways in which the utility considers and manages capacity risk in its AM process.
- **Section D3.4** describes the expenditure program planning process that Toronto Hydro uses to derive a capital expenditure plan from its AM Process.

For an overview of how the practices discussed in this section informed Toronto Hydro's 2020-2024 Capital Expenditure Plan for system-related investments, see Section E2.2.

D3.1 Asset Lifecycle Optimization Practices

As noted in Section D1, the broad objective of Toronto Hydro's AM Process is to realize sustainable value from the organization's assets for the benefit of customers and stakeholders. At the most fundamental level, this value is realized by consistently implementing prudent lifecycle optimization practices tailored to specific asset classes. These practices serve as guidelines for when and how to inspect and intervene on a specific asset, where intervention includes asset maintenance, refurbishment, and replacement.

Toronto Hydro's lifecycle optimization practices are the result of many decades of experience managing major distribution assets across a dense, mature, and congested major city that is served by various system designs and configurations. These practices take into account the various attributes of an asset class, including, but not limited to: (i) the intended functionality of the asset in the distribution system; the various modes of deterioration and failure over the asset's typical lifespan; (ii) the potential impact of various failure modes on distribution service; and (iii) the typical costs and customer impacts of intervention.

The following two sub-sections describe Toronto Hydro's asset lifecycle optimization practices, beginning with the utility's foundational maintenance and refurbishment practices, followed by a description of the utility's typical asset replacement practices for major asset classes.

D3.1.1 Maintenance and Refurbishment Practices

As part of its overall asset management process, Toronto Hydro aims to ensure the continuous serviceability (i.e. usefulness) of assets over their typical or expected useful lives, and to extend an asset's serviceability when it is feasible and economical to do so. Asset maintenance and refurbishment practices are the means by which Toronto Hydro supports these objectives.

D3.1.1.1 Reliability Centered Maintenance

Toronto Hydro typically conducts inspection and maintenance tasks on a fixed cycle. These activities are focused on preserving and maximizing an asset's performance over its expected useful life while mitigating a wide variety of system risks. Maintenance activities support the minimization of overall lifecycle costs and account for factors such as the safety of Toronto Hydro employees and the public, responsible environmental stewardship and associated obligations, and compliance with statutory and regulatory requirements.

Toronto Hydro's foundation for maintenance planning is Reliability Centered Maintenance ("RCM"), an established engineering framework for the maintenance of assets throughout their lifecycles. The RCM framework determines failure management policies for any physical asset in its present operating context to maximize useful life and reliability based on the asset's function and the consequences of functional failure, including the asset's criticality to the distribution system. The output of an RCM analysis includes failure mode analysis, which is used to identify proactive tasks (with associated time intervals) that help to predict or prevent failures from occurring. It also focuses on preventing failures where consequences are most severe. Toronto Hydro initially adopted an RCM

framework in 2003 and subsequently reviewed and updated its outputs in 2011 and over the 2016 and 2017 period, ensuring compliance with the Society of Automotive Engineers ("SAE") standards SAE JA-1011[1] and SAE JA-1012.[2]

RCM is a comprehensive approach to the lifecycle maintenance of distribution system assets. Initially developed in the airline industry to manage high maintenance costs and high failure rates, RCM has allowed Toronto Hydro to increase its analytical capabilities in determining the optimal level of maintenance expenditures and the appropriate time of intervention for a specific asset class. The RCM framework incorporates a thorough analysis of assets going beyond manufacturer's requirements to evaluate functional failures under utility-specific operating conditions. The analysis identifies and categorizes consequences of failure (i.e. safety, cost, reliability). Maintenance programs are subsequently set to mitigate these consequences by establishing recommended optimal asset intervention timelines.

The benefits of RCM include:

1) A structured and data-driven targeted maintenance program;
2) Reduced efforts and costs expended on maintenance programs with little resultant value; and
3) Increased reliability due to the effectiveness of the failure prevention program.

Toronto Hydro leverages the RCM framework, in combination with the OEB's Minimum Inspection Requirements and the continuous monitoring and assessment of asset performance, to derive its maintenance programs and associated expenditure plans. The expenditure plans for these maintenance programs can be found in Exhibit 4A, Tab 2, Schedules 1-3. Table 1 below provides a summary of the maintenance plans for the major asset types on each part of Toronto Hydro's distribution system.

[1] Standard SAE JA-1011 (Evaluation Criteria for Reliability Centered Maintenance (RCM) Processes) outlines requirements for an RCM analysis process. This standard is intended to be used to evaluate any process that purports to be an RCM process. The standard also specifies the minimum characteristics that a process must have in order to be an RCM process.
[2] SAE JA-1012 ("A Guide to the Reliability-Centered Maintenance (RCM) Standard") amplifies and clarifies each of the key criteria listed in SAE JA-1011, and summarizes additional issues that must be addressed in order to apply RCM successfully. It does not provide an additional list of requirements that must be met, rather it provides guidance on how to meet the requirements of SAE JA-1011. The resulting analysis produces failure management policies forming part of the maintenance program that are deemed to be the most cost and risk effective at sustaining asset performance in accordance with the company's risk tolerance level.

1 **Table 1: System Maintenance Practices**

System	Asset Class/Type	Planned Maintenance Activities	Toronto Hydro Cycle
Overhead	*Pole-top Transformer*	Line Patrols	3 Years Visual, 1 Year Infrared
	Distribution Poles	Line Patrols	3 Years Visual
		Wood Pole Inspection & Treatment	10 Years
	Primary Conductors	Line Patrols	3 Years Visual, 1 Year Infrared
		Tree Trimming	1-5 Years, with the majority being 2-3 Years
	Secondary Conductors	Line Patrols	3 Years Visual
	Switches	Line Patrols	3 Years Visual, 1 Year Infrared
		Maintenance (SCADA-Mate & Gang-Operated)	4 Years
		Battery Replacement for Switches (SCADA-Mate & Gang-Operated) and Repeater Radio	3 Years
	Insulators	Insulator Washing (for Porcelain)	6 Months
Underground	*Padmounted Transformer*	Inspection (Civil + Electrical)	3 Years
	Submersible Transformer	Vault Inspection (Civil + Electrical)	3 Years
	CRD Transformer		1 Year
	URD Transformer		
	Building Vault Transformer	Inspection (Civil + Electrical)	3 Years
	Padmounted Switch	Inspection (Civil + Electrical)	1 Year
		Battery Replacement	3 Years
	Cable Chamber	Cable Chamber	10 Years
	Cables	Contact Voltage Scanning	1 Year
Network	*Network Transformer*	Network Vault Inspection - Electrical	1 Year
		Network Vault Inspection - Civil	6 Months
		Reverse Power Breaker Overhaul	3 Years
		Protector Top Cleaning	1 Year

System	Asset Class/Type	Planned Maintenance Activities	Toronto Hydro Cycle
		Network Protector Overhaul - HV[3]	4 Years
		Network Protector Overhaul - LV[4]	5 Years
Station	*Station TS & MS Facilities*	Monthly Inspections	1 Month
		Seasonal Detailed Inspection	6 Months
	Circuit Breaker (All Types) & Switch	Maintenance	4 Years
	Bus Disconnect Switches		
	B-Bus	B-Bus Cleaning	4 Years
	Power Transformer	Equipment Maintenance	4 Years
	DC Battery & Charger	Seasonal Detailed Inspection	6 Months
	Compressed Air System	Station Compressed Air System Maintenance	6 Months
	Station Alarms in Downtown	Alarm Testing	1 Year
	Pilot Wire	Pilot Wire Protection	6 Years

D3.1.1.2 Summary of Maintenance Programs and Activities

Asset maintenance programs (Exhibit 4A, Tab 2, Schedules 1-5) are grouped into four major categories based on their functionality, as shown below:

- Preventative Maintenance;
- Predictive Maintenance;
- Corrective Maintenance; and
- Emergency Maintenance.

The framework of asset preventative and predictive maintenance programs is driven primarily by regulatory requirements, as mandated by the OEB's Distribution System Code Minimum Inspection Requirements (Appendix C to the Distribution System Code).

In addition, preventative and predictive maintenance programs, and maintenance activities are scheduled to be closely in line with the output of RCM analyses, which is performed on a per-asset class basis and informed by condition-based maintenance principles and an emphasis on maximizing

[3] High Voltage ("HV")
[4] Low Voltage ("LV")

productivity. RCM is an established engineering framework that determines failure management policies for any physical asset in its present operating context to maximize reliability based on the asset's function and criticality to the distribution system. The output of RCM consists of proactive tasks and associated time intervals in order to predict or prevent failures from occurring. Condition-based maintenance promotes the adjustment of maintenance frequencies based on the condition of a particular asset class as opposed to a strict frequency based approach.

1. Preventative Maintenance

This type of maintenance involves inspections and maintenance tasks on a fixed cycle, which emphasizes preserving asset performance over its expected life, and maintaining public and employee safety. Maintenance cycles are defined based on the mean time between failures of a given asset class, and are intended to maintain the asset before it is statistically likely to fail. An example of a preventative maintenance task is the inspection of wooden utility poles, which is carried out on a ten-year cycle. For additional information, refer to Exhibit 4A, Tab 2, Schedules 1-3.

2. Predictive Maintenance

Predictive maintenance involves the testing and inspection of equipment for predetermined conditions that are indicative of a potential failure, and then undertaking maintenance tasks to prevent those failures. Predictive maintenance is the most effective maintenance approach for those assets that exhibit conditions that can be identified, practically monitored, and corrected prior to failure. An example of a predictive maintenance task is Dissolved Gas Analysis of power transformer mineral oil, which identifies the presence of dissolved gases and other chemical compounds in the oil as an indication of potential failure modes (e.g. overheating, excessive moisture, or breakdown of the insulating paper). Corrective maintenance tasks can then be undertaken to correct the deficiencies to avoid equipment failure. For additional information, refer to Exhibit 4A, Tab 2, Schedules 1-3.

3. Corrective Maintenance

Corrective maintenance involves repairing or replacing equipment after a deficiency has been reported during the execution of preventative or predictive maintenance tasks or other planned work. These tasks typically involve a short planning horizon since a portion of the distribution system is faulted, isolated, or in a substandard condition thereby putting the system at risk. Since defective equipment is a major contributor to SAIFI and SAIDI, corrective maintenance emphasizes restoring

assets to an acceptable level of operation, thereby improving system reliability. Examples of corrective maintenance tasks included: (i) the replacement of a cracked porcelain insulator; (ii) the repair of a broken guy wire; (iii) the removal of vegetation growing on a pole and into an overhead line; or (iv) the replacement of a conductor splice. These actions are undertaken in response to line patrol findings (and infra-red inspections) as part of the Preventative and Predictive Maintenance programs (Exhibit 4A, Tab 2, Schedules 1-3).

Corrective maintenance can also be required as a result of an unplanned system event or emergency. For example, a faulted section of underground cable that had been isolated from the system during an emergency response would be unearthed and replaced as a corrective maintenance action. For additional information, refer to Exhibit 4A, Tab 2, Schedules 4-5.

4. Emergency Maintenance

Emergency maintenance involves the urgent repair or replacement of equipment that has failed or is in imminent danger of failure, in order to restore or maintain power. This type of maintenance may also involve an immediate response to a safety or environmental hazard. It emphasizes safe and prompt response to restore service or prevent a service disruption. An example of emergency maintenance would be restoration of service to customers that have lost power due to a broken tree branch on the overhead lines. Refer to Exhibit 4A, Tab 2, Schedule 5 for further information.

The details of how the asset inspections and capital and maintenance programs are related are summarized below as part of the deficiency capturing process in Figure 1.

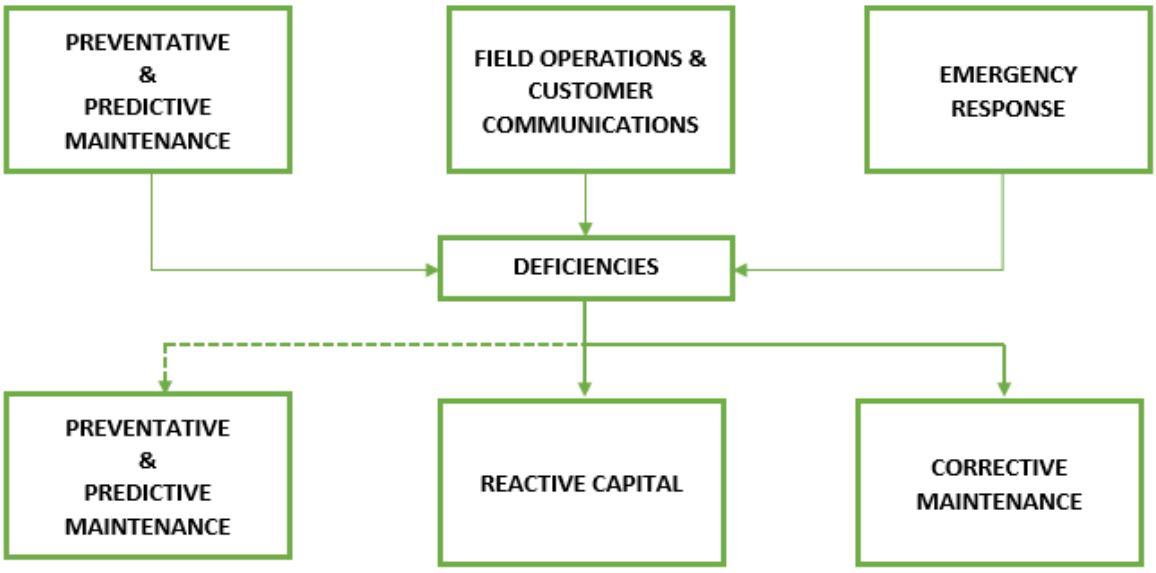


Figure 1: Deficiency Capturing Process

Distribution system events such as power outages are initially addressed through the Emergency Response program (Exhibit 4A, Tab 2, Schedule 5). The cost of any capital work (e.g. asset replacement) carried-out during an Emergency Response event is captured in the Reactive Capital segment (See Exhibit 2B, Section 6.7 Reactive and Corrective Capital program). An Emergency Response event can also result in follow-up work to be carried out via the Reactive Capital segment.

The more substantial source of Reactive and Corrective Capital work is the identification of asset failures and deficiencies through maintenance activities and daily utility operations, including:

- Toronto Hydro's Preventative and Predictive Maintenance programs systematically identify asset failures and priority deficiencies through regularly scheduled system maintenance activities. Through the "find it and fix it" practices, on-site repair of minor deficiencies is carried out. For more details on these programs, refer to Exhibit 4A, Tab 2, Schedules 1-3**.**
- Failures and deficiencies are also identified through daily field operations and customer contacts. These include observations by field crews and system operators during the normal course of operations, external emails, customer inquiries requiring field assessment and follow up including phone calls received from the customer service team, and meter errors captured through internal data collection systems.

These processes and activities can result in both capital and operating expenditures (e.g. corrective tree trimming). The Corrective Maintenance program (Exhibit 4A, Tab 2, Schedule 4) is the operational counterpart to the Reactive Capital segment.

Toronto Hydro has an established internal process for reviewing all work inquiries from these sources to validate the need for reactive intervention, assess the nature of reactive intervention required (i.e. capital versus maintenance), and the level of urgency/priority to be assigned to each item. Prioritization of the asset deficiencies identified as part of the work request process is based on the urgency of the work and how quickly it needs to be resolved. The work requests are classified into three categories (P1, P2, and P3) as discussed in Section D3.2.1.3 and illustrated in Figure 2:

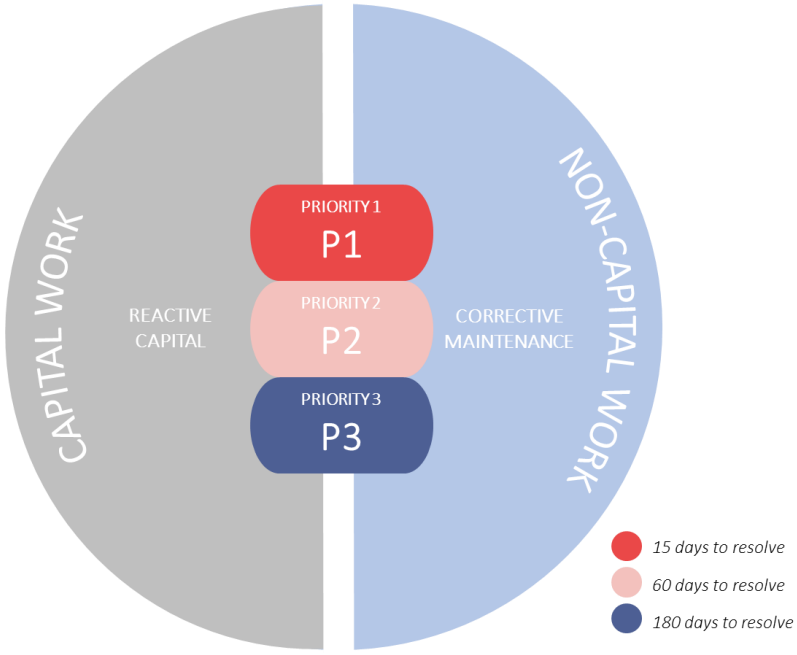


Figure 2: Work Request Prioritization

D3.1.1.3 Impact of System Renewal on Maintenance Planning

Toronto Hydro routinely assesses the impact of its system renewal investments on preventative and predictive maintenance plans. The directional relationship between asset replacement and planned maintenance is largely dependent on the maintenance requirements for the assets being removed and installed.

A significant portion of maintenance program expenditures is directed toward activities that are independent of system renewal programs, including: (i) routine maintenance to preserve asset performance over its expected life; (ii) vegetation management to maintain minimum clearance requirements for overhead conductors and equipment; (iii) cyclical patrols and inspections undertaken to comply with minimum requirements under the Distribution System Code; (iv) corrective maintenance activities to address deficiencies caused by material and equipment deterioration, and animals, pests, vegetation, and other environmental influences; and (v) emergency maintenance following severe weather and storm damage. Maintenance programs also provide the asset condition information necessary to plan system renewal programs.

Certain types of system renewal investments can reduce planned maintenance costs in specific circumstances. Generally, the removal of legacy and functionally obsolete assets from the system can eliminate the need for maintenance activities or higher maintenance frequencies that are specific to the legacy asset type. At the same time, new equipment and new standards and practices may introduce incremental maintenance requirements. The utility considers maintenance requirements when evaluating new products and developing new standards as part of its continuous Standards and Practices Review activities.

Toronto Hydro anticipates that system renewal programs targeting legacy assets such as vacuum circuit breakers, non-submersible network protectors, reverse power breakers, automatic transfer switches, porcelain insulators, and rear lot construction, will contribute to a gradual and modest reduction in costs related to legacy equipment maintenance as the population declines and the assets are replaced with equipment that typically requires lower maintenance costs or is maintenance free. System service programs such as Network Condition Monitoring and Control (Section E7.3) are also expected to contribute to modest reductions in the amount of on-the-ground maintenance required for the network system. Due to the overall age and condition of the system, remaining volume of obsolete legacy assets, and increasing pressure from adverse weather events, Toronto Hydro does not anticipate a decline in corrective maintenance, emergency maintenance, or reactive capital expenditures in the forecast period.

D3.1.1.4 Overview of Toronto Hydro's Refurbishment Practices

Both maintenance and refurbishment involve intervening on an asset to maintain or maximize its serviceability. Maintenance consists of activities that are necessary to ensure the reliable operation of an asset over its expected useful life. Refurbishment differs from maintenance in that it involves

renovating an asset to extend its serviceable life. For example, tree trimming is a form of maintenance, while rebuilding a vault roof is a form of refurbishment.

Toronto Hydro's refurbishment efforts are mainly focused on assets that have been taken out of service (e.g. through a renewal project or as a result of failure). An asset may be considered for refurbishment if it meets specific criteria and is in good enough condition to be reintroduced into the system after appropriate testing. This is done for major asset types like transformers, network protectors, and switches. Toronto Hydro evaluates major equipment returned from the field, and categorizes it based on the following criteria:

1) **Decommissioned equipment that remains operational:** Should a major asset such as a station power transformer be removed from the system as part of a system renewal project, or due to station decommissioning, Toronto Hydro will inspect and test the equipment to determine if it is still fit for service. If the equipment is still operational, the utility will keep it as a spare in case of reactive replacements.
2) **Repair of failed or defective equipment:** Equipment will be repaired or refurbished if it meets the following criteria: (i) it is under warranty; (ii) it is a critical spare (e.g. 4 kV assets); (iii) transformers less than 10 years old; (iv) network protectors less than 15 years old; (v) overhead switches less than five years old; or (vi) underground switches less than 15 years old. An example would be load conversion, where 4 kV equipment is removed from the system and replaced with the current standard. The removed assets are typically refurbished and kept as spares due to the scarcity of these obsolete asset types and in the event that other 4 kV assets on the system need to be replaced reactively.

Equipment that does not meet the specific criteria for re-use listed above will be scrapped.

Where appropriate, Toronto Hydro undertakes targeted refurbishments in the field to maximize the serviceable life of existing assets. For example, as mentioned above, the utility will rebuild a deteriorated vault roof, extending the useful life of the entire vault. Another example is the refurbishment of a particular line section by replacing legacy porcelain insulators with new polymeric equivalents.

D3.1.2 Asset Replacement Practices

The decision to replace an asset can result from many drivers, including asset failure, deterioration and failure risk, functional obsolescence, historical performance, standards alignment, planning and execution efficiencies, capacity requirements, and third-party requests.

Failure, failure risk, and functional obsolescence are the three most significant trigger drivers for asset replacement in the System Renewal investment category. Renewal-driven replacement practices for specific asset classes can range from primarily reactive replacement, where replacement largely occurs when the asset has failed (i.e. it can no longer serve its intended function), to primarily proactive replacement, where the consequence of failure for an asset class (i.e. the asset's criticality) is high, making it unacceptable to run the asset to failure under most circumstances.

While a few asset classes are situated at the far ends of the reactive-proactive spectrum, Toronto Hydro manages most major asset classes using a blend of reactive and proactive replacement strategies. This approach reflects how the risk profile and specific performance challenges within and across asset classes evolves over time, particularly in a large, dense, and congested city served by a variety of highly utilized systems inherited from several predecessor smaller utilities. It also reflects variability in the location-specific criticality of individual assets across the system. The proportion of assets the utility replaces proactively is related to the utility's performance objectives and the risk assessments underlying projected performance.

Tables 2 to 6 below provide an overview of Toronto Hydro's current replacement practices for assets on each part of the distribution system.

1 **Table 2: Summary of Overhead System Asset Replacement Practices**

Asset	Asset Replacement Practices
Poles	Toronto Hydro manages the risk profile of its pole population by proactively replacing poles in alignment with condition demographics and other risk factors (e.g. legacy asset replacement needs). Poles are replaced on an individual basis or as part of area rebuilds. Poles are prioritized for replacement based on condition, age, criticality, and relationship (e.g. proximity) to other high-risk assets. In the event poles fail while in service, Toronto Hydro replaces them reactively. Due to the urban environment in which the Toronto Hydro operates, the utility has a very low risk appetite for catastrophic pole failure (i.e. collapse of pole) and designs its pole testing, inspection and reactive replacement programs to substantially mitigate this risk.
Pole-top Transformers	Toronto Hydro manages the risk profile of its pole-top transformer population through proactive and reactive replacement. The utility prioritizes transformers that present heightened failure risks based on condition, age, area reliability, and environmental risks (e.g. oil leaks containing polychlorinated biphenyls ("PCBs")). Due to the low individual criticality of a typical, PCB-free pole-top transformer, Toronto Hydro will generally replace these assets reactively or as part of a larger proactive area rebuild project when there are economies of scale. As noted in Sections D2 and E2, Toronto Hydro is forecasting a greater rate of proactive pole-top transformer replacement in 2020-2024 due to demographic failure risks (i.e. significant age backlog) and PCB oil spill risk for units manufactured in 1985 and earlier.
Overhead Switches	Toronto Hydro does not have a dedicated proactive renewal strategy for overhead switches. Where appropriate, switches are replaced as part of a planned area rebuild, or else reactively upon failure due to age, condition, or external factors. Where safety risks are identified for a type or class of switches, the utility executes planned replacements of these assets to mitigate the risks.

Asset	Asset Replacement Practices
Overhead Conductors (primary and secondary)	Toronto Hydro does not have a dedicated proactive renewal strategy for overhead conductors. Where appropriate, conductors are replaced as part of a planned area rebuild (e.g. upgrade to tree-proof conductor in heavily treed areas) or reactively upon failure due to age, condition, or external factors.

1 **Table 3: Summary of Underground System Asset Replacement Practices**

Asset	Asset Replacement Practices
Underground Cables (Polyethylene)	Toronto Hydro manages the risk profile of its underground cable population by both proactively and reactively replacing polyethylene (e.g. cross-linked polyethylene ("XLPE")) cables. The utility proactively replaces aged or poor performing cables through neighbourhood rebuild projects to manage significant reliability risks associated with these assets, mainly targeting poor performing direct-buried cables in the Horseshoe area. Otherwise, if these cables fail while in service, they are repaired or replaced reactively.
Underground Cables (Lead)	Underground lead cables have traditionally been replaced reactively on the downtown underground distribution system. With increasing reliability, safety, and operational risks associated with lead cable (i.e. leaking cables, congested cable chambers, increasing numbers of splices, dwindling supply and expertise), Toronto Hydro is shifting from a reactive repair and replacement strategy to a proactive strategy to gradually remove the large population of deteriorating and obsolete cable types, replacing them with modern polyethylene cables. The utility prioritizes cable replacement based on a predictive risk model. Aside from the modest proactive investments that are planned for the 2020-2024 period, these cables are repaired or replaced reactively when they fail while in service.
Underground switches	Toronto Hydro manages the risk profile of underground switches by proactively replacing them through neighbourhood rebuild projects (triggered by direct-buried cable replacement priorities), taking into consideration age, condition, and failure impact. Otherwise, switches that fail while in service are replaced reactively.

Asset	Asset Replacement Practices
Underground Transformers	Toronto Hydro manages the risk profile of its underground transformer population through proactive and reactive replacement. Underground transformers are replaced as part of planned area rebuilds (triggered by direct-buried cable replacement needs) or on an individual basis if they pose an environmental risk due to the risk of leaking oil containing PCBs and are at or past their useful life and/or in deteriorating condition. Otherwise, transformers that fail while in service are replaced reactively.
Cable Chamber	Toronto Hydro manages the risk profile of its underground cable chambers by proactively replacing assets based on condition. Historically, Toronto Hydro has replaced cable chambers reactively. However, due to the growing number of deteriorating chambers and the complexity of chamber reconstruction work, the utility is shifting to a planned renewal strategy to replace cable chambers (or rebuild cable chamber roofs) in end of serviceable life condition. Otherwise, cable chambers that fail while in service are addressed reactively.
Underground Residential Distribution ("URD")	Toronto Hydro manages the reliability performance for customers served by the URD system by proactively replacing URD assets. Toronto Hydro targets critical and obsolete URD assets in deteriorating and poor condition or past their useful life such as switching and non-switching vaults, switches, and transformers that contribute to the deterioration of system reliability. Otherwise, assets that fail while in-service are replaced reactively.

1 **Table 4: Summary of Network System Asset Replacement Practices**

Asset	Asset Replacement Practices
Network Automatic Transfer Switches ("ATS") and Reverse Power Breakers ("RPB")	Toronto Hydro reduces safety and reliability risks on the network system by proactively removing functionally obsolete ATS and RPB equipment. Toronto Hydro is replacing them with standard equipment at a pace expected to eliminate them completely during the 2020-2024 period. Otherwise, assets that fail while in service are replaced reactively.

Asset	Asset Replacement Practices
Network Units	Toronto Hydro manages the risk profile of its network unit population by proactively replacing units in alignment with condition demographics and other risk factors (e.g. safety and environmental risks). The utility proactively replaces network units with a higher risk of failure due to age, condition, obsolescence, or location (i.e. prone to flooding). Older units with obsolete "non-submersible" protectors, which make them susceptible to water ingress causing failure, are generally beyond their useful life and are at risk of leaking oil containing PCBs. The utility is aiming to reduce and eventually eliminate the population of non-submersible units due to increasing risks of flooding. Otherwise, units that fail while in service are replaced reactively.
Network Vaults	Toronto Hydro manages the risk profile of its network vault population by proactively replacing vaults or vault roofs in alignment with condition demographics and other risk factors (e.g. safety risks). Due to the complexity of vault rebuild projects, Toronto Hydro must maintain a steady pace of renewal targeting the worst condition locations. Vaults are prioritized primarily based on condition and the associated safety risks of structural deterioration, customers served, and external factors (i.e. road moratoriums). If a deteriorated vault is no longer needed due to load displacement, then the utility will decommission it. Otherwise, vaults that fail while in service are addressed reactively.
Network Cables	See Underground cables – polyethylene and lead.

1 **Table 5: Summary of Stations Asset Replacement Practices**

Asset	Asset Replacement Practices
Transformer Station ("TS") Switchgear	Toronto Hydro manages the risk profile of its TS switchgear population by proactively replacing assets to manage overall switchgear demographic risk and system reliability. Given the high criticality of these assets, the utility has a low risk appetite for reactive replacement. Existing units are often difficult and infeasible to safely maintain due to their design, and therefore, proactive replacement is preferred to resolve maintenance issues. Asset replacements need to be done proactively as they have long lead times to procure (e.g. 12-18 months), and design and construct (e.g. 3-4 years). Replacement prioritization is dependent on various factors, including: age, breaker condition, obsolescence, and safety. These assets can fail while in service, and in such situations, customers may experience long outages while Toronto Hydro restores power and subsequent reactively repairs or replaces the failed switchgear.
TS Oil Circuit Breakers (KSO)	Toronto Hydro manages the risk profile of its TS oil circuit breaker population by proactively replacing assets. Given the high criticality of these assets, the utility has a low risk appetite for reactive replacement. Asset replacements need to be done proactively as they have long lead times. Toronto Hydro replaces TS KSO oil circuit breakers based on age, condition, obsolescence, and safety and environmental risks (i.e. oil containing PCBs). Otherwise, assets are replaced reactively when they fail while in service.
Municipal Station ("MS") Switchgear	Toronto Hydro manages the risk profile of its MS switchgear population by proactively replacing them. Given the high criticality of these assets, the utility has a low risk appetite for reactive replacement. Asset replacements need to be done proactively due to long lead times. Existing units are often difficult and infeasible to safely maintain due to their design, and therefore, proactive replacement is preferred to resolve maintenance issues. Toronto Hydro replaces MS switchgear based on age, breaker condition assessment results, the obsolescence of the asset, and the safety and reliability risks they present. When these assets fail while in service, Toronto Hydro will first attempt to repair the unit, but depending on the severity of the fault, may replace it reactively.

Asset	Asset Replacement Practices
MS Primary Supply	MS primary supply assets (disconnect switches, cables, and circuit breakers) are proactively replaced to maintain overall condition demographics and reliability. MS primary supply assets are replaced proactively as part of MS power transformer replacement projects and may be included as part of a switchgear replacement projects. For 2020-2024, Toronto Hydro plans to target some MSs (i.e. not planned for decommissioning or transformer or switchgear replacement) for primary supply replacement as well. Prior to 2018, power transformer replacements were typically completed without replacing MS primary supply as these assets were generally replaced reactively. This change in strategy is due to many assets operating beyond their useful life and the time of required replacement. MSs targeted for primary supply replacement are prioritized based on failure risk as determined by age and configuration (e.g. direct-buried cable).
Power Transformers	Toronto Hydro manages the risk profile of its power transformers by proactively replacing assets to manage overall demographic risk and system reliability. Power transformers require long lead times (e.g. 12 months) to procure, design and construct and therefore need to be replaced as part of a steady proactive renewal program. These assets are prioritized based on age and condition.
Station Service Transformers ("SSTs")	Toronto Hydro replaces SSTs proactively to manage age demographics and maintain reliability on the system. Asset replacement also requires long lead times and as a result, needs to be done proactively. Units are prioritized based on their age and associated environmental risk (i.e. risk of oil containing PCBs). Once these assets fail in service, the station service supply cannot afford to experience a subsequent failure as that failure would render the station inoperable. Moreover, any planned renewal or maintenance work of ancillary systems may be delayed.
Remote Terminal Units ("RTUs")	Toronto Hydro replaces functionally obsolete RTUs proactively as they are beyond their useful life, and no longer supported by their manufacturers. These assets can be repaired within a two-week period, however, repairs cannot be maintained over the long term due to the scarcity of spare parts. These assets also have a long replacement time (e.g. 6 months) and are therefore difficult to replace reactively.

Asset	Asset Replacement Practices
Pilot-wire Relays & Copper Communication Cable	Toronto Hydro replaces these assets proactively to maintain overall condition demographics and reliability. Pilot-wire relays and copper communication cables are replaced proactively as these assets are functionally obsolete, and are no longer produced or supported by the manufacturer (i.e. lack of spare parts) making it difficult to maintain and repair the asset. Copper communication cables are also experiencing increasing failures which have severe consequences on the system, including the loss of remote control and monitoring of the station, protection for MSs, and security systems. Both assets require long lead times to procure, design, and construct the replacement units regardless of whether the replacement is proactive or reactive. As such, they are prioritized based on the reliability risks they present to the system and large customers.
Direct Current ("DC") Battery Systems	Toronto Hydro replaces and maintains DC battery systems to ensure they can supply power to the station for eight hours (as mandated by the Transmission System Code). Replacement of the assets is prioritised based on functional obsolescence, age, and condition of the asset.

1 **Table 6: Summary of Metering Asset Replacement Practices**

Asset	Asset Replacement Practices
Meters	Toronto Hydro replaces meters proactively at or beyond the end of their useful life to manage risk of failure and customer billing interruptions. Meters are replaced reactively if they fail to read or communicate or suffer complete failure.

D3.2 Asset Lifecycle Risk Management Policies and Practices

Customer-focused outcome measures such as system reliability, safety incidents, connections efficiency, and oil spills are lagging indicators of system performance. These measures are essential to understanding the actual experience of customers, stakeholders, employees, and the general public in relation to the distribution system. However, certain lagging measures, by their nature, can be difficult to directly influence through actions taken in the near-term. This is especially true for measures that are influenced by asset failure. Toronto Hydro manages hundreds of thousands of distribution assets that are typically in service for decades. These asset can fail in a variety of ways at any point in their lifespan, and it is impossible to know with precision exactly when failure will occur. Therefore, in the daily effort to direct expenditures toward cost-effective interventions that will drive performance outcomes, Toronto Hydro must rely on risk – a leading indicator of performance – to make informed investment decisions.

As a large urban utility with a highly utilized system and a significant asset renewal need, risk assessment is essential to ensuring that system reliability and other outcomes can be maintained with a constrained expenditure plan.

This section outlines Toronto Hydro's lifecycle risk management methods and practices for its distribution assets, detailing the utility's risk assessment frameworks, including key considerations in risk evaluation, and typical risk mitigation approaches. Capacity related risk is discussed separately in Section D3.3.

D3.2.1 Overview of Risk Assessment Methods

Toronto Hydro's risk assessment framework consists of the following key elements:

- Probability of Failure;
- Consequence of Failure; and
- Risk Analysis.

Details of each key element follows.

D3.2.1.1 Probability of Failure

Probability (i.e. likelihood) of failure is an important consideration in determining whether asset intervention is necessary. This section focuses upon two key forms of analytics that are utilized to

enable Probability of Failure evaluation: (i) Asset Condition Assessment ("ACA"); and (ii) predictive failure modelling.

1. Asset Condition Assessment (ACA)

As explained in Section D1 and in Appendix C to Section D, Toronto Hydro employs an ACA methodology to monitor the condition of various key asset classes within its system and produce a health index ("HI") score to support project planning. The ACA allows Toronto Hydro to use data collected data through inspections to produce a numerical representation of an asset's condition, taking into account key factors that affect its operation, degradation, and lifecycle. Toronto Hydro uses ACA to support tactical and strategic investment planning decisions. Planners use inspection data and individual HI scores – in combination with other information and professional judgement – to prioritize assets for tactical intervention in the short- to medium-term. This includes identifying priority deficiencies that require reactive or corrective action, and prioritizing assets for planned renewal projects in a given budget period. At a strategic level, Toronto Hydro uses ACA results to examine condition demographics and trends within major asset classes to support the development of longer-term investment plans within the annual Investment Planning & Portfolio Reporting ("IPPR") Process.

As part of the efforts to continually improve its asset management and decision-making framework, Toronto Hydro worked with EA Technology to develop new asset health models based upon the Common Network Asset Indices Methodology ("CNAIM"). CNAIM is the approach used by distribution network operators in the United Kingdom to report asset health as part of their regulatory reporting requirement. Toronto Hydro has used the outputs from this CNAIM-based model to support an advanced condition-based approach for planning and evaluating strategic capital investments. Toronto Hydro has provided additional details on the new ACA methodology in Appendix C to Section D of the DSP.

The approach used to develop the HI for each asset is illustrated in Figure 3.

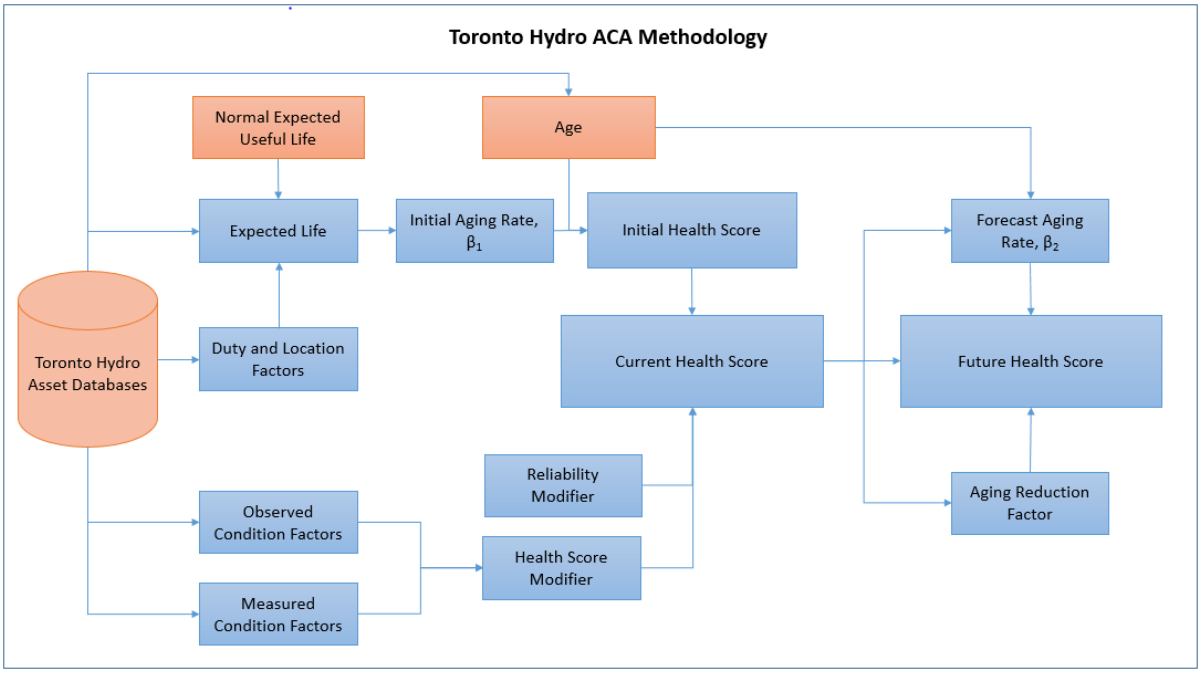


Figure 3: Asset Condition Assessment Process as Part of ACA

ACA results for a particular asset class are grouped into five HI bands that represent key stages of an asset's lifecycle, ranging from new or like new condition to the stage where asset degradation is significant enough to warrant urgent attention. Toronto Hydro uses asset HI demographics during the scope development phase of IPPR, as outlined in Section D1. It enables planners to assess the relative probability of failure of their assets in the short and mid-term timeframe based on the HI band. The bands are defined as per Table 7 below.

Table 7: Health Index bands and definitions

Band	Lower Limit of Health Score	Upper Limit of Health Score	Definition
HI1	≥ 0.5	< 4	New or good condition
HI2	≥ 4	< 5.5	Minor deterioration; in serviceable condition
HI3	≥ 5.5	< 6.5	Moderate deterioration; requires assessment and monitoring
HI4	≥ 6.5	< 8	Material deterioration; consider intervention
HI5	≥ 8	≤ 10	End of serviceable life; intervention required

Examples of asset classes with HI scores are shown in Table 8 below.

Table 8: Assets Evaluated in the ACA Program

Switches	Breakers	Vaults	Transformers	Other
• Overhead Gang-Operated • SCADA-Mate • Air-Insulated Padmount • SF_6-Insulated Padmount • SF_6-Insulated Submersible • Air-Insulated Submersible	• 4 kV Oil Circuit (MS) • KSO Oil Circuit (TS) • SF6 Circuit (TS) • Vacuum Circuit (MS & TS) • Air Magnetic Circuit (MS & TS) • Airblast Circuit (MS & TS)	• ATS • CLD • CRD • Network • Submersible Switch • URD	• Station Power • Network • Submersible • Vault • Padmount	• Wood Poles • Network Protectors • Cable Chambers

The ACA output is essential in two respects. First, the ACA produces a relative outlook of the population's condition for each individual asset class within the program. Second, the ACA program highlights trends in the condition of asset classes. These trends can highlight issues that are specific to particular asset classes or subtypes such as manufacturing defects, or design practices. For system planners, these insights along with the health band of an asset provide an indication of the probability of failure for an asset. Being aware of these issues and trends allows Toronto Hydro to balance capital investments against continuing maintenance. More generally, the ability to compare current and future health index results for an asset class can support decision-making when developing expenditure plan envelopes for longer-term investment programs. In its 2020-2024 DSP, Toronto Hydro has used this information to compare proposed investment levels against current and projected volumes of assets in the two worst health bands ("HI4") and ("HI5"). For more information, refer to Section E2.

For more information on Toronto Hydro's ACA approach, refer to Appendix C to Section D.

2. Predictive Failure Modelling

Predictive failure modelling represents the other essential component of the Probability of Failure analysis. It involves the derivation of hazard rate functions for each asset class – also referred to as the assets' probability of failure. In this case, an asset's age is used as an input into the hazard rate calculation in order to produce the conditional probability of an asset failing based on the remaining population that has survived up until that time. The results from these failure curves provide insights

into the expected failure rates of assets, which is critical information for determining the investments required to manage assets over the medium term.

Toronto Hydro's hazard rate distribution functions were each calibrated to a useful life value. Toronto Hydro's useful life values are also used separately as part of the Assets Past Useful Life ("APUL") calculation, in order to assess the demographics of assets, especially those approaching or past their useful life. Toronto Hydro utilizes this information to ascertain the upcoming "asset walls" and investment requirements that will emerge over a long-term period, and better equip its planners to make informed investment decisions and develop effective plans based on the needs of the system.

The aggregate information extracted from predictive failure modelling combined with the APUL calculation can be used as an input in determining the levels of expenditures required for managing each asset type. The predictive failure modelling procedure is also used as part of the economic risk-based analysis and reliability projection procedures, which are further discussed in Section D3.2.1.3.

3. Historical Reliability Analysis

The last component of Toronto Hydro's probability of failure analysis involves the analysis of historical reliability data from the Interruption Tracking Information System ("ITIS"), in order to identify assets with a high frequency of failure.

ITIS is used to store historical outage information which Toronto Hydro uses as a key tool in developing capital spending. By continuously analyzing the reliability performance of its circuits and substation assets, Toronto Hydro is able to identify areas experiencing reliability issues, which may be caused by asset deterioration or legacy design related issues. Toronto Hydro utilizes the following ten major cause codes to classify historical outages within ITIS:

- Adverse Environment;
- Adverse Weather;
- Defective Equipment;
- Foreign Interference;
- Human Element;
- Lightning;
- Loss of Supply;
- Scheduled Outages;

- Tree Contacts; and
- Unknown.

From a Probability of Failure perspective, the data contained within ITIS can be used to identify those asset classes and sub-classes, as well as parts of the system that experience a high frequency of failure. As an example, ITIS data has been utilized as part of Toronto Hydro's planning procedures to identify feeders containing the most problematic direct-buried underground cables.

D3.2.1.2 Consequences of Failure

When determining the risk of asset failure, there are two components considered; the probability (explained in Section D3.2.1.1) as well as the consequences and impacts of failure, which go into to the specific failure modes and effects associated with those failure modes. These consequences are generally broken down into key categories that generally align with Toronto Hydro's outcomes framework (i.e. customer service, reliability, environment, safety, and financial impacts).

1. Customer and Reliability

Derivation of the customer or reliability impacts is undertaken through a number of tools and approaches, including:

- Customer engagement and consultation activities;
- Key account customer program and responses to customer calls and complaints;
- Reliability analysis identifying long-duration impacts; and
- Application of customer interruption costs.

Table 9 provides additional information related to each of the aforementioned tools and approaches.

1 **Table 9: Summary information related to Customer and Reliability Tools and Approaches**

Tool or Approach	Summary
Customer engagement and consultation activities	Toronto Hydro executes a variety of customer engagement programs designed to establish interactions with customers and provide necessary details related to capital and maintenance plans, including the following: a) Town hall meetings in specific districts or parts of the city to communicate investment plans or proposed projects and execution strategies; b) Ward or neighbourhood outreach activities where city councillors are provided necessary information from Toronto Hydro in regards to major investments and issues being mitigated within their respective communities; and c) A customer-focused power quality program in which Toronto Hydro monitors and investigates power quality issues for customers.
Key account customer program	Toronto Hydro manages a key account customer program for large commercial and industrial customers to address specific concerns and issues. Additionally, any specific customer concerns or complaints captured through Toronto Hydro's call centre are directed to engineers, asset planners, and managers within the Engineering (and Asset Management) group to investigate and determine whether projects already exist to address the concerns or if new projects (and additional actions) are required.
Reliability analysis identifying long-duration impacts	As explained above in Section D3.2.1.1, Toronto Hydro utilizes its ITIS system to gather historical reliability data across the distribution system for the purposes of performing reliability-driven analyses. For example, ITIS is relied upon for insight into the number of customers affected by outage events in the system and the duration of each event. From a consequences of failure perspective, this information is used to identify typical outage duration impacts within the system, and to plan and prioritize projects as illustrated in programs such as Area Conversions (Exhibit 2B, Section E6.1) and Underground System Renewal – Horseshoe (Exhibit 2B, Section E6.2). Given Toronto Hydro's reliance on the functionality that ITIS provides, Toronto Hydro is investing in this functionality as part of its upgrade of the existing Outage Management System with a new Network Management System ("NMS"). Toronto Hydro expects that this investment will provide more robust data and enable greater insights. These upgrades are expected to be completed in the period 2018-2020.

Tool or Approach	Summary
Application of customer interruption costs	Toronto Hydro utilizes customer interruption costs ("CICs") which represent a measure of monetary losses for customers due to an interruption of electric service. CIC values are calculated in two parts: the Event cost and the Duration cost. The Event cost represents the impact to customers due to the occurrence of the outage whereas the Duration cost represents the costs incurred as the length of the outage increases. Toronto Hydro currently adopts $30 per kVA (peak load) as the Event cost to represent the CIC value due to the initial period of the outage, and $15 per kVA (peak load) per hour to represent the CIC value due to the increasing duration of the outage. Toronto Hydro continues to enhance these values by directly surveying customers to understand their valuation of interruption costs. These CICs are used as input within the economic risk-based analysis as described in Section D3.2.1.3. As part of this analysis, the CICs are paired with customer impact information, including the associated customer load that will experience an interruption should the evaluated asset fail. This customer impact information includes the identification of the upstream protective device that will contain the fault, as well as the customer loading impacts, which are derived from the peak load of the downstream transformers. Collectively, this information is used to quantify the full customer impact of failure for each evaluated asset within the system.

2. Environment

Toronto Hydro takes all reasonable actions to reduce the risk of asset failures resulting in adverse effects to the environment as well as safety incidents to its employees, customers and the public. In the case of equipment failure, environmental impact, and potential non-compliance or breach of regulatory obligations may result. Toronto Hydro's major environmental concerns include: (i) oil leaks of all types; (ii) reducing greenhouse gas emissions; and (iii) the use of substances like asbestos, lead, and PCBs in its equipment.

Through planned asset inspections, oil deficiencies in the system are identified and necessary corrective action is taken. Toronto Hydro is continuously striving to mitigate environmental risks such as the risk of oil spills, while simultaneously ensuring compliance with federal, provincial, and municipal regulations pertaining to the release of oil into the environment. Similarly, through inspection and renewal programs, assets containing lead, asbestos, and PCBs are identified and proposed for replacement with standardized and less harmful equipment.

3. Safety

Mitigating safety risks to Toronto Hydro employees and its customers is the highest priority objective of Toronto Hydro's AM process. As highlighted in Section E2.3, customers consider the safety of the system to be a default priority for the utility. Toronto Hydro continues to strive for zero public and employee safety incidents each year.

Nearly all of the utility's asset renewal, service, and maintenance activities are driven in part (and sometime entirely) by safety considerations. For example, Toronto Hydro's programs to reduce and eliminate obsolete legacy equipment and configurations are driven in large part by known safety risks and related operational restrictions. Examples of these activities include:

- Eliminating safety risks related to Electrical Utility Safety Rules ("EUSR") compliance issues associated with legacy box construction configurations; and
- Reducing public and employee exposure to safety risks as a result of outages in rear lot configurations.

Toronto Hydro's Environmental, Health and Safety ("EHS") and Standards functions, funded by the Human Resources and Safety program (Exhibit 4A, Tab 2, Schedule 15) and the Asset and Program Management program (Exhibit 4A, Tab 2, Schedule 9), have important roles in maintaining safe work practices, implementing engineering controls, and adhering to requirements related to environmental protection and occupational health and safety. In the event of an incident relating to asset failure(s) where there is an environmental or safety risk, staff responsible for the aforementioned functions (i.e. EHS and Standards) will investigate to determine the defect in the equipment. EHS bulletins will be released for immediate notification of potential workplace hazards, accidents, injuries, near misses, environmental issues, and important information regarding accident prevention. If applicable, a new standard for a replacement product will be developed.

If the defective equipment poses a significant risk to the system, a capital or maintenance program would be proposed to replace the asset with a new standardized equipment. This was the case in the 2015-2019 CIR Programs of SCADA-Mate R1 Switch Renewal, Handwell Upgrades, and Polymer SMD-20 Switch Renewal. Within this application the Contact Voltage Scanning Segment under Preventative and Predictive Underground Line Maintenance (Exhibit 4A, Tab 2, Schedule 2) addresses the scanning of the distribution system for contact voltage to reduce risk of public exposure to contact voltage from energized surfaces and structures.

4. Public Policy

In addition to addressing customer reliability, environmental, and safety concerns, Toronto Hydro must remain compliant with public policies and regulations. Through its renewal programs and consistent with the Ontario Long-Term Energy Plan, Toronto Hydro is investing in asset designs that are more resilient to changes in weather and climate such as the use of submersible network protectors to tolerate flooding. Additionally, implementing demand response programs reduces the strain on Toronto Hydro distribution assets and as such reduces failure risk.

Certain circumstances or asset failures carry with them the risk of putting Toronto Hydro in violation of public policies. Some relevant public policies include:

- Managing asbestos as per the *Ontario Occupational Health and Safety Act* as well as the *Canadian Environmental Protection Act* to eliminate and phase out asbestos;
- Reducing the risk of PCB leakage into the environment and eliminating all PCB containing equipment greater than 50 ppm to comply with PCB Regulations as defined in the *Canadian Environmental Protection Act*, SOR/2008-273 and in the City of Toronto *Municipal Code,* Chapter 681 – Sewers; and
- Ensuring compliance with *Ontario Regulation* 22/4 and safety performance as measured through the Serious Electrical Incidents Index.

5. Financial

Some of the consequences of asset failure discussed above can also have significant financial impacts for Toronto Hydro. Asset failure can cause outages disrupting the normal operations of businesses (leading to monetary losses as represented by CICs discussed in Table 9 above), damage the surrounding area (e.g. through oil spills), and create safety risks. These can increase the risk of Toronto Hydro incurring additional costs for environmental remediation, fines, and legal costs in the form of claims and resulting litigation. The potential financial impacts of failure differ depending on the nature of the failure and from asset to asset because assets operate under varying conditions and loadings.

D3.2.1.3 Risk Analysis

The probability and consequence inputs, as identified in Sections D3.2.1.1 and D3.2.1.2 respectively, are used either individually, or in combination as part of analyses prior to arriving at risk-based

decisions related to long-term and short-term asset management plans and investments. The risk of failure may be determined by using a combination of qualitative and quantitative methods. Various risk-based tools are utilized to provide multi-faceted perspectives that support and ultimately justify investment decisions.

The following subsections provide insight into the various risk-based decision-making tools that are used at Toronto Hydro.

1. Economic Risk-Based Analysis

Toronto Hydro's economic risk-based analysis methodology supports the utility's engineering assessment of system intervention and design alternatives. This methodology calculates an economic end-of-life for each asset by balancing the increasing risk of asset failure against the necessary investment costs that must be incurred in order to mitigate these risks. Toronto Hydro leverages the Feeder Investment Model ("FIM") tool to produce these calculations. Key input data includes results from Predictive Failure Modelling described in Section D3.2.1.1, and quantified reliability impacts to customers (i.e. customer interruption costs).

The FIM also stores the financial costs to the utility for replacing the evaluated assets should they fail within the system, along with the typical failure modes associated with the asset in question. From these parameters, an annualized risk cost and an annualized capital cost can be derived for the new asset to be installed, and a life-cycle cost established based upon a sum total of these two components. The lowest life-cycle cost of the new asset – or the Equivalent Annual Cost ("EAC") – may be compared to the risk cost of the existing asset to identify the economic end-of-life for the existing asset. This is further illustrated in Figure 2.

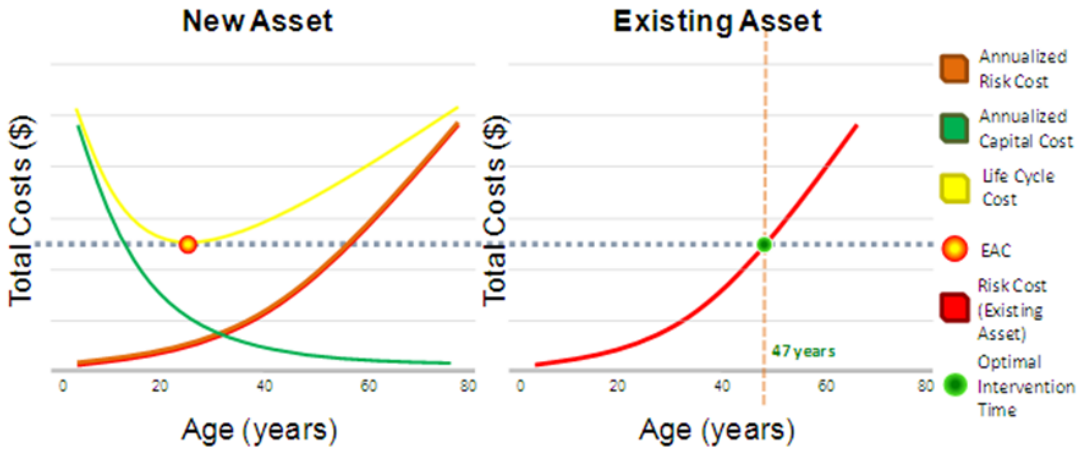


Figure 4: Typical Example of Establishing the Optimal Intervention Time for an Existing Asset

Figure 4 illustrates that past the point of the lowest life-cycle cost (i.e. EAC), it becomes more expensive to continue to operate the existing asset, when taking into consideration both financial impacts to the utility as well as socioeconomic impacts (including those relating to customer and reliability, safety, and environmental impacts). The economic end-of-life results from this analysis are mainly used to evaluate the net benefits of asset intervention alternatives.

2. Reliability Projections

In order to conceptualize the impact of investment programs, Toronto Hydro performs an analysis of historical system reliability and produces a reliability projection ("RP"). The RP provides a risk-based view utilizing the major reliability indices (e.g. SAIFI, SAIDI) and enables informed decision making for capital investments. The RP is based upon:

a) asset demographics data;
b) historical reliability performance; and
c) planned program investments.

The system historical reliability category is broken into individual cause codes and in some cases (e.g. defective equipment) down to the asset level.

As part of the RP process, a reactive replacement scenario is produced, to estimate the performance of the current system without proactive intervention. The scenario depicts what is expected if assets remain in service and naturally reach end-of-life. Asset failures increase as they are operated beyond

useful life, contributing to worsening reliability. This provides a reliability centric risk view for Toronto Hydro.

In addition to the reactive replacement approach, Toronto Hydro produces program scenarios to project the reliability impact of the investment programs on the system. This is determined by reviewing each planned program for reliability benefits, improved operational flexibility, and influences on asset demographics. The program benefits are applied to the individual outage cause codes (listed above in section D3.2.1.1) based on their level of impact on reliability. The results are then aggregated to the system level to obtain the final system-wide reliability projections. RP analysis and results used in the development of the capital expenditure plan are discussed in Section E2.2.2.3.

In general, this conceptual analysis is used by Toronto Hydro to evaluate reliability impact of the proposed capital expenditure plan. It should be noted that this projection does not consider major event days, nor the lasting impacts that major weather events can have on asset performance in future years.

3. Worst Performing Feeder ("WPF")

Toronto Hydro assesses the overall performance of the system in order to improve service reliability for customers supplied by poorly performing feeders. The utility identifies feeders at risk of experiencing seven or more sustained interruptions ("FESI-7") each year (or over a 12-month rolling period). Once the feeder and the root cause of its failures have been identified, mitigation work on these feeders is conducted so that the risk of additional interruptions to customers can be mitigated. In addition to the FESI-7 metric, Toronto Hydro has introduced a FESI-6 metric that identifies at-risk feeders serving Large Commercial & Industrial class customers within the distribution system. Additional details related to these measures, which are in place to improve reliability and meet the needs of customers, may be found in Exhibit 2B, Section C.

The WPFs in the system are typically addressed through a combination of short-term intervention (both capital and maintenance) and complementary planned renewal work. As a result of investments to improve the reliability of these feeders, sustained improvements have been achieved as illustrated in Section C.

For more detail on the work proposed as part of WPF investments, refer to Exhibit 2B, Section E6.7.

4. Enterprise Risk Management

Toronto Hydro considers a broad range of risks that the corporation faces through the Enterprise Risk Management ("ERM") process. Toronto Hydro's ERM framework has been designed to manage risks at the corporate level, and considers the risks facing individual asset classes and risks relevant to investment programs.

Toronto Hydro continuously works to identify and manage corporate risks that emerge from the asset base, and create new programs to manage these risks when prudent to do so. For example, various risks have been analyzed and managed using the ERM framework including risks posed by direct-buried cables, porcelain insulators, cable chamber lids, and secondary cables. The ERM framework groups such risk under categories such as "asset integrity risk" or "public safety risk". The ERM framework and the analytical results derived from the ERM process serve as another input into Toronto Hydro's overall risk assessment and management procedure. This input is available and updated regularly for monthly and annual tracking of risk mitigation measures while providing visibility into broader corporate risks.

5. Defective Equipment Tracking and Priority Deficiencies

When defective equipment is found, either through a planned inspection or following emergency response, Toronto Hydro applies a risk framework to help prioritize repairs and corrective actions. In addition, the framework, which is referred to as Defective Equipment Tracking System ("DETS"), is useful for assessing risk trends related to both particular asset classes and the system overall.

The DETS framework utilizes information about defective equipment to assign a score, which reflects the following criteria:

- **Impact**: number of customers impacted by the defective equipment incident;
- **Contingency**: what is the criticality of the equipment and are there any contingency options; and
- **Restoration**: the estimated restoration time to the customers.

Each criteria is assigned individual scores and when combined for a particular piece of equipment, could reach a maximum of 1,000. Once scored, a piece of defective equipment is then prioritized for corrective work as part of Toronto Hydro deficiency prioritization process that is used for all

deficiencies identified during the course of utility operations (and not just defective equipment deficiencies). That process has three categories of priorities:

- **P1**, requiring a resolution within 15 days;
- **P2**, requiring a resolution within 60 days; and
- **P3**, requiring a resolution within 180 days.

A P1 is assigned to defective equipment that has a DETS score greater than 100 and a P2 is assigned to defective equipment that has a score less than 100. Analysis of the DETS scores and the volumes of priority deficiencies provides Toronto Hydro with another layer of risk modelling and inputs for risk management.

For additional details related to deficiencies, defective equipment, and prioritized reactive and corrective actions, please see the Reactive and Corrective Capital (Exhibit 2B, Section E6.7), Corrective Maintenance (Exhibit 4A, Tab 2, Schedule 4), and Emergency Response (Exhibit 4A, Tab 2, Schedule 5) programs.

6. Legacy Assets

Toronto Hydro's risk assessment frameworks include inventories of legacy assets and configurations that have been identified based on various factors (e.g. their likelihood of failure and resulting impact on system reliability, safety, or the environment). These assets and configurations are also typically functionally obsolete with limited or no support from manufacturers or third party service providers. Toronto Hydro monitors these legacy assets to manage and minimize their associated risks to customers, employees, and the public. The utility evaluates legacy asset risk and performance over time, adjusting investment plans over the short-, medium- and long-term to ensure the risks are being addressed at an appropriate and feasible pace. The reduction or elimination of these assets and the associated risks was a major contributing factor when developing the investment plans outlined in Section E of the DSP. For more information on Toronto Hydro's legacy assets, please refer to Section D2.

D3.2.2 Overview of Risk Mitigation Methods

Through its capital and maintenance investment plans, Toronto Hydro mitigates both the quantitative and qualitative risks identified above. Toronto Hydro manages risks by prudently investing in its assets while deriving value for customers. As such, the risk-based models and

approaches described above are key inputs into the decision-making process for investment planning. Assets that pose a risk to the system are identified based on their contribution to the various risk factors discussed above as part of the IPPR process and grouped into investments categories of System Renewal or System Service.

D3.2.2.1 System Renewal Investments

As part of Toronto Hydro's risk mitigation efforts, System Renewal investments form a significant portion of the utility's capital investments. In addition to investments that help reduce the probability of failure based on age and condition, this investment category also contains programs aimed at addressing the other risk areas identified in Section D3.2.1.2 and D3.2.1.3 above. Programs such as Area Conversions (Exhibit 2B, Section E6.1) are aimed at eliminating legacy designs along with their reliability and safety consequences. In addition, renewal programs inherently target assets that pose environmental risks, such as oil leaks, especially for equipment containing PCBs. The System Renewal category also includes more specialized programs that address areas with high historical failures or failed assets, through programs such as the Reactive and Corrective Capital program (Exhibit 2B, Section 6.7).

D3.2.2.2 System Service Investments (Enhancements)

In addition to mitigating risk through the renewal of assets, Toronto Hydro invests in programs that allow for other cost-effective forms of risk mitigation. For example, in the network system, Toronto Hydro is investing in monitoring capability for vaults through the Network Monitoring and Control program. This program allows Toronto Hydro to proactively identify key issues affecting the network system such as vault flooding in order to intervene prior to potentially catastrophic asset failure. Installation of network monitoring and control systems or SCADA-Mate switches (on overhead lines) allows Toronto Hydro to address reliability related risks (in particular, outage duration risks), in a manner that compliments renewal activities in delivering the utility's overall reliability objectives.

D3.2.2.3 Maintenance and Refurbishment Activities

Toronto Hydro uses maintenance programs, as detailed in Exhibit 4A, to both identify and mitigate risks in the system. Inspections are key in providing data inputs for risk analyses, including assessment of asset condition and identifying priority deficiencies that require intervention. This data provides Toronto Hydro with information on assets that is critical to decision making, such as the presence of oil leaks or other forms of equipment deterioration. In addition, maintenance

programs can help maximize the life of assets, thereby managing the overall need for capital intervention. For example, treatment of wood poles helps protect against infestation and rot, reducing the probability of failure.

D3.2.2.4 Other Investments

Toronto Hydro must also invest to ensure it manages risks in terms of meeting the needs of its customers and stakeholders. For example, it must meet the expectations of regulatory bodies and governments with respect to policies. This includes proactive metering investments that ensure Toronto Hydro remains in compliance with the requirements set by Measurement Canada. Investments are also required to ensure that capacity is available for connecting customers, which is further discussed in Section D3.3.

D3.3 Asset Utilization Policies and Practices

This section highlights Toronto Hydro's policies and practices in regards to capacity planning and the connection of both load and generation customers. It details Toronto Hydro's process to assess capacity requirements, connections, and steps to mitigate risks.

D3.3.1 Capacity and Connections Capability Assessments

Toronto Hydro continues to monitor capacity related risks within its system from both a short- and long-term view point. This includes working with third parties such as the Transmitter (i.e. Hydro One Networks) and the IESO as required for planning purposes, for both load connections and generation connections.

D3.3.1.1 Distribution Capacity & Capability Assessments

1. Load Forecasting

Toronto Hydro uses a load forecasting process to identify spare capacity at substations or points of constraint within the system. This allows Toronto Hydro to maintain awareness of bus capacity as new connections are made and natural load growth (or reductions) occur. The load forecast provides a short- to mid-term view of the station bus capacity so that appropriate plans can be made to accommodate varying growth rates within the system.

In order to complete a ten-year load forecast at the substation level, as shown in Figure 5, Toronto Hydro identifies the annual peak loads (both summer and winter peaks) for each bus at its substations. These peak loads are then normalized based on historical temperatures at which these peaks occur. Any information available for customer connections at the time of analysis is included based on the required connection time and the load requested by the customer. Only 70 percent of the requested load is applied, as past experience indicates that the load requested is often overstated in the application phase. Next, historical growth rates are calculated and used to forecast future load growth. If no discernable trend can be identified, then the growth rate used in Hydro One's long term forecast, as presented in the Metro Toronto Regional Infrastructure Plan (Exhibit 2B, Section B, Appendix C), would be used instead. Finally, any planned work which will directly or indirectly transfer load from one bus to another, such as load transfers or voltage conversions, is incorporated into the forecast.

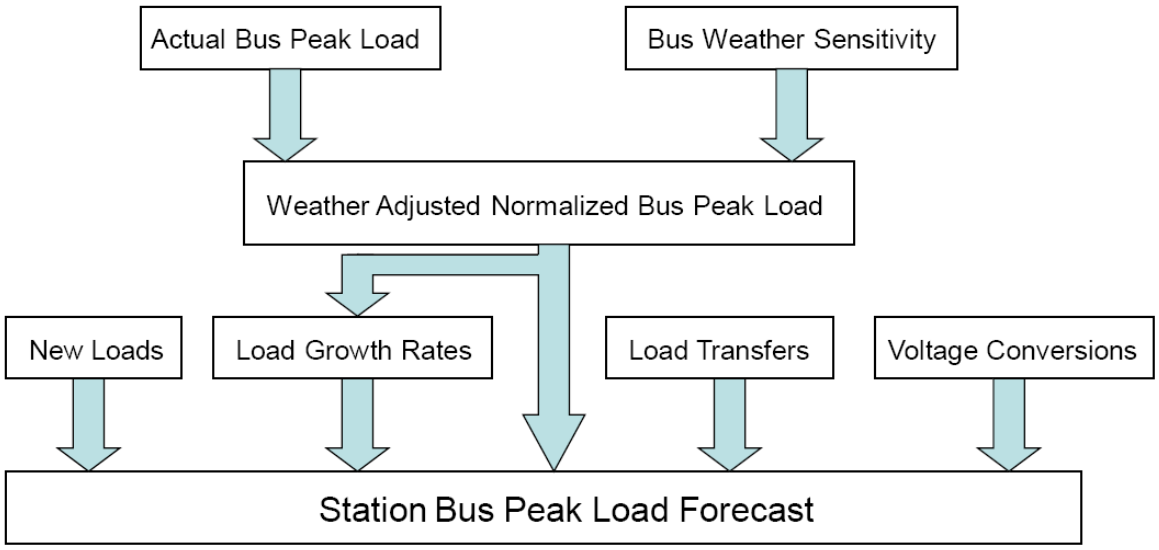


Figure 5: Process to Forecast Load at Substations

2. Connection Capability

In order to connect new customers, both capacity and spare feeder positions are needed. As existing feeders reach their capacity, new feeders must be pulled from a station into the distribution system to connect new customers. Although a station may have the capacity to supply this demand, if there are no feeder positions to connect new feeders to the station, then the station would be unable to support new connections. To this end, Toronto Hydro also monitors the number of spare feeder positions at its stations. When new feeders are needed and no spare feeder positions are available, Toronto Hydro engages in capital work under the Load Demand program to transfer feeder loads and free up feeder positions so that new customer connections can be made.

D3.3.1.2 Generation Capacity & Capability Assessment

Increased demand for power from consumers and the interconnection of distributed generation ("DG") has placed limitations on certain areas of the system. Toronto Hydro supports connecting DG to the distribution system in alignment with the Distribution System Code and in coordination with Hydro One Networks and the IESO. Toronto Hydro has identified a number of constraints within its system that impact DG connections and interconnection-related decisions, including the following:

1) limited breaker and station equipment capacity due to short circuit capacity constraints;

2) reverse power flow limitations based on transformer thermal capacity and minimum load requirements;
3) anti-islanding conditions for DG; and
4) system thermal limits and load transfer capability.

Fault assessments conducted by Toronto Hydro, and a prior DG capacity study conducted by Navigant in April 2011, have shown short circuit limits on station equipment to be the primary constraint.[5]

To determine the short circuit capacity at stations and other locations on the distribution system, sophisticated fault and power flow simulation models are employed. These models predict how much fault current will flow to a specific location from generators located throughout the distribution system. The presence of DG on distribution feeders can contribute to fault current that can cause station equipment, such as circuit breakers, to exceed short circuit capacity limits. Studies are performed for each new DG application enabling Toronto Hydro to continually evaluate the available existing short circuit capacity of the system.

D3.3.2 Capacity Risk Mitigation Methods

Based on the risk assessments above, Toronto Hydro invests in a number of programs to mitigate the risk of capacity shortfalls or the inability to connect new customers. These methods include expansion to increase capacity, enhancements to better utilize existing equipment, and load transfers as detailed below.

D3.3.2.1 Expansion Investments

Expansion investments provide one approach to manage the risk of capacity shortfalls within the system. By increasing capacity at substations, Toronto Hydro is able to address the need in localized areas of the system that experience load growth. Investments for expansion are primarily funded through the Stations Expansion program, as detailed in Exhibit 2B, Section E7.4. Expansion investments often require involvement from the transmitter, and Toronto Hydro may need to provide capital contributions for upgrades to transmission equipment at substations to enable an increase in capacity. Expansion may also be embedded as part of renewal activities for power transformers and switchgear units if deemed necessary, either to increase capacity or to increase

[5] See EB-2011-0144 Exhibit G1 Tab 1 Schedule 2 THESL 2012 GEA Plan – Appendix D: DG Interconnection Capacity Study

the number of feeder positions available at a substation to provide new feeders to connect customers.

D3.3.2.2 Load Transfers

Prior to investing in expansion projects, Toronto Hydro assesses the feasibility to alleviate capacity shortfalls by transferring load to adjacent feeders, buses, or substations. If feasible, transfers are typically more cost effective than expansion. This approach allows Toronto Hydro to ensure efficient utilization of its existing infrastructure prior to investments in expansion.

D3.3.2.3 Enhancement Investments

Toronto Hydro also considers investments that allows it to enhance the system in order to alleviate capacity shortfalls or connection limitations. To manage load restrictions, especially due to peaks, Toronto Hydro has worked extensively with its customers to implement a Local Demand Response program to manage peak demand effectively, as detailed in Exhibit 2B, Section E7.4. For generation connections, investments in monitoring and control equipment are made through capital programs (e.g. Generation Protection, Monitoring, and Control, as further explained in Exhibit 2B, Section E5.5) to actively manage DG sources to ensure safe connections. These investments allow Toronto Hydro to effectively manage capacity and connection limitations, without the need for extensive renewal activities, thereby deferring large capital investments.

D3.4 Program Planning Approach and Project Development

This section details the framework and process that Toronto Hydro relies on to develop its capital and maintenance programs. It highlights the key components of the IPPR process that drives the development of investment programs for distribution assets, as shown in Figure 6.

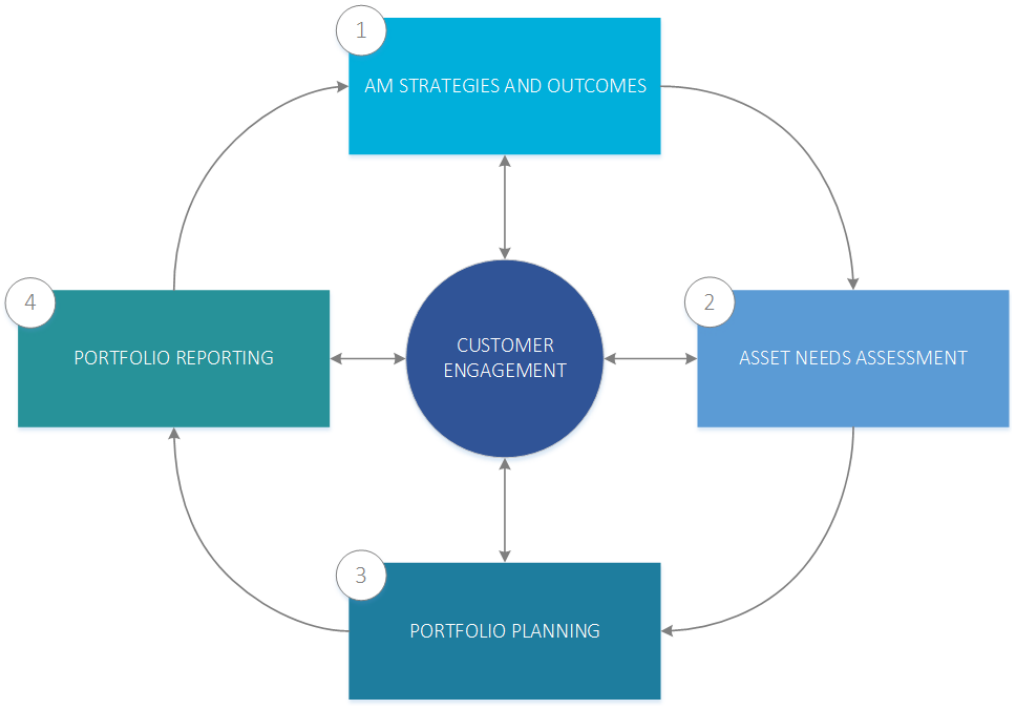


Figure 6: The IPPR Program Development Framework

The process can be divided into four key components:

1) **Asset Management Strategies and Outcomes:** The process begins by establishing the investment plan objectives and is informed by both the broader corporate strategy as well as customer engagement feedback.
2) **Asset Needs Assessment:** This part of the process establishes an understanding of the current state of assets based on asset demographics and ACA results. This information provides the base data required for planners to analyze the risk that the asset poses to the system.
3) **Portfolio Planning:** Based on the information outputted from the first two steps and the various risks discussed above, Toronto Hydro analyzes assets to identify the required level

of spend to manage risk and in turn achieve the intended outcomes. Based on the driver of the work, investment programs are established as part of this step.

4) **Portfolio Reporting:** Once investment programs have been executed in the field through individual projects, the IPPR process includes a feedback loop where the project-specific execution status and project expenditures are reported to evaluate the projects proposed in upcoming years.

D3.4.1 Asset Management Strategies and Outcomes

As discussed in Section D1, Toronto Hydro's AM Process is guided by strategies and related outcome objectives that the utility sets in alignment with its corporate pillars and Customer Engagement results. Figure 4 in Section D1 provides a summary of the AM strategies and outcomes, and Section E2 provides an overview of how Toronto Hydro established its AM outcome objectives for the 2020-2024 DSP.

Toronto Hydro uses outcome measures in each outcome area to quantify the impact of investments towards each outcome. This framework is integral in enabling decision-making for asset management in both the long-term and short-term. Toronto Hydro's Custom Performance Measures for the 2020-2024 period are discussed in detail in Section C.

D3.4.2 Asset Needs Assessment

In order to create an optimized program, Toronto Hydro completes a needs assessment. In this regard, an important tool is the current state analysis ("CSA") which provides Toronto Hydro with an assessment of the major assets that are currently installed in the system.

Key parameters that are collected from and integrated into the CSA include:

- asset registry data (e.g. nomenclature, asset class/sub-class, installation type);
- asset quantity data;
- age and condition demographics data; and
- asset-class and system-wide replacement value based upon useful life criteria.

The CSA utilizes information from Toronto Hydro's various enterprise systems, including the Geographic Information System ("GIS") and Enterprise Resource Planning ("ERP") system to establish the core asset registry data and asset demographics. Through the development of the CSA, Toronto

Hydro can quickly establish key information on major assets including condition, age, useful life, and replacement value.

There are two key outputs from the CSA process:

- **Asset demographic data:** Provides a yearly break down for the number of asset units installed along with their respective costs. As a key input for a data driven long-term planning process, this data set ultimately allows Toronto Hydro to establish the percentage of assets past useful life.
- **Condition demographic data:** Indicates demographics from a HI perspective for each asset class and sub-class, helping to flag higher risk assets within the system from a condition perspective.

This process establishes foundational data that is used in the long-term and short-term planning processes for distribution assets. Figure 7 illustrates the inputs, elements, and outputs associated with the CSA.

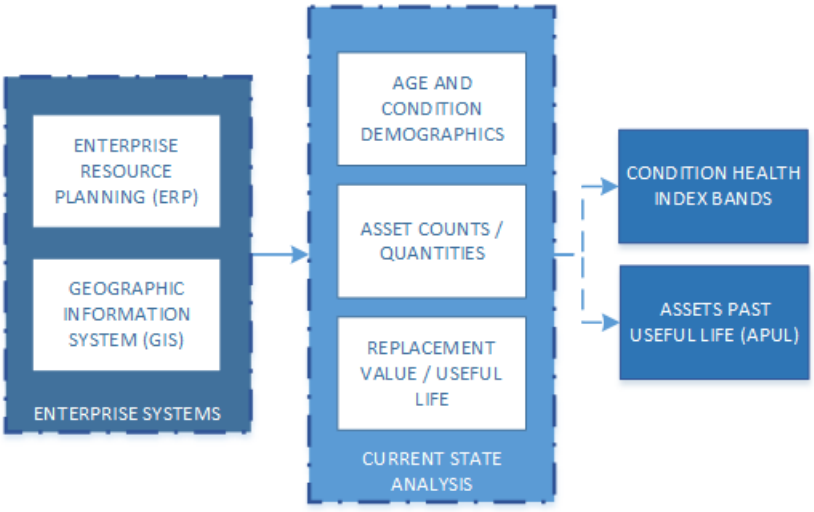


Figure 7: CSA Process

In addition to asset specific data, Toronto Hydro assesses emerging needs and challenges of the system by evaluating additional risk factors. For example, Toronto Hydro evaluates the available and forecasted capacity of the system to identify capacity related risks. As discussed in Section D1.2.1.2 as well as D3.3 above, this is done through load forecasting, load and generation connections forecasting, as well as the Regional Planning Process. These processes enable Toronto Hydro to

identify spare capacity and anticipate areas of potential constraints as a result of developments and load growth or reductions in different areas of the City. The Regional Planning Process is an important input for distribution system planning (specifically, station plans), as a result of infrastructure planning on a regional basis to better predict system challenges.

Toronto Hydro accounts for emerging needs as they arise in the system. This could be as a result of asset specific information (legacy assets and configurations, safety and environmental concerns relating to a specific type of asset), climate and weather impacts, or available capacity to connect customers. The processes identified in this section are used to assist system planners with developing well informed plans that consider the various risks and challenges mentioned above in order to meet the needs of the system.

The results of the Asset Needs Assessment that formed the basis of Toronto Hydro's system investment plan for 2020-2024 is discussed in Section E2.2.

D3.4.3 Portfolio Planning

The Portfolio Planning process produces program-level expenditure plans in alignment with the utility's asset management objectives. As part of Portfolio Planning, asset-related data from the CSA is combined with system-wide information regarding known challenges facing the distribution system in order to assess asset and system needs. Toronto Hydro relies on the analyses and decision support tools (as discussed in Section D3.2 and Section D3.3) to identify assets or areas with high levels of risk requiring intervention. When identifying and proposing portfolios, the utility also accounts for customer feedback resulting from regular customer engagement activities. Customers' needs and preferences are a key input for determining the investments needed to meet customers' expectations on service.

During the Portfolio Planning process, Toronto Hydro develops investment requirements for managing system assets and challenges, based on the condition of assets, age of assets, risks of asset failure, legacy assets within the system, load growth, opportunities for modernization, etc. The analysis of assets from both a risk and outcomes perspective during the investment planning process ultimately drives the development (and management) of capital programs, which are detailed in Exhibit 2B, Sections E5 to E7 of the DSP.

The various risk analyses presented in Section D3.2 and Section D3.3 drive the overall investment required to manage the distribution system. Toronto Hydro assesses its entire asset base in light of

the risks discussed above. Assets that are past their useful life or in HI4 ("material deterioration") or HI5 ("end of serviceable life") condition are identified, as defined earlier in Section D2.2. Information regarding historical failures is combined with asset level information to better understand not just the probability of failure but the cause of failure as well. The configuration of the system is also analyzed in these cases to see if inherent design limitations are contributing to increased risk for specific assets or types of configurations in the system. For example, the presence of legacy assets, such as box construction, can often result in safety or environmental consequences. The severity of the risk posed by these assets is considered when deciding whether to invest in replacing these assets proactively and also in determining the correct pace of replacement. Ultimately, similar types of interventions with the same driver are aggregated into capital programs. The expected probability of failure and localized reliability information also drives the requirement for Reactive and Corrective capital in order to address the level of failures observed.

In addition, Toronto Hydro must also consider work that must be accomplished as part of its mandate (e.g. pursuant to the Distribution System Code), and responsibility as a Local Distribution Company ("LDC"). These investments may be demand driven or initiated by a third party, and are categorized as System Access programs, such as Customer Connections or Externally Initiated Plant Relocations.

Program expenditures are then aggregated to create a total investment plan for any given year. The impact of the cumulative investment plan on outcomes is considered to ensure that investments are made in a prudent manner that manages the various risks discussed in this section while providing value for the customer.

Toronto Hydro considers, on an aggregate level, the impact of various investment levels on outcome measures, including (but not limited to) to SAIFI, SAIDI, FESI, system health, system capacity, and PCB contaminated oil spills. By forecasting the performance of key outcome measures over the long-term under proposed investment levels, Toronto Hydro is able to understand trade-offs in investing in different programs and at different investment levels. This initial investment requirement represents a bottom-up needs assessment by system planners for the optimal expenditure levels required.

Various investment strategies are reviewed and challenged internally before selecting a proposed approach. Once investment plans are reviewed, the information becomes a foundational input as part of other corporate business planning activities.

For more details on how these activities unfolded for the 2020-2024 Capital Expenditure Plan, see Section E2.

D3.4.4 Portfolio Reporting

The IPPR process also creates a feedback loop that provides information about program level completion and historical work executed in each program.

Information is reported on an individual project basis and includes the project's total spending and assets replaced or installed in any particular program. This data is broadly used within Toronto Hydro in assessing the status of capital programs as a result of the completed projects. This was first outlined in Section D1.2.1.3 under the discussions regarding the IPPR process. The aggregate of project-specific expenditures and asset units installed indicates how much of the capital investment program has been executed relative to the target for the program. Reporting is an important component in the process as it provides feedback on Toronto Hydro's ability to execute proposed investments as well as an opportunity to revisit and adjust plans for the upcoming years if needed.

D3.4.5 Project Development and Prioritization

As part of short-term planning activities, once capital investment programs are established, as explained in Section D3.4.3, assets and issues identified for each program are addressed as part of discrete capital projects. As explained within Section D1.2.2, the scope and project development process includes four phases: (i) identification of specific needs; (ii) assessment of options; (iii) high level scope creation; and (iv) refinement of scope and cost estimation.

During the first two phases, investment planners analyze discrete portions of the distribution system, such as a neighbourhood or street, in order to identify projects that align with the investment program criteria and drivers. Depending on the investment program driver and program type (i.e. core renewal, critical issues, or other necessary day-to-day operational investments), enterprise data is used to identify assets at a discrete level so that investment opportunities are identified, risk is managed, and outcome objectives are achieved. For example, with respect to a program driven by failure risk, enterprise systems and the analyses discussed in Section D3.2 can be utilized to identify the program-level prioritized assets that align with this driver.

In addition, ACA results can be used to identify those assets in HI4 and HI5, and the FIM can be used to evaluate the highest-value investments from a risk-mitigation perspective. ITIS can be used to cross-reference studied locations against historical reliability events and performance issues. Finally, enterprise systems including the GIS are used to further support the study process, by providing supplementary details such as age, asset type and sub-type information.

For safety or capacity constraint-driven programs, nameplate information or localized data (as per the load forecasting process, discussed in Section D3.3) may be used to identify specific investment needs.

When an investment need for a project within a particular investment program has been confirmed and verified, phase three of the Scope and Project Development is carried out. A project draft, also known as scope of work, is produced which confirms the assets to be replaced, and establishes the high-level design for the new assets to be installed. While some projects may involve assets replaced in-kind, other projects may result in the installation of new assets as per a new configuration. Examples include the conversion of overhead plant rear lot to underground plant in order to minimize non-asset-risk exposure, or the re-configuration of radial circuits to looped circuits and redistribution of load in order to reduce outage duration and impacts. Ultimately, the high-level forecasts produced via the long-term planning process will be further refined into an annual capital budget, as more rigorous project estimates are produced.

In tandem with producing the high-level design, Toronto Hydro documents the scope of work to be performed and produces a high-level cost estimate to execute the project. Efficiency savings can be realized by addressing the prioritized assets and issues along with adjacent assets that also require intervention as a single project, as opposed to replacing these assets individually on a reactive basis. A project study may also be divided into multiple project drafts where necessary to allow construction to be executed in manageable pieces that are minimally intrusive to both the general public as well as customers. As part of the project development process, Toronto Hydro also considers issues such as city road moratoriums, physical restrictions, or particular design related problems that may delay the project or require a redesign. The project draft then undergoes a quality control assessment, before proceeding into the project finalization stage through the planning supervisor.

Once approved, the project is further refined both in terms of the scope of work as well as the cost estimate. As part of this process, field visits are conducted to ensure accuracy of the data that is used, obtain additional information and measurements, and to understand other potential risks for construction. Permitting requirements are also dealt with at this stage. This process results in a more refined project draft and cost estimate.

Ultimately, a series of projects are produced for each investment program, which results in further refinement to the capital investment spending levels for the associated program. Once the projects

are finalized, they will be scheduled for execution based upon the Project Management and Execution process outlined in D1.2.3. Each project is scheduled based upon relative priority, resource availability, and system constraints (e.g. contingency issues or summer switching restrictions). Factors that impact project scheduling and execution include:

- project scope and requirements, for example, asset delivery to locations and complexity of the site;
- external constraints such as coordination with external groups;
- permitting and moratoriums;
- coordination between other projects; and
- resource balancing.

As part of scheduling, investment planners and program managers meet to discuss the relative priority of the various projects to establish the capital work program for execution in a given year. As part of the execution process, the detailed project design and estimate are produced to finalize capital investment spending levels. To address any required change to the project cost, schedule, or scope of work, Toronto Hydro maintains a change management and governance process. This process provides visibility across all relevant stakeholders on major project changes, requiring approval so that the change is appropriately processed and documented for awareness regarding lessons learned for future projects.

D4 Facilities Asset Management Strategy

Toronto Hydro maintains a complex portfolio of facilities, including critical operational sites (e.g. stations and control centres), in support of the reliable and efficient operation of the utility's distribution system. The effective maintenance of these facilities is required in order to ensure adequate protection for electrical grid equipment, secure access for employees and security of designated areas, and appropriate work conditions to support employee productivity. In this regard, the utility strives to optimize the value and function of relevant assets through its Facilities Asset Management Strategy (the "Strategy"), which takes into account:

- Lifecycle management;
- Enhancement initiatives; and
- Regulatory compliance.

By implementing the Strategy, the utility's primary objective is to maintain the functionality and safety of its work centres and stations. This document describes the methodology and processes that comprise the Strategy and support Toronto Hydro's four strategic pillars: People, Financial, Operations, and Customer.

D4.1 Asset Management Process

Integrated asset management systems are integral to the operation of a large facilities program. Toronto Hydro's management of facility assets involves the continual analysis of asset condition on a planned cycle:

- **Daily:** through our robust Preventive Maintenance Program ("PMP") and Computerized Maintenance Management Software ("CMMS"). Various facilities metrics derived from CMMS are used to assess business cases for an assets upgrade/replacement/overhaul during the asset management process;
- **Monthly:** through our field inspections and safety audits; and
- **Annually:** through lifecycle reports, lessons learned from completed projects, and a defined maintenance manual.

When planning and executing projects, the utility makes strategic decisions that take into account complete project costs, operational costs, and business impact to Toronto Hydro. In addition, this decision-making process is based on Asset Condition Assessments that review:

- Actual field conditions;
- Industry standard useful life data (i.e. ASHRAE and RS Means Data);
- Analysis of lessons learned from past projects;
- Assessments and reports by independent experts (e.g. Asbestos Containing Materials Report, Designated Substances Report, Water Infiltration Report, Roof Condition Assessment, lighting assessment reports, Current Condition and Code Compliance of Vertical Service Ladders, and Security Systems Assessment); and
- Detailed Asset Registry maintained through CMMS.

D4.1.1 Condition Assessment Process

Asset condition is gathered and assessed through continual inspections, maintenance, and analysis. Relevant considerations (including observed condition, major findings, recommendations, and supporting photographs) are organized using UNIFORMAT II classifications in order to effectively compare and prioritize similar assets across Toronto Hydro's large facilities portfolio. A numeric value is assigned to each asset based on the following rubric:

Table 1: UNIFORMAT II Classifications

Rating	Condition	Recommendation
1, 2, 3	*Poor*	Budget within 1-5 years
4, 5, 6	*Fair*	Budget within 5-10 years
7, 8, 9	*Good*	No investment required

"Good" assets function satisfactorily or with only minor deficiencies that marginally affect performance. "Fair" assets have deficiencies that, if not corrected, could cause intermittent problems in the near term or complete failure or significant risk of failure in the long term. "Poor" assets have critical deficiencies which currently affect their function.

To appropriately reflect asset criticality as part of the assessment process, assets are also assigned a priority level based on the following rubric:

Table 2: Asset Priority Level Rubric

Rating	Priority
1	Critical System
2	Building Functionality
3	Run to Fail/Low Impact
4	Redundancy or Cost Effective Upgrade

A "Critical System" would be one that poses an immediate safety hazard if required replacement or maintenance is not carried out (e.g. fire or life systems, water infiltration prevention/protection systems). "Building Functionality" assets are those required for a building's efficient daily operation (e.g. doors, windows, electrical/mechanical systems, interior finishes, etc.). "Run to Fail/Low Impact" assets are those whose failure entail minimal risk and would not significantly affect Toronto Hydro's operations (e.g. Baseboard Heaters etc.).

D4.2 Asset Renewal Process

Toronto Hydro aims to minimize the impact of planned asset renewals. When assets are identified to be poor condition, a plan is implemented to repair, upgrade or replace the asset to restore or enhance its functionality in accordance with current standards (including regulatory and Toronto Hydro standards). The typical planning process includes a review of:

1) Lifecycle analysis;
2) CMMS analysis; and
3) Project requirements, such as accessibility, budget, environmental liabilities, inter-project dependencies, and coordination with other Toronto Hydro capital projects and planned maintenance.

D4.2.1 Asset Standardization

Toronto Hydro's facilities standards are based on legislated and regulatory requirements. Some examples include:

- Ontario Building Code;
- Ontario Fire Code; and
- *Accessibility for Ontarians with Disabilities Act*, *2005*.

The implementation of consistent standards across all work centres produces efficiencies by minimizing design, repair and inventory costs. Further cost savings can be achieved by maximizing the useful life of facility assets while balancing and optimizing the total lifetime cost of each asset.

D4.3 Investment Planning and Forecasting

Facilities Investment Planning and Forecasting ("IPF") is the process of developing a five-year program of prioritized investments (pursuant to the prioritization process discussed above), including a detailed plan for each year of the program. The IPF Process is divided into three streams:

- Lifecycle management;
- Enhancement initiatives; and
- Regulatory requirements.

The primary objective of facility asset lifecycle management is to minimize an asset's total lifecycle cost (i.e. by establishing the End of Economic Life) while ensuring reliable asset performance. As shown in the figure below, End of Economic Life is the point where total cost (including total ownership and maintenance costs) is at its lowest over an asset's lifecycle. Through the Strategy, the utility aims to ensure satisfactory service for Toronto Hydro employees and customers while achieving significant stable financial benefits. Capital projects are planned on a yearly cycle to adhere to strict budgetary restraints. When cost overruns occur (e.g. due to incremental needs), the root cause is identified and lessons learned are reflected in future project plans to enhance the accuracy of cost forecasting.

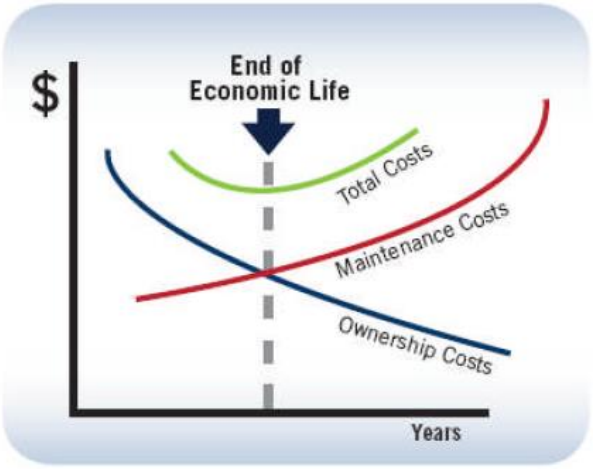


Figure 1: End of Economic Life Cost

D4.4 Summary

Through the Strategy, Toronto Hydro strives to maintain the operating functionality and safety of its facilities portfolio while optimizing asset lifecycle cost and related financial performance. Regular field condition assessments allow the utility to accurately capture the current state of an asset and evaluate asset maintenance costs and useful life so as to ascertain its impact in relation to the distribution business. The utility leverages robust planning and integrated CMMS to create metrics and reporting systems to ensure all assets are functioning as intended and minimize total lifecycle cost (including maintenance and ownership costs). Appropriate and timely corrective action is crucial to mitigating the impact of asset deficiencies or failures on Toronto Hydro's core business while supporting the minimization of total lifecycle costs. As discussed herein, the processes and methodologies that comprise the Strategy help ensure that Toronto Hydro makes prudent investments in its facilities portfolio in accordance with industry standard asset management practices and in support of Toronto Hydro's strategic pillars.

D5 Information Technology Asset Management Strategy

Informational technology ("IT") is a critical enabler for utility operations. Toronto Hydro relies on IT assets and systems to satisfy its obligations as a distributor, deliver its capital plans and operational programs, and pursue efficiencies and innovation.

The primary objective of Toronto Hydro's IT Asset Management Strategy is to derive sustainable value from its IT assets for the utility and customers. IT systems provide optimal value when they deliver expected levels of service in a sustainable manner and effectively mitigate risks (i.e. impact of failure, cyber security) at optimal costs. This schedule describes the IT asset management principles and IT investment planning methodology that enable Toronto Hydro to achieve this key objective.

IT asset management includes the purchase, operation, maintenance, renewal, replacement and disposition of IT data, hardware, and software assets. IT asset management is defined by IT standards, and includes:

- Requirements for data, hardware, and software assets (e.g. physical, performance, compatibility, security, etc.);
- IT architecture which establishes expected service levels (e.g. performance measurement, reliability requirements, incident/problem management for the assets); and
- Lifecycle management schedules for each type of asset.

IT Investment Planning is the process of making the best possible decisions regarding the scope and sequencing of asset management initiatives, including sustainment and enhancements. This process is based on well-defined IT standards and up-to-date information about the utility's IT assets.

Toronto Hydro's IT Investment Planning process is divided into two streams: (i) sustainment of existing systems; and (ii) enhancement initiatives. The process leads to the development of a five-year program of prioritized investments, including a detailed plan for the first year.

D5.1 IT Asset Management

Toronto Hydro developed IT standards to streamline and optimize IT asset life cycle, define system architecture and to gain operational efficiencies through the standardization of IT assets and

components. IT standards are based on information provided by equipment producers (e.g. statistics on mean time to failure), internal historical data regarding asset failures, and industry best practices. Toronto Hydro reviews its IT standards regularly to ensure that they remain relevant for the utility and in alignment with the aforementioned considerations.

As described in more detail below, Toronto Hydro has adopted IT standards and architecture for data, hardware, and software assets. Having aligned hardware and software standards enables the implementation of an internal cloud platform – a collection of hardware resources which are required to complete desired computing operations that exceed the requirements of a single hardware machine. The implementation of an internal cloud platform provides the following benefits:

- Better management of IT assets, incidents, problems, changes, configurations, security, capacity, and availability of IT assets;
- Enhanced reliability of IT systems;
- Streamlined procurement processes and reduced operating costs;
- Operational efficiencies;
- Simplified monitoring of IT assets; and
- Enhanced security.

D5.1.1 IT Hardware Standards

IT hardware standards define the management of the physical IT components from acquisition through disposal. Common IT hardware asset management practices include need identification, procurement management, life cycle management, redeployment, and disposal management. These practices are applied to the following categories of hardware assets (see Figure 1):

1) **Core backend infrastructure assets**, which are responsible for the computation, storage and communication necessary to support IT systems; and
2) **Endpoint assets**, which allow end-users to execute, process, complete and review business tasks and operation.

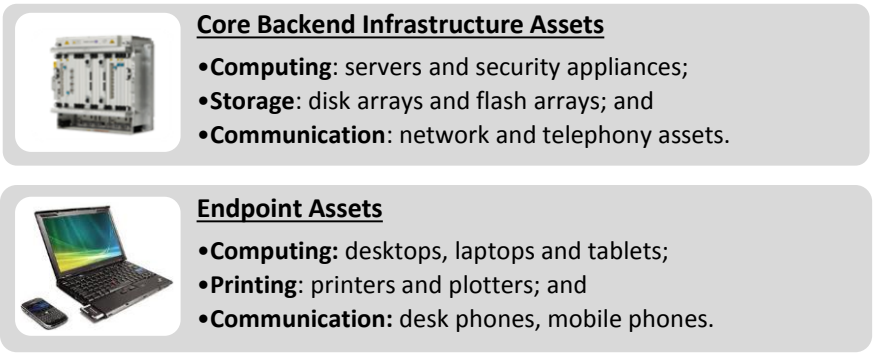


Figure 1: IT Hardware Asset Categories

IT hardware standards and architecture specify which types of hardware assets Toronto Hydro requires to ensure a highly reliable, scalable and manageable platform for business applications, and document the capacity and lifecycle of these different assets.

IT hardware must be periodically refreshed to guarantee expected service levels of the systems and minimize the risk and impact of failure to the business. Through its IT hardware standards, Toronto Hydro seeks to define the optimal timing of asset replacement such that hardware assets are operated with the lowest acceptable failure rate at optimal costs. As illustrated in Figure 2 below, the lifecycle of IT assets generally follows a "bath tub curve" that breaks out into three distinct regions:

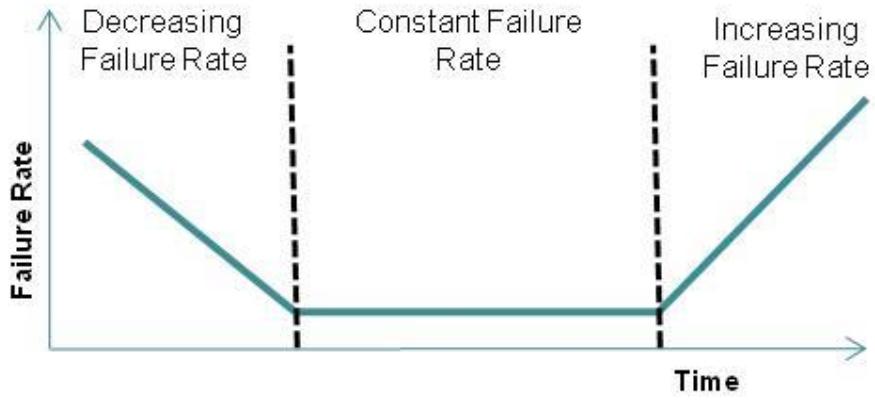


Figure 2: IT Hardware Asset Lifecycle Failure Rate over Time

- **Decreasing Failure Rate:** This is the region of the curve associated with a reduced failure rate over time. This is typical of new IT hardware, where once upfront implementation issues are addressed, failure rates tend to drop.

- **Constant Failure Rate:** As failure rate decreases to a certain point, it begins to stabilize and remain almost constant. The cost of ownership in this area of the bathtub curve is steady and considered financially optimal.
- **Increasing Failure Rate**: As the IT hardware ages beyond useful life, its failure rate starts to increase again due to the general operational wear and tear of the asset as well as vendor focus on development of new products (i.e. a lack of investment in and support for now obsolete products). As a result, system failures and associated maintenance costs start to rise steeply in this portion of the bathtub curve.

Based on the criticality of the infrastructure, industry best practice, and vendor specifications, IT hardware standards define the optimal time of refresh before reaching the "Increasing Failure Rate" portion of the lifecycle. This approach minimizes the risk of interruption to the core processes and technology that the company relies on to execute its capital plans and operational programs in a safe, effective and efficient manner. This approach also helps reduce IT related operational and capital expenditures.

D5.1.2 IT Software Standards

Under Toronto Hydro's IT software standards, software applications are categorized as Tier 1 and Tier 2 based on the operational criticality of the application, level of complexity, integration with other applications, maintenance costs and number of users.

- **Tier 1** applications enable Toronto Hydro's business operations and support company-wide business processes. They are functionally integrated with other applications, and are supported by complex underlying infrastructure such as databases, middleware, storage and network. As a result, Tier 1 applications generally have higher maintenance costs and a large user base. In a disaster scenario, the recovery point objective is less than 4 hours. Examples of Tier 1 applications include the Enterprise Resource Planning System, Inventory Management System and Geospatial Informational System.
- **Tier 2** applications enable specific divisional and departmental processes. These applications have little to no integration with other enterprise applications, and are typically supported by relatively simple infrastructure. In a disaster scenario, the recovery point objective is less than 24 hours. Tier 2 applications generally have lower maintenance costs, and cater to a smaller user base than Tier 1 applications. An example of a Tier 2 application is Hydropedia, a knowledge base system that helps customer service

representatives quickly and accurately address customer questions about Toronto Hydro processes during a phone call.

Regular software upgrades reduce the risk of system failures and cyber security breaches, and align software assets with vendor support cycles. Similar to IT hardware assets, if an application is not upgraded before the vendor support cycle expires, Toronto Hydro may have to procure specialized technical resources to maintain and support the application. These upgrades also reduce IT related operational and capital expenditures.

Through its IT software standards, the company also seeks to maintain the compatibility of software applications and the underlying components (e.g. servers and operating systems) to ensure uninterrupted IT system operations and deliver the desired end user experience and functionality. Because IT systems and their underlying components are often on different end-of-life and vendor support cycles, maintaining compatibility can be a complex task. Nonetheless, it is a key consideration in mitigating security and failure risks to IT systems from the underlying components.

IT software standards take into account average vendor release cycles, as well as the need to minimize incompatibility risks with underlying components. Software asset upgrades could be triggered if the asset reaches its maximum age, if the asset is more than one version behind the latest vendor-released version, or based on specific compatibility drivers and considerations (e.g. hardware upgrades).

D5.2 IT Investment Planning

IT investment planning is the process of developing a five-year program of prioritized investments, including a detailed plan for the first year. Toronto Hydro's IT investment planning process is divided into two streams: (i) sustaining existing systems; and (ii) enhancement initiatives.

The primary objective of Toronto Hydro's IT investment planning process is to maintain the IT assets that are required to satisfy optimal IT system reliability and availability. The sustainment stream is intended to provide satisfactory levels of service for customers and the utility, and mitigate IT-related business and operational risks (e.g. non-compliance and failure impact) in a cost efficient manner.

A secondary objective is to maximize cost savings through enhancement initiatives. Enhancement initiatives enable Toronto Hydro to leverage technological solutions to optimize or enhance

business operations in order to ultimately deliver greater value to customers, and to ensure compliance with new or modified external requirements from entities such as Measurement Canada, the Ontario Energy Board ("OEB"), and the Independent Electricity System Operator ("IESO").

D5.2.1 Sustaining Existing Systems

The scope and timing of IT sustainment investments is based on IT standards and asset specific information stored in Toronto Hydro's electronic IT assets inventory system. The utility makes investment decisions based on structured and up-to-date IT asset information, including: hierarchy of assets and interdependencies, key dates in each asset's lifecycle, vendor, contract and licence information, and capacity planning data.

IT system criticality (i.e. the impact of system failure) is the main consideration for purposes of investment prioritization. Priorities are also informed by internal program dependencies, asset type complexity, and resource balancing.

In making IT investment planning decisions, Toronto Hydro may also consider additional factors relating to general business growth and associated increase in IT requirements, such as process re-engineering, historic trends of current assets capacity versus utilization by existing IT systems.

D5.2.2 Enhancement Initiatives

As part of its commitment to continuous improvement, Toronto Hydro regularly evaluates and considers opportunities to enhance business processes based on new IT solutions.

Prior to investing in new IT systems, Toronto Hydro follows an evaluation process to help ensure that the utility makes well-informed decisions relating to new IT investments. That process includes the following steps:

1) **Evaluate:** The utility validates the proposed initiative, and works with the relevant business unit(s) to determine the project scope, business requirements, current state business processes, future state business processes, the options to achieve the future state and the preferred approach, costs and benefits.
2) **Align***:* Toronto Hydro reviews the proposed project to help ensure the following:
    - Governance, due-diligence, rationale and accuracy of the project costs and benefits;

- Strategic alignment with Toronto Hydro's objectives (e.g. value for money);
- Alignment with Toronto Hydro's risk profile (e.g. cyber security); and
- Alignment with existing technology investments and standards.

1) **Prioritize:** Toronto Hydro prioritizes the project based on a combination of factors, including project dependencies, costs, benefits, strategic alignment and risk assessment.
2) **Execute:** Project execution typically consists of the following steps:
   - Gathering more detailed user and technical requirements;
   - Mapping the relevant business processes;
   - Developing and/or procuring the application as needed;
   - Provisioning the infrastructure to host the application;
   - Configuring the application to meet business requirements;
   - Testing the application for compatibility with Toronto Hydro's infrastructure;
   - Engaging users to test that the application meets their business and functional requirements;
   - Training users on the features and functionality of the application; and
   - Implementing the application across the appropriate departments.

D5.3 Five-Year IT Investment Plan

The output of Toronto Hydro's IT investment planning process is a five-year IT investment plan that: (i) is expected to deliver optimal levels of IT system reliability and availability; (ii) complies with the utility's IT standards and asset management practices; and (iii) mitigates risks related to IT assets in a cost efficient manner.

In developing its IT plan, Toronto Hydro has also considered IT industry best practices, vendors' information, distribution capital program growth and overall business growth, as well as trends of evolving regulatory requirements. Based on the overall schedule and cost estimates contained in the five-year IT investment plan, the utility develops a detailed plan for the next year which lists, prioritizes, and tracks all the key investment initiatives while in execution.

Toronto Hydro's IT capital investment plan incorporates some level of flexibility in order to manage externally-driven risks, such as an increase in software and/or hardware costs over the 2020 to 2024 period or a change in the release dates for certain applications; new threats, vulnerabilities, or modes of cyber security attacks; and unpredictable nature of new or evolving requirements from regulatory bodies such as the OEB, Measurement Canada and the IESO. For

example, the OEB's Policy Review of Electricity and Natural Gas Distributors' Residential Customer Billing Practices and Performance[1] resulted in a number of significant changes (e.g. the implementation monthly-billing) to the customer billing system. Any of these events could affect the cost, timing and pacing of a program in a given year.

Furthermore, the technology landscape evolves at a fast pace with new products frequently entering the market. If new technologies that are relevant to Toronto Hydro become available during the 2020 to 2024 period, Toronto Hydro plans to evaluate and consider these new technologies.

[1] EB-2014-0198, Ontario Energy Board Amendments to the Distribution System Code (April 15, 2015).

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED ("THESL")

Distribution System Plan Asset Management Review

SECTION I - INTRODUCTION

The Ontario Energy Board's ("OEB" or "the Board") Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5, Consolidated Distribution System Plan Filing Requirements state an expectation that "the DS Plan optimizes investments and reflects regional and smart grid considerations; serves present and future customers; places a greater focus on delivering value for money; aligns the interests of the distributor with those of customers; and supports the achievement of public policy objectives."

Furthermore, the Board wants to ensure that its established performance outcomes for electricity distributors are being achieved. Specifically, these outcomes include:

- Customer Focus: services are provided in a manner that responds to identified customer preferences;
- Operational Effectiveness: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;
- Public Policy Responsiveness: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and
- Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable.

A specific requirement of the Board for the Distribution System Plan ("DSP") is for the Electricity Distributor to explain its asset management process in order to provide the Board and stakeholders with an understanding of not only the processes themselves but how they create and drive the expenditure decisions in the DSP. The objective is to allow the Board to assess whether and how a distributor's DSP delivers value to customers, including controlling costs through optimization, prioritization and pacing of capital-related expenditures based on the condition of the assets and their ability to meet the specified performance outcomes.

Implicit in the Board's requirements is that the filing utility's DSP be based on sound asset management principles. To that end Torys LLP ("Torys"), acting on behalf of Toronto Hydro-Electric System Limited ("THESL" or "the Company"), engaged UMS Group to evaluate its asset management practices as they relate to the formation and execution of its DSP.

Overview

UMS Group completed personnel interviews and reviewed the relevant sections of THESL's 2020-2024 DSP Filing in order to evaluate the asset management practices that THESL used to develop its Distribution System Plan (DSP).

The purpose of these interviews and the document review was to gain an understanding, from an asset management perspective, of how the DSP was constructed. The objective was to gather information that UMS could use to evaluate whether the aspects of the asset management system

relevant to the construction of the DSP are in alignment with industry standard practices per ISO 55001. ISO 55001 is the global industry standard which specifies the requirements for the establishment, implementation, maintenance and improvement of a management system for asset management of physical assets. It was used as a basis of comparison to provide a level of objectivity to the evaluation of THESL's Asset Management practices.

From the interviews and the review of DSP documents, UMS qualitatively evaluated where it believes Toronto Hydro's maturity level currently is across the relevant domains within the standard. In order to provide some external context to its evaluation, UMS scored THESL's asset management maturity using the ISO 55001 maturity scale and compared it to a group of 14 North American electric utility business units for which UMS Group has previously performed asset management assessments.

The bases for UMS's findings include insights formed in working with other electric utilities worldwide in developing and implementing asset management capabilities, along with its formal expertise as an IAM Endorsed Assessor for ISO 55001 certification.

UMS Group Qualifications

UMS Group, headquartered at 300 Interpace Parkway, Parsippany, NJ, 07054, has been a leading provider of utility asset management services for over 25 years. UMS published its first report on this topic – the ISAM Report ("International Strategic Asset Management") in 1992 after conducting a worldwide search for best practices in utility asset management.

In the decades since, UMS Group has performed over 200 utility projects covering the full gamut of asset management. These include asset management gap assessments, multi-year large scale company-wide asset management transformations, development and implementation of asset management Operating Models, development of guiding documents/strategies (i.e., AM Policies, Strategic Asset Management Plans, Asset Management Plans, etc.), definition and implementation of asset management processes, and development and implementation of asset management tools (i.e., economic models, portfolio optimization tools, risk management tools, etc.)

UMS has developed and continually adapted its assessment methodologies to align them with emerging industry standards. In August 2010, UMS Group, as one of the first 11 firms so named, was appointed an Endorsed Assessor for the PAS 55 standard by the Institute of Asset Management (IAM), the professional body of those involved in the acquisition, operation and care of physical assets – particularly critical infrastructure. The Endorsed Assessor designation followed a rigorous IAM review of the expertise, practices, tools and techniques which UMS Group applies to asset management compliance assessments. UMS Group has since been appointed an Endorsed Assessor and Endorsed Trainer for the ISO 55000/1/2 standard by the IAM. **Appendix A** provides additional details regarding UMS Group's qualifications and those of the individual assigned to this effort.

The UMS Group-assigned expert for this effort, Mr. Steven Morris, fully acknowledges his duties as an expert in accordance with Rule 13 and Form A of the Ontario Energy Board's ("OEB" or

"Board") Rules of Practice and Procedure. In so doing, he acknowledges that it is his duty to provide evidence in relation to this report as follows:

- To provide opinion evidence that is fair, objective and non-partisan;
- To provide opinion evidence that related only to matters that are within his area of expertise; and
- To provide such additional assistance that the Board may reasonably require, to determine a matter in issue.

He acknowledges that the duty referred to above prevails over any obligation, which he may owe either Torys or THESL.

Structure of the Report

The ensuing discussion is divided into three sections:

- Section II – Executive Summary: A summarization of UMS's conclusions on the maturity of THESL's asset management practices used to develop its 2020-2024 Distribution System Plan (DSP),
- Section III – Project Approach: A description of and rationale for the approaches, methodologies, criteria and frameworks used to evaluate THESL's asset management maturity relative to development of the DSP
- Section IV – Summary of Results: An expanded discussion of findings, conclusions and recommendations around the topic of asset management.

SECTION II – EXECUTIVE SUMMARY

Overview of DSP Asset Management Review

UMS Group was retained to evaluate THESL's asset management practices as they relate to the formation and execution of its DSP. In accomplishing these objectives, UMS Group:

- Conducted a series of interviews with several THESL stakeholder organizations (e.g.; Planning Integration, Investment Planning, System Planning, Standards and Technical Studies, Program Management, Engineering Services, Fleet, Facilities, IT, etc.),
- Reviewed the relevant sections of the 2020-2024 Distribution System Plan filing,
- Evaluated THESL's asset management capabilities per the ISO 55001 domains relevant to the DSP,
- Compared THESL to a group of 14 electric utility business units on their asset management maturity per the ISO 55001 standard,
- Analyzed the results of the interviews, DSP review, and asset management assessment.

Evaluation of THESL's Asset Management Capabilities as Applicable to the DSP

Toronto Hydro has been developing its asset management capabilities for a number of years and exceeds the North America average level of maturity in all relevant areas, even reaching into "Best Practice" for North American utilities for some domains. In general, North American utilities are not as advanced in the discipline of asset management as global leaders in Northern Europe, Australia, and New Zealand, although there is a large degree of variance in the maturity of specific utilities.

Furthermore, THESL has clearly adopted the principle of continuous improvement such that it strives to 1) use asset data to optimize the decisions is makes about its assets, and 2) identify opportunities to improve operational effectiveness.

In UMS's numerous assessments of asset management maturity, one of the areas in which UMS has found that utilities have the most difficulty is in translating Strategic Objectives into Actions at the asset level. There is often a disconnect between what outcomes Leadership wants to achieve and what work is actually performed. However, this does not seem to be an issue for THESL. Senior Leadership has defined clear strategic objectives which are directly addressed in decisions made around Programs for the DSP. In addition, the Strategic Objectives have been directly linked to the Performance Outcomes enumerated in the Board's Chapter 5 filing requirements – Customer Focus, Operational Effectiveness, Public Policy Responsiveness, and Financial Performance. This link helps ensure that asset-based decisions in the DSP meet both Utility and Stakeholder interests.

To ensure that the decisions made are delivering on the objectives, THESL continues to improve its performance management framework to track performance of its annual investment program. For this DSP filing, THESL is developing capabilities to measure performance in terms of outcomes in order to be able to demonstrate the link between the plan and programs, and the outcomes, as well as to measure the efficiency in achieving the outcomes.

THESL's asset lifecycle processes used to identify projects to be included in the DSP programs is at a higher than average level of maturity and is moving towards best practice. Lifecycle planning, risk assessment, maintenance optimization, and asset condition assessment are all key asset management processes which THESL uses to identify and evaluate projects to be included in the DSP. Economic analysis, stakeholder outcomes, and operational effectiveness are all considered in prioritizing projects for inclusion in Programs.

THESL's asset management processes include a variety of quantitative and qualitative analyses including the analysis of Customer Interruption Costs and the direct costs of responding to a failure, as well as ranges of customer outcomes related to reliability, safety, the environment, and financial impacts. While quantitative methods are used to identify projects, the methodology used for prioritizing individual projects is largely qualitative, as the desire to address a variety of stakeholder-driven outcomes precludes the use of a single (i.e., economic) measure. This demonstrates a level of maturity in translating customer needs and expectations into decision-making that exceeds most North American utilities. THESL also has a well-defined process for decision-making and the prioritization of projects as input to DSP Programs. This process ensures that needs and risks are assessed as required by industry standards. In alignment with ISO 55001 requirements, roles and responsibilities for the creation and execution of the DSP are clearly defined.

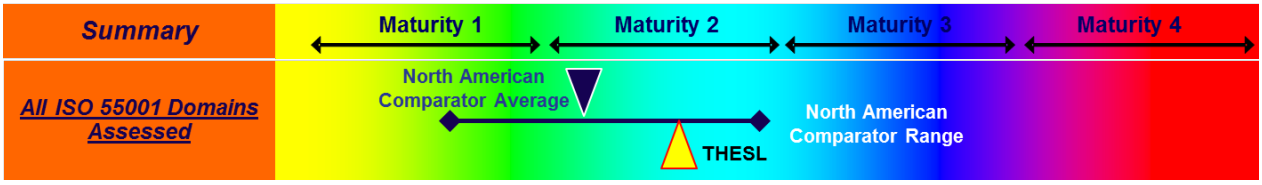
Asset management is a data-driven discipline and a higher level of maturity means incorporating quantitative analysis into decision-making using data – asset data, work data, customer data, cost data, system data, etc. While, UMS did not directly examine THESL's data, through information gathered in the interviews it appears that THESL's data for major asset classes is generally thought to be good. As with the industry as a whole, the quality of THESL's data varies among different asset classes. However, for the major asset classes, THESL's data appears to be sufficient for supporting its asset management decision-making processes. In addition, THESL strives to continuously improve the quality of data. For example, Mobile Data Terminals are being used to collect inspection data, and during the inspection, existing data is validated and the condition of the asset is noted. Where other data gaps in the asset register exist (e.g., asset age), predictive algorithms are being used to estimate data values.

From an Enabling Technology perspective, THESL is generally more mature than the typical utility with good modeling and Business Intelligence tools for performing lifecycle analysis, as well as forecasting failures and their impacts. UMS considers the Feeder Investment Model and Reliability Projection Methodology as examples of best practice asset management analytical techniques. In addition, Asset Condition Assessment has moved from a relatively simplistic model to a more sophisticated one which would be considered to use best practice techniques.

While THESL's asset management practices used to develop the DSP are above average, there are still some opportunities for improvement to achieve best practice levels. First, while the asset

management system is well-defined, the level of documentation could be improved to ensure sustainability over the long-term. Second, while THESL does a good job addressing risk at both the corporate and DSP level, the methodology THESL uses for assessing and tracking the risk of deferred investment is not a highly standardized process. In addition, asset class level risk registers and an associated asset risk assessment process would assist THESL in being more proactive in ensuring risks beyond reliability are kept within tolerances. Finally, THESL's current portfolio optimization approach is manual, while the industry is moving to using tools which can provide a more comprehensive, programmatic optimization analysis that provides greater transparency into trade-offs.

In order to provide context to its qualitative evaluation of the extent to which THESL's asset management system aligns with the standard for good asset management, UMS also scored THESL's asset management maturity on the ISO 55001 scale and compared it to a database of 14 transmission and/or distribution utility business units for which it had previously conducted asset management maturity assessments. Across the ISO 55001 domains assessed, THESL's average maturity level is a 2.1, while the North American Comparator Average is a 1.6. The range of average maturity levels for the individual comparators ranges from 1.1 to 2.4. The result from the comparison of THESL's maturity scores versus the comparator group confirms and is in alignment with UMS's qualitative assessment of its relevant asset management practices, most of which exceed the industry standard and some of which are in alignment with best practices.

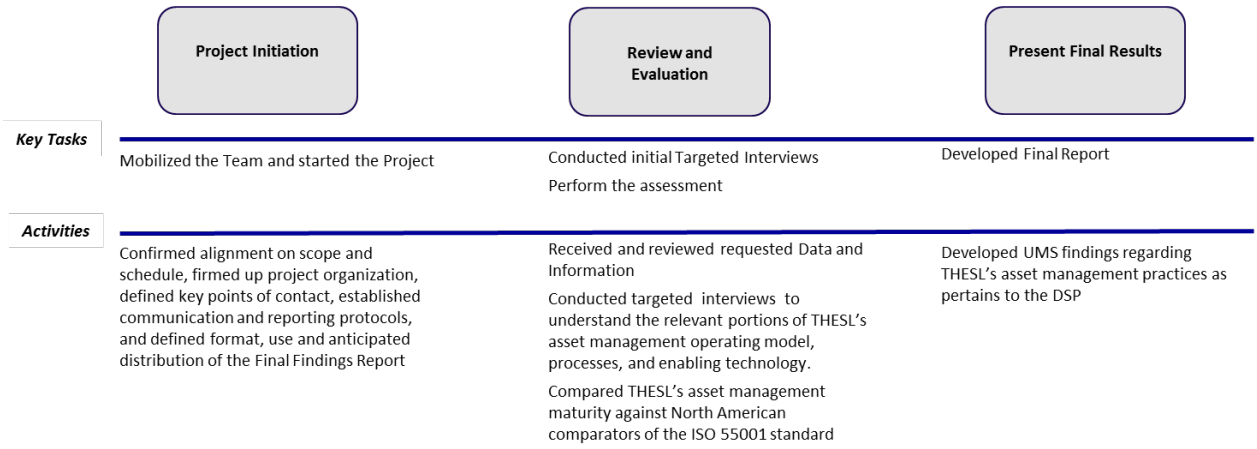


It should be noted that this finding is only against the 11 ISO 55001 domains assessed, not the full 24 domains within ISO 55001. The reason for this subset is that not all aspects of asset management are directly involved in the development of the DSP, and THESL desired a focus evaluation, rather than a more general one. These 11 domains represent the asset management domains that a utility should be using to create a capital plan like the DSP. That being said, and given that UMS did not specifically assess the other 13 ISO 55001 domains, UMS's view, based on the interviews and documentation review performed, is that THESL would likely exceed the industry average across most, if not all, 24 domains as well. However, that assessment is not specifically supported by this review.

SECTION III – PROJECT APPROACH

UMS Group implemented the following Project Work Plan (Figure III-1) to review THESL's asset management practices as relevant to the DSP and evaluate them against the ISO 55001 standard to provide an independent opinion on their competence:

Figure III-1: DSP Asset Management Review Overview



From Project Initiation to the Presentation of Results, UMS Group applied several elements of its endorsed and time-tested asset management assessment methodology to independently evaluate THESL's asset management maturity for those domains relevant to the DSP. The following discussion will expound on those aspects of UMS's approach that contributed to UMS achieving the level of objectivity and relevance needed to provide an independent review.

Practices Assessment

UMS Group met with a number of organizations within THESL (e.g.; Planning Integration, Investment Planning, System Planning, Standards and Technical Studies, Program Management, Engineering Services, Fleet, Facilities, IT, etc.) to gain insights and perspective regarding the asset management practices it uses to develop the DSP. UMS also received demonstrations of some of the key tools used to perform analyses to support decision-making around the DSP. A standard practice of most of UMS's assessment engagement is to perform interviews and review documentation to understand what and how a utility practices asset management. UMS has well established frameworks and interview guides to determine the relative maturity of practices versus the ISO 55001 standard.

DSP Domains

In order to evaluate the application of asset management principles to the development and execution of the DSP, UMS Group identified a number of asset management domains (Table III-1) which are relevant to the efforts undertaken. These domains formed the basis of UMS's

evaluation of asset management maturity, as each was assessed individually against both the relevant ISO 55001 standard and UMS's experience gained from working with numerous North American electric utilities.

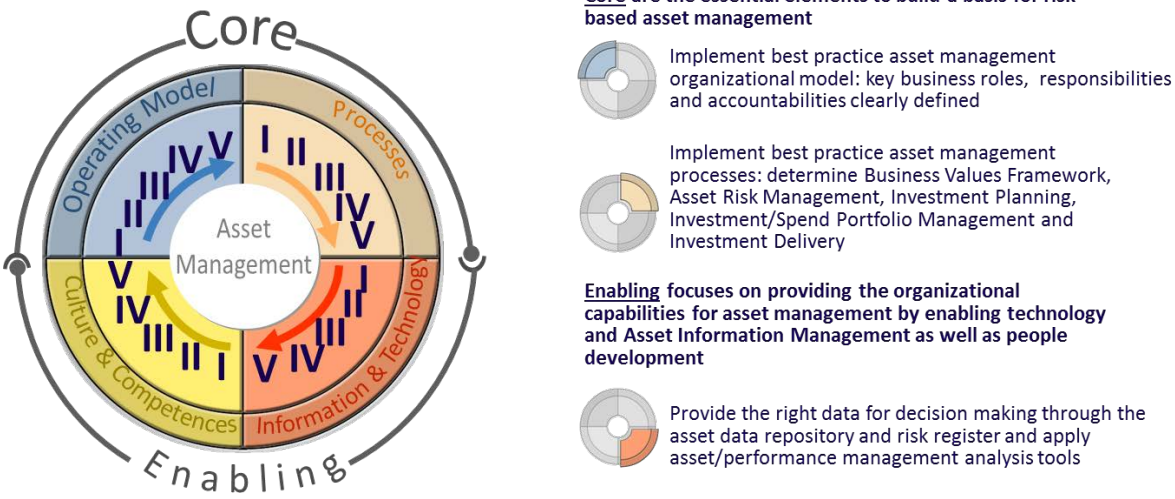
Table III-1: DSP Review Domains

Alignment of Strategy, Objectives, and Initiatives	Line-of-Sight Performance Objectives
Asset Management Systems and Tools	Performance Management
Application of Asset Management Processes	Resource Strategy and Plan to Execute the DSP
Application of Risk to Decision-making	Risk Tolerance
Business Value Framework	Role Clarity in Developing the DSP
Data Collection and Management	Scope of the AM System
DSP Feasibility	Stakeholder Management
DSP Formulation	Strategic Objectives

Strategic Asset Management Model

As an organizing framework, UMS Group used its proprietary Strategic Asset Management (SAM) Model (Figure III-3) which aggregates individual ISO 55001 domains into a holistic, risk based management model for asset-intensive businesses. The model embodies a well-defined organization structure, set of management processes, performance framework, and supporting information systems. The model also aligns with ISO 55001 and puts the key elements of ISO 55001 into a framework that more easily enables understanding of gaps and application of recommendations to improve the asset management system.

Figure III-3: Strategic Asset Management (SAM) Model



Evaluation Model

In defining the framework used to perform the review, UMS linked the DSP domains evaluated to the Strategic Asset Management Model domains. Similarly, the corresponding ISO 55001 Standard domains were linked to the corresponding Strategic Asset Management Model domains. This framework provides a holistic way to directly tie the DSP review to ISO 55001 in a more holistic and understandable format (Table III-3).

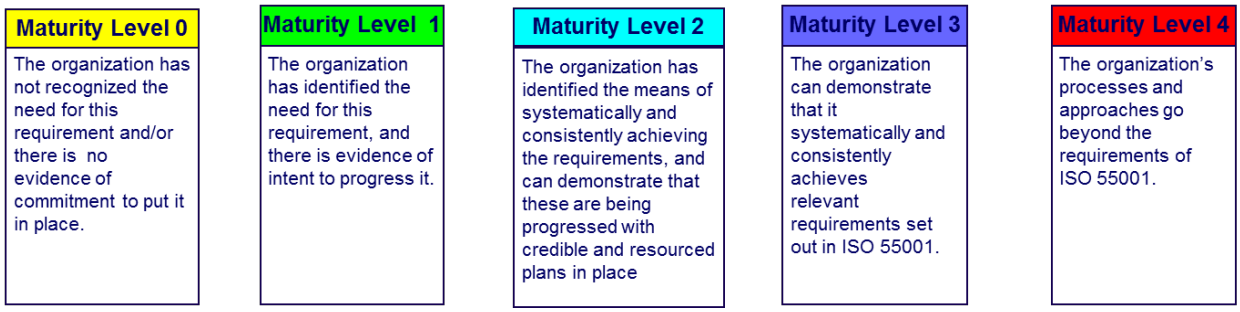
Table III-2: Relationship between ISO 55001, SAM Model, and DSP Domains

DSP Domain	Strategic Asset Management Model Domain	ISO 55001 Domain
Strategic Objectives, Business Value Framework, Stakeholder Management	Operating Model	4.2 Understanding the Needs and Expectations of Stakeholders
Scope of the AM System		4.3 Determining the scope of the AM system
Risk Tolerance		5.1 Leadership and Commitment
Role Clarity in Developing the DSP		5.3 Organizational Roles and Responsibilities
Performance Management		10.3 Improvement
DSP Formulation, Application of AM Processes	Processes	6.2 Asset Management Objectives and Planning
Resource Strategy and Plan to Execute the DSP		7.1 Resources
Application of Risk to Decision-making		6.1 Actions to Address Risks and Opportunities
DSP Feasibility (i.e.; Portfolio Execution)		8.1 Operational Planning and Control
Alignment of Strategy, Objectives, and Initiatives. Line-of-Sight Performance Objectives		9.1 Monitoring, Measurement, Analysis and Evaluation
Data Collection and Management, AM Systems and Tools	Enabling Technology	7.5 Information Requirements

ISO 55001 Maturity Scoring

To perform the comparative evaluation against the utility comparators, UMS Group used the ISO 55001 Maturity scale (Figure III-2) as the standard to assess asset management practices as they relate specifically to the Distribution System Plan (DSP). This scale was used for both THESL and the other assessed comparator utilities.

Figure III-2: ISO 55001 Maturity Scale



In order to be certified as ISO 55001 compliant, a company must be at Maturity Level 3 in all of the ISO 55001 domains. It should be noted that to date, UMS Group knows of only one North American utility business unit which has been ISO 55001 certified – PG&E Gas Operations. Therefore, UMS's intent was not to compare THESL against the certification level of maturity, but rather against the North American utility industry. To do so in a quantitative manner, UMS Group compared THESL against a comparator group made up of 14 North American electric utility business units for which it has performed asset management assessments (Table III-3). While these utilities were not specifically selected to represent the industry as a whole, as a consultancy who has performed scores of such assessments, UMS believes that the results are consistent with its qualitative view of asset management maturity across the North American utility industry.

Table III-3: North American Electric Utility AM Maturity Assessment Comparator Group

Avista Utilities – Distribution	Nova Scotia Power – T&D
Avista Utilities – Transmission	PowerStream – Distribution
EPCOR – Distribution	PSEG LI - Distribution
Lansing Board of Water & Light – T&D	PSE&G - Distribution
Manitoba Hydro – Distribution	Sask Power – T&D
Manitoba Hydro – Transmission	Southern California Edison - Substations
NB Power – T&D	Tennessee Valley Authority - Transmission

SECTION IV – SUMMARY OF RESULTS

The following discussion summarizes the results of an approach that:

- Utilized UMS Group's endorsed and time-tested asset management assessment methodology,
- Drew upon UMS's extensive experience performing asset management assessments and helping develop and implement asset management competencies and tools for utilities, and
- Captured insights and perspectives from key management and staff within the THESL organization.

Review of THESL's Use of Asset Management in the DSP

This section provides UMS's evaluation of the asset management maturity of the key domains which it believes are relevant to development and execution of THESL's 2020-2024 DSP Plan. These domains have been grouped into three areas of the UMS SAM Model – Operating Model, Processes, and Enabling Technology.

OPERATING MODEL

Clarity of Roles and Responsibilities

THESL has clearly defined the roles and responsibilities around asset management and has defined accountability for creation and execution of the DSP. This helps ensure that all necessary process steps to develop the DSP are performed and that decisions are made at the appropriate level. There is a designated responsible person for each of the DSP programs who is responsible for key decisions and actions around each Program. This provides THESL with greater accountability than much of the industry which typically relies on a committee-based approach for decision-making. While committees are good for achieving consensus, they do not provide accountability for decisions or actions which is a requirement for good asset management. In defining programs, alternatives are identified and analyzed to determine how they can help meet objectives. In addition, the decision-making criteria that is applied to this analysis is appropriate for the importance and complexity of the decisions being made. The use of alternative analysis and appropriate decision-making criteria provide both more consistency and transparency in DSP development.

Scope of the Asset Management System

THESL has identified the key assets to be covered by the asset management system, taking into account relevant internal and external issues, and addressing the needs and expectations of stakeholders. The scope of the asset management system is driven by the importance and level of risk around the assets and ensures that asset management processes are applied to the Program assets (i.e., Distribution Infrastructure, IT, Facilities, and Fleet) in the DSP. Similarly, the level of analysis used to develop programs is increased for the major assets which drive

outcomes and are a larger portion of the capital spend. While THESL's asset management system is fairly well defined, the level of documentation around some parts of it could be improved to ensure sustainability.

Incorporation of Strategy and Business Value Framework

THESL has a good understanding of stakeholder needs and expectations and includes them in its decision-making criteria. The process used to develop Programs for the DSP is directly and clearly linked by line-of-sight to the strategic objectives which are based on an assessment of Stakeholder needs and expectations. The outcomes-based framework is based on stakeholder input and directly aligned with the four performance outcomes the Board has established for electricity distributors. Not only does the link between Programs and the outcomes-based framework provide confidence that the DSP addresses the Board's performance requirements, but THESL's process for defining strategic objectives, aligning them with stakeholder needs, and formalizing them into a framework to support asset-related decisions (such as development the DSP) is one of the most thorough and comprehensive that UMS has seen in the North American utility industry.

Application of Risk Tolerance Framework

A corporate risk matrix and tolerance levels have been established and needs and risks are assessed qualitatively as part of project prioritization. In addition, risk is used to identify projects and build programs, as well as to assess feasibility and manage implementation of the DSP. The process around risk management provides assurance that risk is being addressed in constructing the DSP. And while many utilities have a corporate risk matrix and established tolerance levels like THESL, not as many use risk as extensively to drive asset management decisions, nor have many "monetized" risk to be able to calculate a dollar-based risk reduction value as THESL has. At the same time, while risk is used to identify projects and build programs, assessment and monitoring of the risk of deferred investments beyond reliability impacts is not performed using optimization techniques that would align with best practice.

Line-of-sight Performance Management

THESL's asset management process ensures that objectives flow down throughout the organization to individual goals to ensure Line-of-Sight alignment. In addition, a process exists to ensure that performance aligns with the objectives and Management has a monthly review of the asset management system to ensure that it is performing acceptably. Finally, a new initiative will improve tracking of costs and link outcomes to projects to enable continuous improvement. This Performance Management framework around the DSP demonstrates that THESL is striving to identify opportunities to achieve continuous improvement.

Stakeholder Management / Benefit Capture Framework

THESL undertakes both formal and informal efforts to identify stakeholder needs and expectations. Stakeholders have been identified – Customers, Regulator, City, Province, Employees – and their requirements and expectations have been defined through multiple avenues, both formal and informal. Stakeholder needs are reflected in the decision-making framework ("outcomes framework") and are well communicated to the personnel who make the decisions so that they are kept informed on stakeholder needs. The process used to engage

stakeholders, identify their needs, and translate them into outcomes helps ensure that the DSP aligns the interests of the Distributor with those of customers and public policy. In addition, THESL's benefits capture framework exceeds what is typically seen in the industry in terms of formally translating these needs and expectations into desired outcomes which are linked to DSP Program development. To achieve best practice, THESL would need to measure the results of its efforts against the desired outcomes and use deviations to drive performance improvement initiatives. This is an action which THESL has said it plans to undertake for the 2020-2024 period.

PROCESSES

Distribution System Plan Formulation

THESL has a well-defined process for creating the DSP that takes into account needs and risks as part of its prioritization process and links decisions to its objectives. asset management is integrated with Financial and Business Planning to achieve the strategic objectives. The Programs take into account requirements from outside the asset management system such as financial constraints, resource constraints, and legal/regulatory constraints. Individual projects are identified through a variety of qualitative and quantitative analyses, and comparing individual projects puts a strong reliance on subject matter experts to make the right choice.

For Distribution, condition assessment is a key driver for plan development, with the level of condition assessment used to drive DSP programs varying for different asset classes. For Fleet, lifecycle replacement timing drives development of the plan based on current vehicle mix and age. For IT, equipment is replaced on a fixed lifecycle schedule. Applications are prioritized based on business case analysis of alternatives incorporating risk. For Facilities, the program is driven by poor condition assets, age, and criticality. Overall, the processes used to formulate the DSP provide confidence that it was created using sound asset management techniques.

THESL uses an optimization, rather than prioritization approach to its Program portfolios which exceeds what is typical in the industry. However, THESL's current optimization approach is manual, while the industry is moving to using tools which can provide a more comprehensive, programmatic optimization analysis. THESL has recognized this improvement potential and has said it is exploring opportunities to move to a more automated methodology to ensure that it is selecting the projects and overall portfolio which will deliver the most value against the desired outcomes.

Distribution System Plan Feasibility

THESL's practices for assessing the feasibility of the DSP are in alignment with or exceed industry standard practice. Senior Leadership sets objectives and selects the level of funding for Programs. Outcomes are modeled to determine if Programs meet objectives and if not, the Program goes back to Designated Responsible Person with a request to assess changes to Programs or alternatives. The evaluation of Programs to determine if they can deliver on the objectives despite constraints, as well as the costing out of the Programs using high-level average costs is consistent with the approach used by most of the industry.

THESL's practices around ensuring delivery of the DSP border on best practice in terms of having a cross-functional Project Development Group to develop cost estimates, conduct constructability reviews, develop execution strategies, and gain stakeholder agreement. This is also true for the Program Management group which matches projects to the resource pool, uses resource availability to schedule projects, and makes decisions whether to use internal or external resources.

THESL treats and monitors risks identified through a risk assessment of each project. Risks are also assessed at the program level where a mitigation strategy is developed and monthly reporting performed. This use of individual project risk assessments, program risk assessments, and avoidance of contingencies built into budgets is a more sophisticated way of managing implementation risk than used at most utilities. Overall, the process used to assess and manage DSP feasibility provides a high degree of confidence that the DSP will be achieved.

Performance Management

THESL has a process which provides line-of-sight to corporate objectives and ensures that the assets and the asset management system are performing as expected and achieving targeted stakeholder outcomes. The performance of both capital and maintenance work is also tracked to ensure compliance with asset management strategies and programs, as well as to drive continuous improvement in execution efficiency and effectiveness. In addition, for the 2020-2024 DSP, THESL will link projects to outcomes to track that they deliver cost-effective benefits to customers. This performance management framework of THESL's is in alignment with best practice asset management in terms of linking strategy to actions and measuring the results. The performance management framework also helps ensure THESL is meeting the objectives established in the DSP. While most utilities measure performance, many find it difficult to link the actions directly to the utility's strategic objectives. In addition, many utilities do not have a good performance feedback loop to ensure that non-conformities and opportunities for improvement are identified and addressed. THESL has both parts of the process and is continually increasing the use of performance results to drive improvement.

Application of Asset Management Processes

THESL has a number of key asset management processes which are used in developing the DSP. Asset risk management is performed as part of lifecycle optimization, as well as in response to specific incidents, and critical assets have a more targeted risk assessment focused on them. Lifecycle planning is performed across all the divisions to understand the trade-offs between alternatives and optimize on cost, performance, and risk. Maintenance strategies are developed through RCM and lifecycle analysis, where appropriate, and adjusted as necessary. Asset Condition Assessment has transitioned from a relatively simplistic model which is consistent with industry standard practice to a more sophisticated one which uses best practice techniques. Failures are forecast and reliability projections are used to understand medium- and long-term threats from asset failure which is then used to guide Program development. Assets are not just assessed individually, groups of assets are assessed to identify opportunities to replace assets in a more cost efficient manner (i.e., area replacement). Monetized risk models exist and are used to identify risk and develop the economic business case for decisions. As a whole, the asset management processes provide confidence that the DSP delivers value to stakeholders by

optimizing decisions from an asset lifecycle perspective and balancing risk with cost and performance.

The use of lifecycle planning to understand the trade-offs between alternatives and optimize on cost, performance, and risk; the use of failure forecasting to develop reliability projections; and the use of monetized risk models to assess the financial cost/benefit of projects are all examples of practices that exceed what is typically found in utility asset management programs. The new asset condition assessment model (based on CNAIM) is in alignment with best practice techniques. Outside of the Distribution System assets, Fleet's asset management processes are consistent with the level of maturity typically found in the utility industry in this domain. IT's performance of risk assessments, lifecycle analysis, and business cases exceeds industry standard practices for this domain. Facilities' use of lifecycle analysis, failure-based maintenance strategies, asset condition assessments, and criticality and risk assessment place it above the average utility Facilities organization in asset management competence.

ENABLING TECHNOLOGY

Data Collection and Management

THESL has identified the data needed to support its asset management activities and has implemented technology to assist in collecting and managing that data. Data quality is reported to vary by asset class, but is generally thought to be good for major assets. While, UMS did not directly examine data, through its interviews, UMS determined that the quality of data THESL uses to supports its asset management decisions and practices, including formulation of the DSP, is consistent with the industry as a whole. As is common in most utilities, data quality varies by asset class, but is generally good for major assets, particularly asset classes with small numbers of expensive assets. Having sufficient and reasonable quality data helps assure the accuracy of the decisions that the DSP is built upon. To continue moving towards best practice in data collection and management, THESL continues to develop data quality measures and address deficient data needed to improve decision-making.

Asset Management Systems and Tools

THESL has the necessary tools and models to perform best practice asset management analyses. In some cases, THESL exceeds industry standards with its tools and models, such as those used to support key asset management analyses such as asset health indexing, lifecycle costing, risk costing, economic analysis, and reliability analysis. THESL is also using best practice Business Intelligence tools to develop Programs that are more efficient. THESL has an asset register to capture asset data for each asset type (e.g., Distribution, Fleet, Facilities, IT, etc.) and a risk register exists at the corporate level. While this use of an asset register and a corporate risk register to support asset management are in alignment with typical industry practices, best practice would be to have an asset risk register to track risks for individual asset classes. Overall, the application of systems and tools to perform needed asset management analyses provides confidence that the DSP is data-driven and based on appropriate asset lifecycle analysis.

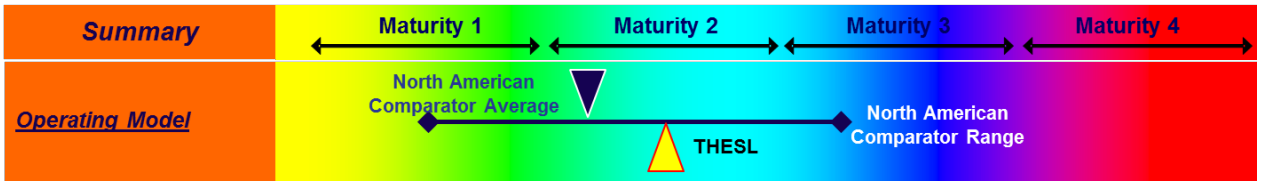
Comparison of THESL to Comparator Group

In addition to the evaluation of THESL's application of asset management to the development and execution of the DSP, UMS assessed the maturity of THESL's asset management capabilities against the international standard, ISO 55001. For reference purposes, UMS used a group of 14 North American utilities ("comparators") for which it had previously performed asset management maturity assessments. While these utilities were not specifically chosen as a representative sample of the electric utility industry, based on UMS's experience performing utility asset management assessments, as well as assisting utilities in building their asset management capabilities, it believes the results are a reaonably accurate representation of the North American industry.

In order to make the results more meaningful from a holistic perspective, UMS aggregated the scores across the domains in the Strategic Asset Management (SAM) Model.

The Operating Model domain assesses the extent to which the asset management system aligns with ISO 55001 standards for good asset management in terms of the definition and distinction between roles, responsibilities, and accountabilities. It also evaluates the consistency between overall strategy, the underlying philosophy in managing the assets, and the deployment of personnel in capturing the value of installed assets. Finally, it assesses the degree to which stakeholder needs and expectations are captured and used to drive business decisions.

Across the sub-domains which make up this domain (see Table III-3), UMS scored THESL as an average 2.0 maturity, while the comparator group average was 1.6. The maturity level of individual comparators (averaged across the sub-domains) ranged from 1.0 to 2.7.



THESL's scores in the five ISO 55001 domains which make up this aggregated score range from 1.8 to 2.5. As Table IV-1 below demonstrates, THESL's asset management maturity exceeds the comparator group average maturity in all the sub-domain areas that make up the Operating Model domain.

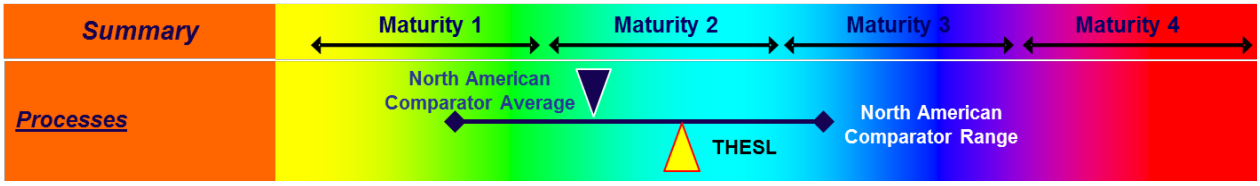
Table IV-1: Comparison of THESL against Comparators (Operating Model)

ISO 55001 Domain (SAM Domain)	Maturity Level 3 per Standard	UMS Assessment of THESL	THESL Maturity	Comparator Avg. Maturity
4.2 Understanding the Needs and Expectations of Stakeholders (Operating Model)	The organization identifies stakeholders that are relevant to the AM system, and captures their requirements and expectations. The organization determines criteria for AM decision making which includes where appropriate consultation with relevant stakeholders. Relevant stakeholder requirements are determined for recording of	Multiple formal and informal efforts are undertaken to understand stakeholder needs and expectations which are reflected in the decision-making framework.	2.5	1.9

ISO 55001 Domain (SAM Domain)	Maturity Level 3 per Standard	UMS Assessment of THESL	THESL Maturity	Comparator Avg. Maturity
	information relevant for AM, and for their reporting internally and externally.			
4.3 Determining the scope of the AM system (Operating Model)	The scope of the asset management system is clearly documented in terms of its boundaries, applicability, interfaces with other management systems and the asset portfolio covered. It is also aligned with AM Policy and Strategy (SAMP).	The scope of THESL AM system and its outputs enable the delivery of the organizational objectives. Overall AM system documentation could be improved.	1.8	1.6
5.1 Leadership and Commitment (Operating Model)	Top management ensures that the AM Policy, SAMP, and Objectives are in place and consistent with organizational objectives. The AM system is fully integrated with the organization's business processes. The approach used for managing AM related risk is aligned with the organization's risk management approach.	Asset management is integrated with the DSP planning process. A corporate risk matrix and tolerance levels have been established to provide a consistent basis for managing risk.	2.0	1.6
5.3 Organizational Roles and Responsibilities (Operating Model)	Top management has assigned responsibility and authority for: i) establishment and update of the SAMP, AM objectives and AM plans; ii) ensuring the adequacy, suitability and effectiveness of the AM system in delivering the strategy and conforming to ISO 55001; and iii) reporting on the performance of the AM system.	Roles and responsibilities for asset management (and the DSP) have been clearly defined.	2.0	1.4
10.3 Improvement (Operating Model)	The organization can demonstrate that the suitability, adequacy and effectiveness of its AM system is being continually improved through its processes for monitoring and evaluation, reviews by top management, and the existence of AM objectives and actions designed to improve the system.	Performance of the DSP in terms of results are tracked to both ensure conformity with AM strategies and programs and identify opportunities for improving execution efficiency and effectiveness.	2.0	1.7

The Processes domain assesses the extent to which the asset management system aligns with ISO 55001 standards for good asset management in terms of the consistency of risk analysis methodology and investment planning, and linking it to asset management policy and corporate/business area strategy. It also assesses the extent to which investments are identified, prioritized and optimized based on overall value, resources, and risk; as well as how asset management plans, processes and procedures are factored into the planning and execution of capital projects and O&M programs. Finally, it assesses how strategy is aligned with action through use on line-of-sight measures.

Across the sub-domains which make up this domain, UMS scored THESL as an average 2.1 maturity, while the comparator group average was 1.6. The maturity level of individual comparators (averaged across the sub-domains) ranged from 1.1 to 2.6.



THESL's scores in the five ISO 55001 domains which make up this aggregated score range from 2.0 to 2.2.

As Table IV-2 below demonstrates, THESL's asset management maturity exceeds the comparator group average maturity in all the sub-domain areas that make up the Processes domain.

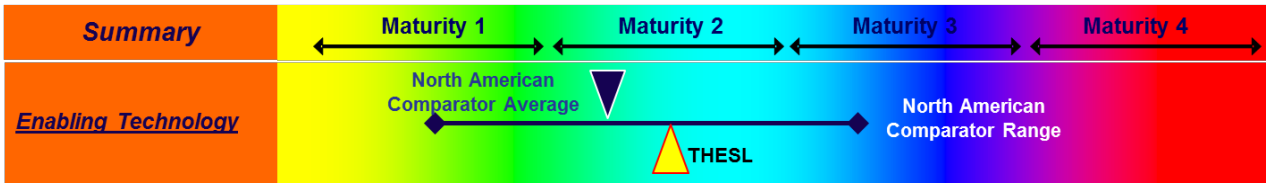
Table IV-2: Comparison of THESL against Comparators (Processes)

ISO 55001 Domain (SAM Domain)	Maturity Level 3 per Standard	UMS Assessment of THESL	THESL Maturity	Comparator Avg. Maturity
6.1 Actions to Address Risks and Opportunities (Processes)	Processes and measures are in place to assure that the desired outcomes of the AM system are achieved and undesired effects are mitigated. Internal and external context and stakeholder requirements are considered in determining the risks and opportunities. The organization monitors the effectiveness of actions and processes for addressing the risks and opportunities, and can demonstrate how continual improvement is achieved through risk and opportunity management.	Risk assessment is carried out across multiple dimensions and at multiple points in asset lifecycle analysis. Opportunities are identified both internally and externally through communication with stakeholders. Risk and performance are monitored.	2.2	1.8
6.2 Asset Management Objectives and Planning (Processes)	The organization has documented AM objectives to align with and enable achievement of organizational objectives and AM policy. It considers stakeholder and other requirements in establishing AM objectives. It effectively communicates its AM objectives with those responsible for achieving them. The AM objectives are measurable, monitored, reviewed and updated. It has established and documented its planning processes, methods and decision criteria to achieve objectives.	There is a clear link between asset management objectives and the DSP programs. AM processes are in alignment with industry standard practice and in many cases exceed them.	2.0	1.7
7.1 Resources (Processes)	The organization can demonstrate that it has evaluated and provided adequate resources to establish, maintain and improve the asset management system.	A defined process and responsible group exist to determine the resources needed, including the division of work and use of external resources.	2.2	1.7
8.1 Operational Planning and Control (Processes)	Operational planning and delivery processes are being controlled in accordance with the specified criteria. Documented evidence provides assurance that processes have been carried out as planned. Risks associated with delivery activities are being managed.	Program Management oversees planning and control processes to ensure execution of the DSP, including risk management.	2.0	1.5
9.1 Monitoring, Measurement, Analysis and Evaluation (Processes)	The organization can demonstrate that it has established what needs to be monitored / measured so it can determine whether it achieves the intended outcomes of its AM system.	A performance management framework exists which links directly to strategic objectives and outcomes are compared to targets. A formal process exists for monitoring the asset management system to ensure it is meeting objectives.	2.2	1.3

The Enabling Technology domain assesses the extent to which the asset management system aligns with ISO 55001 standards for good asset management in terms of whether the asset

management information management architecture and processes (for systems and data) in place are adequate to support asset-related decisions.

In this domain, UMS scored THESL as a 2.0 maturity, while the comparator group average was 1.7. The maturity level of individual comparators ranged from 1.0 to 2.8.



As Table IV-3 below demonstrates, THESL's asset management maturity exceeds the comparator group average maturity in the one sub-domain area that makes up the Enabling Technology domain.

Table IV-3: Comparison of THESL against Comparators (Enabling Technology

ISO 55001 Domain (SAM Domain)	Maturity Level 3 per Standard	UMS Assessment of THESL	THESL Maturity	Comparator Avg. Maturity
7.5 Information Requirements (Enabling Technology)	All information identified as required for asset management purposes is defined, along with the sources, quality assurance requirements and processes to manage the information. The information is traceable and consistent, including between financial and non-financial information.	THESL has identified the information needed to support development of the DSP and has implemented appropriate technology to use data to support decision-making	2.0	1.7

Appendix A – UMS Group Qualifications

UMS Group is an International Utility Management Consulting firm founded in 1989 to serve the global electric and gas utility industry which specializes in asset management and performance management. UMS is a private employee-owned company incorporated in New Jersey with headquarters in Parsippany, New Jersey, and major branch offices in Australia, The Netherlands, and The Philippines. This project was managed out of UMS Group's Headquarters Office, located at Morris Corporate Center 1, 300 Interpace Parkway, Suite C380, Parsippany, NJ 07054.

UMS brings to its clients a unique knowledge of global industry best practices, an advanced library of diagnostic methodologies and performance benchmarking data, and a strong base of utility strategic and operational expertise. UMS combines experienced utility consultants and seasoned industry professionals with world class tools and intellectual capital to assist its clients in diagnosing problems, designing solutions, and implementing change.

UMS Group has been a leading provider of asset management services to utilities for over 25 years. It published its first industry report on this topic – the "International Strategic Asset Management Report" in 1992 after conducting a worldwide search for best practices in utility asset management. In the decades since, UMS has developed and continually adapted its methodologies to align them with emerging industry standards; while retaining and refining its proprietary tools and delivery systems.

In recognition of this industry profile, in 2007 UMS Group was invited to participate in the review and update of PAS 55 (Publicly Available Specification 55), the British Standards Institute's definitive specification for Strategic Asset Management processes, practices and organization elements. In August 2010, UMS Group, as one of the first 11 firms so named, was appointed an Endorsed Assessor by the Institute of Asset Management (IAM). The Endorsed Assessor designation followed a rigorous IAM review of the expertise, practices, tools and techniques which UMS Group applies to asset management compliance assessments. UMS has since been appointed both an Endorsed Assessor and an Endorsed Trainer for ISO 55001.

In assisting its clients in meeting the relevant aspects of the international standard, ISO 55000 and the former UK based standard, PAS 55, UMS provides added assurance that they have all the programmatic elements in place to manage their assets, and importantly, to manage all known and implied risks, thus creating superior lifecycle value from their owned and/or operated asset base. In this way, UMS bridges the gap between theoretical knowledge and practical application.

UMS Group also has extensive experience in leading and facilitating major strategic asset management transformations – perhaps more than any other global consultancy dedicated to the utility industry. The major strategic asset management transformations facilitated by UMS Group for 24 separate major clients are credited with achieving significant cost reductions/productivity improvements, process efficiency and effectiveness improvements, system reliability and customer satisfaction improvements and OpEx and CapEx optimization. In addition, this practice competency has given rise to a number of asset management decision support tools.

In 2009, UMS Group created an international consortium of electric transmission companies focused on improving the effectiveness of their Asset Management function. The International Transmission Asset Management Study (ITAMS) provides participants (currently 14 global utilities) with an assessment of their Asset Management Operating Model, Processes, Competences, and Enabling Technology against both their peers and the ISO 55001 standard. It also provides a forum for discussing asset management best practices and a network of contacts for continual sharing and learning.

Apart from these credentials, UMS has accomplished similar projects with clients in various markets around the world. The following table (A-1) summarizes the successful completion of relevant, recent North American projects.

Table A-1: Recent UMS Group North American Asset Management Engagements

Client / Project	Relevant Analyses
Avista Utilities	• Asset Management Maturity Assessment • Asset Management Business Case Development
Nova Scotia Power	• Asset Management Maturity Assessment • Asset Management Operating Model
Manitoba Hydro	• Asset Management Maturity Assessment
Southern California Edison	• Asset Management Maturity Assessment • Asset Management Gap Closure Implementation Plan • Economic Model Development
Tennessee Valley Authority	• Asset Management Maturity Assessment • Asset Management Transformation
PSE&G and PSEG LI	• Asset Management Maturity Assessment • Asset Management Operating Model Development
Lansing Board of Water & Light	• Asset Management Maturity Assessment • Asset Management Transformation
AES	• Asset Management Maturity Assessment • Asset Management Plan Development
PG&E	• Asset Management Plan Development
Baltimore Gas & Electric	• Economic Model Development
Portland General Electric	• Portfolio Optimization Process and Tool
Dominion Resources	• Portfolio Optimization Process and Tool

Experience Summary of Steven J. Morris

Mr. Morris is a Principal of UMS Group. He has 30 years of consulting and management experience with the last 23 years spent in the electric and gas utility industries. He has significant expertise in asset management, performance management, strategic planning, financial analysis, and benchmarking and has written/edited dozens of analytical reports on utility industry topics.

He also leads most of UMS' North American asset management maturity assessment projects and is currently responsible for leading the firm's client-sponsored benchmarking and best practices study projects in which ad hoc groups of utilities are brought together to perform targeted, deep dive studies into issues of industry concern.

Prior to joining UMS, Mr. Morris worked for both Andersen Consulting and Navigant Consulting. He also founded Research Reports International, a business focused on providing data and information on key issues facing electric and gas industry executives. Mr. Morris holds a B.A. in Economics and an M.B.A. both from Cornell University.

Highlights of Experience

Led an Asset Management Gap Assessment for a Western U.S. vertically integrated electric and gas utility. Assessed Generation, T&D, Facilities, and IT business units' asset management maturity versus the IAM Maturity Model. Identified alternative Delivery Models to close gaps and developed Business Cases for each model. Identified Alternative Approaches for asset management Operating Models and developed an Implementation Roadmap for closing gaps and implementing the new Operating Model.

Led an Asset Management Gap Assessment for a Canadian vertically integrated electric utility. Assessed Generation, T&D, Facilities, Vegetation Management, and Vehicle Fleet business units' asset management maturity versus the IAM Maturity Model. Developed recommendations for combining business unit asset management functions into an Enterprise Asset Management group. Facilitated site visits for key executives to other North American electric utilities to discuss best practice asset management tools, processes, and techniques.

Led a multi-year Asset Management Transformation for the Transmission Business Unit of a large Southern, multi-state electric utility. Project required creation of an Asset Management organization and development and implementation of all capabilities needed to meet ISO 55001 competence requirements. Specific deliverables included AM Policy, AM Vision, Strategic Asset Management Plan, Asset Risk Assessments, Asset Management Plans, AM Training Program/Material, Economic Lifecycle Models, Data Architecture, and Performance Management Framework.

Led an ISO 55001 Asset Management Gap Assessment for a Canadian Crown Corporation Electric Utility. Performed a corporate-level assessment and individual assessment for the Generation, Transmission, and Distribution business units. Identified gaps and developed prioritized recommendations for closing the gaps. Performed a Work Shop for Executive Leadership to educate them on asset management, discuss the recommendations from the assessment, and review options for organizational structure of asset management.

Led an Asset Management Gap Assessment project for a large Northeastern combination (gas & electric) utility. Review all aspects of current asset management practices against the ISO 55000 standard in order to identify gaps in processes, practices, data, technology, organization, and competencies. For gaps identified, assessed cost, difficulty, and impact of implementation, and created a roadmap structured around designing the needed changes, implementing the changes and working the new processes, and becoming excellent at asset management.

Led an ISO 55000 AM gap assessment for a West Coast electric utility's Generation business unit. Performed an assessment at both the business unit and plant level identifying both gaps and differences in practices. Following completion of the Gap Assessment, led a significant number of Business Unit staff through a 2-day workshop to familiarize them with AM concepts and link them to the findings of the gap assessment. Led the development of a detailed implementation plan to execute a complete Asset Management Transformation for the organization. This plan included identifying all tasks for the 11 work streams needed to close the AM gaps, resource loading those tasks, developing a detailed project scheduled for those tasks, and costing out the tasks. Deliverables included development of an Excel model which calculated time and cost trade-offs between use of internal and external resources at the work stream level for each asset class. End result was a 9000 line item Project plan with a 3 ½ year time frame and 50,000 man-hours of work identified.

Led a project to develop and implement an economic modeling tool and process to support a Canadian Gas utility's natural gas distribution and storage assets. Developed failure curves, identified degradation factors, and developed AHI formulations for 33 asset sub-classes. Developed economic model to link AHI, failure probability, risk, consequence, and intervention costs into an analysis of optimal life cycle replacement. Defined processes for implementing, operating, and updating overall framework and methodology for ongoing use in rate cases development, capital planning, and asset management decision-making.

Led a project to develop and implement a process and analytical tools to support decisions related to the health of a West Coast utility's station assets. Identified the customized functionality necessary for existing AHI tool in order to provide the decision support capabilities required. Developed algorithms for determining effective age and identified the sources of input data needed for the model. Defined failure modes and assessed impact of failure. Defined and map the processes needed to make optimum use of the tool.

Led a project for a major West Coast combination utility to develop skills and competencies in asset management for Transmission and Distribution. Performed 2-day Asset Management Workshop for 30 client managers and engineers. Developed template and process for creating Asset Life-cycle Strategies and supported client Asset Strategists in creating the first two strategies, Distribution Wood Poles and Substation Transformers.

Lead an industry forum, the Substation Construction, Maintenance, and Asset Management Best Practice Collaborative, which comprises approximately 20 North American electric utilities who conduct an annual study and share best practices at an annual conference. Now in its 6th year, Mr. Morris created the initial program and has been Program Director since its inception in 2013. Facilitates meetings with the Steering Group to determine annual program content. Oversees design and administration of study, development of study report, conference agenda, and execution of the conference.

Recent Publications/Presentations

- The Development of a Proactive and Predictive Integrity Management Model, World Gas Conference, Washington, DC, June 25-29, 2018

- ISO 55000 Certification Panel, WEI Operations Conference, Phoenix, AZ, April 25-27, 2018
- Real World Experience in Developing Asset Management Plans, CEATI Strategic Asset Management Conference, Vancouver BC, November 1-2, 2017

Power System Engineering, Inc.

Full-service consultants



Standards Review – 2018 Update

Prepared for:

Toronto Hydro Electric System Limited

July 31, 2018

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July 31, 2018

Toronto Hydro Electric System Ltd.
Ms. Emma Halilovic
500 Commissioners Street
Toronto, Ontario
Canada

Subject: Standards Review – 2018 Update

Dear Emma:

I am pleased to present the enclosed Standards Review - 2018 Update report for Toronto Hydro Electric System Limited's consideration. The report reflects our review process as well as our findings.

Please do not hesitate to contact me with questions.

Respectively submitted,

Erik S. Sonju

Erik S. Sonju

Table of Contents

1 Introduction 1
1.1 Background and Purpose 1
1.2 Review Scope 1
1.3 Approach 3

2 Design & Construction 4
2.1 Standard Design Practices 4
2.2 Distribution Construction Standards 5

3 Material Specifications 7
3.1 Equipment Technical Specifications 7

4 Procedural Processes 9
4.1 Major, Non-Major and Ancillary Equipment Approval 9

5 Conclusion 10

6 Appendix 12

1 Introduction

1.1 Background and Purpose

Toronto Hydro Electric System Limited ("THESL") is the largest municipal electrical distribution company in Canada, serving approximately 766,000 customers in the City of Toronto. THESL is the result of six different utilities that amalgamated on January 1, 1998. This amalgamation nearly tripled Toronto Hydro's customer base at the time. Following the amalgamation, THESL initiated the process of integrating various engineering and construction standards, practices, and processes (herein referenced as "Standards") of the different utilities. The result was a single comprehensive set of Standards with the focus on the principles of safety, reliability, and efficiency, while also working within the framework of industry best practices.

In 2010, THESL re-structured its Standards Department with the direction to establish, refine, and maintain the company's Standards that pertain to the design, materials, construction, and maintenance of the electric distribution system infrastructure. This undertaking resulted in three years of dedication by the Standards Department to review and renovate all major Standards used by THESL's engineering and operations personnel. In 2013, before fully deploying the results of their efforts, the Standards Department determined value in hiring an outside independent party to review what had been assembled as a method to ensure the Standards met established industry practices and promoted the previously mentioned principles. Subsequently, THESL retained the services of Power System Engineering, Inc. ("PSE") to conduct this review.

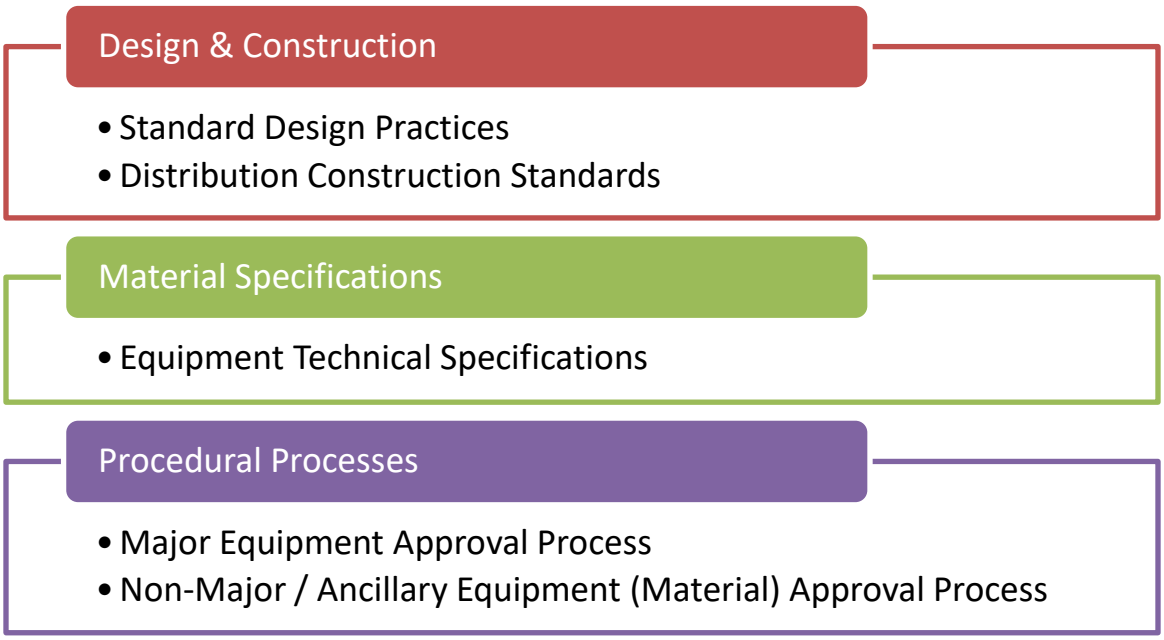
In January 2014, PSE provided THESL with a report summarizing the result of the independent third-party review ("2014 Independent Review"). The review process conducted by PSE consisted of interviews with key individuals in the Standards Department and examination of Standards that were to be deployed across the Company. The focus throughout the review process was to determine if THESL's Standards advocated the principles of safety, reliability, and efficiency, as well as followed industry best practices.

Following the 2014 Independent Review, the THESL Standards Department continued to maintain their Standards through a managed revision process. In March 2018 THESL retained the services of PSE to conduct an update to the 2014 Independent Review, with a focus on Standard revisions that occurred between January 2014 and March 2018. The purpose of this report is to summarize PSE's review of the revised standards ("2018 Independent Review").

1.2 Review Scope

There are three major Standard categories that heavily influence the design, construction and maintenance of THESL's electric distribution infrastructure. These categories include design and construction, major material specifications, and procedural processes. Within the design and construction category are THESL's Standard Design Practices and Distribution Construction Standards. The material specifications category is controlled through THESL's Equipment Technical Specifications. Finally, THESL's Major, Non-Major and Ancillary Equipment

Approval Process sets the structure of internal Procedural Processes. Each Standard has a specific focus, yet each of the individual Standards complement each other, creating a comprehensive framework for all design, construction and maintenance activities associated with the THESL's electric distribution infrastructure.



1.3 Approach

As previously indicated, the purpose of this 2018 Independent Review is to address Standard revisions that occurred between January 2014 and March 2018. As such, the volume and type of information reviewed was extensively less than that covered in the 2014 Independent Review. Therefore, the review process was conducted by two PSE industry experts who specialize in electric distribution systems as compared to a larger team.

The following industry experts participated in this review include:

- **Erik S. Sonju**
  Erik earned a BS degree in Electrical Engineering from North Dakota State University at Fargo, North Dakota with an emphasis in power systems. He has over 20 years of experience in the power industry, with the majority of those years providing professional engineering consulting services to electric utilities and private industry throughout the United States and Canada with an emphasis in planning and design. He regularly presents at industry conferences on a variety of topics. Erik is a licensed Professional Engineer in 20 states and in the Canadian province of Saskatchewan.

- **Douglas R. Joens**
  Doug earned a BS degree in Electrical Engineering from South Dakota State University at Brookings, South Dakota. He has over 40 years of experience in electric utility distribution system planning, substation and line design, system protection and operation, and work order inspections. He has also participated in large power contract negotiations, and has managed projects related to overcurrent protection and on-site generator installations. Doug is a licensed professional engineer in Minnesota and Alaska.

The review of the revised Standards was divided amongst the abovementioned individuals. Following their review, they jointly discussed their findings for developing this report. The review was conducted at a high level with similar intentions used in the 2014 Independent Review.

In addition to the review, specific Standard revisions questions that arose during the review were submitted to THESL.

2 Design & Construction

2.1 Standard Design Practices

The Standard Design Practices (SDP) document confers THESL's Standards as they relate to the design of the electric distribution system.

PSE specifically reviewed Revision 3 of the SPD that was approved on February 8, 2018. The SDP Revision 3 contained approximately 125 modifications as compared to SDP Revision 2 with the purpose of alignment amongst other standards and processes, continuous improvement, third party requirements, and general engineering & operations considerations.

Overall, PSE found the SDP to be aligned with others in the industry. Only a few minor items were noted. These items are summarized below along with THESL's comments.

LED Luminaires

PSE noted that the lighting section of the SDP did not mention the application of LED luminaires while they were included in the material technical specification.

THESL verified that they have developed technical specifications and approved an LED luminaire, which was installed at several LED pilot sites in 2015. THESL further verified that although LED luminaries have been installed in a couple of projects at the City's request, the City has not given official direction to implement LED lighting on a large scale. Therefore, the currently approved street lighting standards include High Pressure Sodium (HPS) and Metal Halide (MH).

Direct Buried Conduit

PSE noted that the application of direct buried conduit was not prominent in the SDP.

THESL verified that concrete encased ducts are used if: 1) ducts are carrying primary cables (750 V or more), 2) ducts are under roadway or driveway, 3) ducts have 90 degree bends, 4) the number of ducts are more than 8. Direct buried conduit is used if these categories do not apply. Additionally, THESL verified that in certain instances (ex. replacement of primary direct buried cables within a townhome complex with various grade levels/retaining walls and mature trees), direct buried conduits are used. THESL also indicated that they are currently co-funding a CEATI initiative to evaluate direct buried duct vs. concrete encased duct which is anticipated to be completed in September 2018.

Voltage Rating of Cutouts

PSE noted the use of 25kV cutouts, rather than 15kV cutouts, on the 13.8kV system.

THESL verified that they have found benefit, from a material inventory standpoint in using 25kV cutouts on both their 13.8kV and 27.6kV systems.

Secondary Voltage Drop

PSE noted the maximum allowable voltage drop on the secondary bus and service cables as it relates to voltage variation limits.

THESL clarified that the maximum allowed voltage drop (in terms of Volts) shall be less than the voltage drop calculated from voltage variation limit levels.

Unmetered Connections

PSE noted a misunderstanding of unmetered connection replacements.

THESL clarified that rather than unmetered connections, it is the service cables that may be replaced if determined from field conditions. THESL verified that this clarification will be made in Revision 4 of the SDP.

Conductor Replacement Based on Splices

PSE noted that bare primary conductors shall be re-used when it does not have more than two splices per span.

THESL confirmed this requirement.

PSE recommends that THESL considers splices within multiple adjacent spans when considering the replacement or re-use of a conductor.

Of the items noted above, THESL could provide PSE with corresponding clarifications of, or justifications for, their standard design practices. For example, THESL has an action plan to further assess their practices around the application of direct buried conduit following the completion of a third-party study being conducted by CEATI. Another example is the application of LED street lighting which is pending direction from the City of Toronto. These examples, along with clarifications provided by THESL, gave PSE a level of satisfaction that the SDPs are well thought through and are backed by sound engineering analysis and decision making.

2.2 Distribution Construction Standards

The Distribution Construction Standards (DCS) provide Standards applicable to construction of the THESL electric distribution system.
PSE only reviewed construction standards that have been revised since the 2014 Independent Review. Since this review, THESL made 12 revision releases (Standards Revision #42 through

#53). A copy of these revision releases and the corresponding DCS revisions are provided as an Appendix to this report.

Overall, PSE found the DCS revisions to be aligned with others in the industry. Only a few minor items were noted. These items are summarized below along with THESL's comments.

Replacement of Design Guides (DCS 7-3100 through 7-3400)

PSE noted the removal of certain design guides that are used for determining certain factors such as guying.

THESL verified that all guying design analysis is carried out by using a pole loading analysis tool available to designers or a non-linear pole loading analysis software program. These tools have made DCS 7-3100 through 7-3400 obsolete.

Three-Bolt Clamps (DCS 7-5300)

PSE noted the application of 3-bolt clamps used on guy wires.

THESL verified the use of pre-formed guy grips on all connections to a guy wire with the exception at the lower connection point. A 3-bolt clamp is used at the lower connection point to allow for adjustment of the guy tension.

Elbow Arrestor on Radial Fed Padmount Transformers (DCS 7-5300)

PSE noted the absence of elbow arresters on radial fed padmount transformers.

THESL verified that they do not apply elbow arresters on radial fed padmount transformers.

PSE recommends the application of elbow arresters at these locations if lightning induced failures have been experienced on THESL's underground system.

Similar to their SDPs, THESL could provide PSE with corresponding justifications for their distribution construction standards. For example, THESL has implemented computer applications to provide a more efficient and thorough assessment of pole loadings that has allowed them to remove certain design guides from their standards. Also, as another example, THESL has chosen to continue the use of three-bolt clamps on guy wires for benefiting line personnel when adjusting wire tensions. These examples, gave PSE a level of satisfaction that the DCSs are well thought through and are backed by sound engineering and operations analysis and decision making.

3 Material Specifications

3.1 Equipment Technical Specifications

Equipment Technical Specifications (ETS) are used for specifying and purchasing equipment to be used on the THESL system. PSE reviewed ETS that were added or modified since the 2014 Independent Review. These specifications include:

Major Equipment Technical Specifications

- Single-Phase Submersible Distribution Transformers (KNAN Type)
- Three-Phase Submersible Distribution Transformers
- Single-Phase Pole-Mounted Distribution Transformers
- Single-Phase Submersible Distribution Transformers (ONAN Type)
- Distribution Polymer Insulators
- Pad-Mounted Three-Phase Live Front Distribution Transformers (ONAN Type)
- Pad-Mounted Low Profile Single-Phase Distribution Transformers with Internal and Loadbreak Switches (ONAN and KNAN Types)
- Pad-Mounted Three-Phase Distribution Transformers with Internal and Loadbreak Switches (ONAN)
- Distribution Composite Pole
- Treated Western Red Cedar Poles
- 3 MVA to 12 MVA Outdoor Station Power Transformer
- Tree Proof Cable
- Neutral Supported and Field Lashed Secondary Cable Rated 600 Volt
- Polyethylene Covered Weatherproof Line Wire
- Transformer Drop Wire
- Paper Insulated Lead Covered Polyethylene Jacketed Power Cable Rated 5 to 30 kV
- Single Conductor and Triplexed Tree Retardant Crosslinked Polyethylene Insulated Power Cable 15 to 30 kV
- Underground Secondary Cable Rated 600 Volt

Overall, PSE found the reviewed ETS to be aligned with others in the industry. Only one minor item was noted. This item is summarized below along with THESL's comments.

Non-Application of EPR Cable

PSE noted, of the technical specifications reviewed, and the SDP revisions made, the application of EPR was not present; leading to the question if THESL only uses TRXLPE for non-PILC cable.

THESL verified their experience with TRXLPE cable extends over 30 years. One of the advantages of TRXLPE is that the compounds are not proprietary in nature (as they are with EPR), which allows for direct comparison of different manufacturer's TRXLPE cables.

THESL further verified that in 2017, they developed a performance based technical specification of reduced wall thickness design EPR cables that will replace 13.8 kV PILC cables installed in 3.5" ducts are smaller; where TRXLPE cable cannot be applied. At the time of this report, 500 kcmil Cu 15 kV EPR cable has been approved and revisions to the applicable Standards are in progress. Existing cable accessories used by THESL are compatible with the approved EPR cable.

4 Procedural Processes

4.1 Major, Non-Major and Ancillary Equipment Approval

THESL has two approval processes for equipment. One is the approval process for major equipment while the other is for non-major equipment and ancillary.

In all categories, THESL's equipment approval process provides a reasonable degree of assurance that products applied to the system are safe and reliable. For instance, items that fall under the major equipment category must adhere to THESL technical specifications. These specifications, that are all reviewed and approved by a THESL professional engineer, include industry standards and qualifying tests amongst other elements. Non-major equipment must either be pre-approved by a recognized certification organization, or have a proven historical record of successful use in the industry. Ancillary Equipment may be approved via:

1. Certification against Industry Standards and/or Field Evaluation Agency or;
2. Electrical Safety Code (ESC) Rule 2-024.

Since the 2014 Independent Review THESL modified the process slightly to include a Product Change Committee (PCC) to receive all major, non-major and ancillary equipment requests before going through the previously established approval process. The PCC must approve the initial equipment request and assign a task for technical evaluation to standards and materials before the process can proceed. Additionally, the PCC must accept the technical evaluation results provided by standards and materials before the equipment is approved for use.

This approval process is in alignment with the technical guidelines for the approval of electrical equipment as outline by the Electrical Safety Authority (Ontario Regulation 22/04).

5 Conclusion

THESL's revised Standards were found by PSE to be thorough, well documented, and consistent with what is seen in the industry. The results of PSE's review and evaluation produced only minor questions and comments, which have been discussed with the THESL staff. Of these questions and comments, THESL was either able to sufficiently provide supporting justification to uphold a specific Standard or set into action further review for change.

It is also worth noting that this is an update to a standard review conducted by PSE in 2014 and general observations previously identified continue to exist today. These observations include:

- The Standards Department at THESL consists of professionals who have previous experience with outside entities, which has brought the Department various levels and types of expertise. The Department also consists of professionals who have a long-term relationship and understanding of the downtown Toronto electric distribution system. This blend of outside experience and internal knowledge is personified by a diverse group of professionals with the breadth and depth of knowledge that is needed by the trustees of the Company's Standards.

- The Department's engineers also continue to gain industry knowledge by engaging and participating in various associations, forums and initiatives. One example of this is THESL's participation in the Institute of Electrical and Electronic Engineers (IEEE) and Canadian Standards Association (CSA) working groups. IEEE is considered to be the world's largest professional association that serves technical professionals globally. IEEE has a Standards Association that offers a library of current standards in the electrical industry. THESL is a subscriber to IEEE Explore, which provides web access to all IEEE standards. The Canadian Standards Association is a non-profit standards organization that develops industry standards across 57 areas of specialization, with electrical standards being one area of expertise. CSA develops, updates, and sells standards through their Standards Store. THESL has a significant library of such CSA Standards. THESL is also currently engaged with CSA industry initiatives and committees, currently serving on the Technical Subcommittee for Transformers. By participating in both IEEE and CSA initiatives and activities, THESL is actively and continually exposed to the development of standards both locally and globally.

- THESL is also actively involved with the Utilities Standards Forum (USF) as well as an Inter-Utility Forum. The USF is an organization representing approximately 50 Ontario electric distribution companies. Its goal is to collaboratively define standards for its members and reduce duplication of efforts. The USF has developed design standards for electricity distribution that meet the requirements of Ontario Regulation 22/04 under the Electricity Act of 1998. The Inter-Utility Forum is made up of a small group of utilities including Alectra, Veridian Connections, Peterborough Utilities Group, and London Hydro. THESL's involvement in both forums has and will continue to help cross-pollinate concepts and ideas with other Ontario-based utilities.

- THESL is also a member of the Centre of Energy Advancement through Technological Innovation (CEATI International). CEATI International is a user-driven organization that provides technology solutions and training to electrical utility participants. CEATI International is driven by over 120 organizations, including electric utilities, governmental agencies, and research-based organizations. THESL can benefit from this membership by looking to CEATI International as a research and development aid that will help keep personnel current with new technologies, as well as solidify their understanding of existing technical concepts. Information gained from CEATI International's efforts and reports can be applied to new and revised THESL Standards.

6 Appendix

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #42

REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
RORY CALHOUN	00-0001		TABLE OF CONTENTS	0	Revised	- tabs 22 and 33 have been changed to read (For Future Use)
James Daniel	03-2000		Overhead - Minimum Clearances Standard Attachment Points	3	Revised	- Added Trolley TTC cable attachment - Updated pictorially
Tarek Turk	05-1220		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Semi-Triangular Circuit Side Mounted Angles 0 to 15 Degrees	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-1240		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Single Circuit Vertical Configuration Angles 0 to 15 Degrees	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-1260		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase In-Line Rolled Configuration Angles 0 to 3 Degrees	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-1320		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Suspension Vertical Configuration Angles 16 to 45 Degrees	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-1340		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Vertical Configuration Angles 0 to 45 Degrees	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-1360		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Semi-Triangular Circuit Angles 16 to 45 Degrees	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-1380		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Suspension Angles 46 to 90 Degrees	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-1400		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Double Dead-End Vertical Configuration Angles 61 to 90 Degrees	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-1480		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Dead-End Vertical Configuration	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-1600		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Double Dead-End or Transition Between Bare and Treeproof Vertical Configuration	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-1740		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Double Circuit Vertical Angles 0 to 15 Degrees	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-1760		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Double Circuit Vertical Angles 16 to 45 Degrees	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-1840		4.16 to 27.6 kV Treeproof and Bare Primary Double 3-Phase Vertical Configuration 1 Tangent Circuit and 1 Dead-end Circuit	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #42

REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
Tarek Turk	05-1860		4.16 to 27.6 kV Treeproof and Bare Primary Double 3-Phase Dead-end Vertical Configuration	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-1880		4.16 to 27.6 kV Treeproof and Bare Primary Double 3-Phase Double Dead-end or Transition Between Bare and Treeproof Vertical Configuration	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-2040		4.16 to 27.6 kV Treeproof and Bare Primary 1-Phase Run-Off From 3-Phase Vertical	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-2060		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Vertical Run-Off From 3-Phase Vertical Near Side	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-2080		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Vertical Run-Off From 3-Phase Vertical Far Side	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-2280		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Vertical Run-Off From Double 3-Phase Vertical Dead-end Circuit	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-2400		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Double Circuit Run-Offs From 3-Phase Double Circuit Dead-end Vertical Configuration	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Emma Halilovic	07-0000		INDEX OF STANDARDS	7	REVISED	-Title change 7.6 page 3 for STD. 07-5320
Emma Halilovic	07-5320		SPAN & DOWN GUYS - TWO ON CONCRETE, WOOD OR STEEL POLE	7	Revised	Change to add Steel Pole and title change
Emma Halilovic	07-5370		SPAN AND STRUT GUYS - TWO	7	Revised	BOM title change
John Hecimovic	12-3350		Primary Service Risers Fused 1-Phase 4.16 kV to 27.6 kV GRD. Y	12	Revised	Bom change and added 2 notes
John Hecimovic	12-3550		Primary Service Risers Fused 3-Phase 4.16 kV to 27.6 kV GRD. Y	12	Revised	Bom change and added 2 notes
James Daniel	15-3800		Secondary Underground Services Up To 200 A Temporary Service Installation	15	Revised	- Revised min. depth of cover - Replaced PVC with schedule 40 - Updated reducer pictorially
Ingrid Eleosida	18-3250		Cable Guard For Direct Buried Cable	18	Revised	Bom legend C and D
James Daniel	23-1110		Overhead System - Pole Attachments Temporary Banner and Flower Basket Size and Clearances	23	Revised	- Revised basket location in note 2

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #42

REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
James Daniel	23-1120		Overhead System - Pole Attachments Temporary Flowwer Baskets on Ornamental Streetlight Pole	23	Revised	- Revised basket location in note 3 - Added note 5
James Daniel	23-1130		Overhead System - Pole Attachments temporrary Seasonal Lighted Decoration Size and Clearances	23	Revised	- Revised attachment location in note 2
John Hecimovic	24-1300		OVERHEAD FUSING	24	Revised	1 Changes in notes and 2 changes in legend
James Daniel	30-4210		COBRA HEAD LUMINAIRE ON ALUMINUM POLE 28',35',BASE MOUNTED & 37' DIRECT BURIED	30	REVISED	BOM #2 DISCRIPTION REVISED
James Daniel	31-1120		CONDUITS CONCRETE ENCASED & DIRECT BURIED DUCTS	31	Revised	- Converted 11" x 17" drawing to 8-1/2" x 11" - Added 15 duct structure - Revised notes
James Daniel	31-1170		CONDUITS DIVERTING DUCT BANK	31	Revised	- Converted 11" x 17" drawing to 8-1/2" x 11"
James Daniel	31-1220		CONDUITS INSTALLATION OF DUCTS FROM POLES	31	Revised	- Converted 11" x 17" drawing to 8-1/2" x 11" - Replaced PVC with schedule 40 bends - Revised min. depth of cover - Deleted note 5 and 7
James Daniel	31-1260		CONDUITS FIBERGLASS REINFORCED EPOXY (FRE) CONDUITS FOR BRIDGE CROSSINGS (TYP.)	31	Revised	- Added imperial dimensions - Updated title - Added FRE duct annotation
James Daniel	31-1370		SUPPORT OF U.G. CONDUIT CROSSING EXCAVATIONS	31	Revised	- Converted 11" x 17" drawing to 8-1/2" x 11"
James Daniel	31-4015		Padmounts Clearance Zone	31	Revised	- Added 1-Phase and 3-Phase transformer - Updated PME/PMH switchgear - Revised notes - Revised title
James Daniel	31-4080		Padmounts Guard Posts (Bollards)	31	Revised	- Added 1-Phase and 3-Phase transformer - Updated pme/pmh switchgear - Revised note 13
James Daniel	31-6000		Customer-Owned Structures Design and Construction Requirements	31	Revised	- Revised sections 1.0, 2.0, 3.0 and 4.0
James Daniel	31-6010		Customer-Owned Structures Vault Design Requirements	31	Revised	- Revised (previously labelled) sections 1.0, 2.0, 3.0, 4.0, 5.0, and 6.0 - Added vault access requirements section

TORONTO HYDRO

STANDARDS REVISION #42

REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
James Daniel	31-6020		Customer-Owned Structures Above Grade - Walk-In Vault	31	Revised	- Revised detail 'B' - Updated notes and added note 5
James Daniel	31-6030		Customer-Owned Structures Below-Grade Walk-In Vault	31	Revised	- Updated vault table - Revised detail 'B' - Updated notes and added note 5
James Daniel	31-6035		Customer-Owned Structures Above-Grade Walk-In or Below Grade Switching Vault	31	Revised	- Revised detail 'B' - Updated notes and added note 7, 8, and 9
James Daniel	31-6040		Customer-Owned Structures Stair and Access Well Detail For Below-Grade Vaults	31	Revised	- Added imperial dimensions - Updated notes
James Daniel	31-6050		Customer-Owned Structures Louver Details For Vent Openings	31	Revised	- Updated notes - Revised detail 'A' - Added reference Std. 31-6060 in annotations
James Daniel	31-6080		Customer-Owned Structures 4.16 kV - 13.8 kV Transformer Vaults	31	Revised	- Revised all vaults - Added note 1 - Updated reference standards
James Daniel	31-8290		Top Sections (Frame and Plates) No Vehicular Traffic 2160 x 1140 x 1980 mm Deep Submersible Vault	31	Revised	- Converted 11" x 17" drawing to 8-1/2" x 11" - Added BOM legend - Updated BOM and notes
James Daniel	31-8330		Aluminum Ladderway Grid	31	Revised	- Updated panel dimension - Updated sections 'C-C' and 'D-D' and details 'C' and 'D'
James Daniel	31-8410		Material Fabrication Caulking of Removable Slabs	31	Revised	- Added BOM - Updated notes - Revised section 'A-A'

DISTRIBUTION CONSTRUCTION STANDARDS

STANDARDS REVISION #43

REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
John Hecimovic	03-0000		INDEX OF STANDARDS	3	REVISED	NEW STANDARD ADDED
James Daniel	03-2100		OVERHEAD - MINIMUM CLEARANCES CROSSING IN SPAN	3	REVISED	REVISED
James Daniel	03-2250		OVERHEAD - MINIMUM CLEARANCES PARALLELING TRANSMISSION LINES	3	REVISED	COMPLETE STANDARD REVIEW
James Daniel	04-5100		GENERAL INFORMATION CEDAR,CONCRETE,AND STEEL POLES	4	REVISED	LANGUAGE REVISED
Emma Halilovic	05-0010		GENERAL INFORMATION	5	REVISED	ADDED MANUFACTURER RECOMMENDED BOLT TIGHTENING TORQUE FOR LINE POST INSULATORS
Tarek Turk	05-1000		4.16KV TO 27.6KV TREEPROOF AND BARE PRIMARY 1-PHASE	5	REVISED	Revise BOM
Emma Halilovic	05-1820		4.16KV TO 27.6KV TREEPROOF AND BARE PRIMARY 3-PHASE	5	REVISED	ADDED A NOTE
Emma Halilovic	06-1000		SAGS AND TENSION	6	REVISED	ADDED STOCK CODE FOR TENSION METER
Emma Halilovic	07-0000		INDEX OF STANDARDS	7	REVISED	Index of Standards revised due to new standard
Emma Halilovic	07-4250		GUYING INSTALLATION PROCEDURE STRUT	7	NEW	New standard added
Kalyan Sarkar	08-0000		INDEX OF STANDARDS	8	REVISED	New standard added
Kalyan Sarkar	08-3120		OVERHEAD CONNECTORS HAND TAPING SLEEVE	8	NEW	New
John Hecimovic	09-0000		INDEX OF STANDARDS	9	REVISED	Index of Standards revised due to new standard
Emma Halilovic	09-3300		CONNECTIONS CURRENT LIMITING FUSE CONNECTION DETAILS	9	REVISED	REVISED CLF TERMINAL
John Hecimovic	09-9500		PRIMARY DROP LEADS 1-PHASE TRANSFORMERS	9	REVISED	Changed from solid tap to a hot line solution and BOM

DISTRIBUTION CONSTRUCTION STANDARDS

STANDARDS REVISION #43

REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
John Hecimovic	09-9510		PRIMARY DROP - LEADS 1-PHASE TRANSFORMERS - DEAD-END CONFIGURATION	9	NEW	New
John Hecimovic	09-9550		PRIMARY DROP LEADS 1-PHASE TRANSFORMERS - OVERBUILD AND UNDERBUILD	9	REVISED	Changed from solid tap to a hot line solution and BOM
John Hecimovic	09--9600		PRIMARY LOOP LEADS 3-PHASE TRANSFORMERS	9	REVISED	Changed from solid tap to a hot line solution and BOM
John Hecimovic	09-9610		PRIMARY DROP LEADS 3-PHASE TRANSFORMERS - DEAD-END CONFIGURATION	9	NEW	New
Tarek Turk	10-1300		OVERHEAD SWITCHES	10	REVISED	Revise drawing and BOM
Kalyan Sarkar	11-5400		120 V CONNECTION FOR UNMETERED SERVICES FED FROM OVERHEAD SUPPLY	11	REVISED	Part number change
John Hecimovic	12-0000		INDEX OF STANDARDS	12	REVISED	Index of Standards revised due to new standard
James Daniel	12-1200		RISER INSTALLATION DETAILS - CABLE CAURD OR PIPE	12	REVISED	Updated notes, BOM, pictorial revisions
John Hecimovic	12-3360		Primary Service Risers Fused 1-Phase 13.8 kV to 27.6 kV GRD. Y Above Existing Underbuild	12	NEW	New
John Hecimovic	12-3560		Primary Service Risers Fused 3-Phase 13.8 kV to 27.6 kV GRD. Y Above Existing Underbuild	12	NEW	New
Igor Simonov	13-0000		INDEX OF STANDARDS	13	REVISED	INDEX
Igor Simonov	13-5010		13.8kV NETWORK SYSTEM NETWORK TRANSFORMER VAULTS	13	REVISED	Revision of BOM
Igor Simonov	13-5020		13.8 KV NETWORK SYSTEM STAND ALONE NP	13	REVISED	Updated BOM with new 3 hole fuse
John Hecimovic	13-7200		GRD. Y VAULT - TYPICAL LAYOUT 27.6 Kv	13	REVISED	Changed from NX fusing to MCLF
John Hecimovic	13-7500		3 1-PHASE TRANSFORMER VAULT 27.6 Kv CUSTOMER ROOM WITH SF6 SWITCHGEAR	13	REVISED	Dimentions added

DISTRIBUTION CONSTRUCTION STANDARDS

STANDARDS REVISION #43

REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
John Hecimovic	13-7520		3 1-PHASE TRANSFORMER VAULT 13.8 Kv CUSTOMER ROOM WITH SF6 SWITCHGEAR	13	NEW	New
John Hecimovic	13-7810		UNDERGROUND DISTRIBUTION SWITCHGEAR EQUIVALENT TO PMH-9	13	REVISED	Revise notes and drawing for oriantation of padmount
John Hecimovic	13-7820		UNDERGROUND DISTRIBUTION SWITCHGEAR EQUIVALENT TO PMH-11	13	REVISED	Revise notes and drawing for oriantation of padmount
Kalyan Sarkar	15-2000		SECONDARY UNDERGROUND SERVICES UP TO 100 A INTRODUCTION	15	REVISED	Revise notes
John Hecimovic	15-2100		Secondary Underground Services Up To 100 A Fed From Cable Chamber or Tap Box	15	REVISED	Full Review and Evaluation (NO MU)
Tarek Turk	15-2700		120V CONNECTION FOR UNMETERED SERVICE	15	REVISED	Revised drawing to add ground at customer connection , Revised note 9
Kalyan Sarkar	15-3100		SECONDARY UNDERGROUND SERVICES UP TO 200 A FED FROM CABLE CHAMBER OR TAP BOX	15	REVISED	Revise notes
Kalyan Sarkar	15-4100		SECONDARY UNDERGROUND SERVICES UP TO 200 A FED FROM CABLE CHAMBER OR TAP BOX	15	REVISED	Revise notes
Kalyan Sarkar	16-0000		INDEX OF STANDARDS	16	REVISED	Index of Standards revised due to new standard
Kalyan Sarkar	16-0280		600 V SECONDARY CABLES PHYSICAL CHARACTERISTICS	16	NEW	New
Kalyan Sarkar	16-4580		PRIMARY - INLINE TRANSITION JOINT HAND TAPING METHOD	16	REVISED	Revised dimentions and BOM
Kalyan Sarkar	16-4600		PRIMARY - INLINE TRANSITION JOINT HAND TAPING METHOD	16	NEW	New
Kalyan Sarkar	16-4620		PRIMARY - TRIFURCATING TRANSITION JOINT	16	REVISED	Revised BOM
Kalyan Sarkar	16-5400		SECONDARY - TERMINATIONS	16	REVISED	REVISED BOM
Ingrid Eleosida	18-1000		GENERAL INFORMATION	18	REVISED	Dimensions change, 3/0 grounding for network vault

DISTRIBUTION CONSTRUCTION STANDARDS

STANDARDS REVISION #43

REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
James Daniel	18-3250		OVERHEAD CABLE GUARD FOR DIRECT BURRIED CABLE	18	REVISED	
John Hecimovic	21-0000		INDEX OF STANDARDS	21	REVISED	Index of Standards revised due to new standard
John Hecimovic	21-1100		GENERAL INFORMATION STENCILING INFORMATION	21	REVISED	Added to BOM
John Hecimovic	21-2110		2 X 3 PHASE POCKET PANNELS	21	NEW	New
John Hecimovic	21-3900		UNDERGROUND STENCILING	21	REVISED	Distributed generation label added
James Daniel	23-1020		OVERHEAD SYSTEM - POLE ATTACHMENTS OVERHEAD 120 V CONNECTION FOR UNMETERED SERVICES	23	REVISED	Revised drawing and BOM
James Daniel	23-1030		UNDERGROUND 120 UNMETERED CONNECTION SERVICE ATTACHED TO TORONTO HYDRO POLES	23	REVISED	BOM REVISED
John Hecimovic	24-1100		OVERHEAD FUSING TRANSFORMERS	24	REVISED	Revised fusing location chart
Igor Simonov	24-2100		UNDERGROUND FUSING NETWORK PROTECTORS	24	REVISED	Revised BOM
James Daniel	30-4100		CONCRETE POLE 25' & 30' WITH UNIVERSAL LUMINAIRE	30	REVISED	Clean up of drawing
James Daniel	30-4290		COMPOSITE POLE 30' WITH UNIVERSAL LUMINAIRE	30	REVISED	Updated dimensions, notes, BOM, pictorial revisions
James Daniel	31-1100		CONDUITS GENERAL INFORMATION	31	REVISED	Full Review and Evaluation
James Daniel	31-2130		CABLE CHAMBERS UNDERPINNING CHANBER STRUCTUAL DETAILS	31	REVISED	Added new note 8
James Daniel	31-2190		Cable Chambers Underpinning Chambers	31	REVISED	Full Review and Evaluation
James Daniel	31-4050		PADMOUNTS THREE PHASE PMH 9/11 SWITCHGEAR 1980mm X 2160mm X 1350mm	31	REVISED	To revise notes

DISTRIBUTION CONSTRUCTION STANDARDS

STANDARDS REVISION #43

REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
James Daniel	31-5120		SPLICE VAULT 'D' For 1000 kcmil Primary cables 1625 mm (5'-4") X 2750 mm (9'-0") X 2250 mm (7'-5") Deep	31	REVISED	Full Review and Evaluation
James Daniel	31-5150		Single Unit Transformer Vault 2290 mm (7'-6") X 3650 mm (12'-0") X 3650 mm (12'-0") Head-Room	31	REVISED	Full Review and Evaluation
Tarek Turk	33-1000		GENERAL INFORMATION SK/SKE	33	NEW	New

DISTRIBUTION CONSTRUCTION STANDARDS

STANDARDS REVISION #44

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
1	JAMES DANIEL	03-0000		INDEX OF STANDARDS	03	REVISED	NEW AND OBSOLETED STANDARDS
2	JAMES DANIEL	03-2000		OVERHEAD-MINIMUM CLEARANCES STANDARD ATTACHMENT POINT	03	REVISED	NOTE 2 ABCDE CHANGED
3	JOHN HECIMOVIC	03-2050	03-2100	OH MINIMUM CLEARANCES	03	OBSOLETE	SEE STANDARD 03-2100
4	JAMES DANIEL	03-2350		OVERHEAD - MINIMUM CLEARANCES BETWEEN CONDUCTORS AND SWIMMING POOLS	03	REVISED	UPDATE DIMENSIONS,NOTES, BOM PICTORIAL REVISIONS
5	JAMES DANIEL	03-2400		OVERHEAD-MINIMUM CLEARANCES POLES AND PRIVATE FENCES	03	Revised	UPDATE DIMENSIONS,NOTES, BOM PICTORIAL REVISIONS
6	JAMES DANIEL	03-2500		OVERHEAD - MINIMUM CLEARANCES BETWEEN CONDUCTRS AND NAVIGABLE WATERWAYS	03	REVISED	UPDATE DIMENSIONS,NOTES, BOM PICTORIAL REVISIONS
7	JAMES DANIEL	03-2600	03-2000	OH MINIMUM CLEARANCES BETWEEN CONDUCTORS AND STREETLIGHT BRACKET	03	OBSOLETE	SEE STANDARD 03-2000
8	JAMES DANIEL	03-2650		OVERHEAD - SECONDARY SERVICE CONNECTION MINIMUM CLEARANCE ABOVE FINISHED GRADE	03	Revised	Updated dimensions, notes, BOM, pictorial revisions
9	JAMES DANIEL	04-5100		GENERAL INFORMATION - CEDAR, CONCRETE, AND STEEL POLES	04	REVISED	DOC
	EMMA HALILOVIC	05-0000		INDEX OF STANDARDS	05	REVISED	DOC
10	EMMA HALILOVIC	05-1360		4.16 TO 27.6 kV TREEPROOF AND BARE PRIMARY 3-PHASE SEMI-TRIANGULAR CIRCUIT ANGLES 16 TO 46 DEGREES	05	REVISED	ADDED OPTION FOR CIRCUIT WITH 2 PHASES IN SUSPENSION AND 1 PHASE IN
11	EMMA HALILOVIC	05-1370		4kV - 27.6kV TREEPROOF AND BARE PRIMARY 3-PHASE SEMI-TRIANGULAR CIRCUIT	05	NEW	NEW STANDARD

DISTRIBUTION CONSTRUCTION STANDARDS

STANDARDS REVISION #44

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
12	EMMA HALILOVIC	07-3000		GUYING - GENERAL INFORMATION	07	REVISED	Notes added to 3)
13	EMMA HALILOVIC	07-4240		GUYING INSTALLATION PROCEDURE INSULATOR ROD	07	REVISED	Revised to add double eye link
14	EMMA HALILOVIC	07-5500		SPAN GUY - ONE ON CONCRETE, WOOD OR STEEL POLE	07	REVISED	MUs REQUIRED Revised notes 3 and 5 and figure 1
15	JOHN HECIMOVIC	09-1300		GENERAL INFORMATION INSTALLATION	09	REVISED	NOTE CHANGE
16	JOHN HECIMOVIC	09-8600		3-PHASE CONSTRUCTION 8000/13800 -120/2040-50kV	09	REVISED	CHECK MU's NOTE CHANGE
17	JOHN HECIMOVIC	09-8700		3-PHASE CONSTRUCTION 8000/13800 - 120/208-100 & 167kVA	09	REVISED	CHECK MU's NOTE CHANGE
18	JOHN HECIMOVIC	09-8800		3-PHASE CONSTRUCTION 16000/27600 - 120/208 V - 50kVA	09	REVISED	NOTE CHANGE
19	JOHN HECIMOVIC	09-8900		3-PHASE CONSTRUCTION 16000/27600	09	REVISED	NOTE CHANGE
20	JOHN HECIMOVIC	09-9100		3-PHASE CONSTRUCTION 2400/4160 - 347/600 V WYE 100 & 167kV	09	REVISED	NOTE CHANGE
21	JOHN HECIMOVIC	09-9200		3-PHASE CONSTRUCTION 8000/13800 - 347/600V WYE ALL KVA SIZES	09	REVISED	NOTE CHANGE
22	JOHN HECIMOVIC	09-9300		3-PHASE CONSTRUCTION 16000/13800 - 347/600 V WHY ALL KVA SIZES	09	REVISED	NOTE CHANGE
24	JAMES DANIEL	10-3100		3-PHASE LOAD INTERRUPTER SWITCH	10	NEW	NEW STANDARD

DISTRIBUTION CONSTRUCTION STANDARDS

STANDARDS REVISION #44

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
25	EMMA HALILOVIC	10-3700		COMMUNICATION AND CONTROL UNIT (CCU) SCADA AND FEEDER AUTOMATION	10	REVISED	NOTES AND BOM CHANGE
26	EMMA HALILOVIC	10-3710		SCADA ANTENNA MOUNTING DETAIL	10	REVISED	DRAWING CHANGE
27	EMMA HALILOVIC	11-0000		INDEX OF STANDARDS	11	REVISED	Revised to include new Standard 11-3600
28	EMMA HALILOVIC	11-2020		OVERHEAD SECONDARY SECONDARY BUS, TRANSFORMER SECONDARY DROP LEADS AND SECONDARY SERVICES	11	REVISED	Revised Secondary Services Notes
29	EMMA HALILOVIC	11-3210		MULTIPLEXED SECONDARY BUS SERVICE TAPS 120/240 V AT POLE	11	REVISED	Removed 400A service size, replaced solid bail with flexible bail grip wedge
30	EMMA HALILOVIC	11-3250		MULTIPLEXED SECONDARY BUS SERVICE TAPS 120/240 V AT MID-SPAN	11	REVISED	Removed 400A service size, replaced solid bail with flexible bail grip wedge
31	EMMA HALILOVIC	11-3600		MULTIPLEXED SECONDARY BUS SERVICE TAP AT TRANSFORMER POLE 120/240 V 400 A	11	NEW	New Standard
32	EMMA HALILOVIC	11-5200		OVERHEAD SECONDARY SERVICES SERVICE ENTRANCE 120/240 V CONNECTION TO CUSTOMER'S SERVICE MAST	11	REVISED	Added 400A service size for Commercial service type
33	JAMES DANIEL	12-1200		RISER INSTALLATION DETAILS - CABLE GUARD OR GALVANIZED PIPE	12	REVISED	Updated dimensions, notes, BOM, pictorial revisions
34	JOHN HECIMOVIC	12-3000		PRIMARY SERVICE RISERS PRIMARY DROPS AND CONNECTORS FOR 1-PHASE SERVICE RISER	12	REVISED	- REVIEW STANDARD TO REPLACE SOLID TAPS WITH REMOVABLE HOT LINE CONNECTORS - ADD ONE INSULATOR TO HALO TOP PHASE, VERTICAL TOP AND MIDDLE PHASE, SEMI-TRIANGULAR TOP PHASE, IN-LINE ROLLED TOP AND MIDDLE PHASE
35	JOHN HECIMOVIC	12-3100		PRIMARY SERVICE RISERS PRIMARY DROPS AND CONNECTORS FOR 3-PHASE SERVICE RISER	12	REVISED	- REVIEW STANDARD TO REPLACE SOLID TAPS WITH REMOVABLE HOT LINE CONNECTORS - ADD ONE INSULATOR TO VERTICAL, IN-LINE ROLLED, SEMI-TRIANGULAR, HALO

DISTRIBUTION CONSTRUCTION STANDARDS

STANDARDS REVISION #44

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
36	JOHN HECIMOVIC	12-3600		PRIMARY SERVICE RISER (200A MAX) FUSED 3 PHASE FOR 27.6 KV DELTA TRANSFORMER	12	REVISED	NOTES AND BOM CHANGE
37	KALYAN SARKAR	15-2000		SECONDARY UNDERGROUND SERVICES 100A INTRODUCTION	15	REVISED	NOTE ADDED
38	KALYAN SARKAR	16-0020		GENERAL INFORMATION OF CABLES	16	REVISED	REVISED DRAWING
39	KALYAN SARKAR	16-0350		PRIMARY CABLES CROSSBONDING SCHEME FOR TRXLPE CABLE 15kV , 1 CONDUCTOR, CU, 1000 kcmil AND LARGER	16	REVISED	DOC
40	KALYAN SARKAR	16-3820		Primary - Polymeric Cable Straight Joints Cold Shrink Method, 15kV, 1 Conductor	16	REVISED	NOTES AND BOM CHANGE
41	KALYAN SARKAR	16-4100		Primary - Polymeric Cable Terminations TRXLPE - OUTDOOR -COLD SHRINK,15KV,1 CON	16	Revised	NOTES AND BOM CHANGE
42	KALYAN SARKAR	16-4600		PRIMARY - INLINE TRANSITION JOINT HAND TAPING METHOD	16	REVISED	NOTES AND BOM CHANGE
43	JOHN HECIMOVIC	16-5200		SECONDARY - STRAIGHTJOINT COLD SHRINK METHOD 600V AND BELOW, 1 COND	16	Revised	REVISED DRAWING
44	JAMES DANIEL	18-5000		UNDERGROUND SYSTEMS GUARD POST GUARDING DETAIL	18	REVISED	UPDATE DIMENSIONS,NOTES, BOM PICTORIAL REVISIONS
45	JOHN HECIMOVIC	21-0000		INDEX OF STANDARDS	21	REVISED	INDEX CHANGE NEW STANDARD
46	JOHN HECIMOVIC	21-2100		OVERHEAD STENCILING POLE NUMBERING	21	REVISED	TEXT CHANGE
47	JOHN HECIMOVIC	21-2120		OVERHEAD STENCILING REDUCED POLE HEIGHT IDENTIFICATION	21	NEW	NEW STANDARD

DISTRIBUTION CONSTRUCTION STANDARDS

STANDARDS REVISION #44

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
48	KALYAN SARKAR	21-4200		UNDERGROUND STENCILING PRIMARY CABLE LABELLING	21	NEW	NEW STANDARD
49	KALYAN SARKAR	21-4300		UNDERGROUND STENCILING SECONDARY CABLE LABELLING	21	NEW	NEW STANDARD
50	JAMES DANIEL	23-1220		OVERHEAD SYSTEM - COMMUNICATION CABLE UNDERGROUND RISER	23	REVISED	UPDATE DIMENSIONS,NOTES, BOM PICTORIAL REVISIONS
51	JAMES DANIEL	23-2020		UNDERGROUND SYSTEM - DUCT OCCUPANCY COMMUNICATION CABLE GENERAL INFORMATION	23	REVISED	UPDATE DIMENSIONS,NOTES, BOM PICTORIAL REVISIONS
52	JAMES DANIEL	23-2030		UNDERGROUND SYSTEM - DUCT OCCUPANCY COMMUNICATION CABLE WITHIN CABLE CHAMBERS	23	REVISED	UPDATE DIMENSIONS,NOTES, BOM PICTORIAL REVISIONS
53	JOHN HECIMOVIC	24-1200		FUSING AT RISER POLES	24	REVISED	DOC
54	JAMES DANIEL	30-0000		INDEX OF STANDARDS	30	REVISED	STANDARD OBSOLETED
55	JAMES DANIEL	30-9560		Wall Mounting Plate and Bracket	30	REVISED	Full Review and Evaluation
56	JAMES DANIEL	31-1230		CONDTUITS SUPPLYING CUSTOMER'S BUILDING	31	REVISED	UPDATE DIMENSIONS,NOTES, BOM PICTORIAL REVISIONS
57	JAMES DANIEL	31-1240		Conduits Civil Underground Secondary Service Projects Conversion From Overhead To Underground Feed and Underground To Underground Feed	31	REVISED	Full Review and Evaluation
58	JAMES DANIEL	31-1250		CONDUITS UNDERGROUND SECONDARY SERVICE PROJECTS FOR NEW INSTALLATION	31	REVISED	REVISE WORD CONTENT
59	JAMES DANIEL	31-2170		CABLE CHAMBERS	31	REVISED	REVISED DRAWING AND BOM

DISTRIBUTION CONSTRUCTION STANDARDS

STANDARDS REVISION #44

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
60	JAMES DANIEL	31-4015		PAD-MOUNTS CLEARANCE ZONE	31	REVISED	UPDATE DIMENSIONS,NOTES, BOM PICTORIAL REVISIONS
61	JAMES DANIEL	31-4020		PAD-MOUNTS - SINGLE PHASE PRECAST PAD-MOUNT 1070mm X 1320mm X 1350mm	31	REVISED	DRAWING REVISION
62	JAMES DANIEL	31-4030		PAD-MOUNTS - 3-PHASE PRECAST PAD-MOUNT 1830mm X 1830mm X 1220mm	31	REVISED	DRAWING REVISION
63	JAMES DANIEL	31-4040		PAD-MOUNTS - 3-PHASE PMH 4 - 25kV SWITCHGEAR	31	REVISED	DRAWING REVISION
64	JAMES DANIEL	31-4050		PAD-MOUNTS - 3-PHASE PMH 9/11 SWITCHGEAR	31	REVISED	DRAWING REVISION
65	JAMES DANIEL	31-4080		PAD-MOUNTS GUARD POSTS (BOLLARDS)	31	REVISED	UPDATE DIMENSIONS,NOTES, BOM PICTORIAL REVISIONS
67	JAMES DANIEL	31-8310		Switch / Splice Vault Cover	31	REVISED	COMPLETED REVIEW OF STANDARD

DISTRIBUTION CONSTRUCTION STANDARDS

STANDARDS REVISION #45

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
01	JAMES DANIEL	03-2000		OVERHEAD - MINIMUM CLEARANCES STANDARD ATTACHMENT POINTS	03	REVISED	Updated dimensions, notes, BOM, pictorial revisions
02	JAMES DANIEL	03-2300		OVERHEAD - MINIMUM CLEARANCES BUILDINGS AND PERMANENT STRUCTURES	03	REVISED	Jeffry: Revised notes and revised dimensions
03	JAMES DANIEL	04-5200		CEDAR AND CONCRETE POLES IN BOULEVARD (HAND DIG AND VACUUM TRUCK)	04	REVISED	Updated dimensions, notes, BOM, pictorial revisions
04	JAMES DANIEL	04-5300		CEDAR AND CONCRETE POLES IN SIDEWALK	04	REVISED	Updated dimensions, notes, BOM, pictorial revisions
05	JAMES DANIEL	04-5400		CEDAR AND CONCRETE POLES IN BOULEVARD AND SIDEWALK, FOR TTC TROLLEY SUSPENSION	04	REVISED	Updated dimensions, notes, BOM, pictorial revisions
06	JAMES DANIEL	04-5500		CEDAR AND CONCRETE POLES IN POOR SOIL	04	REVISED	Updated dimensions, notes, BOM, pictorial revisions
07	JAMES DANIEL	04-5600		CEDAR AND CONCRETE POLES IN SLOPES AND HILLSIDES	04	REVISED	Updated dimensions, notes, BOM, pictorial revisions
08	ROB MCKEOWN / JAMES DANIEL	05-0000		INDEX OF STANDARDS	05	REVISED	Added new standard
09	ROB MCKEOWN / JAMES DANIEL	05-1200		4.16 TO 27.6 KV TREEPROOF AND BARE PRIMARY 3-PHASE HALO CONFIGURATION ANGLES 0 TO 15 DEGREES	05	REVISED	Added MIN to clearance dimension
10	ROB MCKEOWN / JAMES DANIEL	05-1260		4.16 TO 27.6 KV TREEPROOF AND BARE PRIMARY 3-PHASE IN-LINE ROLLED CONFIGURATION ANGLES 0 TO 3 DEGREES	05	REVISED	Added MIN to clearance dimension
11	ROB MCKEOWN / JAMES DANIEL	05-1590		4.16 TO 27.6 KV TREEPROOF AND BARE PRIMARY 3-PHASE DOUBLE DEAD-END HORIZONTAL CONFIGURATION	05	NEW	NEW STANDARD
12	ROB MCKEOWN / TAREK TURK	05-1800		4.16 TO 27.6 KV TREEPROOF AND BARE PRIMARY 3-PHASE DOUBLE CIRCUIT VERTICAL ANGLES 46 TO 90 DEGREES	05	REVISED	Updated extension insulator to new stock code.
13	ROB MCKEOWN / JAMES DANIEL	05-1860		4.16 TO 27.6 KV TREEPROOF AND BARE PRIMARY DOUBLE 3-PHASE DEAD-END VERTICAL CONFIGURATION	05	REVISED	Updated extension insulator to new stock code.
14	JAMES DANIEL	05-2170		4.16 TO 27.6 kV TREEPROOF AND BARE PRIMARY - 3-PHASE RUNOFF FROM 3-PHASE HALO	05	REVISED	updated stock code for item 26

DISTRIBUTION CONSTRUCTION STANDARDS

STANDARDS REVISION #45

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
15	ROB MCKEOWN / JAMES DANIEL	05-2460		4.16 TO 27.6 KV TREEPROOF AND BARE PRIMARY 3-PHASE MID-SPAN TAP HORIZONTAL CONFIGURATION	05	REVISED	Added Note stating that main circuit pole to be 5' higher than tap pole.
16	ROB McKEOWN	06-0000		INDEX OF STANDARDS	06	REVISED	Added new standards
17	ROB McKEOWN	06-5100		SAGS AND TENSIONS TABLE 3 – #1/0 QUADRUPLEX SERVICE CONDUCTORS WITH #1/0 ACSR NEUTRAL PVC JACKET 15M-30M SPANS	06	NEW	NEW STANDARDS
18	ROB McKEOWN	06-5110		SAGS AND TENSIONS TABLE 2 - #4/0 TRIPLEX SERVICE CONDUCTORS WITH #2/0 ACSR NEUTRAL 15M-30M SPANS	06	NEW	NEW STANDARD
19	ROB McKEOWN	06-5120		SAGS AND TENSIONS TABLE 3 - #1/0 QUADRUPLEX SERVICE CONDUCTORS WITH #1/0 ACSR NEUTRAL 15M-30M SPANS	06	NEW	NEW STANDARD
20	ROB McKEOWN	06-5130		SAGS AND TENSIONS TABLE 2 - #2 TRIPLEX SERVICE CONDUCTORS WITH #4 ACSR NEUTRAL 15M-30M SPANS	06	NEW	NEW STANDARD
21	ROB McKEOWN	06-5140		SAGS AND TENSIONS TABLE 3 - #4 QUADRUPLEX SERVICE CONDUCTORS WITH #4 ACSR NEUTRAL 15M-30M SPANS	06	NEW	NEW STANDARD
22	ROB McKEOWN	06-5150		SAGS AND TENSIONS TABLE 2 - #4 TRIPLEX SERVICE CONDUCTORS WITH #4 ACSR NEUTRAL 15M-30M SPANS	06	NEW	NEW STANDARD
23	ROB McKEOWN	06-6100		SAGS AND TENSIONS TABLE 15M SLACK SPAN SAGS AND TENSIONS FOR BARE PRIMARY CONDUCTORS	06	NEW	NEW STANDARD
24	ROB McKEOWN	06-6200		SAGS AND TENSIONS TABLE 15M SLACK SPAN SAGS AND TENSIONS FOR TREEPROOF PRIMARY CONDUCTORS	06	NEW	NEW STANDARD
25	ROB McKEOWN	06-6300		SAGS AND TENSIONS TABLE 15M SLACK SPAN SAGS AND TENSIONS FOR SECONDARY BUS CONDUCTORS	06	NEW	NEW STANDARD
26	ROB/TAREK	07-0000		INDEX OF STANDARDS	07	REVISED	Added new standard
27	ROB/TAREK	07-1000		ANCHORING - INTRODUCTION AND SOILD CLASSIFICATIONS	07	REVISED	Added sentence indicating soil maps are available on Plugged In
28	ROB/TAREK	07-1200		ANCHOR SELECTION HOLDING CAPACITIES FOR VARIOUS SOIL CLASSES	07	REVISED	Updated to include additional anchor types

DISTRIBUTION CONSTRUCTION STANDARDS

STANDARDS REVISION #45

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
29	ROB/TAREK	07-3000		GUYING - GENERAL INFORMATION	07	REVISED	Added comment that other pole loading analysis software could be used.
30	ROB/TAREK	07-3100		GUYING - GUY SELECTION	07	REVISED	Added comment that other pole loading analysis software could be used.
31	ROB/TAREK	07-3200		GUYING - DETERMINE ULTIMATE LOAD AND GUY TENSION	07	REVISED	Added comment that other pole loading analysis software could be used.
32	ROB/TAREK	07-3300		GUYING - BISECTOR CHART METHOD	07	REVISED	Added comment that other pole loading analysis software could be used.
33	ROB/TAREK	07-3400		GUYING - LINE TERMINATION CHART METHOD	07	REVISED	Added comment that other pole loading analysis software could be used.
34	ROB/TAREK	07-4250		GUYING - INSTALLATION PROCEDURE - STRUT GUY	07	REVISED	Updated to show detail for 3 wire strut guy clamp.
35	ROB/TAREK	07-4320		GUYING - INSTALLATION DETAILS - GUY ATTACHMENTS TO STEEL POLE	07	REVISED	Updated pole band clamp for steel poles to new stock code.
36	ROB/TAREK	07-5100		DOWN GUY – ONE ON CONCRETE, WOOD OR STEEL POLE	07	REVISED	Updated pole band clamp for steel poles to new stock code.
37	ROB/TAREK	07-5200		STRUT GUY – ONE ON CONCRETE, WOOD OR STEEL POLE	07	REVISED	Updated pole band clamp for steel poles to new stock code.
38	ROB/TAREK	07-5250		STRUT GUYS - THREE ON CONCRETE OR WOOD POLE USING INSULATOR ROD(S)	07	NEW	NEW STANDARD
39	ROB/TAREK	07-5300		SPAN & DOWN GUY – ONE ON CONCRETE, WOOD OR STEEL POLE	07	REVISED	Updated pole band clamp for steel poles to new stock code.
40	ROB/TAREK	07-5310		SPAN & DOWN GUY – ONE ON CONCRETE, WOOD OR STEEL POLE USING INSULATOR ROD	07	REVISED	Updated pole band clamp for steel poles to new stock code.
41	ROB/TAREK	07-5320		SPAN & DOWN GUYS – TWO ON CONCRETE, WOOD OR STEEL POLE	07	REVISED	Updated pole band clamp for steel poles to new stock code.
42	ROB/TAREK	07-5340		SPAN & STRUT GUY – ONE ON CONCRETE, WOOD OR STEEL POLE	07	REVISED	Updated pole band clamp for steel poles to new stock code.

DISTRIBUTION CONSTRUCTION STANDARDS

STANDARDS REVISION #45

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
43	ROB/TAREK	07-5350		SPAN & STRUT GUY – ONE ON CONCRETE, WOOD OR STEEL POLE USING INSULATOR ROD	07	REVISED	Updated pole band clamp for steel poles to new stock code.
44	ROB/TAREK	07-5370		SPAN & STRUT GUYS – TWO ON CONCRETE, WOOD OR STEEL POLE WITH ONE SPAN GUY USING INSULATOR ROD	07	REVISED	Updated pole band clamp for steel poles to new stock code.
45	ROB/TAREK	07-5500		SPAN GUY – ONE ON CONCRETE, WOOD OR STEEL POLE	07	REVISED	Updated pole band clamp for steel poles to new stock code.
46	ROB/JOHN	08-3510		LIVE LINE - STIRRUP APPLICATION AND SELECTION TABLE	08	REVISED	Updated to add 795 conductor
47	JOHN HECIMOVIC	09-8100		1-PHASE CONSTRUCTION - 2400-120/240 V - ALL kVA SIZES	09	REVISED	Added detail 'C' and a note for installation of stick pins; added max and min height for clearances
48	JOHN HECIMOVIC	09-8200		1-PHASE CONSTRUCTION - 8000-120/240 V - ALL kVA SIZES	09	REVISED	Added detail 'C' and a note for installation of stick pins; added max and min height for clearances
49	JOHN HECIMOVIC	09-8300		1-PHASE CONSTRUCTION - 16000-120/240 V - ALL kVA SIZES	09	REVISED	Added detail 'C' and a note for installation of stick pins; added max and min height for clearances
50	JOHN HECIMOVIC	09-8400		3-PHASE CONSTRUCTION - 2400/4160 - 120/208 V - 50 kVA	09	REVISED	Added detail 'C' and a note for installation of stick pins; added max and min height for clearances
51	JOHN HECIMOVIC	09-8500		3-PHASE CONSTRUCTION - 2400/4160 - 120/208 V - 100 & 167 kVA	09	REVISED	Added detail 'C' and a note for installation of stick pins; added max and min height for clearances
52	JOHN HECIMOVIC	09-8600		3-PHASE CONSTRUCTION - 8000-120/208 V - 50 kVA	09	REVISED	Added detail 'C' and a note for installation of stick pins; added max and min height for clearances
53	JOHN HECIMOVIC	09-8700		3-PHASE CONSTRUCTION - 8000-120/208 V - 100 & 167 kVA	09	REVISED	Added detail 'C' and a note for installation of stick pins; added max and min height for clearances
54	JOHN HECIMOVIC	09-8800		3-PHASE CONSTRUCTION - 16000/27600 - 120/208 V - 50 kVA	09	REVISED	Added detail 'C' and a note for installation of stick pins; added max and min height for clearances
55	JOHN HECIMOVIC	09-8900		3-PHASE CONSTRUCTION - 16000/27600 - 120/208 V - 100 & 167 kVA	09	REVISED	Added detail 'C' and a note for installation of stick pins; added max and min height for clearances
56	JOHN HECIMOVIC	09-9100		3-PHASE CONSTRUCTION - 2400/4160 - 347/600 V WYE 100 & 167 kVA	09	REVISED	Added detail 'C' and a note for installation of stick pins; added max and min height for clearances

DISTRIBUTION CONSTRUCTION STANDARDS

STANDARDS REVISION #45

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
57	JOHN HECIMOVIC	09-9200		3-PHASE CONSTRUCTION - 8000/13800 - 347/600 V WYE ALL kVA SIZES	09	REVISED	Added detail 'C' and a note for installation of stick pins; added max and min height for clearances
58	JOHN HECIMOVIC	09-9300		3-PHASE CONSTRUCTION - 16000/27600 - 347/600 V WYE ALL kVA SIZES	09	REVISED	Added detail 'C' and a note for installation of stick pins; added max and min height for clearances
59	EMMA HALILOVIC	10-0000		INDEX OF STANDARDS	10	REVISED	Standards title change and added new standard
60	EMMA HALILOVIC	10-1120		DISCONNECT IN-LINE SWITCHES FUSED 200 A DOUBLE DEAD-END 13.8 kV TO 27.6 kV HORIZONTAL CONFIGURATION	10	REVISED	Removed 11" insulator rod from BOM
61	EMMA HALILOVIC	10-1660		13.8 kV & 27.6 kV BARE AND TREEPROOF 3-PHASE FUSED RUN-OFFS VERTICAL CONSTRUCTION FUSED ISOLATION	10	REVISED	Revised BOM & BOM References
62	EMMA HALILOVIC	10-3100		3-PHASE LOAD INTERRUPTER SWITCH SCADA-OPERATED 13.8 & 27.6 kV FEEDER RISER	10	REVISED	Added Note 12 regarding Feeder Automation
63	EMMA HALILOVIC	10-3500		3-PHASE LOAD INTERRUPTER SWITCH SCADA-OPERATED 13.8 & 27.6 kV TIERED OUTBOARD TYP	10	REVISED	Added Switch Dimensions, Added Insulator Extension Link to BOM
64	EMMA HALILOVIC	10-3700		COMMUNICATION AND CONTROL UNIT (CCU) SCADA AND FEEDER AUTOMATION	10	REVISED	Revised Notes, Added Switch Reference Standard in BOM
65	ROB MCKEOWN / TAREK TURK	11-5200		120/240 V CONNECTION TO CUSTOMER'S SERVICE MAST	11	REVISED	Updated to allow use of Insulinks
66	ROB MCKEOWN / TAREK TURK	11-5220		120/208 V CONNECTION TO CUSTOMER'S SERVICE MAST	11	REVISED	Updated to allow use of Insulinks
67	ROB MCKEOWN / TAREK TURK	11-5240		347/600 V CONNECTION TO CUSTOMER'S SERVICE MAST	11	REVISED	Updated to allow use of Insulinks
68	ROB MCKEOWN / TAREK TURK	11-5300		120/240 V CONNECTION TO CUSTOMER'S SERVICE MAST WITH ALLEY JUMP	11	REVISED	Updated to allow use of Insulinks
69	James Daniel	12-1200		RISER INSTALLATION DETAILS - CABLE GUARD OR GALVANIZED PIPE	12	REVISED	Revised drawings, BOM, notes
70	IGOR SIMONOV	13-2010		4.16 KV TRANSFORMER VAULT LAYOUT AND INSTALLATION	13	REVISED	Updated layout, BOM, notes

DISTRIBUTION CONSTRUCTION STANDARDS

STANDARDS REVISION #45

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
71	IGOR SIMONOV	13-7010		1 PH SUBMERSIBLE VAULT	13	REVISED	SPLIT 11"X17" TO 8.5"X11", UPDATE BOM AND REFERENCES
72	JOHN HECIMOVIC	13-7810		PAD-MOUNTED DEAD FRONT 27.6kV SWITCHGEAR EQUITO PMH-9	13	REVISED	NOTES REVISED
73	JOHN HECIMOVIC	13-7820		PAD-MOUNTED DEAD FRONT 27.6kV SWITCHGEAR EQUITO PMH-11	13	REVISED	NOTES REVISED
74	IGOR SIMONOV	14-3500		INSTALLATION 27.6 Kv 1 PHASE LOW PROFILE 27.6 KV	14	REVISED	CRF-2014-0345. Revised standard to include number of terminations, added cable type options, updated BOM
75	JAMES DANIEL	15-8300		INSTALLATION OF 28 kV, #1/0 TRXPLE CABLES IN SUBMERSIBLE TRANSFORMER VAULT CONVERTED TO A SPLICE VAULT	15	REVISED	Updated dimensions, notes, BOM, pictorial revisions
76	IGOR SIMONOV	16-0000		INDEX OF STANDARDS	16	REVISED	REVISED NEW STANDARD ADDED
77	KALYAN SARKAR	16-2340		CABLE JOINTS AND TERMINATIONS GENERAL INSTALLATION INSTRUCTIONS	16	REVISED	REVISED NEW STANDARD ADDED
78	KALYAN SARKAR	16-2350		PRIMARY-JOINT Joint Slice kit quk selection chart	16	REVISED	REVISED NEW STANDARD ADDED
79	KALYAN SARKAR	16-3770		PRIMARY- TRXLPE STRAIGHT JOINT HEAT SHRINK SPLICE REDUCING 15kV 1 CONDUCTOR	16	REVISED	REVISED NEW STANDARD ADDED
80	JOHN HECIMOVIC	16-4180		PRIMARY - TRXLPE TERMINATIONS 600A DEADBREAK CONNECTORS 15 kV 1 COND.	16	REVISED	Revised drawings, BOM, notes
81	JOHN HECIMOVIC	16-4260		PRIMARY TRXLPE TERMINATIONS 600 A DEADBREAK CONNECTORS 28 KV 1 COND	16	REVISED	Revised drawings, BOM, notes
82	Kalyan Sarkar	16-4610		PRIMARY INLINE TRANSITION JOINT HEAT SHRINK SPLICE 15kV 1C PILC TO 1C TRXLPE	16	NEW	New standard to show details for 1 ph pad/submersible transformers secondaries terminations
83	Kalyan Sarkar	16-4340		PRIMARY TRXLPE TERMINATIONS 600 A DEADBREAK STRAIGHT RECEPTACLES 15kV 1 COND	16	REVISED	Revised drawings, BOM, notes
84	IGOR SIMONOV	16-6000		SECONDARY TERMINATIONS SUBMERSIBLE TRANSFORMER TERMINAL CLUSTER 600 V OR BELOW	16	REVISED	CRF-2014-0343. Revised standard to include number of terminations, added cable type options updated BOM

DISTRIBUTION CONSTRUCTION STANDARDS

STANDARDS REVISION #45

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
85	IGOR SIMONOV	16-6020		SECONDARY TERMINATIONS 1 PH SUBMERSIBLE AND 1 PH PADMOUNTED TRANSFORMERS	16	NEW	New standard to show details for 1 ph pad/submersible transformers secondaries terminations
86	IGOR SIMONOV	16-6040		SECONDARY TREMINAL LIGS TERMINATION	16	NEW	Provide details for secondary terminal lugs termination
87	KALYAN SARKAR	16-6210		CABLE REEL DATA CABLE AND WIRE REEL CHART	16	REVISED	REVISED NEW STANDARD ADDED
88	JAMES DANIEL/IGOR	17-0000		INDEX OF STANDARDS	17	REVISED	UPDATED STANDARDS LIST AND DESCRIPTION
89	JAMES DANIEL	17-2250		MINIMUM CLEARANCE BETWEEN METER SOCKET AND GAS RELIEF VENT	17	NEW	NEW STANDARD
90	JAMES DANIEL	17-2300		SECONDARY- RESIDENTIAL TYPICAL MOUNTING LOCATION	17	REVISED	Updated dimensions, notes, BOM, pictorial revisions
91	TAREK TURK	17-3100		S-BASE SOCKET TYPE TYPICAL TERMINATOR ARRANGEMENTS	17	REVISED	Updated dimensions, notes, BOM, pictorial revisions
92	JAMES DANIEL	18-0000		INDEX OF STANDARDS	18	REVISED	Updated dimensions, notes, BOM, pictorial revisions
93	JAMES DANIEL	18-3200		OVERHEAD SYSTEM - CABLE GUARD OR GALVANIZED PIPE	18	REVISED	Updated dimensions, notes, BOM, pictorial revisions
94	JAMES DANIEL	18-3250		OVERHEAD SYSTEM CABLE GUARD FOR DIRECT BURIED CABLE	18	REVISED	Updated dimensions, notes, BOM, pictorial revisions
95	EMMA HALILOVIC	18-3600		OVERHEAD SYSTEM NEUTRAL BONDING	18	REVISED	Revised BOM, Added Reference to Std 18-4100
96	EMMA HALILOVIC	18-4100		OVERHEAD SYSTEM COMMUNICATION MESSENGER BONDING	18	REVISED	Revised Title, Added BOM. Added Reference to Section 23
97	JAMES DANIEL	18-5000		UNDERGROUND SYSTEMS GROUND POST GROUNDING DETAILS	18	REVISED	Updated dimensions, notes, BOM, pictorial revisions
98	IGOR SIMONOV	18-5200		Underground System Submersible or Splice Vault	18	REVISED	UPDATED BOM, REFERENCES, DRAWING TO REFLECT MU SPLIT WITH 13-7010

DISTRIBUTION CONSTRUCTION STANDARDS

STANDARDS REVISION #45

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
99	JAMES DANIEL	18-5400		UNDERGROUND SYSTEM SPLICE VAULT 'B'	18	REVISED	Updated dimensions, notes, BOM, pictorial revisions
100	JOHN HECIMOVIC	21-1100		GENERAL INFORMATION STENCILING MATERIALS	21	REVISED	INFORMATION CORRECTION
101	JOHN HECIMOVIC	21-2400		IN-LINE SWITCH NUMBERING	21	REVISED	INFORMATION CORRECTION
102	ROB MCKEOWN / JAMES DANIEL	23-0000		INDEX OF STANDARDS	23	REVISED	Removed obsolete standard
103	ROB MCKEOWN / JAMES DANIEL	23-1200		OVERHEAD SYSTEM POLE ATTACHMENTS - COMMUNICATION CABLE ATTACHMENTS	23	REVISED	Added wording to Anchors section. Added details to diagram.
104	ROB MCKEOWN / JAMES DANIEL	23-1210		COMMUNICATION CABLE LOCATIONS ON POLES	23	OBSOLETE	OBSOLETED NO LONGER REQUIRED
105	ROB MCKEOWN / JAMES DANIEL	23-1220		OVERHEAD SYSTEM POLE ATTACHMENTS - COMMUNICATION RISER AND NEUTRAL BONDING	23	REVISED	Revised diagram
106	John Hecimovic	24-1100		OVERHEAD FUSING TRANSFORMRERS	24	REVISED	Updated note
107	IGOR SIMONOV	24-2100		UNDERGROUND FUSING FOR NETWORK PROTECTORS	24	REVISED	Revised to to remove 9663518
108	EMMA HALILOVIC	30-1100		GENERAL INFORMATION	30	REVISED	Changed general information
109	James Daniel	30-4210		ALUMINUM POLE WITH COBRA HEAD LUINAIRE	30	REVISED	Revised drawing, dimensions, notes and BOM
110	James Daniel	31-0000		INDEX OF STANDARDS	31	REVISED	Revise Standard Title's in index to match with the corresponding Standard
111	JAMES DANIEL	31-0100		UNDERGROUND CLEARANCES	31	REVISED	Updated note
112	JAMES DANIEL	31-1120		CONDUITS CONCRETE ENCASED AND DIRECT BURIED DUCTS	31	REVISED	Updated dimensions, notes, BOM, pictorial revisions

DISTRIBUTION CONSTRUCTION STANDARDS

STANDARDS REVISION #45

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
113	JAMES DANIEL	31-1250		CONDUITS UNDERGROUND SECONDARY SERVICE PROJECTS FOR NEW INSTALLATION	31	REVISED	Updated dimensions, notes, BOM, pictorial revisions
114	JAMES DANIEL	31-1310		CABLE CHAMBERS LID PLACEMENT	31	REVISED	Updated dimensions, notes, BOM, pictorial revisions
115	JAMES DANIEL	31-2010		CABLE CHAMBERS GENERAL INFORMATION AND GUIDELINES	31	REVISED	Updated dimensions, notes, BOM, pictorial revisions
116	JAMES DANIEL	31-2120		CABLE CHAMBERS LID PLACEMENT	31	REVISED	Updated dimensions, notes, BOM, pictorial revisions
117	JAMES DANIEL	31-2130		CABLE CHAMBERS STRUCTUAL DETAIL	31	REVISED	Updated dimensions, notes, BOM, pictorial revisions
118	JAMES DANIEL	31-2140		CABLE CHAMBERS DEEP NECK CHAMBERS STRUCTUAL DETAILS	31	REVISED	Updated dimensions, notes, BOM, pictorial revisions
119	JAMES DANIEL	31-2160		CABLE CHAMBERS PRECAST CHAMBER	31	REVISED	Updated dimensions, notes, BOM, pictorial revisions
120	JAMES DANIEL	31-2180		CABLE CHAMBERS TYPICALRACKING ARRANGEMENTS	31	REVISED	Updated dimensions, notes, BOM, pictorial revisions
121	JAMES DANIEL	31-2240		VAULTS SPLICE 'B' - 3 PIECE PRECAST	31	REVISED	Updated dimensions, notes, BOM, pictorial revisions
122	JAMES DANIEL	31-4080		CABLE CHAMBERS LID PLACEMENT	31	REVISED	Updated dimensions, notes, BOM, pictorial revisions
123	JAMES DANIEL	31-5120		SPLICE VAULT 'A' FOR 1000 kcmil CABLES	31	REVISED	Updated dimensions, notes, BOM, pictorial revisions
124	James Daniel	31-8260		MATERIAL FABRICATION - CABLE RACK	31	REVISED	Revised BOM
125	JAMES DANIEL	31-8270		MATERIAL FABRICATION CABLE ARMS	31	REVISED	Updated dimensions, notes, BOM, pictorial revisions
126	ROB MCKEOWN / TAREK TURK	34-0000		INDEX OF STANDARDS	34	REVISED	Revised to add 34-1000

DISTRIBUTION CONSTRUCTION STANDARDS

STANDARDS REVISION #45

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
127	ROB MCKEOWN / TAREK TURK	34-1000		CONSTRUCTION DEVIATION GUIDELINES	34	NEW	New Constructin deviation

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #46

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
1	JAMES DANIEL	03-2150		OVERHEAD MINIMUM VERTICAL CLEARANCES ABOVE GROUND OR RAILS	03	REVISED	Jeffry: Revised notes and revised dimensions
2	JAMES DANIEL	04-5600		CEDAR AND CONCRETE POLES	04	REVISED	CHANGE IN TEXT PLEASE REPLACE OLD ONE
3	ROB MCKEOWN	05-0000		INDEX OF STANDARDS	05	REVISED	ADD NEW STANDARD
4	ROB MCKEOWN	05-1130		4.16 TO 27.6 KV TREEPROOF AND BARE PRIMARY MID-SPAN OPENER	05	NEW	New sketch, contains mid-span opener, front and isometric view
5	ROB MCKEOWN / JAMES DANIEL	05-1580		4.16 TO 27.6 KV TREEPROOF AND BARE PRIMARY 3-PHASE DOUBLE DEAD-END OR TRANSITION BETWEEN BARE AND TREEPROOF HORIZONTAL CONFIGURATION	05	REVISED	Added notes indicating line angles that can be accomodated.
6	ROB MCKEOWN	05-1590		3-PHASE DOUBLE DEAD-END HORIZONTAL CONFIGURATION	05	REVISED	Added Bolt and Guy and revised BOM
7	ROB MCKEOWN	05-1880		DOUBLE 3-PHASE DOUBLE DEAD-END OR TRANSITION BETWEEN BARE AND TREEPROOF VERTICAL CONFIGURATION	05	REVISED	Added Bolt and Guy and revised BOM
8	ROB MCKEOWN	05-2030		4.16 TO 27.6 kV TREEPROOF AND BARE PRIMARY 1-PHASE RUN-OFF FROM 3-PHASE HORIZONTAL	05	REVISED	Added figure 2 which provides outside phase run-off
9	JAMES DANIEL	05-6070		SYSTEM NEUTRAL TAP AND RUN-OFF	05	REVISED	REVISED BOM FOR PERMUTATION G, H, I
10	ROB MCKEOWN	06-1000		INTRODUCTION	06	REVISED	Additional wording added to Initial Sags section
11	IGOR SIMONOV	09-1400		GENERAL INFORMATION BUSHING CONFIGURATION	09	REVISED	including two tools method field connection to terminal tap
12	IGOR SIMONOV	09-9200		3-PH CONSTRUCTION 8000/13800-347/600 VV WYE ALL SIZE	09	REVISED	double up secondary drop leads for a 167unit shall not apply to std. 09-9100
13	IGOR SIMONOV	09-9300		3-PH CONSTRUCTION 16000/27600-347/600 VV WYE ALL SIZE	09	REVISED	double up secondary drop leads for a 167unit shall not apply to std. 09-9100
14	EMMA HALILOVIC	10-1300		ALL VOLTAGES AND CONFIGURATIONS	10	REVISED	Drawing,Comment and BOM change
15	EMMA HALILOVIC	10-2400		MANUALLY OPERATED 13.8kV & 27.6kV FEEDER RISER	10	REVISED	Added Dimensions, Revise BOM and added details
16	EMMA HALILOVIC	10-2600		MANUALLY OPERATED13.8kV and 27.6kV TIER OUTBOARD TYPE	10	REVISED	Added Dimensions, Revise BOM and added details
17	EMMA HALILOVIC	10-3100		SCADA-OPERATOR 13.8 & 27.6kV FEEDER RISER	10	REVISED	Added Detail 'A', 'B', 'C'; Added dimensions and clearances, gonding schematic; Edited notes, BOM and BOM legend
18	EMMA HALILOVIC	10-3700		COMMUNICATION AND CONTROL UNIT(CCU) SCADA AND FEEDER AUTOMATION	10	REVISED	Revised notes
19	ROB MCKEOWN	11-3170		MULTIPLEXED SECONDARY BUS - DEAD -END ON TTC STEEL POLE	11	REVISED	Added Double Dead-End option and revised BOM

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #46

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
20	ROB MCKEOWN	11-3180		MULTIPLEXED SECONDARY BUS - DEAD -END ON CONCRETE OR WOOD POLE	11	REVISED	Added Double Dead-End option and revised BOM
21	ROB MCKEOWN	11-3190		MULTIPLEXED SECONDARY BUS - TURNING ANGLE 4 TO 90 DEGREES ON TTC STEEL POLE	11	REVISED	Revised BOM
22	ROB MCKEOWN/JOHN HECIMOVIC	12-3500		PRIMARY SERVICE RISERS - FUSED 3-PHASE WITH CLF 13.8kV & 27.6kV GRD Y	12	REVISED	NEW REVISION OF AN OLD STANDARD THAT WAS OBSOLETE.
23	IGOR SIMONOV	13-5010		13.8 Kv NETWORK SYSTEM NETWORK TRANSFORMER VAULTS	13	REVISED	BOM CHANGED
24	IGOR SIMONOV	13-7010		27.6 Kv or 13.8 Kv 1PH SUBMERSIBLE TRANSFORMER VAULT	13	REVISED	NOTE CHANGED AND BOM CHANGED
25	IGOR SIMONOV	14-1030		13.8 Grd. Y 8.0 kV 1 PH URD/LOOP SYSTEM	14	REVISED	NOTE CHANGED
26	IGOR SIMONOV	14-1040		13.8 kV 3 PH RADIAL DELTA PRIMARY CONNECTION	14	REVISED	NOTE CHANGED
27	IGOR SIMONOV	14-1050		13.8 kV 3 PH RADIAL URD/LOOP SYSTEM	14	REVISED	NOTE CHANGED
28	IGOR SIMONOV	14-1060		27.6 Grd. Y 16 Kv 1-1PH RADIAL/LOOP SYSTEM	14	REVISED	NOTE CHANGED
29	IGOR SIMONOV	14-1070		27.6 Grad. 16kV 3-PH RADIAL/LOOP SYSTEM	14	REVISED	NOTE CHANGED
30	IGOR SIMONOV	14-3600		INSTALLATION-27.6Kv RADIAL / LOOP	14	REVISED	NOTE CHANGED
31	KAL SARKAR	15-3760		SECONDARY 120/240V UNDERGROUND SERVICE UP TO 200A TYPICAL TAP BOX USING E TYPE CONNECTORS	15	REVISED	Full Review and Evaluation
32	KAL SARKAR	15-8200		PRIMARY SERVICES	15	REVISED	REVISION OF BOM
33	KAL SARKAR	16-0000		INDEX OF STANDARDS	16	REVISED	Added Std. 16-2360
34	KAL SARKAR	16-0280		600V SECONDARY TERMINALS	16	REVISED	PART NUMBER CHANGES
35	KAL SARKAR	16-1220		TABLE OF RATINGS OF CABLES 600 V SECONDARY BUS AND SERVICE CABLES	16	REVISED	TEXT AND BOM CHANGE
36	KAL SARKAR	16-2340		CABLE JOINTS AND TERMINATIONS - GENERAL INSTALLATION INSTRUCTIONS	16	REVISED	Changed stock code from the old to the newly approved 4-panel windshield (pg.8)
37	KAL SARKAR	16-2360		Primary - Termination, Termination Kit Quick Selection Chart	16	New	Created selection chart for termination kit
38	ROB MCKEOWN	23-1020		OVERHEAD 120 V UNMETERED CONNECTION SERVICES ATTACHED TO TORONTO HYDRO POLES	23	REVISED	Revised notes

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #46

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
39	ROB MCKEOWN	23-1030		UNDERGROUND 120 V UNMETERED CONNECTION SERVICES ATTACHED TO TORONTO HYDRO POLES	23	REVISED	Revised notes
40	JAMES DANIEL	23-1150		Temporary Decorative Pole Wrap	23	REVISED	Revised notes and made adjustments to dimensions
41	JAMES DANIEL	30-5000		Decorative Streetlighting Pole Capella Pole 30' - Yonge Street (Dundas to Shuter)	30	REVISED	Revised drawing, dimensions, notes and BOM
42	JAMES DANIEL	31-1240		Residential Underground Secondary Service Rebuilds	31	REVISED	Revised notes, drawing, and dimensions
43	JAMES DANIEL	31-1390		Conduits Joint Trenching	31	REVISED	MEASUREMENT CHANGE
44	JAMES DANIEL	31-5120		SPLICE VAULT 'A' FOR 1000 kcmil CABLES - 1625 mm (5'-4") x 2750 mm (9'-0")	31	REVISED	Edited diagrams and Revised Note
45	ROB MCKEOWN / TAREK TURK	34-1000		CONSTRUCTION DEVIATION GUIDELINES	34	REVISED	Revised to show that relocating pole mount transformer is a technical deviation due to voltage drop calculations.

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #47

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
1	**Rob McKeown**	**03-0000**		INDEX OF STANDARDS	**03**	**Revised**	Revised to add new Standard
2	**Rob McKeown**	**03-1100**		Overhead - General Information	**03**	**Revised**	revised point 10 to reflect new standard 03-2310
3	**Rob McKeown**	**03-2000**		Overhead - Minimum Clearances	**03**	**Revised**	revised point 10 to reflect new standard 03-2310
4	**Rob McKeown**	**03-2150**		Overhead - Minimum Clearances	**03**	**Revised**	Drawing revised
5	**Rob McKeown**	**03-2250**		Overhead - Minimum Clearances	**03**	**Revised**	Notes have been revised
6	**Rob McKeown**	**03-2300**		Overhead - Minimum Clearances Buildings and Permanent Structures	**03**	**Revised**	Revised note to reflect new standard 03-2310
7	**Rob McKeown**	**03-2310**		Overhead - Swing Allowance for Conductors	**03**	**New**	New
8	**Rob McKeown**	**03-2700**		Overhead Minimum Clearance - Between Service Mast and Readily Accessible Surfaces	**03**	**New**	New standard to show clearances for readily accessible surfaces
9	**James Daniel**	**04-4100**		POLE LOCATION GUIDELINES	**04**	**Revised**	Revised clearances
10	**James Daniel**	**04-4200**		Pole And Pole Settings - Gurd	**04**	**Revised**	Revised clearances
11	**Rob McKeown**	**05-0000**		Index of Standards	**05**	**Revised**	Added 05-2180, Rev 13
12	**Rob McKeown**	**05-0010**		Introduction	**05**	**Revised**	Revised Notes
13	**Rob McKeown**	**05-1580**		3-Phase Double Dead-End or Transition Between Bare and Treeproof Horizontal Configuration	**05**	**Revised**	Revision made to notes
14	**Rob McKeown**	**05-1880**		DOUBLE 3-PHASE DOUBLE DEAD-END OR TRANSITION BETWEEN BARE AND TREEPROOF VERTICAL CONFIGURATION	**05**	**Revised**	Added correct (hidden) part to drawing
15	**Rob McKeown**	**05-2180**		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Horizontal Run-Off From 3-Phase Horizontal	**05**	**New**	Created standard to show 3 ph horizontal run off from 3 ph horizontal (NEW)
16	**Rob McKeown**	**07-0000**		Index Of Standards	**07**	**Revised**	**Revised To Remove Standards**
17	**Rob McKeown**	**07-1200**		ANCHOR SELECTION HOLDING CAPACITIES FOR VARIOUS SOIL CLASSES	**07**	**Revised**	Revised Notes

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #47

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
18	Rob McKeown	07-2200		ANCHOR INSTALLATION EXPANSION ANCHOR CLASS 8 SOIL TYPE	07	Revised	Revised Drawing
19	Rob McKeown	07-3100		GUY SELECTION	07	Obsolete	Remove from standards
20	Rob McKeown	07-3200		DETERMINE ULTIMATE LOAD AND GUY TENSION	07	Obsolete	Remove from standards
21	Rob McKeown	07-3300		BISECTOR CHART METHOD	07	Obsolete	Remove from standards
22	Rob McKeown	07-3400		LINE TERMINATION CHART METHOD	07	Obsolete	Remove from standards
23	Rob McKeown	07-3500		GUYING - Typical Guying Arrangements	07	Revised	Revised description under the 'Type of Guy' column
24	Rob McKeown	07-4000		GUY COMPONENTS	07	Revised	Revised Notes
25	Rob McKeown	07-4250		Guying Installation Procedure Strut Guy	07	Revised	Revised Notes
26	IGOR SIMONOV	09-9500		1-Phase Transformers	09	Revised	BOM CHANGED
27	IGOR SIMONOV	09-9510		1-Phase Transformers - Dead-End Configuration	09	Revised	BOM CHANGED
28	IGOR SIMONOV	09-9600		3-Phase Transformers - Overbuild Only	09	Revised	BOM CHANGED
29	IGOR SIMONOV	09-9610		3-Phase Transformers - Dead-End Configuration	09	Revised	BOM CHANGED
30	Emma Halilovic	10-1300		Disconnect in-Line Switches All Voltages	10	Revised	Revise
31	EMMA HALILOVIC	10-2400		3-PHASE LOAD INTERRUPTER SWITCH	10	Revised	Changes of bill of material
32	EMMA HALILOVIC	10-2600		Manually-Operated 13.8kV and 27.6kV Tier Outboard Type	10	Revised	Revised Drawing and BOM
33	EMMA HALILOVIC	10-2810		Three Phase Load Interpuder mterup	10	Revised	Revised Drawing and BOM
34	EMMA HALILOVIC	10-3000		Scada-Operated 13.8 kV & 27.6 kV Feeder Riser Using Upright Type Switch	10	Revised	Revised Drawing and BOM
35	EMMA HALILOVIC	10-3500		SCADA-Operated 13.8kV & 27.6kV Tier Outboard Type	10	Revised	Revised Drawing and BOM

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #47

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
36	**EMMA HALILOVIC**	**10-3510**		SCADA Operated 13.8kV & 27.6kV Tier Outboard Type (Feeder Tie)	**10**	**Revised**	Revised Drawing and BOM
37	**EMMA HALILOVIC**	**10-3610**		SCADA-Operated 13.8kV & 27.6kV Upright Type	**10**	**Revised**	Revised Drawing and BOM
38	**Rob McKeown**	**11-3170**		Multiplexed Secondary Bus Dead-End on TTC Steel Pole	**11**	**Revised**	Revised drawing to show neutral
39	**Rob McKeown**	**11-3180**		Multiplexed Secondary Bus Dead-End On Concrete or Wood Pole	**11**	**Revised**	Revised drawing to show neutral
40	**Rob McKeown**	**11-5500**		120 V CONNECTION FOR UNMETERED SERVICES STAND ALONE STRUCTURES	**11**	**Revised**	Revised standard
41	**Rob McKeown**	**12-0000**		Index of Standards	**12**	**Revised**	Revised standard
42	**Rob McKeown**	**12-1200**		Riser Installaion Details - Cable Guard or Pipe	**12**	**Revised**	Revised note 1
43	**Rob McKeown**	**12-3000**		Primary Service Risers - Primary Drops and Connections For 1-Phase Service Riser	**12**	**Revised**	Drawing And Material Change
44	**Rob McKeown**	**12-3100**		Primary Service Risers - Primary Drops and Connections For 3-Phase Service Riser	**12**	**Revised**	Drawing And Material Change
45	**Rob Mckeown John Hecimovic**	**12-3500**		PRIMARY SERVICE RISERS - FUSED 3-PHASE WITH CLF 13.8kV & 27.6kV GRD Y	**12**	**Revised**	NEW REVISION OF AN OLD STANDARD THAT WAS OBSOLETE.
46	**John Hecimovic**	**12-4000**		PRIMARY FEEDER RISERS - FUSED 13.8kV & 27.6kV GRD Y	**12**	**Revised**	**Drawing And Material Change**
47	**Benson Lo**	**13-7060**		3 1-PHASE TRANSFORMER VAULT 27.6 Kv TYPICAL LAYOUT	**13**	**Revised**	**Note revision**
48	**John Hecimovic**	**13-7200**		GRD. Y VAULT - TYPICAL LAYOUT 27.6 Kv	**13**	**Revised**	Full Review and Evaluation
49	**John Hecimovic**	**13-7500**		3 1-PHASE TRANSFORMER VAULT 27.6 Kv CUSTOMER ROOM WITH SF6 SWITCHGEAR	**13**	**Revised**	Full Review and Evaluation
50	**IGOR SIMONOV**	**14-3200**		Padmount Transformers	**14**	**Revised**	**Note change**
51	**IGOR SIMONOV**	**14-3300**		Padmount Transformers	**14**	**Revised**	Note change
52	**IGOR SIMONOV**	**14-3400**		Padmount Transformers	**14**	**Revised**	**Note change**
53	**IGOR SIMONOV**	**14-3500**		Padmount Transformers	**14**	**Revised**	Note change

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #47

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
54	IGOR SIMONOV	14-3600		Installation - 27.6kV radial/Loop 3 - phase 27.6kV radial Loop System	14	Revised	Note 5 and material change
55	John Hecimovic	16-2350		UG Cables, Joints, Terminations and Connectors	16	Revised	drawing change
56	John Hecimovic	16-3700		UG Cables, Joints, Terminations and Connectors	16	Revised	drawing change
57	John Hecimovic	16-3940		UG Cables, Joints, Terminations and Connectors	16	Revised	drawing change
58	John Hecimovic	16-5200		UG Cables, Joints, Terminations and Connectors	16	Revised	Standard Change
59	Tarek Turk	16-6210		Cable Reel Data Cable And Wire Reel Chart	16	Revised	Data revision
60	JAMES DANIEL	17-2250		MINIMUM CLEARAN	17	Revised	Note change
61	JAMES DANIEL	17-2310		Secondary - Outdoor Service Pedestal, Single Phase, Up to 200A	17	Revised	Full Review and Evaluation
62	JAMES DANIEL	17-4600		PRIMARY METERING - 27.6 kV, 600 A - 3-PHASE 4 WIRE TYPICAL OUTDOOR INSTALLATION	17	Revised	Revised Notes
63	EMMA HALILOVIC	18-5000		Guard Post Grounding Detail	18	Revised	Revised Notes
64	JAMES DANIEL	21-2100		OVERHEAD STENCILING - POLE NUMBERING	21	Revised	Revised Notes
65	JAMES DANIEL	21-2200		PRIMARY SERVICE RISER - FUSED 1 PHASE BACK TO BACK	21	Revised	Revised Notes
66	JAMES DANIEL	21-2400		IN-LINE SWITCH NUMBERING	21	Revised	Revised Notes
67	JAMES DANIEL	21-2500		COMMUNICATION AND CONTROL UNIT NUMBERING	21	Revised	Revised Notes
68	JAMES DANIEL	21-2700		REPEATER RADIO NUMBERING - (FOR FEEDER AUTOMATION)	21	Revised	Revised Notes
69	JAMES DANIEL	21-3200		UNDERGROUND STENCILING - TAP BOX/ TAP BOX VAULT STENCILING	21	Revised	Revised Notes
70	JAMES DANIEL	21-3300		UNDERGROUND STENCILING - 3-PHASE PRIMARY METERING CABINET	21	Revised	Revised Notes
71	JAMES DANIEL	21-3500		3-PHASE PAD-MOUNTED TRANSFORMER	21	Revised	Revised Notes

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #47

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
72	JAMES DANIEL	21-3700		UNDERGROUND STENCILING - CABLE CHAMBER STENCILING	21	Revised	Revised Notes
	IGOR SIMONOV	21-3900		Underground Stenciling	21	Revised	changed drawing on page 3
73	JAMES DANIEL	21-4300		UNDERGROUND STENCILING - CABLE CHAMBER STENCILING	21	Revised	Revised Notes
74	Rob McKeown	21-4700		UNDERGROUND STENCILING - SECONDARY CABLE LABELLING	21	Revised	Revised Notes
75	Rob McKeown	23-0000		INDEX OF STANDARDS	23	Revsed	Revised to add new standard
76	Rob McKeown	23-1260		FOREIGN ATTACHMENTS	23	New	New Standard
77	IGOR SIMONOV	24-1400		Underground fusing 27.6 kV transformer in vault	24	Revised	revised notes
78	IGOR SIMONOV	24-1600		Underground fusing 13.8 kV URD system	24	Revised	revised notes
79	IGOR SIMONOV	24-2000		Underground fusing molded current-limiting fuse	24	Revised	revised notes
80	James Daniel	27-8000		Legend/Drafting Symbols	27	Revised	Page 2 Section of standards revised
81	EMMA HALILOVIC	30-0000		INDEX OF STANDARDS	30	Revised	Revised to remove Standards
82	EMMA HALILOVIC	30-3250		Installation Detail light-trespass Sheilds	30	Obsolete	obsoleted
83	EMMA HALILOVIC	30-3300		Installation Detail Lamp Holder Ajustment in the universal Luminaire	30	Obsolete	Standard obsoleted
84	James Daniel	30-3570		Installation of Sidemounted Plate	30	Revised	Material Change
85	IGOR SIMONOV	30-3810		Typical in-line Fuse Installation	30	Obsolete	standard obsoleted
86	James Daniel	30-4100		Concrete Pole 25' & 30' With Universal Luminaire	30	Revised	Drawing revised and added note 6
87	James Daniel	30-7160		DECORATIVE STREET LIGHTING POLE HISTORICAL OLD FOREST HILL	30	Revised	Drawing revised
88	James Daniel	30-9780		Reinforced Sidewalk Bay	30	Revised	Drawing revised

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #47

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
89	James Daniel	30-9800		Civil Construction Reinforced Bay	30	Revised	Drawing revised
90	James Daniel	30-9820		Reinforced Side Walk Bay	30	Revised	Drawing revised
91	James Daniel	31-0100		Underground Clearances	31	Revised	Notes have been revised
92	James Daniel	31-1400		Duct Sealant Installation	31	New	New
93	James Daniel	31-2120		Cable Chambers Lid Placement	31	Revised	Revised to a new construction standard from the old format
94	James Daniel	31-4030		Three Phase Precast Pad-Mount 1830 mm x 1830 mm x 1220 mm	31	Revised	Revised measurement
95	James Daniel	31-4080		Padmounts Guard Posts(Bollards	31	Revised	Revise notes
96	James Daniel	31-5100		Vaults Precast Concrete	31	Revised	Revised Measurements
97	James Daniel	31-5190		VAULT 1 - 2000 kVA NETWORK VAULT 3000 mm (10'-0") X 4600 mm (15'-0") X 3660 mm (12'-0") HEAD ROOM	31	Revised	Revised measurement
98	James Daniel	31-7100		DRAINING STRUCTURES	31	Revised	Revised to a new construction standard from the old format
99	James Daniel	31-8320		LADDERWAY GRID FRAME FOR TRANSFORMER VAULT	31	Revised	Revised measurement and fonts
100	James Daniel	31-8390		Vault Transformer Vault Ladder	31	Revised	Revised measurement and fonts
101	James Daniel	31-8560		Material Fabrication - Ladderway Intake Vent Frame	31	Revised	Revised measurement and fonts
102	Kalyan Sarkar	70-10		Underground Secondary - Straight Joint Hand Taping Method 600 V and Below, 1 Conductor	70	New	New standard made for reactive maintenance for Hand Taping Method

DISTRIBUTION CONSTRUCTION STANDARDS

REVISION #48

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised/ Obsolete	Revision number at date of issue	Revision Description
1	03	03-2000	Clearances	Standard Attachment Points	Revised	7	Request to reduce clearances for overhead secondary's and primary
2	05	05-1340	Pole Framing	4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Vertical Configuration Angles 0 to 45 degrees	Revised	2	Revised location of ground rods from inside to outside with rods connected to form a loop - Added notes 1 to 4 and 6 - Added missing items 7, 10 to 13 in BOM
3	05	05-1420	Pole Framing	4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Double Dead-end Horizontal Configuration Angles 61 to 90 degrees	Revised	2	Initiator requires re-configuration for clearances of overhead back to back crossarm configuration
4	05	05-1820	Pole Framing	4.16 to 27.6 kV Treeproof and Bare Primary Double 3-Phase Double Dead-End 90 Degrees	Revised	2	Provides more working clearance and better direction to construction crews.
5	05	05-1840	Pole Framing	4.16 to 276 kV Treeproof and Bare Primary Double 3-Phase Vertical Configuration 1 Tangent Circuit and 1 Dead-end Circuit	Revised	2	Dimensions added on the Drawing
6	05	05-2170	Pole Framing	4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Horizontal Run-Off From 3-Phase Halo	Revised	2	Centre phase jumper moved to the opposite side of the pole.
7	05	05-2420	Pole Framing	4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Double Circuit Run-Offs from 3-Phase Double Circuit Vertical Configuration	Revised	2	Revised standard to show alternate installation for permutation B.
8	07	07-1200	Anchoring and Guying	Anchor Selection Ultimate Holding Strength Capacities Under Various Soil Classes	Revised	4	Wording Revised and conversion from mm to inches corrected.
9	07	07-2600	Anchoring and Guying	Expanding Pole Key Anchor Class 5 to 8 Soil Types	Revised	2	Spud Bar option added and notes Revised accordingly
10	07	07-3000	Anchoring and Guying	General Information	Revised	6	Changes made to drawing and notes to supplement engineering bulletin
11	07	07-3600	Anchoring and Guying	Location of Guy Insulator	Revised	2	Changes made to drawing and notes to supplement engineering bulletin
12	07	07-5100	Anchoring and Guying	Down Guy - One on Concrete, Wood or Steel Pole	Revised	5	Changes made to drawing and notes to supplement engineering bulletin
13	07	07-5110	Anchoring and Guying	Down Guy - One on Concrete or Wood Pole Using Insulator Rod(s)	Revised	4	Changes made to drawing and notes to supplement engineering bulletin
14	07	07-5160	Anchoring and Guying	Down Guy - One on Concrete or Wood Pole Using Insulator Rods on Armless Construction	Revised	5	Changes made to drawing and notes to supplement engineering bulletin
15	07	07-5170	Anchoring and Guying	V - Guying on Concrete or Wood Pole Using Insulator Rods on Armless Construction	Revised	1	Changes made to drawing and notes to supplement engineering bulletin
16	07	07-5200	Anchoring and Guying	Strut Guy - One On Concrete, Wood or Steel Pole	Revised	6	Changes made to drawing and notes to supplement engineering bulletin
17	07	07-5220	Anchoring and Guying	Strut Guys-Two On Concrete or Wood Pole Using Insulator Rod(s)	Revised	6	Changes made to drawing and notes to supplement engineering bulletin
18	07	07-5230	Anchoring and Guying	Strut Guys-One On Concrete or Wood Pole Using Insulator Rod(s)	Revised	1	Changes made to drawing and notes to supplement engineering bulletin
19	07	07-5240	Anchoring and Guying	Strut Guy-Two on Cedar Or Concrete Pole Using Insulator Rod	Revised	1	Changes made to drawing and notes to supplement engineering bulletin
20	07	07-5250	Anchoring and Guying	Strut Guys - Three on Concrete or Wood Pole Using Insulator Rod(s)	Revised	1	Changes made to drawing and notes to supplement engineering bulletin
21	07	07-5340	Anchoring and Guying	Span & Strut Guy - One On Concrete, Wood or Steel Pole	Revised	6	Changes made to drawing and notes to supplement engineering bulletin
22	07	07-5350	Anchoring and Guying	Span & Strut Guy - One On Concrete, Wood or Steel Pole Using Insulator Rod	Revised	6	Changes made to drawing and notes to supplement engineering bulletin
23	07	07-5370	Anchoring and Guying	Span & Strut Guy - Two On Concrete, Wood or Steel Pole With One Span Guy Using Insulator Rod	Revised	7	Changes made to drawing and notes to supplement engineering bulletin
24	07	07-5380	Anchoring and Guying	Span & Strut Guys - Two On Concrete or Wood Pole Using Insulator Rod	Revised	4	Changes made to drawing and notes to supplement engineering bulletin

DISTRIBUTION CONSTRUCTION STANDARDS

REVISION #48

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised/ Obsolete	Revision number at date of issue	Revision Description
25	07	07-5300	Anchoring and Guying	Span & Down Guy - One on Concrete, Wood or Steel Pole	Revised	5	Changes made to drawing and notes to supplement engineering bulletin
26	07	07-5310	Anchoring and Guying	Span & Down Guy - One on Concrete, Wood or Steel Pole Using Insulator Rod(s)	Revised	5	Changes made to drawing and notes to supplement engineering bulletin
27	07	07-5320	Anchoring and Guying	Span & Down Guy - Two on Concrete, Wood or Steel Pole	Revised	6	Changes made to drawing and notes to supplement engineering bulletin
28	07	07-5400	Anchoring and Guying	Storm Guy on Concrete Or Wood Pole	Revised	4	Changes made to drawing and notes to supplement engineering bulletin
29	07	07-5500	Anchoring and Guying	Span Guy - One On Concrete, Wood or Steel Pole	Revised	5	Changes made to drawing and notes to supplement engineering bulletin
30	08	08-0000	INDEX	INDEX of Standards	Revised	6	Revised to add 2 new standards
31	08	08-3450	Overhead Conductors and Connectors	Bolted Tap - Box Application and Selection Table	Revised	2	Identified requirement for more equipment, Revised table to include additional material
32	08	08-3620	Overhead Conductors and Connectors	Overhead Connectors - Pulling Grips Application and Selection Table	Revised	1	Revised selection table to show new conductor selection list. Notes were also Revised to compliment new selection table.
33	08	08-3630	Overhead Conductors and Connectors	Overhead Connectors - Temporary Pulling Grips Application and Selection Table	New	0	CRF was created by field rep to have standards identify correct pulling grip
34	09	09-1300	Overhead Transformers	General Information Installation	Revised	5	Review the submitted drawing and update the standards so they are constant
35	09	09-3500	Overhead Transformer	Wild Life guard Details	Revised	3	Wild life guard change to new design as the existing one did not fit correctly for 27.6 transformers
36	09	09-9500	overhead transformers	1 Phase Transformer	Revised	5	Update standard to reflect and show the standard off installation dimensions and consider changing
37	09	09-9510	overhead transformers	Primary drop leads	Revised	2	Update standard to reflect and show the standard off installation dimensions and consider changing
38	09	09-9600	overhead transformer	Primary drop leads	Revised	5	Update standard to reflect and show the standard off installation dimensions and consider changing
39	10	10-3700	Overhead Switches	Communication and Control Unit (CCU) SCADA and Feeder Automation	Revised	11	Revised BOM to include padlock and antenna cable for SD9 radio
40	10	10-3800	Overhead Switches	3-Phase primary	Revised	5	CRF-2014-0112. Revised standard to include riser notes , updated BOM to meet the April 2016 open bin material
41	11	11-3110	O/H Secondary & Primary Services	Multiplexed Secondary Bus Break On Concrete or Wood Pole Or Midspan	Revised	3	Midspan bus break option added to the drawing, Revised BOM and BOM Legend
42	11	11-3210	Overhead Primary & Secondary Service	Multiplexed Secondary Bus: Service Taps 120/240V at Pole	Revised	4	Storm safe grip was introduced for the purpose of having the service break from the line side and not the house side and also preventing the customer electrical stack from being pulled down
43	11	11-3250	Overhead Primary & Secondary Service	Multiplexed Secondary Bus: Service Taps 120/240V at Mid-Span	Revised	4	Storm safe grip was introduced for the purpose of having the service break from the line side and not the house side and also preventing the customer electrical stack from being pulled down
44	11	11-3300	Overhead Primary & Secondary Service	Multiplexed Secondary Bus: Service Taps 120/208V at Pole	Revised	3	Storm safe grip was introduced for the purpose of having the service break from the line side and not the house side and also preventing the customer electrical stack from being pulled down
45	11	11-3350	Overhead Primary & Secondary Service	Multiplexed Secondary Bus: Service Taps 120/208V at Mid-Span	Revised	3	Storm safe grip was introduced for the purpose of having the service break from the line side and not the house side and also preventing the customer electrical stack from being pulled down
46	11	11-3400	Overhead Primary & Secondary Service	Multiplexed Secondary Bus: Service Taps 600 V or 347/600V at Pole	Revised	3	Storm safe grip was introduced for the purpose of having the service break from the line side and not the house side and also preventing the customer electrical stack from being pulled down

53	11	11-4600	Overhead Primary & Secondary Service	Open Secondary Bus Open Secondary Bus 120/240 V at	Revised	3	ıe service venting the
54	11	11-4650	Overhead Primary & Secondary Service	Open Secondary Bus Open Secondary Bus 120/240 V at Mid-Span	Revised	4	ıe service venting the
55	11	11-5200		120 V CONNECTION FOR UNMETERED SERVICES STAND ALONE STRUCTURES	Revised	6	

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #48

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised/ Obsolete	Revision number at date of issue	Revision Description
67	13	13-4100	UG Transformer &switchgear	13.8kV Radial System 600 A Secondary Manual Switch ATS Replacement	Revised	1	to revise standard to reflect changes required for switch ratings
68	16	16-4180	UG Cables Joints Terminations & Connections	600 A Deadbreak Connectors 15 kV, 1 Cond.	Revised	3	Added notes to include stock code bushing insert torque tool that are available.
69	16	16-4220	UG Cables Joints Terminations & Connections	200 A Loadbreak Connectors 15 kV, 1 Cond.	Revised	3	Added notes to include stock code bushing insert torque tool that are available.
70	16	16-4260	UG Cables Joints Terminations & Connections	600 A Deadbreak Connectors 28 kV, 1 Cond.	Revised	2	Added notes to include stock code bushing insert torque tool that are available.
71	16	16-4300	UG Cables Joints Terminations & Connections	200 A Loadbreak Connectors 28 kV, 1 Cond.	Revised	3	Added notes to include stock code bushing insert torque tool that are available.
72	16	16-4640	UG Cables, Joints/Terminations and Connectors	Hand Taped Splice, 5 kV, 1 Conductor TRXLPE to RILC	Obsolete	0	Standard to be used for reactive construction. Moved to section 70-8 (Reactive Maintenance).
73	16	16-4660	UG Cables, Joints/Terminations and Connectors	Hand Taped Splice, 5 kV, 1 Conductor TRXLPE to RILC	Obsolete	2	Standard to be used for reactive construction. Moved to section 70-8 (Reactive Maintenance).
74	16	16-6000	UG Cables, Joints, Terminations and Connectors	SECONDARY TERMINATIONS SUBMERSIBLE TRANSFORMER TERMINAL CLUSTER 600 V OR BELOW	Revised	6	BOM and drawing has been Revised to identify changes identified by initiator
75	16	16-6020	UG Cables, Joints, Terminations and Connectors	SECONDARY TERMINATIONS 1 PH SUBMERSIBLE AND 1 PH PADMOUNTED TRANSFORMERS	Revised	1	BOM and drawing has been Revised to identify changes identified by initiator
76	17	17-0000	Revenue Metering	Index	Revised	11	Revised Index to add standards 17-8210 and 17-8220.
77	17	17-8210	Revenue Metering	Pole Mounted Cellular Gatekeeper - Fed From Overhead Secondary Main	New	0	Standard was required for future installations as required
78	17	17-8220	Revenue Metering	Pole Mounted Cellular Gatekeeper - Fed From Underground Secondary Main	New	0	Standard was required for future installations as required
79	18	18-3200	Grounding	Overhead System Cable Guard or Galvanized Pipe riser For duct Bend	Revised	3	1)Separated grounding detail of cable guard from bonding detail of GI pipe as per Std 12-1200 2)Added depth of rod 3)Added Details B and D to show installation of 3-phase cable guards 4)Changed Detail 'A' to 'C' to show installation on cable guard5)Revised BOM Legend 'A' and 'B' to apply to Rigid PVC Type only (instead of GI Pipe) 6)Corrected quantity of material required 7)Revised BOM to specify ½" bolt instead of 3/8" for ground wire connection to cable guard
80	18	18-3250	Grounding	Overhead System Cable Guard For Direct Buried Cable	Revised	7	1) Updated cable guard installation as per standard 12-1200 2)Revised dimension for depth of ground rod installation to include max 3)Revised Note 1 from specifying requirements for cable guard installation to referencing applicable standard 12-1200 4)Deleted Note 2 which specified situations where ground rod is not required. As per Section 18, ground rods are required for riser terminations 5)Revised Detail 'A' to show installation on cable guard 6)Added Detail 'B' to show installation of 3-phase cable guards
81	18	18-5400	Grounding	Splice Chamber	Revised	3	Revised standard to include ground loop external to the pad
82	21	21-1100	Overhead and Underground Stenciling	Stenciling Material	Revised	5	CRF-2016-0021 has been completed and the standard 21-1100 has been Revised and stamped.
83	21	21-2100	Overhead and Underground Stenciling	Overhead Stenciling Pole Numbering	Revised	4	Clarify stenciling as per CRF
84	21	21-2110	Overhead and Underground Stenciling	Phase Configuration Identification	Revised	1	To provide better direction to construction crews in the field
85	21	21-3400	Overhead and Underground Stenciling	1-Phase Low Profile Pad-Mounted Transformer	Revised	2	Revised as per SMT to show 1" elbow numbers inside the 3" phase markers. Notes were also Revised to aid in identifying associated standards and to reflect changes made to phase marker detail.
86	21	21-3500	Overhead and Underground Stenciling	3-Phase Pad-Mounted Transformer	Revised	3	Revised as per SMT to show 1" elbow numbers inside the 3" phase markers. Notes were also Revised to aid in identifying associated standards and to reflect changes made to phase marker detail.

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #48

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised/ Obsolete	Revision number at date of issue	Revision Description
87	21	21-4200	Overhead and Underground Stenciling	Underground Stencilling Primary Cable Labeling	Revised	1	Revisions have been made as per CRF-2016-0076, however the standard is still being Revised as per CRF-2015-0285 for NPI
88	27	27-1000	Legend/Drafting Symbols	switches and fusing	Revised	3	Designer changed cell library location. We have to revise standard accordingly
89	27	27-2000	Legend/Drafting Symbols	Transformer	Revised	3	Designer changed cell library location. We have to revise standard accordingly
90	27	27-3000	Legend/Drafting Symbols	conductors and connectors	Revised	2	Designer changed cell library location. We have to revise standard accordingly
91	27	27-4100	Legend/Drafting Symbols	civil structures	Revised	2	Designer changed cell library location. We have to revise standard accordingly
92	27	27-4200	Legend/Drafting Symbols	civil landbase	Revised	2	Designer changed cell library location. We have to revise standard accordingly
93	27	27-5000	Legend/Drafting Symbols	street lighting	Revised	2	Designer changed cell library location. We have to revise standard accordingly
94	27	27-6000	Legend/Drafting Symbols	grid solutions	Revised	2	Designer changed cell library location. We have to revise standard accordingly
95	27	27-7000	Legend/Drafting Symbols	metering and miscellaneous	Revised	2	Designer changed cell library location. We have to revise standard accordingly
96	27	27-8000	Legend/Drafting Symbols	assemblies	Revised	3	Designer changed cell library location. We have to revise standard accordingly
97	28	28-0400	Distribution Construction Standard	Concrete Pole Ground Bar Connection Details	Revised	2	Added drawing, Revised notes and BOM
98	31	31-0000	INDEX	INDEX	Revised	18	Update index as there are 1 standard new and 2 obsoleted standards from this section and relocated to section 70 for reactive maintenance
99	31	31-0100	Civil Construction Standard	Underground Clearances	Revised	6	Please close the CRF-2016-0083. Soft copy of Revised std. has been placed in Projectwise
100	31	31-0700	Civil Construction	Shoring / Excavation In the Vicinity Of Toronto Hydro Underground Plant	NEW	0	Engineer initiative for Utility Circulation for shoring guidelines
101	31	31-1220	Civil Construction	Installation of Bends on Pole	Revised	10	Drawing added for new GI Bend, Revised notes
102	31	31-3140	Civil Construction	handwell with polymer concrete lid	Revised	3	Revised drawing with details to represent consistency with the manufacturer drawing.
103	31	31-5100	Civil Construction	Precast Concrete Two Pieces Submersible vault 940 mm (3'-1") x 1960 mm (6'-5") x .1830 mm (6'-0")	Revised	12	Revised Notes, BOM, Installation, and Drawing to show drain from submersible vault to a gravel sump pit when used as splice vault
104	31	31-8120	Civil Construction	100 mm (4") galvanized iron bend	Obsolete	1	
105	57	57-0000	Station Equipment	Index of Standards	Revised	1	Addition of a standard to the section.
106	57	57-6000	Station Equipment	Tools For DST	New	0	New STD. for Station Technologist
105	70	70-4640	REACTIVE MAINTENANCE	PRIMARY STRAIGHT JOINT	RE LOCATED	1	TO BE USED FOR MAINTENANCE ONLY AS NO LONGER USE AS A STANDARD AND ONLY TO BE USED AS MAINTENANCE
106	70	70-4660	REACTIVE MAINTENANCE	PRIMARY STRAIGHT JOINT	RE LOCATED	1	TO BE USED FOR MAINTENANCE ONLY AS NO LONGER USE AS A STANDARD AND ONLY TO BE USED AS MAINTENANCE

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #49

4	05	05-0000					
5	05	05-1130	Pole Framing	4.16 to 27.6 kV Treeproof and bare Primary mid-span opener.	REVISED	1	about ıg LC# ard. ails"
6	05	05-1140	Pole Framing	4.16 To 27.6 kV Treeproof and Bare Primary 1-Phase Double Dead-End or Transition between Bare and Treeproof	REVISED	3	ing OM
7	05	05-1280	Pole Framing	horizontal configuration 0 to 3 degrees.	REVISED	2	
8	05	05-1600			REVISED	3	
9	05	05-1740			REVISED	2	
					REVISED	2	
11	05	05-2020			REVISED	1	
12	05	05-1770			NEW	0	
13	06	06-6300					

14	08	08-3630			REVISED	1	
16	09	09-8400					
18	09	09-8800	Overhead Transformer	3- Phase Construction 16000/27600 - 120/208 V - 50 kVA	REVISED	14	ew t a
19	09	09-9100	Overhead Transformer	3- Phase Construction 2400/4160 - 347/600 V WYE 100 & 167 kVA	REVISED	14	ew t a
[illegible]	[illegible]	[illegible]	[illegible]	WYE all kVA Sizes	[illegible]	[illegible]	
22	10	10-1600			REVISED	3	
23	10	10-1640			REVISED	2	
24	10	10-1660			REVISED	4	
25	10	10-1710			REVISED	1	
26	10	10-1730			REVISED	1	
27	10	10-2600			REVISED	9	
28	10	10-3500			REVISED	12	

29	10	10-3510			REVISED	4	
30	11	11-0000					
31	11	11-3810			New	0	
32	13	13-0000					
33	13	13-1000	UG Transformer and Swtichgears	Underground Transformers General	REVISED	2	
34	13	13-5000	U/G Transformer and Switchgears	13.8 kV network Systems General Information	REVISED	4	
35	13	13-5030	U/G Transformer and Switchgears	Innards For Network Protectors	NEW	0	
					REVISED	1	
					REVISED	12	
38	13	13-7810			REVISED	5	
41	14	14-3300					

43	14	14-3500					
45	17	17-9500			REVISED	3	
46	21	21-1100	Overhead and Underground Stenciling	General information Stenciling Information	Revised	6	2)
47	21	21-2100	Overhead and Underground Stenciling	Overhead stenciling Pole numbering	Revised	5	i. label as
48	21	21-3400	[illegible]	[illegible]	[illegible]	[illegible]	
49	21	21-3500					
50	21	21-3800			Revised	2	
51	23	23-0000					
52	23	23-1020			REVISED	4	
					REVISED	4	
54	23	23-1100					

55	23	23-1130			REVISED	2	
56	23	23-1140			OBSOLETE	0	
58	24	24-1300					
59	24	24-1400	Fusing	Underground fusing 27.6 kV transformer in vault	Revised	4	inged
60	28	28-0000	O/H and U/G Material Fabrications	Index of Standards	REVISED	4	ew
61	[illegible]	[illegible]	O/H and U/G Material Fabrications	Mount	[illegible]	[illegible]	
63							
65							
67							

69							
71							
72	28	28-0414	O/H and U/G Material Fabrications	Concrete Pole 16.76 m (55'-0") Class G Direct Buried	REVISED	3	poles in ole,
73	28	28-0415	O/H and U/G Material Fabrications	Concrete Pole 16.76 m (55'-0") Class H Direct Buried	REVISED	2	poles in ole,
[illegible]	[illegible]	[illegible]	O/H and U/G Material Fabrications	Buried	[illegible]	[illegible]	
75							
					NEW		
77					NEW		
					NEW		

TORONTO HYDRO

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #49

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised/ Obsolete	Revision number at date of issue	Revision Description
81	30	30-1120	Street Lighting	Acorn Luminaire Selection Table	NEW	0	New standard to include details of the Acorn Luminaires including photometric file that is required for design.
82	30	30-1300	Street Lighting	Secondary Bus Cables Selection Table	NEW	1	Revised colour of cable jacket. Added O/H cable and underground #2 AWG street lighting and expressway cables.
83	30	30-1600	Street Lighting	Street Light Brackets - Details	NEW	0	New standard to show various street light brackets required for Cobra Head and Acorn Luminaires.
84	30	30-3600	Street Lighting	Overhead 120 V Supply to Pole-Mounted Luminaire	NEW	0	New standard to show various street light brackets required for Cobra Head and Acorn Luminaires.
85	30	30-3700	Street Lighting	Underground 120 V Supply to Pole-Mounted Luminaire at the First Pole with In-Pole Circuit Breaker	REVISED	3	Revised notes, wiring connection and BOM. Replaced split bolt with ground connector. Revised stock code for ground rod to #6 AWG wire connection. Added ground rod and installation details. Revised circuit breaker details as per shop drawing.
86	30	30-3730	Street Lighting	120 V Service Entrance without Circuit Breaker 1-Phase In-Pole Type at the First Pole	OBSOLETE	0	Standard obsoleted. Refer to standard 30-3800.
87	30	30-3800	Street Lighting	Underground 120 V Supply to Pole-Mounted Luminaire	REVISED	3	Removed details of U/G supply duct into pole aperture. Revised notes and BOM. Replaced split bolt with ground connector. Added BOM legend for installation with and without ground.
88	30	30-3820	Street Lighting	Underground Supply Duct into pole Aperture	NEW	0	New civil standard. To clarify duct structure going into pole for streetlight service
89	30	30-4100	Street Lighting	Concrete Pole with Acorn Luminaire	REVISED	8	Revised standard title, edited the note, added pole base detail, and changed the BMO and BOM Legend to show the four street lighting pole heights (25', 30', 35', 40')
90	30	30-4110	Street Lighting	Acorn Luminaire with Bracket Typical Installation on Concrete, Wood or Steel Pole	REVISED	4	BOM's in street lighting had many permutations causing the size of the BOM to span over a few pages. This standard has been revised to show various installations on one standard instead of having 3 standards to display the installations.
91	30	30-4120	Street Lighting	Roadway Types - Universal Luminaire on a Cedar Pole	OBSOLETE	3	Standard obsoleted. BOM's in street lighting had many permutations causing the size of the BOM to span over a few pages. This standard has been Obsolete since the information depicted within this standard will now be covered in standard 30-4110.
92	30	30-4130	Street Lighting	Roadway Types - Universal Luminaire on a Steel Pole	OBSOLETE	4	Standard obsoleted.BOM's in street lighting had many permutations causing the size of the BOM to span over a few pages. This standard has been Obsolete since the information depicted within this standard will now be covered in standard 30-4110.

TORONTO HYDRO

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #49

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised/ Obsolete	Revision number at date of issue	Revision Description
93	30	30-4210	Street Lighting	Aluminum Pole with Cobra Head Luminaire	REVISED	7	Added bracket installation details. Revised BOM legend and BOM.
94	30	30-4220	Street Lighting	Concrete Pole with Cobra Head Luminaire	REVISED	8	Added concrete pole base detail. Added 25' Class C base-mounted pole. Revised BOM legend and BOM.
95	30	30-4240	Street Lighting	Cobra Head Luminaire with Bracket Typical Installation on Concrete, Wood, or Steel Pole	REVISED	3	BOM's in street lighting had many permutations causing the size of the BOM to span over a few pages. This standard has been revised to show various installations on one standard instead of having 3 standards to display the installations.
96	30	30-4250	Street Lighting	Roadway Types - Cobra Head Luminaire on a Cedar Pole	OBSOLETE	3	Standard obsoleted. BOM's in street lighting had many permutations causing the size of the BOM to span over a few pages. This standard has been Obsolete since the information depicted within this standard will now be shown in 30-4240.
97	30	30-4260	Street Lighting	Roadway Types - Cobra Head Luminaire on a Steel Pole	OBSOLETE	2	Standard obsoleted. BOM's in street lighting had many permutations causing the size of the BOM to span over a few pages. This standard has been Obsolete since the information depicted within this standard will now be shown in 30-4240.
98	30	30-4290	Street Lighting	Composite Pole 30' with Universal luminaire	OBSOLETE	1	Standard has been OBSOLETED.
99	30	30-9100	Street Lighting	Laneway Lighting Bracket Acorn or Cobra Head Luminaire on Wood Pole	REVISED	3	Deleted luminaire and electrical installation details from the standard. Added bracket details.
100	30	30-9500	Street Lighting	Design Criteria Concrete Foundations for Base Mounted Street Lighting Poles	OBSOLETE	3	Standard has been OBSOLETED. Some of the information was no longer required since it is part of legacy. The required information has been transferred to 30-9850.
101	30	30-9600	Street Lighting	Civil Construction - Concrete Foundation for Base Mounted - Aluminum Poles	OBSOLETE	3	Standard has been OBSOLETED.The details of concrete foundation in standard 30-9600 have been moved to standard 30-9820.
102	30	30-9840	Street Lighting	Reinforced Sidewalk Bays Concrete & Steel poles	OBSOLETE	3	Standard has been OBSOLETED.Required information has been added to 30-4100 and 30-4220.
103	30	30-9850	Street Lighting	Pole Anchors for Base-Mounted Poles	NEW	0	New standard.
104	31	31-1200	Civil Construction	Tunnelling Under TTC Tracks	REVISED	2	Added 6 new notes as identified by Triangles NOTE 6 into notes and specified the details of Section A-A.

TORONTO HYDRO

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #49

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised/ Obsolete	Revision number at date of issue	Revision Description
105	31	31-5000	Civil Construction	Sleeve-Lifting for Removable Concrete Slab	REVISED	2	Standard revised to Improve clarity on drawing and text. Adding "slab" on the concrete section view to allow user to determine which portion of the drawing is the slab material. Combined two of the comments on the section view.
106	31	31-7400	Civil Construction	Sewer Drain Connection From Cable Chamber or Transformer Vault	REVISED	1	Standard reviewed and BOM legend was added ,BOM added Note 2 added.
107	31	31-8470	Civil Construction	Sleeve-Lifting for Removable Concrete Slab	REVISED	2	Standard revised to Improve clarity on drawing and text. Adding "slab" on the concrete section view to allow user to determine which portion of the drawing is the slab material. Combined two of the comments on the section view.
108	34	34-0000	Engineering Information and References	Index of Standards	REVISED	4	New standards added to section 34, revision required Index has been revised to reflect new standards added to section 34-3200,34-3300 and 34-3400
109	34	34-1000	Engineering Information and References	Construction Deviation Guidelines	REVISED	3	To provide better examples, Revised points 1 and 3 in Non-Technical Deviation Examples section to fulfill CRF Request. These changes improve clarity for the examples.
110	34	34-3000	Engineering Information and References	Atypical Units Selection Table	NEW	0	This standard was created to help designers in the selection of Non-Construction Activity Units. As per the Asset Assembly Initiative
111	34	34-3200	Engineering Information and References	Additional Support Units	NEW	0	This standard was created to help designers in the selection of Non-Construction Activity Units. As per the Asset Assembly Initiative
112	34	34-3300	Engineering Information and References	Additional Resources	NEW	0	This standard was created to help designers in the selection of Non-Construction Activity Units. As per the Asset Assembly Initiative
113	34	34-3400	Engineering Information and References	Asset Removal Units Selection Table	NEW	0	This standard was created to help designers in the selection of Non-Construction Activity Units. As per the Asset Assembly Initiative

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #50

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised /Obsolete	Revision number at date of issue	REVISION DESCRIPTION
1	04	04-0000	Poles and Pole Settings	Index of Standards	REVISED	4	Addition of new standard 04-5610 to index.
2	04	04-1200	Poles and Pole Settings	General Information Concrete Poles	REVISED	2	Updated explanation of design specifications, pole heights, grounding, marking, and storage.
3	04	04-5200	Poles and Pole Settings	Cedar and Concrete Poles in Boulevard (hand Dig and Vacuum Truck)	REVISED	4	Revised concrete pole stock codes for poles having additional harmonized holes.
4	04	04-5500	Poles and Pole Settings	Cedar and Concrete Poles in Poor Soil	REVISED	3	Revised concrete pole stock codes for poles having additional harmonized holes.
5	04	04-5600	Poles and Pole Settings	Cedar and Concrete Poles in Slopes and Hillsides	REVISED	3	Revised concrete pole stock codes for poles having additional harmonized holes.
6	04	04-5610	Poles and Pole Settings	Pole Setting with Retaining Wall near Pole	NEW	0	New standard created for additional guidance to crews on installing poles near customer built retaining walls.
7	05	05-0010	Pole Framing	General Information Introduction	REVISED	4	Addition of note, "Additional materials such as stringing blocks and eye nuts (item I.D. 2520024) may be required for installation purposes.", to note 9.
8	05	05-1880	Pole Framing	Double 3-Phase Double Dead-end or Transition Between Bare And Treeproof Vertical Configuration	REVISED	4	Moved components such as washer, bolt, and cartridge to open bin. Revised quantity of insulators required.
9	07	07-4000	Anchoring and Guying	Guying - Guy Components	REVISED	3	Note 8 revised due to obsolete status of green guy guards.
10	07	07-5100	Anchoring and Guying	Down Guy - One on Concrete, Wood or Steel Pole	REVISED	6	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
11	07	07-5110	Anchoring and Guying	Down Guy - One on Concrete or Wood Pole Using Insulator Rod(s)	REVISED	5	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
12	07	07-5160	Anchoring and Guying	Down Guy - One on Concrete or Wood Pole Using Insulator Rods on Armless Construction	REVISED	6	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
13	07	07-5200	Anchoring and Guying	Strut Guy - One on Concrete, Wood or Steel Pole	REVISED	7	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
14	07	07-5220	Anchoring and Guying	Strut Guy - Two on Concrete or Wood Pole Using Insulator Rod(s)	REVISED	7	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
15	07	07-5230	Anchoring and Guying	Strut Guy - One on Concrete or Wood Pole Using Insulator Rod(s)	REVISED	2	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
16	07	07-5240	Anchoring and Guying	Strut Guy - Two on Cedar or Concrete Pole Using Insulator Rod	REVISED	2	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
17	07	07-5250	Anchoring and Guying	Strut Guy - Three on Concrete or Wood Pole Using Insulator Rod(s)	REVISED	2	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
18	07	07-5300	Anchoring and Guying	Span & Down Guy - One on Concrete, Wood or Steel Pole	REVISED	6	Green Guy Guard obsolete. BOM & BOM Legend have been revised.

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #50

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised /Obsolete	Revision number at date of issue	REVISION DESCRIPTION
19	07	07-5310	Anchoring and Guying	Span & Down Guy - One on Concrete, Wood or Steel Pole Using Insulator Rod	REVISED	6	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
20	07	07-5320	Anchoring and Guying	Span & Down Guys - Two on Concrete, Wood or Steel Pole	REVISED	7	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
21	07	07-5340	Anchoring and Guying	Span & Strut Guy - One on Concrete, Wood or Steel Pole	REVISED	7	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
22	07	07-5350	Anchoring and Guying	Span & Strut Guy - One on Concrete, Wood or Steel Pole Using Insulator Rod	REVISED	7	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
23	07	07-5370	Anchoring and Guying	Span & Strut Guy - Two on Concrete, Wood or Steel Pole with One Span Guy Using Insulator Rod	REVISED	8	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
24	07	07-5380	Anchoring and Guying	Span & Strut Guy - Two on Concrete or Wood Pole Using Insulator Rod	REVISED	5	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
25	07	07-5400	Anchoring and Guying	Storm Guy on Concrete or Wood Pole	REVISED	5	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
26	10	10-3800	Overhead Switches	3-Phase Primary Drops All Voltages	REVISED	6	Revised quantity for BOM Item I.D. 7105235 (350 kcmil 61 STR WIRE)
27	13	13-0000	UG Tranformer & Switchgears	Index of Standards	REVISED	12	Obsoleted Std. 13-4010 from index.
28	13	13-4010	UG Tranformer & Switchgears	13.8 kV Radial System Above Grade Transformer Vault - Modular Switchgear Transformer Vault 8534 x 3048 (28' x 10')	OBSOLETE	N/A	Obsoleted 13-3010 and moved to 13-4020.
29	13	13-4020	UG Tranformer & Switchgears	13.8 kV Compact Radial Design	REVISED	8	Combined 13-4010 and 13-4020 into 13-4020. Changed material quantity in BOM. Changed the dimensions of the transformer on page 6.
30	14	14-3500	Padmounted Transformers	Installation - 27.6 kV 1-Phase Low Profile 27.6 kV system	REVISED	11	BOM revised due to Open Bin materials change.
31	15	15-1100	UG Secondary and Primary Services	Secondary Underground Services Cable Limiters	REVISED	4	Added associated standards 16-5300 and 16-5400 to BOM.
32	16	16-0000	UG Cable Joints Terminations & Connections	Index of Standard	REVISED	13	Added 16-1280 and 16-4320 to index.
33	16	16-1280	UG Cable Joints Terminations & Connections	Underground Primary Cable Testing	NEW	0	New standard created as instructions for proper operation and troubleshooting of new cable testing equipment.
34	16	16-4180	UG Cable Joints Terminations & Connections	600 A Deadbreak Connectors 15kV, 1 Conductor	REVISED	4	Addition of BOM legend F (copper 350 kcmil compressed). BOM item 8 (adapter cable deadbreak 350 kcmil) and item 9 (AL terminal lug for 15 kV 350 kcmil)
35	16	16-4260	UG Cable Joints Terminations & Connections	600 A Deadbreak Connectors 28kV, 1 Conductor	REVISED	3	Addition of BOM legend G (copper #4/0 compressed). BOM item 17 (adapter cable deadbreak #4/0) and item 18 (AL terminal lug for 28 kV #4/0).
36	16	16-4300	UG Cable Joints Terminations & Connections	200 A Loadbreak Connectors 28kV 1 Conductor	REVISED	4	Addition of BOM legend D (copper #4/0 compressed) and BOM item 3 (#4 cable elbow).

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #50

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised /Obsolete	Revision number at date of issue	REVISION DESCRIPTION
37	16	16-4320	UG Cable Joints Terminations & Connections	Primary - Cable Test Lead 15 kV or 28 kV For Cables Connected to Pad/Submersible Transformer and Switchgear	NEW	0	New standard for Cable Test Lead required for testing operations on cables connected to padmounted and submersible equipment.
38	16	16-5300	UG Cable Joints Terminations & Connections	Junction Connector and Fuse Limiter 600 V and Below	REVISED	4	Secondary Junction Connector Service Cable Std. 16-5400 added to associated standards.
39	21	21-0000	Overhead and Underground Stenciling	Index of Standards	REVISED	10	Updated title of Std. 21-2120.
40	21	21-4000	Overhead and Underground Stenciling	Underground Stenciling Network Equipment	NEW	0	New standard for network transformer nomenclature.
41	23	23-1200	Foreign Attachments	Overhead System - Pole Attachments Communication Cable Attachments	REVISED	2	Clause 6 revised to provide instruction on use of 'auxiliary eye'.
42	27	27-3000	Legend/Drafting Symbols	Conductors and Connectors	REVISED	3	New symbol created for Transition Splice.
43	27	27-4100	Legend/Drafting Symbols	Civil Structures	REVISED	3	New symbols created for Down guy and Strut Guy.
44	27	27-5000	Legend/Drafting Symbols	Street lighting	REVISED	3	New symbol created for transfer of street light bracket and luminaire.
45	27	27-8000	Legend/Drafting Symbols	Assemblies	REVISED	4	New symbols created for MINI Rupter switch and SF6 switchgear.
46	30	30-0000	Street Lighting	Index of Standard	REVISED	14	Updated titles of Std. 30-9780 and 30-9820, added 30-9860, removed 30-9500.
47	30	30-3700	Street Lighting	Underground 120 V Supply to Pole-Mounted Luminaire at the First Pole with In-Pole Circuit Breaker	REVISED	4	Revised BOM for ground wire and associated connector (from #6 to #2 AWG)
48	30	30-3800	Street Lighting	Underground 120 V Supply to Pole-Mounted Luminaire	REVISED	4	Revised BOM for ground wire and associated connector (from #6 to #2 AWG)
49	30	30-6400	Street Lighting	Pedestrian Lighting City Type II Post Top Mounted	REVISED	3	Added details 'C', 'D', and 'E'. Revised detail 'A', and 'B'. BOM change, title change, and additional revision of details.
50	30	30-9500	Street Lighting	Design Criteria Concrete Foundations for Base Mounted Street Light Poles	OBSOLETE	3	The information in this standard is existing in other standards. (duplicated information)
51	30	30-9510	Street Lighting	Civil Construction - Pole Base/Reinforced Sidewalk Bay General Information	REVISED	2	Added section regarding handwell locations within reinforced sidewalk bays
52	30	30-9780	Street Lighting	Reinforced Sidewalk Bay Concrete Pole - 25' Class B, Base Mounted	REVISED	5	Changed design of sidewalk bay with added notes and new BOM.
53	30	30-9820	Street Lighting	Pole Base / Reinforced Sidewalk Bay Aluminum Pole (Base Mounted)	REVISED	5	Revised design, notes, and BOM.
54	30	30-9860	Street Lighting	Pole base/Reinforced Sidewalk Bay, Pedestrian Scale-City Type 2, Victorian Poles.	NEW	0	New standard created to provide details on dimensions of pedestrian scale victorian poles.

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #50

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised /Obsolete	Revision number at date of issue	REVISION DESCRIPTION
55	31	31-0000	Civil Construction	Index of Standard	REVISED	20	Addition of standard 31-5000 into index. Updated titles of Std. 31-1200, 31-1350, 31-8280.
56	31	31-1350	Civil Construction	Duct or Cable - Support in Place System	REVISED	2	Added new techniques of support-in-place construction. Removed certain dimensions.
57	31	31-8280	Civil Construction	Material Fabrication Cable Chamber Sump Grate 384 mm x 370 mm x 40 mm	REVISED	4	Added strut supports to diagram, changed dimensions of grate, added section B-B diagram.
58	34	34-0000	Engineering / References	Index of Standard	REVISED	5	Standard 34-2100 added to index.
59	34	34-3200	Engineering / References	Asset assembly - Additional Support Units	REVISED	1	Added a new row and column for contractor traffic control work.
60	34	34-3300	Engineering / References	Asset Assembly - Additional Resources	REVISED	3	Added a new row and column for third pole cut down work.
61	34	34-3400	Engineering / References	Asset assembly - Asset Removal Units Selection Table	REVISED	2	Added a new row and column for third pole cut down work.
62	34	34-4000	Engineering / References	Lock Reference	NEW	0	New standard to show various lock types and their applications.

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #51

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised /Obsolete	Revision number at date of issue	REVISION DESCRIPTION
1	04	04-1100	Poles and Pole Settings	General Information Wood (Cedar) Poles	REVISED	3	Corrected grammatical error.
2	04	04-2100	Poles and Pole Settings	Selection Criteria Wood (Cedar) Poles	REVISED	3	Updated the wood pole classification table. Moving the pole diameter table from 04-2100 to 04-5100 and adding note for reference.
3	04	04-2200	Poles and Pole Settings	Selection Criteria Concrete Poles	REVISED	2	Updated the concrete pole classification table. Updated pole class and guidline table and notes.
4	04	04-5300	Poles and Pole Settings	Cedar and Concrete Poles in Sidewalk	REVISED	3	Updated information for 65 and 70 foot poles. Updated BOM for 50, 55, and 60 foot concrete poles, 65 and 70 foot cedar poles.
5	05	05-1200	Pole Framing	4.16 to 27.6 Treeproof and Bare Primary 3-Phase Halo Configuration Angles 0 to 15 Degrees	REVISED	2	Added anti-split bolt installation to associated standards.
6	05	05-1260	Pole Framing	4.16 to 27.6 Treeproof and Bare Primary 3-Phase Inline Rolled Configuration Angles 0 to 15 Degrees	REVISED	3	Added anti-split bolt installation to associated standards.
7	05	05-2460	Pole Framing	4.16 to 27.6 Treeproof and Bare Primary 3-Phase Mid-Span Tap Horizontal Configuration	REVISED	2	Changed tap material from stockcode 7105230 to 9662862.
8	05	05-2480	Pole Framing	4.16 to 27.6 Treeproof and Bare Primary 3-Phase Mid-Span Tap Vertical Configuration	REVISED	1	Changed tap material from stockcode 7105230 to 9662862.
9	05	05-6070	Pole Framing	System Neutral Tap And Run-off	REVISED	2	Changed tap material from stockcode 7105230 to 9662862.
10	07	07-3600	Anchoring and Guying	Guying Location of Guy Insulator	REVISED	3	Note and drawing have been revised for second guy insulator installation details.
11	07	07-4000	Anchoring and Guying	Guying Components	REVISED	4	Revised the name and description of thimble clevis.
12	07	07-4230	Anchoring and Guying	Guying Installation Procedure Guy Strand Termination at Eye Nut	REVISED	4	Revised the drawing and note of thimble clevis.
13	07	07-4300	Anchoring and Guying	Guying Installation Details Guy Attachments to Concrete Pole	REVISED	2	Revised the drawing and description of thimble clevis.
14	07	07-4310	Anchoring and Guying	Guying Installation Details Guy Attachments to Wood Pole	REVISED	2	Revised the drawing and description of thimble clevis.
15	07	07-5170	Anchoring and Guying	V-Guying on Concrete, Wood or Steel Pole Using insulator rods on armless construction	REVISED	2	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
16	07	07-5300	Anchoring and Guying	Span & Down Guy - One on Concrete, Wood or Steel Pole	REVISED	7	Note has been revised for second guy insulator installation details. Revised the drawing and description of thimble clevis.
17	07	07-5310	Anchoring and Guying	Span & Down Guy - One on Concrete, Wood or Steel Pole Using Insulator Rod	REVISED	7	Note has been revised for second guy insulator installation details. Revised the drawing and description of thimble clevis.
18	07	07-5320	Anchoring and Guying	Span & Down Guy -Two on Concrete, Wood or Steel Pole	REVISED	8	Note has been revised for second guy insulator installation details. Revised the drawing and description of thimble clevis.
19	07	07-5340	Anchoring and Guying	Span & Strut Guy - One on Concrete, Wood or Steel Pole	REVISED	8	Note has been revised for second guy insulator installation details. Revised the drawing and description of thimble clevis.
20	07	07-5350	Anchoring and Guying	Span & Strut Guy - One on Concrete, Wood or Steel Pole Using Insulator Rod	REVISED	8	Note has been revised for second guy insulator installation details. Revised the drawing and description of thimble clevis.
21	07	07-5370	Anchoring and Guying	Span & Strut Guy - Two on Concrete, Wood or Steel Pole With One Span Guy Using Insulator Rod	REVISED	9	Note has been revised for second guy insulator installation details. Revised the drawing and description of thimble clevis.

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #51

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised /Obsolete	Revision number at date of issue	REVISION DESCRIPTION
22	07	07-5380	Anchoring and Guying	Span & Strut Guy - Two on Concrete, Wood or Steel Pole Using Insulator Rod	REVISED	6	Note has been revised for second guy insulator installation details. Revised the drawing and description of thimble clevis.
23	07	07-5400	Anchoring and Guying	Storm Guy on Concrete or Wood Pole	REVISED	6	Removed stockcode 2450035 and 2450026 from BOM.
24	07	07-5500	Anchoring and Guying	Span Guy - One on Concrete, Wood or Steel Pole	REVISED	6	Note has been revised for second guy insulator installation details. Revised the drawing and description of thimble clevis.
25	09	09-0000	Overhead Transformers	Index of Standards	REVISED	14	Removed obsolete standard 09-8400, 09-8600, and 09-8800 from index.
26	09	09-1300	Overhead Transformers	General Information Installation	REVISED	6	Table description change.
27	09	09-1400	Overhead Transformers	General Information Bushing Configurations	REVISED	4	Pole mounted transformer stock code change.
28	09	09-8100	Overhead Transformers	1 Phase Construction 2400-120/2401 V All kVA Sizes	REVISED	7	Added secondary risers bundled together and pole-mounted transformer stock code change.
29	09	09-8200	Overhead Transformers	1 Phase Construction 8000-120/240 V All kVA Sizes	REVISED	8	Added secondary risers bundled together and pole-mounted transformer stock code change.
30	09	09-8300	Overhead Transformers	1 Phase Construction 16000-120/240 V A kVA Sizes	REVISED	9	Added secondary risers bundled together and pole-mounted transformer stock code change.
31	09	09-8400	Overhead Transformers	3-Phase Construction 2400/4160-120/208V - 50 kVA	OBSOLETE	11	Obsoleted 09-8400 and moved to 09-8500
32	09	09-8500	Overhead Transformers	3-Phase Construction 2400/4160 -120/208V - All kVA Sizes	REVISED	11	Added standard 09-8600 with 50 kVA to 09-8700. Updated the transformer kit and transformers' stock codes in BOM.
33	09	09-8600	Overhead Transformers	3-Phase Construction 8000/13800-120/208V - 50 kVA	OBSOLETE	11	Obsoleted 09-8600 and moved to 09-8700
34	09	09-8700	Overhead Transformers	3-Phase Construction 8000/13800-120/208V - All kVA Sizes	REVISED	13	Added standard 09-8600 with 50 kVA to 09-8700. Updated the transformer kit and transformers' stock codes in BOM.
35	09	09-8800	Overhead Transformers	3-Phase Construction 16000/27600-120/2080V - 50 kVA	OBSOLETE	15	Obsoleted 09-8800, moved to 09-8900.
36	09	09-8900	Overhead Transformers	3-Phase Construction 16000/27600-120/2080V All kVA Sizes	REVISED	14	Added standard 09-8600 with 50 kVA to 09-8700. Updated the transformer kit and transformers' stock codes in BOM.
37	09	09-9100	Overhead Transformers	3-Phase Construction 2400/4160-347/600V WYE 100 & 167 kVA	REVISED	15	Updated the transformer kit and transformers' stock codes in BOM.
38	09	09-9200	Overhead Transformers	3-Phase Construction 8000/13800-347/600V WYE All kVA Sizes	REVISED	15	Updated the transformer kit and transformers' stock codes in BOM.
39	09	09-9300	Overhead Transformers	3-Phase Construction 16000/27600-347/600V WYE All kVA Sizes	REVISED	17	Pole mounted transformer stock code change.
40	09	09-9500	Overhead Transformers	Primary Drop Leads 1-Phase Transformers	REVISED	6	Added additional support arm, revised dimensions, removed AMPACTS from open bin.
41	09	09-9510	Overhead Transformers	Primary Drop Leads 1-Phase Transformers - Dead-End Configuration	REVISED	3	Added additional support arm.
42	09	09-9600	Overhead Transformers	Primary Drop Leads 3-Phase Transformers - Overbuild Only	REVISED	6	Added additional support arm, removed AMPACTS from open bin.
43	09	09-9610	Overhead Transformers	Primary Drop Leads 3-Phase Transformers - Dead-End Configuration	REVISED	2	Added additional support arm.
44	11	11-2020	O/H Secondary & Primary Services	Overhead Secondary Bus, Transformer Secondary Drop Leads And Secondary Services	REVISED	5	Revised note a) to "All secondary busses shall be installed on the street side of the pole; except when the line angle is greater than 3 degrees, then the bus may be installed on the house side of the pole."
45	11	11-3550	O/H Secondary & Primary Services	Multiplexed Secondary Bus Service Taps 600V or 347/600 V at Mid-span	REVISED	3	Corrected the BOM legend description of "at pole" to " at mid-span".

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #51

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised /Obsolete	Revision number at date of issue	REVISION DESCRIPTION
46	12	12-3000	Primary and Secondary Service Risers	Primary Services Risers Primary Drops And Connections For 1-Phase Service Riser	REVISED	6	Showing the stand off installation dimensions and updating the 3D view.
47	12	12-3100	Primary and Secondary Service Risers	Primary Services Risers Primary Drops And Connections For 3-Phase Service Riser	REVISED	6	Showing the stand off installation dimensions and updating the 3D view.
48	12	12-4000	Primary and Secondary Service Risers	Primary Feeder Riser, 3-phase 27.6 kV 600A	REVISED	12	Consolidated open bin list with standard list. Changed 350 kcmil wire from 427 str to 61 str CU Wire and associated terminal lug. Added grounding stirrup for duck bill clamp, and longer ½" bolt for use with Std. 10-3000 (added BOM Legend C and D). Added hardware for grounding of bracket and removed reference to equipment grounding standard. Updated required quantity of ½" bolts and associated hardware. Added Detail 'A' and Detail 'B' for terminal lug. Updated required quantity of white wedge connectors. Revised note 12 from "temporary attachment of primary cables" to "cable guard or pipe installation details". Removed item 2420260 bracket termination support since it is provided with termination kit (reference standard 16-4160).
49	12	12-4500	Primary and Secondary Service Risers	Primary Feeder Riser, 3-phase 13.8 kV 600A	REVISED	9	Consolidated open bin list with standard list. Changed 350 kcmil cable from 427 str to 61 str CU Wire and associated terminal lug. Added grounding stirrup for duck bill clamp. and longer ½" bolt for use with Std. 10-3000 (added BOM Legend I and J). Added hardware for grounding of equipment arm and removed reference to equipment grounding standard. Updated required quantity of ½" bolts and associated hardware. Revised bolt from 3" bolt to 3-1/2" bolt. Added notes 4 and 5. Removed PILC pothead terminations from BOM Legend (A, B, E, F) and Detail B and Detail C. Added Detail B and C for terminal lug. Updated required quantity of RWB disks. Included required quantity of banding. Included grounding wire along bracket.
50	13	13-2020	UG Transformer and Switchgears	4.16kV Transformer Vaults/rooms ARC Stranglers with three 50, 100 & 167 kVA Transformers - Single feeder supply	REVISED	4	Added fault indicators for each primary feeder.
51	13	13-2030	UG Transformer and Switchgears	4.16kV Transformer Vaults/rooms ARC Stranglers with three 50, 100 & 167 kVA Transformers - Dual feeder supply	REVISED	4	Added fault indicators for each primary feeder.
52	13	13-2040	UG Transformer and Switchgears	4.16 kV Transformer Vaults ARC Stranglers with three 50, 100 & 167 kVA Transformers Non-Standard vaults single feeder supply	REVISED	4	Added fault indicators for each primary feeder.
53	13	13-4020	UG Transformer and Switchgears	13.8 kV Compact Radial Design - General Information	REVISED	8	Added fusing cabinet related information.
54	13	13-5100	UG Transformer and Switchgears	13.8 kV Network System Network protector automation	REVISED	2	Revised communication box installation clearance and BOM quantity.
55	13	13-7030	UG Transformer and Switchgears	Customer Transformer Vault for 1 PH Transformer 13.8 kV & 27.6 kV Distribution System	REVISED	6	Added fault indicators for each primary feeder.
56	13	13-7050	UG Transformer and Switchgears	3 1-Phase Transformer Vault 13.8 kV Typical Layout	REVISED	5	Added fault indicators for each primary feeder. Revised the drawing by adding showing the elbows.
57	13	13-7060	UG Transformer and Switchgears	3 1-Phase Transformer Vault 27.6 kV Typical Layout	REVISED	6	Added fault indicators for each primary feeder. Revised the drawing by adding showing the elbows.
58	16	16-0000	UG Cables Joints Terminations & Connectors	Index of Standards	REVISED	14	Added new standard 16-4630 to index.
59	16	16-4260	UG Cable, Joints, Terminations & Connections	Primary Trxple Terminations 600 A Deadbreak Connectors 28 kV, 1 Conductor	REVISED	4	Revised the drawing for grounding of LACT shield. Updated the wire to #2 19 STR copper wire.
60	16	16-4370	UG Cable, Joints, Terminations & Connections	Grounding Clamp Assembly Shielded Cable	REVISED	2	Added item 9665444 to cable size table. Revised the descriptions of other items in cable size table. Modified the drawing of PVC tape in the sketch.

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #51

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised /Obsolete	Revision number at date of issue	REVISION DESCRIPTION
61	16	16-4420	UG Cable, Joints, Terminations & Connections	Primary - TRXLPE Application Bonding For Hand Taped Straight Splices	REVISED	2	Added 7 items in BOM Legend and revised BOM as well. Revised notes on page 2 and 3.
62	16	16-4540	UG Cable, Joints, Terminations & Connections	Primary Cable Support of Splices on Cable Arms	REVISED	3	Deleted item 9662901 , added item 5240030 and 7360306 to BOM. Created the detail of polymeric or transition splice in the sketch.
63	16	16-4580	UG Cable, Joints, Terminations & Connections	Primary - Inline Transition Joint Hand Taping Method 15 kV, Cu, 1 conductor PILC to TRXLPE	REVISED	4	Added 1C 1000 kcmil Cu shielded PILC to 1C 750 KCMIL Cu TRXLPE and 1C 1000 kcmil Cu shielded PILC to 1C 1000 KCMIL Cu TRXLPE to BOM legend. Revised the note on page 2 and 3.
64	16	16-4600	UG Cable, Joints, Terminations & Connections	Primary - Inline Transition Joint Hand Taping Method 28 kV, Cu, 1 conductor PILC to TRXLPE	REVISED	2	Added 1C 1000 kcmil Cu shielded PILC to 1C 750 KCMIL Cu TRXLPE and 1C 1000 kcmil Cu shielded PILC to 1C 1000 KCMIL Cu TRXLPE to BOM legend. Revised the note on page 2 and 3.
65	16	16-4630	UG Cable, Joints, Terminations & Connections	Primary - Transition Joint Bonding For Hand Taped Inline Transition Splices	NEW	0	New standard created for additional guidance to crews on installing primary transition joint.
66	18	18-5100	Grounding	Underground System Cable Chamber Grounding	REVISED	4	Revised method of supporting neutral cables from wall clips to cable clamps on unistrut, Removed cable joint from standard, and associated note reference and #1/0 wire from BOM, Included dimensions of previous note 1 on the drawing. Revised quantity of hardware for cable chamber size of 3.5 m x 4 m.
67	23	23-1400	Foreign Attachments	Overhead System - Pole Attachments Enbridge Gas Rectifier	REVISED	1	Added 50 V 12A rectifier to standard.
68	27	27-3000	Legend/Drafting Symbols	Conductors and Connectors	REVISED	4	Change Transition Splice to "Transition Splice PILC to TRXLPE".
69	27	27-8000	Legend/Drafting Symbols	Assemblies	REVISED	5	Removed 13.8 kva from description.
70	28	28-0000	OH and UG Material Fabrications	Index of Standards	REVISED	5	Added new standards 28-0421, 28-0422 to index.
71	28	28-0421	OH and UG Material Fabrications	Concrete Pole 9.41 m (30'-0") Class C Base Mount	NEW	0	New standard for concrete pole.
72	28	28-0422	OH and UG Material Fabrications	Concrete Pole 10.67 m (35'-0") Class C Base Mount	NEW	0	New standard for concrete pole.
73	31	31-0000	Civil Construction	Index of Standards	REVISED	21	Added new standard 31-0800 to index.
74	31	31-0800	Civil Construction	Mapping of Underground Utility Infrastructure	NEW	0	New standard for Mapping of all TH underground assets.
75	31	31-1150	Civil Construction	Conduits - Reduced Depth of Cover	REVISED	5	Material change to replace steel plates.
76	31	31-1220	Civil Construction	Conduits - Installation of Bends of Poles	REVISED	11	Removed product as it was financially unfeasible .
78	31	31-5000	Civil Construction	Padmounts Precast Concrete Lid (Cover) To Convert Padmount To a Splice Box	REVISED	1	Corrected the dimensions of 3 phase precast concrete lid to 1830mm.
79	31	31-5120	Civil Construction	Splice Vault 'A' for 1000	REVISED	6	Relocated duct entry points for ease of installation and cable organization.
80	31	31-8340	Civil Construction	Aluminum Ladderway Grating Guard	REVISED	5	Guard has been revised to be more durable.
81	34	34-3300	Engineering / References	Asset assembly - Additional Resources	REVISED	3	Added a new column for Daily Travel benchmark.

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #52

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised /Obsolete	Revision number at date of issue	REVISION DESCRIPTION
1	03	03-2000	Clearances	Overhead - Minimum Vertical Separations - Standard Attachment Points	REVISED	9	Note 2 revised to combine 2D and 2E which refer to section 10. Note 7 revised to clarify that minimum seperation between SL brackets and communication attachment is 1m. Note 9 added to specify minimum seperation between secondary busses.
2	04	04-0000	Poles and Pole Settings	Index of Standards	REVISED	5	Standard 04-5400 added to index.
3	04	04-5300	Poles and Pole Settings	Cedar and Concrete Poles - In Sidewalk	REVISED	4	Added 35' and 75' pole to standard.
4	04	04-5400	Poles and Pole Settings	Cedar and Concrete Poles - In Boulevard and Sidewalk, for TTC Trolley Suspension	REVISED	3	Added 35' pole to standard.
5	04	04-5700	Poles and Pole Settings	Steel Pole - In Blvd, for TTC Trolley Suspension (Hand Dig and Vacuum Truck)	REVISED	2	Corrected Typo (m to mm).
6	04	04-5800	Poles and Pole Settings	Steel Poles - In Sidewalk, for TTC Trolley Suspension (Hand Dig and Vacuum Truck)	REVISED	2	Corrected Typo (m to mm).
7	08	08-3130	Overhead Conductors And Connectors	Overhead Connectors - Full Tension and Non-Tension Sleeves Application	REVISED	2	Standard 08-3130 was revised to provide appropriate language as to how many sleeves can be installed as well as developed.
8	10	10-3710	Overhead Switches	SCADA Antenna Mounting Detail - 13.8kV & 27.6kV Systems	REVISED	4	Revised BOM item #3 from 3/4" to 3/8" strap. Added quantities for previously listed open bin items. Removed note 4 that referenced standard practices SP#005. Revised 1m seperation to 1.5m to account for omni-directional antenna length.
9	11	11-2020	Overhead Primary and Secondary Service	Overhead Secondary - Secondary Bus, Transformer Secondary Drop Leads and Secondary Services	REVISED	6	Revised minimum vertical seperation from 10" to 20" between adjacent busses.
10	15	15-1400	UG Secondary and Primary Services	General Information Typical Underground Entrance for Services 1200 A and Up - Collector or Stub Buses	REVISED	4	Added new note (7) and renumbered notes to accommodate change.
11	15	15-5100	UG Secondary and Primary Services	Secondary Underground Services 600 A - 2000 A Fed from Transformer Vault/Pad-Mounted Transformer	REVISED	5	Added new note (3) to provide information for Pad Mounted Transformers on Customer Property.
12	16	16-3700	UG Cables, Joints, Terminations & Connectors	Primary - TRXLPE Straight Joint - Hand Taped Splice, 15kV, 1 Conductor	REVISED	5	Additional comments added to stipulate when this standard should be used. Open Bin Material Section in BOM was removed.
13	16	16-4580	UG Cables, Joints, Terminations & Connectors	Primary - Inline Transition Joint - Hand Taping Method 15kV, Cu, 1 Conductor PILC to TRXLPE	REVISED	5	Additional comments added to stipulate when this standard should be used. Open Bin Material Section in BOM was removed.
14	16	16-4600	UG Cables, Joints, Terminations & Connectors	Primary - Inline Transition Joint - Hand Taping Method 28kV, Cu, 1 Conductor PILC to TRXLPE	REVISED	3	Additional comments added to stipulate when this standard should be used. Open Bin Material Section in BOM was removed.
15	16	16-6200	UG Cables, Joints, Terminations & Connectors	Cable Reel Data - Approved Standard Reel Sizes	REVISED	4	Updated note 2 to follow the latest edition of NEMA Standards.
16	16	16-6210	UG Cables, Joints, Terminations & Connectors	Cable Reel Data - Cable and Wire Reel Chart	REVISED	10	Added 5 new types of cable (9665326, 9665327, 9665328, 9665329, 9665330) to the chart. Revised some cable data.
17	18	18-2300	Grounding	Overhead System - Wood Pole - Ground Wire Installation Details	REVISED	7	Revised BOM legend to include option B for bom without ground rod, included quantity for staples since open bin has been removed
18	30	30-0000	Street Lighting	Index of Standards	REVISED	15	Standard 30-1350 added to index.

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #52

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised /Obsolete	Revision number at date of issue	REVISION DESCRIPTION
19	30	30-1350	Street Lighting	Underground Unshielded Cable Testing (#2 and #6 Cables Rated 600V or Less)	NEW	0	New standard created for cable testing.
20	31	31-0000	Civil Construction	Index of Standards	REVISED	22	Name for standard 31-7100 in index was edited to match the title of the standard.
21	31	31-0100	Civil Construction	Underground Clearances	REVISED	7	Revised clearances to meet existing MCR.
22	31	31-1310	Civil Construction	Underground Conduits - Crossing Railway Tracks	REVISED	3	Adjusted requirements to accommodate GO Metrolinx RER tracks.
23	31	31-6020	Civil Construction	Customer-Owned Structures - Above Grade - Walk-In Vault	REVISED	8	Standard revised to provide better readability. Note 4 was removed and a new Note 5 was added - the numbering of notes was changed to accommodate this revision.
24	31	31-7100	Civil Construction	Draining Structures	REVISED	4	Dimensions of reducer fitting adjusted to 150 mm for both the reducer and NPS.
25	51	51-0000	Cable Tray Supports	Index of Standards	REVISED	3	Standards 51-4500, 51-4510 and 51-4520 added to index.
26	51	51-4500	Cable Tray Supports	EMT Conduit Run	NEW	0	New Standard created for EMT Conduit Run.
27	51	51-4510	Cable Tray Supports	EMT Conduit Support Distances	NEW	0	New Standard created for EMT Conduit Support Distances.
28	51	51-4520	Cable Tray Supports	Conduit Fill	NEW	0	New Standard created for Maximum Conduit Fill.
29	57	57-2100	Station Equipment	DC System 125 V 200 AH - 400 AH with Free Standing Charger	REVISED	1	BOM Revised due to Obsolete Stock Code.
30	57	57-2120	Station Equipment	DC System 125 V 50 AH - 100 AH with Free Standing Charger	REVISED	1	BOM Revised due to Obsolete Stock Code.
31	57	57-2130	Station Equipment	DC System 125 V 50 AH - 100 AH with Wall Mounted Charger	REVISED	1	BOM Revised due to Obsolete Stock Code.
32	57	57-2140	Station Equipment	DC System 48 V 50 AH - 100 AH with Free Standing Charger	REVISED	1	BOM Revised due to Obsolete Stock Code.
33	59	59-0000	Stations Legend/Drafting	Index of Standards	NEW	0	Index created for new Standards' Section - Stations Legend/Drafting.
34	59	59-1000	Stations Legend/Drafting	General Information	REVISED	1	New Standard created for General Information, revision was made due to feed back from the stations department.
35	59	59-1010	Stations Legend/Drafting	Circuit Breakers	NEW	0	New Standard created for Circuit Breakers Symbol Library.
36	59	59-1020	Stations Legend/Drafting	Transformers	NEW	0	New Standard created for Transformers Symbol Library.
37	59	59-1030	Stations Legend/Drafting	Relays	REVISED	1	New Standard created for Relays Symbol Library.
38	59	59-1040	Stations Legend/Drafting	Switches	NEW	0	New Standard created for Switches Symbol Library.
39	59	59-1050	Stations Legend/Drafting	Ground and Lightning	NEW	0	New Standard created for Ground and Lightning Symbol Library.
40	59	59-1060	Stations Legend/Drafting	Instrumentation and Metering	NEW	0	New Standard created for Instrumentation and Metering Symbol Library.
41	59	59-1070	Stations Legend/Drafting	Cables	NEW	0	New Standard created for Cables Symbol Library.
42	59	59-1080	Stations Legend/Drafting	Fusing	New	0	New Standard created for Fusing Symbol Library
43	59	59-1090	Stations Legend/Drafting	Miscellaneous	New	0	New Standard created for Miscellaneous Symbol Library

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #52

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised /Obsolete	Revision number at date of issue	REVISION DESCRIPTION
44	70	70-11	Reactive Maintenance Standards	Legacy Overhead Secondary Services - Compression Sleeves Selection Table	NEW	0	Standard 70-11 provides a guide between the old and new cables, and the type of sleeves they need to complete the project.

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #53

#	Standards Section #	Standard #	Section Title	Standard Name	STATUS New/Revised/ Obsolete	REVISION NUMBER at date of issue	Revision Description
1	03	03-0000	Clearances	Index of Standards	REVISED	6	Standards 03-2160 and 03-2170 added to index.
2	03	03-1100	Clearances	Overhead - General Information	REVISED	5	Revised minimum horizontal and vertical clearances.
3	03	03-2160	Clearances	Overhead - Minimum Vertical Clearances - Toronto Hydro Lines Perpendicular to Metrolinx Electrified Rail	NEW	0	New Standard to address clearances when Toronto Hydro (TH) overhead lines are perpendicular to the Metrolinx (MX) electrified rail.
4	03	03-2170	Clearances	Overhead - Minimum Vertical Clearances - Toronto Hydro Lines Parallel to Metrolinx Electrified Rail	NEW	0	New Standard to address clearances when Toronto Hydro (TH) overhead lines are parallel to the Metrolinx (MX) electrified rail.
5	04	04-1100	Poles and Pole Settings	General Information - Wood (Cedar) Poles	REVISED	4	Revision to Storage Section to include Conversion Table.
6	04	04-7300	Poles and Pole Settings	Reinforce Sidewalk Bays Cedar Poles - 38.5' and 43' Class 3, Base Mounted	REVISED	4	Note 4 revised to remove the mention of pole surface treatment. Note 6 added to reference AODA requirements.
7	05	05-1280	Pole Framing	4.16 to 27.6 kV Treeproof and Bare Primary - 3-Phase Tangent Horizontal Configuration 0 to 3 Degrees	REVISED	3	Standard revised to include overbuild horizontal framing configuration.
8	05	05-1590	Pole Framing	4.16 to 27.6 kV Treeproof and Bare Primary - 3-Phase Double Dead-End Horizontal Configuration	REVISED	2	Note 7 added to mention that the Red, White, and Blue phases on either side of the horizontal dead-end shall be the same.
9	07	07-1300	Anchoring and Guying	Anchoring - Positioning of Anchors	REVISED	2	Revised to include new section for Anchor Alignment with Pole.
10	08	08-3120	Overhead Conductors and Connectors	Overhead Connectors - Hand Taping of Sleeve for Primary Tree Proof Cable For Retrofit Application	REVISED	1	Revised to include reinsualtion of tree proof cables where the covering has been cut back to accommodate installation of temporary grounds.
11	08	08-3160	Overhead Conductors and Connectors	Overhead Connectors - Non-Tension Compression Sleeves Selection Table	REVISED	2	Revised to add stock code for non-tension Al 250 kcmil sleeve.
12	09	09-3800	Overhead Transformers	Installation 1 -Phase Transformer Monitor	REVISED	1	Revised note 5 to explicitly state the ordering of two replacements kits.
13	10	10-0000	Overhead Switches	Index of Standards	REVISED	10	Standard 10-1310 added to index. Standards 10-1100, 10-1120 and 10-3100 removed from index. Title change for Standard 10-1300.
14	10	10-1100	Overhead Switches	Disconnect In-Line Switches - Solid Blade 600 A double dead-end 4.16 kV to 27.6 kV Horizontal Configuration	OBSOLETE	7	Standard 10-1100 has been incorporated into Standard 10-1300.
15	10	10-1120	Overhead Switches	Disconnect In-Line Switches - Fused 200 A Double Dead-End 13.8 kV to 27.6 kV Horizontal Configuration	OBSOLETE	1	Standard 10-1120 has been incorporated into new Standard 10-1310.
16	10	10-1300	Overhead Switches	Disconnect In-Line Solid Blade Switches - All Voltages and Configurations	REVISED	9	Fused switch (permutation B) has been moved to new Standard 10-1310. Overbuild horizontal framing configuration added.
17	10	10-1310	Overhead Switches	Disconnect In-Line Switches Fused 200A 13.8 kV to 27.6 kV	NEW	0	New Standard created for in-line fused switches, including new AMPACT Fuse In-Line Mount Switch.
18	10	10-3100	Overhead Switches	3-Phase Load Interrupter Switch SCADA-Operated 13.8 & 27.6 kV Feeder Riser	OBSOLETE	2	Standard has been moved to Section 70 for reactive maintenance use only.
19	11	11-0000	Overhead Primary and Secondary Service	Index of Standards	REVISED	10	Standard 11-3220 added to index.Title Change for Standards 11-2050 and 11-3810.
20	11	11-2050	Overhead Primary and Secondary Service	Overhead Secondary Services Temporary Service Connection - Up to 200 Amp Service	REVISED	1	Standard revised to clarify the scope of temporary service connection for up to 200 A service (120/240V, 120/208V or 347/600V). Revision includes changes to Figure, Notes, Dimensions, and Title.

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #53

#	Standards Section #	Standard #	Section Title	Standard Name	STATUS New/Revised/ Obsolete	REVISION NUMBER at date of issue	Revision Description
21	11	11-3220	Overhead Primary and Secondary Service	Multiplexed or Field Lashed Secondary Bus - Angles 46 to 90 Degrees on Concrete or Wood Pole	NEW	0	SKE-331 converted to a Standard.
22	11	11-3810	Overhead Primary and Secondary Service	Multiplexed Secondary Bus - Temporary Service Tap at Transformer Pole for Construction Site 347/600 V, 400 A and 600 A, 3-Phase	REVISED	1	Standard revised to clarify that it is applicable for 400 A and 600 A service. Revision includes changes to Notes and Title.
23	13	13-0000	UG Transformers and Switchgears	Index of Standards	REVISED	13	Standard 13-7550 added to index. Title change for Standard 13-2100.
24	13	13-2010	UG Transformers and Switchgears	4.16 kV Transformer Vault Layout & Installation of Three 50, 100 & 167 kVA Transformers	REVISED	4	Revised to accommodate vibration pad installation in vault type transformer vault.
25	13	13-2100	UG Transformers and Switchgears	Transformer Vault Drainage With or Without Sump Pump	REVISED	2	Title Change. Standard updated to include new sump pump and drainage requirements.
26	13	13-2200	UG Transformers and Switchgears	Vault Lighting Arrangement	REVISED	2	Revised to include vault lighting selection for one network vault.
27	13	13-5010	UG Transformers and Switchgears	13.8 kV Network System - Network Transformer Vaults	REVISED	9	Revised to reference underground service cable limiters from associated standard.
28	13	13-5020	UG Transformers and Switchgears	13.8 kV Network System - Typical Stand Alone Network Protector (SANP) Vault	REVISED	3	Revised to reference underground service cable limiters from associated standard.
29	13	13-5100	UG Transformers and Switchgears	13.8 kV Network System - Network Protector Automation	REVISED	3	Revision to diagram. Moved location of fibr patch panel and vault communication box for better access.
30	13	13-7010	UG Transformers and Switchgears	27.6 kV or 13.8 kV 1-Ph Submersible Transformer Vault	REVISED	13	Revision depicts layout with new disconnectable connector and provides new BOM option for 8-14 secondary terminations.
31	13	13-7030	UG Transformers and Switchgears	Customer Transformer Vault For 1-Ph Transformer -13.8 kV & 27.6 kV Distribution System	REVISED	7	Revised standard and BOM to accommodate vibration pad installation in vault type transformer.
32	13	13-7050	UG Transformers and Switchgears	3 1-Phase Transformer Vault 13.8 kV Typical Layout	REVISED	6	Revised Standard and BOM to accommodate vibration pad installation in vault type transformer.
33	13	13-7060	UG Transformers and Switchgears	3 1-Phase Transformer Vault 27.6 kV Typical Layout	REVISED	7	Revised Standard and BOM to accommodate vibration pad installation in vault type transformer.
34	13	13-7080	UG Transformers and Switchgears	Delta Vault - Typical Electrical Layout - 27.6 kV Loop System	REVISED	7	Revised Standard and BOM to accommodate vibration pad installation in vault type transformer.
35	13	13-7200	UG Transformers and Switchgears	Grd. Y Vault-Typical Electrical Layout - 27.6 kV System	REVISED	11	Revised Standard and BOM to accommodate vibration pad installation in vault type transformer.
36	13	13-7500	UG Transformers and Switchgears	3 1-Phase Transformer Vault 27.6 kV Customer Room with SF6 Switchgear	REVISED	3	Revised Standard and BOM to accommodate vibration pad installation in vault type transformer.
37	13	13-7520	UG Transformers and Switchgears	3 1-Phase Transformer Vault - 13.8 kV Customer Room with SF6 Switchgear	REVISED	1	Revised Standard and BOM to accommodate vibration pad installation in vault type transformer.
38	13	13-7550	UG Transformers and Switchgears	Vibration Pads for Distribution Transformers	NEW	0	New Standard developed for vibration pad installation.
39	14	14-1070	Padmounted Transformers	27.6 Grd. 16 kV 3-Phase - Radial/Loop System	REVISED	4	Revised to include minimum impedance percentage for 750-1000 kVA and 1500 kVA units.
40	15	15-0000	UG Secondary and Primary Services	Index of Standards	REVISED	9	Title change for Standard 15-3800.

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #53

#	Standards Section #	Standard #	Section Title	Standard Name	STATUS New/Revised/ Obsolete	REVISION NUMBER at date of issue	Revision Description
41	15	15-3800	UG Secondary and Primary Services	Underground Secondary Services Temporary Service Connection - Up to 200A Service	REVISED	2	Standard revised to clarify the scope of temporary service connection for up to 200 A service (120/240V, 120/208V or 347/600V). Revision includes changes to Figure, Notes, Dimensions and Title.
42	16	16-0000	UG Cables, Joints, Terminations & Connectors	Index of Standards	REVISED	15	Standards 16-1300 and 16-6010 added to index. Title change for Standard 16-6000.
43	16	16-0940	UG Cables, Joints, Terminations & Connectors	Cable Ratings - 4.16 kV RILC	REVISED	2	BOM revised to update obsolete stock code.
44	16	16-1300	UG Cables, Joints, Terminations & Connectors	Fault Locating Strategy - Underground Primary Cable	NEW	0	New Standard created for Fault Locating Strategy for Underground Primary Cable.
45	16	16-6000	UG Cables, Joints, Terminations & Connectors	Secondary Terminations - Submersible Transformer Terminal Cluster for Non-Removable Low Voltage Terminal/Spade 600 V or Below	REVISED	7	Title revised and note 2 added to notify users that this standard is applicable for legacy transformers with Non-Removable Terminal/Spade.
46	16	16-6010	UG Cables, Joints, Terminations & Connectors	Secondary Terminations - Submersible Transformer Terminal Cluster for Removable Low Voltage Terminal/Spade 600 V or Below	NEW	0	New Standard created to show the components required for installing disconnectable flood seal connectors.
47	18	18-4100	Grounding	Overhead System Communication Messenger Bonding	REVISED	5	Copper wire size changed from #2 to #6 AWG to align with communication company standards.
48	21	21-1000	Overhead and Underground Stenciling	General Information - Location and Equipment Numbering	REVISED	5	Revision to note 3 to include reference to Standard 53-5000.
49	21	21-1100	Overhead and Underground Stenciling	General Information - Stenciling Materials	REVISED	7	Outdoor and Indoor Danger Signs added to BOM.
50	23	23-1220	Foreign Attachments	Overhead System - Pole Attachments - Communication Riser and Neutral Bonding	REVISED	3	Copper wire size changed from #2 to #6 AWG to align with communication company standards.
51	24	24-0000	Fusing	Index of Standards	REVISED	4	Standard 24-2200 added to index.
52	24	24-2200	Fusing	Underground Fusing - Pad-Mount Bay-O-Net Fuses	NEW	0	New Standard created to show the stock codes for field replaceable Bay-O-Net fuses for 1-Phase and 3-Phase Pad-Mount Transformers.
53	27	27-4100	Legend/Drafting Symbols	Civil Structures	REVISED	4	Revised primary splice box and secondary splice tap box.
54	30	30-0000	Street Lighting	Index of Standards	REVISED	16	Title change for Standard 30-4280.
55	30	30-4220	Street Lighting	Concrete Pole with Cobra Head Luminaire	REVISED	9	BOM revised to include 30' and 35' Base Mounted Pole.
56	30	30-4280	Street Lighting	Aluminum Pole - Davit Style for Expressways/Highways with Cobra Head Luminaire	REVISED	2	Title revised. Additional revisions made to provide details on dimensions and installation methods.
57	31	31-0000	Civil Construction	Index of Standards	REVISED	23	Standard 31-2250 added to index.
58	31	31-1100	Civil Construction	Conduits - General Information	REVISED	6	Standard revised to include electrical and communication cables.
59	31	31-1120	Civil Construction	Conduits - Concrete Encased and Direct Buried Ducts	REVISED	8	Revised to account for the use of RED ducts for all new or rebuild direct buried THESL communication cables.
60	31	31-1400	Civil Construction	Duct Sealant Installation	REVISED	1	Revised to fix typo. Nofrino should be Nofirno.
61	31	31-2250	Civil Construction	Cable Chambers - Core Drilling into Existing Cable Chamber	NEW	0	New standard created to provide guidelines on core drilling in exisiting cable chambers.
62	34	34-1000	Engineering/References	Construction Deviation Guidelines	REVISED	4	Revision made to Deviations section to distinguish design/engineering responsibility for review/sign-off.
63	53	53-0000	Stenciling	Index of Standards	REVISED	4	Standard 53-5000 added to index.
64	53	53-5000	Stenciling	Customer Indoor or Outdoor Substation Stenciling for 13.8 kV Switchgear Underground Radial in Former Toronto District	NEW	0	No previous Standard for 13.8 kV Switchgear.

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #53

#	Standards Section #	Standard #	Section Title	Standard Name	STATUS New/Revised/ Obsolete	REVISION NUMBER at date of issue	Revision Description
65	55	55-0000	Cable Terminations	Index of Standards	REVISED	2	Title change for Standard 55-3110.
66	55	55-3110	Cable Terminations	Station Transformer Termination - 13.8 kV and 4.16 kV Station Transformer Secondary Termination	REVISED	1	Revision to title and notes. Addition of a Recommended Cables for Transformer Ratings Chart.
67	59	59-0000	Stations Legend/Drafting	Index of Standards	REVISED	1	Standard 59-2000 added to index.
68	59	59-2000	Stations Legend/Drafting	Conductor Naming Convention	NEW	0	New Standard created for conductor naming convention.

Toronto Hydro Asset Condition Assessment Methodology

Table of Contents

1. Introduction 2

2. Asset Condition Assessment General Discussion 2

a. **ACA Description** 2

b. **ACA in Asset Management** 2

c. **Legacy Approach - Weighted Arithmetic Summation Model** 3

(i) Weak Relationship between Health Scores and Probability of Failure 3

(ii) Data Exclusions and Lack of Projection Capabilities 4

d. **Decision to Adopt a New ACA Approach** 5

3. Selection of CNAIM for ACA 5

4. Toronto Hydro's Implementation of CNAIM 6

a. Formulation of ACA 6

1. Formulas 6

2. Data Inputs 8

3. Differences between Ofgem and Toronto Hydro implementations of CNAIM 8

4. Third-party review of Toronto Hydro's CNAIM implementation 8

b. Approach to implementation 9

c. Implementation Progress to Date 9

d. ACA Integration in CIR Framework 12

e. Areas for Continuous Improvement 12

Appendix A – Explanation of the Methodology 14

Appendix B – Duty Factor Values and Condition Factor Parameters 25

(i) Duty Factor Values 25

(ii) Observed Condition Factors 26

(iii) Measured Condition Factors 55

(iv) FFA Test Input 61

(v) Oil Test Input 62

(vi) DGA Test Input 62

(vii) Reliability Modifiers 63

Appendix C – Current and Future Health Score Tables 64

1. Introduction

This report discusses Toronto Hydro's approach to Asset Condition Assessment ("ACA"). Sections 2a and 2b provide a brief description of ACA and how it is used in asset management. Sections 2c and 2d discuss the legacy approach (weighted arithmetic summation model) used by Toronto Hydro and the associated limitations which led to the decision in 2016 to adopt a new methodology. Toronto Hydro's selection of the Common Network Assets Indices Methodology ("CNAIM"), which was developed and used by utilities in the U.K., is discussed in Section 3 and its implementation in Section 4. The Appendices provide additional details on the ACA algorithm and parameters as well as ACA results for Toronto Hydro assets assessed using the methodology.

2. Asset Condition Assessment General Discussion

a. ACA Description

In simple terms, ACA involves the use of condition inspection data to estimate the remaining serviceable life of physical assets. Utilities periodically inspect physical assets to monitor signs of degradation (e.g. visible corrosion) that can lead to asset failure. Inspection data on its own is useful in identifying and prioritizing assets for maintenance, refurbishment, or replacement. An ACA augments inspection data for assets by processing such data to arrive at a health index ("HI") score that represents an asset's remaining useful life.

b. ACA in Asset Management

Utilities use ACA results to gain insight into the likelihood that major assets will fail over time. This helps with anticipating failures and failure rates, and to plan and budget for the investments needed to maintain or improve system performance in light of asset failure risk.

Toronto Hydro uses condition information to support tactical and strategic investment planning decisions. Planners use inspection data and individual HI scores – in combination with other information and professional judgement – to prioritize assets for tactical intervention in the short- to medium-term. This includes identifying priority deficiencies that require reactive or corrective action, and prioritizing assets for planned renewal projects in a given budget period. At a strategic level, Toronto Hydro uses ACA results to examine condition demographics and trends within major asset classes. ACA results for a particular asset class are grouped into five HI bands that represent key stages of an asset's lifecycle, ranging from new or like new condition to the stage where asset degradation is significant enough to warrant urgent attention. This information supports the development of longer-term investment plans within the annual Investment Planning & Portfolio Reporting Process ("IPPR").

When applied across an asset class, HI scores can be an effective leading indicator of future failure rates within that class and, as an extension, an effective leading indicator of future reliability performance and other outcomes driven by asset failure. Investing at a pace that allows the utility to maintain or, where appropriate, improve the condition demographics for an asset class is an important means of ensuring consistent and predictable performance over the long-term (as measured by lagging indicators like system average reliability performance).

Along with, or in the absence of condition information, age-based probability of failure analysis is a key input to the prioritization of assets for intervention and the forecasting of system-wide performance. Asset age is also typically a significant factor in the calculation of HI scores, partly due to the fact that age bears a strong statistical relationship with probability of failure. The extent to which a utility can monitor significant degradation characteristics that are predictive of asset failure varies depending on the type of asset. Even when the utility is able to monitor a number of condition variables that are strongly predictive of an asset's remaining life, it remains necessary to include age as an ACA variable.

c. Legacy Approach - Weighted Arithmetic Summation Model

Prior to 2017, Toronto Hydro used a weighted arithmetic summation model to calculate HI scores. This methodology assigns specific weights to a number of condition parameters reported during field inspections, sums the results, and calculates the weighted arithmetic mean to compute an HI score along a continuum of potential HI values. For reporting purposes, assets are then placed into five HI categories or bands, from "very good" condition to "very poor" condition. This ACA methodology was the first to be employed by utilities in Ontario and has become the default approach to ACA in the sector.

Toronto Hydro has relied on this model as an indicator of failure risk and a leading indicator of future asset performance to help guide prudent investment planning decisions in the short- to medium-term. While the model has generally proven fit for this purpose, Toronto Hydro's experience over the last eight years has, in the utility's view, revealed certain limitations in relation to: (1) short- to medium-term planning capabilities; and (2) emerging expectations that utilities be able to demonstrate a relationship between the health of assets and investment planning objectives over longer planning horizons. These limitations are outlined in the following sections.

(i) Weak Relationship between Health Scores and Probability of Failure

The weighted arithmetic summation model lacked a formal, mathematical link between the condition of an asset and its probability of failure. Put another way, the legacy model did not allow the utility to toggle between an asset's health score and its probability of failure. The legacy model computed a weighted health score, which is useful for assessing the overall condition of an asset relative to a new asset, and the health of assets relative to each other. As mentioned above, assets were placed into five condition

categories based on the HI, from best condition to worst condition. While these different categories could be assigned a suggested range of time to replacement (e.g. an asset in "very poor" condition may generally need to be addressed in one to two years), these ranges were based primarily on engineering judgement and did not provide a precise analytical basis for assessing asset risk and more precise replacement needs based on condition.

A second limitation of the legacy model is that it can struggle to provide a meaningful link to probability of failure. Over time, Toronto Hydro has observed that the weighted arithmetic summation methodology does not consistently provide an accurate representation of asset health degradation. In the weighted summation model, critical conditions that can lead to total asset failure, even if assigned a higher weighting, can be masked by the combination of all other benign condition attributes. This dynamic dilutes the relationship between the HI scores and asset failure risk, with a structural bias toward understating the magnitude of deterioration in an asset's health. For short-term planning horizons (i.e. one to two years), this limitation is not a significant concern, as Toronto Hydro's planners tend to rely directly on condition information from field inspection reports, augmented by other information and professional judgement, to make tactical decisions regarding which assets to prioritize for intervention. However, over the medium- to long-term, a weak relationship between HI scores and asset failure risk can be problematic for strategic investment planning, including longer-term risk and performance management.

As such, Toronto Hydro concluded that alternative ACA approaches needed to be explored to address these concerns while offering additional functionality.

(ii) Data Exclusions and Lack of Projection Capabilities

Another shortcoming of the legacy model was its inability to model the future condition of assets. In regulatory jurisdictions where condition analysis plays a key role in longer-term planning (e.g. the U.K., where regulatory planning horizons are eight years long), the ability to model the asset condition demographics for an asset class at a future point in time is an important means of assessing the pacing and effectiveness of a utility's investment plans. While Toronto Hydro's weighted arithmetic summation model was able to provide condition demographics based on the most recent condition inspections, it was difficult to draw meaningful conclusions from this data about the appropriate pacing of investment over a planning horizon of five years or more.

A related limitation of the legacy model is the model's rejection of assets that lack a minimum amount of condition data. Specifically, the model is not considered reliable if less than 60% of the condition data for an asset is available. This has, in practice, resulted in the exclusion of a large number of assets from the overall ACA sample within an asset class, even if the available condition data for those assets suggests significant degradation (another reason why planners tend to rely on raw inspection information when making short-term planning decisions). While Toronto Hydro, through the use of tablets and improved

inspection forms, is continuously improving its asset condition inspection data, the utility nonetheless needs to be able to have a maximally comprehensive view of the condition of its assets based on available data.

d. Decision to Adopt a New ACA Approach

Toronto Hydro continuously seeks opportunities to improve its analytical capabilities and to progress towards best-in-class asset management practices. Due to the limitations discussed above, Toronto Hydro decided in 2016 to take the next step with its ACA by moving to a new methodology. The need to prioritize ACA enhancements was further underscored by the increasing regulatory emphasis on the link between asset condition, probability of failure, and longer-term system investment needs as expressed in five-year utility system plans. The following section discusses Toronto Hydro's selection of the CNAIM and the benefits of that model.

3. Selection of CNAIM for ACA

Toronto Hydro reviewed the ACA methodologies used in Ontario and confirmed that utilities continue to rely mainly on the weighted arithmetic summation methodology, with slight variations in approach. Looking outside of Ontario, Toronto Hydro ultimately gravitated to the CNAIM used by the Office of Gas and Electricity Markets ("Ofgem") and the United Kingdom's distribution network operators. This methodology was developed collaboratively by the network operators regulated by Ofgem and other industry experts, and benefited from the sponsorship and guidance of Ofgem. The methodology was submitted to Ofgem for initial approval in July 2015 and was further refined following public consultation. In February 2016, Ofgem approved the model and directed all network operators to use CNAIM in the 2015-2023 rate-setting period. Additional refinements and enhancements have occurred since this time.

Ofgem describes CNAIM as "a common framework of definitions, principles and calculation methodologies […] for the assessment, forecasting and regulatory reporting of Asset Risk."1 Toronto Hydro took particular interest in this model specifically because it was developed collaboratively by large, mature and heavily urbanized utilities, in consultation with their regulator and the public, in an advanced performance-based regulatory jurisdiction with an even longer rate-setting period than that of Ontario. The methodology's ability to support rigorous assessment of condition-based probability of failure over an eight-year horizon was appealing to Toronto Hydro for a number of reasons, including the Ontario Energy Board's increasing emphasis on similar evaluation frameworks and principles as a means of supporting Renewed Regulatory Framework objectives and outcomes.

[1] Ofgem. (2017, January 30). *DNO Common Network Asset Indices Methodology Version 1.1.* Online https://www.ofgem.gov.uk/system/files/docs/2017/05/dno_common_network_asset_indices_methodology_v1.1.pdf

The primary benefits of CNAIM with respect to assessing asset health and probability of failure are expected to be as follows:

i. a robust scoring methodology that emphasizes deficiencies which directly impact equipment failure;
ii. fewer asset exclusions due to data availability;
iii. a stronger and more objective relationship between condition and probability of failure; and
iv. the ability to project future asset health scores, providing strategic insight into longer-term investment strategies using forecasted HI demographics.

To date, Toronto Hydro has implemented the aspects of CNAIM necessary to immediately achieve the benefits described in items (i), (ii) and (iv) above. For item (iii), Toronto Hydro is currently in the process of developing the formulas required to convert an HI score produced by CNAIM into a probability of failure.

Asset health and probability of failure are only one part of the CNAIM. The full methodology also addresses consequences of failure and asset criticality. This includes a common methodology for assigning monetized risk values to assets based on consequences of failure – a concept that is analogous to the avoided risk cost methodology in Toronto Hydro's existing Feeder Investment Model ("FIM").

Toronto Hydro's immediate objective in moving to CNAIM was to replace the functionality of the previous ACA, which did not include a consequence of failure or asset criticality component. Going forward, in addition to developing the incremental capability to convert an HI score to probability of failure, Toronto Hydro intends to explore the consequence of failure and criticality aspects of CNAIM. It will also examine opportunities to derive additional value from the existing FIM by connecting it with, or subsuming it within, the CNAIM approach to asset risk evaluation.

The following section describes Toronto Hydro's implementation of the CNAIM to date.

4. Toronto Hydro's Implementation of CNAIM

a. Formulation of ACA

1. Formulas

To date, Toronto Hydro's implementation of CNAIM has covered the derivation of current and future health calculations. Using the CNAIM framework, the current health of an asset is represented by a health score using a continuous scale between 0.5 and 10 (extended up to 15 for forecasting of future health), where 0.5 represents the condition expected of a new asset. A health score of 5.5 represents the point in

an asset's life beyond which significant deterioration is likely to be observed. A health score of 10 represents an asset in a state unacceptable to Toronto Hydro.

The steps for deriving current and future health scores in the CNAIM framework include the following (Appendix A of this report provides additional details on the algorithm and each of the variables):

- Calculate an *Initial Health Score* based on the asset's age and expected life, taking into account its operational use (duty) and operating conditions.
- Determine the *Health Score Modifier* based on the known conditions of the asset, including information gathered from inspections the asset, diagnostic tests or measurements. The observed and measured condition inputs are used to determine the *Health Score Factor*, *Health Score Cap* and *Health Score Collar*.
- Determine *Reliability Modifier*, where applicable for the asset's subcategory to account for generic issues affecting asset health or reliability associated with a specific manufacturer or model type. The *Reliability Modifier* comprises a *Reliability Factor* and a *Reliability Collar*.
- Calculate the *Current Health Score* by multiplying the *Initial Health Score* by the *Health Score Factor* and the *Reliability Factor,* and applying the upper and lower thresholds defined by the *Health Score Cap* and *Health Score* and *Reliability Collars*.
- Generate the *Future Health Score* by inputting results into an equation that projects the asset's condition at a desired point in time.

For the purpose of reporting, the *Current* and *Future Health Scores* are mapped onto one of five HI Bands as follows, with *Current Health Score* represented on a continuous scale of 0.5 – 10 and *Future Health Score* represented on a continuous scale of 0.5 – 15:

Table 1: Health Index bands

HI Band	Lower Limit of Health Score	Upper Limit of Health Score	Definition
HI1	≥ 0.5	< 4	New or good condition
HI2	≥ 4	< 5.5	Minor deterioration; in serviceable condition
HI3	≥ 5.5	< 6.5	Moderate deterioration; requires assessment and monitoring
HI4	≥ 6.5	< 8	Material deterioration; consider intervention
HI5 (Current Health)	≥ 8	≤ 10	End of serviceable life; intervention required
HI5 (Future Health)	≥ 8	≤ 15	

2. Data Inputs

The data inputs required to calculate *Current* and *Future Health Scores* for an asset include age and condition and operation data. Condition data includes observations and test results recorded during routine maintenance and field inspections. Asset operation data relates to the use of the asset and varies based on the type of asset (e.g. percent utilization for transformers and number of operations for circuit breakers).

3. Differences between Ofgem and Toronto Hydro implementations of CNAIM

The Ofgem CNAIM model was built around 25 asset types that are common among U.K. utilities. In many cases, the manufacturing and functional characteristics of these assets differ from Toronto Hydro's assets. It was therefore necessary in Toronto Hydro's implementation of the CNAIM approach to adjust certain input factors and initial condition scores to accurately reflect the utility's system and operating realities. The two main areas included:

- adjustments to the caps and collars for each failure mode of an asset to reflect Toronto Hydro's experience with asset deficiencies and failures on its own system; and
- adjustments to duty values, i.e. the loading on an asset or the frequency with which it is used, to reflect the functionality and the way the asset is used in Toronto Hydro's operating context.

In making these necessary utility-specific adjustments, Toronto Hydro did not fundamentally alter or deviate from the core principles or methodology of CNAIM.

Toronto Hydro is exploring additional opportunities to align its implementation of CNAIM with the utility's operational reality. For example, environmental and climate conditions in the U.K. are different from those in Toronto. Toronto Hydro is currently working on developing appropriate location factors which will better define the environment in which the assets are functioning. In the interim, the location factor values are currently defaulted to a value of one, which is consistent with the CNAIM model for situations where the data is not available.

4. Third-party review of Toronto Hydro's CNAIM implementation

To ensure the appropriate implementation of the CNAIM model, including the validity of the aforementioned utility-specific adjustments, Toronto Hydro retained U.K. firm EA Technology to review its newly developed asset health models, recommend areas for improvement, and provide guidance and training to ensure organizational alignment with the asset management philosophy, principles and practices underpinning the CNAIM approach. Toronto Hydro selected EA Technology for this task as they are the foremost experts in the CNAIM model, having provided support for the development of the

original methodology as well as the delivery and implementation of the common models to all U.K. distribution network operators.

The following section provides additional details on Toronto Hydro's approach to CNAIM implementation.

b. Approach to implementation

Through its Reliability Centred Maintenance ("RCM") framework, Toronto Hydro categorizes the failure modes and deficiencies for each asset type and documents maintenance strategies for mitigating deficiencies. The utility used RCM information to build the Health Score Modifiers – i.e. the observable and measurable condition variables that modify the health score of an asset – for each asset type modeled in the CNAIM. Unlike Toronto Hydro's legacy ACA methodology, the CNAIM is fully aligned with Toronto Hydro's RCM, meaning that the likelihood that condition variables required by the new ACA model will not be captured during field inspections is low. For more information on Toronto Hydro's RCM, refer to Exhibit 2B, Section D1.2.2.4 and Section D3.1.1.1.

Toronto Hydro determined the condition variables for each asset class based on the following criteria: deficiencies that lead to an asset failure; deficiencies that lead to a component of the asset failing; and deficiencies that degrade the performance of an asset but do not lead to an immediate asset or component failure. The utility performed a comparative analysis of these condition points and assigned appropriate calibration values.

RCM was critical to Toronto Hydro's determination of minimum health score limits in CNAIM, known as "collars." If a deficiency that has a collar is noted during an inspection, the CNAIM algorithm checks to see if the final health score value is above the collar value. If the value is not above the collar value, then the health score is replaced with the collar value. In this way, the severity of any deficiency which may lead to asset failure is not dampened by the appearance of less or no degradation for other condition variables. This eliminates one of the limitations of Toronto Hydro's legacy ACA methodology discussed above.

A detailed technical explanation of the CNAIM model, algorithms, and Toronto Hydro's implementation of those algorithms can be found in Appendix A to this document.

c. Implementation Progress to Date

Toronto Hydro has implemented both the *Current Health Score* and *Future Health Score* for the asset classes listed in Tables 2 and 3, below. Table 2 summarizes the *Current Health Score* demographics for each asset class and Table 3 summarizes the *Future Health Score* demographics for these assets in 2024 assuming no interventions.

Table 2: Summary of Current Health Index Distribution.

Asset Class	Current Health Score				
	HI1	HI2	HI3	HI4	HI5
Overhead Gang-Operated Switches	854	27	76	3	9
SCADA-Mate Switches	1,084	1	26	0	8
Wood Poles	68,425	5,777	20,915	10,877	1,074
4kV Oil Circuit Breakers (MS)	36	4	123	24	0
KSO Circuit Breakers (TS)	10	7	11	11	1
SF6 Circuit Breakers (TS)	130	6	18	3	3
Vacuum Circuit Breakers (MS & TS)	578	46	13	2	29
Air Magnetic Circuit Breakers (MS & TS)	145	90	247	21	53
Airblast Circuit Breakers (MS & TS)	15	9	206	1	3
Station Power Transformers	83	77	61	13	8
Network Transformers	1,334	255	166	60	7
Network Protectors	1,086	185	319	74	26
Cable Chambers	8,112	1,162	1,350	398	89
Submersible Transformers	7,816	588	271	172	55
Air-Insulated Padmount Switches	404	20	73	30	45
Vault Transformers	6,807	4,315	450	214	45
Underground Vaults (combined)	1,017	186	72	12	29
ATS Vaults	8	0	0	0	0
CLD Vaults	21	0	0	0	0
CRD Vaults	9	0	1	0	0
Network Vaults	322	120	63	11	29
Submersible Switch Vaults	115	5	0	0	0
URD Vaults	542	61	8	1	0
Padmount Transformers	5,547	656	283	113	18
SF6-Insulated Padmount Switches	402	0	2	0	6
SF6-insulated Submersible Switches	353	14	7	3	19
Air-Insulated Submersible Switches	755	79	27	7	0

Table 3: Summary of Future Health Index in 2024.

Asset Class	Future Health Score (2024)				
	HI1	HI2	HI3	HI4	HI5
Overhead Gang-Operated Switches	712	135	22	41	59
SCADA-Mate Switches	1,015	43	27	0	34
Wood Poles	59,851	8,767	4,177	17,449	16,824
4kV Oil Circuit Breakers (MS)	36	0	6	119	26
KSO Circuit Breakers (TS)	1	9	7	10	13
SF6 Circuit Breakers (TS)	127	3	4	5	21
Vacuum Circuit Breakers (MS & TS)	575	3	5	54	31
Air Magnetic Circuit Breakers (MS & TS)	97	48	57	277	77
Airblast Circuit Breakers (MS & TS)	3	12	21	194	4
Station Power Transformers	75	25	58	62	22
Network Transformers	1,153	173	229	102	165
Network Protectors	1,027	57	47	177	382
Cable Chambers	6,829	1,546	1,931	327	478
Submersible Transformers	7,447	364	537	143	411
Air-Insulated Padmount Switches	371	30	20	6	145
Vault Transformers	5,397	1,623	3,910	491	410
Underground Vaults (combined)	960	70	162	85	39
ATS Vaults	7	1	0	0	0
CLD Vaults	21	0	0	0	0
CRD Vaults	7	2	0	1	0
Network Vaults	273	55	103	76	38
Submersible Switch Vaults	113	7	0	0	0
URD Vaults	539	5	59	8	1
Padmount Transformers	5174	345	605	227	266
SF6-Insulated Padmount Switches	402	0	0	0	8
SF6 insulated Submersible Switches	346	9	12	4	25
Air Insulated Submersible Switches	710	55	69	23	11

Toronto Hydro does not produce health scores for all major asset classes. The exclusion of an asset class from the ACA is typically due to one of two reasons: (1) it is technically infeasible to collect condition data without damaging the asset; or (2) Toronto Hydro has not developed or fully carried out an advanced inspection program that will provide the inputs necessary to calculate the health score.

Underground cables are an example of the first case described above. Historically, Toronto Hydro has not introduced a cable testing program because the testing methods themselves would shorten the life of the asset. More recently, Toronto Hydro has adopted a new approach and is in the process of implementing

it. If successful, the utility will consider using cable testing information to develop an ACA algorithm for cables.

Pole top transformers are an example of an asset for which Toronto Hydro does not presently have a sufficiently advanced, dedicated inspection program. Toronto Hydro performs a cursory inspection of pole top transformers during routine overhead line patrols, checking for any major, readily visible deficiencies. These defects are noted for consideration in reactive and corrective program planning, but the data is not substantial enough to form the basis of a complete ACA algorithm.

d. ACA Integration in CIR Framework

Toronto Hydro's new ACA is a significant part of the utility's 2020-2024 DSP. The utility has leveraged the improved information, including asset condition projections, to help demonstrate the appropriate pacing of planned asset replacement strategies over the forecast period. As mentioned in the introductory sections of this document, a robust ACA can serve as a strong leading indicator of future system performance, including the reliability and safety outcomes that matter most to customers. By gaining better visibility into the overall condition demographics of its major assets, Toronto Hydro has been able to validate and refine its expenditure plans to address assets at a pace that aligns with current and future system needs and customer preferences.

As explained in Section C of the DSP Toronto Hydro has proposed to track and report on a new metric, System Health – Asset Condition (Poles), for the 2020-2024 period. The measure is focused on the percentage of wood poles that are in HI4 or HI5 condition. Since the introduction of an annually reported System Health metric using an adjusted CNAIM methodology is a new development for Toronto Hydro and the Ontario distribution sector in general. As such, additional maturation is still required to enable the projection of Future Health Scores. Toronto Hydro therefore proposes to report on the percentage of wood pole assets in HI4 or H5 category each year through the 2020 to 2024 period and to use the five-year actual data to determine a baseline against which future performance may be measured. This approach is consistent with the OEB's current approach to performance measurement.

e. Areas for Continuous Improvement

(i) Average Age Values

As a step toward refining the accuracy of the model, EA Technology recommended Toronto Hydro undertake a review of its asset useful life values (i.e. minimum expected useful life, maximum expected useful life, and typical useful life for each asset class type). Over time, Toronto Hydro has made minor adjustments to these values based on utility experience, but has not performed a full review of its useful

life values (including review of the derivation methodology) since the Kinectrics study performed in 2010.[2] Toronto Hydro intends to update its useful life values and age-based probability of failure curves in the future.

(ii) Location Factor

As mentioned above, the Ofgem algorithm uses location factors values (such as Distance to Coast, Altitude Factor and Corrosion Factor) to determine the expected life of assets. While these factors are suitable to the conditions in the U.K., they may not be suitable for the environmental conditions in Toronto. Toronto Hydro has currently defaulted these values to one and is engaged on developing better condition criteria that will account for the effects of Toronto's environment on the asset deterioration process.

(iii) Reliability Modifier

CNAIM provides for a reliability modifier that can help the utility differentiate subgroups within a specific asset class, e.g. different manufacturers and designs. Currently this has been set to a default neutral value of one. Toronto Hydro requires more information to determine the appropriate scoring of this factor for the algorithm. More data can be collected from field inspections and asset failure resulting in outage events which can be leveraged to develop the reliability modifier.

[2] Kinectrics Inc., *Asset Depreciation Study for the Ontario Energy Board* (July 8, 2010).

Appendix A – Explanation of the Methodology

Introduction

Toronto Hydro's model is similar to Ofgem's CNAIM with minor customizations to fit Toronto Hydro's asset classes. Figure 1 illustrates the methodology, followed by additional details on the major inputs and calculations.

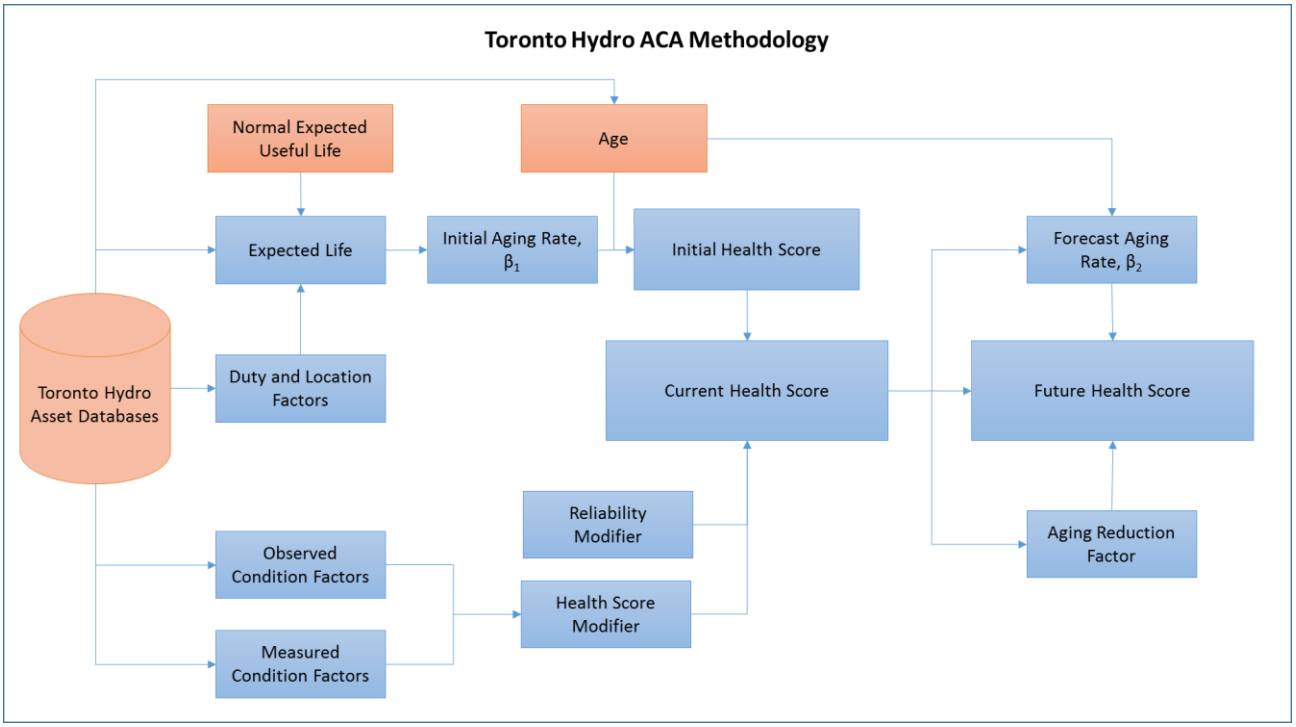


Figure A1: Flow Chart of Toronto Hydro's ACA methodology

Inputs

Inputs such as asset inspection data, nameplate details, location and duty information is provided to the ACA algorithm, from Toronto Hydro's enterprise resource planning (Ellipse) and GIS (GEAR) databases.

Normal Expected Useful Life

The *Normal Expected Useful Life* of an asset is the mid-point between the Minimum and Maximum Useful Life for the asset from the Kinectrics study and is generally aligned with current Toronto Hydro organization-wide practices.

Expected Life

The *Expected Life* of an asset is the *Normal Expected Useful Life* for the asset group adjusted to account for the asset's specific operating conditions (i.e. its environment and the way it is used) as shown in Equation 1.

Eq. 1

$$Expected\ Life = \frac{Normal\ Expected\ Useful\ life}{(Duty\ Factor * Location\ Facor)}$$

Where *Location Factor* and *Duty Factor* are as described below.

Location Factor

Location Factors account for the environmental conditions in which an asset operates. As conditions in Toronto differ from the U.K., factors used by Ofgem are not necessarily suitable for use by Toronto Hydro. Therefore, Toronto Hydro is currently working on developing the *Location Factor* condition criteria for its assets. Currently, the *Location Factor* value is defaulted to one for all assets.

Duty Factor

The *Duty Factor* is applied to account for the fact that the expected life of an asset varies depending on the way it is used, i.e. its duty. The CNAIM allows for an asset to have two different duties, but Toronto Hydro only included one *Duty Factor* based on the available inputs for its assets. Table 4 shows the basis on which *Duty Factors* are assigned for each asset category, as they are defined differently depending on the type of asset. Appendix B provides additional detail on how specific *Duty Factor* values are assigned to assets based on the variables in Table 4.

Table A1: Duty Factor Definitions by Asset Category

Asset Category	Duty Factor 1	Duty Factor 2
Overhead Gang Switches	Normally Opened/Normally Closed	N/A
SCADAMATE R2 Switches	Normally Opened/Normally Closed	N/A
Wood Poles	N/A	N/A
4kV Oil Circuit Breakers	Number of Operations	N/A
KSO Circuit Breakers	Number of Operations	N/A
SF6 Circuit Breakers	Number of Operations	N/A
Vacuum Circuit Breakers	Number of Operations	N/A
Air Magnetic Circuit Breakers	Number of Operations	N/A
Air Blast Circuit Breakers	Number of Operations	N/A
Station Power Transformers	% Utilisation	N/A
Network Transformers	% Utilisation	N/A
Network Protectors	Number of Operations	N/A
Cable Chamber	N/A	N/A
Submersible Transformers	% Utilisation	N/A
Air-Insulated Padmount Switches	N/A	N/A
Vault Transformers	% Utilisation	N/A
Padmount Transformers	% Utilisation	N/A
SF6-Insulated Padmount Switches	N/A	N/A
SF6 insulated Submersible Switches	N/A	N/A
Air Insulated Submersible Switches	N/A	N/A
Underground Vaults	N/A	N/A

Initial Aging Rate, β_1

The aging rate of an asset is modeled based on an exponential curve. The *Initial Aging Rate* is the generic rate at which an asset would be assumed to reach its *Expected Life* adjusted to account for its specific operating conditions, i.e. normalized by its *Expected Life* as shown in Equation 2.

$$\beta 1 = \frac{ln\left(\frac{H_{expected\ life}}{H_{new}}\right)}{Expected\ Life} \qquad \text{Eq. 2}$$

Where,

- H_{new} is the health score of a new asset and is equal to 0.5.
- $H_{expected}$ life is the health score of the asset when it reached expected life, which is 5.5.
- *Expected Life* is calculated based on Equation 1 above.

Initial Health Score

The *Initial Health Score* is based on a generic exponential relationship to the age and the *Initial Aging Rate* of the asset as shown in Equation 3. The *Expected Life* of the asset determines the shape of the exponential curve through the *Initial Aging Rate*. The *Initial Health Score* only considers the operating conditions and age of an asset and does not consider the current condition of the asset. Therefore, the *Initial Health Score* is capped at a value of 5.5, so that the health score is not purely dependant on age and operating conditions.

$$Initial\ Health\ Score = H_{new} * e^{(\beta_1 * age)} \quad \text{Eq. 3}$$

Where,

- H_{new} is equal to 0.5
- β_1 is the *Initial Aging Rate*
- *Age* is the current age of the asset

Current Health Score

The *Current Health Score* is determined by applying the *Health Score Modifier* and *Reliability Modifier* to the Initial Health Score. These modifiers account for the condition of the asset (*Health Score Modifier*) and any generic issues affecting the probability of failure of certain subcategories (e.g. manufacturer) of assets (*Reliability Modifier*) and are discussed in more detail below. Both modifiers include a factor that is multiplied by the *Initial Health Score* as shown in Equation 4. That product is then checked to ensure that it is within the limits set out by the other elements of the modifiers (cap and collars) according to the logic shown below. The *Current Health Score* has a scale of 0.5 to 10.

$$Current\ Health\ Score = Initial\ Health\ Score * Health\ Score\ Factor * Reliability\ Factor \quad \text{Eq. 4}$$

IF Current Health Score > Health Score Cap
THEN Current Health Score = Health Score Cap

IF Current Health Score < Max (Health Score Collar, Reliability Collar)
THEN Current Health Score= MAX (Health Score Collar, Reliability Collar)

Reliability Modifier

The *Reliability Modifier* is applied to the *Current Health Score* of an asset to account for any subcategories of assets shown to have different probabilities of failure given the same Health Score due to a generic issue that affects health and reliability with respect to the make, type, or construction of the asset. This

modifier consists of a *Reliability Factor*, which is multiplied by the *Initial Health Score* (see Equation 4), and a *Reliability Collar*, which defines the minimum value the *Current Health Score* can take.

Currently, for most assets, the *Reliability Factor* is set to a default neutral value of one and there is no *Reliability Collar* as Toronto Hydro needs to collect more information and data on asset failures to implement this modifier. The one exception is for network protectors for which there currently is sufficient information to support the use of different *Reliability Modifier* values, which are provided in Appendix B for the different network protector types (fibretop, submersible, ventilated and semi-dust).

Health Score Modifier

The *Health Score Modifier* is specific to individual assets and is based on the condition of the asset as observed or measured during routine maintenance and field inspections. The *Health Score Modifier* has three elements, including a factor and a collar which are used in the same way as the corresponding elements of the *Reliability Modifier*. It also includes a *Health Score Cap*, which is the maximum allowable value for the *Current Health Score*. As shown in Figure 2, the *Health Score Modifier* is derived from two condition modifiers (*Observed Condition Modifier* and *Measured Condition Modifier*), which also each consist of three elements (factor, cap and collar). The condition modifiers are in turn determined from observed and measured condition inputs as described in more detail below. Note that the *Health Score Modifier* for station transformers is based on three other modifiers (*Oil Test Modifier*, *Dissolved Gas Analysis ("DGA") Test Modifier* and *Furfuraldehyde Analysis ("FFA") Test Modifier*) determined from oil analyses, in addition to the *Observed* and *Measured Condition Modifiers*. This is discussed in more detail at the end of this appendix.

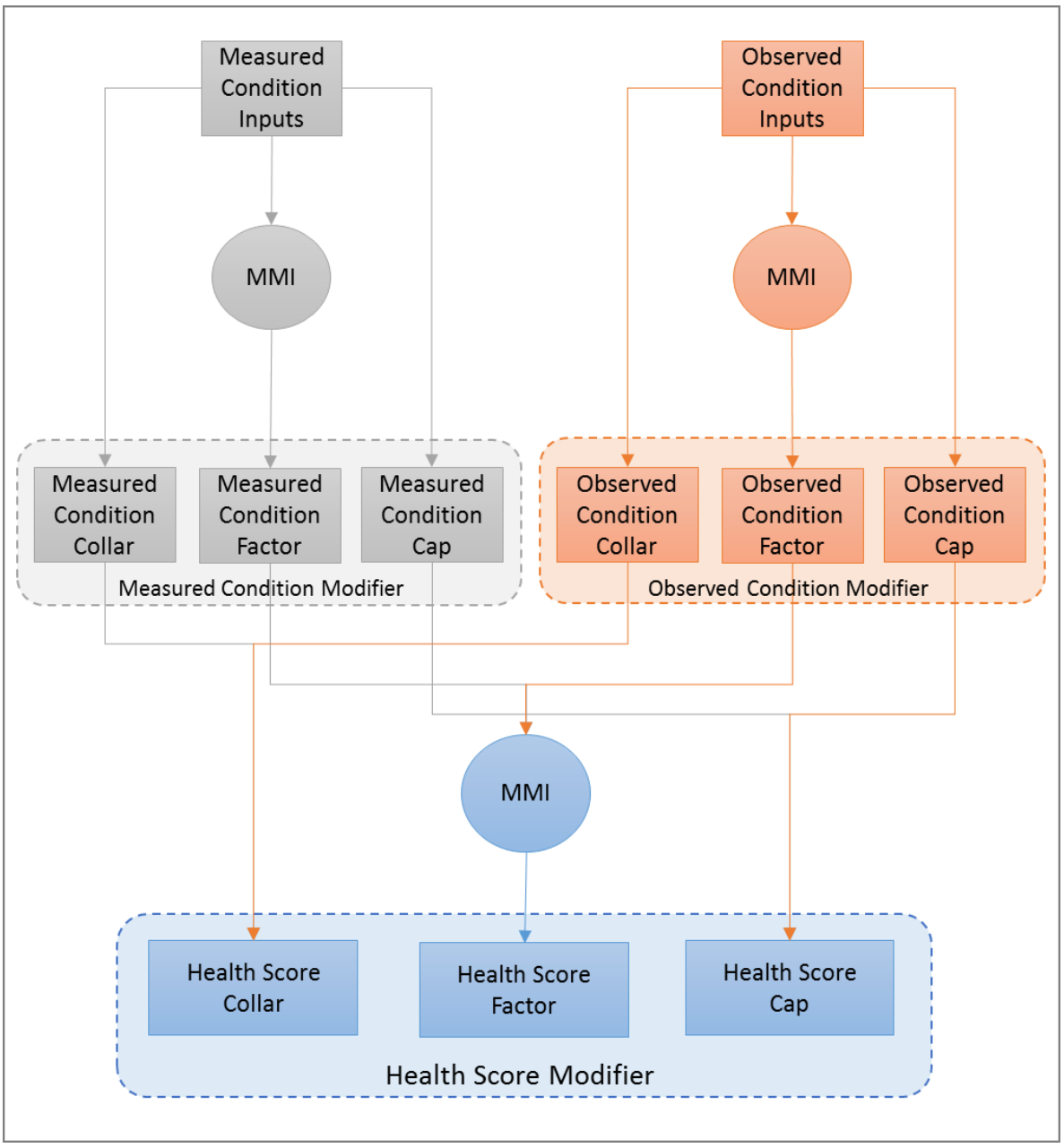


Figure A2 – Process for determining Condition Modifiers and Health Score Modifier.

The Health Score Factor is determined by combining the Observed Condition Factor and Measured Condition Factor using the Maximum and Multiple Increment ("MMI") technique (see below for details). The Health Score Collar is the maximum of the Observed and Measured Condition Collars and the Health Score Cap is the minimum of the Observed and Measured Condition Caps.

Observed Condition Modifier

The *Observed Condition Modifier* is based on observed conditions such as visual checks or function tests without measurements. It is used in combination with the *Measured Condition Modifier* to derive the *Health Score Modifier* as described above. However, in some cases, for assets that do not have any field measurements, the ACA algorithm considers only the *Observed Condition Modifier* in determining the *Health Score Modifier*.

Like, the *Health Score Modifier*, the *Observed Condition Modifier* consists of a factor, a cap, and a collar. This modifier is determined by combining all of the asset's Observed Condition Inputs, which also each consists of a factor, a cap and a collar, in the same way that the Observed and Measured Condition Modifiers are combined to determine the Health Score Modifier:

- The *Observed Condition Factor* is determined by combining all the *Observed Condition Input Factors* using the MMI Technique.
- The *Observed Condition Cap* is the minimum of all the *Observed Condition Input Caps*.
- The *Observed Condition Collar* is the maximum of all the *Observed Condition Input Collars*.

Each asset class has its own set of *Observed Condition Inputs* based on the available inspection points and impacts of observed deficiencies on the asset. *Observed Condition Inputs* are based on Toronto Hydro analysis of RCM information regarding deficiencies that lead to asset or component failure or to degraded performance. The three elements of each *Observed Condition Input* are assigned values based on the following:

- *Observed Condition Input Factor* – This is the score given to each recorded observed condition. Each condition will have a specific score based on the severity of the deficiency and how it will affect the asset.
- *Condition Input Cap* - This is the upper limit assigned to each observed deficiency. This value is usually 10, which is the upper limit for the Current Health Score.
- *Condition Input Collar* – This is the lower limit assigned to each observed deficiency. Collars are given to each condition deficiency based on how it affects the asset. The use of this collar is intended to prevent the severity of a deficiency that could lead to asset failure from being dampened by the inclusion of other conditions variables for which there is less or no degradation.

Appendix B provides details on how factors, caps and collars are assigned values for each condition of each asset class.

Measured Condition Modifier

The *Measured Condition Modifier* is used and derived in the same way as the *Observed Condition Modifier*, but the *Measured Condition Inputs* are based on measured values from maintenance activities and field inspections (e.g. from failure finding or condition monitoring tests) instead of observed conditions. Furthermore, as measured condition inputs tend to be more accurate, less subjective and better indicators of internal (as opposed to external) issues affecting assets, *Measured Condition Factors* tend to have a higher score than *Observed Condition Factors*.

Maximum and Multiple Increment (MMI) Technique

The MMI technique is used to combine two or more input factors into a single factor such that the value of the final factor is primarily driven by the strongest input factor, supplemented to a lesser and controlled degree by the other input factors (depending on their strength). The ACA methodology uses this technique to determine the *Observed Condition Factor* and *Measured Condition Factor* from multiple condition input factors and to combine the two condition factors to form the *Health Score Factor*.

The final combined factor is the sum of two variables (Var_1 and Var_2), which are based on the input factors.

$$CombinedFactor = Var_1 + Var_2 \qquad \text{Eq. 5}$$

These two variables are determined in one of two ways depending on whether any of the input factors are greater than 1.

If any input factor is greater than 1, then Var_1 is the highest of the input factors and Var_2 is calculated using the remaining highest input factors greater than 1 (up to a maximum) as shown in Equation 7 below.

$$Var_1 = F_1 \qquad \text{Eq. 6}$$

$$Var_2 = \frac{\sum_2^n (F_i - 1)}{FD_1} \qquad \text{Eq. 7}$$

Where:

- F_i represents each of the input factors greater than 1 ranked in descending order such that F_1 is the highest factor, F_2 the second highest, etc.
- n represents the maximum number of total factors contributing to the *Combined Factor* and is a calibration parameter.
- FD_1 represents a constant, *Factor Divider 1*, which specifies the degree to which additional factors are able to influence the *Combined Factor*.

If all the factors are less than or equal to 1, then Var_1 is the lowest of the input factors and Var_2 is based on the second lowest as shown in Equation 9.

$$Var_1 = F_1 \qquad \text{Eq. 8}$$

$$Var_2 = \frac{F_2 - 1}{FD_2} \qquad \text{Eq. 9}$$

Where,

- F_1 represents the lowest input factor and F_2 the second lowest.
- FD_2 represents a constant, *Factor Divider 2*, which specifies the degree to which the second input factor is able to influence the *Combined Factor*.

Forecast Aging Rate, β_2

The *Forecast Aging Rate* is used to relate the *Future Health Score* to the *Current Health Score*. It is based on the condition of the asset (through the *Current Health Score*) and the age of the asset as shown in Equation 10. The *Forecast Aging Rate* is capped at less than twice the value of the *Initial Aging Rate* (β_1) calculated using Equation 2. This is to prevent unrealistically high rates of deterioration being applied to relatively new assets where reliability issues have been identified early on in their life.

$$\beta_2 = \frac{ln\left(\frac{\text{Current Health Score}}{H_{new}}\right)}{\text{Age}} \qquad \text{Eq. 10}$$

Where,

- *Age* is current age of the asset
  Current Health Score is the value calculated for the asset using Equation 4.

Future Health Score

Like the *Initial Health Score*, the *Future Health Score* is based on an exponential equation (see Equation 11). In this case, it is based on the current condition of the asset (as reflected by *Current Health Score*) and the shape of the curve is determined by the *Forecast Aging Rate* (modified by the *Aging Reduction Factor* as discussed below). The *Future Health Score* is capped at 15.

$$Future\ Health\ Score = Current\ Health\ Score\ *\ e^{(\frac{\beta_2}{r})*t)} \qquad \text{Eq. 11}$$

Where,

- *t* is the number of years into the future for which the *Future Health Score* is to be calculated
- β_2 is the *Forecast Aging Rate* calculated using Equation 10
- *r* is the *Aging Reduction Factor* described below

Aging Reduction Factor, r

As the *Future Health Score* is modeled using an exponential curve, assets with a high *Current Health Score* may have a high *Forecast Aging Rate*. For assets reaching end of life ("EOL"), this can result in a run-away effect in the *Future Health Score*, which would not reflect the deterioration that is observed in real life.

The *Aging Reduction Factor* is introduced to reduce the potential overstatement of the *Future Health Score* by flattening the exponential curve to a degree determined by the *Current Health Score* as shown in Table 5.

Table A2: Aging Reduction Factors

Current Health Score	Aging Reduction Factor
<2	1
2 to 5.5	(Current Health Score -2)/7) + 1
>5.5	1.5

Additional Condition Modifiers for Station Power Transformers

Due to their larger size and rating compared to distribution transformers and the availability of extra information available from oil analyses, three additional modifiers are used in combination with the *Observed* and *Measured Condition Modifiers* to determine the *Health Score Modifier* for station power transformers. The *Oil Test Modifier*, *DGA Test Modifier* and *FFA Test Modifier* also each consist of a factor, cap and collar and these values are determined from oil test results in a manner similar to that used to determine the *Measured Condition Modifier* from *Measured Condition Inputs*. The cap for each of these modifiers is set to 10. Additional details on the modifiers are provided below.

Oil Test Modifier

The *Oil Test Modifier* provides additional information on the condition of a station power transformer. The *Oil Test Factor* is determined using information from moisture content, acidity and breakdown strength tests of the oil. These results are grouped into three categories based on IEEE Std. C57.106-205.

The values for the *Oil Test Factors* and *Oil Test Collars* are assigned based on these categories as detailed in Appendix B.

DGA Test Modifier

The *DGA Test Modifier* is based on the dissolved gas content of the oil. This information can be used to detect abnormal electrical or thermal activity within the asset.

Of the gases measured during DGA, only the results for hydrogen, methane, ethylene, ethane and acetylene are used to derive the *DGA Test Modifier*. The DGA results for each of these gases are classified into standard scores based on IEEE Std. C57.104-2008. The formulas used to calculate the components of the *DGA Test Modifier* as shown below are in line with the Ofgem CNAIM.

The scores for the aforementioned five gases are multiplied by values relative to the importance of the quantity of each gas measured, and summed to create a DGA Score as shown below.

$$DGA\ Score = 50Hydrogen\ Score + 30Methane\ Score + 30Ethylene\ Score + 30Ethane\ Score + 120Acetylene\ Score \quad \text{Eq. 12}$$

The *DGA Test Collar* is determined by dividing the DGA Score by 220 to get a value between 1 and 10. This will result in a minimum *Current Health Score* of at least 7 for an asset when DGA levels are indicative of severe degradation.

The *DGA Test Factor* is determined by comparing the current DGA Score with historical results for the same asset. The percentage change is calculated using the following formula:

$$\%\ Change = \frac{DGA\ Score_{latest} - DGA\ Score_{previous}}{DGA\ Score_{previous}} * 100\% \quad \text{Eq. 13}$$

The value of the percentage change is categorized into five bands (negative, neutral, small, significant or last) and factors assigned based on the percentage change as detailed in Appendix B.

FFA Test Modifier

The *FFA Test Modifier* is determined from the level of furfuraldehyde in the oil, providing an indication of the extent to which the paper insulation of the transformer windings has deteriorated.

The *FFA Test Collar* is calculated using the following empirical relationship:

$$FFA\ Test\ Collar = 2.33\ S^{0.68} \quad \text{Eq. 14}$$

Where *S* is the FFA value in ppm.

The FFA value is divided into five categories and the *FFA Test Factors* assigned based on those categories as detailed in Appendix B.

Appendix B – Duty Factor Values and Condition Factor Parameters

(i) Duty Factor Values

Table B1: Distribution Transformers

Max % Utilisation under normal operating conditions	Duty Factor
<= 50%	0.9
> 50% and <= 70%	0.95
> 70% and <= 100%	1
> 100%	1.4
Default	1

Table B2: Network Protectors

Number of operations	Duty Factor
<= 1000	0.9
> 1000 and <= 2000	0.95
> 2000 and <= 3000	1
> 3000 and <= 5000	1.3
> 5000	1.4
Default	1

Table B3: Station Power Transformers

Max % Utilisation under normal operating conditions	Duty Factor
<= 50%	1
> 50% and <= 70%	1.05
> 70% and <= 100%	1.1
> 100%	1.4
Default	1

Table B4: Station Circuit Breakers

Number of operations	Duty Factor
Normal/Low (1<10000 operations)	1
High (10000+ operations)	1.2
Default	1

Table B5: Overhead Switches

Usage	Duty Factor
Normally Open	1
Normally Closed	1.2
Default	1

(ii) Observed Condition Factors

Submersible Transformers

Table B6: Submersible Transformers – External Condition of Tank (Lid and Base)

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Deterioration	1.05	10	0.5
Poor	1.15	10	5.5
Very Poor	1.35	10	7
Default	1	10	0.5

Table B7: Submersible Transformers – Oil Leak (Base)

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Leak	1.25	10	7
Poor	1.35	10	8
Very Poor	1.5	10	9
Default	1	10	0.5

Table B8: Submersible Transformers – Connection Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As new	0.9	10	0.5
Normal Wear	1	10	0.5
Some Deterioration	1.12	10	0.5
Substantial Deterioration	1.25	10	0.5
Default	1	10	0.5

Table B9: Submersible Transformers – External Condition of Tank (Transformer Body)

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Deterioration	1.02	10	0.5
Poor	1.1	10	4
Very Poor	1.2	10	6.5
Default	1	10	0.5

Table B9: Submersible Transformers – Oil Leak (Not Base)

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Leak	1.1	10	4
Poor	1.2	10	5.5
Very Poor	1.25	10	6
Default	1	10	0.5

Vault Transformers

Table B10: Vault Transformers – External Condition of Tank (Lid and Base)

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Deterioration	1.05	10	0.5
Poor	1.15	10	5.5
Very Poor	1.35	10	7
Default	1	10	0.5

Table B11: Vault Transformers – Oil Leak (Base)

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Leak	1.25	10	6
Poor	1.35	10	7
Very Poor	1.5	10	9
Default	1	10	0.5

Table B12: Vault Transformers – Connection Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As new	0.9	10	0.5
Normal Wear	1	10	0.5
Some Deterioration	1.12	10	0.5
Substantial Deterioration	1.25	10	0.5
Default	1	10	0.5

Table B13: Vault Transformers – External Condition of Tank (Transformer Body)

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Deterioration	1.02	10	0.5
Poor	1.1	10	4
Very Poor	1.2	10	6.5
Default	1	10	0.5

Table B14: Vault Transformers – Oil Leak (Not Base)

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Leak	1.1	10	4
Poor	1.2	10	5.5
Very Poor	1.25	10	6
Default	1	10	0.5

Padmount Transformers

Table B15: Padmount Transformers – Condition of Transformer (Lid and Base)

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Deterioration	1.05	10	0.5
Poor	1.15	10	5.5
Very Poor	1.35	10	7
Default	1	10	0.5

Table B16: Padmount Transformers – Oil Leak (Base)

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Leak	1.25	10	6
Poor	1.35	10	7
Very Poor	1.5	10	9
Default	1	10	0.5

Table B17: Padmount Transformers – Condition of Transformer (Enclosure)

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Deterioration	1.05	10	0.5
Poor	1.15	10	5.5
Very Poor	1.35	10	7
Default	1	10	0.5

Table B18: Padmount Transformers – Connection Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As new	0.9	10	0.5
Normal Wear	1	10	0.5
Some Deterioration	1.12	10	0.5
Substantial Deterioration	1.25	10	0.5
Default	1	10	0.5

Table B19: Padmount Transformers – Condition of Transformer (Transformer Body)

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Deterioration	1.02	10	0.5
Poor	1.1	10	4
Very Poor	1.2	10	6.5
Default	1	10	0.5

Table B20: Padmount Transformers – Oil Leak (Not Base)

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Leak	1.1	10	4
Poor	1.2	10	5.5
Very Poor	1.25	10	6
Default	1	10	0.5

Network Transformers

Table B21: Network Transformers – External Condition of Tank (Lid and Base)

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Deterioration	1.05	10	0.5
Poor	1.15	10	5.5
Very Poor	1.35	10	7
Default	1	10	0.5

Table B22: Network Transformers – Oil Leak (Base)

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Leak	1.25	10	6
Poor	1.35	10	7
Very Poor	1.5	10	9
Default	1	10	0.5

Table B23: Network Transformers – Connection Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As new	0.9	10	0.5
Normal Wear	1	10	0.5
Some Deterioration	1.12	10	0.5
Substantial Deterioration	1.25	10	0.5
Default	1	10	0.5

Table B24: Network Transformers – External Condition of Tank (Transformer Body)

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Deterioration	1.02	10	0.5
Poor	1.1	10	4
Very Poor	1.2	10	6.5
Default	1	10	0.5

Table B25: Network Transformers – Oil Leak (Not Base)

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Leak	1.1	10	4
Poor	1.2	10	5.5
Very Poor	1.25	10	6
Default	1	10	0.5

Table B26: Network Transformers – Primary Switch Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Normal Wear	1	10	0.5
Some Deterioration	1.2	10	0.5
Substantial Deterioration	1.3	10	6.5
Default	1	10	0.5

Network Protectors

Table B27: Network Protectors – Gasket/Seal Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
Satisfactory	1	10	0.5
Not Satisfactory	1.2	10	5.5
Default	1	10	0.5

Table B28: Network Protectors – Protector External Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Deterioration	1.05	10	0.5
Poor	1.1	10	4
Very Poor	1.2	10	5.5
Default	1	10	0.5

Table B29: Network Protectors – Internal Flood Water Stains

	Condition Input Factor	Condition Input Cap	Condition Input Collar
Satisfactory	1	10	0.5
Not Satisfactory	1.3	10	6.5
Default	1	10	0.5

Table B30: Network Protectors – Protector External Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No dirt observed during inspection	1	10	0.5
Some dirt observed but cleaned during inspection	1.05	10	0.5
Substantial dirt observed, requires cleaning	1.2	10	0.5
Default	1	10	0.5

Air-Insulated Padmount Switches

Table B31: Air-Insulated Padmount Switches – Enclosure Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Deterioration	1.05	10	0.5
Poor	1.1	10	5.5
Very Poor	1.3	10	7
Default	1	10	0.5

Table B32: Air-Insulated Padmount Switches – Phase Barriers Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No	1	10	0.5
Missing/damaged	1.35	10	7
Default	1	10	0.5

Table B33: Air-Insulated Padmount Switches – Arc Suppressors Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No	1	10	0.5
Missing/damaged	1.3	10	0.5
Default	1	10	0.5

Table B34: Air-Insulated Padmount Switches – Connection Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As new	0.9	10	0.5
Normal Wear	1	10	0.5
Some Deterioration	1.05	10	0.5
Substantial Deterioration	1.2	10	0.5
Default	1	10	0.5

Table B35: Air-Insulated Padmount Switches – Switch Blade Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No	1	10	0.5
Missing/damaged	1.4	10	8
Default	1	10	0.5

SF6-Insulated Padmount Switches

Table B36: SF6-Insulated Padmount Switches – Enclosure Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Deterioration	1.05	10	0.5
Poor	1.1	10	5.5
Very Poor	1.3	10	7
Default	1	10	0.5

Table B37: SF6-Insulated Padmount Switches – Gas Leak

	Condition Input Factor	Condition Input Cap	Condition Input Collar
Gas Pressure Gauge Color: Green	1	10	0.5
Gas Pressure Gauge Color: Red	1.4	10	8
Default	1	10	0.5

Table B38: SF6-Insulated Padmount Switches – Connection Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Normal Wear	1	10	0.5
Some Deterioration	1.05	10	0.5
Substantial Deterioration	1.2	10	0.5
Default	1	10	0.5

Air-Insulated Submersible Switches

Table B39: Air-Insulated Submersible Switches – External Condition of Switch

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Deterioration	1.05	10	0.5
Poor	1.1	10	5.5
Very Poor	1.3	10	7
Default	1	10	0.5

Table B40: Air-Insulated Submersible Switches – Phase Barrier Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No	1	10	0.5
Missing/damaged	1.35	10	7
Default	1	10	0.5

Table B41: Air-Insulated Submersible Switches – Connection Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As new	0.9	10	0.5
Normal Wear	1	10	0.5
Some Deterioration	1.05	10	0.5
Substantial Deterioration	1.2	10	0.5
Default	1	10	0.5

Table B42: Air-Insulated Submersible Switches – Internal Flood Water Stains

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No	1	10	0.5
Missing/damaged	1.3	10	6.5
Default	1	10	0.5

SF6-Insulated Submersible Switches

Table B43: SF6-Insulated Submersible Switches – Enclosure Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Deterioration	1.05	10	0.5
Poor	1.1	10	5.5
Very Poor	1.3	10	7
Default	1	10	0.5

Table B44: SF6-Insulated Submersible Switches – Gas Leak

	Condition Input Factor	Condition Input Cap	Condition Input Collar
Gas Pressure Gauge Color: Green	1	10	0.5
Gas Pressure Gauge Color: Red	1.4	10	8
Default	1	10	0.5

Table B45: SF6-Insulated Submersible Switches – Connection Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Normal Wear	1	10	0.5
Some Deterioration	1.05	10	0.5
Substantial Deterioration	1.2	10	0.5
Default	1	10	0.5

Wood Poles

Table B46: Wood Poles – Pole Leaning

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No Lean	1	10	0.5
Slight Lean	1.01	10	0.5
Moderate Lean	1.05	10	0.5
Extensive Lean	1.1	10	4
Default	1	10	0.5

Table B47: Wood Poles – Pole Base Rot

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No Pole Base Rot	1	10	0.5
Slight Pole Base Rot	1.1	10	0.5
Moderate Pole Base Rot	1.15	10	4
Extensive Pole Base Rot	1.2	10	6
Default	1	10	0.5

Table B48: Wood Poles – Pole Void

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No Pole Void	1	10	0.5
Slight Pole Void	1.1	10	0.5
Moderate Pole Void	1.15	10	4
Extensive Pole Void	1.2	10	6
Default	1	10	0.5

Table B49: Wood Poles – Bird/Animal Damage

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No Animal Damage	1	10	0.5
Slight Animal Damage	1.05	10	0.5
Moderate Animal Damage	1.1	10	4
Extensive Animal Damage	1.15	10	5.5
Default	1	10	0.5

Table B50: Wood Poles – Pole Separation

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No Pole Separation	1	10	0.5
Slight Pole Separation	1.1	10	0.5
Moderate Pole Separation	1.15	10	4
Extensive Pole Separation	1.2	10	6
Default	1	10	0.5

Station Power Transformers

Table B51: Station Power Transformers – Oil Leak (Base)

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Leak	1.25	10	0.5
Poor	1.35	10	7
Very Poor	1.5	10	9
Default	1	10	0.5

Table B52: Station Power Transformers – Oil Leak (Not Base)

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Leak	1.1	10	0.5
Poor	1.2	10	6
Very Poor	1.25	10	7
Default	1	10	0.5

Overhead Gang-Operated Switches

Table B53: Overhead Gang-Operated Switches – Interphase Operator Link

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.3	4	10
Substantial Deterioration	1.5	8	10
Default	1	0.5	10

Table B54: Overhead Gang-Operated Switches – Operation Handle

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some deterioration	1.3	4	10
Substantial deterioration	1.5	8	10
Default	1	0.5	10

Table B55: Overhead Gang-Operated Switches – Insulator

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.3	4	10
Substantial Deterioration	1.5	8	10
Default	1	0.5	10

Table B56: Overhead Gang-Operated Switches – Stationary Contacts

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.3	4	10
Substantial Deterioration	1.5	8	10
Default	1	0.5	10

Table B57: Overhead Gang-Operated Switches – Switch Blade

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.3	4	10
Substantial Deterioration	1.5	8	10
Default	1	0.5	10

Table B58: Overhead Gang-Operated Switches – Switch Base Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.3	4	10
Substantial Deterioration	1.5	8	10
Default	1	0.5	10

Table B59: Overhead Gang-Operated Switches – Arc Interrupters

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.3	4	10
Substantial Deterioration	1.5	8	10
Default	1	0.5	10

Table B60: Overhead Gang-Operated Switches – Connection

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	0.5	10
Substantial Deterioration	1.25	8	10
Default	1	0.5	10

Table B61: Overhead Gang-Operated Switches – Ground Connection

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	0.5	10
Substantial Deterioration	1.25	8	10
Default	1	0.5	10

Table B62: Overhead Gang-Operated Switches – Corrosion

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Low Corrosion	1.05	0.5	10
Medium Corrosion	1.25	5.5	10
High Corrosion	1.5	8	10
Default	1	0.5	10

SCADA-Mate R2 Switches

Table B63: SCADA-Mate R2 Switches – Insulator

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.2	0.5	10
Partially repaired, follow up required	1.8	8	10
Substantial Deterioration	1.9	8	10
Default	1	0.5	10

Table B64: SCADA-Mate R2 Switches – Switch Operation Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.5	0.5	10
Partially repaired, follow up required	1.7	8	10
Substantial Deterioration	1.8	8	10
Default	1	0.5	10

Table B65: SCADA-Mate R2 Switches – Remote Operation Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.35	0.5	10
Partially repaired, follow up required	1.75	8	10
Substantial Deterioration	1.85	8	10
Default	1	0.5	10

Table B66: SCADA-Mate R2 Switches – Ground Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1	0.5	10
Partially repaired, follow up required	1.25	0.5	10
Substantial Deterioration	1.45	0.5	10
Default	1	0.5	10

Table B67: SCADA-Mate R2 Switches – Switch Mounting Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1	0.5	10
Partially repaired, follow up required	1.65	8	10
Substantial Deterioration	1.75	8	10
Default	1	0.5	10

Table B68: SCADA-Mate R2 Switches – Corrosion

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Normal Wear	1.15	0.5	10
Low Corrosion	1.45	2.5	10
Medium Corrosion	1.5	5.5	10
High Corrosion	1.6	8	10
Default	1	0.5	10

4kV Oil Circuit Breakers

Table B69: 4kV Oil Circuit Breakers – Arc Extinguishing Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.15	0.5	10
Substantial Deterioration	1.25	5.5	10
Default	1	0.5	10

Table B70: 4kV Oil Circuit Breakers – Primary Contact Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.15	0.5	10
Substantial Deterioration	1.25	5.5	10
Default	1	0.5	10

Table B71: 4kV Oil Circuit Breakers – Arcing Contact Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.15	0.5	10
Substantial Deterioration	1.25	5.5	10
Default	1	0.5	10

Table B72: 4kV Oil Circuit Breakers – Breaker Mechanical Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.25	0.5	10
Substantial Deterioration	1.4	8	10
Default	1	0.5	10

Table B73: 4kV Oil Circuit Breakers – Oil Tank Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.25	0.5	10
Substantial Deterioration	1.4	8	10
Default	1	0.5	10

Table B74: 4kV Oil Circuit Breakers – Trip Mechanism Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.15	0.5	10
Substantial Deterioration	1.3	8	10
Default	1	0.5	10

Table B75: 4kV Oil Circuit Breakers – Charging Mechanism Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.15	0.5	10
Substantial Deterioration	1.3	8	10
Default	1	0.5	10

Table B76: 4kV Oil Circuit Breakers – Closing Mechanism Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.05	0.5	10
Substantial Deterioration	1.2	5.5	10
Default	1	0.5	10

Table B77: 4kV Oil Circuit Breakers – Anti-Pump Operation Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.05	0.5	10
Substantial Deterioration	1.2	5.5	10
Default	1	0.5	10

Table B78: 4kV Oil Circuit Breakers – Corrosion

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Normal Wear	1.05	0.5	10
Low Corrosion	1.1	4	10
Medium Corrosion	1.15	5.5	10
High Corrosion	1.35	8	10
Default	1	0.5	10

KSO Oil Circuit Breakers

Table B79: KSO Oil Circuit Breakers – Arc Extinguishing Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	4	10
Substantial Deterioration	1.15	5.5	10
Default	1	0.5	10

Table B80: KSO Oil Circuit Breakers – Primary Contact Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	4	10
Substantial Deterioration	1.15	5.5	10
Default	1	0.5	10

Table B81: KSO Oil Circuit Breakers – Arcing Contact Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	4	10
Substantial Deterioration	1.15	5.5	10
Default	1	0.5	10

Table B82: KSO Oil Circuit Breakers – Breaker Mechanical Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.25	4	10
Substantial Deterioration	1.3	8	10
Default	1	0.5	10

Table B83: KSO Oil Circuit Breakers – Oil Tank Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.25	4	10
Substantial Deterioration	1.3	8	10
Default	1	0.5	10

Table B84: KSO Oil Circuit Breakers – Oil Condition Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.25	4	10
Substantial Deterioration	1.3	8	10
Default	1	0.5	10

Table B85: KSO Oil Circuit Breakers – Trip Mechanism Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.15	4	10
Substantial Deterioration	1.2	6.5	10
Default	1	0.5	10

Table B86: KSO Oil Circuit Breakers – Charging Mechanism Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.15	4	10
Substantial Deterioration	1.2	6.5	10
Default	1	0.5	10

Table B87: KSO Oil Circuit Breakers – Closing Mechanism Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.05	4	10
Substantial Deterioration	1.1	5.5	10
Default	1	0.5	10

Table B88: KSO Oil Circuit Breakers – Anti-Pump Operation Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.05	4	10
Substantial Deterioration	1.1	5.5	10
Default	1	0.5	10

Table B89: KSO Oil Circuit Breakers – Corrosion

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Normal Wear	1.1	0.5	10
Low Corrosion	1.15	5.5	10
Medium Corrosion	1.25	6	10
High Corrosion	1.35	8	10
Default	1	0.5	10

Vacuum Circuit Breakers

Table B90: Vacuum Circuit Breakers – Breaker Mechanical Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.25	4	10
Substantial Deterioration	1.9	8	10
Default	1	0.5	10

Table B91: Vacuum Circuit Breakers – Trip Mechanism Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.2	0.5	10
Substantial Deterioration	1.75	6.5	10
Default	1	0.5	10

Table B92: Vacuum Circuit Breakers – Charging Mechanism Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.2	0.5	10
Substantial Deterioration	1.75	6.5	10
Default	1	0.5	10

Table B93: Vacuum Circuit Breakers – Closing Mechanism Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	4	10
Substantial Deterioration	1.55	5.5	10
Default	1	0.5	10

Table B94: Vacuum Circuit Breakers – Anti-Pump Operation Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	4	10
Substantial Deterioration	1.55	5.5	10
Default	1	0.5	10

Table B95: Vacuum Circuit Breakers – Corrosion

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Normal Wear	1	0.5	10
Low Corrosion	1	0.5	10
Medium Corrosion	1.15	2.5	10
High Corrosion	1.2	4	10
Default	1	0.5	10

Air Magnetic Circuit Breakers

Table B96: Air Magnetic Circuit Breakers – Arc Extinguishing Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.5	4	10
Substantial Deterioration	1.8	6.5	10
Default	1	0.5	10

Table B97: Air Magnetic Circuit Breakers – Primary Contact Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.5	4	10
Substantial Deterioration	1.8	6.5	10
Default	1	0.5	10

Table B98: Air Magnetic Circuit Breakers – Arcing Contact Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.5	4	10
Substantial Deterioration	1.8	6.5	10
Default	1	0.5	10

Table B99: Air Magnetic Circuit Breakers – Breaker Mechanical Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.6	4	10
Substantial Deterioration	1.9	8	10
Default	1	0.5	10

Table B100: Air Magnetic Circuit Breakers – Trip Mechanism Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.4	4	10
Substantial Deterioration	1.7	6.5	10
Default	1	0.5	10

Table B101: Air Magnetic Circuit Breakers – Charging Mechanism Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.4	4	10
Substantial Deterioration	1.7	6.5	10
Default	1	0.5	10

Table B102: Air Magnetic Circuit Breakers – Closing Mechanism Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.05	4	10
Substantial Deterioration	1.55	5.5	10
Default	1	0.5	10

Table B103: Air Magnetic Circuit Breakers – Anti-Pump Operation Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.05	4	10
Substantial Deterioration	1.55	5.5	10
Default	1	0.5	10

Table B104: Air Magnetic Circuit Breakers – Corrosion

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Normal Wear	1.1	0.5	10
Low Corrosion	1.2	0.5	10
Medium Corrosion	1.25	4	10
High Corrosion	1.3	5.5	10
Default	1	0.5	10

Airblast Circuit Breakers

Table B105: Airblast Circuit Breakers – Arc Extinguishing Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.05	4	10
Substantial Deterioration	1.4	6.5	10
Default	1	0.5	10

Table B106: Airblast Circuit Breakers – Primary Contact Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.05	4	10
Substantial Deterioration	1.4	6.5	10
Default	1	0.5	10

Table B107: Airblast Circuit Breakers – Arcing Contact Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.05	4	10
Substantial Deterioration	1.4	6.5	10
Default	1	0.5	10

Table B108: Airblast Circuit Breakers – Pressure Relief Valve Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.05	4	10
Substantial Deterioration	1.4	6.5	10
Default	1	0.5	10

Table B109: Airblast Circuit Breakers – Breaker Mechanical Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	4	10
Substantial Deterioration	1.5	8	10
Default	1	0.5	10

Table B110: Airblast Circuit Breakers – Trip Mechanism Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.05	4	10
Substantial Deterioration	1.35	6.5	10
Default	1	0.5	10

Table B111: Airblast Circuit Breakers – Closing Mechanism Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.05	4	10
Substantial Deterioration	1.3	5.5	10
Default	1	0.5	10

Table B112: Airblast Circuit Breakers – Anti-Pump Operation Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.05	4	10
Substantial Deterioration	1.3	5.5	10
Default	1	0.5	10

Table B113: Airblast Circuit Breakers – Corrosion

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Normal Wear	1	0.5	10
Low Corrosion	1	0.5	10
Medium Corrosion	1.15	4	10
High Corrosion	1.25	5.5	10
Default	1	0.5	10

SF6 Circuit Breakers

Table B114: SF6 Circuit Breakers – Breaker Mechanical Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.2	4	10
Substantial Deterioration	1.8	8	10
Default	1	0.5	10

Table B115: SF6 Circuit Breakers – SF6 Gas Quality

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.2	4	10
Substantial Deterioration	1.8	8	10
Default	1	0.5	10

Table B116: SF6 Circuit Breakers – SF6 Gas Leaks Detected

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.2	4	10
Substantial Deterioration	1.8	8	10
Default	1	0.5	10

Table B117: SF6 Circuit Breakers – SF6 Control Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.2	4	10
Substantial Deterioration	1.8	8	10
Default	1	0.5	10

Table B118: SF6 Circuit Breakers – Trip Mechanism Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.15	4	10
Substantial Deterioration	1.7	6.5	10
Default	1	0.5	10

Table B119: SF6 Circuit Breakers – Charging Mechanism Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.15	4	10
Substantial Deterioration	1.7	6.5	10
Default	1	0.5	10

Table B120: SF6 Circuit Breakers – Closing Mechanism Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	4	10
Substantial Deterioration	1.55	5.5	10
Default	1	0.5	10

Table B121: SF6 Circuit Breakers – Anti-Pump Operation Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	4	10
Substantial Deterioration	1.55	5.5	10
Default	1	0.5	10

Table B122: SF6 Circuit Breakers – Corrosion

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Normal Wear	1.1	0.5	10
Low Corrosion	1.15	5.5	10
Medium Corrosion	1.25	6.5	10
High Corrosion	1.35	8	10
Default	1	0.5	10

Cable Chambers

Table B123: Cable Chambers – Walls

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.3	0.5	10
Substantial Deterioration	1.5	8	10
Default	1	0.5	10

Table B124: Cable Chambers – Floor

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.3	0.5	10
Substantial Deterioration	1.5	8	10
Default	1	0.5	10

Table B125: Cable Chambers – Roof/Slabs

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.3	0.5	10
Substantial Deterioration	1.5	8	10
Default	1	0.5	10

Table B126: Cable Chambers – Lid/Cover

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.2	0.5	10
Substantial Deterioration	1.4	6.5	10
Default	1	0.5	10

Table B127: Cable Chambers – Cable Racking

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	0.5	10
Substantial Deterioration	1.3	5.5	10
Default	1	0.5	10

Table B128: Cable Chambers – Ducts

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	0.5	10
Substantial Deterioration	1.3	5.5	10
Default	1	0.5	10

Table B129: Cable Chambers – Working Space

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	0.5	10
Substantial Deterioration	1.3	5.5	10
Default	1	0.5	10

Table B130: Cable Chambers – Drain

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	0.5	10
Substantial Deterioration	1.3	0.5	10
Default	1	0.5	10

Table B131: Cable Chambers – Flooding

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	0.5	10
Substantial Deterioration	1.3	0.5	10
Default	1	0.5	10

Table B132: Cable Chambers – Sump Pump

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	0.5	10
Substantial Deterioration	1.3	0.5	10
Default	1	0.5	10

Underground Vaults

Table B133: Underground Vaults – Structure Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	10	0.5
Good	1.1	10	0.5
Slight Deterioration	1.2	10	4
Poor	1.3	10	5.5
Very Poor	1.5	10	8
Default	1	10	0.5

Table B133: Underground Vaults – Hatchway Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	10	0.5
Some Deterioration	1.1	10	0.5
Substantial Deterioration	1.3	10	0.5
Default	1	10	0.5

Table B134: Underground Vaults – Ducts

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.8	10	0.5
Some Deterioration	1	10	0.5
Substantial Deterioration	1.1	10	0.5
Default	1	10	0.5

Table B135: Underground Vaults – Flooding

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	10	0.5
Some Deterioration	1.05	10	0.5
Substantial Deterioration	1.2	10	0.5
Default	1	10	0.5

(iii) Measured Condition Factors

Padmount Switches

Table B135: Padmount Transformers – Partial Discharge

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No Partial Discharge	1	10	0.5
Low	1.1	10	0.5
Medium	1.3	10	5.5
High (Not Confirmed)	1.5	10	8
Default	1	10	0.5

Table B136: Padmount Transformers – Temperature Readings

	Condition Input Factor	Condition Input Cap	Condition Input Collar
≤ 55	1	10	0.5
> 55 - ≤ 80	1.1	10	0.5
> 80 - ≤ 95	1.2	10	0.5
> 95 - ≤ 105	1.3	10	0.5
> 105	1.4	10	5.5
Default	1	10	0.5

Network Transformers

Table B137: Network Transformers – Partial Discharge

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No Partial Discharge	1	10	0.5
Low	1.1	10	0.5
Medium	1.3	10	5.5
High (Not Confirmed)	1.5	10	8
Default	1	10	0.5

Table B138: Network Transformers – Temperature Readings

	Condition Input Factor	Condition Input Cap	Condition Input Collar
≤ 55	1	10	0.5
> 55 - ≤ 80	1.1	10	0.5
> 80 - ≤ 95	1.2	10	0.5
> 95 - ≤ 105	1.3	10	0.5
> 105	1.4	10	5.5
Default	1	10	0.5

Network Protectors

Table B139: Network Protectors – Tripping Test Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
Acceptable	1	10	0.5
Unacceptable	1.3	10	0.5
Default	1	10	0.5

Table B140: Network Protectors – Closing Test Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
Acceptable	1	10	0.5
Unacceptable	1.2	10	0.5
Default	1	10	0.5

4kV Oil Circuit Breakers

Table B141: 4kV Oil Circuit Breakers – Contact Resistance Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.15	0.5	10
Substantial Deterioration	1.25	5.5	10
Default	1	0.5	10

Table B142: 4kV Oil Circuit Breakers – Insulation Resistance Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.25	8	10
Substantial Deterioration	1.4	8	10
Default	1	0.5	10

KSO Oil Circuit Breakers

Table B143: KSO Oil Circuit Breakers – Contact Resistance Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	4	10
Substantial Deterioration	1.15	5.5	10
Default	1	0.5	10

Table B144: KSO Oil Circuit Breakers – Insulation Resistance Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.25	8	10
Substantial Deterioration	1.3	8	10
Default	1	0.5	10

Vacuum Circuit Breakers

Table B145: Vacuum Circuit Breakers – Contact Resistance Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.2	6.5	10
Substantial Deterioration	1.8	6.5	10
Default	1	0.5	10

Table B146: Vacuum Circuit Breakers – Insulation Resistance Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.5	8	10
Substantial Deterioration	1.9	8	10
Default	1	0.5	10

Table B147: Vacuum Circuit Breakers – Dielectric Withstand Test

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.5	8	10
Substantial Deterioration	1.9	8	10
Default	1	0.5	10

Air Magnetic Circuit Breakers

Table B148: Air Magnetic Circuit Breakers – Contact Resistance Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.2	4	10
Substantial Deterioration	1.8	6.5	10
Default	1	0.5	10

Table B149: Air Magnetic Circuit Breakers – Insulation Resistance Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.5	0.5	10
Substantial Deterioration	1.9	8	10
Default	1	0.5	10

Airblast Circuit Breakers

Table B150: Airblast Circuit Breakers – Contact Resistance Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.2	0.5	10
Substantial Deterioration	1.8	6.5	10
Default	1	0.5	10

Table B151: Airblast Circuit Breakers – Insulation Resistance Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.5	0.5	10
Substantial Deterioration	1.9	8	10
Default	1	0.5	10

SF6 Circuit Breakers

Table B152: SF6 Circuit Breakers – Contact Resistance Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.2	0.5	10
Substantial Deterioration	1.8	6.5	10
Default	1	0.5	10

Table B153: SF6 Circuit Breakers – Insulation Resistance Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.5	0.5	10
Substantial Deterioration	1.9	8	10
Default	1	0.5	10

Air-Insulated Padmount Switches

Table B154: Air-Insulated Padmount Switches – Partial Discharge

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No Partial Discharge	1	10	0.5
Low	1.1	10	0.5
Medium	1.3	10	5.5
High (Not Confirmed)	1.5	10	8
Default	1	10	0.5

Table B155: Air-Insulated Padmount Switches – Hot Spots Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No Hotspot Detected	1	10	0.5
Low - Class C (< 30°C)	1.1	10	0.5
Medium - Class B (30°C - 50°C)	1.2	10	0.5
High - Class A (> 50°C)	1.3	10	7
Default	1	10	0.5

SF6-Insulated Padmount Switches

Table B156: SF6-Insulated Padmount Switches – Partial Discharge

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No Partial Discharge	1	10	0.5
Low	1.1	10	0.5
Medium	1.3	10	5.5
High (Not Confirmed)	1.5	10	8
Default	1	10	0.5

Table B157: SF6-Insulated Padmount Switches – Hot Spots Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No Hotspot Detected	1	10	0.5
Low - Class C (< 30°C)	1.1	10	0.5
Medium - Class B (30°C - 50°C)	1.2	10	0.5
High - Class A (> 50°C)	1.3	10	7
Default	1	10	0.5

Air-Insulated Submersible Switches

Table B158: Air-Insulated Submersible Switches – Hot Spots Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No Hotspot Detected	1	10	0.5
Low - Class C (< 30°C)	1.1	10	0.5
Medium - Class B (30°C - 50°C)	1.2	10	0.5
High - Class A (> 50°C)	1.3	10	7
Default	1	10	0.5

SF6-Insulated Submersible Switches

Table B159: SF6-Insulated Submersible Switches – Hot Spots Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No Hotspot Detected	1	10	0.5
Low - Class C (< 30°C)	1.1	10	0.5
Medium - Class B (30°C - 50°C)	1.2	10	0.5
High - Class A (> 50°C)	1.3	10	7
Default	1	10	0.5

Wood Poles

Table B160: Wood Poles – Pole % Strength

	Condition Input Factor	Condition Input Cap	Condition Input Collar
≥90%	0.8	10	0.5
80% - 89%	1	10	0.5
67% - 79%	1.05	10	0.5
50% - 66%	1.3	10	5.5
<50%	1.4	10	8
Default	1	10	0.5

Table B161: Wood Poles – Shell Thickness

	Condition Input Factor	Condition Input Cap	Condition Input Collar
Acceptable - ≥ 3 inches	1	10	0.5
Unacceptable - < 3 inches	1.3	10	7
Default	1	10	0.5

(iv) FFA Test Input

Table B162: Station Power Transformers – FFA Test Factor

> FFA Value (ppm)	<= FFA Value (ppm)	FFA Test Factor
-0.01	4	1
4	5	1.1
5	6	1.25
6	7	1.4
7	-	1.6

(v) Oil Test Input

Table B163: Station Power Transformers – Oil Test Factor

Class	Description	Oil Test Factor	Oil Test Collar	Oil Test Cap
Class I	Mineral Oil is in satisfactory condition for continued use.	1	0.5	10
Class II	Mineral Oil does not meet the dielectric breakdown voltage and/or water content requirement.	1.05	0.5	10
Class III	Mineral Oil in poor condition that do not meet the limits.	1.1	3	10

Table B164: Station Power Transformers – Suggested Limits, IEEE Std. C57.106-2015 (Table 3)

Test	Limits
Dielectric breakdown voltage (kV)	> 23
Neutralization number (acidity)(mg KOH/g)	< 20
Water Content mg/kg (ppm)	< 35

(vi) DGA Test Input

Table B165: Station Power Transformers – Hydrogen Condition State Calibration

> Hydrogen (ppm)	<= Hydrogen (ppm)	Hydrogen Condition State
-	100	0
100	700	2
700	1800	4
1800	-	10

Table B166: Station Power Transformers – Methane Condition State Calibration

> Methane (ppm)	<= Methane (ppm)	Methane Condition State
-	120	0
120	400	2
400	1000	4
1000	-	10

Table B167: Station Power Transformers – Acetylene Condition State Calibration

> Acetylene (ppm)	<= Acetylene (ppm)	Acetylene Condition State
-	1	0
1	9	2
9	35	4
35	-	8

Table B168: Station Power Transformers – Ethylene Condition State Calibration

> Ethylene (ppm)	<= Ethylene (ppm)	Ethylene Condition State
-	50	0
50	100	2
100	200	4
200	-	10

Table B169: Station Power Transformers – Ethane Condition State Calibration

> Ethane (ppm)	<= Ethane (ppm)	Hydrogen Condition State
-	65	0
65	100	2
100	150	4
150	-	10

Table B170: Station Power Transformers – DGA Change Category

> % Change	<= % Change	Change Category	DGA Test Factor
-1000	-5	Negative	0.9
-5	5	Neutral	1
5	25	Small	1.1
25	100	Significant	1.2
100	1000	Large	1.4

(vii) Reliability Modifiers

Table B170: Network Protectors – Protector Enclosure Type Reliability Modifiers

Enclosure Type	Reliability Factor	Reliability Collar
Fibertop	1.4	7
Ventilated	1.25	4
Semi-Dust	1.1	0.5
Submersible	1	0.5

Appendix C – Current and Future Health Score Tables

Table C1: Current Health Score Distribution by Asset Class

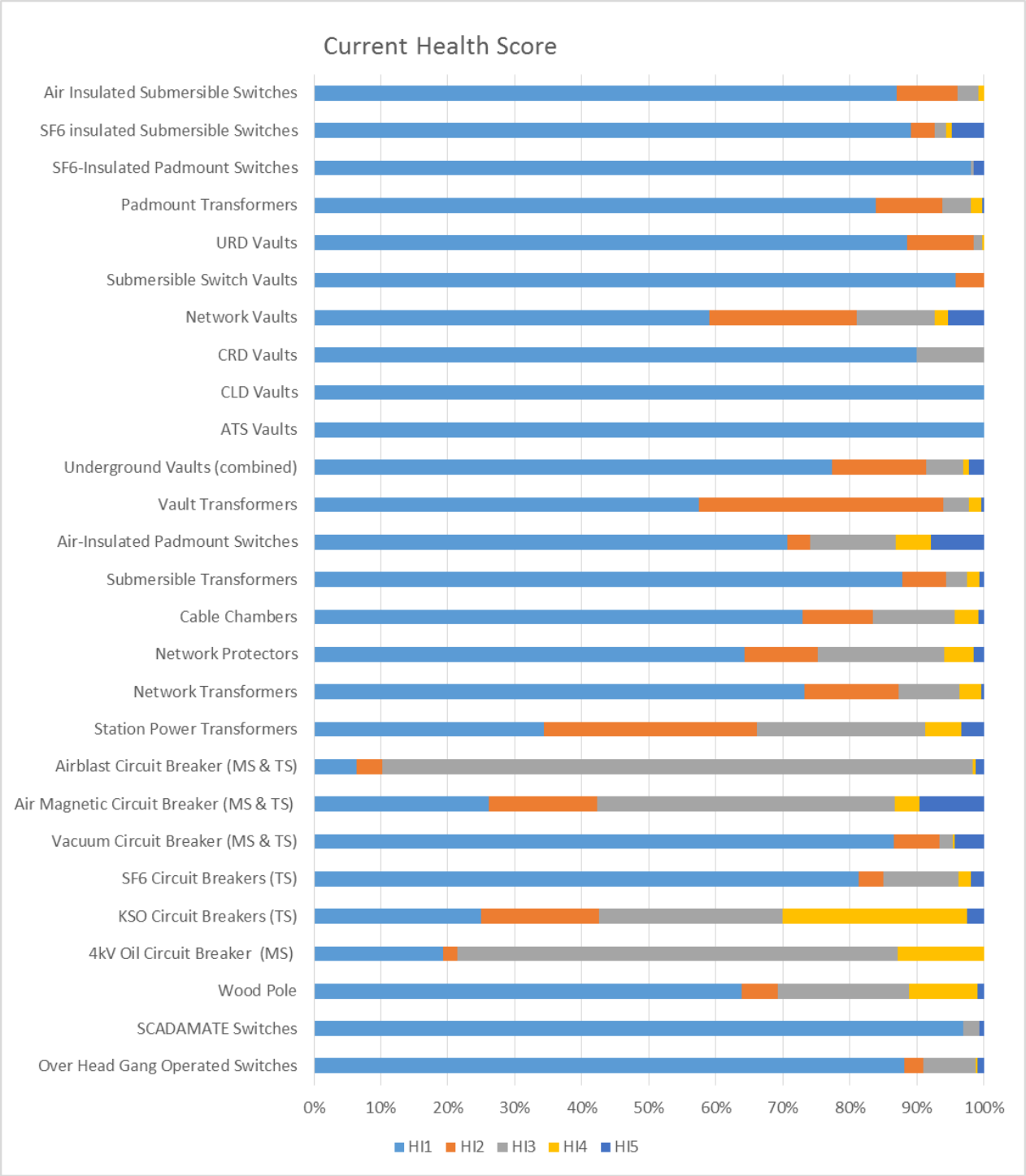
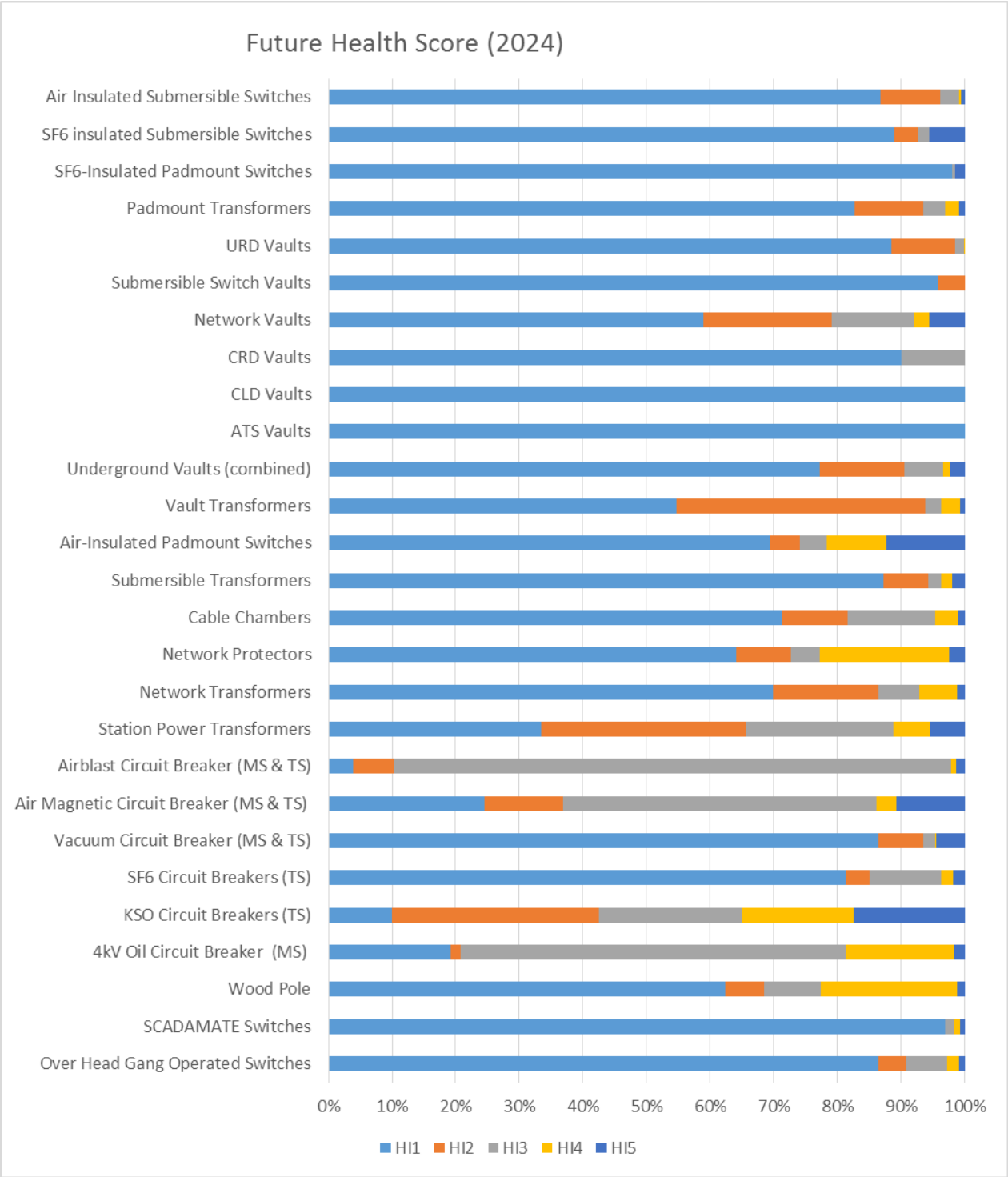


Table C2: Future Health Score 2024 Distribution by Asset Class



Toronto Hydro-Electric System Limited
EB-2018-0165
Exhibit 2B
Section D
Appendix D
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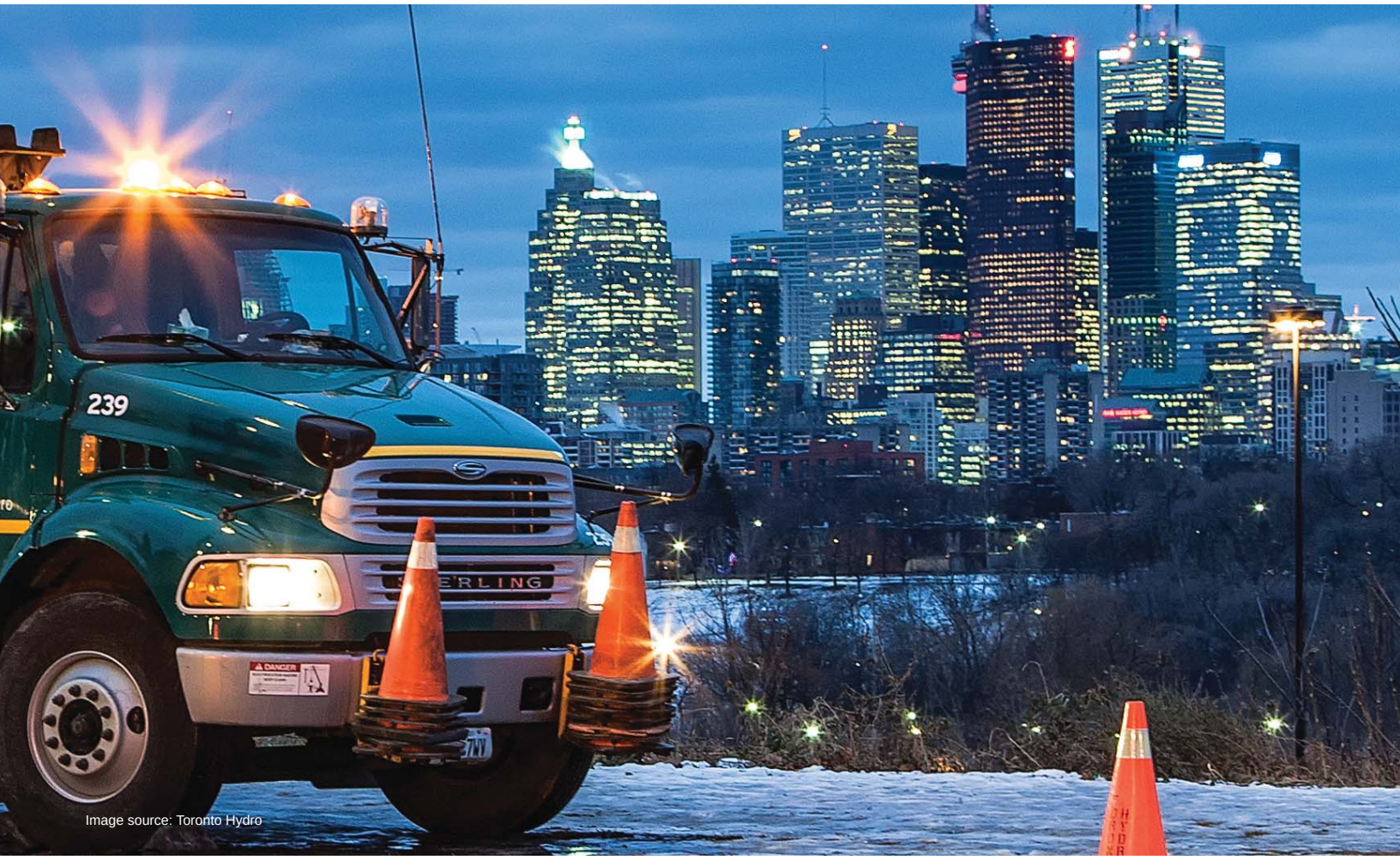
(204 pages)

Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment

June 2015



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Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment

Application of the Public Infrastructure Engineering Vulnerability Assessment Protocol to Electrical Distribution Infrastructure

Final Report - Public

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June 2015

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Executive Summary

The current study aims to evaluate the vulnerability of Toronto Hydro's electrical distribution system within the City of Toronto to a changing climate by employing Engineers Canada's Public Infrastructure Engineering Vulnerability Assessment Protocol (PIEVC Protocol). This study is a high level screening analysis designed to determine where infrastructure vulnerabilities to climate change may be present, to suggest avenues for adapting infrastructure to climate change, and to identify areas of further study.

Electrical Distribution System under Study

Toronto Hydro distributes electricity across the City of Toronto, Canada's largest city and home to approximately 2.8 million people in 2014. Toronto Hydro serves approximately 740,000 customers in the City of Toronto and owns approximately $3 billion dollars in assets, including over 170 transformer stations, approximately 29,000 km of overhead and underground wires, 20,000+ switches, 60,000+ transformers and 176,000+ poles.

The study period of this assessment was 2015 to 2050. A "system" level approach was employed to assess the impacts of climate change on the various parts of the electrical distribution system. This approach divided the distribution system into six major asset categories: stations, feeders, communications systems, civil structures, auxiliary mechanical systems and human resources. Asset categories were assessed based on their general characteristics (e.g. typical, representative or common electrical or mechanical configurations, standards, equipment). For example, this analysis focused on how systems designed to current (post 2000) CSA standards may interact with the climate parameters being considered. Changes to the electrical system considered in this assessment included the planned transition from rear lot to front lot power lines, the partial phase out of 4.16 kV system, some demand and supply projections[1], and replacement of non-submersible equipment. The streetlighting system and systems serving the Toronto Transit Commission (TTC) were not within the scope of this study.

Toronto Hydro documentation, electrical standards and consultations with Toronto Hydro staff (through ongoing communications and two workshops) were all used to help identify and describe asset categories, general characteristics and sensitivities to climate related stresses (climate parameters[2]).

Climate Parameters

20 climate parameters including high temperature, heavy rainfall, snowfall, freezing rain, high winds and lightning were considered in this assessment. Relevant climate parameters and threshold values at which infrastructure performance would be affected were identified through a literature review, consultations with Toronto Hydro staff and analysis of past outage events.

The probability of a climate parameter occurring during the study period was determined using global climate modelling (GCM) data obtained from the Intergovernmental Panel on Climate Change's 5th Assessment Report (IPCC AR5). In many cases, this information was validated or refined through the use of regional climate modelling data, statistical downscaling and climate analogues.

The probability of a climate parameter occurring is expressed both as a study period probability value (i.e. what is the probability of a climate parameter occurring sometime between 2015 – 2050) and an annual probability value centred around the 2030's and 2050's (i.e. what is the annual probability of a climate parameter occurring around

[1] It should be noted that city-wide land use changes (high rises, condo development and population growth) were not included in the analysis, due to the scope of such an undertaking and the complexity of information required. Vulnerabilities were determined based on the assumption that gradual population growth would generally be accommodated by corresponding growth of Toronto Hydro systems under business as usual practices without the added stress of climate change.

[2] A climate parameter is defined by the PIEVC Protocol as a specific set of weather conditions or climate trends deemed to be relevant to the infrastructure under consideration. The parameter may be a single variable, such as mean monthly temperature, or a combination of variables, such as low temperature combined with rainfall.

the 2030's and 2050's). Examining both annual and study period probability was useful for understanding vulnerabilities that may stem from events which could occur on an annual basis (e.g. high temperature) against those which could occur less than annually, but have the potential to cause significant damage to the system sometime during the 35 year study period (e.g. ice storms, high winds, tornadoes). The list of climate parameters considered in this study is shown in table ES-1.

Table ES-1 Climate Parameters and Probability of Occurrence

Climate Parameter		Annual Probability (Historical; **Projected 2030's and *2050's***)	Probability of Occurrence Study Period (2015-2050)
Daily Maximum Temperatures	25°C	66 per year; **84 per year**, ***106 per year***	100%
	30°C	16 per year; **26 per year**, ***47 per year***	100%
	35°C	0.75 per year; **3 per year**, ***8 per year***	100%
	40°C	~0.01 per year; **0.3 to 2 days per year, *1-7 days per year***	~100%
High Daily Avg. Temperature	30°C	0.07 per year; **N/A, *1.2 days per year***	~100%
Heat Wave	3 days max temp over 30°C	0.88 per year; **>1 for both**	100%
High Nighttime Temperatures	Nighttime low ≥23°C	0.70 per year; **7 per year, *16 per year***	~100%
Extreme Rainfall	100 mm in <1 day + antecedent	0.04 per year; ***extreme precipitation expected ↑, percentage unknown***	~75%-85%
Ice Storm/Freezing Rain	15 mm (tree branches)	0.11 per year; **>0.13 per year, *>0.16 per year***	>99%
	25 mm ≈ 12.5 mm radial	0.06 days per year; **>0.07 per year, *>0.09 per year***	>95%
	60 mm ≈ 30 mm radial	Upper bound of estimate: 0.007 events per year; **>0.008 per year; *>0.01 per year*** Lower bound of estimate: 0.002 events per year; **> 0.0023 per year; *0.003 per year***	High: ~25% Low: ~8%
High Winds	70 km/h+ (tree branches)	21 days per year***; N/A, *24 to 26 per year***	100%
	90 km/h	2 days per year; **N/A, *>2.5 per year***	100%
	120 km/h	~0.05 days per year; ***likely ↑, but % unknown***	~85% or higher
Tornado	EF1+	1-in-6,000; ***Unknown, no consensus***	~0.6%
	EF2+	1-in-12,000; ***Unknown, no consensus***	~0.3%
Lightning	Flash density per km km^2	1.12 to 2.24 per year per km^2; ***Expected increase, % change unknown***	~50-70%(Lg); ~10-20% (Sm)
Snowfall	Days w/ >10 cm	1.5 days per year; ***Trend decreasing but highly variable***	100%
	Days w/ > 5cm	5 days per year; ***Trend decreasing but highly variable***	100%
Frost		229 frost free days; **249 frost free days, *273 frost free days***	100%

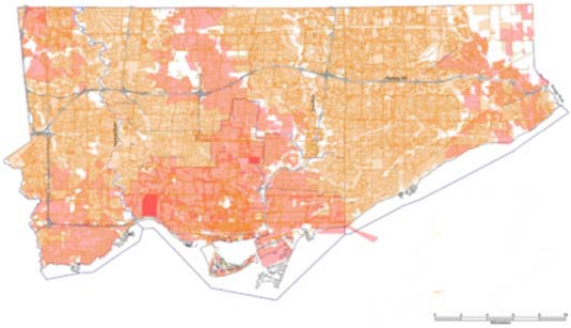
Assessing Vulnerability

The vulnerability of the electrical system to climate parameters was determined using a risk based framework (probability of occurrence of a climate parameter coupled with the severity/consequence of the impact on the system). All high risk interactions were deemed as vulnerabilities for Toronto Hydro. Medium risk interactions were evaluated in further detail through an engineering analysis. Those which exhibited sensitivities or consequences similar to high risk interactions were also deemed as vulnerabilities for Toronto Hydro. Finally, interactions rated as low risk were generally judged as not being a significant issue or vulnerability for Toronto Hydro.

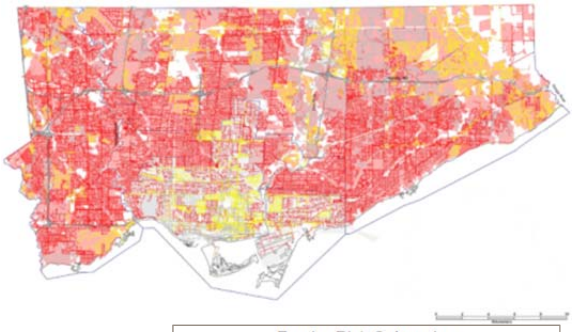
A mapping of the risk ratings was also completed as part of this study and represents a useful first approximation of spatial nature of climate change vulnerabilities to the electrical system. The mapping exercise provides additional information on how vulnerabilities stemming from stations can combine with vulnerabilities to feeder systems. In some cases, vulnerabilities stem primarily from station assets, while in other cases, both station and feeder vulnerabilities to weather events contribute to an area of greater vulnerability within the city. This mapping information can be easily combined with other layers of information such as technical hazard information (e.g. flood mapping), critical building and infrastructure locations (e.g. emergency resource centres, hospitals, transportation networks) and social vulnerability indices (e.g. age, income, population density, etc.) from other sources (e.g. TRCA, City of Toronto) to support further mapping studies and in depth analyses.

Figure ES-1 Example Maps Based on Risk Ratings for High Heat, Freezing Rain and Lightning

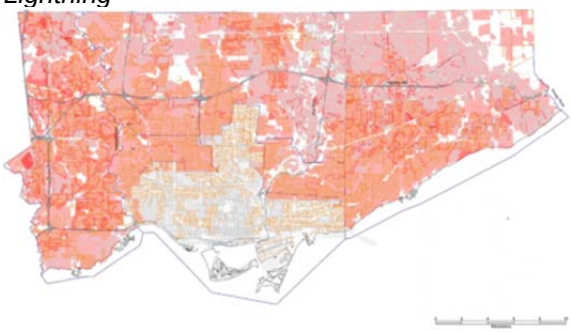
High Ambient Temperatures



Freezing Rain



Lightning





This study found that distribution system vulnerabilities to a changing climate were divided into five groups based on how climate parameters affect the system.

High Ambient Temperatures – Station and Feeder Assets

High ambient temperatures create problems for the distribution system because of the compounding effect of high demand (e.g. for cooling) and high ambient temperature affecting power transformer capacity and electrical transmission efficiency. Two climate parameters were of most significant concern, daily maximum temperatures exceeding 40°C (excluding humidity) and daily average temperatures exceeding 30°C. For these climate parameters, the analysis found that such extreme temperatures have occurred rarely in the past, but are projected to occur almost semi-annually by the 2030's, and annually by the 2050's. It is anticipated that vulnerability to high heat events will be concentrated in the Former Toronto area, although there are several horseshoe station service areas which would also be vulnerable.

Freezing Rain, Ice Storms, High Wind and Tornadoes – Overhead Station and Feeder Assets

Freezing rain, ice storms, high wind and tornado events can cause immediate structural issues for overhead station and feeder assets, as they have the capacity to exceed the design limits of equipment and their supports. Outages may result from damage to equipment arising from direct forces applied by climate parameters (e.g. wind, ice weight) or by other objects (e.g. tree branches, flying debris). Toronto Hydro has experienced problems related to freezing rain, ice storms (up to 25 mm) and high winds (up to 90 km/h) in the past. These events are projected to continue in the future, but continue to occur on a less than annual, or even decadal frequency. Nonetheless, the damages caused by these kinds of events can be severe, and mostly affect outdoor station and feeder assets, much of which is concentrated in the horseshoe service area.

Extreme Rainfall – Underground Feeder Assets

Extreme rainfall events may potentially flood underground feeder assets. These vulnerabilities are largely concentrated in the Former Toronto and northeastern horseshoe areas. Toronto Hydro is aware of these issues in relation to its assets and has programs to replace non-submersible equipment with submersible type equipment, to relocate equipment where possible. However, due to the large quantity of underground feeder assets across the city, replacement and reinforcement of underground assets will be a gradual and ongoing activity for Toronto Hydro over the study period. As such, some underground feeder assets may remain an area of vulnerability for Toronto Hydro.

Snowfall, Freezing Rain - Corrosion of Civil Structures

The degradation of civil structures (i.e. concrete and steel), which is accelerated by humidity and the presence of de-icing salts, was identified as a potential area of vulnerability to climate change. Corrosion is already an ongoing issue for Toronto Hydro. As such, current assets have a design lifespan which accounts to a great extent for corrosion issues. However, it is not clear from this study whether the climate change stresses will exacerbate this problem. While snowfall days are generally expected to decrease with a warming climate, they will continue to occur annually through to the 2050's. As a result, and in combination with freezing rain events, de-icing salts will also be applied annually through the study horizon, and corrosion will continue to be an ongoing preoccupation. Nonetheless, it should be emphasized that corrosion represents a long-term and on-going vulnerability for Toronto Hydro.

Lightning – Overhead Feeder Assets

Based on workshop feedback and an examination of Toronto Hydro's interruption tracking system's (ITIS) outage data, Toronto Hydro recognizes that lightning impacts are a significant source of outages on the distribution system today. While there have been advances in predicting lightning activity, there was insufficient data available on lightning strike intensity and arrester performance to suggest how future lighting activity may affect the electrical system. For these reasons, this study suggests that lightning strikes will continue to be an area of vulnerability.

Adaptation Options and Areas of Further Study

This study provides high level adaptation options under the themes of engineering actions, management actions, monitoring activities and further study. Generally, for high heat related climate parameters, Toronto Hydro could further investigate avenues to enhance the system's capacity to deal with higher demand under high temperature conditions, especially since extreme heat events are projected to occur on a semi-annual to annual basis by the 2030's and 2050's. On climate events causing structural damage issues (i.e. freezing rain, ice storms, high winds and tornadoes), adaptation options include optimizing emergency response and service restoration, as well as infrastructure hardening and burying infrastructure. While the latter engineering-type solutions are relatively capital intensive, asset renewal cycles provide excellent opportunities to consider these types of upgrades. This study also recommends that Toronto Hydro continue monitoring the occurrences and impacts of major freezing rain, high wind and tornado events on the system, as well as the science of climate change projections. This multi-faceted approach provides Toronto Hydro with greater flexibility in managing vulnerabilities related to these types of extreme climate events.

Other potential options to address identified vulnerabilities include continued monitoring and evaluation of climate change projection science, monitoring impacts of a changing climate on certain asset classes, evaluating the need to strengthen or defend certain infrastructure and equipment from climate parameters, and enhancing emergency response and service restoration practices.

Acknowledgements

This study was completed with support from Natural Resources Canada. It was produced through its Adaptation Platform Electrical Sector Working Group[3]. AECOM would also like to acknowledge Engineers Canada for the technical support, participation and for the use of its Public Infrastructure Engineering Vulnerability Committee (PIEVC) Protocol. The Toronto region's WeatherWise Partnership is also acknowledged for its work on bringing the issue of climate related threats on electrical infrastructure to the forefront, and for its support in bringing about this study. AECOM would like to thank the Clean Air Partnership for the opportunity to undertake this study.

AECOM would also like to acknowledge Toronto Hydro staff for their time and effort in providing information about their system, participating in workshops and meetings, providing insight into the functionality of their system, and reviewing documents and reports. Without their valuable contributions, this study could not have proceeded.

[3] For more information on climate change impacts and adaptation, please visit adaptation.nrcan.gc.ca" (or for French language publications/sites: "adaptation.rncan.gc.ca").

Table of Contents

1 Study Context 1

1.1 Introduction and Mandate 1

1.2 Methodology and Approach 1

1.3 Structure of this Report 2

2 Description of the Infrastructure 3

2.1 Study Area 3

2.2 General System Overview 5

2.3 Substations 7

2.4 Feeder Systems 10

2.5 Communications Systems 13

2.6 Civil Structures 14

2.7 Auxiliary mechanical 15

2.8 Human Resources 15

2.9 Time Horizon 15

2.10 Other Potential Changes that May Affect Infrastructure 16

2.11 Data Sufficiency 17

3 Assessment of Climate Changes 19

3.1 Climate Data Development Methodology 19

3.2 Summary of Results 22

3.3 Data Sufficiency and Recommendations 23

4 Vulnerability Assessment Methodology 25

4.1 Risk Tolerance Thresholds 25

4.2 Yes/No Analysis 25

4.3 Infrastructure Performance Responses - Systems Level Approach 25

4.4 Scoring Severity 28

4.5 Mapping Risks 29

5 Assessment Results 31

5.1 Low Risk Interactions 31

5.2 Medium Risk Interactions 32

5.3 High Risk Interactions 34

5.4 Special Cases – High Severity, Low Probability Events 36

5.6 Special Cases – Low Severity, High Probability Events 37

5.7 Mapping Risk Results 37

6 Engineering Analysis 43
6.1 Municipal and Transmission Stations and Communications Systems 44
6.2 Underground and Overhead Feeders 44
6.3 Civil Structures 46
6.4 Human Resources 47
7 Conclusions 49
7.1 Vulnerabilities to a Changing Climate 49
7.2 Adaptation Options 50
7.3 Other Areas of Study 53
8 Bibliography 55

List of Tables

Table 2-1 Transmission Stations and Service Areas 8
Table 2-2 Load Projections by Transmission Station 17
Table 3-1 PIEVC Version 10 Probability Scores based on Method B 22
Table 3-2 Climate Parameters and Thresholds, Occurrence Probabilities and PIEVC Scoring 22
Table 4-1 Risk Tolerance Thresholds 25
Table 4-2 Severity Rating Based on Station Capacity by the 2050's 27
Table 4-3 Severity Rating Based on Feeder Configuration 28
Table 4-4 Severity Scoring Scale for Electrical Distribution Systems 29
Table 6-1 Engineering Analysis Results 43
Table 7-1 Vulnerabilities and Adaptation Options by Infrastructure Asset, Climate Parameter 50

List of Figures

Figure 2-1 Major System Categories Under Study 4
Figure 2-2 City of Toronto Study Area 4
Figure 2-3 Typical Electric Power System 6
Figure 2-4 Transmission Stations 7
Figure 2-5 The Station Yard at Cavanagh Transmission Station 9
Figure 2-6 Residential Area MS (front and rear views) 10
Figure 2-7 Location of Feeders, by Type 12
Figure 5-1 Risk Map, High Temperature Above 40°C, 2050's 38
Figure 5-2 Risk Map, Extreme Rainfall, 100 mm in less than 24h, 2050's 38

Figure 5-3 Risk Map, 25 mm Freezing Rain, 2050's.....39
Figure 5-4 Risk Map, Electrical Distribution Systems Potentially Affected by Lightning Strikes 40

Appendices

Appendix A Workshop Presentations
Appendix B Background Information on Developing Climate Data
Appendix C Forensic Analysis of Weather Related Power Outage Events
Appendix D Risk Assessment Matrix
Appendix E Risk Maps
Appendix F Load Projection Methodology – Toronto Hydro
Appendix G Engineering Analysis
Appendix H PIEVC Worksheets

List of Acronyms

CAP	Clean Air Partnership
GCM	Global climate model
GIS	Geographic Information Systems
HONI	Hydro One Networks Inc.
ITIS	Interruption Tracking System
NRCan	Natural Resources Canada
OPG	Ontario Power Generation
PIEVC	Public Infrastructure Engineering Vulnerability Committee
Protocol	The climate change based public infrastructure vulnerability assessment developed by the PIEVC and Engineers Canada
RCM	Regional climate model
RCP	Representative concentration pathway
RSI	Risk Sciences International
THESL	Toronto Hydro-Electric System Limited
TTC	Toronto Transit Commission

1 Study Context

1.1 Introduction and Mandate

In 2012, Engineers Canada partnered with the Clean Air Partnership (CAP) and Toronto Hydro to evaluate the risks of climate change on Toronto Hydro's electrical distribution infrastructure in the City of Toronto. At that time, CAP mandated AECOM and Risk Sciences International (RSI) to undertake a Public Infrastructure Engineering Vulnerability Assessment Protocol (PIEVC Protocol, or the Protocol)[4] based study on select components of Toronto Hydro's electrical distribution system to historical climate. That study, named the Toronto Hydro-Electric System PIEVC Pilot Case (pilot case study), was meant to demonstrate the applicability of the Protocol to electrical systems. The pilot case study was also envisioned as the first of a two-phase project to assess climate change related vulnerabilities to electrical systems. The pilot case study was completed at the end of summer 2012 (AECOM and RSI, 2012).

In summer 2013, CAP and Toronto Hydro elected to pursue the second phase of the climate change assessment with support from Natural Resources Canada's (NRCan) "Enhancing Competitiveness in a Changing Climate" program. NRCan's program is designed to facilitate the development and sharing of knowledge, tools and practices which assist decision-makers in the analysis and implementation of climate change related adaptation measures. CAP, once again mandated AECOM and RSI to carry out the Phase 2 climate change vulnerability assessment (Phase 2 study). The Phase 2 study is the subject of the current report.

1.2 Methodology and Approach

The Phase 2 study again employs the Protocol as the framework for the climate change analysis. The Protocol is composed of five steps:

- Step 1 – Project Definition;
- Step 2 – Data Gathering and Sufficiency;
- Step 3 – Risk Assessment;
- Step 4 – Engineering Analysis;
- Step 5 – Recommendations and Conclusions.

In contrast to the pilot case study, the scope of Phase 2 study was extended to include most of Toronto Hydro owned electrical distribution infrastructure and civil support structures across the City of Toronto. Toronto Hydro's streetlighting system and electrical systems for the Toronto Transit Commission were not within the scope of the present study. Anticipated climate changes and impacts at the 2030 and 2050 time horizons were evaluated. Most of the activities prescribed by the Protocol were completed as part of Phase 2 with the exception of a site visit. The triple-bottom line adaptation solutions development module, an optional undertaking in the PIEVC Protocol, was also not completed as part of Phase 2 of this study[5].

As part of the activities of Phase 2, two workshops were held with Toronto Hydro staff. The first workshop was held on July 3, 2014 in Toronto Hydro's offices in Toronto. At this workshop, an overview of the infrastructure and climate components (Steps 1 and 2 of the Protocol), were presented for discussion and validation with Toronto Hydro staff. On October 10, 2014, a second workshop was held to validate the risk assessment completed by AECOM and RSI (Step 3 of the Protocol).

[4] The Protocol is a structured and documented methodology for a screening level assessment of infrastructure vulnerability to a changing climate, and for developing adaptation solutions to identified vulnerabilities. The Protocol, currently in version 10, also allows users to evaluate the vulnerabilities stemming from current climate to the infrastructure as part of the overall assessment.

[5] The triple-bottom line adaptation solutions development module guides users in the development and screening of potential solutions to address the impacts of climate change identified in the preceding steps of the Protocol. It was not in the scope of the current study.

The components of the electrical distribution system (e.g. stations, power lines, transformers, switches, supports) under study are highly interdependent, and failures in one part of the system may result in interrelated structural, electrical or functional issues in other portions of the system (e.g. failures in poles may bring down power line and transformers, electrical faults may cause the system to lose protection, control or redundancy). For this reason, the study of electrical systems cannot be examined solely on the basis of its individual pieces or classes or equipment. This study adopts a *systems level approach*[6] to examining the climate change risks to the extensive, complex and interdependent components of Toronto Hydro's electrical distribution system. This approach divides the electrical distribution system into six major systems categories encompassing different individual components and classes of equipment. This generalization of electrical components into major systems categories facilitates an analysis that considers system dependencies and redundancies.

However, by generalizing the system into major systems categories, the granular detail of the system and its components (e.g. site specific characteristics, unique or individual pieces of equipment) may not be adequately captured. Therefore, to complete a reasonable study of the entire electrical distribution system, this study has made assumptions, informed by input from Toronto Hydro staff, about the types and classes of equipment and components typically found within each category. While the loss of granular detail may mask localized issues and vulnerabilities, it does allow this project to provide the first climate change based vulnerability assessment of electrical distribution infrastructure. This can help prioritize future investigations, resources and investment on vulnerable systems and their components in order to enhance the resilience of the electrical system.

1.3 Structure of this Report

This report is divided into seven chapters, including the present one. They are:

- Chapter 1: Study Context;
- Chapter 2: Description of the Infrastructure;
- Chapter 3: Assessment of Climate Changes;
- Chapter 4: Vulnerability Assessment Methodology;
- Chapter 5: Assessment Results;
- Chapter 6: Engineering Analysis; and,
- Chapter 7: Conclusions.

Note that Chapter 3, Assessment of Climate Changes and **Appendix B** and **C**, were authored by Risk Sciences International in consultation with AECOM study authors.

[6] This is in contrast to the component level analysis approach which was employed in the pilot case study.

2 Description of the Infrastructure

2.1 Study Area

The Phase 2 study covers Toronto Hydro's electrical distribution infrastructure and supporting civil infrastructure within the boundaries of the City of Toronto. Toronto Hydro distributes electricity across the City of Toronto, Canada's largest city, the provincial capital of Ontario, and home to approximately 2.8 million people (City of Toronto, 2014). The City of Toronto is bordered by the municipalities of Mississauga to the west (in Peel Region), Vaughan and Markham to the north (in York Region), and Pickering to the east (in Durham Region).

The City of Toronto covers approximately 641 km^2 on the northwestern shore of Lake Ontario (City of Toronto, 2014). The city's topography slopes gradually from the lakeshore, approximately 75 m above sea level to 200 m above sea level at its highest point along its northern border (City of Toronto, 2014). Three river systems cross the City of Toronto and flow into Lake Ontario. The Humber River lies on the west side of the City. The Don River essentially crosses the middle of the City of Toronto and flows into Lake Ontario just east of downtown. Finally, the Rouge River crosses the city's eastern edge. These rivers, their tributaries and creeks total about 307 km of water courses and punctuate the City's generally flat landscape with ravines.

The City lies at the eastern edge of the Carolinian Forest zone. The City contains approximately 10 million trees, approximately 4 million of which are publically owned. Of the latter, there are approximately 600,000 trees along streets and public right of ways, and another 3.5 million trees in parks, ravines and other natural areas of the city (City of Toronto, 2014).

2.1.1 Major Systems Categories Under Study

In 2014, Toronto Hydro's electrical distribution system served approximately 740,000 customers, of which around 658,000 were residential customers. The components of the Toronto Hydro's electrical distribution system are extensive, covering approximately $3 billion dollars in assets, including over 170 transformer stations of different classes, 29,000 km of overhead and underground wires, 20,000+ switches, 60,000+ transformers and 176,000+ poles (Toronto Hydro, 2014b). The present study covers most of Toronto Hydro's electrical distribution infrastructure and civil support structures, with the exclusion of its streetlighting system, and systems serving the Toronto Transit Commission (TTC). The electrical distribution system was divided into six *major systems categories* for the purposes of this study: transmission stations, feeder configurations, system communications, civil structures, mechanical auxiliaries and human resources. Figure 2-1 provides a schematic overview of the systems under study. The *major systems categories* are described hereafter, and hypotheses and generalizations that were made to facilitate the *system level analysis* approach are explained in this chapter. Supporting detail is included in Worksheet 1 of **Appendix H**.

This analysis divides the City of Toronto into two areas: the Former Toronto area and horseshoe area. This distinction is made because most of the legacy equipment is usually found in downtown Toronto and while equipment of newer design can usually be found in the horseshoe area. As such, the *major systems categories* (with the exception of human resources) are also separated between the Former Toronto area (which represents the downtown and inner city) and the horseshoe area (which covers the outlying suburbs). Figure 2-2 shows the division between the Former Toronto area (in green) and the horseshoe area (in blue).

Information about the *major systems categories* was drawn from three principal sources:

- *Overview of the Toronto Hydro Distribution Systems*. Toronto Hydro-Electric System Limited, 2014, Power point 203 p.
- *Overview of the Toronto Area Transmission Systems and Toronto Hydro Distribution Systems*. Toronto Hydro-Electric System Limited, 2014, Power point 121 p.

- System Expansion and Studies Section System Reliability Planning Department. *Toronto Hydro Distribution System Planning Guidelines.* Toronto Hydro-Electric System Limited, 2007, 22 p.

Figure 2-1 Major System Categories Under Study

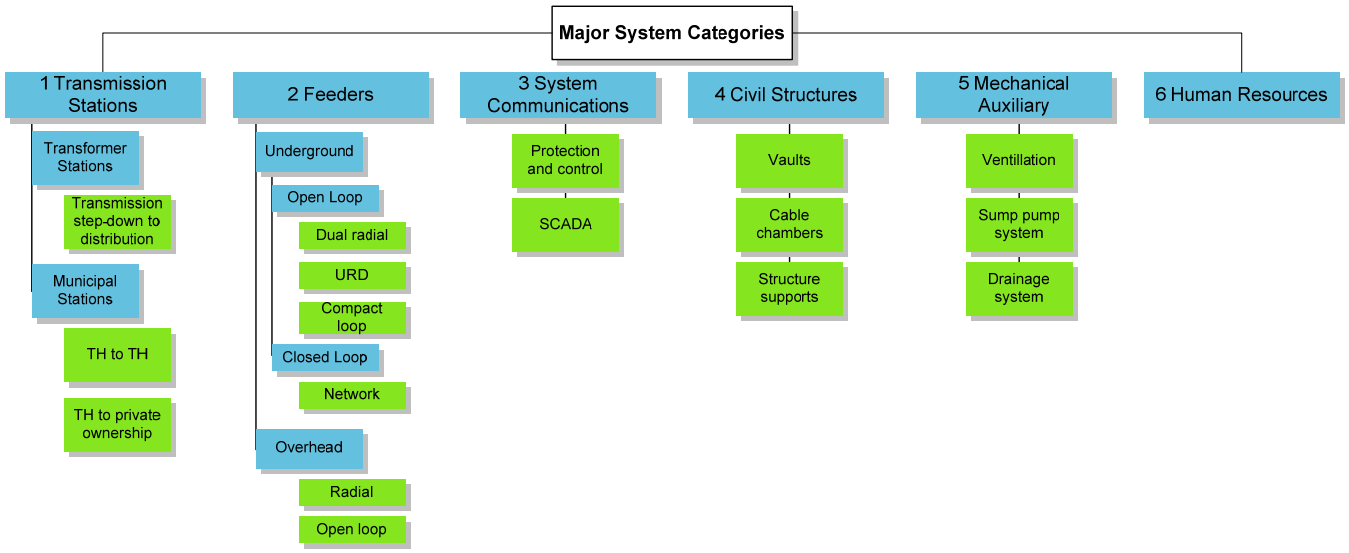
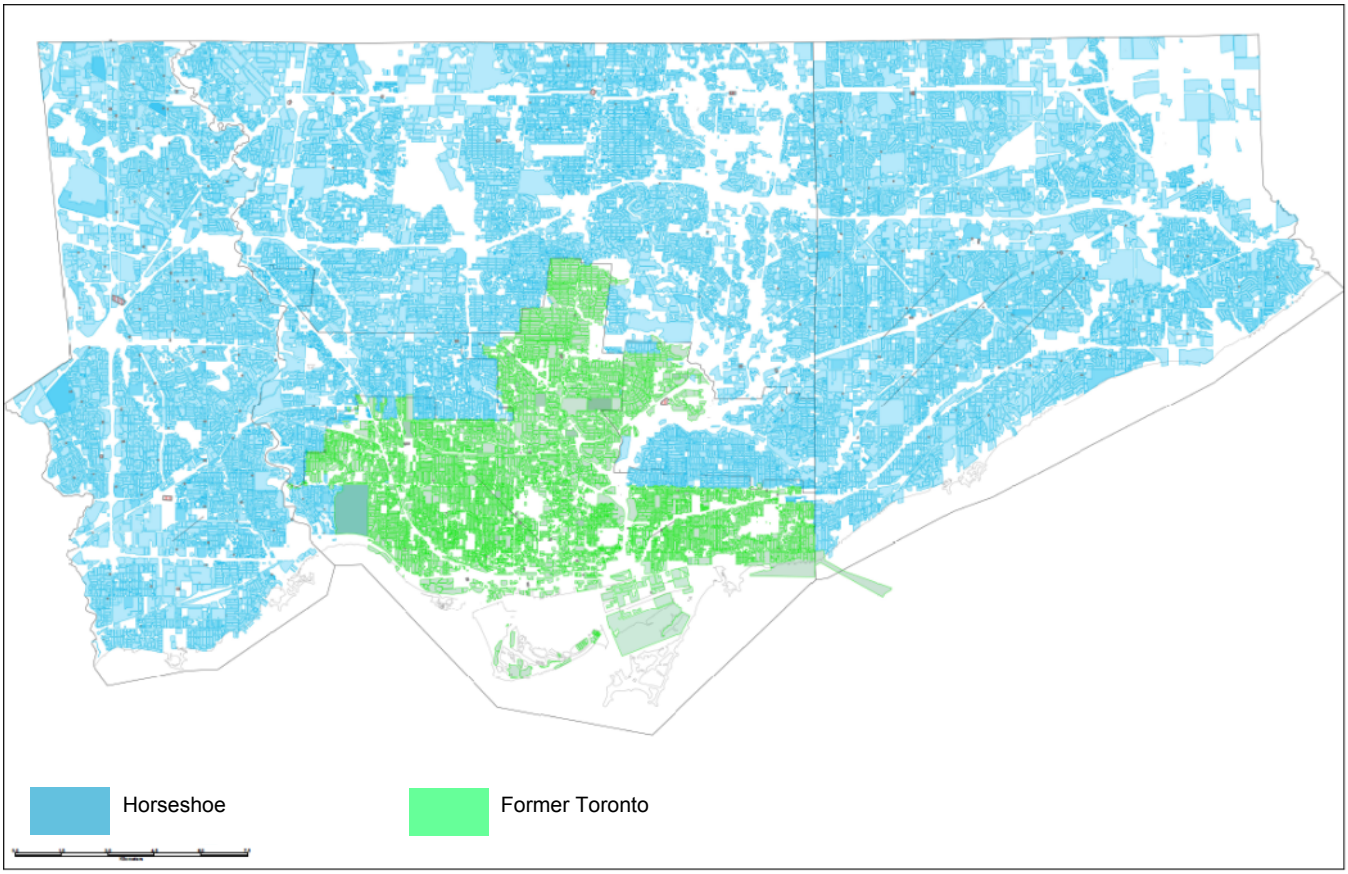


Figure 2-2 City of Toronto Study Area



2.2 General System Overview

The electric power system of the province of Ontario is a large interconnected electrical system of generating, transmission, and distribution infrastructure. Generating stations in Ontario are either privately or publicly owned. From the generation stations, the electricity is transmitted throughout the province over high voltage transmission lines, the majority of which is owned by Hydro One Networks Inc. (HONI). The electricity is then distributed to customers by local distribution companies like Toronto Hydro (Figure 2-3).

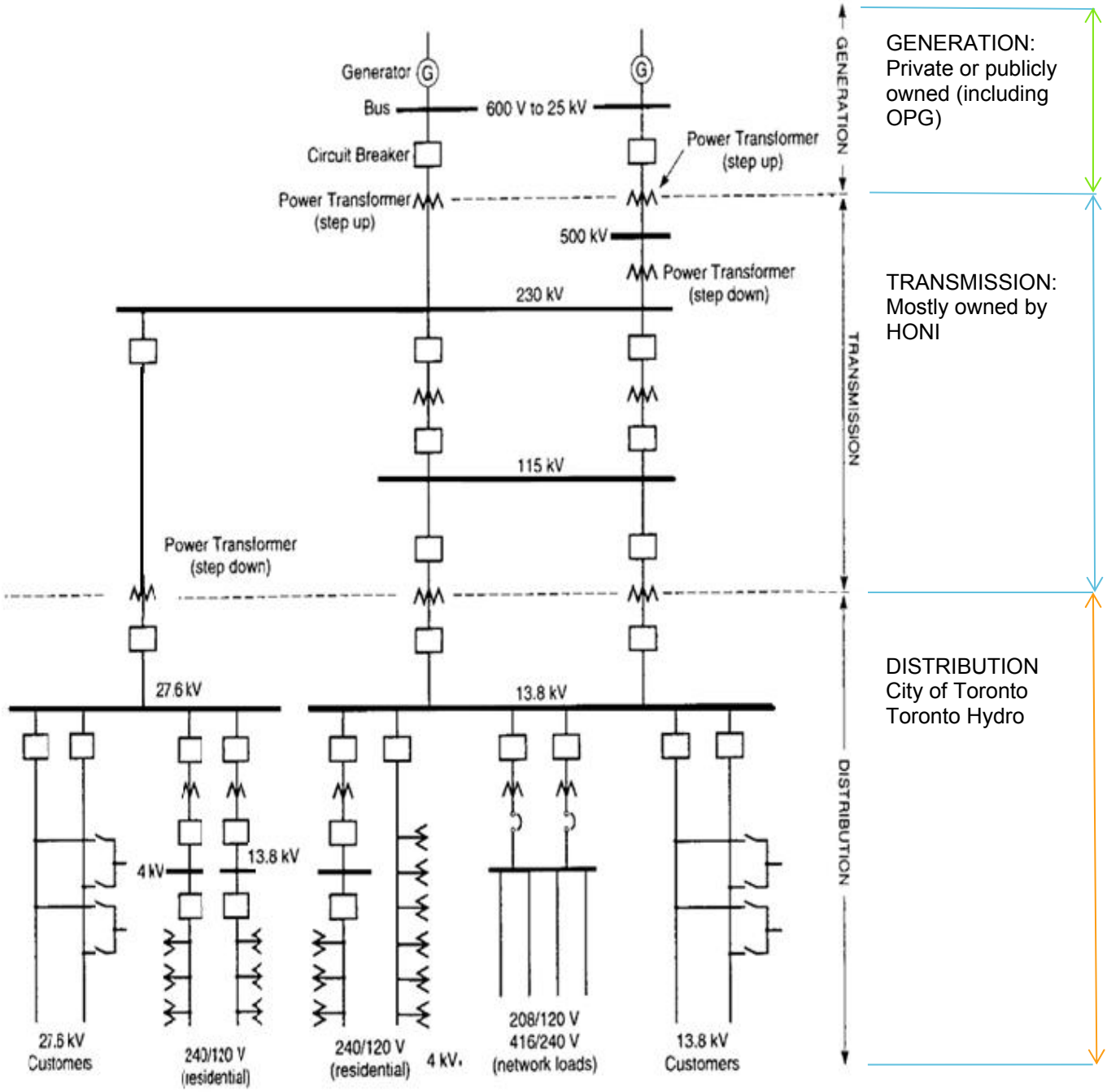
In the case of the City of Toronto, 230 kV and 115 kV transmission lines owned and operated by HONI bring power to the city. The 230 kV transmission lines mostly serve the horseshoe area, while the 115 kV lines serve most of the Former Toronto area. The 115 kV transmission lines are supplied from three major sources: Leaside station (230/115 kV step down) from the east, Manby station (230/115 kV step down) from the west, and by one generating station located within city limits, the Portlands Energy Centre (PEC) owned by Ontario Power Generation (OPG). PEC generates electricity through three natural gas turbine generators.

Presently, there are 35 transmission stations that step down high voltage currents (230 kV and 115 kV) to the distribution system voltages used by Toronto Hydro (i.e. 27.6 kV and 13.8 kV) (Figure 2-4). The equipment within these stations is owned by either Hydro One or Toronto Hydro, with the exception of Cavanagh station, where all equipment is owned by Toronto Hydro. The division of equipment ownership varies by station. However, since transmission stations are critical, first points of entry of electricity into the city's distribution network, this study considers all equipment within the transmission station, since equipment failure within the station, irrespective of ownership, may compromise its function.

From transmission stations, Toronto Hydro distributes electricity via a network of underground and overhead feeder systems at voltages of 27.6 kV and 13.8 kV. A third distribution voltage level of 4.16 kV, a legacy from historical distribution practices, also operates in the city. The 4.16 kV network is supplied by transformation of 27.6 kV or 13.8 kV feeds at Toronto Hydro owned municipal transformer stations. These three distribution voltages will remain in service for the duration of the Phase 2 study period, even though many of the 4.16 kV power lines are gradually being converted to 13.8 kV and 27.6 kV lines.

This electrical distribution infrastructure is connected via communications systems which afford control and protection of electrical equipment from damage or faults. This system is critical to the operation of the electrical system and is part of this study. In addition, this study considers all civil structures that support the electrical equipment and all mechanical equipment inside underground vaults (ventilation, sumps and pumps). A last category includes all human resources operating and managing Toronto Hydro distribution system.

Figure 2-3 Typical Electric Power System



Source: (Toronto Hydro, 2014d)

Figure 2-4 Transmission Stations

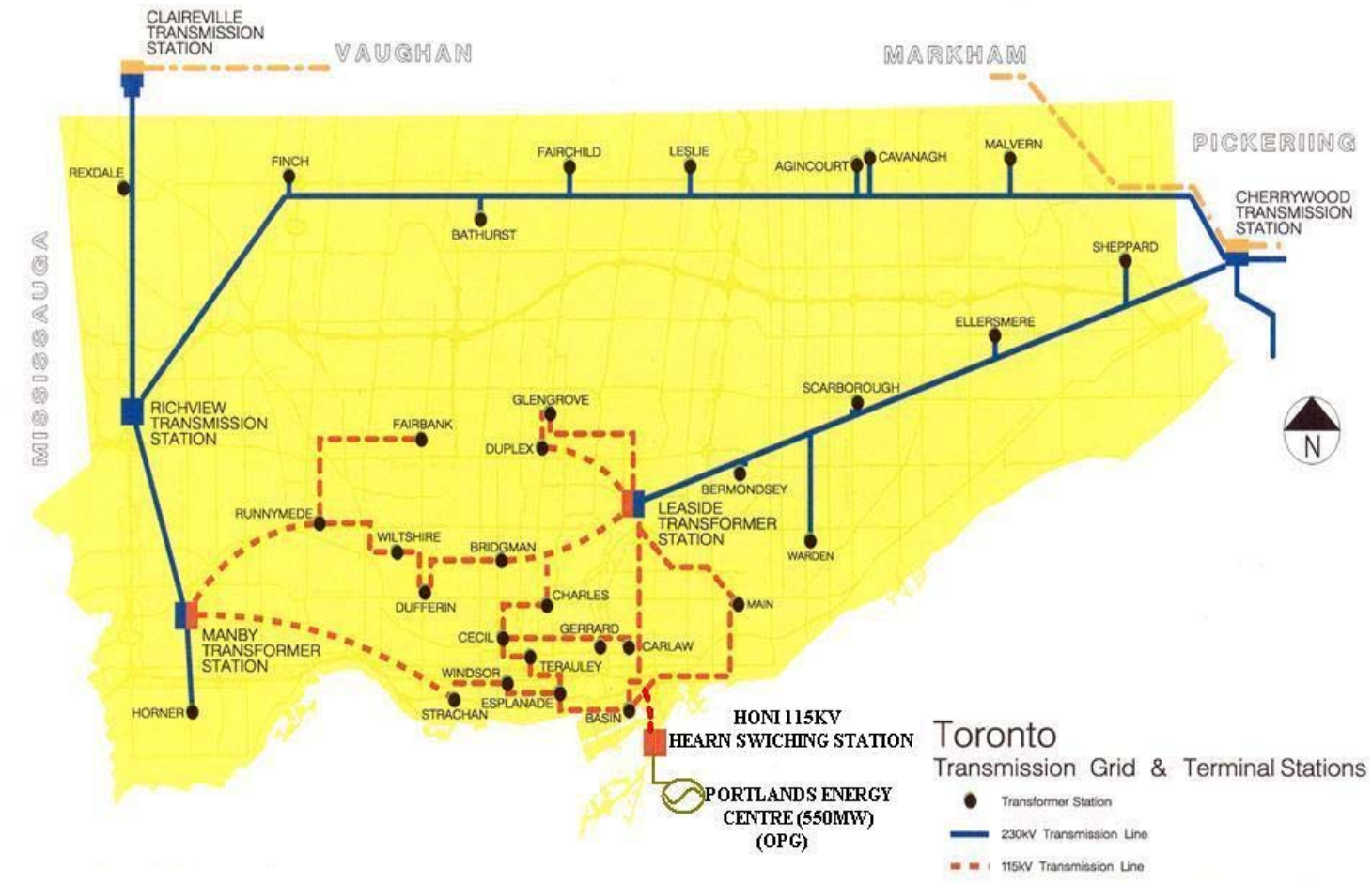


Figure source: (Toronto Hydro, 2014d)

2.3 Substations

2.3.1 Transmission Stations

At the moment, there are 35 transmission stations located in the City of Toronto. Most transmission stations located in the downtown and inner city have primary voltages at 115 kV and step-down to 13.8 kV. In the horseshoe area, the primary voltage is 230 kV and stepped-down to 27.6 kV (most) or 13.8 kV (some). The table below illustrates the list of stations that are divided into the two main service areas, and six sub-service areas[7] (Table 2-1).

[7] Stations have been grouped into these service areas by Toronto Hydro due to:
- Similarity of historical development and presumed potential for future development;
- Theoretical potential for permanently transferring load between neighbouring stations on an operational basis and/or through capital projects;
- Statistical correlation (coefficient of determination, R2) of the overall area growth rate to actual historical peak loads in the area (relative to potential alternative area groupings).

Table 2-1 Transmission Stations and Service Areas[8]

Service Area *(Voltage step down)*	Number of Stations
Former Toronto	
Downtown core *(115 kV/13.8 kV)*	6
Downtown outer *(115/13.8 kV, 230/115 kV, 115/27.6 kV)*	11
Horseshoe	
North Stations *(230/27.6 kV)*	2
East *(230 kV/27.6 kV, 230/115 kV)*	10
Northwest *(230 kV/27.6 kV)*	4
Southwest *(230/27.6 kV, 230/115 kV)*	2

In the Former Toronto area, there are no station ties between station service areas to allow for the transfer of some feeder loads from one station to another. In the horseshoe area, there are existing station ties available to allow the transfer some feeder loads from one station to another.

In the horseshoe area, the transmission stations are considered “outdoor”, as all equipment’s are exposed to the elements. A control building containing weather sensitive equipment and operators control room is located adjacent to the station. In the Former Toronto area, most stations are configured with equipment located indoors. The entire transmission station is surrounded by fences or walls for public safety.

All stations are essentially based on the Dual Element Spot Network (DESN) design configuration. Typically DESN has two power transformers with 230 kV or 115 kV primary windings, two 27.6 kV or 13.8 kV secondary windings and two buses.

By 2016, the Copeland Station (a gas insulated station) will be brought into service in the Former Toronto area. Gas Insulated Stations occupy less space than air insulated stations of comparable capacity. The gas used for insulation in the Copeland Station is Sulfur Hexafluoride (SF6).

Typical equipment – Transmission Stations

While each of the 35 transmission stations have site specific characteristics, representative and typical equipment found in all stations are:

[8] Station names have been excluded from this version of the report.

- Power transformers
- Lightning arresters
- Current and voltage transformers (instrument transformers)
- Disconnect-switches or interrupters (loadbreak switches)
- Circuit Breakers
- Medium voltage switchgears
- Bus bars
- Transmission station configurations: double bus - double breaker configuration, double bus - single breaker, double bus - double breaker or double bus and one and a half breakers.

A picture of a typical transmission station yard is shown in Figure 2-5.

Figure 2-5 The Station Yard at Cavanagh Transmission Station



Picture source: (Toronto Hydro, 2014a)

Note that this station *major systems category* does not include civil structures or protection and control systems. These other critical infrastructure components which form part of the transmission station are described under separate *major systems categories* below.

2.3.2 Municipal stations

The municipal stations are divided into two sub-categories. First, “Toronto Hydro to Toronto Hydro” municipal stations step down from 27.6 kV to 13.8 kV or to 4.16 kV in the Horseshoe Area, and in the Former Toronto area from 13.8 kV to 4.16 kV. There are also smaller transformer stations located on the sites of Toronto Hydro customers with high load demands. These stations are called “Toronto Hydro to Private ownership” stations in this study.

Toronto Hydro is converting its 4.16 kV voltage level over time to 13.8 kV and 27.6 kV because of age, loss minimization, equipment inventory reduction, and required or projected future load growth (Toronto Hydro, 2007). Toronto Hydro estimated that by 2030, 50% of the 4.16 kV equipment will be converted in the Horseshoe Area and all of it will be phased out in the Former Toronto area. By 2050, Toronto Hydro is expected to have replaced 70% of the 4.16 kV overhead power lines in the Horseshoe (Hypotheses issued in Workshop 1, 2014).

Toronto Hydro to Toronto Hydro

There are around 169 municipal stations (27.6 kV/ 13.8kV or 27.6 kV/13.8 kV / 4.16 kV) within the City of Toronto. Approximately 82 municipal stations are located entirely within a building, and these indoor stations are mostly located in the Former Toronto area. The remaining stations have some or all equipment located outdoors. These stations are classified as outdoor stations for the purposes of this study, and most are located in the horseshoe area. Figure 2-6 shows a picture of a typical outdoor station located in a residential area. For the purpose of this study, it is assumed that all Former Toronto area municipal stations are indoors, while horseshoe stations are outdoors. For those few outdoor stations in the Former Toronto area, their vulnerability will be identical to the outdoor stations in the horseshoe area.

Figure 2-6 Residential Area MS (front and rear views)



Figure source: (Toronto Hydro, 2014a)

Toronto Hydro to Private Ownership

Toronto Hydro to Private Ownership stations supply large loads at low voltages to private customers. The station is located on private property inside a closed room. Most of these stations are owned by Toronto Hydro, although some are owned by the customer.

Typical equipment – Municipal Stations

Typical equipment within municipal stations is similar to transmission stations, but are generally smaller in size because less capacity is required. In general, municipal stations include:

- Oil power transformers (ONAN/ONAF);
- Instrument transformers;
- Disconnect switches;
- Circuit Breakers;
- Cables;
- Fuses;
- Arresters.

2.4 Feeder Systems

Toronto Hydro employs feeder systems, or systems of power lines, transformers, switches and related equipment, to distribute electricity across the City of Toronto. The feeders are either installed on overhead poles (overhead systems) or travel through underground cables (underground systems). Overhead feeder systems can be located on the front side of a property (front lot) or at the back of the property (rear lot). However, rear lot systems will be phased out by the 2030s and are not considered in the scope of this study. They are progressively being replaced

by front lot overhead or underground infrastructure, which provides Toronto Hydro more convenient access. In total, Toronto Hydro customers are served by over 900 feeders[9] (Navigant Consulting Ltd. 2011).

Approximately 30 % of Toronto Hydro's distribution network is comprised of 27.6 kV feeders from 3 - 4 km (considered ''short'' lines) to 5 - 6 km (considered ''long'' lines) in length. These systems are mostly located in the horseshoe area. 70 % of Toronto Hydro's distribution feeders operate at 13.8kV, and vary in length between 2 – 3 km (short) to 3 - 4 km (long) (Navigant Consulting Ltd., 2011). The 13.8 kV systems serve both the downtown and horseshoe areas. A very small percentage of feeders still operate at 4.16 kV.

2.4.1 Electrical Configurations

The electrical configuration of a feeder determines the way electricity is delivered to customers. It is indicative of the feeder's ability to provide electrical service in the event of equipment damage and electrical faults. There are many different electrical configurations of feeders, and they include radial, dual radial, open loop and closed loop systems. Some of these systems may also be nested within one another (e.g. an open loop system with downstream radial feeders). Toronto Hydro's main underground and overhead feeders are arranged in an open loop type configuration, although there are also dual radial and radial feeder systems, some of which may be nested within the open loop configuration. Only one feeder type, the 13.8 kV network, is arranged in a closed loop type configuration. The various electrical configurations considered in this study are:

- Underground dual radial and underground residential distribution (URD) feeders;
- Underground closed loop network feeders;
- Overhead open loop and radial feeders.

In the open loop system, the feeder line runs out of the station through two separate feeder arms that eventually reconnect outside the station to form a loop. A load interrupting switch (tie switch) is located at the reconnection point and is normally kept open between the two feeder arms. If one feeder arm goes out, the load can be fed by the other feeder arm by closing the tie switch. In open loop systems under single contingency condition[10], the customer typically experiences an interruption when the feeder is switched from one feeder arm to the other.

In radial systems, the customer is supplied by only one feeder. It is the least expensive design but also offers the least flexibility in electrical service restoration in the event of a fault, as there is no other feeder that can supply electricity until the line is repaired. Radial feeder segments may be nested within open loop systems.

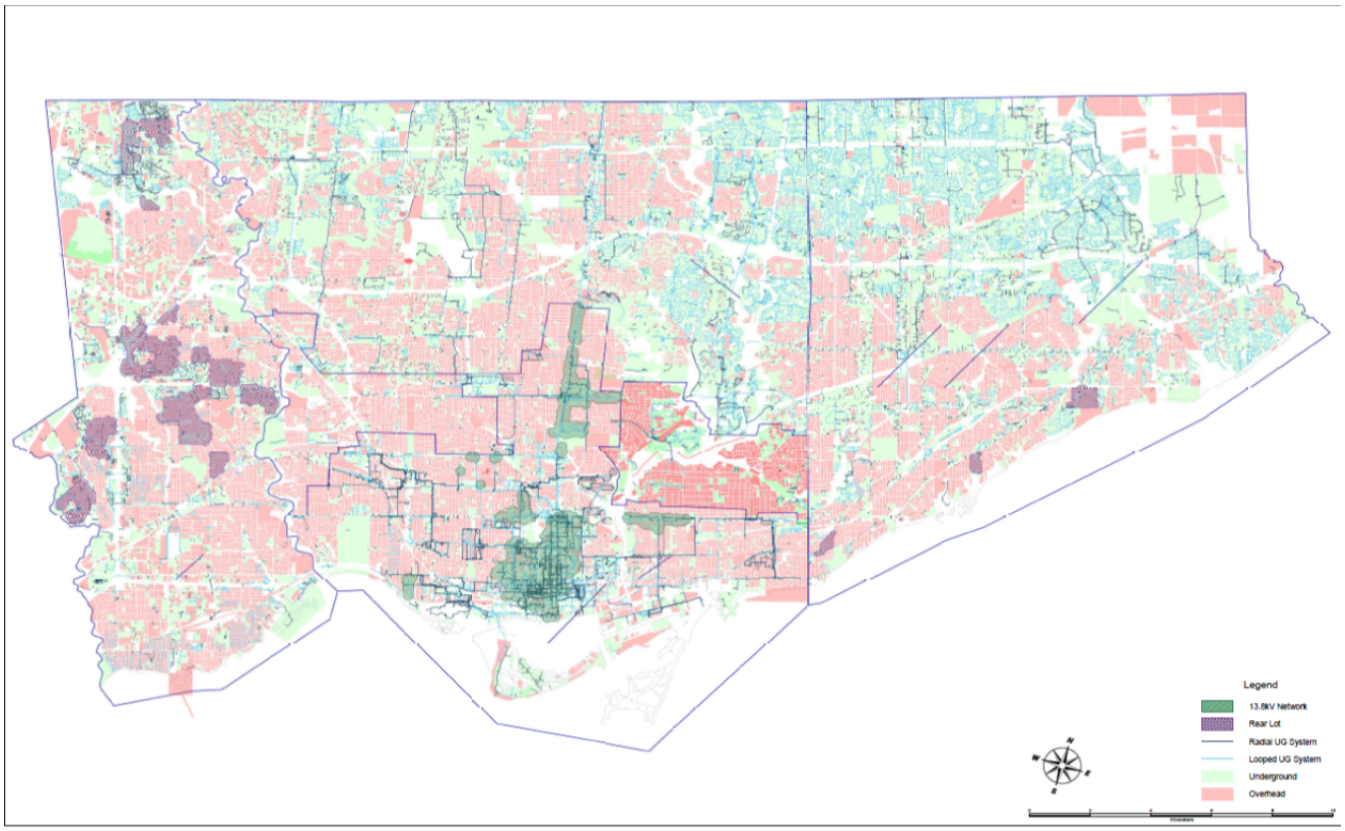
Dual radial systems are similar in design to radial feeders except that each customer is connected to two parallel radial feeders. The load is supplied by one of the radial feeders, as the other radial feeder remains on standby. In the case of a fault, the load is transferred from one feeder to the other by manipulating interrupter switches tying the two radial feeders together. Large commercial and industrial customers, as well as Toronto Hydro municipal stations and several older Toronto Transit Commission (TTC) stations are typically served by dual radial systems. A compact loop system is similar in configuration to a dual radial system, but is employed where space is more limited (e.g. in existing vaults).

In closed loop systems, customers are supplied by multiple feeders, and are fed via several redundant transformers and network protectors. If one feeder goes out, the customer can be supplied by another feeder. Closed loop systems are advantageous because under single contingency conditions, customers experience no power interruptions (Toronto Hydro, 2007). Only Toronto Hydro's 13.8 kV network system is a closed loop system.

[9] This total may vary depending on how feeder branches and sub-branches are counted.
[10] Single contingency condition or N-1 represents the condition where all electrical equipment is in service except one element. For example, if a substation has two power transformers, but one of them is out of service, the condition is called "N-1". The condition "N-1" generally occurs after a major disturbance causes equipment to trip and go-offline.

Figure 2-7**Error! Reference source not found.** shows the distribution of feeder types across the city. The 13.8 kV network, represented in dark green, is mostly concentrated in downtown Toronto (downtown core and the Yonge Street and Bloor Street corridors), while the other feeder types can be found across the city.

Figure 2-7 Location of Feeders, by Type



Source: Toronto Hydro

Typical equipment

For all underground feeders

The distribution transformer station of underground feeder systems can be classified according to one of three types:

- Vault type: The vault transformer can be small and located just below ground for single phase clients, or large and deeper underground for clients requiring larger, three-phase power supplies. Some vault type transformers can be located above ground inside a building. The equipment located in vault type enclosures cannot operate if the vault is flooded.
- Submersible type: They are designed similarly to the vault type transformer stations but the equipment is designed to operate when submersed. For example, submersible transformers are capable of continuous unattended operation while completely submerged under a head of 3 m of water over the top of the tank (IEEE Std C57.12.24, 2009, p. 3). They are currently the preferred design due to their submersibility.
- Padmount type: The padmount transformer is located on ground level in a metal-clad enclosure.

Underground feeder equipment typically consists of the following:

- Cables: The cables used in underground systems are generally insulated with cross-linked polyethylene (XLPE) or a paper insulated lead cover (PILC). The PILC cables also contain oil
- Pilot wire: For large and sensitive customers

- Fault circuit indicators
- Power transformers modules:
    - Load-break switch modules: Metal enclosed, air insulated, Vacuum or SF6 arc extinction, motorized or manual;
    - Fuse modules: Metal enclosed, air insulated, electronic fuses or SF6 power fuses or current limiting fused;
    - Power transformer : Oil type (most), dry type (in above grade vaults) or some used FR3 fluid (environmental friendly);
    - Elbows: cable connections to power transformers.
- Specifically for the network system, typical equipment consists of the following:Primary feeders;
- Network Units;
    - Primary Switch – Embedded in power transformer;
    - N/W Transformer: dry type;
    - N/W Protector: Breaker, back-up fuse, relays, current transformers, cable limiter.
- LV secondary network grid or spot networks;
- Except for the old network protectors, all network unit equipment are submersible.

For overhead, open loop and radial feeders:

- Poles: See civil categories below;
- Distribution transformers : ONAN (Oil Natural Air Natural) system;
- Gang-operated switches, single-phase switches or SCADA switches;
- Load interrupting switches;
- Fuse disconnecting switches;
- Conductors: “tree proof” protected aluminium (AL) conductors, steel reinforced aluminium conductors (ACSR), aluminium conductors (no tree proof protection), and copper (CU, legacy);
- Voltage Regulators;
- Circuit-breakers with reclosers;
- Capacitors;
- Insulators: made from porcelain (approximately half of all installed insulators) and polymer material (porcelain insulators are being progressively replaced by polymer insulators).

2.5 Communications Systems

The communications systems support the control and protection of electrical equipment. They are divided between protection and control systems, and the SCADA system.

For power lines, the distribution switch automation is generally limited to the 27.6 kV systems (Toronto Hydro, 2007).

Protection and control systems

The protection and control systems are located inside control buildings. Except for batteries, they are located in a temperature controlled room. Batteries at some stations in the Former Toronto area are currently located in the basement of buildings. However, Toronto Hydro expects to relocate these battery assets above grade by the 2030’s in order to help reduce flooding threats.

Typical electrical equipment

- Relays:
- Fuse, Load-break Switch, Circuit Breaker;
- Batteries;
- Auxiliary systems: cranes, fire alarm systems, air compressors, etc.

SCADA system

The supervisory control and data acquisition (SCADA) system is an automated system to remotely control equipment and gather operating information about electrical equipment.

Typical electrical equipment

- SCADA Switch;
- Battery;
- The remote terminal unit (RTU);
- Fault Detector;
- Fiber optic conductor;
- Motorized cell interrupter.

2.6 Civil Structures

The civil structures house or provide structural support for all electrical equipment. They are found in transmission and municipal stations, and all underground and overhead feeder systems.

As a general rule of thumb, civil structures are generally older in the Former Toronto than in the horseshoe area. Older structures (before 1970) may be more susceptible to climate impacts due to their degradation (wood rotting, corrosion of steel) and lack of reinforcement in concrete and design loads.

Typical equipment

For transmission and municipal stations:

- Gantry Towers;
- Exit lines;
- Equipment supports;
- Building: for indoor stations.

For underground feeders and transformer stations:

- Reinforced concrete cable chambers;
- Concrete vaults;
- Underground cable ducts.

For overhead feeders:

- In 2014, there were approximately 176,000 poles in Toronto Hydro's electrical distribution system. The types of poles by construction material are approximately distributed as follows :
    - Concrete : 36%;
    - Aluminum: 2%;
    - Steel: 4%;
    - Cedar Poles : 58%;
    - Fiber glass: Negligible.
    - Iron: Negligible.
- Conductors and hardware (e.g. supports, bolts, etc.);
- Concrete footings (for steel, aluminium, concrete and some wood poles).

2.7 Auxiliary mechanical

Ventilation

All vaults have passive ventilation i.e. natural ventilation through slot openings in cover grates.

Drainage system

Toronto Hydro drainage systems can generally be divided according to the two types of vaults in which they are found:

- Small, shallow single phase sub vaults: do not contain pumps. These vaults' drains are connected to the city's sewer or storm sewer system and drain naturally. These vaults are also being fitted with automatic Petro plugs which stop drainage when oil is detected in the flow (equipment or other pollutant source) in order to prevent oil leaks into the sewer.
- Big deep vaults for Network, URD feeders: most of these kinds of vaults are equipped with mechanical pumps as they are located at a significant depth below grade and often below city sewers. Drains are installed in the walls of the vault and pumps are used to force water into the city's sewer systems. Approximately 10 % of network, URD vaults have drains without pumps (i.e. gravity driven natural drainage).

Sump pump

In 2014, approximately 1600 vaults out of 14,937 vaults had sump pumps (11%) (Toronto Hydro, 2014e). Toronto Hydro estimates that by the 2030's, these sumps will have oil sensing traps that will close if oil (equipment or other pollutant source) is detected.

2.8 Human Resources

Toronto Hydro has approximately 1,500 employees comprised of certified tradespeople, engineers and management professionals (Toronto Hydro, 2012). Employees who are involved in the operation of the electrical distribution system include supervisors and field crews for overhead, underground and network systems, control room staff, call centre workers and dispatchers. Toronto Hydro staff also includes the management team, engineers, asset management specialists and electrical system designers.

Weather can generally affect human resources in two ways. Adverse weather events can affect travel conditions on the journey to and from work for all employees. Furthermore, adverse weather events can affect the working conditions for field crews and field supervisors who need to access, operate or work on equipment across the city. Toronto Hydro strives to ensure a safe working environment for its employees, and has occupational health and safety policies and procedures in place that conform with the international occupational health and safety management system specification OHSAS 18001. These policies and procedures are complemented by the professional judgement of its workers as to whether conditions are safe enough to access outdoor equipment.

2.9 Time Horizon

The evaluation was carried out for the study period (2015 to 2050), but with specific focus on the possible state of the electrical system at the 2030's and 2050's time horizons. For example, this study considered changes to infrastructure systems based on current practices, trends and policy directions (e.g. transition from rear lot to front lot power lines, the partial phase out of 4.16 kV system, some demand and supply projections[11], replacement of

[11] It should be noted that city-wide land use changes (high rises, condo development and population growth) were not included in the analysis, due to the scope of such an undertaking and the complexity of information required. However, system vulnerability was judged based on climate change stresses, as it was assumed that gradual population growth would be accommodated by corresponding growth of Toronto Hydro systems under business as usual practices without the added stress of climate change.

non-submersible equipment). Toronto Hydro documentation, electrical standards and consultations with Toronto Hydro staff were all used to help identify and describe the potential changes to assets at the 2030's and 2050's time horizon. The probability of a climate parameter occurring during the study period and on an annual basis for the 2030's and 2050's was also determined (see next chapter for further details).

2.10 Other Potential Changes that May Affect Infrastructure

2.10.1 Dependencies on Hydro One Infrastructure

Toronto Hydro is part of an interdependent electrical system that is reliant on infrastructure facilities that generate electricity, transmission systems that transport electricity over long distance, and transformer stations that convert voltages for transport and use. The electrical generation and transmission supply infrastructure on which Toronto Hydro relies upon can also be vulnerable to the impacts of a changing climate, and are owned by other electrical companies and organizations in Ontario. Therefore, it is important to note that the vulnerability of Toronto Hydro is therefore also tied to the vulnerability of these supply side infrastructure.

It should also be noted that in the event of a power outage, certain facilities and dependent infrastructure can be supplied by temporary, backup power generators (such as diesel or natural gas generators). In some cases, homeowners may be equipped with photo-voltaic cells that may be able to provide some power in the event of an outage. However, these forms of dispersed generation are specific to facilities and individuals, and not sufficient to meet the demands of larger portions of the population. Dispersed generation does not currently provide sufficient capacity to alleviate Toronto Hydro of its dependence on the large scale electrical generation and transmission supply infrastructure.

Most of the 230 kV, 115 kV and 27.6 kV station equipment that tie Hydro One transmission infrastructure to Toronto Hydro are owned by Hydro One, except for the 27.6 kV breakers at the transmission stations supplying the former North York area and the Cavanagh transmission station, which is totally owned by Toronto Hydro. In general, Toronto Hydro owns the 13.8 kV switchgear equipment. Toronto Hydro and Hydro One share a common Transmission Connection Agreement (Toronto Hydro, 2007).

2.10.2 Load Projections

Electrical load or demand is a significant factor in the operation of transmission stations. Demand is influenced by a variety of factors, including population size, types of uses (e.g. residential, commercial, industrial, institutional, infrastructure), time of day (e.g. peak, off-peak, night time), as well as daily temperature (e.g. heating, cooling).

For the present study, the projections of electrical load on each of the main transmission stations serving the City of Toronto were completed, and are shown in the next table. The methodology used by Toronto Hydro to calculate the projected load for the 2030's and 2050's is described in **Appendix F**. Major future load demand, added transmission station added capacity (i.e. growth), and proposed load transfers[12] were considered by Toronto Hydro.

[12] Load transfer represents the capability to discharge some load from one station to another transmission station. In case of an outage or a very high demand, the loss of supply, or requirement for additional electricity can be provided by another location. Some transmission stations have higher transfer capabilities than others due to higher installed capacity and/or lower demand. However, this capability changes with time: the increasing demand can lessen this flexibility, while investments in new additional capacity can increase the station capability.

Table 2-2 Load Projections by Transmission Station

Service Area *(Voltage step down)*	Number of Stations	Projected load (2030's)[13]	Projected load (2050's)
Former Toronto			
Downtown core *(115 kV/13.8 kV)*	6	86-95%	>95%
Downtown outer *(115/13.8 kV, 230/115 kV,115/27.6 kV)*	2	70-85%	>95%
	6	86-95%	
	3	>95%	
Horseshoe			
North Stations *(230/27.6 kV)*	1	86-95%	>100%
	1		86-95%
East *(230 kV/27.6 kV, 230/115 kV)*	1	<70%	70-85%
	2	<70%	86-95%
	3	70-85%	86-95%
	2	86-95%	86-95%
	1	86-95%	>100%
	1	>100%	>100%
Northwest *(230 kV/27.6 kV)*	2	70-85%	>100%
	1	86-95%	86-95%
	1	<70%	86-95%
Southwest *(230/27.6 kV,230/115 kV)*	2	86-95%	>100%

2.11 Data Sufficiency

The general characteristics of the systems under review were adequate for the purpose of this exercise, although it should be noted that no site visit was conducted in the project. Chapter 7 contains recommendations about further work that can be used to enhance the analysis of electrical system performance and sensitivities to climate related stresses.

[13] Note that Toronto Hydro considers 95 % as the max station load capacity in former Toronto area. This is because there are no station ties between station service areas to allow for the transfer of some feeder loads from one station to another. When a former Toronto area station achieves 95% of its capacity, it signals to Toronto Hydro that a station load relief project is required. In the horseshoe area, station max capacity is considered to be 100% max load capacity, as there are existing station ties available to allow the transfer of feeder loads from one station to another.

3 Assessment of Climate Changes

This chapter describes how the climate data used in this study was developed. This work involved three activities, the identification of climate parameters, the estimation of the historical and future probability of occurrence of climate parameters, and the conversion of probabilities into PIEVC scoring to support the risk assessment. The results of this work are summarized in a table at the end of this chapter (Table 3-2). **Appendix B** and **C** support this chapter, providing additional background information on the methods, information sources and assumptions. The climate work was principally conducted by Risk Sciences International in collaboration with AECOM.

3.1 Climate Data Development Methodology

The development of climate data to support this study involved three main activities.

- First, climate parameters (e.g. temperature, precipitation, wind) and threshold values at which infrastructure performance would be affected were identified (i.e. climate parameters);
- Next, the probability of occurrence of each climate parameter was estimated for future climates; and,
- Finally, the probability information of climate parameters was converted into the PIEVC seven point scoring scale to support the risk assessment.

3.1.1 Identification of Climate Parameters

The identification of relevant climate parameters and infrastructure impact thresholds was an iterative process involving a combination of three methods:

- Literature review of design loads in codes, standards and published literature;
- Practitioner consultation, including targeted interviews, email communications, and workshops; and,
- Forensic analyses of either system specific case studies or relevant cases in the published and grey literature.

While these methods were employed during Phase I, they were expanded significantly and updated for Phase 2. The list of climate parameters from Phase 1 of this study was revisited through practitioner consultations (i.e. workshops), and a more thorough forensic analysis process was conducted using newly available impacts data provided by Toronto Hydro. Literature, including the Institute of Electrical and Electronics Engineers (IEEE) and CSA standards, was reviewed by both RSI and AECOM research team members, yielding more specific design thresholds and criteria. Further information about these techniques can be found in **Appendix B.**

3.1.2 Estimating the Probability of Occurrence of Climate Parameters

To estimate the probability of occurrence of climate parameters over the study period, their probability of occurrence was first established for historical climates. Future conditions cannot be well understood until current and historical climate conditions are quantified, particularly with regards to already existing vulnerabilities and thresholds present within the distribution system. This historical information was combined with climate projections from an ensemble of global climate models through the application of the “Delta-method” (see description on next page) to obtain estimates of the probability of occurrence for climate parameters. Additional complementary estimation techniques (i.e. regional climate models, statistical downscaling, climate analogues) were also employed to evaluate several complex climate events (e.g. freezing rain, ice storms, high intensity rainfall, lightning, tornadoes), as well as to validate or refine the results obtained from the “Delta-method” approach. These tasks are summarized in the following section while more details can be found in **Appendix B**.

Establishing Historical Climate Baseline

The probability of occurrence of climate parameters under historical climate conditions was established in Phase I of this study. Phase 2 reviewed and further refined them in order to serve as a baseline for climate change projections.

Historical climate conditions were established based on Environment Canada's climate station network, the most reliable and highest quality long-term climate record in Canada. While there are numerous climate stations in and around the City of Toronto, detailed hourly weather data are usually only available from airport locations. Thus, the majority of historical climate information used in this analysis is based on records from Pearson International Airport, with further contributions from Buttonville and Toronto Island Airports. Toronto is also the location of the climate station with the longest period of record in Canada, located at its City Centre location, a separate site which provided further perspective on longer term historical climate.

In the case of extreme, very localized, or complex climate events (e.g. tornadoes, freezing rain, ice storms, lightning storms), authors employed alternative methods (e.g. using averaging periods greater than 30 years) or consulted alternative data sets (e.g. the historical tornado database) to establish a historical baseline because this information was not directly available from weather station data.

Future Projections

The climate projection data which serves as a basis for this study was sourced principally from global climate models (GCMs). The latest International Panel on Climate Change (IPCC) 5th Assessment Report (AR5) provided results from 40 GCMs, produced and operated by modeling centres from around the globe. These models provide many of the basic parameters used in developing projections, as well as providing the "boundary conditions" for more detailed assessments, such as downscaling studies. The availability of multiple models also allows for the use of climate model "ensembles," which use multiple models for the development of projections, rather than employing the results of a single model which may contain biases affecting the accuracy of results. The use of ensembles is considered by the IPCC as a best practice for climate analyses, and therefore has been the dominant method used for climate projections in Phase 2.

GCMs require "emissions scenarios" as inputs for the calculation of climate projections. The latest IPCC AR5 has introduced a new method of describing future changes in emissions. Representative Concentration Pathways, or RCPs, describe explicitly the expected increase in energy generated by increases in greenhouse gases. The most pessimistic emissions scenario, RCP 8.5, indicates an increase of 8.5 watts per square meter of additional energy under future climate conditions. It is referred to as the "business as usual" emissions scenario, provides the best fit based on historical trends in global emissions, and was the scenario used for Phase 2. Further details on IPCC findings, GCMs, RCPs, and other aspects of climate change projections, can be found in **Appendix B.**

Applying the "Delta-Method"

Individual GCMs contain inherent biases when attempting to recreate historical climate, for example being either too cool or warm compared to historical averages. To compensate for this effect, the "Delta-method" was employed. First, GCMs were evaluated to determine changes from their own respective baselines. This difference between model baseline and projected conditions is then applied to the observed historical climate baseline. For example, if the GCM ensemble indicated an average increase of 2 degrees between the baseline period and the 2050's, and a given station shows an average annual temperature of 3°C, then the projected annual average temperature for that location for the 2050's becomes 5°C. This represents the "delta", or the change in climate parameter based on the difference projected by the GCM ensemble applied to historical baseline data.

Treatment of Complex Climate Events

To validate the results obtained from the GCM – "Delta-Method" for some of the climate parameters, three other complementary estimation techniques were also used, regional climate modeling, statistical downscaling

techniques and climate analogues. Furthermore, some complex climate events tend to occur on much smaller spatial and temporal scales than are covered by GCMs (e.g. tornadoes, freezing rain, ice storms, lightning). Use of these three complementary estimation techniques was necessary to develop projections for these kinds of climate parameters.

It should be noted, however, that even with the availability of specialized methods, there remain highly localized atmospheric events which cannot be projected with confidence, and the effects of climate change on these types of events are still being researched by the climate research community. See **Appendix B** for further discussion of developing projections for complex climate events.

Estimating the Probability of Occurrence of Climate parameters

The methodology used for determining climate parameter probabilities for Phase 2 was somewhat modified from standard PIEVC Protocol based studies. The Protocol (Engineers Canada, 2012) indicates that the probability of a climate parameter occurring should be based on the probability of occurrence during the *full* time period of the study, which is typically the life cycle and long-term planning considerations of the infrastructure under study. For Phase 2, a period of 35 years between 2015 and 2050 was chosen. However, in recognition that response to these hazards can include both asset hardening/replacement cycles (long-term measures) as well as maintenance and management considerations (short term measures), a second set of probabilities based on annual occurrence was also determined. Examining both annual and study period probabilities was useful for understanding vulnerabilities based on climate parameters that would occur on an annual basis (e.g. high temperature) against those which would occur less than annually, but with the potential to cause significant impacts sometime during the 35 year study period (e.g. ice storms, high winds, tornadoes).

Annual probabilities are expressed as the number of occurrences per year for historical and (where available) projected estimates for the 2030's and 2050's, or more specifically for 30 year periods centred on those future decades. The so-called "study period" or "lifecycle" probability of occurrence is then expressed as a percentage (i.e. given those annual frequencies, what is the overall probability that an event will occur during the *entire 35 year time horizon*?).

The probability of occurrence of a climate parameter considered in this project is, in most cases, representative of a "point" probability (i.e. historical probability values based on measurements at a single location). However, the lightning and tornado climate parameters were also evaluated using different "target" sizes to illustrate the effects of changing this perspective, as well as to better correspond with field conditions and associated response. More detailed information about how the probabilities of individual climate parameters were determined can be found in **Appendix B**. The results of this work are listed in Table 3-2 at the end of this chapter.

3.1.3 Assigning a PIEVC Score to Climate parameter Probabilities

The probability of occurrence for climate parameters both annual and during the study period were converted into PIEVC probability scores (i.e. 0-7) for the risk assessment, following the quantitative "Method B" approach indicated in the Protocol (Engineers Canada, 2012) (see Table 3-1). For example, the annual probability of occurrence of high temperatures above 40°C was estimated to occur approximately 0.01 times per year in the historical period (last 100 years), or 1 % probability of occurring each year (PIEVC score 1). Similarly the annual probability for this parameter was 0.3 to 2 times per year for the 2030s, which signifies a 30 % to >100 % probability of occurring each year (PIEVC scores 4 to 7 respectively). This climate parameter is estimated to occur between 1 to 7 days per year by the 2050s, such the annual probability of occurrence is >100% (PIEVC score 7).

Table 3-1 PIEVC Version 10 Probability Scores based on Method B

Score	Probability	
0	< 0.1 %	< 1 in 1,000
1	1 %	1 in 100
2	5 %	1 in 20
3	10 %	1 in 10
4	20 %	1 in 5
5	40 %	1 in 2.5
6	70 %	1 in 1.4
7	> 99 %	> 1 in 1.01

3.2 Summary of Results

24 climate parameters covering temperature, precipitation, wind and lightning hazards were considered within the climate analysis. However, four of them were not carried forward in the vulnerability assessment due to data availability issues or relevance[14]. Table 3-2 provides a summary of the climate data results. Relevant climate parameters and infrastructure thresholds (climate parameters) to be used in this study are listed. For these climate parameters, historical and future probabilities of occurrence, as well as PIEVC probability scores for annual and study period probabilities are presented.

Table 3-2 Climate Parameters and Thresholds, Occurrence Probabilities and PIEVC Scoring

Climate Parameter	Threshold	Annual Probability (Historical; **Projected 2030 and *2050***)	Probability of Occurrence Study Period (2015-2050)	PIEVC Scoring		
				Historical	2030's & 2050's	Study Period
Daily Maximum Temperatures	25°C	66 per year; **84 per year**, ***106 per year***	100%	7	7	7
	30°C	16 per year; **26 per year**, ***47 per year***	100%	7	7	7
	35°C	0.75 per year; **3 per year**, ***8 per year***	100%	6	7	7
	40°C	~0.01 per year[15]; **0.3 to 2 days per year, *1-7 days per year***	~100%	1	4 - 7	7
High Daily Avg Temperature	30°C	0.07 per year[16]; **N/A, *1.2 days per year***	~100%	3	7	7
	35°C	*Zero* occurrences historically; ***zero occurrences projected***	0%	0	0	0
Heat Wave	3 days max temp over 30°C	0.88 per year; **>1 for both**	100%	6	7	7
High Night time Temperatures	Nighttime low ≥23°C	0.70 per year; **7 per year, *16 per year***	~100%	6	7	7
Extreme Rainfall	100 mm in <1 day + antecedent	0.04 per year; ***extreme precipitation expected ↑, percentage unknown***	~75%-85%	2	3	6

[14] The climate parameters not evaluated in the vulnerability assessment were high daily average temperature above 35°C (relevance), 6 hr+ freezing rain (relevance, as no ice accretion threshold was known), Minor ice accretion and deicing agents (complex interaction, no projection data available) and tree growth, pest and disease (complex interaction, no data available).
[15] Based on data from Toronto City Center station rather than Pearson Airport.
[16] Based on 4 occurrences since 1961 at Pearson Airport; see discussion in text for further details.

Climate Parameter	Threshold	Annual Probability (Historical; **Projected 2030 and *2050***)	Probability of Occurrence Study Period (2015-2050)	PIEVC Scoring		
				Historical	2030's & 2050's	Study Period
Ice Storm/Freezing Rain	15 mm (tree branches)	0.11 per year; **>0.13 per year, *>0.16 per year***	>99%	3	3	7
	25 mm ≈ 12.5 mm radial	0.06 days per year; **>0.07 per year, *>0.09 per year***	>95%	2	3	7
	60 mm ≈ 30 mm radial	High Risk: 0.007 events per year; **>0.008 per year; *>0.01 per year*** Low Risk: 0.002 events per year; **> 0.0023 per year; *0.003 per year***	High: ~25% Low: ~8%	0-1	0-1	2-4
	6 hours + freezing rain	0.65 days per year; **~0.75 per year, ~0.9*4 per year***	100%	5	6	7
High Winds	70 km/h+ (tree branches)	21 days per year***; N/A, *24 to 26 per year***	100%	7	7	7
	90 km/h	2 days per year; **N/A, *>2.5 per year***	100%	7	7	7
	120 km/h	~0.05 days per year; ***likely ↑, but % unknown***	~85% or higher	2	2	7
Tornado	EF1+	1-in-6,000; ***Unknown, no consensus***	~0.6%	0	0	1
	EF2+	1-in-12,000; ***Unknown, no consensus***	~0.3%	0	0	0
Lightning[17]	Flash density per km km^2	1.12 to 2.24 per year per km^2; ***Expected increase, % change unknown***	~50-70%(Lg); ~10-20% (Sm)	Lg - 2 Sm - 0	n/a	Lg – 6 Sm - 3
Snowfall	Days w/ >10 cm	1.5 days per year; ***Trend decreasing but highly variable***	100%	7	7	7
	Days w/ > 5cm	5 days per year; ***Trend decreasing but highly variable***	100%	7	7	7
Frost		229 frost free days; **249 frost free days, *273 frost free days***	100%	7	7	7
Complex Interactions	Minor ice accretion + deicing agents	***Projections unavailable***	N/A		N/A	
Complex Interactions	Changes in tree growth, disease conditions	***Projections unavailable***	N/A		N/A	

3.3 Data Sufficiency and Recommendations

The primary sources of information used in this climate data work were:

- Environment Canada Weather Station Data;
- IPCC AR5 quality controlled GCM output;
- TRCA environmental data and observations (TRCA 2014).

The climate data available for this study was judged to be sufficient to cover the majority of climate related stresses to electrical distribution systems (stemming from temperature, precipitation and wind). The study area of the City of Toronto also benefited from having good quality, long-term climate data that covered most areas of the city for these types of climate parameters. While further studies, in-depth analyses, and data quality improvements can be made (see Chapter 7), the climate data that was available was sufficient to support the risk assessment.

[17] Note that "Lg" and "Sm" refer to large and small transformer stations, see Appendix B for more details.

4 Vulnerability Assessment Methodology

The vulnerability of the electrical system to climate parameters was initially completed by employing a screening level risk based methodology (risk assessment) to identify low, medium and high risk interactions. The level of risk was evaluated based on the probability of occurrence of a climate parameter coupled with the severity (consequence) of the impact on the system and on electrical service provision. Low risk level interactions were generally judged as not being a significant issue for Toronto Hydro. Medium level risks were evaluated through a further engineering analysis to determine whether the interaction resulted in vulnerabilities (or part of a general pattern of vulnerability). Finally high risk level interactions were deemed as vulnerabilities for Toronto Hydro.

The general procedure for the risk assessment is described in Step 3 of the Protocol. However, study specific considerations (e.g. the *systems level approach*), adaptations and guidance for completing the risk assessment are described in the following chapter. Completion of the risk assessment follows the "Consultant Option" of the Protocol[18]. Notably in this option, AECOM completed the risk matrix through internal meetings with its own electrical engineers. This information was then validated with Toronto Hydro staff in a workshop held on October 10, 2014, at Toronto Hydro's offices.

4.1 Risk Tolerance Thresholds

The risk tolerance thresholds employed within this analysis conform with the proposed thresholds of the Protocol as given in the table below. These thresholds were validated with Toronto Hydro at the workshop.

Table 4-1 Risk Tolerance Thresholds

Risk Range	Threshold	Response
< 12	Low Risk	Monitoring or no further action necessary
12 – 36	Medium Risk	Vulnerability may be present. Action may be required, TBD through engineering analysis
> 36	High Risk	Vulnerability present, action required

4.2 Yes/No Analysis

The first consideration of the risk assessment is to identify whether a climate parameter will interact with the infrastructure system under consideration. A Yes/No analysis column for each of the 20 climate parameters is included in the risk assessment matrix presented in **Appendix D**. A "No (N)" result means that there is no interaction between the climate parameter and infrastructure system, while a "Yes (Y)" result means that there may be an interaction. The severity assessment is conducted only for "Yes" interactions.

4.3 Infrastructure Performance Responses - Systems Level Approach

As mentioned in the introduction, this study adopts a *systems level approach* to the analysis of climate change impacts on Toronto Hydro electrical distribution infrastructure due to the extensive, complex and interdependent nature of the electrical system. The severity of impact is evaluated based on the consequences of the interaction of different weather events with the systems and subsystems under study.

The relevant infrastructure performance responses remain the same as presented in the pilot case study. Notably, they are:

- Structural design - *Structural integrity, cracking, deformation, foundation anchoring, etc.*

[18] This approach, rather than the facilitated option, was adopted in this study because it was more efficient; the learnings gained from the pilot case study provided AECOM with the necessary insight to complete the risk assessment on its own prior to validation with Toronto Hydro.

- Functionality - *Effective load capacity, efficiency, etc.*
- Serviceability - *Ability to conduct maintenance or refurbishment, etc.*
- Operations, maintenance and materials performance - *Occupational safety, worksite access, operations and maintenance practices (frequency and type), etc.*
- Emergency Response - *Planning, access, response time*
- Insurance Considerations (Toronto Hydro perspective) - *claimable for repair, cause 3rd party payment, affect insurance rates*
- Policy and Procedure Considerations - *Planning, public sector, operations, maintenance policies and procedures, etc.*
- Health and Safety - *Injury, death, health and safety of Toronto Hydro employees, the public, etc.*
- Social Effects - *Use and enjoyment, access, commerce, damage to community assets (buildings), public perception, etc.*
- Environmental Effects - *Release or harm to natural systems (air, water, ground, flora, fauna)*

It is clear that within a *systems level approach*, weather interactions with infrastructure systems can solicit a range of different performance responses, as well as responses of differing degrees (i.e. intensity) from different components. In other words, some components within a system are more sensitive to certain types of weather events than others (e.g. heat affects the operation of transformers more than it affects the wooden pole on which the transformer is attached).

In order to conduct a logical, structured analysis, the proposed *systems level approach* identifies the infrastructure performance response stemming from the component (e.g. pole, transformer, power line, switch, etc.) which constitutes the weakest link in the system category for a given weather parameter. The component whose functionality, capacity, structural integrity or operation is affected or compromised the most, which in turn may cause other interdependent components or the entire system to cease to operate, fail, or lose capacity, constitutes the weakest link in the system. For example, the failure of a station power transformer due to high temperature and load may cut off electricity service, irrespective of what the heat may do to other equipment and structures. The station power transformer is thus considered to be the most sensitive and weakest link under high heat conditions.

As the primary role of Toronto Hydro's electrical distribution infrastructure is to provide electricity, one primary guiding criteria was used to determine which component(s) within the major systems categories constituted its weakest link: the component which, due to an interaction with a weather event, resulted in damage/failure of that component, which in turn compromised the ability of the system to deliver electricity to customers safely and securely. The risk assessment matrix presented in **Appendix D** contains a column named "consequence" which identifies the weakest link component and the anticipated infrastructure performance response.

4.3.1 Consideration of Redundancy and Station Capacity

While a component malfunction or failure may compromise the system's ability to provide electricity safely and securely, a *systems level approach* allows system design characteristics to mitigate this impact. Two notable characteristics of electrical systems are considered by this study: redundancy and station capacity.

Redundancy is the duplication of equipment and systems that afford an alternative way to deliver electrical services in the event of equipment damage or failure. In electrical systems, redundancy is provided through the presence of similar or identical equipment operating in parallel or kept on standby, and is a key component of essential infrastructure services such as electricity provision. Station capacity indicates that a station possesses capacity in excess of normal demand (i.e. under normal circumstances).

Redundancy and station capacity are characteristic of the different types of electrical systems under study. As redundancy and station capacity can mitigate component failures (i.e. allow systems to continue to provide electricity despite equipment failure in one area), they are used as mitigating factors which can attenuate severity

scores. The explanation of how redundancy and station capacity are evaluated for each of the major systems categories is in presented in the sections below.

Transmission Stations

A station's ability to mitigate the system's vulnerability to climate is most usefully considered with respect to high temperatures. During high temperatures, stations with greater excess capacity will be able to continue to supply electricity despite increased demand, while stations with less excess capacity may have to reduce demand (e.g. shed load through temporary forced outages) in order to operate station equipment acceptably (e.g. to avoid overheat and burnout).

Transmission station capacity is based on the load projection exercise completed by Toronto Hydro for this project. This study is briefly described in **Appendix F (**Also see Chapter 2, *Load projections*, for more information). Station capacity is rated as low or good based on the load cut-offs shown in the table below. If the station capacity is rated as low by the end of the study period (2050's), its severity evaluation for high temperature parameters is increased by ''+1''.

It is possible that excess station capacity can also be considered as a mitigating factor in the event of freezing rain, flooding, high winds, etc. For example, if a high wind event causes flying debris to damage an outdoor station, an adjacent station can help by picking up some of the load. In this case, it is the capacity of adjacent stations which helps determine the vulnerability of a service area. In the horseshoe area, station and feeder ties between service areas allow some of the load to be transferred[19]. However, this factor is not considered in the present study because adjacent stations can only take on a small portion of a faulted station's load (i.e. no station is designed to take the full load of an adjacent station, otherwise it would be overdesigned), nor are there sufficient feeder or station ties to allow the complete transfer of the load. Thus, large portions of a service area may still be susceptible to an outage at its transmission station in spite of the fact that an adjacent station has excess capacity.

Table 4-2 Severity Rating Based on Station Capacity by the 2050's

Severity Rating	Station Projected Load by the 2050's
Low (+1)	≥ 95 % (Toronto) and ≥100% Horseshoe Area
Good (no change)	< 95 %

Municipal Stations

The redundancy of the municipal stations is based on geography, and only considered for high temperature parameters for the same reasons as listed above under transmission stations. According to Toronto Hydro, if a municipal station is located in the Former Toronto area, it is generally considered that the station has less transfer capability than a station located in the horseshoe area. Severity ratings for all municipal stations in the Former Toronto area are increased by ''+1'' to reflect the low station transfer capacity in the event of a problem. This severity increase for former Toronto area municipal stations does not apply to other climate events such as freezing rain or wind because these stations are generally located indoors in the Former Toronto area.

The Toronto Hydro to Private ownership stations are dedicated to the owner. There are no transfer capacities to another station. A ''+1'' is added to the severity rating for high temperature parameters.

[19] Recall that at present, there are no station ties between station service areas in the Former Toronto area. The addition of station ties in this area is constrained by the fact that infrastructure is older, located in a dense built urban environment, and generally underground. At present, Toronto Hydro is considering the addition of station ties in the Former Toronto area, but this is not considered in this risk assessment due to its preliminary nature of this idea. In the horseshoe area, station ties allow stations to provide some load relief to adjacent service areas when required.

Underground Feeders

The redundancy of the underground feeders is based on the configuration of the feeder and its location in the city. Dual radial and residential feeders in the Former Toronto area are considered to have the lowest redundancy and capacity because structures are older, more stressed by higher loads, and are installed with less space between the conductors. The arrangement of the conductors is important because the ampacity of conductors are sensitive to the heat generated by nearby conductors. Severity ratings for these feeders are increased by ‘’+1’’ as a result (Table 4-3).

Table 4-3 Severity Rating Based on Feeder Configuration

Severity Rating	Increasing Levels of Feeder Redundancy
Low (+1)	Dual Radial & URD : Former Toronto
Moderate (no change)	Dual Radial & URD : Horseshoe
Good (no change)	Compact Loop Design
Best (no change)	Network

Overhead Feeders

The redundancy of the overhead feeders is considered between two configurations: radial or loop. Radial lines cannot be backed-up in the event of a fault, while loop configurations could allow electricity to be brought in through the “other side” of the loop. For this purpose, the severity ratings for radial feeder configurations are increased by ‘’+1’’.

Communications Systems

The redundancy evaluation is not considered for the communications systems, as they do not mitigate circumstances of loss of electrical service provision.

Civil Structures

Historically, infrastructure built for the distribution of electricity in the City of Toronto were concentrated in the downtown core and inner city and later extended to the horseshoe area. Part of the electrical equipment was replaced over time but much of the civil structures (e.g. underground vaults) remain in place due to their expected lifespan (35 - 60 years). It is thus assumed that the civil structures in the Former Toronto area are older and more degraded than the structures in the Horseshoe Area. A ‘’+1’’ severity scoring is added to the Former Toronto civil structures.

4.4 Scoring Severity

The severity scoring exercise is conducted using the scoring scale defined by the Protocol, method D. Examples of impacts on different equipment were developed in the course of this analysis. In addition to the guidance provided by the Protocol on severity scoring, this study provides a further, electrical system specific consideration in severity scoring. Two complementary, severity scoring scales were developed for this study to reflect the severity scoring differences between stations and feeder systems. As stations represent major nodes in the distribution of electricity, an affected or disabled station could result in a loss of service on all downstream feeder systems and customers. However, if a feeder branch or sub-branch is affected, only the customers on the branch or sub-branch may be affected. Thus, the impacts on station equipment are judged to be more severe than impacts on feeder systems. The severity scoring scale employed in this study, as presented below, reflects this general consideration.

Table 4-4 Severity Scoring Scale for Electrical Distribution Systems

Score	Stations			Feeders	
	Method D	**Descriptive**	**Examples**	**Descriptive**	**Example**
0	No Effect	Negligible or N/A		Negligible or N/A	
1	Measurable	Very Low - Some measurable change		Some loss of serviceability & capacity, no loss of function	*Arrestor failure, overheating cables, salt deterioration of civil/electrical equipment*
2	Minor	Low - Slight loss of serviceability	*Station battery – lifespan shortened*	Some loss of capacity & function	*Overheating transformer from high load*
3	Moderate	Moderate loss of serviceability, some loss of capacity, but no loss of function	*Station transformer heating up, but possibility of meeting demand from another station*	Moderate loss of function	*Broken spring in underground switchgear, distribution transformer out (must replace), cable*
4	Major	Major loss of serviceability, some loss of capacity & function	*Station transformer heating up, need to do load shedding*	Major loss of function of multiple equipment – localized	*Transformer and switchgear out (replace multiple equipment)*
5	Serious	More loss of capacity & function	*Station transformer heating up, need to do load shedding for longer duration*	Major loss of function of multiple equipment – wide area	*Transformer and Switchgear out Flooded vault that cannot be pumped*
6	Hazardous	Major - Loss of Function	*Loss of CT/VT transformer, battery assets*	Major loss of function of multiple equipment – wide area	*Leaning pole/downed line*
7	Catastrophic	Extreme – Loss of Asset	*Station trans. failure*	Major loss of function of multiple equipment – wide area	*Downed pole, line and transformer*

4.5 Mapping Risks

Due to the sheer number of similar assets and their distribution across the city, study authors and Toronto Hydro have elected to map climate change risks to the electrical distribution system in the City of Toronto. It was decided that two main asset classes would be included in the risk map: stations and feeders. The risks to supporting infrastructure, such as communication systems and civil structures, were difficult to represent on such a large scale. Furthermore, the risks to these systems are generally associated with, and can be adequately illustrated by, the risks to the stations and feeder systems.

The risk mapping exercise was completed using the geographic information systems (GIS) resources provided by Toronto Hydro. AECOM provided the final risk assessment matrix results to Toronto Hydro's GIS team. Each of the station and feeder assets in the risk assessment matrix were identified on GIS maps. Stations were illustrated as polygons representing the stations' service areas rather than as points where stations are located. This was done in order to illustrate the fact that faults at a station can affect an entire service area. Feeder systems were illustrated as line vectors on the map. Next, the low, medium or high classification of station or feeder risks were represented by colouring the assets class representations (polygons or lines) in yellow, orange or red to denote low, medium and high risks respectively. Where there were no interactions between climate and infrastructure, asset representations were coloured in grey. Finally, white spaces within the City of Toronto generally indicate where no electrical service is provided. Results of the risk mapping exercise are presented in Chapter 5 and in **Appendix E**.

5 Assessment Results

This chapter presents a summary of anticipated impacts from the interaction of climate events with electrical distribution system infrastructure resulting in low, medium and high risk interactions. In addition, special case risks are also presented.

5.1 Low Risk Interactions

High Temperature

SCADA systems may be affected by ambient air temperatures above 40°C. According to equipment design specifications (S&C manufacturer, 2011), such temperatures constitute unusual conditions for the interrupters within the SCADA system. At high temperatures over 40°C, the accuracy of power line current and voltage sensors, as well as the ability to provide DC voltages for the control of the switch, are not assured. SCADA system equipment are tested to operate between -40°C to +40°C. However, other components of the SCADA system like the communication and control unit can operate at temperatures up to +70°C. A low risk score was given considering that the SCADA switch is able to operate in temperatures above 40°C, but its performance (accuracy of sensors) may decrease.

Extreme Rainfall

Extreme rainfall poses a low risk to certain underground feeder systems in the horseshoe area. Underground feeder systems with some equipment located in above ground vaults or on padmounts may be affected by localized flooding due to extremely rainfall. This creates an issue in terms of accessing equipment.

Some transmission stations in the Former Toronto area currently have batteries and switchgear located below grade. This equipment could be damaged if flooding occurred. Toronto Hydro is currently moving its battery assets above grade when they reach the end of their lifecycle (typically 10 – 12 years). By the 2030's, it is expected that all station batteries will be moved above grade. Some of the switchgear equipment will also be moved above grade, although stations in the Former Toronto area may face space constraints to moving all equipment above grade. As such, it is likely that some switchgear will still be located below grade by the 2030s. However, stations are equipped with multiple sump pumps which can evacuate water that flows into the basements. According to a Toronto Hydro representative, there have been no flooding incidents to Toronto Hydro stations owing to heavy precipitation over the last several decades due to the pump and drainage systems found in stations. Based on expected work to relocate batteries and certain switchgear, and continued adequacy of sump pumps, the risk of flooding from extreme rainfall for transmission stations in the Former Toronto area was rated as a low risk.

Freezing Rain

For stations, 15 mm or less of freezing rain are not expected to create sufficient ice loads to cause structural problems. Freezing rain could cause some delays in accessing equipment (e.g. ground or equipment encrusted with a layer of ice), although this was judged to be of low risk by workshop participants

Snow

Snow accumulation and snow fall, especially for days with >10 cm of snow, can also cause visibility and access issues. Access to padmounted transformers and switches, as well as underground vaults may be hampered by snow pushed aside from road and sidewalk snow clearing equipment, thereby lengthening the time needed to access equipment. However, access issues from snow were judged to be of low risk by workshop participants.

Frost

Frost may cause the displacement of the ground (frost heave) and compromise the stability of the foundations of poles, vaults and cable chambers. Frost heave events are generally localized, and do not tend to disrupt electrical service. Furthermore, the number of frost free days are expected to increase by 2050 due to increases in annual temperatures. For these reasons, frost was judged to be of low risk. Civil structures located in the former Toronto area were given a slightly higher (+1) severity rating (and therefore risk rating) because the infrastructure is generally older than those found in the horseshoe area.

5.2 Medium Risk Interactions

High Temperature

High ambient air temperatures starting at 25°C and above are responsible for the majority of medium risks evaluated within this study. Unless stated, the temperatures presented below exclude consideration of humidity on felt temperature (i.e. humidex). From an electrical equipment point of view, it is the ambient air temperature, not humidity, which impacts the structural integrity or lifespan of equipment. Humidity, coupled with high ambient air temperatures may result in higher felt temperatures by people, which in turn can increase the demand for air-conditioning. However, risks posed by high temperatures to infrastructure are evaluated in terms of their design and performance characteristics (ability to shed heat or cool down), which are not affected by humidity levels. High humidity was considered when evaluating the risks to Toronto Hydro personnel.

High temperatures affect the lifespan of station batteries. Where the air temperature of rooms that house station batteries exceeds 25°C, the lifespan of the batteries will begin to degrade. This will result in the long-term in the replacement of batteries sooner than expected. The buildings containing the rooms where batteries are stored afford some protection from changes to external air temperatures. This means that an external air temperature of 25°C may not immediately trigger the premature degradation of batteries. However, rooms where batteries are stored are not temperature regulated, and the impacts to battery lifespan will increase as external air temperatures increase above 25°C. Heat impacts on station battery lifespan were judged to be of medium risk.

As maximum daily air temperatures exceed 35°C, station power transformers will be the most critical pieces of equipment to be affected. First, the use of air-conditioning will increase, thereby increasing the electrical load on transformers. Transformers will heat up, but warm ambient air temperatures also reduce the effectiveness of natural or mechanical cooling. Stations with low projected excess capacities by the 2030's and 2050's will be less able to meet additional demand during periods of high temperature because of higher existing base load. These include transmission stations located in downtown areas, as well as Bathurst station, Sheppard, Leaside, Rexdale, Woodbridge, Manby and Horner. These were judged to be slightly more at risk (+1 severity) as compared to other stations in the East and Northwest sub-service areas.

Heat waves, when the daily maximum temperature during three consecutive days exceeds 30°C, as well as warm nights (minimum temperatures ≥ 23°C) both constitute medium risks for station power transformers. High night time temperatures will result in continued electrical use for air-conditioning, and also decrease the potential for transformers to cool down overnight. However, overall electrical demand is lower at night than during the daytime, and Toronto Hydro staff did not consider high night time temperatures to be as significant a concern as high daytime temperatures or heat waves from an electrical system point of view (Workshop 2).

High temperatures above 40°C, average temperatures over 30°C on a 24h basis, heat waves and high night time temperatures were also judged to be a medium risk for underground and overhead feeder systems due to high electrical demand for cooling and high ambient temperatures. Cables and power transformers were the two most vulnerable parts of these feeder systems in terms of heat. Under high demand, underground conducting wires and their housing undergo thermal expansion. This affects the structural integrity of the housing by causing wear and potentially leading to microfractures that are susceptible to water infiltration. Underground cables laid in close proximity or side by side, as is the case for underground feeders in the denser Former Toronto area, are also

more susceptible to these expansion effects than underground feeders in the horseshoe area. Adjacent cables tend to heat one another up, and the increased heat reduces the cables' electrical transmission capacity. In overhead systems, cables under high demand will also lead to cable expansion and conductor sag. While this sag is generally accounted for in tree trimming and object clearance around power lines, excessive sag may be more prone to contacting objects and causing an electrical fault.

Feeder system power transformers are affected in a similar manner as their station counterparts. High ambient temperatures place additional demand from air-conditioning on transformers, while also affecting their ability to effectively cool. Overheating overhead transformers may fail or catch fire and will have to be replaced. In terms of relative risk, it should be noted that an overheating feeder line power transformer is less critical than an overheating station transformer, as the former serves fewer clients than the latter.

Underground dual radial, URD, compact loop and network systems afford increasing levels of redundancy for clients, due to their ability to supply electricity in the event of an outage through a different branch, loop or conduit of the feeder system. In this study, dual radial and URD feeders in the Former Toronto area were considered to be less able to cope with high electrical demand and mitigate outages than similar electrical feeder types in the horseshoe area. This is due to the fact that feeders in the Former Toronto area are already under high base load (denser environment), their equipment is generally older and cables running side by side increase the heat load and reduce their maximum capacity. Therefore, underground feeders in the Former Toronto area are considered to be slightly more at risk (+1 severity) to heat impacts as compared with similar feeder types in the horseshoe area.

Overhead feeder systems were judged to be slightly more at risk (+1 to +2 severity) than underground systems to temperatures above 40°C and to average temperatures above 30°C on a 24h basis. While electrical load demands may be similar for underground and overhead transformers, direct solar radiation and exposure to high ambient air temperatures can reduce the ability of overhead transformers to disperse heat. On the other hand, overhead transformers were judged to be less vulnerable to high night time temperatures than underground systems, due to increased circulation of cooler nighttime air around overhead transformers as compared to those located in underground vaults.

High ambient air temperatures were also judged to be medium-low risks for protection and control systems. Like station batteries, high temperatures will degrade the expected lifespan of batteries used to power the feeder protection and control systems in the event of a power failure.

Extreme Rainfall

The most significant medium risks from extreme rainfall events are related to the flooding of non-submersible vault-type electrical components kept below grade. Vaults below grade are usually equipped with either passive drainage systems or active pumping drainage systems to keep them from flooding. However, under extreme rainfall conditions, it is possible that the sewers to which these drainage systems are connected may themselves be at capacity, and without the ability to evacuate the water, some vaults may flood. In flooded vaults, non-submersible electrical equipment could be damaged, and an outage may occur. This is also a concern in some network type feeders in downtown Toronto, where old network protection equipment are not housed in submersible enclosures. Toronto Hydro is gradually installing submersible equipment in all below-grade vaults, but non-submersible equipment is still expected to be in present by the end of the study period. Furthermore, the equipment in flooded vaults cannot be accessed until the water is evacuated, creating a delay in responding to electrical incidents.

While not exclusively a problem related to heavy rainfall events, water infiltration into the ground and moisture around underground cables can lead to water treeing[20] and cracking of cable insulation. Deterioration of cable housing could lead to electrical faults if cracks become sufficiently large to allow ground moisture to serve as a pathway for electricity to ground.

[20] Tears in the cable's insulating layer caused by the presence of moisture and an alternating current's (AC) electric field.

It was noted in the workshop that extreme rainfall can be beneficial to overhead feeder systems. Salt residues from the wintertime and dust throughout the year can accumulate on electrical insulators. Moist conditions such as fog, mist or light rainfall can cause these accumulations to serve as conduits to ground, causing flashovers and potential pole fires and outages. Heavy rainfall events, especially in the early spring, are in fact beneficial for washing off the salt and dirt residues from insulators. Note that 27.6 kV and 13.8 kV lines are more prone to flashovers due to their higher voltages. It was noted in the workshop that 27.6 kV systems in particular may require more frequent cleaning than is currently the case in order to prevent flashovers, while flashovers do not tend to occur with 4.16 kV equipment.

High Winds

High winds over 70 km/h (but less than 90 km/h) were considered a medium risk to overhead power lines. While lines and poles are designed to withstand such wind speeds, it has been found that tree branches may begin to break at these thresholds and fall onto lines. Overhead conductors may also flail in the wind and contact branches. At the least, these tree contacts may cause momentary interruptions to electrical service. At the worst, tree branches and limbs may fall on and damage or sever power lines, potentially causing outages, fires and public safety hazards.

Lightning

Lightning strikes on overhead feeder systems was rated as a medium risk. Lightning arrestors installed on overhead power lines are designed to direct lightning surge currents to ground and protect pole mounted equipment such as transformers, switches and SCADA equipment. However, failure of the lightning arrestors can result in damaged equipment from lightning strikes and potentially lead to a localized outage.

Human Resources

Most of the human resource interactions with climate parameters (high heat, heavy precipitation, 15 mm of freezing rain, high wind, tornadoes, lightning and snowfall) were judged to be of medium risk. High heat conditions can make it dangerous to work on outdoor and overhead equipment for extended periods of time. For underground systems, high ambient temperatures can exacerbate hot conditions in vaults (heated by transformer operation), thereby also making it unsafe to work on equipment for extended periods of time. Workers tend to defer work under high heat conditions until temperatures above ground or within vaults cool sufficiently to allow safe continuous access. This may however cause a delay in the response to incidents on the electrical system.

Heavy precipitation, freezing rain and snowfall may make it difficult for all employees to travel to and from work, while also making it dangerous for field workers to get to equipment. During severe events such as high winds, tornadoes and lightning, workers apply their judgement and generally delay accessing equipment until the severe weather event has passed. Interestingly, the severity scoring of high winds at 70 km/h were slightly higher than scores for higher wind speeds (90 km/h, 120 km/h or tornadoes). This is because unsafe work conditions are very clear under extreme high wind events. However, at lower wind speeds, work conditions may appear to be acceptable, and workers may decide that the threat is reasonable given the need to restore electrical service. However, sudden, abrupt wind gusts could momentarily jeopardize worker safety.

As Toronto Hydro has occupational health and safety policies and procedures in place, the consequence of severe weather on workers tends to be delaying access and work on equipment until weather conditions, road access improves, and worksites are declared to be safe.

5.3 High Risk Interactions

The highest risks found in this study are related to structural damage and failure of electrical systems and components. In general, station equipment and overhead feeder systems were the two main system infrastructure categories susceptible to climate interactions that yield high risk interactions.

High Temperature

Days with peak temperatures above 40°C and days where average ambient temperatures exceed 30°C on a 24h basis are the two significant climate parameters rated as high risk for transmission and municipal stations. Days with peak temperatures above 40°C are currently a very rare occurrence, but are expected to occur on an almost annual basis by the 2030's and on an annual basis by the 2050's. Similarly, high ambient temperatures exceeding 30°C on a 24h basis are currently a rare occurrence, but may occur on an annual basis by the 2050's. In both cases, high electrical demand, coupled with loss of cooling efficiency, will cause station power transformers to overheat. In the most severe of cases, demand cannot be maintained without damaging station power transformers, which have an average replacement cost of around $500 K[21]. A coping mechanism employed by electrical utilities is to shed electrical load (load shedding), which entails instituting temporary outages in various sectors of the city in order to reduce load demand. For buildings and residents dependent on air-conditioning for cooling purposes, this represents a significant public health risk at a time of extreme heat events.

This high risk is especially relevant for transmission and municipal stations with low excess capacity by the 2030's and 2050's. As such, during periods of high demand, these stations have less excess capacity with which to meet electrical demand.

Freezing Rain and Ice Storms

There are three significant thresholds to consider for freezing rain and ice storm effects on the electrical distribution system. First, preliminary forensic analyses of outages from freezing rain indicate that 15+ mm of freezing rain is a trigger for the breaking of tree branches and limbs. These pose a threat to overhead feeder systems, and these freezing rain amounts have resulted in widespread outages in Toronto in the past due to tree contacts. The next threshold is 25 mm of freezing rain, which is the CSA design requirement for overhead electrical systems. Theoretically, overhead feeder systems, as well as the overhead exit lines at stations are supposed to withstand 25 mm of freezing rain (12.5 mm of radial ice accretion). However, such quantities of freezing rain and ice accretion on overhead infrastructure bring them to their structural design limits, which are further exacerbated by breaking tree branches and wind. Finally at 60 mm of freezing rain, the weight of ice accretion on overhead lines and station exit lines exceeds their design limit, and will likely cause them to collapse.

It should be noted that the high risk ratings for 15 mm and 25 mm of freezing rain on overhead feeder systems and station exit lines is based on probability of occurrence for the study period (probability scores of 7, event will occur during the study period)[22]. From an annual probability perspective, freezing rain events at 15mm and 25mm of freezing rain would actually result in medium risk ratings. As can be seen from Table 3-2 in Chapter 3, the current annual probability of occurrence of 15 mm of freezing rain is 0.11 days / year (1 in 9 year return period), and is projected to increase to 0.16 days / year (1 in 6 year return period) by the 2050's. The current annual probability of 25 mm of freezing rain is 0.06 days / year (1 in 17 year return period), and is projected to increase to 0.09 days per / year (1 in 11 year return period) by the 2050's.As the projected trend for 15 mm and 25 mm freezing rain events is increasing in the future, the interaction of these two climate parameters with overhead feeder systems and station exit lines are maintained as a high risk.

Similarly, it was found that 60 mm freezing rain events would actually fall into a medium risk category (study period probability of 4, annual probability of 1, severity score of 7). However, major ice storms are part of a pattern of risk that is similar to 25 mm freezing rain events. For this reason, it is maintained in the high risk category

High Winds

High winds and wind gusts at 90 km/h and 120 km/h were judged to be a high risk to overhead feeder systems. These wind speeds reach and exceed the design limits of conductor connections to support poles, and the poles

[21] Estimate provided through correspondence with Toronto Hydro staff.
[22] A comparison for freezing rain/ice storm lasting at least 6hr+ based on annual probability versus study period probability does not change the high risk rating.

themselves. Further compounding impacts is the potential for flying debris, such as broken tree branches and limbs, to further bring down overhead feeder systems.

The threats from high winds and gusts above 120 km/h were judged to be high risk due to wind forces on station overhead exit lines (exceeding design standard for poles). Furthermore, there is the potential for flying debris to damage station equipment at outdoor stations.

As is the case for freezing rain, it should be noted that the high risk ratings wind over 120 km/h were on overhead feeder systems and station exit lines is based on probability of occurrence for the study period (probability scores of 7, event will occur during the study period)[23]. However, from an annual probability perspective, events producing 120 km/h high winds would actual result in low and medium-low risk ratings for station and overhead feeder systems respectively. This is because the current annual probability of 120 km/h wind events is 0.05 days per year (1 in 20 year return period). This frequency is expected to increase during the study horizon, although the projected value is not known. These significant wind events are similar to the case of tornadoes, in that they are infrequent but can lead to significant damage to large areas of the distribution system if they occur (low probability, high severity events). As they are however expected to be more frequent than tornadoes, the 120 km/h wind – overhead systems interaction is maintained as high risk in this study.

Lightning

Lightning strikes on station equipment, notably power transformers, were rated as a high risk. Lightning arrestors at stations are designed to direct lightning surge currents to ground and protect electrical equipment. However, failure of the lightning arrestors can result in damaged equipment from lightning strikes and potentially causing an outage to an entire service area.

Human Resources

Heavy freezing rain events constitute a high risk for Toronto Hydro personnel. First, slippery surfaces make travel to and from work, and out to worksites dangerous for field crews. Second, field crews also have to contend with a layer of ice over electrical equipment, trees, and other overhead structures such as buildings. As such, the risk of injury to workers from freezing rain events remain even after the storm has passed due to the continuous ice loads on overhead power lines and trees, which may cause them to break without warning.

5.4 Special Cases – High Severity, Low Probability Events

Tornadoes

Tornadoes represent a high severity, low probability event. As mentioned in Chapter 3, while the likelihood of a tornado event touching down at a specific point or location is extremely small, the likelihood of a tornado occurring somewhere in the City of Toronto over study period (2015 – 2050) is in fact considerable. Furthermore, due to the lake breeze effect, northern portions of the city tend to have a high probability of seeing a tornado event, although it does not preclude an occurrence closer to the lakeshore. Tornadoes were judged to have catastrophic consequences on all above ground infrastructure, while underground infrastructure may become inaccessible due to windblown debris.

[23] A comparison for freezing rain/ice storm lasting at least 6hr+ based on annual probability versus study period probability does not change the high risk rating.

5.6 Special Cases – Low Severity, High Probability Events

Snowfall and freezing rain

The degradation of concrete and corrosion of steel materials (at grade and underground feeder systems) is a case of high probability, low severity events. These processes are accelerated by the application of de-icing salts during snowfall and freezing rain events. The application of salts can accelerate the corrosion of metal housing and enclosures of electrical equipment, resulting in shorter lifespans. It also affects the steel and concrete of vaults and cable chambers (civil equipment). Future warming associated with climate change is expected to decrease the number of days without snowfall, but the trend for freezing rain is expected to increase. Nonetheless, snowfall is expected to continue to be an annual event throughout the time horizon of this study. As such, degradation of civil structures will continue to be an issue for Toronto Hydro over the study period.

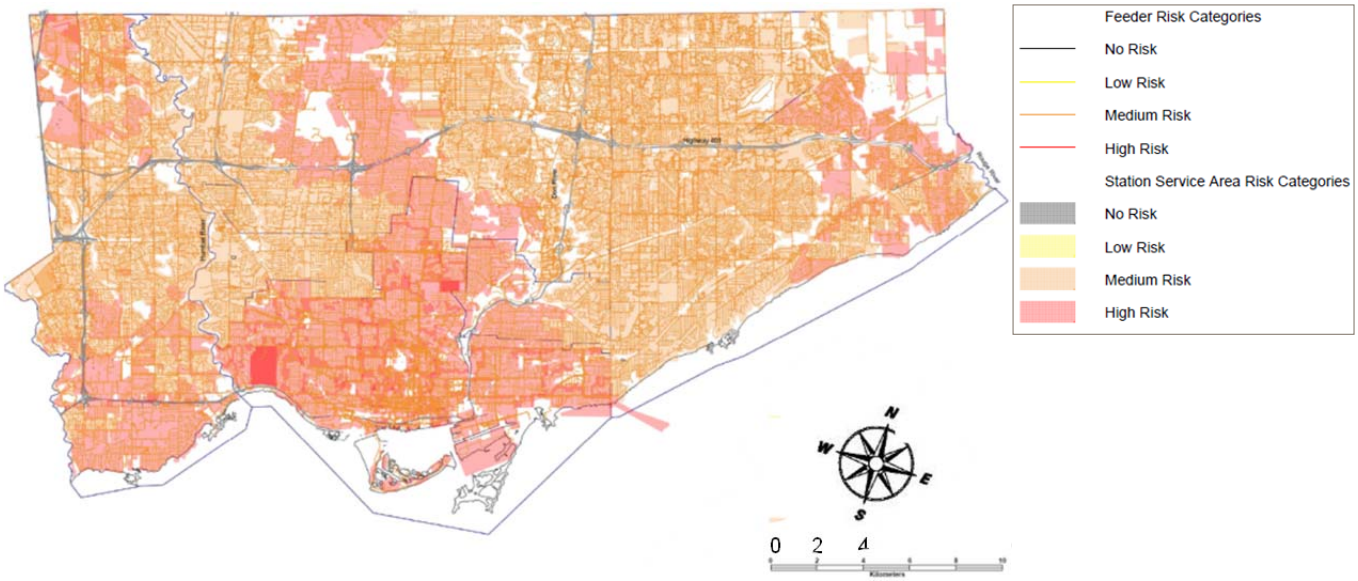
Underground electrical feeder equipment and civil structures located in the Former Toronto area received a slightly (+1) higher severity rating (and a medium-low risk rating) because the infrastructure is generally older than those found in the horseshoe area. It was found that older equipment and structures are more susceptible to degradation if corrosion had already begun (e.g. protective layers of paint may be worn off). Furthermore, older equipment may not be as resistant to corrosion as newer equipment due to the advancement of enclosure design and testing over time (Nema standard).

Some of this salt is dispersed by the moisture in the air, and can accumulate through the winter season on insulators on poles. These salt accumulations can cause electrical short circuits that could result in pole fires. Loop feeder systems are judged to be of lower risk than radial systems in the event of a short circuit or fire due to the potential to provide power temporarily through another loop of the feeder.

5.7 Mapping Risk Results

The mapping of risks provides complementary information to the risk assessment matrix, and facilitates a spatial understanding of low, medium and high risk interactions, and vulnerabilities (i.e. the medium and high risk interactions). For example, maps can provide an indication of the areas of vulnerability of overhead and underground infrastructure with respect to different kinds of weather events. Furthermore, the mapping exercise actually provides a new set of information on how vulnerabilities stemming from stations can combine with vulnerabilities to feeder systems. In some cases, vulnerabilities stem primarily from station assets (e.g. 120km/h wind and underground feeder assets), while in other cases, both station and feeder vulnerabilities to weather events contribute to an area of greater vulnerability within the city (i.e. freezing rain affecting both station and overhead feeder assets). The following section provides some spatial observations about the four climate parameters affecting electrical distribution infrastructure. All mapping results are provided in **Appendix E**.

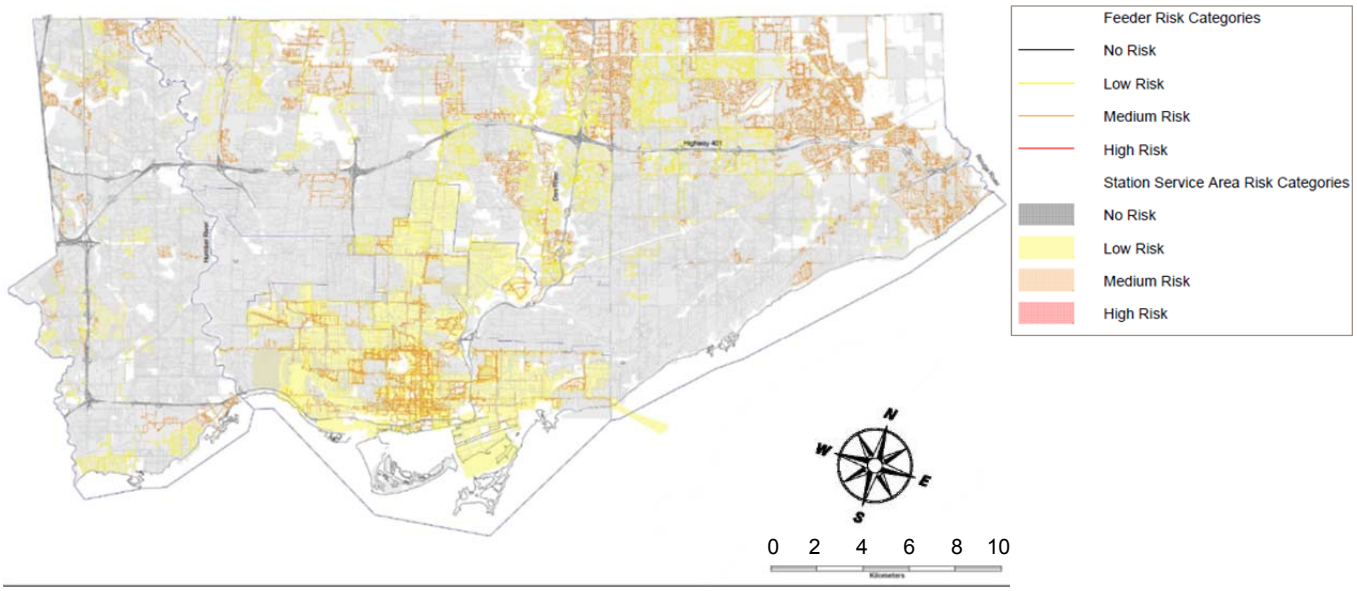
Figure 5-1 Risk Map, High Temperature Above 40°C, 2050's



Vulnerabilities from high heat events stem primarily from projected available station capacity by the 2050s, as this study did not find that vulnerabilities varied significantly (all rated medium risk) for feeder assets. Vulnerabilities to high heat events are more heavily concentrated in the Former Toronto area, although several horseshoe area stations would also be vulnerable during high heat events (Figure 5-1).

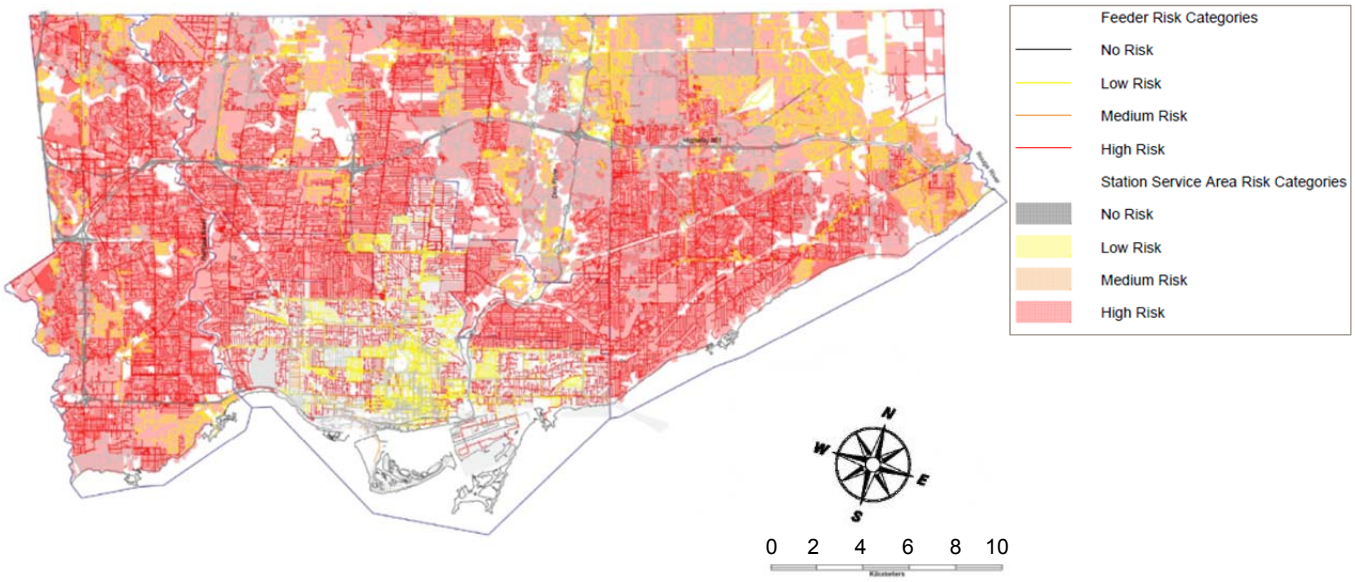
In terms of potential heavy rainfall risks to Toronto Hydro infrastructure, underground feeder systems that may be subject to flooding are located largely in the Former Toronto area and northeastern sections of the horseshoe (Figure 5-2). Some transmission station service areas in the Former Toronto area are marked as low risk due to the presence of some switchgear equipment that will likely remain in basements through the study period. Note however that sump pumps in stations make the probability of flood damage in stations from heavy precipitation less likely.

Figure 5-2 Risk Map, Extreme Rainfall, 100 mm in less than 24h, 2050's



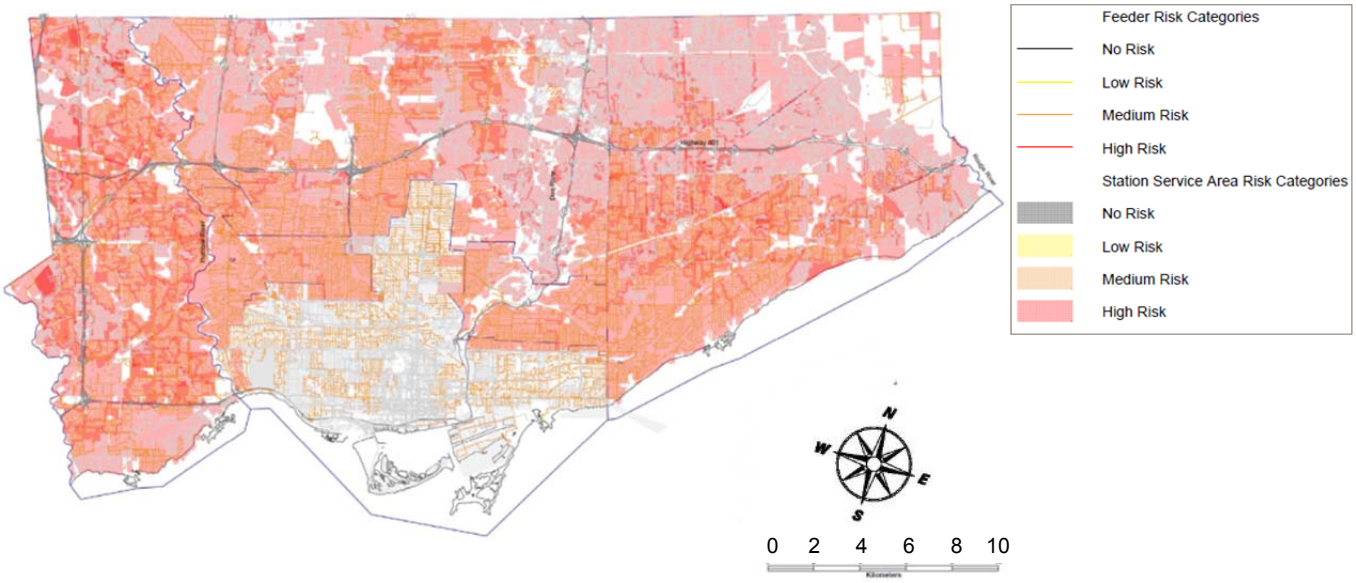
Toronto Hydro has a significant quantity of overhead distribution systems which are at vulnerable to extreme freezing rain, ice storms, high wind and tornado events. These feeder vulnerabilities combine with the fact that stations in the horseshoe area have station exit lines that are outdoors. This combination makes certain portions of the horseshoe particularly vulnerable to heavy freezing rain events and ice storm. Figure 5-3 shows the areas of vulnerability stemming from 25 mm of freezing rain, and is indicative of extreme precipitation/wind related vulnerabilities to overhead systems across Toronto.

Figure 5-3 Risk Map, 25 mm Freezing Rain, 2050's



Lightning strike vulnerabilities are largely concentrated in the horseshoe area, where both outdoor station equipment and overhead feeder systems are predominant. However, overhead feeder systems in the the Former Toronto area are also vulnerable (Figure 5-4).

Figure 5-4 Risk Map, Electrical Distribution Systems Potentially Affected by Lightning Strikes



There are several caveats that should be mentioned with respect to interpreting mapping results, due in large part to the fact that risk ratings were evaluated based on general system characteristics. Localized site characteristics that may mitigate or worsen risk ratings were not adequately captured in the mapping exercise. They include:

- Local geographic characteristics, assets and features. There may be local site characteristics such the tree canopy cover, types of trees, presence of buildings or other overhead structures, which may exacerbate weather events (e.g. wind) or shelter infrastructure from impacts. The presence of low lying areas (e.g. bowls, flood plains) was also not considered. This level of detail, provided by a full site inspection and digital terrain mapping, were not available for this project. Such information would be useful in refining the risk ratings and mapping for extreme rainfall, freezing rain and wind;

- Areas with lower drainage capacity due to configuration of city storm drainage infrastructure. This type of information requires a very detailed understanding of city infrastructure, which was not available for this study. Furthermore, this level of data is most useful when combined with digital terrain mapping in order to identify low lying areas with problematic drainage. Finally, future projections as to how city infrastructure might evolve over time were also not available for this project;

- The moderating effect of Lake Ontario. As noted in Chapter 3, the lake can play a significant role in influencing temperature and humidity along the lakeshore. For example, the lake effect can moderate temperatures during heat waves and can reduce the possibilities of freezing rain or snow falling on areas closer to the lakeshore. The extent and intensity of the lake effect can vary depending on the event and weather conditions. It was not possible to estimate the geographic extent of the lake effect, or by how much the probability scoring for certain climate parameters may be affected. As such, the lake effect's moderating influence was not taken into account sufficiently in the risk assessment and mapping exercise;

- Local electrical configurations and characteristics. There are likely cases where location specific electrical equipment may make certain feeder or station systems inherently more robust or redundant than would be the case of the general class of equipment. For example, additional feeder ties, loops or circuits could make certain feeders more redundant in the event of a downed power line. The age of equipment, their future replacement schedule will also have an effect on their risk rating. This level of detail is not captured at level of analysis undertaken in this study;

- For the extreme rainfall risk map, it should be noted that the mapping of transmission stations includes all stations. Information identifying the location of the stations whose batteries and switchgear are located below grade was not available. Further analysis is required to identify the precise locations of transmission with below grade assets in order to get a better mapping of flood related risks.

In spite of these shortcomings, the mapping exercise represents a useful first approximation of spatial nature of electrical system vulnerabilities to climate change. Furthermore, this mapping information can be more easily combined with other layers of information such as technical hazard information (e.g. flood mapping), physical locations (e.g. emergency resource centres, hospitals, transportation networks) and social vulnerability indices (e.g. age, income, population density, etc.) from other sources (e.g. TRCA, City of Toronto) to produce further mapping studies and in depth analyses to suit the needs of other policy makers.

6 Engineering Analysis

This chapter presents the results of the Step 4 of the Protocol, the Engineering Analysis. The purpose of Engineering Analysis is to conduct a further assessment of the system-climate interactions that were rated as a medium risk (interactions scoring between 14 and 35). For these interactions, the engineering analysis attempts to evaluate whether the infrastructure is vulnerable to a changing climate. To do so, the various factors that affect the load and the capacity of the infrastructure for the study time horizon are calculated. However, quantitative calculations of load and capacity were not always possible to make due to a lack of data to support such an analysis. For this reason, professional judgment is also applied in the engineering analysis. Infrastructure which is found to be vulnerable is passed to Step 5, while those which were not were discarded from further consideration.

In total, nineteen medium risk interactions were analyzed. Fifteen of them were deemed vulnerable and passed to Step 5, while 4 were discarded from further analysis. The following table summarizes the results of the engineering analysis. A brief description of the reasoning behind the results for each of the medium risk interactions is presented in this chapter, while the full engineering analysis can be found in **Appendix G.**

Table 6-1 Engineering Analysis Results

	Affected infrastructure	Climate Parameter	Further Action Recommended
	Municipal and Transmission Stations and Communications Systems		
1.	Transmission and municipal stations	High temperature above 25°C and above 30°C	Yes
	Protection and control systems	All temperatures	
2.	Transmission stations	High temperature above 35°C	Yes
3.	Transmission stations	High temperature above 40°C and average temperature > 30°C	Yes
4.	Transmission stations	Heat wave and high nighttime temperatures	Yes
5.	Transmission and municipal stations	Freezing rain, ice Storm 60 mm	Yes
6.	Municipal stations	High temperature	Yes
		Underground and Overhead Feeders	
7.	Underground feeders	High temperature maximum above 35°C & above 40°C, average temp >30°C, heat wave and high nighttime	Yes
8.	Underground feeders	Extreme rainfall	a. Feeders/water treeing: Yes b. Nun submersible vault: Yes c. Above ground stations: No d. N/W feeders: Yes
9.	Padmount stations	High winds 120 km/h	No
10.	Overhead feeders (radial and loop)	High temperature maximum above 35°C & above 40°C, average temp >30°C and heat wave	Yes
11.	Overhead feeders (radial)	High nighttime temperatures	No
12.	Overhead feeders (loop)	Freezing rain, ice Storm 15 mm	Yes
13.	Overhead feeders (radial and loop)	Freezing rain, ice Storm 60 mm	Yes
14.	Overhead feeders (radial and open loop) and SCADA system	Lightning	Yes
15.	Overhead feeders (radial)	Snow > 5 cm and snow > 10 cm	No
		Civil Structures	
16.	Civil structures: underground feeders (Former Toronto)	Extreme rainfall, freezing rain/ice storm 15 mm & 25 mm & 6hrs+ (combination of events)	Yes
17.	Civil Structures: underground feeders (Former Toronto)	Snow > 5 cm and snow > 10 cm	No, but combinations of climates need additional study.
18.	Civil structures	Frost	Yes
19.	Human resources	All climate parameters	Yes

6.1 Municipal and Transmission Stations and Communications Systems

1. High temperature above 25°C and above 30°C / transmission and municipal stations and all Temperatures / protection and control systems

Further action recommended. Under higher temperatures, battery life expectancy (e.g. around 10 years) may decrease. Toronto Hydro has already encountered problems with some batteries failing prior to their expected lifespan..

2. High temperature above 35°C / transmission stations

Further action recommended, conclusions for high temperature and power transformers also apply (see Chapter 7). Transmission station designers will need to take into account the significant increase in days with maximum temperatures above 35°C, which reduces station capacity while, on the other hand, experiences an increased load demand. At the moment, no load growth rate for the period of this study was estimated. The recommendations given in Chapter 7 for transmission stations and maximum temperature above 40°C / average temp above 30°C also apply to this interaction.

3. High temperature above 40°C and average temperature > 30°C / transmission stations

Further action recommended. Most of the transmission stations considered in this study were judged to be vulnerable (high risk rating) to high temperatures. The stations in the Horseshoe received a medium-high risk score (35) due to the application of the concept of excess capacity, which is qualitative and notional (refer to the **Appendix F**). As such, it is recommended that transmission stations receiving a medium-high risk score be considered vulnerable to extreme high temperatures as part of a consistent pattern of risk. This will also help Toronto Hydro to adopt a consistent approach in the design, operations and maintenance of stations.

4. Heat wave (+30°C) and high nighttime temperatures (+23°C) / transmission stations

Further action recommended. Power transformers are vital equipment in the distribution of electricity and high temperatures have a significant impact on the capacity of the transformers. For these reasons, the conclusion of this report for temperature above 40°C and for high daily average temperature > 30°C are also relevant to the heat wave and high nighttime temperature parameters.

5. Freezing rain/ice storm 60 mm ≈ 30 mm radial (major outages) / transmission stations and municipal stations

Further action recommended. This interaction is part of a similar pattern of vulnerability as 25 mm freezing rain events. Therefore, solutions for 25 mm events are also relevant to mitigating heavy freezing rain events of ~ 60 mm.

6. High temperature (+35°C,+ 40°C, average temperature > 30°C, heat wave, high nighttime temperatures) / municipal stations

Further action recommended. High temperature and combinations of high temperature, high average temperature, high nighttime temperature and high load demand will have consequences on the capacity of the power transformers and cables.

6.2 Underground and Overhead Feeders

7. High temperature maximum above 35°C & above 40°C, average temp >30°C, heat wave and high nighttime / underground feeders

Further action recommended. Toronto Hydro replaces cables based on asset life replacement cycles or premature failures. However, it is projected that climate change related high temperatures could create higher

demand for cooling, and may place greater stress on cables and lead to increasing occurrences of cable failures. Therefore, high heat impacts on cable was deemed to be a vulnerability.

8. Extreme rainfall / underground feeders

a. Feeders: Water treeing of the cables, flooding

Further action recommended. Climate change related stresses (i.e. higher temperature, higher loading, flooding from extreme rainfall) will continue to stress underground cables and constitute a vulnerability for Toronto Hydro.

b. Non-submersible equipment failure in vault type stations below ground in the Horseshoe Area (Former Toronto has a high risk result)

Further action recommended. While Toronto Hydro is gradually replacing vault type non-submersible equipment with submersible versions, non-submersible vault type equipment is likely to remain in the system over the study period.

c. Above ground vault stations, access to the vault station and to the station equipment could be limited due to localized flooding of streets around the vault station, or at the station itself

No further action required. This impact does not relate to station load or capacity. The consequence is that the access to the vault stations or the stations equipment could be temporarily impeded. Impact is localized and temporary, and was not judged to warrant further action beyond current practices.

d. Network feeders: old N/W protectors are not submersible

Further action recommended. The old N/W protector may not operate properly if flooded. However, failure of the N/W protector will not automatically result in an interruption to the customer, since network systems are highly redundant. Toronto Hydro is installing new N/W protectors that are submersible, but there may still be older non-submersible N/W protectors in the systems, particularly in downtown over the study period. Further study could be undertaken to evaluate the cost of replacing old network protectors prior to the end of their expected lifecycle against the frequency and consequence of old N/W protectors being flooded.

9. High winds (120 km/h) / padmount stations on distribution network (Former Toronto)

No further action required. The damaged equipment will result in an overall or some loss of service capacity and function. However, it is judged that flying debris is too much of a random occurrence to warrant further action.

10. High temperature maximum above 35°C & above 40°C, average temp >30°C and heat wave / Overhead power lines (radial and loop)

Further action recommended. Higher temperatures will have impacts on the overall capacity of the power lines. In the downtown area, there are critical, constrained areas (i.e. built up zones) where added conductor/transformer capacity may be difficult to implement.

11. High nighttime temperatures / Overhead power lines (radial)

No further action required. Night time temperatures with minimum ≥ 23°C in and of itself is not a significant concern for Toronto Hydro in terms of electrical service provision as peak demand has subsided. However, it is important to note that high daily temperatures in combination with high night time temperatures are a concern. This has been considered under different climate-infrastructure interaction, average temperature over 30°C on a 24 h basis, so this particular interaction does not warrant further action.

12. Freezing rain - ice Storm 15 mm and high winds 70 km/h / Overhead feeders in loop configuration

Further action recommended. The risk assessment of radial systems resulted in a high risk rating for this interaction. In overhead loop systems, it was hypothesized that their more redundant configuration would reduce customer interruptions, affect fewer clients or cause outages of shorter durations, thus yielding a high-medium risk rating of 35. However, the frequency of freezing rain events are projected to increase slightly by the end of the study horizon compared to present day (see table 3-2). The tree canopy may also be weakened by increased disease threats. Finally, freezing rain events tend to be widespread, and there is no reason to believe that both branches of an overhead loop circuit might not be equally susceptible to damage. For all of these reasons, all overhead power lines, irrespective of electrical configuration, were deemed as vulnerable.

13. Freezing rain/ice storm 60 mm ≈ 30 mm radial (major outages) / overhead lines (radial and loop)

Further action recommended. See explanation for freezing rain and stations (item 5 above).

14. Lightning / overhead power lines (radial and open loop) and SCADA system

Further action recommended. It is difficult to predict the increase of lightning strikes for the study period; however it is interesting to note that the probability of a lightning strike in an area of 0,015 km^2 anywhere within the City of Toronto is very high for the study period. At the moment, lightning strike intensity, the number of lightning arrestors/km and arrestor performance are not monitored by Toronto Hydro. Given this uncertainty, and since lightning strikes are currently a frequent source of outages, lightning strikes were judged to be a continued vulnerability.

15. Snow > 5 cm and snow > 10 cm / overhead power lines (radial)

No further action required. The number of snow days is highly variable. The trend seems to be decreasing, but snow days will still occur annually. During the workshop, Toronto Hydro mentioned having problems regarding insulator tracking leading to pole fires especially at higher voltages (13.8 kV and 27.6 kV) and switch failures. However, Toronto Hydro is already monitoring and dealing with this issue.

6.3 Civil Structures

16. Extreme rainfall, freezing rain/ice storm 15 mm & 25 mm & 6hrs+ (combination of events) / civil structures: underground feeders (Former Toronto)

Further action recommended. Vaults and chambers already suffering from degradation issues will deteriorate more rapidly over time. From THESL (Toronto Hydro, 2014a): *As below-grade structures age, the greatest concern becomes structural strength. Structural deficiencies affecting vaults include degradation of concrete and corrosion of supports such as beams and rebar. Once degradation and corrosion sets in, conditions can deteriorate rapidly and in many cases from one season to the next. Of particular concern is the winter season when moisture and water enter in below-*grade *structures, freezes and thaws, and carries with it salt that has been used at grade to melt ice and snow.*

While maintenance can reduce the rate of deterioration, incidence of extreme rainfall, snowfall, freezing rain and the application of road salt will persist throughout the study period and continue to contribute to the premature aging of civil structures. While, it could not be determined in the study whether premature aging of civil structures will be exacerbated by a changing climate, this issue will persist over the study period and is therefore judged as an on-going vulnerability

17. Snow > 5 cm and snow > 10 cm / civil structures: underground feeders (Former Toronto)

No further action required, but combinations of climates events require additional study. As days with snow will probably decrease, the snow days alone were not judge to be a significant vulnerability. However, snow days will still occur over the study period, and in combination with extreme rainfall, freezes and thaw, freezing rain, and the continued application of road salt, premature degradation of civil structures was judged to be an

ongoing vulnerability for Toronto Hydro.

18. Frost / civil structures (overhead and underground feeders)

Further action recommended. While the threat of frost is decreasing over the study period, it is noted that frost penetration will still occur with occasional extreme cold weather. Since Toronto Hydro already experiences problems with frost and its civil infrastructure, frost impacts are judged to be a vulnerability.

6.4 Human Resources

19. All climate parameters / human Resources

Further action recommended. While occupational health and safety procedures will continue to be in place in the future, human resources will continue to be vulnerable to climate change related weather events due to the need to travel, access, and work on equipment in spite of the weather.

7 Conclusions

The Phase 2 study presents a climate change based vulnerability assessment of electrical distribution infrastructure. It seeks to inform future investigations, planning and investment decisions on system and component vulnerabilities, and to support efforts to enhance the resilience of the electrical system. This chapter presents Step 5 of the Protocol and covers electrical distribution system vulnerabilities within the City of Toronto, adaptation options and areas of further study.

7.1 Vulnerabilities to a Changing Climate

The Phase 2 employed a high level risk based screening methodology to determine where infrastructure vulnerabilities to climate change may be present. All high risk infrastructure-climate parameter interactions, as well as medium risk interactions assessed as vulnerable through the engineering analysis comprise the vulnerabilities identified for Toronto Hydro's electrical distribution system to a changing climate. These vulnerabilities can be divided into five groups based on how climate parameters affect the system. The following paragraphs summarize these vulnerabilities, while table 7-1 provides more detailed information by infrastructure-climate parameter interactions.

High Ambient Temperatures – Station and Feeder Assets

High ambient temperatures create problems for the distribution system because of the compounding effect of high demand (e.g. for cooling) and high ambient temperature affecting equipment cooling and electrical transmission efficiency. Two specific climate parameters were of most significant concern, daily peak temperatures exceeding 40°C (excluding humidity) and daily average temperatures exceeding 30°C. In these cases, the climate analysis found that such extreme temperatures have occurred only rarely in the past, but are projected to occur on an almost semi-annual to annual basis by the 2030's and 2050's respectively. Through preliminary demand and supply growth projections completed for this study, these vulnerabilities were identified based on the notion that extreme heat will generate electrical demand for cooling in areas where station excess capacity is projected to be marginal. Furthermore, such temperature extremes may cause equipment, notably power transformers, to operate beyond their design specifications and increases the likelihood of failure. It is anticipated that vulnerability to high heat events will be concentrated in the Former Toronto area, although there are several horseshoe station service areas which would also be vulnerable.

Freezing Rain, Ice Storms, High Wind and Tornadoes – Overhead Station and Feeder Assets

Freezing rain, ice storms, high wind and tornado events cause immediate structural issues for overhead distribution assets, as they have the capacity to exceed the design limits of equipment and their supports. Outages may result from damage to equipment arising from direct forces applied by climate parameters (e.g. wind, weight of ice) or by other objects (e.g. tree branches, flying debris). These kinds of events affect outdoor station and feeder assets, which are largely concentrated in the horseshoe service area. It is important to emphasize that Toronto Hydro has experienced problems related to freezing rain, ice storms (up to 25 mm) and high winds (up to 90 km/h) in the past. These events are projected to continue in the future, but continue to occur on a less than annual or even decadal frequency. More severe ice storms (60 mm), high winds (over 120 km/h) and tornadoes (EF1+) have been extremely rare in the past, and while there is a lack of scientific consensus on projected future frequencies for these extreme events, they are likely to remain rare in the future. Nevertheless, the damages caused by these kinds of events can be severe. Therefore, they were judged as ongoing and future vulnerabilities for Toronto Hydro.

Extreme Rainfall – Underground Feeder Assets

Extreme rainfall events may potentially flood underground feeder assets, which are largely concentrated in the Former Toronto and northeastern horseshoe areas. Toronto Hydro is aware of these issues in relation to its

assets and has programs to replace non-submersible equipment with submersible type equipment, to relocate equipment where possible. However, due to the large quantity of underground feeder assets across the city, replacement and reinforcement of underground assets will be a gradual and ongoing activity for Toronto Hydro over the study period. As such, some underground feeder assets may remain an area of vulnerability for Toronto Hydro.

Snowfall, Freezing Rain - Corrosion of Civil Structures

The degradation of civil structures (i.e. concrete and steel), which is accelerated by humidity and the presence of de-icing salts, was identified as a potential area of vulnerability to climate change. Corrosion is already an ongoing issue for Toronto Hydro and current assets have a design lifespan which accounts to a great extent for corrosion issues. However, it is not clear from this study whether the climate change stresses will exacerbate the problem. While snowfall days are generally expected to decrease with a warming climate, they will continue to occur annually through to the 2050's. As a result, and in combination with freezing rain events, the application of de-icing salts will also be applied annually through the study horizon. Nonetheless, it should be emphasized that corrosion represents a long-term and on-going vulnerability for Toronto Hydro.

Lightning – Overhead Feeder Assets

Based on workshop feedback and an examination of Toronto Hydro's ITIS outage data, Toronto Hydro recognizes that lightning impacts are a significant source of outages on the distribution system today. While there have been advances in predicting lightning activity, there was insufficient data available on lightning strike intensity and arrester performance to suggest how future lighting activity may affect the electrical system. For these reasons, this study suggests that lightning activity will continue to be an area of vulnerability.

7.2 Adaptation Options

Adaptation options are suggested for all the infrastructure-climate parameter interactions identified as vulnerabilities. The Protocol classifies adaptation options in four possible categories:

- remedial engineering actions which aim to strengthen or upgrade the infrastructure;
- management actions to account for changes in the infrastructure capacity;
- continued monitoring of performance of the infrastructure and impacts; and
- further study required to address gaps in data availability and data quality.

Adaptation options by infrastructure-climate parameter interaction are presented in Table 7-1.

Table 7-1 Vulnerabilities and Adaptation Options by Infrastructure Asset, Climate Parameter

Affected infrastructure	Climate Parameter	Adaptation Option	Details
Stations, Communications and Protection Systems			
1. Transmission stations, municipal stations, protection and control systems Critical component: batteries	High temperature above 25°C	Further study required	Toronto Hydro has experienced problems with station batteries failing short of expected lifespans (i.e. approximately 10 years). Operating batteries in rooms where the ambient temperatures increases above 25°C is a contributing factor to premature battery failure (Toronto Hydro, 2014c). As battery rooms are not temperature controlled, Toronto Hydro could monitor how ambient temperatures of rooms within stations housing batteries fluctuate during the warmer summer months and evaluate whether additional measures are needed (e.g. review of battery technical specifications, including aging factor) to reduce battery degradation.

Affected infrastructure	Climate Parameter	Adaptation Option	Details
2. Transmission stations, municipal stations Critical component: power transformers	High temperature above 35°C, 40°C Average daily temperature > 30°C Heat wave High nighttime temperatures	Further study required	Given the increased frequency of high heat conditions in the future, coupled with continued demand growth, infrastructure owners (Toronto Hydro and Hydro One), could conduct a could conduct a further study evaluating the technical and financial feasibility of installing transformers with a higher capacity, or installing more transformers at stations (shared load) where space permits. Another possibility is to evaluate the technical and financial feasibility of increasing the design standard for current power transformer equipment, for example, by designing to a daily average ambient temperature higher than 30 °C (35 °C) and maximum temperature with a higher temperature than 40°C (45 °C). Finally, these measures should be complemented by continued demand side management /energy conservation programs.
3. Transmission stations: only outdoor stations 4. Municipal stations: Horseshoe area outdoor stations Critical component: Overhead exit lines (for freezing rain and high winds parameters)	Freezing rain/ice storm : 25 mm, 60 mm High winds : 120 km/h and tornadoes	Management actions and further study required .	Major freezing rain, ice storm, high wind and tornado events are not expected to be an annual occurrence in the future, but will still likely occur over the study period. Station exit lines, either overhead ones or where underground cables surface, are a particular point of vulnerability, as downed exit lines can sever power supply to the entire service area. Toronto Hydro could monitor the frequency of damage to station exit lines and poles across a range of potential weather threats (freezing rain, high winds) to evaluate whether this critical portion of the distribution network requires strengthening. Toronto Hydro could also consider a station by station study of surroundings to identify areas around stations susceptible to generating flying debris (e.g. trees, buildings). Emphasis should also be placed on optimizing the emergency response and restoration procedures to reduce system down time. Note that Toronto Hydro is already undertaking a review and enhancement where necessary of response planning, dispatching operations, prioritization of restoration activities, coordination with other utilities, response team training and preparation.
Arresters (for lightning parameter)	Lightning	Monitoring activities	Lightning events and strikes are difficult to predict, but are likely to increase in frequency and intensity. However, lightning strike intensity and arrester performance is not currently monitored. Given the importance of lightning strikes as a cause of outages, it is recommended that the lightning activities (e.g. frequency, intensity), soil resistivity (i.e. decreased soil moisture from longer and hotter summers) and impacts on the system could be more closely monitored to provide more information regarding the risks of lightning strikes. For example, where high voltage arresters are installed, counters (if not already present) could also be installed to check if a particular phase or transmission line suffers from an exceptionally high number of overvoltages leading to arrester operation. Lightning strikes on the building housing stations could be investigated to determine whether they resulted in any overvoltage impacts. If further studies on lightning activity result in a better definition of lightning characteristics and impacts, or if monitoring indicates a higher rate of failure, a review of actual design practices could be undertaken.

Affected infrastructure	Climate Parameter	Adaptation Option	Details
Feeders, Communication and Protection Systems			
5. Underground feeders Critical component: cables and power transformers	High temperature above 35°C, 40°C Average daily temperature > 30°C Heat wave High nighttime temperatures	Monitoring activities	For power transformers, see discussion above on station power transformers (see row 2). For cables, increased temperature operation tends to reduce the dielectric strength of the cables. Toronto Hydro is currently trialing cable diagnostic testing techniques as a method of detecting vulnerabilities in cables. If cable testing techniques prove reliable in detecting potential failures, Toronto Hydro could consider extending diagnostic techniques to all cables to monitor heat stress impacts on cables to evaluate whether high design standards or more frequent replacement is required.
6. Underground feeders : Submersible type Critical component: cables	Extreme rainfall: 100 mm <1 day + antecedent	Monitoring activities	The presence of water can lead to an electrical failure of the cables (water treeing) and/or reduce the dielectric strength of cables. Cable diagnostic testing can be employed to monitor the degradation of underground cables. This study also supports Toronto Hydro's program to replace and renew older cable assets with moisture and tree resistant underground conductors such as TRXLPE cables. The development of flood risk mapping, coupled with historical registry of flood related equipment failures could enhance the identification of areas for priority intervention.
7. Underground feeders: Vault type – Below ground Critical component: non-submersible equipment	Extreme rainfall: 100 mm <1 day + antecedent	Remedial engineering actions	Toronto Hydro is currently upgrading non-submersible equipment located in below grade vaults with submersible equipment, or relocating them above grade. The development of flood risk mapping, coupled with historical registry of flood related equipment failures could enhance the identification of areas for priority intervention.
8. Underground feeders: 13.8 kV Network systems	Extreme rainfall: 100 mm <1 day + antecedent	Remedial engineering actions	Many old network protectors are not submersible, particularly in the downtown area. The current Toronto Hydro standard is to use submersible network protectors when replacing old equipment. Further study could be undertaken to evaluate the benefit and cost of replacing old network protectors prior to their end of life versus replacement at their end of life (i.e. potential for flood damage and outages prior to replacement).
9. Overhead feeders (Radial and loop) Critical component: power transformers and conductors	High temperature above 35°C High temperature maximum above 40°C Average daily temperature > 30°C Heat wave	Monitoring activities	Climate change is projected to increase the frequency of high heat conditions in the future. Coupled with continued demand growth, this is projected to increase heat stresses on overhead distribution feeder assets. However, unlike the case with station transformers, where projected heat and capacity reveal a clear vulnerability in terms of supply capacity, it is not clear whether high temperatures will have the same impact across the distribution feeder system (i.e. are there bottlenecks to supplying electricity during periods of high heat at certain stations or across the grid?). Toronto Hydro should continue to monitor key grid operational indicators for distribution transformers, such as load currents, billing data, transformer oil and ambient temperatures. This information can be used to help evaluate whether distribution line capacities are sufficient to handle increased electrical loads.
10. Overhead feeders (Radial and loop) Critical component: conductors	Freezing Rain/Ice storm: 15 mm and high winds 70 km/h	Management actions and remedial engineering actions	Toronto Hydro is already experiencing outages caused by tree contacts and is planning to increase its vegetation management activities. This study supports the need for increased tree trimming practices around overhead power lines and use of tree proof conductors in areas where outages due to tree contacts have been frequent.
11. Overhead : Radial and Loop Critical component: poles	Freezing rain/ice storm: 25 mm High winds: 90 km/h and 120 km/h, tornadoes	Management actions and further study required	See recommendations for stations above on freezing rain and tornadoes (see row 3).

Affected infrastructure	Climate Parameter	Adaptation Option	Details
12. Overhead power lines (radial and open loop) and SCADA system	Lightning	Monitoring activities	See recommendations for stations above on lighting (see row 3).
Civil structures			
13. Civil structures: Underground feeders (Former Toronto)	Extreme rainfall, freezing rain/ice storm 15 mm & 25 mm & 60 mm (combination of events)	Further study required	While maintenance can mitigate the risks of civil structures deterioration, changing climate conditions (e.g. freezing rain, rainfall, freeze-thaw) may exacerbate premature degradation issues. However, it could not be determined in this study whether current design standards are sufficient to withstand future climate - salt and moisture related degradation. Further study could be undertaken to estimate salt/moisture corrosion effects in relation to climate change.
14. Civil structures: transmission and municipal stations, underground feeders	Frost	Further study required	The nature of the frost heave impacts to civil structures was not sufficiently evaluated within this study. Further study can be undertaken to identify whether there are any specific location, ground condition and structure combinations which contribute to frost heave impacts.
Human Resources			
15. Human Resources	Heat, freezing rain, wind and tornadoes	Management actions	Toronto Hydro applies an occupational health and safety manual. Toronto Hydro is already conducting a review of its procedures in light of future extreme events to determine whether modifications in procedure or training are needed.

7.3 Other Areas of Study

Additional climate and infrastructure related areas of further study that can be used to enhance the understanding of electrical system vulnerabilities to climate change are listed below.

Climate

- Increase monitoring of important climate parameters across the city. For both the climate assessments and forensic analyses, a lack of observational data made understanding climate risk challenging and introduced uncertainties, particularly for specific climate parameters such as wind gusts, hourly rainfall measurements, and freezing precipitation accumulations. New monitoring would provide important benefits, including:
    - Addressing gaps in historical data;
    - Facilitating comparisons between sites across the city;
    - Improving the spatial resolution of the climate monitoring network, increasing the likelihood of capturing important meteorological events; and,
    - Providing additional data to assist in detecting new and emerging trends sooner than would be possible using the current network.
- Enhance details about weather impacts contained in the ITIS database. Although information contained within the database was extremely useful and yielded important insights, there were still gaps in the details of weather related outages which limited the evaluation of impacts;
- Refine and expand forensic investigations (see **Appendix C**) completed in this Phase 2 study. Several climate parameters, individual climate events and impacts were not investigated thoroughly due to the scope of the present study. In particular, further analyses could be done on:
    - Lake modified air and lake breeze influences on atmospheric hazards, especially extreme temperatures, ice accretion events, and severe thunderstorms (including extreme rainfall, downbursts/microbursts, and tornadoes);
    - December 2013 ice storm and other ice accretion events, particularly to help refine understanding of apparent variations in impacts between different sections of the city.

  - Temperature gradients across the city during periods of extreme heat. For example, why do some days show greater temperature gradients across the city than others, and what impact does this have on the system?
- Monitor and study the complex interaction between changes in tree growth, pest and disease conditions and resultant changes in risk to overhead systems. This could include investigating
  - The extent to which accelerated tree growth affects tree strength, and specifically resistance to wind and ice accretion loading;
  - Emerging and/or worsening tree pest and disease conditions which could reasonably be expected within the City of Toronto in the coming decades, and what potential changes in risk these will pose to overhead systems.

Infrastructure

- Site specific electrical configuration and area characteristics were not collected due to the scope of this study and scale of infrastructure system being analyzed (e.g. land use changes, high rise and condo development, population growth, terrain elevation, sewers, storm sewers, roads, tree canopy and tree type, buildings). Specific site characteristics, equipment age, or unique or uncommon equipment can alter sensitivity and vulnerabilities. Further study approaches could adopt a smaller spatial scale (e.g. station service areas, neighbourhoods) to reduce these scope and level of effort challenges and identify more site specific vulnerabilities;
- The scope of study and level of effort did not permit a detailed analysis of system performance and outage management (i.e. simulations of power rerouting or contingencies under different outage scenarios to various parts of the system). Further study approaches could adopt a smaller spatial scale (e.g. station service areas, neighbourhoods) to reduce these scope and level of effort challenges and permit a more detailed study and understanding of system performance and outage management;
- Smart Grid Data: Toronto Hydro has recently begun collecting information about outages from its grid based on smart grid feedback. Data history was short and not reviewed in this analysis. Further study examining smart grid data can be used to identify problem areas due to high load demand.

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Appendix A
Workshop Presentations

Appendix B
Background Information on Developing Climate Data

Appendix C
Forensic Analysis of Weather Related Power Outage Events

Appendix D
Risk Assessment Matrix

Appendix E
Risk Maps

Appendix F
Load Projection Methodology – Toronto Hydro

Appendix G
Engineering Analysis

Appendix H
PIEVC Worksheets

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Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment

Application of the Public Infrastructure Engineering Vulnerability Assessment Protocol to Electrical Distribution Infrastructure

Final Report Appendices - Public

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Appendix A
Workshop Presentations

This information has been removed from the public version of this report

Appendix B
Background Information on Developing Climate Data

Appendix B: Background Information for Developing Climate Data

B.1 Introduction

The following Appendix provides additional details about the methods used to develop the climate data used in the Toronto Hydro PIEVC Climate Change Risk Assessment. The development of climate data to support this study involved three main activities.

- Identify climate parameters (e.g. temperature, precipitation, wind) and threshold values at which infrastructure performance would be affected (i.e. climate hazards);
- Project the probability of occurrence of climate hazards for future climate; and,
- Convert projected probability of occurrence of future climate parameters into the seven point scoring scale employed by PIEVC studies to support the risk assessment.

This appendix provides more detailed information about the first two activities, namely the identification of relevant climate hazards and the estimation of their probability of occurrence in the future. The conversion of this probability information into PIEVC scores is not covered here, as it is already explained in the PIEVC Protocol V. 10.

B.2 Identification of Climate Parameters and Infrastructure Thresholds

In this study, the identification of relevant climate parameters and infrastructure impact thresholds (i.e. climate hazards) involved a combination of the three methods:

- Literature review;
- Practitioner consultation; and,
- Forensic analyses.

B.2.1 Literature Review

Design values in codes and standards generally provide an excellent “first guess” to determine infrastructure impact thresholds, providing information on not only baseline climatic design values, but on safety factors, load combinations, and so on. Codes and standards can also provide an understanding of changing thresholds depending on the age of infrastructure and therefore applicable code or standard. These values can also be used as a basis for discussion with practitioners, to determine if there are local modifications for in-field infrastructure. The occasional review and updating of codes and standards also tends to generate discussion and papers in the published literature, which can further provide background on why changes were made, how climatic data was processed, and when these changes became effective.

B.2.2 Practitioner Consultation

Discussion and consultation with practitioners is invaluable. Practitioners can describe important historical events and their impacts, relevant logistical and operational elements of the system, and new and emerging problems which may not be documented elsewhere. More generally, practitioners can provide guidance on where problematic interactions tend to arise and what can be done to reduce those impacts (i.e. adaptation measures).

This project included two workshops in which assumptions regarding climate elements and infrastructure breakdown were evaluated, discussed and modified. The first workshop played a significant role in re-evaluating climate elements which had been identified under Phase I. For example, in light of recent severe weather events **(see Appendix C)**, extreme rainfall and freezing rain were given somewhat higher priority under Phase II. Following a preliminary climate analysis, several thresholds were removed, modified, or refined at the second workshop, and the discussion of complex interactions confirmed findings from the forensic.

B.2.3 Forensic Analyses

Forensic analysis is the evaluation of past events through the application of scientific techniques and understanding to establish facts. It is meant to diagnose the causes of, and contributing factors to, a given infrastructure failure incident. These analyses can be used to refine our understanding of not only what caused a given failure, but also how to prevent or reduce the risks of similar failures in the future. In the context of extreme weather, we can evaluate the meteorological conditions associated with an incident and compare those to impacts produced (i.e. what was damaged, how was it damaged, etc.) and the supposed design capacity of that system (i.e. what was it designed for, do field conditions match design requirements).

Forensic analysis first requires the identification of important historical climatic events. In this case this was provided by Toronto Hydro's ITIS database, and further augmented by newspaper and press release searches. These events were then compared to all available observational data, including both Environment Canada's climate network and as well as data provided by TRCA (TRCA 2014) for several specific events. A full report containing analyses of several different events in the GTA is provided in **Appendix C**. These results were then compared to the literature and were also presented to practitioners for further scrutiny. Findings included the apparent impact of tree canopies on wind resistance of trees (resulting in subsequent secondary impacts on overhead systems), as well as regional differences in impacts from freezing rain, likely the result of a combination of local meteorological conditions (temperature regimes) and regional differences in canopy cover and tree health.

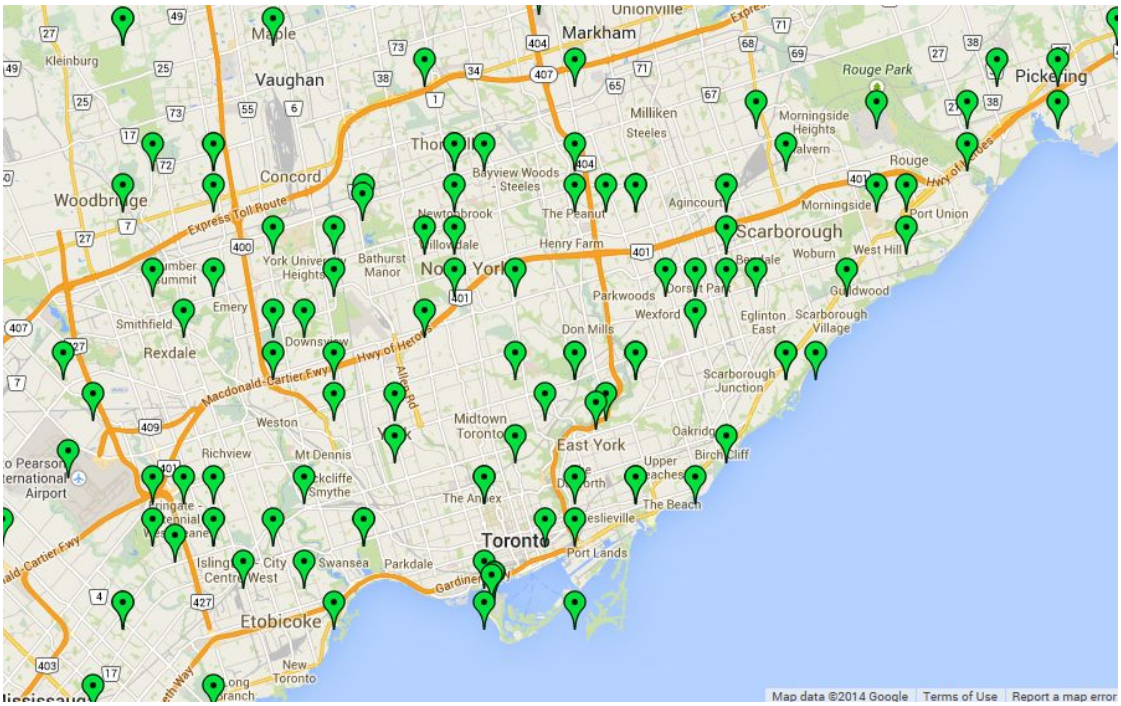
B.3 Establishing the Probability of Occurrence of Climate Hazards

The following section provides information necessary to project the future probability of occurrence of climate hazards. Information about the development of a historical climate baseline, the sourcing and use of future climate projection data, and the treatment of complex variables is presented.

B.3.1 Historical Climate Observations

Environment Canada is the authoritative source of climate information in Canada. In the Toronto region many observations stations have been in place and subsequently closed (see **Figure B.1**). In most cases stations only have observations for a few years – too short to establish a 'climatology'. The most recent normals period established by the World Meteorological Organization (WMO) was 1981-2010. Although 30 years is the accepted minimum, Environment Canada has calculated normals for stations which have at least 10 years of data within this period.

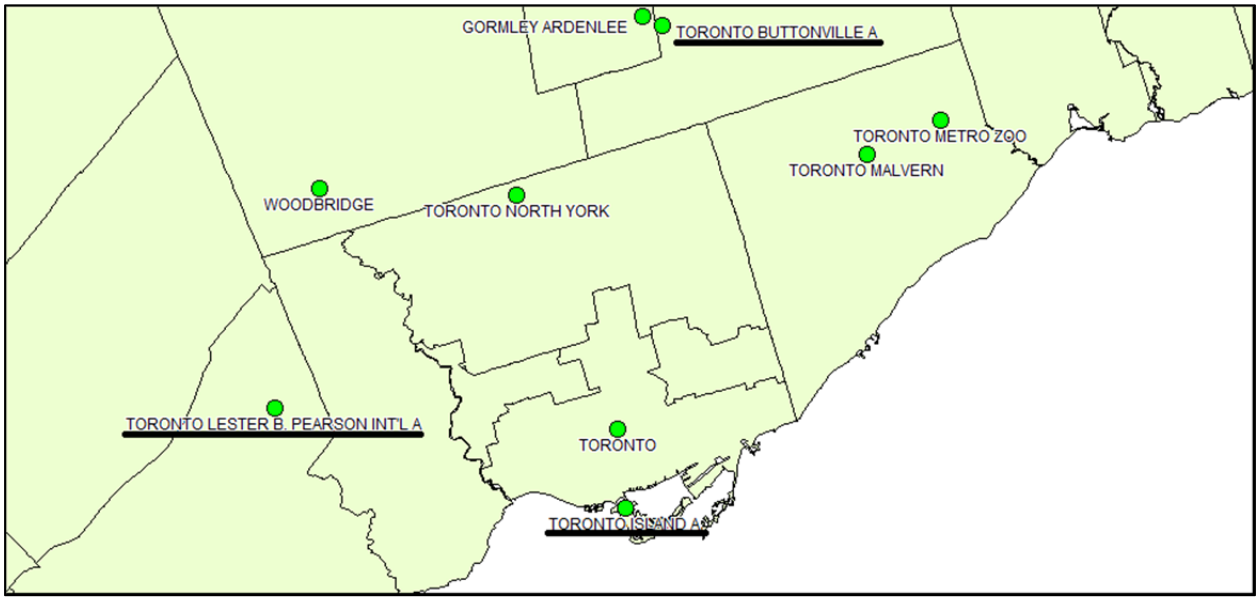
Figure B.1 All Historical Environment Canada Stations



Note: includes those not currently open

To establish reliable statistics on the frequency of events, long term records are preferred and with this area, there are some stations available. It is generally accepted that to establish a 'normal' climate, a minimum of 30 years of data as required. This supposedly ensures that short term natural variability is averaged out. Detailed hourly observations are usually only available at airport locations such as Toronto Pearson, Buttonville and Toronto Island. These airport locations are also typically the only source of variables other than temperature and precipitation (such as wind or weather observations). Of these, Toronto Pearson has the lengthiest reliable data record. Those regional stations for which normals data was calculated for 1981-2010 are shown in **Figure B.2**.

Figure B.2 Environment Canada 1981-2010 Normals Locations



Note: Stations with additional weather and wind data are underlined.

B.3.2 Future Projections

B.3.2.1 Global Climate Models

These variables will consider both the historical period frequencies observed in the region and the corresponding projections used in the most recent Intergovernmental Panel on Climate Change (IPCC)'s Fifth Assessment Report (AR5). The suite of models used in AR5 is from the Fifth Coupled Model Intercomparison Project (CMIP5), coordinated by the World Climate Research Program, and was retrieved from the following data portal:

http://cmip-pcmdi.llnl.gov/cmip5/guide_to_cmip5.html.

Since the second IPCC Assessment released in 1995, the number of contributing international climate modelling centres, models, and their complexity, have increased significantly – from 11 models to the current 40. With increased computing power, better refinement of atmospheric phenomena have been incorporated, and model spatial and temporal resolution has improved (Kharin et al. 2013). An important outcome of this increase in model availability is the ability to produce projections of future climate based upon an 'ensemble' of many models versus the use of single or only a few models. In this report, all available AR5 model runs (many models have more than a single projection available) were used. The use of multiple models to generate a 'best estimate' of climate change is preferred over a single model outcome. Research has indicated that the use of multi-model ensembles is preferable to the selection of a single or few individual models since each model can contain inherent biases and weaknesses (IPCC-TGICA, 2007, Tebaldi and Knutti, 2007). The use of the ensemble projection from the family of global modelling centers is likely the most reliable estimate of climate change projections on a large scale (Gleckler et al, 2008).

A full list of the climate models and their country of origin is presented in **Table B.1**.

Table B.1 List of CMIP5 Global Climate Models (GCMs) Used for this Study

Model Name	Organization	Country	Organization Details
ACCESS1-0	CSIRO-BOM	Australia	CSIRO (Commonwealth Scientific and Industrial Research Organisation, Australia), and BOM (Bureau of Meteorology, Australia)
ACCESS1-3	CSIRO-BOM	Australia	CSIRO (Commonwealth Scientific and Industrial Research Organisation, Australia), and BOM (Bureau of Meteorology, Australia)
BCC-CSM1-1	BCC	China	Beijing Climate Center, China Meteorological Administration
BCC-CSM1-1-M	BCC	China	Beijing Climate Center, China Meteorological Administration
BNU-ESM	GCESS	China	College of Global Change and Earth System Science, Beijing Normal University
CanESM2	CCCma	Canada	Canadian Centre for Climate Modelling and Analysis
CCSM4	NCAR	US	National Center for Atmospheric Research
CESM1-BGC	NSF-DOE-NCAR	US	National Science Foundation, Department of Energy, National Center for Atmospheric Research
CESM1-CAM5	NSF-DOE-NCAR	US	National Science Foundation, Department of Energy, National Center for Atmospheric Research
CMCC-CESM	CMCC	Italy	Centro Euro-Mediterraneo per I Cambiamenti Climatici
CMCC-CM	CMCC	Italy	Centro Euro-Mediterraneo per I Cambiamenti Climatici
CMCC-CMS	CMCC	Italy	Centro Euro-Mediterraneo per I Cambiamenti Climatici
CNRM-CM5	CNRM-CERFACS	France	Centre National de Recherches Meteorologiques / Centre Europeen de Recherche et Formation Avancees en Calcul Scientifique
CSIRO-Mk3-6-0	CSIRO-QCCCE	Australia	Commonwealth Scientific and Industrial Research Organisation in collaboration with the Queensland Climate Change Centre of Excellence
FGOALS-g2	LASG-IAP	China	LASG, Institute of Atmospheric Physics, Chinese Academy of Sciences
FGOALS-s2	LASG-IAP	China	LASG, Institute of Atmospheric Physics, Chinese Academy of Sciences
FIO-ESM	FIO	China	The First Institute of Oceanography, SOA, China
GFDL-CM3	NOAA GFDL	US	Geophysical Fluid Dynamics Laboratory
GFDL-ESM2G	NOAA GFDL	US	Geophysical Fluid Dynamics Laboratory
GFDL-ESM2M	NOAA GFDL	US	Geophysical Fluid Dynamics Laboratory
GISS-E2-H	NASA GISS	US	NASA Goddard Institute for Space Studies
GISS-E2-H-CC	NASA GISS	US	NASA Goddard Institute for Space Studies
GISS-E2-R	NASA GISS	US	NASA Goddard Institute for Space Studies
GISS-E2-R-CC	NASA GISS	US	NASA Goddard Institute for Space Studies
HadCM3	MOHC	UK	MetOffice Hadley Centre (additional HadGEM2-ES realizations contributed by Instituto Nacional de Pesquisas Espaciais)
HadGEM2-AO	MOHC	UK	MetOffice Hadley Centre (additional HadGEM2-ES realizations contributed by Instituto Nacional de Pesquisas Espaciais)
HadGEM2-CC	MOHC	UK	MetOffice Hadley Centre (additional HadGEM2-ES realizations contributed by Instituto Nacional de Pesquisas Espaciais)
HadGEM2-ES	MOHC	UK	MetOffice Hadley Centre (additional HadGEM2-ES realizations contributed by Instituto Nacional de Pesquisas Espaciais)
INMCM4	INM	Russia	Institute for Numerical Mathematics
IPSL-CM5A-LR	IPSL	France	Institut Pierre-Simon Laplace
IPSL-CM5A-MR	IPSL	France	Institut Pierre-Simon Laplace
IPSL-CM5B-LR	IPSL	France	Institut Pierre-Simon Laplace
MIROC-ESM	MIROC	Japan	Japan Agency for Marine-Earth Science and Technology, Atmosphere

Model Name	Organization	Country	Organization Details
			and Ocean Research Institute (The University of Tokyo), and National Institute for Environmental Studies
MIROC-ESM-CHEM	MIROC	Japan	Japan Agency for Marine-Earth Science and Technology, Atmosphere and Ocean Research Institute (The University of Tokyo), and National Institute for Environmental Studies
MIROC4h	MIROC	Japan	Atmosphere and Ocean Research Institute (The University of Tokyo), National Institute for Environmental Studies, and Japan Agency for Marine-Earth Science and Technology
MIROC5	MIROC	Japan	Atmosphere and Ocean Research Institute (The University of Tokyo), National Institute for Environmental Studies, and Japan Agency for Marine-Earth Science and Technology
MPI-ESM-LR	MPI-M	Germany	Max Planck Institute for Meteorology (MPI-M)
MPI-ESM-MR	MPI-M	Germany	Max Planck Institute for Meteorology (MPI-M)
MRI-CGCM3	MRI	Japan	Meteorological Research Institute
NorESM1-M	NCC	Norway	Norwegian Climate Centre
NorESM1-ME	NCC	Norway	Norwegian Climate Centre

B.3.2.2 Representative Concentration Pathways

A new initiative in the IPCC AR5 is the introduction of RCPs (Representative Concentration Pathways; see **Figures B.3** and **B.4**). They represent a range of possible projection outcomes which depend upon different degrees of atmospheric warming. The lowest RCP 2.6, represents an increase of 2.6 W/m^2 to the system, while the highest RCP 8.5 represents an increase of 8.5 W/m^2 of energy. This range encompasses the best estimate of what is possible under a small perturbation situation (2.6) and under a large increase in warming (8.5). It is unknown which of the RCPs will apply in the future. However, it is important to note that historically, the GHG emissions have followed the highest (8.5) pathway. In the absence of a global agreement on GHG reduction, this trend is expected to continue which would support this pathway going forward. Nevertheless, in this report, 4.5 (moderate) and 8.5 (high) projected change are presented. The number of models used for the ensemble varies with the RCP selected since not all international modelling centres generated model runs for all RCPs.

Figure B.3 Representative Concentration Pathways used for AR5

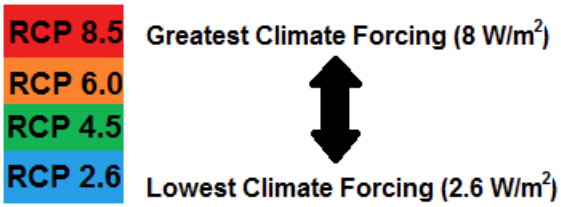
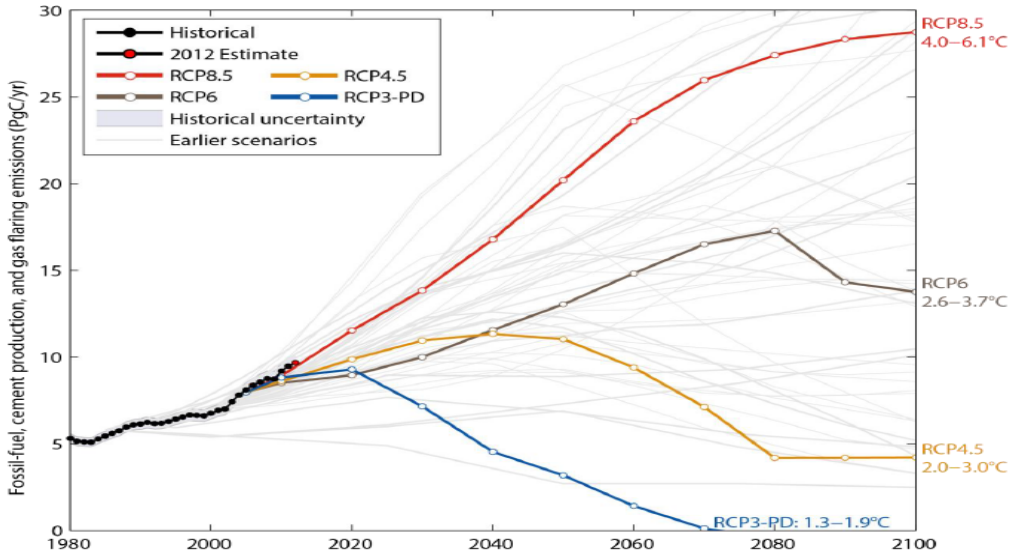


Figure B.4 Global GHG Emissions and their Relationship with Representative Concentration Pathway Assumptions



Source: Peters et al. 2012a

Factors influencing the RCP include population growth, economic growth, degree of urbanization, land use change, use of green versus carbon-based energy sources and any future international agreements on greenhouse gas (GHG) emissions, among others.

B.3.2.3 Important IPCC Findings

The full IPCC AR5 Working Group 1 Report was released in September 2013 and provides general details of the IPCC position on climate change. It can be found here: http://www.ipcc.ch/report/ar5/wg1/

Some of the main findings of this report are summarized in the Summary for Policymakers and are reproduced below:

- Warming of the climate system is **unequivocal**, and since the 1950s, many of the observed changes are unprecedented over decades to millennia. The atmosphere and ocean have warmed, the amounts of snow and ice have diminished, sea level has risen, and the concentrations of greenhouse gases have increased.

- Each of the last three decades has been successively warmer at the Earth's surface than any preceding decade since 1850.

- Over the last two decades, the Greenland and Antarctic ice sheets have been losing mass, glaciers have continued to shrink almost worldwide, and Arctic sea ice and Northern Hemisphere spring snow cover have continued to decrease in extent.

- The atmospheric concentrations of carbon dioxide (CO2), methane, and nitrous oxide have increased to levels unprecedented in at least the last 800,000 years.

- Human influence on the climate system is clear. This is evident from the increasing greenhouse gas concentrations in the atmosphere, positive radiative forcing, observed warming, and understanding of the climate system.

- Human influence has been detected in warming of the atmosphere and the ocean, in changes in the global water cycle, in reductions in snow and ice, in global mean sea level rise, and in changes in some climate extremes. This evidence for human influence has grown since AR4. It is *extremely likely* that human influence has been the dominant cause of the observed warming since the mid-20th century.

- Observational and model studies of temperature change, climate feedbacks and changes in the Earth's energy budget together provide confidence in the magnitude of global warming in response to past and future forcing.

- Climate models have improved since the AR4. Models reproduce observed continental-scale surface temperature patterns and trends over many decades, including more rapid warming since the mid-20th century and cooling immediately following large volcanic eruptions.

- Global surface temperature change for the end of the 21st century is *likely* to exceed 1.5°C relative to 1850 to 1900 for all RCP scenarios except RCP2.6. It is *likely* to exceed 2°C for RCP6.0 and RCP8.5, and *more likely than not* to exceed 2°C for RCP4.5. Warming will continue beyond 2100 under all RCP scenarios except RCP2.6. Warming will continue to exhibit interannual-to-decadal variability and will not be regionally uniform.

- Changes in the global water cycle in response to the warming over the 21st century will not be uniform. The contrast in precipitation between wet and dry regions and between wet and dry seasons will increase, although there may be regional exceptions.

- Continued emissions of greenhouse gases will cause further warming and changes in all components of the climate system. Limiting climate change will require substantial and sustained reductions of greenhouse gas emissions.

With each subsequent report, the evidence of climate change builds and increasingly points towards greater confidence that human-kind is having and will continue to influence our future climate, from warming, to extreme events, to sea-level rise to melting sea-ice. Among the most recent IPCC reports was the addition of a separate document on climate extremes, the IPCC SREX document (SREX-IPCC, 2012). So in addition to changes in the mean climate, extreme climate events will also be impacted, and in many cases the changes in the extremes are expected to be greater than mean changes.

Of particular interest are some conclusions from the extremes report (SREX-IPCC, 2012):

- It is *virtually certain* that increases in the frequency and magnitude of warm daily temperature extremes and decreases in cold extremes will occur in the 21st century at the global scale.

- It is *very likely* that the length, frequency, and/or intensity of warm spells or heat waves will increase over most land areas

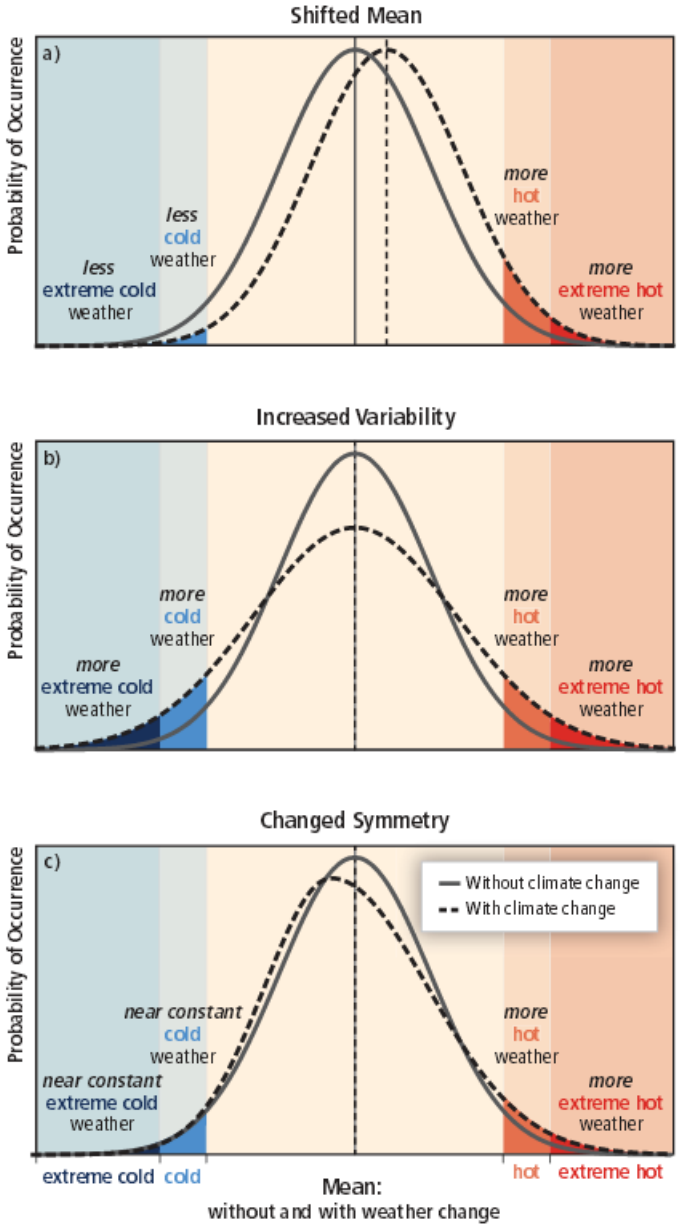
- It is likely that the frequency of heavy precipitation or the proportion of total rainfall from heavy falls will increase in the 21st century over many areas of the globe

- Extreme events will have greater impacts on sectors with closer links to climate, such as water, agriculture and food security, forestry, health, and tourism

- Attribution of single extreme events to anthropogenic climate change is challenging

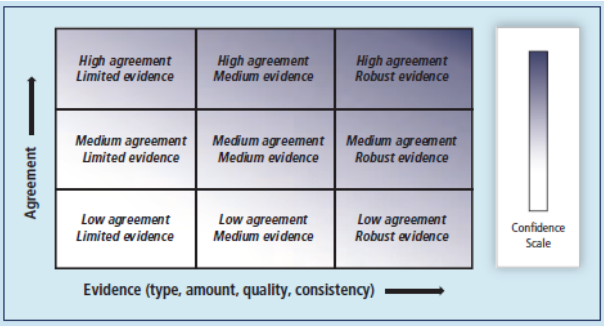
An example from the report is shown below for changes in temperature, which demonstrate how greater likelihood of extremes is possible through changes in mean, variability and symmetry.

Figure B.5 How Changes in Temperature Distributions can affect Extremes (IPCC, 2012)



Confidence wording in the IPCC documents are characterized by the use of specific terms such as 'very likely' or 'virtually certain', where in previous reports changes may have been referred to as 'likely'. There has been a gradual increase in confidence of the projections from climate models over time. A summary of the confidence terminology used in the official reports is shown below (SREX-IPCC, 2012):

Figure B.6 IPCC Confidence Terminology



A depiction of evidence and agreement statements and their relationship to confidence. Confidence increases toward the top-right corner as suggested by the increasing strength of shading. Generally, evidence is most robust when there are multiple, consistent independent lines of high-quality evidence.

The following terms indicate the assessed likelihood:

Term*	Likelihood of the Outcome
Virtually certain	99–100% probability
Very likely	90–100% probability
Likely	66–100% probability
About as likely as not	33–66% probability
Unlikely	0–33% probability
Very unlikely	0–10% probability
Exceptionally unlikely	0–1% probability

* Additional terms that were used in limited circumstances in the Fourth Assessment Report (*extremely likely:* 95–100% probability, *more likely than not:* >50–100% probability, and *extremely unlikely:* 0–5% probability) may also be used when appropriate.

With each report there are more and higher quality observations of the changing climate and improvements in the models equations/parameterizations, and their spatial and temporal detail. The IPCC reports continue to provide the best science-based information on projected climate change assembled from the best climate researchers worldwide. Climate change projections for this report are based upon the same new models used for guidance in the IPCC AR5 report recently released.

B.3.3 Climate Projection Methodology

B.3.3.1 The Delta-Method Applied to the Ensemble

The use of the CMIP5 ensemble not only allows for the calculation of an average projection of future climate which represents the consensus of all independent models, but it also allows for the estimation of projection uncertainty and statistical distributions which could not be determined from a single model. The projections for the variables in this report represent the 'best estimate' available – and are more indicative of the general expectations of climate change over any single model.

The ability of the CMIP5 ensemble to reproduce the historical temperature gives us confidence that the newest models used in this report are reliable and when grouped can provide accurate estimates. This would imply that reliable historical climatology should lead to reliable future projections.

This study uses a so-called 'delta' approach (sometimes also called 'climate change factor approach'), to obtain future estimates of climate variables. It is generally comprised of the following tasks.

1. Obtain a baseline climate condition (or 'average' climate).

2. Using an ensemble of all available CMIP5 models ('CMIP5 ensemble'), we obtain the model average climate for this same period – the average of all models for the grid covering Peel region. However, each modeling center does not use the same grid alignment and resolution, so a first step before obtaining the average of all the models is to regrid them all to a common resolution. This regridding typically uses a scale representative of the resolution of the models, in this case approximately 200 by 200 km.

3. The CMIP5 ensemble future climate is obtained for this same cell for each of the required future periods. In this case, every 10 years starting in the year 2011 and ending in the year 2100. From this we will have average future conditions of all the models for ten 10 year periods.

4. The difference (or 'delta') between the CMIP5 baseline and CMIP5 future periods are obtained – this represents the change in climate condition. Ten climate deltas are produced, for example, the delta between the baseline (1981-2010) and the 2051-2060 period is one of the deltas.

5. The final step is to then apply this delta value to the baseline period.

B.3.3.2 Complex Climate Events: Regional Climate Models and other projection techniques

The delta method applied to an ensemble of GCMs is not the only method available for climate change studies. Instead of using a delta ensemble approach, the delta approach could also be applied to single model, but the projection estimates would therefore only rely on ones assumption that the single model employed was the ideal choice. In climate science there are tradeoffs between model complexity and expediency.

It should be noted that many high impact atmospheric events tend to occur on much smaller spatial and temporal scales than are covered by GCMs (e.g. lightning, freezing rain, ice storms, tornadoes). Two main strategies have been developed to help address this, the use of regional climate models (RCM's) [1] and statistical downscaling studies. Both strategies were used in Phase 2 for several of the more localized and shorter duration climate elements analyzed. For one set of climate hazards (e.g extreme temperatures), the technique of employing a climate analogue was also used to validate the "delta-method" for determining these climate hazard probabilities.

Regional Climate Models

Another approach for obtaining specific climate projection information is to run a very high resolution model once over the area of interest (so called 'dynamical downscaling'). In the simplest of terms one can either have 'many model runs at a coarse resolution' or 'few model runs at high resolution'. These high resolution models are called 'Regional Climate Models' (RCMs). There are RCMs available, but this data can be difficult to obtain and they still require a coarser resolution CMIP5 or earlier model to act as a precursor. Over North America, the North American Regional Climate Change Assessment Program (NARCCAP) has assembled less than a dozen RCMs for various time periods (http://www.narccap.ucar.edu/). As these models have a high temporal and spatial resolution (i.e. hours and tens of kilometers), there are fewer RCMs available than the CMIP5 Global Climate Model collection. In addition there are far fewer model runs from which to obtain an average climate change value. For this study, the decision was to use many coarser models from which to obtain the climate change signal rather than fewer higher resolution models. However, some of the probability results for one set of climate hazards in Phase 2 (extreme temperatures) were generated using the CANRCM4 model, and a discussion of associated uncertainties can be found under the specific descriptions for those climate hazards found below.

Statistical Downscaling

Statistical downscaling studies attempt to solve the spatial challenges by developing statistical links between GCM scale climate conditions and localized, short duration events (e.g. freezing rain/ice accretion and wind gusts). Historical, point location climate data is compared with conditions on the scale of GCM grids. Statistical links, so called "transfer functions", are then developed based on these relationships. After GCM projections are developed for a given future period, these transfer functions are then used to "downscale" GCM projection back down to local scales. Although much less computationally intensive than RCMs, individual statistical downscaling studies still require significant expertise and time for proper execution.

[1] These are sometimes referred to as "dynamical downscaling" methods, to provide an analogous term to alternative "statistical downscaling" methods.

The main drawback of this technique is that climate projections can then only be obtained from specific observation station locations which have sufficiently long data records. This method calibrates historical climate observed at an observation station (for example Toronto Pearson Airport), with historical model data at a coarse scale (called 'predictors'), to obtain a statistical relationship. For example, perhaps the daily temperature observed is related to the modeled upper atmosphere wind direction. If one provides the future upper atmosphere wind direction from a climate change model, it could then be used as one of the variables to predict the future temperature. The difficulty with this process even with pre-constructed software is that spurious associations based on pure statistics and not climatology can be applied which would produce unrealistic future conditions. Certainly some expertise in the statistical software is required. Additionally, this method requires specially formatted input statistical climate model data which is only available for a few models – and for few model runs and RCPs. This procedure would have to be repeated for all station locations for which there was long term reliable station observation data to produce estimates of climate change for only those specific locations.

An IPCC document entitled "Guidelines for Use of Climate Scenarios Developed from Statistical Downscaling Methods" (Wilby et al, 2004) further discusses these procedures.

Phase 2 made use of previously published statistical downscaling studies to support future climate change projections (Cheng, Li and Auld 2011, Cheng 2014).

Climate Analogues

In the case of extreme temperatures (i.e. average temperature over 30 and 35 C, extreme over 40C) climate change projections were also compared to a "climate analogue." Climate analogues refer to locations in other geographical areas which possess historical climates which resemble in many respects the future climate of the study area. The future temperature regime for the 2050's for the City of Toronto is very similar to the current and historical climate of northern Kentucky. While not an exact comparison – there are significant differences in regional geographical characteristics, for example – rough, "order of magnitude" comparisons can be made to help further determine if climate change projections are in fact realistic and represent potentially "real" climates.

B.4 Determining the Probability of Occurrence of Specific Climate Hazards

Based on the general methodology presented above, the probability of individual climate hazards were determined. The following sections describe in detail how they were estimated.

Extreme Temperatures

Temperatures and temperatures related indices are the most basic and reliable of climate elements, and therefore associated trends and projected changes to temperatures have the greatest confidence. Thresholds are based on previous consultation work from Phase I, IEEE standards for switching and transformer equipment, with some additional consideration from impact studies found in the literature - for example, see (McEvoy, Ahmed et Mullett 2012). The lowest thresholds generally address load forecasting and related factors, while higher temperatures begin to consider direct impacts to equipment.

Historical values were assessed using observations for Pearson Airport for the 1981-2010 normals period. Climate projections were then developed using the AR5 ensemble and RCP 8.5 emissions scenario. For temperature related thresholds which require information of *daily* temperature information, such as heat waves, 40°C maximum daily temperature, or the 35°C average daily threshold, required special treatment and were developed using projections from the CanRCM4 regional climate model (RCM), again using the RCP 8.5 scenario. The "Delta method" was then used to apply the modeled changes in frequency of those days applied to historical averages. It should also be noted that the range indicated for the 40°C threshold is the result of applying two methods, RCM and GCM based estimates,

since RCMs are again potentially prone to overestimates due to numerical instability[2], while the GCM method may under-estimate the frequency of extremes due to averaging from large spatial scales. These results were further checked against climate analogues in northern Kentucky, again to serve as a consistency check against model projections to determine if these projected increases were realistic.

Extreme Daily Averaged and Maximum Temperatures

Manufacturers of electrical distribution equipment specify both maximum *one day average* and *peak ambient* temperatures for the operation of transformers and other components. With global warming, it is unsurprising that all thresholds show an increase in event frequency. High temperatures which already occur several times per year increase further in frequency, and a few extreme temperatures which are currently less than annual occurrences (e.g. daily average temperature of 30°C) are projected to become annual events.

The most striking results were noted with some of the highest temperature thresholds. For example, days with peak temperatures of 40°C or greater are extremely rare, with only one incident on record for Toronto's Downtown station[3], and *no* events reported at Pearson Airport during its entire period of record. However, indications are that these extreme heat days may become an annual or near-annual occurrence by the 2050's. Similarly, days with 24 hour *average* temperatures of 30°C or higher are also extremely rare but may become, on average, annual occurrences. However, as with the historical behaviour of lower threshold values, there will likely be some years with several days over the "new" threshold, while other years will have none.

Multi-Day Heat Events and "Warm" Nights

Other measures of extreme heat have been proposed as having a potential impact on electrical infrastructure.

While heat waves, defined as three or more days with maximum temperatures above 30°C, are currently slightly less than annual events, these are expected to increase in frequency to just over 1 per year, on average, into the 2030's and 2050's. The length of a given heat wave may also increase into the future. Regional climate model results suggest that for the 2030's, an average of approximately four (4) consecutive days over 30°C will occur every year, and by the 2050's the estimate is as high as *six* (6) consecutive days over 30°C per year.

So-called "warm nights" have also been implicated in excessive stress on electrical infrastructure (McEvoy, Ahmed et Mullett 2012) through increases in nighttime electrical customer use (i.e. need for continuous use of air conditioning systems), combined with an inability for equipment to sufficiently cool under warm nighttime ambient temperatures. These have increased substantially in recent years, with average of greater than one event per year in the most recent 15 year period of record at Pearson Airport. This includes a record of five (5) warm nights in 2005, as well as the warmest overnight temperature ever recorded in 2006 at 26.3°C. However, while the literature has indicated that the latter element may be important for combined impacts and stress to the electrical system, most workshop participants were indeed quite skeptical that warm nights were an important measure for electrical system impacts, indicating they considered extreme *daytime* temperatures and electrical use as the dominant cause for impacts to distribution systems, rather than warm nights.

[2] Estimated increases in frequency from CanRCM4 were indeed so striking that they were checked against GCM based estimates for consistency. However, even when considering spatial and temporal averaging which will occur with the larger grid spacing and time steps inherent in GCMs, the ensemble still indicated significant increases in extreme heat days well beyond anything within historical experience.

[3] Three (3) consecutive days in July 1936 showed maximum temperatures reaching 40.6°C.

Spatial Geographical Variability

Mapping of extreme temperature days (**Appendix C**) indicate important temperature differences across the city, with temperature differences of 3-5 degrees between the shores of Lake Ontario and northern portions of the city. This is a direct result of the presence of Lake Ontario and its lake breeze, with cooler air from the lake keeping the shoreline and nearby areas cooler than parts of the city further north.

Extreme Short Duration Rainfall

The July 8, 2013 flash flood event in the GTA provided an example of the vulnerability of underground infrastructure to atmospheric events. While this particular case impacted Hydro One infrastructure, it is indicative of possible impacts to similar infrastructure owned and operated by Toronto Hydro. It was also an example of the importance and potential impacts generated by the loss of 3rd party infrastructure on which Toronto Hydro relies, emphasizing the interconnectedness of the electrical grid.

The threshold of "100 mm + antecedent" is based on rainfall accumulations estimated near the failure sites from the July 8th, 2013 event as well as other cases **(see Appendix C)**, although workshop participants felt this threshold might indeed be as low as 60 mm of rainfall. This threshold is in specific reference to high-intensity, localized rainfall events, characteristic of severe thunderstorms during the warm season. These generally last only a few hours in total, with the majority of that rain (over 50%) falling within a 1 hour time period. However, in every case, there was also antecedent rainfall in the preceding week which likely contributed to the overland flooding.

While these events are very difficult to predict even in short term forecasts, historical analyses on global precipitation extremes indicate that, in general, they will increase in intensity with climate change. However, the magnitude of this change, particularly for specific geographical regions, is not well understood (Kunkel, et al. 2013). Extreme, localized rainfall events represent an event type which cannot be modeled directly by GCM or even RCM output, and unfortunately no statistical downscaling studies for extreme thunderstorm rainfall exists for the GTA or nearby regions. However, global trends of historical increases in extreme rainfall are so significant that the climate team chose to increase annual probability score by one to account for this clear increase in thunderstorm extreme rainfall risk

Ice Storms and Freezing Rain Ice Accretions

Damage thresholds were also based on previous forensic work on freezing rain impacts, most notably Klaassen et al. (2003), as well as design requirements in codes and standards (CSA 2010a). These include thresholds for tree damage (15 mm) and for minimum CSA design (25 mm totals ≈ 0.5 inch radial). Freezing rain events represent an example of meteorologically complex events which require special treatment, and hence future projections presented here are based on tailored statistically downscaled results from published studies. Customized data specifically developed for Pearson International Airport were provided courtesy of C. Cheng (2011), using the same methodology employed in Cheng et al. (2011, 2014). Downscaled projections are expressed in *duration* rather than *accumulation amounts* due to the nature of the analysis methods used for downscaling. Climate projections of the parent large scale weather patterns (so-called "synoptic map typing") are based on the patterns and conditions which produce ice storms. For the downscaling work, these weather patterns were linked to the *duration* of freezing precipitation and not *amounts*, since total precipitation accumulation can vary significantly depending on available moisture. The duration threshold is also quite low (6 hours+) due to sample size, since storms of this magnitude or greater are infrequent.

However, these projections can be applied to other measures of ice storm severity given the following considerations:

1. Storms producing amounts on the order of 15 and 25 mm are of part of this "6 hour+" population, and we can therefore use results for the 6 hour+ storms as guidance for what will happen with 15 and 25 mm events; and,

2. Cheng et al. (2011, 2014) consistently showed greater increases in frequency for higher thresholds, hence storms with higher thresholds are expected to increase in frequency as much as or more than storms at lower thresholds;

Hence, changes in 6 hour+ event frequency are expressed as particular values, whereas the greater accumulation events are expressed as "greater than" some value.

Regional Differences in Severity

The severity of freezing rain events, specifically in terms of total ice accretion, tend to be lower for areas closest to Lake Ontario. In contrast to the summer, the lake acts to keep temperatures warmer during the early winter, an effect that appears to have been a factor during the December 2013 ice storm (see **Appendix C**). However, there are also indications from the forensic analyses that older portions of the city, particularly areas with a combination of significant, mature tree canopy cover and older overhead electrical distribution equipment, may be more sensitive to ice storms and are therefore more susceptible to smaller ice accretions.

It is very difficult to determine the return period or annual frequency of the extreme cases, since no events producing greater than 40 mm of total ice accretion have been reported in the GTA. The CSA standard for transmission line design (CSA 2010b) contains return period estimates for radial ice accretion for various locations[4]. Depending ones location within the City of Toronto, estimates for 30 mm ice accretion event (roughly 60 mm of total ice) indicate anywhere from a 1-in-150 to a 1-in-500 year return period event, termed "high" and "low" risk values, respectively, in table 3-2 in the main report. When increases in frequency of large ice storms is taken into account, these produce 35 year study period/"lifecycle" probability estimates of ~25% and ~8%, respectively[5]. However, these values are based on estimated return periods for extremely rare events, and the period of record on which they are based is far shorter than the return periods assigned to these ice accretion values.

Complexity of Freezing Rain Accretion versus Impacts

A myriad of measurements are given for freezing rain ice accretion due its complexity. Accumulations from airports, for example, represent *total* freezing rain amounts and not the thickness of accretions on overhead lines and structures, and hence certain freezing rain amounts can result in very different levels of ice accretion on infrastructure depending on numerous other factors (e.g. time, wind speeds, ambient temperatures). We also note that a significant majority of damage from the December 2013 ice storm was due to tree contacts at accretion thresholds lower than design requirements **(Appendix C)**, hence the inclusion of the 15 mm threshold.

High Winds

High winds can be produced by a variety of storm types and vary greatly in scale, intensity and duration. Design wind speeds found in codes and standards are based on large scale (synoptic) storms, while cases of extreme localized damage tend to occur with thunderstorm winds, including microbursts and tornadoes. This complexity introduces significant challenges when attempting to determine wind speed return periods for engineering design using historical data (Lombardo, Main et Simiu 2009), let alone the challenge of understanding how these might change under future climate conditions. Much like ice storms, wind gusts tend to also be affected by highly localized meteorological and geographical factors, and so meaningful projections cannot be directly extracted from GCMs or even RCMs.

[4] The values provided in the CSA standard (CSA 2010b) are themselves based on the Chaîné ice accretion model. These were felt to be accurate enough to provide estimates of extreme ice storms in the GTA for this study.

[5] Based on climate design table, highest risk locations are Etobicoke and North York, with the lowest risk is in Scarborough (CSA 2010a), the former not surprisingly representing areas which are slightly further away from the lake.

The 70 and 90 km/h thresholds are based on practitioner consultation from Phase I as well as forensic analyses conducted for Phase II (**Appendix C**). The highest threshold, 120 km/h, is based on IEEE design standards for switch gear and transformers, as well as other impact thresholds work, for example the EF-scale and McDonald and Mehta (2006). Climate change projections for the 70 and 90 km/h thresholds were obtained from statistically downscaled results in the published literature (Cheng, Li et Li, et al. 2012, Cheng 2014) using statistical downscaling methods similar to those used for freezing rain, while projections for 120 km/h threshold were not available.

The statistically downscaled results indicate increases for both thresholds analyzed here. Cheng et al. (2012, 2014) also indicated that increases in frequency of wind gusts were consistently greater as thresholds also increased (e.g. 80 km/h gusts increased more than 70 km/h gusts), but did not conduct analyses for thresholds greater than the 90 km/h due to small sample size.

Tornadoes

Tornadoes are small scale, isolated events, and hence the only available historical data are records of observations of their occurrence and/or resulting damage. Probability scores for EF1 and EF2 tornadoes were calculated based on historical records of occurrence within the City of Toronto from the most recently available 70 years of observational data. Historical data prior to this was deemed too unreliable to contribute to statistics in a meaningful fashion. This inconsistency also renders historical trend detection nearly impossible[6]. Their localized and complex nature also prevents the development of meaningful climate projections through any of the methods described here, including GCM or RCM output as well as statistical downscaling.

As with extreme temperatures, lightning and ice accretion, the northern portions of the city such as the North York and Rexdale (northern Etobicoke) areas exhibit a higher risk of tornadoes historically, again mainly due to the effects of the Lake Ontario lake breeze, but this does not exclude the occurrence of tornadoes in and around the downtown core.

Two different intensity levels were chosen due to important differences in their impacts. Research on historical events indicated that concrete utility poles and other more resilient infrastructure only fail in EF2 or stronger tornadoes, and hence these were investigated separately to determine relative risk.

High Impact/Low Probability Events: Probability Estimates and Their Interpretation

Tornado probabilities were subject to further analyses beyond those used for most other climate elements. Probability scores in Table 3-2 of the main report reflect the probability of occurrence for a *single point*; however, since these values are extremely small, a different statistical perspective was needed to better represent the type of risk posed by tornadoes. The City of Toronto has recorded five (5) F-2[7] tornadoes on two separate days since 1900, with a possible sixth case in 1976 in North York. Hence, over the 35 year life cycle study period, there is a 46% to 61% chance that a weather event producing one or more EF-2 tornadoes will strike somewhere within the City of Toronto. While the probability of a direct impact to a specific point or location is extremely small, the likelihood of a significant event *somewhere* in the city between 2015 and 2050 is in fact considerable, and could entail catastrophic impacts to a portion of the city's infrastructure.

Lightning

As with all other climate elements, lightning can vary significantly in intensity, with the same storm producing different lightning strikes with amperage values varying by several orders of magnitude. Even

[6] However, some very recent work in the United States may finally be revealing changes in tornado climatology potentially associated with climate change in the form of increased *variability* in occurrence[6] (Brooks, Carbin et Marsh 2014).

[7] The so-called "Enhanced" Fujita, or EF-Scale, has only been used in Canada as the official replacement to the F-scale since 2013; however, the EF-scale is intended to be compatible with F-scale ratings in the historical record, and so references to tornadoes using the F-scale can, for the purposes of this report, simply be considered as storms of equivalent intensity.

for a single thunderstorm event, there now exists a great deal of data currently available for use in analyses and even forecasting of lightning occurrence, particularly following the establishment of the North American lightning detection network in the late 1990's, and more recent "total lightning" detection networks being installed in the GTA for meteorological monitoring for the upcoming 2015 PanAm games. It is suggested that Toronto Hydro investigate this data to better understand how lightning interacts with the electrical distribution system, such as investigation of significant lightning events (e.g. July 21 & 22, 2002) to determine why and how they generated so many impacts.

Investigation of New Probability Scoring Methodology

Lightning probability scores differ from Phase I due the changes in the method used to calculate probability values. The annual average frequency of cloud-to-ground lightning strikes varies across the city from under 1.12 to over 2.24 lightning strikes per square kilometer. The highest frequencies are seen in the northwest portions of the city, while the lowest are seen in southern Etobicoke (see Figure B-7). However, each individual strike will only affect a very small area. Hence, the probability of impact was estimated using representative "target sizes" (i.e. areas which represent the usual footprint of a given piece of infrastructure). A further assumption was tested assuming that lightning strikes would need to be within 25 meters of a piece of overhead infrastructure to produce negative impacts. The resulting probability scores were felt to be more representative of field conditions, particularly when considering the frequency of lightning impacts reported by Toronto Hydro (**see Appendix C**). These were also weighed against mounting evidence that lightning occurrence will increase in frequency with climate change, for example (Romps, et al. 2014), but by an uncertain amount[8].

Using two different "target" sizes provided by AECOM representing large (0.015 km^2) and small municipal (0.0001 km^2) transformer stations, probability of impact were calculated and compared, with and without the assumption of a 25 meter radius of impact. The results are provided in Table B-2 below.

Figure B-7 Lighting Distribution in Greater Toronto Area for 1999 – 2008 period, Lightning Strikes / /km^2•yr)

[8] Romps et al. (2014) indicated a potential increase of ~50% in total lightning strikes in the continental United States by the end of the century. However, while their methodology proved to be quite robust when compared to observational data, there was no assessment of GCM error in recreating the indices which drove this increase. Their index and model also appear to have difficulty with lake breeze related convection, which is of great importance for Toronto's lightning climatology. Hence, the RSI climate team chose to not apply these percentages as there remains too much uncertainty in how global climate change will impact lightning frequency in the Toronto area specifically.

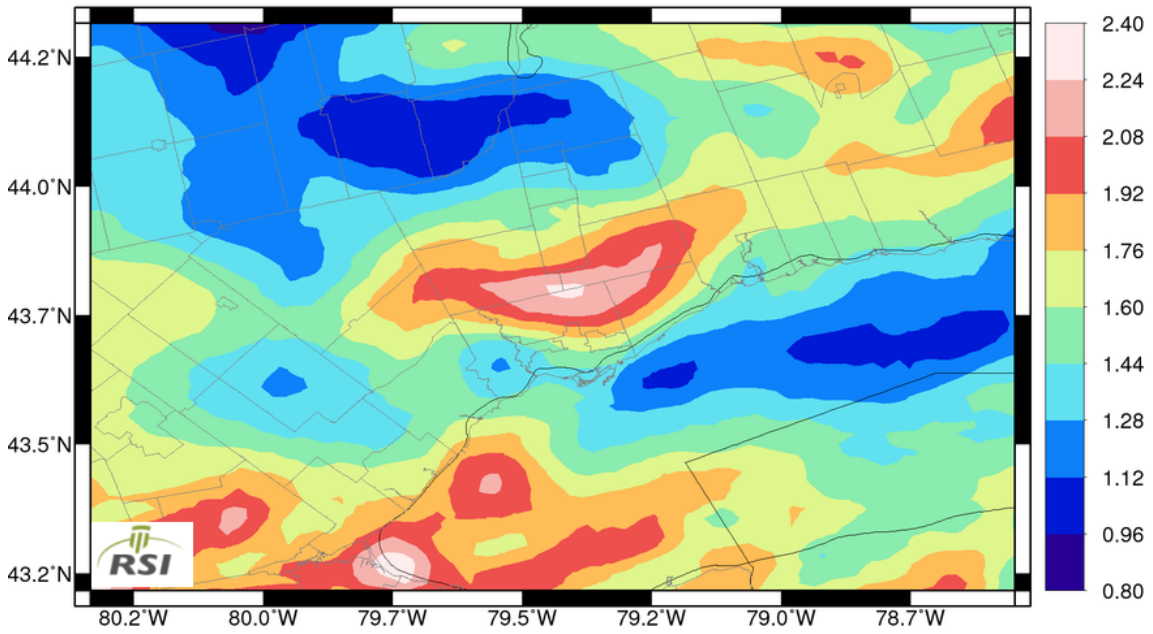

44.2˚N
44.0˚N
43.7˚N
43.5˚N
43.2˚N
80.2˚W
80.0˚W
79.7˚W
79.5˚W
79.2˚W
79.0˚W
78.7˚W
RSI
2.40
2.24
2.08
1.92
1.76
1.60
1.44
1.28
1.12
0.96
0.80

Table B.2 Lightning Strike Probabilities Transformer Stations

Target Type	Annual Lightning Frequency (km^{-2})	Annual Probability Score (2050's)	Study/"Lifecycle" Period Probability Score (2015-2050)
Large Transformer Station	1.12	1	5
Large Transformer Station	2.24	2	6
Municipal Transformer Station	1.12	0	2
Municipal Transformer Station	2.24	0	3

Snow

Snowfall thresholds were chosen following the second workshop and are intended to address "nuisance" events, such as those which require the application of deicing agents (5 cm+) and those leading to restricted to site access (10 cm+). The group chose to focus upon nuisance events at the "lower end" of the snowfall accumulation spectrum, rather than extreme snowfall events, since overhead systems were not considered by workshop participants as being sensitive to direct snow loading. Historical data indicate that the total number of days exceeding these thresholds are decreasing, as expected with global warming, but not at all rapidly enough to consider snow a "disappearing" hazard. In addition to this, and in contrast to days with small snowfall totals, days with extreme snowfall will continue to occur well into the future, and may in fact *increase* in intensity with further warming (Kunkel, et al. 2013). Hence, days in which snow will pose a hazard to infrastructure will continue well into the coming decades, even with continued warming.

Frost

Participants at the second workshop also indicated frost depth as being a concern for civil infrastructure, particularly following the extreme cold experienced during the 2013-14 winter season. As with other cool season hazards, the frost free period is expected to increase in length, which will result in less frost penetration on average, although occasional extremely cold winters will continue to occur well into the future. Frost depth calculations were not conducted for this project due to time and resource constraints, as well as significant variability associated with frost depth under the same atmospheric conditions. The latter is impacted by soil moisture, thermal conductivity, snow cover, and several other factors which vary greatly across the city. However, if frost heave is considered an important risk, further study could be conducted, using the 2013-2014 winter season as an example case study.

Complex Interactions

Complex interactions are generally defined as interactions which generate negative or unwanted impacts to infrastructure but which are the result of a *sequence* of events involving both climate and human factors. For the sake of simplicity, we have considered most climate elements in isolation. As the forensic analyses indicate, however, most real-world climate impacts are often attributed to one dominant element but with additional impacts from other simultaneously occurring hazards.

High Humidity Near-Zero Winter Environments

This complex interaction type was identified through both workshops and forensics work, and their occurrence appears to result from a *sequence* of events involving a combination of minor ice accretions followed by the application of de-icing agents. These are characterized by multi-day periods in which temperatures are near zero degrees, often "crossing" the zero degree line multiple times, and include

multiple periods of freezing or frozen precipitation. Ice accretion may be from a combination of freezing rain, wet snow or rain-on-snow “re-freezing”, with possible *additional* accretion from fog which is often present between periods of precipitation. These very moist conditions are then coupled with de-icing agents to cause short circuits, resulting in pole top fires and other incidents associated with short circuiting of insulators and switch gear.

Such a complex events entail the sequential occurrence of several meteorological factors coupled with human factors and are therefore impossible to project using the current set of climate change projection techniques. However, having identified these conditions, their occurrence could be monitored and even anticipated several days in advance using a combination of current conditions and short term weather forecasts, allowing for the mobilization of operational resources. The January 31st to February 3rd, 2003 event described in **Appendix C**, and a similar event which was identified for the transmission sector “sister” PIEVC study (January 2000) can be used to form the basis of pattern recognition for future events of a similar nature.

Tree Growth, Disease and Pests: Implications for Overhead Infrastructure

The second important complex interaction identified by our analysis entails the impacts of environmental changes affecting tree growth and health, affecting their resiliency to climatic loading. Higher average temperatures are expected to extend the growing season. This will likely result in faster tree growth and necessitate more spending on right-of-way maintenance, as well as possibly increasing tree vulnerability to wind and ice loading. The impacts of new and/or exacerbated disease and pest conditions can also increase tree vulnerability to damage, with the December 2013 ice storm and impacts on emerald ash borer infested trees being an example of this increased vulnerability. The complex interaction between accelerated growth rates, disease and pest regimes, and the resulting changes in vulnerability to adjacent infrastructure have only recently been identified and are not well understood, but should be subject to further study.

Appendix C
Forensic Analysis of Weather Related Power Outage Events

Brief Forensic Analyses of Weather Related Power Outage Events

C.1 Introduction

To better understand the nature and magnitude of climatic and meteorological events responsible for impacts to Toronto Hydro's electrical distribution system, as well as neighboring LDCs, RSI staff conducted forensic analyses of events generating significant impacts to the system. Information on the nature and extent of those impacts was compared to meteorological data to understand the nature and magnitude of atmospheric loads and conditions associated with these impacts. The analyses below consist of what can be termed either "single incident" or "cross-incident analyses," the former consisting of a "deep dive" into an individual events (listed in **Table C.1**), while the latter consists of the inter-comparison of numerous similar events to help determine commonalities.

In particular, events that were deemed meteorologically complex or multi-causal in nature, as well as meteorological events representing instances of impact thresholds, were selected for further assessment under "single incident" analysis to help refined our understanding of the thresholds at which impacts begin to occur, and what the causes and drivers of those impacts might be. Winter storms (including freezing rain events), summer thunderstorms, and a high heat case were evaluated for more detailed analyses. Other cases, such as fall season high winds, were evaluated under "cross-incident" analyses, for the purpose of evaluating and cross-checking thresholds determined from other sources (e.g. literature and practitioner interviews).

Several data sources were consulted for both meteorological and infrastructure impacts information. The former included data from Environment Canada's national climate data archive, Toronto Region Conservation Authority (2014) precipitation data, consultant reports (Cole Engineering 2013), as well as remote sensing data where appropriate. Impacts data were provided directly by Toronto Hydro, as well as outage incident press releases, newspaper accounts, and internal report (where available). Events which underwent detailed analyses are listed below in **Table C.1**.

C.1.1 Event Types and Relation to Impacts

Any number of climate and weather related events are capable of producing unwanted interactions with power distribution infrastructure. Direct impacts from severe winds, ice accretion, heavy/wet snow, extreme heat and lightning can directly overload support structures and conductors, as well as adjacent vegetation, which is also prone to failure, causing secondary impacts. Underground infrastructure is sensitive to flooding and longer term processes, such as enhanced corrosion through seepage and penetration of deicing agents. For each hazard, there are generally a small sub-set of mechanisms which can produce them. High winds during the warm season are associated with severe thunderstorms (including downbursts, microbursts and tornadoes), which tend to be intense but localized, whereas should season and winter severe winds are associated with large scale low pressure systems (so-called "synoptic lows"). Winds associated with these events are more widespread and can last for several

hours to more than a day. Similarly, precipitation events are generally associated with thunderstorms during the warm season and low pressure systems in the cool season (snow storms, ice storms, etc.). It should become quickly apparent that several event types can occur simultaneously, resulting in multiple cause power outage events.

Identification of event type is critical in understanding what types of impacts to expect at different times of year, including duration of the event, potential challenges for response and maintenance, presence of simultaneously occurring hazards, and for some event types what antecedent conditions to monitor to help anticipate or forecast weather related impacts. During the late spring and summer, for example, a number of significant thunderstorm events tend to be proceeded by high temperature and humidity combinations which themselves may have generated impacts on the system. While individual events are indeed complex, infrastructure operators can begin to understand the antecedent conditions to help increase readiness for such events.

Event type identification is also critical to climatological analyses and the development of adaptation responses. More localized, short duration events present significant challenges for assessing future climate vulnerability and risk, but less complex climate elements, such as temperature, are far less difficult to analyze, and confidence in both the consistency of historical data as well as certainty in projected trends are much greater.

Adaptation responses, particularly those regarding maintenance and operations, must take into account the nature of the events generating impacts. How much lead time can one expect for storm warnings, if any? What hazards may be posed to repair crews, or restrict access to damage locations? For example, a number of recent press releases indicated that full repair efforts have been postponed based on the timing of high winds, with crews waiting for the "worst to pass" before executing major restoration efforts (see "Superstorm Sandy" analysis below). More sophisticated operations and management actions such as these are critical to optimizing response to severe weather events.

C.1.2 Brief Note on Impacts Data

Staff at Toronto Hydro kindly provided outage incident data for this analysis, which proved invaluable for determining the types and magnitude of events which were responsible for significant power outage events. However, this type of cross-disciplinary forensic analysis was not the original intent of the failure database, and as such there were a number of challenges which presented themselves when using the data.

Most notably, it became clear that data collection was inconsistent throughout the period of record. While the database contains events from the years 2000 to 2013 inclusive, earlier events have dozens of reports per date, while more recent major outage events do not. In 2013, the July 8th flood and December 21st-22nd ice storm, which Toronto Hydro staff indicated were among the worst in their history, have very few listings in the database. This is likely due to changes in reporting practices, which apparently began in 2007 judging from the frequency of weather events with 20+ reports each, but this requires confirmation Toronto Hydro staff.

This emphasizes the need for the standard forensic practice of consulting and comparing multiple sources of data. For example, impacts data can be used to indicate if event intensity, such as high winds, could have been significantly higher than meteorological measurements may indicate. Conversely, meteorological data can be used to either guide and/or refine the search for impacts data, or even correct coding or other errors in impacts data.

C.2 Toronto Hydro Outage Data

As indicated above, outage data from Toronto Hydro were interrogated to identify significant outage events which could be used for further study. Days with 20 or more reports were identified, and these were further refined by checking for potentially related reports on days before and after identified event dates. While it is fairly clear that data from 2007 to 2013 were collected under different reporting requirements, 2000-2006 appear to be consistent, and so data for this period will be evaluated here.

A total of 46 weather events were identified with this methodology. Just over half (54%) of these events occurred over fairly extended periods of 12 to 48 hours; this has implications for maintenance and repair response measures. For fall wind storms and winter precipitation events, this quite literally meant several consecutive hours of either high winds or precipitation generating impacts, while for summer events this likely represents two or more episodes of thunderstorm activity within a one to two day period.

C.2.1 "Worst" Years

In terms of the "worst" years, we have two measures; total number of events, total number of damage reports for these events, and number of damage reports per event. The years 2000 and 2005 are tied for the most events in a given year (9). In terms of total reports for all events combined, 2000 has the highest at 6—followed by 2003. In terms of average event severity, the total number of reports was divided by the number of events in a given year as a rough measure of "average" severity for a given year. The year 2003 had the highest average, with an average of just over 84 reports per event. Even though 2000 and 2005 contain single major events, their averages fall well below those seen in 2003, 69 and 56 reports per event respectively.

The year 2000 followed two main themes. A series of severe winter storms in February were responsible for multiple reports and were characterized by either freezing rain or heavy wet snow and rainfall combinations, both characteristic of "warm" winter storms producing heavy precipitation at temperatures near or at 0°C[1]. This was followed by late spring to summer severe thunderstorm events, including the May 12-13, 2000 event, as well as a thunderstorm event on July 14, 2000, which generated over 100 reports through mainly lightning related damage.

The year 2005 was characterized by high heat and humidity during the summer months, which either directly contributed to infrastructure underperformance as well as severe thunderstorm events, most

[1] At temperatures at or just below freezing, atmospheric water content is at its highest while still being able to support ice formation; hence temperatures near zero are associated with either freezing rain or high density, wet snow capable of physically coating and loading overhead lines and trees.

notably the August 19th, 2005 storm. This was followed in the fall by a series of wind storms which produced scattered outages throughout the GTA, which was among several areas across Ontario which were impacted by intense fall windstorms (e.g. over 100,000 Hydro One customers lost power during the November 6, 2005 synoptic storm; Hydro One 2005).

Finally, in 2003, Toronto Hydro was impacted by a similar combination of event types, with two winter storms in rapid succession in February, followed by severe thunderstorm activity during the late spring and summer, followed by large scale wind events from late September to mid-November.

All of the so-called "worst" years identified here have the following in common:

- Repeated events, often with only days between similar types of incidents
- Two or three "modes" of high impact weather events in the same year, specifically:
    - "warm" winter storms, meaning they were associated with temperatures at or just below 0°C with some combination of heavy snow, freezing rain or even rainfall mid-winter;
    - Severe thunderstorms and high heat and humidity during the summer;
    - Multiple fall season large scale (synoptic) wind storms;
- One major event which produced over 150 damage reports

These findings can help with better planning and anticipation of particularly high impact years. For example, periods of very high heat and humidity should be watched closely, as they are occasionally followed by severe thunderstorm events when the heat "breaks" with the passage of a cold front or other air mass change. Fall and spring large scale wind storms will occasionally occur in series, as occurred between September 29th and November 13th 2005[2], repeatedly impacting the same area. These findings appear to be consistent with recent experiences; in 2013, Toronto Hydro suffered two major weather related outage events, one in the summer from a severe thunderstorm event producing extreme rainfall, followed in the winter by a freezing rain event.

It may also be possible to anticipate a particularly severe damage year since the "major" events producing over 150 reports tend not to occur in isolation but usually occur in years with a number of less severe but still significant events, although the consistency of this pattern requires further research.

C.2.2 "Worst" Events for 2000 to 2006 Period

The two events with the greatest number of reports, May 12-13, 2000 and August 19, 2005, were both subject to detailed analyses. Another three events (Jan 31-February 4, 2003; July 14, 2000 and July 21-22, 2002) produced over 100 reports, with September 19, 2003 coming very close at 99 reports.

What is of particular interest is the number of severe thunderstorm related reports which were accompanied by mainly lightning related outages. Even for storms which included extreme rainfall and high winds related impacts, lightning appeared to be the dominant factor in producing outages. The July

[2] A fourth synoptic storm occurred on November 15 to 16, 2005 but did not cause significant impacts to Toronto Hydro's infrastructure, instead tracking to the north east and affecting Georgian Bay and the "Nickel Belt," causing over 50,000 Hydro One customers to lose power.

21-22, 2002 event is particularly noteworthy. Although we do not have detailed lightning information, such information is available from the national lightning detection network, and the frequency and amperage of lightning experienced during this thunderstorm series could be investigated to determine what made this particular lightning storm so damaging to the system in comparison to any number of other events. A summary of all events identified through this method is provided in **Table C.2**.

C.3 Fall and Winter Storms

C.3.1 December 20-22, 2013 Ice Storm

The December 2013 ice storm in south central Ontario has been deemed the worst ice storm in Toronto Hydro's history in terms of impacts to the city's distribution system. It is estimated that at the peak of event during the overnight hours between December 21st and 22nd, ~300,000 customers were without power. The most recent estimates of total damage incurred by Toronto Hydro's distribution system has been placed at nearly $15 million, specifically for restoration and repair (Toronto Star: March 31, 2014).

The storm also impacted several other adjacent LDC's, including:

- Enersource (Mississauga), 91,000 customers affected (Mississauga.ca 2014);
- Hydro One Brampton, 15,500 customers (Brampton Guardian, Dec 30, 2013);
- PowerStream (York Region[3]) 92,000 customers (Markham Economist and Sun, December 31, 2013);
- Veridian (Pickering/Ajax/Port Hope) 40,000 (Veridan Connections Press Release, Dec 22, 2013);
- Whitby 13,000 (Oshawa This Week, Dec 22, 2013)
- Oshawa Public Utilities Company ~30,000; and,
- Rural areas of Clarington (Hydro One) ~46,000 (Ajax News Adviser, Dec 23, 2013)

Meteorological data from both Environment Canada and Toronto Region Conservation Authority stations were analyzed to estimated ice accretion totals and rates in and around the GTA, which were then compared to impacts on electrical distribution infrastructure in the area.

C.3.1.1 Impacts and Meteorological Conditions: City of Toronto

Figure C.1 compares estimated ice accretion values at Pearson and Buttonville Airports with the total number of customers affected reported by Toronto Hydro. While ice accretion values were not directly reported by any of the stations evaluated, they can be estimated by combining hourly observations of precipitation type with daily rainfall totals. Freezing rainfall and drizzle totals were estimated by first determining the fraction of precipitation falling as freezing rain or drizzle (since liquid rainfall and snow were also reported on some days). Accretion rates were then weighted by precipitation type (1 for rain, 0.5 for moderate rain, and 0.1 for drizzle, based relative accretion rates from Klaassen et al. 2003), which were then further developed into estimated hourly average accretion rates. These were then summed for each day between December 20th and December 23rd for both Pearson Airport and

[3] PowerStream also suffered the complete outage of their website, which had not been designed to receive the traffic volumes which it encountered during the event (Markham Economist and Sun, December 31, 2013).

Buttonville Airports, the only locations near the City of Toronto for which hourly observations of precipitation type were available. Given that several locations experienced both above zero temperatures and liquid precipitation during the multi-day period under analysis, and that ice accretion on overhead structures, lines and trees is further affected by wire or branch diameter and surface characteristic, it is likely that estimated multi-day ice accretion estimates are *over*-estimates of true accretion values. This will be taken into account during the discussion of impacts.

Ice accretion totals for the 3 day period are over 30 mm for Pearson Airport and nearly 35 mm at Buttonville. A review of hourly temperatures at both airport for the same time period (not shown) also indicate that Pearson Airport was above zero for several hours longer than Buttonville, implying that less freezing precipitation accretions may have been retained there than at Buttonville. A comparison of photographs taken following the storm, both of ice accretions on different objects, as well as the apparent severity of tree damage to areas near the two airports provide evidence that ice accretions immediately north of the City of Toronto incurred ice accretion amounts several millimeters greater than those experiences in northern portions of the city (**Figure C.2**).

The relative impacts of temperature regimes become readily apparent, however, when ice accretion estimates are isolated to include only freezing rain totals beginning late morning on December 21st, excluding accretion contributions from the December 20th to 21st overnight precipitation episode. Ice accretion values become only 13 mm for Buttonville and *25* mm for Pearson. This implies to important elements for understanding how ice accretion values evolved in different portions of the GTA, particularly:

- Higher than 13mm ice accretion values for municipalities north of Toronto cannot be explained without including precipitation amounts from the earlier December 20th-21st episode;
- Lower than 25 mm ice accretion values near Pearson Airport likely cannot be explained without considering periods of >0°C temperatures, combined with the effects of liquid (non-freezing) rain and drizzle

Estimate ice accretion values on the order of ~20 mm were present when outages began, with amounts of 18 and 23 mm at Pearson and Buttonville respectively just prior to first report of 8,500 outages. Press releases indicate that this initial damage was indeed focused in northern and northeastern portions of the city (Toronto Hydro Press Release; December 21, 11:58 PM); accretion values estimated from these airports are likely representative of those experienced in the first areas suffering from widespread power outages. Rounding down to allow for some ice accretion losses due previously discussed factors, a range of 15-20 mm are likely responsible.

To better understand conditions in and near the downtown core versus surrounding portions of the city, hourly temperatures at the Downtown meteorological station (located at the University of Toronto campus on Bloor Street) and Toronto Island's Billy Bishop airport, were compared to those at Pearson Airport (**Figure C.3**). Radar imagery (**Figure C.4**) indicates that precipitation elements were moving very rapidly (over 100 km/h) during the freezing rain event, hence hourly precipitation reports at Pearson Airport are likely representative of the occurrence or non-occurrence of precipitation conditions at

stations located less than 20 km to the ESE, where manned observations of precipitation type are not available. Precipitation reports from Pearson Airport were therefore superimposed on temperature plots to indicate when precipitation was occurring, and more importantly to imply whether or not precipitation was falling as liquid rain or freezing rain for downtown locations for a given hour.

Figure C.4 shows hourly temperatures at the three Toronto locations, implying that the city's downtown core likely received much less freezing rain than surrounding areas (the so-called "horseshoe" of former suburbs), and that accretions from December 20th and most of December 21st would have been unable to remain on exposed surfaces. However, a period of particularly heavy precipitation overnight between December 21st and 22nd correspond with temperatures below freezing, with both downtown stations falling below 0°C between 10 and 11 PM on the night of the 21st.

Toronto Island Airport reported 17.7 mm on December 21st and 13.9 mm on December 22 and the Downtown station reported 17.0 mm and 14.3 mm, respectively. Assuming the majority of precipitation on December 22nd fell as freezing rain, with some additional contributions from precipitation late in the evening on December 21st, ice accretion values in the downtown core were likely on the order of ~15 mm, compared to estimated values in excess of 25-30 mm or more estimated for northern portions of the city and adjacent municipalities. The implication, however, is that severely impacted portions of the city of Toronto near the downtown core may have seen significantly smaller ice accretion values than other parts of the city but still suffered from multi-day power outages.

Estimates of ice accretion rates at Pearson and Buttonville airports, along with the severity of impacts in the downtown core, which likely only saw ~15 mm, suggest that the final hours of the freezing rain event produced much more rapid ice accretion rates than earlier phases. Between 11 PM December 21st (when downtown stations were below 0°C) and 9AM the following morning, only 7 hours of freezing rain was observed at Pearson Airport. Even with significant averaging inherent in ice accretion rate estimates calculated in **Figure C.1** for Pearson and Buttonville airports, freezing rain ice accretion rates peaked during the early morning hours of December 22nd, estimated at 2.13 mm/h at Pearson and 1.25 mm/h at Buttonville, compared to estimated hourly rates on preceding days (0.79 and 0.95 mm/h for Pearson; 0.92 and 1.19 mm/h for Buttonville). A review of radar imagery for that time period (**Figure C.3**) indicates that a particularly heavy area of precipitation, associated with a small scale meteorological feature, tracked over the GTA and surrounding areas in the early morning hours of December 22nd. This corresponded with the rapid increase and peak in reported outages, and was likely responsible for a large portion, if not the majority, of ice accretions experienced in and around the downtown core.

Immediately following the ice storm, one spokesperson for Toronto Hydro indicated the worst damage appeared to be following highway 401, but this was prior to knowing full extent of damage in Scarborough (Toronto Star; December 23, 2013). Outage maps of the city the following day showed a clear delineation of much less severe impacts south of Bloor Street versus areas north and east of the downtown core, however a lack of both detailed impacts data and/or meteorological observations, particularly for Scarborough and East York, complicate better diagnoses of the reasons for these differences. At these scales, there could be a complex interplay between local topography, infrastructure characteristics, tree canopy extent and/or health, as well as small scale meteorological

elements (e.g. there may have been marked small scale differences in temperature gradients or locally enhanced precipitation). Without higher resolution data, all potential causes for these boundaries remain speculative.

C.3.1.2 Impacts and Atmospheric Conditions: Durham Region LDCs

Analyses of impacts to LDC's east of the city of Toronto are complicated by a lack of both detailed impacts information as well as aforementioned meteorological observation data. Only daily precipitation totals and hourly temperature data are available for Oshawa Airport, and only a small number of TRCA stations were available to provide temperature data for the Ajax and Pickering areas, but did feature high sampling rates (5 and 15 minute intervals). However, given the characteristics of damage reported by the press, it can be easily surmised that a significant amount of ice accretion occurred in the region.

A review of hourly temperature data for Oshawa Airport indicate that for the 72 hour period beginning at 4 PM on December 20th, there were only ~4 hours in which temperatures were at or just slightly above 0°C, specifically between 11 PM December 22nd and 2 AM December 23rd. This suggests that the majority of the precipitation on December 21st and 22nd, with daily totals of 17.6 mm and 10.3 mm, respectively, was likely freezing rain. Accretions could have also included some of the 8.1 mm reported on December 20th, where temperatures remained below 0°C after 4 PM. Similarly, temperature data from a TRCA weather station at Bayly and Church in Ajax (**Figure C.6**) indicate ~3.5 hours mid-day on December 21st, for which temperatures were above 0°C for the same time period, as do temperature data for the Brock West Landfill site, north of Pickering, for ~3.3 hours (TRCA 2014). The overnight temperature spike indicated at Oshawa Airport on December 21st and 22nd also shows up clearly for these two stations, but remains *below* freezing. Temperatures remained below 0.5°C for all three sites, even with sampling rates of 15 and 5 minutes for the two TRCA sites. Hence, when considering temperature conditions associated with the event, freezing rainfall totals in the ~25-35 mm range are likely for portions of southern Durham region.

Restoration times were checked in local newspapers and available press releases from LDCs (mainly Veridian) to ascertain how quickly Durham region LDCs recovered from the event when compared to Toronto Hydro. A rough benchmark of 90% restoration was used to compare the LDCs and using the morning of December 22nd as a start time for full restoration efforts:

- Veridian (Ajax, Bowmanville, Newcastle, Port Hope), restored by 8 PM December 24th, 2.5 days;
- Oshawa PUC, restored mid-day December 23rd, ~1 day;
- Whitby Hydro, fully restored by December 24th, 1-2 days;

These are compared to Toronto Hydro, which required more than **5** days to restore power to 90% of customers affected by the event. The effects of scale on Toronto Hydro's distribution system, as well as increased vulnerability from aged infrastructure, aged trees adjacent to overhead lines, and difficulty servicing and accessing equipment cannot be underestimated. There are also likely differences in the ratio of response capacity (e.g. number of personnel versus number of customers) as well as shear geographical area to be covered. Significant differences in recovery time appear to be an excellent

example of how logistical challenges for larger metropolitan LDCs can result in marked difference in vulnerability when compared to much smaller LDCs servicing small cities and rural areas, in spite of the fact that Durham Region appears to have, on average, been impacted by similar to possibly higher ice accretions than large portions of the City of Toronto. Overall, at least in the case of the December 2013 ice storm, larger LDCs appear to be more susceptible to ice storms than smaller ones, likely due to a combination of factors.

Veridian indicated that by noon on December 26th, only ~1,700 of the original 40,000 customers who had lost power remained without service (DurhamRegion.com, Dec 27, 2013), and that these mainly consisted of particularly difficult to repair elements, such as backyard supply lines. Similar comments were made by Toronto Hydro staff regarding back-lots which needed to be serviced and which were quite common in some parts of the city, although indications are that these will be eventually phased out.

Tree impacts were again named explicitly as the cause of much of the damage in Durham Region (Ajax News Adviser; December 23, 2013). On December 26th, Oshawa PUC continued to report problems with tree branches falling on lines generating new damage, and on the same day a statement by utilities officials in Whitby indicated that recent snowfalls had added more weight to ice covered tree limbs, and warned of an increasing the risk of breakage and the potential for new damage (Durham Region.com, December 26, 2013). These concerns are again similar to those expressed by Toronto Hydro and indicate an aspect of ice storm damage which should be considered in response and recovery methods.

C.3.1.3 Case Specific Findings December '13 Ice Storm:

While ice accretion values likely approached or even slightly exceeded minimum CSA design requirements (CSA 2010) for overhead systems for small portions of the city of Toronto, Durham Region, and other areas, it appears that the vast majority of damage inflicted on overhead distribution lines during the ice storm was due to the impacts from falling tree limbs. Immediately following the ice storm, tree damage was indicated as "worse than originally anticipated" (TH Press Release, Dec 23, 2014, 3 PM) in spite of what has since been termed aggressive tree trimming programs in place prior to this event. At least two municipalities, Brampton and Whitby, also indicated concerns that emerald ash borer (EAB) affected trees posed particular risks due to their weakened state. Tree impact damage continued for several hours to several days after significant ice accretion ceased. One line worker described how falling tree limbs continued to damage lines even during maintenance, and that repairs had to be redone at some locations (Toronto Star: December 23, 2013). This is also consistent with continued tree fall observed by one of the authors (S. Eng) during the mid and late-afternoon of December 22nd in central Etobicoke area, again several hours after significant ice accretions had ceased.

It is hypothesized that continued damage may have been due to both continued light freezing and frozen precipitation which continued periodically at various locations through December 22nd and 23rd, and gradual loss of fiber strength from prolonged loading.

During the recovery effort, there were notable. increases in estimated restoration times as efforts progressed. Estimates in earlier press releases indicated restoration times of 12-16 hours were

expected, while *eventual* restoration times, particularly for the remaining 10% of customers to be restored, were in excess of 5 days.

Total ice accretion amounts for areas surrounding the City of Toronto were likely much higher than those experienced in the downtown core and surrounding areas. In areas within Durham and York Regions, temperatures generally remained cold enough to maintain freezing rain ice accretions which began as early as the afternoon of December 20th. As one approached the downtown core of the City of Toronto, the event transitioned to one better characterized as a relatively short duration but fairly intense period of freezing rain, the majority of ice accretions and impacts occurring during the overnight and early morning hours between December 21st and 22nd, rather than multi-day ice accretions apparent in areas surrounding the city. These characteristics of the freezing rain event need to be understood when considering differences in both impacts and vulnerability of Toronto Hydro's distribution network when compared to LDCs in adjacent municipalities.

Press releases in the days following the event placed a clear emphasis on electrical stand pipe damage to individual homes in Toronto Hydro press releases. It is hypothesized that, as ice accretion amounts increase, more and more elements of the electrical system are damaged, hence repairs become exponentially more difficult to execute, as impacts progress from isolated large branches on lines to entire trees, and as a higher percentage of individual residences suffer damage, as indicated by the widespread damage to individual residential standpipes suffered in the Toronto Area. Similar impacts were noted during the January 1998 ice storm in Quebec, where all not only transmission corridors were severely damaged, but also individual residential lines, making recovery especially challenging due to numerous repairs on the individual customer level.

A lack of manned observations of precipitation type south and east of Pearson Airport was found to be frustrating to the investigation, particularly for **Toronto City Center** and **Island Airport** stations as well as **Oshawa Airport**. While useful findings were developed based on precipitation estimates and proxy analyses (e.g. use of temperatures to imply precipitation type), manned observations confirming precipitation type and accumulation rates would greatly assist with diagnoses of conditions in downtown Toronto as well as for Durham Region LDCs. Impacts data in the form of outage timelines and descriptions of damage could then be combined with more representative meteorological data to compare relative sensitivities of adjacent LDCs to ice storm conditions. A lack of any meteorological observations for East York and Scarborough were particularly frustrating, given apparent (and as of yet unexplained) boundaries in impact severity for these portions of the city.

Similar problems were encountered with TRCA data. While some locations provide precipitation data during the winter, all were well north and west of both Toronto's downtown core, as well as populations centers in Durham Region impacted by the storm. This indicates the need for improved monitoring of winter precipitation in populated areas of the GTA, since differences in impact severity between different municipalities is difficult without detailed observational data on precipitation characteristics.

A significant meteorological component of the event, especially for areas in and around Toronto's downtown core, appears to have been a particularly heavy episode of precipitation during the early

morning hours of December 22nd associated with a small scale meteorological feature. This implies that for high impact winter events, even those associated with large scale processes, difficult to forecast smaller scale[4] meteorological phenomenon, perhaps only a few dozen kilometers in physical extent and affecting a given location for only a few hours, may still play an important role in generating impacts. This emphasizes the need for continued monitoring of weather forecasts and meteorological remote sensing data such as radar, since the onset of impacts from these types of phenomenon can be quite rapid and are akin to severe thunderstorm events during the warm season.

In addition to Toronto Hydro, several other LDCs also indicated marked differences in the severity and extent of impacts within individual municipalities. Enersource outage maps, for example, showed particularly severe impacts in the northwestern portion of Mississauga. Veridian indicated that southeastern portions of Ajax suffered more damage and were more difficult to restore, mainly due to aged trees characteristic of the area (Ajax News Adviser; Dec 23, 2013), and similar reports of particularly heavily affected areas were also noted for Pickering (DurhamRegion.com; Dec 24, 2014), although a specific cause for these difficulties was not given. More detailed studies of these localized disparities in impacts would be extremely informative. These would likely consist of surveys and could include a review of individual incident reports and the collection of visual materials, as well as an assessment of contributing factors such as tree species and canopy cover maps, infrastructure age and characteristics, and so on.

C.3.2 Other Winter Storms

For comparison to the December 2013 event, other ice storms were reviewed to determine if thresholds from previous research (Klaassen et al. 2003) were directly applicable to the City of Toronto and to also determine the severity of impacts from less severe and widespread storms. Klaassen et al. (2003) indicated that ice storms with as little as 15 mm of total ice accumulation have resulted in widespread power outages, mainly due to tree limb impacts, and while this agrees well with analyses from the December 2013 storm, other events should also be interrogated.

C.3.2.1 January 31st to February 4th, 2003: Complex Winter Event

The period between January 31st and February 4th, 2003 saw multiple types of precipitation and a variety of conditions impacting the Toronto Hydro distribution system, and resulted in over 50,000 customers being affected at various time by power outages (ITIS data). Some 160 incidents were reported in the ITIS database beginning on the evening of January 31st through to February 4th, including blown transformers and current limiting fuses, tracking problems, and some instances of galloping and tree contacts. On the night of February 3, 2003, “hundreds” of car accidents and numerous power outages were blamed on a combination of freezing rain and high winds, mainly across Scarborough and North York (Toronto Star, February 4, 2003). These impacts were the result of a complex weather event which involved two large scale low-pressure systems, several different types of precipitation, and significant associated temperature variations over the course of 5 days.

[4] In meteorology, these are termed “meso-scale” weather phenomenon, which tend to occur on spatial scales smaller than distances between important surface observation stations, and on sub-daily (less than 24 hour) temporal scales.

A low pressure system which had originated in Alberta impacted southern Ontario on January 31st and February 1st, followed by a second low pressure system which had originally formed over Texas and Oklahoma, impacting Toronto on February 3rd and 4th. In addition to impacts to Toronto Hydro's system, power outages were also reported in Richmond Hill and Markham (Toronto Star Feb 4, 2003).

Impacts on February 1st were almost exclusively restricted to 27.6 kV equipment (except for one report), and, save for a few downed wired and tree contacts, were generally characterized generally consisted of tracking, electrical shorts and blown fuses associated with ice accretions. Beginning at around 10:30 am on February 1st through to the morning of February 3rd, several reports of electrical shorts and salt covering equipment were received, likely associated with attempts at deicing following the January 31st-February 1st storm. On February 3rd, freezing rain related reports began anew at ~5 PM and continued until 6 AM one February 4th. For this episode of severe weather, winds had been forecast to reach 70 km/h on February 3rd; maximum gusts would eventually be measured at 78 km/h (Pearson Airport) and 85 km/h at (Toronto Island Airport) the following day.

Conditions at Pearson Airport indicate that for the entire period between January 31st and February 4th the atmosphere was near or at saturation, with fog and haze being reported in conjunction with and between bouts of freezing rain, drizzle or light snow, however a total of only four hours of freezing rain were reported at Pearson Airport during that period. Temperatures crossed the 0°C boundary no less than *eight* times during this time period (**Figure C.7**).

The types of impacts, where descriptions were available, were quite different than those indicated for the December 2013 ice storm. Reports during the first portion of the event, mainly on February 1st, involved blown current limiting fuses and tracking problems. During the "break" in precipitation between February 1st and 3rd, 14 instances of *salt* related problems were addressed. Following this, a second round of precipitation, including the only reported freezing rain at Pearson Airport, combined with increasingly strong winds into February 4th, brought the first reports of galloping (mainly in Etobicoke) and only 4 reported instances of tree contacts, in addition to more blown fuses and pole top fires from icing related electrical shorts.

A *separate* storm over the Atlantic coast during the same time period, impacting the Maritimes on February 2nd and 3rd and producing 40-60 mm of ice accretion knocking out power to over 63,000 customers and causing other *very* significant damage, including roof collapses of barns and other storage buildings (EC 2003). By February 5th, 27,000 customers remained without power in New Brunswick (Toronto Star, Feb 5, 2003). The majority of repairs to the electrical system lasted for 5 days, and several locations had to be repaired twice or three times due to continued falling of ice laden trees, which was further exasperated by winds of ~75 km/h following the freezing rain (EC 2003). Massive ice accretions associated with this storm were at least partially due to the proximity of the storm to its source of moisture. Hence, while it produced similar wind speeds to the February 3rd and 4th low pressure system that affected southern Ontario, ice accretion amounts were *far* greater.

C.3.2.2 Case Study Specific Findings for January 31st-Febraury 4th

Galloping was indicated during the second storm, mainly in Toronto's west end, from what were likely a combination of ice accretions of on the order of 10 mm or less, but with winds gusting to the 70 to 80 km/h range. This is fairly close to the "15mm + 70 km/h" wind threshold indicated in previous work (CSA 2010), but may have been associated with lower ice accretion values but higher wind speeds. Additional cases would be needed to understand if galloping due to combined ice-wind loads occur in a range of wind speed and ice accretion combinations, but this case does indicate the potential for forecasting such problems when combined with monitoring of ice accretion.

Additional ice accretion, from either drizzle or light snow, coupled with several hours of reported fog or haze, is also highly likely for this event, but additional date related to this event is needed to diagnose actual accretion amounts and their causes. One should also consider that heavier precipitation may have occurred further east in North York and Scarborough, where the majority of ice accretion related impacts were reported. Indeed, several ITIS damage reports from those locations indicated ongoing snow and/or freezing rain for times when conditions at Pearson did not indicate *any* ongoing precipitation (e.g. two reports of snow in North York on the night of January 31st correspond with reports of "haze" at Toronto Pearson for the same time period). High wind and galloping conditions are likely better captured by records at Pearson Airport, since many of those incidents were reported much closer in Etobicoke.

When considering the types of impacts reported for this even, it is suggested that fog ice accretion may have slightly different characteristics than freezing rain ice accretion, which may result in slightly different impacts; i.e. when ice accretes due to fog and light drizzle in a humid environment, does it coat equipment differently than more rapidly accreting freezing rain? Did this lead to more localized problems associated with shorts and arching, in contrast to failures associated with direct physical impacts from ice loading and tree contacts? The role temperature fluctuations during and following periods of precipitation should also be investigated further. The degree of temperature variability for this event was much greater for this even when compared to the December 2013 ice storm, which again may have affected the type and degree of impacts (see **Table C.3**).

C.3.3 Large Scale Wind Storms

Large scale wind storms were identified through the Toronto Hydro Outage data for the 2000-2006 period. The maximum wind gusts reported during these storms were then compared to the number of outage events reported in the ITIS database and were also compared to the cause description, mainly identifying whether or not tree contacts were mentioned. The results of this comparison are described in **Table C.4** and illustrated in **Figure C.8**. Large scale, long duration wind events associated with low pressure systems were chosen instead of summer severe wind events associated with severe thunderstorms, since wind measurements at Pearson and Island airports were more likely to be representative of wind conditions at the damage sites for the large scale storms.

For the majority of events, a threshold wind speed of around 90 km/h emerges. A recent event on November 1, 2013, described in Toronto Hydro press releases but not well captured in ITIS, bears this

out, in which 3,500 customers lost power during a wind storm which produce gusts up to 91 km/h at Pearson Airport.

It is notable that one of the most significant events, September 19, 2003 with 99 damage reports, also had the lowest reported gust at 72 km/h and is a pronounced outlier on the graph (bottom bar in **Figure C.8**), and the only other event which occurred in September shows the 2nd lowest wind speed value at 78 km/h.

To further investigate this wind speed relationship, the month of November 2005 was "back checked" to see how well a threshold of ~90 km/h was able to predict impacts to the Toronto Hydro system (**Table C.5** and **Figure C.9**). A total of 53 outage incidents were reported in ITIS for this month, with the largest number reported on November 6th and into the early morning hours of November 7th (35 reports). As indicated in **Table C.4**, these correspond with gusts of up to 89 km/h. Incidents were reported on 6 other days, with the second greatest number occurring on November 9th (9 reports). That day saw snow during the morning hours, followed by severe thunderstorm activity which resulted in one tornado in the City of Hamilton. Damage from thunderstorms is expected to be localized and therefore low wind speeds measured at Pearson airport are not surprising. The day with the third greatest number of reports also shows the second highest gust reported that month.

There are a number of potential reasons for this apparent seasonal difference between wind speed thresholds, most likely the effects of deciduous trees being still in full leaf, but, other considerations, such ground softness due temperatures remaining above freezing, must be considered given the very small sample size present here. However, data do appear indicate that threshold winds for damage increased from ~70 km/h during early fall up to ~90 km/h for late fall and winter windstorm events, and the causes listed for these impacts hint at a relationship to tree contacts.

We should mention that spring low pressure systems are also capable of producing high winds, but these do not seem to be as significant as fall season large scale wind storms. Spring severe wind storms also tend to have embedded thunderstorms, which act to further localize winds and complicate efforts to determine the representativeness of measurements. Examples of this event type include the April 20 to 21, 2000 and April 12, 2001 storms. March 9-10, 2002 is the only significant spring wind storm in the 2000-2006 period, but this event was also accompanied by severe thunderstorm activity which produced much more significant impacts in other parts of Ontario, including the loss of multiple Hydro One electrical transmission towers.

C.3.3.1 Superstorm Sandy: October 29-30, 2012

So-called "Superstorm" Sandy, responsible for major devastation in several major east coast cities in the United States, also produced impacts in Canada, including one fatality from windblown debris. Toronto Hydro estimated about 60,000 customers had lost power during the storm (T.H. Press Releases, Toronto Star 2012). Adjacent LDE Enersource reported approximately 6,000 customers lost power during the event, with 6 crews beginning restoration efforts at around 6PM on October 29th (Mississauga News 2012). Causes for these outages included the loss of three hydro poles. ORNGE air crews had also been grounded at 2 pm October 29th due to high winds (Toronto Star 2012).

Toronto Hydro had been initially criticized for not immediately declaring Level 3 status for this event and beginning repairs; however, the vice president of grid management indicated attempting repairs during the storm would have been futile and dangerous for repair crews (Toronto Star 2012). "There's nothing we could have done between 2 am and 6 am." Press releases issued as early as 6 PM on October 29th warned customers that repairs may be impossible during high winds.

A map depicting impacts and rainfall measurements for the event is provided in **Figure C.10**. Unfortunately, outage incident data appears to be incomplete for this time period (the event having occurred after 2006), and media reports for the city of Toronto lack specific damage and failure location descriptions. This is in sharp contrast to media reports from the City of Mississauga (Mississauga News 2012), the source of all media damage reports indicated in **Figure C.10**.

With the exception of one incident, wind damage reports from ITIS all appear in the southern half of the City of Toronto, and these also correspond very well with media reports of wind damage in Mississauga, as well as the difference in measured severity between Pearson (80 km/h max gust) and Toronto Island (91 km/h). There are simply too few available rain related damage reports to determine if important thresholds were reached for direct overland flooding related damage, and a comparison between Buttonville and Pearson to determine if antecedent rainfall played an important role appears to be negative. Both areas experienced similar amounts of antecedent rainfall on October 28th, followed by wind gusts of similar magnitudes on October 29th; however, only areas located southwest and southeast of Pearson reported any notable wind damage.

Toronto Hydro press releases, including those issued as early as 9:30 PM on October 29th, before the peak of the storm, in indicated trees and tree limb contact with overhead wires as the main cause of the outages (T.H. 2012). The October 30th 10:39 PM press release specifically indicated, "Toronto Hydro estimates that more than 85 per cent of outages were caused by tree contacts with power line[s]" Further indicating that repairs are expected to exceed $1 million and that other jurisdictions, which have far less tree cover, were not expected to be as heavily impacted. On the evening of October 30th, the worst affected area was roughly bounded by "Talwood Drive (north), Eglinton Ave E (south), Bayview Ave (west) and Don Mills Rd (east)"

The preponderance of tree and tree related damage in the southern portions of Toronto and Peel, coupled with the transition from wind gust regimes from 80 km/h to 90 km/h, further supports the findings from the analysis of large scale wind storms indicating wind speed thresholds of 90 km/h, again likely related to tree contacts. Budget and time limitations prevent further analysis of this event (e.g. search for impacts in Durham region) for the time being, but further research is strongly indicated.

C.4 Severe Summer Thunderstorm Events

C.4.1 July 8, 2013 Extreme Rainfall Event

"Little India resident Kurt Krausewipz, said the 'thick heavy sheets of rain,' reminded him of monsoon season in Southeast Asia." (Toronto Star, July 9, 2013)

The flash flood event on July 8th, 2013 was responsible for the largest 24 hour rainfall amount ever reported at Pearson Airport. The event was notable for a number of important impacts, including the stranding hundreds of GO transit commuters for 5 hours on a flooded train in the Don Valley (Toronto

Star, July 9, 2013), as well as an eventual tally of nearly $1 billion in insured damages (CBC.ca 2014), mainly resulting from basement flooding. It also resulted in a significant power outage event for Toronto Hydro, with approximately 300,000 customers losing power for several hours[5] (Toronto Hydro Press Release, July 9, 2013). The outage event was mainly triggered by the failure of critical infrastructure located below grade[6] at two transformer stations linking Toronto's distribution system with Ontario's electrical transmission system.

To understand the magnitude of the event, and to assist with developing a threshold for this type of failure, maps depicting rainfall amounts across the city (Cole Engineering Group, 2013) were compared with media reports of damage, as well as the locations of the two transmission stations which suffered failures during the event (Hydro One, 2014). See **Figure C.11** for station locations relative to rainfall accumulation amounts.

The extreme rainfall event began around 4 PM and produced eventual failures at Manby and Richview transformer stations, with Hydro One declaring a "Level 2 Transmission Emergency" (Hydro One 2014). Both are located within and near the area of greatest rainfall accumulations recorded for the event, located roughly along and on either side of the Etobicoke-Mississauga border (Cole Engineering Group, 2013). A rainfall total of 126 mm was reported at Pearson International Airport, with a maximum 1 hour total of 74 mm (EC 2014); however, this was roughly within the western edge of what municipal rain gauge networks indicate as a "bull's-eye" centered slightly E of Pearson International, which contained accumulations of over *130 mm* of rain (Cole Engineering Group, 2013). Richview TS is located in the *immediate center* of this area of extreme precipitation. Manby TS is located several kilometers to the south and was subject to far less rainfall in its immediate vicinity, located nearly on and just north of the 80 mm rainfall contour. It is not clear how much additional flooding at Manby TS was the result of runoff from areas further north, or if the design and characteristics of Manby TS may have made it more vulnerable to flooding than other stations. Hydro One's system officially returned to "normal" status at 2:44 PM July 15th (Hydro One 2014).

"Level 2 remained in effect until 5:34 p.m. on July 12th as Hydro One worked to reinforce the system with restored transmission connections between Richview TS and its remote terminal stations: Trafalgar TS, Cherrywood TS, Parkway TS and Claireville TS. This provided redundant supplies and vastly improved network security." (Hydro One, 2014)

It is notable that stations located near a secondary maximum over downtown Toronto (particularly Leaside TS), did not suffer the same impacts as Richview and Manby. Rainfall in the core of the downtown maximum approaching 100 mm. Toronto's climate station at the U of T campus reported 96.8 mm of rain (EC 2014), but Leaside TS is located approximately 3-4 km to the NW of the core of this

[5] In contrast to the Dec 2013 ice storm, however, the nature of the failures allowed for ~90% restoration for distribution customers by the early hours of the following morning (TH Press Release, July 9, 2013).

[6] Interviews by RSI with practitioners at the OPA for the "sister" transmission case study indicated that placement of critical infrastructure in below grade locations may have also played a critical role in the failures experienced in this case.

much smaller maximum subject to an estimated 65-70 mm rainfall, and was also not "down-stream" from another maximum as was the case for Manby TS.

Rainfall data from Pearson International also indicate possible antecedent rainfall conditions, since 26.6 mm of rain were recorded on July 7th, the day prior to the event, and a total of 31.4 mm of rain was recorded in the full week prior to the rainfall event (EC 2014). Similarly, Toronto's downtown climate station reported 38.1 mm of rainfall on July 7th and a total of 48 mm during the week preceding the July 8th flood.

"Since June 1, downtown has seen 165 mm of rain, about double the average of 87 mm." (Toronto Star July 9, 2013)

As with the Superstorm Sandy case, outage data appeared to also be lacking in the ITIS data, with only one listing indicated for this event. However, the clear cause in this case was the direct impact to transmission infrastructure, reducing the need for similar analyses conducted for other cases in which outage causes were more local and directly related to physical impacts to the distribution system.

C.4.1.1 Case Specific Findings July 8th Flood

Rainfall in excess of 100 mm in less than 24 hours, and indeed within the span of only a few hours, appears to have been required to cause the types of failures experienced at the two western Toronto stations. Antecedent rainfall may have also played a role in the flooding, generating more runoff than would have otherwise occurred. Topography and associated runoff patterns may have also played a role, particularly for Manby TS, but conclusive evidence of this would require further investigation.

This may also be a case of extreme rainfall rates under the "sub-daily" category, given that both this case and August 19, 2005 saw the majority of rainfall occur within a few hours, with a majority of the total 24 hour rainfall occurring within approximately *one* (1) hour. Extreme rainfall rates should be directly correlated with runoff efficiency and design requirements (e.g. pumping rates for mitigation, flash flood peaks, etc.) and may be important in determining how such events generate severe impacts to these systems.

While the main infrastructure that failed was indeed owned by Hydro One, these findings have direct implications of great importance to Toronto Hydro Infrastructure. Toronto Hydro was still directly and severely impacted by the failure of 3rd party infrastructure. The PIEVC process includes 3rd party infrastructure among the needed elements for review and consideration, and this is particularly relevant for the highly interconnected electrical grid as a whole. While this was not the case in this particular event, similar infrastructure owned by Toronto Hydro may be susceptible to extreme rainfall conditions. These locations and infrastructure elements should be explicitly identified and evaluated for their vulnerability.

C.4.2 August 19, 2005 Finch Washout Event

A large "supercell" thunderstorm produced significant impacts across a swath of south-central Ontario on August 19, 2005. Perhaps the most well-known and publicized impacts from the event consisted of the complete washout of a section of Finch Avenue at Black Creek in North York. In addition to this,

however, there were numerous reports of basement flooding in Toronto and York region, several vehicles being swept off of roads or submerged, in addition to several thousand homes in Toronto suffering power outages, mainly in Etobicoke and Scarborough areas (Toronto Star, August 20th, 2005). The specific causes for these outages were not provided by media reports, however ITIS incident reports, coupled with the location of reported damage, indicate that outages were mainly related to flooding. Preceding the impacts in the GTA, the supercell storm produced two large, F2 tornadoes west of the city in the Listowel and Fergus areas, severely impacting farming and cottage communities.

A map of reported impacts is provided in **Figure C.12**, combining ITIS and media damage reports with meteorological measurements for comparison. A fairly clear pattern emerges in which a corridor of extreme rainfall with embedded amounts in excess of 100 mm corresponds quite well with the majority of extreme rainfall related outage incidents, indicated by red and orange circles superimposed with an "X" in a band extending from central North York ESE to Scarborough. Extreme rainfall amounts to the immediate north of Toronto were also associated with significant basement flooding in York region. A second more isolated patch of extreme rainfall may be indicated in north Etobicoke, but could also be illusory due to the suspect reading (only 24.7 mm) located north of the Finch Washout.

Interestingly enough, tree contact and wind related damage reports are generally located south of the corridor of extreme precipitation; this is consistent with the storm type. While impacting Toronto and the GTA, the storm produced a swath flooding rainfall and large hail under as a core of heavy precipitation tracked across the city, while winds gusting to ~70 km/h or more were present *south* of this core and were responsible for several minor tree contact related damage reports[7]. A comparison between wind measurements at different locations, however, could not be conducted, as wind gust data are not available for this date for Toronto's Island airport.

C.5 Extreme Heat Days

While it is generally common knowledge that during hot and humid days during the summer, air temperatures are much cooler along the shores of Lake Ontario than they are in other parts of the city, the potential impact this temperature difference may have on electrical system response is not often considered.

Table C.6 provides a comparison between three stations to determine temperature differences across the City of Toronto on days in which high heat impacts on the distribution system were indicated (see **Table C.2** for greater details). These stations are located on or very near the western, southern and northern boundaries of the City of Toronto and provide an excellent measure of the temperature differences experienced across the city. Temperature differences of between 2.6 and 5.7 degrees are evident, while the locations of impacts strongly indicate a preference for impacts to infrastructure in Etobicoke. The number of incident reports appear to be correlated to the maximum temperature, although sample size is extremely small. The average temperature difference between Pearson Airport

[7] Had the storm produced a tornado while over the city, it would have been located at the southern edge of the heavy precipitation core. Luckily, the storm changed characteristics when approaching the GTA and appears to have been no longer tornadic when impacting the area.

and Toronto Island Airport is 4.1 degrees for the four high heat days, and the difference between North York Climate Station and Toronto Island is slightly less at 3.1 degrees.

Figure C. 13 shows an example of a high heat day (July 16, 2006) in which impacts began to be reported in North York at two different transformer stations. Interestingly enough, two of the four reports are listed as "Adverse Weather/Tree Contacts", and we are unsure of the nature of these reported causes. Either they have been mistakenly coded, or tree contacts may have occurred due to line sag, but details on the specific impact characteristics are lacking. The small number of reports indicated in North York for this date and the inter-comparison in **Table C.6**, coupled with results from the literature review and discussions with practitioners, provide additional evidence that negative impacts to the distribution system begin to appear as temperatures approach ~35°C.

This case, however, provides an excellent example of the temperature gradient often present across the City of Toronto during extreme heat days, with slightly higher temperatures occurring further from the lake. During the summer, the temperature difference between land and lake often result in the production of a lake breeze, in which cooler, heavier air over the lake flows inland, the leading edge of that air often acting as a miniature cold front. This can result in notable temperature gradients across the city, and can also trigger and/or enhance thunderstorm activity at the boundary between lake air and air further inland.

Although time and resources did not allow for more detailed assessment, a greater number of days in which extreme heat impacted the Toronto Hydro distribution system should be further investigated to help refine this threshold further. Further analysis is also needed to ensure that the impacts of other air mass boundaries (i.e. large scale fronts) are not skewing the results presented here, as similar temperature gradients can be produced through other mechanisms unrelated to the effects of the lake.

C.6 Final Conclusions

In summary, the forensic analyses resulted in the following conclusions:

- Although data sufficiency and time allotted to the project prevented the thorough investigation of many of the events identified through this forensic analysis, several avenues of future research were identified which could lead directly to improved operational maintenance and management measures, including improved forecasting of climatic impacts to assist in anticipation and preparation for significant events.
- In some cases, it was clear that Toronto Hydro operations and maintenance crews were making effective use of forecasts to help plan and optimize repair and response, such as allowing severe weather conditions to pass before full repair operations were initiated.
- In most cases, and particularly for those in which localized differences in impact severity were evident, further analysis was stymied by a lack of observational data. Even with the inclusion of additional observational data provided by TRCA (2014), spatial gaps in observations prevented the assessment and diagnosis of conditions in certain locations (e.g. December, 2013 ice storm

damage in Scarborough lacking ice accretion or temperature measures; August 19, 2005 severe thunderstorm wind speed measurements in southern portions of the city).

- The majority of power outage events identified in the 2000-2006 period were extended events lasting up to 48 hours, representing the need for sustained operational response, but the characteristics of these events differed depending on season:
    - Extended warm season events consisted of 2 or more acute weather events in quick succession, and were a combination of related hazards producing impacts (e.g. extreme heat followed by thunderstorm activity)
    - Cool season and shoulder season events tended to last several hours; when storms occurred in succession, they tended to be separated by periods of one or more days
    - The years with the greatest reported impacts to the distribution system were characterized by multiple moderate to major outage events occurring in different seasons (e.g. significant severe thunderstorm event during the summer followed by one or more wind storms during the fall season)
- Thresholds determined for wind speed and ice storm damage agree well with previous work and research, and these also appear to be *directly* related to tree contact related impacts rather than direct climatic loading of infrastructure through wind or ice accretion.
    - The 70 km/h threshold for wind gusts, originally provided by Toronto Hydro staff during Phase I, appears to be correlated with tree damage, particularly during the warm portions of the year when deciduous trees are in full leaf, resulting in secondary impacts to the distribution system; further research is needed to confirm this relationship
    - The 90 km/h threshold appears to be both related to the baseline climatic loading used in design of civil infrastructure components (see CSA 2010) as well as tree damage after deciduous trees have shed their leaves
    - The lower bound of 15 mm for freezing rain totals resulting in tree contacts with overhead systems agree well with the findings from Klaassen et al. (2003)
    - Freezing rain totals of less than 15 mm, however, may cause impacts when combined with high humidity environments near the 0°C boundary. This can specifically result in flashovers and other related impacts. While not as severe as direct damage to overhead lines and other equipment, these types of impacts can be numerous, widespread, and localized, presenting particular challenges for restoration efforts
- Overall, larger metropolitan LDCs appear to be more vulnerable to climatic events than smaller LDCs, particularly when considering overall restoration times; this is likely due a culmination of factors, not the least of which include the state and age of equipment, difficulty of access for system repair in an urban environment, and the relative proportion of staff available with respect to total number of customers and the size of a geographical area of responsibility.
- Certain regions within the city appear to be more susceptible to weather related power outages; potential regional differences in vulnerability should be investigated further. It is not clear at this time if these vulnerabilities are due to aging infrastructure, proximity to aged canopies, difficult to access infrastructure (e.g. back-lots) or some other combination of factors.

- There were several cases in which events tended to follow one-another in series, with either the restoration following a major event being hampered by subsequent smaller events, or several moderate events resulting in prolonged, multi-day outage cases where new damage occurred immediately following recovery from previous events
- Extreme rainfall impacts are worst with warm season severe thunderstorms. These were characterized by highly localized events impacting only a portion of the City, generating rainfall accumulations of over 100 mm, the majority of which (>50%) falling on during a period of *one hour*. Rainfall impacts with longer the longer duration, larger scale events investigated here (e.g. "Superstorm Sandy") appeared to be minor.
- Changes in tree health conditions such as disease and pests may also be playing a role in increasing sensitivity to damage, as suggested by analyses of the December 2013 ice storm. These represent very complex interactions, since the extent of certain disease and pests will also be affected by changing climate regimes, and their interaction with the structural integrity of trees and limbs is still unknown.
- Even for winter events, which are ostensibly much less localized in nature than warm season storms, localized differences in infrastructure impacts were evident, and without additional data, the causes for these disparities were not entirely clear. In one case (December 21-22, 2013) a small scale weather feature was explicitly identified as having very likely been a major contributor to the case overall, and similar findings are expected if similarly in-depth analyses are conducted of other high impact winter storms.
- Differences in impacts due to storm structure and other localized meteorological factors were evident in some cases (e.g. separation of precipitation and wind related impacts Aug 19, 2005). While these are to be expected, they may also assist in response to events when combined with remote sensing data, such that response crews may be better informed as to the type of impacts they may encounter following a severe storm.
- Events were not only characterized by impacts to the distribution system, but tended to consist of multiple, often severe impacts to other buildings and infrastructure, including transportation, and communication infrastructure. These impacts compounded effects on the distribution system by further complicating operational response.
- Smaller events which barely generated more than 20 damage reports, such as July 1, 2001 (lightning and rainfall) or April 28, 2002 (high winds), should be studied to understand where the lower damage thresholds may lie and/or which areas within the city or infrastructure types/categories are the *most* vulnerable
- The presence of Lake Ontario directly impacts the behaviour of certain weather hazards, generating differences in risk across the city; it generally moderates temperatures, warming areas adjacent to the lake during the cool season and cooling areas near the lake during the summer. This effect either mitigates or exacerbates the severity of hazards depending on the type of hazard (e.g. areas downtown are kept cooler during extreme heat days, but the leading edge of the lake breeze also plays a role in enhancing severe thunderstorm hazards for other portions of the city).

- The interconnectivity of Ontario's electrical grid is vital to understanding the potential impacts from atmospheric hazards; coordination between transmission providers and LDCs in risk assessment analyses may be *pivotal* in understanding and addressing these risks.

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Table C.1: Events subject to detailed investigation.

Date(s)	**Event Hazard Type(s)**
January 31st to February 4th, 2003	Multi-day ice accretion event; complex interactions
August 19, 2005	Flash flooding; lightning, some winds (tree contacts)
July 16, 2006	Extreme Heat; threshold/borderline event
October 29-30, 2012	Superstorm Sandy; winds, possible rainfall impacts
July 8, 2013	Flash Flooding; failure of 3rd party underground infrastructure
December 21-22, 2013	Ice Storm; mainly tree contacts

Table C.2: Toronto Hydro Events Outage Events 2000-2006 with *20 or more* incident reports.

Medium to High Impact Events T.H. Failure Database	Event Type	Number of Reports
February 23 to 25, 2000	rain and snow	49
February 3 to 4, 2000	freezing rain	37
February 16, 2000	snow and freezing rain	72
4/20/2000 and 4/21/2000	high winds and rainfall	42
May 12 to 13, 2000	wind, rain and lightning	157
6/14/2000 and 6/15/2000	lightning and "adverse weather"	58
14-Jul-00	lightning	121
7/17/2000 and 7/18/2000	lightning, some high winds, extreme heat	88
5-Jan-01	snow	28
12-Apr-01	high winds	33
1-Jul-01	rain and high wind	21
4-Jul-01	rain, lightning, and wind	21
7/22/2001 and 7/23/2001 and 7/24/2001	lightning	53
8/7/2001 to 8/9/2001	heat and humidity	72
25-Oct-01	high winds	20
1-Feb-02	high winds	29
March 9 to 10, 2002	"adverse weather"	78
28-Apr-02	high winds, rain	21
7/21/2002 to 7/22/2002	lightning, some heat and humidity	107
9/20/2002 to 9/21/2002	rain and lightning	23
1/31/2003 to 2/1/2003	snow and freezing rain	155
2/3/2003 to 2/4/2003	freezing rain	71
5/5/2003 and May 6, 2003	lightning	45
8/21/2003 and 8/22/2003	lightning, high winds and rain	58

19-Sep-03	high winds	**99**
10/15/2003 and 10/16/2003	high winds	**81**
11/12/2003 and 11/13/2003	high Winds	**80**
4-Jul-04	lightning, rain	**43**
23-Dec-04	Freezing rain	**27**
2/6/2005 and 02/07/2005	fog	**25**
6/13/2005 and 6/14/2005	lightning, some "tree contacts"	**42**
28-Jun-05	lightning	**30**
4-Jul-05	lightning, some wind and rain	**68**
July 11 to 12, 2005	heat and humidity	**39**
8/19/2005 and 8/20/2005	extreme rainfall, high winds and lightning; DETAILED ANALYSIS	**162**
29-Sep-05	high winds	**42**
6 to 7-Nov-05	high winds	**35**
2/17/2006 and 2/16/2006	high winds	**49**
31-May-06	lightning	**24**
6/28/2006 and 6/29/2006	lightning, rain extremes	**88**
10-Jul-06	rain, lightning	**24**
7/17/2006 & 7/18/2006	lightning, heat and humidity, some wind	**66**
8-Sep-06	rain, lightning	**24**
10/4/2006 and 10/3/2006	lightning and high winds	**30**
29-Oct-06	high winds	**28**

Table C.3: Comparison of ice accretion events with reported impacts.

Dates	Estimated Total Ice Accretion	Total # Hours **Freezing Rain** and Drizzle	Impacts
January 31-February 4, 2003	Est. ~10-12 mm (difficult given complex temperature regime and multiple	**Pearson: 4 hours (Feb 3rd);** no freezing drizzle reported, but snow, drizzle, fog and haze reported at various times	Most damage from shorted and blown fuses, tracking, few downed lines, galloping during high winds following 2nd period of precipitation; high humidity and multiple

	precipitation types)		temperature changes about 0°C
December 20-22, 2013	Est. <15 mm Downtown Toronto to 25-35 mm York and Durham Regions	**Pearson: 4, 16 and 6**, and 2, 5 and 10; **Buttonville: 8, 13 and 8**,and 1, 5 and 10; Total hours for December 20th, 21st, and 22nd, respectively	Mainly due to tree impacts, greater periods of temperatures above 0C and liquid precipitation for locations closer to downtown Toronto, significantly reducing ice accretion totals for full 3 day period

Table C.4: Comparison of highest wind gusts with large scale outage events.

Date	**Peak Measured Gusts (km/h)**	**Cause Description**[8]
25-Oct-01	Pearson: 91; Toronto Island: 82	Tree contacts 8/20
19-Sep-03	Pearson: 72; Toronto Island: 80	Tree contacts 32/99; other causes included "driving rain", "auto reclose" of breaker due to high winds
15 to 16-Oct-03	Pearson: 91; Toronto Island: 89	Tree contacts 30/81; remainder mainly "high wind/adverse weather", one report of "fuse fell open in high wind"
12 to 13-Nov-03	Pearson: 93; Toronto Island: 96	Tree contacts 16/64; remainder simply indicated as "high wind/adverse weather", some lightning
29-Sep-05	Pearson: 78	Tree contacts 28/42, rest related to high winds, including broken insulator
6 to 7-Nov-05	Pearson: 89	Tree contacts 13/35
16 to 17-Feb-06	Pearson: 91	Tree contact: 8/13 (16th) & 12/34 (17th); also some freezing rain reported on both dates, remaining[9] were generally listed as high winds, incl. one broken insulator
29-Oct-06	Pearson: 96	Tree contact: 12/28 reports
1-Nov-13	Pearson: 91	Tree contacts: 3/7 reports

Table C.5: Comparison of *all* impact reports for November 2005 to maximum gust speed.

Date	Gust Speed (Pearson Airport)	**Number of Reports**; Notes
Nov 6th	89	**35**; 2 early morning Nov 7th, considered same event
Nov 9th	59	**9**; same day F1 Tornado, Hamilton, ON; morn report include

[8] Tree contacts were counted both when coded as cause, as well as cases where cause was coded as "adverse weather" but description of impacts indicated tree contacts were responsible.

[9] One report of a "temperature extreme" causing a failure at -3°C ambient temperatures appears to be a coding error.

		snow, thunderstorms mid-day and evening, wind caused limbs on wires 3 reports, lightning related outages 3 others
Nov 11th	35	**1**; rain indicated as cause
Nov 16th	83	**4**; three high wind reports, one "no cause", "switch fell open"
Nov 17th	59	**1**; large tree on line, rain indicated
Nov 24th	78	**2**; winds indicated as cause, possible duplicate report of one incident
Nov 25th	48	**1**; conditions indicated as "clear" no specific cause given

Table C.6: Comparison of maximum temperatures (°C) for high and extreme heat days.

Date	**Impacts (# heat related reports)**	**Pearson Airport**	**Toronto Island Airport**	**North York Climate Station**
July 17, 2000	Minor; only 2 in Etobicoke	28.6	24.4	27.0
Aug 8, 2001	33 total; 18 in Scarborough, 10 Etobicoke	37.9	34.7	37.5
July 11, 2005	19 total; 10 Etobicoke, 7 North York	35.5	29.8	34.0
July 12, 2005	18 total; 7 Etobicoke, 7 North York	34.7	31.4	34.5

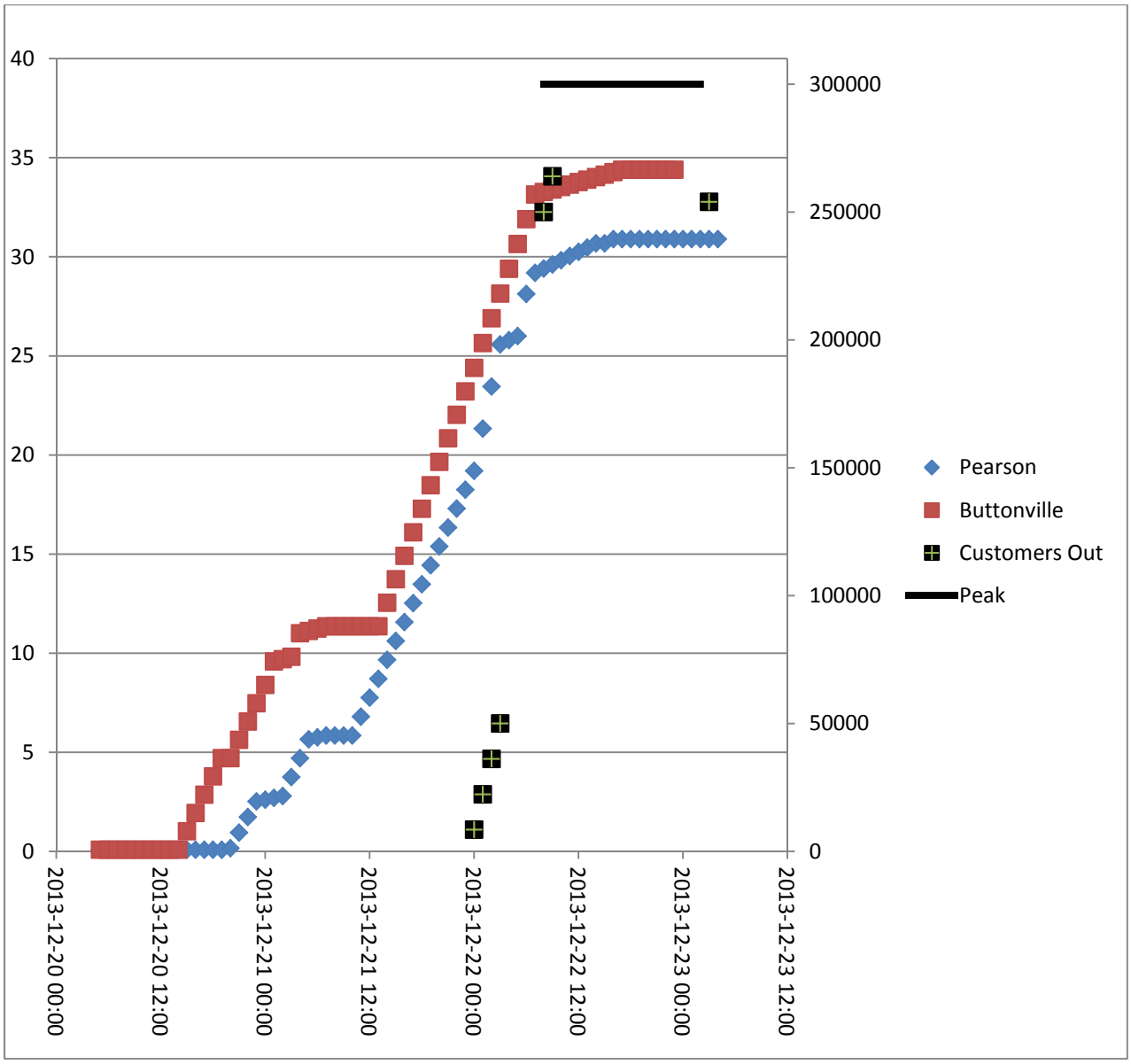


Figure C.1: Estimated ice accretion rates using observations at Pearson and Buttonville Airports. Peak outages (300,000 customers) is represented a long black bar since the exact time period in which this number of customers were without electrical service was not given and indeed may not be known.

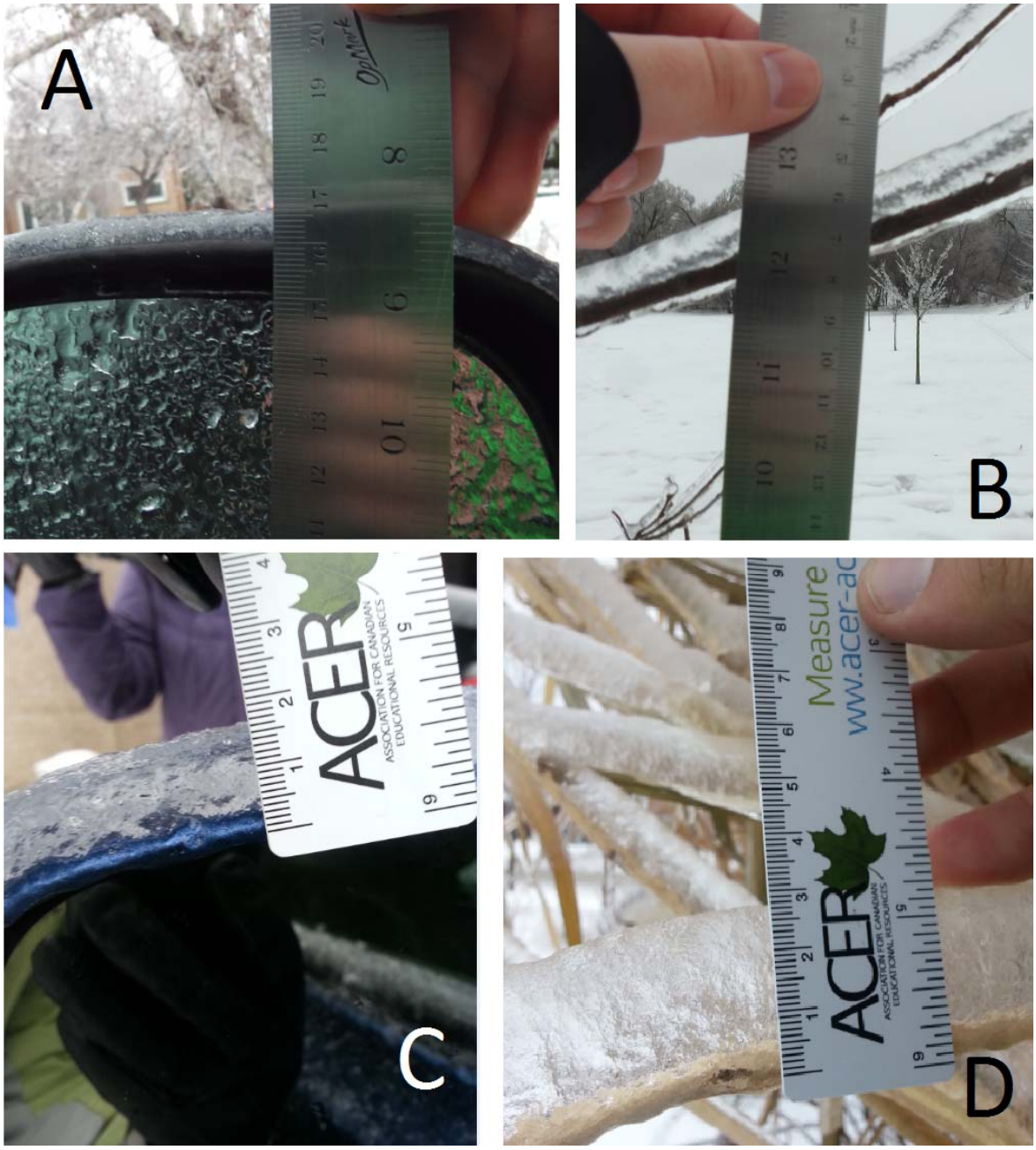


Figure C.2: Ice accretion measurements on similar objects are compared between locations in central Etobicoke (A and B), located ~5 km SE of Pearson airport, and Richmond Hill (C and D), ~9 km NW Buttonville Airport. Ice accretions on car side mirrors are measured at 6 and 15 mm and for branches of similar diameter at 10 and 23 mm, for Etobicoke and Richmond Hill locations, respectively. While measurements are not exactly equivalent in terms of exposure and accretion surface and shape characteristics, they do provide evidence that ice accretion amounts were appreciably higher for municipalities north of the City of Toronto in comparison to locations near Pearson Airport. Photos by RSI team members H. Auld (Thornhill) and S. Eng (Etobicoke).

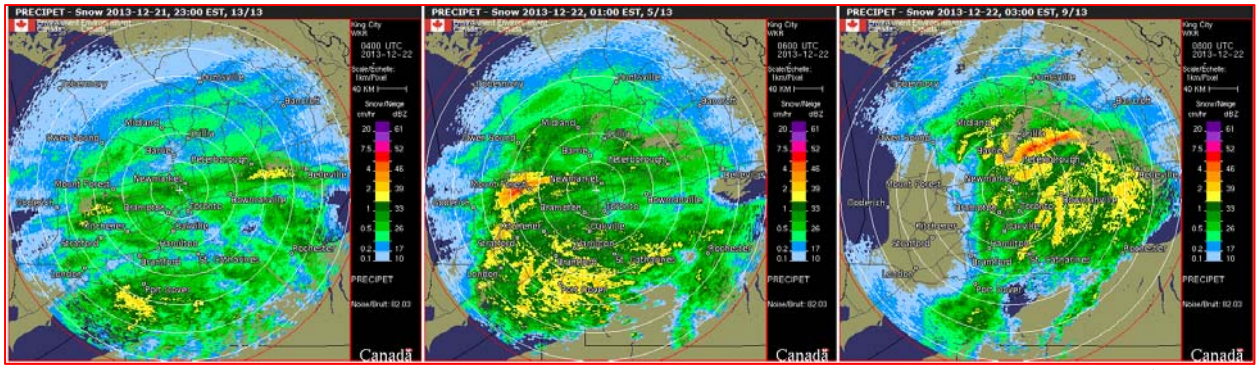


Figure C.3: King City radar imagery; panel times (left to right)correspond to 11 PM December 21st, 1 AM December 22nd and 3 AM, December 22nd, 2013. A small scale meteorological feature appears to have been responsible for an area of particularly heavy precipitation which tracked across the GTA in early morning hours, corresponding with the highest ice accretion rate estimates for the entire event.

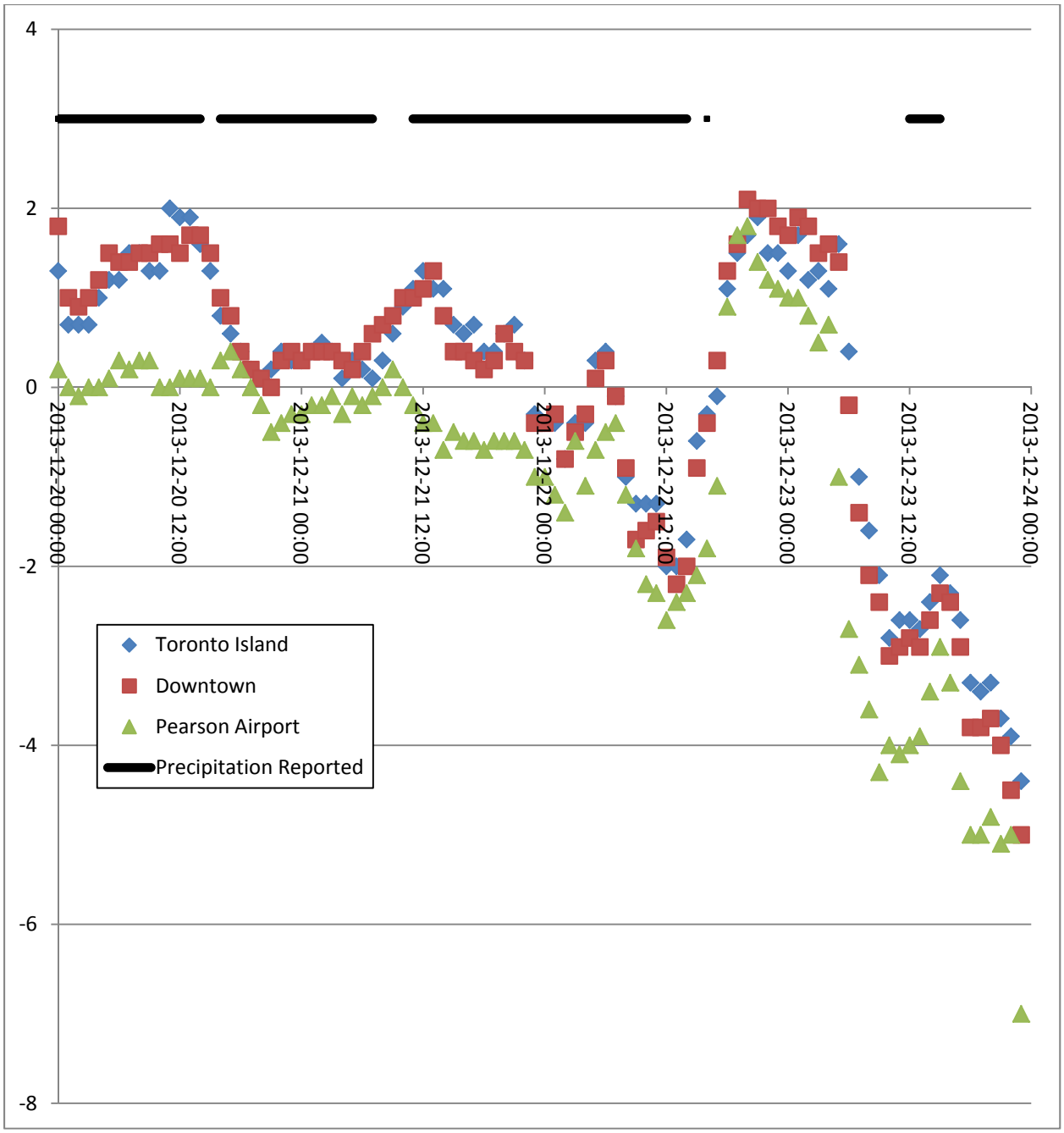


Figure C.4: Comparison of hourly temperatures between Pearson International Airport and stations located in downtown, accompanied by hours with reported precipitation. It is likely that precipitation occuring before 11 PM on December 21st did not contribute to any important ice accretion, but still resulted in significant impacts to many neighbourhoods in and around the downtown core.

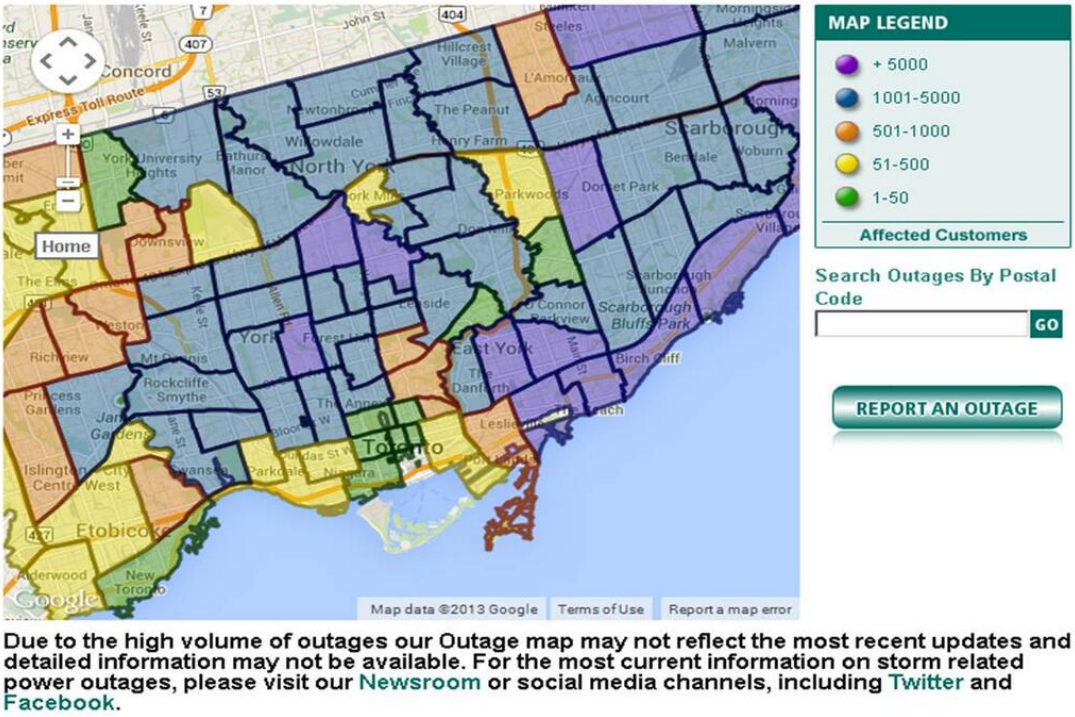


Figure C.5: Toronto Hydro outages map valid for 11 AM December 23rd. Note clear boundaries to north of Bloor and east of Woodbine/Don Valley. Unfortunately, both detailed impacts data and meteorological observations prevent better diagnoses of causes for these differences in system response to the event for areas like East York and Scarborough. Image retreived 11:50 AM December 23rd, 2013.

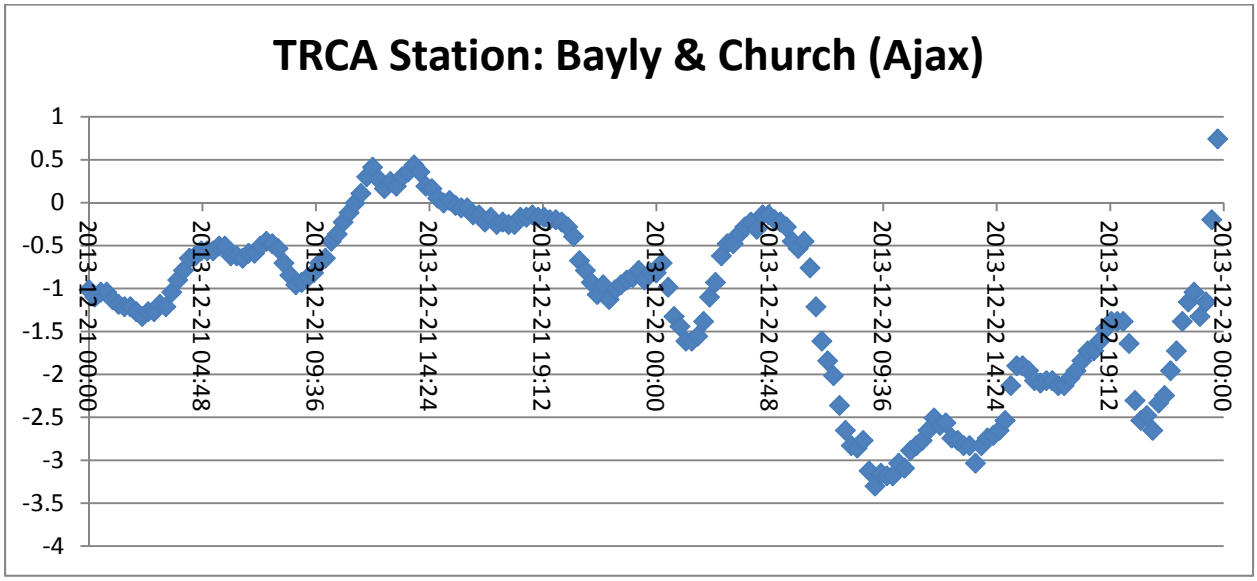


Figure C.6: Temperature Data from Bayly and Church in Ajax. When considered in conjunction with temperature and precipitation measurements from Oshawa Airport, these temerpatures indicate likelyhood that the majority of precipitation experienced between December 21st and December 23rd

was in the form of freezing rain, suggesting ice accretions in Ajax were likely similar to other portions of Durham Region. Data courtesy of Toronto Region Conservation Authority.

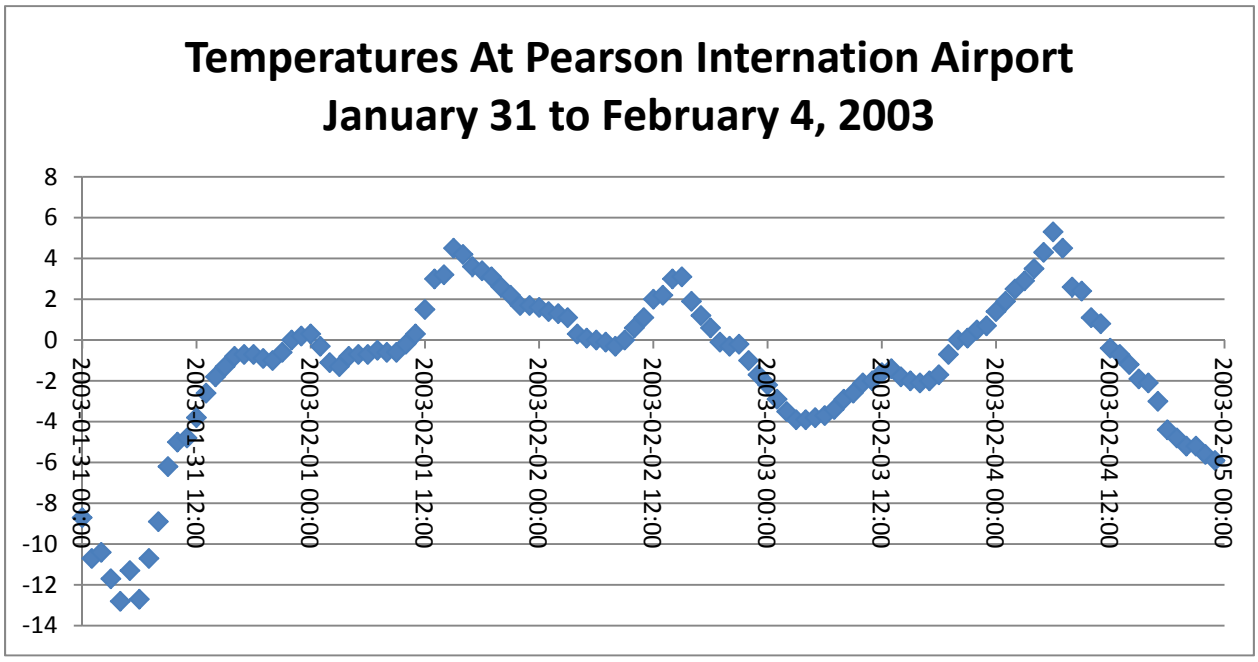


Figure C.7: Hourly temperatures at Pearson Airport between January 31st and Febraury 4th, 2003, corresponding with a complex winter event that produced a total of 160 incident reports as well as outages for over 50,000 Toronto Hydro customers. Temperatures "crossed" the 0°C line no less than 8 times during the 5 day period of unsettled weather.

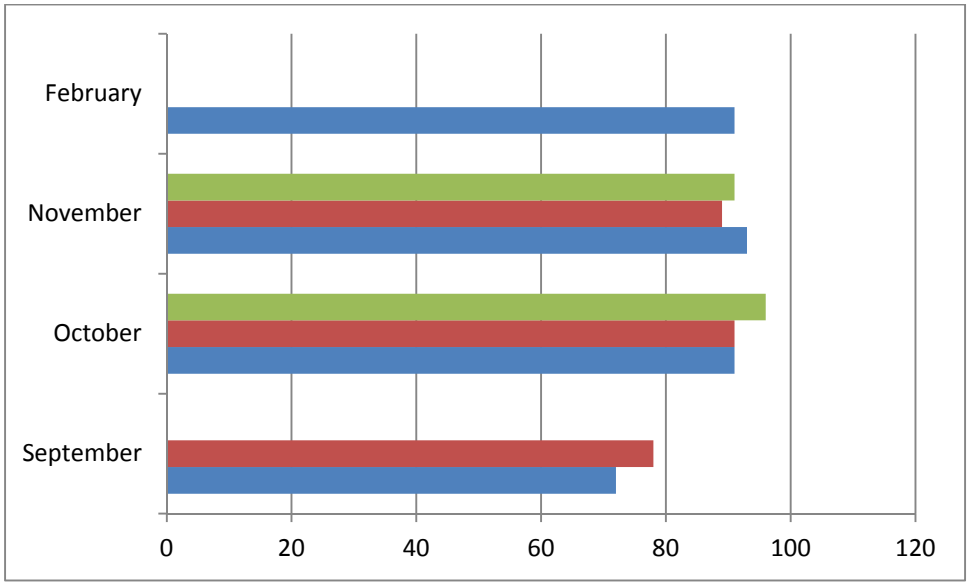


Figure C.8: Max gusts for outage events plotted by month indicate a potential relationship which deserves further study.

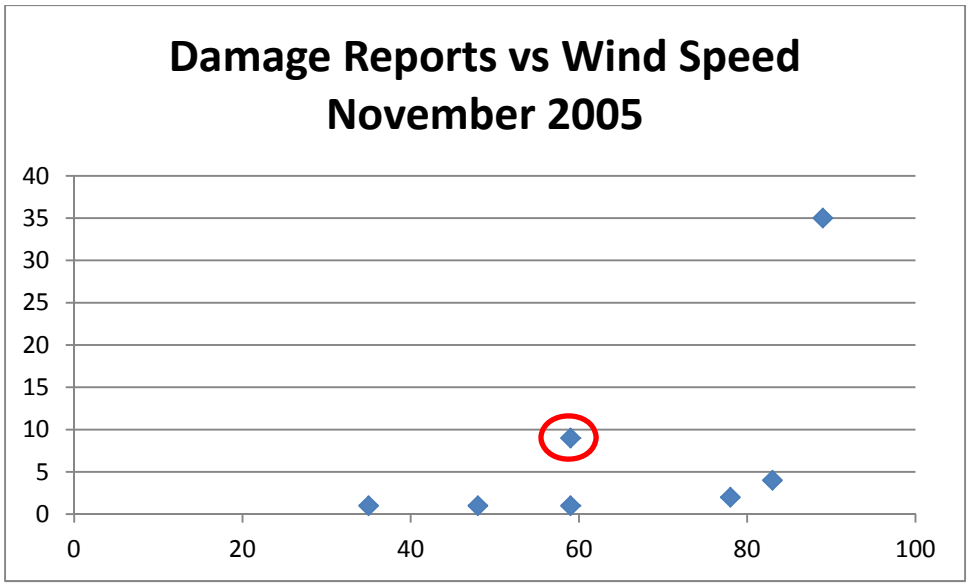


Figure C.9: Number of reports versus max gust reported for November 2005. Note the one apparent outlier, circled in **red**, is November 9th, in which localized impacts are expected and conditions at Pearson Airport are expected to be less representative of conditions producing impacts at a given site.

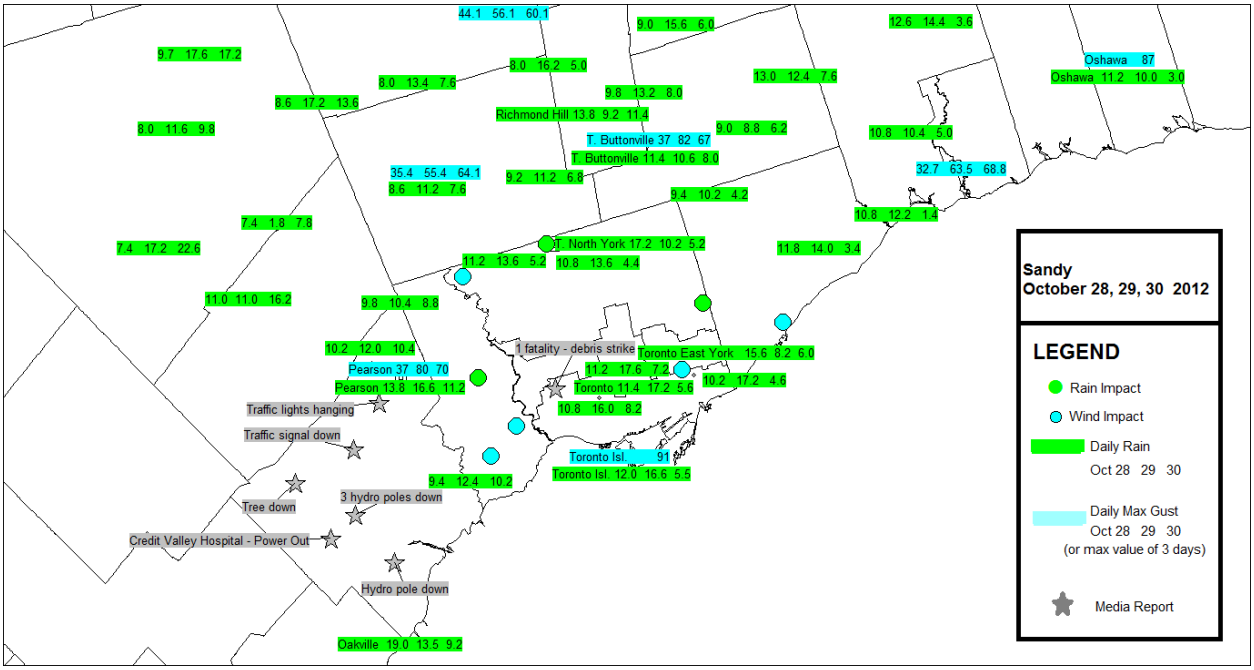


Figure C.10: Map comparing reported impacts with meteorological data for "Superstorm" Sandy. Meteorological data are for October 28th, 29th and 30th and help illustrate the progression of events. Precipitation and wind values are a combination of both EC and TRCA (2014) observational data.

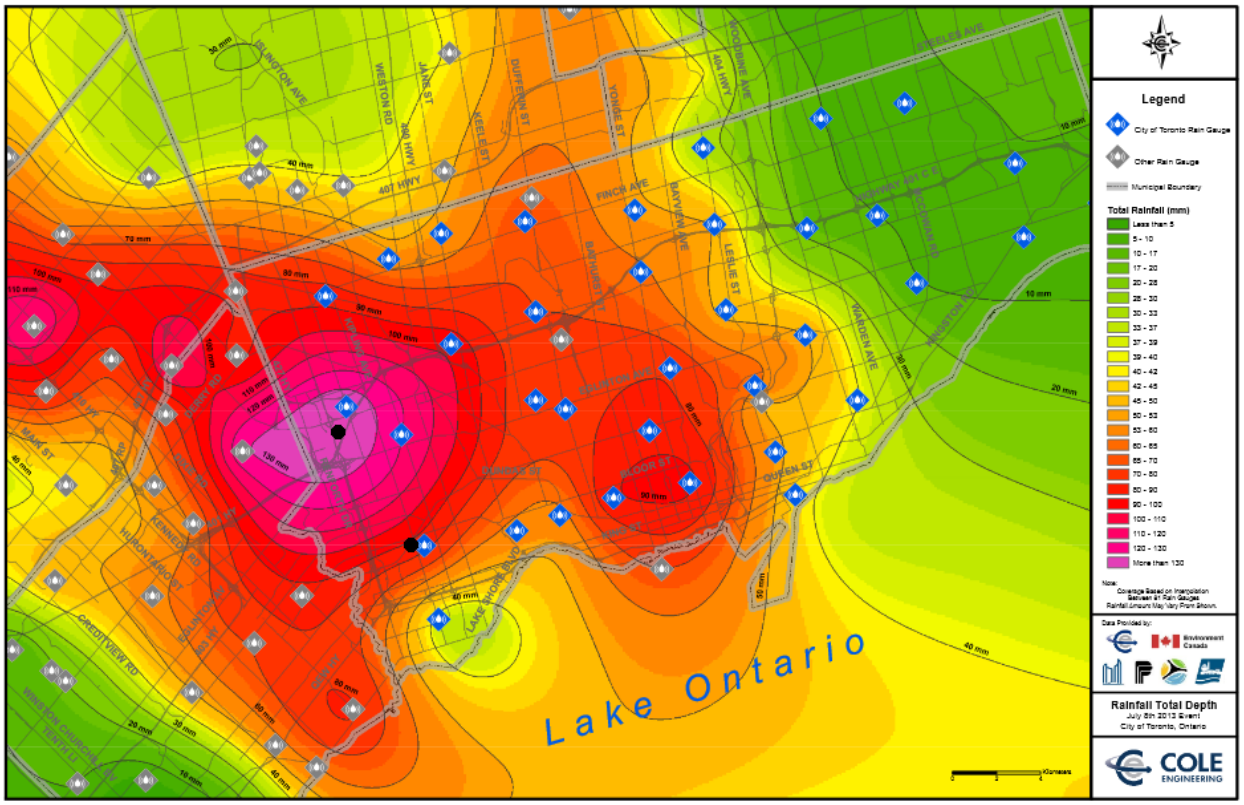


Figure C.11: Contoured 24 hour rainfall totals for the City of Toronto with the locations of Richview and Manby TS superimposed (black dots) added. High resolution PDF map of rainfall totals is available online: http://coleengineering.ca/wordpress/wp-content/themes/Evolution/pdf/2013-articles/rainfall-map.pdf (Cole Engineering Group, 2013)

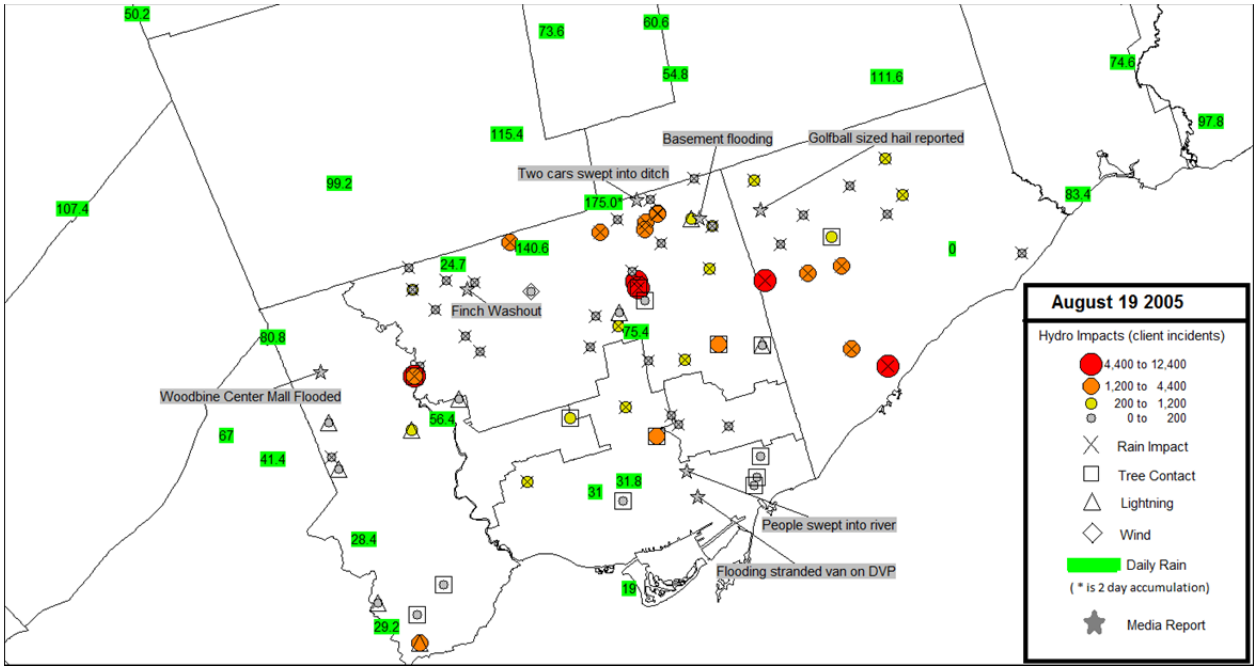


Figure C.12: August 19, 2005 severe thunderstorm event. Map of impacts combining impact types from ITIS and media reports with meteorological data.

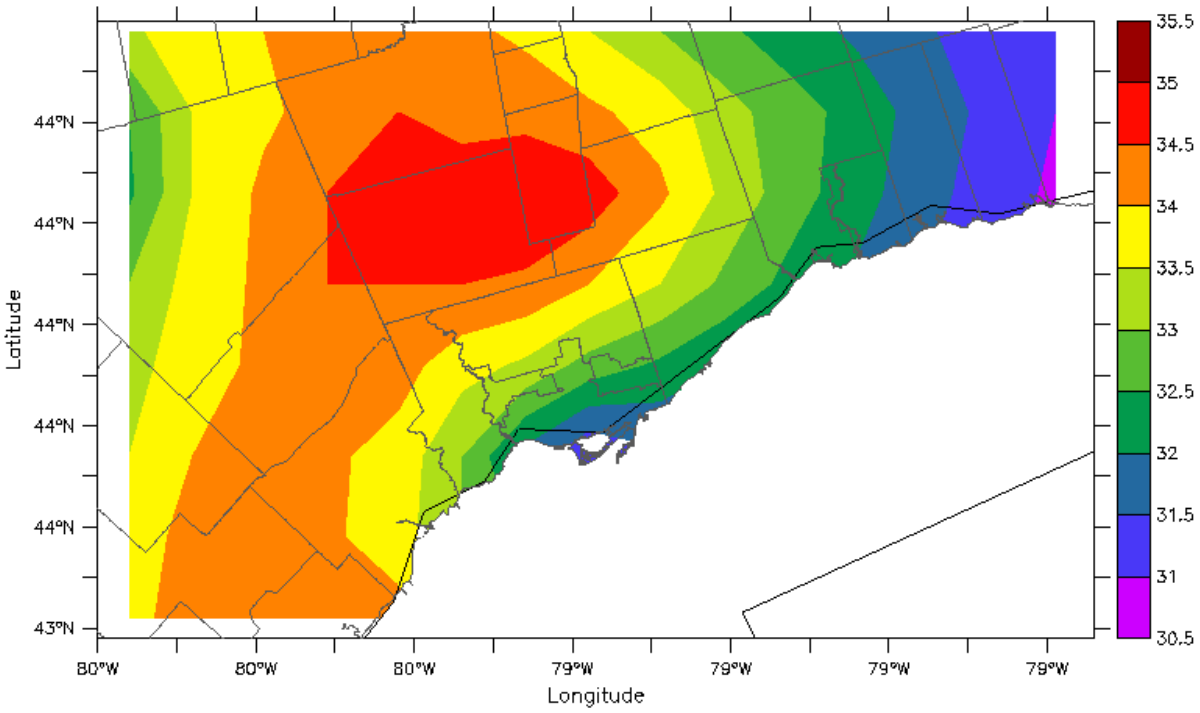


Figure C.13: July 16, 2006, maximum surface temperature (°C) for Toronto and surrounding areas. Data from Cangrd gridded data set.

Appendix D
Risk Assessment Matrix

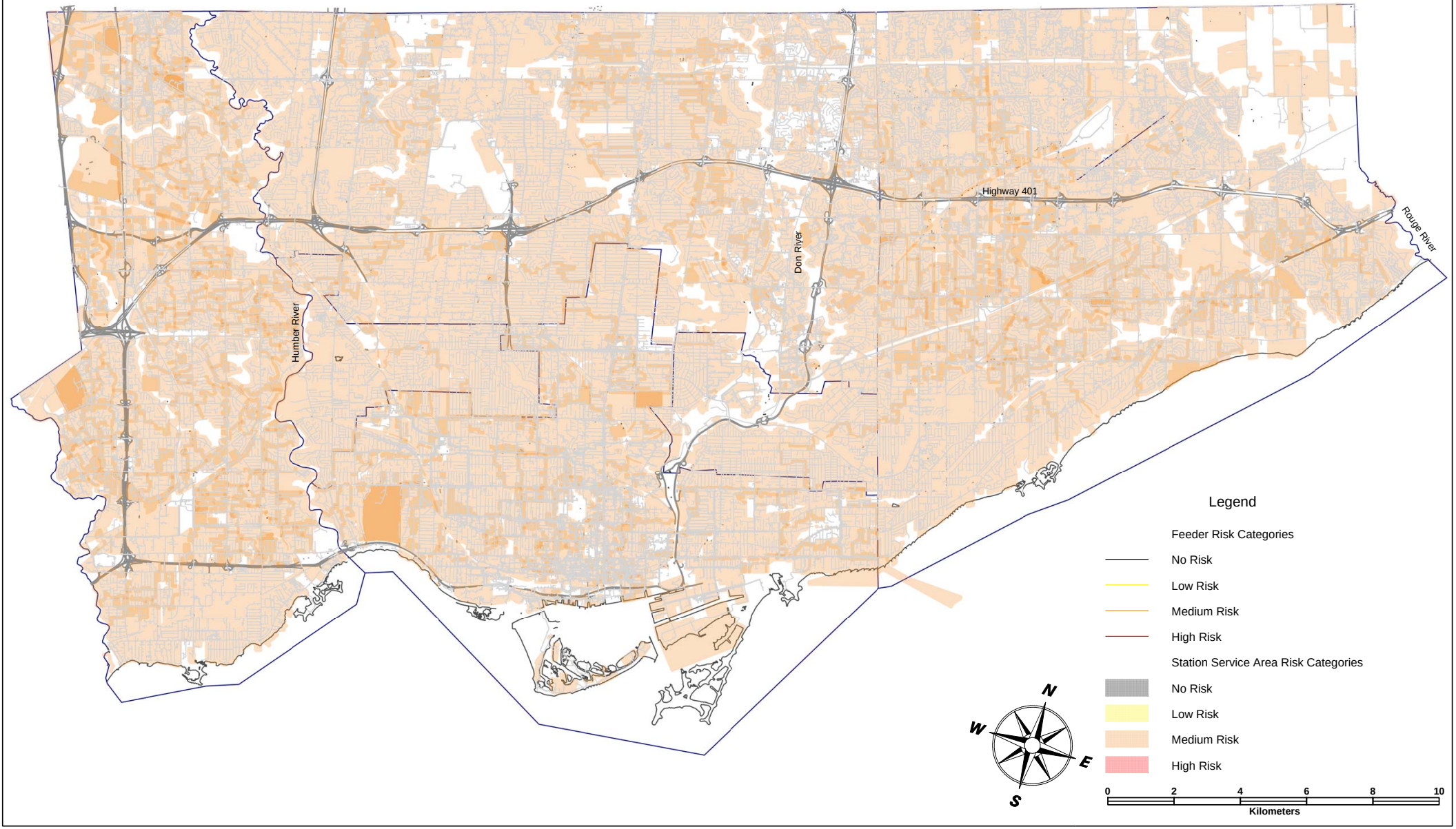
| Study Period | Evaluation | Other Comment | 1 High Temperature | | | | | | | 2 High Temperature | | | | | | | 3 High Temperature | | | | | | | 4 High Temperature | | | | | | | 5 Average temperature >30°C | | | | | | | 6 Heat Wave | | | | | | | 7 High Nighttime Temperatures | | | | | | | 8 Extreme Rainfall | | | | | | | 9 Freezing Rain/Ice Storm | | | | | | |
|---|---|---

10	Freezing Rain/Ice Storm				11	Freezing Rain/Ice Storm				12	High Winds				13	High Winds				14	High Winds				15	Tornadoes				16	Tornadoes				17	Lightning				18	Snow				19	Snow				20	Frost (ground)			
25 mm (design threshold)					60 mm(major outages)					70 km/h+ (tree branches)					90 km/h (min design value; TH higher??)					120 km/h					EF1+					EF2+ (concrete poles, permanent structures)					Days with > 5 cm					Days with > 10 cm					Extreme cold weather			
Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R
N	7					N	4					N	7					N	7					N	7					Y	1	Debris could impact the building	7	7	7	Y	0	Building and equipment can be damaged	7	7	0	N	6					N	7					N	7					N	7			
N	7					N	4					N	7					N	7					N	7					Y	1	Debris could impact the building	7	7	7	Y	0	Building and equipment can be damaged	7	7	0	N	6					N	7					N	7			
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7					N	7					Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7					N	7			
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7					N	7					Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7					N	7			
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7					N	7					Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7					N	7			
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7					N	7					Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7					N	7			
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7					N	7					Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7					N	7			
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7					N	7					Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7					N	7			
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7					N	7					Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7					N	7			
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7					N	7					Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7					N	7			
N	7					N	4					N	7					N	7					N	7					Y	1	Debris could impact the building	7	7	7	Y	0	Building and equipment can be damaged	7	7	0	N	6					N	7					N	7			
Y	7	Exit lines	6	6	42	Y	4	Exit lines: overhead	7	7	28	N	7					N	7					Y	7	Exit lines, and flying debris could impact the equipement	6	6	42	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7					N	7			
N	7					N	4					N	7					N	7					N	7					N	1					N	0					Y	6					N	7					N	7			
Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7	Y	4	Salt corrosion - electrical metal enclosures, access	1	1	4	N	7					N	7					N	7					N	1					N	0					N	6					Y	7	Salt corrosion - electrical metal enclosures	1	1	7	Y	7	Salt corrosion - electrical metal enclosures, Access	1	1	7	N	7			
N	7					N	4				0	N	7					N	7					N	7					N	1					N	0					N	6					N	7					N	7			
Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7	Y	4	Salt corrosion - electrical metal enclosures, access	1	1	4	N	7				0	N	7					N	7					N	1					N	0					N	6					Y	7	Salt corrosion - electrical metal enclosures	1	1	7	Y	7	Salt corrosion - electrical metal enclosures, Access	1	1	7	N	7			
Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7	Y	4	Salt corrosion - electrical metal enclosures, access	1	1	4	N	7					Y	7	Debris could impact the equipement	1	1	7	Y	1	Pad mount equipment can be damaged	2	2	2	Y	0	Pad mount equipment can be damaged	2	2	0	N	6					Y	7	Salt corrosion - electrical metal enclosures	1	1	7	Y	7	Salt corrosion - electrical metal enclosures, Access	1	1	7	N	7			
Y	7	Salt corrosion - electrical metal enclosures, access	1+	2	14	Y	4	Salt corrosion - electrical metal enclosures, access	1+	2	8	N	7					N	7					N	7					N	1					N	0					N	6					Y	7	Salt corrosion - electrical metal enclosures	1+	2	14	Y	7	Salt corrosion - electrical metal enclosures, Access	1+	2	14	N	7			
N	7					N	4					N	7					N	7					N	7					N	1					N	0					N	6					N	7					N	7			
Y	7	Salt corrosion - electrical metal enclosures, access	1+	2	14	Y	4	Salt corrosion - electrical metal enclosures, access	1+	2	8	N	7					N	7					N	7					N	1					N	0					N	6					Y	7	Salt corrosion - electrical metal enclosures	1+	2	14	Y	7	Salt corrosion - electrical metal enclosures, Access	1+	2	14	N	7			
Y	7	Salt corrosion - electrical metal enclosures, access	1+	2	14	Y	4	Salt corrosion - electrical metal enclosures, access	1+	2	8	N	7					Y	7	Debris could impact the equipement	1+	2	14	Y	1	Pad mount equipment can be damaged	2+	3	3	Y	0	Pad mount equipment can be damaged	2+	3	0	N	6					Y	7	Salt corrosion - electrical metal enclosures	1+	2	14	Y	7	Salt corrosion - electrical metal enclosures, Access	1+	2	14	N	7			
Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7	Y	4	Salt corrosion - electrical metal enclosures, access	1	1	4	N	7					N	7					N	7					N	1					N	0					N	6					Y	7	Salt corrosion - electrical metal enclosures	1	1	7	Y	7	Salt corrosion - electrical metal enclosures, Access	1	1	7	N	7			
Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7	Y	4	Salt corrosion - electrical metal enclosures, access	1	1	4	N	7					N	7					N	7					N	1					N	0					N	6					Y	7	Salt corrosion - electrical metal enclosures	1	1	7	Y	7	Salt corrosion - electrical metal enclosures, Access	1	1	7	N	7			
Y																		Y																																						
Y	7	Poles & conductors downed, Salt+Contamination	6+	7	49	Y	4	Poles & conductors downed, Salt+Contamination	6+	7	28	Y	7	Conductors (tree contacts)	4+	5	35	Y	7	Poles & conductors	6+	7	49	Y	7	Poles	7	7	49	Y	1	All structures	7	7	7	Y	0	All structures	7	7	0	Y	6	If arresters don't work, a localize outage can occur	4+	5	30	Y	7	deposit of salt on insulator can create a failure	1+	2	14	Y	7	deposit of salt on insulator can create a failure	1+	2	14	Y	7	Foundations for concrete, steel poles, frost heave	1+	2	14
Y	7	Poles & conductors downed, Salt+Contamination	7	7	49	Y	4	Poles & conductors downed, Salt+Contamination	7	7	28	Y	7	Conductors (tree contacts)	4+	5	35	Y	7	Poles & conductors	6+	7	49	Y	7	Poles	7	7	49	Y	1	All structures	7	7	7	Y	0	All structures	7	7	0	Y	6	If arresters don't work, a localize outage can occur	4+	5	30	Y	7	deposit of salt on insulator can create a failure	1+	2	14	Y	7	deposit of salt on insulator can create a failure	1+	2	14	Y	7	Foundations for concrete, steel poles, frost heave	1+	2	14
Y	7	Poles & conductors downed, Salt+Contamination	7	7	49	Y	4	Poles & conductors downed, Salt+Contamination	7	7	28	Y	7	Conductors (tree contacts)	4+	5	35	Y	7	Poles & conductors	6+	7	49	Y	7	Poles	7	7	49	Y	1	All structures	7	7	7	Y	0	All structures	7	7	0	Y	6	If arresters don't work, a localize outage can occur	4+	5	30	Y	7	deposit of salt on insulator can create a failure	1+	2	14	Y	7	deposit of salt on insulator can create a failure	1+	2	14	Y	7	Foundations for concrete, steel poles, frost heave	1+	2	14
Y	7	Poles & conductors downed, Salt+Contamination	6	6	42	Y	4	Poles & conductors downed, Salt+Contamination	6	6	24	Y	7	Conductors (tree contacts)	4	4	28	Y	7	Poles & conductors	6	6	42	Y	7	Poles	7	7	49	Y	1	All structures	7	7	7	Y	0	All structures	7	7	0	Y	6	If arresters don't work, a localize outage can occur	4	4	24	Y	7	deposit of salt on insulator can create a failure	1	1	7	Y	7	deposit of salt on insulator can create a failure	1	1	7	Y	7	Foundations for concrete, steel poles, frost heave	1	1	7
Y	7	Poles & conductors downed, Salt+Contamination	7	7	49	Y	4	Poles & conductors downed, Salt+Contamination	7	7	28	Y	7	Conductors (tree contacts)	4	4	28	Y	7	Poles & conductors	6	6	42	Y	7	Poles	7	7	49	Y	1	All structures	7	7	7	Y	0	All structures	7	7	0	Y	6	If arresters don't work, a localize outage can occur	4	4	24	Y	7	deposit of salt on insulator can create a failure	1	1	7	Y	7	deposit of salt on insulator can create a failure	1	1	7	Y	7	Foundations for concrete, steel poles, frost heave	1	1	7
Y	7	Poles & conductors downed, Salt+Contamination	7	7	49	Y	4	Poles & conductors downed, Salt+Contamination	7	7	28	Y	7	Conductors (tree contacts)	4	4	28	Y	7	Poles & conductors	6	6	42	Y	7	Poles	7	7	49	Y	1	All structures	7	7	7	Y	0	All structures	7	7	0	Y	6	If arresters don't work, a localize outage can occur	4	4	24	Y	7	deposit of salt on insulator can create a failure	1	1	7	Y	7	deposit of salt on insulator can create a failure	1	1	7	Y	7	Foundations for concrete, steel poles, frost heave	1	1	7
N	7					N	4					N	7					N	7					N	7					N	1					N	0					N	6					N	7					N	7			
Y	7	Access	1	1	7	Y	4	Access	1	1	4	N	7					N	7					N	7					N	1					N	0					Y	6	Equipment could fail if protection won't work	3	3	18	N	7					N	7					N	7			
N	7					N	4					N	7					N	7					Y	7	TC & CVT structures			0	Y	1	All supports	7	7	7	Y	0	All supports	7	7	0	N	6					N	7					N	7					Y	7	Foundations, frost heave	2	2	14
Y	7	Gantry + exit lines	1	1	7	Y	4	Gantry + exit lines	7	7	28	N	7					N	7					N	7					Y	1	Gantry	7	7	7	Y	0	Gantry	7	7	0	N	6					N	7					N	7					Y	7	Foundations, frost heave	2	2	14
Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	14	Y	4	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	8	N	7					N	7					N	7					N	1					N	0					N	6					Y	7	Salt corrosion - concrete and steel	1+	2	14	Y	7	Salt corrosion - concrete and steel, access	1+	2	14	Y	7	Foundations, frost heave	1+	2	14
Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	14	Y	4	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	8	N	7					N	7					N	7					N	1					N	0					N	6					Y	7	Salt corrosion - concrete and steel	1+	2	14	Y	7	Salt corrosion - concrete and steel, access	1+	2	14	Y	7	Foundations, frost heave	1+	2	14
N	7					N	4					N	7					N	7					N	7					N	1					N	0					N	6					N	7					N	7					Y	7	Foundations, frost heave	1+	2	14
Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	7	Y	4	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	4	N	7					N	7					N	7					N	1					N	0					N	6					Y	7	Salt corrosion - concrete and steel	1	1	7	Y	7	Salt corrosion - concrete and steel, access	1	1	7	Y	7	Foundations, frost heave	1	1	7
Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	7	Y	4	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	4	N	7					N	7					N	7					N	1					N	0					N	6					Y	7	Salt corrosion - concrete and steel	1	1	7	Y	7	Salt corrosion - concrete and steel, access	1	1	7	Y	7	Foundations, frost heave	1	1	7
N	7					N	4					N	7					N	7					N	7					N	1					N	0					N	6					N	7					N	7					Y	7	Foundations, frost heave	1	1	7
Y	7	safe access to site	6	6	42	Y	4	safe access to site	6	6	24	Y	7	access, location has to be declare safe	2	2	14	Y	7	access, location has to be declare safe	2	2	14	Y	7	access, location has to be declare safe	2	2	14	Y	1	access, location has to be declare safe	2	2	2	Y	0	access, location has to be declare safe	2	2	0	Y	6	staff security	3-4	4	24	Y	7	Access, staff security	1-2	2	14	Y	7	Access, staff security	3	3	21	N	7									

Appendix E
Risk Maps

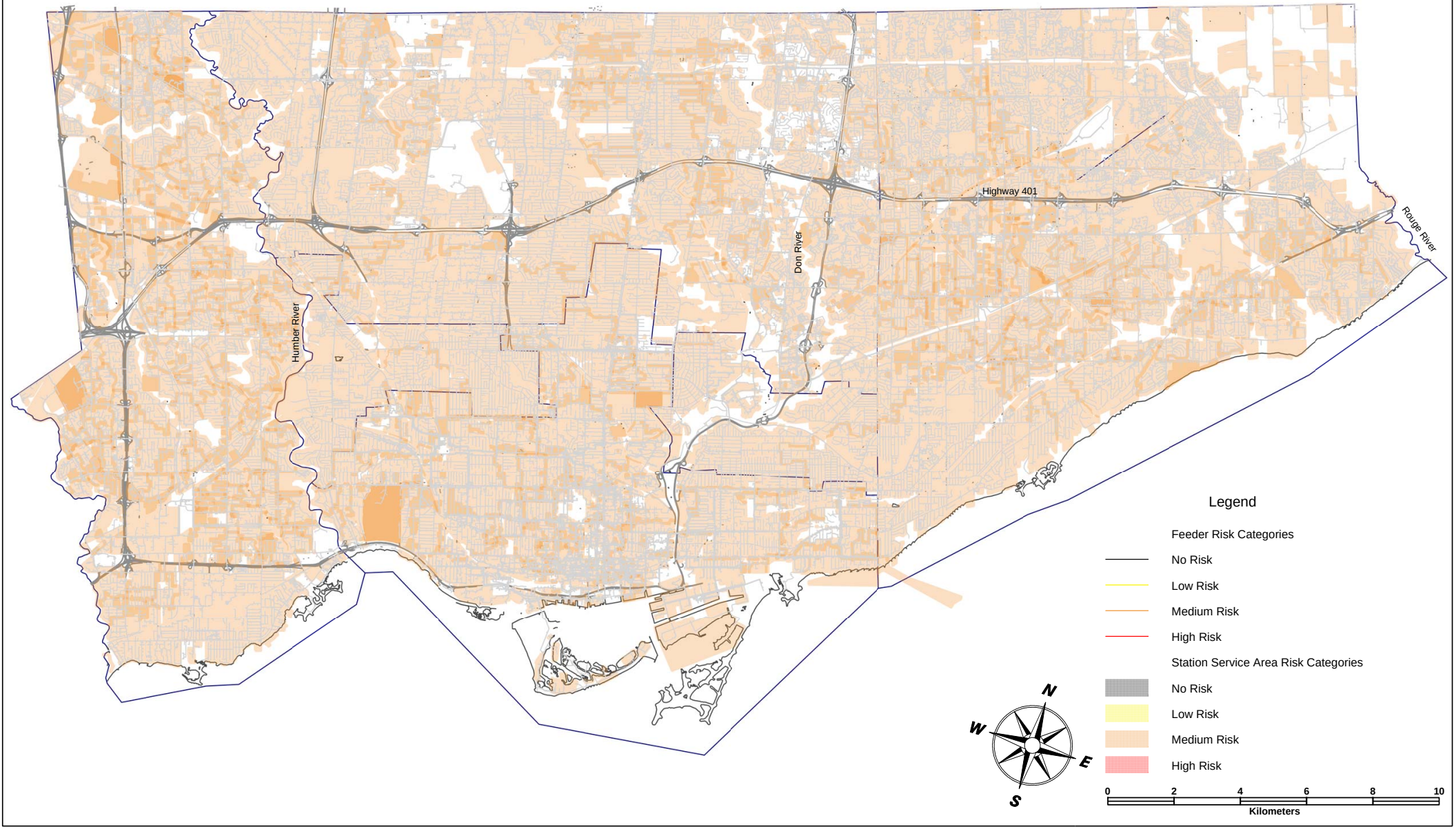
PIEVC Phase 2 Climate Change Risk Map by 2050

1. High Temperature Maximum Above 25 C



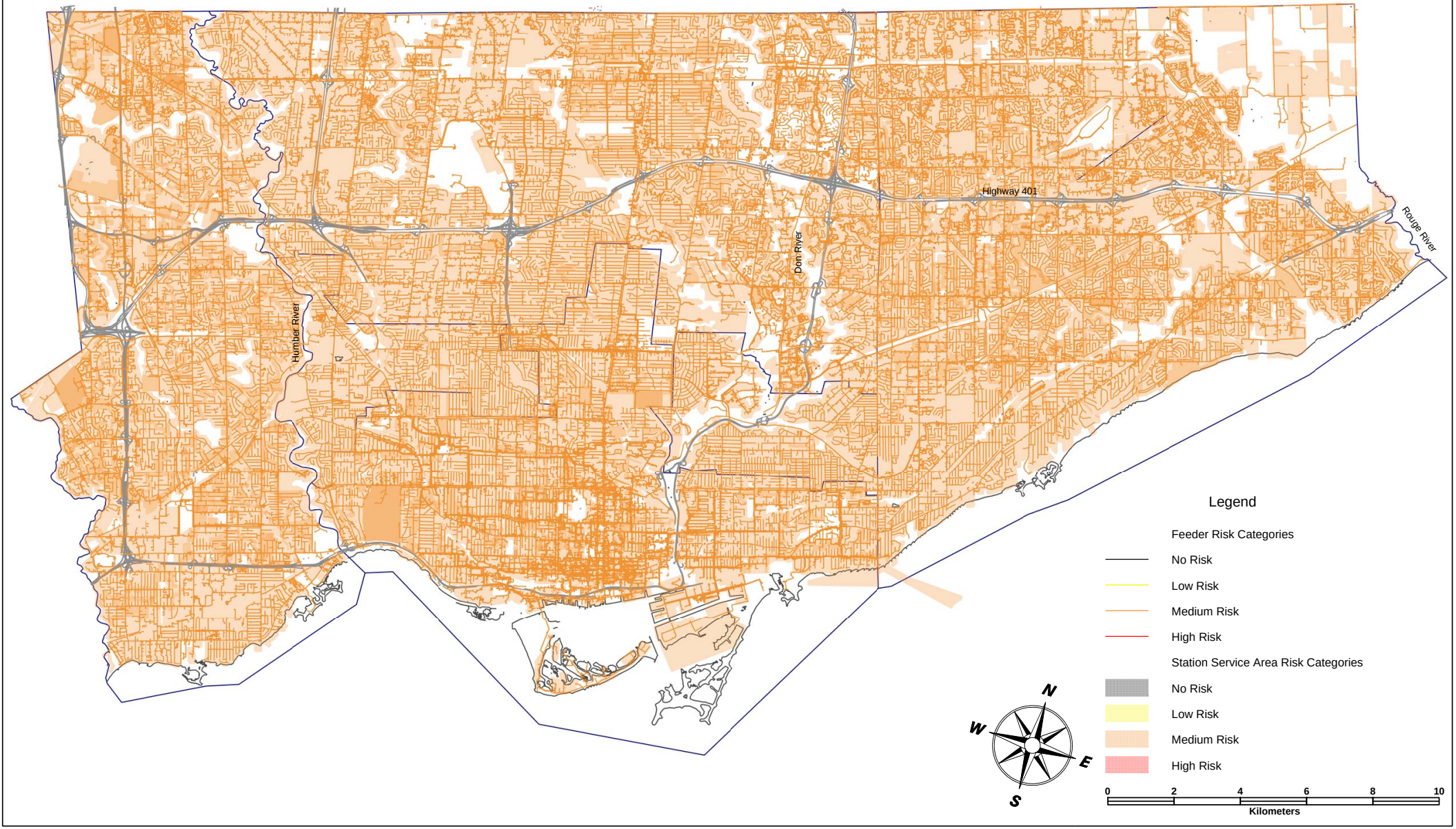
PIEVC Phase 2 Climate Change Risk Map by 2050

2. High Temperature Maximum Above 30 C



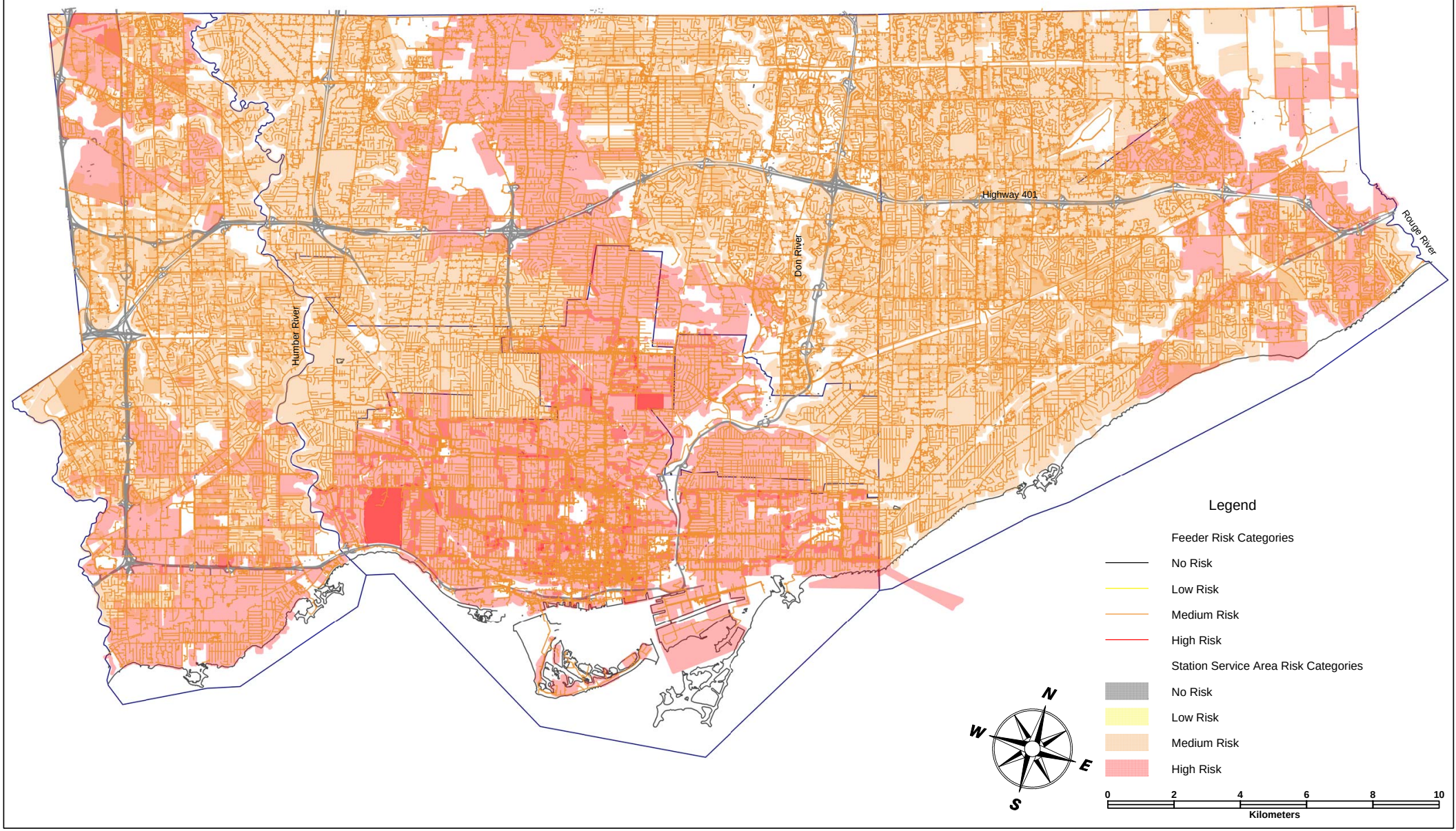
PIEVC Phase 2 Climate Change Risk Map by 2050

3. High Temperature Maximum Above 35 C



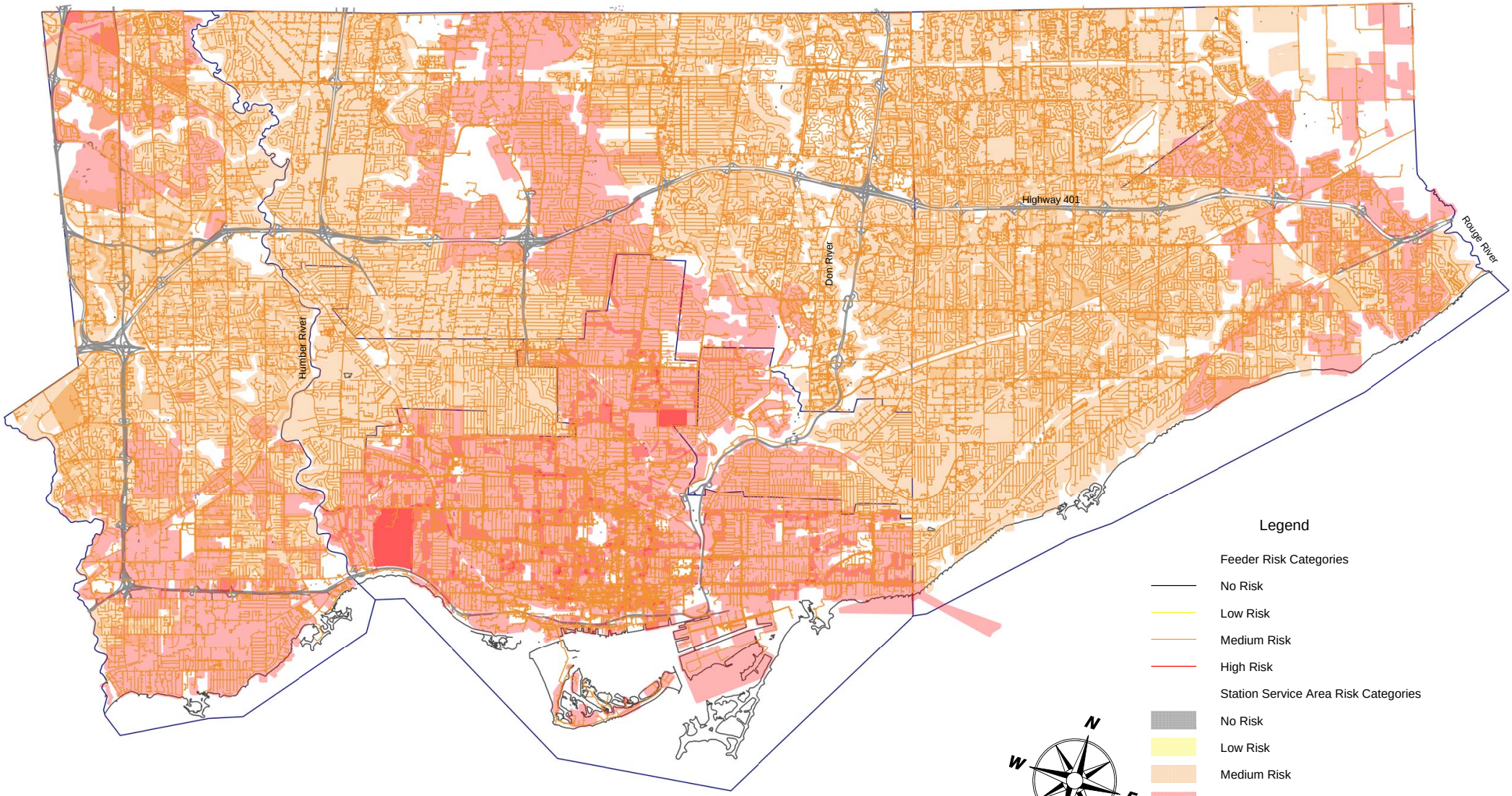
PIEVC Phase 2 Climate Change Risk Map by 2050

4. High Temperature Maximum Above 40 C



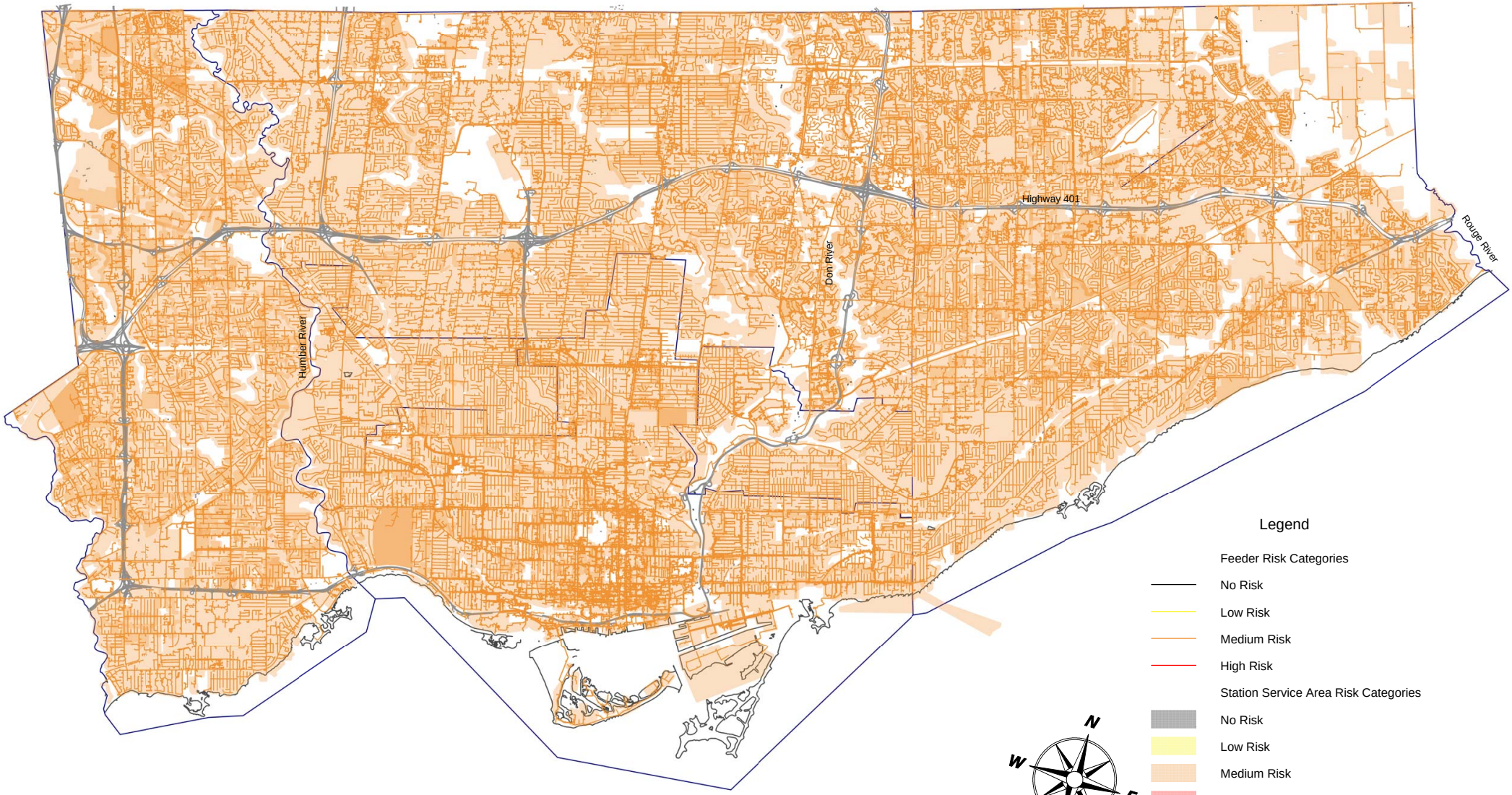
PIEVC Phase 2 Climate Change Risk Map by 2050

5. Average Temperature Above 30 C for 24 Hours



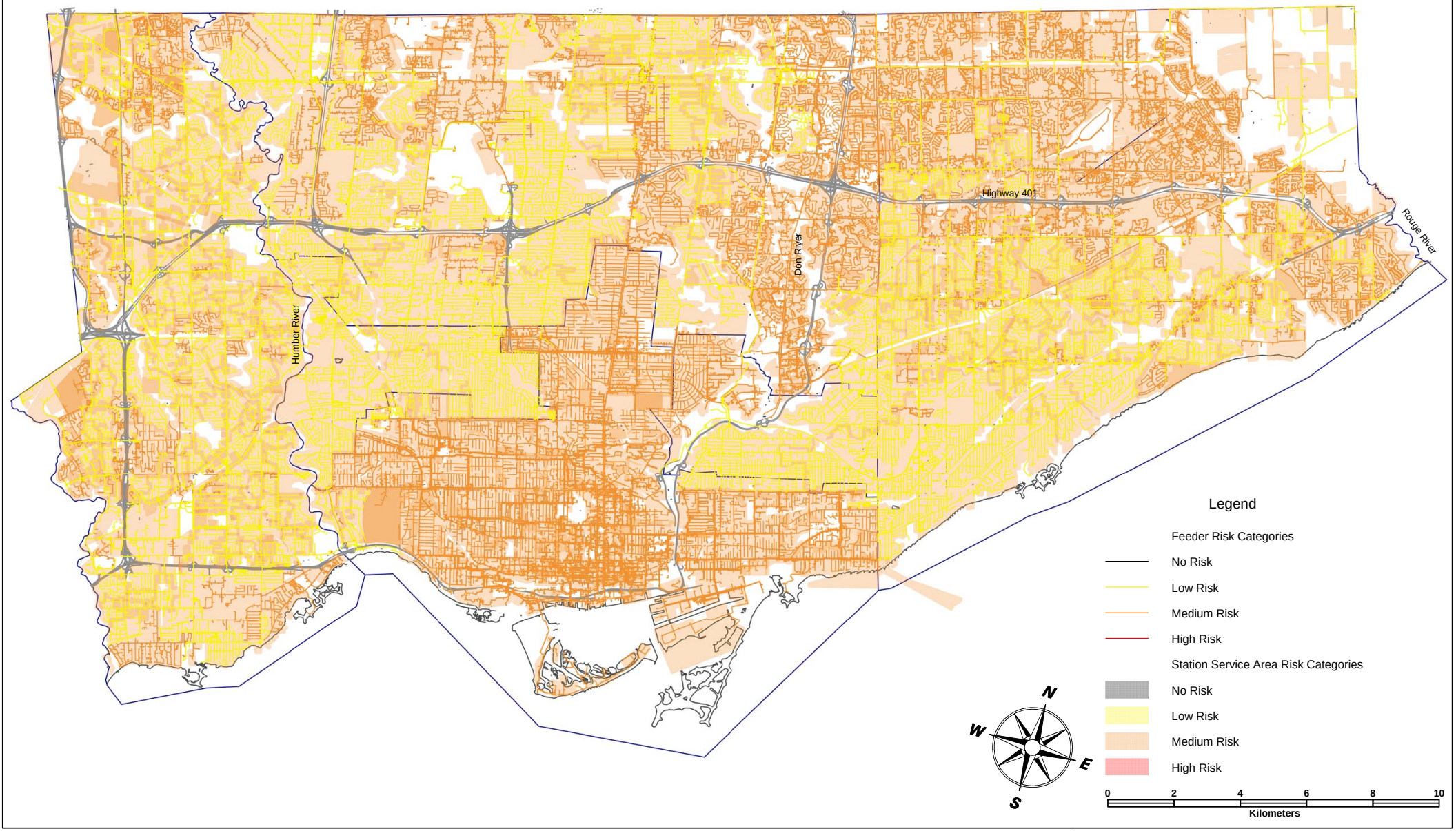
PIEVC Phase 2 Climate Change Risk Map by 2050

6. Heat Wave 3 Day with Maximum Temperature Above 30 C



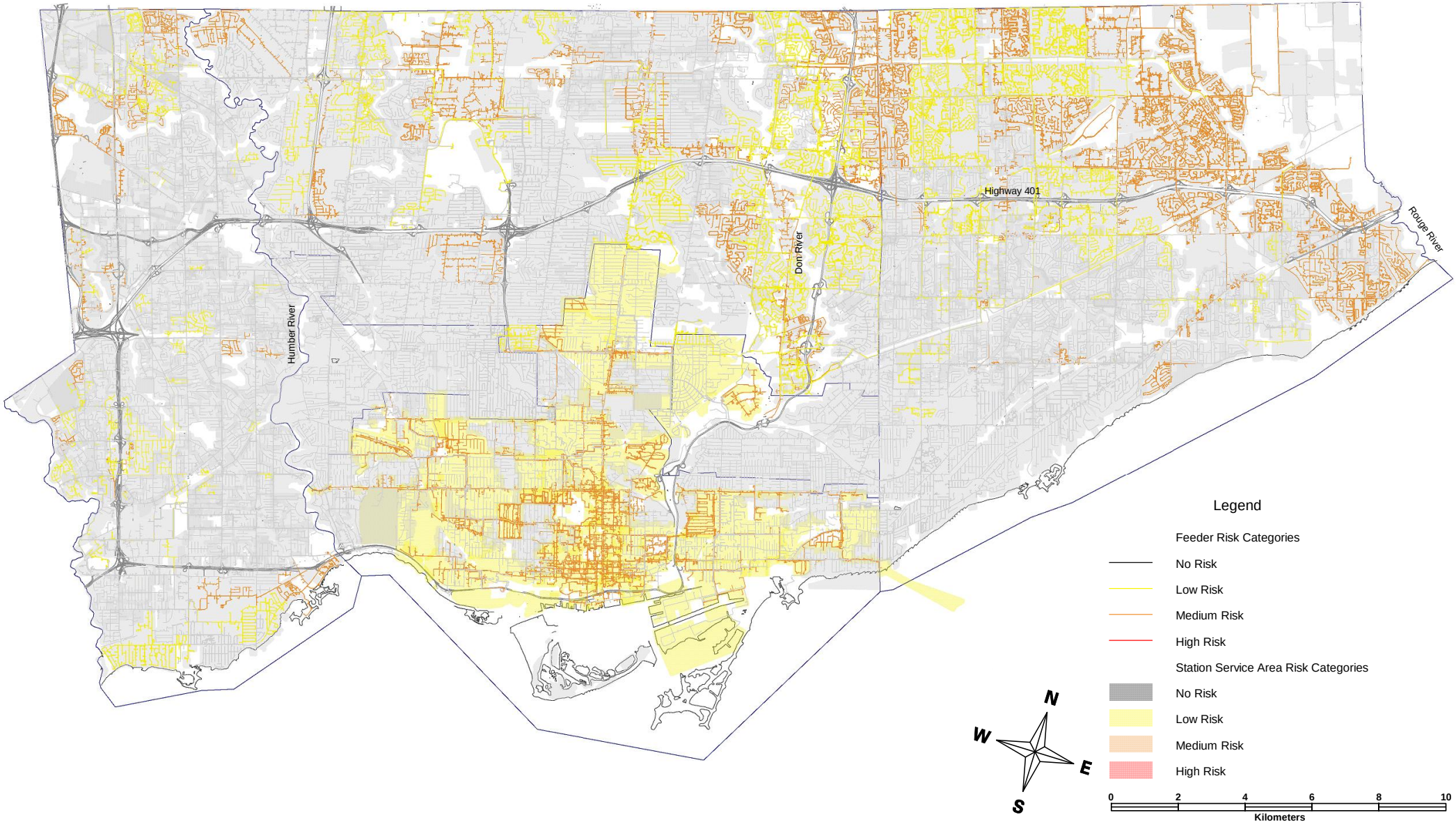
PIEVC Phase 2 Climate Change Risk Map by 2050

7. High Night Time Temperature Minimum Above 23 C



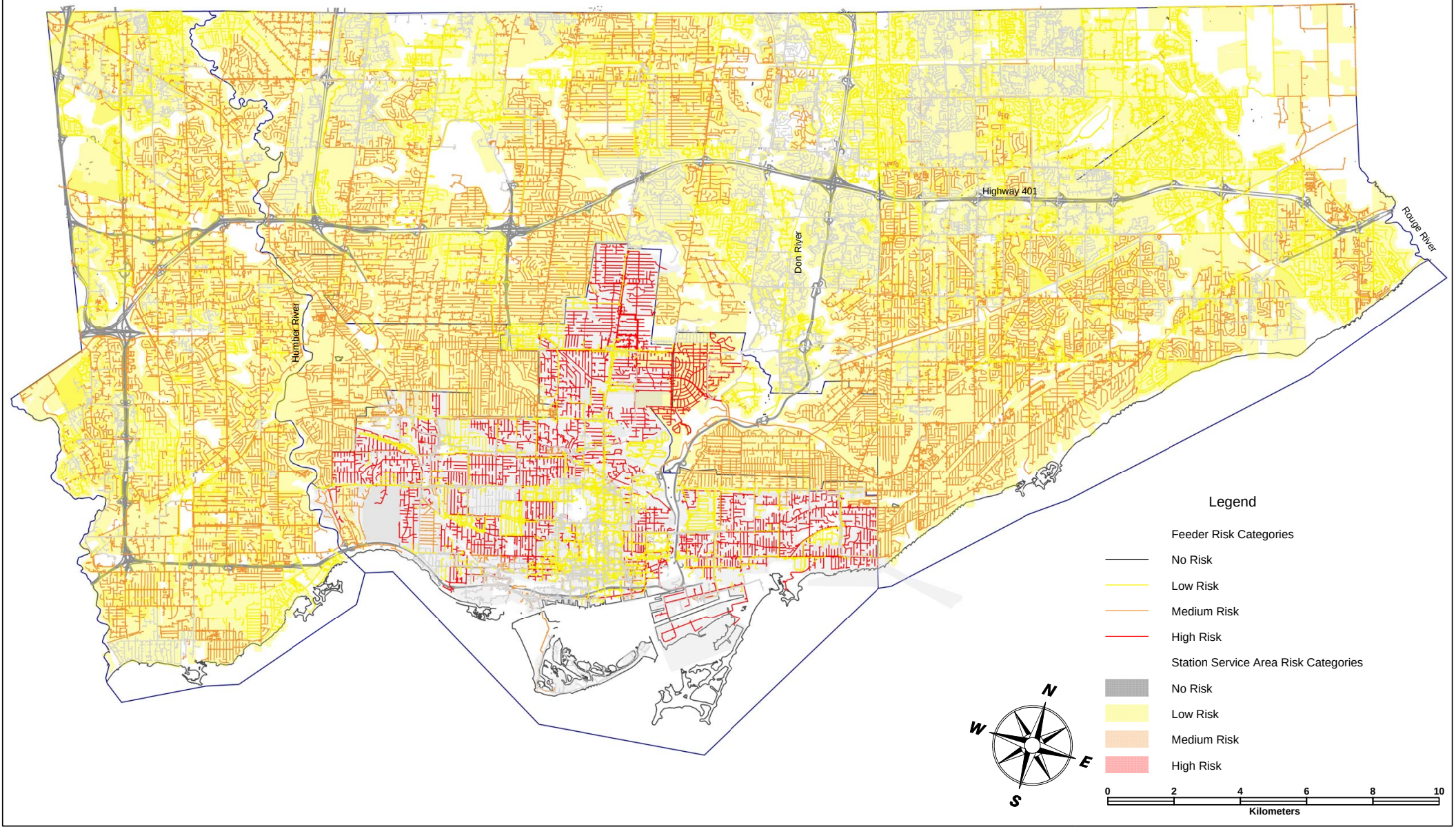
PIEVC Phase 2 Climate Change Risk Map by 2050

8. Extreme Rainfall 100mm in Less than 24 Hours



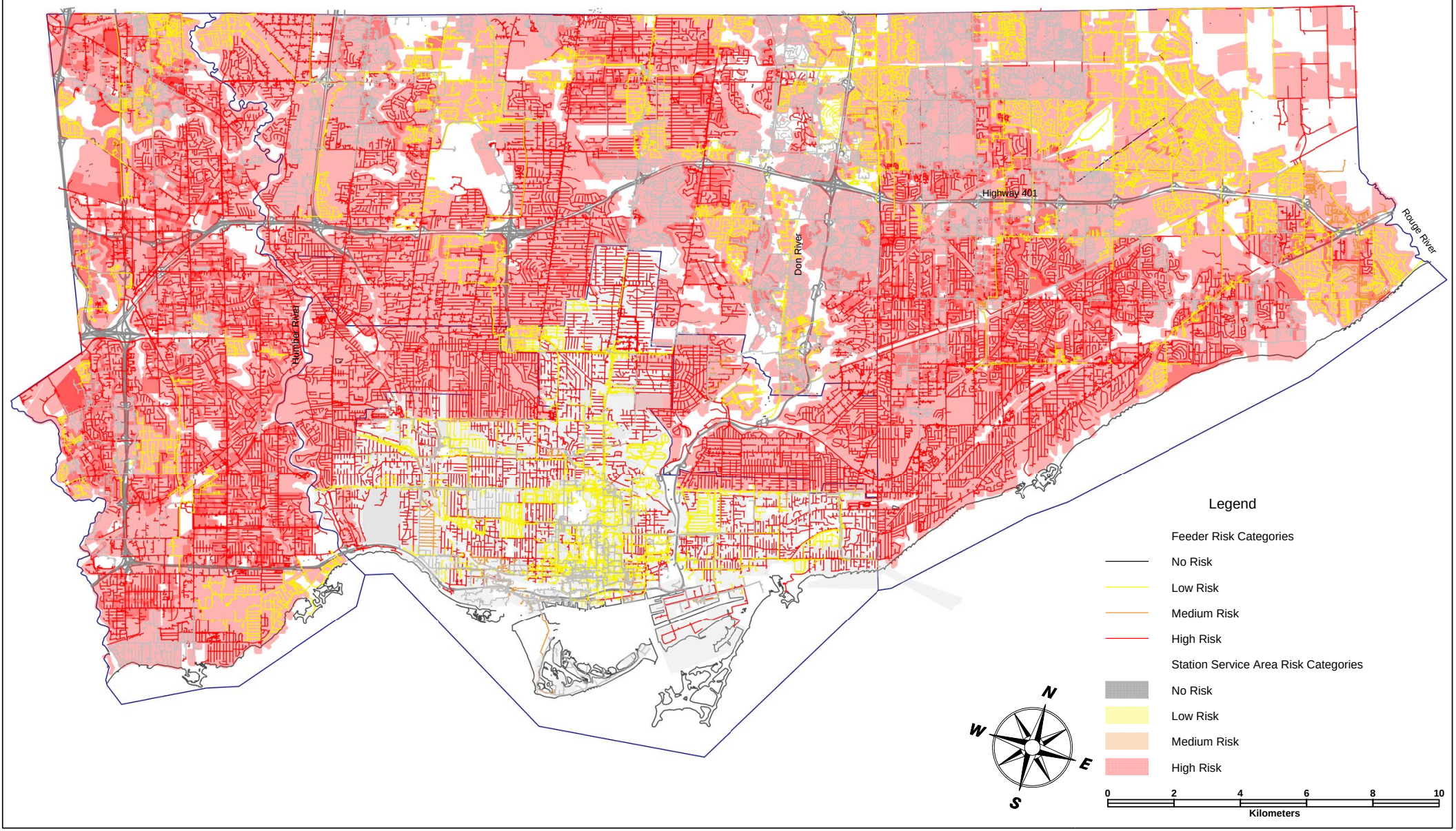
PIEVC Phase 2 Climate Change Risk Map by 2050

9. 15mm Freezing Rain/Ice Storm



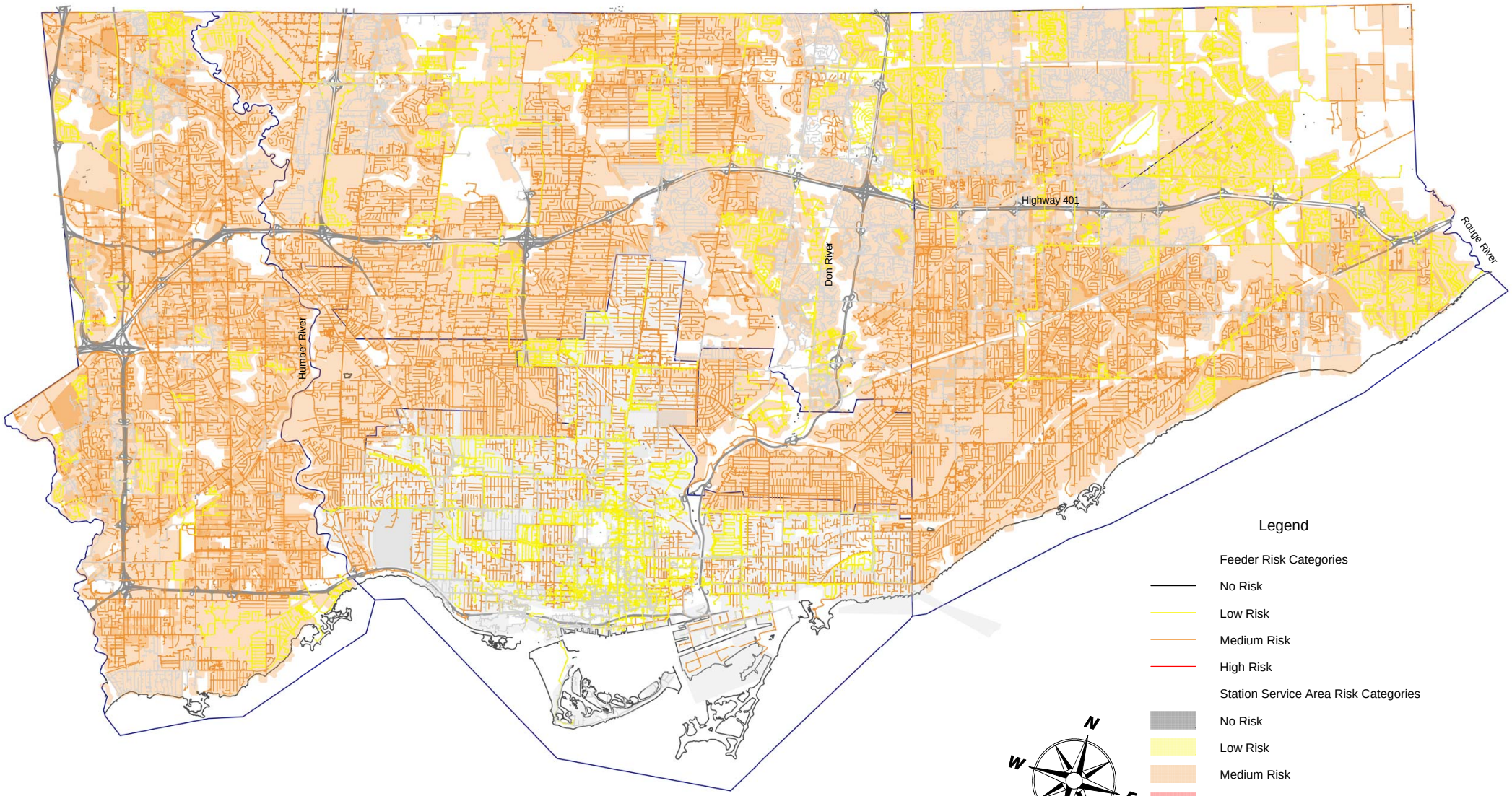
PIEVC Phase 2 Climate Change Risk Map by 2050

10. 25mm Freezing Rain/Ice Storm



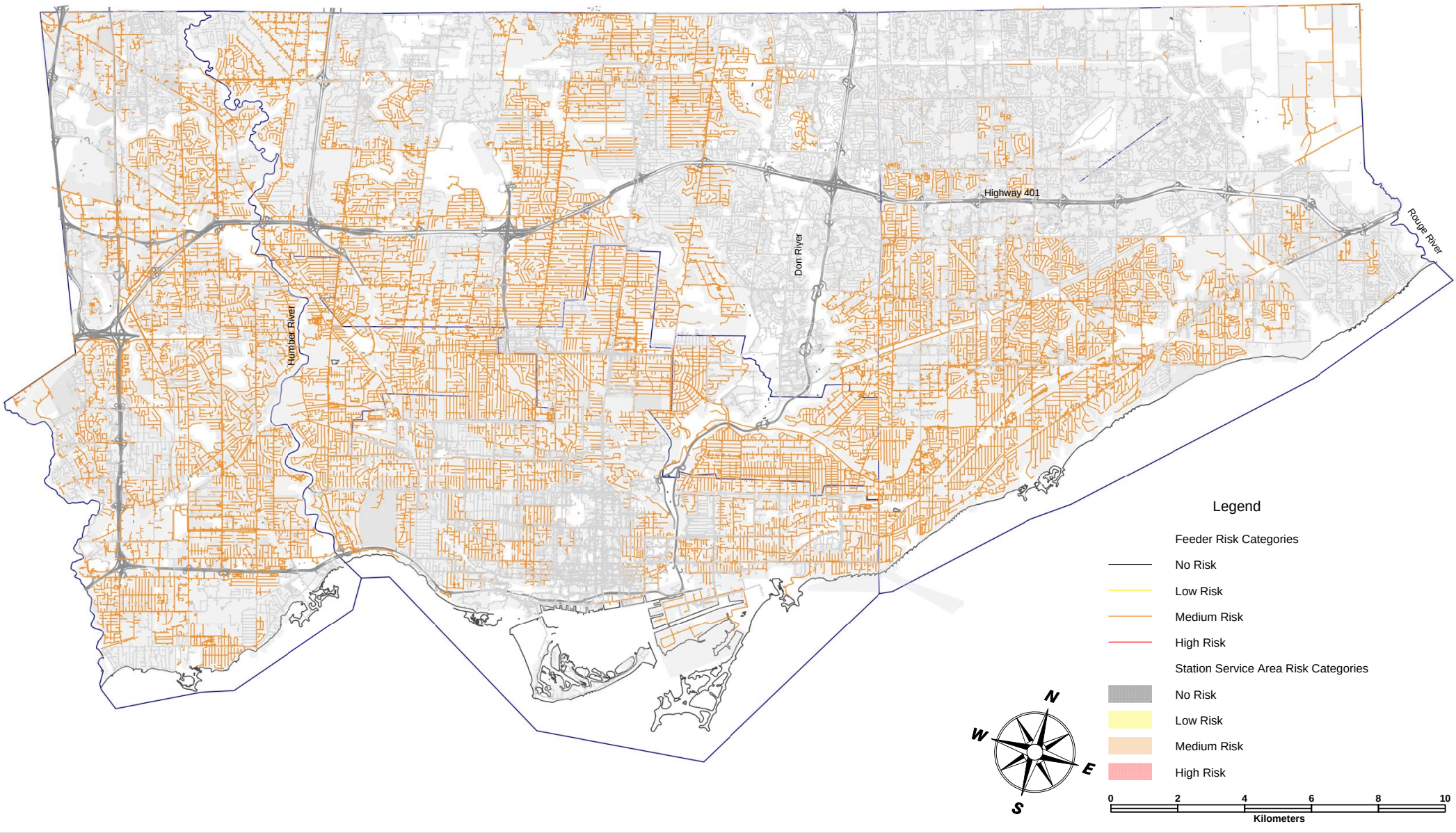
PIEVC Phase 2 Climate Change Risk Map by 2050

11. 60mm Freezing Rain/Ice Storm



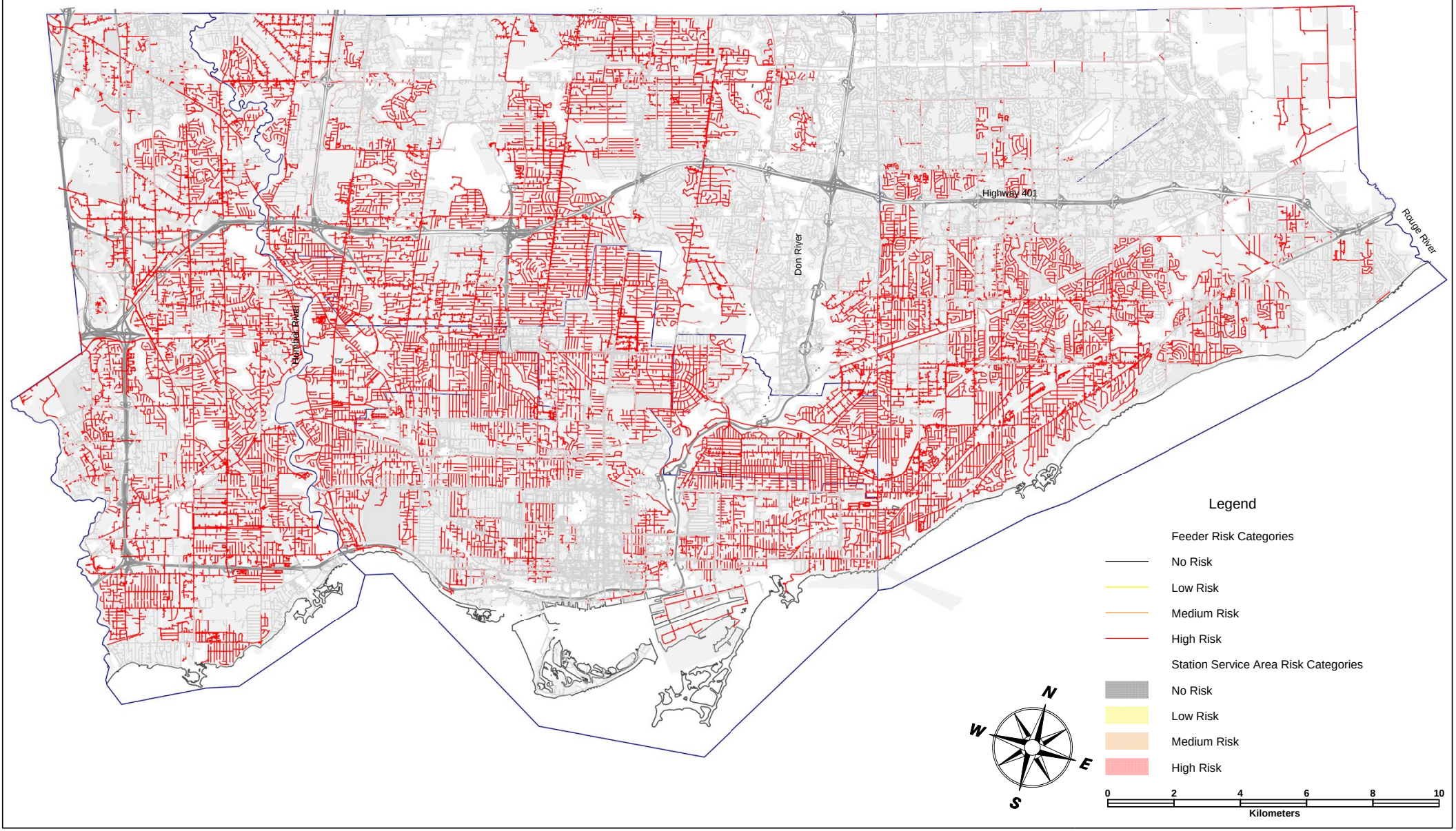
PIEVC Phase 2 Climate Change Risk Map by 2050

12. High Winds Greater Than 70km/h



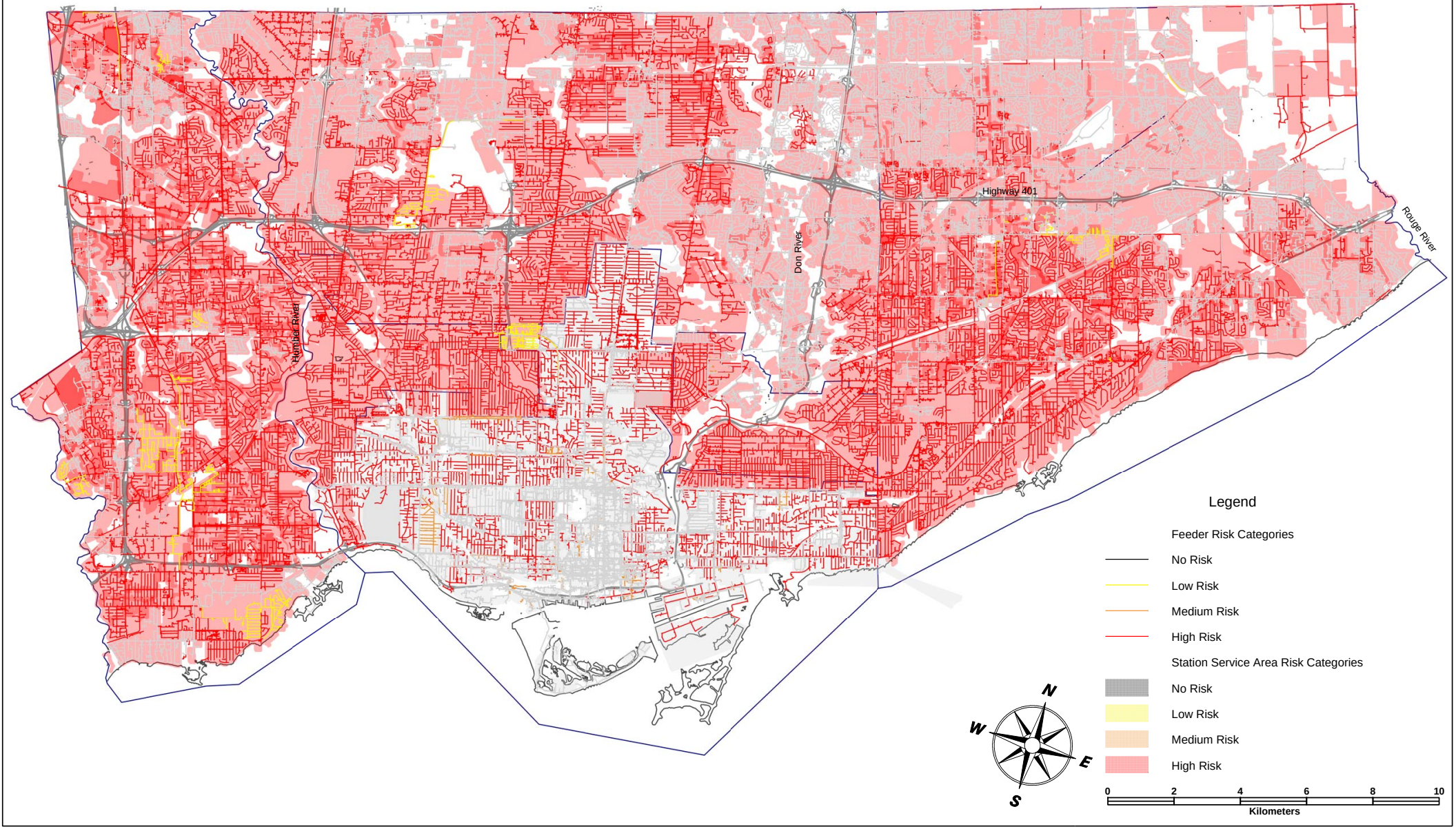
PIEVC Phase 2 Climate Change Risk Map by 2050

13. High Winds Greater Than 90km/h



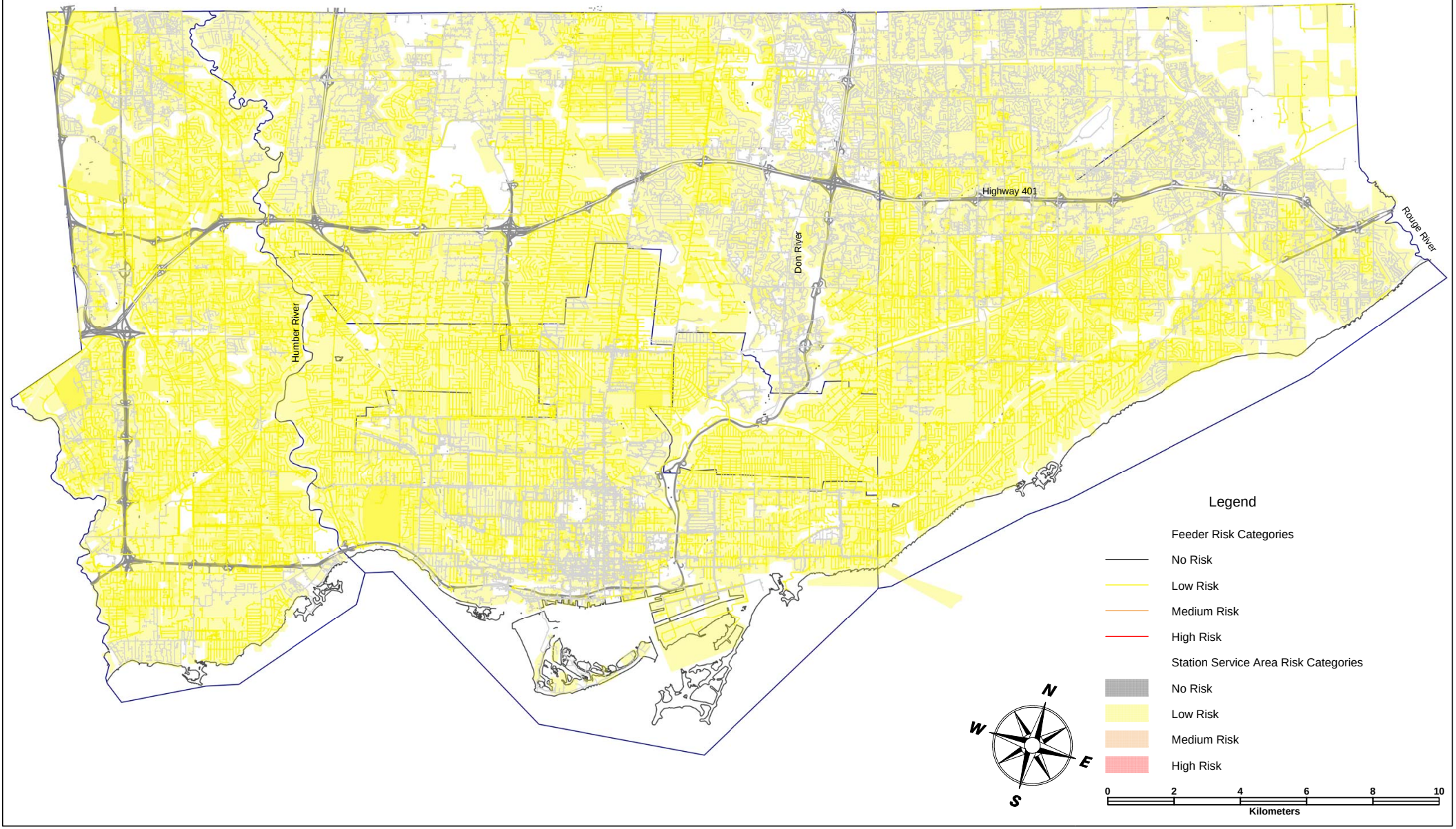
PIEVC Phase 2 Climate Change Risk Map by 2050

14. High Winds Greater Than 120km/h



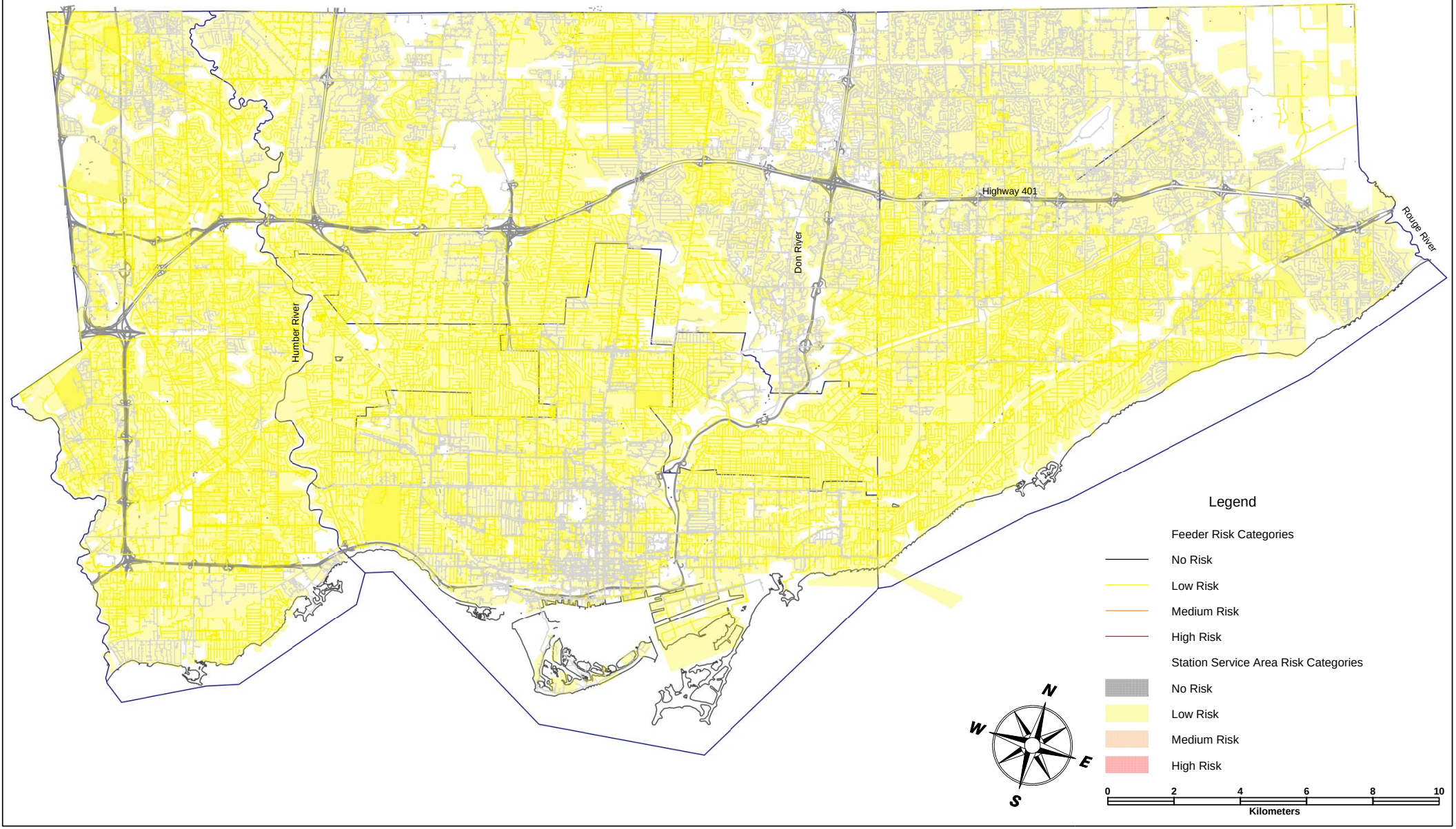
PIEVC Phase 2 Climate Change Risk Map by 2050

15. Tornadoes EF1+



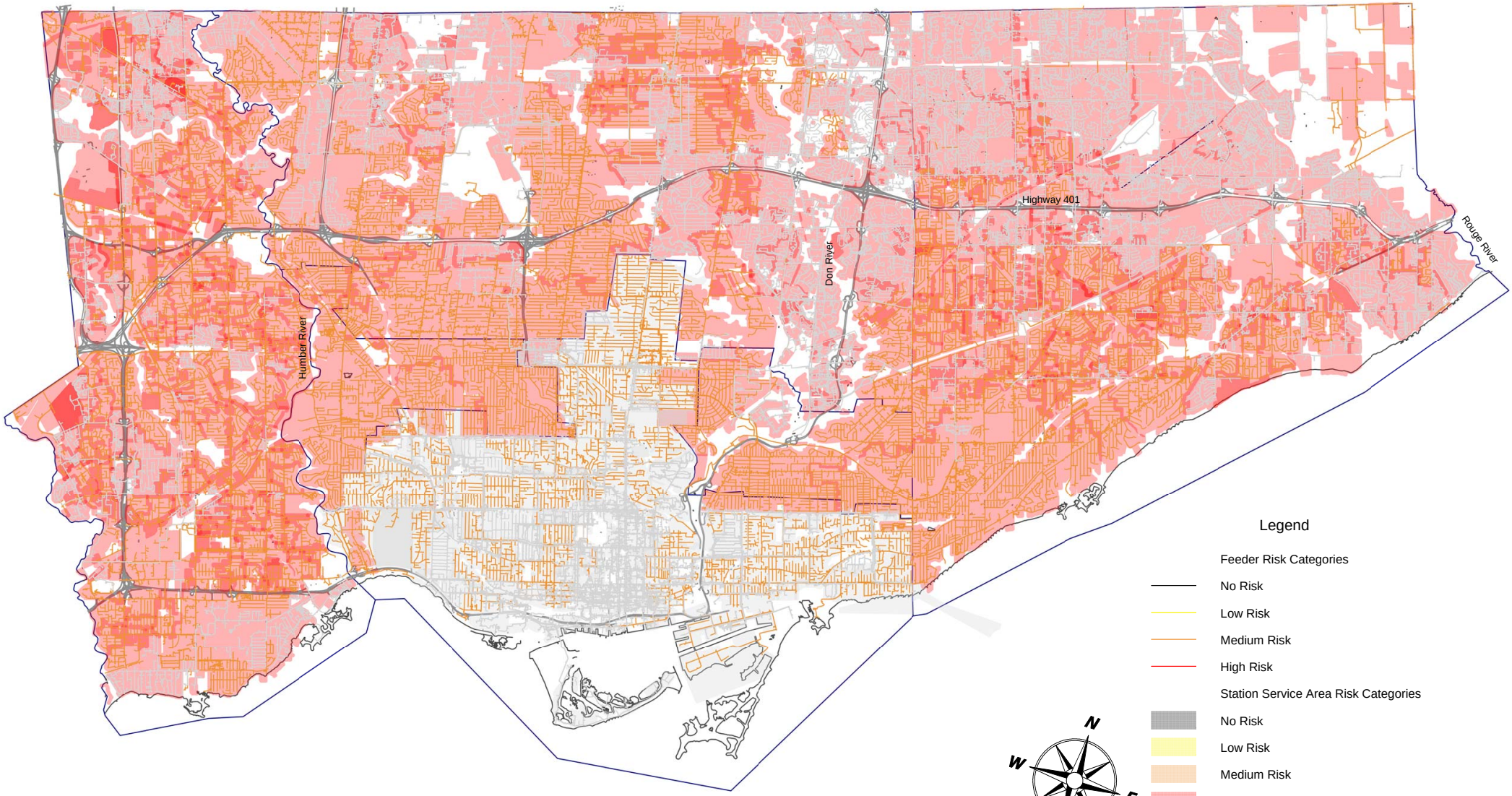
PIEVC Phase 2 Climate Change Risk Map by 2050

16. Tornadoes EF2+



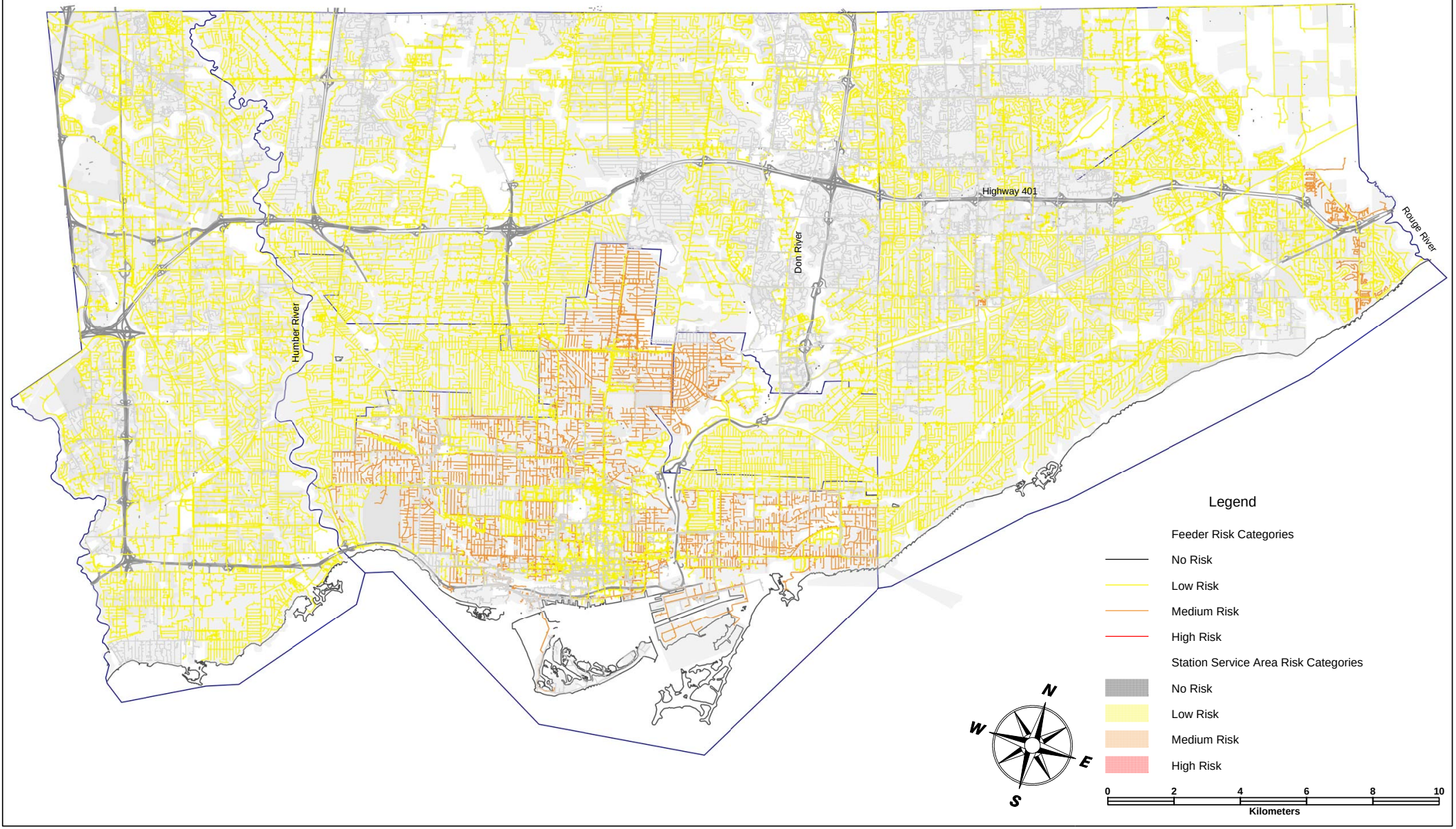
PIEVC Phase 2 Climate Change Risk Map by 2050

17. Lightning



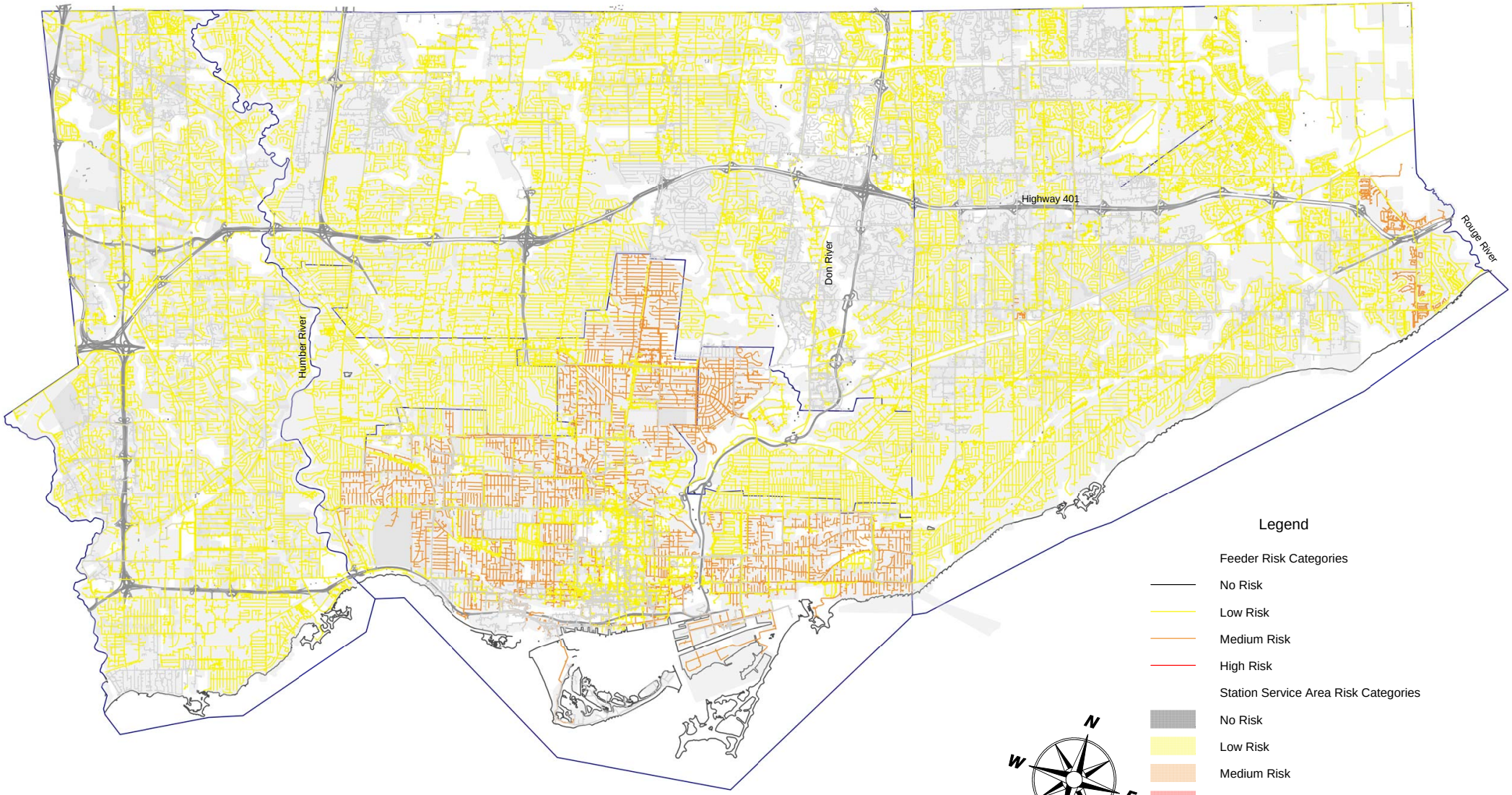
PIEVC Phase 2 Climate Change Risk Map by 2050

18. Snow >5cm



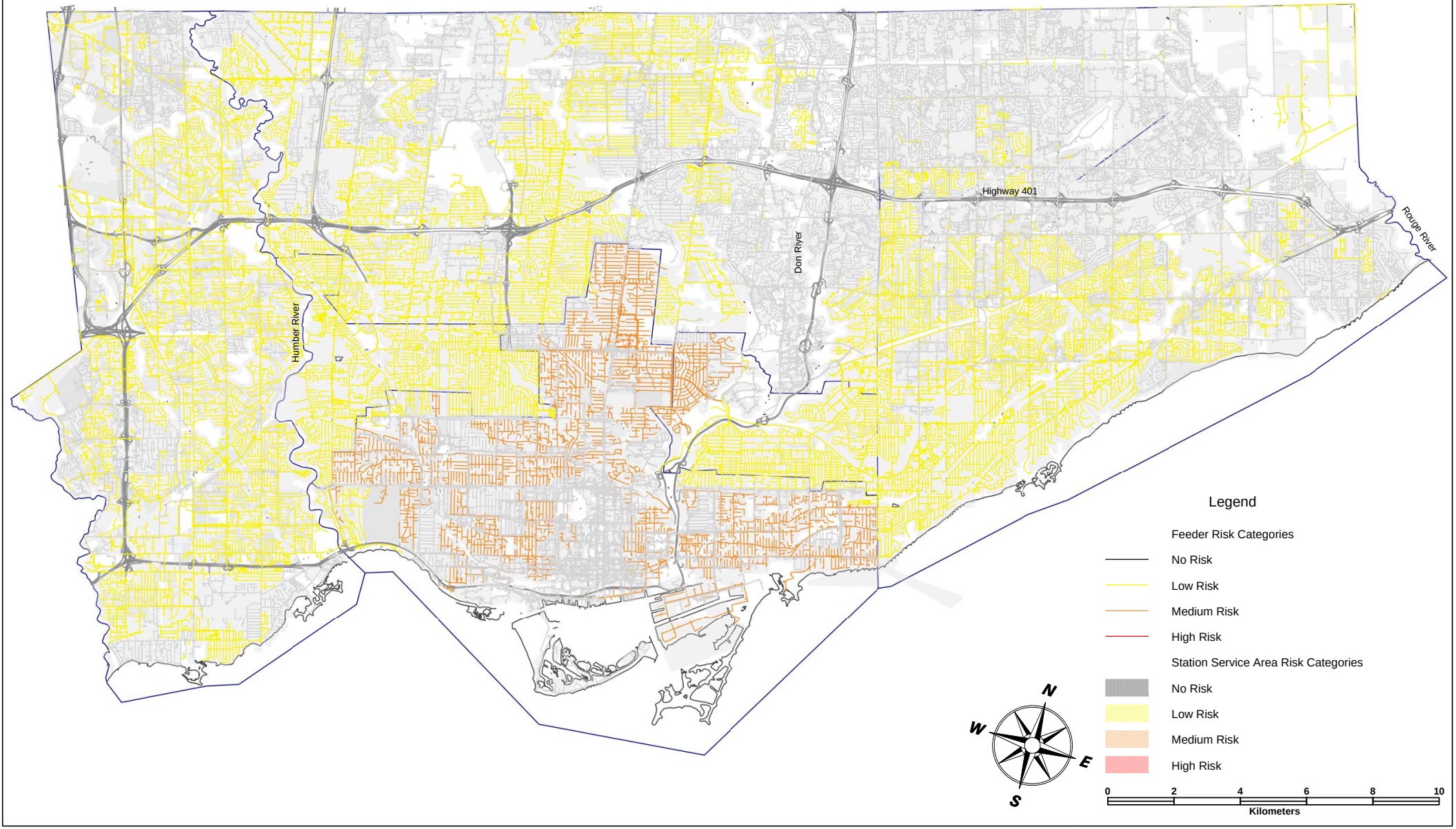
PIEVC Phase 2 Climate Change Risk Map by 2050

19. Snow >10cm



PIEVC Phase 2 Climate Change Risk Map by 2050

20. Extreme Cold Weather



Appendix F
Load Projection Methodology – Toronto Hydro

This information has been removed from the public version of this report

Appendix G
Engineering Analysis

Worksheet 4

The following appendix provides details about the estimation and calculation of the various load and capacity factors used in the Engineering Assessment of medium risk climate/infrastructure interactions. AECOM has elected to present this material in the following section in lieu of worksheet 4 template of the PIEVC Protocol.

1.1 Engineering Analysis Method

The engineering analysis is presented according to the following structure:

1. # Climate parameter / infrastructure system or component

Results and consequences: a recapitulation of the risk scoring results (scores range from 1 to 49) and consequences from Protocol Step 3, risk assessment activity

Task 1: Total Load: The total projected load, L_T, is the sum of three load parameters, $L_E + L_C + L_O$
- L_E = Existing load.
- L_C = Changing climate load placed on the infrastructure components for the project time horizon (2030 – 2050).
- L_o = Other projected change loads.

Task 2: Capacity: The total projected capacity, C_T is the sum of three parameters, $C_E - C_{\Delta E} + C_A$
- C_E = Existing capacity.
- $C_{\Delta E}$ = Projected change (loss) in capacity arising from aging and normal wear and tear of the infrastructure components
- C_A = Other projected additional capacity

Task 3: Vulnerability ratio: When possible, the vulnerability ratio is calculated

$$V_R = \frac{L_T}{C_T}$$

→ When $V_R > 1$, the infrastructure component is vulnerable

→ When $V_R < 1$, the infrastructure component has adaptive capacity

Task 4: Capacity Deficit: When the infrastructure is considered vulnerable, the projected capacity deficit, C_D is calculated, where possible. $C_D = L_T – C_T = L_T – (C_E + C_{\Delta E} + C_A)$

Task 5: Conclusions from the Engineering Analysis: A statement is made as to whether the climate parameter-infrastructure interaction should be passed to Step 5 of the Protocol (i.e. making a recommendation to mitigate a vulnerability) or need not be considered further due to resilience to climate change.

When the engineering analysis cannot be completed, data gaps and possible types of additional studies are described that would facilitate the assessment of infrastructure vulnerability.

1.2 Resiliency or Vulnerability Evaluation

1. High temperature above 25°C and above 30°C / Transmission and Municipal stations and all Temperatures / Protection and Control systems

- **Results and consequences**: Risk scores of 14 and 21 depending on station excess capacity rating. Batteries lifespan is reduced. They are vital components because they are used as back-up power in case of power outages and emergencies and supplied DC current to many equipment in the stations.

- **Load**

L_E = Continuous loads (e.g. lighting) + Noncontinuous loads (e.g. fire protection systems) + Momentary loads (e.g. switchgear operations). A margin of 10-15% can be applied by the designer. Also the battery's rated capacity should be at least 125% (1.25 aging factor) of the load expected of its service life (IEEE-Std-485, 1997).

L_C: Same loads will apply. Ventilation may be a little bit higher because of higher temperatures but the load will not change drastically.

L_o: No other load to consider

$L_T = L_E + L_C + L_O = L_E + xL_E + 0$, where x is very small. Approximation: $L_T = L_E$

- **Capacity**

C_E: The batteries are designed to operate at a temperature of 25°C. They are not installed in a temperature controlled room.

C_E capacity at 25°C = 100%. Expected service life = 25 years
The end of life of a battery is considered to be at 80% of its capacity (IEEE 485).

$C_{\Delta E}$: Battery capacity at higher temperatures will actually increase if the cells are designed for a capacity of 100% at 25°C. From IEEE (IEEE-Std-485, 1997), "If the lowest expected electrolyte temperature is above 25 °C (77 °F), it is a conservative practice to select a cell size to match the required capacity at the standard temperature and to recognize the resulting increase in available capacity as part of the overall design margin". However, sustained high ambient temperatures result in reduced battery lifetimes.

$C_{\Delta E}$ capacity over 25°C: more than 100%. Expected Service life will be less than 25 years. From Toronto Hydro's experience, some batteries have only lasted 10 years when they were expected to last 25 years.

C_A: Battery designs are maintained at 100% capacity at 25°C.

$C_T = C_E - C_{\Delta E} + C_A = C_E – (-xC_E) + 0 = (1+ x)\ C_E$, but expected lifetime decrease.

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{Le}{(1+x)Ce} < 1\ but\ life\ expenctancy\ decrease$$

- **Conclusion: Yes. Further action recommended.** Under higher temperatures, batteries will continue to be able to supply the necessary power to operate equipment (e.g. lighting, fire protection systems, switchgears). However, battery life may continue to be shorter than expected. Toronto Hydro has already encountered this problem, as batteries with a lifespan of 25 years are being replaced after 10 years.

2. High temperature above 35°C / Transmission stations

- **Results and consequences**: Risk scores of 21 and 28 depending of station excess capacity rating. Power transformers may be overloaded.

- **Load**

L_E = Maximum coincident load (year of design) + % of contingency at ambient temperature of 30°C
The actual peak load of the area is around 5 000 MVA.

L_C = Load will increase because temperature is higher, demand will be higher (air conditioning) = aL_E

L_o = Load will increase caused to higher consumption of clients = bL_E

$L_T = L_E + L_C + L_O = L_E + aL_E + bL_E = (1+a+b)L_E \rightarrow L_T > L_E$

- **Capacity**

C_E: Horseshoe area station power transformer capacity is considered maximum with 100% of its total capacity at 30°C average ambient, and hottest point within power transformers not exceeding 110 °C. For Former Toronto area, the station capacity is restricted to no more than 95% of its total capacity because there are no station ties among transformer stations.
Expected service life = 20.55 years (180 000 hours).
Toronto Area transmission stations installed capacity is around 7 550 MVA.

$C_{\Delta E}$: x%, where x is less than 100. According to IEEE (IEEE-Std_C57.91, 2012) the associated maximum air temperature should not be more than 10°C above the average ambient air temperature for air-cooled transformers (40°C). Station capacity at higher temperatures (e.g. 35°C) will be lower than at design temperature (30°C ambient) because the hottest point within power transformers has to be maintained below 110°C. Same expected service life if the load is adjusted (i.e. decreased) to meet these temperature restrictions. There x% at maximum temperatures above 35°C will not be large.

C_A: Additional capacity will depend on the station. Some transmission stations will have added capacity by the end of the study period due to planned or anticipated upgrades, while others will not. The added capacity was evaluated within the risk assessment. “Good” rating mean that the transmission stations will have a greater future capacity margin, while “moderate” and “low” ratings mean stations will have less of a future capacity margin. From an overall systems standpoint, the worst case scenario is equivalent to no additional capacity added.

$C_T = C_E - C_{\Delta E} + C_A = C_E – (xC_E) + 0 = (1 - x)\ C_E$ = Approximation $C_T \approx C_E$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1 + a + b)Le}{Ce} = \frac{Load\ growth\ rate\ \times 5000\ MVA}{7550\ MVA}$$

Value of (1+ a + b) = Toronto Hydro could estimate a mean load growth rate for the study period.

- **Capacity deficit**

$C_D = L_T – C_T = (1 + a + b)\ L_E – (1-x)\ C_E$.

The capacity deficit can’t be calculated because the load growth rate for the study period is not known.

- **Conclusion: Additional study recommended, conclusions for high temperature and power transformers also apply (see Chapter 7).** Transmission station designers will need to take into account the significant increase in days with maximum temperatures above 35°C, which reduces station capacity while, on the other hand, experiences an increased load demand. At the moment, no load growth rate for the period of this study was estimated. This could be calculated in further studies. The recommendations given in Chapter 7 for transmission stations and maximum temperature above 40°C / average temp above 30°C apply to this interaction.

3. High temperature above 40°C and Average temperature > 30°C / Transmission stations

- **Results and consequences**: risk score of 35 for transmission stations which have good future capacity (excess capacity) in the Horseshoe Area. Transmission stations with low future capacity ratings scored a high risk. Power transformers will be overloaded.

- **Vulnerability Ratio:** Refer to parameter #2.

- **Conclusion: Further action recommended**. Most of the transmission stations considered in this study were judged to be vulnerable (high risk rating) to high temperatures. The stations in the Horseshoe received a medium-high risk score (35) due to the application of the concept of excess capacity, which is qualitative and notional (refer to the **Appendix F**). As such, it is recommended that transmission stations receiving a medium-high risk score be considered vulnerable to extreme high temperatures as part of a consistent pattern of risk. This will also help Toronto Hydro to adopt a consistent approach in the design, operations and maintenance of stations.

4. Heat wave (+30°C) and High nighttime temperatures (+23°C) / Transmission stations

- **Results and consequences**: risk rating of 21, 28 and 35 depending of station capacity rating by 2050. Power transformers may be overloaded.

- **Load**

L_E = Maximum coincident Load (year of design) + % of contingency at ambient temperature of 30°C

L_C = Load will increase because temperature is higher, demand will be higher (air conditioning) = aL_E

L_o = Load will increase caused to higher consumption of clients = bL_E

$L_T = L_E + L_C + L_O = L_E + aL_E + bL_E = (1+a+b)L_E \rightarrow L_T > L_E$

- **Capacity**

C_E: Horseshoe area station power transformer capacity is considered maximum with 100% of its total capacity. For Former Toronto area, the station capacity is restricted to no more than 95% of its total capacity because there are no station ties among transformer stations.
Expected service life = 20.55 years (180 000 hours).

$C_{\Delta E}$: x%, where x is lower than 100. Power transformers can operate at temperature above 30°C, but long periods of high temperature can affect the equipment, such as when night time temperatures are high. The power transformer has no time to cool.

C_A: Additional capacity will depend on the station. Some transmission stations will have added capacity by the end of the study period due to planned or anticipated upgrades, while others will not. The future capacity was evaluated within the risk assessment. “Good” rating mean that the transmission stations will have a greater future capacity margin, while “low” rating means stations will have less of a future capacity margin. From an overall systems standpoint, the worst case scenario is equivalent to no additional capacity added.

$C_T = C_E - C_{\Delta E} + C_A = C_E – (xC_E) + 0 = (1 - x)\ C_E$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1 + a + b)Le}{(1 - x)Ce} = \frac{Load\ growth\ rate\ \times 5000\ MVA}{(1 - x)7550\ MVA}$$

Value of (1+ a + b) = Toronto Hydro could estimate a mean load growth rate for the study period.

Value of (1-x) = The loss of capacity is highly variable. It will not only depend of the maximum temperatures but also of the minimum temperatures. If the minimum temperature stays high during many days the power transformers will have no time to cool and its capacity will have to be reduced. High nighttime is important in that sense.

- **Capacity deficit**

$C_D = L_T – C_T = (1 + a + b) L_E – (1-x) C_E$.

The capacity deficit cannot be calculated because the load growth and the loss of capacity are not known.

- **Conclusion: Additional study recommended, conclusions for high temperature and power transformers also apply (see Chapter 7).** Consecutive days with high temperatures and high night time will increase over the study period. For example, high nighttime temperatures will go from 0.7 day/year to 7 days/year in 2030 to 16 days/year in 2050. Power transformers are vital equipment in the distribution of electricity and high temperatures have a significant impact on the capacity of the transformers. For these reasons, the conclusion of this report for temperature above 40°C and for high daily average temperature>30°C are also relevant to the heat wave and high nighttime temperature parameters. A load growth rate could be calculated for a better evaluation of impacts.

5. Freezing Rain/Ice Storm 60 mm ≈ 30 mm radial (major outages) / Transmission stations and Municipal stations

- **Results and consequences**: risk rating 28
  Outgoing lines (overhead) could fall down

- **Load**

L_E = Actual load is equal to the actual number of days of freezing rain

L_C = The load due to the freezing rain will slightly increase, **$L_C = aL_E$,** where ''a'' is a % of increase (small)

L_o = N/A

$L_T = L_E + L_C + L_O = L_E + aL_E = (1+a)L_E \rightarrow L_T > L_E$

- **Capacity**

C_E: The overhead power lines in the Toronto area are designed based on the CSA standard 22.3. Loads and load combinations correspond to so-called "Heavy Loading" specified in Table 30 of the CSA standard: wind of 400 Pa, 12.5 mm ice, -20°C temperatures.

$C_{\Delta E}$: It is assumed that the capacity will remain the same if the design criteria are not changing. **$C_{\Delta E} = 0$**

C_A: N/A

$C_T = C_E - C_{\Delta E} + C_A = C_E$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1+a)Le}{Ce} > 1$$, the infrastructure is vulnerable

- **Capacity deficit**

$C_D = L_T – C_T = (1 + a) L_E – C_E$.

- **Conclusion: Further action recommended.** The probability of occurrence of a heavy freezing rain event of 60 mm is relatively low in the future (8 – 25% probability of occurrence over the 35 year study period). However, this this interaction is part of a similar pattern of vulnerability as 25 mm freezing rain events (design capacity). Therefore, solutions for 25 mm events also relevant to mitigating heavy freezing rain events of ~ 60 mm.

6. High temperature (+35°C,+ 40°C, average temperature > 30°C, heat wave, high nighttime temperatures) / Municipal stations

- **Results and consequences**: 21, 28, 35. Medium to high medium risks.
  Consequences: Power transformers may overload.

- **Load & Capacity:** Same assumptions as for the power transformers in the transmission stations.
  The load will increase because of warmer temperatures. The capacity will decrease because of power transformers low ability to withstand hot temperatures for extended periods.
  Added capacity: Many Toronto Hydro to Toronto Hydro stations which interconnect the 4.16 kV power lines, will progressively be replaced by converted lines at 13.8 kV. Most of the municipal stations will then be to interconnect voltage levels from 27.6 kV to 13.8 kV. It is assumed that added capacity during the study period will be low for the 27.6-13.8 kV / 4.16 kV stations. More capacity can be added to the 27.6 kV/13.8 kV stations and will be variable depending on the stations need.
  For Toronto Hydro to Private owner ship, added capacity is possible and will be very variable depending on Client's need.

  $L_T = L_E + L_C + L_O = L_E + aL_E + bL_E = (1+a+b)L_E \rightarrow L_T > L_E$
  $C_T = C_E - C_{\Delta E} + C_A = C_E – (xC_E) + yC_A$ where x is variable and y is small and variable$\rightarrow C_T < C_E$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1+a+b)Le}{\mathrm{CE} - (\mathrm{xCE}) + \mathrm{yCA}} < 1$$

- **Conclusion: Further action recommended**. High temperature and combinations of high temperature, high average temperature, high nighttime temperature and high load demand will have consequences on the capacity of the power transformers and the cables. For Toronto Hydro to Private ownership stations, a case by case evaluation is recommended.

1.2.1 Underground and Overhead feeders

7. High temperature maximum above 35°C & above 40°C, average temp >30°C, heat wave and high nighttime / Underground feeders

- **Results and consequences**: risk ratings 14, 21 and 28. The high demand stresses cables and power transformers. More capacity was available in the horseshoe area giving slightly lower results.

- **Load**

L_E = Actual demand + % of contingency

L_C = Load will increase because temperature is higher, demand will be higher (air conditioning) = aL_E

L_o = Load will increase because of higher electrical consumption of clients (more electronic devices) = bL_E

$L_T = L_E + L_C + L_O$

- **Capacity**

C_E: Actual design of cables and power transformers is based on the actual load plus a margin. For underground feeders in the dual radial system, feeder capacity equals 50% of load for two parallel feeders. IEC 60287 base maximum ambient temperature at 35°C and maximum ground temperature at 20°C (IEC-60287))

$C_{\Delta E}$: XLPE cables have an expected life of 40 years (for concrete duct installations) and for PILC cables 75 years. These cables are today reaching their expected life because they were installed during the early 1900s (for PILC)

and 1950s (for XLPE). They will be changed through testing or from failure, because even if the cables are old they could be still being in good conditions (Toronto Hydro - OM&A, 2014). However, with climate changes (higher temperature), these cables will be stressed more often. Aging processes will accelerate and reduce capacity. This is a highly variable factor and cannot easily be calculated.

C_A: Added capacity will be done by Toronto Hydro. Underground planning group could estimate the projected capacity for the study period.

$C_T = C_E - C_{\Delta E}$? + C_A

- **Conclusion: Further action recommended.** The vulnerability ratio and the capacity deficit cannot be calculated because the projected load on cables is not known. However, it is projected that climate change related high temperatures could create higher demand for cooling, and may place greater stress on cables and lead to increasing occurrences of cable failures. Therefore, high heat impacts on cable was deemed to be a vulnerability.

8. Extreme rainfall / Underground feeders

- **Results and consequences**: risk rating of 12, 18, 24, 30
    a. Feeders: Water treeing of the cables, flooding (18-24);
    b. Nun-submersible equipment failure in vault type stations below ground (30 Horseshoe Area, 36 Former Toronto);
    c. Above ground stations, access could be limited (12);
    d. Network feeders: old N/W protectors are not submersible (30).

a. Feeders: Water treeing of the cables, flooding (18 Horseshoe Area, 24 Former Toronto)

Water treeing refers to a partially conductive structure that may form, in the presence of water, within the polyethylene dielectric used in buried high voltage cables. […] Water trees begin as a microscopic region near a defect. They then grow under the continued presence of a high electrical field and water. Water trees may eventually grow to the point where they bridge the outer ground layer to the center high voltage conductor, leading to complete electrical failure at that point (Wikipedia).

- **Load**

L_E = Actual demand + % of contingency

L_C = Load will increase because temperature is higher, demand will be higher (air conditioning) = aL_E

L_o = Load will increase due to higher electrical consumption by clients (more electronic devices)= bL_E

$L_T = L_E + L_C + L_O$

- **Capacity**

C_E: Actual design of cables is based on the actual load plus margin. For the underground feeders in the dual radial systems, each feeder capacity is equal to the load x 2.

$C_{\Delta E}$: Flooding and heavy soil moisture tends to reduce the dielectric strength of cables. This cannot be calculated as it is highly variable. *The aging mechanism of underground cables depends on factors that involve the cable characteristics, accessory characteristics, and operating conditions, different power cable systems will age in different ways. In fact, aging degradation, and failure mechanisms are statistical in nature.* (NEETRAC, 2010)

C_A: Toronto Hydro shall have a planning procedure for increasing the capacity of their underground system in line with load growth.

- **Conclusion: Further action recommended.** The load can be calculated by Toronto Hydro's estimates. However, the capacity is very hard to define, as aging degradation depends on many factors. Nonetheless, in combination with high heat events, extreme rainfall impacts on underground cables was deemed a vulnerability.

b. Non-submersible equipment failure in vault type stations below ground in the Horseshoe Area (30) (Former Toronto has a high risk result)

- **Load**

$\mathbf{L_E}$ = 0.04 flood per year (over 100 mm + short duration).

$\mathbf{L_C}$ = 0, flood intensity is considered to be the same for a given event (100 mm rainfall), but it will occur with greater frequency. Another complicating factor is how local drainage conditions (area topography, sewer system changes, land use changes) may or may not change flood characteristics in below ground vaults. At the scale of the current study, site specific flooding characteristics are not considered.

$\mathbf{L_o}$ = N/A

$\mathbf{L_T = L_E + L_C + L_O} = L_E$.

- **Capacity**

$\mathbf{C_E}$: Cannot work when flooded. Most of the vaults have pumps when they are deeper than the city sewers. Small shallow single phase vaults drain naturally to the sewers. Pumps usually work well. There is no specific information available on the capacity of the pumps, but they are assumed to function correctly, as there are no indications that pump capacity needs to increase.

$\mathbf{C_{\Delta E}}$: same as today. $C_{\Delta E} = C_{E1} - C_{E2} = 0$.

$\mathbf{C_A}$: No additional capacity required.

$\mathbf{C_T = C_E - C_{\Delta E} + C_A = C_E}$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{Le}{Ce} = 1$$

Conclusion: Further action recommended. Without replacement of non-submersible equipment by submersible equipment, the performance of electrical equipment in below grade vaults will not change over time (i.e. non-functional when flooded) The planned conversion of non-submersible equipment to submersible types in flood prone areas will help reduce vulnerability. While Toronto Hydro is gradually replacing vault type non-submersible equipment with submersible versions, non-submersible vault type equipment is likely to remain in the system over the study period, and hence remain a vulnerability for Toronto Hydro.

c. Above ground stations, access to the station and to the station equipment could be limited due to localized flooding of streets around the station, or at the station itself

- **Results and consequences** Low –medium risk.

- **Conclusion: No further action required.** This impact does not relate to station load or capacity. The consequence is that the access to the vault stations or the stations equipment could be temporarily impeded. Impact is localized and temporary, and was not judged to warrant further action beyond current practices.

d. Network feeders: old N/W protectors are not submersible (30)

- **Conclusion: Additional Study Recommended.** The old N/W protector may not operate properly if flooded. A network protector automatically connects and disconnects its power transformer from the network when the protector relay detects that power starts flowing in a reverse direction, preventing back feed, which is a potential safety hazard. However a failure of the N/W protector will not mean an interruption to the customer, since network systems are highly redundant. Network protectors are overhauled on a three-year cycle.

  Installations of new N/W protectors are submersible but there are still many old N/W protectors in the systems, particularly in downtown. Further study could be undertaken to evaluate the cost of replacing old network protectors prior to the end of their expected lifecycle against the frequency and impact of old N/W protectors being flooded.

9. High winds (120 km/h) / Padmount stations on distribution network (Former Toronto)

- **Results and consequences**: risk rating 14. Flying debris could impact the equipment.

- **Vulnerability Ratio:** The consequence of high winds and structural loads from flying debris are difficult to establish in terms of the load and the capacity of padmount stations. It's an independent impact based on a statistical probability.

- **Conclusion: No further action required.** The damaged equipment will result in an overall or some loss of service capacity and function. However, it is judged that flying debris is too much of a random occurrence to warrant further action.

10. High temperature maximum above 35°C & above 40°C, average temp >30°C and heat wave / Overhead power lines (radial and loop)

- **Results and consequences**: risk ratings of 14, 21, 28, 35
  These 4 climate parameters have the same consequences: Overload of the ONAN power transformers and the overhead conductors.

- **Load**

$\mathbf{L_E}$ = Max load + % of contingency

$\mathbf{L_C}$ = Load will increase because temperature is higher, demand will be higher (air conditioning) = aL_E

$\mathbf{L_o}$ = Load will increase because of load growth due to population growth = bL_E

$\mathbf{L_T = L_E + L_C + L_O = L_E + aL_E + bL_E = (1+a+b)L_E \rightarrow L_T > L_E}$

- **Capacity (ONAN power transformers)**

$\mathbf{C_E}$: 100% at 30°C average ambient + hottest point within transformer not exceeding 110 °C.

$\mathbf{C_{\Delta E}}$: x%, where x is lower than 100. Capacity at higher temperature will decrease, because the hottest point has to be kept under 110°C.[1]

$\mathbf{C_A}$: Additional capacity can be added by adding more power transformers on the lines.

$\mathbf{C_T = C_E - C_{\Delta E} + C_A = C_E – (xC_E) + C_A = (1 - x)\ C_E + C_A}$

- **Capacity (overhead conductors)**

[1] For example: temperature of 40°C during 10 hours, the average load should not excess 80-85% of the nominal kVA.

C_E: 100% at 75°C for ACSR conductors and 25°C ambient (manufacturers' limits).
Effects of high temperature can results in the annealing[2] of aluminum used within ACSR and AAC conductors. This effect begins at 93°C for these types of conductors, and is a function of the magnitude of the temperature and the duration of the application (electrical power flow).

$C_{\Delta E}$: x%, where x is lower than 100. The added combination of high temperature and higher current flow will significantly reduce the capacity of the conductors.
Other impacts: loss of strength due to annealing, increase in sag.

C_A: Capacity can be added by using other or larger types of conductors. However, in some place it could be difficult to do so as it would means to redesign the existing lines and may result, for example, in the replacement of existing poles by stronger ones generating high costs.

$C_T = C_E - C_{\Delta E} + C_A = C_E – (xC_E) + C_A = (1 - x)\, C_E + C_A$.

The reduction of the capacity is difficult to calculate because of the great diversity of operating circumstances and loading of the entire system. However, calculations for critical areas, where added capacity can be difficult to do, should be done.

- **Vulnerability Ratio:** Cannot be calculated because too many variables are not known.

- **Conclusion: Further action recommended.** Higher temperatures will have impacts on the overall capacity of the power lines. In the downtown area, there are critical, constrained areas (i.e. built up zone) where added conductor/transformer capacity may be difficult to implement.

11. High nighttime temperatures / Overhead power lines (radial)

- **Results and consequences:** risk rating 14
  Overload of the ONAN power transformers

- **Load and Capacity:**
  Refer to the previous evaluation. However, the capacity of the power transformers will not be reduced as much as for higher daily maximum temperature. Therefore, $C_E = xC_E$, with x as a small value.

  High nighttime temperatures have consequences on the capacity of the power transformer to cool enough before being loaded the next day. Climate projections show a significant increase in the number of days with low night time temperatures ≥ 23°C. The actual design of power transformers can support this temperature limit. As such, this impact was judged as low.

- **Conclusion: No further action required.** Night time temperatures with minimum ≥ 23°C will not have big impacts on the delivery of electricity. However, it is important to note that combination events of high daily temperature and high night time temperature are a concern. This is taken into account under the parameter, average temperature over 30°C on a 24 h basis.

12. Freezing Rain - Ice Storm 15 mm and high winds 70 km/h / Overhead Feeders in Loop Configuration

- **Results and consequences**: risk ratings of 28, 35 Conductors (tree contacts).

- **Load:**

[2] Annealing is the metallurgical process where applied temperature softens hardened metal resulting in loss of strength. For overhead conductors, annealing can degrade the strength of aluminum wires used in ACSR and AAC conductors (PJM Overhead conductor Ad Hoc Committee, 2010)

L_E = the actual load is based on tree branches that usually start to break with a 15 mm of freezing rain.

L_C = freezing rain of 15 mm will happen a little bit more often for the study period (from 0.11/year to 0.12/year to 0.16/year). Hypothesis $L_C = L_E$

L_o = N/A

$L_T = L_E + L_C + L_O = L_E$.

- **Capacity :**

C_E: Actual overall ''capacity'' of the tree canopy in Toronto.

$C_{\Delta E}$: $C_{\Delta E} = C_{future} < C_E$. The future overall ''capacity'' will decrease (or vulnerability to damage will increase) because of new or exacerbated disease and pest conditions and possibly, because of the tree faster growth (extended growing season, more branches).

C_A: N/A

$C_T = C_E - C_{\Delta E}$

- **Vulnerability Ratio**
  - $VR = \frac{Lt}{Ct} = \frac{Le}{Ce - C\Delta E}, where\ \frac{Le}{Ce} = 1, as\ Ce - C\Delta E$ is smaller, V_R will be >1

- **Capacity deficit**

$C_D = L_T – C_T$ = It cannot be calculated because the future capacity of the trees is not known.

- **Conclusion: Further action recommended.** The risk assessment completed in step 3 for radial systems resulted in a high risk rating for this interaction. In overhead loop systems, it was hypothesized that their more redundant configuration would reduce customer interruptions, affect fewer clients or cause outages of shorter durations, thus yielding a high-medium risk rating of 35. However, freezing rain events are expected to occur slightly more often than it does currently by the end of the study horizon. The tree canopy may also be affected by new or increased disease threats and extended growing season. Conductors will also sag more due to more extreme weather (ice, warm weather, etc.) leading to more contacts with the tree branches. According to THESL (Toronto Hydro - OM&A 2014): "*Vegetation interference is one of the most common causes of power interruption"*. Finally, freezing rain events tend to be widespread, and there is no reason to believe that both branches of an overhead loop circuit might not be equally susceptible to damage. For all of these reasons, all overhead power lines, irrespective of electrical configuration, were deemed as vulnerable.

13. Freezing Rain/Ice Storm 60 mm ≈ 30 mm radial (major outages) / Overhead lines (radial and loop)

- **Results and consequences**: risk rating 24, 28
  Overhead lines could fall down, salt contamination

- **Load**

L_E = Actual load is equal to the actual number of days of freezing rain

L_C = The load due to the freezing rain will slightly increase, **$L_C = aL_E$,** where ''a'' is a % of increase (small)

L_o = N/A

$L_T = L_E + L_C + L_O = L_E + aL_E = (1+a)L_E \rightarrow L_T > L_E$

- **Capacity**

C_E: The overhead power lines in the Toronto area are designed based on the CSA standard 22.3. Loads and load combinations correspond to so-called "Heavy Loading" specified in Table 30 of the CSA standard: wind of 400 Pa, 12.5 mm ice, -20°C temperatures.

$C_{\Delta E}$: It is assumed that the capacity will remain the same if the design criteria are not changing. $C_{\Delta E} = 0$

C_A: N/A

$C_T = C_E - C_{\Delta E} + C_A = C_E$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1+a)Le}{Ce} > 1$$, the infrastructure is vulnerable

- **Capacity deficit**

$C_D = L_T - C_T = (1 + a)\, L_E - C_E$.

- **Conclusion: Further action recommended.** See explanation for freezing rain and stations (item 5 above).

14. Lightning / Overhead power lines (radial and open loop) and SCADA system

- **Results and consequences**: risk rating of 18, 24, 30, failure of equipment (localized).

- **Vulnerability Ratio:** In this case, the impact comes from a direct or indirect strikes and has no consequences on the load and capacity of the infrastructure.

- **Conclusion: Further action recommended.** It is difficult to predict the increase of lightning strikes for the study period; however it is interesting to note that the probability of a lightning strike in an area of 0,015 km^2 anywhere within the City of Toronto is very high for the study period. At the moment, the number of arrestors/km, lightning strike intensity and arrestor performance are not monitored by Toronto Hydro. In the absence of this information, and since lightning strikes are currently a frequent source of outages, lightning strikes were judged to be a continued vulnerability. Further studies could evaluate if the actual protection of overhead power lines is sufficient, or if investments for more protection needs to be made. Direct strike impacts can be studied with software (e.g EMTP), while indirect strikes can be calculated numerically.

15. Snow > 5 cm and Snow > 10 cm / Overhead power lines (radial)

- **Results and consequences**: risk ratings of 14, salt deposited on the roads can also accumulate on insulators from water evaporation and transport through the air, and can create a failure (reduce the effective insulation levels and can lead to insulator tracking, flashover and potential pole fires or switch with porcelain insulator failure).

- **Vulnerability Ratio:** In that case, the impact is indirect and has no consequences on the load and capacity of the infrastructure.

- **Conclusion: No further action required.** The number of snow days is highly variable. The trend seems to be decreasing, but snow days will still occur annually. During the workshop, Toronto Hydro mentioned having problems regarding insulator tracking leading to pole fires especially at higher voltages (13.8 kV and 27.6 kV) and switch failures. However, Toronto Hydro is already monitoring and dealing with this issue. From THESL's report (Toronto Hydro - OM&A 2014): *to mitigate the risk of contamination and insulator tracking, insulators at the highest risk locations are washed twice a year.* Furthermore, recall that porcelain insulators are being

progressively replaced by polymer insulators. *Polymer insulators are hydrophobic, and are not susceptible to the same failure mode due to contamination. […] Regular maintenance enables the detection and prediction of common failure modes. One such mode is the failure of switch's porcelain insulators. […] Porcelain switches pose high safety risks due to their susceptibility to contamination build-up and electrical tracking, which can lead to cracking […] posing a safety risk to employees or members of the public below.* As older porcelain insulators are being replaced by polymer insulators, it was judged that no further action than what is currently underway is required.

1.2.2 Civil structures

16. Extreme Rainfall, Freezing rain/Ice storm 15 mm & 25 mm & 60 mm (Combination of events) / Civil structures: Underground feeders (Former Toronto)

- **Results and consequences**: risk rating of 12, 14
  Accelerated corrosion of reinforcing bars and degradation of concrete in cable chambers and vaults.

- **Load**

L_E = Currently, civil structures (cable chambers, vaults) degrade at a pace related to the actual load (salt and moisture) related to current weather: Extreme Rainfall (100 mm) 0.04/year + Ice Storm (15 mm) 0.11/year + Ice Storm (25 mm) 0.06/year + Ice Storm (6hrs+) 0.65/year.

L_C = In the future, the structures will degrade more rapidly due to the more severe weather:
2030: Extreme Rainfall (100 mm) unknown but increase + Ice Storm (15 mm) 0.12/year + Ice Storm (25 mm) 0.07/year + Ice Storm (6hrs+) 0.73/year.
2050: Extreme Rainfall (100 mm) unknown but increase + Ice Storm (15 mm) 0.16/year + Ice Storm (25 mm) 0.09/year + Ice Storm (6hrs+) 0.94/year.

L_o: No other load.

$L_T = L_E + L_C + L_O = L_E + aL_E = (1+a)L_E$

- **Capacity**

C_E: actual capacity based on design criteria

$C_{\Delta E}$: As vaults are getting older, the capacity of the structures will decrease (approximately 60% of all network vaults will reach their expected life within the next ten years and 80% of network vault roofs and 60% of all cable chamber roofs are already beyond their useful life (Toronto Hydro - OM&A, 2014).

For the purpose of the study, we can then assume that $C_{\Delta E} = aC_E$, where ''a'' equal a percentage of diminution of capacity versus actual capacity

C_A: N/A

$C_T = C_E - C_{\Delta E} + C_A$ = $(1-a)C_E$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1+a)Le}{(1-a)Ce} > 1$$, the infrastructure component is vulnerable

- **Conclusion: Further action recommended.** Vaults and chambers already suffering from degradation issues will deteriorate more rapidly over time. From THESL (Toronto Hydro - OM&A 2014): *As below-grade structures age, the greatest concern becomes structural strength. Structural deficiencies affecting vaults include degradation of concrete and corrosion of supports such as beams and rebar. Once degradation and*

*corrosion sets in, conditions can deteriorate rapidly and in many cases from one season to the next. Of particular concern is the winter season when moisture and water enter in below-*grade *structures, freezes and thaws, and carries with it salt that has been used at grade to melt ice and snow.*

While maintenance can reduce the rate of deterioration, incidence of extreme rainfall, snowfall, freezing rain and the application of road salt will persist throughout the study period and continue to contribute to the premature aging of civil structures. While, it could not be determined in the study whether premature aging of civil structures will be exacerbated by a changing climate, this issue will persist over the study period and is therefore judged as an on-going vulnerability.

17. Snow > 5 cm and Snow > 10 cm / Civil structures: Underground feeders (Former Toronto)

- **Results and consequences**: risk ratings of 14, 21, Degradation of concrete in cable chambers and vaults.
- **Load**

$\mathbf{L_E}$ = Actually the civil structures (cable chambers, vaults) degrade at a rhythm caused by current climate.

$\mathbf{L_C}$ = The ''load'' will probably decrease. $-aL_E$

$\mathbf{L_o}$ = No other load.

$\mathbf{L_T = L_E + L_C + L_O = L_E - aL_E = (1-a)L_E}$

- **Capacity**

$\mathbf{C_E}$: actual capacity based on design criteria

$\mathbf{C_{\Delta E}}$: As vaults age, the capacity of the structures will decrease (approximately 60% of all network vaults will reach their expected life within the next ten years and 80% of network vault roofs and 60% of all cable chamber roofs are already beyond their useful life, (Toronto Hydro - OM&A, 2014)).

For the purpose of the study, we can then assume that $C_{\Delta E} = bC_E$, where ''a'' equal a percentage of diminution of capacity versus actual capacity

$\mathbf{C_A}$: N/A

$\mathbf{C_T = C_E - C_{\Delta E} + C_A} = (1-b)C_E$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1-a)Le}{(1-b)Ce}$$, it is not possible to know if a will be < or > b

- **Conclusion: No further action required, but combinations of climates events require additional study.** As days with snow will probably decrease, the snow days alone were not judge to be a significant vulnerability. However, snow days will still occur over the study period, and in combination with extreme rainfall, freezes and thaw, freezing rain, and the continued application of road salt, premature degradation of civil structures was judged to be an ongoing vulnerability for Toronto Hydro.

18. Frost / Civil structures (overhead and underground feeders)

- **Results and consequences**: risk rating of 14, frost heave of civil structures

- **Vulnerability Ratio:** In the future, the ‘’load’’ will reduced as less frost days are expected. However, as vaults and as the foundations for concrete or steel poles age, the capacity of the structures will decrease.

  Conclusion: Further action recommended. Even if the frost threat is decreasing, it is noted that frost penetration will still occur during the study period with occasionally extreme weather. Since, Toronto Hydro already experiences problems with frost and its civil infrastructure, frost impacts were judged to be a vulnerability.

19. All Climate Parameters / Human Resources

- **Results and consequences:** risk ratings of 14 to 28, weather related impacts on safe site access, work conditions and travel

- **Conclusion: Further action recommended.** While occupational health and safety procedures will continue to be in place in the future, human resources will continue to be vulnerable to climate change related weather events due to the need to travel, access, and work on equipment in spite of the weather.

Appendix H
PIEVC Worksheets

Worksheet 1 and 2 have been removed from the public version of this report.

However, information on infrastructure can be found in summary form in Chapter 2 of this report. Climate information can be found in Chapter 3, and in Appendix B and Appendix C of this report.

Worksheet 3 information can be found in Appendix D.

Worksheet 4 information can be found in Appendix G.

Worksheet 5 information is contained within Chapter 7 of this report.

E Capital Expenditure Plan



E1 Capital Expenditure Plan Introduction

E2 Capital Expenditure Planning Process Overview

E3 System Capability Assessment for Renewable Energy and Conventional Generation

E4 Capital Expenditure Summary

E5 System Access Investments

E6 System Renewal Investments

E7 System Service Investments

E8 General Plant Investments

E1 Capital Expenditure Plan Introduction

E1.1 Introduction

Section E details Toronto Hydro's 2020-2024 Capital Expenditure Plan. It consists of the following sections:

- **Section E1 – Capital Expenditure Plan Introduction:** Provides basic information about the expenditure plan, including drivers, expenditures by category, and associated performance measures.
- **Section E2 – Capital Expenditure Planning Process Overview:** Provides a detailed explanation of how Toronto Hydro's Business Planning Process, including customer engagement, and Asset Management Process (as described in Section D) were used to develop the 2020-2024 Capital Expenditure Plan.
- **Section E3 – System Capability Assessment for Generation Connections:** Provides information on the capability of Toronto Hydro's distribution system to accommodate renewable energy generation ("REG") and other distributed generation ("DG") connections.
- **Section E4 – Capital Expenditure Summary:** Provides a snapshot of Toronto Hydro's capital expenditures over a 10-year period from 2015 to 2024, including explanatory notes on material variances.
- **Sections E5-E8:** Provides detailed, program-specific justifications, and business cases for Toronto Hydro's capital expenditure plan in each of the System Access (E5), System Renewal (E6), System Service (E7), and General Plant (E8) categories.

The following is an introduction to the 2020-2024 Capital Expenditure Plan.

E1.2 2020-2024 Capital Expenditures

Toronto Hydro's capital programs are grouped into the following four categories, as prescribed by the Ontario Energy Board's ("OEB") Chapter 5 Filing Requirements for Electricity Distribution Rate Applications (July 12, 2018):

- System Access Investments (Section E5);
- System Renewal Investments (Section E6);
- System Service Investments (Section E7); and
- General Plant Investments (Section E8).

For categorization purposes, each program is assigned one or more drivers of work, including a single trigger driver (representing the catalyst for the investment) and typically one or more secondary drivers.[1] Programs are allocated to each of the four investment categories in accordance with their trigger drivers. A description of each trigger driver is provided in the table below.

Table 1: Investment Category Trigger Drivers

	Driver	Description
System Access	***Customer Service Requests***	The fulfilment of Toronto Hydro's obligation to connect a customer to its system. This includes both traditional demand customers and distributed generation ("DG") customers. The obligation to connect holds as long as there are no safety concerns for the public or employees and there is no adverse effect on the reliability of the distribution system. The utility undertakes expansion or enhancements to the system when a connection cannot be made with existing infrastructure.
	Mandated Service Obligation	Compliance with all legal and regulatory requirements and government directives.
System Renewal	***Functional Obsolescence***	The asset and/or its installation is no longer aligned to Toronto Hydro's processes and practices such that it can no longer be maintained (e.g. lack of vendor support) or utilized as intended to support the utility's operations.
	Failure	Asset or critical component failure has taken place and Toronto Hydro must respond reactively as part of its capital investment activities.
	Failure Risk	There is imminent risk of failure due to age or condition deterioration. The potential failures will result in significant reliability impacts to customers as well as potential safety risks to crew workers or to the public.
System Service	***Reliability***	Maintain or improve reliability at a local, feeder-wide, or system-wide level.
	Capacity Constraints	Expected changes in load will constrain the ability of the system to provide consistent service delivery and handle demand requirements.

[1] The list of capital investment drivers used in this application were developed based on the OEB's example drivers from Chapter 5 of the OEB's Filing Requirements.

General Plant	***Operational Resilience***	The ability to mitigate and recover from disruptions to core business functions.
	System Maintenance and Capital Investment Support	Required investments to support day to day business operational activities; sustaining operations by providing its employees with a safer environment to operate in an efficient and reliable manner.

Planned expenditures for the 2020-2024 period are presented by investment category in Table 2 below.

Table 2: Planned Capital Investment by Category ($ Millions)

Category	Forecasted Spend						
	Avg.	**2020**	**2021**	**2022**	**2023**	**2024**	**Total**
System Access	100.3	91.8	93.3	93.9	106.0	116.4	**501.4**
System Renewal	324.0	306.6	325.7	323.1	339.0	325.5	**1,619.9**
System Service	47.5	34.2	60.1	71.3	33.6	38.5	**237.7**
General Plant	84.9	78.8	93.7	89.0	77.7	85.2	**424.4**
Other	8.8	7.0	9.0	9.8	9.5	8.7	**44.0**
Total	**565.5**	**518.4**	**581.8**	**587.1**	**565.7**	**574.4**	**2,827.4**

To drive continuous improvement in its distribution planning and implementation work described in the four categories above, Toronto Hydro plans to track 15 utility-specific measures (as shown in Table 3) over the 2020-2024 period (in addition to the OEB's Distributor Scorecard measures and Electricity Service Quality Indicators). These measures reflect Toronto Hydro's Outcomes Framework (described in Exhibit 1B, Tab 2, Schedule 1), and represent its response to customer preferences communicated through formal and informal engagement (see Exhibit 1B, Tab 3, Schedule 1). By monitoring and managing these measures, the utility expects to drive continuous and sustained improvement across the organization through the 2020 to 2024 period.

Table 3: Toronto Hydro's 2020-2024 Custom Performance Scorecard

Toronto Hydro Outcome	Toronto Hydro's Custom Measures	Target
Customer Service	Customers on eBills	Improve
Safety	Total Recorded Injury Frequency	Maintain
	Box Construction Conversion	Improve
	Network Units Modernization	Improve
Reliability	SAIDI - Defective Equipment	Maintain
	SAIFI - Defective Equipment	Maintain
	FESI-7 System	Improve
	FESI-6 Large Customers	Maintain
	System Capacity	Maintain
	System Health (Asset Condition) – Wood Poles	Monitor
	Direct Buried Cable Replacement	Improve
Financial	Average Wood Pole Replacement Cost	Monitor
	Vegetation Management Cost per Km	Monitor
Environment	Oil Spills Containing PCBs	Improve
	Waste Diversion	Monitor

Section E2 provides a detailed discussion of how business planning (including Customer Engagement) and Toronto Hydro's asset management practices and methodologies produced the 2020-2024 Capital Expenditure Plan.

E2 Capital Expenditure Planning Process Overview

Section E2 provides a comprehensive overview of how Toronto Hydro developed its 2020-2024 Capital Expenditure Plan, including the pacing and prioritization decisions that the utility made to support the delivery of outcomes that align with customer needs and preferences. This section is organized into the following three areas:

- **Section E2.1** describes the sequence of business planning activities that produced the Capital Expenditure Plan, and provides an overview of the utility's key considerations and decisions during this process.
- **Section E2.2** focuses on the outputs of Toronto Hydro's asset management and operational planning processes (described in Section D) and how they influenced the pacing and prioritization of the capital expenditure plan.
- **Section E2.3** describes the results of the utility's planning-specific Customer Engagement and how Toronto Hydro developed a plan that is aligned with and responsive to customer needs, preferences and priorities.

Fully detailed justifications and business cases for all of Toronto Hydro's planned capital expenditures can be found in the capital program sections in E5 through E8.

E2.1 Capital Planning in Business Planning

Toronto Hydro's 2020-2024 Capital Expenditure Plan was an output of its outcomes-oriented, customer-focused business planning activities. The plan was derived from the utility's distribution system asset management processes and other operational planning activities, including outputs from the Investment Planning & Portfolio Reporting ("IPPR") process described in Sections D1 and D3. A high-level view of business planning as it relates to the Capital Expenditure Plan is shown in Figure 1.

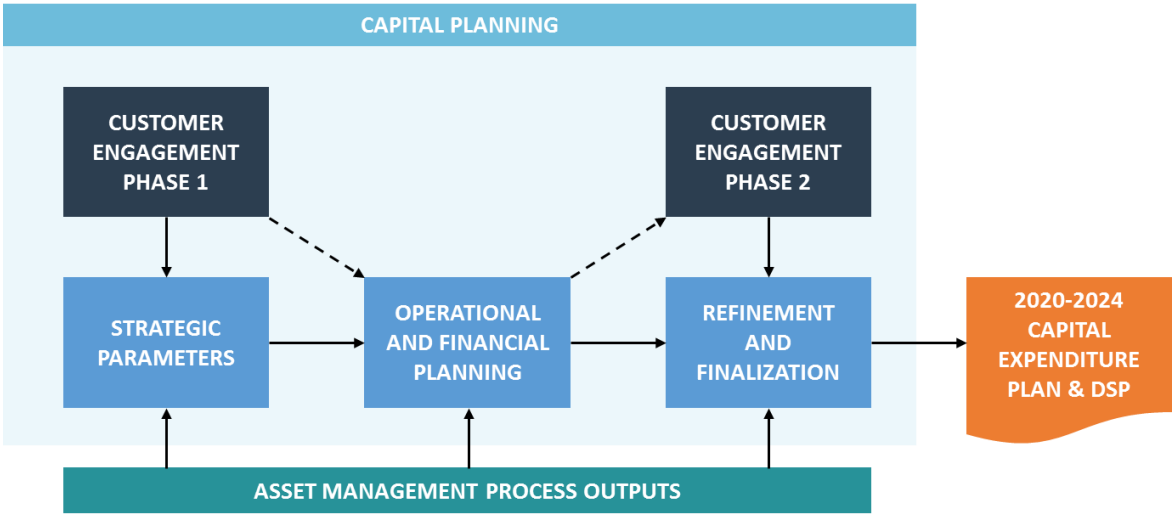


Figure 1: Capital Planning in Business Planning

The following sections provide an overview of how the elements of business planning came together to generate the capital plan that forms the basis of Toronto Hydro's 2020-2024 Distribution System Plan.

E2.1.1 Customer Engagement and Strategic Parameters

Toronto Hydro began business planning by engaging customers (i.e. Phase 1 of Customer Engagement) and using the feedback received to help set the initial strategic parameters for the business planning horizon. Feedback from customers was that price, reliability, and safety were their top three priorities. Overall, most customers preferred prices be kept as low as possible while maintaining average reliability performance and improving reliability for customers experiencing below-average service. [1]

With consideration for customers' priorities and preferences and other inputs (discussed below), Toronto Hydro set the following strategic parameters for the capital plan:

1) **Price Limit:** Toronto Hydro set an upper limit of 3.5 percent as a cap on the average annual increase to base distribution rates.[2]
2) **Capital Budget Limit:** Toronto Hydro set an upper limit of $562 million for the average annual capital plan budget, which corresponded with capping infrastructure and operations

[1] The results of Customer Engagement, Phase 1, are discussed in detail in Section E2.3.
[2] As calculated for the monthly bill of a Residential customer using 750 kWh.

spending predominantly at sustainment levels. As discussed in Section E2.2, this upper limit was based on an assessment of system and operational needs as derived from the utility's asset management processes, reflecting the need to, at a minimum, meet the utility's service obligations, maintain average reliability performance, and sustainably manage asset risk over the long-term while mitigating material safety and environmental risks.

3) **Performance Objectives:** Toronto Hydro developed an Outcomes Framework that aligned with the utility's corporate strategic pillars and the *Renewed Regulatory Framework*, establishing a lens through which the utility could express its plans and performance in terms that demonstrate value for customers, and are meaningful to its operations. This framework is summarized in Figure 2, below.

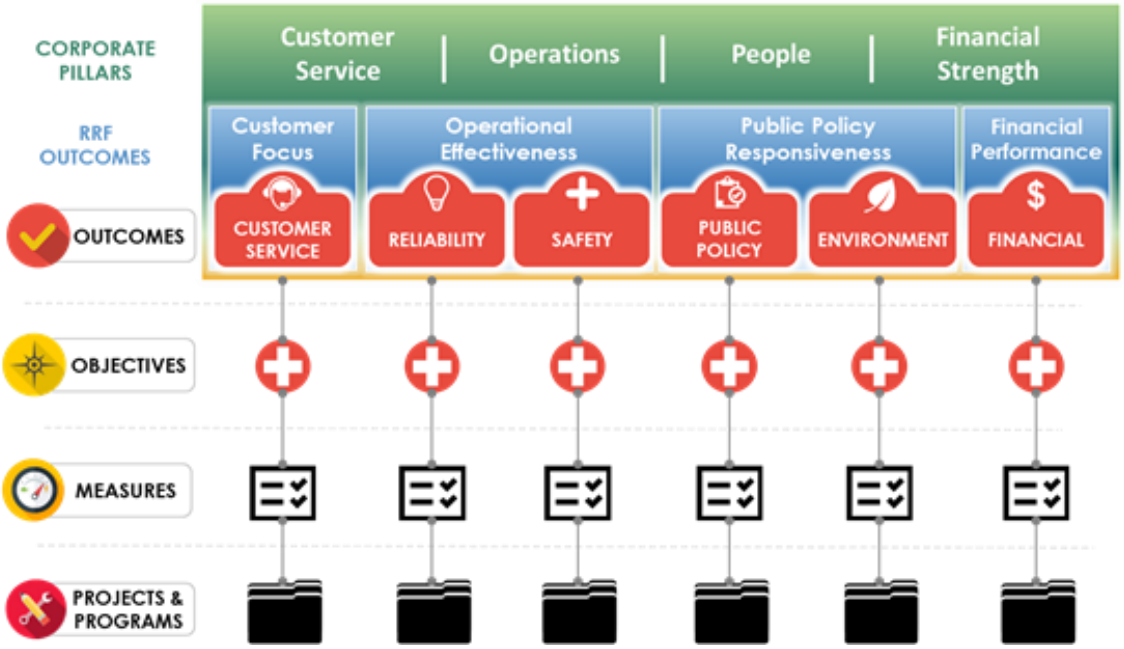


Figure 2: Toronto Hydro's Customer-Focused Outcomes Framework[3]

In developing these strategic parameters, Toronto Hydro considered a number of inputs, including:

- as mentioned above, customer priorities and preferences identified in Phase 1 of the utility's planning-specific Customer Engagement activities;

[3] The RRF Outcomes are aligned alongside Toronto Hydro's Outcomes based on the definitions provided by the OEB in the Utility Rate Handbook. It should be noted that Toronto Hydro's Financial outcome includes cost-related components that the OEB would classify within the Operational Effectiveness outcome.

- customer needs and preferences as understood by the utility through routine and ongoing engagement with customers and community stakeholders;
- historical and forecast system performance;
- projected system use profiles and pressures;
- long-term asset stewardship needs;
- safety and environmental risk assessments;
- evolving business conditions and the emergence of new technologies;
- resiliency and business continuity risks, including climate change risk;
- evolving regulatory and compliance needs;
- workforce needs and challenges;
- inflationary cost pressures, including ongoing and anticipated upward pressure on construction costs in Toronto;
- total cost benchmarking; and
- distributor scorecard benchmarking.

To further inform the selection of price and capital budget limits, Toronto Hydro performed a high-level scenario analysis based on preliminary planning scenarios for each capital program. These scenarios – described further in Section E2.2 – reflected a baseline "sustainment" level of system investment, an "improvement" level, and an "accelerated improvement" level. Figure 3, below, illustrates what the total capital expenditure plan would look like if Toronto Hydro had selected exclusively from either the sustainment, improvement, or accelerated improvement options for every investment program. The three lines represent a fully unconstrained budget on the high-end, a minimal system sustainment budget on the low end, and a mid-point budget in between.

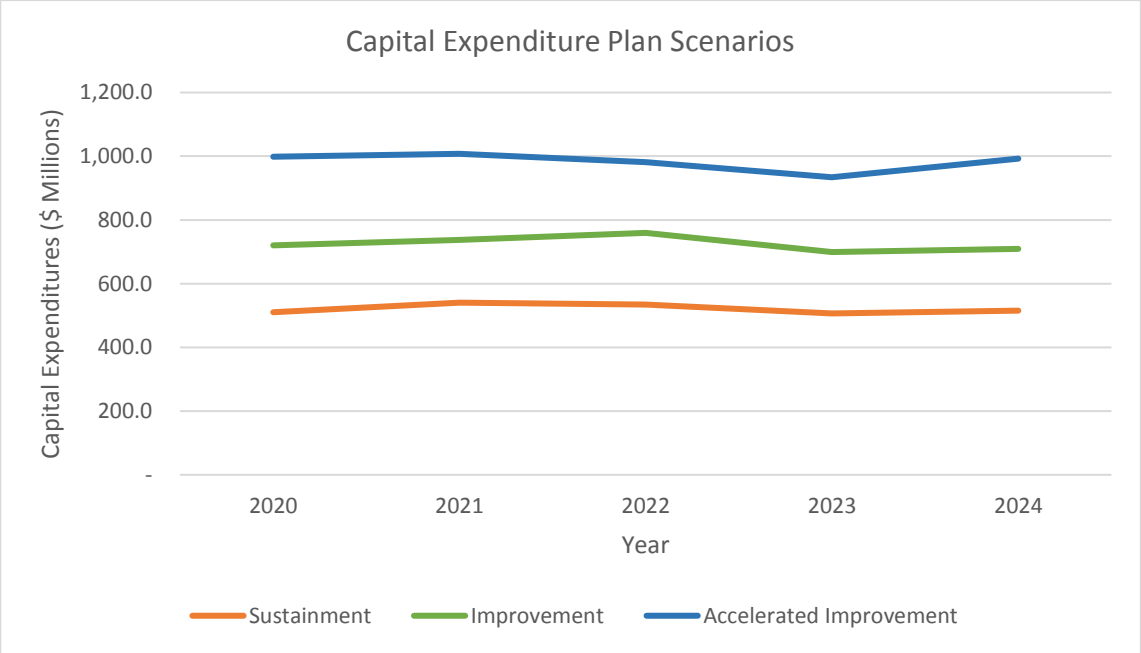


Figure 3: Preliminary High-level Capital Expenditures Scenarios

Toronto Hydro set its $562 million average annual capital budget limit to align predominantly with the "sustainment" level of investment. This level of investment best reflected the need to balance long-term system investment needs with customers' service needs and their general preference for minimizing rate increases.

E2.1.2 Focus on Operational and Financial Planning

The strategic parameters guided the operational and financial planning activities that produced the capital expenditure plan for 2020-2024. Over the course of these iterative planning activities, the utility worked to develop and optimize its program-level capital (and OM&A) expenditure plans to align with short- and long-term asset management ("AM") objectives, while remaining within the financial constraints and considerations set-out in the strategic parameters. A key feature of this planning stage was the formal integration of the utility's customer-focused Outcomes Framework. This helped to ensure that the organization's bottom-up expenditure plan proposals were directly informed by Customer Engagement results and were consistently translated into outcomes that matter to customers.

The utility developed initial capital program expenditure proposals with the aim of fulfilling strategic AM objectives. From this starting point, an iterative process generated multiple versions of the

capital expenditure plan, eventually producing a penultimate plan that formed the basis of Phase 2 of Customer Engagement. The differences between the initial version of the plan – which on an aggregate basis was higher than the $562 million limit on average annual capital expenditures – and the penultimate version of the plan were as follows:

- **System Access:** Toronto Hydro reduced System Access proposals for the 2020-2024 period by approximately $65 million, primarily reflecting revisions and refinements to forecasted demand in the Customer Connections and Externally Initiated Plan Relocations programs.
- **System Renewal:** Toronto Hydro reduced System Renewal proposals for the 2020-2024 period by approximately $325 million. This was the largest curtailment of proposed investment by category, resulting from the utility seeking to strike a balance between long-term system stewardship needs and both (i) near-term customer preferences for price mitigation; and (ii) competing investment needs and priorities. Ultimately, Toronto Hydro managed to constrain the planned pacing of renewal investment to a minimum level where it expects current levels of system average reliability can be maintained, while preventing asset failure and obsolescence risk from reaching unsustainable levels over the 2020-2024 period, and making targeted improvements in critical performance areas such as PCB oil spill risks and worst performing feeders. A description of how the utility leveraged its asset management processes to appropriately pace and prioritize its System Renewal plan is provided in Section E2.2 below.
- **System Service:** Toronto Hydro reduced System Service expenditures by approximately $20 million over the 2020-2024 period. This largely reflected reductions in the scope of work and pacing of system enhancement programs (e.g. SCADA-switch installation in the Horseshoe area of Toronto) to better align with low-volume customer preferences for maintaining current average reliability performance and the need to prioritize the mitigation of failure risk through core renewal work.
- **General Plant:** General Plant expenditures increased slightly, which was the net result of increases and decreases at the program level related to scope and cost estimate refinements that naturally occur during the planning process.

Overall, the utility's result was an approximate $550 million[4] per year capital expenditure plan for 2020-2024, deferring approximately $75 million per year in forecast average capital expenditures

[4] This figure includes inflation and other allocations, and excludes Renewable Enabling Improvement ("REI") expenditures funded through provincial rate relief.

from the initial proposals for the period. This penultimate plan was subsequently refined and finalized as described in the following section.

E2.1.3 Refinement and Finalization of the Capital Expenditure Plan

Toronto Hydro took its penultimate plan back to customers for feedback on how effective the utility was in interpreting the Phase 1 Customer Engagement results and using them to inform the proposed plan. Overall, a majority of customers expressed support for either the proposed plan or doing more. A plurality of customers supported proceeding with the plan as proposed, and a minority of respondents indicated that the utility should do more or less respectively. A full analysis of the Phase 1 and Phase 2 Customer Engagement results is provided in Section E2.3 below.

In an effort to gain additional insight into the more nuanced preferences of customers, this second phase of Customer Engagement provided customers with an opportunity to give feedback on programs where Toronto Hydro assessed that it could adjust pacing to deliver greater benefits. As discussed in E2.3.2.2, customers were particularly supportive of two programs related to preventing network vault floods and fires, and the utility took this feedback into account as it made its final refinements and adjustments to the plan. The adjustments that Toronto Hydro made to programs between the penultimate plan and the final plan were as follows:

- **System Access:** Toronto Hydro further reduced System Access expenditures by approximately $50 million over the 2020-2024 period. This was the result of further demand forecasting refinements and a decision to compress the utility's meter replacement schedule and delay its commencement. The metering decision lowered the amount of spending required in the 2020-2024 period, which allowed the utility to accommodate increases to network system investments supported by customers in the second phase of Customer Engagement.
- **System Renewal:** Toronto Hydro increased System Renewal expenditures by approximately $70 million over the 2020-2024 period. This was the result of a number of refinements to program cost requirements, including an updated assessment of execution capabilities for stations work, resulting in the conclusion that the utility could support a greater pace of stations renewal to deal with a critical backlog of stations asset risk, and updated reactive capital projections based on 2017 actuals. Toronto Hydro also increased the pacing of its Network Unit Renewal work in response to support from customers in the second phase of Customer Engagement.

- **System Service:** Toronto Hydro further reduced System Service expenditures by approximately $90 million over the 2020-2024 period, reflecting further reductions in the scope and pace of System Enhancements work, as well as a reduction in the forecast needs for Stations Expansion investments. Reductions in this category were partially offset by an increase in pacing in the Network Condition Monitoring and Control program, which received support from customers in Phase 2 of Customer Engagement (see Section E2.2 below).
- **General Plant:** General Plant expenditures increased by approximately $20 million, which was the result of cost estimate refinement and forecast revisions.

In the result, Toronto Hydro produced an optimized and customer-aligned capital expenditure plan with an average investment of $562 million[5] per year over the 2020-2024 period. The final plan produced an average annual bill impact (base rates, without riders) for residential customers of 3.0 percent for distribution, below the limit set in the strategic parameters and communicated to customers in the second phase of Customer Engagement.

Section E2.2, below, provides an overview of how Toronto Hydro derived the plan from the asset management processes described in Section D of the DSP. Section E2.3 describes the results of the Customer Engagement process and how they informed the DSP.

[5] This figure includes inflation and other allocations, and excludes Renewable Enabling Improvement ("REI") expenditures funded through provincial rate relief.

E2.2 Asset Management in Capital Planning

Toronto Hydro derived its 2020-2024 Capital Expenditure Plan from the Asset Management ("AM") Process described in Section D. As discussed in Sections D1 and D3, the utility develops its system investment programs through the annual Investment Planning and Portfolio Reporting ("IPPR") process. This process leverages the various asset lifecycle optimization and risk management methodologies discussed in Section D3 to produce capital programs and expenditure plans that are optimized to support the utility's customer-focused outcome objectives. The scenarios and recommendations developed in IPPR become inputs to business planning (discussed in the previous section), where program expenditure plan proposals are further refined, leveraging the same AM Process tools and outputs. (General Plant program proposals are developed via other operational planning activities that are also part of business planning.)

Figure 4 below (originally presented in Section D3.4) is a simplified view of the major program planning elements within the IPPR process. It depicts the cyclical nature of program development and the integration points with customer engagement.

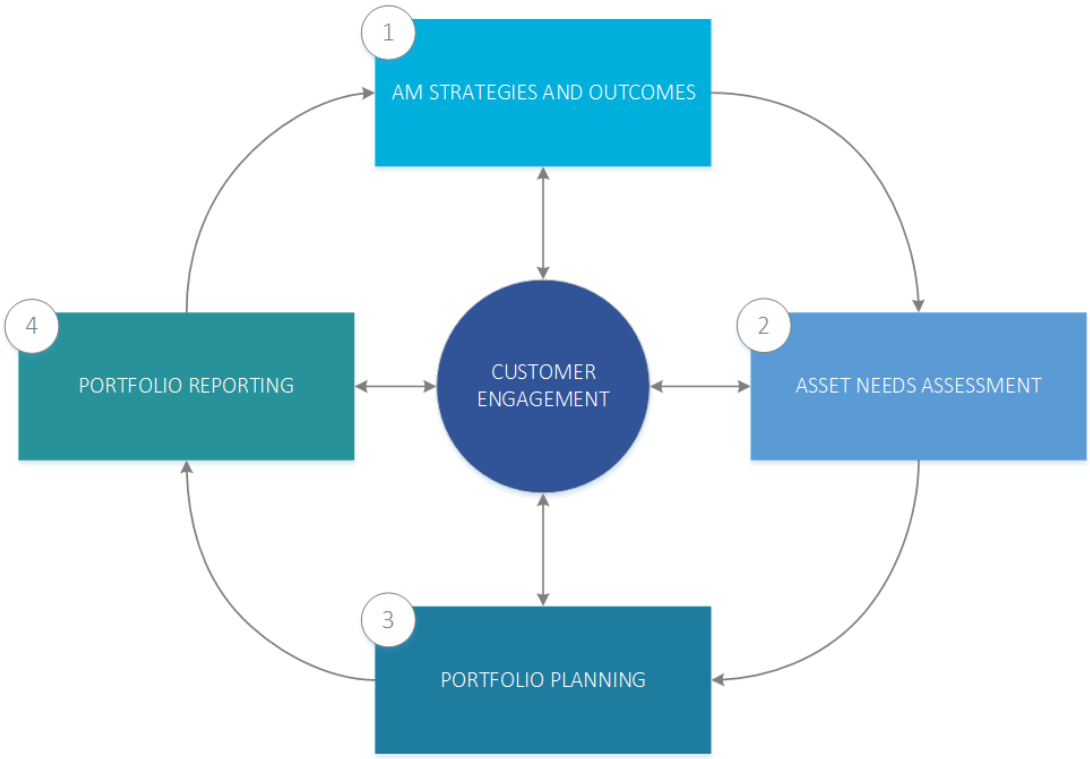


Figure 4: The IPPR Program Development Framework

The following sections explain how each of the elements in this process contributed to the production of the 2020-2024 Capital Expenditure Plan for system-related investments.

E2.2.1 Asset Management Strategies and Outcomes for 2020-2024

As summarized in Section D1, Toronto Hydro integrated its customer-focused Outcomes Framework into planning for 2017 and refined the strategic parameters into specific outcome objectives for the 2020-2024 period as summarized in the table below.

Table 1: Asset Management Outcomes Objectives

Outcome	Objectives
Customer Service	• Continue connecting customers of all types (including distributed energy resources) on time and cost-effectively, without harming system performance for existing customers. • Comply with customer service regulations and standards over the 2020-2024 period.
Reliability & Safety	• Maintain and, where appropriate, reduce asset failure risk – as represented by leading indicators like asset condition – over the 2020-2024 period, supporting stable system reliability and safety outcomes for current and future customers. • Maintain system reliability at current levels over the 2020-2024 period while (1) improving the experience for customers with poor reliability and power quality, and (2) improving the resiliency of the distribution system. • Continue to reduce and eliminate public and employee safety risks, for example by removing higher-risk legacy assets from the system within a specific and reasonable timeframe. • Strive for zero public and employee safety incidents over the 2020-2024 period. • Comply with all safety regulations and standards over the 2020-2024 period.
Public Policy	• Respond effectively to public policy during the 2020-2024 period, including by enabling the timely connection of all forecasted renewable generation projects and implementing a Conservation First approach where appropriate.
Environment	• Endeavour to eliminate the risk of PCB-contaminated oil spills by 2025. • Reduce the system's impact on the environment caused by greenhouse gas emissions and oil leaks of all types. • Comply with all environmental regulations and standards over the 2020-2024 period.
Financial	• Minimize average rate increases over the 2020-2024 period while continuously improving the value delivered to current and future customers.

Once these outcome objectives were established, Toronto Hydro began the process of selecting performance measures and program-level objectives to track and assess the utility's achievement of these outcomes for the 2020-2024 period. This process continued as the program expenditure plan proposals were developed, and throughout the refinement and finalization of those plans. It resulted in the final suite of Customer Performance Scorecard discussed in Section C of the DSP and the program-specific outcome objectives that can be found in the "Outcomes and Measures" section of each capital program in Sections E5 to E8.

E2.2.2 Asset Needs Assessment for 2020-2024

Concurrent with the development of the utility's asset management outcome objectives, summarized in Table 1 above, Toronto Hydro performed an Asset Needs Assessment to develop a baseline understanding of the current state of its distribution system. As explained in Section D3, the Asset Needs Assessment includes a Current State Assessment ("CSA") and a System Needs and Challenges Review. The results of these analyses informed the capital budget limit that Toronto Hydro set in the strategic parameters for the business plan.

E2.2.2.1 CSA Results

The CSA produced foundational information, including asset demographics (i.e. counts, age and nameplate attributes) and condition demographics. These data points informed program pacing and prioritization decisions throughout business planning.

1. Assets Past Useful Life

As discussed in Section D3.2, to assess the age demographics of its distribution system, Toronto Hydro examines the proportion of assets across the system that are operating at or beyond useful life (the Assets Past Useful Life metric, or APUL). The age demographics of the system as of the beginning of 2018 are summarized in Figure 5 below.

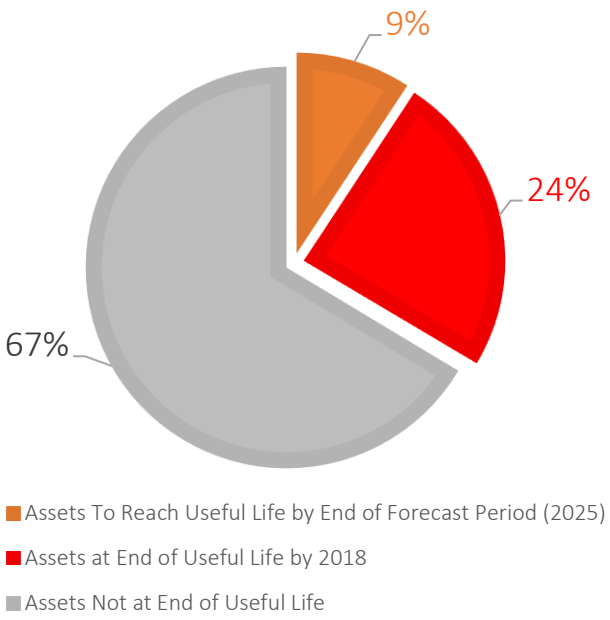


Figure 5: Percentage of Assets Past Useful Life

In 2015, Toronto Hydro's percentage of assets past useful life was 26 percent, with an additional 7 percent forecasted to reach expected useful life by 2020. As a result of Toronto Hydro's ongoing renewal efforts, the APUL measure is no longer deteriorating as it did during Toronto Hydro's previous 2011-2014 rate period. However, approximately a quarter of the utility's asset base continues to be operating beyond its expected useful life, and an estimated additional 9 percent will reach that point by 2025, indicating that a significant proactive renewal program remains necessary to prevent the APUL backlog from increasing. An increase in the APUL backlog would not only amount to a deterioration in these recent improvements, but also a corresponding deterioration in reliability, safety risk, reactive replacement costs, and other outcomes driven by asset failure.

2. Asset Condition Demographics

The utility also examined the current state of its asset condition demographics to determine which asset classes were showing the greatest signs of deterioration, and took this into account in establishing planning scenarios. Among the subset of asset classes that are analyzed using inspection information and Toronto Hydro's Asset Condition Assessment ("ACA") model, major civil assets – including poles, cable chambers, and network vaults – and major stations electrical assets – including circuit breakers and power transformers – are showing the greatest signs of material deterioration.

Civil assets are the backbone of the distribution system and must be adequately maintained to ensure public and employee safety and the long-term viability of the distribution system. Stations assets are the highest criticality assets on the system and require long lead times for replacement. As a result, these assets must be addressed proactively to mitigate the risk of catastrophic failure, high-impact and long-duration outages, and other contingency scenarios. Toronto Hydro considered various sustainment and improvement strategies for these asset classes in developing its planning scenarios in IPPR.

Toronto Hydro set-out to develop a plan that would invest the minimum necessary to prevent these age and condition-related risks from worsening over the 2020-2024 period and beyond. This was a key consideration in the utility's selection of its capital budget limit for business planning. The Portfolio Planning section below (E2.2.3) provides additional details on how asset condition informed the pacing of investment in Toronto Hydro 2020-2024 Capital Expenditure Plan.

E2.2.2.2 System Needs and Challenges Review

In addition to the information generated by the CSA, Toronto Hydro considered a number of other indicators of system investment need, including system utilization, connection capacity, distributed generation forecasts, legacy asset profiles (e.g. lead cable replacement needs), regional planning considerations, and other factors. The utility developed strategic investment scenarios for each of these issues, which in turn informed the capital expenditure plan scenarios discussed in Section E2.1.

Section D2 provides an overview of the various considerations resulting from the System Needs and Challenges Review. Section E2.3.3 provides additional insight into the strategies for addressing these issues in the 2020-2024 Capital Expenditure Plan.

E2.2.2.3 System Reliability Performance and Projection Scenarios

System reliability is an important customer-focused outcome and a lagging indicator of performance, including the effectiveness of the subset of System Renewal and System Service investments that are primarily directed toward preventing outages and shortening outage duration (e.g. direct-buried cable replacement). Toronto Hydro's renewal and modernization efforts over the last decade have paused the overall deterioration in reliability performance that began in the mid-2000s. As shown in Figure 6 and 7, the frequency and duration of outages have essentially plateaued.

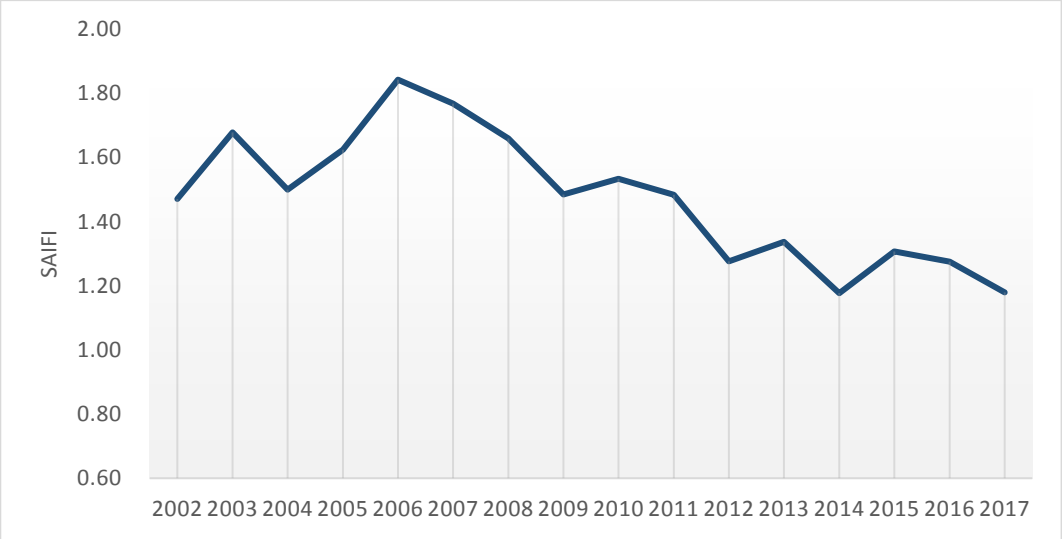


Figure 6: Historical SAIFI (Excluding MEDs and Loss of Supply)

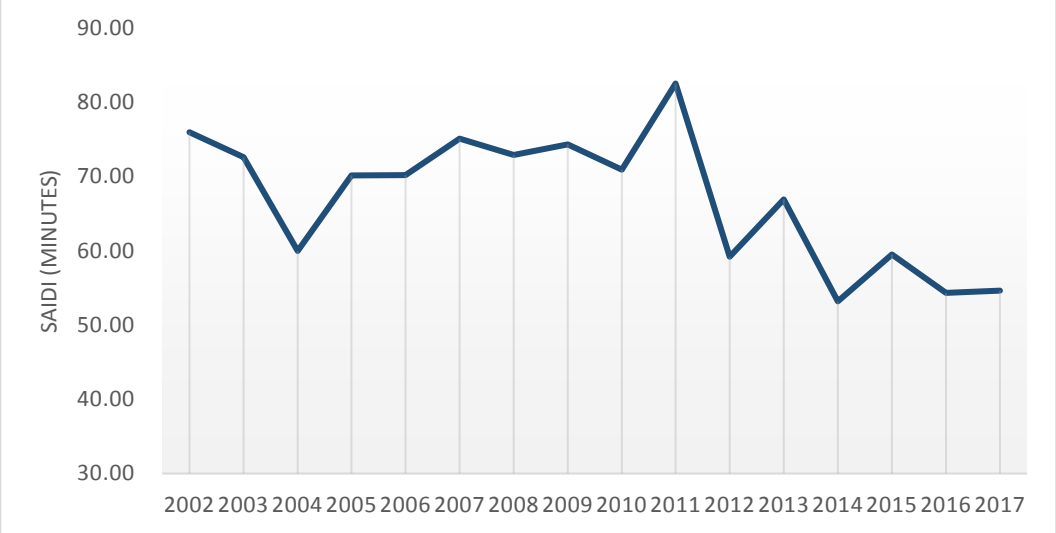


Figure 7: Historical SAIDI (Excluding MEDs and Loss of Supply)

Toronto Hydro has seen improvements in the frequency and duration of outages caused by defective equipment. However, defective equipment continues to be by far the largest contributor to SAIFI, at 36 percent, and SAIDI, at 44 percent. In light of the age, condition, and legacy asset related risks discussed above, Toronto Hydro concluded that a shift to a more reactive renewal approach would – in addition to being a more costly approach to renewal over the long-term – result in a decline in reliability over the near- and long-terms, with potentially significant impacts for customers in areas

served by legacy assets such as direct-buried cable and rear-lot plant. Furthermore, as discussed in detail in Section D2, Toronto Hydro anticipates that increasingly frequent adverse and extreme weather events will put additional reliability pressures on the system, making the resiliency of the system and the utility's operations a greater concern over the medium- to long-term than in past planning cycles.

As illustrated in Figure 2 in Section E2.1, Toronto Hydro developed preliminary "sustainment," "improvement," and "accelerated improvement" expenditure plan scenarios for each system investment program and used these to define the lower and upper bounds of potential capital budgets for the planning period.[6] In the manner described in Section D3.4, Toronto Hydro used the asset demographic information produced by the CSA analysis to run each of the scenarios through its reliability projection methodology to assess at what overall expenditure level the utility could, at a minimum, support the sustainment of current system average reliability for outages caused by defective equipment over the 2020-2024 period. The results of this analysis are shown in Figures 8 and 9 below.

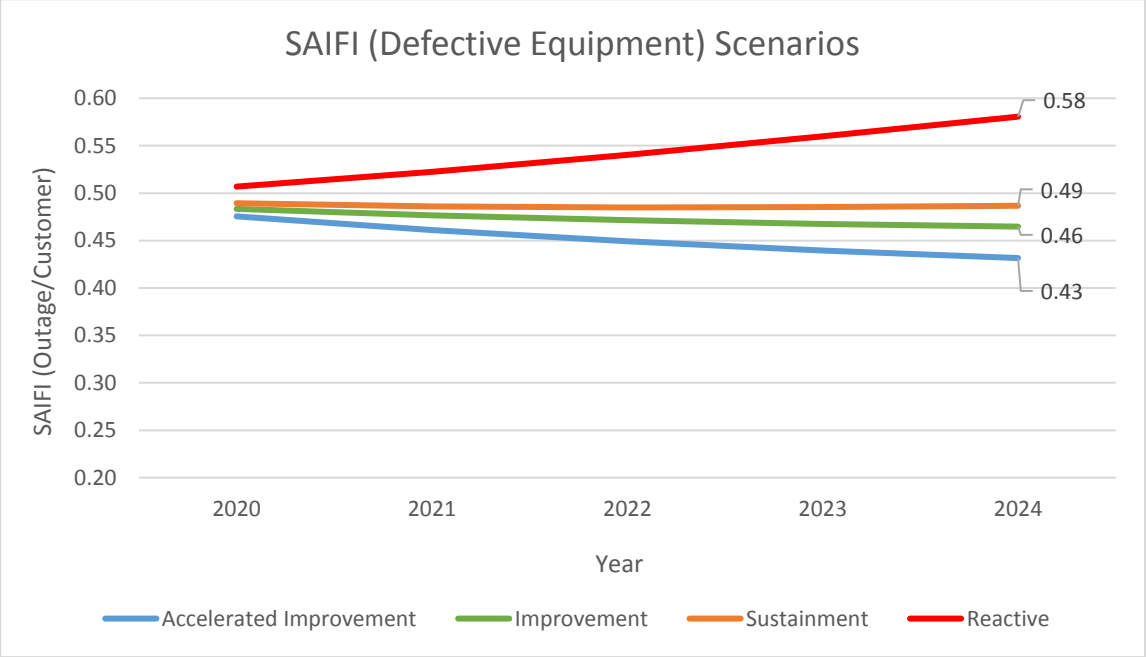


Figure 8: SAIFI Scenarios for Strategic Planning

[6] For the purpose of this analysis, Toronto Hydro assumed General Plant investments in the 2020-2024 period would be in line with historical averages.

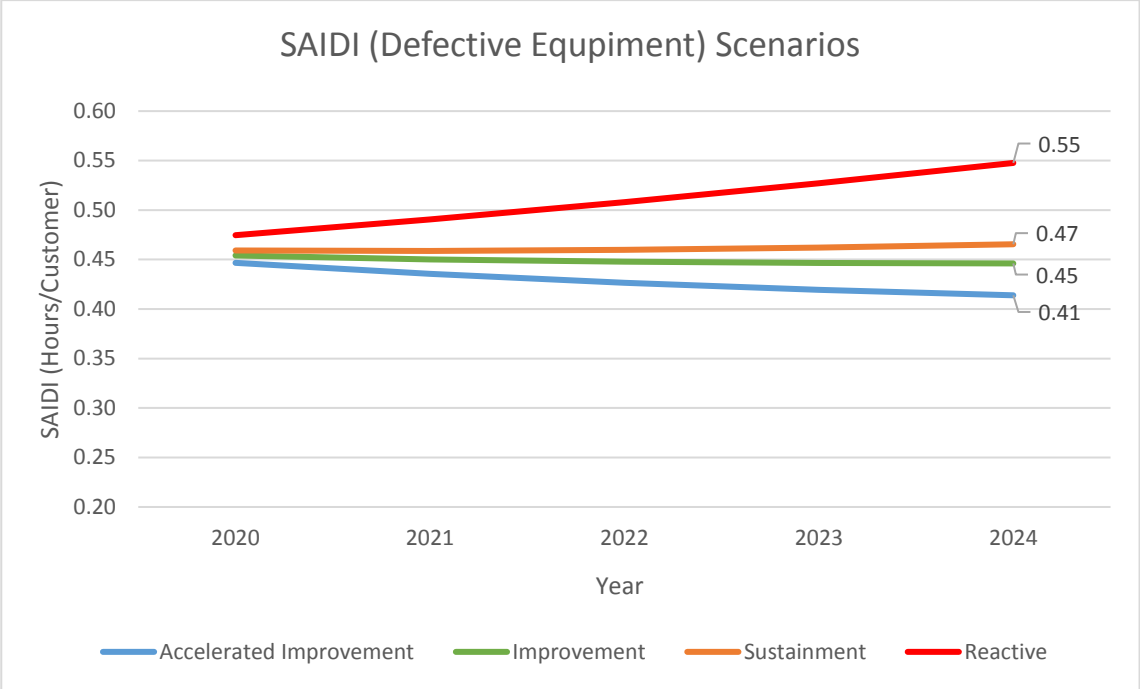


Figure 9: SAIDI Scenarios for Strategic Planning

Toronto Hydro considered the results of these projections alongside the other drivers and risk factors resulting from the CSA and System Needs and Challenges Review, as well as anticipated inflation and cost escalation for the forecast period, and determined that a capital expenditure plan of up to $562 million per year would be necessary to support sustainment of current system reliability while allowing the utility to deliver on the other asset management outcome objectives listed in Section 2.2.1 above. Through refinement, and with consideration for results from Phase 2 of Customer Engagement, the utility produced an optimized plan within this limit. The following section provides a detailed discussion of how this plan was optimized to support Toronto Hydro's customer-focused asset management objectives at the individual program level.

E2.2.3 Portfolio Planning for 2020-2024

Toronto Hydro's Portfolio Planning process used the outputs of the Asset Needs Assessment to develop program-level expenditure plan proposals that would support the utility's asset management outcome objectives for 2020-2024.

As described in Section D3.4.3, Toronto Hydro developed bottom-up expenditure plan scenarios for each capital program, leveraging the asset lifecycle optimization and risk management practices and

methodologies described in Section D3. The proposals were evaluated in relation to their potential contribution to: (i) the utility's asset management outcome objectives and measures; and (ii) alignment with customer needs and preferences. The program proposals were further refined as a result of business inputs and information, as well as feedback received in the second phase of Customer Engagement (discussed in Section E2.3 below).

The following subsections describe how the outputs of the Asset Needs Assessment and the utility's asset lifecycle optimization and risk management practices informed the timing and pacing of the programs in the 2020-2024 Capital Expenditure Plan.

E2.2.3.1 System Access Program Expenditures

Toronto Hydro developed a 2020-2024 System Access expenditure plan that is responsive to the utility's need to continuously meet its legally mandated service obligations, including the requirement to safely connect load and generation customers in a timely manner, and requirements to comply with revenue metering and billing standards. The pacing of investments in this category was largely dictated by the projected demand in these areas over the 2020-2024 period. Customer Service delivery and responsiveness to Public Policy are the primary outcomes supported by these investments.

Table 2: 2020-2024 System Access Expenditure Plan ($ Millions)

Programs	2020	2021	2022	2023	2024
Customer Connections	42.9	43.9	44.8	45.6	46.3
Externally Initiated Plant Relocations & Expansions	11.4	20.8	4.6	4.7	4.5
Generation Protection, Monitoring, and Control	3.7	2.3	2.4	2.5	2.7
Load Demand	11.3	11.4	18.5	22.6	23.6
Metering	22.6	14.8	23.6	30.6	39.2
System Access Total	**91.8**	**93.3**	**93.9**	**106.0**	**116.4**

1. Connecting Load Customers

Toronto Hydro's Customer Connections (E5.1) and Load Demand (E5.3) programs support the safe, timely, and cost-efficient connection of load customers. Forecast expenditures for load connections were based on historical trends in gross cost and customer contribution amounts for load connection activities. They were also informed by development trends in the City. The utility's 2020-2024

expenditure plan anticipates growth in new services, upgrades, and removals based on current and proposed development. (Refer to Section E5.1 for more details.)

The Load Demand program addresses near-term system capacity constraints in areas of concentrated load growth. Toronto Hydro's Distribution Capacity and Capability Assessments (summarized in Section D3.3) identified a number of areas in both the Horseshoe and downtown regions of the system where investments such as load transfers, cable upgrades, and equipment upgrades will likely be required to ensure the utility can continue to connect customers efficiently. These investments are also necessary to maintain sufficient grid flexibility to handle contingency scenarios and optimize planned work schedules, contributing to Toronto Hydro's reliability objectives and improving customer satisfaction by providing large customers with greater scheduling flexibility for planned outages.

Toronto Hydro's 2015-2017 Load Demand investments have been successful in reducing constraints. The utility has (i) alleviated 10 highly loaded buses; (ii) reduced the number of highly loaded feeders by 25; and (iii) reduced the number of feeders subject to switching restrictions during the summer months by 28. As discussed in Section C2.3.3, Toronto Hydro's capacity investment strategies during the 2020-2024 period were developed to prevent system capacity (as indicated by the utility's proposed System Capacity measure) from deteriorating in the face of forecasted development and demand.

Overall, the proposed expenditure plans in these two load-driven System Access programs reflect the investments required to connect customers in accordance with the OEB's service connection targets, while maintaining system performance for existing customers and improving the effects of scheduled outages on the operations of larger customers.

2. Connecting Generation Customers

Toronto Hydro's Customer Connections (E5.1) and Generation Protection, Monitoring, and Control (E5.5) programs support the safe, timely, and cost-efficient connection of distributed generation ("DG") customers to the grid, including renewable energy generation ("REG") projects. The utility aligned the planned 2020-2024 expenditures in both programs with its 2018-2024 generation connection forecasts, illustrated in Figures 2 through 7 in Section E3, and summarized in Figure 10 below. These forecasts took into account historical connection trends, completed assessments, and anticipated projects with respect to various DG programs.

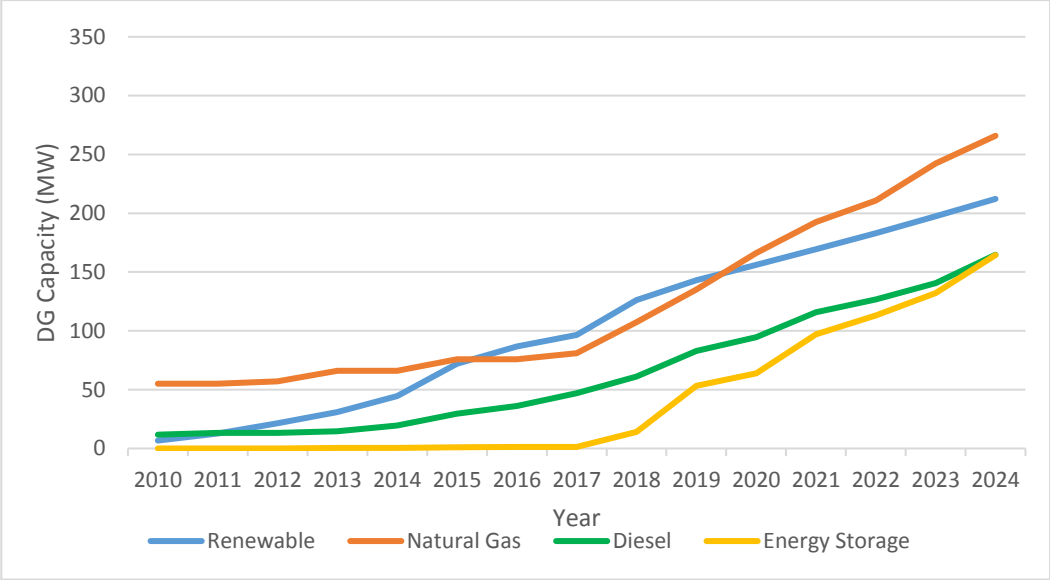


Figure 10: Forecast Generation Capacity

Toronto Hydro's Generation Capacity and Capability Assessment (described in Section E3.3) identified a number of challenges to connecting the forecasted 581 MW of incremental DG anticipated by 2024, including short-circuit capacity constraints (illustrated in Figure 11 below), islanding risks, and system thermal limits.

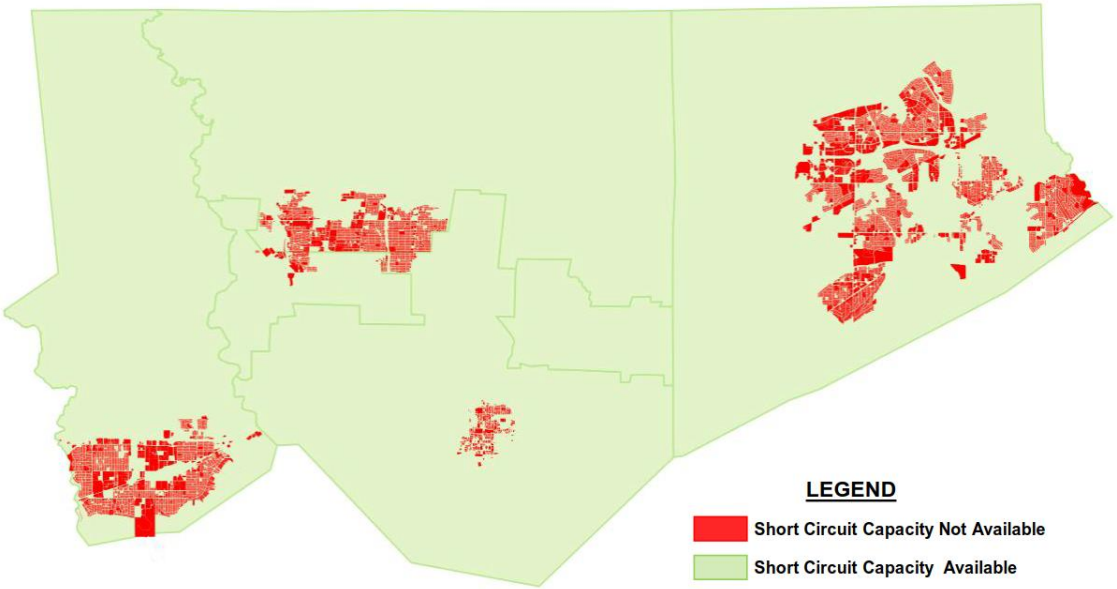


Figure 11: Distribution System Short Circuit Capacity Constraints Map

Connecting all REG projects in accordance with the OEB's generation connections standards continues to be a key Public Policy outcome objective for Toronto Hydro. To support this outcome, the utility developed a plan for the 2020-2024 Generation Protection, Monitoring, and Control program that will make targeted investments in bus-tie reactors and monitoring and control equipment, allowing the utility to address the challenges noted above and continue to connect all forecasted DG. The Energy Storage Systems program (System Service) also includes investments to support the mitigation of DG islanding risk.

3. Accommodating Third-Party Plant Relocation Requests

The Externally Initiated Plan Relocations and Expansions program (E5.2) funds plant relocations and expansions triggered by third-party requests. Toronto Hydro is obligated by the *Public Service Works on Highways Act*[7] ("PSWHA") and section 3.4 of the Distribution System Code ("DSC") to accommodate these requests in a fair and reasonable manner. The timing and scope of work in this program is difficult to predict and largely out of Toronto Hydro's control. For the 2020-2024 period, the utility developed an expenditure plan to address committed relocation and expansion projects by Metrolinx, the TTC, and the City of Toronto. In light of the volatility of this program, the utility proposes to continue the Variance Account for Externally Driven Capital for the 2020-2024 period (Exhibit 9, Tab 1, Schedule 1).

4. Metering Investments

Investments in the Metering program (E5.4) are largely driven by the need to remain in compliance with OEB minimum standards for billing accuracy and Measurement Canada and IESO requirements related to metering and billing. Based on a needs assessment for its metering assets, Toronto Hydro developed a plan for 2020-2024 that is largely driven by the timing of metering and metering system upgrade cycles. Forecast expenditures related to Wholesale Metering Compliance, Suite Metering, Large Customer Interval Metering and System Upgrades are generally in line with, or lower than, 2015-2019 expenditures in these categories.

The primary driver of greater planned expenditures in the outer years of the 2020-2024 period was a necessary ramp-up in the utility's Residential and Small C&I Meter Replacement activities to address end-of-life meters with expiring seals. Toronto Hydro cannot, as a matter of law, bill customers using meters with expired seals. The bulk of these meters will have their seals expire in

[7] R.S.O. 1990, c. P-49.

2024, and, beginning in 2021, they will surpass their expected 15 year lifespan, increasing the probability of failure beyond standard operating levels. Without intervention, 90 percent of these meters will be operating beyond useful life as of 2025. The option of resealing these meters and allowing them to run beyond their expected lifespan was considered, but the risks to billing accuracy, customer satisfaction, and financial stability were deemed too high. Therefore, Toronto Hydro has developed a plan to replace these meters in a staged manner beginning in 2022.

In addition to complying with all customer service and billing regulations for Metering assets, investments in the next-generation metering technology will enhance Customer Service, Reliability and Financial efficiency outcomes to the benefit of current and future customers. For example, the installation of next-generation residential and small C&I meters with "last gasp" functionality will allow Toronto Hydro to pursue customer-specific reliability measures system-wide, while the continued installation of "ION" meters for large users will help Toronto Hydro better diagnose and respond to power quality issues.

5. Grid Modernization in System Access

Toronto Hydro's ongoing grid modernization efforts are supported by Metering and DG-related investments in its 2020-2024 plan. For example, as mentioned above, next generation metering technology will provide enhanced smart grid benefits to support reliability and customers service outcomes, while the expansion of SCADA monitoring and control will allow greater DG penetration.

E2.2.3.2 System Renewal Program Expenditures

As described in detail throughout Section D2 ("Overview of Distribution Assets") and in the System Renewal programs (Section E6), continued proactive renewal expenditures are required during the 2020-2024 period to manage significant safety, reliability and environmental asset risks and to ensure stable and predictable performance for current and future customers. As noted in E2.2.2 above, approximately one quarter of Toronto Hydro's assets are operating beyond Useful Life and the system continues to age at a rate comparable to the projected rate of aging in the 2015-2019 DSP. Furthermore, condition demographic results indicate substantial asset investment needs for a number of critical asset classes, and the utility continues to face challenges related to higher-risk, obsolete legacy assets and asset configurations such as rear lot plant and direct-buried cable.

As noted in the business planning discussion in E2.1, the first phase of the Customer Engagement exercise indicated that most low-volume and medium-sized customers were satisfied with average

reliability performance and would prefer Toronto Hydro maintain current performance while minimizing price increases in the near-term. Larger users indicated a greater interest in reliability and system resiliency and a willingness to pay to maintain or improve performance in these areas. In light of these results, and leveraging the asset risk assessment and mitigation practices discussed in Section D3, Toronto Hydro developed program expenditure plans for 2020-2024 that are set a the minimum pace necessary to sustain overall asset risk and reliability performance at current levels, while driving targeted outcome improvements such as reducing the risk of PCB contaminated oil spills, reducing the level of failure risk related a significant backlog of aging and poor condition stations assets, and improving performance on worst performing feeders.

Table 3: 2020-2024 System Renewal Expenditure Plan ($ Millions)

Programs	2020	2021	2022	2023	2024
Area Conversions	41.4	47.2	46.3	50.4	35.6
Network System Renewal	18.6	19.3	18.5	17.7	18.3
Reactive and Corrective Capital	61.2	62.4	63.5	64.4	65.8
Stations Renewal	27.5	35.3	29.4	27.0	22.4
Underground System Renewal - Downtown	15.1	22.5	23.9	30.0	30.6
Underground System Renewal - Horseshoe	93.0	88.7	90.3	93.1	95.2
Overhead System Renewal	49.8	50.4	51.3	56.5	57.7
System Renewal Total	**306.6**	**325.7**	**323.1**	**339.0**	**325.5**

1. Overhead Asset Renewal Investments

Failure and obsolescence risks related to overhead grid system assets are addressed by Toronto Hydro's Overhead System Renewal (Section E6.5), Area Conversions (Section E6.1) and Reactive and Corrective Capital (Section E6.7) programs. The utility paced the 2020-2024 expenditure plan for these programs to maintain current system reliability performance, prevent age and condition related asset risk from accumulating over the period, and to continue to reduce and eliminate safety and environmental risks (and other deficiencies) associated with legacy assets and asset configurations.

As highlighted in Section D2.1.1, demographic pressures related to wood poles and pole top transformers were identified as key drivers of overhead renewal need during the 2020-2024 period. Wood poles are critical to the safety and viability of the distribution system.



Figure 12: Deterioration at the base of a pole

Toronto Hydro examined the current and projected health scores of its wood pole population to ensure the proposed pacing of wood pole replacement could prevent failure risk across this asset class from worsening over the forecast period. As shown in Figure 13 below, about a third of Toronto Hydro's are showing at least material deterioration, with approximately 11,000 poles in each of the HI4 ("material deterioration") and HI5 ("end-of-serviceable life") condition bands. The utility projects this number could nearly triple to an estimated 34,000 by 2024 without intervention, including an increase in HI5 poles from approximately 1,000 to 17,000. The Overhead System Renewal program budgets for approximately 13,000 pole replacements between 2018 and 2024. Combined with pole replacements in the Area Conversions program and the Reactive Capital program, and prioritizing poles within or nearing the HI5 category, Toronto Hydro anticipates that its 2020-2024 expenditure plan as proposed is sufficient to manage wood pole failure risk.

Wood pole replacement is the highest-volume renewal activity out of the subset of assets that are analyzed through Toronto Hydro's ACA methodology. Given the importance of managing the overall condition-informed failure risk for this asset class over the planning period, the utility is proposing to track and report on wood pole condition demographics as a Custom Performance Measure over the 2020-2024 period (see Section C for more details).

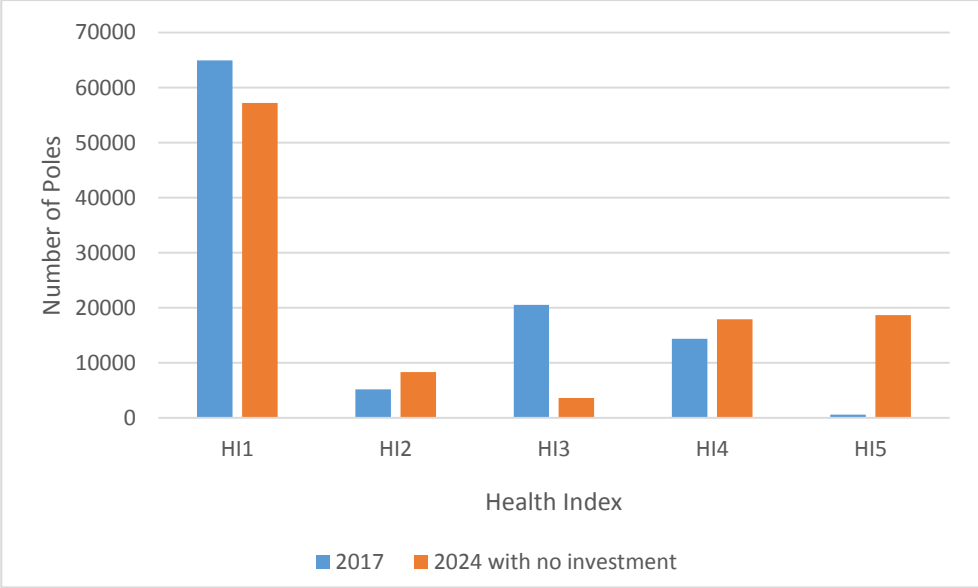


Figure 13: Health of Wood Poles as of 2017 and 2024 (without investment)

The utility also faces a significant increase in failure risk related to pole-top transformers, with the percentage of units operating beyond their 35 year useful life projected to increase from 14 percent to 40 percent by 2024. Compounding the reliability dimension of this risk is the risk of pole-top transformer failure resulting in PCB contaminated oil spills. The utility has paced pole-top transformer replacement in the aforementioned programs to align with the utility's reliability objectives and to work towards eliminating the risk of PCB contaminated oil spills.



Figure 14: Rusted Overhead Transformers at Risk of Leaking Oil

As discussed in Section D2.2.1.1, obsolete, legacy overhead construction types are an ongoing challenge for Toronto Hydro. The utility is continuing to address aging, deteriorating, and poor performing rear lot construction and box construction plant at a steady pace. These asset types carry a number of acute safety, reliability, and customer service risks that Toronto Hydro is in the process of eliminating.



Figure 15: Box Construction (left). Replacing a transformer on a poor condition Rear Lot pole (right)

As detailed in the Area Conversions program (Section E6.1), because of the continuing decline in rear lot plant performance, and the high complexity and duration of rear lot conversion projects, Toronto Hydro determined it is necessary to continue removing rear lot plant proactively at a pace that is consistent with 2015-2019 accomplishments, prioritizing areas where customers are experiencing the worst performance. The long-term pacing strategy for rear lot plant is represented in Figure 16 below.

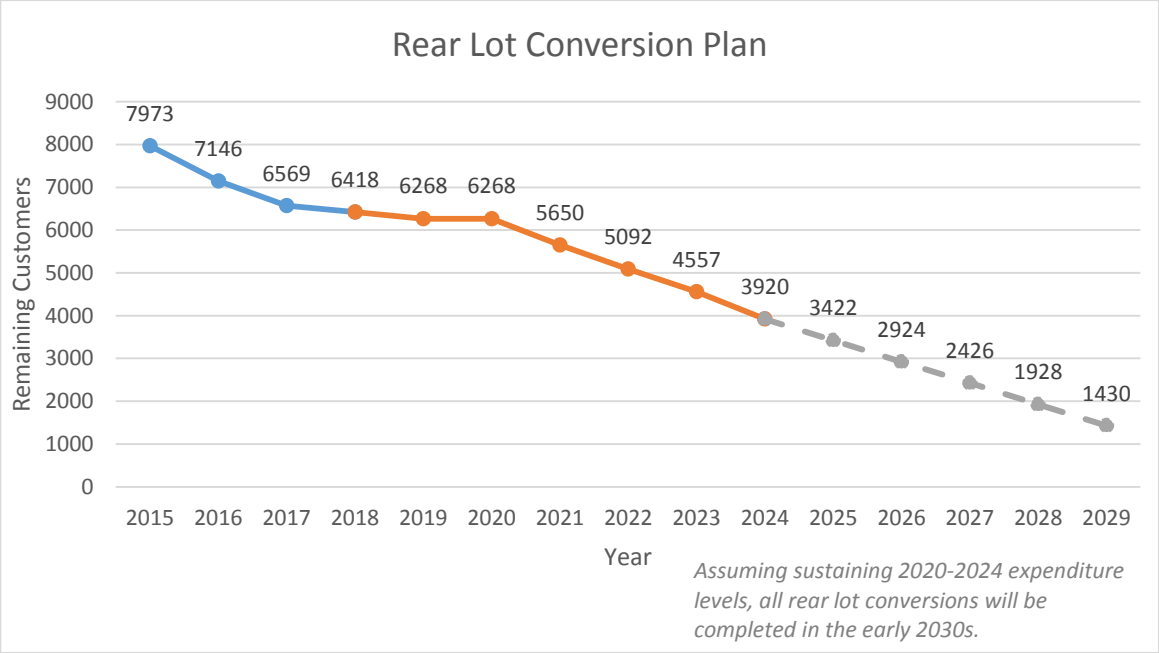


Figure 16: Rear Lot Conversion Plan

Box construction is also addressed in the Area Conversions program. Toronto Hydro developed a plan for 2020-2024 that continues the strategy of eliminating all box construction poles by 2026, as first articulated in the 2015-2019 DSP. This is the fastest executable rate at which the utility can eliminate this legacy configuration. The utility's pacing strategy for this type of equipment is driven primarily by a need to eliminate the various safety risks that these assets present to employees and the public. (For more information, please reference to Section E6.1.) Figure 17 illustrates the plan to eliminate box construction. Toronto Hydro plans to report its progress on this plan as a 2020-2024 Custom Performance Measure under the Safety outcome category (see Section C2.2).

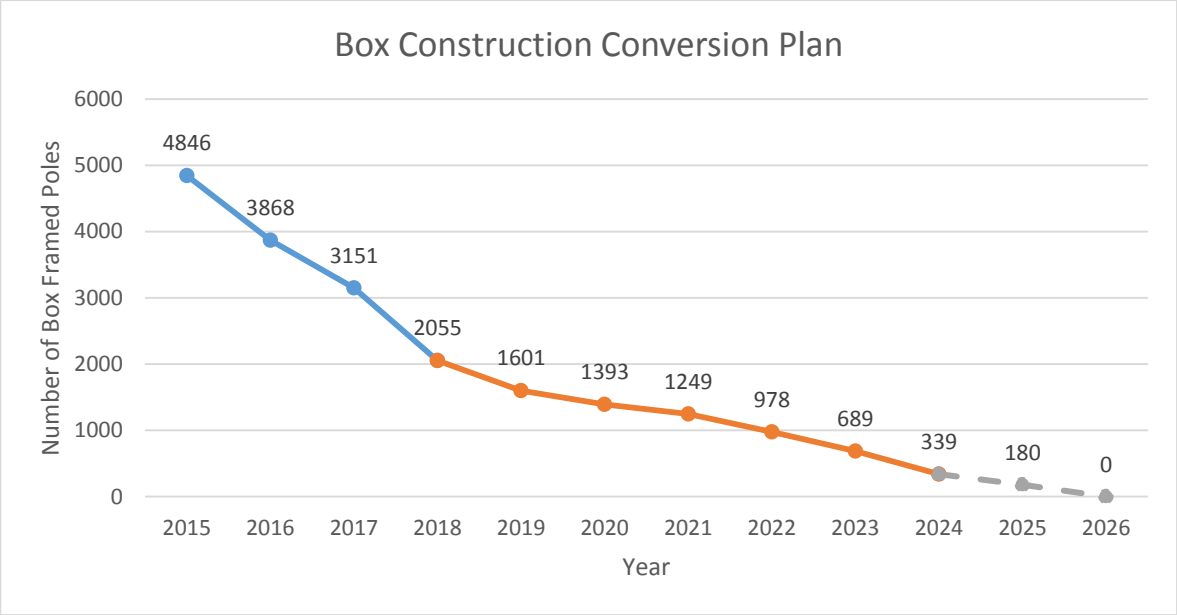


Figure 17: Box Construction Conversion Plan

2. Underground Asset Renewal Investments

Failure and obsolescence risks related to underground system assets are addressed by Toronto Hydro's Underground System Renewal - Horseshoe (Section E6.2), Underground System Renewal - Downtown (Section E6.3), Area Conversions (Section E6.1), and Reactive and Corrective Capital (Section E6.7) programs. The utility paced the 2020-2024 expenditure plans for these programs to maintain current system reliability performance, prevent age, condition and obsolescence related asset risk from accumulating over the period, and to continue to reduce and eliminate safety and environmental risks (and other deficiencies) associated with legacy assets and asset configurations.

Legacy asset performance and risks – particularly the reliability-related failure risks associated with obsolete cables – continue to be the most significant driver of renewal needs on the underground system. Underground cables have been the single greatest contributor to outages caused by defective equipment, resulting on average in 140,000 customer hours of interruption annually. In the Horseshoe area of Toronto, direct-buried cable, and direct-buried cable in duct continues to fail, often in clusters, as it nears and exceeds its expected useful life, resulting in potentially significant reliability impacts and pressure on Toronto Hydro's worst performing feeder measures (e.g. "FESI-7").

The utility's Asset Needs Assessment identified over 800 circuit-kilometres of direct-buried cable and direct-buried cable in duct remaining in the Horseshoe area as of 2018. Of this, approximately 370 circuit-kilometres are of the highest-risk cross-linked polyethylene ("XLPE") type. Approximately 70 percent of this cable is currently beyond its useful life and the utility anticipates that 90 percent will be at or beyond useful life by 2024. To prevent reliability from degrading, the utility developed a plan to proactively replace approximately one quarter of the 800 circuit-kilometres (i.e. an estimated 215 circuit-kilometres) of this cable in the Underground System Renewal – Horseshoe program during the 2020-2024 period, prioritizing the highest-risk neighbourhoods based on cable age, performance, criticality, and adjacency to other assets at risk of failure. Figure 18 below shows Toronto Hydro's long-term direct-buried cable replacement plan. Given its significant impact on reliability and the fact that this is the utility's largest renewal activity, Toronto Hydro plans to report its progress on this plan as a 2020-2024 Custom Performance Measure under the Reliability outcome category (see Section C).

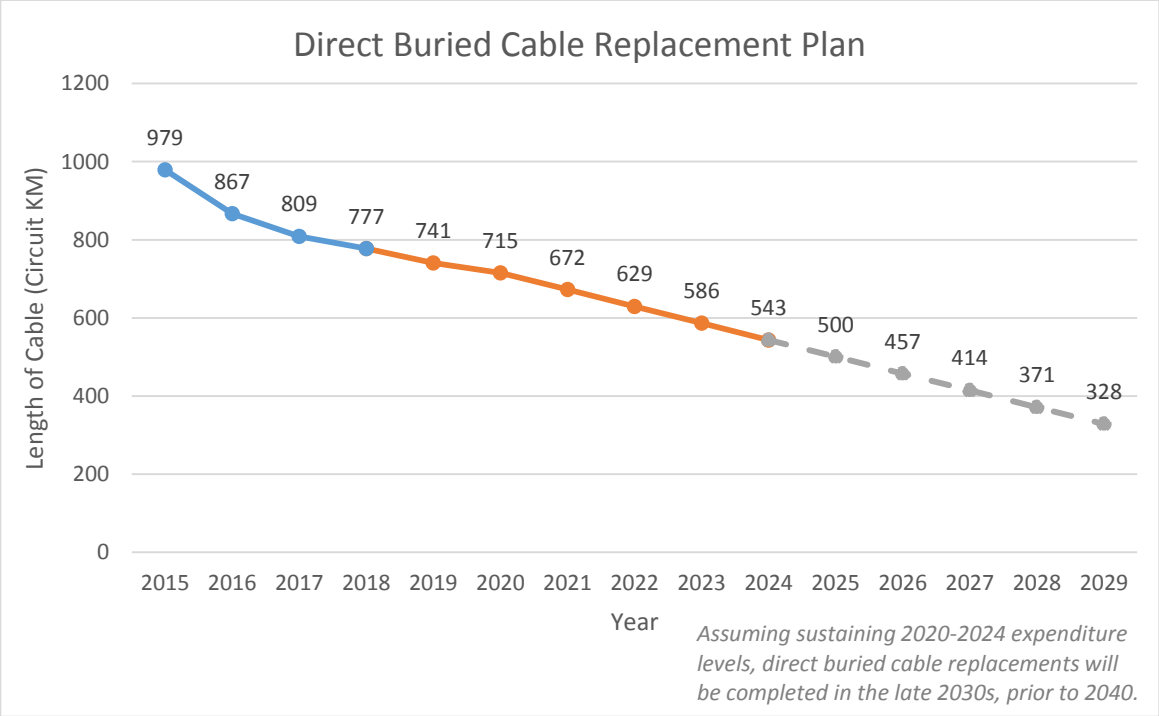


Figure 18: Direct Buried Cable Replacement Plan

Toronto Hydro's Asset Needs Assessment also resulted in the introduction of a long-term renewal strategy for lead cable in the downtown area. Due to the generally good reliability performance of

lead-covered cable, Toronto Hydro has historically managed these assets through reactive and corrective interventions and targeted repairs. However, these cable types have shown signs of aging and declining performance in recent years and are largely considered obsolete in North America due to various safety and environmental risks (see Section E6.3 for more details). There is only one supplier of paper-insulated lead-covered ("PILC") cable remaining in North America and no suppliers of asbestos-insulated lead-covered ("AILC") cable.



Figure 19: Collapsed cable splice

To manage the significant magnitude of this asset renewal need, Toronto Hydro developed a predictive performance model to prioritize the cable segments on the system, using factors such as historical failures, number of splices, age and customer base. The results of this analysis are summarized in Section E6.3, Figures 1 and 2. Based on this prioritization model, Toronto Hydro developed a plan to maintain reliability performance for affected customers by replacing approximately 2 percent of the 1,100 kilometres of PILC cable and 20 percent of the 220 kilometres of AILC cable with modern polymeric cables in the 2020-2024 period. The long-term replacement plans for AILC and PILC cable are represented in Figures 20 and 21 below.

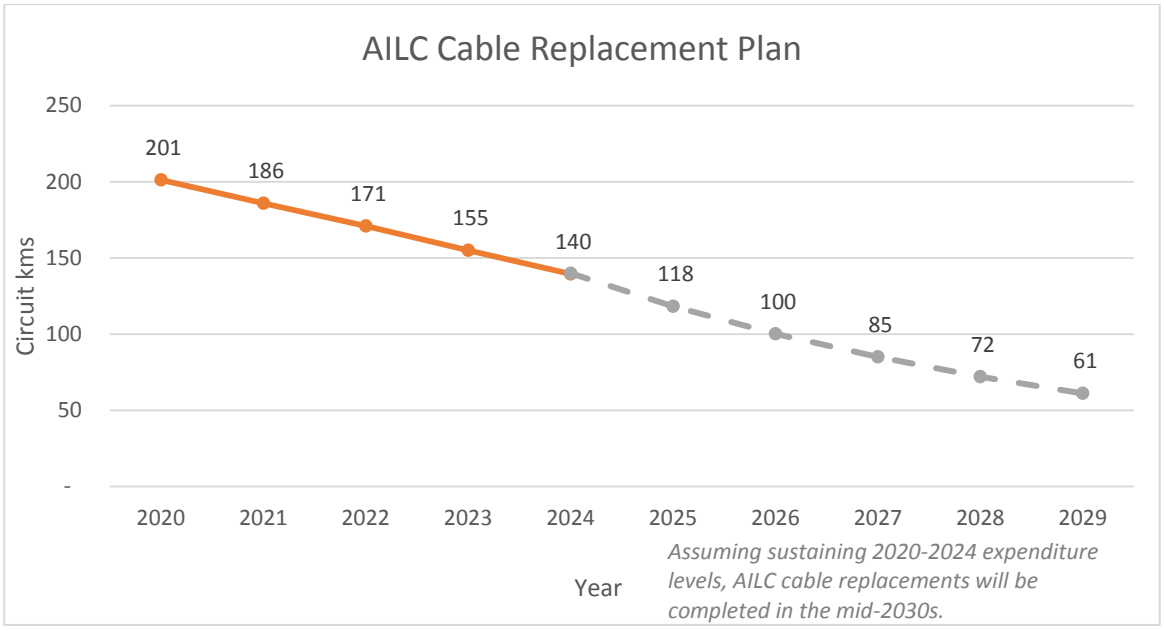


Figure 20: AILC Replacement Plan

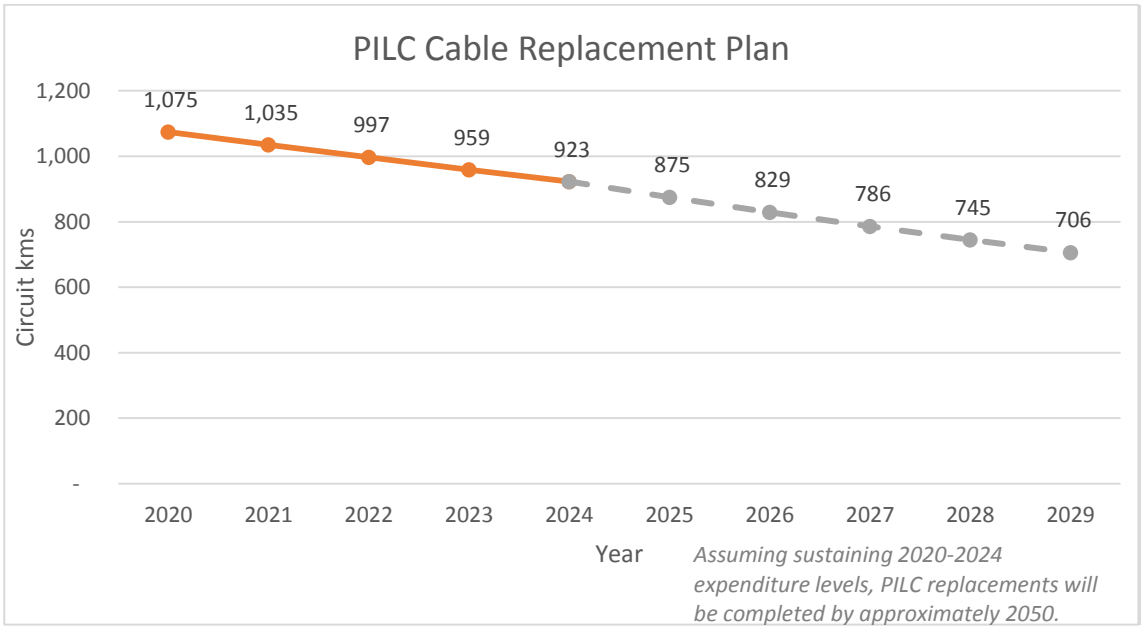


Figure 21: PILC Cable Replacement Plan

Other electrical assets addressed by the Underground System Renewal programs include transformers and switches in the Horseshoe area and on the Underground Residential Distribution ("URD") system, which serves low-volume customers in parts of the downtown area. These assets

will be prioritized based on age, condition and historical performance and will largely be addressed in conjunction with underground cable rebuild projects, except on the URD system and in cases where submersible, pad-mount and vault transformers must be replaced on a spot basis to reduce risks of PCB contaminated oil spills. (More information on Toronto Hydro's PCB risk reduction strategy is provided at the end of this section.)



Figure 22: Corrosion on top of a Submersible Transformer

The Underground System Renewal – Downtown program also introduces a proactive cable chamber renewal plan. Toronto Hydro has historically managed these civil assets reactively. However, the latest Asset Needs Assessment identified a significant population of cable chambers with at least material deterioration. There are 89 cable chambers currently in HI5 condition and 398 in HI4 condition. Managing the condition-related risk of failure of cable chambers is essential to ensuring the safety and long-term viability of the underground system. Toronto Hydro developed a plan to rebuild an estimated 75 cable chambers and an estimated 120 cable chamber roofs proactively over the 2020-2024 period to help prevent condition demographics from deteriorating further.

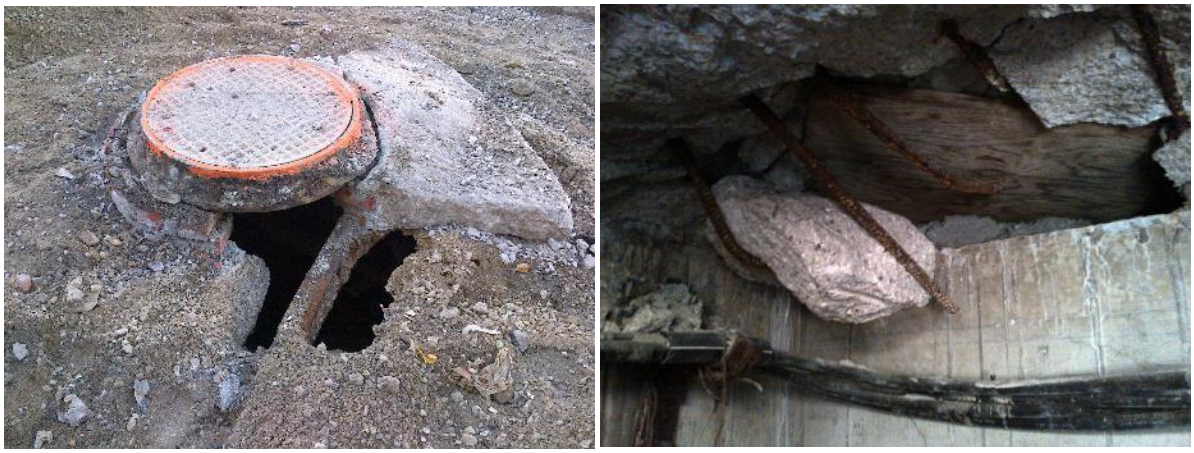


Figure 23: Cable Chamber roof in HI5 condition (left), Cable chamber roof inside view (right)

3. Network Asset Renewal Investments

Failure and obsolescence risks related to network system assets are addressed by Toronto Hydro's Network System Renewal (Section E6.4) and Reactive and Corrective Capital (Section E6.7) programs. The utility paced the 2020-2024 expenditure plans for these programs to maintain current system reliability performance; improve resiliency and operational efficiency of the network; prevent age, condition and obsolescence related asset risk from accumulating over the period; and to continue to reduce and eliminate safety and environmental risks (and other deficiencies) associated with legacy assets and asset configurations.

As discussed in Section D2.2.3, the network system is designed to handle normal failure scenarios better than Toronto Hydro's other system configurations. For this reason, it plays an important strategic role in meeting the reliability expectations of interruption-sensitive customers in the City's core, which contains dense, high-traffic commercial and residential areas. However, in the case of catastrophic failures such as a vault fire, the entire secondary network grid that is connected to the vault must be dropped (i.e. de-energized) until the situation can be safely remedied, which can take over 24 hours. Furthermore, these types of failures can result in risks to public safety and the environment. To minimize these scenarios, Toronto Hydro takes a highly proactive approach to network equipment and vault maintenance and renewal.



Figure 24: Damage from a network vault fire

As noted in Section D2.1.2, seven of the 10 highest rainfall years on record have occurred in the last decade, raising the risk of flooding on the network system. Toronto Hydro developed a plan for the 2020-2024 period that targets non-submersible network units, as these units are susceptible to water ingress and elevated failure risks even when in good condition. In Phase 2 of Customer Engagement, customers expressed support for reducing the risk of network vault fires and flooding,[8] and Toronto Hydro is pacing investments to accomplish this outcome. Condition projections suggest that 267 units will be in HI4 and HI5 condition by 2024 without intervention. Toronto Hydro is planning to replace 43 units in 2018-2019 and 200 units in 2020-2024. Given customer interest in this program's objectives, Toronto Hydro plans to report its progress on this plan as a 2020-2024 Custom Performance Measure under the Safety outcome category (see Section C).

The utility also plans to complete its planned replacement of obsolete and high-risk Automatic Transfer Switches and Reverse Power Breakers, first introduced in the utility's 2012-2014 capital plan, by 2022. These assets are prone to catastrophic failure due to functional obsolescence and can no longer be easily repaired.

To mitigate risks to public and employee safety, the utility also plans to continue proactively renewing network vaults in poor condition. As shown in Figure 25 below, the number of vaults in HI4 and HI5 condition is expected to grow from 40 to over 110 by 2024 without intervention. Network vault rebuilds are complex projects in congested areas and require significant planning efforts,

[8] Exhibit 1B, Tab 3, Schedule 1, Appendix A, Appendix 2.3, p. 28

making it necessary for the utility to maintain a steady and proactive renewal program over time. The utility is planning to proactively address 33 vaults over the 2020-2024 period.

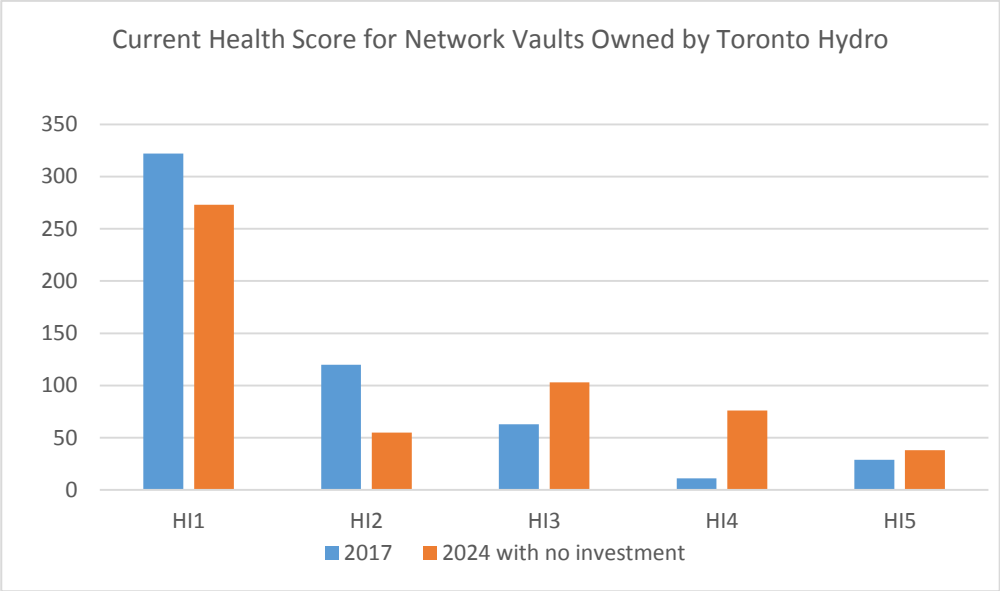


Figure 25: Current and 2024 health scores for Toronto Hydro network vaults.

4. Stations Renewal Investments

Failure and obsolescence risks related to stations assets are addressed by Toronto Hydro's Stations Renewal (Section E6.6) and Reactive and Corrective Capital (Section E6.7) programs. Stations assets are the highest criticality assets on the system due to their potential for causing widespread and lengthy interruptions in the event of failure. (For more information on Stations failure impacts, refer to Section E6.6.) Stations asset replacement projects are highly complex and typically require long lead and execution timelines. In light of these operational constraints and a growing backlog of stations renewal needs, Toronto Hydro developed a plan for the 2020-2024 period that addresses stations equipment at a faster pace than in the 2015-2019 period. This pace of execution has been enabled by a focused effort by the utility to expand its resource pool for stations project design and field work, and other operational improvements. The utility expects to be able to perform previously delayed stations renewal work in the downtown area due to the impending completion of the Copeland Transformer Station ("TS") project, which will alleviate operational constraints in the core of the City. The work planned for the 2020-2024 period must be performed to support the utility's safety, reliability, and resiliency objectives, and to ensure that stations-related asset risk does not increase to unsustainable levels.

The Asset Needs Assessment for stations assets identified a significant backlog of aging equipment, with 40 percent of switchgear, 51 percent of power transformers, 13 percent of outdoor breakers, and 35 percent of DC battery systems operating at or beyond their useful life. The need for investment was further underscored by the high proportion of assets in moderate, material, and end-of-serviceable-life condition, as shown in Figure 26 below.

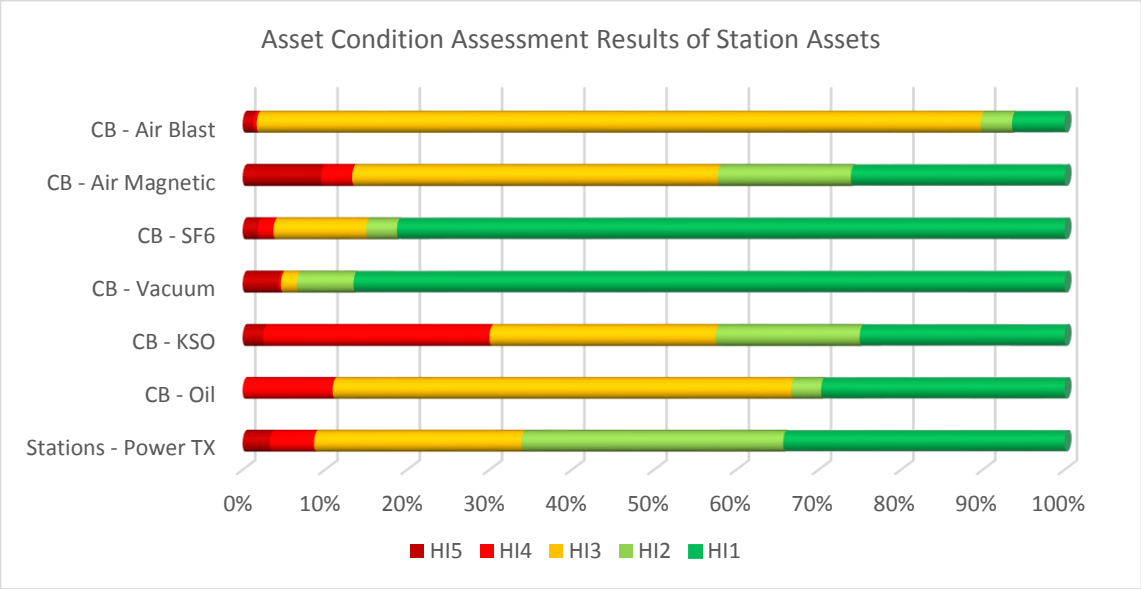


Figure 26: Asset Condition Assessment of Station Assets

Overall, in support of its objectives to maintain reliability, improve system resiliency, and manage the long-term viability of the distribution system, Toronto Hydro developed plans to execute the following work in the 2020-2024 period:

- Replace five TS switchgear units – serving the highest-density areas of Toronto – all of which are beyond their 50-year useful life and feature obsolete circuit breaker designs contained within non-arc resistant enclosures (elevating safety risks for employees);
- Replace nine TS outdoor circuit breakers prioritized based on condition, age, load served, and PCB content;
- Replace 61 TS outdoor switches that are beyond their 50-year useful life, reducing the risk of lengthy interruptions for customers in the North York area of Toronto;
- Remove 12 aging and deteriorating Municipal Station ("MS") switchgear with obsolete oil circuit breakers and a lack of SCADA functionality;

- Replace 10 power transformers, all of which will be older than 60 years of age by the time of replacement and have identified condition concerns such as high power factor and low insulation resistance;
- Replace 11 end-of-life MS primary supplies, all but one of which will have assets older than 60 years of age at the time of replacement;
- Renew critical stations communications infrastructure – including installing six new remote terminal units ("RTUs"), renewing 39 existing RTUs, upgrading protections at five pilot-wire locations, and replacing 45 kilometres of old copper control cable – to improve system resiliency and maintain overall stations reliability; and
- Renew end-of-life stations battery and ancillary systems.

5. PCB Risk Reduction Strategy

A driver and prioritization consideration for multiple renewal programs is Toronto Hydro's risk mitigation strategy for PCB contaminated oil spills. As explained in Section D2, Toronto Hydro defines "PCB at-risk equipment" as an asset that (i) is known to contain oil with greater than 2 ppm concentration of polychlorinated biphenyl ("PCB"), or (ii) has an unknown concentration of PCB and was manufactured in 1985 or earlier (and is therefore at a high risk of containing PCBs). Due to the toxic and persistent nature of PCB, Environment Canada's PCB Regulations prohibit the use of equipment that contains greater than 50 ppm PCBs, or the release of greater than one gram of PCBs, which could result from an oil leak with significantly less than 50 ppm. The City of Toronto also enforces its own PCB-related bylaws with a near-zero tolerance for the discharge of PCBs into the storm and sanitary sewer systems. The vast majority of PCB at-risk equipment will be operating beyond useful life by 2020, necessitating a proactive strategy to avoid the significant and highly undesirable consequences of a PCB contaminated oil spill on the environment and local communities.

Toronto Hydro is endeavouring to eliminate the risk of oil spills containing PCBs on its overhead, underground, and network systems by 2025 through inspection and testing under its maintenance programs (discussed in Exhibit 4A, Tab 2, Schedules 1-4) and through targeted asset replacement in capital programs such as Overhead System Renewal (Exhibit 2B Section E6.5), Underground System Renewal (Sections E6.2 and E6.3), Stations Renewal (Exhibit 2B Section 6.6), and Reactive and Corrective Capital (Section E6.7). Refer to each of these programs for a description of how the planned investments address PCB at-risk equipment. Due to the importance of this strategy, Toronto Hydro is proposing to track and report the number of PCB contaminated oil spills as a Custom

Performance Measure during the 2020-2024 period, with an objective to improve this environmental outcome over the period. Refer to Section C for more information.

6. Grid Modernization in System Renewal

Toronto Hydro's ongoing grid modernization efforts are supported by System Renewal activities such as Stations Control and Monitoring, Network Unit Renewal, and various other programs that replace deteriorating and obsolete assets with assets that have remote capabilities. These investments help to support reliability outcomes and improve operational efficiency.

E2.2.3.3 System Service Program Expenditures

Toronto Hydro developed a 2020-2024 System Service expenditure plan that targets a select number of system enhancement needs that support the utility's asset management objectives for the period and deliver customer value using technology-driven solutions.

Table 4: 2020-2024 System Service Expenditure Plan ($ Millions)

Programs	2020	2021	2022	2023	2024
Energy Storage Systems	1.0	3.7	3.8	1.0	1.0
Network Condition Monitoring and Control	7.6	10.2	12.6	15.3	17.4
Stations Expansion	19.5	40.0	49.3	12.5	15.2
System Enhancements	6.2	6.2	5.6	4.8	4.9
System Service Total	**34.2**	**60.1**	**71.3**	**33.6**	**38.5**

1. Capacity Expansion and Demand Response

The largest investment for the 2020-2024 period is in the Stations Expansion program (Section E7.4). However, with the Copeland TS project coming to a close in 2015-2019 and a stable overall system loading trend, the stations level capacity needs for the 2020-2025 period are lower than in Toronto Hydro's previous DSP.

Investments for the 2020-2024 period are driven by anticipated bus-level constraints for stations serving areas of high growth and development, and are fully aligned with the results of IRRP activities conducted in coordination with the IESO and Hydro One. The most recent planning document from this process is the Needs Assessment Report for the Toronto Region ("Needs Assessment" or "NA"). Refer to Section B for more information on coordinated system planning with third parties. The planned expenditures will add or free-up over 400 MVA, supporting the sustainment of reliability,

operational flexibility, and connections capabilities as indicated by Toronto Hydro's proposed System Capacity measure (see Section C).

Toronto Hydro's expansion plans and their alignment with regional planning outputs are summarized in Tables 5-7 below.

Table 5: Needs Identified in Previous Regional Infrastructure Plan ("RIP")

Needs Identified in Previous RIP	NA Report Section	RIP Report Section	Stations Expansion Narrative
South-West Toronto – Station Capacity	*7.2.1*	*7.2*	Addressed with Horner expansion in 2020-2024 Stations Expansion plan.
Downtown District – Station Capacity	*7.2.2*	*7.3*	Addressed with Copeland TS – Phase 2 expansion in 2020-2024 Stations Expansion plan.

Table 6: End-of-Life Assets – Metro Toronto Region

EOL Asset	Replacement/ Refurbishment Timing	Details	Stations Expansion Narrative
Charles TS T3/T4 Transformers	*2024-2025*	EOL Transformers and other high voltage ("HV") equipment are identified at these stations for replacement with higher rated equipment, and are discussed further in Section 7.1.1.2 of NA report	Included in 2020-2024 Stations Expansion plan.
Duplex TS: T1/T2 Transformers	*2023-2024*		Included in 2020-2024 Stations Expansion plan.
John TS: T1, T2, T3, T4, T6 Transformers and 115 kV breakers	*2024-2025*	EOL Transformers and other HV equipment are identified at these stations where scope for replacement is to be further assessed, and are discussed further in Section 7.1.1.3 of NA report.	Included in 2020-2024 Stations Expansion plan.

Table 7: 2020-2024 Hydro One Contribution Projects based on the most recent Needs Assessment report

Project	Project Type
Horner Expansion	Station Capacity Expansion
Charles TS – T3/T4 Upgrade	Transformer Upgrade
Duplex TS – T1/T2 Upgrade	Transformer Upgrade
Windsor TS – T1/T2/T3/T4 Upgrades	Transformer Upgrade
Finch TS B-Y Replacement	Bus Replacement

In addition to traditional expansion investments, the Stations Expansion program includes a continuation of Toronto Hydro's "Local Demand Response" activities introduced in the 2015-2019 DSP. These "Conservation First" investments involve installing battery storage and implementing targeted demand response incentive programs to reduce peak demand by 10 MW, allowing the utility to defer an estimated $135 million of expansion investments at Cecil TS and Basin TS. These investments support the utility's 2020-2024 objectives of responding effectively to Public Policy and minimizing average rate increases over the period.

2. System Design Enhancements and Modernization

Through the Asset Needs Assessment and the Portfolio Planning process, Toronto Hydro identified several targeted opportunities to address asset risk and enhance customer value by improving system design and investing in system modernization. The bulk of this planned investment is in the System Enhancements (Section E7.1) and Network Condition Monitoring and Control (Section E7.3) programs. These programs will continue Toronto Hydro's efforts to identify spots on the system where asset failure risk can be mitigated, outage restoration capabilities improved, and future operational costs reduced through the installation of protection devices and remote SCADA-enabled switches and sensors.

The Network Condition Monitoring and Control program is new for 2020-2024 and arose out of the need to address performance risks and connection capability challenges on the network system. These issues risk eroding the long-term viability of the network at a time when its compact and reliable design is becoming an increasingly effective option for medium and large customers in developing, high-density areas of the City. Toronto Hydro's modernization strategy for the network will see the utility target 90 percent coverage of the network system with SCADA enabled monitoring and control capabilities by 2024. This highly cost-effective investment supports multiple outcomes

by allowing the utility to: (i) remotely identify flood, fire and oil deficiency risks to prevent outages and environmental and safety incidents; (ii) improve resiliency by sustaining service for significantly more customers during multiple contingency events; (iii) gain accurate real-time loading information, which will allow Toronto Hydro to more efficiently connect more customers to the network; and (iv) reduce maintenance costs through remote condition monitoring. Toronto Hydro's planned pacing in this program is aligned with strong customer support received in Phase 2 of Customer Engagement (see E2.3 below).

The utility is also proposing a continuation of its Energy Storage Systems program (Section E7.2) in 2020-2024, with modest investments planned to support grid performance (e.g. power quality issues) and to enable the connection of renewable generation projects. Toronto Hydro is also planning to offer customer-specific battery storage solutions in accordance with "beneficiary pays" principles. For more information, refer to Section E7.2.

3. Grid Modernization in System Service

Most of the investments in the System Service category support the further expansion of grid modernization technologies across the system, including energy storage systems and SCADA-enabled monitoring and control equipment.

E2.2.3.4 General Plant Expenditures

Toronto Hydro developed a General Plant expenditure plan leveraging the asset management principles and strategies outlined in Sections D4 ("Facilities Asset Management"), D5 ("IT Asset Management"), and Section E8.3 ("Fleet and Equipment Services"). The utility held overall expenditure levels in this category in line with spending of the 2015-2019 period. Investments in this category are necessary to keep the utility running efficiently and effectively and are generally driven by lifecycle cost management principles, business continuity needs, and emerging customer needs and preferences.

Table 8: 2020-2024 General Plant Expenditure Plan ($ Millions)

Programs	2020	2021	2022	2023	2024
Facilities Management and Security	11.6	11.8	12.1	12.3	12.6
Fleet and Equipment	8.6	8.9	8.5	8.7	7.8
IT/OT Systems	54.8	55.7	49.5	56.6	64.8
Control Operations Reinforcement	3.9	17.4	18.9	-	-
General Plant Total	**78.8**	**93.7**	**89.0**	**77.7**	**85.2**

1. Fleet and Facilities

The utility's 2020-2024 Facilities Management and Security (E8.2) and Fleet and Equipment (E8.3) needs are primarily driven by asset obsolescence, condition and lifecycle cost analysis for major work centres, stations buildings, physical security systems, and vehicles. Toronto Hydro's planned investments in these programs are optimized to minimize overall lifecycle costs, mitigate safety and security risks, improve efficiencies, and ensure business continuity.

2. Information and Operational Technology (IT/OT)

The utility's planned IT/OT Systems investments (E8.4) for the 2020-2024 period are primarily directed at maintaining current business capabilities, with the remainder directed at expanding existing business capabilities or driving new ones in alignment with outcome objectives and customer needs. The IT/OT program consists of the following key elements:

- **IT Hardware:** Planned expenditure levels were developed to align with asset lifecycles for backend assets (e.g. servers) and endpoint assets (e.g. laptops) that require replacement, and to meet anticipated business needs as forecasted through business planning.
- **IT Software:** Planned expenditure levels were developed in anticipation of upgrade requirements (i.e. security patches, version upgrades to secure vendor support, etc.) for major IT systems such as the utility's Enterprise Resource Planning ("ERP") and Customer Information System ("CIS"), as well as minor applications. Expenditures also include software enhancements to improve and expand business functionality (e.g. data analytics), including responding to emerging business risks (e.g. cybersecurity), customer needs and preferences (e.g. credit card processing), and regulatory compliance needs.
- **Communication Infrastructure:** Planned expenditure levels were developed to address communications infrastructure that is relied upon by core utility operations to maintain and

operate the distribution system in a safe and reliable manner. Proposed investments will address functional obsolescence and reliability risk (e.g. upgrading the communications technology that supports the utility's critical SCADA system), safety and operational risks (i.e. underground radio expansion) and support for system modernization investments (e.g. fibre-optic plant replacement and expansion to support Network Condition Monitoring and Control).

To inform the level of overall IT/OT expenditures, Toronto Hydro procured an independent benchmarking study by Gartner Consulting (see Section E8.4, Appendix A), which concluded that the utility's total IT expenditures per user in both 2017 and 2020 benchmark competitively against industry peers. Gartner also concluded that, in both years, the distribution of Toronto Hydro's IT investments "by cost category, investment category, and functional area are all comparable to the peer group, with some variation but no significant issues identified."

3. Control Operations Reinforcement

As discussed in Section D2, with the growing economic and institutional importance of the City of Toronto and the existence of threats from factors such as climate change and terrorism, operational resilience of the utility is becoming a greater concern for Toronto Hydro, its stakeholders and its customers. Prior to the business planning process, Toronto Hydro re-evaluated the resiliency of its primary control centre operations and performed a gap analysis on its existing and limited backup control centre. The results of this analysis led to the identification of the need to create a fully functional dual control centre at a separate physical location from the existing primary control centre. Toronto Hydro plans to install this control centre during the 2020-2024 period.

To assess Toronto Hydro's investment in a dual control centre, the utility retained London Economics International ("LEI") to undertake a review of comparator utilities (see Section E8.1, Appendix A). LEI completed a review of various utilities in North America that have distribution operations with more than one control centre. These facilities were fully functional and were able to take over full operational functions from the primary control centre. The review confirmed that utilities serving a critical load in North America invest in more than one fully functioning control centre to support resiliency, increase reliability, and ensure quick recovery from terrorist threats and natural disasters, for example earthquakes and floods.

4. Grid Modernization in General Plant

Grid modernization efforts are supported by various IT software and communications investments (e.g. telecom installation) during the 2020-2024 period. The Control Operations Reinforcement program will also support continuity of grid monitoring and control operations in emergencies.

E2.2.4 Portfolio Reporting

The Portfolio Reporting element of IPPR directly informed the development of capital program expenditure plans for the 2020-2024 period. In particular, Toronto Hydro analyzed actual project accomplishments and costs in each program to establish the project- and/or volume-based assumptions that would form the basis of the high-level program cost estimates for the 2020-2024 period.[9] Due to the unique nature of work in each capital program (e.g. large discrete assets vs. area rebuilds; like-for-like vs. reconfiguration), Toronto Hydro's planners relied on different estimating approaches for different programs, leveraging both historical information and professional judgement. These assumptions were challenged and refined throughout the IPPR process and business planning.

E2.2.4.1 Capital Program Efficiency and Unit Cost Benchmarking

To assess the actual efficiency with which Toronto Hydro executes its system investment and maintenance programs, the utility retained UMS Group ("UMS") to perform a capital and maintenance unit cost benchmarking exercise. The utility provided UMS with actual, all-in capitalized unit costs for major asset classes for the 2014-2016 period. UMS performed a normalized comparison of these results to those of peer utilities across North America. The results of this analysis are provided in Table 9 below.

[9] For many DSP programs, it is practically infeasible to develop project-specific details for a five to seven year planning horizon. Planners used a mix of analogous and parametric estimating techniques to create high-level estimates for the programs in these situations. Analogous estimating involves creating a "top-down" estimate of a project's cost and duration using experience with similar projects. Parametric estimating involves identifying volumetric costs and scaling the project or program estimate by the volume of units.

Table 9: Results of UMS Group's Unit Cost Benchmarking Study

Category / Program	Quartile			
	Top	2nd	3rd	Bottom
Wood Pole		X		
UG Cable (XLPE)		X		
OH Switches (Manual and Remote / Motor-Operated		X		
Pole Top Transformer			X	
Padmount / UG Transformer		X		
Network Transformer / Protector		X		
Breaker (SF_6, Oil, and Vacuum)		X		
Vegetation Management		X		
Pole Test and Treat		X		
Overhead Line Patrol		X		
Vault Inspection		X		

As seen above, Toronto Hydro compared favourably to its industry peers in nearly all areas. These results provide an indication that the utility has delivered its large capital program cost-effectively through rigorous project development, program management, procurement, and execution practices. For the full UMS report, please refer to Exhibit 1B, Tab 2, Schedule 1, Appendix B.

E2.3 Customer Priorities, Needs and Preferences in Capital Planning

As described in Section 1B, Tab 3, Schedule 1, Toronto Hydro undertook extensive Customer Engagement as part of business planning for this application. The utility augmented its routine, ongoing customer engagement by engaging Innovative Research Group ("Innovative") to design and implement a planning-specific Customer Engagement process. This process was structured in two phases:

- In **Phase 1,** Innovative used a range of techniques to assess customers' needs and preferred outcomes. Quantitative methods provided statistically-valid results (e.g. surveys directed at residential, small business and Key Accounts customers). Qualitative methods provided constructive context to the statistical results (e.g. focus groups directed at residential, small business and mid-market customers). The results of this phase directly informed the strategic parameters for the business plan and informed decision-making throughout the planning process that produced the penultimate capital expenditure plan.
- In **Phase 2**, Innovative took Toronto Hydro's plan back to customers to: (i) confirm the needs, preferences and priorities identified in Phase 1, (ii) solicit customer feedback on the utility's penultimate plan, and (iii) explore trade-offs for certain capital programs. The utility used the results of this phase to refine its business plan.

Further details on the engagement process, the methods used, and the engagement results can be found in Section 1B, Tab 3, Schedule 1 ("Customer Engagement") and in the final report from Innovative ("the Innovative Report") at Section 1B, Tab 3, Schedule 1, Appendix A. The following sections provide a detailed overview of how the Customer Engagement results are reflected in the 2020-2024 Capital Expenditure Plan.

E2.3.1 Phase 1 Customer Engagement Results

Key results of Phase 1 included identifying the outcomes that Toronto Hydro's customers care about (i.e. their priorities) and understanding how they rank those priorities. Low-volume (i.e. residential and GS < 50 kW) customer focus groups conducted at the beginning of Phase 1 provided the qualitative information necessary for Innovative to identify the following set of customer priorities:

1) Delivering reasonable electricity prices;
2) Ensuring reliable electrical service;
3) Ensuring the safety of electrical infrastructure;

4) Providing quality customer service;
5) Helping customers with electricity conservation and efficient usage; [10] and
6) Enabling the electrical system to support the reduction of Greenhouse gases.[11]

Toronto Hydro used this list to develop a customer-focused Outcomes Framework, in alignment with both the utility's corporate strategic pillars and the outcomes and performance categories of the *Renewed Regulatory Framework* ("RRF"). The resulting framework, depicted in Figure 2 in Section E2.1, is focused on six key outcomes: Customer Service, Reliability, Safety, Environment, Public Policy (which includes enabling the system to support the reduction of greenhouse gases), and Financial (which includes delivering reasonable electricity prices). This became the lens through which the utility assessed the value to customers of its capital (and OM&A) program expenditure proposals during business planning. As planning progressed, the utility developed measurable objectives for its plan in each of the six outcome categories, and developed specific objectives at the program level that linked to these measurable objectives, resulting in an outcomes-oriented business plan and DSP. Refer to Exhibit 1B, Tab 2, Schedule 1 for more details on the structure of this framework and its alignment with the RRF and Toronto Hydro's strategic pillars.

In addition to identifying and categorizing customers' priorities, Innovative gathered feedback on how customers ranked these priorities. While customer preferences varied somewhat across classes, in Innovative's view, the overall feedback could be characterized by the following common issues:

1) Keeping distribution price increases as low as possible;
2) Maintaining long-term performance for customers experiencing average or better service;
3) Improving service levels for customers experiencing below average service or who have special reliability needs; and
4) Balancing other customer priorities (e.g. customer service) with the need to contain rate increases.[12]

This feedback informed Toronto Hydro's strategic parameters and outcome objectives for business planning. As discussed in Section E2.1 above, the utility sought to minimize rate increases by setting an upper capital expenditures limit that was closest to the baseline "sustainment" scenario shown in

[10] The customer priority "helping customers with electricity conservation and efficient usage" speaks to the Conservation and Demand Management ("CDM") side of Toronto Hydro's business. This priority is addressed in E2.3.1.4 below.
[11] Exhibit 1B, Tab 4, Schedule 1, Appendix A, p. 7
[12] Exhibit 1B, Tab 4, Schedule 1, Appendix A, p. 5

Figure 3 (in Section E2.1), and by limiting price increases for the residential class to no greater than 3.5 percent over the 2020-2024 period. Toronto Hydro concluded that a sustainment level of capital expenditures would provide the minimum funding necessary to:

- hold average reliability steady over the period;
- maintain long-term performance by preventing asset failure risk from increasing over the period;
- deliver targeted improvements to customers with below average reliability service; and
- maintain or, in targeted situations, improve upon the utility's performance in other priority areas (e.g. Customer Service, Safety, etc.).

As explained in Section E2.2.1, the utility refined these strategic parameters into specific asset management objectives for the 2020-2024 period (see Table 1) and developed a penultimate business plan to achieve these objectives. The following subsections describe how each of these objectives aligns with specific Phase 1 Customer Engagement results.

E2.3.1.1 Reliability and Safety Outcomes

1. Customer Views on Reliability and Safety

When asked to score the importance of their priorities (without ranking them against each other) low-volume customers identified safety, reliability and price as equally important and the most important priorities overall.[13] When these customers were then asked to rank their top three priorities, price clearly emerged as the highest priority, with 52 percent of customers choosing it first, followed by reliability at 22 percent, and safety at 8 percent.[14] Innovative notes that while safety drops to third in these rankings, this is in part because customers tend to view safety as "table stakes", i.e. a baseline requirement of a utility's operations.[15] As expressed in Toronto Hydro's corporate strategic pillars, the utility is fully aligned with customers on this point: public and employee safety is the overarching priority of the utility and is built into its culture, operations, and decision-making frameworks. On reliability, customers overall were generally satisfied with the

[13] Ibid., p. 7
[14] Ibid., p. 8
[15] Ibid., Appendix 1.1., p. 13

current level of service, with support for improving service levels for customers experiencing below average service.[16]

Mid-market customers (i.e. GS > 50 kW) expressed preferences similar to lower-volume GS customers. These customers prioritized "cost containment and short-term rate predictability."[17] Acceptance of "reasonable" rate increases appeared to be conditional in part on maintaining current reliability, which these customers generally viewed as good.[18]

For Toronto Hydro's largest commercial and industrial customers, reliability and price were again top priorities. However, "ensuring reliable electrical service" appeared to be more important for large customers than "delivering reasonable electricity prices".[19] In addition to day-to-day reliability, large customers were specifically concerned about the need to "prevent or reduce the length of prolonged power outages caused by extreme weather".[20] In fact, when large customers were asked to consider the importance of various priorities *without* ranking them, the risk of prolonged outages caused by extreme weather was seen as having the greatest importance.[21] When asked to rank their priorities, this risk came in third, behind price as the second priority and reliability as the top priority.[22] Power quality was not listed as a separate priority from reliability in the ranking exercise; however, in response to an open-ended question about potential improvements in service, 13 percent of large customers identified power quality as an opportunity.[23] Overall, a majority of large customers (56 percent) indicated they would be willing to pay more to maintain or improve reliability.[24]

2. Alignment of the Plan with Customer Preferences for Reliability and Safety

Toronto Hydro's Reliability and Safety objectives for its 2020-2024 Capital Expenditure Plan are aligned with and responsive to the customer feedback summarized above. When it comes to Reliability performance, the utility is seeking to minimize price increases by investing only what is necessary to maintain system reliability at current levels while (i) improving the experience for customers with poor reliability and power quality; and (ii) improving the resiliency of the distribution

[16] Exhibit 1B, Tab 3, Schedule 1, Appendix A, p. 5
[17] Ibid., p. 8
[18] Ibid., p. 9
[19] Ibid., p. 11
[20] Ibid., p. 10
[21] Ibid.
[22] Ibid., p. 11
[23] Ibid., p. 9
[24] Ibid., p. 11

system in light of increasing weather-related risks. As discussed in E2.1 and E2.2 above, the utility's capital expenditure plan is projected to maintain overall SAIDI and SAIFI over the plan period. Toronto Hydro is also proposing the incremental Custom Performance Scorecard measures in Table 10 to track its 2020-2024 reliability performance.

Table 10: Custom System Reliability Measures

Toronto Hydro Outcome	OEB Reporting Category	2020-2024 Custom Performance Measure	Target
Reliability	**System Reliability**	SAIDI - Defective Equipment	Maintain
		SAIFI - Defective Equipment	Maintain
		FESI-7 System	Improve
		FESI-6 Large Customers	Maintain

The utility added SAIDI and SAIFI for Defective Equipment outages as these measures are an indicator of the age, health, obsolescence, and modernization of system assets, all of which are key drivers of System Renewal and System Service investments during the period. The utility has also included Feeders Experiencing Sustained Interruptions ("FESI") measures to reflect the need, expressed by customers, to improve performance for customers experiencing below-average reliability. Refer to Section C for more information on these measures.

Toronto Hydro's plan also includes investments to improve the resiliency (i.e. the ability to handle emergency events) of the system and utility operations, which aligns with feedback received from commercial and industrial customers. These investments are discussed throughout Section E2.2 and include the renewal of major stations assets in the downtown core (Section E6.6), modernization of the network system (Sections E6.4 and E7.3), remote switching enhancements in the Horseshoe area (Section E7.1), and a project to create a dual control centre (Section E8.1).

As noted above, in addition to sustained outages, some of Toronto Hydro's commercial and industrial customers have expressed a need for improvements to power quality, including momentary interruptions, voltage sags and other issues that can have a significant impact on business operations. The utility is planning to continue addressing these concerns through a combination of targeted activities, including (i) the installation of new ION meters with added functionality that will allow for the diagnosis of customer power quality issues (Section E5.4), (ii) targeted energy storage investments to address grid issues including power quality on poor performing feeders (Section E7.2), and (iii) corrective maintenance and capital investments on worst performing feeders.

Another significant asset management objective related to customers' Safety and Reliability needs is the utility's goal to maintain and, where appropriate, reduce asset failure risk – as represented by leading indicators like asset condition – over the 2020-2024 period. This objective is necessary to support stable system reliability and safety outcomes for customers in the current period and over the long-term, in alignment with many customers' recognition of the need for Toronto Hydro's investments to be future oriented.[25] Section E2.2 describes the various ways in which the goal of either maintaining, or in some cases reducing, the level of asset risk informed the pacing of Toronto Hydro's investment programs. For example, the utility's pacing of pole replacement for the 2020-2024 period is intended to keep the condition demographics of wood poles from deteriorating over the period, which is a key issue for both Safety and Reliability on the overhead system. Similarly, Toronto Hydro plans to pace direct-buried cable replacement with the intention of preventing the significant Reliability risks related to this asset type from increasing to an extent that would result in deteriorating service and high reactive repair costs over the long-term. Given the significant investment that both of these activities drive in the 2020-2024 period, Toronto Hydro has included Custom Performance Scorecard measures that will track the utility's effectiveness in managing these risks, as shown in Table 11 below. Other System Renewal programs have been paced in a similar manner to manage asset risks and maintain performance while minimizing price increases.

Table 11: Custom Asset Management Measures

Toronto Hydro Outcome	OEB Reporting Category	2020-2024 Custom Performance Measure	Target
Reliability	Asset Management	System Capacity	Maintain
		System Health (Asset Condition)–Wood Poles	Monitor
		Direct Buried Cable Replacement	Improve

Toronto Hydro has also included a System Capacity measure under this category. Available capacity is another leading indicator of reliability performance and the ability of the system to handle contingency events. It is also an important indicator of Toronto Hydro's ability to connect customers and carry-out planned capital and maintenance work efficiently. Toronto Hydro plans to maintain current performance for this measure through investments in the Stations Expansion (E7.4) and Load Demand (E5.3) programs.

[25] Example: Ibid., Appendix 1.2, p. 11

In addition to managing failure risks for assets generally, Toronto Hydro set the following Safety-specific objectives for its capital program in the 2020-2024 period:

- Continue to reduce and eliminate public and employee safety risks, for example by removing higher-risk legacy assets from the system within a specific and reasonable timeframe;
- Strive to target zero public and employee safety incidents over the 2020-2024 period; and
- Comply with all safety regulations and standards over the 2020-2024 period.

These objectives are aligned with customer expectations for a safe distribution system. The majority of Toronto Hydro's capital programs address safety risks or improve the safety of the system or the utility's operations. Among these are a number of programs that address higher-risk legacy assets that the utility is aiming to remove entirely. Box construction poles and non-submersible network units are two examples of legacy assets that present risks to employee and public safety in the congested downtown core. Toronto Hydro plans to track its progress in eliminating these assets during the 2020-2024 period with the measures in Table 12.

Table 12: Custom Safety Measures

Toronto Hydro Outcome	OEB Reporting Category	2020-2024 Custom Performance Measure	Target
Safety	Safety	Total Recorded Injury Frequency	Maintain
		Box Construction Conversion	Improve
		Network Units Modernization	Improve

Toronto Hydro also plans to report on its Total Recorded Injury Frequency metric during the 2020-2024 period. This is a long-standing measure of employee safety at the utility.

In addition to the aforementioned custom measures, the utility plans to continue meeting all of the OEB's existing Safety and Reliability performance standards as reporting on the Electricity Distributor Scorecard (refer to Exhibit 1B, Tab 2 for more information).

E2.3.1.2 Customer Service Outcomes

1. Customer Views on Customer Service

"Providing quality customer service" was not ranked as a top three priority in any of the customer classes that were formally surveyed. However, the results of the mid-market focus groups led Innovative to conclude that Customer Service appeared to be the third ranked priority for GS > 50 kW customers. Specifically, providing accurate and proactive communications around outages was seen

as a priority, as was enhancing customer service to match emerging technological capabilities (e.g. receiving bills by email and creating master accounts to manage multiple bills).[26]

Where customers in other classes provided feedback on Customer Service, it tended to echo the views of the mid-market GS customers. For example, low-volume customers were also interested in receiving accurate restoration times for outages and were interested in tools to make billing, account management, and usage information easily accessible.[27] Large customers were generally satisfied with their level of Customer Service and were mainly focused on additional support in implementing CDM programs.[28] A minority of large customers identified other opportunities to improve their Customer Service, e.g. improving communications around scheduled outages.

2. Alignment with Customer Preferences for Customer Service

The type of feedback that Toronto Hydro received on Customer Service was generally aligned with what the utility hears from its customers on an ongoing basis. Toronto Hydro is working to continuously improve its capabilities around outage communications, billing preferences, and information accessibility through operational improvements and targeted capital investments; for example, installations of next generation metering technology (Section E5.4) with "last gasp" capabilities will allow the utility to find the specific location of an outage faster, supporting improved outage response and outage communications. Planned IT Software upgrades and enhancements will also support improvements to the customer experience of interacting with the utility through digital platforms, and improvements to accurate and timely communication with customers during prolonged power outages (Section E8.4). With respect to receiving electronic bills and access to usage information and other data, Toronto Hydro plans to continue improving the number of customers on "eBills" and will report this under the Customer Service outcome as a Custom Performance Measure for 2020-2024. The movement to eBills is also a continuing source of OM&A cost savings.

Table 13: Custom Customer Service Measures

Toronto Hydro Outcome	OEB Reporting Category	2020-2024 Custom Performance Measure	Target
Customer Service	**Customer Satisfaction**	Customers on eBills	Improve

[26] Ibid., p. 6
[27] Ibid.
[28] Ibid.

Toronto Hydro generally performs at or above standard on the OEB's Electricity Distributor Scorecard measures and Electricity Service Quality Requirements for Customer Service and intends to continue meeting or exceeding the OEB's standards in these areas. This includes connections activities, which were not a concern of the customers engaged in the Innovative Report (as they were already connected customers), but are nonetheless an important driver of System Access and capacity related investments in the 2020-2024 period. As noted in Table 1, Toronto Hydro's objective is to continue connecting customers of all types (including distributed energy resources) on time and cost-effectively, without harming system performance for existing customers.

E2.3.1.3 Environmental Outcomes

With the exception of enabling the grid to reduce greenhouse gases (which is a Public Policy outcome under Toronto Hydro's Outcomes Framework) customers did not identify the environment as a distinct priority, which could be due to a lack of awareness around the environmental risks or issues related to distribution assets. Operating the utility in an environmentally sustainable manner is an important outcome for Toronto Hydro and one that directly affects customers and stakeholders. For the 2020-2024 period, Toronto Hydro's asset management objectives for the Environment include the following:

- Endeavour to eliminate the risk of PCB-contaminated oil spills by 2025.
- Reduce the system's impact on the environment caused by greenhouse gas emissions and oil leaks of all types.
- Comply with all environmental regulations and standards over the 2020-2024 period.

While the utility's PCB risk mitigation objective for the 2020-2024 period is categorized as an Environment outcome, it is aligned with customer expectations for Safety. As discussed in E2.2.3.2, the risk of PCB oil spills is both an environmental issue and, due to the toxic and persistent nature of PCB, a public health and safety concern. Toronto Hydro is required to address these risks in accordance with legislation and City bylaws, and the utility plans to track and report on the number of spills containing PCBs over the 2020-2024 period as a Customer Performance Scorecard measure, as noted in Table 14. The utility's System Renewal (and maintenance) programs deal with various other environmental compliance risks, including the risk of oil spills generally.

Table 14: Custom Environment Measures

Toronto Hydro Outcome	OEB Reporting Category	2020-2024 Custom Performance Measure	Target
Environment	Environment	Oil Spills Containing PCBs	Improve
		Waste Diversion	Monitor

E2.3.1.4 Public Policy Outcomes

While customers typically did not explicitly reference public policy in discussions and responses, many customers did provide feedback on certain topics that are influenced or driven by provincial energy policy. The main focus of customers in this regard was CDM. As noted at the beginning of E2.3.1, "helping customers with electricity conservation and efficient usage" is a common interest across customer classes that speaks to the CDM side of Toronto Hydro's business.[29] As discussed in Section 1B, Tab 2, Schedule 1, Toronto Hydro intends to continue implementing CDM programs and is on track to fulfil its CDM targets set by the IESO by 2020.

Most of the utility's CDM programs are not rates funded. However, the utility's business plan does include a continuation of the utility's targeted Local Demand Response initiative, which features rates-funded demand response activities to defer distribution infrastructure. Details on this activity can be found in Section E7.4 (Stations Expansion). This program supports the "Conservation First" objectives of the Long-Term Energy Plan and contributes to minimizing price increases in the utility's business plan.

Enabling the electrical system to support the reduction of greenhouse gases is another Public Policy related activity that was identified as a priority for customers. While, on net, both low-volume and large customers viewed this priority as important,[30] it did not rank highly compared to other priorities. Large customers ranked this as the lowest priority, while low volume customers ranked it as the fourth most important priority behind Safety and ahead of conservation/efficient usage and Customer Service.[31] For the 2020-2024 period, Toronto Hydro's planned investments in this area are exclusively related to enabling the connection of renewable energy generation ("REG") projects in accordance with the utility's obligation to provide access to generation customers, and in strict alignment with the forecasted volume of REG connections (as reviewed and supported by the

[29] Ibid.
[30] Ibid, p. 7 and p. 10
[31] Ibid., p.8 and 11

IESO).[32] As discussed in E2.2.3.1, Toronto Hydro plans to meet this demand through investments in the Customer Connections program (E5.1), the Generation Protection, Monitoring, and Control program (E5.5), and the Energy Storage Systems program (E7.2). The utility will continue to report its performance in connecting renewable generation customers through the Connection of Renewable Generation measures on the OEB's Electricity Distributor Scorecard.[33]

E2.3.1.5 Financial Outcomes/Price

As noted at the beginning of this section, overall feedback from customers was characterized by a general preference to keep prices as low as possible, balancing other customer priorities with the need to contain rate increases. Low-volume and mid-market customers ranked price as their top priority, while large customers ranked reliability as the top priority, just ahead of price.

As discussed in detail in E2.1 and E2.2, Toronto Hydro developed a capital plan that made the necessary trade-offs between improvements and price to ensure the delivery of performance and service outcomes that align with customer needs and preferences while minimizing bill impacts. Leveraging the outputs of its asset management tools and processes, Toronto Hydro's plan was calibrated to include only the expenditures necessary to meet these objectives, including the overarching customer priorities of maintaining average reliability now and in the long-term, improving resiliency, and prudently mitigating safety risks over the 2020-2024 period.

In addition to the Cost Control measures reported on the OEB's Electricity Distributor Scorecard, and in recognition of the importance to customers of cost control and price mitigation over this period, Toronto Hydro plans to report on the following custom measures as further indication of the cost efficiency of the utility's system plan over time.

Table 15: Custom Financial Measures

Toronto Hydro Outcome	OEB Reporting Category	2020-2024 Custom Performance Measure	Target
Financial	Cost Control	Average Wood Pole Replacement Cost	Monitor
		Vegetation Management Cost per Km	Monitor

These measures are discussed in detail in Section C of the DSP.

[32] Section 2B, Appendix F
[33] Refer to Exhibit 1B, Tab 2, Schedule 1

E2.3.2 Phase 2 Customer Engagement Results

Innovative translated the penultimate plan developed using the Phase 1 Customer Engagement results into consultation materials for the second phase of engagement. The objective of Phase 2 was to:

- confirm the customer needs, preferences and priorities identified in Phase 1;
- solicit customer feedback on Toronto Hydro's planning development process and the content of its proposed plans and subsequent rate impact; and
- identify customer preferences towards particular capital projects where trade-offs on pacing exist.[34]

E2.3.2.1 Needs, Preferences and Priorities

Innovative found that a "strong majority" of customers were both familiar with Toronto Hydro and satisfied with the services they receive.[35] Survey results confirmed that customers in the low-volume classes ranked price as the top priority, reliability as the second priority, and safety as the third. For mid-market GS customers – who were not formally surveyed in Phase 1 – price and reliability continued to be first and second priority, as identified in the previous focus groups; however, safety took the place of outage communications as the third priority.[36] Large customers reaffirmed their priorities related to reliability, price, and outages caused by extreme weather.[37]

A strong majority of customers did not identify any missing priorities from those identified by customers in Phase 1.[38] Furthermore, a clear majority responded that they felt that Toronto Hydro's Customer Engagement process "seemed like a good way to bring customer needs and preferences into Toronto Hydro's plan."[39]

E2.3.2.2 Opinion of Toronto Hydro's Proposed Plan

Innovative initially presented customers with a general description of the approach behind Toronto Hydro's penultimate plan (e.g. "[…] focuses on delivering current levels of reliability") and provided

[34] Ibid., p. 13
[35] Ibid.
[36] Ibid., p. 14
[37] Ibid., p. 19
[38] Ibid., p. 15
[39] Ibid.

them with the associated bill impacts. As noted in the Innovative Report, in the absence of a discussion of specific benefits and trade-offs for customers, a plurality of participants did not agree with Toronto Hydro's approach, which, in Innovative's view, highlighted "the general concern about delivering reasonable electricity prices […]."[40] Innovative notes that "this is the only trade-off question where respondents appear to place price concerns above the maintenance of reliability and targeted improvements," and that "as customers became more engaged in discussing more detailed trade-offs, their responses favoured the other outcomes over bill impacts."[41]

After considering and providing feedback on the pacing and prioritization of various capital programs and activities, customers were asked whether Toronto Hydro should stick with its proposed plan, improve service, or scale back the plan. A majority of customers across all classes either supported sticking with the plan as proposed or improving service. A plurality of customers in the residential and small business (i.e. GS < 50 kW) classes, and a majority of customers in the mid-market class (GS > 50 kW), supported the plan as proposed. Of the 37 large customers that completed the Key Account online survey, 29 felt that Toronto Hydro should either exceed the current plan to improve services beyond what is being proposed (4 of 37) or stick with the current plan and its expressed outcomes (25 of 37).[42]

E2.3.2.3 Program Specific Feedback and Final Plan Adjustments

Customers were asked to provide feedback on the pacing and prioritization of programs in areas where Toronto Hydro felt it could adjust pacing to achieve greater benefits. The two categories of programs that were presented to customers were "Addressing Safety and Reliability" and "Innovation and Planning for the Future". As Innovative notes, "a majority of customers in each rate class support either the current proposed pace of investments or an accelerated approach and associated outcomes for all six programs […]" in the "Addressing Safety and Reliability" category, which included rear lot conversion, direct-buried cable replacement, lead cable replacement, network unit replacement, cable chamber renewal, and contingency enhancements.[43] Under the "Innovation and Planning for the Future" category, customers strongly supported investing in monitoring and control equipment (e.g. Network Monitoring and Control), with more customers

[40] Ibid.
[41] Ibid. 16
[42] Ibid. 20
[43] Ibid.

indicating that Toronto Hydro should be spending more on these investments rather than reducing the current pace. Customers did not support doing more than planned in the other programs in this category.[44]

As discussed in Sections E2.1 and E2.2, Toronto Hydro took this feedback into account as it refined and finalized its 2020-2024 Capital Expenditure Plan. The utility took customers' support for the overall plan and the Customer Engagement process as confirmation that the plan achieves an appropriate balance between addressing long-term system needs and risks, delivering the outcomes that customers need and prefer, and keeping price increases as low as possible. Given the particularly strong support across customer classes for programs that address the risk of network vault floods and fires (i.e. Network Unit Renewal and Network Condition Monitoring & Control), Toronto made minor adjustments to the pace of these programs to address these issues at an accelerated pace over the 2020-2024 period. Refer to E2.2.3.2 and E2.2.3.3 for more details.

[44] Ibid., p. 17

E3 System Capability Assessment for Renewable Energy and Conventional Generation

This section provides information on the capability of Toronto Hydro's distribution system to accommodate renewable energy generation ("REG") and other distributed generation ("DG") connections. This information includes REG applications, overall DG connection projections, the distribution system's ability to connect, as well as known constraints on the distribution system.

E3.1 Applications

Since the introduction of the *Green Energy and Green Economy Act, 2009*, Toronto Hydro has responded to over 8,000 inquiries from customers and developers seeking to connect generation under various programs such as IESO programs (FIT, HCI, PSUI-CDM, RESOP, HESOP),[1] Net-Metering, Energy Storage, Combined Heat and Power ("CHP"), Closed Transition and Load Displacement. A wide range of proponents have submitted project applications, including many schools, housing developments, large grocery stores, condominium corporations, and department stores.

As of the end of 2017, Toronto Hydro has connected nearly 1,800 unique DG connections to the distribution grid. Figure 1 provides an overview of existing DG connections within Toronto Hydro's service territory. This represents over 225 MW of generation capacity across various types of DG technologies.

[1] Feed-in Tariff ("FIT"); Hydroelectric Contract Initiative ("HCI"); Process and Systems Upgrade Initiative – Conservation Demand Management (PSUI-CDM"); Renewable Energy Standard Offer Program ("RESOP"); and Hydroelectric Standard Offer Program ("HESOP");

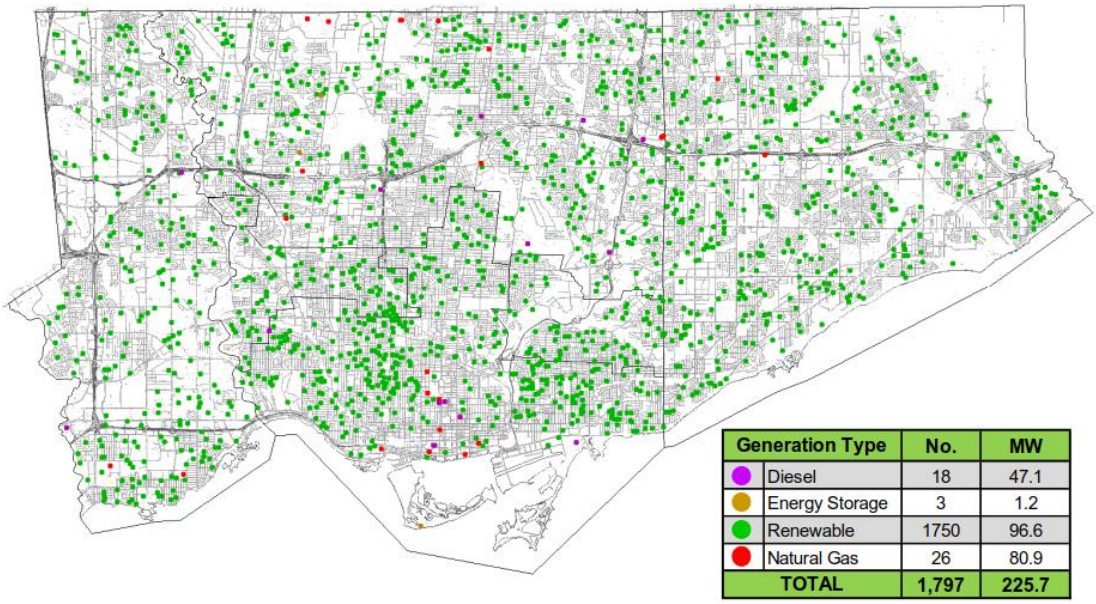


Figure 1: Toronto Hydro DG Connections (as of December 31st, 2017)

From 2014 to 2017, Toronto Hydro connected about 131 MW of generation to its distribution system, which represents roughly 43 percent of the connected capacity that was projected for the same time period in the 2015 CIR application. The lower the expected DG capacity connected during this period can be attributed to various reasons:

- Eight medium and large DG's totalling about 32 MW were cancelled by the customer.
- 14 medium and large DG's totalling about 76 MW deferred by the customer and are expected to be installed between 2018 and 2020.
- 12 new medium and large DG's totalling about 43 MW were forecasted to be connected between 2015 and 2017 based on historical connections and consultations at the time. However, only six new medium and large DG's totalling about 20 MW were connected during this timeframe.
- 114 MW of FIT and microFIT generations were forecasted to be connected between 2015 and 2017 based on the pace of applications and connection requests at the time. However, due to reductions in incentive rates by the IESO, customer interest proved lower than expected and only 70 MW of these FIT and microFIT generations were connected during this timeframe.

E3.2 Forecasted Generation Connections

Interest in generation projects within Toronto Hydro's service territory has been steady in recent years, and is anticipated to continue into the future. In particular, there has been a growing interest in Net Metering and battery energy storage, due to provincial policy changes and falling costs of solar photovoltaic panels, inverters, and lithium-ion batteries. Inquiries regarding conventional generators have also increased as micro-turbine based installations become more economically viable and commercial and industrial customers attempt to increase site reliability and operational cost savings.

Toronto Hydro's 2018-2024 DG connection and capacity forecast takes into account historical connection trends, completed assessments, and anticipated projects with respect to various DG programs. Toronto Hydro used a linear approximation to forecast the anticipated amount of connections and associated capacity from 2018 through 2024. The forecast connection rates of DG and REG are consistent with expectations from the Long-Term Energy Plan and IESO procurement plans and assumes the following:

- The microFIT and FIT program will transition to a net metering program in 2018, as per the directive issued by the Minister of Energy on April 5, 2016.
- No major changes will be introduced to the net metering program from 2020 to 2024
- A steady 3 percent increase year-over-year for REG connections (90 micro and 60 small sized REG connections in 2019 are used as the baseline);
- Increased demand for energy storage connections due to lithium-ion battery prices reductions:
    - 12 micro, five small, and three medium sized energy storage connections in 2019 are used as the baseline. A 20 percent increase year-over-year is used to forecast 2020-2024 connections;
- Increased demand for CHP and diesel connections due to customers seeking site reliability and electricity charge reductions:
    - 15 small and two medium sized natural gas connections in 2019 are used as the baseline. A 15 percent increase year-over-year is used to forecast 2020-2024 connections; and
    - one small and four medium sized diesel connections in 2019 are used as the baseline. An extra unit is forecasted to be added every two years.

DG projects are expected to more than double by 2024, reaching approximately 3,600 connections. This represents an additional 581 MW on top of the 226 MW in connected DG as of December 2017. Forecasts for renewable and conventional generation are shown in Figures 2 and 3 below.

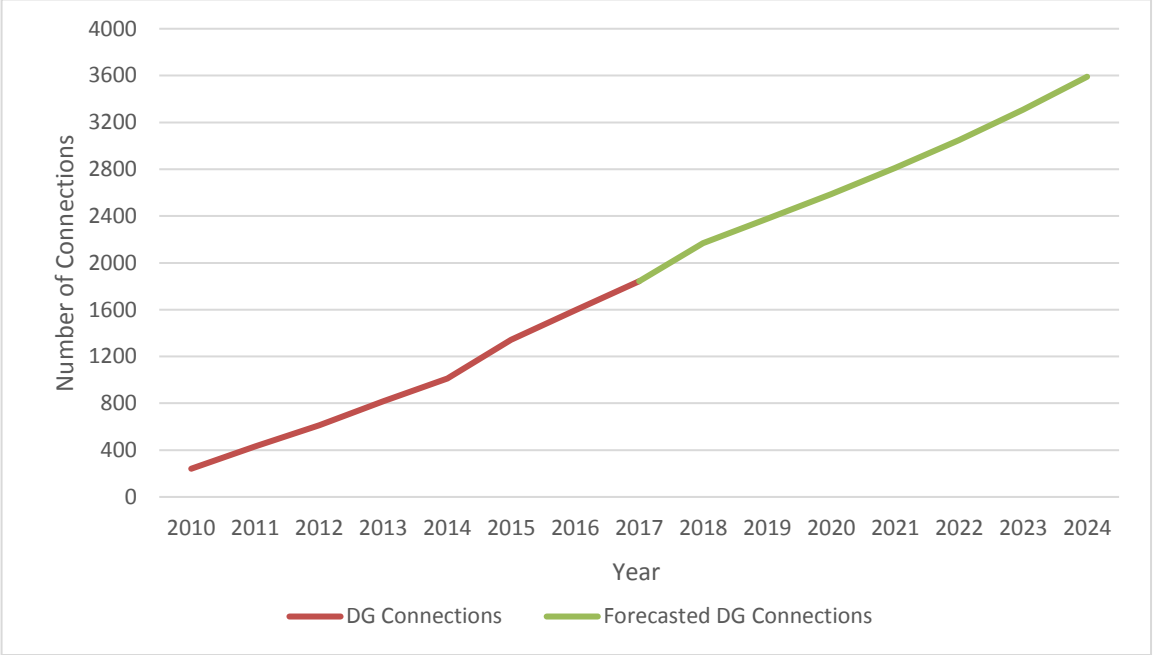


Figure 2: Historical and Forecasted Generation Connections

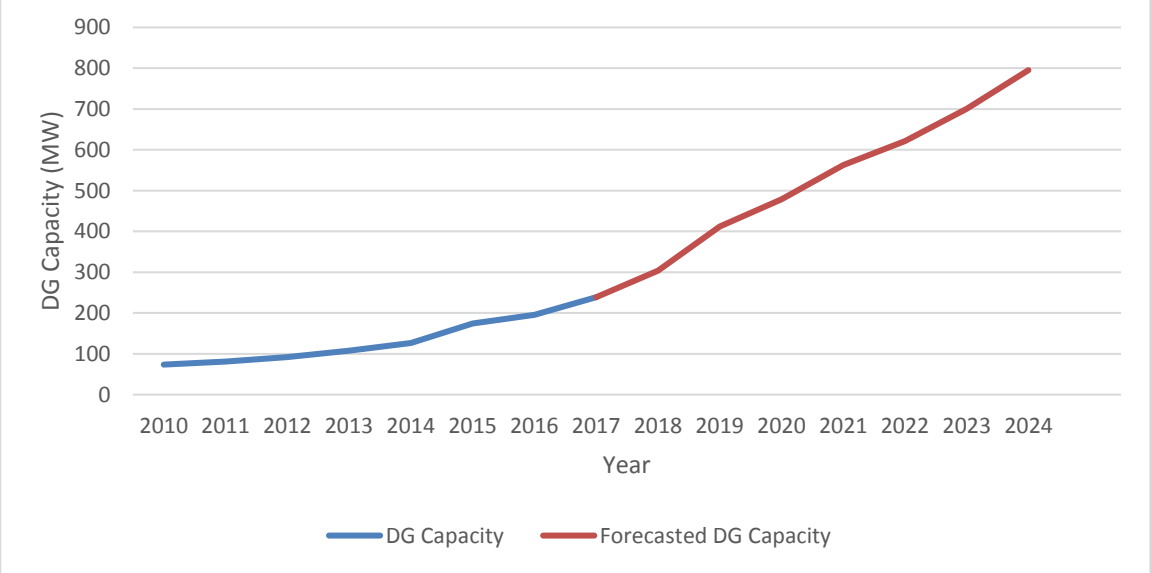


Figure 3: Historical and Forecasted Generation Capacity

E3.2.1 Forecasted Connections for Renewable

The policy and economic conditions within Toronto Hydro's service territory in recent years have facilitated a steady interest in REG projects, which is expected to continue into the foreseeable future. In addition, the combination of decreasing costs of photovoltaic panels and termination of the IESO FIT program has generated growing interest in the IESO Net Metering program.

As of the end of 2017, Toronto Hydro has assessed and approved over 450 micro and small REG projects totalling 31 MW under the microFIT, FIT, and Net Metering programs. These projects are expected to be connected to the distribution system by the end of 2018.

Based on historical trends and given the end of the IESO FIT program in 2018, Toronto Hydro anticipates the pace of REG connections to slow slightly beginning in 2019. However, forecasted REG installations will likely be larger in size compared to the past due to cost reductions in solar photovoltaic panels.

Between 2019 and 2024, Toronto Hydro forecasts roughly 830 additional REG connections (totalling 69 MW) to the distribution system.

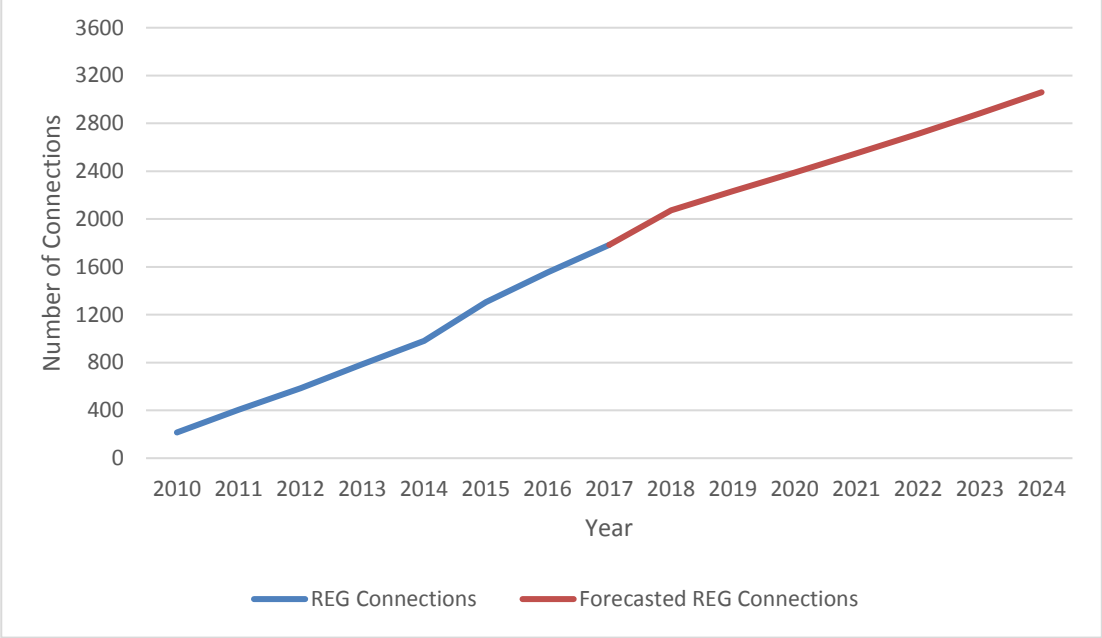


Figure 4: Historical and Forecasted REG Connections

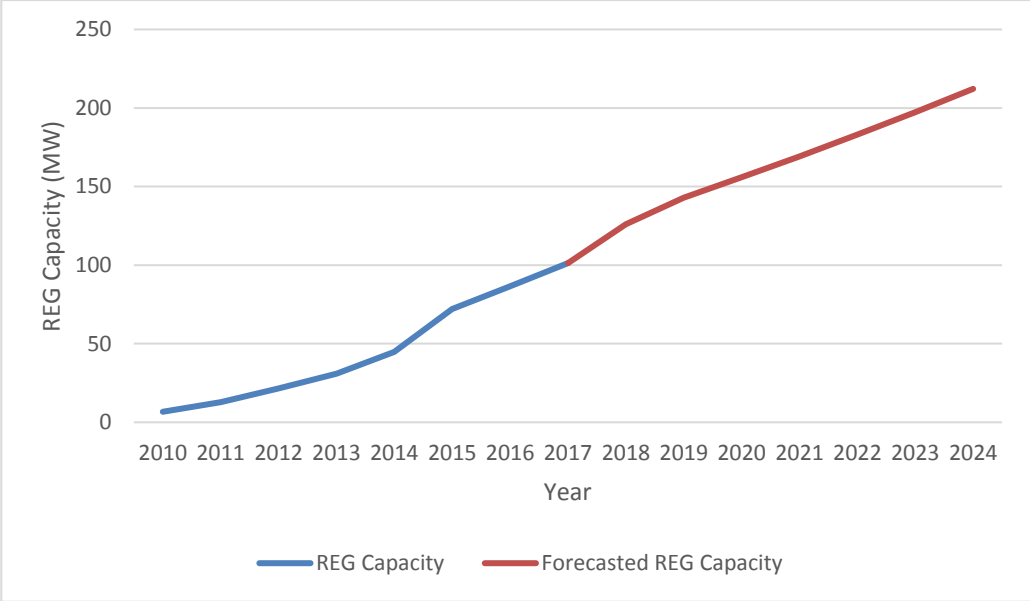


Figure 5: Historical and Forecasted REG Capacity

E3.2.2 Forecasted Connections for Conventional

Inquiries regarding conventional generation connections has also increased in Toronto Hydro's service area in the past few years, primarily due to industrial and commercial customers seeking site reliability and operational cost savings. Specifically, inquiries relating to mid- and large-sized CHP installations have more than tripled from 15 in 2015 to almost 50 in 2017.

Toronto Hydro has also observed increased interest in small scale micro turbine-based installations. As a proven technology that is already in extensive use throughout North America, this type of installation is ideally suited for small-scale power generation in commercial and multi-level residential buildings. The number of connection requests for micro turbine-based CHP jumped from 25 in 2015 to 120 in 2017. Over the 2020-2024 period, Toronto Hydro anticipates a larger volume of applications as more customers become aware of the economic benefits of micro turbine-based CHP.

Battery energy storage is becoming the next major generation technology as costs associated with lithium-ion batteries continue to fall. As a result, Toronto Hydro has seen exponential growth in battery energy storage inquiries. Based on market projections, battery energy storage connections are expected to increase between 15 and 25 percent year-over-year as the technology matures and prices fall to a point where it makes economic sense to invest in battery storage.

Toronto Hydro is aware of 19 CHP, Diesel Closed Transition and Energy Storage projects totalling 124 MW of nameplate capacity. These projects are in various stages of development, and due to being larger in nature, will take longer to be connected to the distribution system. These DG's are anticipated to be connected over the 2018-2020 period.

Toronto Hydro's forecasts for conventional generation are based on initial consultations and preliminary assessments received and completed to date, including potential projects with a relatively high level of intent to proceed under CHP, Closed Transition, Load-Displacement, IESO Energy Storage Procurement Request for Proposal ("RFP"), and other IESO programs such as PSUI.

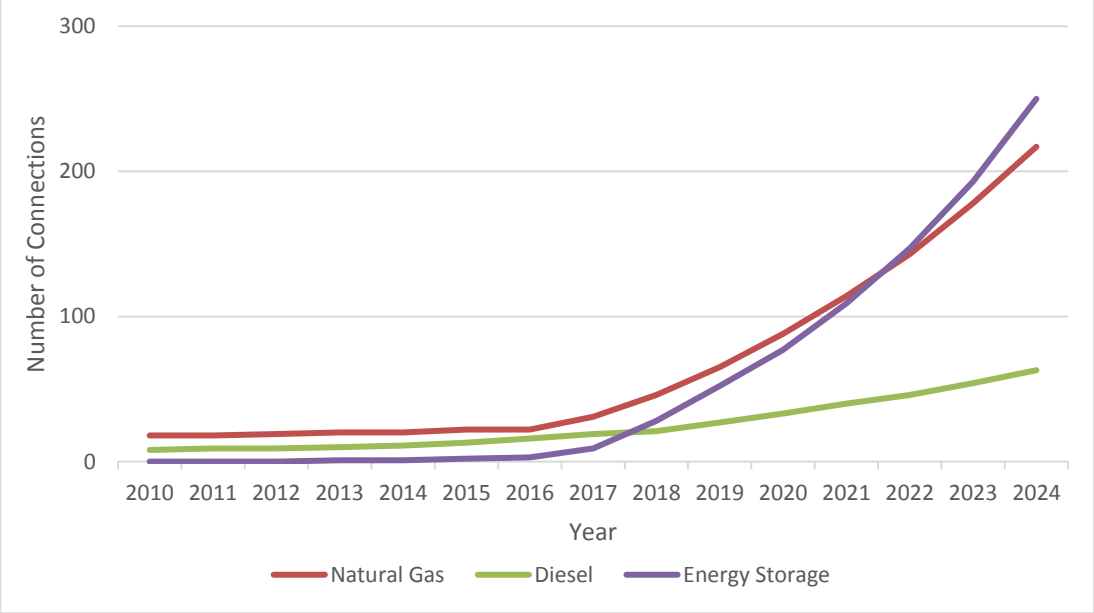


Figure 6: Historical and Forecasted Generation Connections

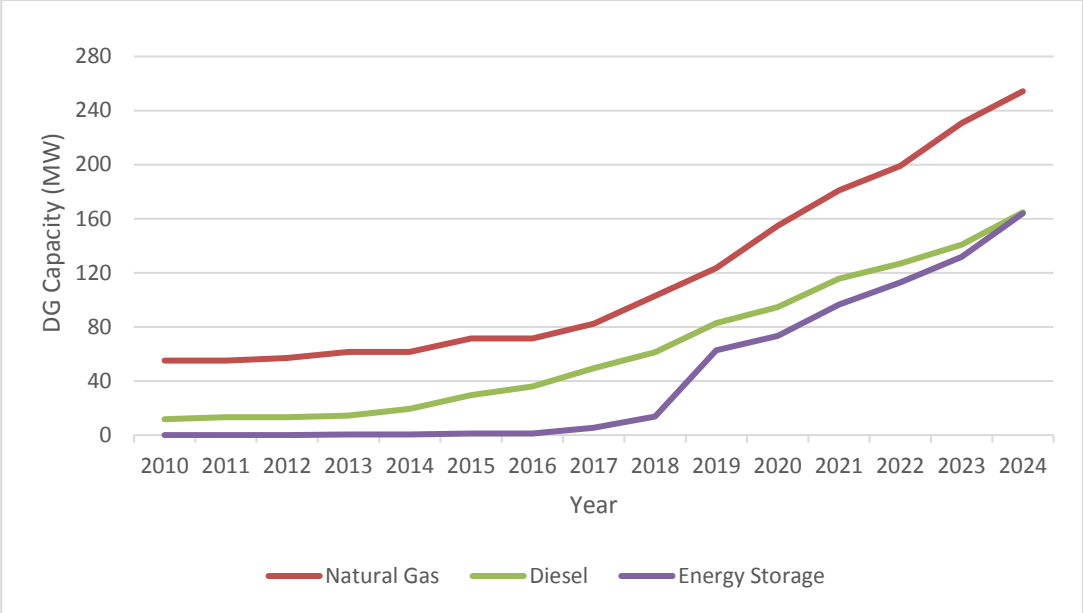


Figure 7: Historical and Forecasted Conventional Generation Capacity

E3.3 Capacity and Constraints to Connect Distributed Generation (DG)

E3.3.1 Existing Capacity to Connect

There are several challenges associated with connecting the forecasted 581 MW of DG to the Toronto Hydro system. On the distribution level, short circuit capacity is the main constraint that prevents new DG connections to certain stations.

E3.3.2 Existing Constraints to Connect

There are a number of constraints limiting Toronto Hydro's ability to connect DG, including fault current, thermal limits, anti-islanding, and the ability to transfer loads between feeders in the event of a contingency. The primary constraint at this time is short circuit capacity.

1. Short Circuit Capacity Constraints

To maintain safe and reliable operation of the distribution system, Toronto Hydro cannot connect DG in situations where short circuit capacity limitations exist. The existing distribution based short circuit capacity constraints are identified in Figure 8. This map shows the areas within Toronto that are approaching or have reached short circuit limits at various stations. These stations are supplied by Hydro One Networks Inc. ("Hydro One") transformers and directly connect to Toronto Hydro feeders. Toronto Hydro is proposing to install bus tie reactors to mitigate the existing short circuit capacity constraints, so as to allow the distribution system to accommodate new DG connections. More detailed information is provided in Section E5.5.

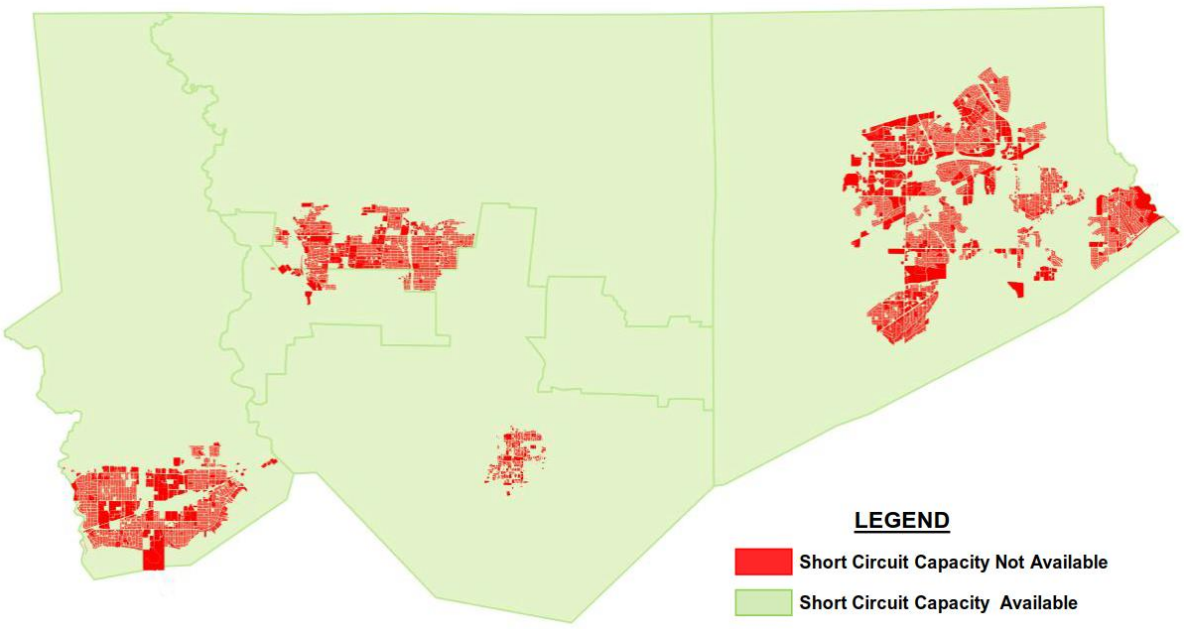


Figure 8: Map of Distribution System Short Circuit Capacity Constraints

2. Anti-Islanding Condition for Distributed Generators

Islanding occurs when a DG source continues to power a portion of the grid even after the main utility supply source has been disconnected or is no longer available. This situation must be avoided as it can interfere with grid protection systems and potentially endanger Toronto Hydro crews.

The connection of photovoltaic solar inverters and other DG sources must be accomplished in a manner that ensures that unintentional islanding of cannot take place. Toronto Hydro plans to deploy real-time monitoring and control investments proposed within the Generation Protection, Monitoring, and Control program at every new DG site to provide the ability to address anti-islanding concerns. More detailed information is provided in Section E5.5.

As the ratio of generation capacity to minimum load increases, the amount of time required by inverters to respond to anti-islanding scenarios also increases and the effectiveness of inverter response to anti-islanding scenarios decreases. Based on common industry practice, Toronto Hydro aims to ensure that "DR aggregate capacity is less than one-third of the minimum load of the Local

Electric Power System (EPS)."[2] Toronto Hydro plans to deploy energy storage investments to help mitigate feeders with high generation to load ratio in order to address anti-islanding concerns. More detailed information is provided in Section E7.2.

3. System Thermal Limits and Load Transfer Capability

For large generation or aggregated generation connections, an important operating limit stems from a feeder's continuous load thermal ratings. Exceeding system thermal limits adversely affects the lifespan of distribution equipment and can cause immediate equipment failure.

In undertaking feeder planning and operations, Toronto Hydro considers the system impact of the generator being online versus offline. The aforementioned thermal ratings affect the variability of various generation sources, system load growth, and the occurrence of contingencies. The ability to provide monitoring and control allows Toronto Hydro to monitor and mitigate feeder thermal loading. More detailed information is provided in Section E5.5.

E3.3.3 Planned Investments to Eliminate Constraints

In order to connect the forecasted amount of DG to Toronto Hydro's distribution system, the following solutions have been identified for the 2020 to 2024 period:

1) A bus-tie reactor is expected to increase DG connection capacity by lowering the short circuit current on the station bus and distribution system. Based on forecasted DG growth outlined in section E3.2, Toronto Hydro anticipates that five bus-tie reactors will be required over the 2020 to 2024 period to alleviate short circuit capacity constraints. The station buses where bus tie reactors are proposed are shown in the table below.

[2] IEEE 1547 Standard for Interconnecting Distributed Resources ("DR") with Electric Power Systems, section 4.4.1,

Table 1: Locations of Proposed Bus Tie Reactors (2020-2024)

Station	Bus	DG Connections as of end of 2017		Forecasted DG Connections by 2024	
		Total Capacity (MW)	Available Short Circuit Capacity (MVA)	Total Capacity (MW)	Available Short Circuit Capacity (MVA) without Bus-Tie Reactors
Ellesmere TS	*J*	7.9	49.6	12.47	-0.5
Esplanade TS	*A1A2*	7.3	57.6	17.88	-29.6
Fairbank TS	*YZ*	2.7	6.0	7.92	-10.6
Horner TS	*BY*	14.55	92.8	20.82	-4.6
Sheppard TS	*BY*	3.54	21.7	9.39	-4.0

As shown in the table above, as of the end of 2017, the five station buses have available short circuit capacity to connect DG. Based on the forecast methodology outlined in section E3.2, the total DG capacity expected to be connect by 2024 to each station bus (assuming no constraints) is also shown in the table. The connection of all the forecasted DG's would result in these five buses exceeding their short circuit limits by the amount shown in the final column.

1) Real-time monitoring and control are expected to allow Toronto Hydro to connect the forecasted amount of DG sources, and continue to meet the mandated requirements of the Distribution System Code.
2) Energy storage is expected to support network operation, by absorbing energy in off-load hours and supplying a certain amount of energy during peak periods to mitigate generation to load ratio concerns. The benefit is an improvement of voltage profiles, reduction in substation transformers and line overloading, reduction in system losses, and increase in network REG hosting capacity.

   Based on forecasted DG growth outlined in section E3.2, Toronto Hydro intends to install three energy storage systems over the 2020 to 2024 period to alleviate generation to load ratio concerns for three feeders, as outlined in the table below.

Table 2: Proposed Energy Storage Systems (2020-2024)

No.	Feeder	Station	Bus	Gen to Min Load Ratio	ESS (MW)	ESS (MWh)	ESS Cost ($M)
1	***51-M25***	*Leslie TS*	J	0.38	0.35	1.40	$1
2	***51-M32***	*Leslie TS*	Q	0.46	0.87	3.50	$2
3	***80-M27***	*Fairchild TS*	J	0.51	1.08	4.30	$2
Total					**2.30**	**9.20**	**$5.0**

By implementing these solutions, Toronto Hydro expects to be able to provide access across the distribution system, allowing REG source to connect on a grid-wide basis. In addition, Toronto Hydro forecasts that these investments will permit the distribution system to accommodate the total forecasted 800 MW of DG by the end of 2024. For more detailed information regarding the Generation Protection, Monitoring, and Control program, please refer to Exhibit 2B, Section E5.5.

E4 Capital Expenditure Summary

This section provides a 10-year view of Toronto Hydro's capital spending and System O&M for the 2015-2024 period, including explanatory notes on: (i) plan versus actual variances and trends during the historical period (i.e. 2015-2019), and (ii) shifts in forecast versus historical expenditures by investment category. The explanations in this section are focused on investment category level (and total) variances as presented in OEB Appendix 2-AB.[1] Toronto Hydro has also completed OEB Appendix 2-AA, which includes a 10-year view of expenditures across the utility's various capital programs.[2] Explanations for material variances and trends at the program level are provided within the "Expenditure Plan" section of each capital program narrative in sections E5 through E8.

E4.1 Plan versus Actual Variances for 2015-2019

In Toronto Hydro's 2015-2019 Custom IR Application, the OEB approved the utility's custom rate-setting mechanism and a resulting capital related revenue requirement of $2,497.9 million during the 2015-2019 period. As discussed in the Deferral and Variance Accounts exhibit, Toronto Hydro's actual capital spending is slightly less than approved for the period, resulting in a refund to customers of $59.4 million through the CRRR Variance Account.[3]

The OEB's envelope approval of CRRR for the 2015-2019 period did not include prescribed adjustments to the expenditure plans within specific programs or investment categories. Toronto Hydro received final rates in the first quarter of 2016 and proceeded to manage spending through the normal course of business planning and execution during the remaining years of the plan. This has included reprioritizing projects and adjusting program pacing where needed in order to: (i) remain within the OEB's approved CRRR, (ii) deliver on the highest priority objectives of the original 2015-2019 DSP,[4] and (iii) adapt to the typical variances and evolving circumstances that arise during the planning and execution of a large capital program.[5]

[1] Exhibit 2A, Tab 4, Schedule 3
[2] Exhibit 2A, Tab 4, Schedule 2
[3] See Exhibit 9, Tab 1, Schedule 1 for more information.
[4] Some of the highest priority objectives for the 2015-2019 DSP included reducing the backlog of aging assets, improving reliability, reducing the number of high-risk legacy assets, reducing capacity constraints, and executing the Operating Centres Consolidation Program. Toronto Hydro's measured performance during 2015-2017 – including reliability performance – is discussed in in Section 1B, Tab 2, and in Section C of the DSP. Section E2 includes information on how historical performance influenced the 2020-2024 plan, and the narratives in Sections E5 through E8 discuss historical accomplishments relative to the 2015-2019 plan at the program level.
[5] Examples include: weather, feeder availability, permitting timing, and restrictions, etc.

In Table 1 below, Appendix 2-AB, and throughout the remainder of this section, Toronto Hydro refers to its filed 2015-2019 DSP as the "Plan" for 2015-2019. By comparing the 2015-2019 DSP to the actual and bridge year expenditures, the utility is able to provide a meaningful and complete picture of where adjustments were made through normal course planning to manage within approved rates, respond to evolving system and customer needs, and adapt to work program execution restrictions such as weather.

Toronto Hydro forecasts $2,383.5 million in actual capital expenditures over the 2015-2019 period, which is 4 percent lower than the $2,489.3 million forecasted in the 2015-2019 DSP. The breakdown of plan versus actuals by year and by category is presented in Table 1 below, and explanations for each category are provided in the following subsections.

Table 1: Historical Capital Expenditure Summary ($ Millions)

Category	Historical									Bridge					
	2015			2016			2017			2018			2019		
	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	For.	Var.	Plan	For.	Var.
System Access	86.1	58.3	(32%)	95.3	79.0	(17%)	104.9	65.5	(38%)	95.8	100.8	5%	92.3	97.1	5%
System Renewal	251.7	304.1	21%	239.6	266.1	11%	256.2	250.3	(2%)	275.9	229.4	(17%)	287.3	253.4	(12%)
System Service	76.5	37.9	(50%)	70.7	53.3	(25%)	65.1	72.4	11%	52.6	41.4	(21%)	80.2	41.8	(48%)
General Plant	104.6	79.4	(24%)	101.5	109.5	8%	30.3	98.9	226%	34.2	70.0	105%	30.3	40.2	33%
Other	12.2	11.6	(5%)	11.6	3.7	(68%)	10.8	10.7	(1%)	11.5	6.3	(46%)	12.1	2.4	(80%)
Total CAPEX	**531.1**	**491.4**	**(7%)**	**518.8**	**511.6**	**(1%)**	**467.4**	**497.8**	**7%**	**470.0**	**447.8**	**(5%)**	**502.2**	**434.9**	**(3%)**
System O&M	128.8	116.1	(10%)	126.5			126.3			126.9			131.0		

E4.1.1 2015-2019 Variances: System Access

As shown in Table 1, above, actual System Access expenditures were lower than forecast in each of 2015, 2016, and 2017, and are forecasted to be 16 percent lower than forecast for the five year period 2015 through 2019. The 2015 through 2017 variances were primarily driven by the following factors:

- Major projects with significant construction activities planned for the 2015-2019 period such as Metrolinx Eglinton Crosstown Light Rail Transit ("ECLRT"), Finch West Light Rail Transit ("FWLRT"), and Sheppard East Light Rail Transit ("SELRT"), and Union Pearson GO transit

were delayed largely due to third party planning changes, resulting in lower than forecast costs in the first three years of the plan period. See Section E5.2 (Externally Initiated Plant Relocations and Expansion) for more details.

- A subset of generation protection and control projects did not proceed due to a number of technical and customer-related factors. For example, advancement of a Hydro One station upgrade project made it unnecessary to invest in short-circuit capacity constraints at that location, and shifts in the type of inverter technology favored by generation customers forced the utility to seek alternative solutions for relieving short-circuit constraints at Leslie TS. Additionally, delays in the procurement of monitoring and control systems deferred $1.8 million of work from the 2015-2019 period into the 2020-2024 period in the Generation Protection, Monitoring and Control ("GPMC") program. See Section E5.5 for more details.
- The Customer Connections program (Section E5.1) was materially less than forecast. This is a highly volatile program driven by various external factors (e.g. size and location or connections, available capacity provisions, economic drivers). Higher than anticipated capital contributions were a significant contributor to the lower than forecast net expenditures in this program. Toronto Hydro has adjusted its 2020-2024 forecasts to reflect this trend. See the Customer Connections narrative for additional details.

As discussed in each of the program justifications in Section E5, Toronto Hydro has taken the experience of the 2015-2019 period into account in developing the forecasts for the 2020-2024 period.

E4.1.1.1 2015-2019 Variances: System Renewal

As shown in Table 1, above, actual System Renewal expenditures were higher than forecast in each of 2015 and 2016, lower than forecast in 2017, and, overall, are projected to be in line with the forecast for the five year period 2015 through 2019. The 2015 through 2019 variances were primarily driven by the following factors:

- During 2015 and 2016, Toronto Hydro experienced a higher amount of Overhead System Renewal work (see Section E6.5) driven by declining reliability in 2013 and 2014; a higher amount of Underground System Renewal work (see Section E6.2) driven by improved inspection data, which identified an urgent need to address submersible transformers at risk of spilling oil contaminated with PCB; and higher than forecast Reactive Capital expenditures.

- In light of higher than forecast spending in 2015 and 2016, Toronto Hydro reduced forecast spending in 2017, 2018, and 2019 to remain in alignment with the utility's original five-year forecast for System Renewal.

As discussed in each of the program justifications in Section E6, Toronto Hydro has taken the experience of the 2015-2019 period into account in developing the forecasts for the 2020-2024 period.

E4.1.2 2015-2019 Variances: System Service

As shown in Table 1, above, actual System Service expenditures were lower than forecast in 2015 and 2016, higher than forecast in 2017, and are expected to be lower than forecast in 2018 and 2019. Overall, spending in the System Service category is expected to be 28 percent lower than forecast during the 2015-2019 period. The 2015 through 2019 variances were primarily driven by the following factors:

- Over the 2015-2019 period, Toronto Hydro reduced the pace of Feeder Automation and Contingency Enhancement investments. Both of these programs were developed to add remote switching capabilities and tie points in the Horseshoe area of the system, with the Feeder Automation program adding incremental capabilities by creating automated (i.e. "self-healing") switching schemes to improve outage restoration time. As discussed in Section E7.1 (System Enhancements), Toronto Hydro encountered operational limitations in its efforts to scale-up its use of peer-to-peer Feeder Automation technology. This led the utility to alter its approach to Feeder Automation, with a plan to explore a potentially more feasible centralized communications solution that leverages basic SCADA-enabled remote switching technology in combination with the utility's planned Network Management System ("NMS") upgrades. As a result of this decision, the utility significantly curtailed investment in the Feeder Automation program during the 2015-2019 period, and intends to develop the alternative solution during the 2020-2024 period. Toronto Hydro also scaled down its Contingency Enhancement program during the 2015-2019 period. Some of the highest priority work from this program was bundled with overhead rebuild work in the System Renewal category in order to deliver sustainable reliability benefits in poor performing areas.
- Lower than forecast spending in 2015 and 2016 was also related to delayed investments in the Stations Expansion program. The Copeland TS – Phase 1 project, a large and complex

project of unprecedented scale for Toronto Hydro, experienced slower progress and less spending than planned in 2015 and 2016 due to several unforeseen events and factors. The project is now scheduled for completion in 2018. Overall, Toronto Hydro is forecasting that Stations Expansion expenditures will be approximately 6 percent lower than forecast for the 2015-2019 period. Section E7.4 provides additional information on Copeland TS and other cost and timing variances for Stations Expansion work, including variances related to Toronto Hydro's capital contributions to Hydro One for transformer station upgrades.

E4.1.3 2015-2019 Variances: General Plant

As shown in Table 1, General Plant expenditures were lower than forecast in 2015 and higher than forecast in 2016 and 2017. Toronto Hydro expects expenditures to be greater than forecast in 2018 and 2019. Overall, 2015-2019 General Plant expenditures are projected to be 32 percent higher than forecast. Variances related to two major projects – the Operating Center Consolidation Program ("OCCP") and the Enterprise Resource Planning ("ERP") system – accounted for the majority of the variance between actual and planned spending:

- The OCCP was a real estate initiative from 2014 to 2018, intended to: (i) ensure security of tenure at major crew-supporting operating centers; (ii) ensure the uninterrupted continuation of critical functions; and (iii) achieve permanent significant cost savings for ratepayers. The OCCP program exceeded planned costs by $46.5 million due to higher than forecast capital improvement costs at 715 Milner Rd., 71 Rexdale Blvd., and 500 Commissioners St. These improvements were necessary to support consolidation. Changes in capital improvement costs were largely driven by changes in project costs between the initial and final estimates, including increases associated with the Ontario Building Code, environmental considerations, and design considerations.

Despite these variances, the program has generated more value in returns to rate payers than originally planned. Table 2 shows the variances on cost and net gains of sale related to the original OCCP scope of work. Net proceeds from the sale of 5800 Yonge Street will be returned to rate payers in the form of a rider over the 2020-2024 period.[6]

[6] Refer to Exhibit 9, Tab 1, Schedule 1 for more information on the OCCP deferral and variance account.

Table 2: Costs and Gains Associated with the OCCP Program ($ Millions)

	Planned	Actual	Variance
Capital Cost	160.0	206.6	**46.6**
Net gain from Sale	72.5	142.2	**69.7**

/C

Beyond the original planned scope of consolidation, the program's space utilization efforts allowed Toronto Hydro to dispose of an additional property, at 60 Eglinton Ave., the proceeds of which will also be returned to ratepayers in the form of a rider over the 2020-2024 period. The employees from 60 Eglinton Ave. were transferred to other Toronto Hydro owned properties in June 2017, allowing for a reduction in maintenance costs related to that property. Overall, the program has achieved an increase of $69.8 million in amounts to be returned to rate payers compared to the original plan.

- IT/OT program investments are expected to exceed planned investments over the 2015-2019 period. Actuals in 2017 and forecasts in 2018 and 2019 are offset by lower than planned expenditures in 2015 and 2016, resulting in an expected variance over the 2015-2019 period of $18.3 million, or 9 percent.

  The majority of this variance is attributed to increased investment in Toronto Hydro's new ERP system, which the utility plans to complete in 2018. Approximately half of the ERP variance is attributed to higher infrastructure costs compared to the original high-level estimates developed in 2013. Drivers of cost changes included changes in the Canadian to American dollar exchange rate, a change in hardware requirements necessitated by standards changes during the period between the initial project estimate and the commencement of the project, additional requirements for components not identified in the 2013 estimate, and scope changes to include additional subscriptions and licenses for capabilities that would deliver greater benefits and better align with business requirements. The remaining variance is the result of a greater allocation of internal employee time in support of the project.

E4.1.4 2015-2019 Variances: Other Capital

Expenditures in the "Other Capital" investment category are projected to be 40 percent less than forecast over the 2015-2019 period. The Other Capital budget had included approximately $20.6 million in road cut repair costs. Toronto Hydro revised its approach during the period to begin

recording actual road cut expenditures against specific projects, resulting in the negative variance shown in Table 1. The utility has carried this approach forward by including road cut repair costs within the capital program forecasts for 2020-2024.

E4.1.5 2015-2019 Variances: System O&M

System Operating and Maintenance ("System O&M") spending is driven by the need to maintain distribution assets and support the execution of Toronto Hydro's capital, maintenance, system response, and customer-driven work activities. The O&M expenditures for this category include the following activities, which are described in detail in Exhibit 4A, Tab 2:

- Supply Chain;
- Asset and Program Management;
- Work Program Execution;
- Customer-Driven Work;
- Control Centre Operations;
- Distribution Maintenance Programs;
- Emergency Response; and
- Fleet and Equipment Services.

As shown in Table 1, the utility's System O&M activities were lowest in 2015. Expenditures increased in 2016 to levels comparable with the originally forecast 2015 levels. Using actual 2015 spending as the comparison point, System OM&A is forecast to increase an average of 3 percent annually over the 2015-2019 period. However, relative to Toronto Hydro's planned 2015 System O&M, expenditures have remained essentially flat.

Fluctuations in costs associated with the business functions included in System O&M occur from year to year for many reasons. Reasons include:

- The volume of maintenance for an asset class is dictated by asset class maintenance cycles and varies from year-to-year.
- The extent of maintenance required for inspected assets can vary from year-to-year depending on observed condition and other factors.
- Costs associated with Emergency Response and Customer-Driven Work are subject to various external factors including weather and customer demand.

In light of the above drivers of variance, adjustments are made in program activities over the course of each year to manage cost increases in one function with deferral of activities and associated costs in other functions where appropriate. For example, costs associated with an increase in station battery failure for a particular year may be offset by a temporary reduction in the number of insulators requiring washing in that year.

In addition to the above noted drivers, capital investment can drive fluctuations in costs for associated planned, predictive, and corrective maintenance activities.

E4.1.5.1 Capital Investment and Planned Maintenance

As discussed in Section D3.1.1.3, the directional relationship between asset replacement and planned maintenance is largely dependent on the maintenance requirements for the assets being removed and installed. Certain types of System Renewal investment can reduce planned maintenance costs in specific circumstances. Generally, the removal of legacy and functionally obsolete assets from the system can eliminate the need for maintenance activities or higher maintenance frequencies that are specific to the legacy asset type. At the same time, new equipment and new standards and practices may introduce incremental maintenance requirements. A reduction in renewal spending can lead to asset deterioration, potentially resulting in the need for additional inspection cycles and associated maintenance. The corollary is also possible. The utility considers maintenance requirements when evaluating new products and developing new standards as part of its continuous Standards and Practices Review activities.

Compared to 2015 actuals, the Preventative and Predictive Maintenance components of System O&M are forecast to have increased by an average of 3 percent per year by 2019. However, a major driver of this increase is the introduction of a preventative Contact Voltage inspection program. When the total is normalized for this inspection program, Preventative and Predictive Maintenance expenditures have increased at 2 percent per year, roughly in line with inflation.[7]

[7] For more information on the Preventative and Predictive Maintenance programs, refer to Exhibit 4A, Tab 2, Schedules 1-3.

E4.1.5.2 Capital Investment and Corrective Maintenance

Corrective Maintenance can also fluctuate in response to capital work. A reduction in renewal spending can lead to asset deterioration, potentially resulting in an increase in corrective maintenance to mitigate increases in failure rates. The corollary is also possible.

As noted in Section D3.1.1.3, due to the overall age and condition of the system, the remaining volume of obsolete legacy assets, and increasing pressure from adverse weather events, Toronto Hydro does not anticipate an overall decline in planned, corrective, or emergency maintenance spending during the 2020-2024 period.

E4.2 Forecast (2020-2024) vs. Historical (2015-2019) Expenditures

E4.2.1 System Access: Historical vs. Forecast Expenditures

Table 3: System Access: 2015-2024 Expenditures ($ Millions)

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
System Access	58.3	79.0	65.5	100.8	97.1	91.8	93.3	93.9	106.0	116.4

Toronto Hydro expects System Access expenditures will be generally stable from 2018 through 2024, with an increase in spending in 2020-2024 relative to the 2015-2019 period. As discussed in Section E2.2, this overall increase is primarily driven by continued growth in customer connections demand, greater certainty around major externally initiated relocations projects, and, beginning in 2022, the need to renew the utility's end-of-life Residential and Small C&I meters. Forecast inflation for construction costs is also a driver of increases in certain programs in this category. For more information on the programs in this category, refer to Section E5.

E4.2.2 System Renewal: Historical vs. Forecast Expenditures

Table 4: System Renewal Expenditures: 2015-2024 ($ Millions)

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
System Renewal	304.1	266.1	250.3	229.4	253.4	306.6	325.7	323.1	339.0	325.5

System Renewal investments are forecast to be relatively stable over the 2020-2024 period at around $325 million per year, an increase over 2015-2019 spending levels. As discussed in Section E2.2, this increase is necessary to manage significant safety, reliability, and environmental asset risks and to ensure stable and predictable performance for current and future customers. There are multiple drivers of the overall increase in investment in 2020-2024, including, for example: wood pole condition demographics; a large population of overhead and underground transformers at risk of spilling oil contaminated with PCB; continuing needs related to high-risk legacy assets such as direct-buried cable and box construction; emerging needs in the downtown core, including replacement of high-risk lead cable; the need to address a growing backlog of critical stations-level equipment at risk of failure; increasing performance pressure on the system from climate change, necessitating greater investment in resiliency; projected increases in the amount reactive capital work; and anticipated cost pressures from construction inflation in the City of Toronto. These and other drivers are discussed in detail in Sections D1, E2, and throughout the System Renewal programs in Section E6.

A number of System Renewal programs included in the 2015-2019 plan are expected to be largely or entirely complete before 2020-2024, including:

- **Paper-Insulated Lead-Covered Leakers and Cable ("PILC") Piece-Outs:** This program will be completed during the 2015-2019 period. This is a targeted program to replace and repair leaking PILC cables and piece-out any cable in congested chambers to manage failure risk and mitigate safety hazards. All known high risk PILC leakers and piece-outs will be completed in the 2015-2019 period resulting in approximately 16 kilometres of PILC cable being addressed. If additional leaker locations are identified, they will either be repaired as part of the Reactive and Corrective Capital program or replaced through the new lead cable replacement segment in the Underground System Renewal – Downtown program (E6.3).
- **Underground Legacy Infrastructure**: The high-risk legacy equipment issues in this program will largely be addressed during the 2015-2019 period. Remaining transclosure units and cable chamber lids at risk of failure will be addressed within the Underground System Renewal Programs (E6.2 and E6.3) as noted below. By 2019, Toronto Hydro anticipates having successfully reduced significant safety and reliability risks on the underground system by addressing the following units 2015-2019:
    - 48 Sachsenwerk switch and fuse units;
    - 66 transclosures;
    - 10 Powerlite switches;

- 7 vault step transformers;
- 1,500 cable chamber covers; and
- Conversion of the legacy system configuration in Thorncliffe Park area.

- **Overhead Infrastructure Relocation**: This program focused on relocating overhead assets in areas with limited or difficult access, station egress assets carrying three or more circuits, and assets crossing highways. The relocation of these assets, improves employee safety and reliability to the distribution system by minimizing duration of interruptions due to accessibility issues. The most inaccessible and high-risk sites are forecast to be completed over the 2015-2019 period. As other inaccessible locations are identified that require relocation, they will be considered for relocation as part of the Overhead System Renewal program (E6.5) in 2020-2024, provided that their condition warrants their replacement.
- **SCADA-Mate R1 Switch Renewal**: All known SCADA-Mate R1 switches – which have numerous safety, reliability and operational concerns – will be replaced in the 2015-2019 period in order to eliminate the defective switches from the system. If additional SCADA-Mate R1 switches are identified, these will be addressed reactively or through renewal work in the Overhead System Renewal program.

E4.2.3 System Service: Historical vs. Forecast Expenditures

Table 5: System Service Expenditures: 2015-2024 ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
System Service	37.9	53.3	72.4	41.4	41.8	34.2	60.1	71.3	33.6	38.5

Overall, System Service investments in 2020-2024 are forecast to be slightly reduced compared to 2015-2019 spending. Reduced expenditures are largely driven by lower forecasted capacity expansion needs in the Stations Expansion program (E7.4) and a deliberately restrained pace of System Enhancement program (E7.1) expenditures, as well as the completion of a number of smaller System Service programs. These program reductions have been partially offset by the introduction of the Network Condition Monitoring and Control program, which aims to modernize the network system with the objective of mitigating safety, reliability and environmental risks and reducing other operational limitations. For additional details on these programs, refer to Section E7.

System Service investments are forecast to increase from 2020 to 2022 and then return to a 2020 spending level in 2023 and 2024. This reflects the pattern of spending in the Energy Storage Systems and Station Expansions programs, while System Enhancements expenditures are forecast to remain relatively stable and Network Condition Monitoring and Control expenditures to steadily increase from 2020 to 2024.

A number of System Service programs included in the 2015-2019 plan are expected to be largely or entirely complete before 2020-2024, including:

- **Design Enhancements:** Moving forward, to improve planning and execution efficiency, Toronto Hydro will include design enhancements such as tree-proof conductor upgrades in planned System Renewal programs or in the Worst Performing Feeder segment (E6.7) for the 2020-2024 period.
- **Overhead Momentary Reduction:** Toronto Hydro is conducting a pilot for Overhead Momentary Reduction study for this program during the 2015-2019 period. It involves the installation of reclosers and communication infrastructure to minimize momentary interruptions to customers. Toronto Hydro plans to install four reclosers on the system in 2019. Toronto Hydro will assess technical issues of implementation such as relay coordination as well as practical benefits to reliability prior to determining the feasibility and benefits of this program.
- **Handwell Upgrades**: Toronto Hydro's replacement of deteriorated and high-risk handwells is on track for completion in the 2015-2019 period. This program involved replacing legacy handwells with non-conductive material as well as renewing the secondary cables between handwells. Due to the safety issue related to the legacy handwell units, Toronto Hydro has upgraded all known locations to the non-conductive type handwells. These upgrades addressed safety issues associated with the risk of contact voltage from conductive handwells so that the risk to individuals, pets, and wildlife are minimized.
- **Polymer SMD-20 Switch Renewal**: Replacement of defective SMD-20 switches is on track for completion during the 2015-2019 period. This program replaces all identified polymer SMD-20 switches in the system with a newer fiberglass core model. Due to the safety risks associated with operating the switch, all locations will be replaced by 2019.
- **Downtown Contingency**: In 2015-2019, this program was planned to address station level contingency risk through the establishment of inter-station feeder ties. Toronto Hydro successfully completed a number of overheard feeder ties, but upon re-evaluating the costs

and challenges associated with underground feeder ties, decided to cancel the remaining underground work in the program. Note that the 2015-2019 spending for Downtown Contingency was included as part of System Enhancements spending in the Capital Projects Table OEB Appendix 2-AA (Exhibit 2A, Tab 4, Schedule 2).

- **Feeder Automation**: As noted in Section 4.1.3 above, Toronto Hydro has changed its approach on Feeder Automation to move away from a peer-to-peer (i.e. switch-to-switch) communication technology to a centralized solution leveraging the planned NMS upgrade. In light of this change, it is no longer necessary to separate the System Service activities that enable feeder automation (i.e. installing automated tie- and sectionalizing-points on feeders) from the Contingency Enhancement segment that is included as part of the System Enhancements program. (Previously, the key difference between Contingency Enhancement and Feeder Automation was the need to retrofit SCADA switches with peer-to-peer communications technology.) For more information on the Contingency Enhancement program for 2020-2024 and the accomplishments of the Feeder Automation program in 2015-2019, refer to the System Enhancements program at Section E7.1.

E4.2.4 General Plant: Historical vs. Forecast Expenditures

Table 6: General Plant Expenditures: 2015-2024 ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
General Plant	79.4	109.5	98.9	70.0	40.2	78.8	93.7	89.0	77.7	85.2

Over the 2020-2024 period, General Plant investments are forecast to be relatively stable with expenditures averaging approximately $85 million per year, a slight increase over 2015-2019 levels. As discussed in detail in Section E2.2, the moderate increase in this category is driven by the new, one-time Control Operations Reinforcement program and increases in spending for the Facilities Management and Security, Fleet and Equipment Services, and IT/OT Systems programs, which are driven primarily by asset lifecycle needs, IT investments to meet evolving customer service needs and preferences, and operational continuity risks. These increases are partially offset by the completion of the Operating Centers Consolidation Program and Program Support programs in 2015-2019. For further information on the 2020-2024 General Plant programs, refer to Section E8.

Two System Service programs included in the 2015-2019 plan are expected to be complete before 2020-2024:

- **Operating Centers Consolidation Program:** On track for completion in 2018. See section E4.2.4 above for more details.
- **Program Support**: Activities in this program will be completed by 2019. This program included climate change related activities (i.e. studies and pilots), the results of which are discussed in Section D2, and upgrades to Asset Management capabilities.

E4.2.5 Other Capital: Historical vs. Forecast Expenditures

Table 7: Other Capital Expenditures: 2015-2024 ($ Millions)

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Other Capital	11.6	3.7	10.7	6.3	2.4	7.0	9.0	9.8	9.5	8.7

Toronto Hydro's forecast for Other Capital expenditures includes forecasted amounts for Allowance for Funds Used during Construction ("AFUDC") and routine costs related to the replacement of major tools used in the execution of capital and maintenance programs.

E4.2.6 System O&M: Historical vs. Forecast Expenditures

Table 8: System O&M Expenditures: 2015-2020 ($ Millions)

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
System O&M	116.1	126.5	126.3	126.9	131.0	130.4				

Overall, System O&M expenditures are expected to remain essentially flat between 2017 and 2020, with an average annual increase of approximately 1 percent per year (and a lower budgeted amount in 2020 than in 2019). For details on the programs that constitute System O&M, refer to Exhibit 4A, Tab 2. These expenditures are the minimum necessary to meet the utility's various system-related outcome objectives during the 2020-2024 period.

E4.2.7 Trends in Category Spending – Historical vs. Forecast

Table 9 below shows the contribution to the total capital program of each investment category for the 2015-2019 and 2020-2024 periods. There are no marked changes in the share of total investment represented by a given investment category over the forecast period relative to the actual spending over the historical period. On a percentage basis, there is a slight shift away from General Plant and System Service investments to System Renewal and Access investments, reflecting the net result of various planning considerations and drivers, as discussed in Section E2 and in Sections E5 to E8.

Table 9: Historical and Forecast Share of Total by Investment Category

Category	Historical Share of Total (%)						Forecast Share of Total (%)					
	2015	2016	2017	2018	2019	Average	2020	2021	2022	2023	2024	Average
System Access	12%	15%	13%	23%	22%	**17%**	18%	16%	16%	19%	20%	**18%**
System Renewal	62%	52%	50%	51%	58%	**55%**	59%	56%	55%	60%	57%	**57%**
System Service	8%	10%	15%	9%	10%	**10%**	7%	10%	12%	6%	7%	**8%**
General Plant	16%	21%	20%	16%	9%	**17%**	15%	16%	15%	14%	15%	**15%**
Other CAPEX	2%	1%	2%	1%	1%	**1%**	1%	2%	2%	2%	2%	**2%**
Total	100%	100%	100%	100%	100%	**100%**	100%	100%	100%	100%	100%	**100%**

E5 System Access Investments



E5.1 Customer Connections

E5.2 Externally Initiated Plant Relocations and Expansion

E5.3 Load Demand

E5.4 Metering

E5.5 Generation Protection, Monitoring, and Control

E5.1 Customer Connections

E5.1.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 176.1	**2020-2024 Cost ($M):** 223.4
Segments: Load Connections; Generation Connections	
Trigger Driver: Customer Service Requests	
Outcomes: Customer Service, Public Policy, Safety, Reliability	

The Customer Connections program ("the Program") captures system investments that Toronto Hydro is required to make to provide customers with access to its distribution system. This includes enabling new or modified load and distributed generation ("DG") connections to the distribution system, in accordance with legal and regulatory obligations under various statutes and codes. This Program is a continuation of customer connection activities described in Toronto Hydro's 2015-2019 Distribution System Plan.[1]

Toronto Hydro's primary objective in this Program is to provide new and existing customers with timely, cost-efficient, reliable, and safe access to the distribution system. In pursuing this objective, the utility strives to meet, and where possible, exceed, all mandated service obligations. In 2017, Toronto Hydro completed 98.32 percent, and 98.41 percent, of low voltage (below 750 V) and high voltage (750 V or above) connections, respectively, as well as 92.41 percent of distributed generation connections on time.[2]

The Program is comprised of two segments:

- **Load Connections**: This segment involves completing new load connections and upgrades to existing load connections. Customers are connected to one of the various overhead or underground distribution systems in the City. The work also includes any expansion work necessary to address capacity constraints for the purpose of connecting customers.

[1] EB-2014-0116, Exhibit 2B, Section E5.2
[2] These metrics will be published in Toronto Hydro's 2017 Scorecard.

- **Generation Connections**: This segment involves connecting DG customers to the distribution system.

The investments made by Toronto Hydro in this Program support the ongoing economic growth and development in the City of Toronto.[3] The connection of DG facilities under this Program supports the achievement of public policy objectives with respect to the expansion of green energy alternatives and mitigation of climate change in alignment with the Long Term Energy Plan ("LTEP") and the directive issued by the Minister of Energy on April 5, 2016.[4]

E5.1.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Service	• Contributes to Toronto Hydro customer service objectives by: ○ Fulfilling customer service requests as mandated by Sections 6.2.4 (generation connections) and 7.2 (customer connections) of the Distribution System Code ("DSC"), *Electricity Act, 1998* (Electricity Act), and *Ontario Energy Board Act, 1998* (OEB Act); and Toronto Hydro's Conditions of Service and Electricity Distribution License; ○ Completing low and high voltage connections within 5 and 10 business days respectively at least 90 percent of the time, as measured pursuant to the OEB's new connection metrics and section 7.2 of the DSC; ○ Completing customer appointments in accordance with the OEB's Appointment Scheduling and Appointments Met metrics, 90 percent of the time, as per sections 7.3 and 7.4 of the DSC; and ○ Responding to inquiries requiring a written response within 10 business days at least 80 percent of the time, as measured pursuant to the OEB's Written Response metric and section 7.8 of the DSC. ○ Connecting DG facilities to the distribution system as mandated by sections 25.36, 25.37, and section 26 of the *Electricity Act,* 1998; and; without extensive delays or adverse impacts to existing customers, within 5 business days at least 90 percent of the time on a yearly basis as per section 6.2.7 of the DSC.

[3] Toronto Economic Bulletin, May 25, 2018, Available from: https://www.toronto.ca/wp-content/uploads/2018/05/95f7-EDC-Toronto-Economic-Bulletin-May-2018.pdf
[4] Ontario Ministry of Energy, Ministerial Directive - Future Renewable Energy Procurements, April 5, 2016.

Public Policy	• Supports the Ministerial renewable energy procurements directive[4] by connecting DG facilities that: ○ Reduce greenhouse gas emissions from fuel burning plants (renewable DG connections); and ○ Reduce "line losses" that occur during the transmission and distribution of electricity (renewable and non-renewable DG connections).
Safety	• Contributes to compliance with *Ontario Regulation 22/4* and safety objectives by: ○ Ensuring service connections are compliant with applicable requirements; and ○ Ensuring Electrical Safety Authority connection permits are available prior to connecting new or upgraded customers' service entrance equipment.
Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7, System Capacity) by installing assets that meet up-to-date standards and provide sufficient capacity when completing the connection request.

E5.1.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Customer Service Requests
Secondary Driver(s)	Mandated Service Obligations

E5.1.3.1 Load Connections

The Load Connections segment is driven by customer requests to connect to Toronto Hydro's distribution system and service upgrades for existing customers. Continuing growth in residential and commercial developments within the City is a fundamental driver of the volume of work in the Load Connections segment, as many, if not all, new developments will require new or modified connections to Toronto Hydro's distribution system. Toronto Hydro anticipates that the number of customer service requests and the size of the requested connections will continue to trend up to accommodate growing residential and commercial needs. Toronto Hydro is required to fulfill these service connection requests or to make an offer to connect ("OTC") any customers in its service area and meet its legal obligation to connect these new and existing customers to its distribution system pursuant to its Conditions of Service and section 28 of the *Electricity Act*, subject to certain exemptions specified in the DSC.

Serving one of the fastest growing cities in North America, Toronto Hydro receives high volumes of requests for connections and upgrades for residential and commercial developments each year. The City of Toronto's current rate of development is expected to continue over the 2020-2024 period. From 2012 to 2016, the City's development pipeline included 2,523 projects in various stages of approval and completion[5] with 1,156 built, 743 active and 624 under review[6] as shown in Figure 1 below. Toronto Hydro anticipates that a large number of projects and proposed loads submitted between 2012 and 2016 as well as those submitted between 2017 and 2019 are expected to be completed within the 2020-2024 period or shortly thereafter based on the average completion rate and the number of units proposed for the City of Toronto.[7] The projects in the City's development pipeline will account for 363,859 residential units and 9.53 million m^2 of non-residential Gross Floor Area, which will require connections to Toronto Hydro's distribution system.

	Built	Active	Under Review	Total in Pipeline	% of Total
City of Toronto	**1,156**	**743**	**624**	**2,523**	
Growth Areas					
Downtown and Central Waterfront	**187**	**129**	**132**	**448**	**17.8**
Centres	**28**	**34**	**26**	**88**	**3.5**
Etobicoke Centre	6	10	3	19	21.6
North York Centre	14	9	9	32	36.4
Scarborough Centre	4	3	1	8	9.1
Yonge-Eglinton Centre	4	12	13	29	33.0
Avenues	**174**	**154**	**147**	**475**	**18.8**
Other Mixed Use Areas	**79**	**82**	**55**	**216**	**8.6**
All Other Areas	**688**	**344**	**264**	**1,296**	**51.4**

Source: City of Toronto, City Planning Division: Land Use Information System II

Development projects with activity between January 1, 2012 and December 31, 2016. Built projects are those which became ready for occupancy and/or were completed. Active projects are those which have been approved, for which building permits have been applied or have been issued, and/or those which are under construction. Projects under review are those which have not yet been approved or refused and those which are under appeal.

Figure 1: Proposed Projects in the City of Toronto (2012-2016)

This pace of development and growth is consistent with the City's projected growth in population, which is over 2.9 million as of July 2017[8] and is expected to reach 3.9 million by 2041.[9] The increase

5 Including projects that are pending approval, approved, awaiting or holding building permits, or under construction.
6 City of Toronto, "How Does The City Grow?" April 2017.
7 Discussed further in the Load Demand program, see Exhibit 2B, Schedule E5.3.
8 City of Toronto, "Toronto at a Glance" Available from: https://www.toronto.ca/city-government/data-research-maps/toronto-at-a-glance/
9 Ontario Ministry of Finance, Ontario Population Projections Update, 2016-2041 Available from: https://www.fin.gov.on.ca/en/economy/demographics/projections/

in population will require additional accommodation, commercial spaces and services.[10] This growth is also reinforced by the projected GDP growth anticipated for the City, which is expected to be around 2 percent per annum for the period of 2020-2024.

As illustrated in Figure 2, from 2007 to 2017, Toronto Hydro connected approximately 88,000 customers, representing a 13 percent increase in its customer base (average of 1.3 percent per year), and approximately 49,000 customers from 2012 to 2017, representing a 7 percent increase (average of 1.4 percent per year). Similar levels of growth are expected for the 2020-2024 period, as described in the Customer Forecast Section.[11] These additional customers were connected to Toronto Hydro's distribution system as a result of the investments in the Load Connection segment.

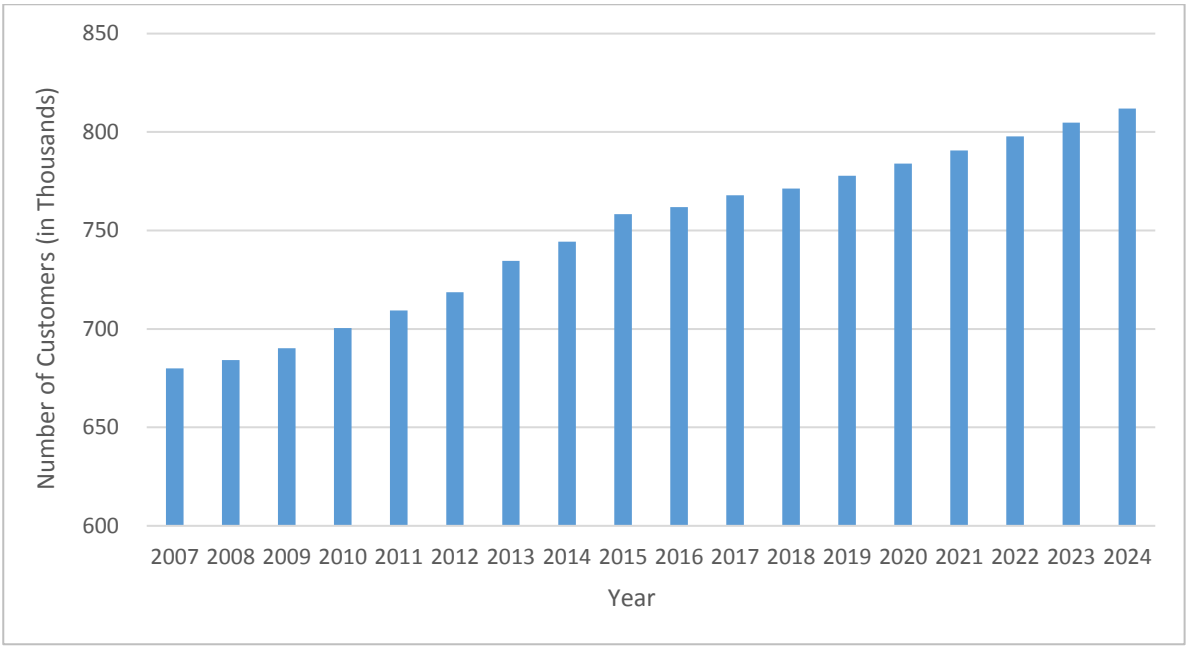


Figure 2: Historical and Forecast Number of Toronto Hydro Customers

Customer connections can be in the form of a basic connection, or a connection requiring expansion work. The types of connections Toronto Hydro performs can generally be divided into two categories as follows:

10 As of 2017, Toronto continues to lead in the number of major buildings under construction, ranking second in tall building construction after New York (Toronto Economic Bulletin, May 25, 2018).
[11] Exhibit 3, Tab 1, Schedule 1.

- **Low voltage requests (below 750 Volts):** These requests primarily involve residential and small commercial customers (GS<50 rate class) supplied at 750 Volts or less whose average monthly maximum demand is less than, or is forecasted to be less than 50 kW. As shown in Figure 3, the volume of low voltage connections has been high in recent years (i.e. consistently exceeding 2,500 per year); however, the work is typically seasonal and has a relatively short turnaround time. As part of Toronto Hydro's obligations, the utility works with customers to provide options for a new connection or service upgrade. As per the DSC, section 7.2.1, these service requests must be completed within 5 business days from the day on which all applicable service conditions are satisfied, or at a later date as agreed to by the customer and distributor.

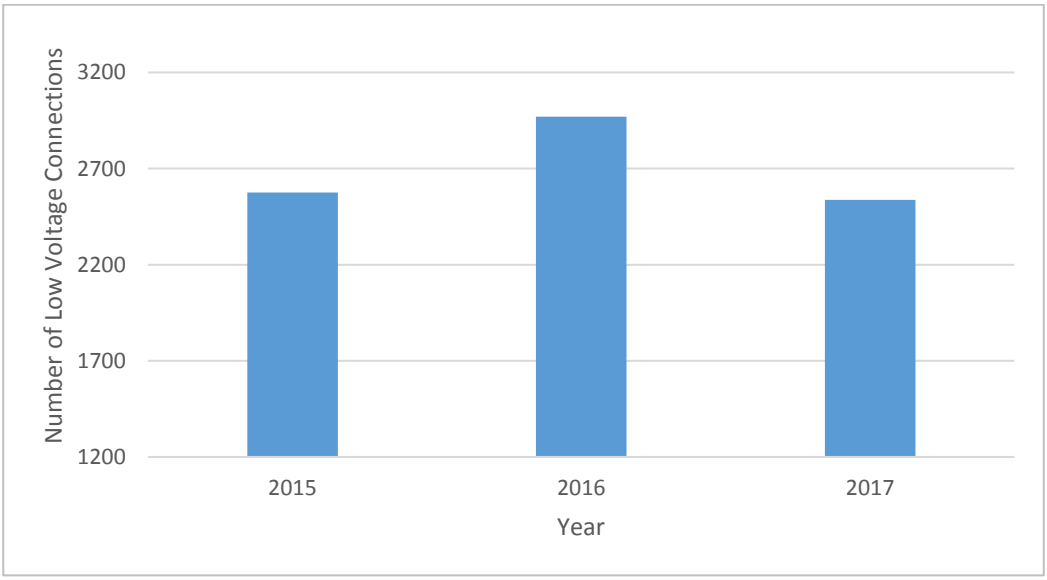


Figure 3: Low Voltage Connections 2015-2017

- **High voltage requests (750 Volts and above):** These requests primarily relate to larger residential and commercial developments. These customers typically engage Toronto Hydro years before service is expected to be required. Figure 4 provides a year-over-year comparison of the volume of new formalized high voltage requests that Toronto Hydro receives on an annual basis. As per section 7.2.2 of the DSC, these service requests must be completed within 10 business days from the day on which all applicable service conditions are satisfied, or at a later date as agreed to by the customer and distributor.

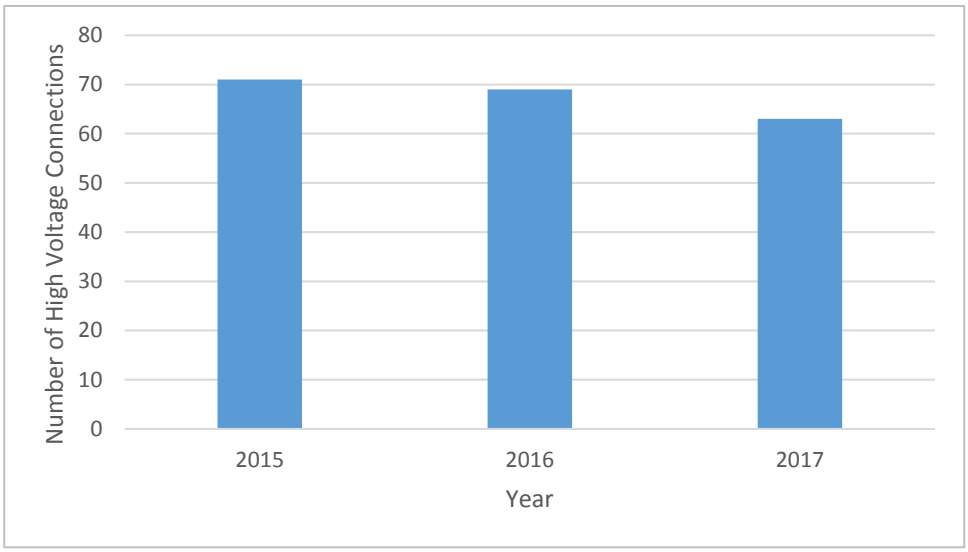


Figure 4: High Voltage Requests 2015-2017

For both low and high voltage service requests, applicable service quality requirement must be met at least 90 percent of the time on a yearly basis. Toronto Hydro processed a total of 1,901 feeder requests[12] over the last five years (i.e. between 2013 and 2017), including 948 (43 percent) during 2016 and 2017, as shown in Figure 5 below. Figure 6 illustrates the variation in location and load requirements for the requests. The overall increasing trend in the volume of requests processed from year to year is expected to continue up to and throughout the 2020-2024 period. Following a feeder request, the connection typically materializes within 5 years, from the day the feeder request was created, excluding any project delays. As a result, a number of feeder requests received between 2015 and 2019 are expected to drive work in the 2020-2024 period.

[12] **Feeder request**: An internal request to determine the appropriate point and method of connecting customers exceeding 50 kW to Toronto Hydro's distribution system. Feeder requests relate to both potential and proposed projects in their preliminary stages.

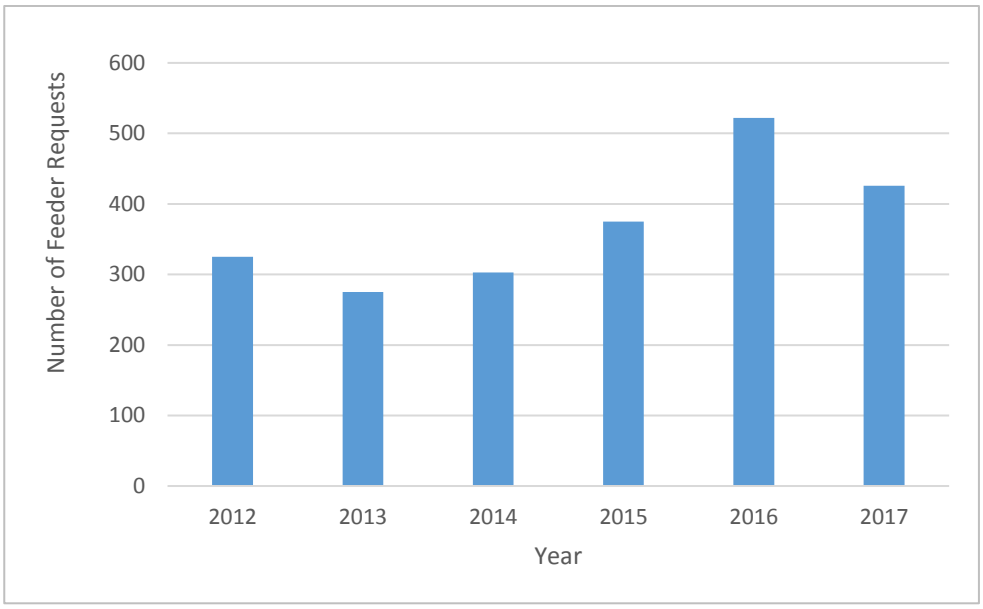


Figure 5: Feeder requests processed (2012-2017)

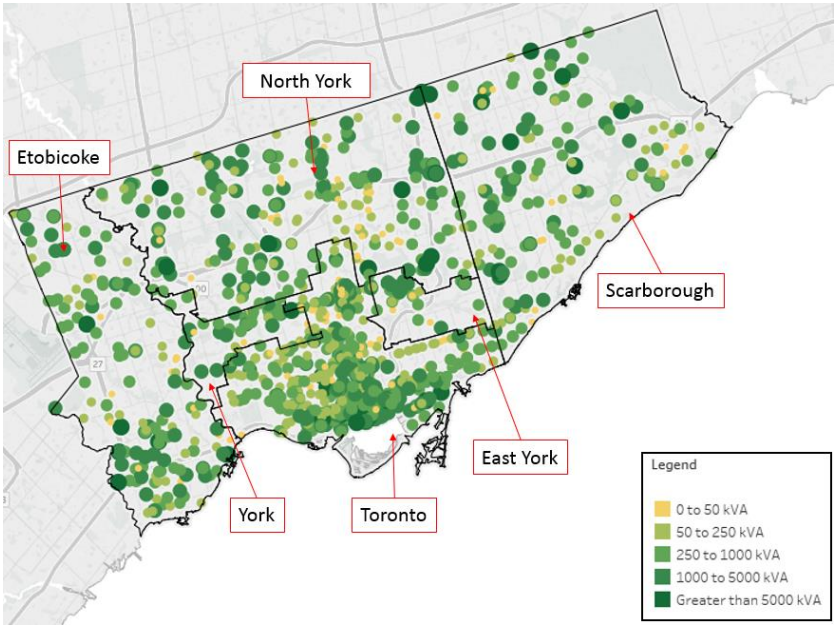


Figure 6: Proposed Load Additions in the City of Toronto during the 2012-2017 Period

Similar trends were observed in the overall increasing volumes of Offers to Connect (OTCs) issued requiring expansion work throughout the 2012-2017 period, as illustrated in Figure 7**.** Expansion work is typically needed for larger connections or requests in areas of the City that are capacity

constrained. This involves the installation or upgrade of distribution assets such as new circuits or civil infrastructure required to accommodate new customer loading. Such work can have a significant cost impact as it typically requires a substantial amount of resources to plan and construct the infrastructure necessary to connect a large customer. The resulting expansion projects are usually large-scale and complex, and thus require weeks or months to complete. Connecting customers to the distribution system without completing the necessary expansions can negatively impact system reliability and safety.

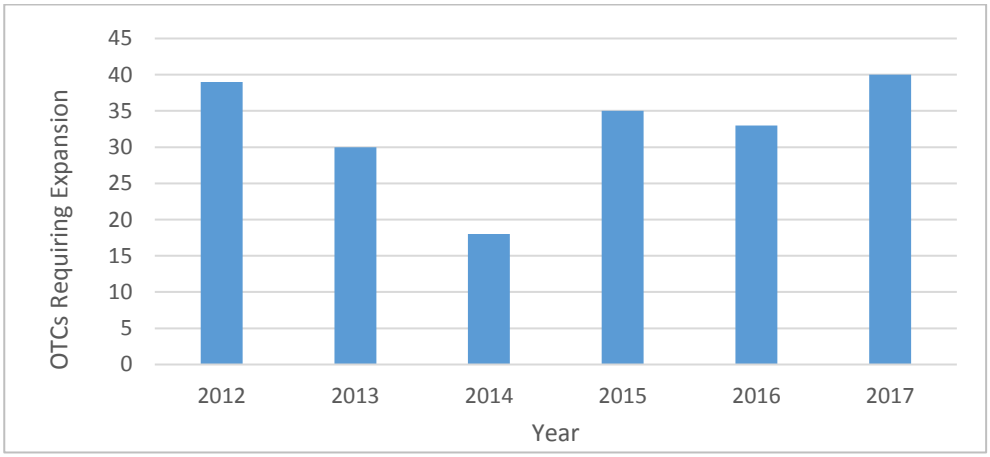


Figure 7: Offers to connect Requiring Expansion

E5.1.3.2 Generation Connections

As per Section 6.2.4 of the DSC, and sections 25.36 of the *Electricity Act*, Toronto Hydro is mandated to connect DG customers to its distribution system while maintaining the safety and reliability of the system for existing customers. Toronto Hydro is also obligated under section 6.1 of its Distribution License and section 26 of the *Electricity Act* to provide generators with non-discriminatory access to its distribution system and to provide priority access for renewable energy generation facilities. It is also required to meet certain timelines when connecting and assessing DG facilities:

- A distributor, as per DSC sections 6.2.7 and 6.2.7A, shall connect an applicant's micro-embedded generation facility to its distribution system within 5 business days from the day on which all applicable service conditions are satisfied, 90 percent of the time on a yearly basis, or at such later date as agreed to by the customer and distributor.
- Section 25.37 of the *Electricity Act* requires that Generation Connection Impact Assessments ("CIA") for renewable energy generation facilities be completed by electricity

distributors within prescribed timelines, and also requires distributors to report quarterly to the OEB on their ability to meet those timelines. Ontario Regulation 326/09 (Mandatory Information re Connections) sets out details regarding the timing of, and reporting on, connection assessments.

Toronto Hydro supports connecting DGs to the distribution system in alignment with the DSC and in coordination with Hydro One and the IESO. As of the end of 2017, Toronto Hydro had responded to over 8,000 inquiries from customers and developers seeking to connect generation under various programs such as the IESO programs,[13] Net-Metering, Energy Storage, Combined Heat and Power ("CHP"), Closed Transition and Load Displacement. A wide range of proponents have submitted project applications, including many schools, housing managers, large grocery stores, condominium corporations, and department stores. As of the end of 2017, Toronto Hydro had connected nearly 1,800 DGs of various sizes totalling 225.7 MW in capacity as seen in Table 4. An overview of the number and total capacity of DGs connected by technology types are provided in Table 4, Table 5 and Figure 8.

Table 4: Cumulative Existing Generation Connections

Generation Type	2010	2011	2012	2013	2014	2015	2016	2017
Renewable	216	407	584	785	978	1304	1554	1750
Natural Gas	18	18	19	20	20	22	22	26
Diesel	8	9	9	10	11	13	16	18
Energy Storage	0	0	0	1	1	2	3	3
Total	**242**	**434**	**612**	**816**	**1010**	**1341**	**1595**	**1797**

Table 5: Cumulative Existing Generation Capacity (in MW)

Generation Type	2010	2011	2012	2013	2014	2015	2016	2017
Renewable	6.7	12.8	21.3	30.9	44.5	71.9	86.6	96.6
Natural Gas	55.1	55.1	57.1	66.1	66.1	75.9	75.9	80.9
Diesel	11.8	13.3	13.3	14.5	19.5	29.6	36.1	47.1
Energy Storage	0.0	0.0	0.0	0.5	0.5	1.2	1.2	1.2
Total	**73.6**	**81.1**	**91.6**	**111.9**	**130.5**	**178.6**	**199.7**	**225.7**

[13] Including Feed-in-Tariff (FIT), microFIT, Process and Systems Upgrade Initiative (PSUI), and Renewable Energy Standard Offer Program (RESOP).

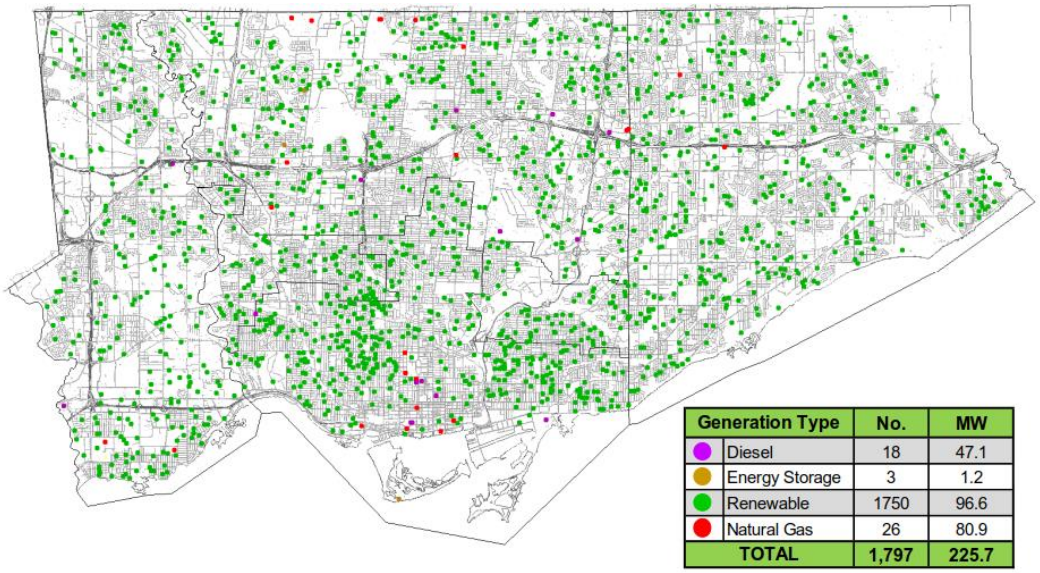


Figure 8: Generation Connections in Toronto Hydro Service Area by Generation Type

Customers have shown a steadily increasing interest in DG projects, as evidenced by the historical connection figures in Table 4 and Table 5 and by the large amount of inquiries received by Toronto Hydro in this regard. The majority of the applications received to date are for renewable generation projects under the FIT and microFIT programs. However, there is a growing interest in the Net-Metering program and battery Energy Storage, due to policy changes[14] in Ontario and as costs associated with solar photovoltaic panels, inverters and lithium-ion batteries continue to fall. Based on market projections, battery energy storage connections are expected to increase between 15 percent[15] and 25 percent[16] year-over-year as the technology matures and prices fall to economical levels.

Figure 9 shows the historical and forecasted DG capacity within Toronto Hydro's service territory up to 2024 (see section 4.2 for forecast details).

[14] See: LTEP and April 5, 2017 Ministerial Directive (*Supra* note 3)
[15] Based on observed trends since the 2015-2019 CIR application and the increased emergence of micro-turbine CHP in recent years.
[16] Navigant Research Report Findings in Hill, J.S. (2015). "Distributed Energy Storage Revenue to Exceed $16.5 Billion by 2024". *CleanTechnica*. Jan 13, 2015. Available from: https://cleantechnica.com/2015/01/13/grid-scale-energy-storage-expected-generate-68-billion-revenue-2014-2024-according-navigant-research/

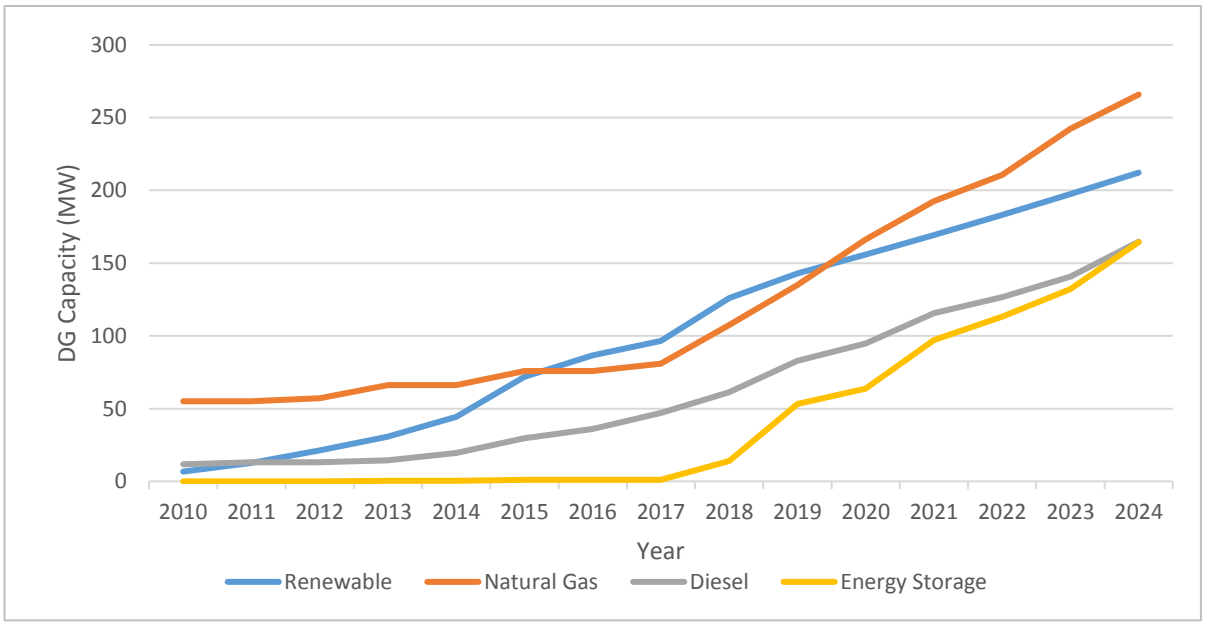


Figure 9: Forecast Generation Capacity

Toronto Hydro's DG connection forecast is based on historical DG connections, initial consultations and preliminary assessments received and completed from 2009 onwards, which include initial consultations regarding the Net-Metering, CHP, Closed Transition, Load-Displacement, IESO Energy Storage Procurement Request for Proposal ("RFP") and IESO programs such as PSUI and FIT[17]. The forecast takes into account the historical connection trends, completed assessments, and anticipated projects with respect to various DG programs.

Forecasts for DG connections and capacity are provided in Table 6 , Table 7 and Figure 9. DG projects are expected to nearly double by 2024, reaching approximately 3600 connections. This represents an additional 581 MW on top of the 225.7 MW of existing DG as of the end of 2017.

Table 6: Forecast Generation Connections (Volumes)

Generation Type	2018	2019	2020	2021	2022	2023	2024
Renewable	2074	2235	2390	2550	2715	2885	3062
Natural Gas	46	65	88	114	143	178	217
Diesel	21	27	33	40	46	54	63
Energy Storage	28	52	77	110	148	194	251
Total	**2169**	**2379**	**2588**	**2814**	**3052**	**3311**	**3593**

[17] *Supra* note 13

Table 7: Forecast Generation Capacity (in MW)

Generation Type	2018	2019	2020	2021	2022	2023	2024
Renewable	126.0	143.0	156.0	169.4	183.2	197.4	212.2
Natural Gas	107.5	135.1	166.3	192.7	210.7	242.3	265.9
Diesel	61.2	82.9	94.7	115.7	126.7	140.7	164.7
Energy Storage	14.0	53.2	63.7	97.1	113.2	132.2	164.4
Total	**308.7**	**414.3**	**480.7**	**574.8**	**633.8**	**712.6**	**807.2**

The above forecast is consistent with the current trend being observed in respect to DG connections. Customer interest in large, medium, and small-scale CHP generation facilities also continues to rise due to industrial and commercial customers seeking site reliability and operational cost savings. Inquiries for medium and large embedded CHP facilities have more than tripled from 15 in 2015 to almost 50 in 2017. Similarly, customer interest in small-scale microturbine-based CHP facilities[18] continues to rise as the number of connection requests has jumped from 25 in 2015 to 120 in 2017. Toronto Hydro anticipates a large volume of applications for these CHP facilities over the 2020-2024 period, as more customers become aware of this technology's economic benefits.

At this time, there are over 450 micro and small sized renewable projects totalling 31 MW that have been assessed and approved by Toronto Hydro for connection under the microFIT, FIT and Net-Metering programs. These projects are expected to be connected to the distribution system by the end of 2018.

Toronto Hydro is aware of 19 medium and large sized CHP, Diesel Closed Transition and Energy Storage projects totalling 124 MW in nameplate capacity. These projects are in various stages of development and will take longer to be connected to the distribution system (i.e. anticipated to be connected between 2018 and 2020) due to their larger size.

[18] This technology is ideally suited for small-scale power generation in multi-level residential buildings.

E5.1.4 Expenditure Plan

Table 8: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Customer Connection	32.6	39.6	22.1	44.8	37.6	42.9	43.9	44.8	45.6	46.3
Generation Connection	(0.9)	0.4	(0.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**31.7**	**40.1**	**21.9**	**44.8**	**37.6**	**42.9**	**43.9**	**44.8**	**45.6**	**46.3**

E5.1.4.1 Customer Connections

Table 9: Historical & Forecast Program Costs ($ Millions)

		Actual			Bridge		Forecast				
		2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Customer Connection	*Gross*	68.3	67.1	58.6	82.1	78.6	73.6	75.3	76.9	78.2	79.6
	CC[A]	(35.7)	(27.4)	(36.5)	(37.2)	(41.0)	(30.8)	(31.4)	(32.0)	(32.7)	(33.3)
	Net	**32.6**	**39.6**	**22.1**	**44.8**	**37.6**	**42.9**	**43.9**	**44.8**	**45.6**	**46.3**

[A] *CC: Customer Contributions*

Expenditure in the Customer Connections segment is driven by a myriad of factors. Year to year variations are due to factors such as economic drivers and changes, the specific type of connection and associated expansion work, and provincial and municipal policies regarding infrastructure and community revitalization projects. As described below, Toronto Hydro's 2020-2024 expenditure forecast is based on historical data.

The irregular nature of expenditures in this segment is attributed to externally driven variables, which include:

1) Economic drivers, changes, and policies influence corporations from various industries (such as technology,[19] design,[20] food & beverage,[21] film, financial services, transportation, etc.) to operate or expand in Toronto, consequently impacting investment needs and expenditures.

[19] Toronto is North America's fastest growing technology market - https://www.toronto.ca/business-economy/industry-sector-support/
[20] Toronto employs the largest design workforce in Canada and third largest in North America - https://www.toronto.ca/business-economy/industry-sector-support/
[21] Toronto is a major decision-making centre for the food industry in Canada, with half of Canada's top ranked food and beverage manufacturers being headquartered in the city https://www.toronto.ca/business-economy/industry-sector-support/food-beverage/

2) Provincial and municipal policies regarding infrastructure and community revitalization projects (e.g. Six Points and Toronto Waterfront), hospitals, universities, public transit projects (e.g. TTC and Metrolinx) may give rise to connection work and consequently create further construction and related work in the relevant project sites and surrounding areas.
3) The number, type, size, and location of connection requests received by Toronto Hydro are factors that inform whether an expansion to the distribution system is required. As elaborated in Section 3.1, expansion work can significantly impact program expenditures as it typically requires a substantial amount of resources to plan and construct the infrastructure necessary to connect a customer.
4) Capacity relief and additional capacity provisions completed under other System Access and System Renewal programs. For example:
    - Areas with load constraints may be relieved under the Load Demand program.
    - Assets replaced to current standards under the Overhead System Renewal program may indirectly include additional capacity provisions for future purposes.
    - Current standards do not specifically aim to increase capacity to facilitate new connections, but rather aim to minimize disruptions and achieve cost efficiencies and savings. For example: (i) poles are replaced with higher or stronger poles to accommodate additional circuits without having to replace the new poles in the future; and (ii) additional ducts may be installed when ducts are rebuilt to leverage trenching costs and avoid future costs.
    - The resulting capacity relief will allow Toronto Hydro to connect customers more efficiently, reducing expansion requirements to the distribution system and consequently reducing connection costs.

Toronto Hydro's customer charges or allowances associated with the work are established pursuant to the DSC, and Toronto Hydro's Conditions of Service. Connection asset related work, less any allowance, is paid for by the customer. Expansion asset related work is evaluated using the Economic Evaluation Model[22] to determine capital contribution and expansion deposit requirements to be met by the customer. One set of allowances are the Basic Connection Fees. As per Revision 17 of the Conditions of Service, Toronto Hydro's Basic Connection Fees are shown in Table 10.[23]

[22] As defined in Section 3 and Appendix B of the DSC.
[23] Fees are reviewed annually and updated with notice to customers when Toronto Hydro's Conditions of Service is revised.

Table 10: Basic Connection Fees

Customer Class		Basic Connection Fee
Class 1 to 5		$1,396
Unmetered (excluding street lighting)	*Overhead Supply*	$446 or $1,011
	Underground Supply	Collected directly from Customer

The contributions filed in the last application assumed a gross spend (and capital contribution ratio of 25 percent) identical to the 2014 historical, which was further adjusted as anticipated Metrolinx costs and contributions were added. However, the actual contributions received in 2015 and 2017 exceeded the forecast by $36 million. Therefore, to smooth any cyclical trends and better reflect actual contributions, the 2020-2024 forecast utilizes the average capital contribution of 46 percent experienced during the most recent 5-year period (i.e. 2013 to 2017).

Overall, for the 2015-2019 period, the load connection segment is forecasted to be within 5 percent of gross expenditures initially planned, however, recovered capital contributions were 90 percent higher than what was initially planned. This resulted in lower net expenditures.

The Customer Connections program is driven by customer service requests and as such, Toronto Hydro ranks and prioritizes jobs in this Program in accordance with the schedules and timelines of individual customers and service requests.

For customers requiring basic connections, prioritization is conducted on a first come, first served basis, taking into account the in-service date requested by the customer. This prioritization applies where Toronto Hydro has sufficient physical infrastructure, such as through overhead or underground lines, to enable the connection as well as adequate capacity on the relevant distribution feeder cable and station bus. Furthermore, customer timelines are considered to minimize disruptions or allow for efficiencies, whenever possible.

Wherever civil or electrical capacity is constrained or reliability is a concern, the connection is completed once the constraints are addressed by an expansion or system enhancement. For connections that cannot be completed without an expansion, prioritization of the work is determined in accordance with the timelines and requirements stated in the OTC.

E5.1.4.2 Generation Connections

Table 11: Historical & Forecast Program Costs ($ Millions)

		Actual			Bridge		Forecast				
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Generation Connection	*Gross*	0.9	0.6	0.8	3.4	2.8	2.9	3.5	3.2	4.1	4.5
	Customer Contribution†	(1.8)	(0.2)	(1.0)	(3.4)	(2.8)	(2.9)	(3.5)	(3.2)	(4.1)	(4.5)
	Net[24]	**(0.9)**	**0.4**	**(0.2)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

† Work and costs associated with additional modifications to the distribution system to incorporate renewable generation into the system are not paid for by the customer, and therefore, not covered under this Program. Such work and costs are discussed in the Generation Protection, Monitoring, and Control program see Exhibit 2B, Section E5.5.

The Generation Connection forecast has been compiled based on historical trends, completed assessments, and anticipated projects. A linear approximation was used to forecast the anticipated number of connections and total generation from 2018 through 2024. The forecast assumes the following:

1) The microFIT & FIT program will transition to a net metering program in 2018, as per the direction issued by the Minister of Energy on April 5, 2016;
    - no major changes will be introduced to the net metering program from 2020 to 2024;
2) A steady 3 percent increase year-over-year for renewable connections;
    - 90 micro and 60 small sized renewable connections in 2019 are used as the baseline;
3) Increased demand for energy storage connections due to reductions in lithium-ion battery prices;
    - 12 micro, 5 small and 3 medium sized energy storage connections in 2019 are used as the baseline, and a 20 percent increase year-over-year is used to forecast 2020-2024 connections;
4) Increased demand for CHP and diesel connections due to customers seeking site reliability and electricity charge reductions;

[24] All DG connections are 100 percent funded by capital contributions from the customer, and consequently, there should be zero net expenditure for DG connections. However, due to the pacing and timing of a DG installation, capital contributions may be collected from the customer in one year whereas the gross expenditures may span several years. As a result, the 2015- 2017 historical yearly total net expenditures do not equal zero.

- 15 small and 2 medium sized natural gas connections in 2019 are used as the baseline, and a 15 percent increase year-over-year is used to forecast 2020-2024 connections; and
- 1 small and 4 medium sized diesel connections in 2019 are used as the baseline, and an extra unit is forecasted to be added every two years.

Table 12 and Table 13 below provide a breakdown of work units and costs associated with the Generation Connection program based on generation type and size.

Table 12: 2015-2019 Volumes (Actual/Bridge)

Generation Type	Actual			Bridge		Total
	2015	2016	2017	2018	2019	
Micro (Renewable & Energy Storage)	122	124	155	247	102	**750**
Small Renewable	251	24	89	99	71	**534**
Small (Natural Gas, Diesel & Energy Storage)	2	2	3	22	23	**52**
Medium (Renewable, Natural Gas & Energy Storage)	1	2	2	6	2	**13**
Medium (Diesel)	3	2	-	8	8	**21**
Large (Natural Gas & Energy Storage)	-	-	-	-	3	**3**
Large Diesel	-	-	-	-	1	**1**

Table 13: 2020-2024 Volumes (Forecast)

Generation Type	Forecast					Total
	2020	2021	2022	2023	2024	
Micro (Renewable & Energy Storage)	108	114	121	129	139	**611**
Small Renewable	62	64	66	68	71	**331**
Small (Natural Gas, Diesel & Energy Storage)	25	30	36	43	51	**185**
Medium (Renewable, Natural Gas & Energy Storage)	4	4	4	5	5	**22**
Medium (Diesel)	9	10	11	13	14	**57**
Large (Natural Gas & Energy Storage)	1	2	-	1	1	**5**
Large Diesel	-	1	-	-	1	**2**

Toronto Hydro does not propose any net expenditure under this Program for the years 2020 to 2024 as all DG connections are 100 percent funded by capital contributions from the customer. Work and costs associated with additional modifications to the distribution system to incorporate renewable generation into the system are not paid for by the customer, and therefore, not covered under this Program but under the Generation Protection, Monitoring, and Control program.[25]

Toronto Hydro has a dedicated generation planning team that supports DG connections. The team works closely with customers to ensure the DG connection process is followed and timelines are met. Generation connections, like customer load connections, are processed and completed on a first come first serve basis. As such, the proposed investment pacing of this Program is based on historical trends, completed assessments, and anticipated projects.

E5.1.4.3 Cost Management

Toronto Hydro integrates the connection work with its planned construction activities to help ensure that the scope, nature and timing of the connection work does not adversely affect the utility's existing customers and planned work program.

If Toronto Hydro anticipates that load growth will require additional infrastructure upgrades beyond what is required under the expansion work set out in the OTC, the utility will include the additional distribution work, which can range from installing larger circuits to rebuilding cable chambers, as a part of the project. Project costs are allocated to the respective programs (e.g. Load Demand, Externally Initiated Plant, Overhead System Renewal, or Underground System Renewal). This coordinated approach is more cost-efficient than returning to the same area at a later date to perform additional upgrades.

An example of this approach can be found in work along Toronto's Waterfront, where the required civil work to connect new condominiums and developments was augmented to include the additional infrastructure necessary to meet future demands and system requirements that are imminently expected based on the City's Precinct Plans and progress for the revitalisation project.

Wherever possible, Toronto Hydro also coordinates its connection work with construction activities undertaken by other utilities or municipal or provincial government agencies. For example, Toronto

[25] Exhibit 2B, Section E5.5.

Hydro is coordinating the expansion work for the Six Points Interchange with the City of Toronto's road allowance infrastructure construction schedule.

Where an expansion overlaps with a capital work program or another project, Toronto Hydro would connect customers under a temporary arrangement until the project is complete. Customer offers and sustainment work are reviewed and switching and restoration plans are made to assist with meeting customer demands.

E5.1.5 Options Analysis

E5.1.5.1 Option 1: Do nothing

Do nothing is not an option as Toronto Hydro would be violating the DSC as well as its Distributor License.

E5.1.5.2 Option 2 (Selected Option): Customer Connections Program

As customers request access to the distribution system, Toronto Hydro endeavours to connect them in the most efficient and economic means available. Specifically, Toronto Hydro aims to connect customers from the closest access points available; where possible.

Depending on the system and customer conditions (e.g. requirements, size, location, and timelines), capacity or access may not be available. In such cases, Toronto Hydro will consider alternative solutions to connect the customer. Such alternatives may include, but are not limited to, transferring existing customers to an alternative feeder to free capacity on the feeder in question, or upgrade, extend, or install feeders, transformers, switches or other relevant equipment, as required. Should multiple options exist to connect a customer, options are reviewed with the customer and any differences (financial or technical) are explained to the customer to allow for an informed decision.

The Customer Connections program is an integral program for Toronto Hydro for purposes of meeting customer service requests in accordance with its mandated service obligations. Without this Program, Toronto Hydro will not be able to serve and connect customers in the manner specified by its Distributor Licence and other applicable regulatory requirements.

E5.1.6 Continuous Improvement

E5.1.6.1 Productivity

In 2017, Toronto Hydro combined two of its design teams: Low Voltage and High Voltage. Prior to this, the Low Voltage team dealt with short turn around seasonal work while the High Voltage team dealt with larger developments that had long lead times. This merger has allowed the allocation and distribution of work across design team members in a more effective and efficient manner.

Toronto Hydro implemented an online form with standardized fields that customers complete in respect of their inquiries. This directs the customers' inquiry promptly and accurately to the correct resource thus minimizing the "bouncing" around of the customer from one department to another.

Wire transfer payments for customer connections have recently been implemented to provide customers with alternate and more efficient methods of payment. This increases efficiency by reducing the time required to receive and cash the funds, improves traceability and reduces the possibility of cheques getting misplaced. Furthermore, this eliminates the need for customers to mail cheques or travel to Toronto Hydro work centers to deposit cheques.

In 2016, Toronto Hydro piloted a Customer Relationship Management ("CRM") system to improve relationship management with customers, better manage status and progress of requests, and enhance project tracking. The pilot provided transparency and allowed Toronto Hydro to better manage requests by recording information such as when requests were received, milestone progress, response times, assigned designer, and project status. This pilot system led Toronto Hydro to consider expanding and implementing the CRM solution to capitalize on the potential benefits offered by the system.

E5.1.7 Execution, Risks & Mitigation

E5.1.7.1 Execution

Customer Connections involves the installation of connection, expansion, and/or enhancement assets, as defined by the DSC. The utility manages the work required under the Customer Connections program for Toronto Hydro. Customers or their representatives are required to consult with Toronto Hydro concerning the availability of supply, supply voltage, service location, metering, and any other details necessary to establish service.

Customers apply for new or upgraded electricity services and temporary power services in writing. Each customer provides Toronto Hydro with sufficient lead-time to ensure the timely provision of adequate electricity supply. Toronto Hydro communicates with the customer in a timely manner in accordance with the DSC and Toronto Hydro's Conditions of Service.

Pursuant to the applicable provisions of the DSC and its Conditions of Service, Toronto Hydro does not connect customers if it has safety concerns or reason to believe that the connection would affect the reliability of its distribution system. A load analysis is performed for each customer request to ensure that the requested connection would not overload Toronto Hydro assets above their rated capacity. For large connections, this analysis also includes protection and coordination studies to ensure the proper protection is in place and to avoid damage to equipment and potential safety risks.

During the consultation and design phase of a customer's request, if a connection could potentially degrade the reliability of the relevant feeder or station, expansion work is deemed necessary to increase capacity or transfer load so that the current level of reliability is maintained.

Toronto Hydro provides customers with an OTC within 60 days from the day all required information is received. The customer is presented with a job quotation or a "short form" OTC, should the connection not require any expansion. Otherwise, the customer is provided with a "long form" OTC.

Customers are required to accept and make all OTC payments within 60 calendar days of receiving the OTC. Once an OTC is executed, the resulting work is to be carried out by Toronto Hydro resources unless the customer pursues an alternative bid where allowed by the OTC.

E5.1.7.2 Risks & Mitigation

Following are a number of risks that may affect the completion of the Program, and associated actions aimed to eliminate or manage such risks:

- **Capacity upgrade requirements**: Due to the increasing quantity and size of customer service requests, Toronto Hydro anticipates that many future connections will require expansion work to deal with capacity constraints. Typically these expansions have long lead times that could present a challenge to Toronto Hydro in meeting the customer's required timelines for connection. The increasing complexity of connections, which may require additional capacity/equipment from Hydro One, may not allow Toronto Hydro to deliver an OTC within 60 days. Toronto Hydro will continue to:

- Use long term forecasting, including analysis of city area and development plans in order to address growth early on and proactively upgrade or install required assets through enhancement work to the system; and
- Engage customers early on in the process to determine needs and assess impact on distribution system.

- **Customer timelines and requirements**: Customers' changing requirements, load demand, deadlines, and delays in providing information, signing offers to connect, and providing payments present a risk to project timelines. These issues could consequently impact resource allocation and timeliness of completion of the project in question (and other projects as well). Additionally, an expedited construction schedule by the customer and/or a strain on Toronto Hydro resources risks the utility's ability to complete the project on time and meet the customer's timeline. Toronto Hydro strives to identify and mitigate these risks early on during the design and consultation phase. Toronto Hydro communicates with the customer in a timely manner in accordance with the DSC and Toronto Hydro's Conditions of Service to ensure requests are continuously progressing. Customers are informed of expectations, timelines, and requirements early on through proper communications. Customers are also required to accept and make all OTC payments within 60 calendar days of receiving the OTC.

E5.2 Externally Initiated Plant Relocations and Expansion

E5.2.1 Overview

Table 1: Program Summary

2015-2019 Forecast ($M): 23.2	**2020-2024 Forecast ($M):** 46.1
Segment: Externally Initiated Plant Relocations & Expansion	
Trigger Driver: Mandated Service Obligations	
Outcomes: Customer Service, Public Policy, Financial, Reliability	

The Externally Initiated Plant Relocations and Expansion program (the "Program") captures work Toronto Hydro must undertake to relocate its infrastructure in order to accommodate construction by third parties. In addition, in some instances, the Program includes work that increases the capacity of Toronto Hydro's system where efficiencies can be achieved by pairing the expansion work with the required relocation work. Relocation requests by third parties are usually received from those required to maintain, upgrade, expand and improve existing public infrastructure such as roads, bridges, highways, transit systems and rail crossings. These governmental third parties include the City of Toronto and the Ontario Ministry of Transportation. Toronto Hydro also receives relocation requests from other agencies, such as Metrolinx, which it assesses in a fair and reasonable manner.

The City of Toronto is experiencing a period of significant infrastructure renewal, neighbourhood revitalizations, commercial development and large transit expansions. Toronto Hydro seeks to respond to relocation requests received from third parties in a safe, environmentally responsible, reliable, cost-efficient and timely manner. In pursuing this objective, the utility aims to meet its obligations under the *Public Service Works on Highways Act* ("PSWHA"),[1] section 3.4 of the Distribution System Code ("DSC") and agreements with third parties.

Typically, when relocations are required, Toronto Hydro replaces the existing facilities on a like-for-like basis. This approach represents the minimum investment required to allow Toronto Hydro to continue providing safe and reliable electricity distribution service. However, at times, the nature of the project is such that like-for-like replacements are not the most efficient or desirable option. In these cases, there will be an opportunity for Toronto Hydro to maximize construction efficiencies and increase the existing capacity at the same time a relocation project is completed. In these cases,

[1] R.S.O. 1990, c. P-49

Toronto Hydro reviews the relocation request in conjunction with its future plans, and, if efficiencies can be achieved, works with the third party to complete system expansion work in conjunction with the required relocation. When Toronto Hydro increases the capacity of its infrastructure during an externally initiated relocation project, this is known as an "expansion" for the purposes of this Program.

As mentioned above, the timing, pace and spending under this Program is driven by third party requirements outside of Toronto Hydro's control. The circumstances and discretion of third parties can cause schedules and project scopes to change. In order to mitigate against the unpredictable nature of the work in this Program, Toronto Hydro seeks base rate funding for committed capital projects only. Toronto Hydro also seeks the continuation of the Variance Account for Externally Driven Capital[2] to capture the difference between the capital spending embedded in base distribution rates and the actual spending over the 2020-2024 plan period. This approach will allow Toronto Hydro to fund necessary non-discretionary work, while protecting ratepayers from potential over recovery. Further details on this variance account can be found in Exhibit 9, Tab 1, Schedule 1.

E5.2.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Service	• Contributes to Toronto Hydro's customer service objectives by responding to relocation requests and undertaking necessary, timely and cost-efficient system expansion work to accommodate future growth and increase system access, which should reduce the frequency and duration of construction disruptions for local area residents.

[2] EB-2014-0116, Toronto Hydro-Electric System Limited Decision and Order (December 29, 2015) at p. 50.

Public Policy	• Contributes to Toronto Hydro's public policy objectives by: ○ Complying with the *PSWHA*, which requires Toronto Hydro to work with prescribed entities to complete the relocation of Toronto Hydro infrastructure, when requested, and subject to the cost responsibility principles established therein; and ○ Complying with section 3.4 of the Distribution System Code by resolving relocation requests in a fair and reasonable manner.
Financial	• Contributes to Toronto Hydro's financial objectives by: ○ Obtaining, from third parties requesting distribution plant relocations, full or partial funding for newly installed/relocated assets pursuant to applicable cost sharing agreements; and ○ Combining externally initiated relocation work with expansion work where doing so provides a more prudent and cost-effective solution than conducting the expansion work at a later date.
Reliability	• Contributes to Toronto Hydro's reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: ○ Installing new infrastructure to current standards; and ○ Improving capacity, where required, through expansion work associated with the relocation.

E5.2.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Mandated Service Obligations
Secondary Driver(s)	Customer Service Requests, Capacity Constraints

E5.2.3.1 Mandated Service Obligations

The projects in this Program are driven by operational decisions of third parties that are beyond Toronto Hydro's control. As mentioned above, the PSWHA requires Toronto Hydro to work with public entities requesting relocation of hydro plant in a timely manner to promote the maintenance

and improvement of public infrastructure. In addition, Toronto Hydro is compelled by section 3.4 of the DSC to resolve third party plant relocation requests in a fair and reasonable manner.

E5.2.3.2 Customer Service Requests

Responding to relocation requests by third parties is part of Toronto Hydro's customer service obligations, including those set out in the PSWHA, which require Toronto Hydro to work with certain third parties to complete relocations when requested. The scope, timing and pacing of externally initiated relocation projects are driven by operational and planning decisions of third parties, which are beyond Toronto Hydro's control.

E5.2.3.3 Capacity Constraints

The scope, timing and pacing of these relocation projects are driven by operational decisions of third parties that are beyond Toronto Hydro's control. However, construction work carried out by third parties does provide an opportunity to expand the distribution system in a manner that minimizes disruption to customers and is more cost-effective for ratepayers. To this end, Toronto Hydro reviews load demand projections in the vicinity of externally initiated relocation work to identify opportunities to increase capacity during a relocation project. When capacity needs are identified, Toronto Hydro integrates expansion work into the relocation project. This offers a more cost-effective solution than conducting the expansion work after the sponsor agency has completed its project.

E5.2.3.4 Program Need

Toronto Hydro undertakes the externally initiated relocations and expansions projects solely in response to the capital work initiated by third parties. Toronto Hydro is required to undertake this work under the applicable legislation for prescribed entities (see Requests from Road Authorities section below) and requests from other private parties are dealt with on a case-by-case basis. Any expansion work carried out under this Program is needed to meet anticipated future load growth, to allow Toronto Hydro to coordinate projects with construction work being carried out by third parties. This minimizes disruptions for customers and provides for an efficient and cost-effective solution.

The projects within this Program can be divided into three broad categories: (i) requests from prescribed entities ("Road Authorities") which are governed by the PSWHA; (ii) requests from other agencies; and (iii) expansion work undertaken in conjunction with the relocation work.

1. Requests from Road Authorities

The PSWHA outlines obligations for utilities with infrastructure on roads and those entities ("Road Authorities") that have control of the construction, improvement, alteration, maintenance and repair of a highway (e.g. City of Toronto, Ministry of Transportation of Ontario). For instance, typical relocation work arising from a City of Toronto initiated project includes relocating hydro poles to enable road realignment.

The PSWHA also provides a costs formula that dictates how costs will be allocated between the parties. The PSWHA establishes a framework for determining cost responsibility for the relocation work. Under this framework, the Road Authority and the operating corporation may agree upon the apportionment of the cost of labour employed in the relocation, but, if there is no such agreement then the labour costs are divided equally between the Road Authority and the utility, and all other costs of the work (such as material costs) are the responsibility of the utility. Consistent with past experience, Toronto Hydro estimates that it will recover approximately a third of the total relocation costs associated with projects from a Road Authority.

For relocation project components that are initiated by a third party and not covered under the PSWHA, such as streetscape improvement projects, Toronto Hydro aims to negotiate agreements that provide greater cost recovery than the default cost apportionment provided for under the PSWHA.

2. Requests from Other Agencies

Where the request is not originating from a Road Authority, the PSWHA does not apply. However, Toronto Hydro is still obligated, under section 3.4 of the DSC to respond to these requests in a fair and reasonable manner. In these cases, the initiating third party typically funds 100 percent of the relocation costs while Toronto Hydro funds any expansion work conducted in conjunction with the relocation work. Metrolinx projects, such as Eglinton Crosstown Light Rail Transit ("LRT") and Finch West LRT, and Toronto Transit Commission projects, such as the Scarborough Subway Extension and Easier Access Program, are examples of major projects not subject to the PSWHA provisions. In these cases, the third party funds 100 percent of the relocation work.

The Regional Express Rail is another large Metrolinx project that is also not subject to the PSWHA. However, the project is subject to a number of legacy rail crossing agreements that could affect the allocation of relocation costs. Toronto Hydro is working with Metrolinx to negotiate cost

responsibility for relocation work, similar to other Metrolinx projects. If, as a result of these negotiations, Toronto Hydro must bear some of the relocation costs, these costs will be recorded in the Variance Account for Externally Driven Capital.

The locations of some of the other major proposed projects in this Program are shown in Figure 1.

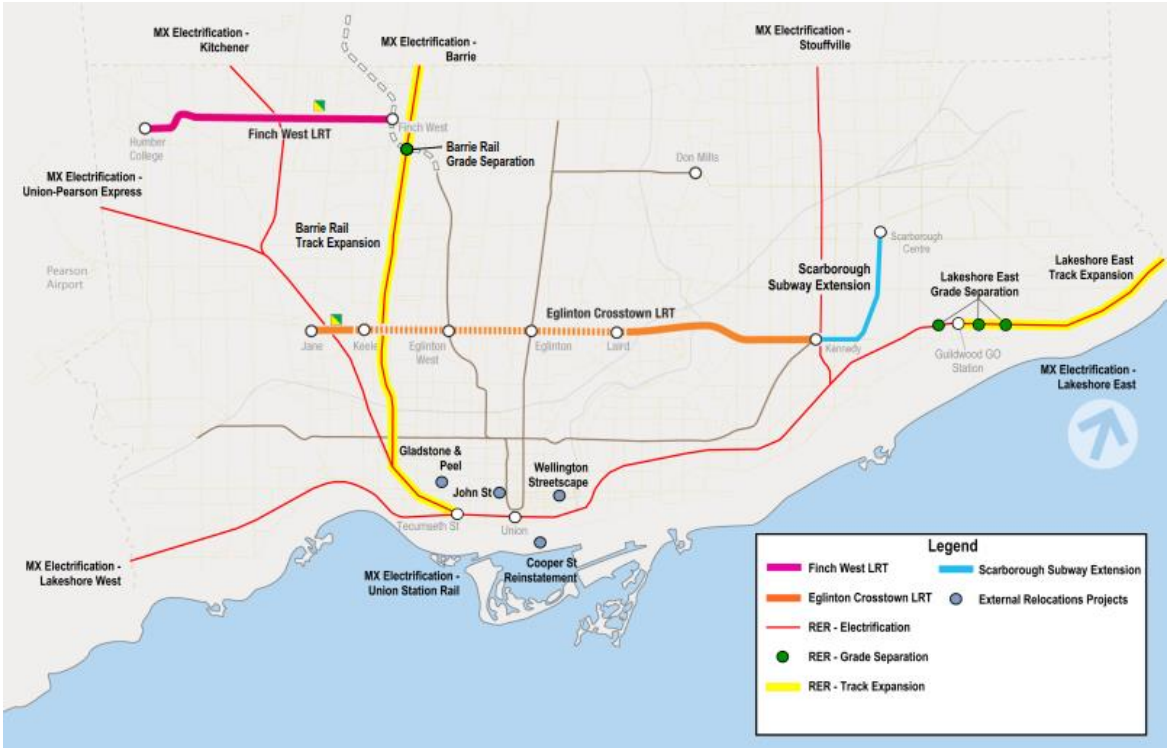


Figure 1: Major Externally Initiated Relocation & Expansion Projects to be constructed during the 2020-2024 Period

3. Expansion Work in Conjunction with Relocation Projects

Expansion work carried out under this Program is needed to meet anticipated future load growth. Pursuing expansion work in conjunction with the externally initiated relocation work allows required infrastructure to be installed where future construction may be restricted due to City streetscaping, commercial developments, City-imposed road work moratoriums or conflicts with other below grade utilities such as water, sewer, gas, and telecommunications.

Incorporating expansion work into the relocation work may result in significant cost savings compared to undertaking expansion work at a later date. Expansion work completed in conjunction

with relocation projects may eliminate future third party utility relocation and coordination work, avoid additional restoration work and minimize disturbance to the general public. Further, undertaking expansion work in conjunction with relocation work ensures that Toronto Hydro infrastructure is installed in already congested rights of way without triggering the need for City approval of encroachment exemptions under the municipal consent requirements for infrastructure clearances. For instance, within the LRT transit corridors of the Eglinton Crosstown LRT and Finch West LRT, Toronto Hydro is taking the opportunity afforded by these relocations to expand its existing infrastructure in preparation for the expected load growth along the LRT lines.

E5.2.4 Expenditure Plan

Toronto Hydro's projected spending in this Program is based on committed capital plans from third party agencies including Road Authorities. Toronto Hydro gathers information on anticipated capital projects through direct consultation with external agencies, participation in the Toronto Public Utilities Coordination Committee, and reviewing governmental and public agency publications, including The Big Move, Metrolinx Five Year Strategy 2015-2020, MTO Southern Highways Program and the City of Toronto's 2017-2026 Capital Budget and Plan. These capital plans and project schedules are subject to change at the sole discretion of the sponsor agencies. Any such changes could impact the timing and execution of Toronto Hydro's relocation and expansion work. The projected quantum and timing of spending shown in Table 4, below, is based on the most current information available from third parties.

Table 4: Historical, Bridge and Projected Program Spending ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Total Project Cost	3.8	9.0	12.5	25.5	21.2	46.3	82.3	56.9	55.8	57.6
Capital Contributions	1.6	6.4	9.9	17.9	12.9	34.9	61.4	52.2	51.1	53.0
Net Cost	**2.2**	**2.6**	**2.6**	**7.5**	**8.3**	**11.4**	**20.8**	**4.6**	**4.7**	**4.5**

In its 2015-2019 Application, Toronto Hydro's forecast cost for the Externally Initiated Relocations and Expansions program was approximately $119 million.[3] This amount was derived from a number of large transit projects scheduled to be undertaken during that plan period by the Province and the

[3] EB-2014-0116, Toronto Hydro-Electric System Limited Custom Incentive Rate-setting Application (Filed July 31, 2014, Updated February 6, 2015), Exhibit 2B, Section E5.3, p. 10.

City. In recognition of the inherent volatility of work included in this Program, Toronto Hydro sought rate funding only for a base amount of approximately $20 million ($4 million of net Toronto Hydro costs per year) and the creation of a variance account to capture the annual differences from the base amount.[4] Toronto Hydro's approach was to ensure funding for necessary, non-discretionary work, while protecting ratepayers from over recovery should the forecasted third party work not materialize due to factors outside of Toronto Hydro's control. The appropriateness of this approach has been validated by the recognition that Toronto Hydro's costs[5] for the 2015-2019 plan period have been less than expected on account of the delay of several major projects.

Toronto Hydro's incurred capital expenditure costs in the 2015-2019 plan period were approximately $23.2 million. Major projects with significant construction activities planned for the 2015-2019 plan period were delayed due to a variety of factors outside of Toronto Hydro's control. These factors include: changes to City and Provincial funding priorities, changes in scope, unforeseen project complications, longer than expected agreement negotiation periods, delayed release or modification of budgets and delays in concluding qualified stakeholder procurement. As such, some of the costs of relocation and expansion work previously anticipated for the 2015-2019 plan period either did not materialize or have been deferred into the 2020-2024 plan period. For example, Toronto Hydro's projected spending is expected to significantly increase over the 2019-2021 period due to the deferral of the Eglinton Crosstown LRT and Finch West LRT relocation projects and associated expansion work.

Toronto Hydro identified a number of major projects that may commence in the 2020-2024 plan period. These are outlined below. Given the uncertainty associated with these projects, Toronto Hydro is seeking rate funding for committed capital projects only (i.e. Eglinton Crosstown LRT and Finch West LRT) during this plan period. If there are any changes to these major projects or any new projects emerge during this plan period, spending under this Program will increase. Therefore, Toronto Hydro requests the continuation of the Variance Account for Externally Driven Capital to record the difference between the capital spending embedded in base distribution rates and the actual spending in this Program over the 2020-2024 plan period.

[4] Ibid at p. 16.
[5] On an ISA basis.

E5.2.4.1 Major Projects

Key projects with anticipated completion in the 2020-2024 plan period, including projects which have carried over from the 2015-2019 plan period, are described below. A number of these projects are still in the scoping phase and, as such, the estimated relocation and expansion costs cannot be determined at this time.

1. Metrolinx Eglinton Crosstown LRT

This is a $5.3 billion investment by the Province of Ontario to expand transit in Toronto by constructing a 19-kilometre LRT line that will run along Eglinton Avenue from Mount Dennis (Weston Road) to Kennedy Subway Station. The project is being carried out by Metrolinx, a provincial Crown agency. Construction along a major corridor such as Eglinton Avenue, with established overhead and underground electricity, water, sewer, gas and telecommunications infrastructure, requires extensive relocation work to avoid conflicts with the construction activities, buildings and infrastructure (e.g. stations, stops, tracks and tunnels). Metrolinx has required that Toronto Hydro assets be relocated to accommodate construction activities which began before 2015. The construction work for this project is expected to continue until 2021, at which time the line is scheduled to go into service. Figure 2, below, shows a typical Eglinton Crosstown LRT Station Box.

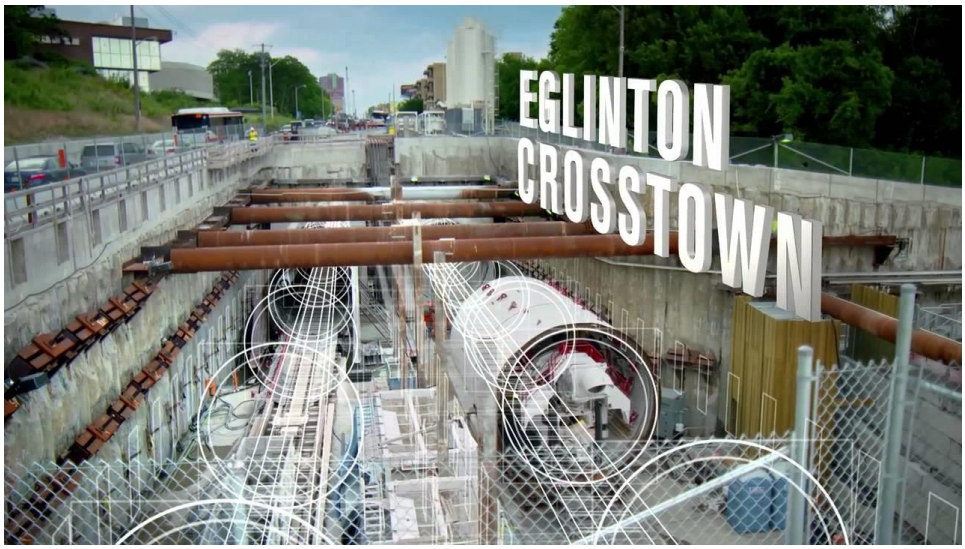


Figure 2: ECLRT Station Box

The project provides an opportunity for Toronto Hydro to undertake needed expansion work in the area. City and provincial policies have targeted the Eglinton corridor as an area of development and

density. Construction of new underground assets by Toronto Hydro within the construction zone will relieve existing area capacity constraints and meet this future growth.

Completing expansion work in conjunction with the proposed construction allows Toronto Hydro to take advantage of construction efficiencies eliminating extensive future relocation work involving complex utility coordination, potential deviation on municipal consent requirements on infrastructure clearances and disturbances to the general public. Construction efficiencies may also be gained by utilizing the same trench for multiple utilities and avoiding additional restoration work. The expansion work is scheduled to occur between 2018 and 2021. The timing of the relocation and expansion work is primarily based on project timelines set by Metrolinx and its contractors.

2. Metrolinx Finch West LRT

This project is a $1.2 billion investment from the Province of Ontario, to be carried out by Metrolinx, to expand transit in Toronto by constructing an 11-kilometre LRT line that will run along the surface of Finch Avenue from Humber College (Hwy 27) to the new Finch West Subway Station. The at-grade LRT will operate on a dedicated right-of-way in the middle of the road. Figure 3, below, shows a typical LRT catenary system.



Figure 3: Typical Overhead Catenary System

With established overhead and underground infrastructure such as electricity, water, sewer, gas and telecommunications infrastructure, relocation work along the Finch West corridor is required to avoid conflicts with construction activities, equipment and infrastructure. Relocations are required to mitigate the conflict with the overhead catenary system for the LRT and Toronto Hydro's overhead distribution lines, as well as to maintain clearances between the LRT rail tracks and Toronto Hydro's underground civil infrastructure. The timeline for the relocation and expansion work is primarily based on the project schedule established by Metrolinx and its contractor. Construction activities will begin in 2018 and will continue into 2022 until this line is in service.

The City and Province have identified the Finch corridor as an intensification corridor where the upgraded transit services will allow for increased growth and development. Toronto Hydro is taking advantage of the relocation work to construct new infrastructure within the Finch West LRT corridor to alleviate capacity constraints and meet the anticipated load growth in the area. Securing expansion work at the same time may provide significant cost savings for ratepayers. These savings may be achieved through cost efficiencies in design and construction including, savings in trenching costs, bulk concrete purchase savings, insurance and digital mapping. Expansion work will be completed in conjunction with the required relocation work causing less disruption to the ratepayer and enabling cost savings due to the elimination of road cut restoration costs.

3. Metrolinx Regional Express Rail

The Regional Express Rail is a $13.5 billion investment from the Province of Ontario, to be carried out by Metrolinx, to enhance and update GO Transit infrastructure across the Greater Toronto and Hamilton Area to support more frequent, two-way, uninterrupted service via electric trains.

This initiative is a multi-year project on the GO rail network that will require extensive relocation of underground and overhead assets along the GO rail corridor in four project categories:

- **GO Electrification**: utilizing an overhead catenary system at 25 kV to operate electric motor trains and phase out diesel trains;
- **Grade Separation**: elevating the rail corridor to separate rail crossings from other modes of transportation;
- **GO Expansion**: expansion of rail tracks and associated infrastructure (i.e. tracks, rails and signals) to facilitate improved uninterrupted service; and

- **GO Station**: construction of new platforms, buildings, stations, traction power stations, parking and maintenance storage facilities to build a connected transit network.

As part of this project, Metrolinx requires the relocation of Toronto Hydro assets to meet infrastructure clearance requirements and to facilitate infrastructure, equipment and construction activities over the course of the proposed 10-year program. Figure 4 shows a typical GO Transit grade separation.



Figure 4: Typical Grade Separation

Toronto Hydro is reviewing available opportunities to take advantage of efficiencies in carrying out necessary expansion work in parallel with the required relocation work. The expansion work involves the construction of new infrastructure within the construction zone of the GO rail corridor and stations. The timing of the proposed work is dependent on the priority and construction of the grade separation, track expansion, electrification and station work determined by Metrolinx which involves relocation work, site preparation, construction and restoration work across the City of Toronto and the surrounding regions.

4. Toronto Transit Commission ("TTC") Scarborough Subway Extension

The TTC is constructing a realignment and extension of the Bloor-Danforth subway line to replace the existing Scarborough Rapid Transit line, also known as the Scarborough Subway Extension

project. The 6-kilometre alignment starts from the east end of Kennedy Station, running in the northerly direction along McCowan Road and ends at the new Scarborough Centre Station. The TTC requires that Toronto Hydro's existing infrastructure be relocated as it is in conflict with this planned subway realignment and extension.



Figure 5: Construction Plan for Scarborough Subway Extension Station

There is work planned for 2018-2019 to relocate Toronto Hydro assets in order to facilitate tunneling at the launch shaft location near Scarborough Centre Station. The rest of Toronto Hydro's relocation work will be driven by the construction schedule for the tunnel and facilities. The planned completion year is 2026. Figure 5, above, shows a typical subway construction configuration. Toronto Hydro is reviewing available opportunities to take advantage of efficiencies in carrying out necessary expansion work in parallel with the required relocation work.

5. TTC Easier Access Program

The TTC initiated the Easier Access Program with the goal of making all of its services and facilities, including key subway and Scarborough Rapid Transit stations, fully accessible to persons with disabilities. The *Accessibility for Ontarians with Disabilities Act*, S.O. 2005 ("AODA") requires that all public facilities and services are accessible by 2025.

Significant subway station infrastructure is impacted by the need for AODA compliance, including the requirement that subway stations be constructed in a tiered configuration, similar to the one set out in Figure 6. Several of the impacted stations are located in the downtown area necessitating relocation of Toronto Hydro's infrastructure. Toronto Hydro has already completed relocation work for four stations. Nine additional station relocations are currently scheduled for completion in the 2020-2024 plan period. Toronto Hydro will evaluate available opportunities to take advantage of efficiencies in carrying out necessary expansion work in parallel with the required relocation work.

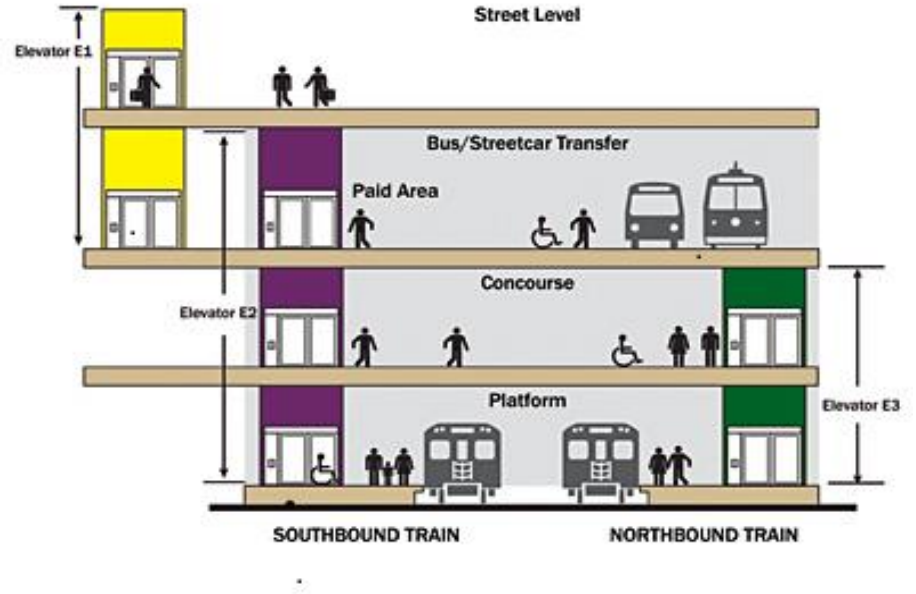


Figure 6: TTC Easier Access Station Concept

6. City of Toronto Projects

The City of Toronto has a $39.7 billion[6] capital budget and plan for 2017-2026 which includes a variety of local and City-wide projects dedicated to the modernization, transformation and renewal of the City. The City approached Toronto Hydro to relocate the utility's infrastructure in conflict with a number of these projects. There are currently 23 active relocation projects, including those in connection with major street development initiatives such as:

[6] City of Toronto 2017-2026 Capital Budget & Plan Executive Committee (Feb 2 2017).

- **John Street Revitalization:** The City and the Toronto Entertainment District BIA are transforming John Street into an arts and culture promenade between Front Street and Stephanie Street by implementing sidewalk widening, road improvements, beautification upgrades and event lighting. Overhead assets will be buried. Civil infrastructure assets required to connect the proposed development to the distribution system will also be installed.



Figure 7: John Street Revitalization Concept

- **Wellington Streetscape:** A public realm (streetscape) improvement initiative between Church Street and Yonge Street implementing sidewalk widening, boulevard improvements and beautification upgrades. The relocation work involves burying overhead electricity distribution assets and the installation of civil infrastructure to connect the development to the distribution system. Toronto Hydro will install additional ducts during the relocation work to address expected load growth in the area.
- **York-Bay-Yonge Ramp Demolition and Harbour Street Widening:** The City is constructing a new off-ramp from the eastbound Gardiner Expressway to Lower Simcoe Street to accommodate traffic flows into the downtown core and waterfront. The project includes the removal of the York-Bay-Yonge off-ramp, the construction of a new ramp ending at Lower Simcoe Street, and improvements to Harbour Street. This project requires the relocation of street-lighting kiosks, transformers and associated infrastructure, as well as the installation

of underground cables and ducts and the rebuilding of cable chambers that conflict with roadway improvement.

A number of rehabilitation projects are put forward every year by the City in connection with its capital plan. With continued City building initiatives and population growth projections, Toronto Hydro anticipates an increase in third party relocation activity during the 2020-2024 plan period pending City council budgetary approvals.

E5.2.4.2 Upcoming Projects

Additional projects that are still in preliminary stages may emerge in the current or next plan period. Government and public agencies such as Metrolinx, TTC, and the City of Toronto have approached Toronto Hydro regarding their initiatives to expand and improve transit and to revitalize public space including, but not limited to, the following projects:

- **Metrolinx**: ECLRT Expansions – Eglinton West LRT and Eglinton East LRT
- **TTC**: Downtown Relief Line and the Yonge Extension to York
- **Waterfront Toronto**: Port Lands Revitalization Waterfront Toronto
- **City of Toronto**: Yonge Street Reimaging
- **City of Toronto**: Port Union Road Widening – Lawrence Ave E to Island Road
- **City of Toronto**: Algonquin Island Bridge
- **City of Toronto**: Scarlett Road Bridge & Road improvement (See Figure 8 below)



Figure 8: Scarlett Road Bridge & Road Improvement Concept

E5.2.5 Options Analysis

E5.2.5.1 Option 1: Completing Externally Driven Relocation Work Only

Toronto Hydro is obligated to relocate its electricity distribution in response to road authorities defined under the PSWHA and respond to relocation requests by third parties in a fair and reasonable manner. As mentioned elsewhere, in general, when relocations are required, Toronto Hydro replaces the pre-existing facilities on a like-for-like basis. This approach constitutes the minimum investment on part of Toronto Hydro to continue providing safe and reliable electricity.

E5.2.5.2 Option 2 (Selected Option): Completing Externally Driven Relocation Work and Expansion Work

Sometimes the nature of a project is such that it is not the most efficient or beneficial option to undertake only relocation work. Upon receipt of a relocation request, Toronto Hydro reviews the future capacity needs in the area and evaluates whether there are opportunities for construction efficiencies available to support undertaking expansion work along with the relocation work. An example of how expansion and relocation work may be combined to maximize efficiencies is the Wellington Streetscape Improvement Initiative.

The Wellington Streetscape Improvement Initiative is a project of the City of Toronto to improve the streetscape along Wellington between Church Street and Yonge Street. Upon being advised of the project by the City, Toronto Hydro worked with the City to identify what infrastructure needed to be relocated and developed a plan to relocate and replace the existing plant according to current standards. Toronto Hydro also reviewed its capital plan to identify expansion work opportunities that could be executed along with the relocation work. Toronto Hydro performed a system analysis to determine expected load growth on the feeders in the area. In reviewing the current feeder loading conditions and approved loads through customer connections and factoring in contingency scenario loading, Toronto Hydro determined that by 2022, seven of nine local feeders would be heavily loaded, requiring relief. To accommodate this anticipated growth, expansion work was integrated into the work plan to be executed during plant relocation initiatives.

Executing expansion work in coordination with the City's capital work was determined to be preferable to only undertaking the relocation work for the following reasons:

- It may be less expensive to construct new civil infrastructure to support the expected load growth in the area if such work is undertaken in conjunction with the relocation work

required by the City's project. If the expansion work is undertaken in the future there would be a need for increased coordination initiatives with third party utilities, more potential for deviation from municipal consent requirements on infrastructure clearances and additional civil construction and restoration work in the area.

- The City's road cut moratorium could prevent Toronto Hydro from installing additional infrastructure when needed to address the expected load growth. The City of Toronto imposes a five-year moratorium on road cuts in an area after road resurfacing is completed. Breaking the moratorium requires City approval and payment of a fee. Failing to complete expansion work during the relocation phase of a project could lead to Toronto Hydro having to install more costly and less optimally located facilities to meet the anticipated demand.
- Completing the expansion work and the relocation work together avoids prolonged disturbances to the residents and businesses in the neighbourhood.

E5.2.6 Distribution Grid Operations Consultation

Consultation with Toronto Hydro's Distribution Grid Operations ("DGO") Department, which coordinates all work on the distribution system, early in the design process improves outcomes for third parties and customers more broadly. Early consultation allows the DGO to sequence work on feeders to accommodate third party relocation work more quickly while minimizing disruptions to customers in the area. The DGO also provides an operational perspective during design review. DGO is able to identify design modifications to improve system reliability early on, thereby avoiding any delay to the overall project.

E5.2.7 Execution Risks & Mitigation

Toronto Hydro's projected spending in this Program is based on a combination of deferred projects from the last plan period, future committed projects and anticipated projects. There is risk that projects in these categories or their timing may be modified or may not materialize as anticipated. In addition, new projects can emerge, adding to program costs. To mitigate the effects of these scenarios for ratepayers, Toronto Hydro requests the continuation of Variance Account for Externally Driven Capital.

The projects proposed under this Program are largely dictated by the schedule and plans of third parties. Third parties often face their own constraints with respect to the execution and completion timelines for their projects. For example, the timing and cost of projects can be affected by City

initiatives such as the King Street Pilot Project. This project aims to improve transit reliability, speed and capacity along King Street and includes limits on the type and timing of construction in the area during the day. These limits may impact project schedules and increase costs arising from the need to undertake work during off-peak hours on evenings and weekends. Toronto Hydro constantly monitors changes to codes, bylaws and legislation which impacts its relocation operations to ensure that its processes and standards align with requirements.

E5.3 Load Demand

E5.3.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 81.9	**2020-2024 Cost ($M):** 87.5
Segments: N/A	
Trigger Driver: Mandated Service Obligations	
Outcomes: Customer Service, Reliability, Safety	

With increasing land development and growth in Toronto Hydro's service territory, the Load Demand program (the "Program") aims to alleviate emerging capacity constraints to ensure the availability of sufficient capacity to connect customers to Toronto Hydro's distribution system efficiently. In doing so, the Program also seeks to minimize the effect of load growth on existing customers. Toronto Hydro's investments in this Program enable the operation of its distribution system under first contingency scenarios,[1] as well as the minimization of potential switching restrictions during summer peak conditions (which can impede the utility's ability to execute maintenance and capital work during summer months). This Program is a continuation of the activities described in the Load Demand program in Toronto Hydro's 2015-2019 rate application.[2]

More specifically, the Program alleviates overloaded equipment and capacity constraints on the distribution system through:

- Load transfers between feeders and station buses to relieve overloads;
- Electrical and civil enhancements to enable capacity upgrades; and
- Cable upgrades, load transfers and equipment upgrades in network vaults to reduce the number of switching restrictions experienced during the summer peak.

[1] "First contingency" occurs when any one primary feeder, transformer, or other critical equipment is lost, either due to a fault or planned outage
[2] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015), Exhibit 2B, Tab 5, Schedule E5.4.

E5.3.2 Outcomes and Measures

Table 2: Outcomes & Measures Summary

Customer Service	• Contributes to the sustainment of service connection targets established by the OEB (i.e. the Electricity Service Quality Requirements) for new residential, small business services, and high voltage services by undertaking targeted capacity upgrades, primarily in the downtown core and areas of high load growth. • Contributes to customer satisfaction results by providing large customers flexibility in scheduling substation maintenance by reducing summer peak switching restrictions.
Reliability	• Contributes to maintaining Toronto Hydro's System Capacity measure, and reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by: o Improving restoration capabilities and reducing customer interruptions by providing additional capacity or maintaining spare capacity through cable upgrades and load transfers; o Improving restoration capabilities in the downtown system by decreasing the number of highly loaded feeders expected by 2024. o Improving restoration capabilities in the Horseshoe system by conducting load transfers for 6 feeders in the high growth areas; o Improving system reliability by reducing the risk of failures due to highly overloaded equipment through mitigation of expected bus overloads; and o Improving downtown reliability by reducing and maintaining the number of heat restricted feeders.
Safety	• Contributes to Toronto Hydro's safety performance objectives (as measured through measures like Total Recordable Injury Frequency) by reducing the failure risk of overloaded infrastructure to Toronto Hydro workers and members of the public.

E5.3.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Mandated Service Obligations
Secondary Driver(s)	Customer Service Requests, Reliability, System Efficiency

E5.3.3.1 Mandated Service Obligations

Toronto Hydro is required to ensure its distribution system can support projected load growth while maintaining reliability and quality of service for customers on both a short-term and long-term basis, as required by sections 3.3.1 and 4.4.1 of the Distribution System Code ("DSC"). Toronto Hydro must also connect new customers within the timelines prescribed by the OEB's service quality standards[3] without adversely affecting the quality of distribution services for existing customers, with 97 percent of new residential and small business services completed on time; and 99 percent of new high voltage connections completed on time.

To satisfy these requirements, Toronto Hydro must maintain sufficient capacity on its system to keep pace with load growth and ensure that its assets are not overloaded (i.e. an overloaded bus is defined as reaching 95 percent of its firm capacity under normal and emergency operating conditions). Highly loaded downtown feeders are defined as feeders that exceed cable ratings under contingency, assuming peak customer loads and a coincidence factor of 1 (i.e. all customers peak at the same time). In the Horseshoe area, sufficient relief must be provided on feeders in high growth areas. The investments in this Program are specifically targeted to meet these mandated service obligations.

The rapid influx of new dense load in the downtown core and Horseshoe areas (see section E5.3.3.2 for more details) poses a challenge for Toronto Hydro to meet its service requirements, as the rapid growth is causing bus loadings to approach their rated capacity (95 percent) over the 2019-2024 period. The forecasted growth in the distribution system is based on the Toronto Hydro 2017 Station Load Forecast.

As discussed in greater detail below, critical parts of Toronto Hydro's distribution system (such as the downtown and Central Waterfront areas) that service a large amount of load or are experiencing high growth are at risk of overloading already highly loaded downtown feeders, with additional overloading expected in the upcoming years. These areas are seeing growth associated with multiple

[3] DSC, section 7.2 Connection of New Services: low voltage (<750 Volts) within 5 business days and high voltage (>750 Volts) within 10 business days.

storey residential condominiums, mixed use buildings and large commercial developments. If no action is taken to alleviate the constraints presented by the highly loaded feeders, load shedding will be required during the summer peak period to mitigate the risk of failure from overloaded equipment. This involves dropping customer loads when the feeders or the equipment that supply them are overloaded so that a tolerable loading level can be maintained. Supplying customers through highly loaded feeders would reduce the level of reliability for downtown customers, thereby causing Toronto Hydro to fail in meeting the top priority of these customers as identified through customer engagement studies.

E5.3.3.2 Customer Service Requests

Toronto Hydro receives customer requests for service connections (called Applications for Service) every time there is a new residential, industrial, or commercial development, or when upgrades are required for an existing connection. Applications for Service are processed as part of the Customer-Driven Work program.[4] In most cases, System Planning[5] input is also required to determine how to service the customer in the most efficient manner. The utility's ability to respond to customer service requests within the OEB-prescribed timelines,[6] without affecting the quality of service for existing customers, is largely dependent on the investments made in this Program. Toronto Hydro relies on the City of Toronto's land planning information to help assess what areas of the system require additional capacity to accommodate customer service requests in a timely and cost-effective manner.[7]

Figure 1 shows the load additions submitted to Toronto Hydro from 2013 to 2017 by geographical region. Figure 2 shows the resulting load impact in each region of the City.

[4] Exhibit 4A, Tab 2, Schedule 8 Customer-Driven Work.
[5] Exhibit 4A, Tab 2, Schedule 9 Asset and Program Management.
[6] DSC, section 7.3 Connection of New Service.
[7] City of Toronto (2017, Apr.). "How Does The City Grow?" Available: https://web.toronto.ca/wp-content/uploads/2017/08/9014-How-Does-the-City-Grow-April-2017.pdf

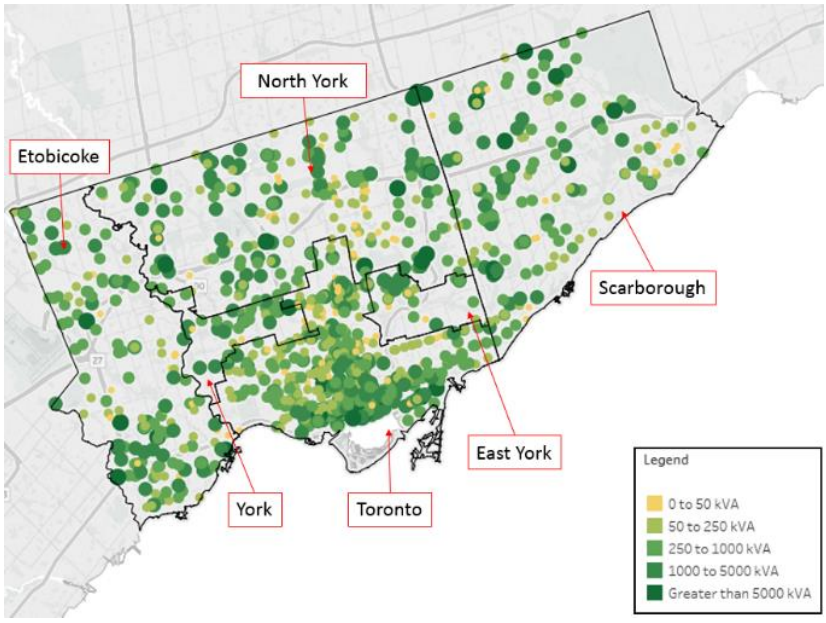


Figure 1: Load Additions in the City of Toronto during the 2013-2017 Period

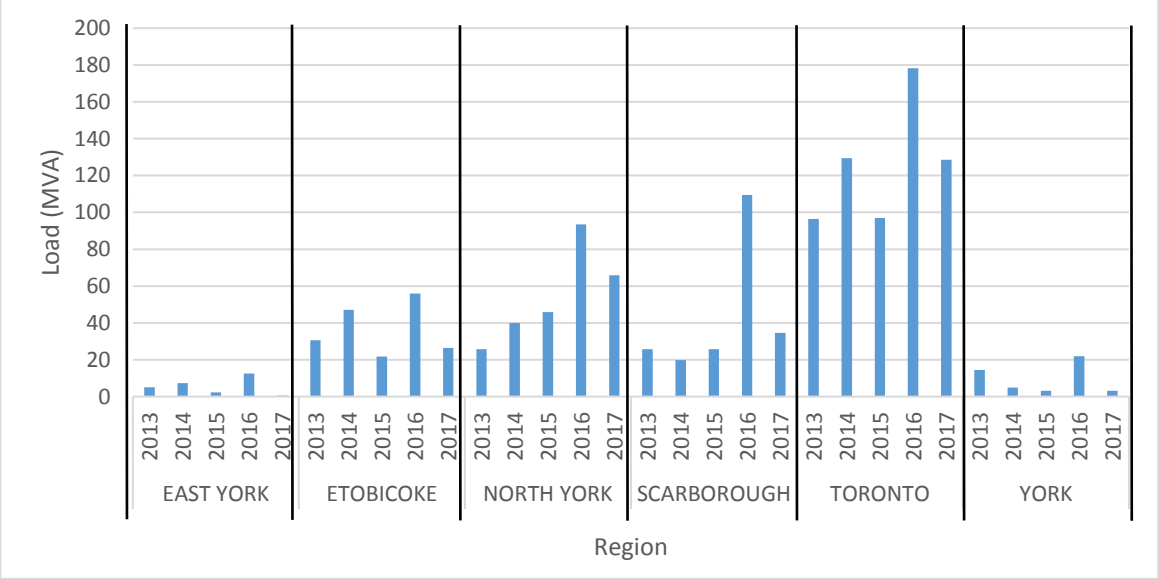


Figure 2: Load Additions by Region during the 2013-2017 Period

The City of Toronto is experiencing an increase in development which is expected to continue throughout the 2020-2024 period. Table 4 below provides a summary of the projects submitted to the City of Toronto's Planning Division between 2012 and 2016, and Figure 3 is a map of the residential units proposed over this period.

Table 4: Proposed Projects in the City of Toronto (2012-2016)[8]

	Built	Active	Under Review	Total in Pipeline	% of Total
City of Toronto	**1,156**	**743**	**624**	**2,523**	
Growth Areas					
Downtown and Central Waterfront	**187**	**129**	**132**	**448**	**17.8**
Centres	**28**	**34**	**26**	**88**	**3.5**
Etobicoke Centre	6	10	3	19	21.6
North York Centre	14	9	9	32	36.4
Scarborough Centre	4	3	1	8	9.1
Yonge-Eglinton Centre	4	12	13	29	33.0
Avenues	**174**	**154**	**147**	**475**	**18.8**
Other Mixed Use Areas	**79**	**82**	**55**	**216**	**8.6**
All Other Areas	**688**	**344**	**264**	**1,296**	**51.4**

Source: City of Toronto, City Planning Division: Land Use Information System II

Development projects with activity between January 1, 2012 and December 31, 2016. Built projects are those which became ready for occupancy and/or were completed. Active projects are those which have been approved, for which building permits have been applied or have been issued, and/or those which are under construction. Projects under review are those which have not yet been approved or refused and those which are under appeal.

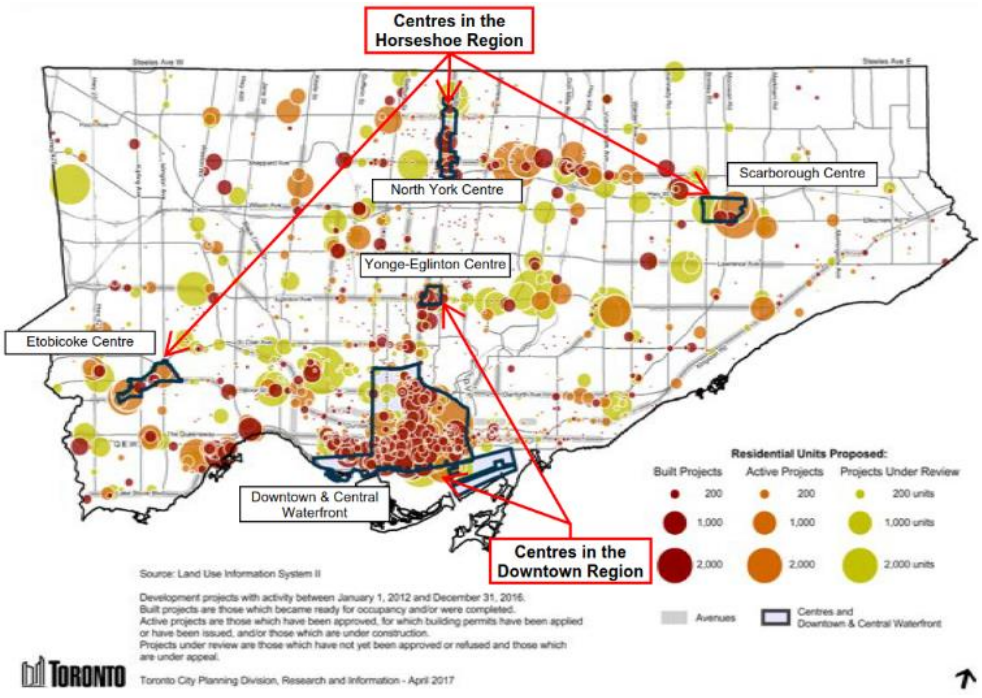


Figure 3: Residential units proposed (2012-2016)

[8] *Supra* Note 8.

As illustrated in Figure 3, the majority of the growth is focused on the downtown system, particularly the downtown and Central Waterfront area, where 42,556 residential units have been built as of the end of 2016 and 141,079 units are in the pipeline for future development. Another area experiencing strong growth in the downtown system is the Yonge-Eglinton Centre, with 1,329 units built by 2016 and 12,975 units in the pipeline.

In the Horseshoe system, Etobicoke Centre, North York Centre, and Scarborough Centre have experienced development growth which are expected to continue: (i) in the Etobicoke Centre area, 970 units were built and 7,261 remain in the development pipeline; (ii) in the North York Centre area, 4,052 units were built and 8,819 remain in the pipeline; and (iii) in the Scarborough Centre area, 853 units were built and 1,591 remain in the pipeline.[9]

Of the total projects proposed over the 2012-2016 period, 123,710 residential units and 3,046,196 m^2 of proposed non-residential Gross Floor Area ("GFA") are currently in the development pipeline as active projects.[10] Based on a load estimate of 2 kVA per residential unit[11] and 0.07 kVA per m^2 of non-residential GFA,[12] Toronto Hydro expects that these projects will result in up to an estimated 460 MVA of new load during an estimated 3 to 7 years after the end of the 2020-2024 period. This estimated load addition does not take into account load subtractions to the distribution system due to redevelopments. Therefore the actual net new load may vary. Furthermore, the actual load added to the distribution system will depend on customer load factors and the system coincidence factors.

Therefore, the utility can expect a steady stream of customer service requests for new connections over the 2020-2024 period and beyond.[13] To meet these requests in a timely and cost-effective manner, and maintain reliability and quality of service for existing customers, Toronto Hydro must invest in infrastructure upgrades and load transfers to alleviate capacity constraints. In particular, the utility must focus its efforts in the downtown area where concentrated growth is straining the distribution system by overloading station buses, feeders, and transformers.

[9] *Supra* note 8.
[10] *Supra* note 8.
[11] OEB, Backgrounder – May 1 electricity price change (2016). Available: https://www.oeb.ca/oeb/_Documents/Press%20Releases/bg_RPP-TOU_20160414.pdf
[12] H. Joshi, "Load Estimates," in Residential, Commercial and Industrial Electrical Systems: Network and Installation, Volume 2, 1st ed. (McGraw-Hill, 2008), pp. 3.
[13] Canada Mortgage and Housing Corporation reports that from 2007 to 2016, an average of approximately 14,700 residential units were built each year. This information confirms that active residential projects will likely be completed in the 2020-2024 rate period. (City of Toronto (2017). "How Does the City Grow?" *Supra* Note 8)

E5.3.3.3 System Reliability and Efficiency

This Program aims to ensure that the system has enough capacity to restore customers during contingency events and that asset failure and loss of supply due to overloading are prevented. Operating assets loaded above their rated capacity for prolonged durations increases their risk of failure and corresponding loss of supply to customers. The risk of overloading is highest during the summer months when system load peaks. These conditions can lead to the premature failure of primary overhead conductor and undersized legacy assets (i.e. underground paper insulated lead-covered "PILC" cables), that were installed over 25 years ago when standard trunk cables were approximately 30 percent smaller and had a 25 percent lower current capacity. Since 2010, Toronto Hydro's distribution system has experienced 175 cable and splice failures on legacy PILC cable.[14]

Overloaded assets pose reliability and public safety risks. For example, the temperature of conductors and cables increases when they are overloaded which reduces the conductor's tensile strength.[15] Loss of the rated tensile strength can cause significant sagging of an overhead feeder line, which makes it more susceptible to external contacts and safety requirement violations.[16,17] Similarly, underground cables, such as the cross-linked polyethylene ("XLPE") cable used in the downtown system, soften as their temperature increases, particularly in areas where the insulation is under mechanical stress (e.g. bends in the route), thereby leading to deformation of the cable. This can lead to electrical failures resulting in outages.[18]

To meet the increasing need for capacity, ensure system reliability and efficiency, and meet the mandated service obligations, four types of work are carried out under this Program:

[14] These cables are addressed through the Underground System Renewal – Downtown program, see Exhibit 2B, Schedule E6.3.
[15] K. Adomah, Y. Mizuno and K. Naito. "Probabilistic assessment of the reduction in tensile strength of an overhead transmission line's conductor with reference to climatic data." *IEEE Transactions on Power Delivery*, vol.15, pp.1221-1224, 2000.
[16] F. Jakl and A. Jakl. "Effect of Elevated Temperatures on Mechanical Properties of Overhead Conductors under Steady State and Short-Circuit Conditions." *IEEE Transactions on Power Delivery*, vol. 15, pp. 242-246, Jan. 2000.
[17] Minimum Safety Clearance as in Toronto Hydro standard 03-2000 Overhead – Minimum Vertical Separations, where the exact clearance depends on the configuration of the pole, the type of attachments on it, and primary voltage.
[18] S. H. Alwan, et al. "Factors Affecting Current Ratings for Underground and Air Cables." *International Journal of Energy and Power Engineering,* vol. 10, pp. 1422-1428, 2016.

- **Bus[19] Level Load Transfers**: load transfers between station buses to alleviate overloaded buses.
- **Feeder[20] Level Load Transfers and Upgrades**: transferring loads between feeders to alleviate overloaded feeders or buses or upgrading undersized feeder trunks to the current standard.
- **Equipment Upgrades**: carried out in network vaults to increase unit size and associated capacity, which reduces the number of switching restrictions experienced during summer peaks.
- **Civil Enhancements**: carried out in duct banks and egress cable chambers to enable capacity upgrades such as cable upgrades.

1. Bus Level Load Transfers

Toronto Hydro plans to execute targeted load transfers on station buses that are expected to become overloaded based on the 2017 Station Load Forecast and those where opportunities will arise to redistribute load with adjacent station buses.[21]

Table 5 lists the specific station buses planned for bus level load transfers during the 2020-2024 period, and Figure 4 shows the stations' locations. Three types of planned transfers will be carried out:

- **Downtown Intra-station Transfers**: load transfer to another bus in the same station;
- **Downtown Inter-station Transfers**: load transfer from one station to another in the area;
- Load Transfers in the Horseshoe area of Toronto.

The completion of Copeland TS Phase 2 under the Stations Expansion program[22] will have the potential to enable load relief at Esplanade TS, Strachan TS, Windsor TS, Cecil TS, and Terauley TS.[23] For these stations, civil and cabling work to enable the transfers is planned to be undertaken before Copeland TS Phase 2 is energized, so that the full benefits of Phase 2 can be realized immediately

[19] **Bus** – A rigid, large conductor usually in substations, to provide a quick and convenient means of rearranging circuit connections to keep power flowing or to restore power after an outage.
[20] **Feeder** – A distribution circuit carrying power from a substation to customers. Feeders consist of circuits and other electrical equipment supported by civil infrastructure like poles and ducts.
[21] See Exhibit 2B, Section E7.5 Stations Expansion.
[22] See Exhibit 2B, Section E7.5 Stations Expansion. Copeland TS Phase 2 is expected to be completed by 2023/2024.
[23] Not all stations listed are addressed through the Load Demand program.

upon its energization. Relief for Horner TS and Manby TS are dependent on the Horner TS station expansion.

Table 5: Station Buses Planned for Relief within 2020-2024

Station	Bus	Target Year	Estimated Load to Transfer (MVA)	Planned Transfer Type
Cecil	*A5-6CE*	2020	2.5 - 10	Downtown Intra-station
Wiltshire	*A5-6W*	2020	5 - 20	Downtown Intra-station
Esplanade	*A1-2X*	2023, 2024	5 - 20	Downtown Inter-station
Basin	*A5-6BN*	2022, 2023	10 - 40	Downtown Inter-station
Horner	*B&Y*	2022, 2023	10 - 40	Horseshoe
Strachan	*(Note 1)*	2023,2024	5 - 20	Downtown Inter-station
Manby	*Q&Z, V&F*	2024	10 - 40	Horseshoe
Windsor	*(Note 2)*	2023,2024	5 - 20	Downtown Inter-station

Note 1: Targeting bus supplying feeders in area bounded by Spadina Ave, Rail Corridor, Strachan Ave, and Lake Ontario.

Note 2: Targeting bus supplying feeders in area bounded by Bathurst St, Adelaide St W, Yonge St, and Railway Corridor.

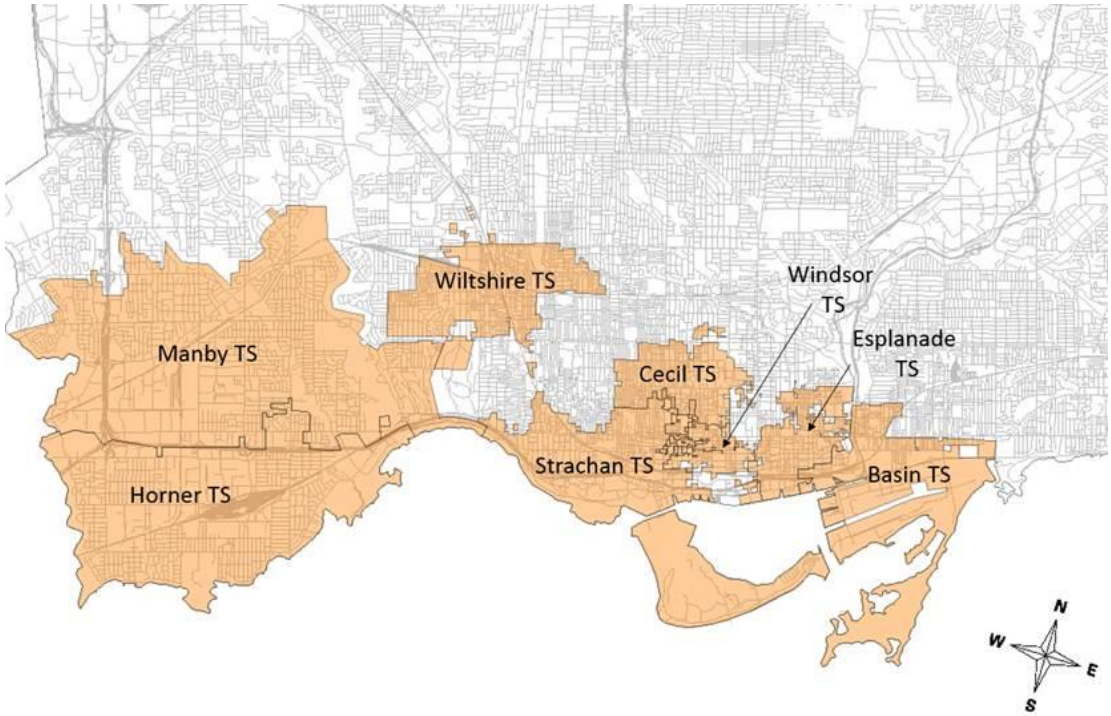


Figure 4: Stations Targeted For Relief during the 2020-2024 Period

If the buses outlined in Table 5 above are not relieved, it may not be possible to connect new customers to these station areas. As a result, new service requests in the areas serviced by these station may have to be supplied from adjacent buses or stations, potentially resulting in system inefficiencies, materially higher connection costs, and longer timelines to complete the work.

Station bus load forecasts are re-evaluated annually, as described in the DSP – Capacity Planning, [24] driven by information on expected new connections, expected load transfers and voltage conversions, re-evaluated growth rate, and the previous years' weather corrected peak which is used as base for load growth. Therefore, based on the outcomes, the need for specific load transfers can either be escalated in priority or deferred. Some of the buses that Toronto Hydro plans to address in the 2020-2024 period were originally planned for relief in the 2015-2019 period. For the reasons summarized in Table 6 below, the investments were deferred to the 2020-2024 period.

Table 6: Deferred Load Transfers from 2015-2019 to 2020-2024

Station	Bus	2015-2019 Referenced Year For Relief	2020-2024 Target Year For Relief	Reasoning
Basin	*A5-6BN*	2019	2022,2023	This transfer is awaiting new capacity at Carlaw TS to transfer load. In the interim, new customer loads will not be added to the A5-6BN bus or smaller transfers may be conducted until load can be relieved by the new capacity at Carlaw TS.
Horner	*B&Y*	2017	2022, 2023	Re-evaluation of load forecast indicated that relief was required in the 2022-2023 timeframe, which aligns with the expansion of the station.
Manby	*Q&Z, V&F*	2017 (Q&Z), 2018 (V&F)	2024	Deferred until the Horner station expansion is completed so that load can be transferred using the new capacity.
Strachan	*A1-2T*	2017	2023, 2024	Re-evaluation of load forecast indicated that relief is not required until 2024. Load will be transferred to Copeland TS upon completion of Phase 2.

[24] See Exhibit 2B, Sections D2.3, D3.3.1, and C3.3

Windsor	*A13-14WR*	2017	2023, 2024	Re-evaluation of load forecast indicated that relief is not required until 2024. Load will be transferred to Copeland TS upon completion of Phase 2.

In order to transfer load from one station to another, Toronto Hydro often needs to install new feeders at stations with spare capacity. These stations are either existing ones with switchgear that have available capacity and feeder positions, or new stations where switchgear will be installed to create additional capacity. New civil infrastructure will be required if the existing infrastructure is in poor condition and requires rebuilding or if there are insufficient ducts to accommodate the new feeder installation. Extensive cable pulling and splices[25] are then required to complete the transfer of customer loads from the existing feeders to the new feeders. Load can also be transferred from one station to another by extending existing feeders to feeders with available capacity. However, in the Horseshoe distribution area, loads can alternatively be transferred by installing new switches or relocating existing switches.

2. Feeder Level Load Transfers and Upgrades

Asset failures (overhead conductors, underground cables, and civil infrastructure) can lead to outages that last over an hour due to the time it takes for crews to switch customers from faulted feeders to standby supplies. In first contingency scenarios, the distribution system is designed to continue operating at or below rated capacity in order to facilitate the transfer of load from feeders under a faulted condition to standby feeders. This allows for the restoration of power to affected customers from the standby feeder while the faulted feeder is being repaired. If feeder capacity is constrained, the number of customers able to be served by the standby supply may be limited, which adversely impacts reliability as those customers that cannot be served by the standby supply would experience lengthy service interruptions. Having available capacity on adjacent feeders in addition to having available standby feeders allows for quicker restoration in the circumstances of a more catastrophic, multiple contingency event, because more operational options will be available to restore customers.

However, when the load on a faulted feeder exceeds the available rated capacity of standby feeders, restoration of power to affected customers is not possible until repairs are completed and, as a

[25] A splice is a joint created to maintain the connectivity between two cable sections or cable types. It is typically carried out when a longer cable is required, a branch is required or part of an old cable is replaced with a new cable.

result, such customers would be at risk of prolonged interruptions. For example, in the overhead system, when a feeder faults and its standby feeder ties cannot be used due to the risk of overloading, the affected customers on the faulted feeder would remain without power until the failure is completely addressed. In addition to the expected reliability improvement, having the flexibility to de-energize feeders improves Toronto Hydro's ability to execute planned capital and maintenance work by enabling the utility to switch customers onto their standby feeders. Toronto Hydro analyzed the reliability on 5 feeders in the Horseshoe area before and after their upgrades between 2010 and 2017. The results of this demonstrate that addressing feeder capacity constraints through upgrades and relief reduces the impact and duration of outage events, as seen in Table 7.

Table 7: Impact of Outages due to Feeder Capacity Constraints before and after the Upgrade

Measure	Before Upgrade/Relief	After Upgrade/Relief
SAIFI	0.008	0.007
SAIDI	0.436	0.172
Customers Interrupted ("CI")	5,384	2,561
Customer Minutes Out ("CMO")	305,987	74,309

When new customers are connected to the distribution system in areas of growth, Toronto Hydro also aims to enhance the capacity of the system. In doing so, it utilizes analytical strategies and tools to evaluate how customers are supplied, optimize the use of existing capacity, and accommodate new customers efficiently. This analysis helps to determine areas requiring feeder level transfers to enable available capacity. In some instances, the utility may decide to perform feeder level load transfers if the cables are already at the maximum size, if the legacy ducts are too small to accommodate the latest cable standards, or if the bus that supplies the feeder has available capacity.

Performing a load transfer between feeders to accommodate a new customer is often the preferred alternative when possible as it can be carried out at a lower cost than upgrading the feeder. Feeder level load transfers are also performed to help relieve bus loading, where possible, and to rearrange load in station areas where there is expected growth. Similar to bus level load transfers, feeder level upgrades and load transfers provide value to current and future customers by ensuring that the system can support rapid growth in a timely and cost-efficient manner, without adversely affecting the quality of service for existing customers. Each planned feeder level transfer is expected to relieve approximately 2 MVA of load. This allows capacity for additional growth on the feeder that is equivalent to accommodating approximately 1,000 new residential customers. The additional 2 MVA

accounts for approximately 25 percent of a downtown feeder's capacity, which is consistent with the improvement seen from a typical downtown cable upgrade targeted in this Program.

The sections that follow describe the load transfer work planned on the 27.6 kV system, which serves the area of the system commonly known as the Horseshoe and the work planned for the 13.8 kV system, which serves the downtown core.

a. The Horseshoe System

The Horseshoe system is arranged in a looped configuration, with feeders tied via switches so that load can be transferred from one feeder to an adjacent feeder during contingency scenarios when a feeder is interrupted. Over time, growth can cause the load to exceed feeder capacity, which can lead to longer outages for customers in the event of a failure. For example, when a feeder experiences a fault, a standby feeder with sufficient capacity should be available to accommodate the customer load on the faulted feeder. If this capacity isn't available, only some sections on the faulted feeder can be restored, thus increasing the time needed to restore service to all affected customers. Similarly, the lack of back-up capacity can lead to challenges, and possibly unnecessary outages for customers, when performing planned maintenance or construction activities as mentioned above.

To manage load growth in the Horseshoe, Toronto Hydro plans to undertake capital investments in feeder level load transfers in the areas surrounding Scarborough Centre, Etobicoke Centre, and North York Centre. Figure 5, Figure 6, and Figure 7 show the Horseshoe feeders in these growth areas, respectively. The projected growth in these centres indicate the need to relieve highly loaded feeders in the area. In these areas, it is estimated that feeders 38M7, 80M28, 80M30, 80M5, E5-1M28 and H9M26 will require relief as they are currently at capacity under first contingency. In total, these feeders serve 12,299 customers, and on average, each of these feeders has 1849 residential customers and 201 commercial customers, for a total of 2050 customers as seen in Table 8. Load transfers are preferred over feeder upgrades because the overhead system, which serves the Horseshoe area, has multiple tie switches making it easier and more cost-effective to transfer load between adjacent feeders thus supporting Horseshoe customer priorities.

Table 8: Horseshoe Feeders Targeted for Relief

Feeder	Residential	Commercial up to 1MW	Commercial >1MW	Total
38M7	2,896	247	0	**3,143**
51M28	397	24	2	**423**
80M28	607	72	5	**684**
80M30	2,325	75	2	**2,402**
80M5	3,909	377	2	**4,288**
H9M26	962	397	0	**1,359**
Averages	**1,849**	**199**	**2**	**2,050**
Totals	**11,096**	**1192**	**11**	**12,299**

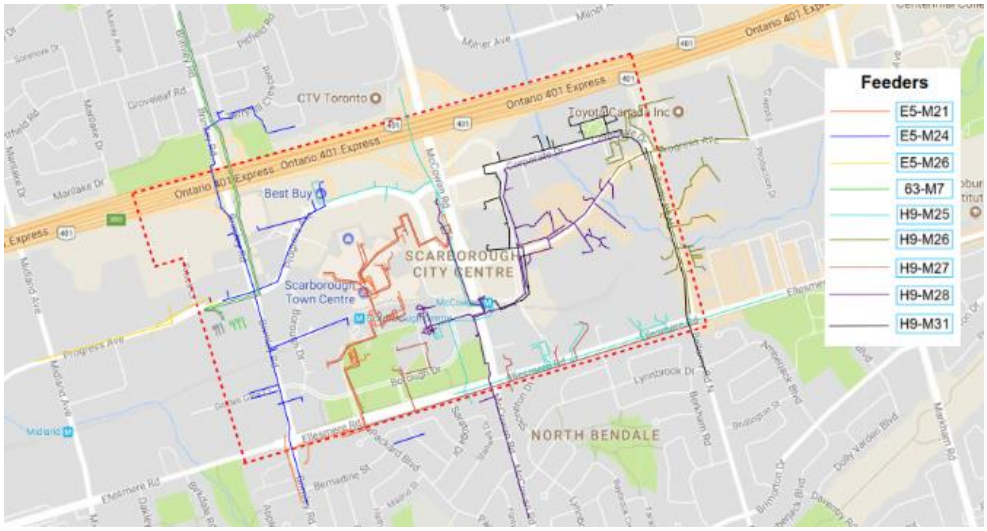


Figure 5: Horseshoe Feeders in the Scarborough Centre

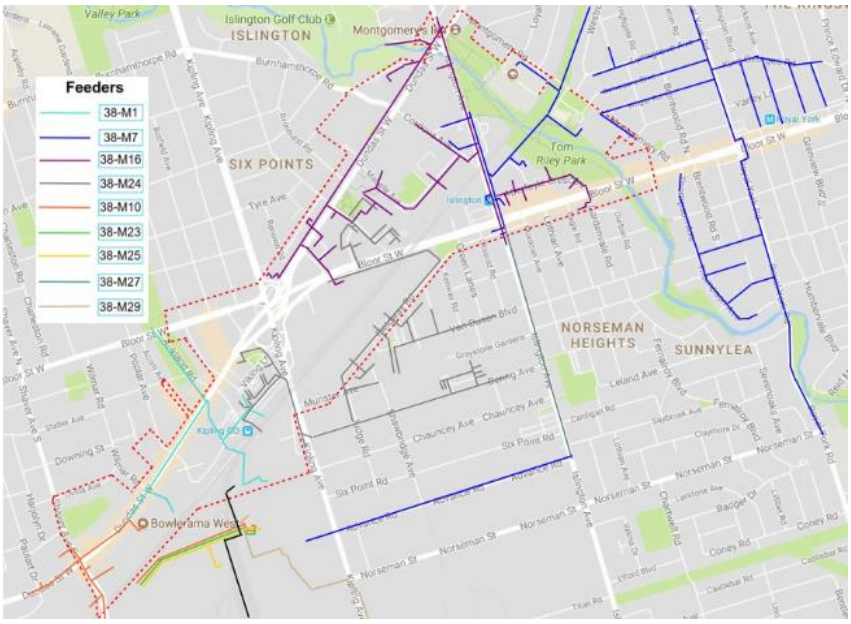


Figure 6: Horseshoe Feeders in the Etobicoke Centre

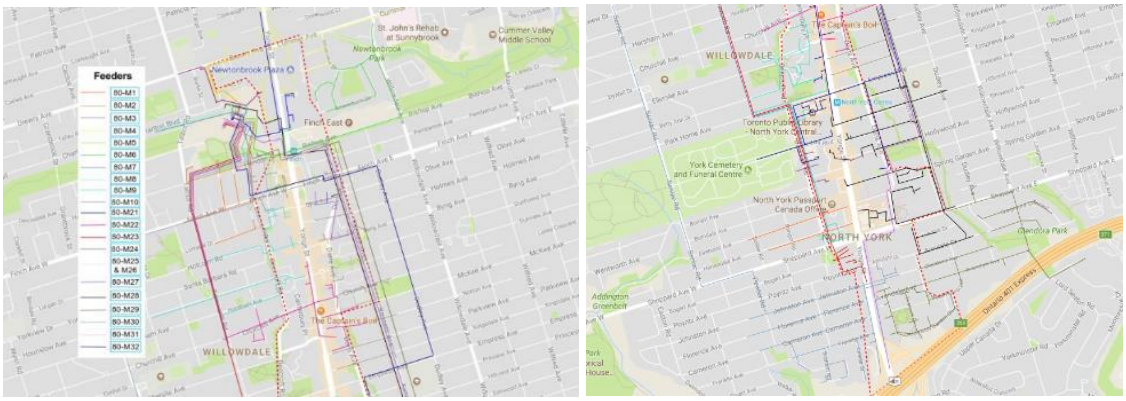


Figure 7: Horseshoe Feeders in the North York Centre

b. The Downtown System

The majority of the underground 13.8 kV system in downtown Toronto is configured as a dual radial scheme. Customers are supplied by two feeders: one that provides their normal supply and the other that operates as standby supply. In areas that have experienced rapid load growth, customers now have an overloaded standby supply, with additional overloaded feeders expected during the 2020-2024 period. To address this issue, Toronto Hydro plans to upgrade primary cables or perform load transfers.

Toronto Hydro analyzed all downtown feeders to determine which feeders are projected to be highly loaded during the 2020-2024 period based on natural load growth and customer connection forecasts. By the end of 2019, Toronto Hydro expects to have 35 highly loaded feeders in the downtown system. Over the 2020-2024 period, there will be 24 new highly loaded downtown feeders in danger of being overloaded under contingency, resulting in 59 highly loaded feeders of the total 843 feeders in the downtown system if no work is done to address them.

As a result, in the 2020-2024 period, Toronto Hydro plans to relieve 28 feeders in the downtown area to manage load growth, including 18 feeder upgrades, and 10 feeder load transfers. The 28 feeders planned for relief at the time of relief will be highly loaded feeders that limit growth and operational flexibility. By comparison, in the 2015-2019 period, Toronto Hydro relieved 25 highly loaded feeders through cable upgrades and cable transfers. The specific feeder upgrades to be completed will depend on where load materializes in the system. On average, each feeder targeted for upgrade or transfer has 111 residential customers, and 7 commercial customers, for a total of 118 customers.

Toronto Hydro plans to upgrade undersized feeder trunks to the current standard (500 kcmil TRXLPE) to utilize previously stranded capacity for feeders that are becoming highly loaded. For example, feeder A94A supplies 12 customers in and around the downtown core, including Sick Kids Hospital courtyard, and customers around the Toronto Eaton Centre and Dundas Square. This feeder is at capacity due to the presence of undersized 2/0 trunk cable. An upgrade to 500 kcmil TRXLPE cable will more than double the capacity on the feeder, allowing for 5 MVA of customer load to be added.

In the downtown area, because of congested civil infrastructure nearing end of life or built to older standards (therefore unable to accommodate the latest standards), it is often necessary to rebuild or expand the existing civil infrastructure when upgrading underground cables. Figure 8 below shows a congested legacy square duct unable to accommodate the current standard trunk cable, therefore limiting the overall capacity of feeders using this civil route. Toronto Hydro plans to complete upgrades or rebuilds of this existing civil plant as part of this Program. It is estimated that 50 percent of the length of the civil route for each planned upgraded feeder will need to be upgraded as well to accommodate the new electrical. This includes cable chamber and ductbank rebuilds.



Figure 8: Example of a Legacy Square Clay Tile Duct

New feeder installations are also required when an area needs more feeder capacity than is available with the existing feeders. For example, express tie feeders must be upgraded or new ties must be installed to realize the full capacity of the infrastructure. Express tie feeders exist when there is not enough physical space in a station to house both the Hydro One transformer and switchgears. In these scenarios, there is a Hydro One transformer at one station supplying the switchgear at another station via express tie feeders. These feeders do not service any other load. In the 2020-2024 period, a new express tie feeder between Bridgman TS and High Level TS is proposed to relieve the capacity constraints on the A5-6H bus. This investment will increase the capacity at the A5-6H bus by 24 MVA, creating capacity to service that is equivalent to 12,000 new residential customers in the area.

3. Network Equipment Upgrades

Due to capacity constraints, Toronto Hydro is forced to impose summer switching restrictions during peak load conditions, such that certain feeders cannot be taken out of service during those periods. If restricted feeders are taken out of service, their corresponding standby infrastructure (standby feeders, adjacent network units) will be overloaded. This practice constrains Toronto Hydro's ability to complete new customer connections and hinders its ability to plan and execute other capital maintenance work in a timely and efficient manner.

Heat restricted feeders are feeders flagged as at-risk of overloading their standby feeders or network equipment during a contingency situation during peak hours or summer days. This means that these feeders should not be taken out of service (at a certain temperature) in the summer months in order to avoid overloading other infrastructure under contingency. Toronto Hydro is seeking to reduce the number of restrictions on its system so as to enhance its ability to take feeders out of service for maintenance or capital work. Cable upgrades and load transfers may be used as strategies to relieve summer switching restrictions on the primary feeder level. The network equipment upgrades as part of the Load Demand program aim to remove restrictions caused by undersized network units. An example of a network unit is shown in Figure 9. A network unit consists of a primary switch, network transformer, and network protector.



Figure 9: An Example 500 kVA Network Unit

In the downtown core, network units are fed from various feeders interconnected on the secondary side (i.e. low voltage) of the distribution transformer in order to provide a redundant and highly reliable supply to customers. This configuration reduces the risk of customers experiencing momentary interruptions during single contingency events. The network system supports reliability for customers in the downtown area, highlighted as a priority through customer engagement.

Current key customers on the network system include Sick Kids Hospital, Sheraton Centre, Bell Canada, and the Ontario Power Building.

Through network equipment upgrades, Toronto Hydro will improve reliability for downtown customers on the network, highlighted as a priority in the customer engagement. This will be done by reducing the number of potential network unit failures due to overloads; increasing the robustness of the network units by introducing the submersible design; and improving the amount of first contingency scenarios supported by reducing feeder restrictions. Network equipment that is at or over capacity must be upgraded to ensure that the network system operates without overloading. Overloading the network equipment can result in premature deterioration and failure of the assets, which in turn drives the need to impose restrictions during peak summer months. An additional benefit of upgrading existing overloaded network equipment is the introduction of a more robust submersible design that is capable of operating under flooded conditions. In locations where an upgrade is not possible because the network units are already at the highest size or if there are civil limitations, an additional transformer in a new vault may be installed or additional secondary cables may be added to support the highly loaded vaults.

In the 2015-2019 CIR application, Toronto Hydro indicated its goal of reducing the number of summer switching restrictions and has been doing so accordingly as seen in its progress presented in Table 9 below.

Table 9: Summer Restrictions by Year

Summer Restrictions	Year				
	2013	**2014**	**2015**	**2016**	**2017**
Number of Feeders Restricted	60	54	49	43	21

By the end of 2019, there are projected to be 7 restrictions remaining, and the growth on the network is expected to overload 8 more network units under contingency by the end of 2024,[26] for a total of 15 restrictions. Toronto Hydro's goal is to reduce the total number of restrictions to below 10 by the end of 2024. To achieve this goal, the utility must perform at least 6 network equipment upgrades during the 2020-2024 period, while mitigating any potential primary feeder restrictions via cable upgrades and load transfers.

[26] The peak load reading of each network unit in the system was taken over the last 5 years and a growth consistent with the Metro Toronto Regional Infrastructure Plan was added to forecast the future overloads.

4. Civil Enhancements

When certain stations are expanded or their switchgear is upgraded, Toronto Hydro must undertake supporting civil enhancement work in the egress cable chambers to enable additional capacity at the station. However, the total capacity of the station bus can be limited by other factors, such as the capacity of the Hydro One transformers supplying the station buses. Table 10 summarizes the expected station upgrades within the 2020-2024 period that will require civil egress rebuilds in order to optimally serve customers. These areas are shown geographically in Figure 10.

Table 10: Stations Requiring Civil Egress Rebuilds

Station	Associated Work	Target Year
Carlaw TS	*Switchgear Renewal*[27]	2021, 2022
Horner TS	*Station Expansion*[28]	2022, 2023
High Level TS	*Switchgear Renewal*[29]	2024, 2025

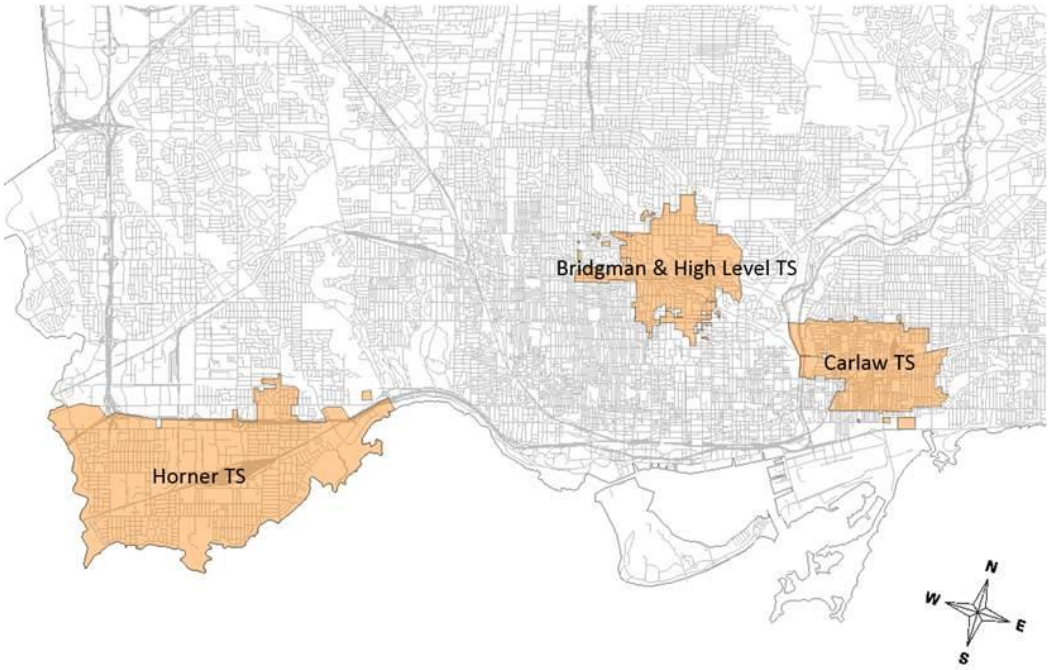


Figure 10: Stations Targeted for Civil Enhancements during the 2020-2024 Period

[27] See Exhibit 2B, Schedule E6.6 – Stations Renewal
[28] See Exhibit 2B, Schedule E7.4 – Stations Expansion
[29] *Supra* note 26

The egress cable chambers at the targeted stations are highly congested, limiting the number of feeders and their directional configurations when exiting the station. The result is that if new feeders are required to serve customers in these areas, it may not be possible to use the shortest optimal route from the station. A longer route may need to be used or a new civil route may need to be constructed, resulting in additional costs to the customer and time to complete the connection work. For example, after the Carlaw TS switchgear renewal, there will be a new switchgear at the northeast corner of the station, egressing through the north cable pit. The majority of the Carlaw feeders already run north and northeast and those that are needed to the south must utilize cable chambers around the station to run south. This creates congestion around the station, as evidenced by the fact that cable chambers 1220, 1107, 1108, and 8285 have over 9 or more feeders running through them. With plans to relieve Basin in the 2020-2024 period[30] (see Table 5), to the south of Carlaw, additional feeders will need to be pulled south and the civil infrastructure must be upgraded and arranged in order to accommodate these plans. If the feeders to relieve Basin cannot be pulled, rapid growth in the Basin areas (such as Ashbridge's Bay), GO Transit and the Portlands development, will overload Basin buses.

Apart from the capacity limitations, congested cable chambers increase the potential impact of chamber collapse on multiple feeders (and the significant customer load they supply in aggregate). For example, a cable chamber of 15 feeders can account for up to 75 MVA of customer load. Congested cable chambers also significantly impede the crews' execution ability given the practical difficulty of performing work within such chambers.

E5.3.4 Expenditure Plan

Table 11: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Load Demand	9.9	16.8	16.2	17.3	21.6	11.3	11.4	18.5	22.6	23.6

[30] Toronto Hydro plans to provide additional relief to Basin TS through Local Demand Response in the 2020-2024 period. See Exhibit 2B, Schedule 7.4 Stations Expansion for more details.

Table 12: Program Costs ($ Millions)

Type of Work	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Load Transfers	4.7	1.9	8.7	4.1	3.4	4.3	1.4	5.5	10.3	8.3
Cable Upgrades	1.7	5.5	2.5	1.2	10.6	6.6	6.8	6.9	9.3	11.9
Equipment Upgrades	0.01	2	0.5	2.6	2.6	0.4	0.2	0.2	0.2	0.2
Civil Enhancements	3.5	7.4	4.5	9.4	5	0.0	3.0	5.9	2.8	3.2

The 2020-2024 expenditure plan is based on the specific work that is planned in each year. As is true with the 2015-2019 period, expenditures vary considerably from one year to the next due to the volume of work associated with the different activities undertaken by the Load Demand program (i.e. load transfers, cable and equipment upgrades, and civil enhancements).

During 2015-2017, Toronto Hydro has relieved capacity constraints on the system through the:

- Alleviation of 10 highly loaded buses through bus level load transfers and by creating new feeder positions;
- Reduction in the amount of highly loaded feeders by 25 through feeder level transfers and feeder upgrades;
- Improvement to the civil egress of George & Duke MS, Runnymede TS, Richview TS and Copeland TS, which enabled additional feeders to make use of the full capacity of the station; and
- Reduction of summer switching feeder restrictions by 28 between 2015 and 2017, with an additional 14 feeder restrictions expected to be eliminated by 2019.

These forecasts are re-evaluated annually, as described in the DSP – Capacity Planning,[31] driven by information on expected new connections, on expected load transfers and voltage conversions, re-evaluated growth rate, and the previous years' weather corrected peak which is used as base for load growth. Based on the annual re-evaluation of station bus load forecasts, Toronto Hydro fully expects that project scheduling will change. This is natural for a program such as Load Demand.

Investments in the 2020-2024 period aim to continue to relieve capacity strained areas in the City of Toronto. The plans are based on 2017 load forecast. As described in section E5.3.3, this Program is

[31] Exhibit 2B, Section D2.3, 3.2.1, and C3.3

made up of investments in station bus load transfer, feeder level load transfers and upgrades, network equipment upgrades and civil egress enhancements.

E5.3.4.1 Station Bus Load Transfers

The proposed work aims to provide load relief to the station buses that are expected to become overloaded in the next rate period due to growth, and which are located in areas where capacity is available at an adjacent station. Some of the planned bus load transfers are dependent on the completion of station expansions projects, such as the Copeland TS Phase 2 project,[32] which will allow Toronto Hydro to provide relief to the buses at Strachan TS, Windsor TS, and Esplanade TS.

The costs for bus level load transfers were forecasted using a cost per MVA transferred value. The cost per MVA can vary greatly for a bus level load transfer, depending on distance between stations involved in the transfer, location of feeders, and geographical constraints, such as the presence of bridges and highways, and civil conditions. Nonetheless, the average cost was derived based on projects from 2015 to 2019 to provide a best possible estimate of future project costs. Further, the per MVA unit costs were separately determined for the following three types of work (as mentioned in section E5.3.3.1 sub-section 1) so as to account for their considerable differences:

- **Downtown (Intra-station) Transfers**: $0.15 million per MVA.
- **Downtown (Inter-station) Transfers**: $0.25 million per MVA.
- **Load Transfers in the Horseshoe area:** $0.08 million per MVA.

Intrastation transfers in the downtown area are less costly than transfers between stations (interstation) because the amount of cabling and civil work required to bring load from different station areas is greater than transferring within the same station area.

Load transfers in the Horseshoe area, which is generally served by the overhead system, are less costly because the transfers can be completed by installing opening, and closing tie switches between feeders. In areas where a transfer is needed but switches do not exist, the cost to install switches and any additional overhead conductors is much lower than the underground feeder extensions and splices that are required for transfers in the downtown area.

[32] Exhibit 2B, Section 7.4 Stations Expansion

E5.3.4.2 Feeder Level Load Transfers and Upgrades

As noted above, Toronto Hydro plans to undertake 18 feeder upgrades and conduct 10 feeder load transfers in the downtown area during the 2020-2024 period. In the Horseshoe system, the utility plans to perform 6 feeder load transfers in the Etobicoke, North York and Scarborough growth centers. This involves transferring load to adjacent feeders via overhead tie switches. The unit costs for feeder level load transfers in the downtown area and in the Horseshoe area are $0.5 million per feeder and $0.15 million per feeder, respectively.

Any cable upgrade to the trunk of a downtown feeder is estimated to upgrade 1,000 meters of cable, which will include civil upgrades for half of the distance. This amounts to 500 meters of duct banks, 10 cable chambers, and 10 splices. The unit cost assumes 1,000 meters of upgrades per targeted feeder because this is the average length of a feeder trunk, with each downtown feeder having a maximum spread of approximately 3,000 meters.

E5.3.4.3 Network Equipment Upgrades

Toronto Hydro plans to complete 6 network equipment upgrades during the 2020-2024 period in order to achieve its target of limiting summer switching restrictions under contingency scenarios to under 10.

For network equipment upgrades, the per unit cost was based on the cost to remove and install a new 750 kVA network unit, which was the most common upgrade seen in the 2015-2019 period. Furthermore, the per unit cost aligns with the average cost of replacing network units in 2017. The cost used for forecasting is $0.17 million per unit upgrade.

E5.3.4.4 Civil Egress Enhancements

Toronto Hydro plans to rebuild the civil egress cable chambers at Carlaw TS (downtown), Horner TS (Horseshoe) and High Level TS (downtown). The cost per station was forecasted based on historical projects in the downtown and Horseshoe areas, $5 million, and $4.5 million respectively.

E5.3.4.5 Project Prioritization

Toronto Hydro considers a combination of several factors when prioritizing projects within the Load Demand program, including:

- **Capacity to connect new customers:** Toronto Hydro addresses areas of the system that are at capacity and that require significant investments to allow the connection of new customers. The lack of forecasted capacity in the short-term is what ultimately triggers projects within this Program.
- **Single contingency operation:** Current limitations on the system prevent overloading during contingency operations. Projects that introduce additional capacity to allow the operators to remove these limitations will receive a higher priority.
- **Reliability:** For load transfer projects, sections of cable that require upgrading and that are on feeders with poor reliability or adjacent feeders will be given higher priority in order to improve future outage restoration times.

E5.3.4.6 Cost Management

Load Demand projects are continuously evaluated to ensure that the spending is in the appropriate areas. For example, the need for each bus level load transfer is re-evaluated annually to see if forecasts still hold true or should be modified. Load forecasts are the basis for determining if buses require relief. As seen in Table 8 above, a number of buses that were expected to be overloaded in the 2015-2019 period were deferred to 2020-2024. This allowed for other Load Demand work to be completed in their place since the transfers identified in Table 8 were no longer immediately required.

By making capacity available by both electrical relief (via bus transfers, feeder transfers, feeder upgrades and equipment upgrades), and civil relief (via station enhancements), customers are able to be connected in an efficient manner. Without available capacity, infrastructure may have to be built using a suboptimal station (i.e. not in the area of the customer(s)) and using suboptimal and lengthy routes. Avoiding this work reduces the utility's cost of connecting customers.

E5.3.5 Options Analysis

E5.3.5.1 Option 1: Do Nothing

Option 1 entails not planning any load transfers, equipment upgrades, or civil enhancements. This option allows Toronto Hydro to defer capital spending. Toronto Hydro anticipates that this option would reduce reliability and increase failure risk. Increasing loading stress on existing electrical infrastructure in heavily loaded areas under first contingency would shorten the operational life time of the electrical infrastructure. Rolling blackouts may be required during the summer to ensure that

the peak loading remains under the capacity for the system, since no investments are being made to resolve the overloads during summer peaks. Areas of heavy loading will continue to experience increased loading, with the capacity to transfer loads under contingency decreasing. Following this option would impair the utility's ability to expedite upgrades to relieve heavily loaded infrastructure effectively and efficiently.

The addition of new high load customers in identified heavily loaded areas may exceed first contingency capacity, making system upgrades increasingly difficult and lengthy as Toronto Hydro would be unable to take feeders out of service for planned work if there is no viable standby feeder to accept the load. Finally, the exposure risk of customers in highly loaded areas to lengthy outages due to equipment failures or severe weather will be higher because of the inability to transfer load to standby or alternate supplies if capacity constraints are violated.

This is not a feasible option as it would give rise to a risk of non-compliance with DSC sections 3.3.1 and 4.4.1, which require Toronto Hydro to prudently and efficiently manage its distribution system, and address forecast load growth.

E5.3.5.2 Option 2: Upgrade Station Capacity

Under Option 2, Toronto Hydro would add station capacity through expansion of existing stations or construction of new stations in the heavily loaded areas where there is a projected influx of new development. This would build a large amount of capacity into the system.

However, this alternative would require a large capital investment spread over multiple years, detailed studies for optimal location (greatest load impact), environmental assessments, drawn-out construction times plus the subsequent work required to distribute the newly created surplus around the grid. This would take eight to ten years to complete which would not address the issues arising in the 2020-2024 period. As a result, this timeline would expose customers in existing high load growth areas to potentially lengthy outages. These outages would result from the inability to restore customers on standby feeders exceeding capacity constraints, and on overloaded equipment resulting in failures. Finally, this option would not make use of existing stranded station capacity that could be made available by load transfers.

Option 2 thus involves long term projects and cannot meet emerging capacity needs in the short to medium-term. Therefore, it would not be prudent to carry out this option.

E5.3.5.3 Option 3 (Selected Option): Upgrade equipment, civil infrastructure and perform load transfers, as per the Load Demand program

The preferred option is to upgrade equipment and infrastructure in highly loaded and congested areas of the system and in areas of proposed high load developments with a focus on relieving overloads under a first contingency basis. It provides capacity for increased loading in heavily loaded areas that are already at maximum capacity, and enables first contingency load transfers in areas of heavy loading that show trending of load increase, which would otherwise exceed present capacity to transfer loads under contingency. As a result, the Program reduces exposure risk and outage durations for customers in identified high load areas resulting from equipment failures or storms.

This option provides capacity to expedite future upgrades and balance system loading, makes use of existing system assets by performing load transfers between highly loaded buses and feeders to lightly loaded alternatives, and allows Toronto Hydro to maintain full compliance with DSC sections 3.3.1 and 4.4.1 with regard to prudent and efficient distribution system management.

However, this alternative requires capital investment to upgrade existing or install new assets. The new assets would be less costly than Option 2, and less than Option 4.

This is the preferred option since it addresses the capacity needs of the distribution system that are arising in the short to medium term. With this option, Toronto Hydro can comply with the Distribution System Code and improve customer service, reliability, and safety of the system.

E5.3.5.4 Option 4: Upgrade all feeder cables, and alleviate all highly loaded buses and feeders

Under this option, in addition to the feeder cables, feeder and bus load transfers to be addressed through Option 3, Toronto Hydro would address the remaining 31 highly loaded downtown feeders identified as being less urgent as those addressed under Option 3. This option would allow for extensive relief on the remaining highly loaded feeders, and therefore increase the capacity on the distribution system to connect customers and ensure system reliability. However, when feeders do not have adjacent feeders with available capacity, the cost of relieving the targeted feeders increases.

At an estimated $130 million, Toronto Hydro determined that this option would be too costly in light of other investment priorities.

E5.3.6 Execution Risks & Mitigation

Several issues can present risks to the execution of the Load Demand program. These include the addition of loads or redevelopment of an area with dated or lacking civil infrastructure, road moratoriums and difficulties coordinating with third party utilities.

In order to complete load transfers and cable upgrades, feeders may need to be pulled or upgraded over long distances (up to 3 kilometres) where voltage drop issues start becoming a concern, utilizing several cable chambers and duct banks along the route. Records provide an indication of what civil costs can be expected for a Load Demand project; however, there can be unexpected rebuilding or expansion of civil infrastructure that is required. Civil inspections performed earlier in the project cycle can help mitigate any unforeseen project costs.

Moratoriums and third party construction can limit and dictate the civil routes used in load transfers. Costlier solutions to bring capacity into an area may be required because we are unable to utilize more optimal routes where moratoriums exist or third party construction is taking place. In these cases, potential impacts must be identified at the early stages of project planning and coordination must be sought and achieved.

5.4 Metering

E5.4.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 105.9	**2020-2024 Cost ($M)**: 130.8
Segments: Revenue Metering Compliance; and Wholesale Metering Compliance	
Trigger Driver: Mandated Service Obligations	
Outcomes: Customer Service, Public Policy, Financial , Reliability	

The Metering program (the "Program") funds investments in the utility's metering technology to ensure the reliable measurement of electricity acquired by the utility through the provincial transmission system and distributed to its customers. The Program consists of two segments: Wholesale Meter Compliance and Revenue Meter Compliance. The Wholesale Meter Compliance ("WMC") segment involves the maintenance and replacement of wholesale meters at transmission supply points. This segment ensures that Toronto Hydro remains compliant with IESO Market Rules pertaining to the Wholesale Market. The Revenue Meter Compliance ("RMC") segment involves the installation of meters for new customers, replacement of faulty or expired meters, and maintenance and upgrades of supporting metering infrastructure. The segment is comprised of specific initiatives that impact all of Toronto Hydro's customers from residential customers to large users. A substantial part of this segment involves the planned replacement of Toronto Hydro's population of first generation residential and small commercial smart meters, many of which will have expired seals and have been in the field beyond their expected useful life during the 2020-2024 plan period. The Program and its constituent segments are a continuation of the activities described in the Metering program in Toronto Hydro's 2015-2019 Rate Application.[1]

The Program's primary objective is to maintain compliance with legal and regulatory metering requirements under the *Electricity and Gas Inspection Act*, the *Weights and Measures Act*, and the IESO's Market Rules. In addition, the investments in this Program facilitate accurate customer billing, enhance Toronto Hydro's ability to monitor the distribution system, respond to outages, and support the utility's financial operations.

[1] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015), Exhibit 2B, Tab 8, Schedule 1, Section E5.1.

E5.4.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Service	• Contributes to Toronto Hydro's customer service objectives by: ○ Maintaining billing accuracy of at least 98 percent by: (i) upgrading and replacing metering infrastructure and limiting the percentage of meters past their useful life; (ii) completing metering system upgrade initiatives that reduce estimated bills and bill corrections; and (iii) implementing a Mobile Workforce Management program to reduce the number of estimated bills due to meter changes; and ○ Installing ION meters so that customers can monitor energy consumption and power quality in real-time.
Reliability	• Contributes to Toronto Hydro's reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by installing new meters with Last Gasp Functionality enabling Power System Controllers to more effectively direct field crews. This also enables emergency response and outage restoration activities that require customer level outage information.
Public Policy	• Contributes to Toronto Hydro's public policy objectives by: ○ Maintaining compliance with various requirements such as Measurement Canada's *Electricity and Gas Inspection Act* and Regulations, and the IESO's Market Rules to enable accurate and timely meter reading, billing and market settlements; ○ Enabling Toronto Hydro to respond more efficiently to changes in Distribution Licence conditions related to customer disconnections with remote disconnect and reconnect meters; and ○ Enabling the full implementation of customer specific reliability measures currently being piloted by the OEB, and contemplated under the Long-Term Energy Plan 2017[2] by installing new meters with Last Gasp functionality.

[2] The Ontario Energy Board's Implementation Plan In response to the Minister of Energy's Directive in respect of the implementation of Ontario's Long-Term Energy Plan 2017: Delivering Fairness and Choice, page 7. https://www.oeb.ca/sites/default/files/OEB-LTEP-Implementation-Plan.pdf

Financial	• Contributes to Toronto Hydro's financial objectives by ensuring energy consumption, and purchase of wholesale energy is measured accurately and in a timely manner.

E5.4.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Mandated Service Obligations
Secondary Driver(s)	Failure Risk, Business Operations Efficiency

E5.4.3.1 Mandated Service Obligations

1. Wholesale Meter Compliance

Toronto Hydro plans to upgrade its wholesale revenue meters to comply with the metering standards mandated by Measurement Canada and the IESO Market Rules. Wholesale revenue metering upgrades require approved instrument transformers, de-registering the existing wholesale revenue metering points, preparing the site for new compliant wholesale metering equipment, and overseeing the wholesale revenue metering installation work, along with completing the registration process with the IESO. Toronto Hydro plans to undertake this work so that it can complete the scheduled metering point upgrades at all applicable wholesale metering points during the 2020-2024 plan period.

2. Revenue Metering Compliance

Measurement Canada has jurisdiction over the administration and enforcement of the *Weights and Measures Act*[3] and the *Electricity and Gas Inspection Act*.[4] These Acts and related regulations govern Toronto Hydro's ability to bill its customers for electricity usage, and require that all meters must be resealed at specified intervals to ensure that a customer's electricity usage is metered accurately. Once a seal expires, the meter cannot legally be used for billing purposes and must either have its seal period extended (via compliance testing), or be replaced.

For large homogenous batches of meters, Measurement Canada permits a sampling protocol to verify the accuracy of the meters. If the statistical accuracy results from the sample testing are within

[3] R.S.C., 1985, c. W-6.
[4] R.S.C., 1985, c. E-4.

acceptable levels, all the meters in the meter group will receive a seal extension. Certain meters need to be "re-verified." Re-verified meters are tested individually because they do not fit within the sampling program and are required by law to be removed for testing and replaced with new meters.

Once the seals of a meter group have expired, Toronto Hydro cannot use the meters in the group to bill its customers. The use of meters with expired seals could result in the incorrect billing of customers due to inaccurate meters. Also, in the event that the meters with expired seals remain in use, Toronto Hydro could face financial penalties, as contemplated by the *Electricity and Gas Inspection Act*.

All categories of meters (residential, commercial and industrial, large users, suite meters, wholesale meters) will need to have their seals extended or be replaced through either the sampling process or re-verification process throughout the 2020-2024 period. The bulk of residential and small commercial & industrial meters (which make up the significant majority of meters in Toronto Hydro's system) will have their seals expire in 2024. Please see Figure 1, below, for a breakdown of the number of meters with seals expiring by year.

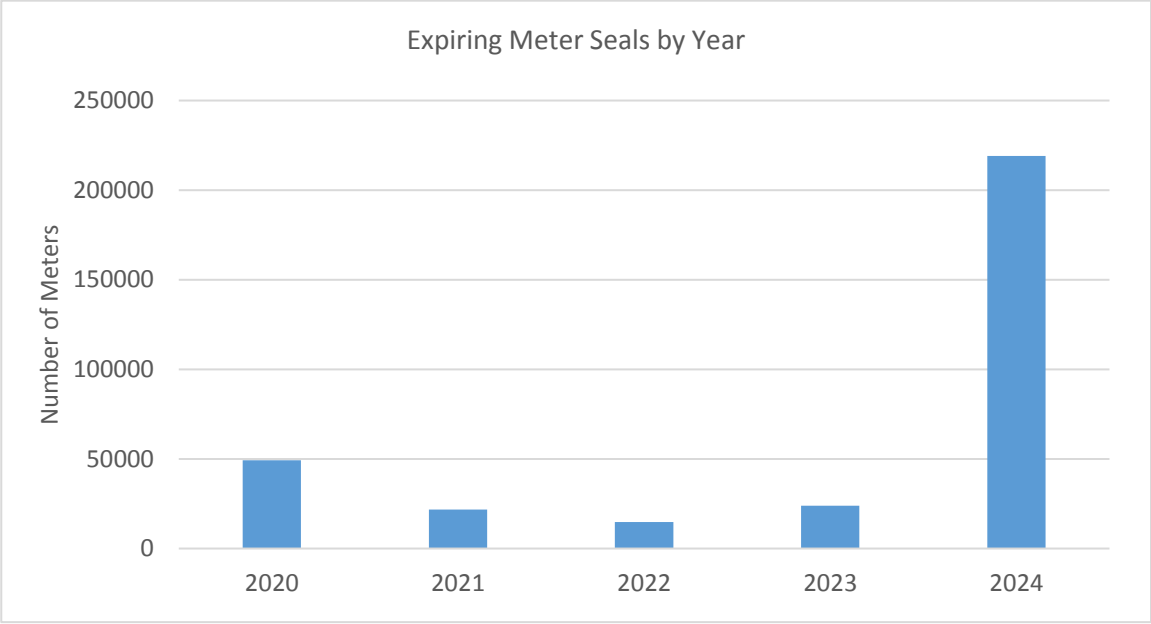


Figure 1: Expiring Meter Seals by Year

a. Meter Re-verification and replacement for Large User Class

Large User Class customers have average monthly demands of over one megawatt (1 MW). They represent only 0.06 percent of Toronto Hydro's customers, yet they generate approximately 13 percent of Toronto Hydro's total yearly revenue. These customers are typically key contributors to the economy of Toronto and Ontario, and can have loads that are sensitive to power quality. Examples of such customers may include auto manufacturers, office towers, entertainment complexes that host national and international entertainment and sporting events, hospitals, and industrial manufacturing plants with sensitive equipment.

Replacing meters currently in use by Large User Class customers at the time of meter re-verification with new ION meters that have added functionality will allow for the diagnosis of customer power quality issues, and could lead to a reduction in customer-specific power interruptions. In addition, these meters provide three-phase power quality information to Toronto Hydro that will be used to investigate distribution system issues related to power quality, in order to take preventative actions. These meters also provide direct benefits to the customers themselves by allowing them to monitor their energy consumption and power quality in real-time.



Figure 2: ION 8650 Meter Installed at Large User Sites

As the ION meters are only installed once the seal on the existing meter has expired, the ION meter implementation is staggered with the majority of the replacements having taken place between 2014 and 2017, see Figure 3, below. Going forward, Toronto Hydro will install new meters as customers meeting the Large User criteria are connected. Toronto Hydro will also have to replace and re-verify

these meters as their meter seals expire. The planned ION installation schedule for 2020 to 2024 is also outlined in Figure 3, below.

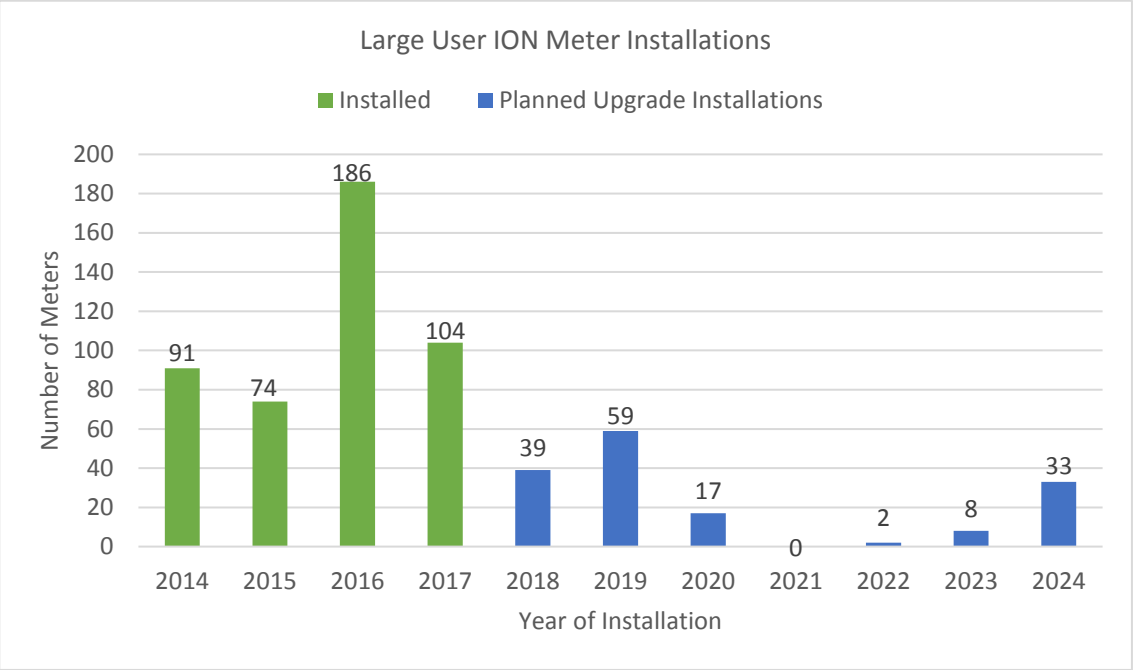


Figure 3: Large User ION Meter Installations by Year

b. Suite Meter Installations

Toronto Hydro is legally obligated to provide suite meter installation service. Utilities like Toronto Hydro offer this service in a competitive environment, and are also providers of last resort in the event that the condominium chooses not to secure a third party meter service provider.

There are currently approximately 79,000 suites that are individually metered by Toronto Hydro and about 3,000 multi-residential buildings that are metered by one bulk meter.

Going forward, Toronto Hydro will continue to offer its suite metering services to new customers and retrofit upgrades with an expected growth of roughly 5,500 new units every year. See Figure 4, below, for a chart showing historic and projected suite metering growth. Toronto Hydro will also continue to maintain the existing population of installed suite meters (see Figure 5, below) by re-verifying and re-sealing the meters as required.

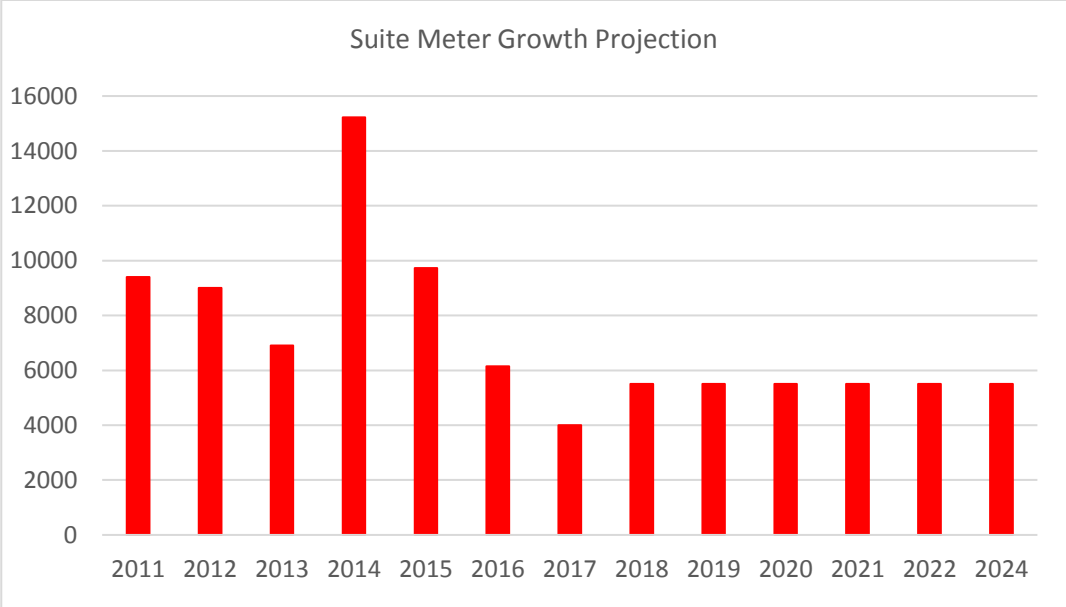


Figure 4: Suite Meter Historical and Projected Growth

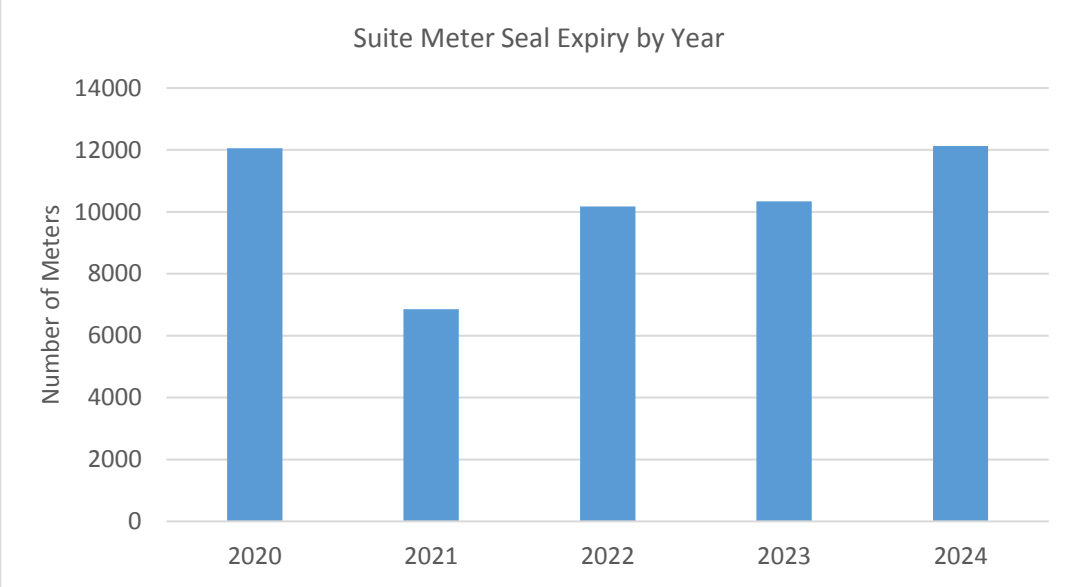


Figure 5: Suite Meter Seal Expiry by Year 2020-2024

c. <u>Continued Provincial Meter Data Management Repository ("MDM/R") Integration</u>

Toronto Hydro's billing systems will be fully integrated with the *Provincial* Meter Data Management Repository *("*MDM/R") by the end of the 2015-2019 period. During the 2020-2024 plan period, the

IESO is anticipated to have a mandatory upgrade and Toronto Hydro will have to ensure that the new upgrade will communicate successfully with Toronto Hydro's internal metering systems, Customer Information System, and Customer Care & Billing system ("CC&B").

In order for smart meter data to be retrieved by the provincial MDM/R from the utility's MDM systems, and to be transmitted back to the utility's billing system, it is necessary for Toronto Hydro's MDM and billing systems to be integrated with the provincial MDM/R system. The integration, or interfacing, must be implemented based on the protocols and specifications defined by the Smart Metering Entity ("SME"). Extensive testing is required when performing the integration to ensure the proper transmission of data between Toronto Hydro's systems and the provincial MDM/R.

E5.4.3.2 Failure Risk

Toronto Hydro was among one of the first utilities to implement Smart Meters in support of provincial policy objectives, installing the bulk of its residential and small commercial meters between 2006 and 2008. Given Toronto Hydro's status as an early adopter provincially and globally, there is an absence of empirical data from other utilities and jurisdictions of meter failure rates in relation to asset lifespan. However, in an Asset Depreciation Study undertaken by Kinetrics for the OEB (the "Kinetrics Report"), the expected lifespan of a typical smart meter was determined to be 5-15 years, which is consistent with Toronto Hydro's internal observed lifespans of other electronic based operational technology assets.[5] Beginning in 2021, Toronto Hydro's meters will surpass this 15 year lifespan, thereby increasing the probability of failure beyond standard operating levels.

As shown in Figure 1, above, the bulk of residential and small commercial & industrial meters will have their seals expire in 2024. At this time, the majority of meters will have been in service for 18 years. As the meter population ages, the probability of meter failures increases. By 2025, approximately 90 percent of Toronto Hydro's residential and small commercial meters will surpass their useful life. This will negatively affect Toronto Hydro's ability to accurately bill its customers (which is tied to the OEB's billing accuracy performance standards) as failed meters result in estimated billing.

[5] Kinetrics Inc., *Asset Depreciation Study for the Ontario Energy Board* (July 8, 2010), available at: < https://www.oeb.ca/oeb/_Documents/EB-2010-0178/Kinetrics-418033-OEB%20Asset%20Amortization-%20Final%20Rep.pdf>.

Higher failure rates pose a critical risk to Toronto Hydro's operations, affecting various elements of its business, including decreased billing accuracy, customer dissatisfaction (due to increased estimated bills and subsequent billing corrections), decreased financial stability (due to increased estimate based billing), increased costs to address meter failures on a reactive basis, and the potential failure to meet mandated OEB and other regulatory service standards (e.g. billing accuracy targets, restrictions on issuing multiple estimated bills, etc.).

To address this risk of failure, Toronto Hydro intends to replace its population of approximately 470,000 Elster REX 1 meters with next generation meters. This replacement will be staged over the 2022 and 2027 period. Meters will be replaced at or shortly following the end of their useful life of 15 years. The replacement schedule for any given meter will take place over the two years between their end of useful life and their seal expiry year.

The installation of next generation meters will also allow Toronto Hydro to expand the functionality of its metering population, through the installation of meters with remote disconnection capabilities. These meters will allow for quicker reconnection times for customers, and also result in less on-site field work, which will save labour and vehicle costs. This is beneficial to both the utility by reducing Toronto Hydro's operational expenditures and to the customer by reducing reconnection time.

In addition, the installation of these next generation meters will allow for "Last Gasp" functionality, which allows the meter to communicate an alert as it experiences an outage (see section below), to be rolled out across the distribution system beginning in 2022.

E5.4.3.3 Business Operations Efficiency

Metering technology supports the efficient and effective operation of Toronto Hydro's system. Given that the majority of Toronto Hydro's residential and small commercial smart meters were installed over 2006-2008, the rapid advancements in technology since that time have rendered the functionality of these first generation meters obsolete. While the replacements of these meters are primarily driven by failure risk, the advancements in technology have allowed for the adoption of new advanced functionalities during the replacement cycle. This new functionality will work to support efficient and effective grid management and customer service.

For example, the introduction of Last Gasp functionality is made available by the new models of the Elster meter. This facilitates customer level outage information and assists Toronto Hydro in reducing the duration of outages. This is accomplished by assisting with the localization of outages and

therefore being able to more quickly direct crew deployments to affected areas. This technology also enables the implementation of customer specific reliability measures contemplated under Ontario's Long-Term Energy Plan.[6]

Following an alert facilitated by the Last Gasp functionality, the information in the Toronto Hydro metering system will be passed to the system for restoration efforts and crew dispatch. Last Gasp will help Toronto Hydro to locate the source of the outage in a more timely manner, which will help facilitate quicker outage response times by allowing crews to locate the source of the outage quicker, with a corresponding effect on system wide SAIDI. See Figure 6, below, for a depiction of the operation of the "Last Gasp" functionality.

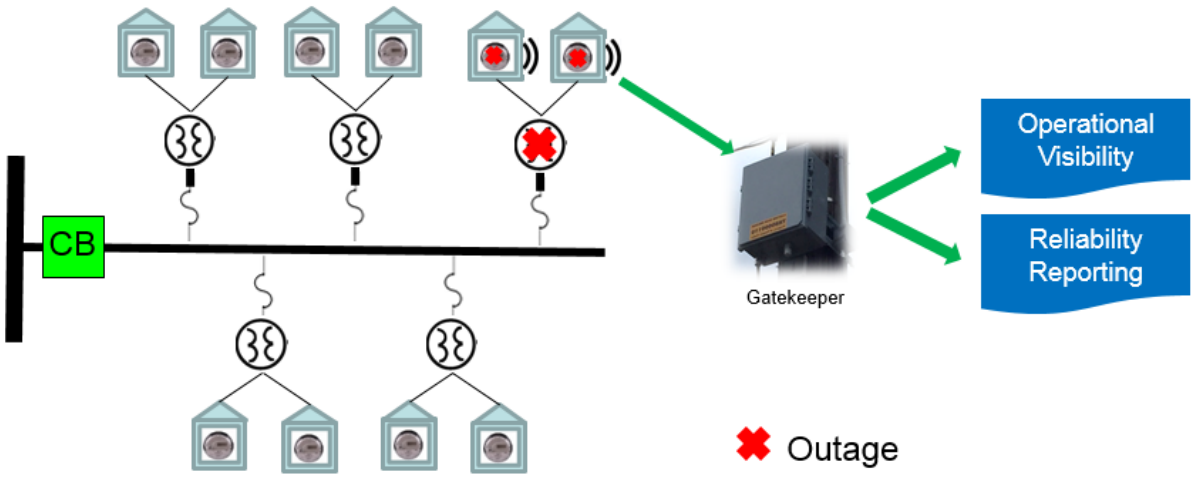


Figure 6: Last Gasp Function

The next generation meters also have a more effective transmitter that will drastically increase the range and penetration of the meter signal. This is expected to increase the number of meters successfully read, reducing "orphaned" meters and the number of manual reads required, and further reducing the number of estimated bills issued, increasing OEB billing accuracy metrics.

The introduction of meters with remote disconnection capabilities allows Toronto Hydro to reduce the cost of performing disconnections on its system, due to the reduced need for staff to physically

[6] Ontario's Long-Term Energy Plan 2017, Delivering Fairness and Choice (October 26, 2017), available at: < https://files.ontario.ca/books/ltep2017_0.pdf>.

attend a customer's property. This feature also enables customers to be reconnected faster after payment has been made, and allows for a more efficient and flexible implementation of OEB policy initiatives related to utility disconnection practices. Toronto Hydro already completes virtually all reconnections within 2 business days at least 90 percent of the time, as required by the OEB[7], but remote reconnection technology will allow for reconnection timelines significantly more convenient to customers.

1. Interval Metering System

Toronto Hydro intends to upgrade the Interval Metering system, ITRON Enterprise Edition ("IEE"), in order to continue to successfully meter Toronto Hydro's interval metered customers (those with greater than or equal to 50 kW demand). In 2011, Toronto Hydro had 3,300 Interval metered customers, and this increased to 7,000 in 2017. Toronto Hydro is projecting a further increase to 13,000 customers by 2020 due to the decommissioning of the 2G network in Toronto, and the consequent conversion by Toronto Hydro of its 2G meters to newer 4G technology. In order to keep up with this growth, the IEE system will need to be upgraded.

This upgrade will also lead to a reduction in the operational cost of the system in terms of licensing fees and IT support. The IEE system will have both data collection and exception management rolled into one system rather than two separate systems, and will also be able to communicate successfully with other meter types such as Suite Metered and Elster Interval meters. This will simplify the Interval data collection process, eliminating the need to collect interval data with multiple meter systems.

2. Residential Metering

Toronto Hydro must continually upgrade its residential metering system to ensure it continues to receive vendor support and is capable of enabling features available on newer generation meters. In 2021, Toronto Hydro plans to implement a new version of the residential metering system. This upgraded version will allow for the new "Synergy Mesh" – enabling enhanced communication features available in newer advanced meters - and implementing a Gatekeeper (Collector) replacement program. The new software will collect data from the residential meters every six hours versus the existing software which collects it once a day. This will allow customers to monitor their consumption with only a six hour delay. More importantly, the new generation of meters will reduce

[7] For a discussion of this OEB metric, please see Service Quality, found at Exhibit 2A, Tab 7, Schedule 1.

the number of manual meter reads and estimated bills. This will also allow Toronto Hydro to continue to ensure it is meeting its customer billing accuracy targets.

3. Suite Metering

Toronto Hydro intends to upgrade its Suite Meter Advanced Metering Infrastructure ("AMI") in order to maintain the meter reading and billing performance mandated by Measurement Canada and the IESO. The City of Toronto is experiencing significant condominium development. As a result of this customer growth, Toronto Hydro's current Suite Meter AMI system (Primeread) will no longer be able to retrieve and process the suite meter data fast enough on a daily basis to meet IESO's specifications, requiring Toronto Hydro to upgrade its data collection system. The lifecycle of the Suite Metering AMI has a scheduled upgrade roughly every three years to keep up with the influx of new suite metered customers. Primeread was initially brought online in 2012, the first upgrade took place in 2015 and the next scheduled upgrade is in 2018.

4. Operational Data Storage Upgrade ("ODS")

Presently, ODS is used solely for transferring consumption data from meters into Toronto Hydro's CC&B. The upgrade scheduled for 2022-2023 will enhance the ODS to better manage Toronto Hydro's billing data and enable energy monitoring and control capabilities for distributed generation energy resources across the Toronto Hydro distribution system. These capabilities will also allow for the management of generation, storage, and demand response assets while the Control Centre will continue to manage system configuration. The ODS will also be used to process smart meter data into the new Network Management System ("NMS"). This will enable a more streamlined and efficient approach to distributed generation projects and a more efficient approach to adding metering data into the NMS for outage management solutions.

5. Mobile Workforce Management

Over 2018 and 2019, Toronto Hydro plans to implement a Mobile Workforce Management system. This system is presently configured to only work with Toronto Hydro's residential meters. The system benefits Toronto Hydro customers as it ensures accurate and timely metering replacements.

When an existing meter in the field is replaced a technician must take an "off read" prior to installing the new meter. This ensures that all of the consumption data registered by the old meter is recorded and billed to the customer. With Toronto Hydro's previous system, this was accomplished with paper

record keeping. The new Mobile Workforce Management software ensures that all meter changes and field activities are processed electronically with the serial number of the old and new meter verified and recoded via a barcode, as opposed to the previous method of recording the serial numbers manually. This new electronic method reduces the risk of billing errors and will allow for the meter "off reads" to be sent directly from the field for billing.

By 2022, Toronto Hydro plans to undertake upgrades to the Mobile Workforce Management System that will ensure continued functionality of the system as the number of meter change and installation requests increases, and will allow it to be used across all of the various meter types in Toronto Hydro's system. This will greatly improve the efficiency of meter changes.

E5.4.4 Expenditure Plan

Toronto Hydro's historic and forecast spending in the Program is shown in Table 4, below. Expenditures in the Program are largely driven by the timing of metering and metering system upgrade cycles.

Table 4: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Metering	14.5	17.4	24.8	23.1	26.1	22.6	14.8	23.6	30.6	39.2

Table 5, below, shows a detailed breakdown of 2015-2019 spending within the Program.

Spending remained generally stable over 2015-2016, with a step increase between 2016 and 2017. This increase was primarily driven by the requirements to undertake a 2G meter replacement. As the 2G network band in Canada is in the process of being shut down, Toronto Hydro must replace all of its existing 2G smart meters with 4G models, and expects to complete this process during the 2017 to 2019 period. The spending over 2017-2019 also reflects increased spending related to the targeted installation of remote disconnect meters in specific locations. These meters allow Toronto Hydro to disconnect service without requiring on-site attendance by a crew, reducing operational costs for the utility, and improving service by reducing reconnection time for affected customers.

As can be seen in Table 5, over 2018-2019, spending decreases on System Upgrades and Large Customer and Interval Metering are offset by cost increases in other areas of the Program, such as the Residential and Small C&I Meter Replacement and Wholesale Metering.

Table 5: Actual & Bridge Program Costs 2015-2019 ($ Millions)

	2015	2016	2017	2018	2019	Total
Residential and Small C&I Meter Replacement	4.4	5.3	4.3	3.7	10.1	**27.8**
Suite Metering	5.9	6.1	5.3	5.2	5.3	**27.8**
Large Customer and Interval Metering	0.0	0.0	6.4	4.3	0.6	**11.3**
Wholesale Metering	2.6	1.7	4.6	3.3	6.5	**18.7**
System Upgrades	1.7	4.3	4.3	6.7	3.7	**20.7**
Total	**14.5**	**17.4**	**24.8**	**23.1**	**26.1**	**106.3**

Table 6, below, provides a breakdown of Toronto Hydro's forecast expenditures over the 2020-2024 plan period. This forecast is based on the number of meters that will need to be resealed or replaced in each year. Costs for metering system upgrade initiatives are based on a paced installation schedule using currently available cost estimates.

As shown below, Toronto Hydro's forecast spending in most categories over the 2020-2024 plan period is generally stable and in-line with its historical spending over the 2017-2019 period. The sole exception is the residential and small commercial meter replacement initiative, which reflects Toronto Hydro's intention to replace these meters over a six year period beginning in 2022, corresponding to the period during which these meters will both age beyond their expected useful life and have their seals expire (refer to Options Analysis section for additional details).

Table 6: Forecast Program Costs 2020-2024 ($ Millions)

	2020	2021	2022	2023	2024	2020-2020 Total
Residential and Small C&I Meter Replacement	7.1	4.2	15.6	24.5	31.9	**83.3**
Suite Metering	4.7	5.2	4.7	4.4	4.4	**23.5**
Large Customer and Interval Metering	0.7	0.0	0.0	0.1	0.4	**1.3**
Wholesale Metering	7.3	1.6	0.0	0.0	0.0	**9.1**
System Upgrades	2.8	3.8	3.2	1.5	2.4	**13.7**
Total	**22.6**	**14.8**	**23.6**	**30.6**	**39.2**	**130.8**

Toronto Hydro prioritizes the replacement of meters based on their seal expiry dates. Those meters with earlier seal expiry dates will be prioritized for replacement. The meters with expiring seals typically also reflect the oldest meters in the meter population.

E5.4.5 Options Analysis

E5.4.5.1 Options for Revenue Meter Compliance

The Revenue Meter Compliance segment includes many tasks that must be completed in order to remain in compliance with Measurement Canada Regulations. This includes the Revenue Meter Replacement program for Suite Meters, Interval Meters, and Large Users and the Metering System Upgrades for Residential, Suite Meters, and Interval Meters. These projects must be completed to ensure continued compliance with Measurement Canada and OEB regulations. For example, for the interval and suite metering projects, Toronto Hydro must maintain the meter seals to ensure continued compliance with requirements contained in the *Weights and Measures Act* and the *Electricity and Gas Inspections Act*.

The major project for the Revenue Meter Compliance segment over the 2020-2024 plan period is the residential and small commercial meter replacement. This project has four options for completion, which are discussed in detail below.

Adjusted cost calculations were derived based on the total cost of each option. The calculation for the seal extension option was derived with the total cost of the program out to 2033, when the last of the meters would be replaced.

1. Option 1: Seal Extensions for Residential and Small Commercial and Industrial Meters

This option would require Toronto Hydro to sample the residential and small C&I (Commercial and Industrial) meters that will expire over the 2024-2026 period and extend the seals of the meters for another 6 years. This involves forming sample groups, randomly selecting approximately 3 percent of the meters in each sample group, taking them out of service, and testing them for accuracy. If the old meters pass the test, then all meters in the sample group will have their seals extended by 6 years. The meters would then be replaced upon expiry of the re-seal, beginning in 2030.

The main benefit of this option is that it is the least capital intensive of the three, as it defers the meter investment into a future period. However, this option carries with it some considerable risk. First, it is based on an optimistic assumption that all meter batches will pass the resealing test (and

will not require immediate replacement). There is also a considerable risk that even after being resealed, the meters may deteriorate or fail in the field. Most meters would be 20-25 years old by the time of the next reseal cycle, nearly 10 years beyond their expected maximum useful life of 15 years. Substantial meter failures would have a significant impact on Toronto Hydro's operations, affecting billing accuracy, customer satisfaction, compliance, and financial stability. Such meter failures would also negatively affect Toronto Hydro's operational costs by requiring more costly reactive spot replacements.

In addition, by continuing to rely on the first generation meters, Toronto Hydro would not be able to take advantage of additional benefits offered by newer generation meters, including remote disconnect capabilities and Last Gasp functionality that would enable quicker restoration times during outages. The latter is also an enabling component of Customer Specific Reliability Measures, which the OEB has been exploring on a pilot basis, and which forms part of the Long Term Energy Plan 2017.

The total adjusted cost of this option from 2021-2033 is $90.8 million.

2. Option 2 (Selected Option): Replace Meters over a Six Year Period (2022-2027)

In this option, Toronto Hydro would replace the entire population of Elster REX 1 meters with next generation meters, the replacement would be staged over a five-year period between 2022 and 2026. Meters would start being replaced as soon as or shortly after they hit the end of their useful life of 15 years, and the replacement schedule for any given meter would generally take place over the two years between their end of useful life and their seal expiry year.

This pacing option achieves the objectives of the required replacement by addressing the pending seal expiry issue, adequately addressing the potential failure risk driven by end of life meters, allows for remote disconnect and Last Gasp functionality to be rolled out across the system beginning in 2022, and largely avoids a "lumpy" investment cycle. This option also reduces the financial impacts of the replacement for current ratepayers by delaying and condensing the investment to the maximum extent possible. Given these considerations, Toronto Hydro has selected Option 2 as its approach.

The total adjusted cost of this option from 2021-2033 is $115.1 million.[8]

[8] The adjusted cost only covers the Residential and Small Commercial portion of the budget.

3. Option 3: Replace Meters over a Four Year Period (2024-2027)

This option would require the replacement of the entire population of roughly 470,000 Elster REX 1 meters with next generation meters when the majority of seals expire in the 2024-2026 period. The meters would generally be replaced in the year of their seal expiry.

This option would address the seal expiry issue, and reasonably address the potential failure risk driven by end of life meters, however this option would require the meters to operate roughly three years beyond their expected useful life. It would also allow remote disconnect and Last Gasp functionality to be rolled out across the system beginning in 2024.

Overall, this option requires a considerable capital replacement of meters over a relatively short 3 year period. This would result in a resource intensive replacement program and a "lumpy" investment cycle that negatively affects both rates and future subsequent replacement and maintenance scheduling.

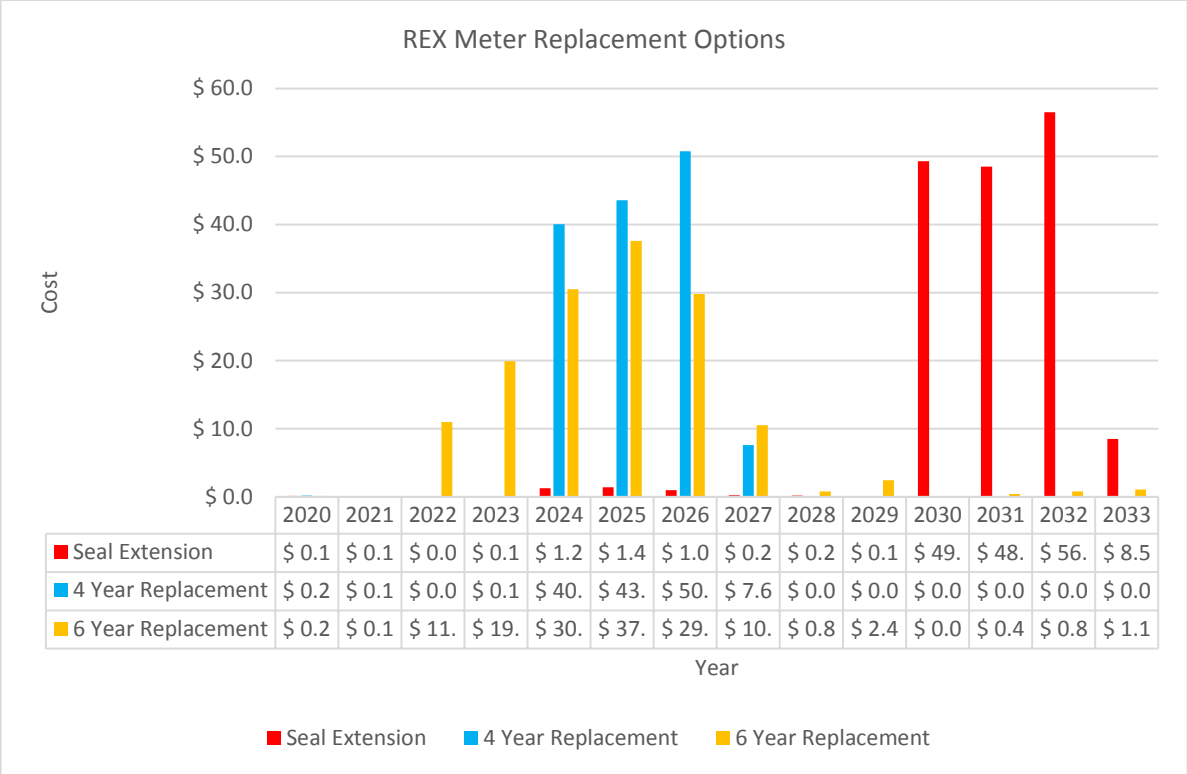
The total adjusted cost of this option from 2021-2033 is $110.2 million.[9]

4. Options Comparison

The Figures below compare the three options, in terms of spending:

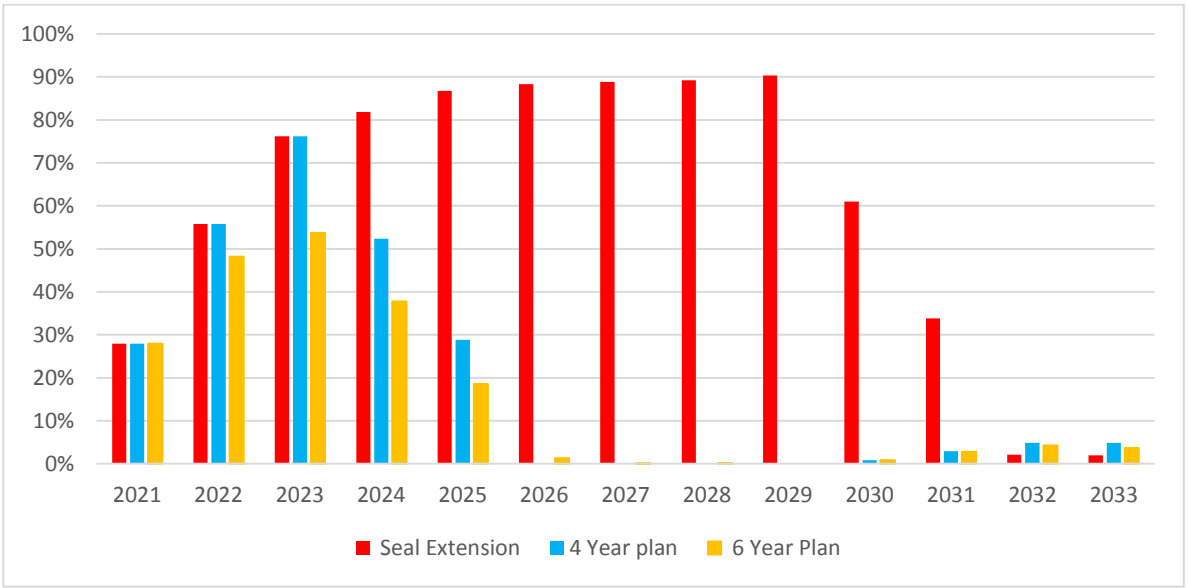
- **Figure 7**: Meter Replacement Options – Spending Profile Comparison, meters past the end of their useful life;
- **Figure 8:** Meter Replacement Options - Meters Past Useful Life; and
- **Figure 9**: Meter Replacement Options – Meter Replacements per Year.

[9] The adjusted cost only covers the Residential and Small Commercial portion of the budget.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Seal Extension	$ 0.1	$ 0.1	$ 0.0	$ 0.1	$ 1.2	$ 1.4	$ 1.0	$ 0.2	$ 0.2	$ 0.1	$ 49.	$ 48.	$ 56.	$ 8.5
4 Year Replacement	$ 0.2	$ 0.1	$ 0.0	$ 0.1	$ 40.	$ 43.	$ 50.	$ 7.6	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0
6 Year Replacement	$ 0.2	$ 0.1	$ 11.	$ 19.	$ 30.	$ 37.	$ 29.	$ 10.	$ 0.8	$ 2.4	$ 0.0	$ 0.4	$ 0.8	$ 1.1

1 **Figure 7: Meter Replacement Options – Spending Profile Comparison**



2 **Figure 8: Meter Replacement Options – Meters past Useful Life**

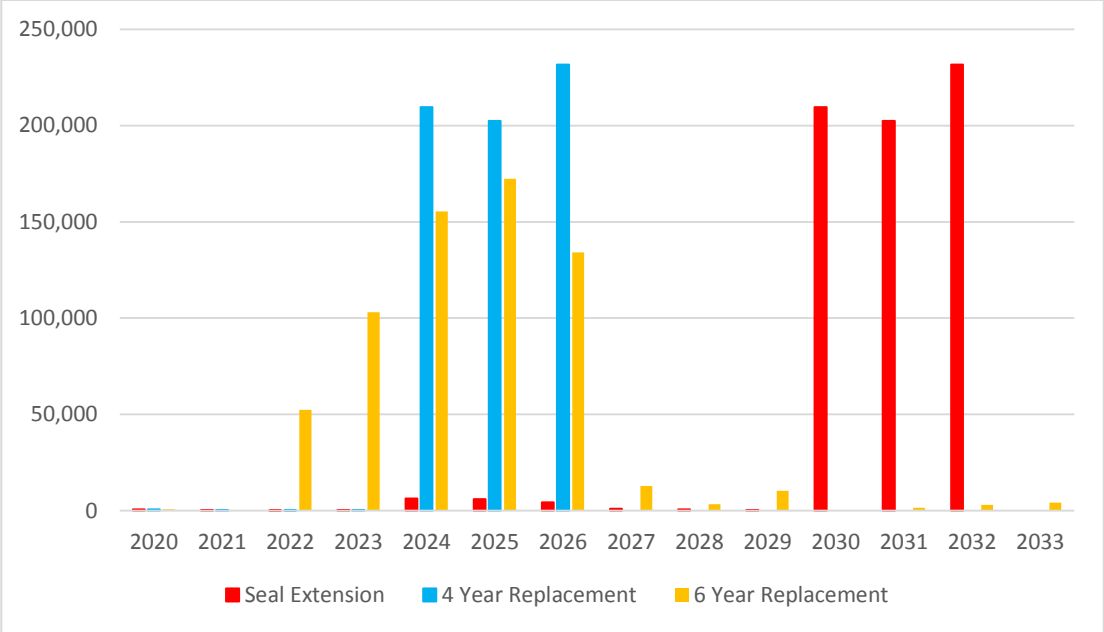


Figure 9: Meter Replacement Options – Meter Replacements per Year

E5.4.5.2 Options for Wholesale Metering Compliance

For the Wholesale Metering Compliance segment, no other options are available to Toronto as the utility is required to complete the remaining Meter Service Provider ("MSP") conversions, in accordance with IESO's mandated requirements.

E5.4.6 Execution Risks & Mitigation

The table below illustrates the major program risks that may occur while executing the Program.

Table 7: Meter Risks, Impact, Probability, and Mitigation

Project Segment	Risk	Impact	Risk Probability	Mitigation
Revenue Meter Compliance	Large Batches of required meters may not be received in time for installation or replacement	The program would have to be modified and timelines potentially stretched. This would potentially force Toronto Hydro to reseal meters past useful life, increasing capital expenditures and risk of failure	Low – Provided enough lead time meters should arrive when required.	Ensure that enough lead time is provided to the vendor to ensure delivery of equipment as required.
Wholesale Metering	Hydro One projects enabling Toronto Hydro's required meter replacements are delayed.	Compliance with IESO Market Rules is affected or delayed.	Medium – projects are complicated and subject to equipment delays and resource availability.	Work closely with Hydro One to schedule work and to allocate appropriate resources to metering compliance projects.

E5.5 Generation Protection, Monitoring, and Control

E5.5.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 13.6	**2020-2024 Cost ($M):** 13.6
Segments: Generation Protection, Monitoring, and Control	
Trigger Driver: Mandated Service Obligations	
Outcomes: Customer Service, Safety, Reliability, Public Policy	

The Generation Protection, Monitoring, and Control program (the "Program") allows Toronto Hydro to fulfill its regulatory obligations under section 6.2.4 of the Distribution System Code ("DSC") and section 25.36 of the *Electricity Act* to connect distributed generation ("DG") projects to its distribution system; including renewable energy generation ("REG") projects such as solar photovoltaic, wind and bio-gas. It also allows Toronto Hydro to meets its obligations under section 6.1 of its Distribution License and section 26 of the *Electricity Act* to provide generators with non-discriminatory access to its distribution system. Toronto Hydro's investments in this Program consist largely of "renewable-enabling improvements", as defined in sections 1.2 and 3.3.2 of the DSC.

As of the end of 2017, Toronto Hydro has connected over 1,780 DGs totalling 226 MW in capacity. The utility is forecasting a continued increase in DG connections (including energy storage), reaching an estimated 800 MW by the end of 2024. To alleviate existing connection capacity constraints that may prevent the expansion of DG in a number of areas, and to provide Toronto Hydro system controllers with the necessary capabilities to monitor and control DG connections, Toronto Hydro plans to continue making investments in two types of work over the 2020-2024 period:

- generation protection measures, through the installation of bus-tie reactors at five station buses to alleviate short circuit capacity constraints; and
- the installation of 414 monitoring and control systems ("MCS") for REG facilities to provide situational awareness and control of DG facilities on the distribution system.

E5.5.2 Outcomes and Measures

Table 2: Outcomes & Measures Summary

Customer Service	• Contributes to Customer Service objectives by: ○ Enabling the connection of new generation customers without extensive delays or adverse impacts to existing and new customers (as per section 6.2.4 of the DSC 90 percent of the time on a yearly basis within 5 business days as per the DSC section 6.2.7 and 6.2.7A); ○ Complying with sections 25.36, 25.37 and section 26 of the Electricity Act, 1998 by connecting DG customers to its distribution system; ○ Providing system Toronto Hydro with a level of precision in DG capacity monitoring to enable the maximum allowable amount of generation to be connected to the grid.
Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: ○ Ensuring the operation of the distribution system remains within allowable designed short circuit current limits by installing 5 bus-tie reactors on station buses; ○ Avoiding unintentional islanding and reducing the islanding risk of DG sources; and ○ Ensuring bi-directional flows remain within distribution system design parameters including thermal and short-circuit capability by installing MCSs at existing and new DG facilities.

Safety	• Contributes to maintaining Toronto Hydro's Total Recorded Injury Frequency (TRIF) measure and employee safety by: ○ Preventing backfeed situations by automatically issuing an electronic trip/shutdown command to isolate DG when feeder breakers are opened (as per the Electrical Utility Safety Association ("EUSA") Rule 149 – Backfeed); ○ Adhering to Ontario Electricity Safety Code ("OESC") Rule 84-008, which requires distributed generation systems to automatically disconnect electric power from the distribution system; and ○ Providing power system controllers tools to remotely disconnect DG as part of the Work Protection Code procedures to safeguard linepersons from unexpected generator start-up, preventing backfeed into the local distribution grid area while field crews are present.
Public Policy	• Contributes to Toronto Hydro's public policy objectives by: ○ Enabling the connection of distributed generation facilities to the system in support of public policy objectives contained within the Green Energy and Green Economy Act ("GEGEA") and the Long Term Energy Plan ("LTEP");

E5.5.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Mandated Service Obligations
Secondary Driver(s)	Reliability, Customer Service Requests

The Program is instrumental to Toronto Hydro's efforts to enable DG connections to its distribution system. This Program is fundamentally customer-driven, as the proposed work will allow Toronto Hydro to connect additional customer DG projects to the distribution system through the Customer and Generation Connections program. Additionally, distribution systems, including monitoring and protection systems, were planned, designed and built to serve loads but were not intended to facilitate the connection and management of a large number of distributed generators. As a result, there is a need to address the system constraints to enable generation connections to the distribution system.

The Program is required to enable system access for the existing and forecasted levels of DG on Toronto Hydro's distribution system (as some existing solar DG connected to the grid does not have and will require MCS). As per Section 6.2.4 of the DSC, and sections 25.36 and 25.37 of the Electricity Act, Toronto Hydro is mandated to connect DG customers to its distribution system. Toronto Hydro is also obligated under section 6.1 of its Distribution License and section 26 of the Electricity Act to provide generators with non-discriminatory access to its distribution system and to provide priority access for renewable energy generation facilities.

The planned investments are critical renewable enabling improvements that Toronto Hydro must carry-out in order to safely and reliably facilitate the continuing proliferation of REG facilities across the City of Toronto. By addressing short-circuit limitations on the system and installing required monitoring and control capabilities, Toronto Hydro will be able to continue to deliver an efficient and timely DG connections program (detailed in section 3.2.1).[1]

Figure 1 below illustrate typical DG installations on the Toronto Hydro distribution system, as enabled by investments in this Program.



Figure 1: Residential (left) and Residential (right) DG Installation

E5.5.3.1 Proliferation of Distributed Generation Facilities

As of the end of 2017, Toronto Hydro has responded to over 8,000 inquiries from customers and developers seeking to connect generation under various programs, including the Independent

[1] As per section 6.2.7 and 6.2.7A of the DSC, Toronto Hydro is required to connect new micro-embedded generation facilities on time, 90 percent of the time on a yearly basis within 5 business days.

Electricity System Operator ("IESO") programs,[2] Net-Metering, Energy Storage, Combined Heat and Power ("CHP"), Closed Transition and Load Displacement. A wide range of proponents have submitted project applications, including many schools, housing managers, large grocery stores, condominium corporations, and department stores. As of the end of 2017, Toronto Hydro has connected over 1,780 DGs of various sizes. Details on the number of projects and total kilowatts of DGs connected by size and technology can be found in the Customer Connections program.[3]

Interest in generation projects within Toronto Hydro's service territory has been steadily increasing and this trend is anticipated to continue into the future. There has been a growing interest in the Net Metering program and battery energy storage as costs associated with solar photovoltaic panels, inverters, and lithium-ion batteries continue to fall. Inquiries for medium and large sized CHP installations have more than tripled since 2015, largely due to larger industrial and commercial customers seeking site reliability. Toronto Hydro has also observed increased interest in small scale micro turbine-based installations. Toronto Hydro anticipates a large volume of applications for the connection of micro turbine-based CHP facilities, which are well-suited to generation in commercial and multi-level residential buildings.

DG projects are expected to more than double by 2024, reaching approximately 3,600 connections. This represents an additional 581 MW on top of the 226 MW of existing DG as of the end of 2017, as seen in Figure 2. Toronto Hydro's DG connection forecast is based on historical DG connections, initial consultations and preliminary assessments received and completed from 2009 onwards. These include initial consultations regarding Net-Metering, CHP, Closed Transition, Load-Displacement, and IESO programs such as PSUI, FIT and Energy Storage Procurement. The forecast takes into account the historical connection trends, completed assessments, and anticipated projects with respect to various DG programs. For more information on generation connections see the Customer Connections program.[4]

[2] Feed-in-Tariff (both micro-FIT ≤10 kW and FIT >10 kW), Process and Systems Upgrade Initiative ("PSUI"), Renewable Energy Standard Offer Program ("RESOP")
[3] See Exhibit 2B, Schedule E5.1
[4] *Supra* note 3.

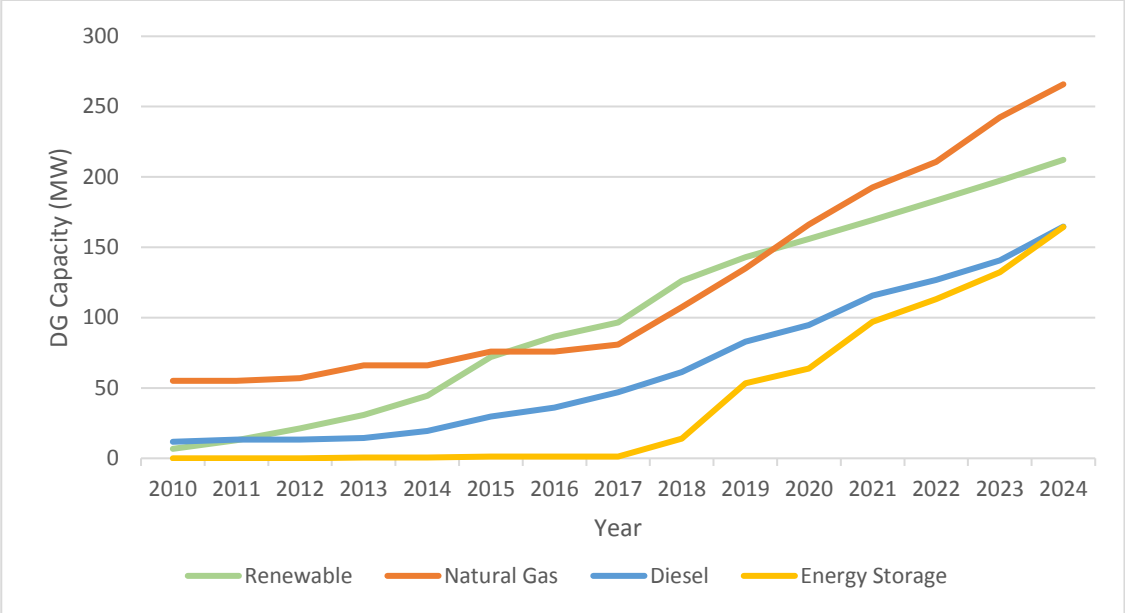


Figure 2: Historic and Forecasted Generation Capacity 2010-2024

Currently, the ability to connect new DG is limited by constraints on Toronto Hydro's system. As DG connection requests increase, it is necessary to address these constraints to accommodate the anticipated connection requests to be made in a timely manner and to meet the requirements set in section 6.2.7 of the DSC. Toronto Hydro faces short circuit, reverse power flow and anti-islanding issues that can inhibit the ability to connect the forecasted DG projects. Over time, larger concentrations of micro-generators, or several medium-sized generators on the same distribution feeder can have a noticeable impact on the short circuit and loading levels on the distribution system and upstream elements. Investments are therefore necessary to overcome short-circuit capacity constraints and to facilitate integration of DG into the distribution grid with bi-directional flow capability. Without these investments, Toronto Hydro may not be able to meet its regulatory obligations and respond to the public policy objectives of the Province with respect to the expansion of renewable energy generation sources.

E5.5.3.2 System Capability to Connect Distributed Generation

Toronto Hydro supports connecting DG to the distribution system in alignment with the DSC and in coordination with Hydro One and the IESO. Toronto Hydro has identified a number of constraints within its system that impact DG connections and interconnection-related decisions. The issues that limit Toronto Hydro's ability to connect DG include short-circuit capacity, risk of islanding, thermal

limits, and the lack of ability to transfer loads between feeders during planned work and emergency situations.

Asset failure can occur when distribution equipment exceeds system short circuit levels, equipment thermal ratings and nominal voltage ratings. Failures due to distribution system stresses from DG sources can cause transformer equipment failure, surge arrester failure, nuisance outages from sympathetic[5] tripping and other similar effects.

The capacity and type of generation connected to both feeders and stations must be managed to ensure reliable operation, and prevent damage to existing transformers, circuit breakers and fuses. Introducing increased levels of bi-directional flows from DG will require protection, monitoring, and control to prevent such occurrences during normal operation, planned work and emergency situations.

1. Short Circuit Capacity Limitations

Short circuit limits on both the Toronto Hydro and Hydro One systems are important factors in determining how much DG can be connected to Toronto Hydro's distribution system. Prior capacity studies (Navigant DG Report, April 2011) confirm short circuit limits on station equipment to be one of the primary limiting factors on the amount of DG that can be installed in certain areas of the Toronto Hydro system.

Recent applications for FIT connections and the Navigant report demonstrate the potential for DG and underscore the impact of short circuit capacity on allowable DG penetration. The primary limiting element for short circuit capacity is substation equipment (where fault current levels are highest) and, more specifically, substation load side breakers. Annual fault studies conducted by Toronto Hydro confirm that stations serving 27.6 kV primary distribution have significantly greater spare short circuit capacity than downtown stations serving 13.8 kV distribution.

2. Bus-Tie Reactors

To facilitate DG connections, bus-tie reactors can be installed on the bus to mitigate high fault current levels. They lower the short circuit current on the station bus and distribution system by inserting impedance at the bus-tie point. This limits the fault contribution of the two transformer windings in

[5] Sympathetic tripping is the phenomenon on feeders when a protective device (that should not operate) operates in response to fault or condition on a downstream part of the feeder that is protected by another protective device.

a typical Dual Element Spot Network ("DESN") type station arrangement. A reactor of 0.5 ohms installed at a bus-tie could allow up to an additional 15 MW of DG capacity. Since they are essentially a linear inductive reactance, their cumulative impedance will add to the system's impedance which will result in a reduction of the fault currents. The main advantage of series reactors is that they allow the use of existing equipment without costly modifications or replacements.

To facilitate Toronto Hydro DG customer connections, coordination with Hydro One is required to install these bus-tie systems. Toronto Hydro plans to work with Hydro One to install bus-tie reactors at stations where fault current constraints become an issue.

Toronto Hydro anticipates that five bus-tie reactors will be required over the 2020 to 2024 period to alleviate short circuit capacity constraints. The station buses where bus tie reactors are proposed are shown in Table 4 below.

Table 4: Bus Tie Reactor Installations

		Forecasted DG Connections by 2019		Forecasted DG Connections by 2024 (without bus-tie reactor)	
Station Name	**Bus**	**Total Capacity (MW)**	**Available Short Circuit Capacity (MVA)**	**Total Capacity (MW)**	**Available Short Circuit Capacity (MVA)**
Ellesmere TS	J	7.9	49.6	12.5	-0.5
Esplanade TS	A1A2	7.3	57.6	17.9	-29.6
Fairbank TS	YZ	2.7	6.0	7.9	-10.6
Horner TS	BY	14.6	92.8	20.8	-4.6
Sheppard TS	BY	3.5	21.7	9.4	-4.0

E5.5.3.3 System Monitoring to Control Distributed Generation

As mentioned, lack of monitoring of and control over the distributed generation on the grid can lead to increased risks of islanding, overloading the system, and increased thermal ratings. These can be addressed through the installation of MCSs.

1. Anti-Islanding Condition for Distributed Generators

Islanding occurs when a DG source continues to power a portion of the grid even after the main utility supply source has been disconnected or is no longer available. This situation must be avoided

as it can interfere with grid protection systems. It can also create dangerous backfeeds on the distribution system exposing workers to live circuits they believed to be de-energized.

Monitoring and control can mitigate the risks associated with DG for the public and Toronto Hydro field personnel. DG systems are required by Rule 84-008 of the *Ontario Electricity Safety Code* ("OESC") to have backfeed protection so that in the absence of electrical power (potential) on the utility's supply, generators cannot energize the utility's supply. Protection circuits can and do fail which can energize supply lines creating contact hazards for utility workers, contractors and the others who may be working on circuits expected to be de-energized. As per EUSA Rule 149, backfeed hazards must be identified and eliminated where possible, or controlled using approved temporary grounding procedures. Due to the hazard of backfeed, work is not to be performed on transformers connected in parallel or banked (except for replacing fuses using live line tools) until all sources of electrical energy have been removed from both the secondary and primary sides of the transformer to be worked on. The Electrical Safety Authority ("ESA") Bulletin DSB-07/11, dated August 17th, 2011, outlines an example where an inverter failed to disconnect and started to back feed into the local distribution system.

> *"The Ontario Electrical Safety Code (OESC) rule 84-008 requires a distributed generation system to automatically disconnect electric power production sources when there is a loss of power from the supply authority. In the case of this near miss incident, the solar inverter's "anti-islanding" feature failed to fully disconnect the energy produced from the PV system."*

If the anti-islanding feature of a DG were to fail, as it did in this situation, the DG would backfeed into the local distribution system. The possibility of electric shock due to this scenario would pose a safety risk to the public, Toronto Hydro field personnel and the system in general. Active monitoring and control systems help avoid this situation by automatically issuing an electronic trip or shutdown command when the feeder breaker is opened.

The connection of photovoltaic solar inverters and other DG sources must be accomplished in a manner that ensures that unintentional islanding of DG sources cannot occur. Toronto Hydro plans to deploy real-time monitoring and control investments proposed within this Program at new DG sites greater or equal to 50 kW as per section 3.3.3 of the DSC to provide the needed ability to address anti-islanding concerns.

One of the anti-islanding measures in the IEEE 1547 Standard for Interconnecting Distributed Resources (DR) with Electric Power Systems, section 4.4.1, recommends that a distributor ensure that "*DR aggregate capacity [be] less than one-third of the minimum load of the Local Electric Power System (EPS).*" As the ratio of generation capacity to minimum load increases, the amount of time required by inverters to respond to anti-islanding scenarios also increases and the likelihood of inverters responding to anti-islanding scenarios decreases.

With the proliferation of DG in Toronto in recent years, several feeder circuits have already surpassed the generation to minimum load ratio of one-third. A total of thirteen distribution feeders have ratios ranging from 0.34 to 0.5 (refer to Table 5 below). These feeders currently present an increased risk of unintentional islanding conditions to the distribution system.

Table 5: Existing Feeders with Generation to Load Ratio Greater Than One-Third

Feeder Name	TS Station Name	TS Bus	DG Connected (MW) in 2017	Minimum Feeder Load (MW)	Generation to Minimum Load Ratio
47-M1	***Sheppard***	*B*	1.8	3.5	0.50
63-M6	***Agincourt***	*Y*	2.9	6.9	0.43
55-M31	***Finch***	*J*	1.3	3.0	0.42
A-35-T	***Strachan***	*A7A8*	1.0	2.4	0.42
A-31-W	***Wiltshire***	*A5A6*	0.3	0.6	0.41
80-M10	***Fairchild***	*Y*	1.4	3.8	0.35
R29-M5	***Rexdale***	*B*	0.5	1.4	0.35
38-M4	***Manby***	*F*	0.6	1.6	0.35
53-M3	***Bermondsey***	*B*	0.6	1.8	0.35
R43-M31	***Warden***	*J*	0.7	2.0	0.34
88-M13	***Richview***	*E*	0.8	2.5	0.34
55-M1	***Finch***	*B*	2.0	6.0	0.34
R30-M3	***Horner***	*B*	0.8	2.4	0.34

DG penetration is growing rapidly as an additional forty five feeders are approaching the one-third limit (as shown in Table 6). These numbers take into account the forecasted 581 MW of additional DG capacity anticipated by the year 2024. This increase in DG penetration will further exacerbate the existing islanding risks and adversely affect Toronto Hydro's ability to safely and reliably connect additional DG to the distribution system. Monitoring and Control Systems allow Toronto Hydro to prevent concerns of anti-islanding as these give the utility the ability to remotely turn off the DG if they unintentionally island. If not addressed by proactive investments in control and monitoring

capabilities, the generation to minimum load ratios could ultimately limit the number of DGs Toronto Hydro is able to connect to the system. These systems also provide greater visibility into the grid and allow the utility to enable more DGs to connect, as explained in section E5.5.3.3.

Table 6: Feeders Forecasted to Exceed Generation to Load Ratio Requirement in 2024

Feeder Name	TS Station Name	TS Bus	DG Connected (MW) in 2024	Minimum Feeder Load (MW)	Generation to Minimum Load Ratio
A-21-CE	***Cecil***	*A1A2*	21.0	3.6	4.19
38-M9	***Manby***	*B*	1.1	0.7	1.49
11-M3	***Runnymede***	*B*	10.6	7.7	1.38
A-16-K	***Gerrard***	*A1A2*	4.3	3.2	1.34
H9-M29	***Ellesmere***	*J*	6.6	5.0	1.31
A-12-BN	***Basin***	*A5A6*	4.0	3.1	1.30
35-M8	***Fairbank***	*Z*	4.1	3.3	1.27
34-M6	***Leaside***	*Y*	23.3	7.2	1.15
A-26-WR	***John***	*A11A12*	3.0	3.0	1.00
502-M32	***Cavanagh***	*Q*	1.4	1.6	0.91
R43-M25	***Warden***	*J*	2.2	2.4	0.90
47-M18	***Sheppard***	*Q*	1.0	1.2	0.84
E5-M24	***Scarborough***	*Q*	4.0	5.0	0.80
53-M12	***Bermondsey***	*Y*	1.9	2.4	0.78
R26-M33	***Malvern***	*J*	5.2	67	0.77
A-12-CE	***Cecil***	*A7A8*	2.1	2.9	0.74
35-M1	***Fairbank***	*B*	1.4	1.9	0.71
11-M1	***Runnymede***	*Y*	1.5	2.1	0.71
R29-M34	***Rexdale***	*Q*	1.4	1.9	0.71
55-M10	***Finch***	*Y*	1.5	2.2	0.71
53-M8	***Bermondsey***	*Y*	3.0	4.5	0.66
85-M30	***Bathurst***	*J*	5.8	1.6	0.63
R26-M31	***Malvern***	*J*	2.1	3.4	0.62
A-65-A	***Terauley***	*A3A4*	1.2	2.0	0.60
E5-M10	***Scarborough***	*Y*	1.9	3.2	0.60
R29-M6	***Rexdale***	*Y*	1.8	3.2	0.58
85-M24	***Bathurst***	*J*	2.2	3.8	0.57
R43-M24	***Warden***	*Q*	1.5	2.7	0.56
R29-M33	***Rexdale***	*J*	1.5	2.6	0.56
35-M23	***Fairbank***	*B*	1.1	2.0	0.55
85-M6	***Bathurst***	*B*	5.9	3.9	0.55

Feeder Name	TS Station Name	TS Bus	DG Connected (MW) in 2024	Minimum Feeder Load (MW)	Generation to Minimum Load Ratio
R29-M3	***Rexdale***	*B*	1.8	3.4	0.54
R26-M32	***Malvern***	*Q*	1.6	3.0	0.54
H9-M32	***Ellesmere***	*Q*	2.8	5.3	0.53
85-M4	***Bathurst***	*B*	1.9	3.6	0.52
47-M15	***Sheppard***	*J*	2.9	5.6	0.52
80-M27	***Fairchild***	*J*	1.0	2.0	0.51
63-M5	***Agincourt***	*B*	2.7	5.3	0.51
R43-M29	***Warden***	*J*	2.5	4.9	0.50
80-M2	***Fairchild***	*Y*	1.6	3.3	0.48
R29-M36	***Rexdale***	*Q*	1.8	3.8	0.47
47-M3	***Sheppard***	*B*	2.2	4.8	0.46
51-M32	***Leslie***	*Q*	1.1	2.4	0.46
11-M5	***Runnymede***	*B*	1.0	2.6	0.39
51-M25	***Leslie***	*J*	2.2	2.6	0.38

2. System Thermal Limits and Load Transfer Capability

Protection, monitoring and control upgrades also provide the ability to connect additional DG by ensuring system loading thresholds are satisfied. Exceeding system loading limits, as seen in Table 5 and Table 6, sacrifices the life of distribution equipment and can cause immediate equipment failure as mentioned earlier.

For large sized generation connections or the aggregation of small and medium sized generation connections, limiting a feeder's continuous load thermal ratings is an important operating condition. Feeder planning and operation account for the system impact when the generator is up and running as well as when the units go off-line. These thermal levels come into play with factors such as the variability of various generation sources, system load growth and the occurrence of contingencies.

The ability to provide monitoring and control allows Toronto Hydro to monitor and mitigate the impact of thermal loading. This enables the utility to have more visibility into actual impact and variability of DG on the system and will therefore enable Toronto Hydro to be better equipped to make more accurate planning and operations decisions regarding thermal levels.

a. Monitoring and Control Systems

Since the 2015-2019 CIR, Toronto Hydro has been installing monitoring and control systems for all new DG connections. This has provided the visibility required to monitor the ratios in real time to ensure all DG sites are de-energized in the event of a system fault. With the continued implementation of the Program, Toronto Hydro will be able to actively monitor and control DG's in real time to ensure these ratios are within tolerable levels and the anti-islanding feature of the DG's have properly operated in the event of a distribution system fault.

Due to the volumes of forecasted DG connections from 2020 through to 2024, Toronto Hydro requires real-time monitoring and control via utility communication networks and the supervisory control and data acquisition ("SCADA") system in order to ensure distribution system safety and the adequate management of bi-directional distribution grid flows from DG connections (Figure 3). Real-time monitoring and control is required for existing and future DG sites of 50 kW and above. Toronto Hydro is mandated to connect DG sites to the distribution system, as per Section 6.2.4 of the DSC.

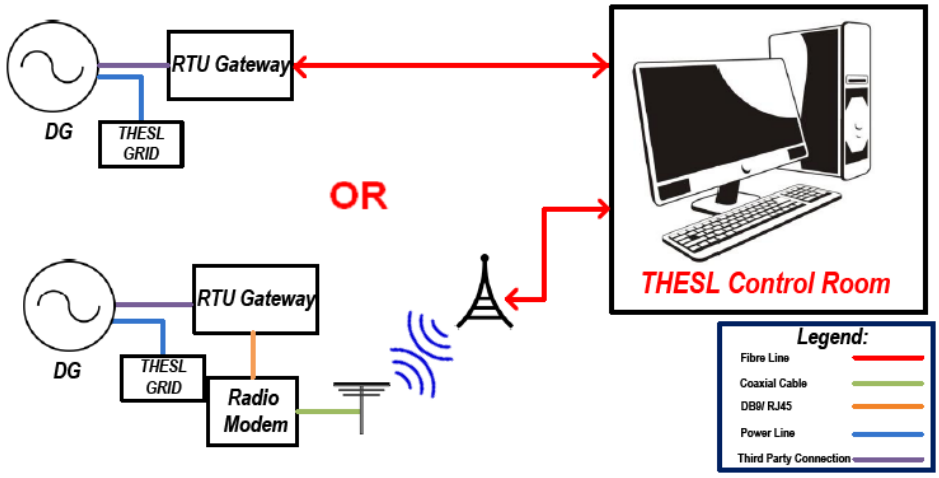


Figure 3: Monitoring and Control Interface to Toronto Hydro SCADA System

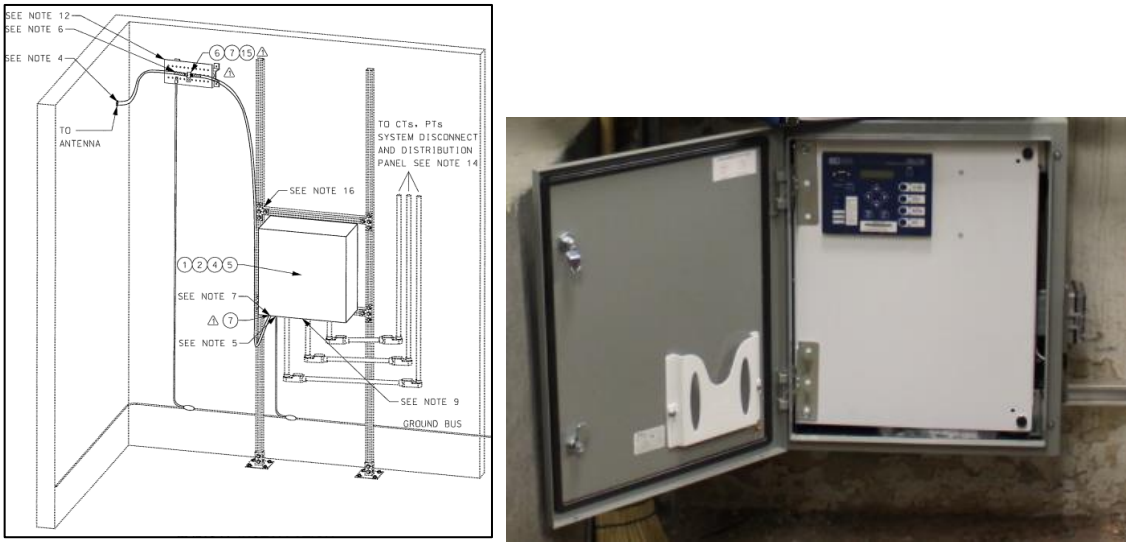
Monitoring and control provide situational awareness into the operating conditions of all DG connected to the distribution system, which will give Toronto Hydro the ability to collect data for planning purposes and to connect additional DG sites to the distribution system. This will have additional long-term value with respect to planning for future DG connections. Currently, Toronto Hydro assesses the potential to connect a DG site to the distribution system based on estimated thermal loading values. This approach assumes that a DG site will continuously generate 100 percent of its rated capacity. This inherently limits the number of DG sites that can be connected to the system, because the conservative estimated value assumes that the thermal loading of the DG site

is greater than it likely is at any given time. Monitoring and control will provide Toronto Hydro actual performance data from in-service connections for thermal loading values which will give a more precise view of existing conditions. This, in turn, will help enable Toronto Hydro to connect additional DG sites to the distribution system.

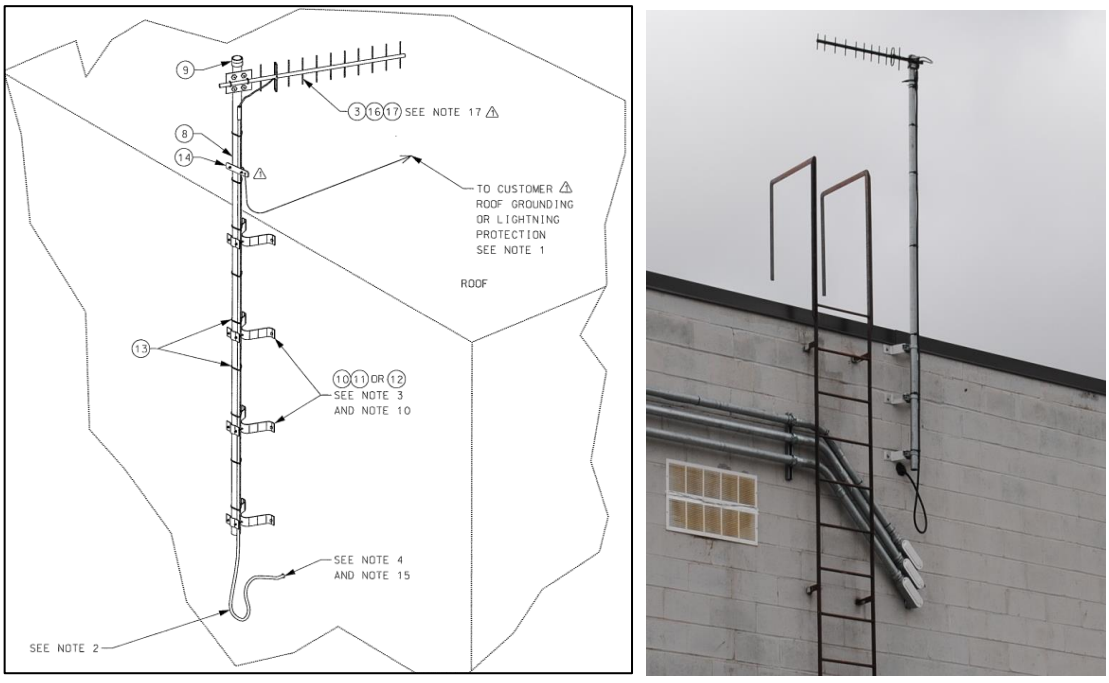
Monitoring and control also enables greater real-time visibility into the operating conditions of DG sites located in Toronto Hydro's service territory. Power system controllers need to know the aggregate generation connected to the system during planned or emergency load transfers. A power system controller must account for all DG during a load transfer because the increase in generation connected to the alternate feeder may cause short circuit capacity to be exceeded. The ability to remotely and automatically disconnect all DG sites on a feeder during planned or emergency load transfers is expected to simplify these operations as it would allow power system controllers to focus on restoration of customers' electricity rather than each individual DG site connected to a feeder.

Toronto Hydro's requirement for monitoring and control is modeled after requirements developed by the IESO. The IESO has developed DG monitoring and control guidelines with a focus on visibility, dispatch and forecasting capabilities for DG sites over 5 MW. Because of the volume and capacity of DG sites in Toronto Hydro's service territory (over 226 MW in aggregate), monitoring and control is required to connect additional DG projects and for grid management. This is also consistent with the requirements and practices of other LDCs.

Toronto Hydro's current monitoring and control process allows for the connection of DG sites through a Toronto Hydro communication interface as shown in Figure 4 below along with the standards it adheres to. Figure 5 shows a customer installation, which also adheres to Toronto Hydro standards.



1 **Figure 4: Toronto Hydro Communication Standard for DG Connections (left) and Communication**
2 **Gateway Installed at Customer DG Site**



3 **Figure 5: Toronto Hydro Communication Antenna Setup Standard (left) and at a Customer Site**
4 **(right)**

E5.5.4 Expenditure Plan

Table 7: Historical, Bridge & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Generation Protection, Monitoring, and Control	-	2.1	0.0	8.0	3.4	3.7	2.3	2.4	2.5	2.7

E5.5.4.1 2015-2019 Variance

1. Generation Protection

In 2015, Toronto Hydro had short circuit constraints on several station buses. To enable the connection of DG at these locations in a timely manner, a high-speed advanced protection scheme was proposed to mitigate the short circuit constraints. The advanced protection system consisted of installing 31 protection and control devices, along with 50-kilometres of fibre optic interface cable for Wiltshire TS, Basin TS and Leslie TS. However, the protection and control devices and fibre optic interface cable were never installed due to the reasons outlined below:

- During the design phase, due to the type of inverters selected by customers, the proposed advanced protection system at Leslie TS was no longer a viable solution. Instead of single, central type inverters, customers selected multiple, string inverters due to their lower costs. These string inverters do not possess the same functionality as their central inverter counterparts. Consequently, the proposed advanced protection systems would not relieve the short-circuit constraint.
- In 2016, Hydro One replaced end-of-life transformers at Wiltshire TS. This cancelled the program's planned work at that station as the specifications of the new transformers increased the short-circuit capability of the buses.
- The planned program work for Basin TS was cancelled due to the lack of progress on a customer's application for the installation of a 10 MW renewable energy generation project in the Basin TS area.
- An alternative solution for Leslie TS was the installation of a bus tie reactor. During the design phase for the bus tie reactor at Richview TS, the installation costs were determined to be more than originally anticipated.

For these reasons, Toronto Hydro intends to re-allocate roughly $0.8 million of the budget intended for advanced protection systems no longer required at Wiltshire TS, Leslie TS and Basin TS, to install bus tie reactors at Leslie TS and Richview TS in 2019.

2. Monitoring and Control

The monitoring and control work planned was delayed as a result of the need to customize and procure the monitoring and control systems to be installed on Toronto Hydro's distribution system (e.g. specifications, components). This delay has led to $1.8 million of work for MCS needs to be carried over into 2020. The high volume of existing and forecasted DG projects makes it challenging to accomplish this work by 2019. Therefore, both planned expenditure and unit values for MCS from 2017 to 2020 have been revised to reflect this new timeline for both existing DGs identified and new DGs.

Between 2012 and 2017, there were over 450 renewable generation connections where the customer purchased and installed MCS for their facilities. Pursuant to sections 3.3.2(g) and 3.3.3 of the DSC, the utility is responsible for costs incurred related to SCADA system design, construction and connection for renewable energy generation facilities. As a result, Toronto Hydro intends to reimburse past customers through the negotiation of a contractual agreement that allows Toronto Hydro to purchase the MCS, and receive assignment of any necessary access rights, warranties etc., which will facilitate Toronto Hydro's ongoing management of the MCS.

In late 2016, Toronto Hydro was able to purchase 211 MCS from its largest proponent of DG installations for $2.1 million. The remaining 240 MCS currently in the field are in the process of being audited by Toronto Hydro and an estimated $2.4 million will be reimbursed to customers in 2018 and 2019 for the purchase of these assets.

In addition to the purchase of 450 MCS from past customers, Toronto Hydro will need to install the radio communication link equipment required to facilitate the two way communication flow back to the Toronto Hydro Control Centre. An RFP process is currently underway to determine the contractor to perform the radio installations and work is expected to commence in early 2018 and be completed by 2020.

Toronto Hydro also forecasts and additional 169 renewable generation sites which will require MCS in 2018 and 2019. The installation of MCS is anticipated to cost $2.8 million and will occur as generation connection requests are received.

To better monitor and control the DGs connected to the grid, Toronto Hydro allocated $4.3 million in energy monitoring and control capabilities (DG SCADA Management), as mentioned in the 2015-2019 CIR. Due to the work delays mentioned above, the allocated budget was carried forward to 2018 and 2019 and increased to $6.6 million.

E5.5.4.2 2020-2024 Forecast

The Program is projected to cost $13.6 million over the 2020 to 2024 period which is consistent with the current forecast for the 2015-2019 period.

Table 8: Forecast Program Costs ($ Millions)

	Forecast				
	2020	**2021**	**2022**	**2023**	**2024**
Generation Protection, Monitoring, and Control	3.7	2.3	2.4	2.5	2.7

1. Bus-Tie Reactors

To mitigate short circuit capacity limitations at transformer stations and prevent the rejection of DG connections, the installation of bus-tie reactors will be required to allow additional DG capacity. The installation of a bus-tie reactors has been successfully done by PowerStream, Guelph Hydro and Hydro One Networks Inc. ("Hydro One"). Based on these installations, the cost associated with the procurement and installation of a bus-tie reactor is approximately $1 million.

Based on forecasted DG proliferation outlined in section 3, Toronto Hydro anticipates that five bus-tie reactors will be required over the 2020 to 2024 period to alleviate short circuit capacity constraints. The station buses where bus tie reactors are proposed are shown in Table 9 below. Toronto Hydro plans to begin the design and construction of the first reactor in 2020 and complete installations of one reactor per year beginning in 2021.

Table 9: Bus Tie Reactor Installations

Station Name	Bus
Ellesmere TS	J
Esplanade TS	A1A2
Fairbank TS	YZ
Horner TS	BY
Sheppard TS	BY

Bus-tie reactor installations will occur in the order at which the need for short circuit capacity mitigation arises. As mentioned above, scheduling of DG installations is dependent on customer planning and timelines. Customers have cancelled or delayed DG projects in the past. As a result, Toronto Hydro will not move forward with a bus-tie reactor installation at a station until a firm commitment, in the form of an Offer to Connect ("OTC"), has been executed by both parties.

2. Monitoring & Control ("MCS")

Pursuant to sections 3.3.2(g) and 3.3.3 of the DSC, Toronto Hydro is required to bear the costs related to communication systems (i.e. MCS) to accommodate the connection of renewable energy generation facilities. For all non-renewable energy generation facilities, the customer is responsible for costs relating to the MCS.

Based on current DG uptake and forecasted development, DG's greater than and equal to 50 kW contribute to over 90 percent of DG capacity in the City of Toronto. Based on this and the current cost of MCS, Toronto Hydro decided that only installations greater than 50 kW would require an MCS. This threshold will provide Toronto Hydro with enough visibility and management of DG to properly achieve the objectives of the Program at a reasonable cost.

The timing and pacing of the installation of MCSs is driven by customer requests to connect DG to the distribution system. The estimated costs of the installation of MCSs over the 2020 to 2024 period is based on forecasts described in section 3. As explained above, MCSs are required for renewable DG facilities greater than 50 kW. The equipment and installation costs associated with the integration of a DG site into Toronto Hydro's SCADA system is roughly $0.02 million and is based on historical DG MCS installations**.**

Toronto Hydro is dependent on the DG project and site owners to co-ordinate resources for the installation and commissioning of MCS equipment, which complicates work program scheduling. Due to the dependency on DG project/site owners, Toronto Hydro plans to complete the MCS work on an ad-hoc basis.

E5.5.4.3 Project Prioritization

The Program is driven by customer requests to connect DG to the distribution system and as such, are prioritized on a first come, first serve basis. DG customer timelines and deadlines are considered to minimize disruptions and allow for efficiencies, whenever possible.

E5.5.4.4 Cost Management

The selection of bus tie reactor projects are continuously evaluated to ensure that the investment is in the appropriate areas. For example, station bus short circuit levels are re-evaluated after each new connection application is received for that bus. Connection Impact Assessments ("CIA") are performed for each new DG and are the basis for determining if buses require short circuit relief.

Toronto Hydro is also regularly engaged with Hydro One and is made aware of future station transformer upgrades. As explained earlier, Wiltshire TS required short circuit relief when the last CIR was submitted, but in the time since, Hydro One upgraded the transformers, and the Generation Protection work was no longer required.

Through an RFP process, which included eleven vendors, a fixed cost for the MCS units has been negotiated with the successful vendor for the next five years. The installation of the MCS will be performed by an external contractor where performance and cost control incentives will be inserted in the contract.

For both segments, variance analyses will also be performed to identify areas for improvement and future cost management.

E5.5.5 Options Analysis

E5.5.5.1 Option 1: Status Quo (Do Nothing)

Under this option, Toronto Hydro will maintain the status quo and not install any bus tie reactors or MCSs. It allows Toronto Hydro to defer capital spending.

DG connections would continue to occur until the distribution system, in its current state, can no longer accept further generation due to short circuit, reverse power flow, and anti-islanding limitations. However, simply maintaining status quo would increase the number of DG application rejections and reduce reliability as Toronto Hydro would reach its operational and system design limits.

Additionally, the inability to have situational awareness and a more precise view into the operating conditions of all DG (through the installation of MCSs), would reduce the utility's capacity to connect additional DG facilities to the distribution system. Failure to connect all possible REG facilities to the Toronto Hydro distribution system would result in non-compliance with the requirements of Toronto

Hydro's distribution license, the DSC and the Electricity Act. As mentioned, as per Section 6.2.4 of the DSC, and sections 25.36 and 25.37 of the Electricity Act, Toronto Hydro is obligated to connect DG customers to its distribution system. Toronto Hydro is also obligated under section 6.1 of its Distribution License and section 26 of the Electricity Act to provide generators with non-discriminatory access to its distribution system and to provide priority access for renewable energy generation facilities. To comply with these obligations, Toronto Hydro evaluated two alternatives (major asset upgrades and the Generation Protection, Monitoring, and Control program) for addressing the system constraints that currently limit the utility's ability to connect the growing demand for DG on the system and safely and reliably manage DG connected to the distribution system.

Without active monitoring of DG facilities, there is an increased risk of unintentional islanding from DG sources thus reducing reliability on the system. This presents an increased risk to Toronto Hydro linespersons as they will be exposed to backfeed situations. Therefore, Toronto Hydro does not recommend this option.

E5.5.5.2 Option 2 (Selected Option): GPMC Program

The Program is the preferred alternative, as it is a much more timely and cost-effective solution and would allow for the continued integration, expanded visibility, and monitoring and control of DG connected to the Toronto Hydro distribution system.

In addition, Toronto Hydro expects that the Program's solutions will enable prediction of the amount of generation produced by DG connected to the distribution system, a capability that is not currently available to system planners. With performance data gathered through the Generation Protection, Monitoring, and Control program, Toronto Hydro will be able to make better informed decisions on the design and operation of the distribution system.

The overall cost of this option is $13.6 million over the 2020 to 2024 period.

E5.5.5.3 Option 3: Major Asset Upgrades

As an alternative to the work planned within the Program, Toronto Hydro could address DG requirements via major asset upgrades at transformer stations where short circuit capacity constraints exist. Assets to be upgraded include power transformers and switchgear. Monitoring and control equipment would also be installed as part of this option.

However, the entire process may take up to five years, which is outside the timeframe by which short circuit limitations would need to be resolved. The internal engineering design and approval process followed by discussions held with Hydro One to obtain the necessary approvals can take up to 2 years. Once the approval process is complete, the major assets associated with this program have 1-2 year material lead-times, and may take more than additional year to install. Additionally, Hydro One owns these major assets, and to replace them outside of their planning cycle would require Toronto Hydro to pay approximately $10-15 million for each station bus upgrade.

E5.5.6 Continuous Improvement and Productivity

With the implementation of MCS, Toronto Hydro will have access to real time data for all generation sites greater than 50 kW. The information obtained from the MCS and the Energy Monitoring and Control Capabilities can be integrated with distribution system analysis software to produce simulations and reports in a more timely, accurate and efficient manner. This would result in CIA's being completed within the prescribed time at a higher rate.

E5.5.7 Execution Risks & Mitigation

The Generation Protection segment may be exposed to the following risks: (i) limited technical labour resources to install systems, (ii) conflicting timing and an inability to coordinate with other capital projects and planned maintenance work of station assets; and (iii) difficulties in transferring existing customer loads to standby feeders. To mitigate these risks, Toronto Hydro plans to advance the planning between relevant Toronto Hydro departments to help address the issues and constraints related to labour availability and general capacity (i.e. load and communication network); and will plan this work during off-peak periods to mitigate potential impacts to standby feeders.

With respect to the Monitoring and Control segment, communication infrastructure (i.e. radio network) may need to be expanded or upgraded to handle high volume of DG connections. Therefore, Toronto Hydro will ensure adequate capacity exists for forecasted DG, and will proactively upgrade radio systems before capacity concerns arise.

E6 System Renewal Investments



E6.1 Area Conversions

E6.2 Underground System Renewal - Horseshoe

E6.3 Underground System Renewal - Downtown

E6.4 Network System Renewal

E6.5 Overhead System Renewal

E6.6 Stations Renewal

E6.7 Reactive and Corrective Capital

E6.1 Area Conversions

E6.1.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 185.7	**2020-2024 Cost ($M):** 220.8
Segments: Rear Lot Conversion, Box Construction Conversion	
Trigger Driver: Functional Obsolescence	
Outcomes: Reliability, Safety, Customer Service, Public Policy	

The Area Conversions program ("the Program") funds the replacement of functionally obsolete 4.16 kV distribution system designs with updated standard 13.8 kV and 27.6 kV lines; focusing mainly on two unique legacy 4.16 kV asset designs known as Rear Lot Construction and Box Construction. These assets serve residential customers in the Horseshoe region, and small commercial and residential customers along main streets in the downtown area of pre-amalgamation City of Toronto. The Program is designed to address below-average customer reliability outcomes, mitigate public and employee safety risks and other operational and customer service deficiencies posed by these legacy and aging assets.

The Program is grouped into the segments summarized below and is a continuation of the renewal activities described in Toronto Hydro's 2015-2019 Distribution System Plan.1

- **Rear Lot Conversion:** this segment continues the replacement of end-of-life overhead and underground assets installed in the backyard, or rear lot, with standard front lot underground supply. Typically installed over 40 years ago, these assets serving residential customers in the Horseshoe region of Toronto present significant safety and reliability risks in the event of failure. Toronto Hydro is on track to successfully upgrade approximately 2,400 rear lot customers to front lot 27.6 kV underground services during the 2015-2019 period. Toronto Hydro's overall objective for this segment is to mitigate and eventually eliminate rear lot equipment failure risk, as failures result in long duration outages and safety risks to customers and crews given the nature of the rear lot plant. To this end, Toronto Hydro plans to spend $109.3 million to convert an additional 2,350 customers over 2020-2024. This

[1] EB-2014-0116, Exhibit 2B, Section E6.6 and E6.7

pacing is needed to continue mitigating the reliability and safety risks associated with rear lot assets.

- **Box Construction Conversion:** a continuation of Toronto Hydro's plan to eliminate aging box construction feeders from the pre-amalgamation City of Toronto. These overhead feeders are located along main streets in the downtown area and serve residential neighbourhoods and small commercial customers. Toronto Hydro no longer builds the system to this standard due to safety compliance, reliability, access, equipment, capacity, and procurement issues. The congested, box-like framing of the circuits prevents crews from establishing safe limits of approach to live conductors, which in turn restricts operations and leads to longer power restoration times for customers when compared to modern overhead standards. During the 2015-2019 period, Toronto Hydro plans to convert approximately 5,300 poles to standard 13.8 kV overhead configurations. To eliminate all remaining box construction by 2026, Toronto Hydro plans to spend $107.3 million to convert approximately 2,600 more poles by 2024. This pacing is needed to continue mitigating the reliability and safety risks associated with box construction feeders.

Toronto Hydro plans to invest $220.8 million in the Area Conversions program in 2020-2024, which is an 18.9 percent increase over projected 2015-2019 spending in this Program (including forecasted inflation). This pace of investment is necessary to mitigate reliability and safety risks of these functionally obsolete system designs.

E6.1.2 Outcomes and Measures

Table 2: Outcomes & Measures Summary

Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by: ○ Eliminating the risk of long (i.e. 5 to 40+ hours) rear lot outages for approximately 2,350 residential customers in the worst performing rear lot areas. ○ Improving average outage restoration times for 22,700 residential and small business customers downtown by converting 2,600 aging and obsolete poles.

Safety	• Contributes to improving Toronto Hydro's Box Construction Conversion Measure, public safety performance and employee safety by mitigating safety risks that are unique to obsolete rear lot and box construction designs. Specifically: ○ Eliminate public safety risks to address compliance issues (i.e. relating to Electric Utility Safety Rule 129 - safe limits of approach, Canadian Standards Association and Electrical Safety Authority) associated with legacy box construction feeders by replacing approximately three quarters of remaining box construction assets by 2024, with a target of 100 percent elimination by 2026. ○ Maintain the pace of rear lot conversion in order to mitigate the risk of equipment failure and safety issues arising from potential crew and public exposure to rear lot access.
Customer Service	• Contributes to Toronto Hydro's customer service performance and customer satisfaction by: ○ Minimizing the need for unplanned crew access of customer property by converting approximately 2,350 residential rear lot customers to front lot service. ○ Improving the speed and cost-efficiency of customer grid access (including generation and electric vehicle access) in high-growth areas of downtown Toronto by converting approximately 2,600 poles (containing approximately 100 kilometres of low capacity and low clearance box construction feeders) to more efficient and flexible higher voltage standards. ○ Reducing public traffic disruptions on main city streets from an operational and maintenance perspective (i.e. less frequent repairs and visits) once the box construction is converted.
Environment	• Contributes to improving Toronto Hydro's Spills of oil Containing PCBs measure by eliminating all PCB at-risk transformers on the box construction and rear lot plant by the end of 2024.

E6.1.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Functional Obsolescence
Secondary Driver(s)	Reliability, Safety

This Program addresses distribution assets with legacy design features that result in substandard reliability performance for customers, safety risks for crews and the public, and other undesirable outcomes. For these reasons, Toronto Hydro considers the assets to be functionally obsolete. As these assets age and deteriorate, risk of failure increases and Toronto Hydro prioritizes them for replacement in order to maintain acceptable reliability outcomes and mitigate exposure to safety risks by utility crews and the public.

Rebuilding these feeders on a like-for-like basis is not a viable option due to the substandard performance, material availability and compatibility issues, and safety risks inherent to the existing designs. Furthermore, as discussed in Exhibit 2B Section D3.2.1, Toronto Hydro is gradually phasing out its 4.16 kV distribution system in favour of the more efficient 13.8 kV and 27.6 kV systems, which are also better suited to efficiently handle urban growth and development in the City of Toronto.

The following sections provide more detailed information about the drivers of work in each of the Rear Lot Conversion and Box Construction Conversion segments.

E6.1.3.1 Rear Lot Conversion

The Rear Lot Conversion segment is a continuation of Toronto Hydro's plan to convert and re-supply rear lot customers with underground front lot services. As illustrated in Figure 1 below, the replacement front lot design supplies customers through lateral underground 27.6 kV primary circuits along the roadways with predominantly padmounted transformers. Once customers are connected to the improved configuration, all remaining rear lot assets are removed to eliminate safety risks.



Figure 1: Legacy rear lot supply vs. replacement front lot supply.

Rear Lot Conversion is necessary to address reliability and safety risks that are caused or exacerbated by poor accessibility and physical encroachments inherent to the existing rear lot plant location.

1. Rear Lot Reliability Issues

Rear lot plant was generally built in the 1960s and a large portion of these assets have been operating for approximately 40 - 60 years. As the plant ages, the risk of outages caused by equipment failure increases. Notably, rear lot plant consistently experiences longer duration outages than the average Toronto Hydro feeder (as illustrated in Figure 2 below), primarily due to difficulty experienced by crews in locating faults and safely accessing and repairing equipment.

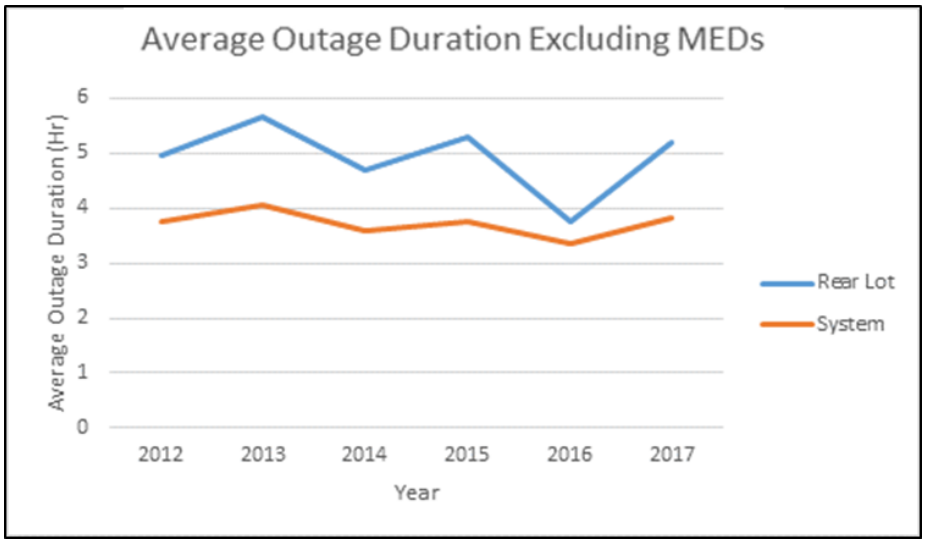


Figure 2: Average Outage Duration Excluding Major Event Days ("MEDs"): Rear Lot vs. All Feeders

On average, over the 2012-2017 period, outages on rear lot feeders were 1.3 hours longer than outages on the system as a whole.

The relatively poor performance of Toronto Hydro's rear lot distribution system is further demonstrated by the number of incidents resulting in loss of service to rear lot customers for at least one day. The location of the infrastructure (i.e. in backyards, often in close proximity to trees and vegetation), and its deteriorating condition make rear lot distribution particularly vulnerable during storms and other severe weather events. Table 4 below contains examples of outages that have occurred, many of which occurred during storm conditions such as on Major Event Days ("MEDs"). In all cases, accessibility challenges contributed to prolonged outage durations. Residential customers have on average demonstrated a tolerance for one to three short outages per year (particularly during non-critical times of use) before customer satisfaction level begins to drop. However, nearly all customers believe that an outage lasting more than five hours is unreasonable.[2] Many outages on rear lot feeders greatly exceed five hours, as shown in Table 4 below.

[2] See: Exhibit 2B Section E2.3

Table 4: Long Duration Events on Rear Lot Feeders

0.6	Station	Feeder	Cause	Duration (hrs)	MED (Y/N)
21-Dec-13	*HARTSDALE MS*	HDF1	Freezing Rain Extreme / Adverse Weather	90.6	Y
09-Feb-14	*HARTSDALE MS*	HDF2	Cable - Primary / Defective Equipment	47.9	N
20-Aug-09	*MILL MS*	LFF1	Wind Extreme / Adverse Weather	44.7	Y
19-Jul-13	*BLACKFRIAR MS*	VCF1	Wind Extreme / Adverse Weather	44.6	N
24-Nov-14	*MILL MS*	LFF2	Cable - Primary / Defective Equipment	43.8	Y
24-Dec-13	*ISLINGTON MS*	PAF3	Freezing Rain Extreme / Adverse Weather	42.8	Y
22-Dec-13	*HIGHBURY MS*	TAF4	Freezing Rain Extreme / Adverse Weather	40.1	Y
22-Dec-13	*HARTSDALE MS*	HDF3	Freezing Rain Extreme / Adverse Weather	37.8	Y
19-Jul-13	*LONGFIELD MS*	BHF1	Wind Extreme / Adverse Weather	34.5	N
22-Dec-13	*HARTSDALE MS*	HDF2	Freezing Rain Extreme / Adverse Weather	31.1	Y
15-Mar-10	*ALBION MS*	MGF1	Cable - Primary / Defective Equipment	28.0	N
05-May-17	*ALBION MS*	MGF1	Cable - Primary / Defective Equipment	26.3	N
01-Jun-12	*NEILSON DR MS*	BAF1	Wind Extreme / Adverse Weather	23.9	N
19-Jul-13	*HIGHBURY MS*	TAF4	Wind Extreme / Adverse Weather	23.5	N
09-May-17	*ALBION MS*	MGF1	Cable - Primary / Defective Equipment	23.1	N
09-Aug-09	*ISLINGTON MS*	PAF3	Lightning	23.1	N
26-Apr-15	*ALBION MS*	MGF1	Cable - Primary / Defective Equipment	22.7	N
23-Dec-13	*ROSETHORNE MS*	SBF3	Adverse Weather / Tree Contacts	21.5	Y

Rear lot reliability issues are caused by the obsolete design of the plant and the challenging environment in which it operates. As an example, Figure 3 below shows the Jamestown residential rear lot area which Toronto Hydro plans to convert. The primary lateral, shown in red, branches off of the main feeder circuit, enters the neighbourhood in between two houses, and is subsequently routed between the rear of residential properties. The secondary circuit, shown in green, branches off and crosses customer properties to the meter base supplying each residence.



Figure 3: Lateral Circuit Configuration - Jamestown Rear Lot Neighbourhood

Outage restoration issues stem from the following factors, which are common to rear lot areas like the one depicted in Figure 3:

- **Manual fault detection:** the vast majority of rear lot feeders operate at 4.16 kV and therefore lack fault detection and isolation technologies like SCADA-mate switches that are standard in up-to-date distribution systems.
- **Accessibility/Visibility:** in a typical rear lot area such as Jamestown, poor access and visibility exacerbate a fault situation, contributing to prolonged outages and inefficient use of resources during fault location and outage restoration. Limited access can restrict the use of

standard equipment such as bucket trucks, drilling machines and other machinery and implements. This means that heavy materials such as poles and transformers must be manually carried or even hoisted over the residence by crane. For overhead feeders, specialized reactive crews are needed to physically climb the poles during repairs. For underground feeders, crews must manually dig trenches to repair direct-buried cables.

- **Obstructions:** spatial constraints like trees and fences may prevent crews from walking on an uninterrupted path along the feeder to locate the fault, forcing them to enter multiple residential backyards along the circuit. Once the fault is located, crews often face the difficult task of repairing the fault and restoring service while being mindful of a customer's private property and compliance with electrical safety regulations. For instance, Figure 3 shows the presence of mature trees and swimming pools in the vicinity of Toronto Hydro plant.
- **Non-standard equipment:** the top left area of Figure 3 shows the location of obsolete T-splices (used to split underground distribution circuits). Any outage downstream of a T-splice will affect all customers on the main branch circuit. This is not the case in modern power system design where fuses prevent this undesirable outcome.

The Jamestown area demonstrates the extent to which reliability can be an issue for rear lots with 15 outages over 2012-2017, the majority of which lasted longer than five hours. Table 5 below shows the number and duration of outages in the Jamestown area from 2012 to 2017. This level of service would be considered unacceptable to most customers.

Table 5: Jamestown Community Outage Stats 2012-2017

Outage Duration in Hours	Number of Outages
1 – 5	3
6 – 10	1
11 – 15	2
16 – 20	4
21 – 25	4
26 – 30	1

During the 2020-2024 period, Toronto Hydro plans to convert and rebuild the Jamestown area and seven other areas. All of these areas have experienced at least three outages from 2012 to 2017. Like

most communities containing rear-lot distribution, 47 percent of the rear-lot poles in these areas have surpassed their useful life and 51 percent of the poles are showing moderate to material deterioration as determined by Toronto Hydro's Asset Condition Assessment methodology. Table 6 shows the breakdown of poles by asset condition category for all rear lot poles.

Table 6: ACA Comparison of Poles

Pole Asset Condition Class	% of Assets per Class (2017)
HI1 – Good Condition	20%
HI2 – Minor Deterioration	2%
HI3 – Moderate Deterioration	33%
HI4 – Material Deterioration	29%
HI5 – End of Life	4%
ACA Data Unavailable	12%

Converting an entire rear lot area is a complex and lengthy undertaking that must be carefully sequenced and executed over multiple years. Given the amount and age of the remaining plant, it is necessary for Toronto Hydro to continue with a steady pace of proactive Rear Lot Conversion, while prioritizing those areas that are experiencing the worst reliability performance. To this end, Toronto Hydro has ranked feeders according to their reliability performance. The following 'heat map' (Figure 4) shows all rear lot outages from 2012-2017 with dots representing a recorded outage in the rear lot system. Based on the Toronto Hydro's 2015 Utility Pulse Survey the dots/outages indicated in the red area are considered unacceptable by customers. The circles overlapping the dots in the chart indicate which feeders have been targeted for conversion for the 2020-2024 period. As is evident from the chart, the proposed rear lot plan will continue to address those areas where customers are experiencing the worst service.

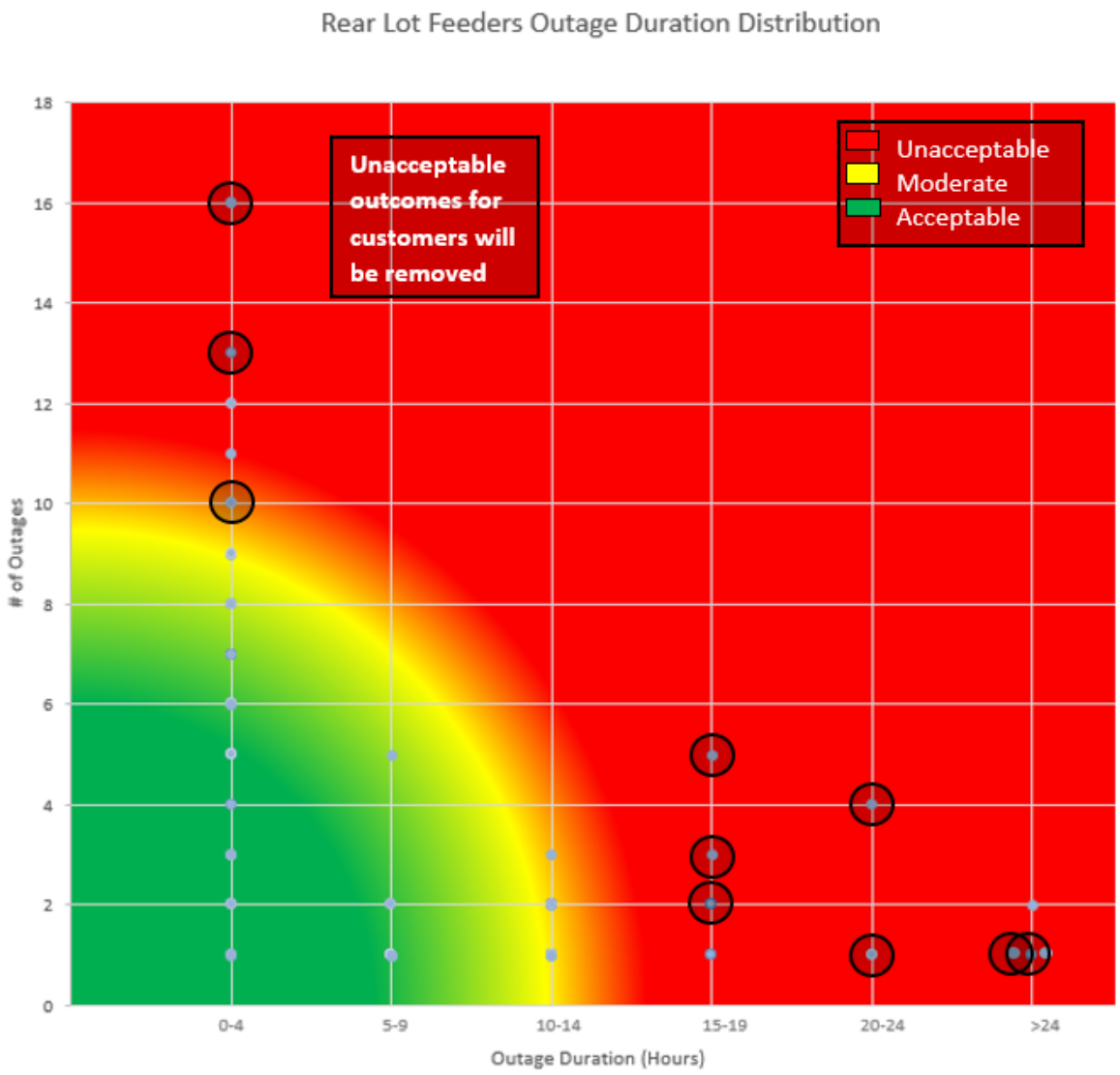


Figure 4: Heat Map of all 2012-2017 rear lot outages

2. Rear Lot Safety Issues

Equally important in the Rear Lot Conversion segment is the need to prudently manage safety risks to crews and the public. These risks are generally caused by the same operational factors and field conditions that contribute to long-duration outages on the rear lot system.

As mentioned above, as assets age and deteriorate, the risk of failure increases along with the likelihood that Toronto Hydro crews will need to access and repair rear lot equipment on a reactive basis. This exposes crew members to potential safety risks such as:

- tight work spaces;
- poor visibility at night;
- poor footing in the winter;
- the need to manually transport equipment to poorly accessible job sites;
- the need to climb poles that may be in poor condition due to rot, animal damage, or other environmental factors and may require additional stabilization; and
- obstacles (e.g. fences, sheds, and pools) and clearances between Toronto Hydro's distribution equipment and customer property that do not meet minimum requirements.

An incident demonstrating these safety risks occurred in 2014. Toronto Hydro dispatched a two-member crew following notification of a fallen tree at the rear of a house that had a steep slope covered with snow and ice. One crew member walked up the slope to locate the cable attachment and slipped and injured his right elbow and hip. The following pictures (Figure 5 and Figure 6) show similar examples of safety challenges faced by Toronto Hydro crews.



Figure 5: Field crews replacing failed transformer on pole in poor condition



Figure 6: Poor condition pole in close proximity to swimming pool

In addition to access issues, mature tree canopy cover (which sometimes requires immediate trimming on site) and poorly constructed landscapes can cause visibility issues in rear lots. Other than contributing to extended outage durations, reduced visibility is a safety concern for crews

executing electrical work. The need to manage crew safety risk is one of the primary reasons that Toronto Hydro needs to minimize the aggregate risk of rear lot asset failure.

Public safety is also a key consideration in respect of the Rear Lot Conversion segment. Rear lot assets installed in the 1960s do not adequately account for access needs related to modern growth of neighbourhoods, expansions of homes and live line clearances. Locations have been identified where live wires are in close proximity to customer homes, sheds, fences, and pools. Exposed wires have also been found at riser poles that have been deteriorating or moved over time due to direct contact. These locations do not comply with (e.g. clearances defined in) the Electrical Utilities Safety Rules ("EUSR") rule 129, and applicable standards of the Canadian Standards Association ("CSA"), Toronto Hydro, and the Electrical Safety Authority ("ESA") (i.e. ESA standard 75-708). Furthermore, when a pole deteriorates or leans, a transformer leaks oil or catches fire, or porcelain insulators break, the safety risk to the public increases when installations are in proximity to the those structures. Figure 7 and Figure 8 illustrate some of these clearance issues.

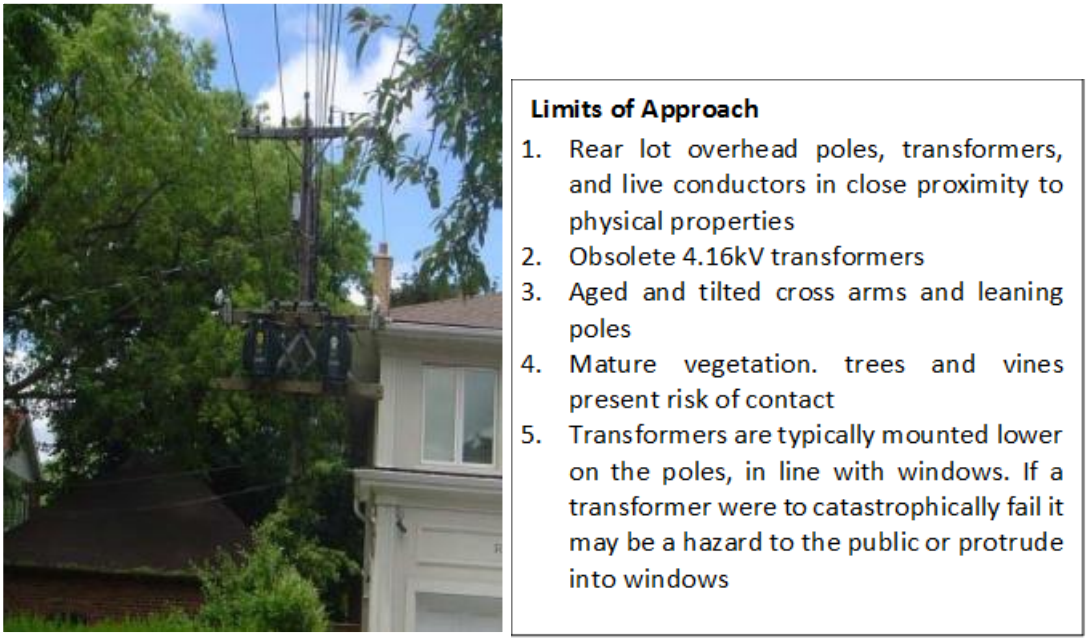


Figure 7: Energized transformer and pole line close to home and covered in vegetation

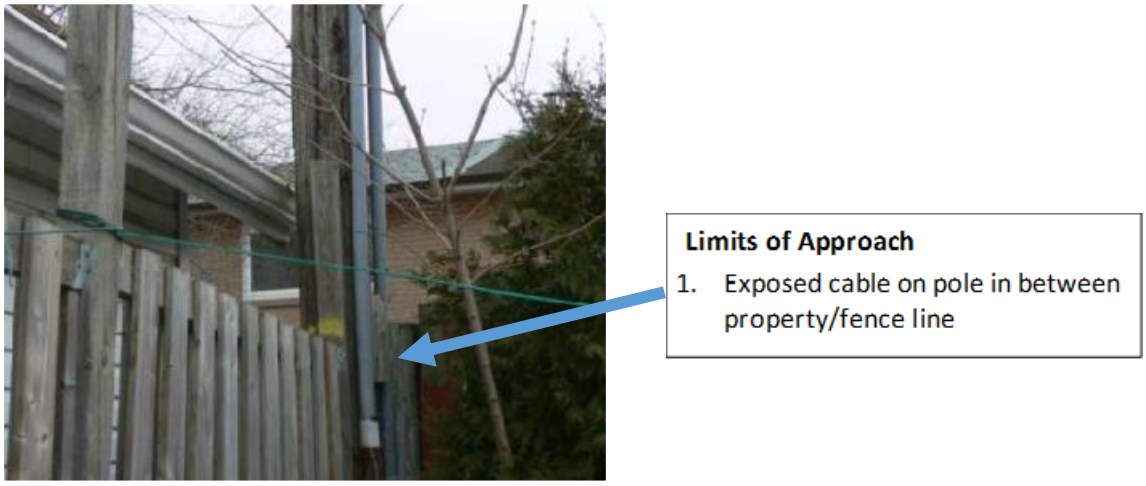


Figure 8: Fence built on easement and exposed cable from broken guard

3. Other Rear Lot Issues

Toronto Hydro is aware of 190 transformers at risk of containing PCBs in areas addressed by the Rear Lot program. This accounts for roughly half of the transformers in the rear lot area as of 2017. Rear Lot projects include the replacement of PCB at-risk transformers. Through the Area Conversion program, Toronto Hydro is proposing to eliminate approximately 100 PCB at-risk transformers by 2024 as part of the planned projects in the rear-lot system. The remaining PCB at-risk transformers will be addressed as part of other programs. This plan supports Toronto Hydro's continuous reduction of PCB-contaminated oil leaks.

E6.1.3.2 Box Construction Conversion

The Box Construction Conversion segment is a continuation of Toronto Hydro's plan to convert functionally obsolete box construction feeders to the standard 13.8 kV armless overhead construction. Box construction is a legacy 4.16 kV overhead design. Due to a number of safety, reliability, access, equipment, capacity, and procurement issues, Toronto Hydro no longer builds the system to this standard. As discussed in detail below, safety compliance issues also drive the need to eliminate box construction from the system. Figure 9 shows the before and after of a completed Box Construction Conversion project from 2013.

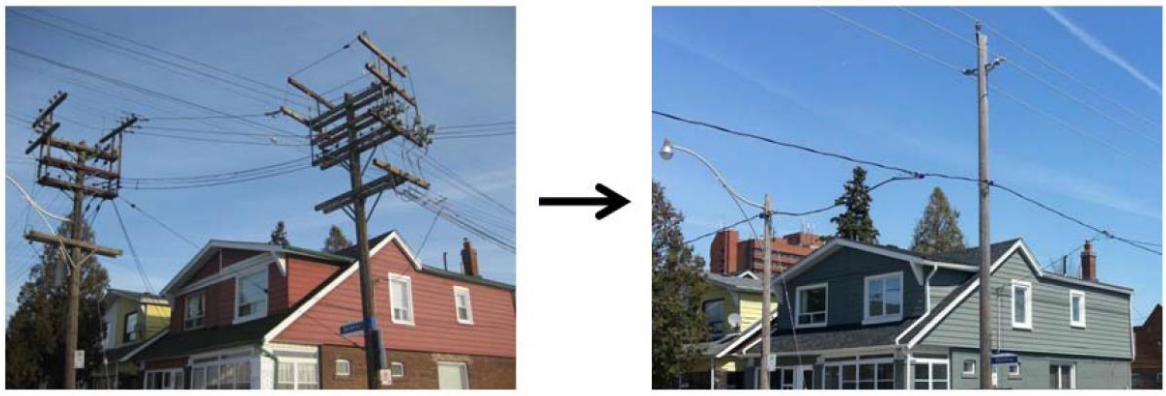


Figure 9: Actual conversion project in the Byron Avenue and Danforth Avenue area. The photograph on the left shows the 4.16 kV box construction feeder prior to conversion. The completed project is shown in the photograph on the right, where all 4 kV box construction has been removed and replaced with a 13.8 kV overhead feeder.

4. Box Construction Safety Issues

The industry-wide practice for overhead pole maintenance is to access circuits using bucket trucks. However, the congested nature of the obsolete box construction design means that most box construction circuits cannot be accessed safely in this manner. Instead, workers must climb these poles, which increases the safety risks they face. Such risks include potential injury from the additional physical exertion from climbing, an elevated falling hazard when compared to the use of a bucket truck, and an increased risk of electrical contact due to the inability to use the insulated aerial boom and bucket liner found on bucket trucks.

Furthermore, Toronto Hydro crews working in close proximity to box construction lines can have difficulty conforming to the working clearances defined in EUSR Rule 129.[3] The required 15 centimeter air gap between people (or tools) and energized conductors cannot always be achieved. Compliance with these safety rules requires adjustments to normal work operations, such as maneuvering around poles in a bucket truck and closing off road access to multiple poles. This in turn contributes to the lengthy outage restoration times discussed below.

[3] Electric Utility Safety Rule 129 - safe limits of approach, Canadian Standards Association and Electrical Safety Authority, Page 34 https://www.ihsa.ca/PDFs/Products/Id/RB-ELEC.pdf

Another crew safety risk is caused by certain obsolete equipment used on box construction feeders. One example is the Positect switch, a non-standard fused switch that is operated by hand, putting field crews in the flash zone of the switch (i.e. an "arc flash" electrical hazard). Positect switches are being removed as part of Box Construction Conversion.

Similar to rear lot lines, some box construction lines fail to comply with contemporary clearance rules resulting in potential safety risks to the public. Live wires have been found in close proximity to customer homes, windows and balconies. Some buildings are within two to three metres of live lines due to the legacy design parameters of box construction. These limits of approach are not consistent with clearance requirements, namely those set out in EUSR rule 129 as well as standards adopted by the CSA, Toronto Hydro, and the ESA (standard 75-708: *Clearances of conductors from buildings*). As such, this issue must be addressed by replacing box construction with updated standard 13.8 kV construction as part of plant renewal. As a visual example, Figure 10 below illustrates a box construction clearance issue.



Limits of Approach

Box Construction poles house conductors with wide cross-arms which cause conductors to be spaced further away from poles and closer to buildings and windows compared to armless construction standards. This photo shows a few of the many issues associated with the obsolete design of box construction:

1. Close proximity of live lines to public and public structures due to box physical properties
2. Aged and tilted cross arms and leaning poles
3. Transformers are typically mounted lower on the Box poles, in line with windows. If a transformer were to catastrophically fail it may cause the windows to break and endanger the public.

Figure 10: Example of Box Construction clearance issues

5. Box Construction Reliability Issues

The existing box construction plant is on average over 50 years old and has exhibited a decline in reliability performance relative to the system as a whole, as shown in Figure 11 and Figure 12 below.

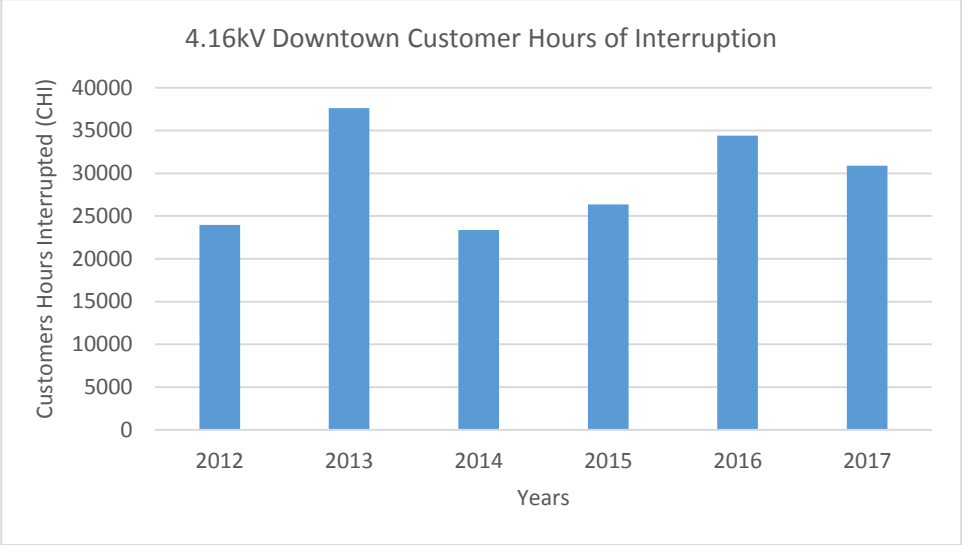


Figure 11: Historical Reliability for Feeders Proposed for Conversion

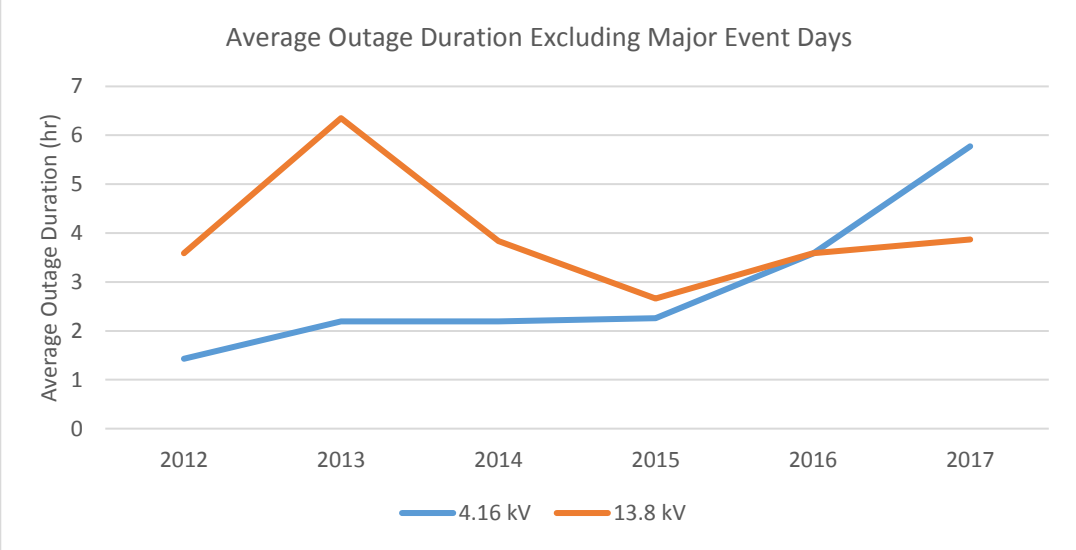


Figure 12: Average Outage Duration for 4.16 kV and 13.8 kV Systems

Between 2012 and 2017, there were 81 outages (excluding MEDs) directly associated with box construction. The top causes of these outages include defective primary overhead and underground equipment failure, adverse weather, tree contacts, and extreme rain and wind. Box construction assets are generally past their useful life and are less capable of withstanding strong winds and contact from trees during storms compared to new 13.8 kV overhead feeders in the downtown area.

Like rear lot plant, box construction feeders tend to require longer restoration times than feeders built to up-to-date standards. The reasons for this are similar to those that drive long duration outages in the rear lot, including: the need for manual fault location; clearance, access and safety issues that slow down operations; and during reactive equipment replacement, the need to integrate newer standard equipment in a unique configuration that is compatible with the existing box construction design.

Toronto Hydro expects reliability to worsen further as assets continue to deteriorate. As shown in Table 7, currently approximately half (or more) of poles, transformers, and switches associated with box construction are past their useful life. Based on inspection and maintenance reports, these assets exhibit moderate to material deterioration.

Table 7: Percentage of Box Construction Assets past Useful Life

Asset	Percentage (%)
Transformers	39%
Switches	60%
Poles	49%

Where box construction assets have already failed, the inability to source obsolete replacement equipment has often forced crews to repair the system using temporary and non-standard solutions. As time passes, workforce retirements will continue to diminish the pool of employees who are experienced in repairing box construction feeders, which further underscores the need to eliminate box construction on a firm timeline.

6. Other Box Construction Issues: Efficiency, Capacity, and PCBs

Box construction feeders are part of the 4.16 kV system. As noted in Exhibit 2B Section D3.2.1, Toronto Hydro is gradually phasing out 4.16 kV in favour of 13.8 kV and 27.6 kV standards. Lower

voltage 4.16 kV feeders are less energy efficient[4], have significantly lower capacity, and are less flexible in accommodating new load than the 13.8 kV feeders that replace box construction. In addition to the environmental and cost benefits of reducing line losses, upgrading 4.16 kV to 13.8 kV feeders will allow Toronto Hydro to more efficiently accommodate new large customers, renewable generation connections, and electric vehicle charging stations in high-growth areas of downtown Toronto. Without these upgrades, Toronto Hydro may need to connect larger loads using alternative means, such as running a new feeder or extending an existing feeder. This requires additional time and resources and may increase the connection costs for customers and developers.

Finally, there are currently 400 PCB at-risk transformers on box construction feeders. This accounts for a third of the transformers on box construction feeders as of 2017. The Box Construction Conversion segment will eliminate an estimated 325 PCB at-risk transformers by 2024 through the planned projects, supporting continuous reductions in PCB-contaminated oil leaks. While PCB at-risk transformers are not the primary driver for Box Construction Conversion, they are an additional consideration reinforcing Toronto Hydro's plan.

E6.1.4 Expenditure Plan

Table 8 below summarizes the historical, bridge and forecast spending for this Program. After examining program need and establishing pacing strategies for each segment, Toronto Hydro developed the expenditure plan details by identifying and prioritizing project boundaries in each segment for the 2020-2024 period and applying volume and cost assumptions based on historical accomplishments. The cost estimates use the historical average cost per customer (Rear Lot) and cost per pole converted (Box Construction) to extrapolate long-term program costs based on high-level project attributes. The forecast Rear Lot Conversion and Box Construction Conversion spending is relatively steady over 2020-2024,with the later decreasing slightly compared to 2015-2019 levels due to the pace of work slowing as the utility gets closer to eliminating all box construction by 2026.

[4] By converting 4.16 kV feeders to 13.8 kV, distribution line losses may be reduced.

Table 8: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Rear-Lot Conversion	26.7	14.5	8.2	5.7	10.0	18.8	26.3	25.2	28.3	14.9
Box Construction Conversion	19.6	13.6	18.7	34.3	34.4	22.7	20.8	21.1	22.0	20.7
Total	**46.3**	**28.1**	**26.9**	**40.0**	**44.4**	**41.4**	**47.2**	**46.3**	**50.4**	**35.6**

E6.1.4.1 Rear Lot Conversion Expenditure Plan

Toronto Hydro invested $49.4 million in rear lot conversion projects between 2015 and 2017, resulting in the conversion of 2,090 customers from aging rear lot service to safer and more reliable front lot underground service. The utility plans to invest $65.1 million by the end of 2019 to convert approximately 2,400 customers over the 2015-2019 period. Spending was approximately $16 million higher than forecast for 2015 and 2016 due to a higher than expected number of projects carried over into the 2015-2019 period and due to project costs variances that occurred as projects progressed from high level estimates to detailed designs (e.g. changes in the design configuration required by the actual conditions at the project site or project scope[5]).

Toronto Hydro plans to invest $113.5 million over the 2020-2024 period to convert approximately an additional 2,350 rear lot customers in the worst performing areas to mitigate the various risks that have been discussed above (including the risk of prolonged outages, ranging from 5 to more than 40 hours). This rate of spending reflects the need to keep up with the pace of rear lot aging and the substantial amount of rear lot plant remaining. Over the long-term, by limiting and reducing the volume of end-of-life rear lot assets, Toronto Hydro aims to prudently manage the safety and reliability risks associated with their failure. Figure 13 shows the estimated rate of conversion from 2015 to 2025.

[5] Project scope changes occurred as designers conducted site visits, identifying that additional or fewer assets and labour were required to execute the job based on asset condition and configuration.

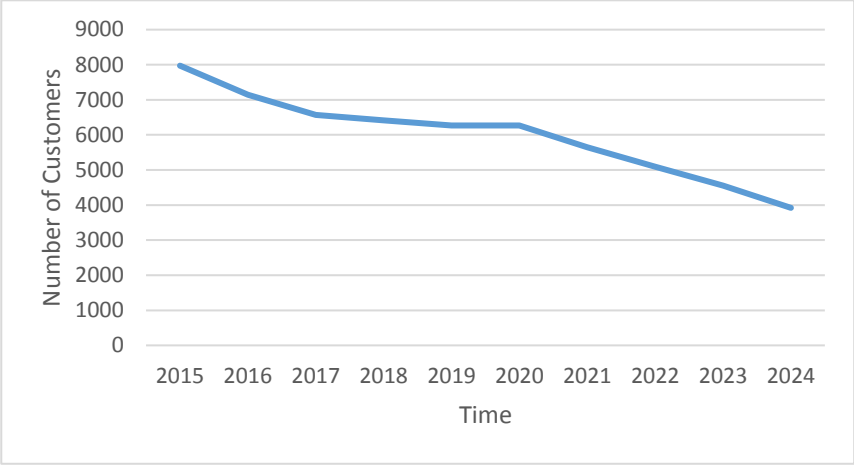


Figure 13: Rate of Conversion of Rear Lot Customers (2015-2024)

Rear Lot Conversion is not a like-for-like replacement activity. Projects are therefore difficult to estimate on an installed asset basis without first completing a preliminary design of the new front lot underground feeder, which does not take place until closer to project execution. As such, Toronto Hydro has used a historical average cost per customer to parametrically estimate 2020-2024 costs for the prioritized project areas. To develop the cost per customer, Toronto Hydro examined three major rear lot areas, consisting of eight projects completed in recent years.

Toronto Hydro applied an average cost of $0.036 million per customer plus inflation and engineering and support costs in developing the segment cost forecasts for the 2020-2024 period. Note that costs for 2018-2019 are based on estimates for the projects proposed over that period and not the aforementioned average cost per customer. The amount required per annum will vary year-over-year based on the timing of each project over multiple calendar years. Toronto Hydro designs and plans projects using a phased approach based on feeder configuration and customer count (e.g. Project Thorncrest with 600 customers involved three phases with 200 customers each) and ensures that civil construction is completed in one year and then followed in the next year by electrical construction. Civil work costs approximately twice as much as electrical and therefore annual costs (total and per customer conversion completed) will vary depending on the balance of civil and electrical work completed each year.

The average duration of a full 200-customer phase rear lot conversion construction project is approximately 13 months. By completing projects in a staggered fashion instead of addressing all the customers at one time, Toronto Hydro can improve reliability by reducing the time until the first

customers will start benefitting from the conversion. For example, if Project Thorncrest were to be done as single phase project it would take about 39 months for all 600 customers to be fully converted and during that time all those customers would continue to experience a higher risk of outages on the legacy equipment. However, when done in phases, the first 200 customers would be converted after only 13 months and the next 200 customers after 26 months. This way only a third of the customers would be at higher risk of outages throughout the full project period. Minimizing the risk of outages minimizes the risk of added costs and long duration outages as our crews can spend less time restoring power on legacy equipment.

Rear Lot Conversion projects are prioritized based on asset reliability, equipment condition, and coordination with planned city road work. Generally, the worst performing feeders are targeted for completion first. To reduce costs, Toronto Hydro also strategically aligns and coordinates rear-lot projects with other conversion projects that share the same feeder. Figure 14 shows the rear lot areas that Toronto Hydro prioritized for conversion during 2020-2024 and Table 10 provides additional details on the project areas. Rear lot areas include transformers at risk of containing PCBs and Toronto Hydro intends to eliminate all of them through the 2020-2024 projects in this segment or through the Overhead and Underground System Renewal programs by 2025.

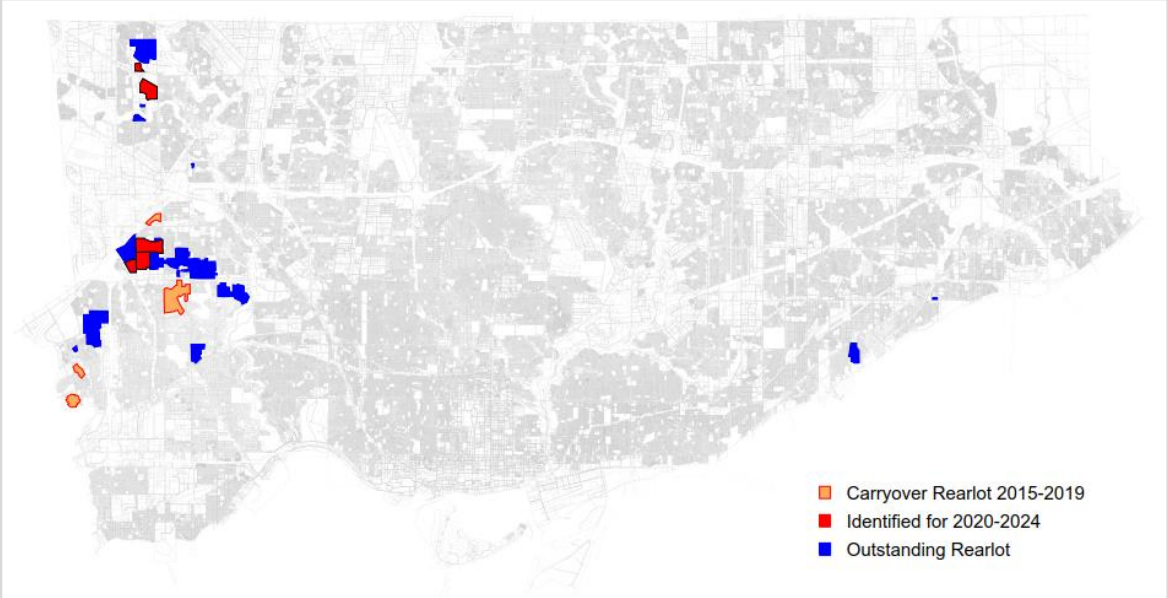


Figure 14: Outstanding Rear Lot Areas to be completed during 2020-2024 and beyond

Table 10: Planned Rear Lot Projects for 2020-2024

Rear Lot Area	Number of Customers	Expected Date of Completion	Number of Outages (2012-2017)	Number of Outages Greater than 5 Hours (2012-2017)
Thorncrest	618	Civil 2020 Electrical 2021	11	2
Jamestown	258	Civil 2021 Electrical 2022	15	12
Markland Woods	300	Civil 2021 Electrical 2022	3	0
Martin Grove Gardens	452	Civil 2022 Electrical 2023	8	4
Mount Olive	83	Civil 2022 Electrical 2023	4	4
Kingsview	173	Civil 2023 Electrical 2024	3	1
Richview Park	263	Civil 2023 Electrical 2024	6	0
Willowridge	201	Civil 2023 Electrical 2024	6	3

It should be noted that the Jamestown project, originally scheduled for 2021-2022 construction, may be advanced to an earlier year due to increasingly deteriorating assets that have led to continued lengthy outages.

E6.1.4.2 Box Construction Conversion Expenditure Plan

Toronto Hydro invested $51.9 million in Box Construction Conversion projects between 2015 and 2017, resulting in the conversion of 2,422 poles framed for safer, more reliable, and more operationally flexible 13.8 kV feeders. The utility plans to invest $68.7 million in 2018-2019 to convert another 2,900 poles. This will leave an estimated total of 3,800 to be addressed between 2020 and the 2026 target date for completion. For the 2015-2019 period, Toronto Hydro expects to spend about 17 percent ($18 million) more than the $102.9 million initially forecast for the period. The higher costs are due to the differences between high level estimates used for the forecasts and the detailed estimates and actual costs following detailed design and construction.

Toronto Hydro plans to invest $107.3 million over the 2020-2024 period to convert approximately 2,600 of the 3,800 remaining poles. The utility expects this work to improve the average outage restoration time for 22,700 downtown residential and small business customers. Other anticipated benefits of this work include reduced safety risks related to EUSR, CSA and ESA compliance issues, improved speed, and cost-efficiency of customer grid access in high-growth areas of downtown Toronto, and reduced traffic disruptions due to less frequent repairs and maintenance. This proposed spending represents a reduction of about 11 percent versus the 2015-2019 pace of investment, but will still allow Toronto Hydro to meet its objective of eliminating box construction by 2026. Figure 15 below shows the forecasted rate of Box Construction Conversion out to 2026.

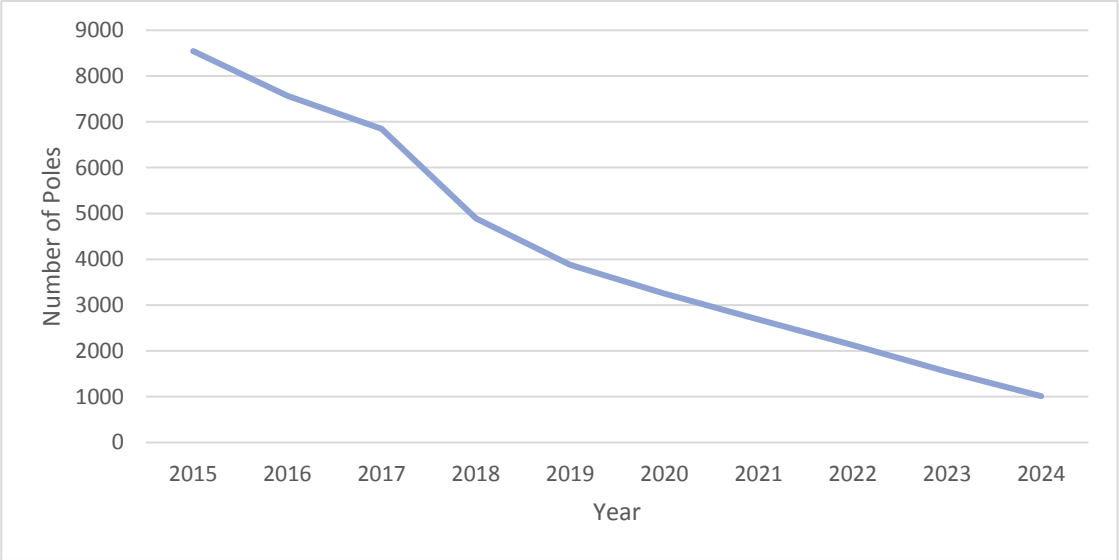


Figure 15: Rate of Conversion of Poles in the Box Construction Program (2015-2024)

Figure 16 shows the approximate location of the box construction conversion areas that Toronto Hydro has prioritized for the 2020-2024 planning horizon.

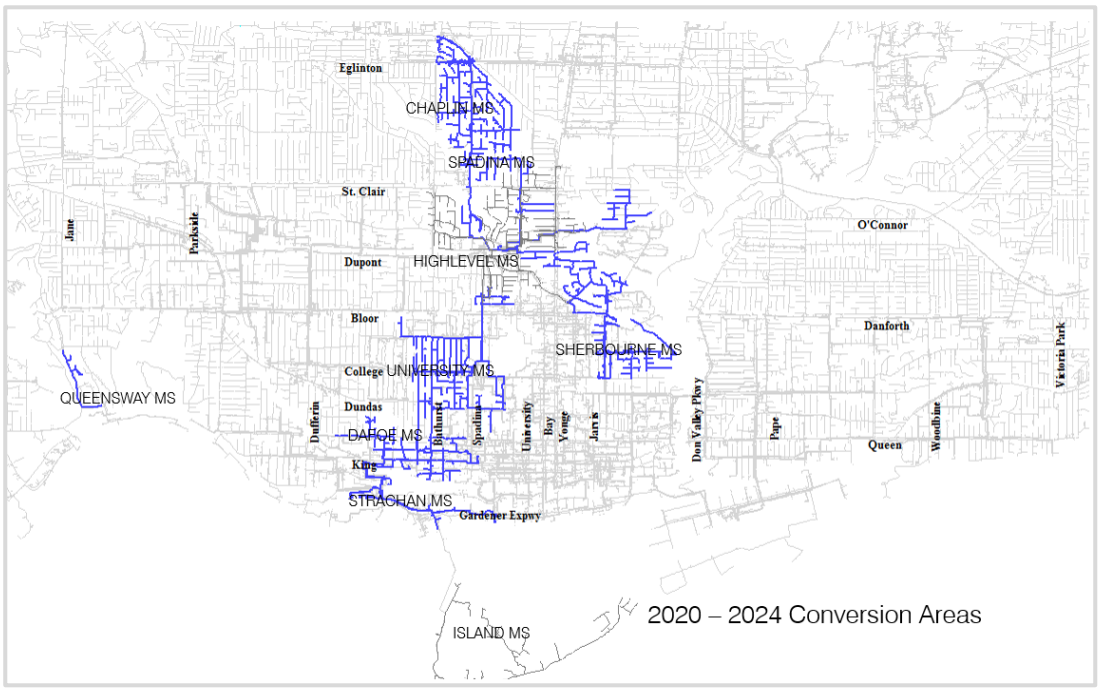


Figure 16: Map of proposed conversion for 2020-2024 (Estimated locations)

To reduce the variance between forecast and actual costs, Toronto Hydro examined a number of completed box construction feeder conversions between 2015 and 2017 to develop an average cost per conversion of a box construction pole. This analysis concluded that costs per pole will vary considerably from one project to the next.

This is driven by specific area characteristics. For example, one street may solely have overhead supply directly feeding customers on a quiet side street without trees or underground risers. Other box construction assets may be on a main downtown artery, such as Queen Street, with both primary and secondary distribution and risers going from overhead to underground and vice versa. Some areas may have heavy vegetation, road moratoriums, road access or timing work restrictions, or third-party attachments such as TTC street cars that require coordination. Further to this, for some projects, based on their location and box construction framing density, crews need to use different techniques to remove the legacy equipment safely.

Toronto Hydro used the average cost of $0.029 million per pole plus inflation and engineering and support costs to derive the forecast costs for 2020-2024. By using historical actuals to estimate costs, Toronto Hydro expects variances to be reduced in the 2020-2024 period.

When planning box construction conversion projects, Toronto Hydro considers reliability, third party scheduling conflicts and the planned decommissioning of municipal stations. For the eight stations remaining that carry box construction lines, Toronto Hydro will coordinate the elimination of box construction with the station and external dependencies listed in Table 12. To improve productivity and safety, crews will cut the top half of the box pole and take it to the yard and disassemble it on the floor with multiple crews instead of disassembling the box construction manually on the roads and sidewalks in a bucket truck.

Table 12: Remaining stations carrying box construction lines

Station	Conversion	Station-related or External Dependencies	Projected Costs ($ Millions)
Sherbourne MS	*2020 -2021*	Station Decommissioning	25.8
Queensway MS	*2020 -2021*	Station Decommissioning	
Dafoe MS	*2020-2022*	Station Decommissioning	17.8
University MS	*2022 -2023*	Station Decommissioning	20.1
Spadina MS	*2022-2023*	Metrolinx Conflict	
Strachan MS	*2023 - 2024*	Hydro One Dependency	18.7
Chaplin MS	*2024 -2025*	Metrolinx Conflict	24.9
High Level MS	*2025-2026*	Hydro One Dependency	40.5

Once the 2020-2024 plan is executed, there should be only one to two stations (i.e. High Level and Chaplain) remaining with Box construction feeders. Projected Costs above include inflation or EAR. Note: 2025-2026 High Level MS is not planned for this rate filing and should be exempted from the total spend.

E6.1.5 Options Analysis

E6.1.5.1 Options for Rear-Lot Conversion

1. Option 1: Reactive replacement approach

This option proposes to maintain the rear lot distribution system and repair it reactively. This option will address equipment issues as feeders fail and involves regular maintenance work to mitigate any critical risks. However, reactive replacement tends to cost more than planned replacement, will not achieve efficiencies and operational expenditure reductions related to moving to 27.6 kV voltage,

and will result in deteriorated equipment remaining in residential backyards. This option does not address the safety, reliability, and access issues that are inherent to the system and is therefore not prudent.

2. Option 2: Rebuild rear lot distribution to ensure it meets current safety regulations

This option proposes to rebuild rear lot distribution to replace the aging and non-standard equipment that is currently in use. Measures should be taken to ensure that identified safety issues are addressed. This would involve installing new poles, transformers, and conductors to meet overhead requirements. For underground equipment, trenching each owner's yard for ducts and then re-sodding the yards would be required. As well, extensive tree trimming, and in some cases tree clearing, may be required in heavy vegetation areas.

This option could reduce the number of outages experienced; however, it does not address access issues and may involve potentially unsafe work environments for Toronto Hydro crew members. Furthermore, fault location and repair will remain a lengthy and difficult procedure and customers will continue to experience long outages when they occur. In addition, the minimum clearance will not be possible to achieve in certain areas of the system. In summary, while a renewal program in the rear lot will improve the equipment, it will not address the operational, safety and reliability issues that are associated with the rear lot. Many of the current issues would reoccur years later, making the benefits arising from this option temporary. Moreover, given the difficulty associated with winter construction, most of the construction would have to take place in the summer and disrupt customers' enjoyment of their backyards.

3. Option 3: Replace rear lot distribution with overhead front lot distribution

This option involves replacing the rear lot distribution system with an overhead front lot distribution system. All 4.16 kV equipment would be removed from the rear lot and customers will be supplied from a 27.6 kV feeder from the overhead front lot. Service conductors will have to be inserted in between property lines to access the meter base located at the back of the houses.

This option is not favourable to customers as it harms the aesthetic value of the front lots in their neighbourhoods. Also, in many areas, large and mature trees would need to be cut down to accommodate a pole line running along the street. This will be opposed by the City's Urban Forestry Department, which has a mandate to grow the tree canopy in Toronto. Furthermore, because communication lines are typically supplied through the rear, there will be an abundance of overhead

lines in the neighbourhoods. Customers and local stakeholders have previously expressed concern about the effect this would have on their neighbourhood and their property values. Likely complaints arising in this regard could trigger project postponement or redesign, ultimately increasing the cost and duration of the projects.

4. Option 4 (Selected Option): Replace rear lot distribution with underground front lot distribution at proposed pace

Under this option, the rear lot distribution would be removed and the customers would be supplied by a 27.6 kV front lot underground service. Service cables would be supplied underground between the customers' properties and connect to the meter base located at the back of the house. This would maintain the aesthetics of the customer's front lot and neighbourhood.

Underground front lot distribution is preferred because it mitigates accessibility and safety issues and addresses aging and non-standard equipment that could reduce reliability and exacerbate other issues. Furthermore, it improves reliability by moving the equipment underground in heavily treed areas. This will reduce faults associated with tree and animal contacts and weather-related outages.

Option 4 is the chosen alternative; as it aligns with current standard design practices and increases the safety and reliability of the system. It also reduces the time and effort required to respond to power outages in the area and maintains neighbourhood aesthetics, thereby maximizing customer value derived from the necessary conversion projects. This option provides short- and long-term benefits to customers and Toronto Hydro.

5. Option 5: Replace rear lot distribution with underground front lot distribution at accelerated pace

At an accelerated pace, Toronto Hydro could eliminate all rear lot plant by the end of 2024. This option would provide the same benefits as Option 4 but for all rear lot areas. Reliability would improve faster and Toronto Hydro crews and the public would be exposed to the safety risks associated with rear lot supply over a shorter period and less spending would be required to replace failed rear lot assets on a reactive basis. However, the aggressive pacing would likely stretch resource requirements and pose scheduling challenges as civil work is usually limited to non-winter months. In addition, Toronto Hydro estimated that the required annual funding would be more than twice that for the recommended plan.

E6.1.5.2 Options for Box Construction Conversion

1. Option 1: Reactive replacement approach

In the status quo scenario, Toronto Hydro would continue to maintain and repair box construction assets and replace failed assets as needed. Due to the high number of box construction assets past their useful lives, Toronto Hydro anticipates that maintaining the status quo would result in additional maintenance costs and deteriorating reliability which are otherwise avoidable. The safety risks and operational issues would remain or worsen.

Option 1 would likely also have the disadvantage of forcing Toronto Hydro to continue investing in and maintaining stations assets at the 4 kV municipal stations that supply existing box construction feeders. Many of these stations are lightly loaded and avoided costs could be realized by decommissioning the stations following load conversion as part of the Box Construction segment.

2. Option 2 (Selected Option): Convert from Box Construction to new armless overhead infrastructure at proposed pace

Converting and renewing the box construction to a standardized system for which replacement components are more readily available would improve safety for the public and Toronto Hydro crews (i.e. by enabling the minimum required clearances). It would also provide capacity to accommodate future load requests, address the risk failure of assets, and reduce outage durations. At the proposed pace Toronto Hydro would be on track to meet its goal of eliminating all box construction by the end of 2026.

Option 2 is the chosen alternative as it provides the most cost effective option to increase the safety and reliability of the system. At the same time, it reduces the time and effort required to respond to power outages in the downtown area, thereby maximizing customer value derived from the necessary conversion projects. This option provides short and long term benefits to the customer and Toronto Hydro.

3. Option 3: Convert from Box Construction to new armless overhead infrastructure at accelerated pace

At an accelerated pace Toronto Hydro could eliminate all box construction by the end of 2023. This option would provide the same benefits as Option 2 but those benefits would be realized earlier in some areas. However, the expedited pace may not be possible due to resource limitations and

station and external dependencies (i.e. Table 12 in Expenditure Plan section) restricting when projects can be executed. In addition, Toronto Hydro estimated that the accelerated rate would cost approximately 50 percent more than the Option 2 plan.

E6.1.6 Execution Risks & Mitigation

E6.1.6.1 Rear-Lot Conversion

Timely third-party project coordination: One program risk is the potential for a minimum five-year moratorium on new road work in areas where Toronto Hydro intends to do rear lot conversion work. Toronto Hydro will mitigate this risk by working closely with the City of Toronto on planned road work (i.e. through utility coordination council meetings). In the event that planned City of Toronto work puts program completion at risk, Toronto Hydro will negotiate with the city to coordinate a construction schedule that is acceptable to all parties and stakeholders involved.

Customer Engagement: Customer care is a significant aspect of risk mitigation during the planning and execution phases of rear lot conversion, which by nature are relatively intrusive and involve construction on multiple sides of each customer property. To determine asset locations that best align to customer preferences, Toronto Hydro maintains extensive and proactive customer communication and provides an opportunity for customers to voice their concerns and to work with the designer and constructor. In most cases, community meetings are held to proactively introduce residents to the project plans and educate them on construction implementation. City Ward councillors are informed of the project and often are invited to community meetings and pre-construction meetings to assist with constituent inquiries. Written letters are sent in advance to customers' homes to inform them of the project, new equipment installations and line of sight to new equipment as per applicable municipal notice requirements.

Conversion coordination: The remaining rear lot configurations feature multiple feeders that provide service across the same easement, making conversion activities relatively complex. These feeders depend on one another for load transfers, especially during contingency scenarios (i.e. during outages on any of the feeders). Feeders tie with one another and can be used to resupply each other if a feeder's primary source of power from a substation is disrupted due to a fault or work being done. Therefore, it is important that alternative sources of power remain available during conversion in the event of an emergency. These interconnections require careful staging of conversion jobs over several years.

E6.1.6.2 Box Construction Conversion

Timely third-party project completion*:*

- **Hydro One:** Toronto Hydro works with Hydro One to schedule preparation and upgrade of stations for conversion. If such preparatory work is not completed on time, it may delay full conversion of the respective feeders. Mitigation through close coordination and communication is key for project execution.
- **Customer Coordination:** For most commercial customers serviced on the 4.16 kV system, there is underground equipment, risers and terminations that are on the pole and supply the customer underground. Transferring a riser and termination requires an outage to the customer to conduct the work safely. Coordinating power interruptions and access with the customer may delay the project and Toronto Hydro seeks to mitigate this risk through proactive and early customer engagement.
- **Construction Coordination:** Many of the remaining box construction assets are within high pedestrian and vehicle traffic areas which also include TTC bus or streetcar routes (see example shown in Figure 17). In this regard, mitigation involves proactive coordination and engagement with the City to create a traffic plan, especially at major intersections. Most pole installations require a single lane to be occupied by trucks and equipment and as such, inadequate coordination would jeopardize project completion in a timely manner.



Figure 17: Area with High Pedestrian and Vehicle Traffic, including TTC Routes.

Third-Party assets attached on Toronto Hydro's assets: Third-party assets attached to utility poles, such as Rogers, Bell, and City assets, can interfere with full conversion and pole removal. Toronto Hydro will engage owners of these assets as soon as possible to coordinate and plan their transfer. Identifying locations that require civil work will enable it to be done prior to pole line installation, so that the start of project work is not delayed.

E6.2 Underground System Renewal – Horseshoe

E6.2.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 420.7	**2020-2024 Cost ($M):** 460.3
Segments: Underground System Renewal Horseshoe	
Trigger Driver: Failure Risk	
Outcomes: Customer Service, Reliability, Environment	

The Underground System Renewal – Horseshoe program ("the Program") addresses major underground distribution assets serving primarily low voltage customers in the Horseshoe area of Toronto. The Program invests in proactive asset renewal to mitigate reliability, safety, and environmental risks, and is a continuation of the activities described in the Underground Circuit Renewal program in Toronto Hydro's 2015-2019 Distribution System Plan.[1]

The Program addresses three major underground asset classes: cables, transformers, and switches. Usage, aging, and exposure to harsh environments cause these assets to deteriorate over time, increasing the risk of failure. Legacy asset design issues further increase the probability of failure for certain asset types addressed by the Program.

Outages caused by asset failure on the underground system take approximately 35 percent longer to restore than outages on the overhead system, and can result in lengthy interruptions lasting as long as 24 hours. The failure characteristics of legacy underground cables are such that customers can experience multiple cable-related outages in a short period, leading to potentially significant declines in customer satisfaction in affected neighbourhoods.

The Program's investments in the three major underground asset classes are summarized as follows:

- **Cables**: Cables are the single greatest contributor to outages caused by defective equipment on Toronto Hydro's system, resulting on average in 140,000 customer hours of interruption annually. Through prioritized neighbourhood rebuild projects, focused on replacement of high-risk direct-buried cross-linked polyethylene ("XLPE") cables, Toronto Hydro has had success in reducing the number of customer interruptions due to cable failure from over

[1] EB-2014-0116, Exhibit 2B, Section E6.1

280,000 per year in 2007 to under 140,000 in 2017. There are currently 809 circuit-kilometres of direct-buried cable and direct-buried cable in duct in the underground system, of which 368 circuit-kilometres are direct-buried XLPE cable, i.e. the subset of cable installations with the highest failure risk. Toronto Hydro expects this asset population to be a significant source of failure risk and driver of reliability outcomes as the cables continue to age over the 2020-2024 period. Approximately 70 percent of this cable has reached or passed its useful life as of 2017. Without investment an estimated 90 percent will be at or beyond useful life by 2024. Toronto Hydro is planning to replace an estimated 215 circuit-kilometres of the highest risk direct-buried XLPE cable during the 2020-2024 period to maintain current average reliability performance on the underground system and to sustain improvements in the number of feeders experiencing seven or more interruptions per year ("FESI-7").

- **Transformers:** Underground transformers are typically exposed to harsh environmental conditions. Defective transformers cause approximately 20,000 hours of customer interruption annually and contribute to 26 percent of failures on the underground system. As of 2017, 19 percent of the transformers in Toronto Hydro's underground distribution system have reached or surpassed useful life, and over 1,000 units exhibit at least moderate deterioration. Without proactive investment, Toronto Hydro expects the proportion of underground transformers past useful life to increase by over 50 percent to 29 percent in 2024, and the number of units with at least moderate deterioration to increase to over 3,500. Generally, Toronto Hydro replaces aging and deteriorated underground transformers proactively as part of its direct-buried cable rebuild projects, and will continue to do so in the 2020-2024 period. To support the utility's objective of reducing the number of potentially high-consequence PCB leaks, Toronto Hydro plans to prioritize the replacement of underground transformers that are at risk of failure are known to contain, or are at risk of containing, PCB-contaminated oil. Overall, the utility plans to replace an estimated 1,900 underground transformers during the 2020-2024 period through a combination of area rebuilds and PCB-targeted spot replacement, with the objective of maintaining average system reliability and continuously reducing the risk of PCB leaks.
- **Switches**: Underground switches are continuously exposed to harsh environmental conditions, and their failure typically leads to prolonged outages, ranging from three hours up to 17 hours and affecting an average of 1,300 customers at a time. On average, switches have contributed to approximately 20,000 hours of customer interruption annually. Failure

of these assets can also pose employee and public safety risks due to the potential for arc flashing, a risk that is higher with Toronto Hydro's remaining population of legacy air-insulated switches. The number of air-insulated switches in end-of-serviceable life condition ("HI5") is anticipated to rise from about 40 to over 130 by 2024, which aligns with the accelerated rate of degradation that Toronto Hydro has seen for this type of switch in the field. (Over 40 percent of the failed switches that the utility analyzed in the last five years failed prior to reaching their expected useful life of 30 years, with the highest rate of failure occurring in the 15-24 years range.) Over 700 switches are currently operating beyond useful life. During the 2020-2024 period, the utility plans to proactively replace an estimated 230 underground switches in conjunction with area rebuild projects, prioritizing higher-risk air-insulated switches operating beyond useful life and/or exhibiting material degradation.

Toronto Hydro plans to invest $460 million in the Underground System Renewal program in 2020-2024, which is a 9.5 percent increase over projected 2015-2019 spending in this Program (including forecasted inflation). This pace of investment is necessary to maintain current average reliability on the underground system, sustain improvements in the number of feeders experiencing seven or more interruptions a year, continuously reduce the risk of PCB-contaminated oil leaks into the environment, and prevent asset-related risk on the underground system from increasing in an unsustainable manner over the long-term.

E6.2.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Service	• Contributes to Toronto Hydro's objectives and obligations to connect low and high voltage customers within 5 and 10 business days respectively at least 90 percent of the time (pursuant to the OEB's new connection metrics and section 7.2 of the Distribution System Code ("DSC"), by upgrading 34 circuit kilometres of low capacity 4.16 kV or 13.8 kV distribution lines to higher voltage capacity of 27.6 kV distribution lines.
Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7, Direct Buried Cable replacement measure) by o Replacing approximately 215 circuit-kilometres of direct buried underground cable that poses elevated risks to reliability; and o Replacing assets at and beyond useful life or showing signs of at least material deterioration (i.e. HI4 and HI5).

Environment	• Contributes to improving Toronto Hydro's Spills of Oil Containing PCBs measure, and reducing the environmental impact and risks associated with Toronto Hydro's distribution system by removing underground assets at or beyond useful life that contain or are at risk of containing PCBs by 2024, pursuant to PCB regulations (the *Canadian Environmental Protection Act*, SOR/2008-273, the *Ontario Environmental Protection Act* and the Toronto Municipal Code, Chapter 681 Sewers)

E6.2.3 Drivers and Need

Table 3: Drivers and Need

Trigger Driver	Failure Risk
Secondary Driver(s)	Environmental Risk, Safety

The Underground System Renewal program focuses on replacing three types of assets: cables, transformers, and switches. These assets are primary components of the underground distribution system and will be replaced, generally on a like-for-like basis, in accordance with current standards.

The proposed renewal is driven by the risk and impact of underground distribution asset failures on system reliability, the environment, and public and employee safety. These risks stem from two primary factors. The first is accelerated degradation of asset condition due to exposure to external elements, including dirt, salt, dust, moisture, and humidity. This contributes to a loss in the integrity of the physical asset installed in the field which can in turn lead to failure. Secondly, assets that are at, or approaching their useful life, are subject to an elevated probability of failure. Table 4 set outs the useful life of the underground assets in the Horseshoe area. Asset failures give rise to: (1) reliability risks, which can cause outages and directly impact customers; (2) environmental risks, caused by oil spills (potentially containing PCBs) into the environment; and (3) safety risks, from arcing, and catastrophic failures.

Table 4: Useful Life of Underground Assets by Type in the Horseshoe

Type		Useful Life (Years)
Direct Buried Cable	*Jacketed*	40
	Un-jacketed	23
Cable in concrete encased duct (Jacketed/Un-jacketed)		50
Transformers	*Submersible*	33
	Padmounted	35
	Building Vault	
Switches	*Padmounted*	30
	Vault	40

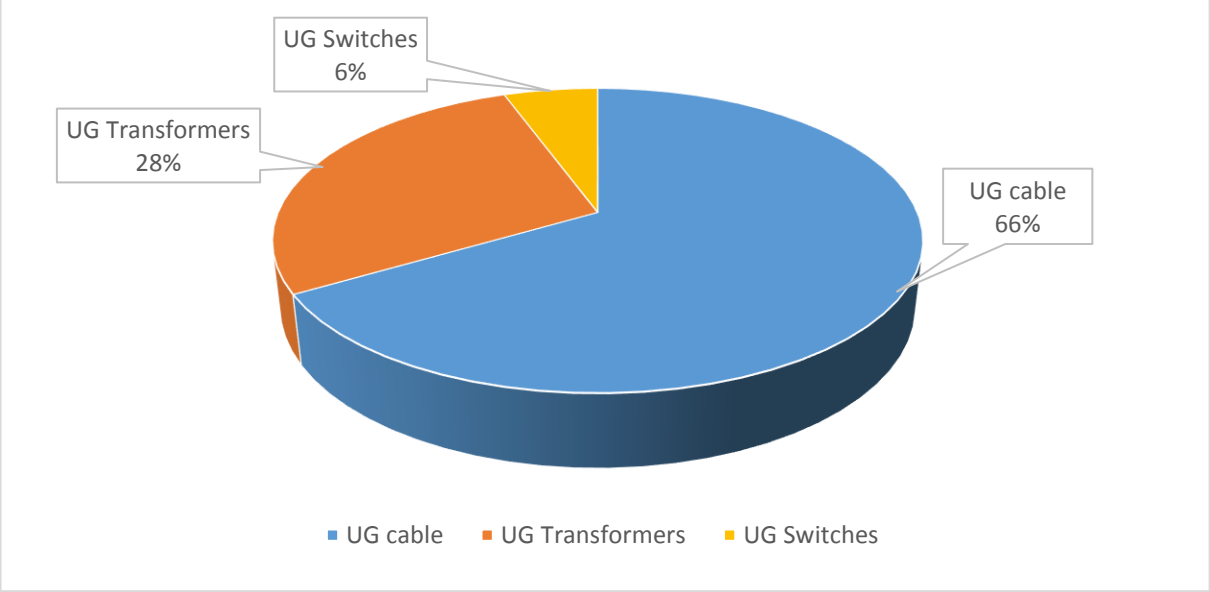


Figure 1: Underground Equipment Failure Rate by Asset Type from 2007 to 2017

Historical investments in the Underground System Renewal program have resulted in improved reliability as illustrated in Figure 2 below. The total number of outages related to underground equipment failures decreased steadily over the last ten years, by an average of 5 percent per year.

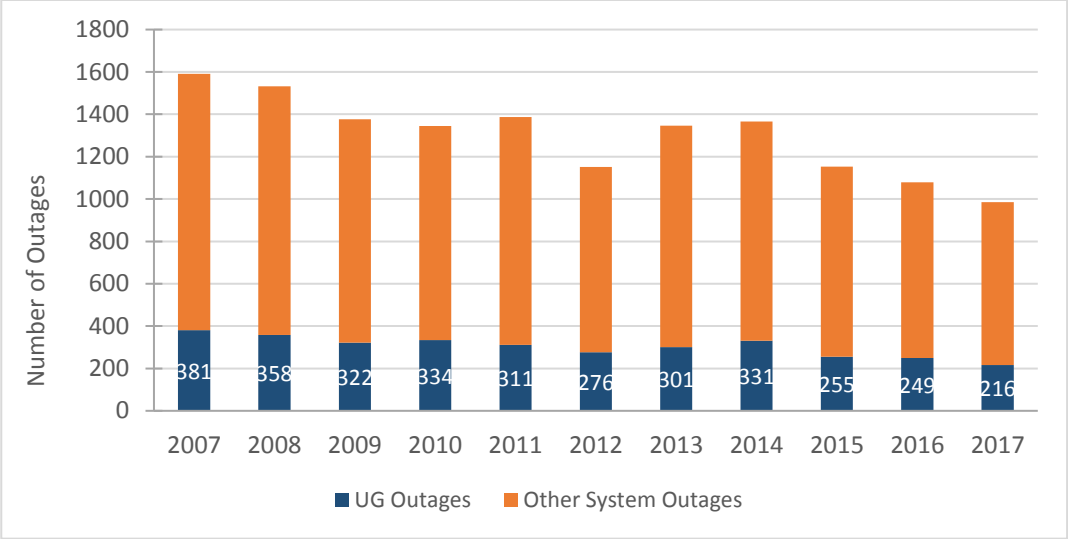


Figure 2: Ten-year Trend of Underground Horseshoe System Contribution to Overall System Outages

These investments have reduced the total number of customers interrupted due to underground equipment failures over the past ten years. Toronto Hydro has been able to sustain the improved numbers, largely keeping them stable over the past five years, as seen in Figure 3.

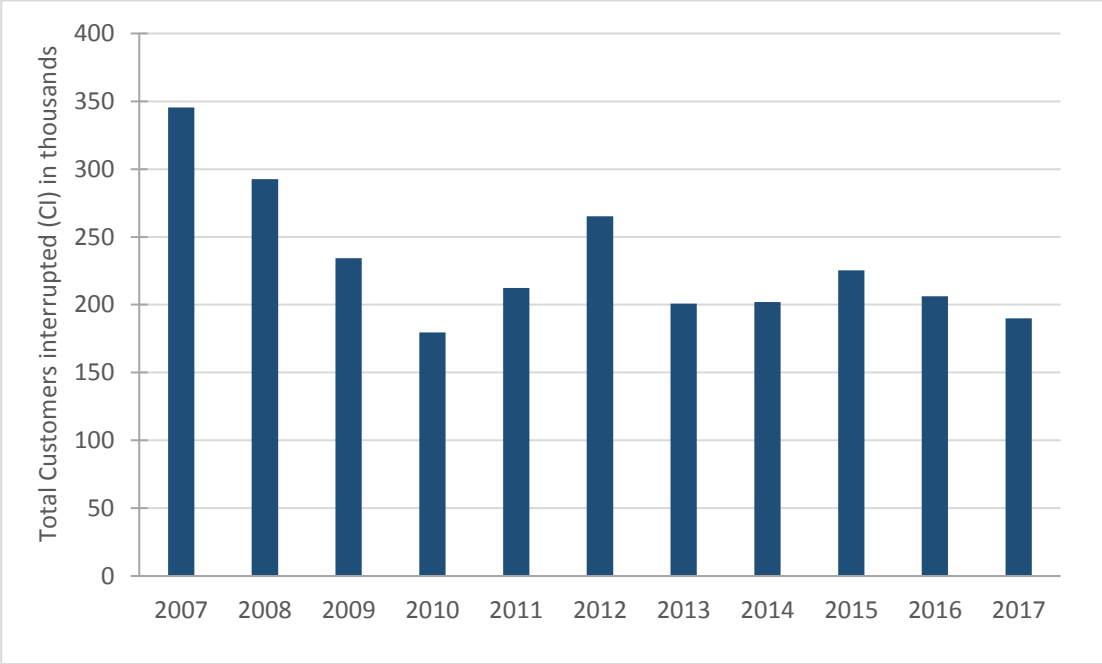


Figure 3: Ten-Year Trend of Customers Interrupted due to Underground Equipment Failure

While historic investments have improved underground reliability in the Horseshoe area, asset demographics are such that Toronto Hydro must maintain the pace of renewal to sustain these improvements. A significant number of assets (e.g. cables) are already past their useful life as of 2017 and the population continues to age. This increases the risk of failure, requiring Toronto Hydro to reactively replace faulted underground equipment. In general, underground assets are more difficult to replace compared to those in the overhead system mainly because they are installed below-grade and not readily visible or accessible for fault locating.

When an underground fault occurs, controllers first check SCADA devices to identify what section of the feeder has faulted. Crews then rely on fault indicators installed on various points on a feeder to find the component that has faulted. This process can take up to hours as crews may have to open every submersible transformer to check for indications of the fault.

Fault locating of direct buried cable is particularly challenging, as crews first need to perform testing that identifies the general location of a fault, then dig up the identified location to confirm and pinpoint the actual cable fault. In certain cases, crews need to dig a number of pits in order to identify the exact location of the fault before repairs can be made. The time required to locate the fault has negative impacts on customers as it can lengthen the outage duration for those customers. Operational outages to repair these assets can also expand the outage to surrounding areas thus affecting more customers.

Additionally, the disruptive nature of the work leads to significant unplanned disruptions and inconveniences for the neighbourhood and community as a whole, and often requires last minute coordination with third parties under emergency situations and tight timelines. For underground assets, this is particularly difficult where customers own the assets (such as vaults), as coordination can delay the repair work and extend the outage. In contrast, proactive replacement allows Toronto Hydro to coordinate work with third parties well ahead of the scheduled repair work.

The Underground System Renewal program is also driven by the need to mitigate the risk of negative environmental impacts from asset failure. Older assets such as transformers are at risk of having insulating oil containing PCBs. This is of concern with respect to underground transformers (padmount, vault, and submersibles) as their surrounding areas are directly connected to the municipal system through drains. Toronto Hydro needs to proactively replace these assets to comply with PCB regulations.

E6.2.3.1 Replacement of Underground Cable

Toronto Hydro plans to replace high risk direct buried cable that causes poor reliability in the Horseshoe area.

Generally, two types of cables exist in the Horseshoe underground distribution system: (i) XLPE; and (ii) tree-retardant cross-linked polyethylene ("TRXLPE"). These can be installed in three ways: (i) direct buried cables; (ii) direct buried ducts; or (iii) concrete encased ducts. Direct buried XLPE cables in Toronto Hydro's system were installed before 1990 and were fabricated using manufacturing processes that are now considered inferior. These assets are a legacy type of construction where cables are laid directly in underground trenches without a protective barrier.

These cables are susceptible to outages due to direct exposure to environmental conditions. Moisture is the most destructive element that affects direct buried XLPE cable. Water ingress into the cable insulation in the presence of an electrical field causes microscopic tears called "water treeing". Overtime, continued moisture penetration and the presence of electrical stresses causes these water trees to become electrical trees (whereby the tears become carbonized and can conduct electricity). This causes the cable to internally short circuit and fail.[2]

Figure 4 shows the current age distribution of direct buried XLPE cable and what it will be in 2024 without investment. As of 2017, the majority (74 percent) of the direct buried XLPE cable in Toronto Hydro's distribution system is at or beyond useful life. There is also a number of circuit-kilometres that are approaching their useful life (i.e. 23 years). Without any replacement, the length of cable at or beyond useful life will reach 333 circuit-kilometres by 2024, which represents 90 percent of direct buried XLPE cable in Toronto Hydro's underground Horseshoe distribution system. An increased percentage of direct buried XLPE cable at or beyond useful life will heighten the risk of cable failure and negate the reliability improvements achieved in recent years.

[2] see Exhibit 2B, Section D2 for more details

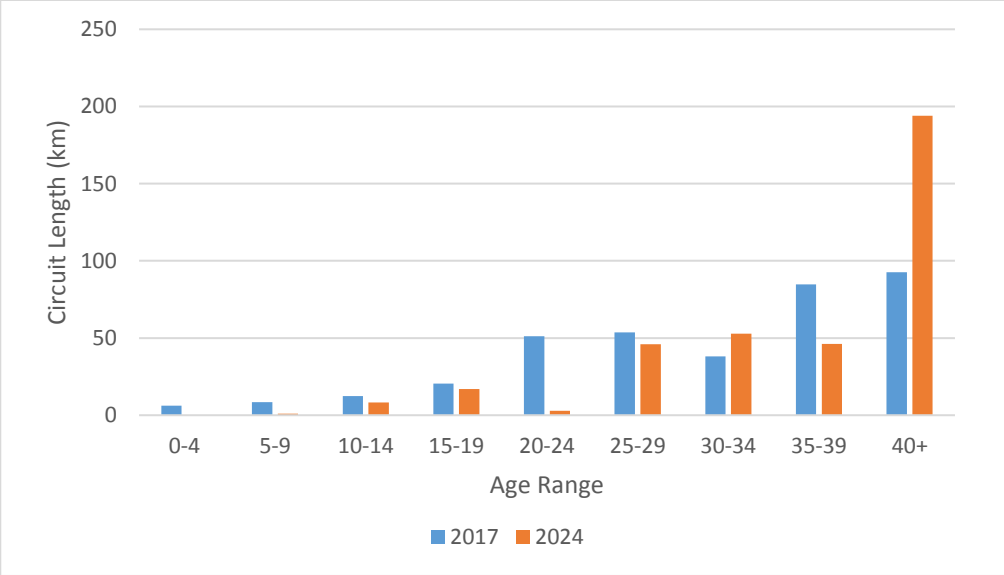


Figure 4: Direct Buried XLPE Cable Age Demographic as of 2017 and by 2024 (without Investment)

Toronto Hydro analyzed over 660 cable failures in the system between 2012 and 2016. The results show that the failure rate of all XLPE cable is significantly higher than TRXLPE cable (499 versus 169 outages). They also show that the rate of failure of XLPE increases with age. These failures can cause customer outages ranging from 4 to 24 hours and affecting an average of 800 customers.

Based on Toronto Hydro's experience with direct buried cables, following an initial failure (which is typically a sign of deteriorated insulation and electrical and thermal stresses along the entire segment), subsequent failures in the cable segment occur with greater frequency. Additionally, voltage stress applied to the cable during the fault locating process further degrades the cable insulation. The following two cases, from 2017, are illustrative of this observed pattern:

1) The residential and non-residential customers in the area of Yonge Street and Hendon Avenue in North York are supplied by a #1/0 solid 28 kV XLPE direct buried cable installed in 1975. Between June and August 2017, there were five cable failures in the same segment as shown in Table 5. As a result, the cable segment was irreparable and a reactive scope of work was issued to replace it with cable in concrete encased ducts.
   Between the time when the scope of work was issued and when the work was fully designed and executed, the area was supplied by a temporary source with no backup thus leaving customers vulnerable to additional and extended outages.

Table 5: Direct buried cable failure Incidents 2017 - Hendon

Date	Outage Duration (min)	Total Customers Interrupted (CI)	Total Customers Minutes Out (CMO)
18-Jun-2017	635	190	42600
19-Jun-2017	27	21	567
19-Jun-2017	128	88	6044
22-Jul-2017	245	88	12980
01-Aug-2017	31	28	630

2) Non-residential customers (i.e. a school and a small commercial plaza) in the area of Cliffwood Road and Don Mills Road in North York are supplied by a #1 solid 28 kV XLPE direct buried cable installed in 1975. Between September and October 2017, three cable failures occurred in the same cable segment, as shown in Table 6. The cable segment continued to fail following the first repair and was deemed irreparable and a reactive scope of work was issued to replace cable in concrete encased ducts.

Table 6: Direct buried cable failures 2017 - Cliffwood

Date	Outage Duration (min)	Total Customers Interrupted (CI)	Total Customers Minutes Out (CMO)
10-Sep-2017	2915	1	2915
02-Oct-2017	1528	1	1528
05-Oct-2017	719	1	719

Underground cable failures account for approximately 70 percent of the underground outages in the Horseshoe system. A snapshot of the ten-year reliability of the underground cables discussed in this Program is shown in Figure 5, Figure 6 and Figure 7. Proactive underground renewal carried out through Toronto Hydro's Underground System Renewal program has improved the system reliability, reducing the number of failures from approximately 200 in the 2008-2010 period to approximately 140 in the 2015-2017 period. Despite this overall trend of decreasing failures over the past 10 years, the number of customer interruption and the hours of customer interruption has decreased at a lesser rate in recent years.

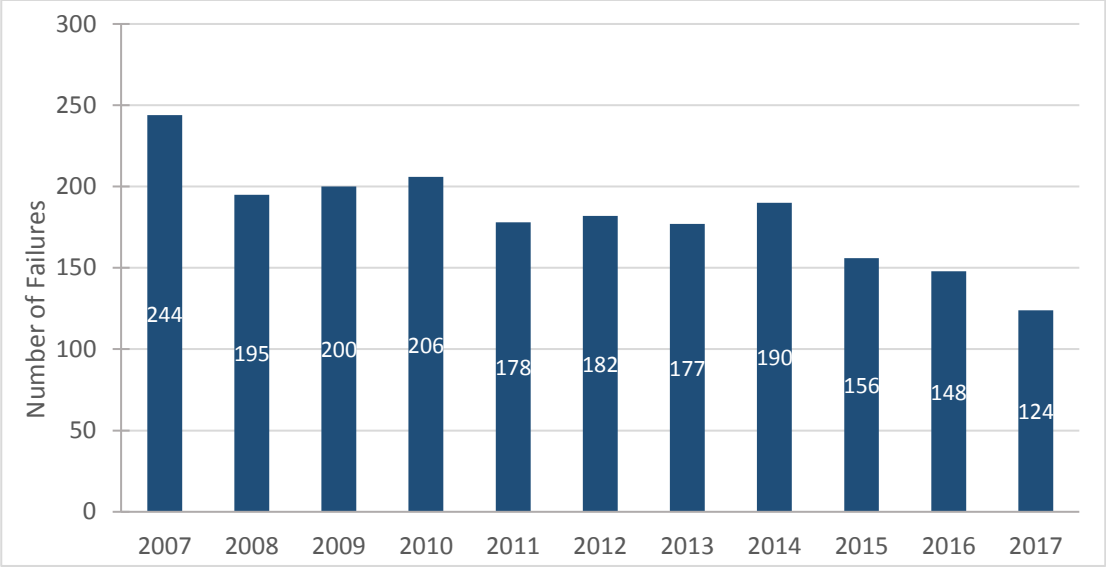


Figure 5: Ten-Year Trend of Outages due to Underground Cable Failure

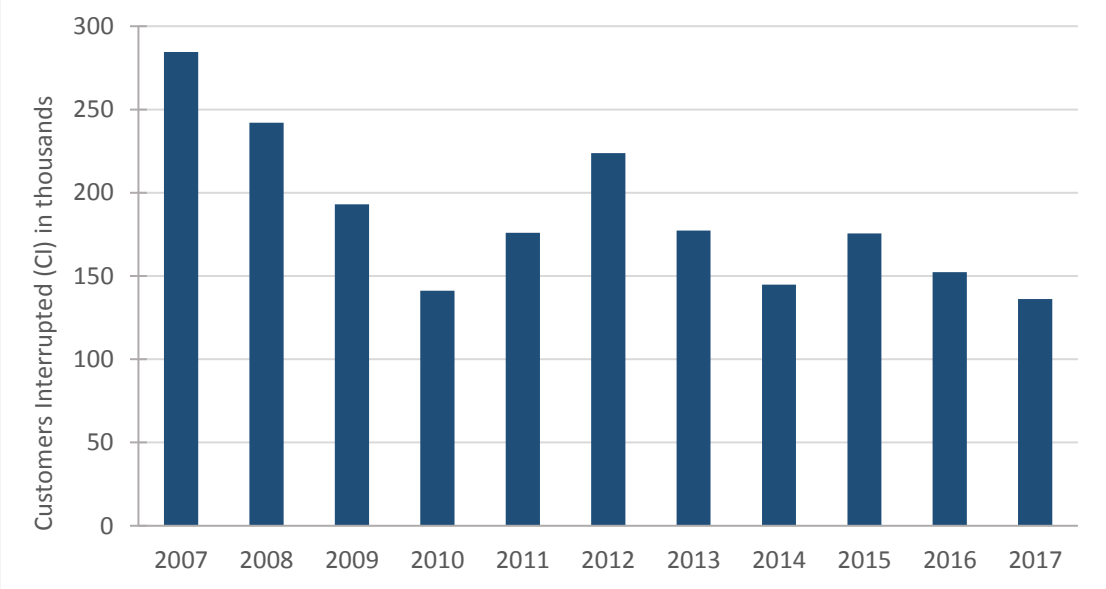


Figure 6: Ten-Year Trend of Total Customers Interrupted (CI) due to Underground Cable Failures

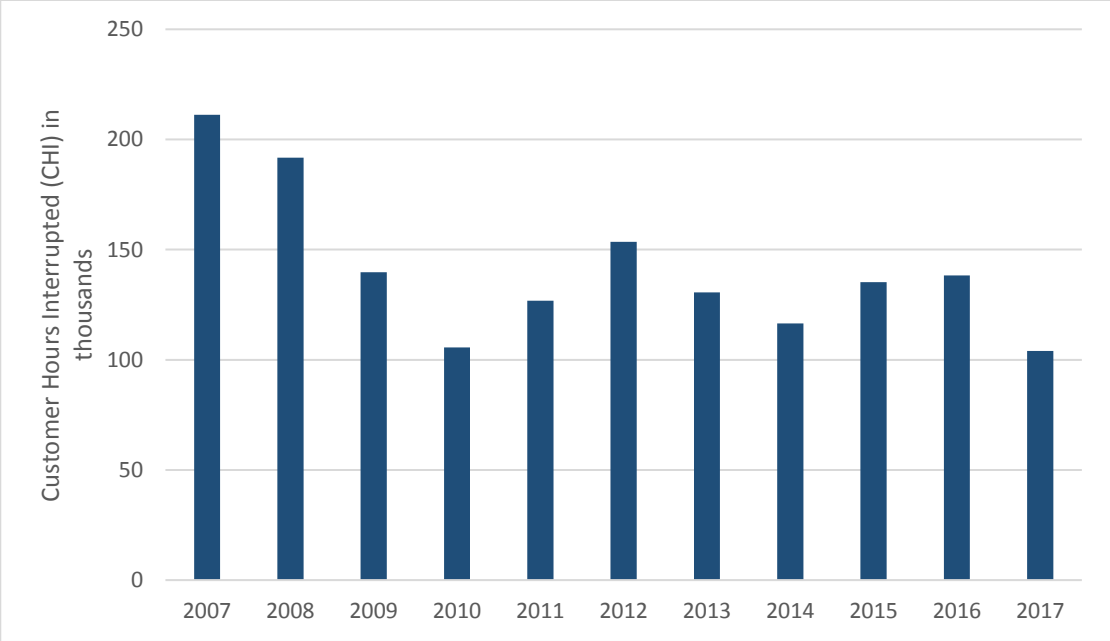


Figure 7: Ten-Year Trend of Total Customer Hours Interrupted (CHI) due to Underground Cable Failures

Of the 809 circuit kilometres of direct buried in cable in Toronto Hydro's system, the utility plans to replace approximately 215 circuit kilometres through underground rebuild projects during the 2020-2024 period. This plan is primarily driven by failure risks associated with these deteriorating and legacy (i.e. direct buried cable) assets.

Toronto Hydro's will install new TRXLPE cable in concrete-encased ducts as opposed to burying cable directly into the soil. This approach increases public safety (e.g. protects the cable from dig-ins) and reliability (e.g. greatly reduces the time it takes to replace faulted cables as new cables can be pulled into existing ducts, eliminating the need to dig out direct buried cables for repairs).

E6.2.3.2 Replacement of Underground Transformers

Toronto Hydro plans to replace transformers that are at risk of failing and pose an environmental risk due to oil leaks that may contain PCBs. Currently, there are 18,254 underground transformers in Toronto Hydro's Horseshoe distribution system.

Underground transformers are key assets used to step-down voltage and supply customers with electricity from underground cables. Three main types of underground transformers are in service:

(i) submersible; (ii) padmounted; and (iii) building vault. Toronto Hydro owns approximately 8,500 submersible, 6,000 padmount, and 3,900 vault transformers. Submersible transformers are found below-grade in small structures (i.e. vaults), on public road allowances or private properties. Padmounted transformers are metal-clad enclosures with lockable cabinet doors located on top of concrete pads within road allowances or on private properties. Vault transformers are located in civil structures above-grade and, similar to padmounted transformers supply residential areas or commercial buildings.

Exposure to harsh environments causes deterioration on these transformers. Moisture is the single most destructive element (e.g. groundwater, moisture ingress), which can cause the enclosures to corrode. Precipitation and humidity over time cause corrosion (tank perforation) which can lead to oil leakage into the environment. The secondary effect of oil leakage is a reduction of transformer oil levels which causes the paper insulation to dry up, and, together with the heat created within the unit due to loading, will result in arcing and potentially catastrophic failure of the unit. As these transformers are located next to sidewalks and on private properties, such failures present significant risks to the public, and Toronto Hydro employees. An example is an incident that occurred due to premature failure of a submersible transformer with a corroded base, causing the insulating oil to slowly leak and diminishing the cooling and insulating properties of the transformer. This led to arcing and increased pressure inside the tank, causing the lid to blow off. This resulted in 3,857 customers interrupted and 1,118 customer hours of interruption.

As of the end of 2017, 400 transformers exhibit at least material deterioration (i.e. HI4 and HI5) as shown in Table 7 below. Without any capital investment, this number is expected to triple to 1,203 by the end of 2024. Not investing in asset renewal will increase reliability risks on the distribution system and run the risk of negative environmental impacts from asset failure as the transformers continue to deteriorate. The asset condition profiles of the transformers as of 2017 and in 2024 (forecasted) without investment can be seen in Figure 8.

Table 7: Asset Condition Assessment for Underground Transformers in 2017 and 2024 without Investment

Condition	UG TX - Padmounted		UG TX - Submersible		UG TX - Vault		Total 2017	Total 2024
	2017	2024	2017	2024	2017	2024		
HI1 - New or Good Condition	4474	4153	6272	5986	1975	1528	**12721**	**11667**
HI2 – Minor Deterioration	603	296	534	280	1385	437	**2522**	**1013**
HI3 – Moderate Deterioration	246	555	232	501	143	1325	**621**	**2381**
HI4 – Material Deterioration	88	205	168	121	74	163	**330**	**489**
HI5 – End-of-Serviceable Life	16	218	42	360	12	136	**70**	**714**
Unavailable	493	493	1198	1198	299	299	**1990**	**1990**
Grand Total	**5920**	**5920**	**8446**	**8446**	**3888**	**3888**	**18254**	**18254**

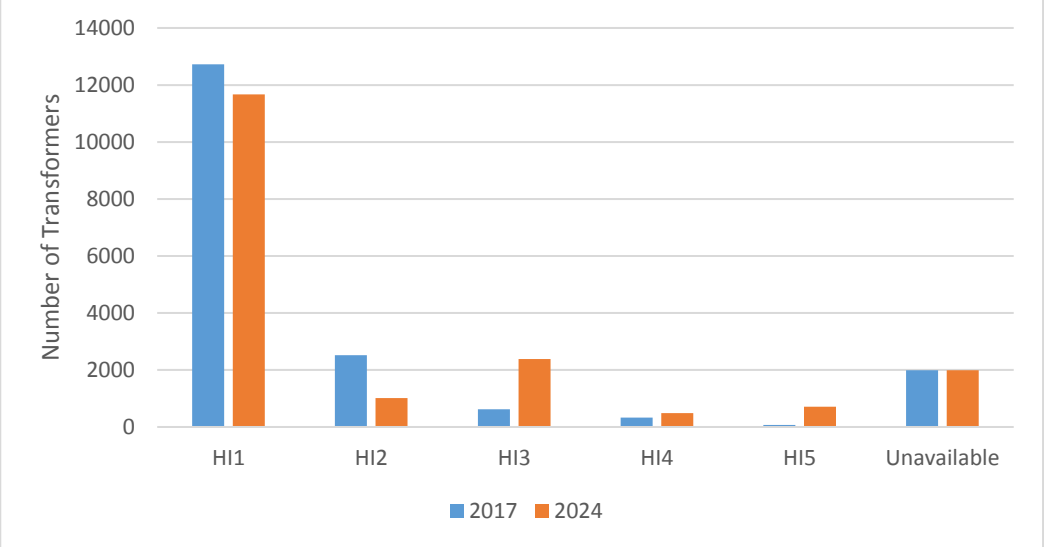


Figure 8: Underground Transformers ACA as of 2017 and in 2024 without Investment

A summary of the 10-year reliability of the underground transformers is shown in Figure 9, Figure 10 and Figure 11. As seen in Figure 9, there has been an overall reduction in the number of system outages (e.g. an average of 99 per year between 2007 and 2009, down to an average of 67 per year

between 2015 and 2017). Without investment, Toronto Hydro expects the reliability improvements made in recent years to be eroded and eventually reversed.

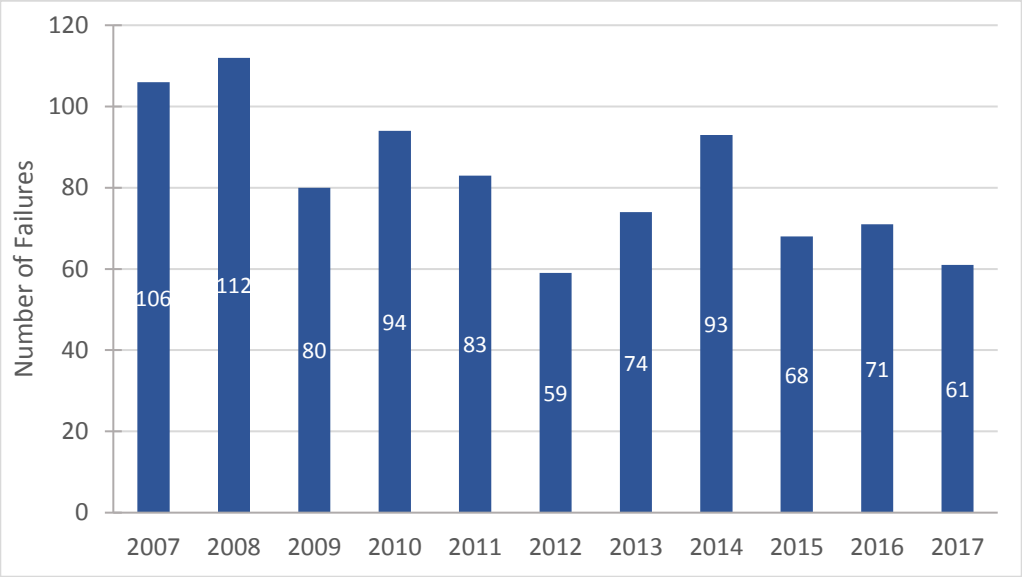


Figure 9: Ten-Year trend of outages due to underground transformer failures

However, despite an overall reduction in the total number of failures, the number of customers interrupted has increased from 2015 to 2017. Over the last two years, customer interruptions resulting from padmounted and submersible transformers failures have risen considerably, as shown in Figure 10. These failures cause outages with durations ranging from 2 to 24 hours and can affect an average of 480 customers.

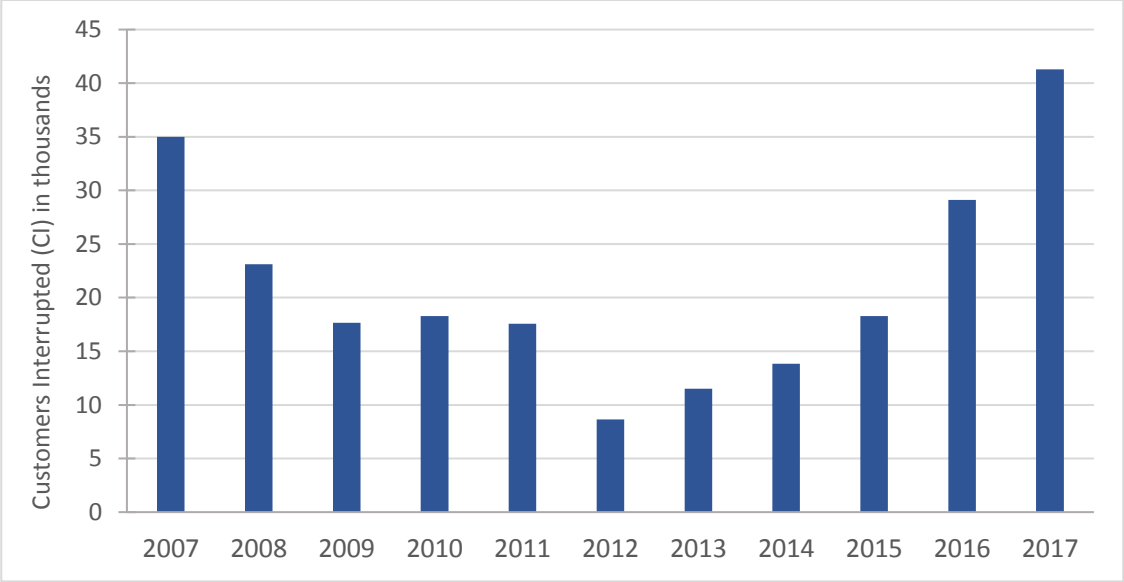


Figure 10: Ten-Year Trend of Total Customers Interrupted (CI) due to Underground Transformer Failures

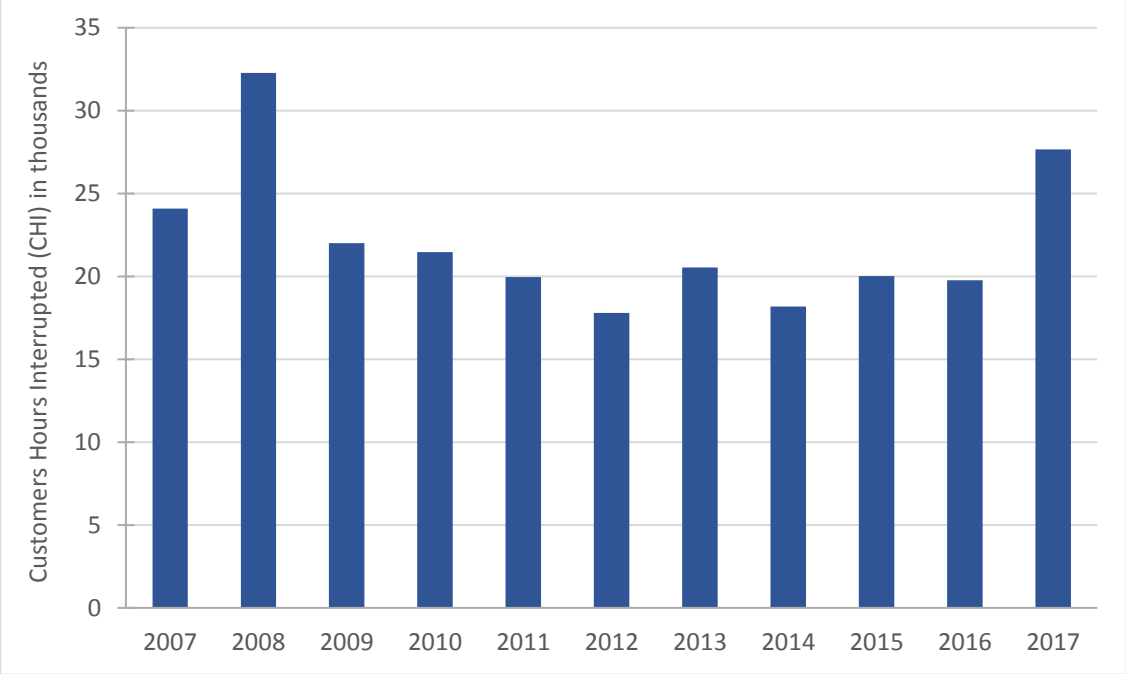


Figure 11: Ten-Year Trend of Customer Hours Interrupted (CHI) due to Underground Transformer Failures

The failure risk of these assets is mitigated through the Preventative and Predictive Underground Line Maintenance program;[3] however, environmental conditions can accelerate the deterioration and failure of these assets prior to their next inspection due to the nature of their surroundings.

Toronto Hydro investigated 257 underground transformers failures that occurred between 2012 and 2017. The results of this analysis (see Figure 12 and Figure 13) show that 35 percent[4] of the failed underground transformers failed at or beyond useful life and that the number of failed units increases with transformer age. Therefore, if not proactively replaced, transformers on Toronto Hydro's distribution system which are at or beyond their useful life of 33 or 35 years are at an increased risk of failing.

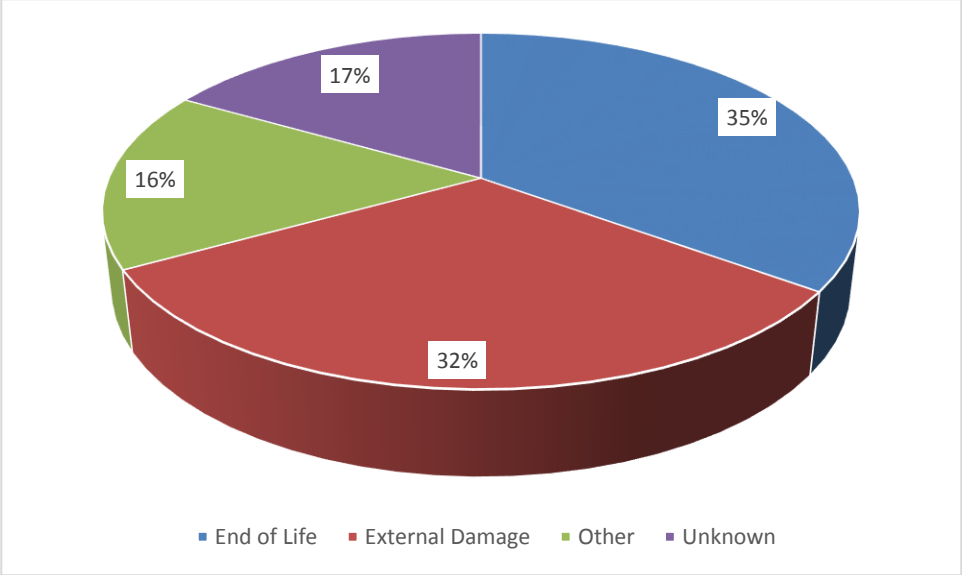


Figure 12: Root Cause Distribution for Failed Underground Transformers from 2012 to 2017

[3] See Exhibit 4A, Tab 2, Schedule 2.
[4] Corrosion, which is known to accelerate degradation and reduce the life of assets, represents 5 percent of these failures and is included in External Damage (see Figure 12).

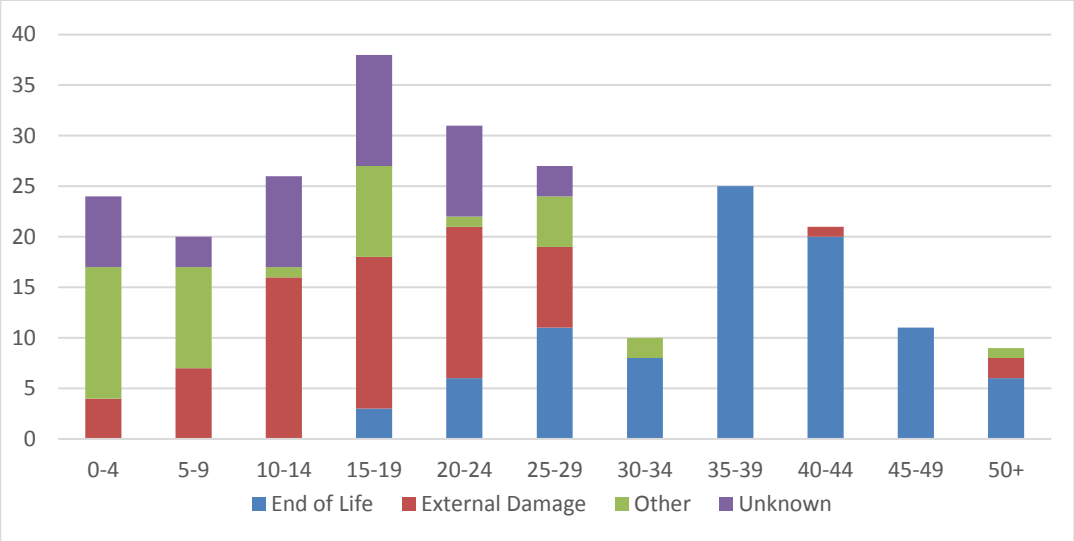


Figure 13: Age of Transformers at Time of Failure

Figure 14 shows the current age distribution of underground transformers in the Horseshoe area and what it will be in 2024 without investment. As of 2017, 19 percent of underground transformers in the Horseshoe area (i.e. 3,505 units) were at or beyond useful life. There are also a high number of transformers approaching their useful life (i.e. 33 years for submersibles and 35 years for padmount and vault). Without any replacement, the percentage of assets at or beyond their useful life will increase by more than 50 percent and reach 29 percent (5,355) by 2024. An increase in the number of transformers at or beyond their useful life will increase the risk of units failing and will erode and eventually reverse the improvements in reliability made in recent years. Additionally, without sufficient replacement, Toronto Hydro will face a backlog of transformers requiring replacement beyond 2024.

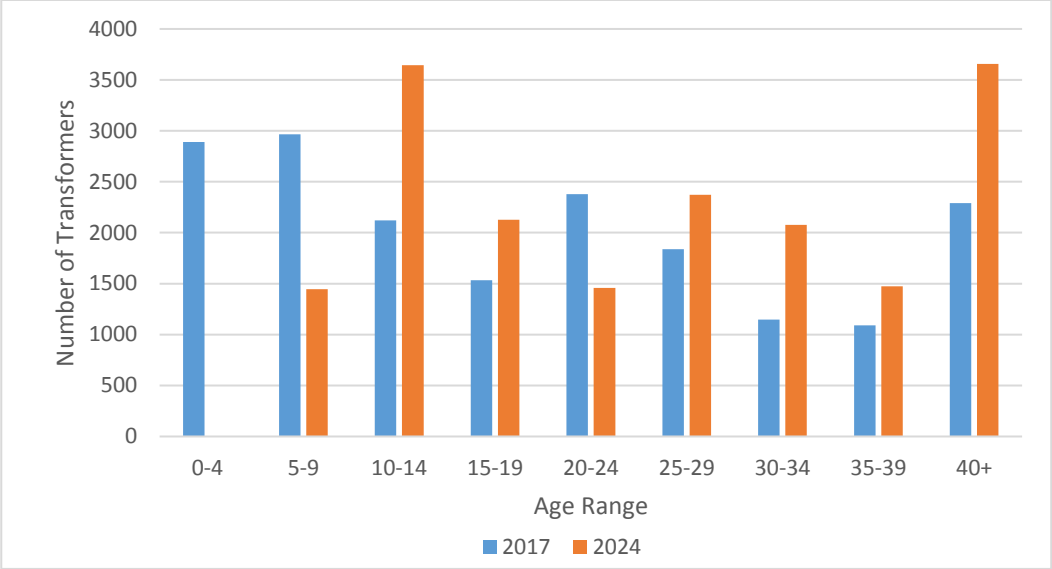


Figure 14: Age Distribution of Horseshoe Underground Transformers as of 2017 and In 2024 without Investment

A number of underground transformer failures in the Horseshoe area also resulted in oil leaks into the environment. Figure 15 below shows the total number of such oil spill incidents doubling over the last three years. Older transformers are at risk of having oil containing PCBs. Releasing oil containing PCBs (or oil on its own) into the environment may constitute a breach of the City of Toronto's Sewer Use By-Law, Ontario's *Environmental Protection Act* and, in some cases, the federal Canadian *Environmental Protection Act*. Toronto Hydro may be ordered to perform work or remediate any non-compliance under one or more of these regimes due to a single incident. A conviction would also likely have serious reputational consequences for Toronto Hydro. Importantly, leaks put communities and the public at risk of exposure to PCBs. During the 2015-2017 period, Toronto Hydro has been contacted by regulatory authorities with respect to oil spills and PCBs on a number of occasions, further highlighting the need to act proactively in this regard.

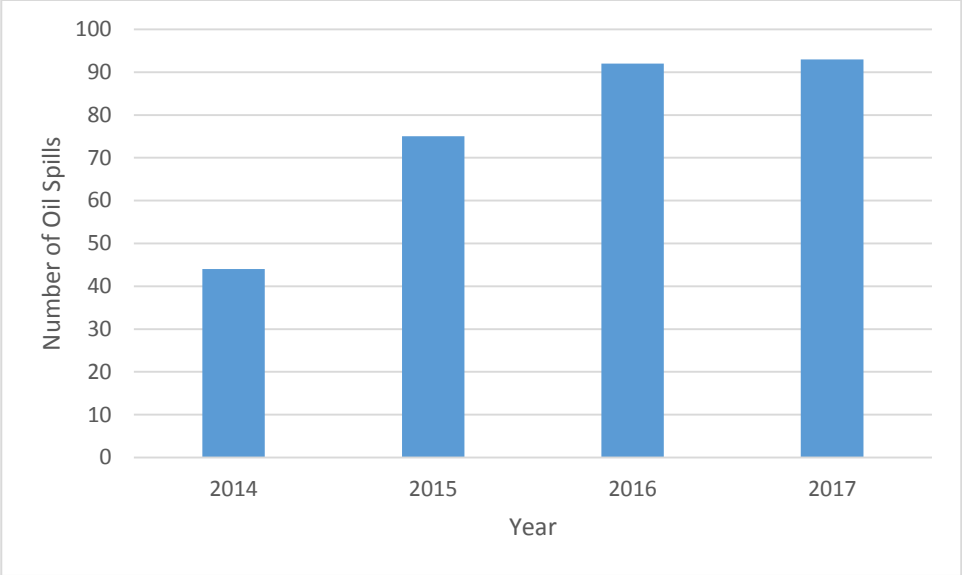


Figure 15: Number of Oil Spill Incidents from Underground Transformers in the Horseshoe Area

As of 2020, Toronto Hydro will have 1,458 underground transformers in the Horseshoe area that contain (or are at-risk of containing) PCBs. Toronto Hydro plans to inspect and replace these through this Program.

E6.2.3.3 Replacement of Underground Switches

Toronto Hydro also plans to replace switches as part of area rebuild projects. There are approximately 5,500 switches in service in the Horseshoe area.

Switches are used for load switching, isolation, and emergency power restoration procedures. Toronto Hydro's underground distribution system uses two types of switches: (1) Padmounted switches (air vented or sealed with SF_6 insulation) which are installed mainly next to boulevards and used for feeder switching; and (2) vault installed switches (air vented or sealed with SF_6 insulation) used for switching and transformer isolation in a vault. The useful life of these switches are 30 and 40 years, respectively.

Exposure to harsh environments may reduce switch lifespans. Padmounted switches are designed to be vented naturally through louvers under the hood of the enclosure, which provide a route for dust and road salt to enter the switching compartments and accumulate within the asset. Scheduled preventive maintenance, such as inspections followed by corrective CO_2 washing, is only effective in removing the excessive buildup of contaminants for a limited time. At the same time, repeated CO_2

washing contributes to the degradation of the switch's insulation strength which can lead to eventual failure. While routine maintenance is part of Toronto Hydro's asset management practice, it cannot be relied upon to extend the life of a padmounted switch in a sustainable manner.

Other sources of contamination include the concrete foundation upon which the padmounted switch rests, where primary cables are attached to the fusing and switching compartments. These cables may be tightly packed within the enclosure, creating an environment with tight clearances and an increased potential for moisture accumulation. As the ambient temperature changes, the trapped moisture condenses into water, dampening the dirt and other contaminants that are already present on the insulation surface. The surface then becomes conductive and may result in a flashover of the unit.

The result of a flashover is a near simultaneous ignition of all combustible material within the compartment. Flashovers can result in a discharge of electrical energy within the other compartments of the switch. This ultimately results in additional flashovers and combustion that leads to the total failure of the unit.

Figure 16 provides an illustration of how contaminants build up on a typical padmounted switch leading to a potential flashover.



Figure 16: Padmounted switch

Condition data for Air and SF_6 type underground padmounted switches are shown in Table 8. Data shows that 70 padmounted switches have at least material deterioration and should be considered for replacement as of 2017. The table also shows that without any capital renewal the number of switches with at least material deterioration is projected to approximately double by 2024 (141 switches) thus increasing the risk of failure due to deteriorated assets on the system.

Table 8: Asset Conditioning for Underground Padmounted Switches – Air and SF_6 Type in 2017 and 2024 without Investment

Condition	UG Switch – Padmounted Air		UG Switch – Padmounted SF_6		Total 2017	Total 2024
	2017	2024	2017	2024		
HI1 - New or Good Condition	381	355	263	263	**644**	**618**
HI2 – Minor Deterioration	19	29	0	0	**19**	**29**
HI3 – Moderate Deterioration	68	20	2	0	**70**	**20**
HI4 – Material Deterioration	29	5	0	0	**29**	**5**
HI5 – End of Serviceable Life	41	136	6	8	**47**	**144**
Unavailable	40	33	256	256	**296**	**289**
Grand Total	**578**	**578**	**527**	**527**	**1105**	**1105**

In Toronto Hydro's underground distribution system in the Horseshoe area, 6 percent of the outages between 2007 and 2017 were caused by switch failure, they can lead to significant public safety risks and extensive disruption to service for an extended period of time. For example, padmounted switches are commonly connected to the trunk portion of a feeder for load distribution and switching. When load is transferred from one feeder to another, individual switches are closed or opened so power can be diverted from one feeder to another. These actions cannot occur when a padmounted switch fails, leading to a significant negative effect on system reliability by causing an outage or extending a feeder outage to the bus level.

A summary of the ten-year reliability of the underground switches discussed in this Program is shown in Figure 17, Figure 18 and Figure 19. Proactive replacement of switches has helped moderate the frequency of outages caused by switch failure since 2012 as shown in Figure 17. However, the population of switches in service is aging and if Toronto Hydro does not maintain the current renewal pace, the utility expects that the current level of reliability performance will not be sustained and failure rates will increase.

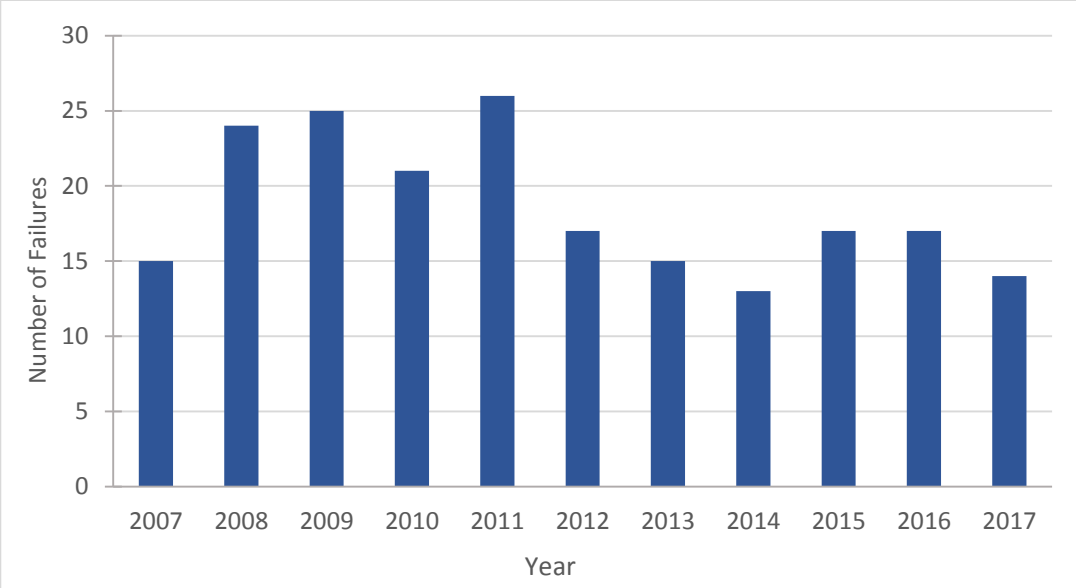


Figure 17: Ten-Year Trend of Outages due to Underground Switches Failures

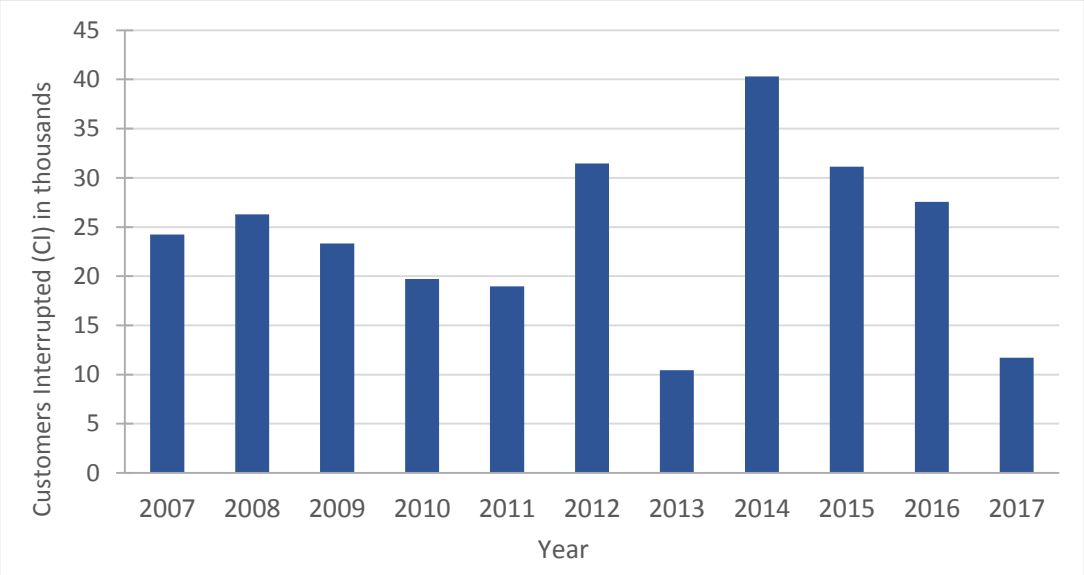


Figure 18: Ten-Year Trend of Total Customers Interrupted (CI) due to Underground Switches Failures

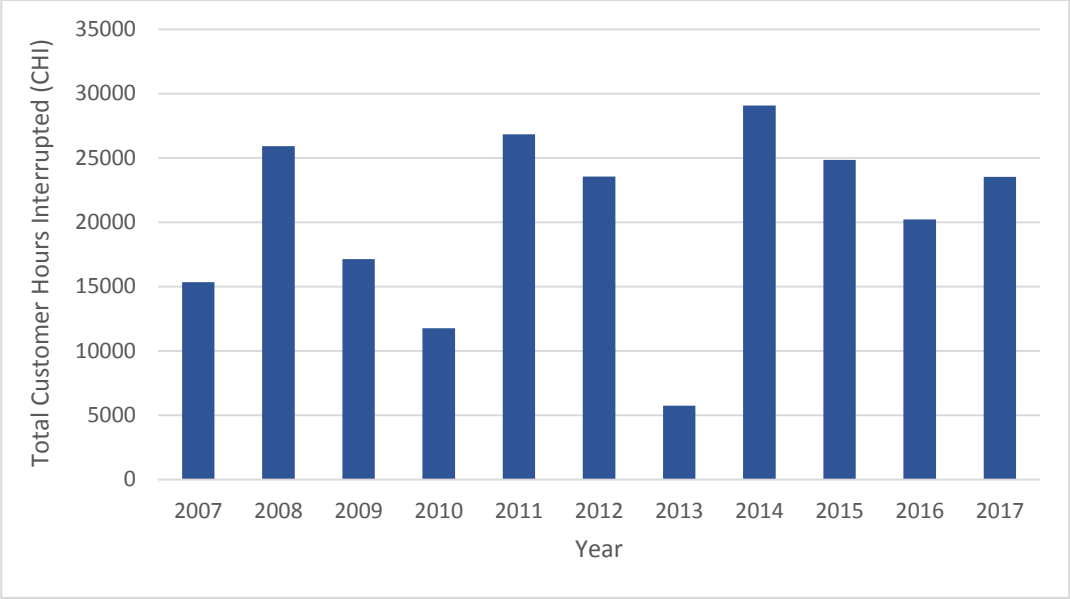


Figure 19: Ten-Year Trend of Total Customer Hours Interrupted (CHI) due to Underground Switches Failures

Figure 20 shows the age demographics of Toronto Hydro's padmount and vault switches, which have useful lives of 30 years and 40 years, respectively. As of 2017, 723 switches on Toronto Hydro's Horseshoe distribution system have already passed their useful life. Without intervention, 1,101 switches will be at or beyond their useful life in 2024. A significant increase in the number of switches at or past their useful life elevates the risks of units failing and will erode and eventually reverse the recent improvements in reliability shown in the figures above.

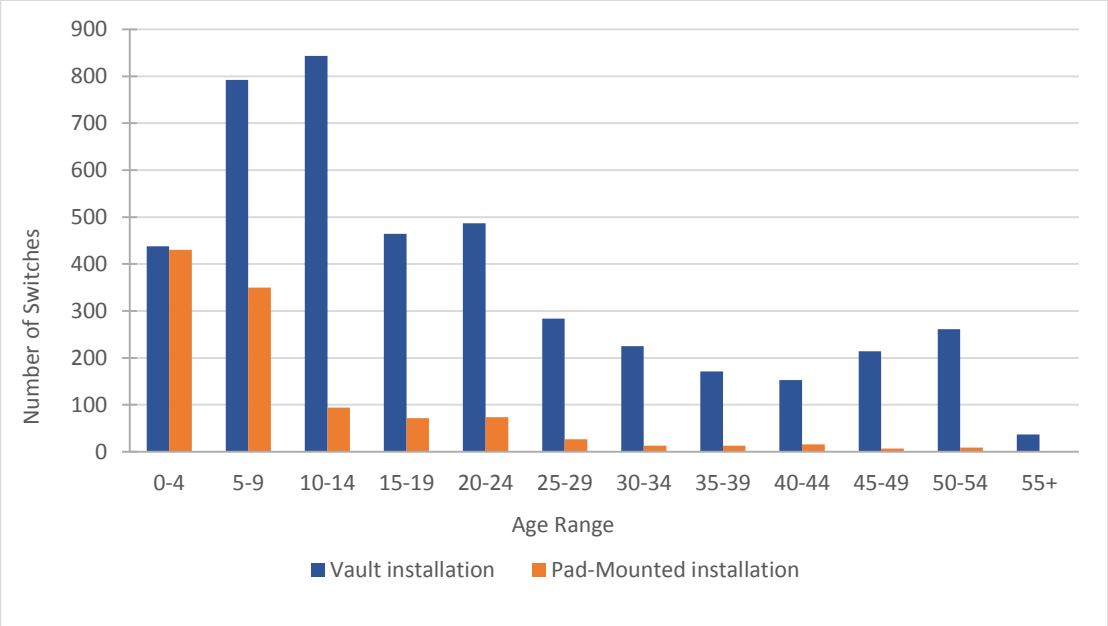


Figure 20: Underground Switches Age Demographic as of 2017

Toronto Hydro analyzed 45 padmounted air insulated switch units that failed between 2012 and 2017. As shown in Figure 21 below, the utility found that the majority of the units failed before their expected useful life of 30 years, with the highest number of failures occurring in the zero to nine years of age range, and the highest rate of failure occurring in the 15 to 24 years of age range. 40 percent of the failures analyzed are attributed to switches prematurely reaching their useful life due to external factors such as weather, contamination, and corrosion. When a switch fails, outages can range from 3 hours up to 17 hours and can affect an average of 1,300 customers.

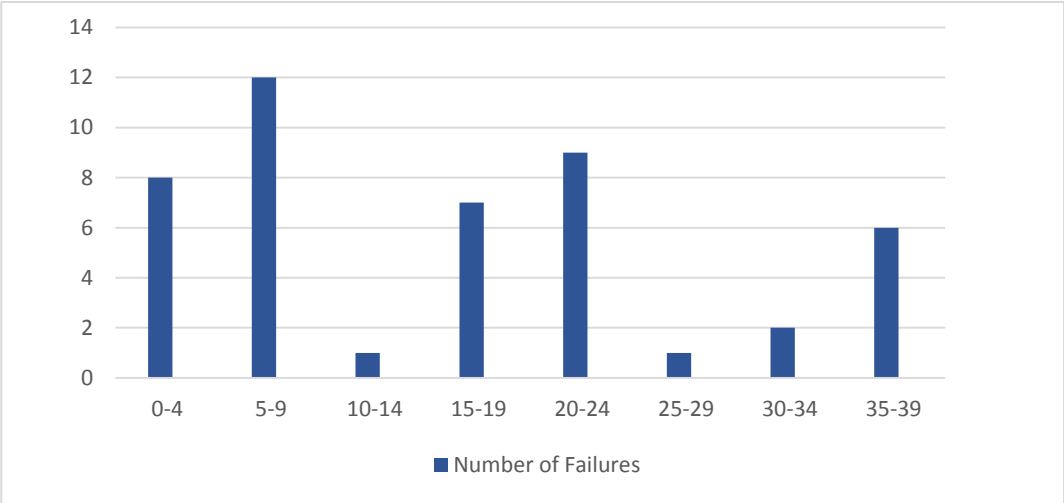


Figure 21: Underground Failures vs. Age Demographic

Of the 723 switches at or beyond their useful life as of 2017. Toronto Hydro plans to replace approximately 231 units over 2020-2024 as part of area rebuild projects under this Program. The utility expects to replace the remaining switches through the Reactive and Corrective Capital program[5] upon failure as they do not present environmental risks.

Given the failure risks associated with air insulated switch types, these units will be replaced with the new generation of SF_6-insulated switches. The new generation of switches has a stainless steel enclosure to prevent premature rusting and degradation of the cabinet. The unit includes welded viewing windows that mitigate SF_6 gas leakage into the environment. Programmable relays are also used instead of fuses for downstream circuit protection, eliminating the need for on-site switch re-fusing after a fault on the branch circuit. The units have internal grounding provisions making grounding easier and safer for crews in comparison to the external grounding elbows on the existing switches.

The new SF_6 switches enable SCADA capability for remote sensing, leading to increased system efficiency. This improves restoration time in the event of a power failure while avoiding costs associated with crews physically operating the switch on site.

Another advantage of padmounted SF_6 insulated switches is that it has the same circuit configuration and footprint as the existing air insulated padmounted units, thereby avoiding unnecessary cable

[5] Exhibit 2B, Section E6.7.

and civil construction work. Additionally, all external components of the SF_6 insulated switches are sealed and do not require costly, routine CO_2 washing to remove accumulated contaminants.

E6.2.4 Expenditure Plan

Table 9: Historical & Forecast Program Cost ($ Millions)

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Underground System Renewal Horseshoe	115.5	80.7	83.1	70.0	71.4	93.0	88.7	90.3	93.1	95.2

E6.2.4.1 2015-2019 Variance Analysis

Over the 2015-2019 period, Toronto Hydro forecasts total spending of $420.7 million in the Underground System Renewal program, which is approximately $39 million lower than planned in the 2015-2019 Distribution System Plan. Nonetheless, Toronto Hydro is on pace to exceed the amount of cable and number of transformers installed related to the same plan.

Over the 2015-2017 period, Toronto Hydro spent $279.1 million and installed 720 kilometres of underground cable in duct, 1,555 transformers, and 213 underground switches, as shown in Table 10. Toronto Hydro plans to invest another $141.4 million in 2018-2019.

Table 10: 2015-2019 Volumes (Actual/Bridge) – Underground Circuit Renewal Horseshoe Program (Primary Electrical Assets)

Asset Class		Actuals			Bridge	
		2015	2016	2017	2018	2019
Cable	*km*	105	442	173	167	159
Transformers	*Units*	105	710	740	310	296
Switches	*Units*	47	79	87	43	41

During 2015-2017, Toronto Hydro invested at a higher pace than planned, installing an incremental 215 circuit-kilometres of primary cable and 611 transformers, and 16 fewer padmounted switches. The increase in the number of transformer units was due to an increasing need to address submersible transformers that were at risk of containing PCBs, had deteriorated in condition, and posed an unacceptable risk to the environment due to oil leaks. This increase was triggered in part by improvements Toronto Hydro made to its inspection forms and processes, resulting in a more accurate picture of the condition of submersible transformers and number of identified leaks. The

higher pace of cable replacement was tied to this same issue, as Toronto Hydro worked to prioritize rebuild projects that addressed submersible transformers.

More broadly, variances in area rebuild programs such as this can be attributed in part to changes in the scope of work as projects moved from high-level estimates to detailed designs. These changes are anticipated for complex construction projects and typically result from a more detailed review of the scope of work and execution needs during the design phase. For example, designers may identify additional or fewer assets that should be included in a project, interference with other utilities and a resultant need to adjust the scope, additional restoration costs, etc., that influence the final cost of a project.

E6.2.4.2 2020-2024 Forecasts

Toronto Hydro plans to spend $460.3 million in this Program over the 2020-2024 period. The 2020-2024 forecast expenditures are based on Toronto Hydro's historical unit costs trends and experience gained executing this type of work over the last three years. The estimated volumes for major underground asset replacements during the 2020-2024 period are shown in Table 11.

Table 11: 2020-2024 Estimated Volumes (Forecast) – Underground Circuit Renewal (Primary Electrical Assets)

Asset Class		Forecast					
		2020	2021	2022	2023	2024	Total
Cable	*km*	103	96	96	98	98	**491**
Transformers	*Units*	407	380	380	387	387	**1,941**
Switches	*Units*	49	45	45	46	46	**231**

The forecasted volumes are estimates based on a preliminary selection of areas targeted for complete rebuilds and spot replacements.

Four types of work are carried out through this Program. They include:

- **Area Rebuilds:** Rebuild projects are prioritized based on the historical failure of major assets (such as cable and transformer) on the feeder, the concentration of assets in deteriorated condition or at or beyond useful life, and potential reliability impact on customers supplied by the feeder. Rebuilding entire areas is intended to ensure proper coordination of work and efficient mobilization of crews as it is in the customers' interest to undergo only one outage

due to planned capital work as opposed to numerous outages during reactive work due to failure. Through these projects, assets connected to a feeder (e.g. cables, transformers, and switches) will be replaced to meet current standards such as cable installed in concrete encased ducts, transformers, padmounted switches.

- **Area Rebuilds with Voltage Conversion:** Where a feeder identified for renewal through area rebuilds is operating on 4.16 kV and 13.8 kV voltages, it will be converted to 27.6 kV. Toronto Hydro plans to perform renewal projects on 69 feeders, of which 11 feeders identified for voltage conversion. Figure 22 depicts the location of the areas with direct buried cable and the transformers at or beyond their useful life containing or at risk of containing PCBs.

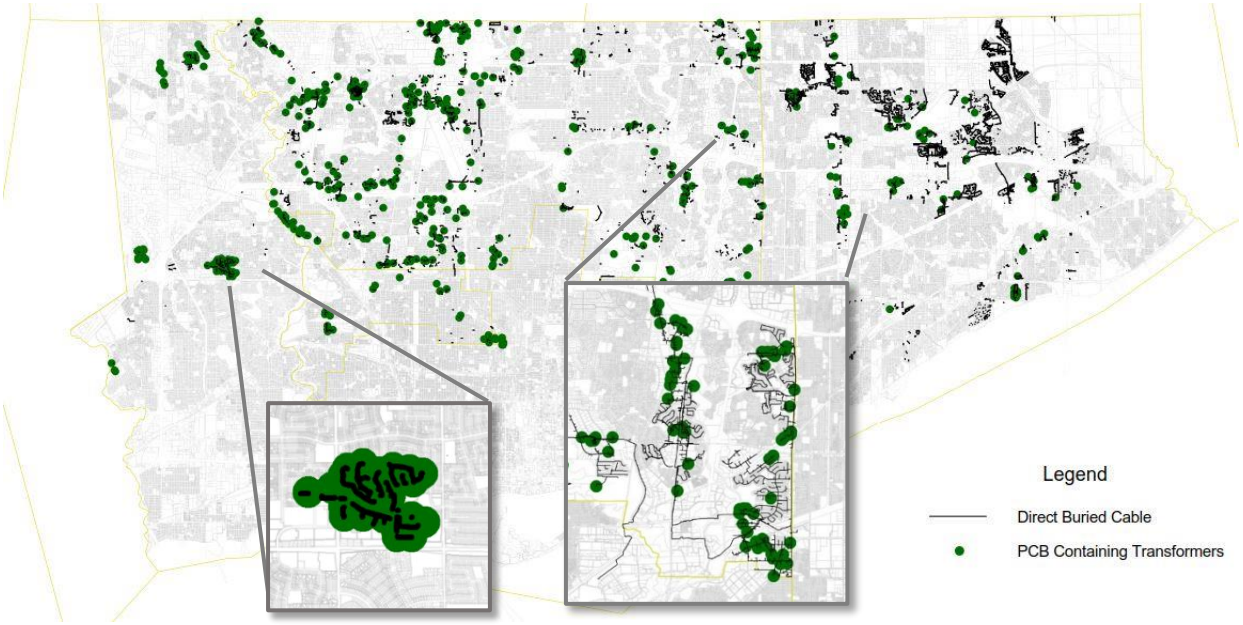


Figure 22: Planned Underground System Renewal Work Areas

- **Spot replacement:** Transformers that are not part of area rebuilds and in need of replacement will be addressed on a spot, like-for-like projects.

Whenever possible, work under this Program is combined or coordinated with projects from other programs (such as overhead renewal and rear lot, conversion) in the same area. Underground renewal projects are broken into civil and electrical phases, and those with significant amounts of civil work are broken down further into sub-phases for better manageability and coordination of resources, especially since all civil work is performed by contractors.

Equipment in the same area and fed from the same Toronto Hydro feeders is coordinated in terms of replacement schedule and sequencing. This approach reduces disruption of supply and requires less mobilization of resources to the same area. Reduced disruption to feeders translates into fewer outages for customers, and improves project efficiencies.

In addition, any voltage conversion underground work is coordinated with stations maintenance. This allows Toronto Hydro to eventually decommission Municipal Stations prior to any major maintenance or renewal investments. From a continuous improvement perspective, voltage conversion from 4.16 kV or 13.8 kV to a 27.6 kV system has the following benefits, which can lead to improved power quality and distribution efficiencies:

- higher voltage distribution lines can carry more power over long distances, meaning the overall distribution system will require fewer municipal substations; and
- less voltage drop at the end of the line and less line losses for the same power delivered.

Once projects are scoped at a high level, they undergo a field inspection in order to validate the scope of work, identify third party conflicts, and refine estimates before design finalization. Through this process, projects identified for renewal may be subject to change, and poorly performing feeders that demonstrate higher risks may take priority.

E6.2.5 Options Analysis

E6.2.5.1 Option 1: Spot replacement of transformers in deteriorated condition at or beyond their useful life

As of 2017, 19 percent of the transformers in the underground Horseshoe distribution system were at or past their useful life. Without investment, this percentage will increase by more than 50 percent to 29 percent by 2024. This option proposes, at a minimum, to replace all transformers that are at or beyond their useful life that contain or are at risk of containing PCBs to address reliability risks and significantly reduce the risk of releasing PCBs into the environment through oil leaks. Under this approach, Toronto Hydro would maintain the percentage of assets past their useful to 2017 levels at 19 percent.

As of 2017, 400 transformers have at least material deterioration (HI4 and HI5). Without any capital investment, this number is expected to triple to 1,203 by the end of 2024. Not investing in asset renewal will increase reliability risks on the distribution system and run the risk of negative

environmental impacts from asset failure as the transformers continue to deteriorate. Under this option, Toronto Hydro plans to replace all transformers that have at least material deterioration.

However, Toronto Hydro would not be able to maintain the recent improvements made to reliability on the underground system. As of 2017, 77 percent of the direct buried XLPE cables were at or beyond their useful life. Without a proactive solution to address or replace high risk direct buried XLPE cables, by 2024, 90 percent of these cables will be at or past their useful life. This will create scenarios such as continuously failing cables, such as discussed in Section E6.2.3.1. Customers will experience an increase in outages and customer hours interrupted.

Under this option, cables will be replaced reactively through the Reactive and Corrective Capital program.[6] The costs associated with reactively repairing cables significantly exceed planned replacements, particularly when increasing operational and maintenance costs are taken into account. Many challenges are associated with reactive repairs of direct buried cables. As faulted cables are repaired with a splice, which introduces weak points into the cable segments and renders cables more susceptible to future failures.

The spot replacement of all underground PCB transformers units would cost Toronto Hydro an estimated $123.4 million (without EAR or Inflation).

E6.2.5.2 Option 2: Area rebuilds

Under this option, Toronto Hydro would carry out area renewals in areas experiencing poor reliability as a result of direct buried cables, and which have transformers at or beyond useful life that contain (or are at risk of containing) PCBs. To maintain recent reliability improvements, Toronto Hydro plans to replace all 368 circuit-kilometres of direct buried XLPE cable in the underground system through area renewal projects.

However, under this approach, Toronto Hydro would not be conducting spot replacements on a planned basis, and would be running assets to failure and replacing them through the Reactive and Corrective Capital program.[6] As of 2017, 19 percent of the transformers in the underground Horseshoe distribution system were at or past their useful life and without investment, this will increase by more than 50 percent to 29 percent by 2024. Under this option, a large number of such transformers will remain on the system, increasing the risks of units failing and eroding and

[6] Exhibit 2B, Section E6.7.

eventually reversing the recent improvements in reliability. This would also pose an environmental risk as transformers will remain in service that may contain PCBs. Releasing oil containing PCBs (or oil on its own) into the environment may be a breach of the City of Toronto's Municipal Code – Sewer by-law, Ontario's *Environmental Protection Act* and/or, the federal *Canadian Environmental Protection Act*. Toronto Hydro may be ordered to perform work or remediate any non-compliance under one or more of these regimes as the result of a single incident. In sum, the remediation and response costs associated with failed assets are higher than the cost associated with proactive replacement.

E6.2.5.3 Option 3 (Selected Option): Area rebuilds and Spot replacement of transformers at or beyond their useful life

This option is in major part driven by the reliability needs of the system associated with deteriorating and legacy (direct buried) cable installations. Proactive underground renewal carried out through Toronto Hydro's Underground System Renewal program has improved the system reliability, reducing the number of failures from 180 in 2013, to approximately 120 in 2017. However, although the number of failures has decreased, the number of customer interruptions and the hours of customer interruption have decreased at a lower rate. Therefore, Toronto Hydro proposes to continue proactively replacing poor performing assets at or beyond their useful life to mitigate reliability and environmental risks.

Under this option, Toronto Hydro proposes 69 area renewal projects to replace 215 circuit-kilometres of direct buried XLPE cable, transformers at and beyond their useful life that contain or risk containing PCBs, and switches at or beyond their useful life. Through these projects, assets connected to a feeder (e.g. cables, transformers, and switches) will be replaced to meet current standards such as cable installations in concrete encased ducts, transformers, padmounted switches. Despite replacing 215 circuit-kilometres under this option, Toronto Hydro will still have approximately 153 circuit-kilometres of high risk direct buried XLPE cable in the system past 2024.

Under this option, Toronto Hydro would replace approximately 600 transformers at or beyond their useful life containing or at risk of containing PCBs, through rebuild projects. The remaining transformers at or beyond their useful life not addressed through these rebuilds would be replaced on a spot, like-for-like basis to mitigate the environmental risks associated with leaking oil containing PCBs.

As of the end of 2017, Toronto Hydro had 723 switches at or beyond their useful life. Through this option, Toronto Hydro would replace approximately 231 units over 2020-2024 as part of the area rebuild projects. The utility expects to replace the remaining switches through the Reactive and Corrective Capital program upon their failure as they do not present significant environmental risks.[7]

This option could reduce the number of outages experienced due to cable fault and the lengthy process of fault locating on direct buried cable, as described in Section 0.

E6.2.5.4 Option 4: Replace transformers at or beyond their useful life that contain or are at risk of containing PCB, all of the highest risk direct buried cables, and assets with at least material deterioration.

The utility will replace all high risk direct buried cables that contribute to negative reliability impacts in the Horseshoe area. This will allow Toronto Hydro to maintain its recent reliability gains. Under this option, Toronto Hydro will replace all transformers at or beyond their useful life that contain or are at risk of containing PCB (as described in Option 1). This work will minimise the risk of environmental impacts resulting from potential PCB oil spills, and help ensure the utility remains compliant with applicable environmental requirements.

Additionally, under this option, Toronto Hydro will proactively replace all aged assets in the underground system (cables in concrete encased ducts or PVC duct, non-PCB transformer, and switches), as well as the 149 switches, and the non-PCB risk transformers (among the 1193 that will reach at least material deterioration, i.e. HI4 and HI5, by 2024).

This alternative would allow Toronto Hydro to maintain and improve reliability in the Horseshoe area by reducing asset failure risk, and minimize environmental risks. While this option is preferred from a risk-mitigation perspective it is a higher cost option that does not represent the optimal balance between customer needs with respect to reliability and price of service.

E6.2.6 Execution Risks & Mitigation

Project execution begins with the civil phase of the underground renewal project. Electrical construction commences upon completion of the civil work. The risks associated with the Underground System Renewal program include, but are not limited to:

[7] Exhibit 2B, Section E6.7

- Unforeseen updates and changes to existing road moratoriums imposed by the City of Toronto in areas where Toronto Hydro intends to perform underground renewal work. In this case, Toronto Hydro will mitigate the risk by through close coordination with the City of Toronto and its representatives, i.e. Ward Councillor, Business Improvement Area delegates.
- Unforeseen weather conditions that may affect Toronto Hydro's ability to take planned outages (i.e. heat restrictions), or construction in the fall and winter due to harsh weather (i.e. storms or extreme cold periods).
- Third party conflicts may require Toronto Hydro to modify its trench route due to underground space limitations, resulting in higher than estimated project costs. Toronto Hydro mitigates this risk by engaging with third parties in the design phase to ensure close coordination and alignment. For instance, Toronto Hydro's participation in the Toronto Public Utility Coordinating Committee meetings is an effective mean of identifying and avoiding third party conflicts.
- Some projects require work within customer owned civil structures or consent on easements from customers to install distribution assets in private property. In the case of customer owned civil structure, the customer may have to perform civil rebuild work prior to Toronto Hydro commencing its activities, causing project delays. Toronto Hydro mitigates this risk by inspecting customer owned assets during the design phase and communicating to the customer by issuing Customer Advice Form ("CAF") for any deficiency identified. This ensures that customers are given advanced notice and have an opportunity to raise their concerns and address the civil work in a timely manner. For permits and easements, Toronto Hydro will reach out and engage customers early in the design phase of the project to account for the possibility of delays. This gives customers the opportunity to meet with the utility to discuss the details of the project and any concerns. This proactive customer engagement approach has been successful in minimizing construction delays.
- All underground projects are designed and constructed in accordance with approved Toronto Hydro's standards and specifications. However, in certain cases, deviations or special considerations are needed during design. Toronto Hydro will follow its established process for all deviation requests so that they can be assessed and approved by the standards department in a timely manner during the design phase. This process helps to prevent delay or costly rework due to operational issues during the execution of the projects.

E6.3 Underground System Renewal – Downtown

E6.3.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 0	**2020-2024 Cost ($M):** 122.0
Segments: Cable Chamber Renewal, Underground Cable Renewal, Underground Residential Distribution Renewal	
Trigger Driver: Failure Risk	
Outcomes: Reliability, Environment, Safety	

The Underground System Renewal – Downtown program (the "Program") addresses aging, deteriorating and poor performing underground distribution assets in the downtown core[1] area of pre-amalgamation City of Toronto. Material asset deterioration and aging have been significant drivers of Toronto Hydro's ramp-up in capital investment since the late 2000's; with the largest renewal investment proactively addressing declining asset condition and performance in the more dispersed inner suburbs (i.e. the Horseshoe area) of Toronto.[2] This Program introduces equivalent rebuild and replacement activities for deteriorating and functionally obsolete underground assets in the City's core. To date, these assets have been managed through a combination of preventative maintenance,[3] targeted refurbishment, and in the event of asset failure, reactive and corrective capital[4] and maintenance.[5] The average condition of these assets (in addition to other pressures discussed below) necessitates a targeted renewal strategy; targeting worst performing and highest risk locations.

The Program is designed to deliver reliability improvements, mitigate asset failure and public safety risks within the downtown core by: (1) replacing obsolete underground lead covered cables with standard tree retarded cross-linked polyethylene cables, (2) reconstructing cable chambers (or components; e.g. roofs, duct banks) at risk of failure due to poor structural conditions, and (3) proactively replacing end-of-life and obsolete underground residential distribution ("URD") assets -

[1] This Program does not address network units or network vaults. Network equipment is addressed within the Network System Renewal program (Exhibit 2B, Section E6.4)
[2] See Exhibit 2B, Section E6.2
[3] See Exhibit 4A, Tab 2, Schedules 1, 2, and 3 Preventative and Predictive Maintenance programs
[4] See Exhibit 2B, Section E6.7
[5] See Exhibit 4A, Tab 2, Schedule 4 Corrective Maintenance

unique, looped distribution design serving primarily low-rise residential customers in limited areas of the pre-amalgamation City of Toronto.

The Program is grouped into the three segments summarized below:

- **Underground Cable Renewal:** This segment replaces the PILC Leakers & Piece-outs program[6] which Toronto Hydro is on track to complete in the 2015-2019 period. While the PILC Leakers & Piece-outs program addressed immediate safety and operational risks related to known leaking cables and congested chambers, this Program focuses on the longer-term challenge of gradually removing the large population of these deteriorating and obsolete cable types from the system. Specifically, the segment will replace obsolete underground lead covered cables with standard tree retarded cross-linked polyethylene cables. Based on the age and condition of Toronto Hydro's population of lead cables, the utility anticipates a decline in reliability performance and an increase in operational and safety risks. Toronto Hydro recognizes the customer value stemming from the removal of these high risk, lead based cables, and plans to invest $89.7 million over the 2020-2024 period to replace approximately 2.5 percent of 1,100 km paper-insulated lead-covered ("PILC") cable and 24 percent of 220 km asbestos-insulated lead-covered ("AILC") cable. It is estimated that these replacements will prevent 2,800 Customer Interruptions ("CIs") and 8,700 Customer Hours Interrupted ("CHI") for downtown customers (mostly commercial customers) over the 2020-2024 period. This will also decrease the presence of designated substances (i.e. lead and asbestos) on the grid. These cables are a critical part of the distribution infrastructure serving large customers (e.g. major financial institutions) and other reliability-sensitive customers (e.g. multi-residential high-rises) in the downtown core. To manage the pacing of investment in this segment, Toronto Hydro has begun to predict with increasing accuracy and precision the cable segments at the highest risk of failure. Combining this risk-based prioritization with the amount and criticality of the load served by each feeder allows Toronto Hydro to direct expenditures to the projects with the greatest customer value. /C
- **Cable Chamber Renewal:** This segment involves the reconstruction of cable chambers or cable chamber components (e.g. roofs, duct banks) that are at risk of failure due to their poor structural condition. To date, Toronto Hydro has managed the reconstruction of cable chambers reactively. However, due to the growing number of failing chambers and the

[6] EB-2014-0116, Exhibit 2B, Section E6.2

complexity of chamber reconstruction work, Toronto Hydro is introducing a planned renewal segment in 2020. The vast majority of chambers in HI4 (material deterioration) and HI5 (end of serviceable life) condition are located in the downtown core, where there is heavy vehicular and foot traffic and a high density of circuits running through each chamber. These chambers can hold up to 29 circuits, supplying up to 3,500 customers per chamber. Typically, these are chambers that supply large condominiums with many suite-metered residential customers. Chambers can also supply one or several large industrial or commercial customers. As of 2017, 16 cable chambers were in HI5 condition and 188 were in HI4 condition. To address this growing backlog, Toronto Hydro's goal is to reach zero cable chambers in HI5 condition by 2024 (this does not include chambers that actively become HI5 over the 2020-2024 period Toronto Hydro has approximately 10,700 cable chambers, including 5,900 in the downtown area. Toronto Hydro plans to execute an estimated 15 chamber rebuilds, 24 chamber roof rebuilds, and three chamber abandonments per year during the 2020-2024 period. Toronto Hydro also plans to replace 200 cable chamber lids per year to address potential public safety risks in high traffic areas. The total forecast cost for this segment is $29.1 million.

- **Underground Residential Distribution ("URD") Renewal:** This segment is focused on the URD system – a unique, looped distribution design serving primarily low-rise residential customers in limited areas of the pre-amalgamation City of Toronto. Toronto Hydro has recently seen a sharp increase in the volume of corrective work requests on this system, along with an increase in outage frequency and an observed deterioration in condition. The utility plans to proactively replace end-of-life and obsolete URD assets that contribute to the deterioration of system reliability, namely switching and non-switching vaults, switches, and transformers. Toronto Hydro's objective for 2020-2024 is to invest the amount needed to maintain average reliability performance for the customers served by this system. The utility aims to achieve this by targeting the worst condition and most critical assets. Toronto Hydro is budgeting an estimated $3.2 million over the 2020-2024 period to address the civil and electrical assets at three to four URD vault locations per year.

The Underground System Renewal – Downtown program for the 2020-2024 rate period is also aligned with the objectives of addressing environmental and safety risks associated with distribution assets containing PCB or asbestos. The total proposed investment for the Program in 2020-2024 is $122 million.

E6.3.2 Outcomes and Measures

Table 2: Outcomes & Measures Summary

Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7) and reduces the risk of lengthy outages on feeders serving thousands of downtown customers, including large, critical customers in the core while improving long-term system health by: ○ Replacing an estimated 27 kilometres of PILC cable that is subject to a high risk of failure. ○ Rebuilding cable chambers known to be in HI5 and HI4 condition. ○ Reducing the average number of splices and transition joints on downtown feeders.
Environment	• Contributes to improving Toronto Hydro's Spills of Oil Containing PCBs measure and reducing the risk of toxic exposure to the environment by: ○ Eliminating PILC cable containing oil and potentially PCBs; ○ Eliminating AILC cable containing asbestos; and ○ Eliminating PILC and AILC cable containing lead.
Safety	• Contributes to the utility's public and employee safety objectives and performance by: ○ Replacing 200 chamber lids per year to reduce the risk of injury or property damage from cable chambers lid ejections; ○ Eliminating safety hazards such as poor structural integrity and cable congestion; ○ Reducing the safety hazards related to the structural failure of cable chambers in high-traffic areas by replacing or abandoning HI5 and HI4 condition chambers and chamber roofs; and ○ Reduce the potential exposure to lead and asbestos classified as Designated Substances under the *Occupational Health and Safety Act* (O. Reg. 490/09 Sections 5 and 10). ○ Safely hand and dispose of asbestos (and lead) as prescribed in the *Ontario Occupational Health and Safety Act* (Reg. 833) and the *Canadian Environmental Protection Act*.

/C

E6.3.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Failure Risk
Secondary Driver(s)	Functional Obsolescence, Safety, Environmental Risk

The Underground System Renewal – Downtown program is driven by the failure risk of key assets that negatively impact reliability and safe operation within the downtown core. Historically, these assets have shown high reliability but have now become obsolete or pose a risk to the public and the environment. Many of these assets are vital to supply critical customers in the downtown district. These are of particular concern for large commercial customers who prioritize reliability over cost and residential customers who prioritize cost over reliability as demonstrated through the customer engagement surveys.

E6.3.3.1 Underground Cable Renewal

The Underground Cable Renewal segment will focus on replacing obsolete primary PILC and secondary AILC underground cables at a high risk of failure with tree retarded Cross-Linked Polyethylene ("TRXLPE") cable. These cables are typically found in the pre-amalgamation City of Toronto, especially throughout the downtown core. This segment replaces the PILC Leakers & Piece-outs program, which Toronto Hydro is on track to complete in the 2015-2019 period.[7] The PILC Piece-out & Leakers program was designed to deal with the rapid emergence of a large backlog of leaking cables, which present a safety hazard to Toronto Hydro crews. The previous program addressed approximately 15 km of PILC cable where numerous critical deficiencies had been noted through inspections. Having dealt with the immediate safety and operational risks related to known leaking cables and congested chambers, Toronto Hydro is now shifting its focus to the longer-term challenge of gradually removing the large population of these deteriorating and obsolete cable types from the system.

PILC and AILC cables were initially installed in the downtown system due to their high reliability and long life span. However, they are becoming obsolete across the industry due to environmental and health and safety concerns (which includes the challenge of safely and skillfully working with lead). Major urban utilities are proactively eliminating lead cable, and only one PILC supplier remains (there

[7] Exhibit 2B, Section E4

are no longer any suppliers of AILC cables). As a result, approximately 42 percent of all PILC cables and 68 percent of all AILC cables in the system are more than 30 years old. Aged cables are showing signs of deterioration, including pin holes, cracks, and leaks.

Other utilities across North America have recognized the customer value stemming from the removal of high-risk lead-based cable. For example, the U.S. Environmental Protection Agency ("EPA") has recognized utilities ConEd of New York and PSE&G of New Jersey for their efforts to remove lead cable from their system. ConEd began their replacement efforts in the 1990s to remove PILC. At the end of 2015, based on an average rate of 120 miles of cable replacement per year, ConEd had 10 percent of PILC cable remaining in its system. PSE&G successfully removed 1.3 million pounds of lead from PILC.

Toronto Hydro is planning to remove approximately 24 percent of AILC cable (53 circuit kilometres of 220 kilometres) and 2.5 percent of PILC cable (27 circuit kilometres of 1,100 kilometres) between 2020 and 2024. The cables will be replaced based on the risk level associated with each cable segment. A statistical method has been developed by Toronto Hydro to prioritize primary cable segments to improve reliability. This was accomplished to generate a prioritized list of high risk cable segments. Various factors, including historical failures, number of splices on feeders, age and customer base, are used to determine cable segment risks. In addition, as primary cables and cable segments are being tested or replaced, Toronto Hydro will re-prioritize at-risk feeders. Where at-risk primary cable sections are identified, this will drive the replacement of the legacy type AILC cable that is connected downstream of these cable sections. /C

PILC cable consists of a conductor surrounded by oil-impregnated paper insulation, lead sheath and an optional linear low-density polyethylene jacket. There are approximately 1,100 circuit-kilometres of 13.8 kV PILC underground cable on the system. These cables are used as the primary service cable in the downtown core, connecting transformer stations to customers or Toronto Hydro owned distribution transformers (these transformers step down voltage and supply residential customers). Approximately 60 percent of all primary cable in the downtown core is PILC cable and approximately 40 percent is XLPE cable.

Figure 1 shows the distribution of PILC cable in the City of Toronto and the level of risk associated with them based on the type of cable, age, and condition (including number of splices and historical faults). The highest risk cables are found both within and around the downtown core, while the medium risk cables are heavily concentrated within the core, and the Financial District in particular.

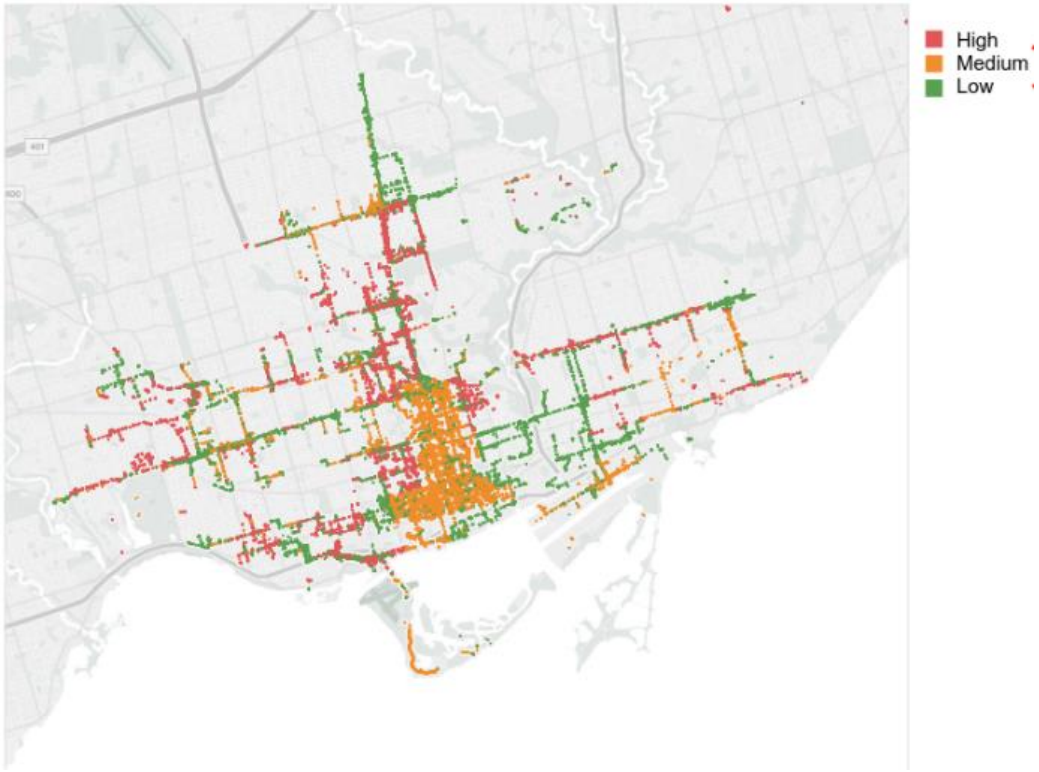


Figure 1: PILC Cable Distribution Risk

AILC cables are found downstream of these PILC cables. They consist of a conductor (typically copper) surrounded by asbestos-based insulation and covered in a ductile lead sheath. These cables account for 64 percent of the secondary voltage connections within the secondary network system.[8]

Figure 2 represents the general distribution of all AILC cables in the city of Toronto and their level of risk based on the associated age and condition of primary assets.

[8] For more information on the Secondary Network System, please refer to Exhibit 2B, Section D2.2.3 of the DSP.

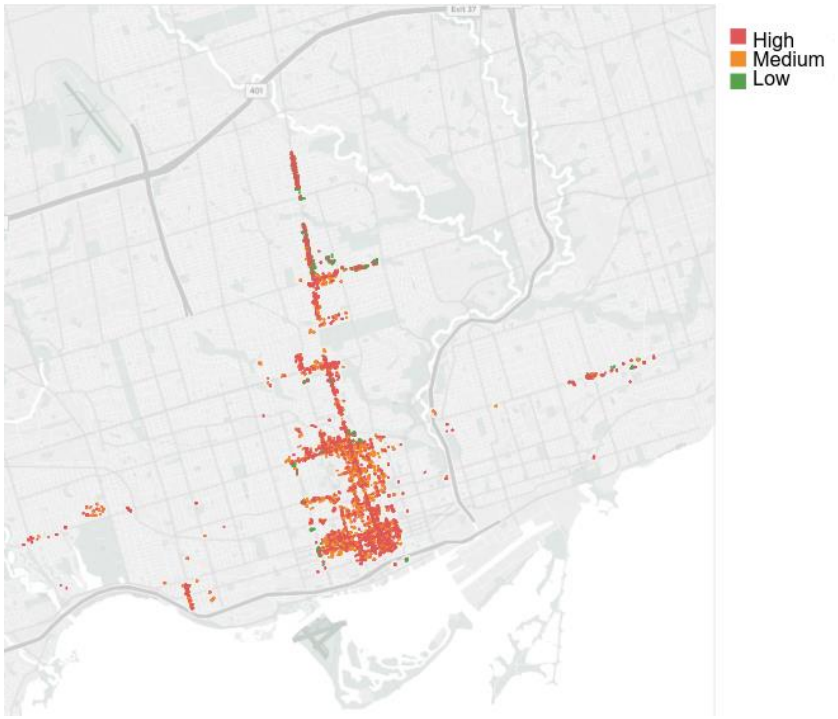


Figure 2: AILC Cable Distribution and Criticality Risk

The increasing non-uniformity of cable types in the system drives the failure risk of these cables. Due to the obsolescence of PILC and AILC cables, the necessary interventions and modifications to downtown feeders have unavoidably resulted in the splicing of XLPE cable into sections of PILC and AILC cable. Splicing is the process used to maintain the connectivity between two cable sections or cable types. It is typically carried out when a longer cable is required, a branch is required, or part of an old cable is replaced with a new cable. Although cables have a long life expectancy, cable splices do not. The failure risk does not stem from the cable itself, but from the splices which are a result of combining cable types on any given feeder. This increases the risk of failure on the system as the majority of Toronto Hydro feeders with PILC and AILC cables do not consist of 100 percent PILC or AILC; instead, a mixture of cable types is common (e.g. PILC and XLPE, or AILC and XLPE).

Table 4 summarizes the programs and types of work that lead to a mix of cable types on Toronto Hydro feeders:

Table 4: Work conducted on Toronto Hydro feeders that lead to mixed cable types

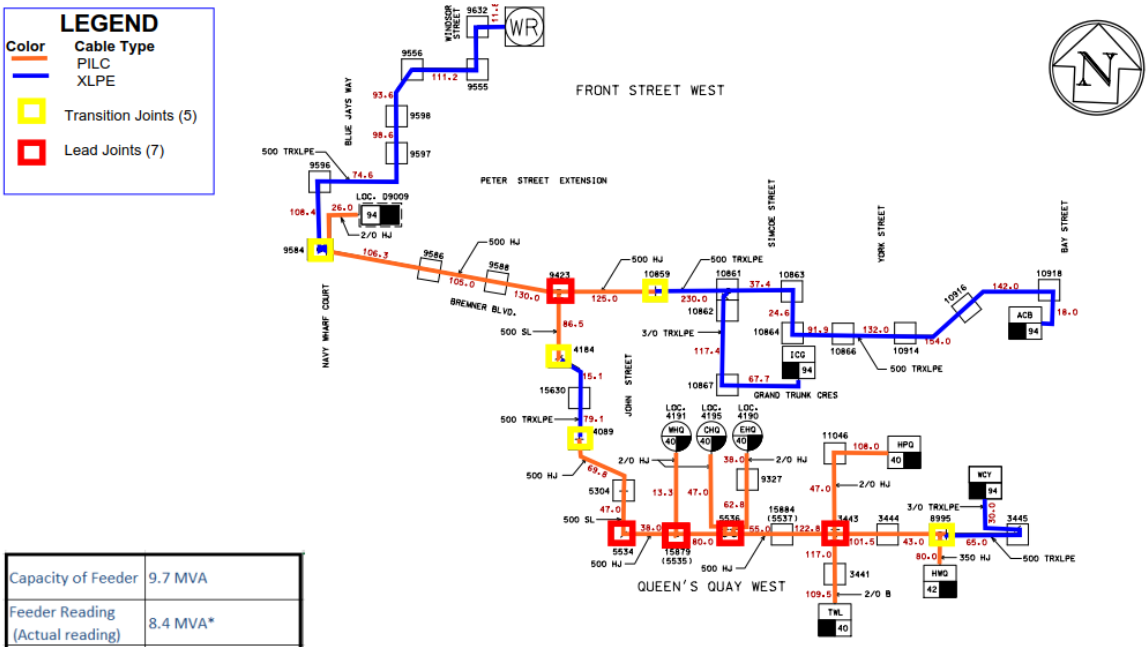
Programs	Description of Work
Customer Connections (Exhibit 2B, Section E5.1)	• Customers are connected with new XLPE type cable spliced to existing PILC cable. • This also includes the addition of XLPE cable for secondary network type connections (replacement of AILC cable).
Reactive Capital (Exhibit 2B, Section E6.7)	• Cable faults or leaking cables are repaired by cutting or piecing-out faulty sections, and replaced with new XLPE cable, using splices.
Load Demand (Exhibit 2B, Section E5.3)	• Cable sections that require upgrades due to capacity limitations are replaced with new XLPE cable.
Network System Renewal (Exhibit 2B, Section E6.4)	• Circuit reconfigurations, required to achieve network stability and improved reliability, involve splicing new secondary and primary XLPE cable into existing AILC and PILC cables. • Network unit replacements include the replacement of critical AILC or PILC type cables that are connected to these units. • Cables to the most upstream cable chamber are replaced resulting in the introduction of splices.

As a result of the Table 4, lead cables become more brittle and prone to cracking, and the number of transition joints or splices increases over time. These splices create and add weak points along the cable and introduce additional failure risk to already aging cables serving many large and critical loads. Consequently, feeder life expectancy and probability of failure worsen. As the weakest point on a feeder, a cable joint may fail primarily due to mechanical stress or water ingress.[9] A fault in the joints may also impact the conductor, insulation, or sheath. For instance, the sheath of the joints can develop corrosion due to thermal stresses of the feeder, which increases the chance for moisture to seep into the joint and consequently cause a failure.

The introduction of mixed insulation types also introduces different dielectric strengths or inconsistent magnetic fields at the joints which would result in higher losses or insulation breakdown. These transition joints (splices) are critical to the continuity of the dielectric properties and magnetic

[9] Nemati, H.M., Sant'Anna, A., & Nowaczyk, S. (2015). Reliability Evaluation of Underground Power Cables with Probabilistic Models, *The 2015 International Conference on Data Mining,* p. 37-43.

field across cable sections. They require a lead sleeve for the cable section to maintain the insulation properties of PILC cable. This is to hold the oil from oil-impregnated paper and protect insulation as much as possible. If these sleeves are compromised, this can result in drying out of the impregnated paper and compromise the insulation properties. Furthermore, as cable sections age, they begin to experience thermal, environmental, or mechanical stresses. Since XLPE and lead cables have different properties, the transition joint on any given feeder experiences the most stress. For example, the Windsor TS feeder A-93-WR supplies 7 large customers, and includes 5 transition splices and 7 lead joints, as shown in Figure 3 below. Failure at any of these splices or joints will result in an outage while crews switch customers to backup supply, which typically takes 2 to 4 hours and subsequently about 8 to 10 hours until full power is restored.



Capacity of Feeder	9.7 MVA
Feeder Reading (Actual reading)	8.4 MVA*
N-1 Contingency (Load if A-94-WR is de-energized)	11.6 MVA*

*Based on a non-coincident peak loading condition

Figure 3: Schematic Feeder A-93-WR that depicts Transitional and Joint Splices

Figure 4 below illustrates examples of splices with deficiencies.



Figure 4: Sample PILC Joint with a Split Sleeve, i.e. Leaker (Left) and Collapsed Cable Splice (Right)

In addition to increased failure risk due to cable splicing, there is the risk of oil leakage from the insulation on PILC cables. Over time, due to load fluctuations and physical stresses on feeder cables, the outer covers of lead cables develop cracks, causing oil from the paper insulation to leak from the cable and pool on the cable chamber floor. On average, Toronto Hydro finds 8 such leaks per year.

As shown in Figure 5 below, the failure rate of lead splices and transition joints per kilometre increases with the age of the feeder sections, i.e. the older the feeder, the higher the number of outages. The majority of these failures are due to moisture ingress, reduction in dielectric strength due to oil leaking from cracks and pinholes, as well as thermal stress.

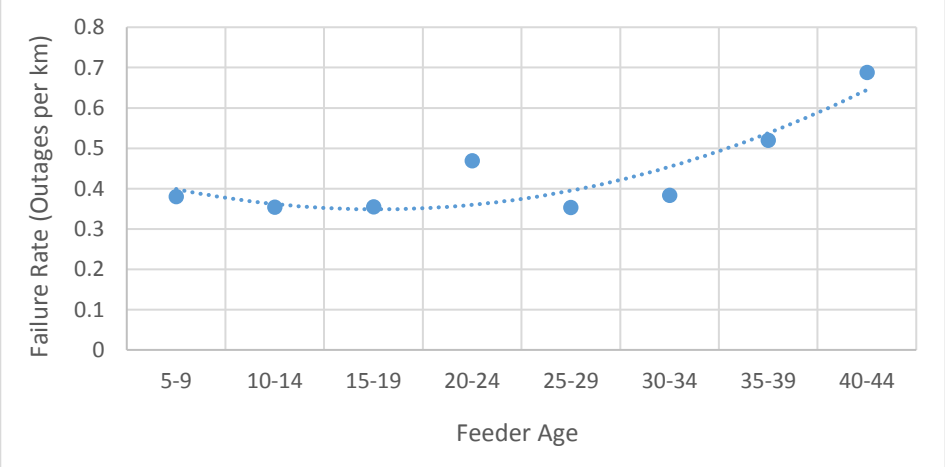


Figure 5: Failure rate of cable splices with PILC[10]

[10] It is important to note that Toronto Hydro keeps a limited quantity of PILC cables on hand for extreme circumstances where reactive repair is required.

On average, there are 6 transition joints and 40 lead joints per primary feeder in downtown Toronto. By the end of 2024, given the PILC cable planned for replacement, Toronto Hydro expects to reduce the average number of transition joints to 4 and lead joints to 30. Figure 6 and Figure 7 illustrate the current state of transition joints and lead joints in the system on feeders (though not all feeders are labelled therein).

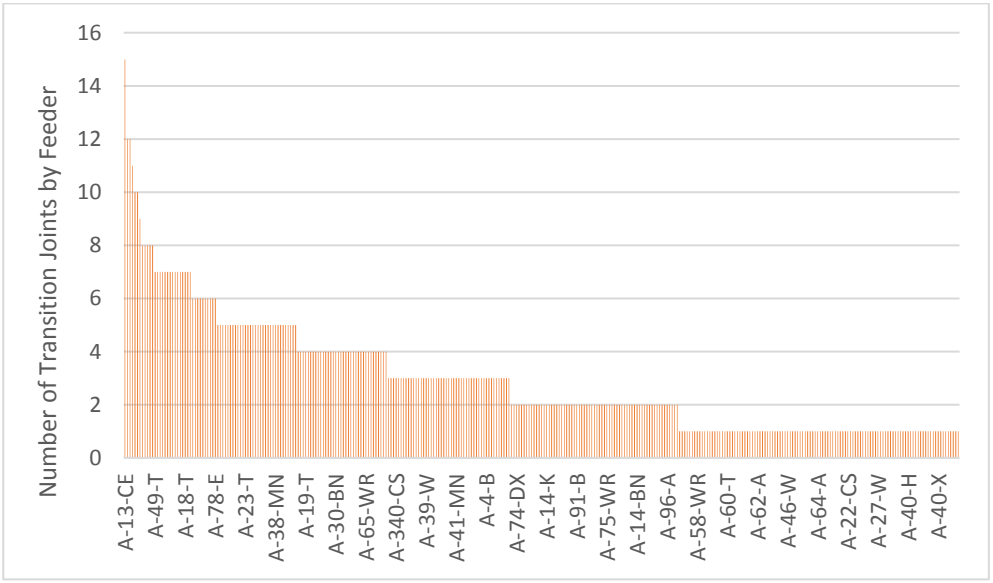


Figure 6: Transition Joints by Feeder

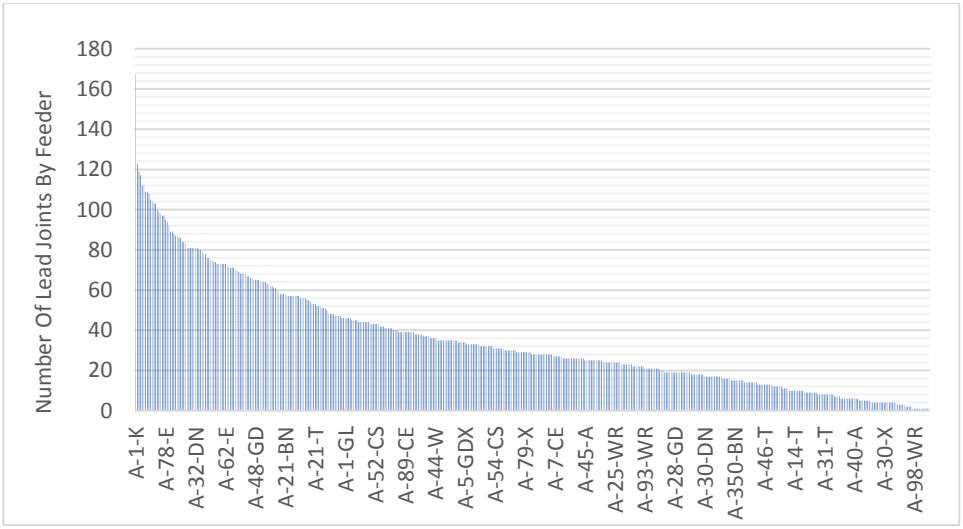


Figure 7: Lead Joints by Feeder

As shown in Figure 8, there are on average 26 reported PILC cable or splice related failures per year, including on average 14 failures per year related to splices.

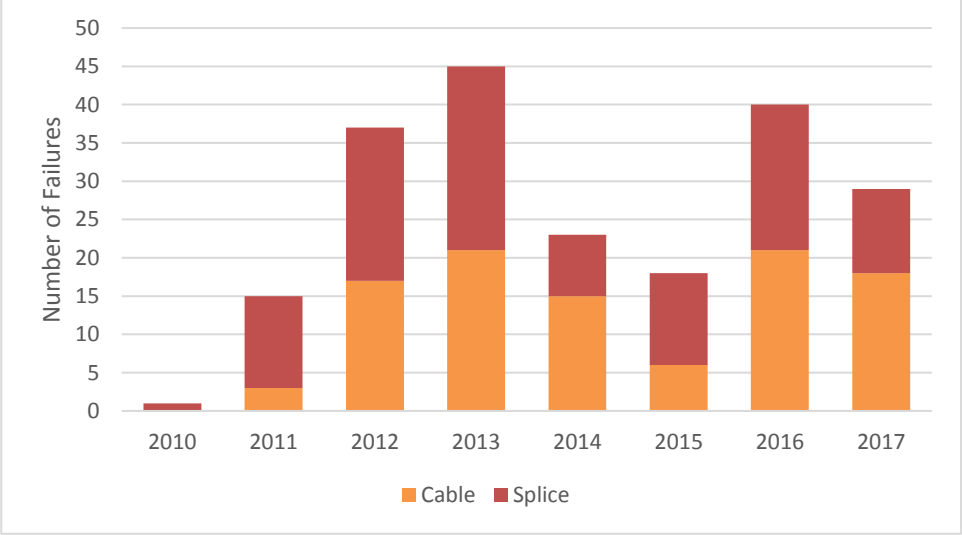


Figure 8: Number of PILC Cable/Splice Failures per Year

Based on the reported 208 cable and cable splice related incidents between 2010 and 2016, there is a clear relationship between age and failure per km. As per Figure 5, the number of failures per km rises with cable age. Quantitatively, this trend aligns with the qualitative observation by field personnel of the rise of failures as more splices are introduced while cable sections age.

Cable failures affect a wide range of customers, whose configuration of connection to the system depends on the feeder and the supply location and not necessarily customer type. Figure 9 below illustrates this using seven sample feeders. This segment aims to target feeders with large loads like the A-93-WR, and introduce uniformity of cable by proactively replacing a large section of cable especially in the downtown core. This aligns with the customer engagement results where downtown customers (especially large customers) prioritize reliability over price. Large multi-residential buildings are treated as large commercial customers since minimal cable renewal investments will impact many end use customers.

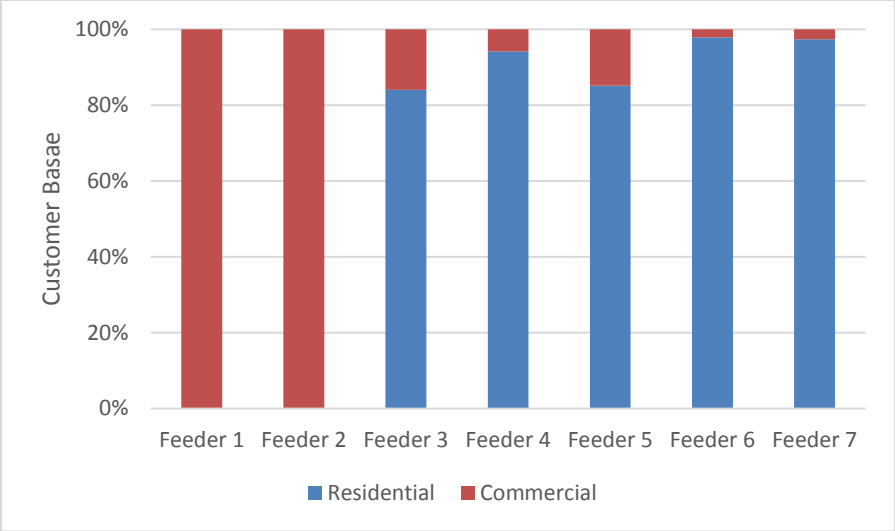


Figure 9: Composition of Customer Type of Circuits with PILC Cable

Lead-based cables (e.g. AILC and PILC) also need to be removed from the system due to a large functional obsolescence component. Lead splicing typically requires highly qualified and trained individuals. Many utilities are facing the challenge to train personnel with respect to lead splicing techniques. The skillset in the workforce is diminishing as lead cable is not actively introduced into the system. Furthermore, PILC cable is only supplied by one North American manufacturer at this time and a procurement problem may arise in the near future, while AILC cables are currently obsolete and are no longer supported by any manufacturers. Although Toronto Hydro stocks minimal PILC cable, it is not actively introduced into the system. Rather, polymeric XLPE and TRXLPE cables are used. As noted above, this increases failure risk if these non-homogenous feeder types are not minimized.

These cables present both safety and environmental risks. Lead is a designated substance as per Ontario Regulation 490/09 (see section 10) and exposure should be minimized to mitigate the health risks. The risks of working with this substance alone is a potential safety hazard as lead needs to be exposed to high temperatures to complete a lead splice. This can create airborne fumes increasing the occupational, and environmental exposure. Further, PILC cables manufactured prior to 1986 may contain PCBs within the oil. Toronto Hydro is committed to mitigating the risks of oil leaks containing PCBs. Leaking PILC cables also present risks to crew and public safety as the likelihood of arc flashes due to the deterioration of the insulation is high. Arc flashes are dangerous to crews and pose a safety risk to the public if leaking oil becomes ignited. Leaking oil is a sign of pending cable failure.

E6.3.3.2 Cable Chamber Renewal

The Cable Chamber Renewal segment will invest in the structural integrity of Toronto Hydro's aging population of cable chambers by rebuilding or abandoning HI4 and HI5 condition chambers. Cable chambers house, protect, and provide access to underground electrical equipment across the city. There are 10,655 cable chambers in Toronto Hydro's underground distribution system of which approximately 80 percent are in the downtown area. These chambers hold up to 29 circuits each, supplying anywhere from 3,500 customers of different types and sizes, down to a few large industrial or commercial customers (e.g. financial institutions, hospitals).

Cable chambers have a useful life of 65 years, while chamber roofs have a useful life of 25 years, meaning that the roof will require a rebuild at least once during the useful life of the chamber. Figure 10 shows the remaining useful life, as of 2017, for all cable chambers and roofs. Approximately 2,400 chambers and 6,800 chamber roofs will be at, or beyond, their useful lives by 2024.

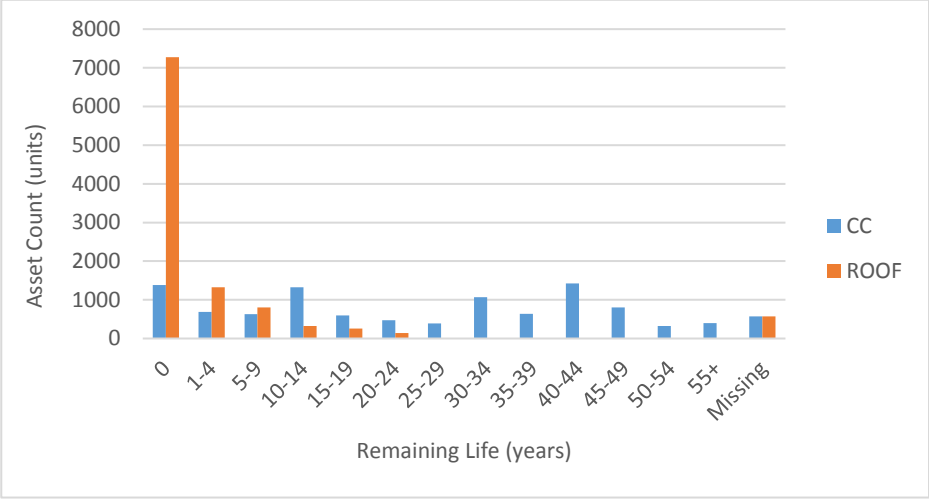


Figure 10: Remaining Useful Life of Cable Chambers (CC) and Roofs

Toronto Hydro inspects cable chambers and cable chambers roofs on a planned 10-year cycle. The growing backlog of aging cable chambers is reflected in the observed condition of the assets. Figure 11 below shows the asset condition of the 10,665 cable chambers in Toronto Hydro's distribution system as of 2017. The data indicates that 507 cable chambers have conditions classified as HI5 or HI4 and will require rebuild in the near-term. Furthermore, inspection data indicates that an additional 102 cable chamber roofs are in HI4 condition.

Depending on the severity of issues, Toronto Hydro ensures the time of rebuild is determined based on a holistic review of the structural condition of the chamber (even if classified as HI5). This means a cable chamber may require a reactive rebuild or temporary repairs to mitigate safety risks which would allow for a planned rebuild in the future.

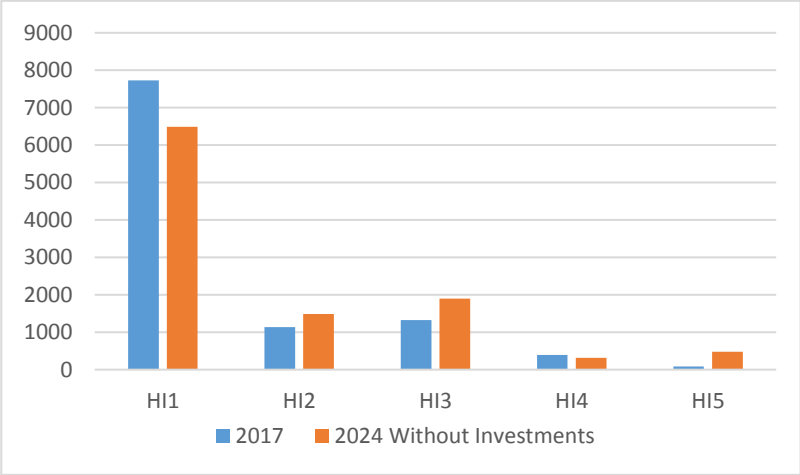


Figure 11: Projected Cable Chamber Asset Condition as of 2020 and 2024 without Investment

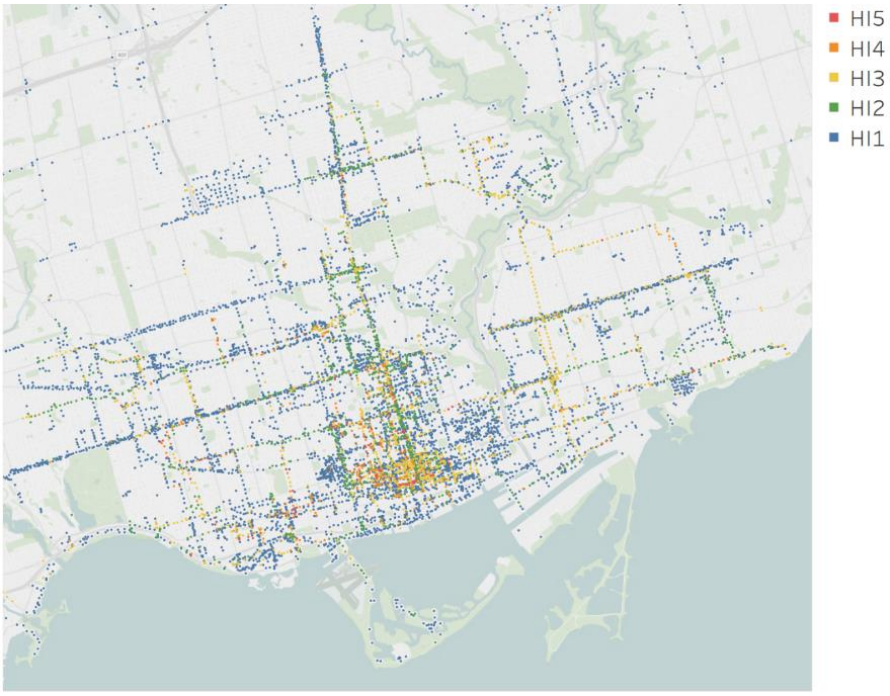


Figure 12: Cable Chamber Locations and Conditions

Figure 12 above shows the high concentration of HI4 and HI5 condition chambers in the downtown core, where, as mentioned above, the chambers tend to carry a high concentration of circuits serving thousands of customers, or large customer loads. Should a chamber or chamber roof collapse to any extent, the equipment in the chamber could be damaged, leading to a potentially lengthy outage for the aforementioned customers.

Of equal or greater concern is the risk to crew and public safety posed by a failing cable chamber. In areas of high vehicular or foot-traffic especially, a structurally unsound chamber or roof can create hazards to the public. The collapse of a chamber or chamber roof could have more severe consequences for the public or for crews working in the chamber. Figure 13 below shows an example of a severely deteriorated cable chamber roof.



Figure 13: Cable Chamber Roof in HI5 Condition (Left), and Cable Chamber Roof Inside View (Right)

The images shown in Figure 13 are an example of a cable chamber with a reduced neck which is common when the City rebuilds or regrades roads. In this situation, when the asphalt was removed, a hole was discovered. This is very dangerous especially if the hole or deteriorated structure is covered by newly paved road.

Depending on the specific site, addressing a HI4 or HI5 condition chamber will include:

- **Full rebuild:** rebuilding the cable chamber civil structure, including its roof and duct banks, and involves some cable replacement; or
- **Roof rebuild:** rebuilding only the roof.

In addition to rebuilds, Toronto Hydro also plans to continue proactively replacing potentially hazardous cable chambers lids. Deteriorated cables running through cable chambers can become hot, potentially causing arcing and igniting gases which then can create a powerful shock wave. These shock waves can dislodge a chamber lid in a violent manner, ejecting it into the air and creating a serious public safety hazard. To date, Toronto Hydro has recorded 43 incidents related to cable chamber lids. As previously proposed in Toronto Hydro's 2015-2019 rate application,[11] the utility planned to replace lids on cable chambers to mitigate ejection risks. The plan was for new ejection-proof lids to become a standard based on trial installations in 2015. After the trials, modifications were required. Nevertheless, Toronto Hydro plans to install only 252 cable chambers lids by the end of 2019. Going forward, Toronto Hydro expects to replace 200 cable chamber lids per year and aims to replace all cable chamber lids that have a potential for lid ejection.

Toronto Hydro plans to replace all cable chamber lids proactively with a new energy mitigating design that will reduce the likelihood that a cable failure or other event within the chamber will cause the lid to become violently dislodged (thus placing the public at risk).

E6.3.3.3 Underground Residential Distribution Renewal ("URD")

This segment aims to replaces end-of-life and obsolete URD assets that contribute to the deterioration of system reliability. These assets include: vaults, switches, and transformers that form part of the URD system. Toronto Hydro plans to invest to maintain reliability performance. As per Toronto Hydro's customer engagement results, residential customers prioritize cost over reliability and therefore, only specific areas of the URD system are targeted for renewal in this segment rather than addressing the system as a whole.

Introduced in the 1990s, the URD system was intended to replace the 4 kV overhead system supplying residential customers in the downtown area. The URD system comprises of redundancies via main loops and sub loops to add a level of robustness by isolating sections of the feeder (see section D2 of the DSP for a more detailed overview of the URD system).[12]

To date, Toronto Hydro has managed the replacement of switches, transformers, and roof repairs on a reactive basis. However, due to the growing number of failing URD vault roofs, severe corrosion and obsolete equipment, Toronto Hydro is introducing a planned renewal segment in 2020. Since

[11] EB-2014-0116 Application, Exhibit 2B, Section E6.3, p. 16.
[12] Exhibit 2B, Section D2.2.2

2010, Toronto has reactively performed close to 4,000 work orders to repair or replace assets tied to the URD system. Figure 14, Figure 15 and Figure 16 below show the work orders issued for URD vault repairs and rebuilds, as well as transformer and switch repairs and replacements since 2010. As seen in Figure 14, Toronto Hydro has recently seen a rapid increase in work orders for URD vault civil repair and rebuilds compared to 2014 and 2015. In the past, most work orders issued addressed URD vault condition repairs. However in 2017, there was an increase in work orders that require URD vault roof rebuilds. As the URD vault roof approaches its end-of-life, an increase in work orders for URD vault roof rebuild is expected.

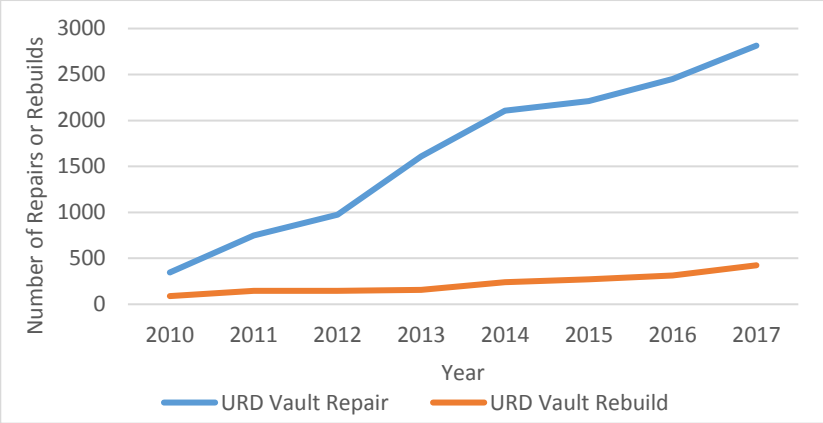


Figure 14: URD vault civil repair and rebuild

Figure 15 shows that for URD transformer replacement, Toronto Hydro has seen an average increase of 10 work orders per year for reactive transformer replacement.

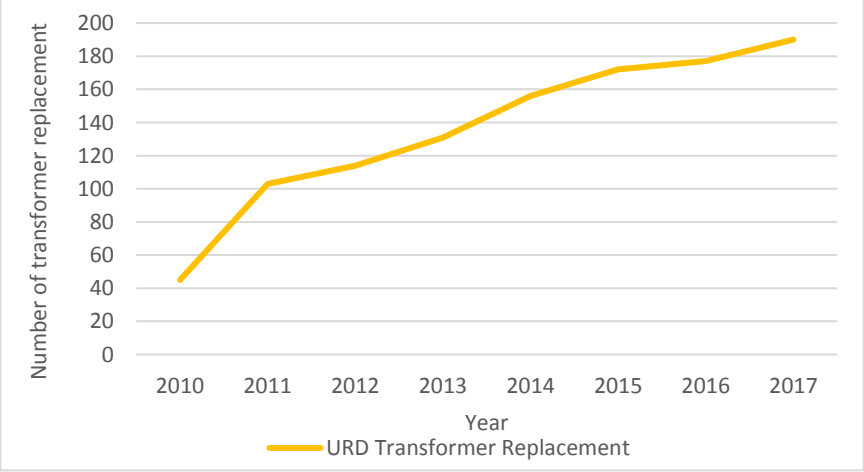


Figure 15: URD transformer repair and replacement

As for URD switch replacement, Toronto Hydro has seen an increase in URD switch replacements between 2010 and 2017 as shown in Figure 16.

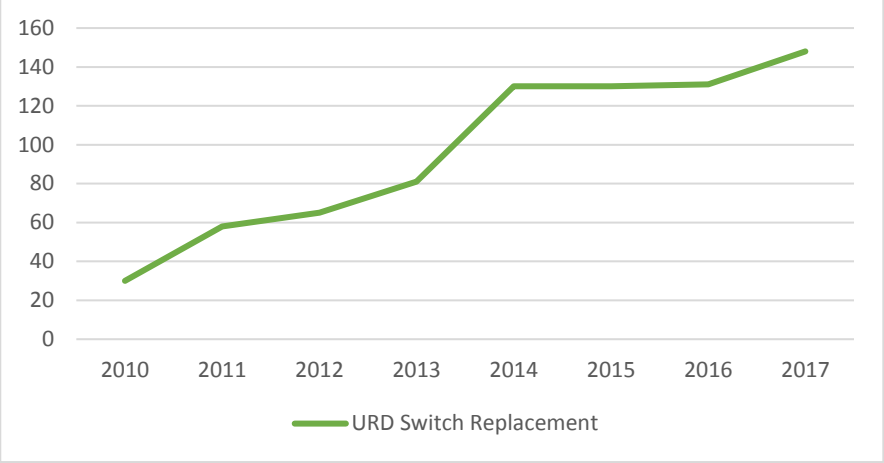


Figure 16: URD switch replacement

The main underground system configurations are either radial or looped. However, system types and configurations are sometimes mixed to provide better reliability or flexibility when repairs are required, as is the case with URD. In the URD system, primary cables, switches, and distribution transformers are placed underground while most secondary voltage connections remain overhead. This system only appears in limited areas throughout the pre-amalgamation City of Toronto, as seen in Figure 17 below.

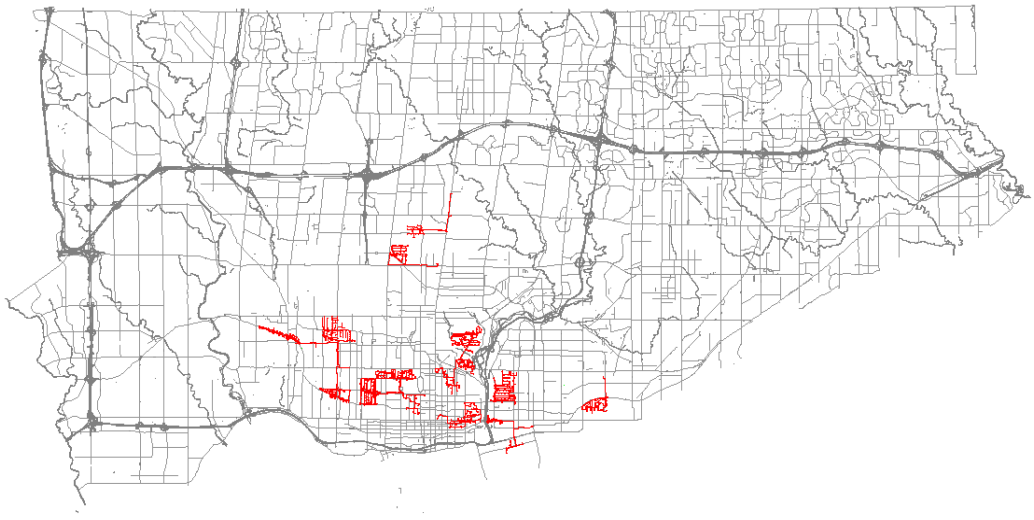


Figure 17: Map of Toronto with URD feeders

The URD has three distinct feeder sections: (i) a main-loop; (ii) sub-loops; and (iii) branch circuits (or sub-sub-loops). The main loop does not serve any customers but is equipped with multiple 600 A switching vaults that allow for the isolation of the sub-loops and branch circuits in the event of a fault. Customers are supplied directly from either the sub-loops or branch circuits, which allows partitions within the feeder to minimize interruptions if work is required. Figure 18 below provides a simplified example of the configuration of a downtown URD feeder.

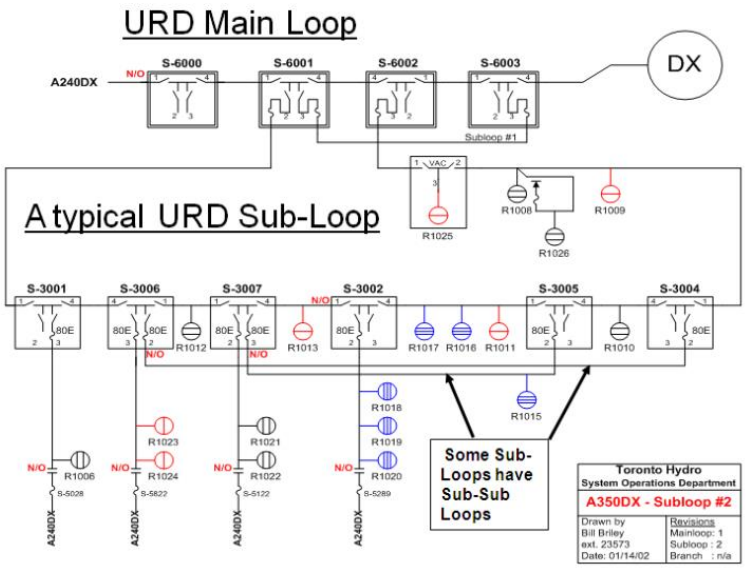


Figure 18: Typical URD Feeder Configuration

The URD installation began in early 1990's for 4 kV to 13.8 kV conversion projects and included a total of 150 normal feeders and 24 standby feeders. As of 2017, there are a total of 25 (normal and standby) 13.8 kV feeders and the majority of the equipment is approaching 25 years. However, due to the nature of costs incurred in rebuilding existing systems into a URD configuration, the URD program was discontinued post-amalgamation (in the early 2000s), thus reducing the planned work of 150 feeders to 25 feeders actually built. Table 5 below shows the total number of assets in Toronto Hydro's URD system.

Table 5: URD Asset Count

Asset Type	Total Number of Assets
Submersible Switches (200A & 600A)	146
Transformers	639
Vaults (Transformers and Switching)	592

In the last 4 years, URD system outages have increased, with an average of 2000 CIs and 7500 CHIs per year. Figure 19 below shows URD system outage statistics between 2010 and 2017.

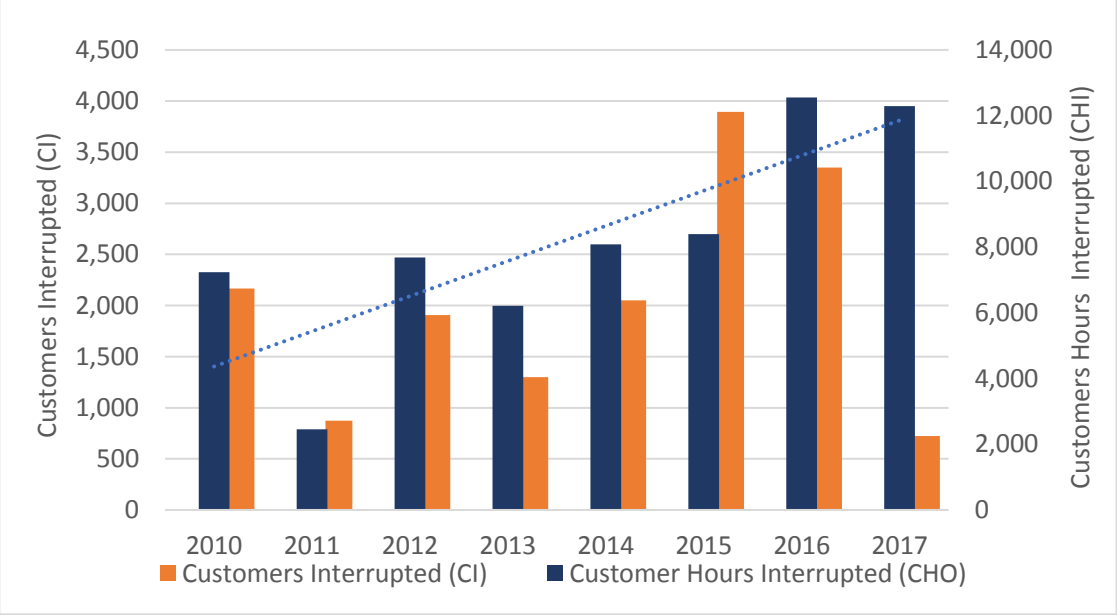


Figure 19: 2010-2017 URD System Outage Statistics

Maintenance and inspection of the URD vaults are performed twice a year, one inspection for the civil condition and the other for the electrical condition. As part of this work, the vaults are inspected to ensure the integrity of the electrical equipment, structure, and security. This includes a thermograph of all electrical assets, cleaning the entire vault and reporting any vaults that require follow-up repairs. The results of the inspections show that URD switching vault equipment is in a poor condition due to rust on the cabinet and corrosion on the connectors. Figure 20 and Figure 21 below provide the URD electrical and civil inspections results, highlighting the most common types of deficiencies identified and found over the past five years (i.e. 2013 to 2017).

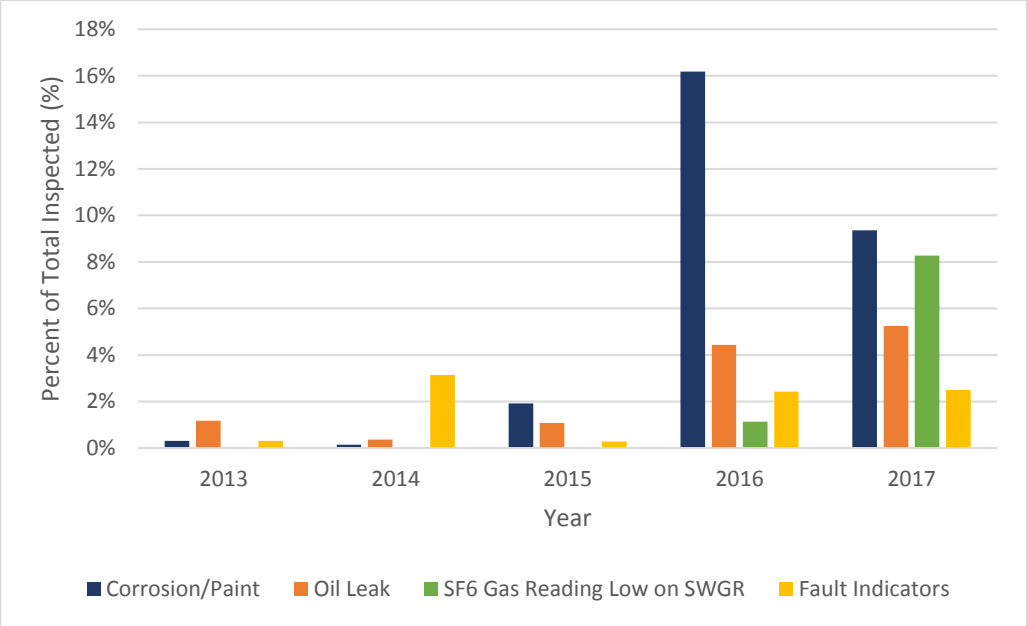


Figure 20: URD Electrical Deficiencies

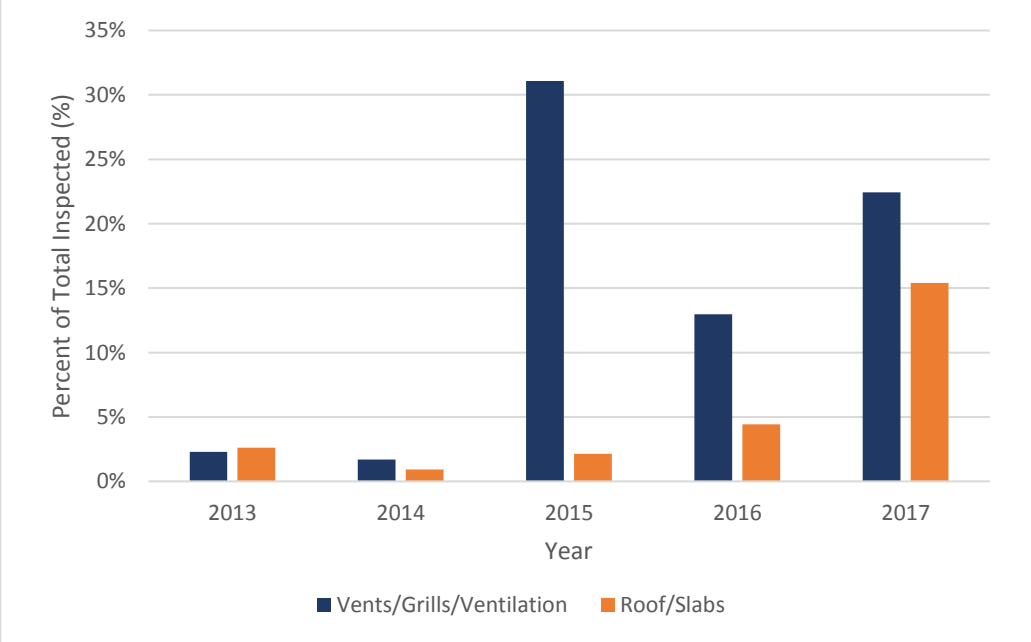


Figure 21: URD Civil Deficiencies

As per the URD electrical inspection data in Figure 20, the main issues are the recent rising incidents of deficient switch gear with low readings and faulty fault indicators, as well as corrosion of electrical

equipment. Consequently, as per the civil inspection data in Figure 21, deficient switch gear due to vents/grills/ventilation and roof/slabs have been steadily increasing from previous years. These deficiencies increase the risk of failure of URD assets and as a result, the renewal process is driven by failure risk. The following sections describe the state of two main assets of the URD system: URD vault roofs and URD switches (including fault indicators) while considering the above mentioned deficiencies.

1. URD Vault roof

Civil conditions of URDs deteriorate over time due to exposure to harsh environments as a result of severe weather, salt, or road construction. Some commonly found structural deficiencies caused by asset aging and environmental factors are exposed roof and wall rebar, corroded I-beams and cracked roof and walls. Such deterioration includes corrosion, spalling of concrete, and cover rusting which pose a potential safety hazard for the public and field crews. Compounding this situation, the ventilation design and equipment layout inside the vault have allowed dirt to accumulate on top of switching equipment, causing corrosion of components such as elbow terminations. This degradation of the URD system increases the failure risk of the assets within it. Illustrative examples of the aforementioned types of roof cracks are shown in Figure 22 and Figure 23 below.



Figure 22: URD Vault with Deficient Roof



Figure 23: URD Vault Deficient Roof Temporarily Repaired with Asphalt

The useful life of a URD vault is 60 years while the roof is 25 years. Therefore, the roof is typically rebuilt at least once or twice during the life of the vault. The current roofs of the URD vaults have reached or passed their useful life, and as such are considered for rebuild. The inspection data (as shown in Figure 21) demonstrates that an increasing number of URD vault roofs are being identified as having some level of roof deficiency.

Given the deficiencies being identified, Toronto Hydro is developing a new roof design that minimizes the amount of dirt, debris, and water that accumulate directly on electrical equipment. The new design will be similar to the compact radial distribution ("CRD") underground vault, which typically supply small retail, apartment, and commercial office buildings. In addition, the new design will improve safety by reducing the potential of tripping incidents, and create a larger opening for the replacement of electrical equipment. When rebuilding a vault roof, the electrical equipment will be assessed and upgraded to the latest standards if existing equipment is in poor condition or obsolete. In situations where the electrical equipment is in good condition, it will remain in-service.

2. URD Switches

Switches used in URD are submersible, 200A and 600A, SF_6-insulated switches which are operable from above grade. SF_6 load break switches are designed and constructed to provide safe and reliable

switching. Using SF_6 for insulation and arc interruption eliminates space, weight and maintenance costs. The switch provides improved interrupting and open gap performance, while at the same time eliminating most hazards associated with vacuum or oil filled equipment. In the URD system, the switches are mounted on stands close to the vault wall for ease of operation, cabling, and space utilization.

As of the end of 2017, these switches are deteriorating in condition. A large portion does not have stainless steel enclosures and are experiencing gas leakage problem inherent to the former design of the bolted viewing window, as shown in Figure 24 below.



Figure 24: Example of a SF_6 Switch with a "Low" Reading

Due to the design and equipment specification of URD 200A and 600A switching vaults, they do not contain an available heat source, such as a transformer, that would promote air circulation. As a result, non-stainless steel switching equipment installed in those vaults are experiencing accelerated corrosion due to exposure to stagnant moisture. Compounding this situation, the ventilation design and equipment layout inside the vault have allowed dirt to accumulate on top of switching equipment, causing corrosion of components such as elbow terminations and supports or support beams. An example of a corroded support beam can be seen in Figure 25.



Figure 25: Example of Switch Supports that have rusted

The 200A SF6 switches are used to switch load as part of the subloop system. They also support 80E SF6 power fuses, which are used for the protection of branch circuits in the URD and are no longer manufactured. (Only 41 remain in Toronto Hydro inventory.) A picture of the 80E Fault Fiter fuse is provided in Figure 26. In this regard, the switches are functionally obsolete, as they are no longer supported by the original manufacturer and no spare parts are manufactured or available. Replacement of both the fuse and switchgear is required to provide the adequate protection for branch circuits.



Figure 26: 80E Fault Fiter Fuse

As the URD vaults, transformers, and switches approach the end of their useful life, related equipment and civil infrastructure need to be updated to mitigate failure risk. The roof vaults will be

replaced with a newer design that reduces the dirt, debris and water entering the vaults, improves safety by reducing tripping incidents and creates a larger opening for replacing old switches. Along with roof rebuilds, electrical equipment such as transformers or switches within the vault will be replaced with the equivalent latest standard. Switches will be replaced with the new generation of SF_6-insulated switches which have stainless steel enclosure to prevent premature rusting and degradation of the cabinet.

E6.3.4 Expenditure Plan

To address the needs of the underground assets in downtown Toronto, Toronto Hydro plans to invest $122.0 million over the 2020-2024 period. Each segment entails a unique investment strategy. As this Program is replacing the Piece-Out and Leakers program (see section E4 for details), it is considered as a new program with no historical costs.

Table 6: Forecast Program Costs ($ Millions)[13]

Segments	Forecast				
	2020	2021	2022	2023	2024
Underground Cable	8.9	16.2	17.3	23.4	23.9
Cable Chamber	5.6	5.7	5.8	5.9	6.1
Underground Residential Distribution ("URD")	0.6	0.6	0.7	0.7	0.6
Total	**15.1**	**22.5**	**23.9**	**30.0**	**30.6**

E6.3.4.1 Underground Cable Renewal

Table 7: Underground Cable Renewal 2020-2024 Program Costs ($ Millions)

	2020	2021	2022	2023	2024	Total
Underground Cable	8.9	16.2	17.3	23.4	23.9	**89.7**

Table 8: 2020-2024 Volumes (Forecast): Underground Cable Renewal

Asset Class		2020	2021	2022	2023	2024	Total
PILC Cable	*km*	2.9	5.1	5.3	7.1	7.1	**27.4**
AILC Cable	*km*	5.6	9.9	10.4	13.8	13.8	**53.3**

/C

[13] Note that costs associated with former streetlighting assets are embedded in the costs of the segments.

The Underground System Renewal – Downtown program prioritizes at risk cable segments based on historical failures, number of splices on feeders, age and customer base. This will be used in conjunction with complementary cable testing data to validate the volume of cable replacement required. This is considered to be a best practice in the industry and is used by utilities such as Consolidated Edison (ConEd) in New York City for their PILC cable replacement program.[14] Studies have shown that this method is driven by condition and is a reliable alternative to traditional methods for asset ranking.[15]

Toronto Hydro has determined that approximately 2.5 percent of the PILC population is in a critical state and should be addressed through proactive replacement during the 2020-2024 period. This 2.5 percent amounts to 27 circuit-kilometres of PILC, and will trigger replacement of 24 percent of the existing AILC population (53 circuit-kilometres) connected downstream of PILC cable. /C

Based on similar past work, Toronto Hydro estimates that PILC cable replacement projects will cost, on average, approximately $1.8 million per circuit-km, while AILC replacement will cost approximately $0.5 million per circuit-km. Toronto Hydro has applied these volumetric costs to the forecast population of critical cables to develop the 2020-2024 segment cost of $63 million.

E6.3.4.2 Cable Chamber Renewal

Table 9: Cable Chamber Renewal 2020-2024 Program Costs ($ Millions)

	2020	2021	2022	2023	2024	Total
Cable Chamber	5.6	5.7	5.8	5.9	6.1	**29.1**

Table 10: 2020-2024 Volumes (Forecast): Cable Chamber Renewal

Asset Class	2020	2021	2022	2023	2024
Cable Chamber	15	15	15	15	15
Cable Chamber Roof	24	24	24	24	24
Cable Chamber Abandonment	3	3	3	3	3
Cable Chamber Lid	200	200	200	200	200

[14] M. Olearczyk et. al., *Notes from Underground – Cable Fleet Management*, Nov. 2010. Available at <http://www.neetrac.gatech.edu/publications/Note_from_Underground_Nov2010.pdf>.
[15] M. Buhari, V. Levi and S. K. E. Awadallah, "Modelling of Ageing Distribution Cable for Replacement Planning," in *IEEE Transactions on Power Systems*, vol. 31, no. 5, pp. 3996-4004, Sept. 2016.

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Toronto Hydro has determined that approximately 2 percent of the PILC population is in a critical state and should be addressed through proactive replacement during the 2020-2024 period. This 2 percent amounts to 23 circuit-kilometres of PILC, and will trigger replacement of 20 percent of the existing AILC population (43 circuit-kilometres) connected downstream of PILC cable.

Based on similar past work, Toronto Hydro estimates that PILC cable replacement projects will cost, on average, approximately $1.8 million per circuit-km, while AILC replacement will cost approximately $0.5 million per circuit-km. Toronto Hydro has applied these volumetric costs to the forecast population of critical cables to develop the 2020-2024 segment cost of $63 million.

E6.3.4.2 Cable Chamber Renewal

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Cable Chamber Lid	200	200	200	200	200

[14] M. Olearczyk et. al., *Notes from Underground – Cable Fleet Management*, Nov. 2010. Available at <http://www.neetrac.gatech.edu/publications/Note_from_Underground_Nov2010.pdf>.
[15] M. Buhari, V. Levi and S. K. E. Awadallah, "Modelling of Ageing Distribution Cable for Replacement Planning," in *IEEE Transactions on Power Systems*, vol. 31, no. 5, pp. 3996-4004, Sept. 2016.

Reconstructing a cable chamber requires breaking into or reconstructing portions of ductbank. As such, the cable chamber renewal segment includes the cost of reconstructing a portion of a duct bank along with the cable chamber. Required electrical work within a cable chamber, road or sidewalk repair or road restoration are also incorporated into the cost. Toronto Hydro's spending plan for this segment is approximately $5.9 million per year for the 2020-2024 period, including, on an annual basis: (i) cable chamber lid replacement for $1.6 million per year ($8,000 per unit), and (ii) 22 cable chamber rebuilds ($170,000 a unit), 24 cable chamber roof rebuilds ($20,000 a unit) and 3 cable chamber abandonments ($20,000 a unit), all at a total cost of $4.3 million on average per year.

In developing the cable chamber renewal segment, Toronto Hydro assumes outages are not required for cable chamber rebuilds. This means cables are tied together and are safely out-of-the-way when rebuilds occur. As a result, cable chambers are mainly prioritized based on the condition of the civil infrastructure as well as the types of customers and thermal loading of feeders.

Based on inspection records, 204 cable chambers and 102 roofs have been identified to be in HI4 and HI5 condition. Since cable chamber renewal is new, Toronto Hydro is planning a small number of rebuilds for the 2020-2024 Program to address chambers that are in HI5 and HI4 condition. It is important to tackle cable chambers with structural failure issues and diligently rebuild a set number of cable chambers every year.

E6.3.4.3 URD Renewal

Table 11: URD Renewal 2020-2024 Program Costs ($ Millions)

	2020	2021	2022	2023	2024	Total
URD	0.6	0.6	0.7	0.7	0.6	**3.2**

Table 12: 2020-2024 Volumes (Forecast): URD Renewal

Asset Class	2020	2021	2022	2023	2024
URD Submersible Switches	3	3	3	4	4
URD Transformers	1	1	1	0	0
URD Vault Roof	3	3	4	4	4

URD renewal segment is a new segment to be carried out in the 2020-2024 period. Currently, severely deteriorated URD roof rebuilds and switch or transformer replacements are handled on a reactive basis. As structures and equipment age, the number of rebuilds required will only increase.

Planned rebuilds are preferred to reactive rebuilds for URD assets that require various resources and co-ordination.

As part of the URD system renewal program, Toronto Hydro will prioritize projects based on the condition of civil roofs as deficient roofs pose an immediate risk to the public. Where civil roofs are considered deteriorating, assets such as URD switches and transformers within these vaults will be replaced on an as-needed basis according to inspection records. Where the civil assets are in good condition and the electrical assets are not, such locations will be assigned a lower priority.

As this is a new program, Toronto Hydro has estimated the completion of three roof rebuilds and switch replacements per year for the first three years. As it develops experience in performing this work, Toronto Hydro would increase the number by one for the remaining years of the Program. In total, Toronto Hydro aims to complete 18 roof rebuilds, 18 switch replacements, and 3 transformer replacements in the 2020-2024 period.

E6.3.5 Options Analysis

E6.3.5.1 Underground Cable Renewal

1. Option 1: Reactive Replacement Approach

In this option, Toronto Hydro will allow all cables to operate under a reactive replacement scenario. Therefore, cables will be replaced under the Reactive and Corrective Capital program.

As mentioned in section 3.1, PILC and AILC cables are becoming obsolete across the industry due to environmental, health, and safety concerns. PILC and AILC cables were initially installed in the downtown system due to their high reliability and long life span. There are approximately 1,100 circuit-kilometres of 13.8 kV PILC underground cable on the system and approximately 42 percent of all PILC cables and 68 percent of all AILC cables in the system are more than 20 years old. These aged cables are showing signs of deterioration, including pin holes, cracks, and leaks. If these cables are allowed to deteriorate, reliability and safety risks will persist and increase as a result of the increasing number and duration of outages in the distribution system.

Therefore, under this option, when PILC and AILC cables fail, Toronto Hydro will splice XLPE cable into sections of PILC and AILC cable to maintain long cable sections. As a result, this will further increase the risk of failure by increasing the percentage of non-uniform cable in the system. These splices create and add weak points along the cable, introducing additional failure risk to already aging

cables that serve many large and critical loads. Consequently, feeder life expectancy and probability of failure worsen drastically. This will negatively impact customer service in the downtown area. The status quo option would not be prudent as it does not address the needs of downtown customers that prioritize reliability over price.

Additionally, when a cable can no longer be maintained through splicing, Toronto Hydro will replace the cable. The costs of replacing a cable reactively is also higher than proactive replacement. Toronto Hydro estimates that replacing all cables reactively could vary considerably, but average out to approximately 10 percent more than the costs allocated to the preferred option (discussed below). Reactive work is especially challenging in the downtown area due to considerable coordination with third parties that is required. Therefore, Toronto Hydro does not recommend pursuing this option.

2. Option 2 (Selected Option): Targeted Replacement of PILC and AILC Cables

Toronto Hydro is planning to remove approximately 24 percent of AILC cable (53 circuit kilometres of 220 kilometres) and 2.5 percent of PILC cable (27 circuit kilometres of 1,100 kilometres) between 2020 and 2024. The cables will be replaced based on the risk level associated with the cable segment. This proposed pace is a particularly conservative pace given that it will take approximately 200 years to renew the existing PILC in Toronto Hydro's distribution system. As a result, the utility expects to increase the pace of this segment following the 2020-2024 period. /C

In addition, as primary cables and cable segments are being tested or replaced, Toronto Hydro will re-prioritize at-risk feeders. Where at-risk primary cable sections are identified, this will drive the replacement of the legacy type AILC cable that is connected downstream of these cable sections.

Under this option, Toronto Hydro would mitigate the failure risk on the downtown distribution system and increase reliability. As mentioned in section 3.1, and in Option 1 above, non-uniformity (i.e. cable splicing) increases the risk of failure. Therefore, by replacing the highest risk cables, the utility will increase the uniformity of cable types in the system (i.e. by replacing the non-uniform cable with XLPE cable), which will increase reliability on the system.

In addition to increasing reliability, this option will reduce the risk of oil leakage from the insulation on PILC cables and therefore, reduce the need for service interruptions on customers to address the leaks.

3. Option 3: Replacement of all PILC and AILC cable over 50 years

As noted under option 2, the proposed plan sets a slow pace for PILC renewal, projected to be 200 years. Under this option, Toronto Hydro would replace PILC and AILC cables in its distribution system. At a pace that achieves a 50-year total renewal period.

This would allow the utility to more assertively address the environmental and safety issues associated with the continued use of PILC and AILC cables. It would also mitigate the risks associated with a single supplier (i.e. procurement risk).

Furthermore, it would address reliability risks and provide downtown customers with enhance reliability.

However, this option is estimated to cost approximately four times the cost of the proposed plan. In addition to being costly, Toronto Hydro may not be able to allocate the required resources for this option in the 2020-2024 period.

E6.3.5.2 Cable Chamber Renewal

1. Option 1: Reactive Replacement Approach

Under the status quo, Toronto Hydro will rely on the Reactive and Corrective Capital program (Exhibit 2B, Section E6.7) to rebuild cable chambers that fail. Cable chamber deterioration is not visible from the surface as the structural elements are below grade.

The freeze-thaw cycle in winter combined with road salt accelerates the deterioration of concrete structures. The number of structures that will fall into 'emergency' category for rebuild is expected to increase to a point that it will be extremely hard to manage the situation through reactive response. The risk of lids lifting off can also be minimized by replacing them with energy mitigating lids.

The load from motor vehicle traffic (particularly heavy trucks) and the general public is another factor that causes the civil condition of the cable chamber to deteriorate over time. Compromised civil condition of cable chambers can eventually result in serious consequences, such as injuries or fatalities due to large pot holes.

In addition, cracked roof slabs can lead to potentially serious harms to Toronto Hydro crews while doing work in the chambers, as chunks of concrete can fall on workers.

Given the above risks, this option is not recommended.

2. Option 2 (Selected Option): Renew Cable Chambers

Toronto Hydro has to proactively engage in renewing its cable chamber population. This Program is therefore essential as a first step to reaching a goal of clearing all the backlog of deteriorated structures and prevent cable chambers from surpassing their useful life.

Cable chamber rebuilds are highly complex projects, as they require not only civil resources but also electrical resources, permits from the City to dig into streets, management of the high volume of downtown vehicular and pedestrian traffic, and extensive coordination between various stakeholders. The new chamber has to conform to current standards and the size may have to be enlarged to minimize congestion of the cables inside and to accommodate more cables for future needs. In light of these needs, a cable chamber rebuild requires a detailed design. If the cable chamber rebuild is done on a reactive basis, the lack of lead time means it will be hard to work within or comply with all of the above constraints. Therefore, planned rebuild as proposed in this Program is a superior option than rebuilding cable chambers reactively.

The preferred pace is moderate and accounts for resourcing considerations as well as the length of time civil deficiencies can be managed before renewal is required.

3. Option 3: Higher Pace Cable Chamber Renewal

With an incremental spend of approximately $22.3 million, Toronto Hydro would eliminate the risk of cable chamber lid ejections are locations identified as posing high and medium risks, and reconstruct all at risk cable chambers within 15 years as opposed to 30 years. Although appealing from an asset management perspective, this accelerated pace of would require significantly more resources and may not be cost-effectively accomplished over the 2020-2024 period.

Furthermore, road moratoriums within Toronto's downtown core may further challenge Toronto Hydro's ability to execute the work at an accelerated pace in the short- to medium-term. As a result, Toronto Hydro is not proposing this option.

E6.3.5.3 URD Renewal

1. Option 1: Reactive Replacement Approach

The useful life of a URD vault is 60 years while the roof is 25 years. Therefore, the roof is typically rebuilt at least once or twice during the life of the vault.

Under the status quo, Toronto Hydro will replace assets reactively once they fail. As such, Toronto would rebuild deficient URD roofs, replace defective URD switches and obsolete fuses that protect URD switches under the Reactive and Corrective Capital program (Exhibit 2B, Section E6.7). URD roof rebuilds are sometimes not visible from the surface as the structural elements are beneath the surface. The civil condition of the URD vault roof can also compromise the electrical equipment within the vault. This would also increase the safety risk for Toronto Hydro employees as crews sometimes enter a vault where a cracked roof slab is present. Chunks of concrete could potentially fall on to the workers and the equipment, giving rise to serious harm.

Under this option, Toronto Hydro expects an increase in failures and outages on the downtown underground distribution system, thus negatively impacting reliability. As identified in the needs section (section E6.3.3), a main cause of failures in switches is corrosion. Failure at the switches can lead to serious consequences causing interruptions to all customers the URD vault serves. Over the last 4 years, URD system work requests and outages have increased considerably, and given that the majority of vault roofs have or will be at or beyond useful life by 2020, managing the URD system on a reactive basis is not prudent.

2. Option 2: (Selected Option) Renew URD assets

Toronto Hydro has to proactively renew the roof of the URD vaults, replacing the 200A switch and other poor conditioned assets. As URD vaults, transformers and switches approach the end of their useful life, related equipment and civil infrastructure need to be updated to mitigate failure risk. It is therefore essential to prevent URD roof rebuilds before emergency rebuild is required.

The roof vaults will be replaced with a newer design that reduces the dirt, debris and water entering the vaults, improves safety by reducing tripping incidents and creates a larger opening for replacing old switches. Along with roof rebuilds, electrical equipment such as transformers or switches within the vault will be replaced with the equivalent latest standard. The 200A switches (which are no longer supported by the manufacturer) will be replaced with the new generation of SF6-insulated switches which have stainless steel enclosure to prevent premature rusting and degradation of the cabinet.

This will prevent a scenario where the utility may run out of fuses in its inventory (which are no longer manufactured).

This proactive replacement strategy will allow Toronto Hydro to assess the deficient URD assets and devise optimal planning strategies for the future of the URD system.

Under this option, Toronto Hydro would maintain and in some instances improve reliability in downtown areas.

3. Option 3: Renew URD assets and replace all URD switches

Under this option, Toronto Hydro would replace a larger population (75 percent) of the obsolete 600A switches between 2020 and 2024 compared to the preferred option as well as renew a larger quantity of URD assets.

Relative to the chosen option, this approach will cost approximately 40 percent more and is therefore not an economically preferable alternative, given that the URD system serves residential load and residential customers prioritize cost over reliability.

E6.3.6 Execution Risks & Mitigation

A key execution risk affecting the Underground System Renewal – Downtown program is external dependencies. In the downtown area, coordination with third parties (e.g. City of Toronto, TTC) has been an on-going requirement. Toronto Hydro invests substantial efforts to ensure effective inter-agency coordination.

Toronto Hydro engineers will ensure optimal routes are chosen based on criteria, such as the avoidance of busy intersections, and paths where utilities reside. Often, projects would involve construction of new civil assets such as duct banks or cable chambers. It is expected that these projects may be delayed without effective coordination. To mitigate risks, these projects will be planned well in advance.

Additionally, road moratoriums have the potential to delay projects in the downtown core. To mitigate this risk, Toronto Hydro will plan and schedule work accordingly.

The Underground System Renewal – Downtown program will prioritize at-risk cables dynamically as testing data, and cable replacement data become available. This means cables that are deemed low-risk in one year, may be high risk in another year. As such, dynamic planning will be required by

engineers and project managers, which is advantageous in targeting, based on best available information, only feeders that are statistically more likely to fail. On the other hand, this approach may result in disruptions to project scheduling and planning. Efforts will be made well in advance to coordinate multiple projects at the same time so projects are deferred or advanced accordingly.

Since all URD assets are located in residential neighbourhoods in the downtown core, coordination with the relevant customers is critical. Toronto Hydro will abide by residential community by-laws such as noise levels placed by the City of Toronto and coordinate with all stakeholders as necessary.

E6.4 Network System Renewal

E6.4.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 90.3	**2020-2024 Cost ($M):** 92.4
Segments: Legacy Network Equipment Renewal (Automatic Transfer Switches & Reverse Power Breakers); Network Unit Renewal; Network Vault Renewal; Network Circuit Reconfiguration	
Trigger Driver: Failure Risk	
Outcomes: Reliability, Safety, Environment, Financial	

The Network System Renewal program (the "Program") addresses deteriorating and functionally obsolete underground network system assets serving primarily small to medium-sized customers in the pre-amalgamation City of Toronto. These customers reside in the City's core and are often sensitive to outages.[1] Examples include commercial businesses, GO Transit, and hospitals. The Program is designed to deliver reliability improvements and mitigate public safety risks by: (1) replacing high-risk, obsolete assets like Automatic Transfer Switches ("ATS") and Reverse Power Breakers ("RPB"); (2) replacing non-submersible network units and vaults in deteriorated condition; and (3) reconfiguring and re-cabling sub-optimal grid networks.

The Program is grouped into the four segments summarized below and is a continuation of the network renewal activities described in Toronto Hydro's 2015-2019 Distribution System Plan.[2]

- **Legacy Network Equipment Renewal**: continues the replacement of obsolete ATS and RPB on the secondary network. These assets are no longer produced by the manufacturer and cannot be properly maintained or replaced on a like-for-like basis. ATSs and RPBs are prone to moisture ingress and can fail catastrophically, resulting in lengthy outages, vault fires and damage to connected and adjacent equipment. Toronto Hydro plans to replace all remaining ATS and RPB units with network transformer units, standalone network protectors

[1] As discussed in Exhibit 2B Section D2.2.2, the underground network system is the most reliable configuration available among Toronto Hydro's distribution schemes, and is therefore an ideal option for customers who are sensitive to outages and concerned about reliability. Toronto Hydro is piloting equipment in during 2015-2019 that will facilitate the expansion of network service to larger residential and commercial towers. Toronto Hydro expects this equipment to be deployed as part of the normal customer connections process in the 2020-2024 period.
[2] EB-2014-0116, Exhibit 2B, Section E6.9, E6.10, E6.11 and E6.12

("SANPs"), or 600A manual secondary switches by the end of 2022, prioritizing assets in the worst condition.

- **Network Unit Renewal:** a continuation of planned replacement of network units at risk of failure. As network unit condition deteriorates, the risk of failure increases, and with it the likelihood of consequences such as lengthy customer outages and vault fires. Since 2012, the network unit renewal segment has focused primarily on eliminating the significant failure risk associated with fibertop network units, a non-submersible unit prone with a high potential of catastrophic failure. Toronto Hydro plans to have essentially all remaining fibertops removed from the system by the end of 2019.

  Beyond 2019, this segment will continue to target the remaining types of non-submersible units. These units are susceptible to water ingress and elevated failure risks even when in good condition. Toronto Hydro will prioritize the worst condition and fastest deteriorating units as indicated by condition inspections and health index scores. Without intervention, the utility projects that 267 units will be materially deteriorated ("HI4") or at end-of-serviceable life ("HI5") by 2024. Customers have expressed support for reducing the risk of network vault fires and flooding,[3] and Toronto Hydro is pacing investments to accomplish this outcome. The utility plans to replace an estimated 200 units between 2020 and 2024, in addition to 43 units planned for 2018-2019. This rate of replacement is expected to reduce failure risk on the network system by improving condition-related asset risk across the network unit population. Toronto Hydro plans to install new network units that are submersible and equipped with sensors to monitor transformer, protector, and vault conditions, resulting in the cost-effective reduction of reliability, environmental, and safety risks associated with network assets.

- **Network Vault Renewal:** a continuation of Toronto Hydro's efforts to rebuild or decommission poor condition network vaults. These civil structures were generally built in the 1950s and 1960s, mainly beneath the sidewalks in the busy downtown core. Toronto Hydro must proactively address structurally deficient vaults in order to mitigate risks to public safety, employee safety, and system reliability, and to maintain the long-term viability of the distribution system. Without intervention, the number of network vaults in HI4 and HI5 condition is expected to increase from 40 to 114 by 2024. During the 2020-2024 period, Toronto Hydro plans to eliminate immediate structural deficiencies of 33 high-risk vaults identified through the ACA process as having at least material deterioration ("HI4"). Due to

[3] Exhibit 2B, Section E2.3

the complexity of this mostly downtown work, the rate of planned replacement is less than optimal. However, the planned pace is such that Toronto Hydro anticipates it will be able to prevent the number of vaults at end-of-serviceable-life ("HI5") from increasing.

- **Network Circuit Reconfiguration:** a continuation of Toronto Hydro's plan to mitigate the impact of multiple contingency failures on the network system. This segment involves reconfiguring and re-cabling secondary grid networks into more robust spot vaults and enhanced grids. The result will be minimized customer interruptions, improved planning, modeling, and operational flexibility, and enhanced ability of the network system to operate under extreme events (e.g. multiple contingency outages). Toronto Hydro plans to reconfigure its five largest secondary networks over the 2020-2024 period, an investment that is expected to deliver long-term reliability and resiliency benefits for network customers in the downtown area.

Toronto Hydro plans to invest $92 million in the Network System Renewal program in 2020-2024, which is a 2.3 percent increase over projected 2015-2019 spending in this Program (including forecasted inflation). This level of investment is necessary to maintain public and Toronto Hydro employee safety, and the service levels that downtown customers rely on and expect from the network system.

E6.4.2 Outcomes and Measures

Table 2: Outcomes & Measures Summary

Reliability	• Contributes to Toronto Hydro's Network Units Modernization measure and system reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by: ○ Eliminating legacy ATS and RPB equipment which is obsolete and prone to failure leading to feeder interruptions; ○ Replacing 200 network units at highest risk of failure due to poor condition or vulnerability to flooding; ○ Eliminating structural deficiencies of 33 high-risk vaults that are placing enclosed equipment at risk; ○ Replacing older network units with ones equipped with sensors to monitor vault conditions and enable quicker response to adverse network conditions; ○ Reducing average restoration time during a full network outage by reconfiguring networks to support all or most of the load; and ○ Reducing customer interruptions by a third during second contingency events, by reconfiguring networks to improve operability under multiple contingency events.
Environment	• Contributes to Toronto Hydro's environmental objectives by eliminating network units at high risk of failure and vulnerable to vault fires or oil spills.
Safety	• Contributes to Toronto Hydro's Network Units Modernization measure and safety objectives by: ○ Minimizing the risk of vault fires in densely populated downtown areas by eliminating the potential catastrophic failure of legacy ATS and RPB assets; and ○ Minimizing the risk of catastrophic transformer failures by replacing network units most at risk due to deteriorated condition or exposure to higher-risk environmental factors; ○ Eliminating potential trip and falling debris hazards at 33 vaults with significant civil deterioration.

Financial	• Contributes to Toronto Hydro's financial objectives by: ○ Reducing the need to dispatch crews in multiple contingency scenarios by reconfiguring the network to support all or most of the network load; and ○ Supporting reduction in summer peak reading inspections by enabling monitoring and control of network units (see Network Condition Monitoring and Control program[4]).

E6.4.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Failure Risk
Secondary Driver(s)	Safety, Environmental Risk, Reliability, System Efficiency

Toronto Hydro's network system plays an important strategic role in meeting the reliability expectations of interruption-sensitive downtown customers. The Network System Renewal program aims to replace network assets at risk of failure due to deteriorating conditions. The failure of these assets negatively impacts reliability and the effective operation of the network system and potentially increases the risk to public safety and Toronto Hydro's crews.

Toronto Hydro's low voltage secondary network distribution system includes the following assets:

- Standard Network Units that consist of primary switches, network transformers, and secondary network protectors, which are assembled into a single unit;
- Legacy Network Units that consist of ATSs and RPBs, both of which include associated subway transformers;
- Network Vaults, which contain the aforementioned equipment; and
- Secondary Cables, which connect the aforementioned equipment and provide service connections to customers.

The Network System Renewal program is needed to replace those assets that are at risk of failure in order to mitigate the associated safety, environmental, and reliability risks and to maintain the service levels that downtown customers rely on and expect from the network system.

[4] Exhibit 2B, Section E7.3

E6.4.3.1 Legacy Network Equipment Renewal (ATS & RPB)

The Legacy Network Equipment Renewal (ATS & RPB) segment is a continuation of the activities previously described in Toronto Hydro's 2015-2019 CIR filing. In 2015, Toronto had a total of 53 ATS and RPB units and by the end of 2019, 13 units will remain. Toronto Hydro plans to replace all remaining units over the 2020-2024 period.

This segment aims to reduce failure and safety risks associated with network equipment that are obsolete, past their useful life, in poor condition, and prone to failure. Failure can occur due to various factors, such as water penetration or exposure to heavy debris and contamination, which results in equipment rusting (see Figure 1 and Figure 2) and control electronics failure. Toronto Hydro will prioritize ATS and RPB unit replacements based on condition to mitigate the risk of equipment failures.



Figure 1: Rusting at Base and Footing of ATS Unit



Figure 2: Rusting on Equipment Surface

1. Failure Risk

In the event of a system fault, failed or defective ATS and RPB units may not operate as intended, and in some instances catastrophic failures can occur. RPB malfunction can prolong equipment exposure to large amounts of fault current, damaging equipment such as cables and transformers that are fed on common feeders. This damage can lead to vault fires and catastrophic failures. From 2010 to 2012, prior to the start of proactive ATS and RBP replacement, Toronto Hydro replaced a total of 33 ATS and RPB units reactively due to equipment deficiencies and failures. Over 20 percent of the combined population of ATS and RPBs are known to be rusted or have failed to operate in the field, and are thus considered high priority for replacement.

2. Functional Obsolescence

Toronto Hydro considers ATS and RPB units to be functionally obsolete equipment designs due to: (i) the equipment enclosure's inability to prevent moisture ingress, which accelerates and leads to equipment failure, and (ii) the cessation of manufacturer support for this type of equipment, and the inability to procure spare parts for equipment repairs, making it difficult for Toronto Hydro to achieve alignment with current maintenance and inspection practices. Going forward, the lack of spare parts

precludes long-term maintenance as a viable option to extend the service life of the assets. For these reasons, this legacy network equipment no longer meets Toronto Hydro's needs.

3. Safety and Environment

Failing ATS and RPB assets can potentially put the safety of the public and Toronto Hydro employees at risk. In some situations, catastrophic failure of such assets has resulted in damage to related equipment and caused vault fires that can harm individuals in proximity to the vault and release toxins into the environment. The inherent safety risk of vault fires is heightened by the fact that these assets are generally located in heavily populated downtown areas.

Such a fire occurred at 33 Princess Street on January 16, 2012 (see Figure 3). An ATS unit failed at approximately 1:25pm, igniting a vault fire in Toronto's downtown (i.e. near Front and Sherbourne) and affecting two feeders, A14GD and A15GD. This fire was contained within the ATS vault; however, the fire damaged the primary cables on both feeders as well as the two distribution transformers supplying 33 Princess Street. The feeders were isolated at the station and power was promptly restored to most customers. Approximately 460 students from George Brown College, 50 seniors from a nearby retirement home, 50 children from a daycare, and customers from 246 The Esplanade were evacuated because of this incident. Two large customers supplied solely from feeders A14GD and A15GD also experienced extended outages. Some were left without power until approximately 2:00 pm the following day (i.e. 24 hours).



Figure 3: Damage from a Vault Fire Caused by Failure of an ATS Unit at 33 Princess Street on January 16, 2012

E6.4.3.2 Network Unit Renewal

The Network Unit Renewal segment is a continuation of the activities identified in Toronto Hydro's 2015-2019 CIR filing. This segment aims to reduce failure risks associated with network units that are obsolete, in poor condition, past their typical useful life, and prone to failure. The goal of the segment is to replace the most at-risk units, as indicated by obsolete design and condition assessment data, before they fail and potentially cause safety or environmental incidents such as fires and oil leaks.

Although replacements are prioritized based on condition, the network units that are replaced are typically of legacy "non-submersible" designs characterized by "ventilated" or "semi-dust-tight" protectors (see Figure 4). These units are susceptible to water ingress and elevated failure risks even when in good condition. These units also typically contain electro-mechanical relays that are not capable of condition monitoring or control. They are replaced with units that are of a submersible design, containing digital relays, and capable of meeting the requirements for Toronto Hydro's Network Condition Monitoring and Control program.

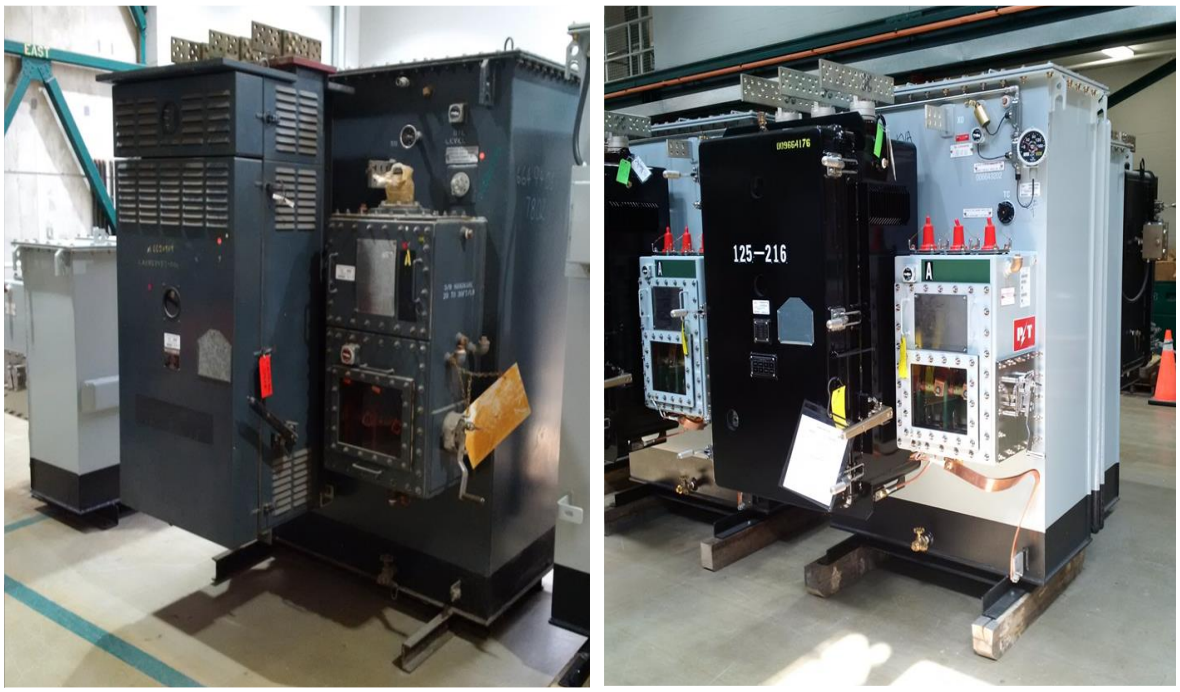


Figure 4: A ventilated network unit is shown on the left and a submersible network unit is shown on the right. The black protector is of a submersible design, which prevents water ingress.

1. Failure Risk and System Efficiency

Two main failure modes can impact a network unit. The first is flooding of the network vault that may damage the protector mechanism causing the unit to short, or fail to operate. The second is an internal transformer failure that is typically caused by overloading, low oil, moisture ingress, or age-related insulation deterioration. To maintain network system reliability, network units need to be both routinely maintained and proactively replaced when they are at an increased risk of failing. Maintenance of network units is summarized in Exhibit 4A, Tab 2, Schedule 2. Not replacing deteriorated network units in a timely manner can lead to equipment failures, and in turn cause interruptions to customers, oil leaks of 1,000 litres and more, and potential vault fires that may impact (including expelling smoke) busy arterial roads in the downtown core of Toronto.

Replacing deteriorated non-submersible ventilated protectors located in areas prone to flooding with submersible protectors that feature watertight cases can help address flooding risks. Toronto Hydro addresses failure risk due to equipment deterioration by prioritizing the replacement of aged units based on condition. Of Toronto Hydro's 1,800 network units, approximately 800 have non-submersible protectors, which are legacy designs that were used prior to the installation of the first submersible units in 2003. As a result, virtually all units older than 15 years are ventilated or semi-dust-tight. Figure 5 below shows the proportion of submersible non-submersible network units by age. The useful life of network units is 35 years of age.

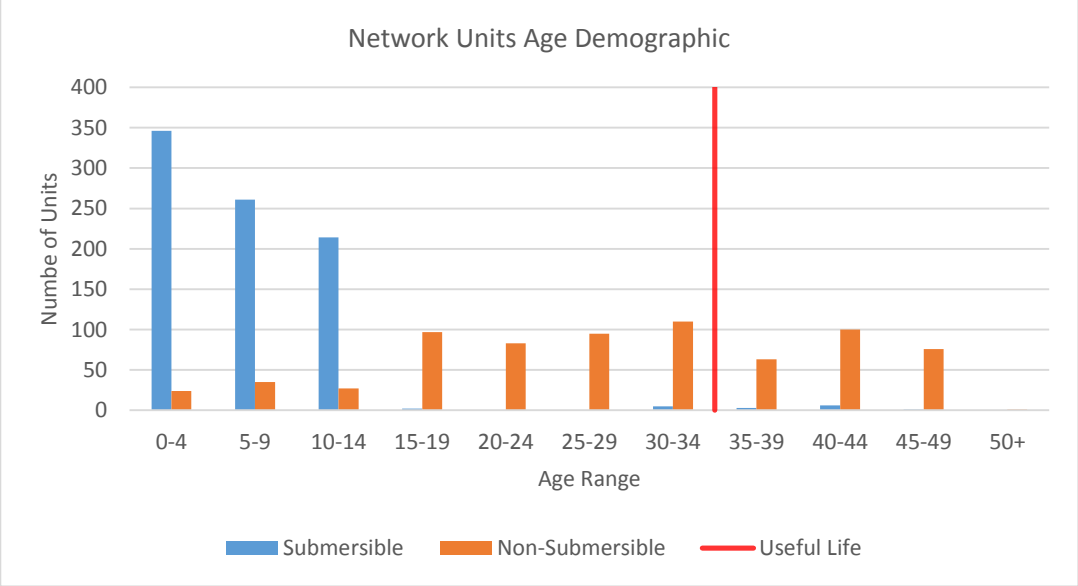


Figure 5: Network units' age demographic by type.

Despite the elevated risks associated with non-submersible network units, Toronto Hydro is proposing to replace units that exhibit deteriorated conditions only. Based on available ACA data, the current and estimated 2024 health index distribution (without proposed work) for network units is shown in Figure 6. HI4 means "material deterioration" and HI5 means "end of serviceable life". There are 267 units that are forecasted to have at least material deterioration by 2024 (including 102 HI4 and 165 HI5) and the network unit renewal segment plans to replace 243 of them, at an average rate of 40 per year for 2020-2024. For 2018 and 2019, 20 and 23 units are planned for replacement, respectively.

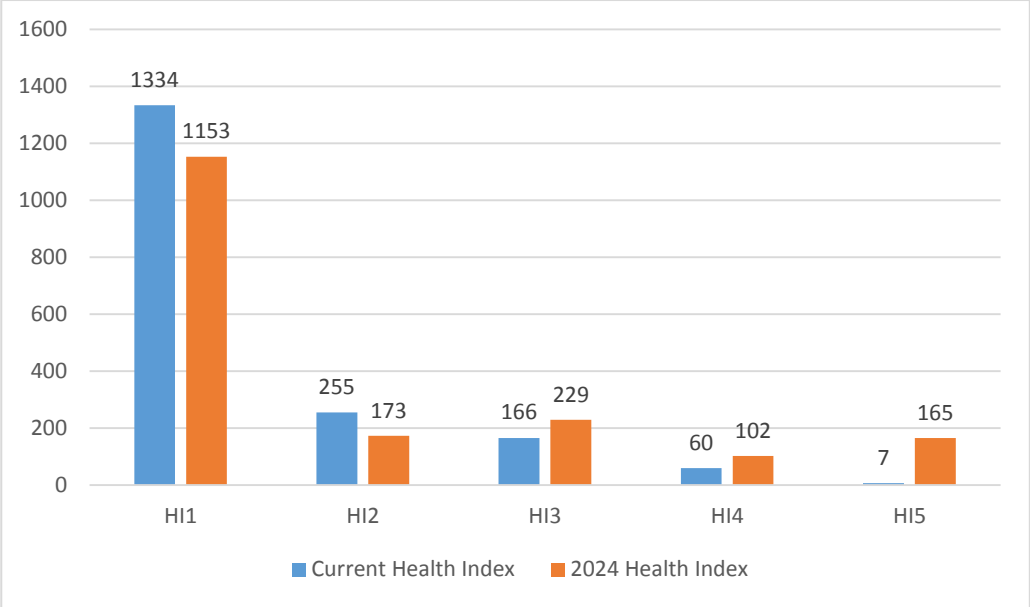


Figure 6: Network Transformers Current and 2024 Forecast (without Renewal) Health Index

2. Safety and Environment

Failure of deteriorated network units can result in both safety and environmental incidents. From a safety perspective, catastrophic failures may cause damage to surrounding property and put the public at risk of injury, especially given that network vaults are typically installed under sidewalks with significant pedestrian traffic. From an environmental perspective, corroded and deteriorated network units may result in oil leaking within a vault, and the possibility of oil escaping through vault drainage system into the environment. Over the 2015-2017 period, Toronto Hydro has experienced 223 oil leaks from network transformers. As network transformers typically contain more than 1,000

litres of oil, oil leaks have the potential to lead to serious environmental consequences. Figure 7 shows the size distribution of 223 network transformer oil leaks experienced by volume of oil leaked.

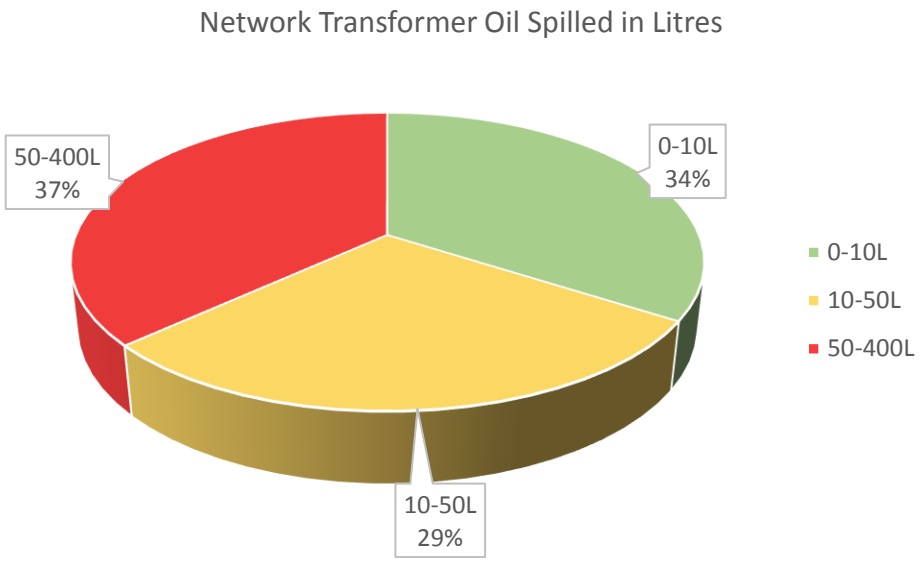


Figure 7: Network Transformer Oil Leaks 2015-2017

Oil leaks are mitigated by replacing deteriorated units and units operating in environments which place them at elevated risk.

E6.4.3.3 Network Vault Renewal

The Network Vault Renewal segment is a continuation of the network vault rebuild and decommissioning activities previously detailed in Toronto Hydro's 2015-2019 CIR filing. Many network vaults associated with the secondary network system were constructed in the 1950s and 1960s, mainly beneath the sidewalks in the busy downtown Toronto core. Today, these assets have many critical structural issues and Toronto Hydro plans to address the worst of them based on condition data. The aim of this segment is to reduce failure risks that can negatively impact the reliability and effective operation of the utility's distribution system as well as safety risks to the public and Toronto Hydro crews.

1. Safety

Table 4 highlights different safety risks to the public and Toronto Hydro crews from deteriorated network vaults. There are two main types of risk to the public. First, cracking and structural shifting

of vault roof structures pose trip and fall hazards. Second, complete failure of roof elements can expose the public to energized electrical equipment.

Table 4: Safety Risk & Descriptions

Safety Risk	Description
Slips, Trips & Falls	A deteriorated vault roof may result in uneven grading on sidewalks or walkways and lead to slips, trips, or falls, which could cause injury to members of the public or Toronto Hydro crews.
Falling Debris	Toronto Hydro crews working inside the vault may encounter falling debris from the deteriorated roof or walls of the vault. This could lead to serious injury, especially when working near live equipment.
Fire	Poor condition of vaults can be a contributing factor to catastrophic failures such as vault fires.

The risk posed by cracking and structural shifting can be controlled by a maintenance program that patches or grinds down hazardous structural elements as needed. However, once a vault reaches the point where major structural deficiencies cannot be addressed by maintenance, three different options are available:

- **Decommissioning vaults** (see Figure 8) that are no longer needed as a result of load displacement. The typical cost to decommission a vault is approximately $50,000 to $150,000 and it takes approximately one month to perform the work;
- **Rebuilding the vault roofs** (see Figure 9) where severe structural deficiencies have been identified, but which are located on network vaults that are otherwise structurally sound. The typical cost of rebuilding a vault roof is up to approximately $250,000 and it can take approximately three months to perform the work;
- **Rebuilding entire vaults** (see Figure 10) that have been identified as having severe structural deficiencies requiring a complete reconstruction. These vaults cannot be decommissioned but require more extensive repairs beyond a vault roof replacement. The typical cost for rebuilding a vault is up to approximately $1 million, which includes the average costs for both civil and electrical work. This work can take between 18 and 24 months to complete.

Toronto Hydro also considers evolving customer needs and system requirements when choosing the best course of intervention for any given vault location.



Figure 8: In-Progress Vault Decommissioning



Figure 9: Temporary Roof during a Roof Rebuild



Figure 10: Completely Rebuilt Vault

For the 2020 to 2024 Network Vault Renewal segment, Toronto Hydro plans to address the immediate structural vault deficiencies of 33 high risk vaults identified through Toronto Hydro's ACA process as having at least material deterioration. In addition to the ACA process, Toronto Hydro carries out civil assessments wherein a civil engineer visually inspects the network vault roof and walls to recommend whether a roof or whole vault rebuild is required.

2. Failure Risk

Vault structural deficiencies are mainly caused by old age and exposure to adverse environmental factors. Currently, Toronto Hydro has 994 network vaults, predominantly in the downtown core, supplying the network system. Figure 11 shows the age distribution of all network vaults with reference to the useful life of both the overall vault (60 years) and the roof (25 years).

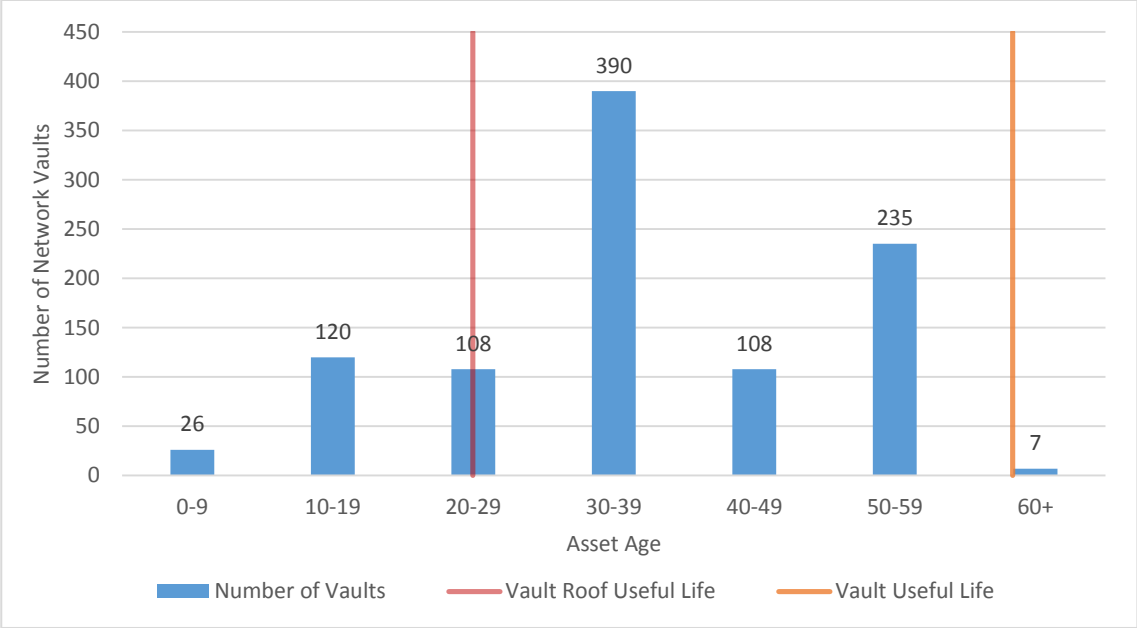


Figure 11: Age Distribution of Network Vaults

The vast majority of vault roofs have reached the end of their expected useful life of 25 years. In addition, over 25 percent of the vault civil structures will reach the end of their expected useful lifespan of 60 years within 10 years. ACA results show that some vaults are aging at an accelerated pace and require repairs even though they have yet to reach their expected lifespan. Increased use of de-icing salts in recent years is contributing to this accelerated aging.

Figure 12 shows that as at the end of 2017, 40 (7 percent) of Toronto Hydro-owned network vaults exhibit at least material deterioration (HI4 and HI5) and are clear candidates for work under this renewal segment. This number is forecasted to grow to 114 (21 percent) in 2024 without the proposed work. To alleviate the risks posed by deteriorated vaults, Toronto Hydro plans to address 33 of these network vaults between 2020 and 2024.

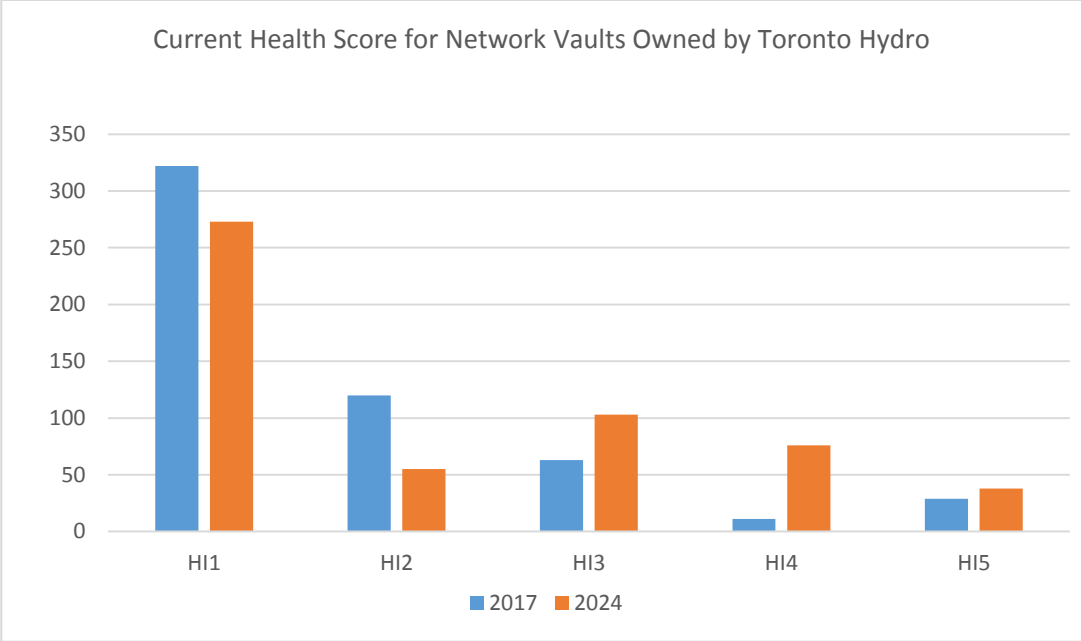


Figure 12: Current and 2024 Health Scores for Toronto Hydro Network Vaults

Some commonly found structural deficiencies caused by asset aging and environmental factors are described in Table 5. Examples of these deficiencies are also shown in Figure 13, Figure 14, Figure 15, and Figure 16 below.

Table 5: Vault Structural Deficiencies and Impacts

Deficiency	Impact
Exposed Roof Rebar	Failure risk that can lead to roof collapse, damage to equipment and safety hazard to the public and Toronto Hydro crews.
Exposed Wall Rebar	Failure risk may result in collapse of the vault walls, potentially leading to damaged equipment, costly repairs, safety hazards, and power outages.
Corroded I-Beams	Failure risk due to age and environmental factors can lead to collapse of the roof structure.
Cracked Roof	Exposes electrical equipment to leaking water and accelerated corrosion which may result in catastrophic failure.
Cracked Walls and Floor	Increases risk of failure causing flooding and damage to equipment which may result in large outage.



Figure 13: Roof and wall with exposed rebar



Figure 14: Corroded I-beams



Figure 15: Cracked roof and wall



Figure 16: Deteriorated Vault Floor

3. Reliability and System Efficiency

As discussed above, there are several failure modes and deficiencies that may lead to structural failure within a vault. Such damage to the network vaults is likely to negatively affect the performance of the electrical equipment contained inside, potentially contributing to a catastrophic failure of the network assets contained within the vaults and thereby causing a power outage in the downtown core. Such a power outage could impact between 500 customers (5 MVA) for smaller network grids and up to 3,000 customers (50 MVA) for the large network grids in the downtown core. The outage can last between several hours to a few days, depending on the location and the network distribution system being impacted.

If a vault roof is not replaced in time, removing it later to replace faulty equipment can cause it to collapse and thereby make it more dangerous and challenging for the crew to replace the equipment. In this scenario, the feeder providing power supply to the failed equipment will be turned off for longer periods of time, which will increase the risk of an outage to the customers fed by that feeder. In order to maintain reliable service to interruption-sensitive downtown customers, it is imperative that these assets be renewed before they fail.

E6.4.3.4 Network Circuit Reconfiguration

Toronto Hydro plans to reconfigure large network grids so that either: (i) sufficient grid flexibility is introduced to enable the sustainment of second contingency events; or (ii) sufficient customer loads

are automatically dropped during second contingency events to allow the remainder of the grids to continue operating reliably.

A reconfigured network should, by design, shed sufficient load under second contingency conditions to allow the remainder of the grid to continue to operate. The network grids targeted for reconfiguration between 2015 and 2024 have six feeders on average and an average of 30 MVA. In a second contingency event, instead of losing all 30 MVA, the reconfigured networks would only lose about 10 MVA. This equates to a 67 percent reduction in interrupted load.

The Network Circuit Reconfiguration segment uses a number of different methods to address the problems and risks associated with multiple contingency events. The methods used depend on the configuration of the network and the requirements needed to reconfigure it into a robust system that supports second contingency. A single reconfiguration project may utilize multiple methods including:

- **Splitting grid into spot vaults:** This option solves overload problems under second contingency events that could result in equipment failure, and eliminates the need for power system controller intervention during these events.
- **Splitting grid into enhanced mini-grids:** This option is able to better sustain customer loads under multiple contingency events than what is possible using the first option. However, a third contingency would still result in a serious transformer overload and require prompt action by the power system controllers to identify the problem and shed load accordingly.
- **Upsizing transformers:** The option allows all customer loads to be sustained during any second contingency condition; however, a third contingency would still result in a serious transformer overload and would require prompt action by the power system controllers to identify the problem and shed load accordingly.
- **Changing primary feeder connections to network transformers:** This option improves diversity in the feeders supplying the network, thereby making it more resilient to multiple contingency events.
- **Reinforcing existing secondary network grid cabling:** This option ensures secondary cabling is not overloaded during multiple contingency events.

1. Failure Risk

Network Circuit Reconfiguration mitigates the impact of failures. Failure risk on the network system has increased over time due to:

- **Evolving Operating Practices:** The secondary network system was originally designed to burn clear faults and self-isolate damaged equipment so that most failures of network transformers and primary and secondary cabling do not result in customer interruptions. However, a small number of transformer failures result in vault fires. The fire department's current practice is to require that Toronto Hydro immediately cut all power supplies into the vault as a first step in fighting the fire. As a consequence, multiple network primary feeders must be tripped, which may leave insufficient remaining contingency capacity to sustain the network grid.
- **Multiple Contingency Events:** Operation of the network system under multiple contingency scenarios imposes challenging requirements on operating personnel. First, a network expert must analyze the grid to identify critical overload conditions and propose customer load reductions and necessary reactive tasks, all within restrictive time limits. If an expert is not immediately available at the control center, power system controllers may be forced to drop the entire grid in order to prevent a network cascade failure. Second, once the necessary reactive switching and load reduction tasks are identified, system response crews must perform this work, and customers need to reduce their loads within the identified time limitations.
- **Reach of the Secondary Network Distribution System:** The secondary network distribution system represents 13 percent of the downtown Toronto peak load (or approximately 230 MVA of 1800 MVA based on 2015 data). Although it is Toronto's most reliable distribution system, when a major secondary network equipment failure occurs, the impact is widespread. Often major portions of station switchgear, with up to 50 MVA of customer load (equivalent to approximately 25,000 residential customers), must be interrupted following such events.

For a typical network with six primary feeders, a widespread forced outage due to a second contingency event would cause about 30 MVA of load to be dropped for four hours to prevent equipment overload. In recent years, these events have occurred approximately once every three years. A reconfigured network grid should be able to sustain a second contingency incident without

requiring the entire network to be dropped. This should typically result in a two-thirds reduction in interrupted load.

2. Reliability and System Efficiency

The network system in Toronto was designed for first contingency operation. Under any first contingency event, power system controllers do not need to take any action to ensure continued reliable supply to network customers. On the other hand, multiple contingency events would require immediate action by power system controllers and system response crews. Often, only minutes are available to take effective action in order to prevent a network cascade failure. As previously mentioned, Network Circuit Reconfiguration enables a network to sustain a second contingency incident without requiring the entire network to be dropped. Since almost all network emergencies involve only first and second contingency outages, this will result in an efficiency improvement in terms of system control.

In addition, most multiple contingency network emergencies require the power system controllers and system response crews to spend hours conducting switching operations to stabilize the network and restore as many customers as possible. As a result, isolation and repair of failed equipment may be delayed until this work is completed. Network Circuit Reconfiguration is expected to reduce the workload required to stabilize the network and restore customers, and allow restoration work to begin at the earliest opportunity, thereby minimizing the time required to restore the network to normal operation.

Table 6 identifies the networks targeted for reconfiguration in the 2020-2024 period. All networks targeted will be reconfigured after they have been updated with monitoring and control through the Network Condition Monitoring and Control program[5]. Through Network Condition Monitoring and Control alone, it is expected that one-third of total network load will be preserved during second contingency events. A reconfigured network will typically preserve two-thirds of the total load during these events (representing an additional one-third savings during second contingency events on networks already updated with condition monitoring and control). The synergies between these two programs are expected to allow many customers to be sustained even during rare third contingency events.

[5] Exhibit 2B Section E7.3

Table 6: Targeted Networks for Reconfiguration

Network	Network Feeders	Total Load on Feeders (MVA)	Network Load (MVA)	Proposed Reconfiguration Year
WR-West Phase 1	9	55	12.5	2021
WR-West Phase 2	9		12.5	2022
GD Phase 1	9	49	11.6	2019
GD Phase 2	9		17.4	2020
A-North Phase 1	9	44	13.5	2023
A-North Phase 2	9		13.5	2024
CS-West Phase 1	8	45	11	2021
CS-West Phase 2	8		11	2024
CE-South Phase 1	8	32	6.5	2022
CE-South Phase 2	8		6.5	2023

The networks to be reconfigured during this filing period represent 50 percent of the major network system load. Multiple contingency events occur approximately once each year and the existing network system can reasonably cope with approximately two-thirds of these events.

3. Functional Obsolescence

The existing secondary grid network distribution system was initially designed for pure network loads and not the mixed network and radial loads that exist today. Network feeders are designed such that they can be highly loaded since loads are automatically redistributed across all other network feeders in case of an outage. However, because radial feeders cannot be loaded as highly, due to the need for them to pick up load during contingency scenarios affecting adjacent feeders, the overall utilization of a mixed feeder is reduced. Furthermore, because of the presence of radial loads on a mixed feeder, the capacity to operate the network under multiple contingencies becomes insufficient. Enhancement of secondary network grid flexibility is necessary to adapt to this new standard.

E6.4.4 Expenditure Plan

To address the critical underlying issues of the network assets in downtown Toronto, Toronto Hydro plans to invest $92.4 million in the Network System Renewal program during 2020-2024. Table 7 below provides Toronto Hydro's annual Historical Year (2015-2017), Bridge Year (2018-2019) and estimated 2020-2024 expenditures for each of the Program segments.

Table 7: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Legacy Network Equipment Renewal (ATS & RPB)	1.0	1.1	3.3	1.8	1.4	1.9	2.0	1.2	-	-
Network Unit Renewal	4.7	7.6	8.3	6.2	11.2	9.5	9.8	10.0	10.1	10.2
Network Vault Renewal	4.6	8.0	2.3	8.6	15.4	6.0	6.1	6.2	6.3	6.5
Network Circuit Reconfiguration	-	0.0	0.7	2.2	1.8	1.2	1.4	1.1	1.2	1.7
Total	**10.2**	**16.8**	**14.7**	**18.9**	**29.8**	**18.6**	**19.3**	**18.5**	**17.7**	**18.3**

E6.4.4.1 Legacy Network Equipment Renewal (ATS & RPB)

The goal of the Legacy Network Equipment Renewal segment is to replace all obsolete ATS and RPB assets within the 2020 to 2024 period. During 2015-17, Toronto Hydro spent $5.4 million to complete replacements of 14 units and expects to spend another $3.2 million to replace 26 units in 2018-2019. Given that certain replacement projects take more than one year to complete, some project spending is allocated to the year prior to unit replacement, causing the unit completion to lag expenditures.

Variances from one year to the next are also attributed to site-specific complexities associated with replacing particular ATS and RPB units. By the end of 2019, Toronto Hydro forecasts to have replaced 40 units over the 2015 to 2019 period. For 2020-2024, 13 units are planned for replacement at a total cost of $5.1 million. Figure 17 shows the annual replacements (actual and forecast) and number of units remaining from 2015 to 2024.

Eliminating these obsolete, prone to failure legacy assets is expected to improve reliability downtown and contribute to Toronto Hydro's system reliability objectives, as well as improve safety by reducing risk of vault fires due to catastrophic failure. Units are prioritized for replacement primarily based on condition and failure risk (e.g. history of water penetration). Where applicable, replacement of ATS or RPB assets will be combined with other work in the Network System Renewal program (e.g. a network vault rebuild) in order to minimize costs and resource requirements.

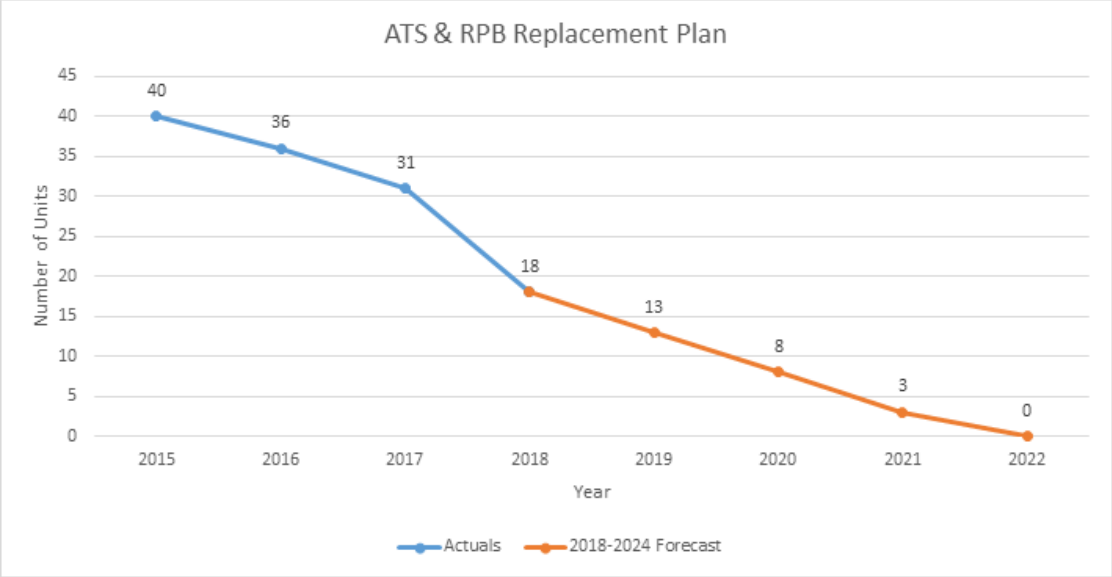


Figure 17: ATS & RPB Burn Down Chart

E6.4.4.2 Network Unit Renewal

The Network Unit Renewal segment replaces end-of-life network units on a planned basis and during 2015-2019 has focused on fibretop units. As of the end of 2017, 16 at risk fibertop units remain on the system and are expected to be essentially replaced by the end of 2019. Toronto Hydro expects to spend a total of $38.1 million on this segment over 2015-2019, which includes spending on Network Condition Monitoring and Control (discussed below). Expenditure vary from one year to the next based on the number of unit replacements and the installation of equipment and fibre optic cable to enable monitoring and control.

In 2015, 2016, and 2017, 17, 25, and 21 network units were replaced respectively. Forty-three additional replacements are planned for 2018 and 2019. The planned replacements are generally lower than were initially expected as deteriorating conditions necessitated the replacement of 127 units reactively during 2015-2017 (see Reactive and Corrective Capital program[6]).

In addition to the network unit replacement work, a portion of spend in this segment was allocated to Network Condition Monitoring and Control, which is included in this DSP as a new, separate program[7]. This work enables remote capabilities to monitor vault conditions such as temperature

[6] Exhibit 2B Section E6.7

and flooding as well as live loading on the network transformer units. Table 8 below shows spending for this part of the Network Unit Renewal segment (separately) over the 2015-2019 period.

Table 8: 2015-2019 Costs (Actual/Bridge): Network Condition Monitoring and Control

	Actual			Bridge	
	2015	**2016**	**2017**	**2018**	**2019**
Network Condition Monitoring and Control	0.2	1.6	3.3	2.8	3.1

Toronto Hydro's forecast cost for 2020-2024 Network Unit renewal is $49.6 million. This will fund the replacement of 40 units per year. 267 network units are forecasted to have at least material deterioration (HI4 and HI5), by 2024. Of these, Toronto hydro plans to replace 243; an average rate of 40 units replaced per year between 2020 and 2024. Replacement of units with the highest failure risk is expected to improve downtown reliability and reduce the safety and environmental risk associated with those units. In addition, newer units will be equipped with new features (e.g. monitoring capabilities to enable faster response to developing problems; and submersible protectors).

In order to minimize costs and use resources efficiently, Network Unit Renewal projects will be combined with overlapping work within the other Network System Renewal segments, where possible. In addition, work on at-risk units fed from a common feeder will be planned to be executed in the same year. The asset condition data collected from inspections (conducted three times per year) is used to determine replacement priority within specific asset classes. Severely deteriorated assets are given the highest priority. Non-submersible units located in areas prone to flooding are also prioritized. Projects can be reprioritized if an urgent need is discovered.

E6.4.4.3 Network Vault Renewal

The Network Vault Renewal segment rebuilds vaults and vault roofs. Over 2015-2017, Toronto Hydro spent $14.9 million to rehabilitate (or decommission) 34 vaults. During 2018-2019, Toronto Hydro expects to spend another $24 million to address 29 vaults.

Variances between years are primarily due to costs associated with particular vaults. Costs for civil work tend to vary greatly between projects because such projects tend to impact city and other utility infrastructure outside of the immediate site. In addition, civil construction projects are impacted by timing and constraints imposed by other major work in the city, such as the Eglinton LRT.

Toronto Hydro plans to spend $31.1 million to rehabilitate 33 of the highest risk vaults during the 2020-2024 period (i.e. approximately seven vaults per year). Through this work, Toronto Hydro expects to improve safety and reliability by removing potential trip and falling debris hazards and reducing the risk that any structural deficiencies could lead to damaged equipment. Figure 18 shows the locations of various proposed projects.

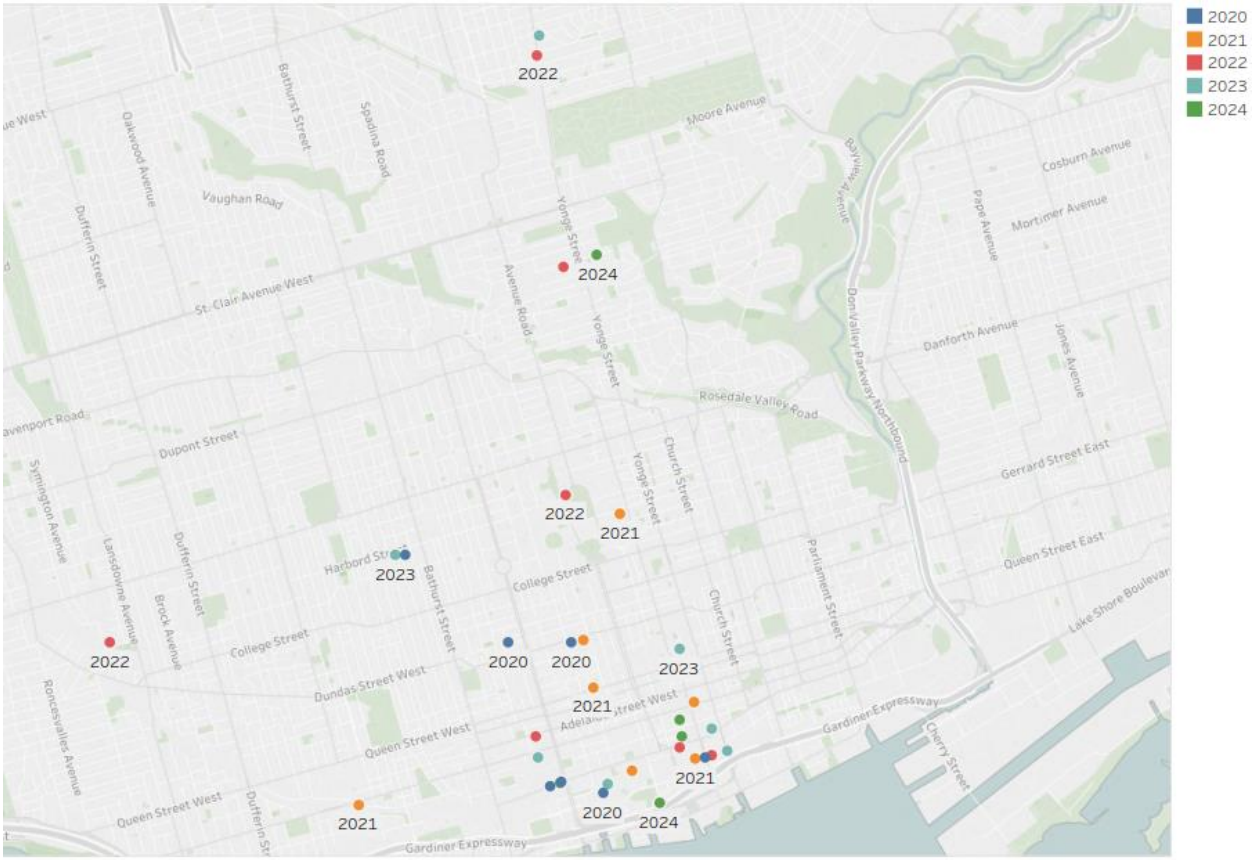


Figure 18: Locations of Network Vault Renewal Projects (2020-2024)

Where applicable, Network Vault Renewal work is combined with overlapping work in the other Network System segments to minimize resource requirements and costs. In addition, projects requiring civil construction work are coordinated with planned City road work to reduce costs associated with routing civil infrastructure around road moratoriums and road cut repairs.

E6.4.4.4 Network Circuit Reconfiguration

The Network Circuit Reconfiguration segment mitigates the impact of multiple contingency events on Toronto Hydro's network system. Through the 2015-2019 period, Toronto Hydro spent $0.7 million on this segment over 2015-2017 and expects to increase spending to $4.0 million over 2018-2019. The variance in spending between 2015-2017 and 2018-2019 is attributed to the timing within the period of the four pilot projects to implement the new 600V network system and the three network grid reconfiguration projects.

The first 600V pilot project began in 2017. Toronto Hydro expects to install the new 600V network system at four other locations (PCS – 1033 Bay St., CTS – 222 Spadina, DHC – 340 College St. and ECE – 25 The Esplanade) in 2018 and 2019. Toronto Hydro expects to complete the reconfiguration of three network grids in 2018 (Cecil North, Carlaw East, Carlaw West) and a portion of the George & Duke network is planned for 2019, with the remainder carrying over into 2020. For 2018, Toronto Hydro is also planning a project to convert an existing subfeeder distribution area to a network system to improve reliability.

Toronto Hydro plans to spend $6.7 million to reconfigure five networks over the 2020-2024 period. Table 6 lists the secondary grid networks chosen for reconfiguration in 2020-2024 based on their size and loading. Toronto Hydro is targeting the five largest networks and expects that their reconfigurations will help to improve outage restoration time and reduce risks associated with second contingency events for downtown network customers.

To minimize costs and resource requirements, Network Circuit Reconfiguration projects are combined with overlapping work in the other Network System Renewal segments, where applicable. Reconfiguration work can vary significantly from one network to another and this holds particularly true during the 2020-2024 period, where the five targeted networks service the most load with complex configurations.

E6.4.5 Options Analysis

E6.4.5.1 Options for Legacy Network Equipment Renewal (ATS & RPB)

Toronto Hydro evaluated the following options for addressing obsolete and deteriorated ATS and RPB units.

1. Option 1: Reactive Replacement Approach

This option entails continuing to operate the ATS and RPB units as is and replacing them reactively upon failure. While failure rates have increased substantially in recent years, manufacturer support and spare parts are not available. Accordingly, maintaining the status quo will negatively affect system reliability and will pose potential safety risks to customers as well as Toronto Hydro personnel. As such, this option is not recommended.

2. Option 2: Like-for-Like Replacement

This option would replace ATS and RPB units with identical units which are no longer considered the standard. The use of non-standard equipment can be very expensive due to high engineering, training, maintenance, manufacturing and inventory costs spread over a relatively small number of assets. These legacy units are no longer supported by manufacturers and therefore, need to be custom made. In addition, when custom equipment is purchased, availability of spare parts and support is limited. As such, this option is not recommended.

3. Option 3 (Selected Option): Replacement with Standard Equipment at Proposed Pace

Replacing legacy network equipment with standard equipment at the pace proposed in the Expenditure Plan will eliminate all remaining ATS and RPB units by the end of 2022. Standard Toronto Hydro network equipment such as 600 A secondary manual switches, stand-alone network protectors, and network transformer units are used to replace legacy network equipment. This allows Toronto Hydro to continue to supply its customers reliably and mitigates the safety risks outlined in this narrative. This option is also the most cost-effective for Toronto Hydro's customers as equipment replacement is prioritized on an asset condition basis, thereby minimizing the likelihood of equipment failure, and minimizing negative impacts to customer reliability. Although reliability and safety risks of these legacy units are mitigated through this plan, some risk will remain until the end of 2022 when all ATS and RPB units will be replaced. However, this is the recommended

option as this level of risk is considered acceptable and the pace of work and spending within this segment is reasonable.

4. Option 4: Replacement with Standard Equipment at Accelerated Pace

By accelerating the pace of work, Toronto Hydro could replace all remaining ATS and RPB units with standard equipment in 2020. This pacing results in the lowest likelihood of ATS and RPB equipment failure; however, it requires that financial and labour resources be applied all at once. Spreading out replacements over the 2020 to 2024 period permits some of these 2020 resources to be applied to other programs that also have assets in varying states of deterioration. Doing so does not change financial and labour resource expenditures over the entire 2020 to 2024 period, but does allow projects in different programs to be collectively prioritized so that risks to safety and customer service reliability are minimized overall. Therefore the option described in Section 5.1.3 above is the preferred option.

E6.4.5.2 Options for Network Unit Renewal

Toronto Hydro considered the following options for addressing network units in poor condition.

1. Option 1: Reactive Replacement Approach

Under this option, Toronto Hydro would continue to maintain existing deteriorated network units and replace each unit upon failure. By maintaining the status quo, the multitude of issues discussed throughout the narrative, including the risk of catastrophic failure due to poor condition or flooding and the associated safety and associated public safety and environmental risks (e.g. oil leaks) would persist. This option is not recommended.

2. Option 2 (Selected Option): Replace Deteriorated Network Units at Proposed Pace

Toronto Hydro's plan addresses safety risks associated with deteriorating network units and would improve reliability and efficiency of the network system. The utility expects the replacement of network units to result in avoided direct and indirect costs associated with in-service asset failures, such as the costs of customer interruptions, emergency repairs and replacement. At the proposed pace of 40 units per year, 243 of the 267 units forecast to have material deterioration by 2024 would be replaced and their associated safety, environmental and reliability risks addressed. However, those remaining units with material deterioration not replaced by 2024 or ones not replaced in a timely manner will continue to pose a higher risk of failure with the potential to cause fires or oil

leaks until they are replaced. Some legacy, non-submersible units without material deterioration, but still at an elevated risk of failure due to flooding, would also remain unaddressed. This is the recommended option as it is expected to result in an acceptable, but not ideal, reduction in the number of at-risk units at a reasonable level of spending.

3. Option 3: Replace Deteriorated Network Units at Accelerated Pace

With this option Toronto Hydro would replace network units at an accelerated rate of 62 units per year to achieve faster reduction of safety and reliability risks associated with deteriorating network units. At this pace, Toronto Hydro would replace most of the 267 units forecast to have material deterioration as well as the majority of network units which will be past their useful life of 35 years by 2024. This would minimize the number of network units at elevated risk of failure, however, it would also cost more than the proposed pace and is therefore not the recommended option.

E6.4.5.3 Options for Network Vault Renewal

Toronto Hydro considered the following options for addressing network vaults in poor condition.

1. Option 1: Maintenance Approach

Under the status quo option, Toronto Hydro would continue to maintain the network vaults in their current state. Maintenance of the vaults involves structural fixes of the roof, wall(s) and/or floor as identified through biannual network vault inspections. Because the vaults proposed for renewal have material deterioration, maintaining (rather than rebuilding) them will inevitably increase the risk of structural failure, which may lead to failure of the equipment housed inside the vaults. Furthermore, safety risks (e.g. tripping and falling hazards) for both the public and Toronto Hydro crews would be elevated. Under this option, Toronto Hydro would be required to resolve these issues reactively, incurring higher costs and unplanned interruptions of supply to the customers. This option is not recommended.

2. Option 2 (Selected Option): Address Deteriorated Network Vaults at Proposed Pace

Toronto Hydro's plan to proactively renew the highest risk network vaults, which have material deterioration, at a rate of five to seven per year is expected to reduce the risk of injury to the public and Toronto Hydro crews and the risk to system performance due to asset failure. These investments would also result in long term benefits (including prolonged expected life and improved standards and materials) for the civil structures of the vaults as well as the equipment housed inside them.

Based on experience to date, Toronto Hydro expects this pace to be achievable and to help mitigate the expected rise in the number of network vaults with material deterioration over the 2020-2024 period. Although Toronto Hydro would address the highest risk vaults, there would still be over 200 network vaults beyond the end of their useful life and over 80 forecast to have material deterioration in 2024. These vaults would continue to pose elevated safety and reliability risks. However, this is the recommended option as it is expected to mitigate risks to an acceptable degree at a pace of work that would be realistically achievable at a reasonable cost.

3. Option 3: Address Deteriorated Network Vaults at Accelerated Pace

By accelerating the pace of network vault renewal, Toronto Hydro Toronto Hydro could go beyond mitigation of the expected increase in the number of network vaults with at least material deterioration and address the majority of all known vaults that are currently known to need work. Reliability and safety risks of deteriorated network vaults would be reduced faster and to a greater degree than with option 2. However, in addition to tripling forecast annual expenditures for this segment, this pace poses issues with resource and outage management resulting in delays of other planned work needed by the Toronto Hydro system and is therefore not recommended.

E6.4.5.4 Options for Network Circuit Reconfiguration

1. Option 1: No Network Configurations

The current operational constraints within the existing network circuit configuration create one to two complete network interruptions each year following multiple contingency network outages. Without additional network reconfiguration, network system reliability is expected to continue to degrade as new customer loads are added, radial and network loads are mixed on the same feeders, and operating practices are modified to enhance safety and satisfy new requirements. The secondary network distribution system would continue to become functionally obsolete and is expected to be less able to meet customers' changing needs, especially given their location in the city's high density downtown core.

2. Option 2 (Selected Option): Reconfiguration of Five Largest Networks

By reconfiguring the secondary network system's five largest network, operating efficiencies can be realized from the reduced amount of load (reduced on average by two-thirds) that needs to be dropped following multiple contingency events on those networks. Furthermore, it would reduce

the workload required to stabilize the networks and restore customers following multiple contingency events and reduce the time required to restore the networks to normal operation. The five targeted networks service the most load and have complex configurations, which means that they would benefit the most from reconfiguration. However, virtually all networks in the downtown would benefit from reconfiguration and those that are not reconfigured are expected to continue to be subject to the reliability, functional obsolescence, and system efficiency issues discussed for the status quo option and in section 3.4. Nevertheless, this is the recommended option as it targets an acceptable level of spending on reconfiguring the networks that will have the greatest impact.

3. Option 3: Reconfiguration of All Major Secondary Network Grids

In addition to the five largest networks described in option 2, eight more networks would be reconfigured. These eight networks would include High Level-Bloor, High Level-St. Clair, Windsor-East, Terauley-East, Duplex-South, Charles-East, Duplex-East, and Charles-St. James. This would extend the benefits described above to the entire secondary network system by 2024. However, Toronto Hydro estimates that this would require approximately three times the financial and labour resources per year as the chosen plan and is therefore not recommended.

E6.4.6 Execution Risks & Mitigation

The Network System Renewal program is subject to the risks facing downtown underground programs and projects. For all segments, these risks include summer feeder restrictions. More specifically, many downtown network feeders have summer feeder switching restrictions imposed to prevent overloading cables and equipment during peak loading periods. To mitigate this risk, projects are scheduled to avoid the summer period if the feeders involved are restricted (i.e. do not have capacity). If a feeder is newly restricted in the project year, the project timeslot could potentially be exchanged with another project. If a restricted feeder supplies a vault being planned for rebuild, then the work may only be conducted during off-peak hours, and this may hinder project execution. Toronto Hydro's Load Demand program for 2015-2019 (see Section E5.4 of the DSP) is intended to help mitigate these risks by enhancing the grid so that feeder restrictions during summer peak times are minimized.

Each segment may also be subject to its own set of additional risks as discussed below.

The City and Toronto Hydro's customers often have special events scheduled that can be negatively impacted by a major construction project. Toronto Hydro communicates with stakeholders and

customers to establish an agreeable timeline in accordance with system priorities. Should a conflict arise, the project timeslot could potentially be exchanged with another project to allow the overall Program to proceed without negative impact.

The removal of a network unit may cause the remaining network units to experience overloads. Toronto Hydro manages this risk by scheduling the replacement of problematic network units outside of the peak loading periods of the particular vault. For example, work on vaults supplying schools or buildings with electric heat may best be scheduled during the summer.

City moratoriums and the Metrolinx subway expansion may impact execution timelines. Although existing City moratoriums are considered when planning vault renewal projects, it is possible that new moratoriums may be subsequently introduced. To mitigate this risk, Toronto Hydro reviews all new moratoriums and adjusts its work plans accordingly. Projects such as the expansion of the transit system in Toronto pose special challenges. When such projects are in the execution phase, the City or Metrolinx may impose moratoriums that suspend all other work until critical phases of transit projects are completed. In addition, transit construction may require relocation of Toronto Hydro assets that impacts the Vault Renewal program. To mitigate this risk, Toronto Hydro communicates with Metrolinx on a continuing basis to identify, monitor, and resolve conflicts.

For the Network Circuit Reconfiguration segment, additional risks are posed by structures at the end of their useful lives and customer-owned civil structures. Projects in this segment typically involve the installation of new cabling within existing cable chambers and duct structures. There is a risk that the required structures will be at the end of their useful lives and may require replacement before the planned work can be executed. This would necessitate scope and timing changes to some projects. However, there are usually multiple options to reconfigure a network. Should the optimal design require civil structure replacement, an alternative that still provides the required reliability and operational improvements, but that does not require civil structure replacement, can likely be found. The design would be revised accordingly to mitigate the cost and timing impacts.

There also may be unforeseen condition or access problems with some customer-owned civil structures. In these situations, the customer may have to perform civil rebuild work before Toronto Hydro's work can commence, thereby causing project delays. This risk can be mitigated by fully inspecting all civil plants prior to finalizing project design, and introducing sufficient lead times for customer civil design and construction activities in the project schedule.

E6.5 Overhead System Renewal

E6.5.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 183.9	**2020-2024 Cost ($M):** 265.7
Segments: Overhead System Renewal	
Trigger Driver: Failure Risk	
Outcomes: Reliability, Environment & Customer Service	

The Overhead System Renewal program (the "Program") manages failure risk on Toronto Hydro's overhead system through the replacement of end -of -life, functionally obsolete assets that are in poor condition or require replacement to mitigate safety and environmental risks.

The Program is a continuation of the Overhead Circuit Renewal Program outlined in Toronto Hydro's 2015-2019 Distribution System Plan,[1] and aims to replace three major overhead asset classes: (1) pole-top transformers; (2) poles and pole accessories; and (3) overhead switches. These assets deteriorate over time due to exposure to harsh environments, usage and age, increasing the probability of asset failure. A summary of the Program's investments in the three major overhead asset classes is as follows:

- **Pole- top Transformers:** The main driver of poor performance in the overhead system is defective equipment in poor condition. Although Toronto Hydro has had some recent success in reducing the total number of overhead transformer failures, they have caused 24 percent of defective equipment outages on the overhead system over the last five years (2013 – 2017). Over the same period, overhead transformers have contributed over 6,000 customer hours interrupted and 10,000 customers interrupted per year on average. Approximately 14 percent of all overhead transformers have already passed their useful life and, without intervention, that number will increase significantly to 40 percent by 2024. This would not only negatively impact system reliability, but also result in a large back log of transformers beyond their useful life that has to be replaced after 2024. In addition, transformers at or beyond their useful life are at risk of having insulating oil containing PCBs that could be released to the environment. Through the Overhead System Renewal program,

[1] EB-2014-0116, Exhibit 2B, Section E6.4

Toronto Hydro plans to replace approximately 6,700 overhead transformers to minimize failures and the environmental risk associated with potential PCB oil spills.

- **Poles and Accessories:** Poles and pole accessories have caused over 40 percent of defective equipment outages on the overhead system over the past five years. Pole failures can lead to extensive and prolonged service disruptions, as well as pose extreme safety risks for utility crews and the public. Poles are frequently exposed to various severe weather conditions, and may become vulnerable to internal rot, decay, and infestation. These conditions, combined with the fact that approximately 25 percent of Toronto Hydro's wood poles are beyond their useful life as of 2017, make these poles more susceptible to failure. Approximately 11 percent of wood poles are already showing signs of material deterioration (as of 2017) and without intervention, this proportion is forecast to increase to 32 percent by 2024. Deteriorated and obsolete accessories such as porcelain insulators are susceptible to contamination build-up, which can lead to asset failure and pole fires. Through continued replacement of poles with porcelain accessories, Toronto Hydro has experienced success in limiting the number of pole fires (from 121 incidents in 2015 to 27 in 2017). Toronto Hydro plans to replace approximately 11,600 wood and concrete poles and associated accessories during the 2020-2024 period to reduce the aforementioned failure and safety risks.
- **Overhead Switches**: Overhead switches are constantly exposed to harsh environmental conditions. Their failure often leads to prolonged outages and can pose significant safety risks to utility workers if an arc flash happens during the switch failure. On average, overhead switches contribute to over 34,000 customer interruptions and 15,000 customer hours interrupted annually between 2013 and 2017. For 2020-2024, Toronto Hydro plans to replace a total of 692 overhead switches in renewal areas with a high concentration of end-of-life transformers in poor reliability.

The Program consists of both complete rebuild projects and spot replacements. Rebuild projects are executed in areas of poor reliability (with substantial concentrations of assets beyond useful life at a high risk of failure) or high volumes of transformers at risk of containing PCBs. Targeted rebuild areas with 4.16 kV or 13.8 kV distribution systems will also be converted to 27.6 kV. Outside of the rebuild project areas, any identified materially deteriorated poles or transformers beyond useful life and at risk of containing PCBs will be replaced through spot replacements.

The objectives of the Overhead System Renewal program for the 2020-2024 rate period are to:

- Renew deteriorated assets that are at or past their useful life to reduce failure risks;

- Maintain overall system reliability and improve reliability for certain poorly performing parts of the overhead distribution system; and
- Address the environmental risks of potential PCB oil spills by replacing transformers containing or at risk of containing PCBs.

E6.5.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Service	• Contributes to Toronto Hydro's objectives and obligations to connect low and high voltage customers within 5 and 10 business days respectively at least 90 percent of the time (pursuant to the OEB's new connection metrics and section 7.2 of the Distribution System Code ("DSC")), by increasing overhead system capacity through voltage conversion from 4 kV and/or 13.8 kV to 27.6 kV in specified areas.
Reliability	• Contributes to Toronto Hydro's system reliability objectives (as measured via metrics like SAIFI, SAIDI, FESI-7, System Health (poles)) by: ○ maintaining current levels of HI4 and HI5 condition poles over the 2020-2024 period; ○ reducing the on-going backlog of deteriorated poles by replacing approximately 11,600 poles known to be in HI4 and HI5 condition ○ reducing the on-going backlog of pole- top transformers past their useful life through area rebuild and spot replacement
Environment	• Contributes to improving Toronto Hydro's Spills of oil Containing PCBs measure, and environmental objectives and obligations by eliminating all equipment containing, or at risk of containing, PCBs from the overhead distribution system by the end of 2024, which would prevent the environmental impacts of possible PCB oil spills and potential breach of applicable environmental requirements (e.g. PCB Regulations SOR/2008-273 under the *Canadian Environmental Protection Act*, the Ontario *Environmental Protection Act*, and Toronto Municipal Code, Chapter 681 Sewers).

E6.5.3 Drivers and Need

Table 3: Drivers and Need

Trigger Driver	Failure risk
Secondary Driver(s)	Environmental Risk

The Overhead System Renewal program focuses on replacing three types of assets: (i) pole-top transformers; (ii) poles and accessories; and (iii) overhead switches. This renewal program is driven by the risk and impact of overhead distribution asset failures on system reliability and safety due to accelerated asset condition degradation resulting from factors such as: sustained exposure to dirt, salt, dust, moisture and humidity, and assets approaching end of their useful life.

Asset failures on Toronto Hydro's distribution system present reliability risks (which can lead to outages and directly impact customers), environmental risks (e.g. oil spills into the environment), and safety risks (e.g. stemming from electrical contacts, arc flashes, and potentially catastrophic fires). Timely replacements are required to avoid the distribution system being operated under contingency conditions (i.e. with interrupted feeders or assets that cannot provide backup supply in the event of a subsequent outage).

Without capital renewal, the risk of overhead asset deterioration and failures would worsen, resulting in more frequent and longer outages (declining SAIDI and SAIFI) and an increasing amount of reactive replacement work. Figure 1 shows the volume of reactive capital work requests generated to address overhead system related deficiencies between 2013 and 2017. On average, about 550 such work requests were initiated annually over that period. Timely replacement of aged and deteriorated equipment before failure can effectively mitigate the frequency and duration of interruptions experienced by customers.

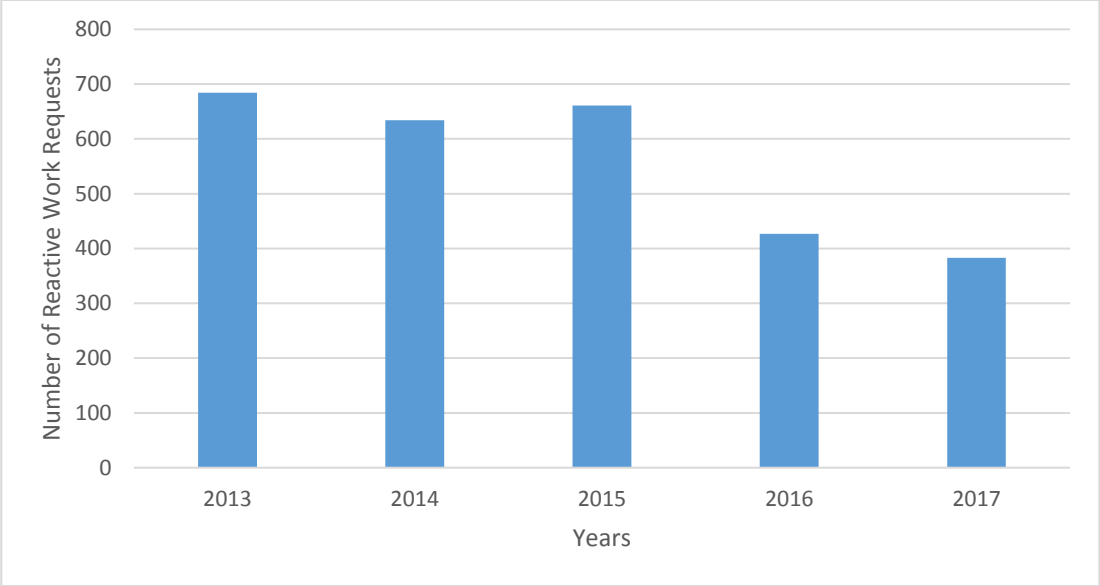


Figure 1: Reactive Work Requests to replace Overhead Assets from 2013-2017

The reliability outcome of historical investments in the Overhead System Renewal program is illustrated in Figure 2. As shown, customers interrupted ("CI") and customer hours interrupted ("CHI") resulting from overhead equipment failures have on average improved over the last two years.

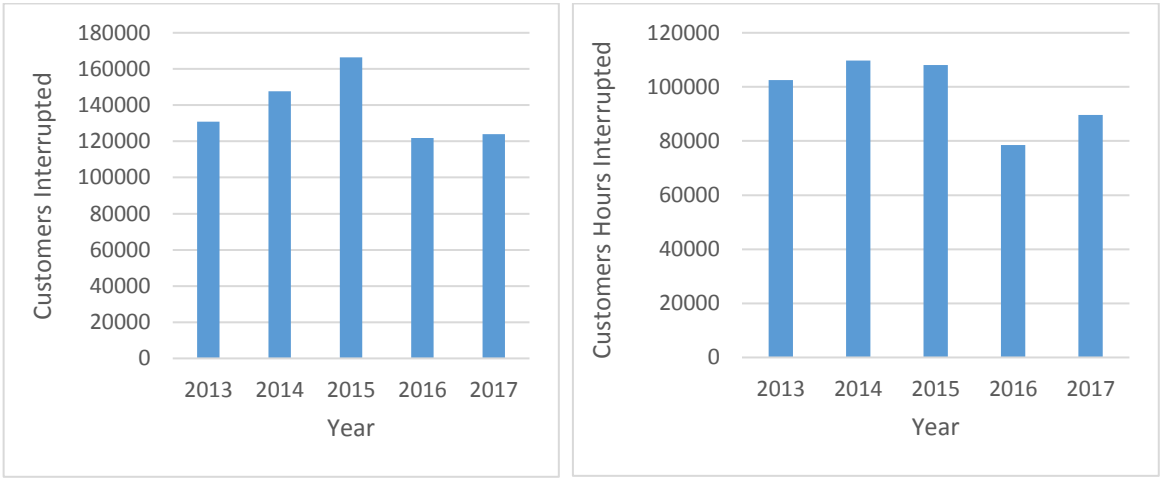


Figure 2: CI (Left) and CHI (Right) on the Overhead System (2013-2017)

Although historical investments have improved the overall reliability of the overhead system, Toronto Hydro must maintain and even increase the current renewal pace to sustain these

improvements. This is necessary to address the large number of overhead assets that are expected to deteriorate in the coming years as they approach the end of their useful life or remain in service well beyond it. Table 4 summarizes the age demographics for poles, transformers and switches in 2017 and by 2024 (assuming the Overhead System Renewal program is not undertaken).

Table 4: Useful Life ("UL") of Overhead Assets

Asset Category	Asset Type	Typical Asset UL (years)	Assets past UL as of 2017 (%)	Assets past UL in 2024 without the Program (%)
Poles	*Wood*	45	25	29
	Concrete	45	20	22
Transformers	*Overhead*	35	14	40
Switches	*Gang Operated Load Break*	40	2	4
	In-line Disconnect	45	27	30

Table 5 shows the condition of Toronto Hydro's poles in 2017 and by 2024 (assuming the Overhead System Renewal program is not undertaken).

Table 5: Condition Data for Wood Poles

Asset Condition Index	Condition of Poles as of 2017	Condition of Poles in 2024 (Without Program)
HI1 – New or Good Condition	64979	57213
HI2 – Minor Deterioration	5210	8310
HI3 – Moderate Deterioration	20542	3596
HI4 – Material Deterioration	14371	17935
HI5 – End-of-serviceable Life	602	18650

Through a combination of spot replacements and complete rebuilds of areas with poor reliability and large concentrations of high-risk assets, Toronto Hydro plans to replace approximately 6,500 overhead transformers, 11,500 poles and 700 switches over the 2020-2024 period. Any target area that still utilize 4.16 kV or 13.8 kV systems will be converted to 27.6 kV. Converting load to 27.6 kV would: (i) enhance power quality with less voltage drop for customers at the end of distribution lines; (ii) reduce line losses, improving the efficiency of the distribution system; and (iii) enable the eventual

decommissioning of Municipal Stations, avoiding operating and maintenance expenditures that would otherwise be incurred.

E6.5.3.1 Replacement of Overhead Transformers

Through the Overhead System Renewal program, Toronto Hydro replaces overhead transformers beyond useful life, which are at risk of failing and potentially posing environmental risk due to oil leaks that may contain PCBs. There are currently 29,628 overhead transformers in Toronto Hydro's distribution system.

As a critical component of Toronto Hydro's overhead system, transformers are used to step down primary distribution voltage to levels required to supply residential and commercial customers. They are mounted on poles and consistently exposed to external elements that cause degradation (e.g. weather conditions, dust, salt, moisture, cyclical loading, faults and humidity). In particular, exposure to precipitation and humidity over time causes corrosion (tank perforation) which can lead to oil leakage into the environment. Figures 3 and 4 show the reactive work requests to replace failed or severely deteriorated pole-top transformers and associated outages during the 2013-2017 period.

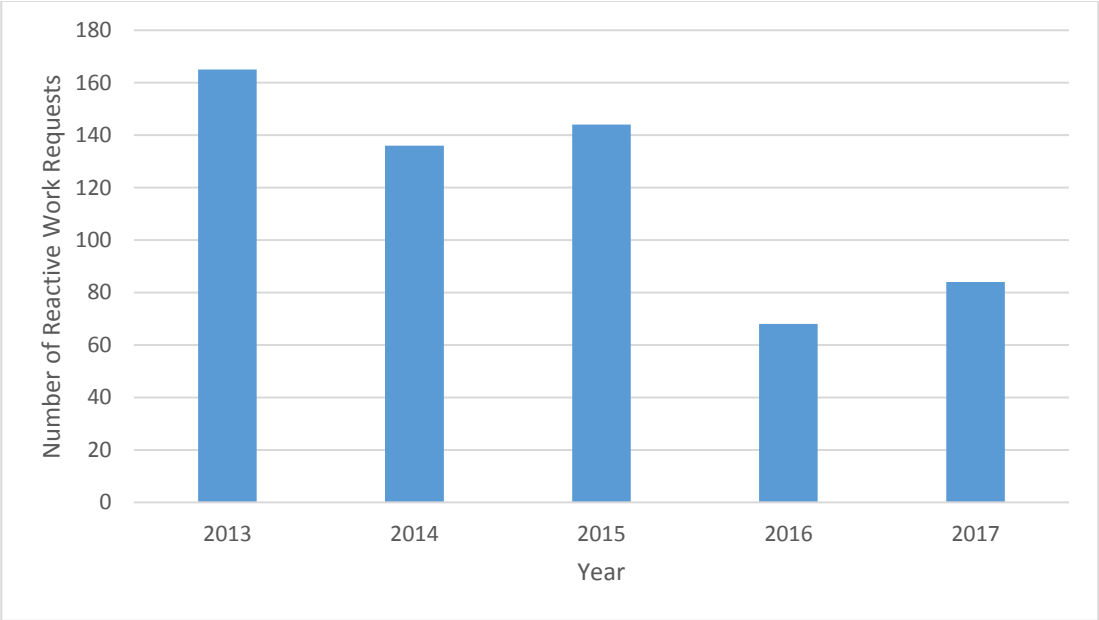


Figure 3: Work Requests for Pole-top Transformer Replacement

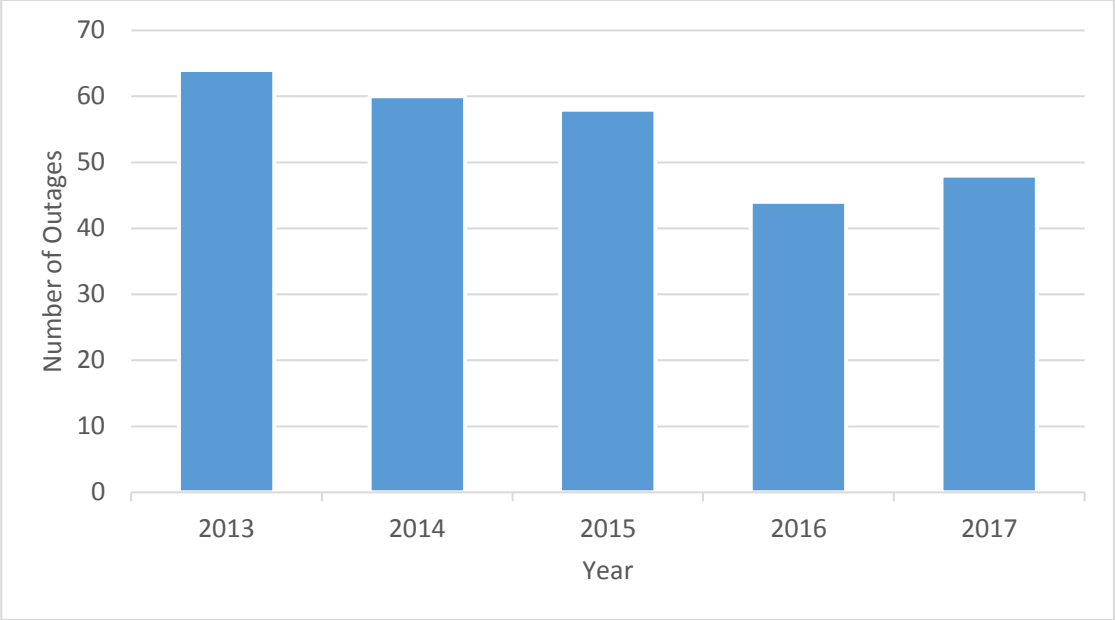


Figure 4: Forced Outages for Pole-top Transformers

Although on-going renewal work has contributed to the overall decline in reactive work requests since 2013, more than 80 requests were still made in 2017 (compared to over 60 in 2016). The vast majority of requests relate to transformer failures (approximately 40 to 70 failures per year), contributing to over 10,400 customers interrupted and 6,100 customer hours interrupted over the same period (see Figure 5).

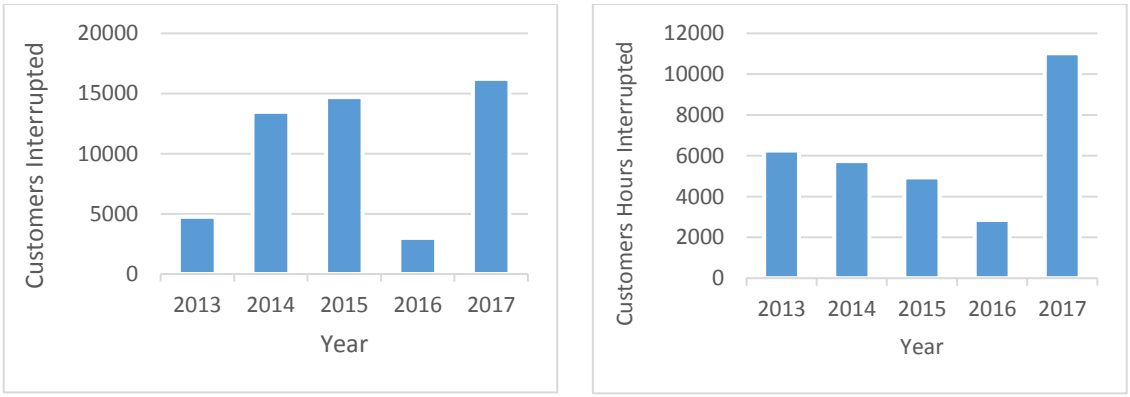


Figure 5: CI (Left) & CHI (right) for Pole-top Transformers

As part of Toronto Hydro's Quality Program, the organization investigated 145 failed overhead transformers between 2013 and 2017 to identify root causes of failure. The investigations found that

37 percent of the failed overhead transformers failed at or past the end of their useful life and that the number of failures increased with transformer age (see Figures 6 and 7). This shows that transformers on Toronto Hydro's distribution system which are at or past their useful life of 35 years are subject to an increased risk of failure.

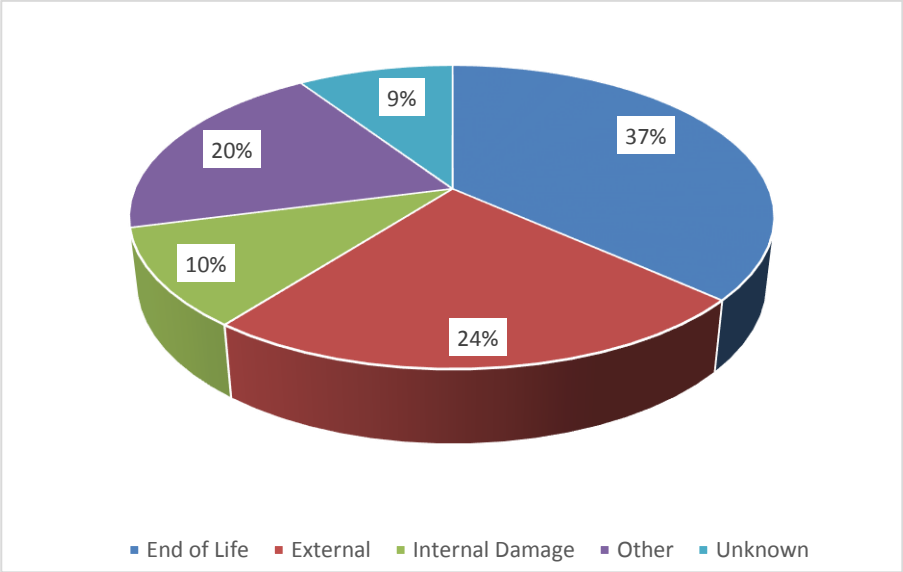


Figure 6: Root Cause Distribution for Failed Overhead Transformers from 2013-2017

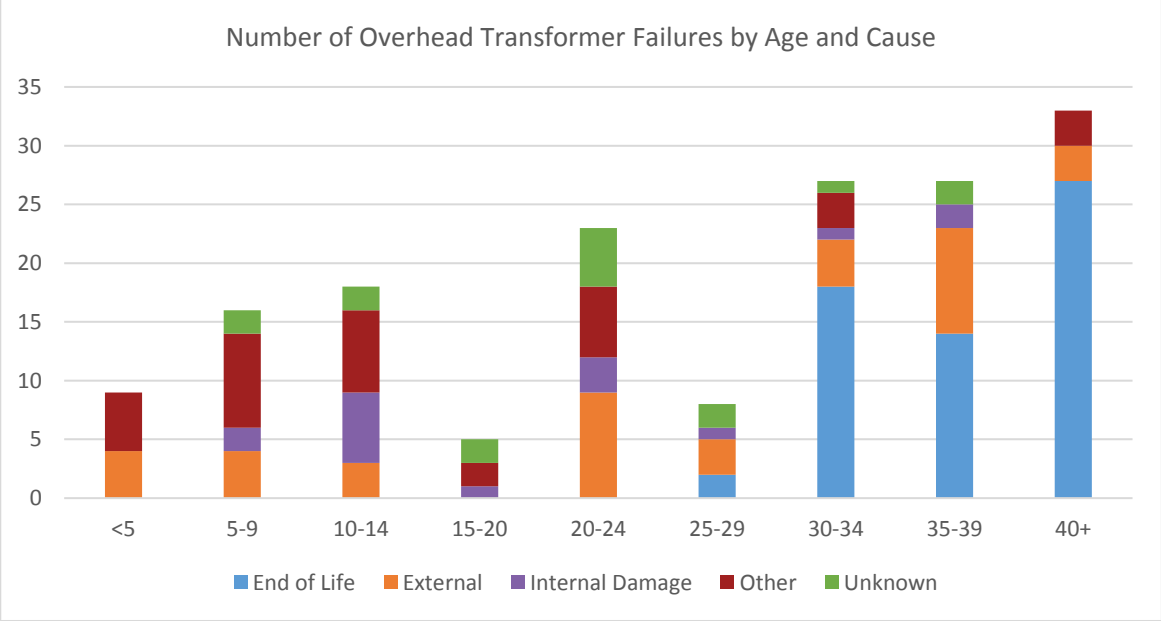


Figure 7: Age Distribution for Failed Overhead Transformers investigated 2013-2017

Figure 8 shows the current age distribution of overhead transformers and what it will be in 2024 without any replacement. As of 2017, 14 percent of overhead transformers had already reached or exceeded the end of useful life. A large number of transformers is also approaching their typical lifespan of 35 years. Without any replacement, this percentage will almost triple to 40 percent (or 11,285 units) by 2024. This drastic increase will exacerbate the risk of transformer failures and reverse the recent improvements in failure rates shown in Figure 3. Unless renewal is undertaken in a timely manner and at a sufficient pace, Toronto Hydro will face a growing backlog of transformers requiring replacement beyond 2024.

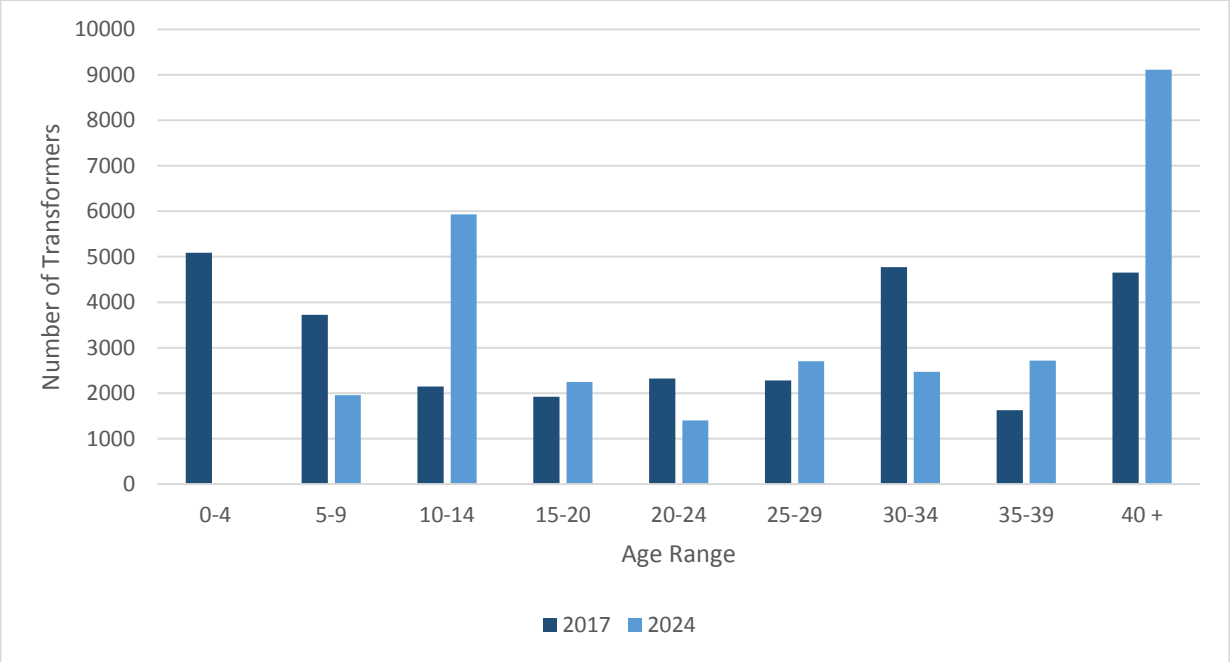


Figure 8: Age Distribution of OH Transformers in 2017 and 2024 (without investment)

A number of overhead transformer failures have also resulted in oil leaks into the environment. Figure 9 shows the total number of reported oil spill incidents for pole-top transformers during the 2013-2017 period. Older transformers are at an especially high risk of having oil containing PCBs. Given the failure risk of aged and deteriorated transformers, the potential for adverse effects on the environmental and affected community in the event of oil leaks is further heightened. Releasing oil containing PCBs (or oil on its own) into the environment may be a breach of the City of Toronto's Sewer Use By-Law, Ontario's *Environmental Protection Act* and, the federal *Canadian Environmental Protection Act* (including the PCB Regulations made thereunder). As the owner and operator of these transformers, Toronto Hydro could be held liable for any environmental impacts and/or ordered to

perform remediation work under one or more regulatory regimes as the result of a single incident. A conviction or finding of non-compliance could also have serious reputational consequences for the utility.

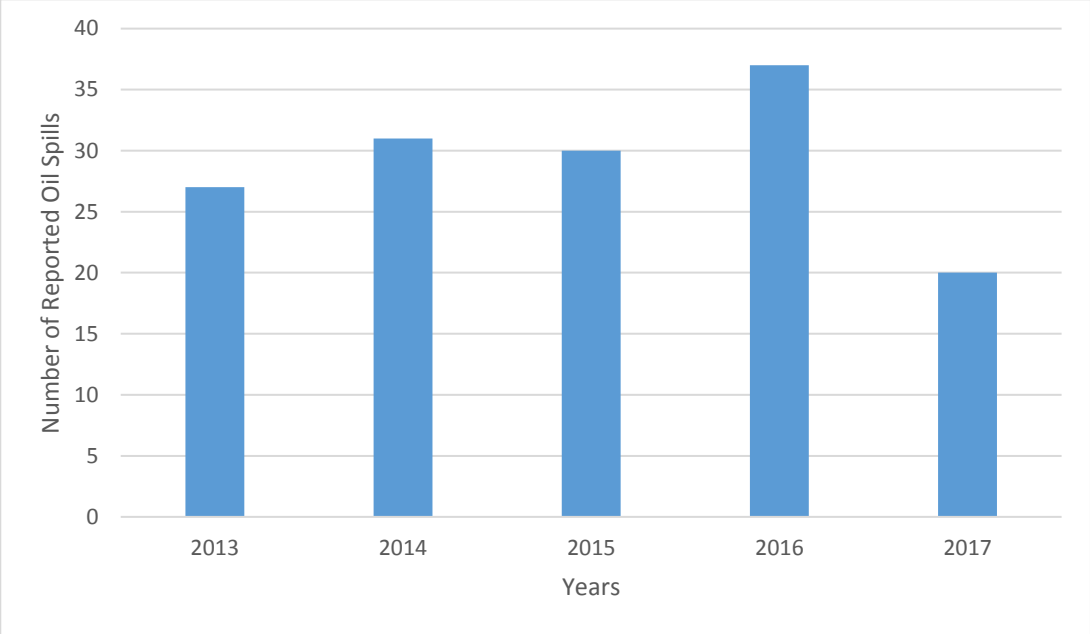


Figure 9: Number of Reported Pole-top Transformer Oil Spills

At the end of 2017, Toronto Hydro had about 6,400 overhead transformers that contain or are at-risk of containing PCBs. Toronto Hydro plans to replace most of these units (approximately 5,200) through the Overhead System Renewal program over 2020-2024. The remaining (approximately 1,200 units) will be replaced as part of the current Overhead System Renewal program prior to 2020 or through other capital programs (e.g. Area Conversions, Reactive and Corrective Capital) by the end of 2024. [2]

E6.5.3.2 Replacement of Poles and Accessories

Through the Overhead System Renewal program, Toronto Hydro also replaces wood and concrete poles showing material deterioration as well as deteriorating or obsolete overhead accessories such as porcelain insulators and non-standard animal guards. Over 40 percent of all forced outages on

[2] Exhibit 2B, Section E6.1 and E6.7

Toronto Hydro's overhead system (excluding animal and tree contacts) over 2013-2017 were due to poles or pole accessories.

Toronto Hydro has approximately 103,000 wood poles and 32,000 concrete poles in service. Poles are exposed to environmental conditions that reduce pole strength, including internal rot and decay at the ground line, shell rot, and infestation. Poles with reduced strength present operational risks to Toronto Hydro crews, safety risks to the public, and reliability risks to the overhead distribution system. The combination of severe weather and poles with reduced strength can lead to catastrophic failure scenarios where one failure can trigger cascading failures on a pole line (i.e. drop of multiple poles and associated equipment, hardware and conductor to the ground). Figure 10 shows the number of poles replaced reactively between 2013 and 2017.

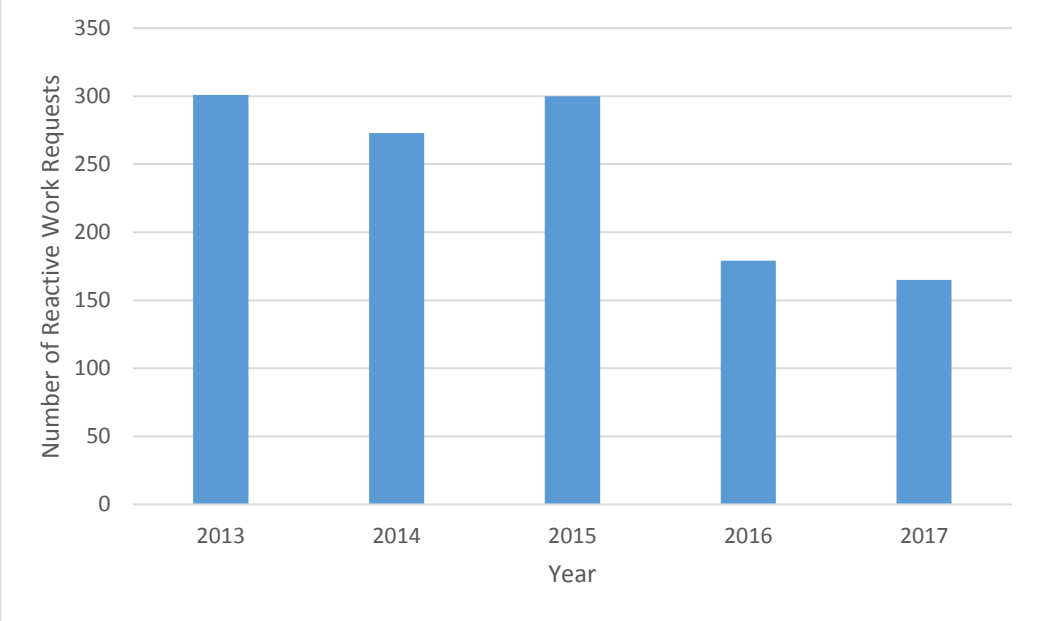


Figure 10: Reactive Work Requests for Pole replacement

In most cases, pole failures can lead to significant public safety risks and prolonged service disruptions. Poles contributed to 7,400 customer interruptions and 7,000 customer hours of interruption per year over the last five years. For these reasons, it is imperative that Toronto Hydro remains diligent and proactive in managing pole failure risks through pole replacements. Despite ongoing renewal, approximately 250 poles on average had to be replaced reactively per year between 2013 and 2017.

Figure 11 shows the age demographics of Toronto Hydro's wood and concrete poles (which have a useful life of 45 years) as of 2017. A significant number of poles on Toronto Hydro's distribution system have already passed their useful life.

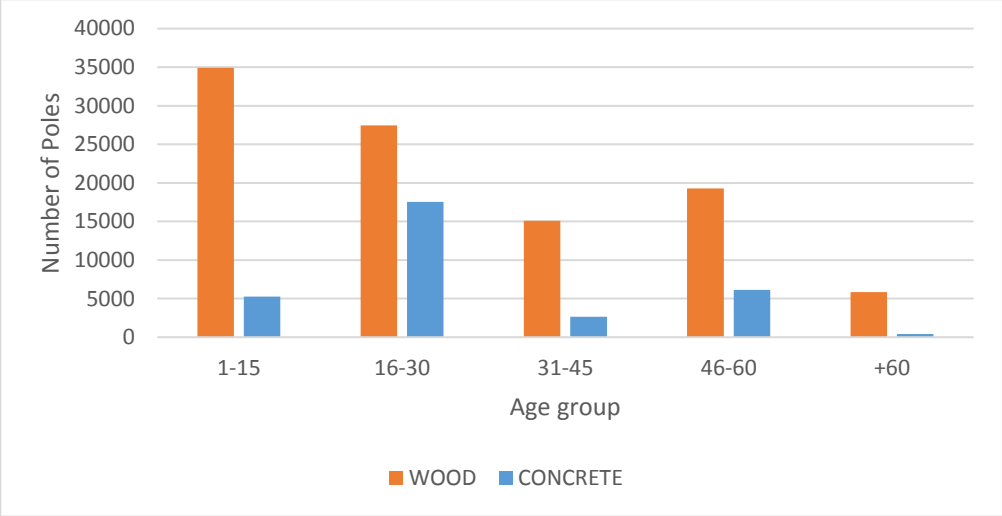


Figure 11: Age of Distribution of All Poles as of 2017

Based solely on age, an estimated 23 percent or 31,600 poles require immediate intervention to mitigate failure risk. However, Toronto Hydro plans to replace only aged poles in the worst condition (i.e. approximately 11,500 of the 31,600 aged poles) during the 2020-2024 period. The overall condition of poles is assessed through Toronto Hydro's pole inspection program. Asset Condition Assessment ("ACA") results indicate that as of 2017, approximately 11 percent of Toronto Hydro's wood poles (approximately 14,500) show signs of material deterioration (classified as HI4 and HI5), and 19 percent of wood poles (approximately 19,600) show signs of moderate deterioration (classified as HI3), as shown in Figure 12.

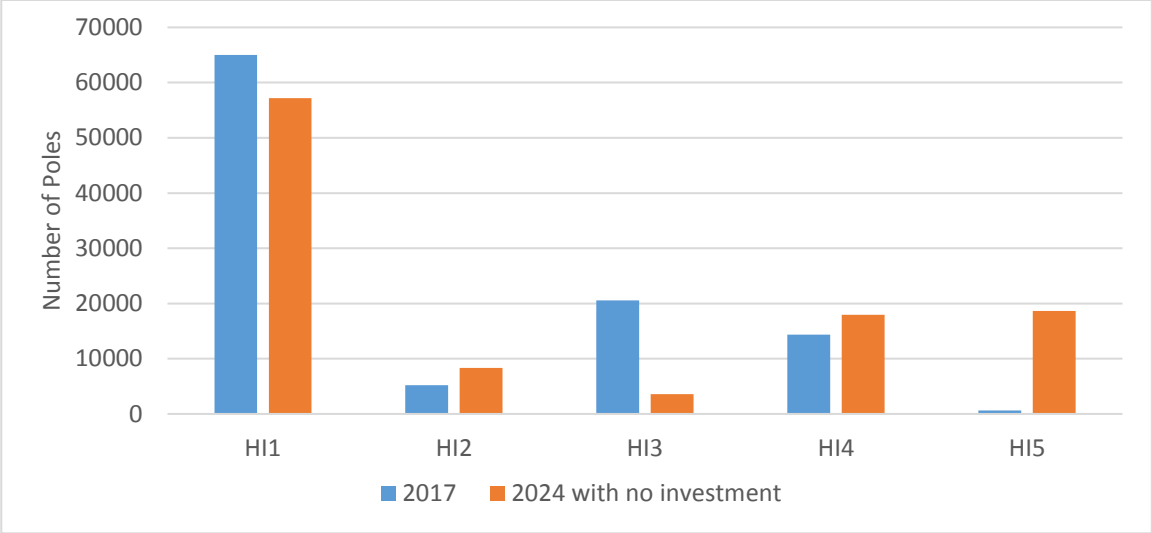


Figure 12: Health of Wood Poles as of 2017 and 2024 (without investment)

Replacement of poles with material deterioration will be carried out through overhead rebuild projects in areas with poor reliability and high concentrations of assets beyond useful life. The remaining units will be addressed by spot replacements.

In addition to replacing poles with material deterioration, the Overhead System Renewal program also replaces deteriorating and obsolete overhead accessories such as porcelain insulators, porcelain lightning arrestors and non-standard animal guards. Pole accessories were the single largest contributor to forced outages on the overhead system in 2013-2017. Toronto Hydro's legacy insulators are predominantly porcelain, which has been used in insulation for switches, lightning arrestors, terminators, and line post insulators. Porcelain insulators possess high dielectric strength and good mechanical properties, including hardness and resistance to chemical erosion and thermal shock. However, it is susceptible contamination build-up, and the accumulation of dirt and salt combined with moisture can lead to insulator tracking, flashover, cracks, insulator shattering and pole fires.

Table 6 shows the total number of pole fire incidents on Toronto Hydro's distribution system from 2015 to 2017. The number of pole fires from one year to the next can vary significantly as risks are related to weather conditions and the presence of contaminants (such as road salts and brines). The impact resulting from a high number of pole fires in 2015 demonstrated how disruptive such incidents can be for the distribution system. The decreasing trend of pole fire incidents is due to

continued replacement of porcelain insulators with polymer insulators under the Overhead System Renewal program, and increased insulator washing under the maintenance programs.

Table 6: Pole Fire Incidents

Year	Number of Pole Fire Incidents
2015	121
2016	39
2017	27

E6.5.3.3 Replacement of Overhead Switches

The last category of assets replaced through the Overhead System Renewal program is overhead switches. Overhead switches are a critical component of the distribution system that facilitates the isolation of feeder sections or equipment for maintenance during interruptions for load shifting and other operating requirements. They also allow workers to operate safely by isolating feeder sections and creating zones that are free of energized equipment. Toronto Hydro uses two types of switches in its overhead system: in-line disconnect switches and gang operated load break switches, each of which further includes both manual load break switches and SCADA controlled switches. Currently there are 2,668 gang operated load switches and 4,951 in-line disconnect overhead switches on the overhead system.

Overhead switches are constantly exposed to harsh environmental conditions such as wind loading and salt spray. These switches can suffer either mechanical failure during operation or electrical failure via a flashover. Failed switches often lead to prolonged outages and pose significant risks to utility workers if an arc flash happens during switch failure. Figure 13 shows that more than 150 reactive work requests were initiated to address the defects found on switches in the overhead system between 2013 and 2017. Figures 14 shows that, despite recent improvement, overhead switches continue to contribute significantly to overhead customer outage frequency and duration. On average over the past five years, overhead switches contributed to over 34,000 total customers interrupted and 15,200 customer hours of interruption per year.

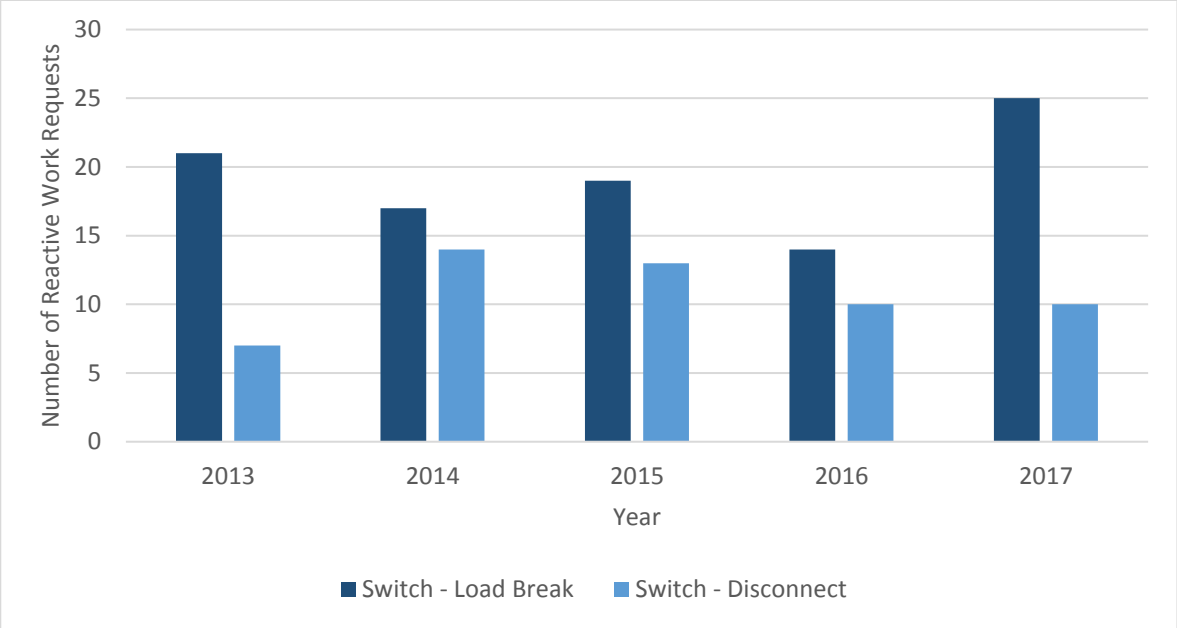


Figure 13: Reactive Work Requests for Switch Defects

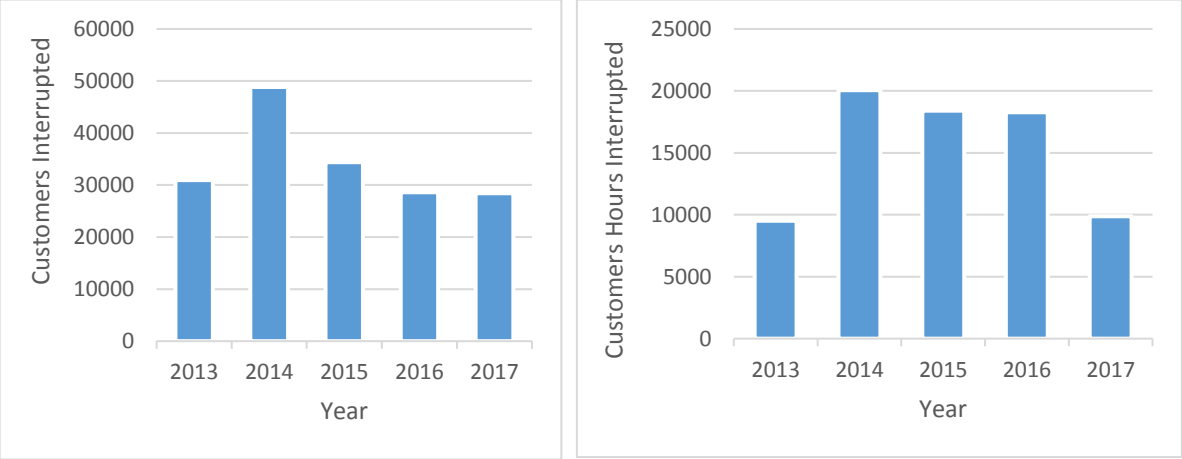


Figure 14: CI (Left) and CHI (right) by Switch Failures

Gang operated load break overhead switches have a useful life of 40 years while inline disconnect switches have a useful life of 45 years. Approximately 2 percent of gang operated switches and 27 percent of inline disconnect switches have reached their useful life as of 2017. Figure 15 shows the age demographics of Toronto Hydro's overhead switches in 2017. There is a considerable number of switches in service that are currently operating beyond their useful life. To maintain reliability,

Toronto Hydro needs to continue its steady renewal of overhead switches to keep pace with the aging asset population and prevent an increase in failure rates.

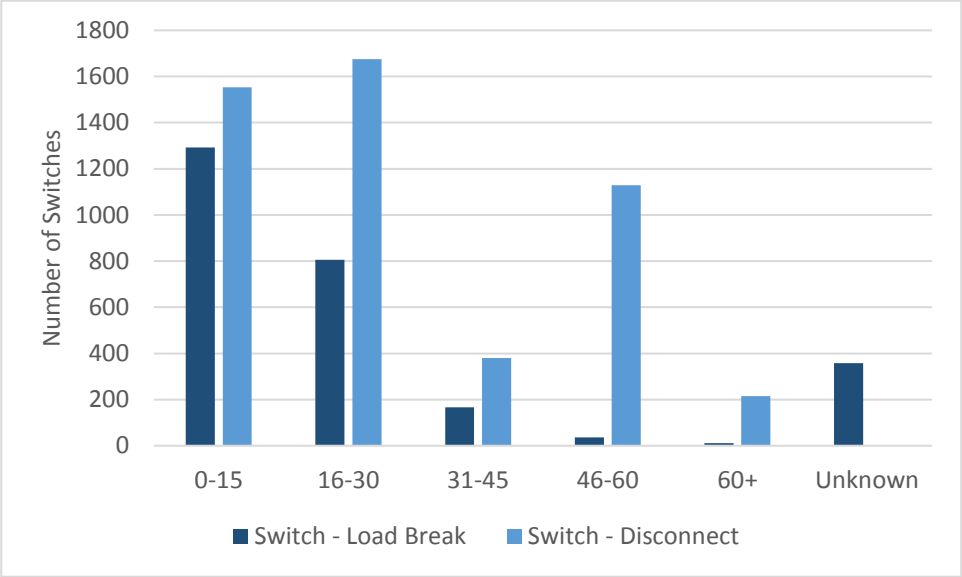


Figure 15: Overhead Switch Age Demographic

E6.5.4 Expenditure Plan

Table 6 provides the Historical (2015-2017), Bridge (2018-2019) and Forecast (2020-2024) expenditures for the Overhead System Renewal program.

Table 6: Historical & Forecast Program Cost ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Overhead System Renewal	61.0	51.0	35.7	18.4	17.8	49.8	50.4	51.3	56.5	57.7

E6.5.4.1 2015-2019 Expenditures

Toronto Hydro invested $148 million in the Overhead System Renewal program between 2015 and 2017, and expects to have invested $184 million by the end of 2019 (almost 25 percent higher than the 2015-2019 DSP forecast of $147.4 million). Table 7 shows the actual and forecast volumes of assets replaced over 2015-2019. During 2015-2016, work volumes and program spending were higher, primarily due to additional overhead renewal rebuild projects planned in 2014 and 2015 (to

address declining reliability seen in 2013 and 2014) which continued into 2016. These investments have contributed to a steady improvement in reliability between 2015 and 2017.

Table 7: 2015 – 2019 Overhead Asset Replacement (Units)

Asset Class	Actual			Bridge		Total 2015-2019
	2015	2016	2017	2018	2019	
Poles	3656	2692	1513	1100	550	**9,023**
Transformers	940	769	441	575	290	**3,174**
OH Switches	192	167	120	55	35	**457**
Conductors* (km)	155	179	123	70	63	**527**

*Primary cables only

Overhead System Renewal spending was ramped down in 2017 through 2019 to accommodate the progression of certain other priority programs (e.g. Box Construction Conversion). Another factor contributing to cost variances is project scope adjustment as projects progressed from high level estimates to detailed designs. For example, designers may identify additional or fewer assets that should be included, scope changes due to interference with other utilities' works, or additional restoration costs.

E6.5.4.2 2020-2024 Forecasts

Toronto Hydro forecasts spending $265.7 million on the Overhead System Renewal program over the 2020-2024 period. This includes the cost of replacing end of life assets, converting the 4.16 kV and 13.8 kV distribution system to standard 27.6 kV lines, and renewing Overhead Street lighting assets deemed to be distribution assets.[3] The 2020-2024 forecast expenditures are based on the historical unit cost trends of major asset classes and the forecast volumes of major overhead asset replacements for the 2020-2024 period, as shown in Table 8.

Table 8: 2020-2024 Volumes (Forecast): Overhead System Renewal

Asset Class	2020	2021	2022	2023	2024	Total
Poles	2,230	2,230	2,220	2,400	2,450	**11,530**
Transformers	1300	1300	1300	1400	1400	**6,700**
OH Switches	130	130	130	160	160	**710**
Conductors* (km)	70	70	70	70	70	**350**

[3] See EB-2009-0180 et al Decision and Order dated February 11, 2010.

*Primary cables only

The 2020-2024 forecast volumes are high level estimates based on a preliminary selection and scoping of areas targeted for complete rebuilds and spot replacements. Complete rebuilds include: replacing pole lines, overhead transformers and switches; upgrading associated overhead accessories; and re-stringing new conductor. Some of these areas are currently supplied by 4.16 kV and 13.8 kV systems, which will be converted to 27.6 kV through these projects. Once high level project scopes are produced, Toronto Hydro performs field inspections to validate the scope of work, identify third party conflicts and refine estimates before final design is completed. Through this process, projects identified for renewal are subject to change. For instance, poorly performing feeders that demonstrate higher risks than originally anticipated may take priority.

The 2020-2024 Program incorporates the three approaches described below.

- **Voltage Conversion:** Voltage conversion of feeders in areas with poor reliability and high concentrations of transformers containing (or at risk of containing) PCBs. Voltage conversion requires that all poles and transformers in each conversion area be replaced.
- **Feeder Rebuild:** Rebuild of feeders in areas with poor reliability and high concentrations of assets in deteriorated conditions that do not require voltage conversion.
- **Spot Replacement**: Spot replacement of transformers containing (or at risk of containing) PCBs and the worst condition poles not targeted in the first two categories as well as any legacy overhead accessories.

The complete rebuild approach is intended to minimize supply disruptions to customers where possible. Reduced disruption to feeders translates into fewer outages for customers and improved project efficiencies. Another way Toronto Hydro maximizes efficiency and cost savings during project planning is by breaking large overhead rebuild projects into smaller phases for enhanced manageability and coordination, providing greater flexibility for scheduling and assigning resources. This approach also reduces the number of scheduled outages and disruptions that customers will experience.

In addition, any voltage conversion overhead work will be coordinated with related stations maintenance work. This will allow feeders to be converted to 27.6 kV and for certain Municipal Stations to be decommissioned, thereby eliminating the need to replace and maintain substation equipment. There are additional costs as well as functional benefits from voltage conversions, including that the 27.6 kV distribution system transports more power over longer distances at lower

losses (i.e. lower voltage drop at greater distances and improved power quality and distribution efficiency) than the existing 4.16 kV or 13.8 kV systems. This also results in fewer required substations, leading to fewer assets to maintain, lower expenditures and greater reliability.

E6.5.5 Options Analysis for Overhead System Renewal

E6.5.5.1 Option 1: Spot replacement of transformers, poles & switches in deteriorated condition, at or beyond their useful life

This option proposes to identify and replace only overhead transformers, poles and switches in deteriorated condition that: (i) are at or past the end of useful life; and (ii) contain or are at risk of containing PCBs. This is a short term mitigation option which focuses on renewing limited overhead assets (transformers, poles and switches) on a feeder segment, reducing the risk of PCB spills into the environment (through oil leaks) and the risk of outages due to asset failures.

This option can provide some improvement in limited circumstances where only a few assets on a feeder segment are in poor condition and eliminating these assets improves overall feeder performance. However, this option does not effectively renew aged or unreliable assets in the field, thus exposing the distribution system to equal or higher risk of asset failure leading to deteriorating reliability and safety to utility workers and the public. As a result of this approach, Toronto Hydro would likely incur higher reactive repair cost potentially with greater disruptions to the public and customers in the course of reactive repair work. This option is not recommended because it does not effectively address the underlying issue of system-wide overhead equipment failures.

E6.5.5.2 Option 2 (Selected Option): Proactive rebuild/ renewal of priority areas exhibiting degradation or poor reliability, voltage conversion, and spot replacement of higher risk transformers and poles.

This option proposes a rebuild or renewal of assets on feeders or geographical areas showing signs of degradation or progressively deteriorating reliability, spot replacement of transformers at risk of containing PCBs, and voltage conversion of functionally obsolete 4.16 kV or 13.8 kV primary voltage designs to 27.6 kV. Specifically, this option will include:

- Full rebuild of areas with poor reliability and a high volume of assets beyond their useful life;
- Full rebuild and voltage conversion in areas supplied by 4.16 kV or 13.8 kV primary voltage and with a history of poor reliability and a high concentration of assets beyond their useful life; and

- Like-for-like spot replacement of transformers which are beyond useful life and contain or are at risk of containing PCBs, poles showing material deterioration and associated overhead accessories.

In arriving at the decision to pursue this option, Toronto Hydro considered the need to strike a balance between maintaining acceptable safety and reliability on its overhead system, while providing electricity distribution services to customers at reasonable costs. Through this option, Toronto Hydro would be best able to manage the failure risk of overhead assets (i.e. by removing aged and unreliable assets to address deteriorating reliability) while also mitigating the environmental risks stemming from transformers at risk of containing PCBs (i.e. by removing them from service). Further, this option will prevent the accumulation of a large backlog of overhead assets at a high risk of failure and in need of replacement beyond 2024, which would reduce reliability and increase costs for customers over the long term.

E6.5.5.3 Option 3: Replace all transformers at risk of containing PCBs, all assets in deteriorated condition (or beyond useful life) and/or convert all 4.16 kV service areas to 27.6 kV

Under this option, the preferred option 2 would be expanded in one or more of the following ways:

- Replace all poles (approximately 36,000) that will reach end of useful life by 2024 (i.e. not just those in the worst condition).
- Replace all transformers beyond useful life, including those not at risk of containing PCBs. This would require replacing over 11,000 overhead transformers by 2024.
- Replace all overhead switches beyond their useful life (approximately 1,600).
- Convert all 4.16 kV service systems to 27.6 kV, which would require rebuilding 333 additional feeders and replacing approximately 1,800 transformers and 11,000 poles, which have not yet reached the end of their useful life.

Taking any of the above actions would provide additional reliability and other benefits such as reducing safety risks or improving system efficiency. This option would also ensure Toronto Hydro would have no backlog of end of life assets by 2024 and that none of the areas in the overhead system will be supplied by 4.16 kV. This is expected to reduce the number of failures on the overhead system, improving reliability and reducing the spending and resources required for reactive replacements and for overhead system renewal beyond 2024. Additional voltage conversion would improve power quality and efficiency, reduce line losses and accelerate decommissioning of certain

municipal stations. However, Toronto Hydro does not consider this to be an economically feasible option at an estimated total cost of $850 million.

E6.5.6 Execution Risks & Mitigation

Large overhead renewal projects can be complicated given that third parties could also be doing work in the same area, resulting in potential conflicts and leading to incremental costs and delays. To ensure effective coordination with the City and other utilities, Toronto Hydro participates in the Toronto Public Utilities Coordinating Committee forum.

Other execution risks associated with large overhead rebuild projects include:

- **Third Party Attachments**: Where third party attachments to Toronto Hydro assets will be affected as part of the project, the relevant owners must be contacted to explore alternative attachment options which may delay the execution timeline. To mitigate this risk, Toronto Hydro will engage owners of these third party attachment assets as soon as possible to coordinate and plan the required transfer.
- **Permitting**: Delays in obtaining permits from applicable authorities (e.g. the City of Toronto, Ministry of Transportation, CN railways and Hydro One) may require extra design time. To mitigate this risk, additional design time will be built into the schedule to ensure the necessary permits are obtained without material effect on project schedule. Also, Toronto Hydro will work closely with the City of Toronto on planned road work through meetings of the Public Utilities Coordinating Committee. If work planned by the City puts Program completion at risk, Toronto Hydro will negotiate with the City to coordinate a construction schedule that is acceptable to all parties involved.
- **Operational risks**: Load transfers can be restricted in certain months of the year due to high usage of electricity (e.g. during the summer months). Toronto Hydro will mitigate this risk by scheduling work to avoid periods of loading restrictions.
- **Resource availability**: Insufficient resources can seriously impact project execution, resulting in delays or deferrals into future years. To address this risk, engineering work plan meetings are held each year as part of the new Enterprise Project Management process to ensure sufficient resources are available to complete the approved projects for that year.
- **Conformance with standards:** Toronto Hydro designs and constructs new overhead rebuild projects in accordance with applicable standards and specifications that are intended to ensure public and employee safety. However, unique situations can sometimes arise to

hinder design or construction in compliance with applicable standards. Identifying and making efforts to accommodate and address these issues during the planning and design stages can mitigate most of these risks. Toronto Hydro has established processes to address potential deviations from standards to ensure that the design and construction processes are not delayed and that any accepted deviations from standards do not impact the utility's ability to remain compliant with applicable requirements (including Ontario Regulation 22/04 - Electrical Distribution Safety).

E6.6 Stations Renewal

E6.6.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 85.3	**2020-2024 Cost ($M):** 141.5
Segments: Transformer Stations, Municipal Stations, Control and Monitoring, Battery and Ancillary Systems	
Trigger Driver: Failure Risk	
Outcomes: Reliability, Safety	

The Stations Renewal program (the "Program") manages stations-level failure risk through the replacement and refurbishment of end-of-life and obsolete assets. Station asset failure can result in power outages to thousands of customers for several hours or more, depending on the failure. Further, the lead time to replace station assets is often lengthy, with replacement of major assets such as transformer station switchgear requiring years to plan and complete. Hence, to meet customer expectations for reliability and system resiliency, Toronto Hydro's tolerance for failure risk in respect of station assets is low (relative to distribution lines assets). Predictive and preventative maintenance helps to maximize useful life, but in the absence of proactive renewal efforts, assets will eventually fail while in service. Toronto Hydro prioritizes station assets for proactive renewal based on age, condition, performance, load served, and customers connected, with the objective of maintaining reliability, minimizing cost impact to customers, and mitigating environmental and safety risks. Through this Program, Toronto Hydro's objective is to maintain current levels of stations reliability.

The Program is grouped into the segments summarized below and is a continuation of the station renewal activities described in Toronto Hydro's 2015-2019 Distribution System Plan.[1]

- **Transformer Stations ("TS"):** This segment involves the renewal of Toronto Hydro's switchgear, outdoor breakers, and outdoor switches located at TSs. The majority of Toronto Hydro's TS assets serve customers in the downtown core, where many customers are highly sensitive to power outages. During the 2020-2024 period, Toronto Hydro plans to replace five TS switchgears, nine TS outdoor breakers, and 61 TS outdoor switches, all at a total

[1] EB-2014-0116, Exhibit 2B, Section E6.13, E6.14, E6.15 and E6.19

estimated cost of $74.5 million. Replacing station assets that have deteriorated, are beyond their useful life, and subject to a heightened risk of failure allows Toronto Hydro to sustain current levels of reliability and mitigate crew exposure to safety hazards.

- **Municipal Stations ("MS"):** This segment involves the renewal of Toronto Hydro's switchgear and transformers located at MSs and their primary supplies. The majority of Toronto Hydro's MS assets serve Toronto's suburban areas which consist largely of residential and general service customers. During the 2020-2024 period, Toronto Hydro plans to replace 12 MS switchgears, 10 power transformers, 10 primary disconnect switches, and a MS primary breaker, at a total estimated cost of $37.7 million. Replacing these deteriorated and obsolete assets will allow Toronto Hydro to maintain the current level of MS reliability.
- **Control and Monitoring:** This segment involves the renewal of protection, control, monitoring, and communication assets at Toronto Hydro's TSs and MSs. During the 2020-2024 period, Toronto Hydro plans to install 6 new remote terminal units ("RTUs"), renew 39 existing RTUs (14 DACSCAN, 15 MOSCAD, and 10 D20 M++/ME), upgrade protections at 5 pilot-wire locations, and replace 45 kilometres of old copper control cable, all at a total estimated cost of $22.1 million. By replacing these obsolete and deteriorating assets, Toronto Hydro will be able to reduce outage durations and maintain overall stations reliability.
- **Battery and Ancillary Systems:** This segment involves the renewal of stations service equipment, DC battery and charger systems, and other supporting systems at Toronto Hydro's TSs and MSs. This segment also installs new systems to mitigate risks posed to and by equipment from flooding or fire susceptibility. During the 2020-2024 period, Toronto Hydro plans to install three sump pumps, replace 67 battery and charger systems, replace six station service transformers, and replace two air compressors at a total estimated cost of $7.3 million. Asset replacement is due to factors including old age, poor condition, obsolescent technology, and PCB contamination. This work will allow Toronto Hydro to maintain station integrity and system reliability for Toronto Hydro customers.

Toronto Hydro plans to invest $142 million in the Stations Renewal program in 2020-2024, which is an increase over the projected 2015-2019 spending in this Program (including forecasted inflation). This level of investment is necessary to address the backlog of high priority station assets that are at or beyond their useful life, have deteriorated in condition, and pose heightened failure risks. Given the necessity of an increased expenditure plan for Stations Renewal, Toronto Hydro has taken several

steps to mitigate potential execution risks to the proposed 2020-2024 Program. These steps include increasing the use of contracted Stations design and field personnel, training and expanding the use of Toronto Hydro Stations internal resources, improved coordination with external parties and improvements in our downtown feeder outage coordination process. These improvements will address resources constraints and other risks associated with executing this increased capital investment in Toronto Hydro Stations assets. An in-depth discussion of execution risks mitigation is provided in Section E6.6.6.

E6.6.2 Outcomes and Measures

Table 2: Outcomes & Measures Summary

Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7, System Capacity) by
	  ○ reducing the percentage of station assets in deteriorated condition and operating beyond their useful life
	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by mitigating the exposure to failure risk for approximately:
	  ○ 32,000 customers by replacing assets at and beyond useful life at Transformer Stations (e.g. switchgears, outdoor breakers, outdoor switches);
	  ○ 25,600 customers by replacing assets at and beyond useful life at Municipal Stations (e.g. switchgears, power transformers, primary disconnect switches);
	  ○ 160,100 customers by renewing functionally obsolete protection, control, monitoring and communication assets; and
	  ○ All customers supplied from 15 TSs and 60 MSs by renewing station service equipment (e.g. sump pumps, battery and charger systems)

Safety	• Contributes to Toronto Hydro's public safety performance (as measured by the OEB distributor scorecard safety metrics) and employee safety (as measured via Total Recordable Injury Frequency) by: ○ Increasing the population of arc-flash resistant TS and MS switchgear resulting in improved worker safety and reduced risk of serious injury; ○ Decreasing the population of oil-filled TS outdoor breakers thereby reducing the risk of oil explosions causing equipment damage and injury.

E6.6.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Failure Risk
Secondary Driver(s)	Functional Obsolescence

The Stations Renewal program addresses failure risk and obsolescence issues associated with Toronto Hydro's highly critical stations assets. A significant portion of Toronto Hydro's station assets are operating beyond their typical useful lives and are subject to an increased risk of failure due to their age and condition. Station asset failures can have high consequences and impact due to the large number of customers served by each station. Often, necessary repairs are complex and require long lead times.

Like distribution line assets, prudent management of station assets is achieved by monitoring asset conditions and demographics. Unlike some distribution line assets however, asset management strategies that include just-in-time asset replacement are generally unacceptable for station assets.

In addition to their increasing failure risk, many older assets are built on technology that has become obsolete due to advancements and other emerging industry trends, and evolving best practices related to safety, customer needs, and functionality. Replacing obsolete assets allows Toronto Hydro to meet public policy and legal requirements (e.g. PCB elimination), accommodate increasingly more sophisticated customer needs (e.g. connection of distributed generation), operate its system more efficiently, and provide increased value to customers.

E6.6.3.1 Transformer Stations ("TS")

Toronto Hydro's TSs supply power to all classes of customers. Major TS assets include TS switchgear, TS outdoor breakers, and TS outdoor switches. A large portion of these assets are operating beyond their useful life and are consequently subject to heightened failure risk. Toronto Hydro uses a risk-based approach to identify the highest priority TS assets for replacement, with the objective of cost-effectively sustaining current levels of reliability and prudently mitigating crew exposure to safety hazards.

1. TS Switchgear

As shown in Table 4 below, by the end of 2019, about a quarter of Toronto Hydro's TS switchgear will be operating past their useful life. Many of these assets are non-arc-resistant and have other obsolete design features that heighten safety risks for crews and the risk of collateral asset damage in the event of switchgear failure.

Table 4: Transformer Station Switchgear Demographics at end of 2019

Switchgear Construction	# of Assets	% of Assets Past Useful Life	Other Demographic Information	
			% of Non-Arc Resistant Switchgear	% of Switchgear with Obsolete Breakers
Metalclad	44	20%	68%	50%
Brick Structure	5	100%	100%	100%
GIS	2	0%	0%	0%
Total	51	27%	69%	53%

Toronto Hydro uses asset age, condition, and operational feedback to identify and prioritize switchgear requiring renewal. Switchgear are composed of many different parts. Each part has its own failure mode and useful life (often less than the 50 years attributed to the switchgear as a whole). Reactive repair and maintenance of individual parts are performed but become less prudent as components which cannot easily be replaced (e.g. bus bars, bus insulators, and miscellaneous control wiring) age and deteriorate.

Toronto Hydro applies infra-red hotspot scanning, and cable termination, connection, and cleanliness qualitative (visual) assessments to measure and assess the condition of switchgear. Major components inside the switchgear such as breakers are also assessed for condition on a per breaker basis. Until recently, Toronto Hydro used these measurements (excluding the breaker condition

assessments) to derive a single health index ("HI") for switchgear. However, results have suffered in quality and reliability due to the limited number of measurements and difficulty in quantitatively balancing different indicators. As a result, Toronto Hydro evaluates these assets on an asset-by-asset basis rather than use a single HI metric. In this regard, Toronto Hydro considers switchgear age, breaker conditions and operational feedback its best indicators for risk assessment of these critical assets. The current age demographics of Toronto Hydro's TS switchgear units is shown in Figure 1 below.

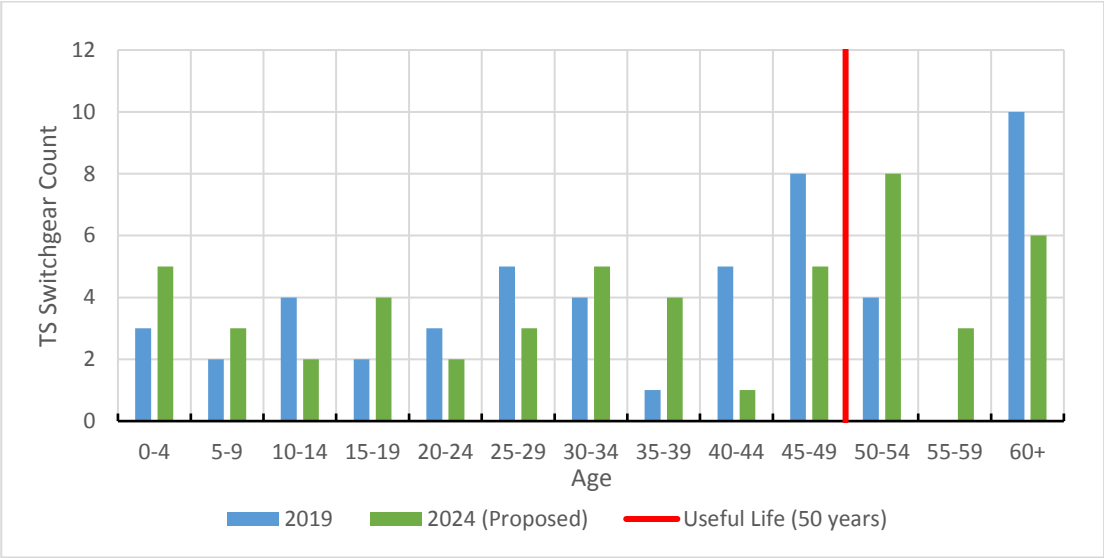


Figure 1: TS Switchgear Age Demographics

As indicated in Figure 1 above, Toronto Hydro will have 14 TS switchgear units operating at or beyond their useful life expectancy at the end of 2019 with an additional 8 more expected to be by 2024. Toronto Hydro's condition assessment for all breakers contained within its TS switchgear population is shown in Figure 2 below, which indicates that a significant proportion of Toronto Hydro's breakers with moderate or worse deterioration are air-blast breakers. Among Toronto Hydro's TS switchgear population, these are the oldest breakers in use and are found in 11 of the switchgear units operating beyond their useful life.

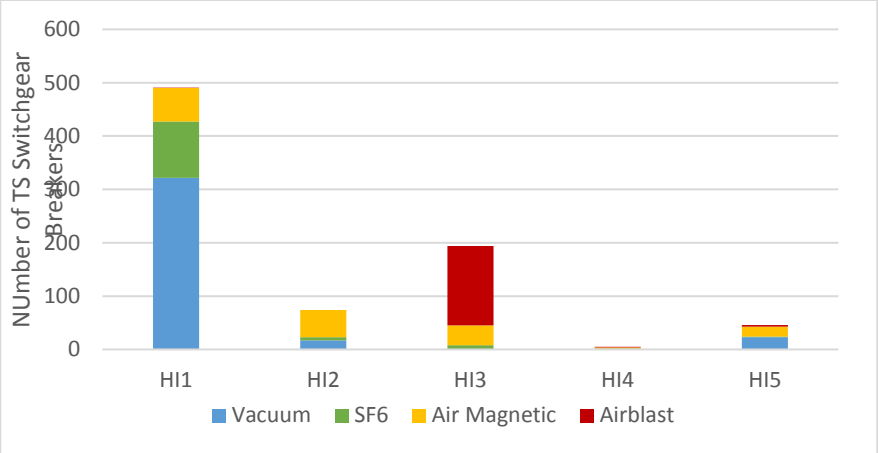


Figure 2: TS Switchgear Breaker Condition by Type as of 2017

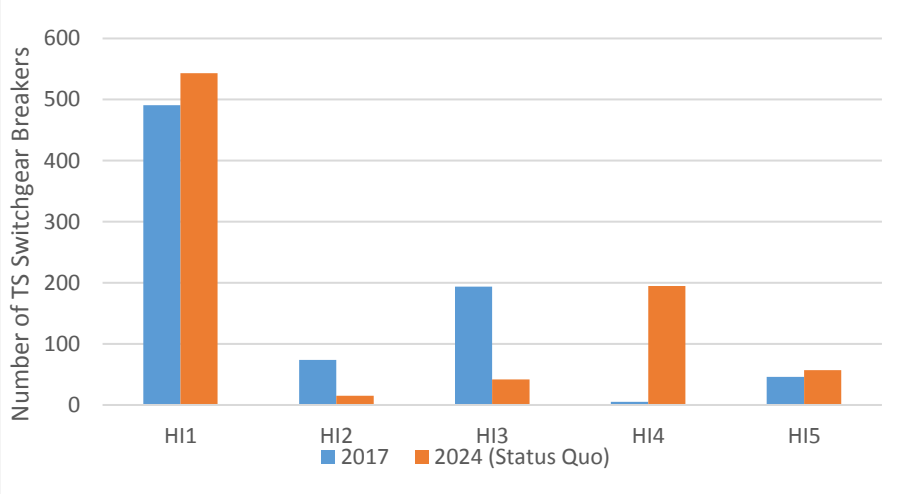


Figure 3: TS Switchgear Breaker Condition Aggregate as of 2017 and in 2024 Without Investment

The impact of switchgear failure is severe. As an example, a recent failure of a switchgear unit due to a failed insulator that flashed-over resulted in an interruption of 6,194 customers and 32 MVA of load. The average affected customer was without power for 9.5 hours while restoration of the last customers took 12 hours. A photo of the failed insulator is shown in Figure 4 below. As shown in this photo, visual condition assessment may not always be effective. In many cases, these components are not accessible for the level of inspection required to detect measurable signs of impending failure. This is particularly true for some metalclad switchgears that require a complete switchgear outage to enable thorough condition observations, which is not possible without significant customer outages given today's system loading.



Figure 4: Failed Switchgear Insulator – Imperfection Difficult to Observe

Toronto Hydro's average TS switchgear supplies 37 MVA of load – more than the failure case highlighted above – and its heaviest loaded unit alone serves 63 MVA of peak load. As shown in Figure 5 below, these assets primarily serve Toronto's downtown and adjacent areas, which include Toronto's financial district, entertainment district, university district, and some of the city's densest residential communities.

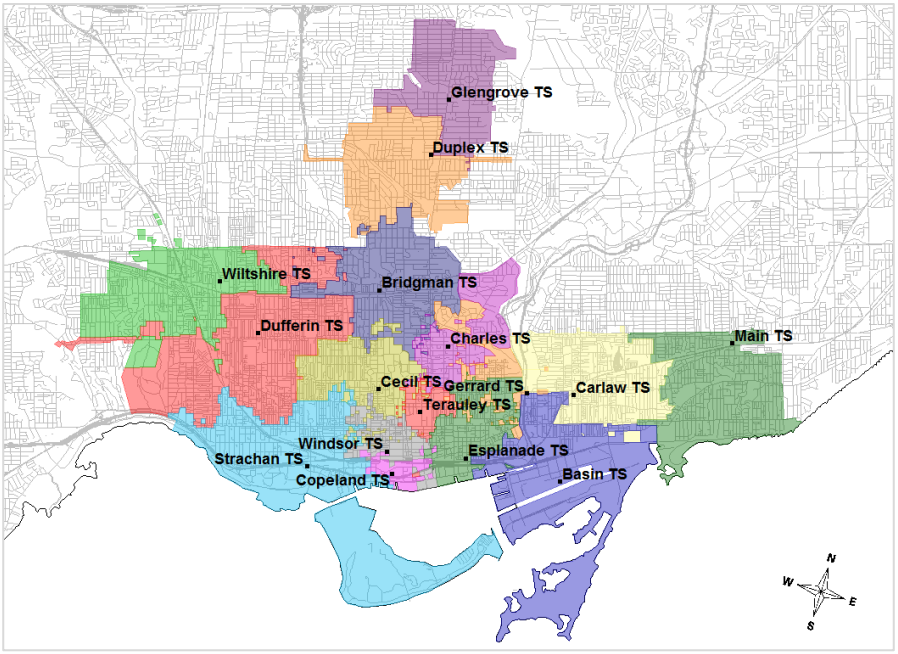


Figure 5: Location of TSs containing Toronto Hydro-Owned Switchgear (excluding Cavanagh TS in North Scarborough)

Toronto Hydro proposes to replace the five TS switchgear units identified in Table 5 below during the 2020-2024 period. All of the units proposed for replacement are beyond their 50-year useful life expectancy and feature obsolete circuit breakers contained within non arc-resistant enclosures. Condition assessments performed during breaker maintenance show that all of the breakers in the switchgear units proposed for replacement suffer from moderate or material deterioration as of 2017. Breakers are used to determine the condition of a switchgear because they are the "moving parts" inside switchgear and are generally indicative of a switchgear unit's overall health.

Table 5: TS Switchgear Proposed for Replacement

Station	ID	Enclosure	Breaker Type	2017 Condition Assessment (for Breakers)	Replacement Year
Strachan TS	*A5-6T*	Metalclad	Air Blast	Moderate Deterioration	2023
Carlaw TS	*A4-5E*	Brick	Air Blast	Moderate Deterioration	2022
Windsor TS	*A5-6WR*	Metalclad	Air Blast	Moderate Deterioration	2023
Duplex TS	*A1-2DX*	Metalclad	Air Magnetic	Moderate Deterioration	2023
Bridgman TS	*A1-2H*	Brick	Air Blast	Moderate Deterioration	2024

As shown in Table 6 below, with these replacements and investments, there will be a decrease in non-arc resistant switchgear and a decrease in switchgear with obsolete breakers compared to 2019 demographics (see Table 4) from 69 percent to 60 percent and 53 percent to 41 percent respectively.

Table 6: Transformer Station Switchgear Demographics at End of 2024 With Investment

Switchgear Construction	# of Assets	% of Assets Past Useful Life	Other Demographic Information	
			% of Non-Arc Resistant Switchgear	% of Switchgear with Obsolete Breakers
Metalclad	45	31%	64%	42%
Brick Structure	3	100%	100%	100%
GIS	5	0%	0%	0%
Total	**53**	**32%**	**60%**	**41%**

The Windsor TS (A5-6WR) switchgear unit is notable for its importance as a critical asset located in and supplying the city's downtown core. It was originally installed in 1956 and will be 63 years old in 2019. High loading on this switchgear combined with its age and condition contributed to the need

for Copeland TS (installed under the Station Expansion program).[2] With Copeland TS online, Toronto Hydro will gain the capacity required to offload and replace the Windsor TS (A5-6WR) switchgear. This will provide increased reliability to 434 customers consuming 53 MVA of peak load, a very high ratio of average load per customer. Many of these customers are large commercial entities in high-rise buildings in the center of the city's financial district. Figure 6 below shows an overview of the volume of customers and quantity of load benefitting from Toronto Hydro's proposed replacement plan.

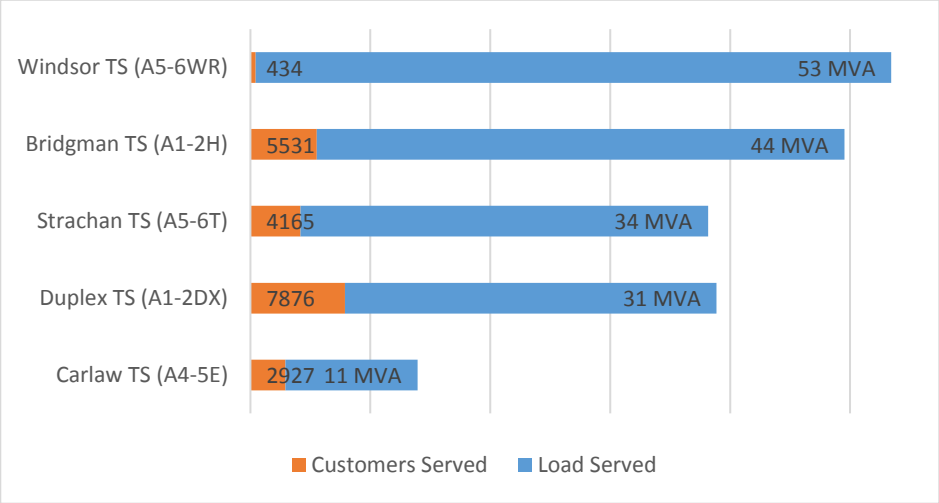


Figure 6: Customer Impact of Switchgear Failure - TS Switchgear Proposed for Replacement

When replacing TS switchgear units, Toronto Hydro installs fully-rated arc-resistant switchgear to utilize the available capacity of the supplying Hydro One transformer. Potential Hydro One transformation upgrades that could justify installing a larger capacity switchgear are considered in coordination with the Stations Expansion program.[3]

Arc-resistant switchgear is installed because it minimizes the safety risk posed to Toronto Hydro personnel presented by arc-flash events. An arc-flash event is a short-circuit inside a switchgear that causes an electrical explosion. If such an event occurs when personnel are switching or working on nearby switchgear that is not arc flash rated, the explosion and associated energy released can be life threatening. Arc-resistant switchgear, which has become an industry standard, is designed to

[2] Exhibit 2B, Schedule E7.4
[3] *Supra* note 2

contain the explosion, and re-direct the energy to reduce the risk of injury to anyone present within the station

2. TS Outdoor Breakers

As shown in Table 7 below, by the end of 2019, 4 percent of Toronto Hydro's TS outdoor circuit breakers will be operating past their 45-year useful life. About a quarter of these breakers (i.e. KSO oil circuit breakers) are based on obsolete technology and may contain oil with PCBs, which, in the case of a breaker failure, would increase the safety risk for crews, the risk of collateral damage to other assets, and the risk of environmental damage.

Table 7: TS Outdoor Breakers Demographics at the end of 2019

Outdoor Breaker Technology	# of Assets	% of Assets Past Useful Life	% of Assets with PCBs>2ppm
KSO Oil Circuit Breaker	20	20%	85%
SF6 Circuit Breaker	25	0%	N/A
Vacuum Circuit Breaker	45	0%	N/A
Total	90	4%	19%

As indicated in Table 7, by the end of 2019, 20 percent of Toronto Hydro's KSO oil-based circuit breakers will be past their useful life of 45-years and 85 percent will contain PCBs greater than 2 ppm (identified through sampling).

Figure 7 below shows the TS Outdoor Breakers condition as of 2017 and the condition of the breakers in 2024 without investment.

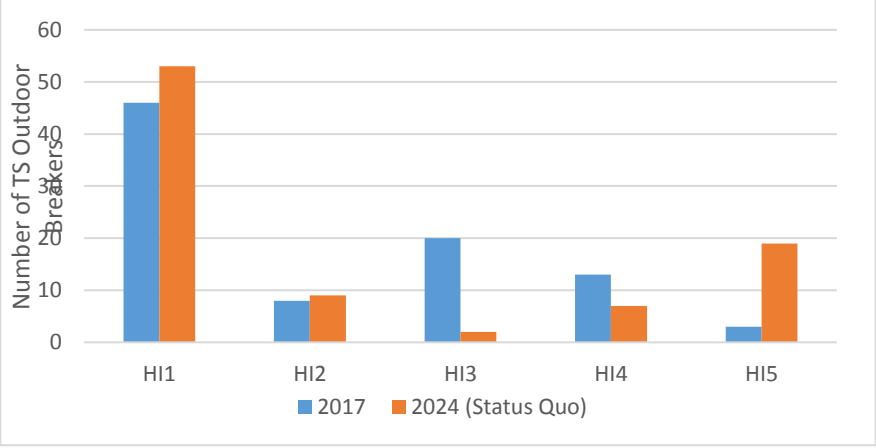


Figure 7: TS Outdoor Breaker Condition as of 2017 and in 2024 without investment

As of the end of 2017, condition observations of these KSO oil circuit breakers in particular show that approximately 55 percent are showing signs of moderate to material deterioration. Figure 8 below illustrates the condition of these circuit breakers at the end of 2017 (including the units planned to be replaced in 2018 and 2019).

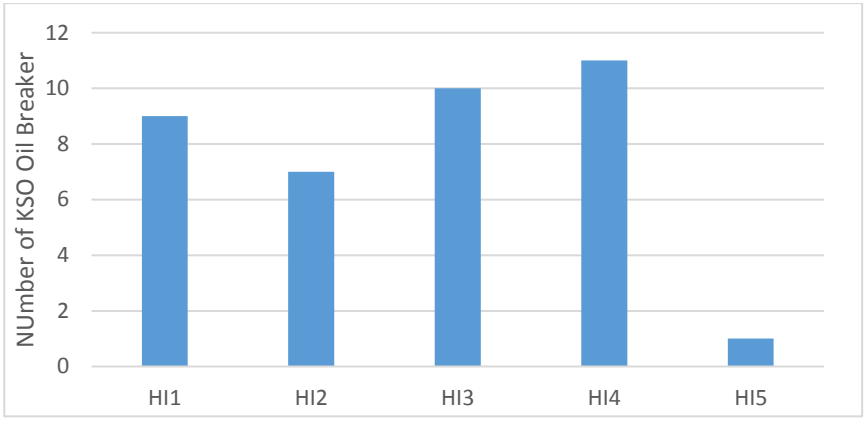


Figure 8: Condition Assessment for KSO Oil Circuit Breakers as of the end of 2017

KSO oil circuit breakers have not been manufactured or purchased by Toronto Hydro since the early 1980s. Recently, Toronto Hydro has had difficulty obtaining the spare parts required to properly maintain them. As shown in Figure 9 below, by the end of 2019, 4 TS outdoor breakers (all KSO oil circuit breakers) will be operating beyond their useful life of 45-years with an additional 9 that will be 45 years or older by 2024.

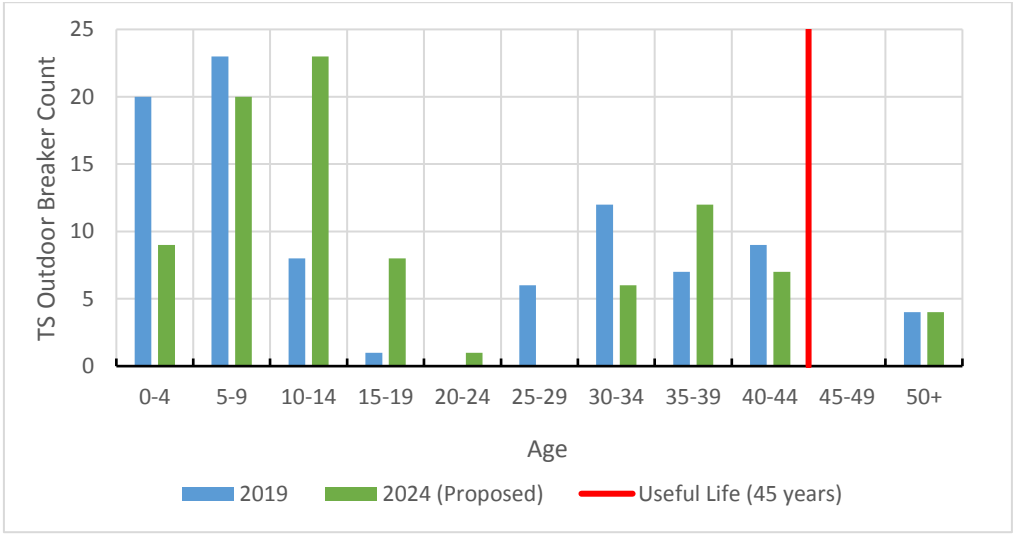


Figure 9: TS Outdoor Breaker Age Demographics at the end of 2019

The life of these breakers has been extended for as long as practical through corrective repair. This is done by obtaining parts for repair from retired units. As the in-service population of KSO oil circuit breakers continues to age and deteriorate, obtaining these spare parts has become less sustainable.

The failure risk of these circuit breakers is high and the impact is significant. When a breaker fails, thousands of customers will experience an outage – typically lasting one to two hours. Circuit breaker failure is most likely to occur when the breaker is triggered to operate. When a circuit breaker fails, the next upstream protection device at the station bus is triggered to operate. A fault that was otherwise localized on a feeder would then extend to all of the customers supplied by that station bus, potentially disrupting anywhere from 1,000 to 10,000 customers depending on the bus. Toronto Hydro recently experienced an outage of this nature when an outdoor breaker at Finch TS failed to open during a fault. The bus protection system was forced to operate, interrupting power to nearly 5,000 customers. Most customers were restored within one hour of the initial incident; however, all of those customers were supplied by feeders that would not have suffered an outage had the breaker operated as intended.

Beyond the outage impact to customers, KSO oil circuit breakers run the risk of failing catastrophically, wherein the circuit breaker explodes and sets fire to its oil, potentially damaging equipment, injuring personnel in the vicinity and impacting the surrounding environment. An example of such a failure recently occurred at Manby TS (owned by Hydro One). A snapshot of the resulting fire is shown in Figure 10 below. Similarly to the Finch incident, upstream protection was triggered and thousands of customers in the downtown west-end of Toronto suffered an outage lasting approximately three hours. Equipment surrounding the breaker also suffered collateral damage from the fire and the explosion. While no public or field personnel were injured during the incident, it highlights the inherent safety risk of using oil as an insulating medium in switching devices.



Figure 10: Catastrophic Failure of an Outdoor Circuit Breaker at Manby TS (Hydro One-owned)

In addition to heightened safety risk, there is also a risk of environmental damage due to oil leakage. Nearly all of Toronto Hydro's KSO oil circuit breakers contain PCBs.

To mitigate the safety risks noted above, Toronto Hydro plans to replace the 9 TS outdoor breakers identified in Table 8 below during the 2020-2024 period. These breakers have been selected using a variety of inputs including current condition assessment, asset age, projected condition in 2024, load served, and PCB content. All of the breakers proposed for replacement will be beyond their 45-year useful life expectancy and contain or at risk of containing oil with PCBs. For work to be done first during the 2020-2024 period, Toronto Hydro will prioritize the breakers presenting highest failure risk.

Table 8: TS Outdoor Breakers Proposed for Replacement

Station	Breaker Type	Feeder	Load Served	Replacement Year
Fairchild TS	*KSO Oil Circuit Breaker*	M10	7 MVA	2020
Leslie TS	*KSO Oil Circuit Breaker*	M26	11 MVA	2021
Finch TS	*KSO Oil Circuit Breaker*	M23	15 MVA	2022
Finch TS	*KSO Oil Circuit Breaker*	M26	16 MVA	2022
Leslie TS	*KSO Oil Circuit Breaker*	M29	15 MVA	2023
Leslie TS	*KSO Oil Circuit Breaker*	M30	15 MVA	2023
Leslie TS	*KSO Oil Circuit Breaker*	M32	10 MVA	2024
Bathurst TS	*KSO Oil Circuit Breaker*	M23	16 MVA	2024
Bathurst TS	*KSO Oil Circuit Breaker*	M32	14 MVA	2024

As per Figure 11, these assets are located at stations serving customers located in the North York area. Once this work is complete, customers and loads connected to these 5 stations will face reduced risk of power disruptions resulting from breaker failure.

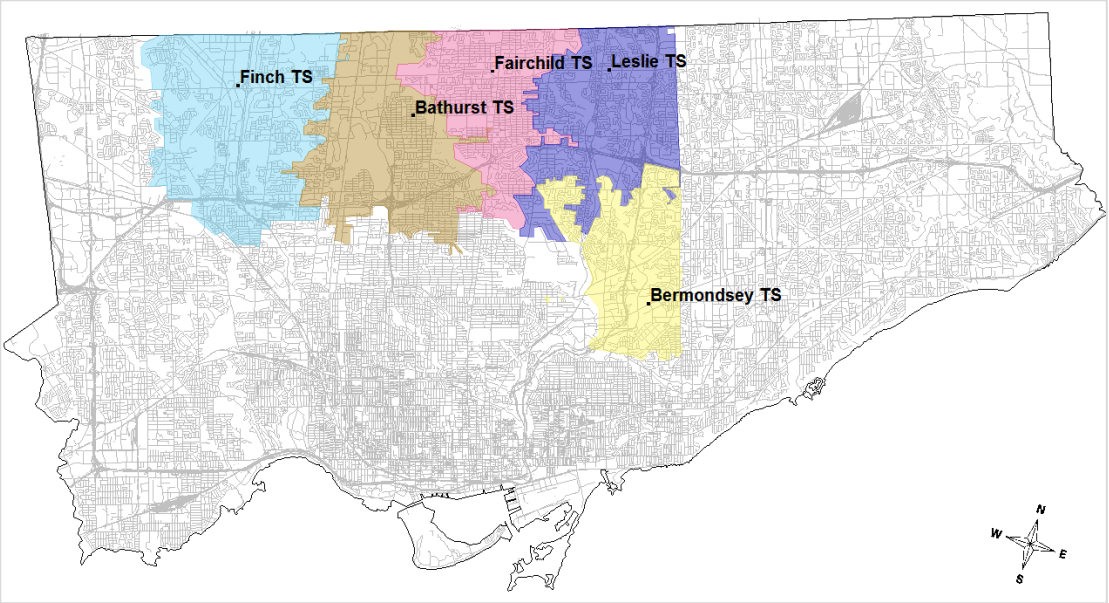


Figure 11: Toronto Hydro-owned TSs containing outdoor circit breakers.

When replacing these KSO oil circuit breakers, Toronto Hydro installs new vacuum circuit breakers with modern protection systems. Vacuum breaker technology is more reliable, does not contain oil, and is effectively the industry standard for breakers of this class. By installing a modern protection system, Toronto Hydro would improve its ability to accommodate new customer connections such as renewable generation or energy storage systems. As such, this work will provide customers with increased reliability and flexibility in addition to eliminating some of the highest safety and environmental risks in the system.

3. TS Outdoor Switches

In addition to owning breakers at the five North York stations identified in Figure 11 above, Toronto Hydro also owns 225 TS outdoor switches located at the same stations. By the end of 2019, 31 percent of these TS outdoor switches will be operating beyond their 50-year useful life. The majority of them have never been replaced since their original switchgear or breaker installations.

Many of these switches have failed in recent years and their aged and deteriorated condition is beginning to show. For example, between 2004 and 2017, 26 defective equipment reports were recorded for these switches. This represents approximately 20 percent of the total deficiencies reported among all Toronto Hydro switchgear assets during the same period, despite these switches making up only 5 percent of the category[4].

Toronto Hydro does not have a Health Index for these switches as a result of their simple and discrete nature. Switches are manual devices that either open or close when operated. Therefore, their condition is best captured by relying on visual assessment by Toronto Hydro field personnel and their experiences operating these switches. In this regard, relevant personnel have noted difficulty operating these switches, citing that in many cases, excessive force is required to close or open them which can damage the switches and result in injuries to workers. The number of broken switches per year can be seen in Table 9 below, which summarizes the number of corrective repairs performed each year from 2007 to 2017. The average age of each switch at its time of repair was approximately 40 years old. Difficult to operate switches create safety issues. They may not operate fully as intended which can lead to risks such as arc-flash, thus increasing the risk to field personnel.

Table 9: TS Outdoor Switches Corrective Repairs and Maintenance

Reactive Repairs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
TS Outdoor Switch	1	6	2	2	2	1	3	1	5	2	1	**26**

As shown in Figure 12 below, by the end of 2019, 69 of Toronto Hydro's TS outdoor switches will be operating beyond their 50-year useful life, with an additional 17 by 2024. Without action during the 2020-2024 period, almost three quarters of Toronto Hydro's TS outdoor switches will be beyond or within 5 years of their useful life expectancy by 2024.

[4] For the purposes of defective equipment reporting, TS switchgear units, MS switchgear units and TS outdoor switches are all included in the same category.

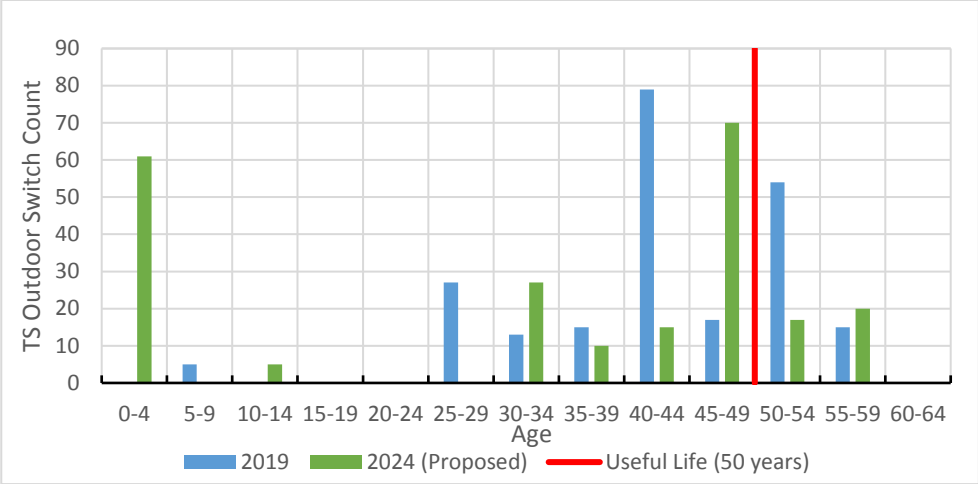


Figure 12: TS Outdoor Switch Age Demographics

Replacing or repairing outdoor switches can be very difficult as they are mounted on structures at the height of and in close proximity to other energized equipment (see example in Figure 13 below). Additionally, when a switch fails, the scheduling and contingency benefits that can be incorporated into a planned replacement are not available. Planned replacements are coordinated with other maintenance or capital work to minimize both switching operations and the risk of customer interruptions. However, when a switch fails, it may not be prudent to coordinate repairs with planned work, because until the switch is repaired the system is left in a state of compromised reliability, which presents the potential for lengthy outages.



Figure 13: Repair of TS Outdoor Switch

To reduce the risk of exposing customers to these periods of reduced reliability, Toronto Hydro plans to replace 61 TS outdoor switches during the 2020-2024 period as outlined in Table 10 below. All switches proposed for replacement will be beyond their 50-year useful life expectancy. Performing this work will reduce the risk of lengthy disruptions for customers served by three TS stations located in North York: Bathurst TS, Leslie TS and Bermondsey TS.

Table 10: TS Outdoor Switches Proposed for Replacement

Station	Feeder Tie Switch	Line Disconnect Switch	Bus Disconnect Switch	Total Switches	Replacement Year
Bathurst TS	1	2	0	3	2020
Leslie TS	1	2	0	3	2021
Bermondsey TS	1	2	0	3	2021
Bathurst TS	2	4	0	6	2021
Leslie TS	2	4	0	6	2022
Bermondsey TS	1	2	0	3	2022
Bathurst TS	1	2	0	3	2022
Bathurst TS	0	0	18	18	2023
Leslie TS	0	0	6	6	2024
Bermondsey TS	0	0	10	10	2024
Total	**9**	**18**	**34**	**61**	-

E6.6.3.2 Municipal Stations ("MS")

Toronto Hydro's MSs supply power to residential and general service customers. Major MS assets include switchgear, power transformers, primary disconnect switches and primary circuit breakers. A large portion of these assets are operating well beyond their useful life and are consequently at a heightened risk of failure. Work proposed under this segment will maintain the current level of reliability for MS-supplied customers by replacing deteriorated and obsolete assets at MSs with no foreseeable voltage conversion plans.

The purpose of an MS is to step down voltage to distribution levels and to provide a supply point for distribution feeders. Because the major assets in an MS are connected serially, power flow to customers is interrupted when any of the station's assets fail. For this reason, all end-of-life assets in the segment can be considered to have equal importance in maintaining overall MS reliability.

An MS supplies hundreds to thousands of customers. If any of a station's major assets fail, then all connected customers will experience a power outage. Power is restored to customers by switching their supply to neighbouring stations via distribution ties, a process which can take several hours to perform. It will then take months to a year before the failed station asset can be replaced and the MS returned to normal service due to equipment and design lead times and coordination. During this period, all customers supplied by the failed MS, and those fed from the neighbouring MSs, are exposed to significantly higher reliability risks due to a lack of second contingency supply. For similar reasons, maintenance or planned replacements cannot be completed at the neighbouring MSs during this period of limited capacity. As a result, system reliability can only be maintained when all MSs are maintained because the stations rely on each other to supply customers during contingencies, maintenance activities, and planned replacements.

Because customers are exposed to significantly reduced reliability when any MS is out-of-service, it is valuable to customers for Toronto Hydro to minimize the number and duration of station outages. For this reason, where possible, Toronto Hydro coordinates end-of-life asset replacements at a single MS during the same year, rather than having replacements and outages spread over multiple years.

1. MS Switchgear

The useful life of an MS Switchgear is 50 years. All of the MS switchgear targeted for replacement, listed in Table 11, will be between 61-70 years old at their time of replacement and are functionally obsolete. None of the targeted switchgear are arc-resistant and they are all equipped with oil circuit breakers. As seen in Figure 14 below, by not replacing switchgear containing oil circuit breakers, the condition of the breakers in the system will deteriorate and reach material deterioration and end of serviceable life. Operating these breakers in this condition increases failure and safety risks.

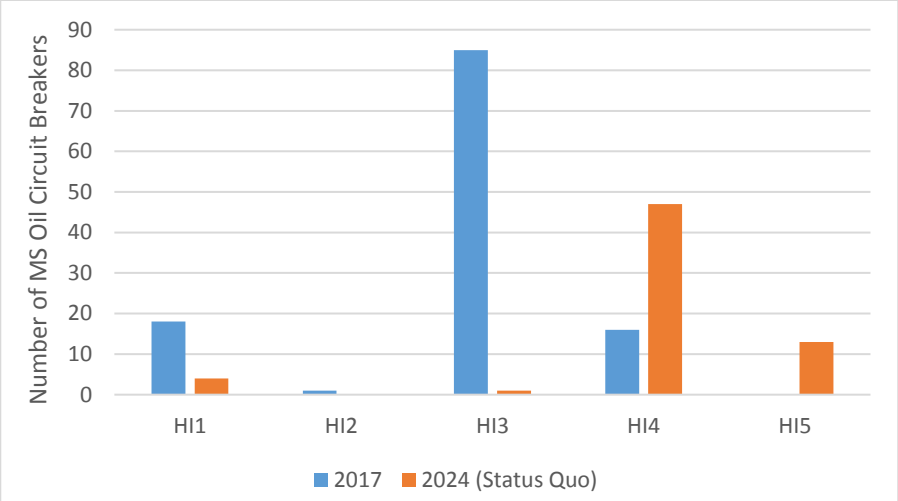


Figure 14: Condition of MS Oil Circuit Breakers as of 2017 and 2024 without investment

Toronto Hydro is prioritizing the replacement of its MS switchgear containing oil circuit breakers because the failure of these assets can cause fire and explosions similar to the KSO oil circuit breakers discussed in sub-section 2 of section E6.6.3.1 above. Such a failure mode presents a safety risk to station workers and the public, can cause collateral damage to other assets within the station or adjacent properties, and can have detrimental environmental impacts due to oil spill. Additionally, all MS oil circuit breakers are assumed to contain PCBs due to their age. Under this segment of work, all MS switchgear containing oil circuit breakers will be removed from service by the end of 2024. The switchgear planned for replacement over the 2020-2024 period, shown in Table 11 below, are currently showing signs of deterioration and are anticipated to have circuit breakers with at least material deterioration by 2024. Beyond condition, Toronto Hydro also considers age, presence (or lack) of SCADA, and failure impact to prioritize its MS switchgear replacements.

Table 11: MS Switchgear Proposed for Replacement

Station	Switchgear	Age at Replacement	Replacement Year
Pharmacy CPR MS	*T1SG*	61	2020
Rosethorne MS	*T1SG*	70	2020
Thistletown MS	*T1-T2SG*	65	2020
Browns Line MS	*T1-T2SG*	69	2021
Galloway Dearhamwoods MS	*T1SG*	62	2021
Neilson Drive MS	*T1-T2SG*	67	2021
Highbury MS	*T1-T2SG*	67	2022

Station	Switchgear	Age at Replacement	Replacement Year
Watercliffe MS	*T1SG*	66	2022
Bellamy Eglinton MS	*T1SG*	64	2023
Midland Lawrence MS	*T1SG*	62	2023
Brimley Seminole MS	*T1SG*	64	2024
Ravensbourne MS	*T1SG*	68	2024

The switchgear proposed for replacement are functionally obsolete, and replacement parts are no longer available. This makes maintenance of the existing switchgear difficult and expensive as replacement parts need to be custom-made or scavenged from other switchgear. Replacement with new switchgear supported by current manufacturers will allow Toronto Hydro to more readily maintain the switchgear as individual components fail in the future.

New switchgear will be arc-resistant and installed with vacuum circuit breakers, a low-maintenance and reliable model of circuit breakers that do not suffer from operating risks associated with oil circuit breakers. Each switchgear replacement will also involve the installation of a new SCADA system at the station since the existing system (if present) has far surpassed its useful life and is highly integrated with the switchgear. A SCADA system provides Toronto Hydro's control centre with the ability to monitor and control a station remotely to better manage the customer experience. Of the 12 stations targeted for a switchgear replacement, 5 of them currently have no SCADA system. These stations will receive a SCADA system for the first time as part of their switchgear replacement. As a result, MS switchgear renewal will also aid in Toronto Hydro's efforts to renew its fleet of RTUs and install new RTUs, as discussed in Section E6.6.3.3 below.

Figure 15 below shows the age profile of Toronto Hydro's MS switchgear in 2019 and 2024 under the proposed replacement and conversion plans (see the Area Conversions program),[5] which will remove switchgear from service. Toronto Hydro identified 12 MS switchgear which will require replacement over the 2020-2024 period due to their condition, age, use of oil circuit breakers, lack of SCADA, and failure impact. Following the replacement plan will result in only 2 units that exceed 65 years by 2024. Under the proposed replacement plan, the population of switchgear aged 61-75 years by 2024 will be kept similarto the population as in 2019. It is necessary to maintain this level as assets in this age group have the greatest risk of failure compared to other age groups.

[5] See E6.1 of this DSP.

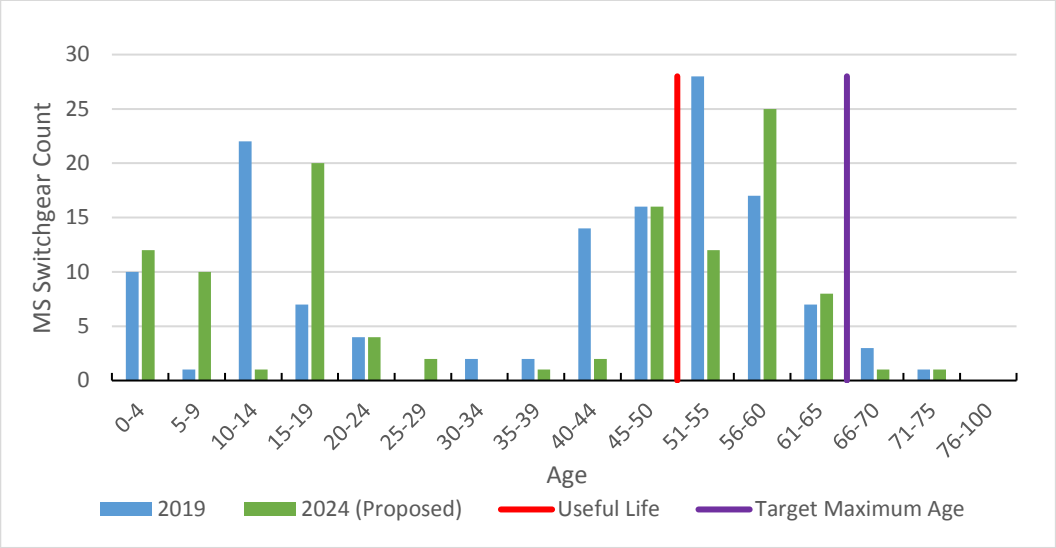


Figure 15: Age Profile of MS Switchgear

By replacing the end-of-life and obsolete MS switchgear targeted in this segment, Toronto Hydro will mitigate the risk of switchgear failure at its MSs, thereby maintaining system reliability.

2. Power Transformers

The useful life of a power transformer is 45 years. All transformers targeted for replacement in the 2020-2024 period, listed in Table 12, will be 60-67 years old at their time of replacement. The transformers will be replaced with units of the same or lesser capacity, where possible, to minimize costs. The proposed replacement is necessary because the reactive replacement of a failed unit takes three to six months to complete even with spare transformers on hand.

As shown in Figure 16 below, by not replacing power transformers by 2024 there is an increase in power transformers reaching conditions of material deterioration and end of serviceable life.

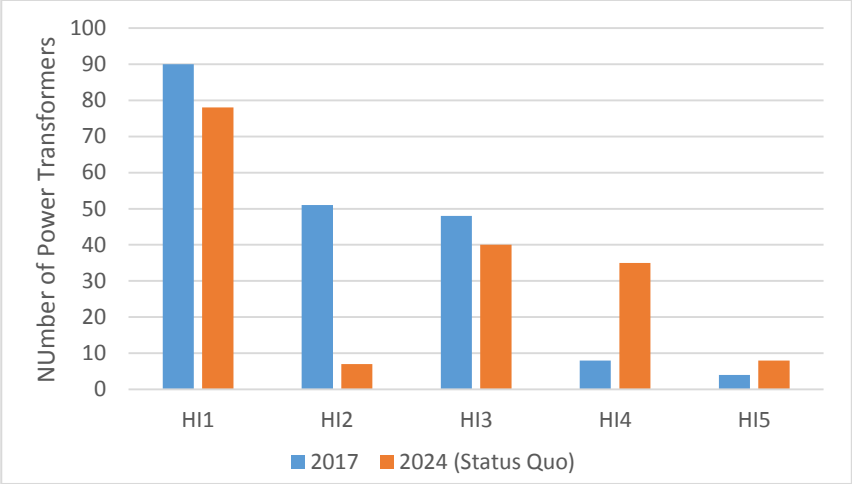


Figure 16: Power Transformer Asset Condition as of 2017 and in 2024 without investment

As shown in Table 12, in addition to condition, Toronto Hydro also considers age, loading, PCB concentration in oil,[6] and failure impact to prioritize its replacements.

Table 12: Power Transformers Proposed for Replacement

Station	ID	Additional Concerns	Age at Replacement	Replacement Year
Brimley Shaddock MS	*TR1*	- High power factor - SFRA[7] indications of winding deformation	65	2020
Pharmacy CPR MS	*TR1*	- High power factor - Low insulation resistance	61	2020
Belfield MS	*TR1*	- Low insulation resistance - SFRA indications of core defects and winding deformation	61	2021
Galloway Dearhamwoods MS	*TR1*	- High power factor - Low insulation resistance - DGA[8] indications of overheating	62	2021
Burlingame MS	*TR1*	- Elevated particle count in oil - Contains PCB - Higher than typical load	61	2022
Highbury MS	*TR1*	- High levels of moisture in oil	67	2022

[6] All power transformers are tested for PCBs with each of their oil tests, which occur annually.
[7] Sweep frequency response analysis ("SFRA") is a test often used to identify defects in the mechanical or electrical integrity of a power transformer.
[8] Dissolved gas analysis ("DGA") is a test often used to identify previous and/or persistent thermal and/or electrical faults occurring within a power transformer.

Station	ID	Additional Concerns	Age at Replacement	Replacement Year
		- Low oil dielectric breakdown		
Bellamy Eglinton MS	*TR1*	- Low oil dielectric breakdown - Elevated particle count in oil	64	2023
Brimley Bernadine MS	*TR1*	- High power factor - Low insulation resistance	64	2023
Humber Bay MS	*TR1*	- Contains PCB	66	2024
Windsor MS	*TR1*	- Higher than typical load	60	2024

Transformer replacements will include the replacement of the transformer's primary supply, discussed in the section below, as these assets exist within the station solely to supply or disconnect the power transformer. In doing so, this will allow Toronto Hydro to optimize their replacement strategy by minimizing station outages.

In addition to causing customer outages, power transformer failures can have significant safety and environmental impacts at a MS. Upon failure, the tank of the power transformer can rupture, result in oil fire, and even explode. This was the case for the 49-year old TR2 at DuPont MS which failed in 2003, as shown in Figure 17 below. Power transformers hold thousands of litres of oil which can fuel the fire that erupts.



Figure 17: Failed Power Transformer TR2 at DuPont MS in 2003

To this end, Toronto Hydro will also install an oil containment system as part of its power transformer replacements, if one is not already present at the station. Toronto Hydro has been following this

practice for all of its power transformer replacements over the 2015-2019 period. The oil containment system will prevent the release of oil into the environment in case the power transformer develops an oil leak or its tank ruptures due to a failure.

Figure 18 below shows the age profile of Toronto Hydro's power transformers at the end of 2019 and 2024 under the proposed replacement and conversion plans (see the Area Conversions program),[9] which will remove power transformers from service. Toronto Hydro identified 10 power transformers which will be in need of replacement over the 2020-2024 period due to their condition, age, and failure impact. Under the proposed replacement plan, the transformer population aged 55-69 will be maintained at the current level as assets of this vintage have the greatest risk of failure.

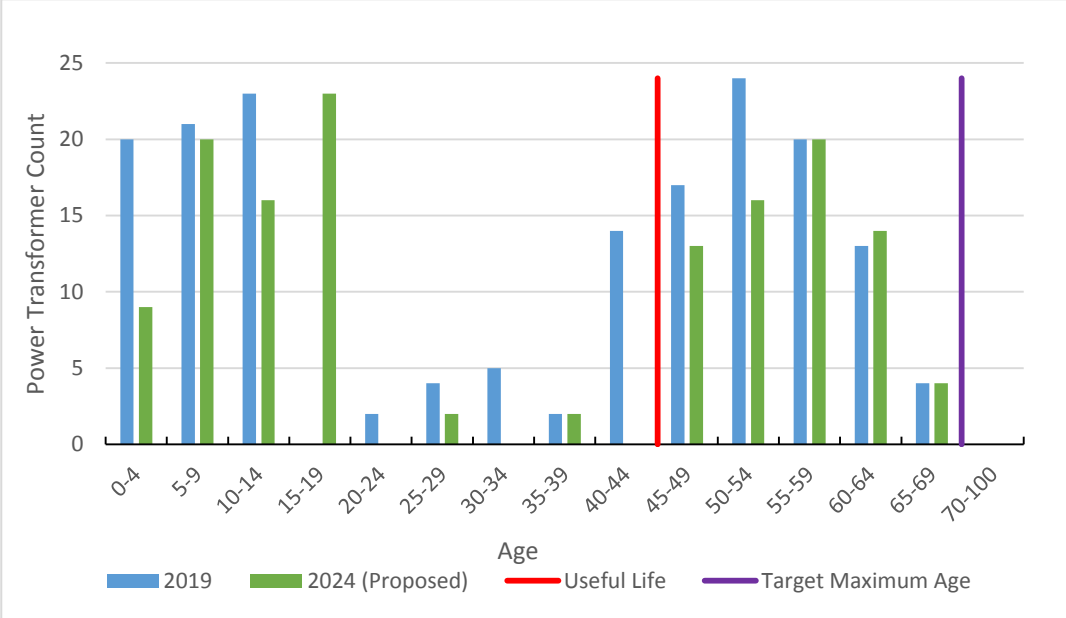


Figure 18: Age Profile of Power Transformers

By replacing the end-of-life power transformers targeted in this segment, Toronto Hydro will mitigate the risk of power transformer failure at its Municipal Stations, thereby maintaining the reliability of its MSs.

[9] See E6.1 of this DSP.

3. MS Primary Supply

The MS primary supply consists of all assets in the station between the distribution system and the primary side of the station transformer, including primary cable, primary disconnect switches, and primary circuit breakers. These assets are used to supply the station transformer with power, or to disconnect the transformer from its supply for maintenance or during a fault. It takes three months to reactively replace a failed primary supply. Prior to 2018, power transformer replacements were typically completed without replacing their MS primary supply. As part of this segment, Toronto Hydro proposes to replace the primary supply at MSs where power transformers were previously replaced.

The MS primary supply replacement projects will target MSs which meet the following criteria.

1) The MS had a transformer replacement from 2005 onwards,
2) The MS primary supply was not replaced,
3) The MS does not have a switchgear replacement planned for the 2020-2024 period (as replacement of the primary supply may be included with a switchgear replacement), and,
4) The MS is not planned to be decommissioned through voltage conversion activities (refer to the Area Conversions program).[10]

Over the 2020-2024 period, Toronto Hydro proposes to replace the primary supply at 11 MSs as listed in Table 13. These stations were selected on the basis of failure risk as determined through the age and configuration of the primary supply assets. Primary supplies will also continue to be replaced as part of power transformer replacements occurring at other stations in the 2020-2024 period (see previous section). This work will mitigate the risks of a primary supply failure.

Table 13: MS Primary Supplies Proposed for Replacement

Station	Age at Replacement	Replacement Year
Brimley Lawrence MS	65	2020
Thornton MS	65	2020
Wexford-Surrey MS	66	2020
Hardwick MS	63	2021
Porterfield MS	65	2021
Dalegrove MS	63	2022

[10] See E6.1 of this DSP.

Station	Age at Replacement	Replacement Year
Scarborough Golf Club Rd Ellesmere MS	64	2022
Lawrence Kennedy MS – TR1	69	2023
Renforth MS	61	2023
Centennial D'Arcy Magee MS	45	2024
Markham Pandora MS	60	2024

The useful life for a primary disconnect switch or a primary circuit breaker is 45 years. For non-lead primary cable, the useful life typically ranges from 25-50 years, depending on the type of cable; and for lead (PILC)[11] cable, the useful life is 75 years. All primary disconnect switches, primary circuit breakers, and non-lead primary cable will be past their useful life at the time of proposed replacement. In particular, all but one of the targeted primary supplies will have assets between 60-69 years old by that time.

Historically, Toronto Hydro has pursued a run-to-fail strategy for managing its MS primary supplies. However, since the failure of a primary supply results in a three month station outage, and many of the assets composing the primary supply are operating far beyond their useful life, a proactive replacement plan is required to manage failure risk.

The existing primary disconnect switches are obsolete end-of-life assets. They can no longer be replaced like-for-like as they are non-standard and no longer manufactured. Primary disconnect switches will be replaced with a standard padmounted switch commonly used in Toronto Hydro's distribution system. The existing MS primary breaker is also an obsolete end-of-life asset and will be replaced with a vacuum circuit breaker in a like-for-like configuration.

The existing non-lead primary cables targeted for replacement have surpassed their useful life, and existing lead cables will be approaching their useful life. These cables were installed either direct buried or in direct-buried ducts. These configurations generally hinder cable replacement if the cable were to fail, resulting in a replacement time of 3 months. On the other hand, if a primary cable fails in concrete-encased ducts, then the cable can be replaced within a few days. For this reason, end-of-life primary cable which is direct buried or in direct buried duct will be replaced with cable of the

[11] Paper Insulated Lead-Covered ("PILC") cable

same capacity within concrete-encased ducts. Existing lead (PILC) cable will be replaced with plastic (XLPE)[12] cable, thereby removing lead from Toronto Hydro's system.

By replacing the end-of-life and obsolete MS primary supplies, Toronto Hydro will mitigate the failure risk these assets pose at its MSs, thereby maintaining the associated reliability performance.

E6.6.3.3 Control and Monitoring

Toronto Hydro uses control and monitoring systems at its TSs and MSs to protect its equipment, provide operators with system oversight, and allow for remote switching operations. Ultimately this allows Toronto Hydro to reduce outage durations and provide customers with high reliability. Major Control and Monitoring assets include RTUs, protection relays, and interstation control wiring. A large portion of these assets are operating beyond their useful life and are at a heightened risk of failure. Toronto Hydro uses a risk-based approach to identify the highest priority assets for replacement and also to identify where installing new systems might be prudent, with the objective of cost-effectively maintaining levels of reliability. Toronto Hydro's most pressing risks and needs for its Control and Monitoring assets are summarized in Table 14 below.

Table 14: Control and Monitoring

Category	Description	Drivers and Failure Consequences
RTU Renewal	*Downtown DACSCAN RTU Replacements*	Main driver is failure risk of aging DACSCAN RTUs in Toronto's core. DACSCAN technology was first developed and installed 30 years ago and is now functionally obsolete. Its supplier is no longer in business and replacement parts are hard to find. The failure consequence is loss of telemetry data and remote control operation at the station (typically a TS) with the failed RTU.
	MOSCAD RTU Replacement	Main driver is failure risk of aging MOSCAD RTUs in Etobicoke area stations. MOSCAD technology was first developed and installed 25 years ago and is now functionally obsolete. Its supplier is no longer in business and replacement parts are hard to find. The failure consequence is loss of telemetry data and remote control operation at the station (typically a MS) with the failed RTU.

[12] Cross-Linked Polyethylene ("XLPE") cable

Category	Description	Drivers and Failure Consequences
	D20 M++/ME RTU Replacement	Main driver is failure risk of aging D20 M++/ME RTUs in Scarborough area stations. D20 technology is approximately 10-20 years old and parts for older units are no longer supported by its manufacturer and difficult to maintain. The failure consequence is loss of telemetry data and remote control operation at the station (typically a MS) with the failed RTU.
New RTU Installations	*New RTU Installations*	Main driver is improving reliability of MSs that currently do not have an RTU. Operators have little oversight of the status of equipment at these stations and rely on customers to alert them of outages. By installing RTUs at these stations, Toronto Hydro will have visibility of equipment status and remote control. This will reduce outage durations and operating costs (i.e. less labour hours for manual service restoration work at these stations).
Pilot-wire Protection and Interstation Control Wiring Renewal	*Pilot-wire Protection Renewal*	Main driver is to replace aging electromechanical pilot-wire protection systems used for large downtown customers (including financial institutions, hospitals, telecom companies, sewage plants, etc.). Failure consequence of these systems is an outage to large customers who rank reliability as their highest priority.
	Interstation Control Wiring Renewal	Main driver is the failure risk of aging copper control wires. Copper control wires allow information to flow between TSs and MSs and between TSs and customers with pilot-wire protection systems. Failure consequence is loss of pilot-wire protection, or loss of communication for critical communication infrastructure (i.e. SCADA, security systems, telephone lines, and other basic services).

Control and Monitoring assets are common to both TSs and MSs and vary in size and complexity depending on the station and its geographical location. Systems located in downtown Toronto TSs are treated with a higher priority than systems located in MSs. However, systems in all stations are important because control operators rely on them to oversee, control and protect the system.

1. RTU Renewal

As shown in Table 15 below, 37 percent of Toronto Hydro's RTUs will be operating at or beyond their 22 year useful life in 2019.[13] The majority of Toronto Hydro's RTUs are built from early computer technologies. Computer technology has advanced considerably in the past 20 years making it difficult to find replacement parts that maintain backwards compatibility with what are now obsolete and out-dated technologies (i.e. MOSCAD, DACSCAN, and D20 M++/ME). Table 15 below shows the types of RTUs in various geographical areas, and the percentage of RTUs that are in-service beyond their useful life (as of the end of 2019).

Table 15: RTU type, communication protocol, quantity, and percent past useful life in 2019

Geographical Area	RTU Type	Communication Protocol	Number of Assets	% of Assets Past Useful Life
Etobicoke	*Motorola SCADA (MOSCAD)*	DARCOM Radio	37	100%
	SEL Axion 2240	SD-9	27	0%
Scarborough	*D20 ME / D20M++*	Telephone Line (Bell Leased)	16	0%
	D20 MX	Telephone Line (Bell Leased)	1	0%
	SEL 2032	5 - Transit	13	0%
North York	*ACS7010A or NTU7010*	Telephone Line (Bell Leased)	17	0%
	SEL RTAC 3530	Telephone Line (Bell Leased)	6	0%
	SEL Axion 2240	Telephone Line (Bell Leased)	1	0%
Old Toronto	*DACSCAN MDO-11*	SONET/ Telephone Line (Bell Leased)	29	100%
	ABB microSCADA	SONET	1	0%
	D20 ME / D20M++	SONET	3	33%
	SEL 3332	SONET	26	0%
	SEL Axion 2240	SONET	5	0%
	GE DART	SONET	1	0%
Total			**183**	**37%**

[13] An RTU has a useful life of 22 years as identified in the Kinectrics Report K418021 "Useful Life of Assets", Aug. 28, 2009.

RTU replacement is driven by their failure risk and associated impact. Toronto Hydro considers RTUs to have a useful life of 22 years. Similar to other computer technologies, with increased age and operation, RTU circuit boards become increasingly prone to failure, and when they fail, do so without warning. All of Toronto Hydro's DACSCAN RTUs and MOSCAD RTUs were installed in the late 1980's and early 1990's and are operating beyond their useful life. Production of these obsolete RTUs has ceased and their manufacturers no longer exist in the market for support or supply of the parts required for repair. Where possible, field crews have salvaged parts from decommissioned units, but this method of maintaining units is becoming more difficult to sustain. Complicating matters, the majority of field staff with the knowledge and ability to troubleshoot these devices have retired. DACSCAN RTUs are located in critical downtown TSs serving thousands of customers, therefore their replacement is higher priority than other RTUs considered in this segment. MOSCAD RTUs are located in Etobicoke MSs and typically serve 4 kV MSs with less customers than other RTUs considered in this segment.

Most of Toronto Hydro's D20 M++/ME RTUs are younger than 22 years; however, some units have suffered several premature failures over recent years. Moreover, configuration software to modify or re-program these units requires use of legacy computer operating systems which are no longer supported by the original RTU manufacturer. Similarly to MOSCAD and DACSCAN RTUs, like-for-like replacement parts for legacy D20 RTUs are no longer available for purchase. To resolve these issues, Toronto Hydro proposes to replace these units with an incremental upgrade option. Two of Toronto Hydro's D20 RTUs are located at TSs while the remainder are located at downtown MSs or at 13.8 kV Scarborough MSs.

When an RTU fails, Toronto Hydro's control centre operators are disconnected from telemetry data and lose operational control of equipment at the station. This prevents operators from viewing the status of equipment at the station, leaving the system in a vulnerable state. If an RTU failure occurs at a critical station, field crews need to be dispatched to the station immediately to manually monitor equipment status and operate where required. This is necessary to ensure Toronto Hydro can adequately respond to outages and prevent equipment damage by ensuring the station operates within its limits. Combined with the difficulty of the repair work required, this makes a failure event operationally expensive and puts customers at risk of longer outages. Modern operation of the electrical grid relies upon having real-time data and control available at the station level at all times.

To mitigate RTU failure risk, Toronto Hydro plans to replace 14 DACSCAN RTUs, 15 MOSCAD RTUs, and 10 D20 RTUs over the 2020-2024 period. This represents all of Toronto Hydro's end-of-life

DACSCAN RTUs (located at downtown TSs), approximately half of Toronto Hydro's end-of-life MOSCAD RTUs (located at Etobicoke MSs), and all of Toronto Hydro's D20 RTUs (located at TSs, downtown MSs and Scarborough MSs). With the exception of MOSCAD RTUs, the remaining RTU units operating beyond their useful life expectancy are at stations with conversion and decommissioning plans and therefore do not require replacement. For MOSCAD RTUs, Toronto Hydro has limited its replacement volume to respect customer priorities as related to cost.

2. New RTU Installations

Toronto Hydro will have 11 MSs without remote monitoring and control in 2019 (i.e. 11 MSs without an RTU). Toronto Hydro plans to install new RTUs at six of these MSs during the 2020-2024 period as discrete projects. The remaining five MSs without an RTU will have RTUs installed as part of their MS Switchgear replacements during the 2020-2024 period, as detailed in sub-section 1 in Section E6.6.3.2. By the end of 2024, all 11 stations without a RTU will have one installed, thus enabling remote monitoring and control capabilities. The proposed MSs for RTU installation and the MSs which will receive RTUs via switchgear replacement are listed in Table 16 below. As a result of this investment, customers connected to these stations will receive the same high level of reliability as customers supplied by Toronto Hydro's other 116 SCADA-enabled MSs.

Table 16: New RTUs Proposed for Installation

Station	Segment	Installation Year
Pharmacy CPR MS	MS Switchgear (see Sub-Section 1 of E6.6.3.2)	2020
Midland-Danforth MS	New RTU Install	2020
Galloway Dearhamwoods MS	MS Switchgear (see Sub-Section 1 of E6.6.3.2)	2021
Ellesmere White Abbey MS	New RTU Install	2021
Panorama MS	New RTU Install	2022
Bellamy Eglinton MS	MS Switchgear (see Sub-Section 1 of E6.6.3.2)	2023
Midland Lawrence MS	MS Switchgear (see Sub-Section 1 of E6.6.3.2)	2023
Markham Eglinton MS	New RTU Install	2023
Brimley Seminole MS	MS Switchgear (see Sub-Section 1 of E6.6.3.2)	2024
Bellamy Lawrence MS	New RTU Install	2024
Livingston Guildwood MS	New RTU Install	2024

At stations without an RTU, Toronto Hydro control center operators have no visibility of equipment status. Consequently, they rely on customers to alert them of outages so they can dispatch field crews to perform the manual switching operations required to restore electrical service to affected customers. Manual switching takes longer to perform resulting in longer than necessary outages. As shown in Figure 19, stations equipped with SCADA tend to experience shorter outage durations compared to stations lacking SCADA. On average, the installation of SCADA is expected to reduce outage duration by approximately one hour.

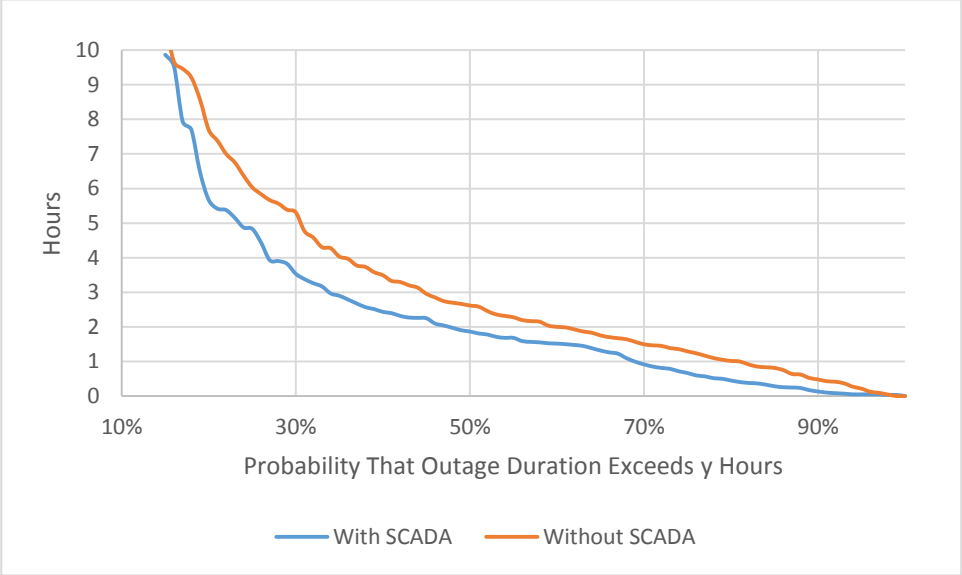


Figure 19: Reliability (SCADA Impact) at Stations with RTUs versus Stations without RTUs

Operating costs for stations without an RTU are higher because additional labour resources are required to investigate and perform the manual switching needed to restore service to customers. The information provided by RTU monitoring systems also allows Toronto Hydro engineers to collect important data such as station loading, number of faults, duration of outages, etc. which is used to perform proper planning and improve reliability in the future.

3. Pilot-wire Protection Renewal

The renewal of Toronto Hydro's pilot-wire protection systems is driven by high failure risk due to their age and their criticality in providing high reliability to certain large customers. High reliability is provided through the use of multiple source feeds (protected by a pilot-wire protection system). Pilot-wire protection renewal projects will only target pilot-wire systems used to protect the supplies

of these individual customers, as opposed to Toronto Hydro's interstation pilot-wire protection systems.

Toronto Hydro's obsolete pilot-wire protection systems rely on electromechanical relays and copper control wiring running between TSs and customers. The majority of Toronto Hydro's pilot-wire protection systems operate using this obsolete technology. The electromechanical relays used are operating beyond their useful life of 30-years and are no longer available on the market. Further, planned switchgear replacements require circuit transfers with this protection system to new switchgear, since new switchgear cannot be made compatible with the obsolete pilot-wire protection relays an upgrade to newer line protection technology is required.

When a pilot-wire protection scheme fails, the individual customer supplied by the system and all of the customers supplied by the upstream switchgear are placed at an increased risk of outage. Without the pilot-wire protection to isolate a fault, the switchgear's bus differential protection would isolate the entire bus in the event of a fault. What should have been a single element failure, impacting only one customer, would become an entire TS switchgear outage affecting hundreds or thousands of customers, similar to the failure impact of TS switchgear as detailed in sub-section 1 of section E6.6.3.1above.

In addition to reducing failure risk, replacing Toronto Hydro's obsolete electromechanical and copper-based pilot-wire protection systems with digital relays and fiber communications has the following benefits:

- Improved protection of customer and utility equipment due to faster relay operation;
- New relays have self-diagnostics which simplifies troubleshooting and makes failures easier to predict;
- Less manual maintenance and testing since the new system has online monitoring and self-diagnostics; and
- As part of each project, copper lines are replaced with fiber. Toronto Hydro will have complete control of the fiber optic communication cables and not be reliant on a privately-owned third party corporation (many copper cables are owned by Bell); therefore, a faster response time can be provided by Toronto Hydro crews in the case of communication line failure.

To maintain a high-level of reliability for these critical customers and to facilitate switchgear replacements, Toronto Hydro proposes to upgrade the pilot-wire protections for 5 locations (with modern line differential protection) during the 2020-2024 period. This represents just under a quarter of Toronto Hydro's pilot-wire protection systems. Ideally, Toronto Hydro would replace all of these obsolete systems; however, cost consideration and resource requirements limit Toronto Hydro to upgrading the protections at one location a year.

4. Interstation Control Wiring Renewal

Renewal of Toronto Hydro's Interstation Control Wiring systems is driven by failure risk due to their age and criticality in supporting the connected SCADA and protection systems. For example, Interstation Control Wiring includes copper control cabling used for telecommunications, interstation pilot-wire protection systems, RTUs, station security, and other systems that rely on interstation communication. This control wiring is located in an outdoor environment, routing through Toronto Hydro's distribution system and interconnecting geographically diverse TSs and MSs as required. Failures due to deteriorated cable have become more frequent and difficult to repair.

Copper wire communication infrastructure is obsolete and no longer used by major communication companies. This has led many suppliers and manufacturers to cease support and manufacturing of replacement parts. Additionally, skilled labour familiar with the technology is hard to find or train. Given the critical nature of the information transmitted through the cables, failure can render entire systems non-functional. Table 17 below summarizes the impact that failure of copper control wiring can have depending on the system involved.

Table 17: Interstation Control Wiring – Failure Impact by System

System	Failure Impact
Interstation Pilot-Wire Protection	Potential loss of supply to a TS or MS switchgear, which would result in a power outage to all customers supplied by the switchgear
Station RTUs	Equivalent impact as loss of an RTU, as discussed in sub-section 1 of section E6.6.3.1
Station Security	Loss of access to MS/TS via swipe card, loss of security cameras, etc.

As an example of a recent failure, in May 2017, an Interstation Control Wiring cable between Gerrard TS and Sherbourne MS failed. To repair the failed control cable, Toronto Hydro had to replace 2.2 km of cabling at a total cost of $170 thousand dollars. The ensuing repair and replacement took

approximately 5 months to perform. While the failure did not result in an outage for the entire 5-month period, the pilot-wire protection system between Gerrard TS and Sherbourne MS was out-of-service. Without the system to isolate a fault on the power cable between the two stations, all of the customers supplied by Gerrard TS and Sherbourne MS were exposed to an increased risk of outage as the upstream protections at Gerrard TS would have had to operate to isolate the entire Gerrard TS switchgear (rather than isolating the single power cable). As this case highlights, relying on reactive repair has tremendous risk due to the lengthy duration of increased exposure to higher impact outages.

To maintain the integrity of the systems supported by this control wiring, Toronto Hydro plans to replace 45 km of old copper cable with new fiber optics-based cables over the 2020-2024 period. This represents just under a quarter of Toronto Hydro's stations copper wiring network. Ideally, Toronto Hydro would replace all of its copper wiring; however, cost consideration, operational restrictions, and resource requirements limit Toronto Hydro to upgrading approximately 10 km a year.

E6.6.3.4 Battery and Ancillary Systems

As shown in Table 18 below, 23 percent of Toronto Hydro's Battery and Ancillary Systems will be operating beyond their useful life in 2019. Depending on the asset, replacement is required due to poor condition, old age, obsolescent technology, oil containing PCBs, or a mixture of these factors. The Battery and Ancillary Systems segment proposes replacing these supporting systems as required to maintain station integrity and system reliability for Toronto Hydro customers.

Table 18: Battery and Ancillary Systems Demographics

Asset Type	Total # of Assets	Useful Life	Assets Beyond Useful Life (2019)	Assets Beyond Useful Life with Program (2024)
Battery and Charger Systems	165	10-12 years	22%	16%
Station Service Transformers	34	45 years	26%	12%
Air Compressors	10	15 years	20%	0%
Total	**209**	**-**	**23%**	**15%**

In addition to the renewal of the assets included above, Toronto Hydro has identified 3 TSs with flood risk requiring mitigation, as detailed in sub-section 3 of section E6.6.3.4.

1. Battery and Charger Renewal

A battery and charger system is installed at every TS and MS to provide DC power supply and backup for essential protection, control and SCADA systems. Due to their critical functionality, station batteries and chargers must be maintained in reliable condition, as required by the Transmission System Code (as specified in Section 10.7.1 thereof). These systems must be able to supply power for a minimum of 8 hours after the loss of main AC power. As shown in Table 19 below, 22 percent of Toronto Hydro's battery and charger systems will be operating beyond their useful life in 2019.

Table 19: Battery and Charger Systems Demographics

Asset Type	Assets Beyond Useful Life Current State (2019)	Assets Beyond Useful Life Without Program (2024)
Battery and Charger Systems	22%	64%

Battery and charger system renewal is required to mitigate their failure risk. Station batteries have a useful life between 10-12 years (depending on the battery type). Batteries deteriorate to the point of failure as they age and a significant number of them are past or close to the end of their useful life. Without any action during the 2020-2024 period, the proportion of batteries operating beyond their useful life would be 64 percent by 2024. Without replacement, failures will increase resulting in higher risk of reduced reliability for Toronto Hydro customers as well as significant equipment damage. As shown in Figure 20 below, the proposed replacement of 67 units will ensure the maximum age of the batteries in the system is kept at 14 years.

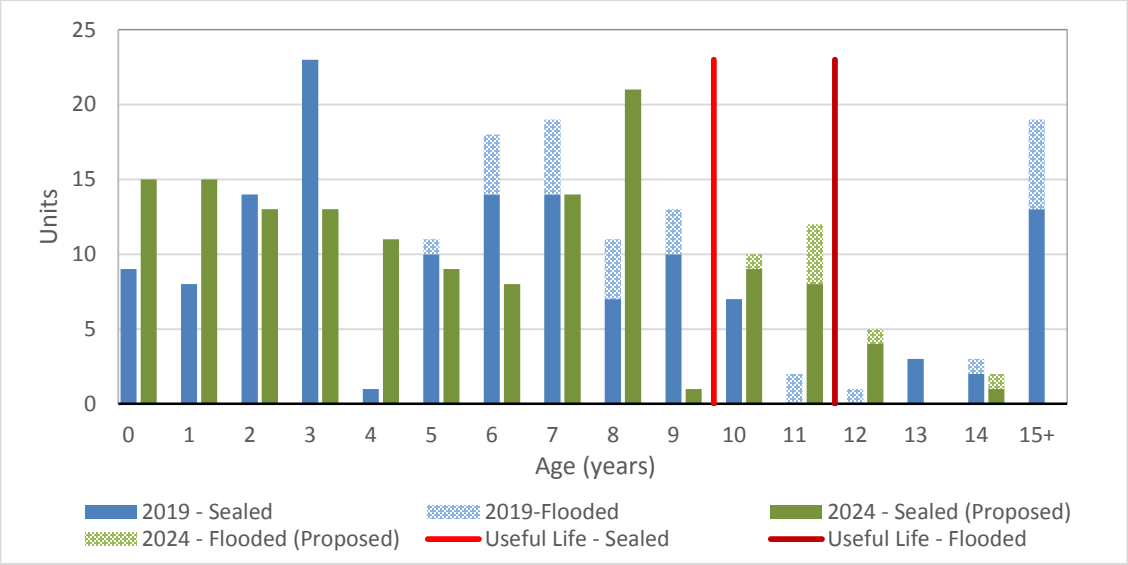


Figure 20: Age Profile of Station Batteries

When a battery or charger fails, its MS or TS loses the source of DC power supply. This in turn renders all protection, control, Station RTUs, and other communication systems non-functional. Failure of protection and control systems is a major safety and reliability risk as the station would lose its ability to isolate faults. Otherwise, loss of functionality would affect the Control and Monitoring systems with similar failure impacts to those detailed in Section E6.6.3.3. Due to this significant failure impact, Toronto Hydro installs a second, back-up battery and charger system at its critical TSs. As listed in Table 20 below, Toronto Hydro proposes the replacement of 67 station batteries and charger systems over the 2020-2024 period. When replacing batteries and chargers, Toronto Hydro will also replace any end-of-life or obsolete DC panels and other smaller series components with similar failure impact.

Table 20: Battery & Charger Proposed Replacement Plan

Year of Replacement	Downtown Replacements	North York Replacements	Scarborough Replacements	Etobicoke Replacements	Total
2020	1	3	4	3	**11**
2021	1	0	5	7	**13**
2022	1	0	5	7	**13**
2023	2	1	2	10	**15**
2024	2	3	6	4	**15**
Total	**7**	**7**	**22**	**31**	**67**

The proposed Battery & Charger Systems replacement projects will maintain the reliability of service for a vast geographical area (as shown in Figure 21 below).

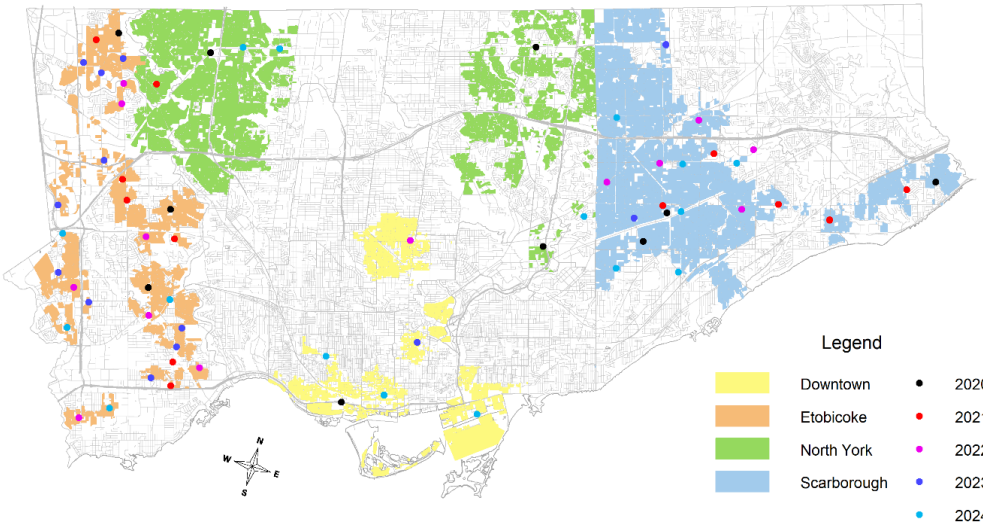


Figure 21: Geographical locations of the 2020-2024 proposed Battery & Charger Systems

2. Station Service Transformer Renewal

A station service transformer ("SST") supplies a station with AC power for use in the station's heating, lighting, and DC charging systems. Therefore, an SST failure has a similar impact as a battery or charger failure, discussed in Sub-Section 1 of Section E6.6.3.4 above. The DC system can maintain the function of critical protection, control, station RTUs, and other communication systems for 8 hours without AC power. However, following this period of time, AC power must be restored or the batteries will drain and these systems will be rendered non-functional. Due to this significant failure impact, Toronto Hydro installs two SSTs at its downtown TSs. SST replacement projects will only target SSTs supplying these TSs.

Historically, Toronto Hydro has pursued a reactive strategy for managing its SSTs. However, following the failure of an SST at Cecil TS in 2015, Toronto Hydro re-examined this approach for its downtown TSs. For such stations, each SSTs must be custom ordered with a total lead time for replacement exceeding seven months. This is a considerable period of exposure to a second contingency event, which would cause the station batteries to deplete after 8 hours.

Such a lengthy lead time combined with the number of SSTs operating at an advanced age necessitate a proactive replacement plan for SSTs located at downtown TSs. A proactive replacement

strategy is in line with customer priorities, because customers supplied from Toronto Hydro's downtown TSs tend to prioritize reliability over cost, and the cost to replace SSTs is relatively small compared given the criticality of their functions.

Toronto Hydro owns 34 SSTs which supply its downtown TSs. As shown in Table 21 below, 26 percent of these SSTs will have reached or surpassed their useful life in 2019. In addition, 9 percent of these SSTs contain PCBs and present risk of environmental damage if they leak.

Table 21: Stations Service Transformer Demographics

Asset Type	Assets Beyond Useful Life Current State (2019)	Assets Beyond Useful Life Without Program (2024)	Assets with PCB >2ppm
Stations Service Transformers	26%	29%	9%

SST renewal is required to mitigate failure risks associated with their age. As shown in Figure 22, nine of the targeted SSTs will exceed their useful life by 2019. Without action during the 2020-2024 period, 29 percent of these SSTs will be operating beyond their useful life by 2024.

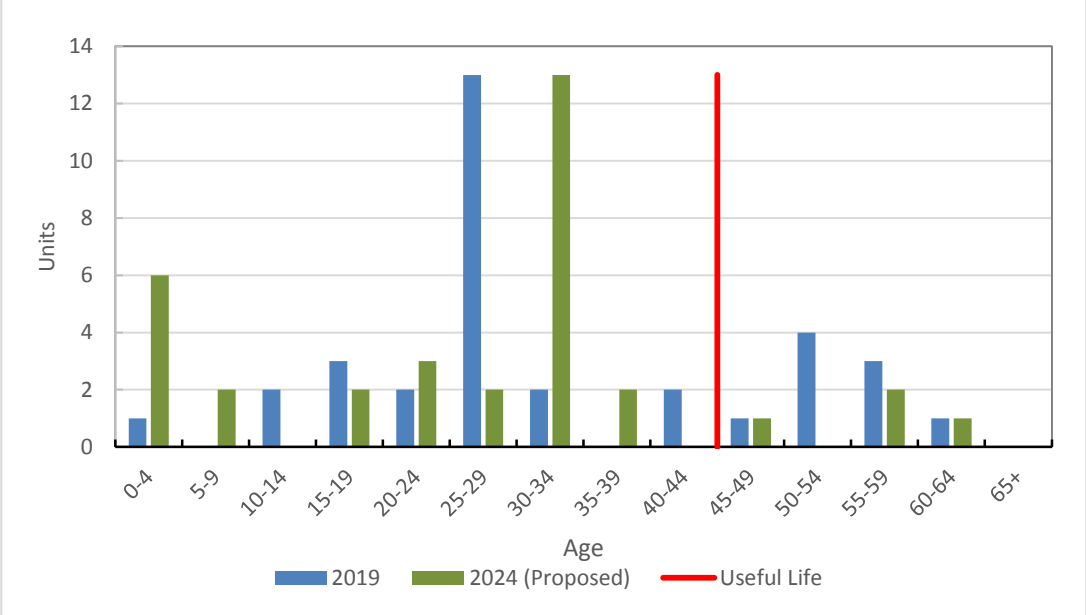


Figure 22: Age Profile of Station Service Transformers

The nine SSTs past useful life by 2019 are located at six TSs (each TS has two SSTs). As listed in Table 22 below, Toronto Hydro plans to replace one SST at each of these six TSs during the 2020-2024 period. This will significantly mitigate the risk of coincident SST failures at these TSs, and in turn will mitigate customer outage risk.

Table 22: SST Proposed Replacements

Station	Asset	Replacement Year
Main TS	*SSTC*	2022
Dufferin TS	*SST2*	2022
Windsor TS	*SST2*	2023
Duplex TS	*SST1*	2023
Cecil TS	*SST1*	2024
Carlaw TS	*SST1*	2024

In addition to the loss of critical systems identified above, a failure of an oil-containing SST risks leaking oil containing PCBs (when present) or causing a fire or an explosion. Most SSTs are located in close proximity to other critical station assets and pose risk of collateral damage. Therefore, SST replacements will mitigate this safety and environmental risk, and remove PCBs from Toronto Hydro's stations.

3. Other Ancillary Renewal

Several other ancillary systems require replacement or installation to maintain the integrity of Toronto Hydro's station infrastructure. Toronto Hydro's most pressing risks and needs for these ancillary assets are summarized in Table 23 below.

Table 24 lists the other ancillary assets to be installed or replaced over the 2020-2024 period.

Table 23: Other Ancillary Systems - Drivers

Asset Group	Asset Class	Drivers and Failure Consequences
Other Ancillary Systems	*Air Compressors*	The main driver is failure risk due to age. 20 percent of Toronto Hydro's remaining[14] air compressors will reach or surpass their useful life by the end of 2021. Air-blast circuit breakers require compressed air to operate and isolate fault currents. When an air compressor fails and an air-blast circuit breaker is unable to clear a fault, the fault triggers the upstream protection systems to operate extending the outage to thousands more customers and damaging equipment.
	Flood Mitigation System	The main driver for this segment is failure risk of station assets due to flooding. The stations selected for sump pump installation have major equipment installed in the basement (e.g. switchgear,station services etc.) that is at risk in case of water infiltration. Lack of sump pumps can lead to a water build-up which could eventually short-circuit and damage equipment.

Table 24: Proposed Other Ancillary Systems Projects

Station	Asset	Replacement Year
Glengrove TS	*Sump Pump*	2020
Carlaw TS	*Sump Pump*	2020
Wiltshire TS	*Sump Pump*	2020
Bridgman TS	*Air Compressor*	2021
Ossington MS	*Air Compressor*	2021

The majority of air compressor units will be decommissioned by 2024 either due to voltage conversion (see Area Conversions program[15]) or switchgear replacements. However, ten units will remain, and two units, at Bridgman TS and Ossington MS will have exceeded their useful life. Given their significant failure impact (loss of breaker operation) and their relatively small cost of renewal, Toronto Hydro plans to replace these two units during the 2020-2024 period. As shown in Figure 23 below, air compressor systems have been failing in recent years, and many repairs have been required. The average age of these air compressors at the time of failure was 13 years, and the units proposed for replacement will be 15 years old upon replacement.

[14] As switchgear containing air-blast circuit breakers are decommissioned or replaced, air compressors may no longer be required within a station.
[15] See E6.1 of this DSP.

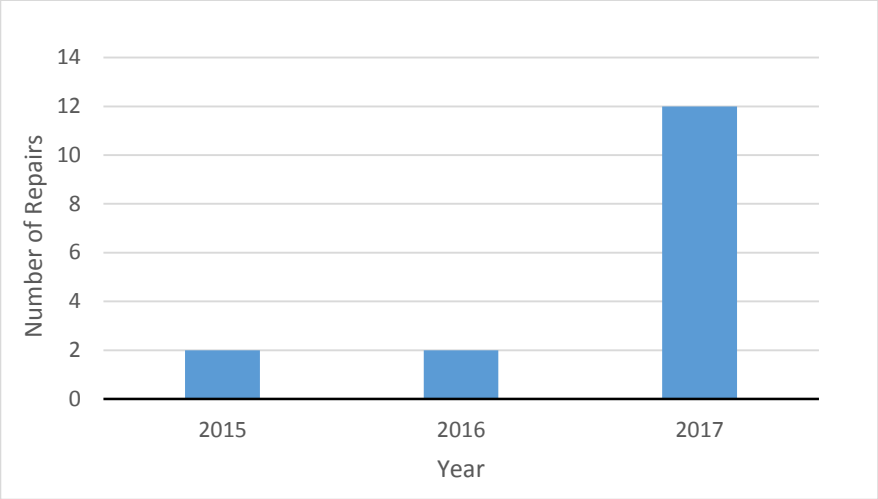


Figure 23: Air Compressor Repairs from 2015 to 2017

Toronto Hydro has also identified three TSs with flooding risks which can be addressed via installation of sump pumps. These stations contain significant assets in their basements and have shown signs of water ingress in the past. Therefore, Toronto Hydro plans to install three sump pumps during the 2020-2024 period. The stations planned for sump pump installation are Carlaw TS, Glengrove TS, and Wiltshire TS.

E6.6.4 Expenditure Plan

Table 25 provides the Historical (2015-2017), Bridge (2018-2019) and Forecast (2020-2024) expenditures for the Stations Renewal program. The Program has been organized in 2020-2024 based on the type of system addressed, work required, and driver of the work.

Table 25: Historical & Forecast Program Costs ($ Millions)

Segment	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Transformer Stations[16]	7.6	6.3	7.0	5.7	15.4	15.5	21.1	16.4	14.2	7.4
Municipal Stations[17]	3.2	3.0	7.6	8.3	3.7	8.2	8.6	7.0	6.6	7.3
Control and Monitoring[18]	0.3	1.3	2.9	2.8	3.6	2.9	4.3	4.4	4.5	6.0
Battery and Ancillary Systems[19]	0.1	0.8	1.4	2.8	1.1	0.9	1.2	1.6	1.7	1.7
Total	**11.3**	**11.6**	**19.0**	**19.7**	**23.7**	**27.5**	**35.3**	**29.4**	**27.0**	**22.4**

Spending in the Stations Renewal program over the 2015-2019 period is projected to be $85.3 million. This spending is forecast to be less than filed due to changes in Toronto Hydro's execution plan. Toronto Hydro evaluated its early (i.e. 2015 and 2016) program performance and modified its forecast and future plans based on that evaluation. In particular, coordination issues with interdependent TS Switchgear replacement projects had a significant impact on Toronto Hydro's 2015-2019 execution plan and spending. Several high-spend projects were dependent on the completion of Copeland TS, which had its energization date delayed to late 2018 (as discussed in the Stations Expansion program).[20] In general, small delays on high spend projects resulted in reductions in overall spending.

Due to the challenges and delays experienced over the 2015-2019 period, there is a back-log of high-priority station projects that need to be completed urgently. As discussed in Section E6.6.3, station assets are critical and have lengthy replacement times. Keeping station asset demographics in check is the best strategy to prevent their high failure impact and, in turn, maintain system reliability. For the 2020-2024 period, Toronto Hydro proposes to spend $141.5 million. A large portion of this spending is required to address deferred, urgent projects. Completion of key projects such as

[16] Transformer Stations segment includes the TS portion of the former Switchgear Renewal program, the former Circuit Breaker Renewal program, and the new TS Outdoor Switch sub segment.
[17] Municipal Stations segment includes the MS portion of the former Switchgear Renewal program, the former Power Transformer Renewal program, and the new MS Primary sub segment.
[18] Control and Monitoring segment includes the former Stations Control and Monitoring program and the new Pilot-wire Protection and Interstation Control Wiring renewal sub segments.
[19] Battery and Ancillary Systems segment includes the former Stations DC Battery Renewal program and the former Stations Ancillary Systems program.
[20] See E7.4 of this DSP.

Copeland TS and improved work processes established during its 2015-2019 program execution will enable Toronto Hydro to complete this volume of work as proposed.

Work in the Stations Renewal program is prioritized at three different levels. First, TS work is prioritized above MS work, since TSs supply customers of all classes and serve more customers than MSs. Therefore, the TS segment as a whole and the portions of the Control and Monitoring and Battery and Ancillary Systems relevant to TSs are given the highest priority. Secondly, the work inside each segment is prioritized differently depending on the specific failure outcomes and risks associated with each asset class. Thirdly, in respect of each asset class, work is prioritized using a variety of data and considerations including condition, customers served, load served, maintenance effort, obsolescence, and asset age.

E6.6.4.1 TS Segment Expenditure Plan

As shown in Table 26 below, Toronto Hydro forecasts to spend $42.1 million over the 2015-2019 period in its TS segment. This is less than Toronto Hydro proposed to spend in its 2015-2019 CIR filing, of the $42.1 million, expenditures for TS switchgear renewal and TS outdoor breaker renewal are expected to be $30.2 million and $11.8 million, respectively. Underspending for TS switchgear replacement is due to the delayed energization of Copeland TS (which must occur before the switchgear at Windsor TS is replaced) and other reasons as discussed in the section below. TS outdoor breaker replacement spending is forecast to be higher than planned due to an increase in unit replacement costs caused by additional scope driven by Hydro One requirements.

Table 26: TS Historical & Forecast Segment Costs ($ Millions)

Expenditures	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
TS Switchgear	5.3	3.8	3.9	4.2	12.9	14.9	20.3	15.1	12.8	5.5
TS Outdoor Breakers	2.3	2.5	3.1	1.5	2.5	0.4	0.4	0.9	0.9	1.4
TS Outdoor Switch	NEW SUBSEGMENT					0.1	0.4	0.4	0.5	0.5
Total	**7.6**	**6.3**	**7.0**	**5.7**	**15.4**	**15.5**	**21.1**	**16.4**	**14.2**	**7.4**

For the 2020-2024 period, Toronto Hydro proposes to spend $74.5 million in its TS segment. As with the 2015-2019 CIR filing, the majority of the 2020-2024 spending is planned for TS switchgear renewal. The remainder is for the replacement of TS outdoor breakers and TS outdoor switches.

Located in different stations than TS outdoor breakers and switches, TS switchgear units have longer replacement and lead times and more complex design and construction, and require more capital investment. For these reasons, TS switchgear are prioritized above the other assets in the TS segment, and in the Stations Renewal program overall.

1. TS Switchgear

As shown in Table 27 below, Toronto Hydro forecasts $30.2 million in spending on TS switchgear over the 2015-2019 period. This spending was or will be incurred for seven switchgear units over the 2015-2019 period, three of which will be completed during 2015-2019 and the other four units will see the majority of their costs carried into the 2020-2024 period.

Table 27: TS Switchgear - Historical Actual, Bridge and Forecast Unit Volumes

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Units (Switchgear)	-	-	1	1	1	-	-	1	3	1

The three switchgear units that will be completed over the 2015-2019 period are found at Carlaw TS (2017), Wiltshire TS (2018), and Strachan TS (2019). Significant spending had already been incurred for these units prior to 2015, and then continued into the 2015-2019 CIR period (forecast to be $15.3 million during 2015-2019, as shown in Table 28 below). Meanwhile, $14.4 million in spending is forecast for 2015-2019 in relation to the start of the replacements at Windsor TS (A5-6WR), Strachan TS (A5-6T), Duplex TS (A1-2DX), and Carlaw TS (A4-5E). Additional to the 2015-2019 CIR filing, $0.5 million in spending is forecast for the replacement of breakers at Dufferin TS, which was identified as being urgent due to their poor condition.

Table 28: 2015-2019 TS Switchgear Replacements – Historical and Bridge Expenditures ($ Millions)

Switchgear Unit	Actual			Bridge		Planned Completion
	2015	2016	2017	2018	2019	
Carlaw TS (A6-7E)	0.3	0.7	1.8	-	-	2017
Wiltshire TS (A3-4W)	1.3	1.5	1.1	1.7	-	2018
Strachan TS (A7-8T)	3.5	1.5	0.9	0.5	0.5	2019
Windsor TS (A5-6WR)	0.2	0.1	0.1	1.5	12.4	2020-2024
Strachan TS (A5-6T)						
Duplex TS (A1-2DX)						
Carlaw TS (A4-5E)						
Dufferin TS Breaker Replacements	-	-	-	0.5	-	2018
Total	**5.3**	**3.8**	**3.9**	**4.2**	**12.9**	

The volume of TS switchgear replacements proposed in Toronto Hydro's 2015-2019 CIR filing was subsequently adjusted as a result of several factors. Notably, two of the planned replacements at Windsor TS depended on the completion of Copeland TS. A delay in the Copeland TS energization had a cascading effect, pushing the first unit to be replaced at Windsor TS (A5-6WR) into the 2020-2024 period and the second unit (A3-4WR), which must be completed after the first, into the following period.

Another factor was the Pan American Games hosted by the City of Toronto in 2015. In 2015, work on TS switchgear replacements was slowed to (i) enable labour resources to be redirected to assist in preparations for the event; and (ii) ensure the system was not in a contingency state. Another factor was Hydro One's replacement of a transformer at Gerrard TS in 2016. As that work conflicted with Toronto Hydro's proposed replacements at Carlaw TS, resources were directed away from Carlaw TS until the Hydro One transformer replacement was completed.

The above discussed factors resulted in a back-log of TS switchgear still requiring replacement. As detailed in sub-section 1 of Section E6.6.3.1, a significant number of TS switchgear units are operating beyond their useful life. The longer the demographic remains at an elevated age, the greater the probability of eventual failure. Due to their criticality, even the failure of one of these units cannot be tolerated. Therefore, Toronto Hydro's strategy is to renew the critical TS switchgear units identified in this Program.

Informed by lessons learned from the 2015-2019 period, Toronto Hydro has further mitigated risks to attaining its 2020-2024 replacement plan, proposing only five TS switchgear replacements over the 2020-2024 period. As shown in Table 29 below, a total of $53.8 million is proposed for 2020-2024 to complete the four carry-over units (further to spending incurred in 2015-2019) and $14.8 million for one additional unit at Bridgman TS (A1-2H). By completing this plan, Toronto Hydro will maintain the number of TS switchgear operating beyond their useful life around the current level, which is approximately 27 percent.

Table 29: 2020-2024 TS Switchgear Replacements – Forecast Expenditures ($ Millions)

Switchgear Unit	Forecast					Unit Estimate	Planned Completion
	2020	2021	2022	2023	2024		
Windsor TS (A5-6WR)	2.0	1.0	2.4	8.8	4.2	20.5	2024
Bridgman TS (A1-2H)	-	4.4	6.0	3.0	1.3	14.8	2024
Strachan TS (A5-6T)	4.0	6.3	3.5	0.5	-	16.7	2023
Duplex TS (A1-2DX)	3.7	4.4	1.6	0.5	-	15.0	2023
Carlaw TS (A4-5E)	5.2	4.2	1.6	-	-	16.1	2022
Total	**14.9**	**20.3**	**15.1**	**12.8**	**5.5**		

This work plan is attainable (and necessary to manage the aging and deteriorating TS switchgear population) in light of the change in circumstances and lessons learned to date during the 2015-2019 period. For example, with the completion of Copeland TS, work on Windsor TS replacements – Toronto Hydro's highest priority switchgear replacements – can begin. Other projects, largely being carry-overs, have known execution risks and challenges that have been addressed over the 2015-2019 period. Toronto Hydro completed replacement of the Carlaw TS (A6-7E) switchgear in 2017. This switchgear replacement will serve as a template for the successful completion of projects into the 2020-2024 period.

The cost of replacement is forecast to be $20.5 million for Windsor TS (A5-6WR), $14.8 million for Bridgman TS (A1-2H), $16.7 million for Strachan TS (A5-6T), $15.0 million for Duplex TS (A1-2DX) and $16.1 million for Carlaw TS (A4-5E). These estimated costs are generally in line with actuals observed for the Carlaw TS project carried out to date over the 2015-2019 period and take into account the size and complexity of the replacements proposed. For example, spending on the Windsor TS (A5-6WR) replacement is higher due to extra scope required to transfer feeders to Copeland TS, which is needed to enable the decommissioning and replacement of the A5-6WR switchgear.

The proposed spending varies between years given, among other things, the need for major component purchases (e.g. switchgear lineup purchases in 2020, 2021 and 2022) during high-spend years. This follows the typical cost profile of a TS switchgear replacement project, where, as the project progresses, actual spend declines after the completion of major procurements but the work becomes more labour intensive. Similarly, the higher spend between 2019 and 2023 compared to the 2015-2018 period is due to the planned purchase of significant switchgear materials and the significant capital contribution expected to be made to Hydro One. Major component purchases and most Hydro One capital contributions for the three units to be completed between 2015 and 2019 were made prior to 2015.

Toronto Hydro plans to replace the TS switchgear units at Main TS, Wiltshire TS, and Windsor TS (which cannot be addressed during the 2020-2024 years) in the following (2025-2029) period. With the exception of the Windsor TS switchgear (A3-4WR), the units have been assessed to entail lower failure and operational risks compared to others prioritized over the 2020-2024 period. After reviewing all factors (age, condition, customers, load, breaker type, arc-flash rating, enclosure construction), these units were found to be lower priority than those proposed. The A3-4WR exception is still high priority but is dependent upon the completion of the A5-6WR for space and capacity reasons and simply can't be done in the period.

Toronto Hydro believes accepting the increased risk – i.e. continuing to operate these units beyond their useful life – to be prudent and necessary in the context of its overall TS Switchgear replacement needs, priorities, and ability. With continued maintenance and monitoring, Toronto Hydro will mitigate failure risk until the units can be replaced.

Toronto Hydro prioritizes the replacement of its TS switchgear in order of the failure risk presented by each switchgear. The failure risk is assessed qualitatively by considering the following factors.

Table 30: TS Switchgear Prioritization

Factor	Prioritization
Age	Older switchgear are given higher priority
Enclosure Construction	Brick constructed switchgear is given higher priority
Condition Assessment	Switchgear receiving worse condition assessments (including breaker condition assessments) are given higher priority

Factor	Prioritization
Type of circuit breaker	Priority given in order of: 1) Obsolete oil circuit breaker 2) Obsolete non-oil air blast circuit breaker 3) Obsolete asbestos-based air magnetic circuit breaker 4) Current SF_6 circuit breakers 5) Current vacuum circuit breakers
Load	Switchgear supplying larger quantities of load are given higher priority
Protection and Control	Switchgear with obsolete protection and control systems are given higher priority.
Arc Flash Rating	Switchgear with lower arc flash protection ratings are given higher priority
Any other issues raised by station crews (such as broken components)	Given higher priority

2. TS Outdoor Breaker

As shown in Table 31 below, Toronto Hydro forecasts the replacement of 28 TS outdoor breakers over the 2015-2019 period at a cost of $11.8 million.

Table 31: TS Outdoor Breakers - Historical Actual, Bridge and Forecast Unit Volumes

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Units (Breakers)	4	2	5	11	6	1	1	2	2	3

For the 2020-2024 period, Toronto Hydro is proposing $4.0 million in spending – a 50 percent reduction compared to the 2015-2019 period, during which the majority of Toronto Hydro's end-of-life oil-based TS outdoor breakers will have been replaced. For the 2020-2024 period, Toronto Hydro only proposes to replace 9 units. This will limit the proportion of TS outdoor breakers operating beyond their useful life at around the current rate of 4 percent. All of the breakers proposed for replacement contain oil and are operating beyond their useful life, and need to be replaced as detailed in Sub-Section 2 of Section E6.6.3.1.

The average cost for TS outdoor breaker replacement over the 2015-2019 period is roughly $0.4 million per unit. This is slightly higher than initial unit pricing estimated for the 2015-2019 period which was $0.3 million per unit. The increase in unit cost was caused by the additional scope required to meet recent Hydro One standards. For new breaker replacements, Hydro One requires a demarcation panel to act as a clean interface point between Toronto Hydro's and Hydro One's equipment, which would minimize confusion between the ownership of Hydro One and Toronto Hydro assets. However, with these new requirements, Toronto Hydro was required to pay a capital contribution to Hydro One. Toronto Hydro has adjusted its 2020-2024 estimates accordingly, forecasting $0.4 million per unit replacement.

Given its 2015-2017 historical achievements in this segment, Toronto Hydro is well positioned to successfully execute its replacement plan for 2020-2024, which proposes at most three replacements in a single year.

Toronto Hydro prioritizes the replacement of its TS outdoor breakers based on the failure risk presented by each breaker. The failure risk is assessed qualitatively by considering the following factors.

Table 32: TS Outdoor Breakers Prioritization

Factor	Prioritization
Age	Older breakers are given higher priority
Type of circuit breaker	Priority given in order of: 1) Oil circuit Breaker 2) SF_6 Breaker 3) Vacuum Breaker
Condition Assessment	Circuit breakers receiving worse condition assessments are given higher priority
Load	Breakers supplying larger quantities of load are given higher priority
PCBs	Breakers containing higher levels of PCBs are given higher priority
Protection and Control	Breakers with obsolete protection and control systems are given higher priority.
Any other issues raised by station crews (such as broken components)	Given higher priority

3. TS Outdoor Switches

As shown in Table 33 below, Toronto Hydro proposes to replace 61 TS outdoor switches during the 2020-2024 period at a cost of $1.9 million. This is a new spending category to address the need identified in Sub-section 3 of Section E6.6.3.13 and has no historical costs associated with it. By replacing these 61 units during the 2020-2024 period, Toronto Hydro will reduce the number of TS outdoor switches operating beyond their useful life to 16 percent. As detailed in Sub-section 3 of Section E6.6.3.1, if this work is not undertaken during the 2020-2024 period, almost three quarters of Toronto Hydro's TS outdoor switches will be operating beyond or within 5 years of their 50-year useful life. Performing the proposed work will allow Toronto Hydro to sustainably manage the demographics of its switches over the longer term and reduce the number of switch failures.

Table 33: TS Outdoor Switch Renewal – Forecasted Unit Volumes

	Forecast				
	2020	**2021**	**2022**	**2023**	**2024**
Units (Switches)	3	12	12	18	16

The year-by-year pacing for TS outdoor switch replacement has been developed to target the highest priority switches, while maximizing efficiencies in terms of construction and outage coordination. As this is new work, only three switches have been proposed for replacement in 2020. This will serve as a pilot project and allow Toronto Hydro to make any refinements necessary to achieve the greater volumes proposed in later years. For the years 2020-2022, Toronto Hydro proposes replacements in sets of three switches per year because each selected set can be replaced in a single outage. This reduces unit costs and reliability risk to customers (which would be higher if each switch was replaced as a separate project). For the years 2023 and 2024, Toronto Hydro has grouped bus disconnect switches with common outages into its replacement plans, which would similarly lead to efficiencies in terms of unit cost and outage coordination.

Toronto Hydro prioritizes the replacement of its TS outdoor switches based on the failure risk presented by each switch. The failure risk is assessed qualitatively by considering the following factors.

Table 34: TS Outdoor Switches Prioritization

Factor	Prioritization
Age	Older switches are given higher priority
Switch Type	Priority given in order of: 1) Feeder tie switches 2) Bus disconnect switches 3) Line disconnect switches
Number of repairs	Switches with more repairs are given higher priority
Any other issues raised by station crews (such as broken components)	Given higher priority

E6.6.4.2 Municipal Stations (MS) Expenditure Plan

As shown in Table 35 below, Toronto Hydro expects to spend $25.9 million over the 2015-2019 period in its MS segment. This includes anticipated spending of $14.6 million and $11.3 million for MS switchgear renewal and power transformer renewal, respectively.

Table 35: MS Historical & Forecast Segment Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
MS Switchgear[21]	2.4	1.7	4.6	4.1	1.9	5.3	5.8	4.3	3.7	4.3
Power Transformer	0.9	1.4	3.1	4.2	1.7	1.9	2.1	2.0	2.1	2.2
MS Primary Supply	NEW SUBSEGMENT					1.0	0.7	0.7	0.7	0.8
Total	**3.2**	**3.0**	**7.6**	**8.3**	**3.7**	**8.2**	**8.6**	**7.0**	**6.6**	**7.3**

During the 2020-2024 period, Toronto Hydro proposes to spend $37.7 million in its MS segment. This spending includes allowances for the addition of a new MS primary supply sub segment, an increased scope of work for power transformer replacements, and the inclusion of the distribution portion of work for MS switchgear replacements in this segment's budget (rather than in the Overhead or Underground System Renewal programs[22] to achieve work bundling). The majority of the 2020-2024 spend relates to MS switchgear renewal ($23.3 million). The remaining spending is planned for replacement of power transformers and MS primary supplies.

[21] Please note the 2015-2019 expenditures do not necessarily align with the volume of units completed since project costs were spread across 2-3 years.
[22] Exhibit 2B, Schedules E6.5, E6.2, and E6.3.

MS switchgear and power transformers are the main assets for a MS. They have the longest replacement and lead times, the largest design and construction work requirements, and the highest cost (including design, material, and construction) compared to assets covered under the MS primary supplies, or other assets located at MSs included in the Control and Monitoring, and Batteries and Ancillary Systems segments. For these reasons, MS switchgear and power transformers are prioritized before all other MS assets, including those covered in the Control and Monitoring and Batteries and Ancillary Systems segments.

MS switchgear and power transformers replacement candidates are prioritized against each other depending on their associated failure risk, which is evaluated qualitatively and described in the subsections below. The replacement of MS primary supplies is prioritized according to age.

1. MS Switchgear

Over the 2015-2019 period, Toronto Hydro replaced 11 switchgear at 11 MSs. Table 36 below provides an annual breakdown of the units completed, and proposed, between 2015 and 2024.

Table 36: MS Switchgear - Historical Actual, Bridge and Forecast Unit Volumes

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Units (Switchgear)	2	0	4	4	1	3	3	2	2	2
Total Feeders[23]	8	0	10	16	3	10	10	7	6	7

The cost to replace a switchgear varies depending on the number of feeders supplied by the switchgear (a measure of size) and the complexity of the distribution portion of the project. A switchgear replacement typically requires all feeder trunks to be replaced in concrete encased ducts. The distribution portion of work that is required is determined by whether concrete encased ducts already exist in the system and the length of feeder and/or duct bank required to be installed.

Historical actuals from 2014 to 2017 were used to arrive at a unit cost of approximately $0.6 million per feeder, which includes both the station and distribution scopes of work. This unit cost was used to forecast expenditures for the 2020-2024 period. Historical unit costs are less than forecasted unit costs for two reasons. First, the two switchgear completed in 2015 were carry-over projects from the

[23] This is the total number of feeders supplied by the switchgear whose replacements were, or are forecasted to be, completed in the specified year.

2012-2014 period, and hence their total cost is not captured in Table 36 above. Second, the majority of the switchgear replacements over the 2015-2019 period did not include the expense of the distribution portion of work, the cost of which was instead included in the Underground and Overhead System Renewal programs.[24] Once these two factors are accounted for, the historical unit cost aligns with the forecast unit cost of $0.6 million per feeder. A balance between annual cost, system need, and ability to execute resulted in an average pace of 2-3 units per year.

Toronto Hydro prioritizes the replacement of its MS switchgear based on the failure risk presented by each switchgear. The failure risk is assessed qualitatively by considering the following factors.

Table 37: MS Switchgear Prioritization

Factor	Prioritization
Age	Older switchgear are given higher priority
Condition Assessment	Switchgear receiving worse condition assessments (including breaker condition assessments) are given higher priority
Type of circuit breaker	Priority given in order of: 1) Obsolete oil circuit breaker 2) Obsolete non-oil air blast circuit breaker 3) Obsolete asbestos-based air magnetic circuit breaker 4) Current SF_6 circuit breakers 5) Current vacuum circuit breakers
Load	Switchgear supplying larger quantities of load are given higher priority
SCADA (Supervisory Control and Data Acquisition) system present?	MSs without SCADA are given higher priority
Resiliency of the surrounding distribution system to withstand switchgear failures	MSs in areas of low resiliency are given higher priority
Any other issues raised by station crews (such as broken components)	Given higher priority
Voltage conversion planned? (see Section E6.6.5.3)	Stations with voltage conversion plans do not need any of their assets to be replaced

Age, condition assessment, circuit breaker type, and issues raised by station crews are used to gauge the probability of a switchgear failure and when a switchgear has reached end-of-life. Furthermore,

[24] Exhibit 2B, Schedule E6.2, E6.3 and E6.5.

switchgear loading, existence of SCADA, and resiliency of the surrounding distribution system (i.e. ability to withstand switchgear failures) are used to gauge the impact of the switchgear failure and the priority of the replacement.

2. Power Transformer

Over the 2015-2019 period, Toronto Hydro expects to complete the replacement of 15 power transformers at 14 MSs. As part of these replacements, Toronto Hydro also replaced the MS primary supply at 6 of the 14 MSs. Table 38 below provides an annual breakdown of the units completed and forecast over the 2015-2024 period.

Table 38: Power Transformer - Historical Actual, Bridge, and Forecast Unit Volumes[25]

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Power Transformers	2	0	5	6	2	2	2	2	2	2

Historical actuals from 2014 to 2017 were used to arrive at a unit project cost of approximately $1.0 million per transformer, which was used to forecast expenditures. The scope of work at each station includes the replacement of the power transformer, installation of an oil containment system, and replacement of the MS primary supply.

Historical unit costs are less than forecasted unit costs for two reasons. First, the two transformers completed in 2015 were carry over projects from the 2012-2014 period. Hence the total expense of these two projects is not captured in the 2015-2019 period. Second, the majority of the transformer replacements over the 2015-2019 period did not also involve the replacement of the associated MS primary supply. Once these two factors are accounted for, the historical unit cost aligns with the forecast unit cost of $1.0 million.

A balance between annual cost, system need, and ability to execute resulted in an average pace of 2 units per year. Toronto Hydro prioritizes the replacement of its power transformers based on the failure risk presented by each transformer. The failure risk is assessed qualitatively by considering the following factors.

[25] Please note the 2015-2019 expenditures do not necessarily align with the volume of units completed since project costs were spread across 2-3 years.

Table 39: Power Transformer Prioritization

Factor	Prioritization
Age	Older transformers are given higher priority
Dissolved gas-in-oil analysis	Transformers in worse condition are given higher priority
Condition Assessment	Transformers receiving worse condition assessments are given higher priority
Loading	Transformers loaded higher relative to their capacity are given higher priority
Load	Transformers supplying larger quantities of load are given higher priority
PCB concentration in oil	Transformers with a higher PCB concentration are given higher priority
Resiliency of the surrounding distribution system to withstand transformer failures	MSs in areas of low resiliency are given higher priority
Any other electrical tests (such as power factor and insulation resistance tests)	Given higher priority
Voltage conversion planned? (see Section E6.6.5.3)	Stations with voltage conversion plans do not need any of their assets to be replaced

Age, dissolved gas-in-oil analysis, loading, and other electrical tests are used to gauge the probability of a power transformer failure and when an asset has reached end-of-life. Further, transformer loading, PCB concentration in the transformer oil, and resiliency of the surrounding distribution system (i.e. ability to withstand power transformer failures) are used to gauge the impact of the power transformer failure and the priority of the replacement.

3. MS Primary Supply

Over the 2015-2019 period, Toronto Hydro did not plan or complete any project which solely replaced a MS's primary supply. As a result, there are no historical actuals for these projects. Over the 2020-2024 period, Toronto Hydro proposes to replace 11 MS primary supplies. The forecasted unit volumes are shown in Table 40 below.

Table 40: MS Primary Supply - Forecasted Units

	Forecast				
	2020	**2021**	**2022**	**2023**	**2024**
Primary Disconnect Switch[26]	3	2	2	2	1
Primary Breaker[26]	0	0	0	0	1

The spending forecast was developed using a unit cost of $0.37 million. A balance between annual cost, system need, and ability to execute resulted in an average pace of 2 units per year. The scope of work required for an MS primary supply replacement is dominated by the distribution portion involving the replacement of the primary cable and related civil work. Therefore, unit costs were developed based on: the costs of similar distribution projects completed in the past, and the material cost of the new asset to be installed (padmounted switch or circuit breaker).

E6.6.4.3 Control and Monitoring Expenditure Plan

As shown in Table 41 below, Toronto Hydro expects to spend $11.0 million over the 2015-2019 period in its Control and Monitoring segment. For the 2020-2024 period, Toronto Hydro proposes to spend $22.1 million in its Control and Monitoring segment.

Table 41: Control and Monitoring Historical & Forecast Segment Costs ($ Millions)

Expenditures	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
RTU Renewal	0.3	0.8	1.8	1.6	1.6	1.3	2.7	2.7	2.8	3.6
New RTU Installation	-	-	1.0	0.2	0.4	0.4	0.4	0.4	0.4	0.8
Pilot-wire Protection Renewal	-	0.5	0.1	1.0	1.6	0.6	0.6	0.6	0.6	1.0
Interstation Control Wiring Renewal	NEW SUBSEGMENT					0.6	0.6	0.6	0.6	0.6
Total	**0.3**	**1.3**	**2.9**	**2.8**	**3.6**	**2.9**	**4.3**	**4.4**	**4.5**	**6.0**

For the 2020-2024 period, the majority of proposed spending is for RTU renewal, which is largely allocated to replace end-of-life DACSCAN RTUs at downtown TSs. The remaining proposed spending is planned for new RTU installations, pilot-wire protection upgrades and a new sub segment,

[26] *The primary cable associated with these assets will also be included in the replacement projects and has been included in the unit costs.*

Interstation Control Wiring Renewal. This new sub segment was added to renew end-of-life copper cables which have not previously been considered under any other programs. Proposed replacements are otherwise a continuation of Toronto Hydro's 2015-2019 CIR plan with cost forecasts updated to accurately reflect the proposed work.

The Control and Monitoring segment is mainly prioritized according to the failure risks and outage impacts on customers. Stations with larger number of customers and at higher risk of asset failure will be given higher priority compared to stations with lower number of customers and lower failure risks. Priority of replacements is assessed qualitatively by evaluating various factors as shown below:

Table 42: Control and Monitoring Prioritization

Factor	Prioritization
Age	The older the RTU or asset, the higher the priority is assigned.
Number of Customers	The larger number of customers connected to the station, the higher the priority.
Load	The larger amount of load (MVA), the higher the priority.
Failure rate	RTUs/assets at stations with higher incident of failures/repairs will have higher priority.
Voltage conversion planned (see Section E6.6.5.3)	Stations with voltage conversion being planned do not need any of their assets to be replaced

1. RTU Renewal

Table 43: RTU Replacement - Historical Actual, Bridge and Forecast Unit Volumes

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
DACSCAN RTUs	-	-	-	2	2	1	3	3	3	4
MOSCAD RTUs	1	5	7	6	5	3	3	3	3	3
D20 M++/ RTUs	-	-	-	1	-	1	2	2	2	3

a. DACSCAN and MOSCAD RTU Replacement

As shown in Table 43, Toronto Hydro forecasts to replace four DACSCAN and 24 MOSCAD RTUs over the 2015-2019 period. Spending is forecast to be $2.0 million for DACSCAN units and $4.0 million for MOSCAD units.

Actual RTU replacements cost more than estimated Toronto Hydro's 2015-2019 filing. This was because additional time was required for investigative and design work, beyond that which was expected. Considerable time was spent researching and specifying a replacement RTU to ensure it would be backwards compatible with existing Toronto Hydro systems (while considering emerging technological trends).

Future forecasts and estimates have been refined based on lessons learned from actual project implementation. For the 2020-2024 period, Toronto Hydro proposes $8.8 million in spending to replace 14 DACSCAN RTUs at a unit cost of approximately $0.6 million, and $3.1 million to replace 15 MOSCAD RTUs at a unit cost of approximately $0.2 million.

- **DACSCAN RTUs**: This spending and work volume is a significant increase from Toronto Hydro's 2015-2019 replacement proposal as these RTUs are critical due to their age and importance in maintaining reliability in the downtown area. The 14 units represent all of Toronto Hydro's end of life DACSCAN RTUs. Any remaining DACSCAN RTUs will be replaced via TS switchgear replacement projects or rendered obsolete as their corresponding MSs are converted. Achieving the proposed pacing will require good planning and proper coordination, but is attainable now that Toronto Hydro has developed a replacement solution to use as a template.
- **MOSCAD RTUs:** As detailed in 1, all of Toronto Hydro's 37 MOSCAD RTUs in-service will be past their end-of-life by 2019. Ideally, Toronto Hydro would replace all of these units. However, given financial constraints and the higher priority replacement of DACSCAN RTUs, Toronto Hydro proposes a reduced volume of work for MOSCAD replacements compared to its 2015-2019 plans. This work volume represents approximately half of Toronto Hydro's end-of-life MOSCAD RTUs and allows Toronto Hydro to manage its overall RTU demographics so that only 12 percent are operating beyond their end-of-life by 2024, a substantial improvement from 37 percent at the end of 2019.

b. D20 M++/ME RTU Replacement

As shown in Table 43, Toronto Hydro forecasts to replace one legacy D20 M++ RTU over the 2015-2019 period at a forecast spend of $0.1 million. An increased number of D20 D20 M++ /ME failures have occurred and its manufacturer has recently ended support for the model most commonly used in Toronto Hydro's system (the D20 ME). Therefore, Toronto Hydro proposes to upgrade these units to the new platform to enable continued support and parts availability.

The D20 M++ replacement project planned for 2018 was added as a pilot project to familiarize Toronto Hydro's design and field staff with the new D20 MX platform, which has considerable software changes from Toronto Hydro's existing systems. Based on the expertise and experience gained in this regard, corrective repair and upgrade of failed legacy units based on the new platform can be feasibly carried out.

For the 2020-2024 period, Toronto Hydro proposes $1.2 million to replace ten legacy D20 M++/ME RTUs. Besides the pilot D20 M++/ME RTU replacement forecasted for 2018 completion, replacement of these assets is new to the Stations Renewal program. Unlike other RTUs replaced in this segment, the D20 platform manufacturer provides upgrade support from their obsolete platform. Therefore, Toronto Hydro proposes to replace its D20 M++/ME units with a comparable replacement from the original manufacturer. This manufacturer support saves Toronto Hydro work effort (e.g. resources for rewiring) and allows the utility to cost effectively renew its D20 platform, as evidenced by the lower RTU replacement costs compared to MOSCAD or DACSCAN RTUs.

Ten D20 M++/ME RTU replacements are proposed to renew all of Toronto Hydro's D20 RTUs at stations with no voltage conversion plans. The remaining legacy D20 RTUs are proposed to operate until customers supplied are converted to higher voltage distribution systems and the relevant stations decommissioned.

2. New RTU Installation

As shown in Table 44, Toronto Hydro forecasts to install five new RTUs over the 2015-2019 period. Spending during the period is forecast to be $1.6 million. Similar to other work completed in the Control and Monitoring segment, RTU installation cost were underestimated in Toronto Hydro's 2015-2019 CIR filing. At that time, Toronto Hydro had a small sample of historical projects to base cost estimates on and several aspects of the scope of work required refinement. Future forecasts and estimates have been refined based on lessons learned from actual completed projects.

Table 44: New RTU Installation - Historical Actual, Bridge and Forecast Unit Volumes

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
New RTUs	-	-	2	1	2	1	1	1	1	2

For the 2020-2024 period, Toronto Hydro proposes $2.3 million in spending to install six new RTUs. As detailed in 2, in combination with RTU installations integrated into MS switchgear replacement

projects, this volume enables SCADA at all remaining Toronto Hydro stations without voltage conversion and decommissioning plans.

3. Pilot-wire Protection Renewal

As shown in Table 45, Toronto Hydro forecasts to upgrade the pilot-wire protection system for nine locations over the 2015-2019 period (in alignment with the proposed 2015-2019 plan). Spending during the period is forecast to be $3.3 million.

Table 45: Pilot-wire-Protection Renewal - Historical Actual, Bridge and Forecast Unit Volumes

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Locations[27]	-	-	1	1	7	1	1	1	1	1

For the 2020-2024 period, Toronto Hydro is proposing $3.5 million to upgrade protection systems for five locations. This is a slight reduction in planned upgrades compared to the 2015-2019 period. Most of the upgrades (scheduled for completion in 2019) are required to enable load transfer from the Windsor TS (A5-6WR) switchgear to the new switchgear at Copeland TS (to facilitate the Windsor TS switchgear replacement discussed in Sub-Section 1 of Section E6.6.4.1 and to utilize Copeland TS). The quantity of work to be completed in 2019 is significantly higher compared to the proposed for other years. In a normal year, Toronto Hydro is more than capable of upgrading one pilot-wire location per year. As the switchgear installed at Copeland TS was designed with pilot-wire protection in mind, a portion of the upgrade work has already been completed. Also due to the overall criticality of Copeland TS projects in Toronto Hydro's system plan, more resources than usual will be assigned to complete the work.

Toronto Hydro's proposed pacing is attainable and informed by 2015-2019 progress in replacing these assets. For example, in 2016/2017, Toronto Hydro upgraded protections for a large customer in the financial district at a cost of $0.6 million. Toronto Hydro expects pilot-wire upgrades proposed between 2020 and 2023 to have similar cost per location due to their similar natures. The cost for

[27] Toronto Hydro's 2015-2019 CIR filing reported units in terms of pilot-wire relays. The actual scope of work extends beyond relay replacement (e.g. communication channel/fiber upgrade). Due to the scope that is required independent of the number of relays, unit attainment is better measured on a per location basis and historical figures have been adjusted accordingly.

the location proposed for 2024 is expected to be higher than average due to the higher number of feeders and the longer route of fiber required between Toronto Hydro's TS and the customer.

4. Interstation Control Wiring Renewal

Toronto Hydro has not previously performed planned replacement of its interstation control wiring. However, a number of recent failures exposed Toronto Hydro's downtown customers to reduced reliability. Advancements in communication infrastructure have also made finding compatible parts and skilled labour difficult, in turn making reactive repair risky and costly. Therefore, as shown in Table 46 below, Toronto Hydro proposes to invest $3.1 million to replace approximately 45-kilometres of interstation control wiring with new fiber optic cables during the 2020-2024 period.

Table 46: Interstation Control Wiring Renewal - Forecasted Unit Volumes

	Forecast				
	2020	**2021**	**2022**	**2023**	**2024**
Control Wiring Length (kilometres)	9	9	9	9	9

Toronto Hydro has identified 19 critical control wire sections interconnecting downtown TSs, MSs, and large customers. These sections make up the backbone of Toronto Hydro's control wiring network in the Esplanade TS, Strachan TS, and Windsor TS service areas. These stations supply Toronto's downtown core, the region in the city with the highest reliability demands. For this reason, these sections have been prioritized for replacement over the remainder of Toronto Hydro's aging control wiring.

The total length of wiring proposed for replacement is approximately 45 km. To replace these wires, Toronto Hydro proposes to replace 3-4 interstation control wire sections per year, resulting in approximately 9 km of cable replaced each year. This pace will allow Toronto Hydro to target its highest priority stations at an attainable replacement rate.

As discussed in Sub-Section 4 of Section E6.6.3.3, control wires of this type have failed in the past. Emergency replacement of these wires cost approximately $0.08 million per kilometre of cable, including urgent material order and procurement which drive up the cost beyond that of planned work. Taking this into account, Toronto Hydro estimates the cost of a planned replacement at $0.07 million per kilometre of cable, adding up to approximately $0.6 million to replace 9 kilometres of cable per year over the 2020-2024 period.

E6.6.4.4 Battery and Ancillary System Expenditure Plan

As shown in Table 47 below, Toronto Hydro forecasts to spend $6.3 million during the 2015-2019 period in its Battery and Ancillary System segment. This spend is expected to be of $3.6 million, $0.8 million, and $1.8 million respectively for batteries and chargers, SSTs, and ancillary projects.

Table 47: Battery and Ancillary Systems Historical & Forecast Segment Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Battery and Charger Renewal	0.1	0.8	1.4	0.7	0.6	0.7	0.9	1.0	1.1	1.1
SST Renewal	-	-	0.1	0.4	0.3	-	-	0.6	0.6	0.6
Other Ancillary Renewal	-	-	-	1.7	0.1	0.2	0.3	-	-	-
Total	**0.1**	**0.8**	**1.4**	**2.8**	**1.1**	**0.9**	**1.2**	**1.6**	**1.7**	**1.7**

During the 2020-2024 period, Toronto Hydro proposes to spend $7.3 million in its Battery and Ancillary System segment. Similar to the 2015-2019 period, the majority of 2020-2024 spending is for Battery and Charger Renewal, with the remainder allocated to SST Renewal and Other Ancillary Renewal.

The battery and ancillary systems at Toronto Hydro TSs are prioritized above the same assets at MSs due to the sheer volume of customers that are served through each TS. A TS asset failure affects many more customers than the same asset failing at an MS. Battery and ancillary systems projects at downtown MSs are prioritized over the projects at Horseshoe MSs, because the volume of customers served by Horseshoe MSs is much lower. Also, survey results have shown that Horseshoe customers have indicated preference of lower electricity rates over reliability of service.

1. Battery and Charger Renewal

As shown in Table 48 below, Toronto Hydro replaced 44 battery and charger systems during the 2015-2019 period.

Table 48: Battery and Charger Renewal - Historical Actual, Bridge and Forecast Unit Volumes

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Battery and Charger Systems	3	9	13	9	10	11	13	13	15	15

A battery and charger system's replacement cost can vary considerably (between $0.04 million and $0.15 million), depending on its size, type, and station served. Additionally, project cost can vary depending on the scope of work required to correct deficiencies related to a station's broader DC or AC wiring system.

During the 2015-2019 period, Toronto Hydro replaced a considerable number of larger battery and charger systems at its downtown TSs, resulting in a higher unit cost than what is typical. TS battery and charger replacement projects are more costly than their MS counterparts due to their increased size and complexity. One such replacement took place at Terauley TS (located next to City Hall), where Toronto Hydro replaced and relocated a battery and charger system and the station's DC panels at a total cost of $0.5 million. The scope of work completed for this project was greater than typical battery and charger system replacements. Additional scope was required to relocate the battery and charger system so that its space could be used for a TS switchgear replacement planned for the 2025-2029 period. As the batteries were at end-of-life, adding relocation to the scope of work prevents the need for duplicate investment in the 2025-2029 period. Excluding the replacement at Terauley TS, Toronto Hydro forecasts replacement of 43 battery and charger systems at an average cost of $0.07 million per replacement.

For the 2020-2024 period, Toronto Hydro is proposing $4.8 million in spending to replace 67 end-of-life battery and charger systems. This spending and pacing is a continuation of Toronto Hydro's 2015-2019 replacement strategy. Toronto Hydro proposes to maintain the number of its battery and charger systems operating beyond their useful life at existing levels in order to maintain system reliability. This volume is attainable based on historical performance and reasonable given these assets' criticality to the operation of Toronto Hydro's TS and MS protection and control systems. Toronto Hydro forecasts total spending to be $4.8 million, or $0.07 million per replacement which is in line with 2015-2019 actuals.

Toronto Hydro prioritizes the replacement of its battery and charger systems based on the failure risk and impact posed by each system. The failure risk is assessed qualitatively by considering the following factors.

Table 49: Battery and Charger Prioritization

Factor	Prioritization
Age	Older battery and charger systems are given higher priority.
Number of Customers	The larger the number of customers connected to the station, the higher the priority (e.g. battery and charger systems located at Transformer Stations are given higher priority than those located at Municipal Stations).
Failure Rate	DC systems that have frequent SCADA alarms and have a history of individual cell failure/repairs will be given a higher priority.
Other factors determined on a case-by-case basis	Systems which are non-standard or contain obsolescent technology are given higher priority (e.g. some DC distribution panels are obsolete). Spare parts that should be accessible routinely are no longer available (e.g. DC panel breaker).
Voltage conversion planned? (see Section E6.6.5.3)	Stations with voltage conversion plans do not need any of their assets replaced.

2. Station Service Transformers (SST)

As shown in Table 50 below, Toronto Hydro replaced three SSTs during the 2015-2019 period. Spending during the period is forecast to be $0.8 million.

Table 50: SST Renewal - Historical Actual, Bridge and Forecast Unit Volumes

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
SSTs	-	-	1	1[28]	1[28]	-	-	2	2	2

[28] Replacement of SSTs was not included in Toronto Hydro's 2015-2019 CIR filing. Units were proactively replaced in 2017 and 2018 after they were identified as having significant failure risk.

For the 2020-2024 period, Toronto Hydro is proposing $1.9 million to replace 6 SSTs located at 6 of its 15 downtown TSs. This volume is proposed to address the need detailed in Sub-Section 2 of Section E6.6.3.4.

Work to be completed in 2018 and 2019 was added following Toronto Hydro's 2015-2019 CIR filing. This work was driven by failure risk due to each SST's age, condition, and failure impact. A typical SST project can vary between $0.27 million and $0.33 million depending on the scope of the project – e.g. replacement and relocation (higher cost) or replacement in place (lower cost). Exact scope depends on site specific constraints (e.g. space, flood risk).

Toronto Hydro will be able to achieve the replacement of 6 SSTs during the 2020-2024 period by replacing 2 SSTs per year beginning in 2022. SST replacements have not been planned earlier than 2022 due to their relative priority compared to other projects in the segment and in an effort to maintain a flat investment profile over the 5 year period. The proposed spending of approximately $0.3 million per unit is consistent with Toronto Hydro's latest estimates to replace an SST.

3. Other Ancillary Renewal

As shown in Table 51 below, Toronto Hydro replaced four air compressors, installed one sump pump and installed two fire barrier or suppression systems during the 2015-2019 period. Spending during this period is forecast to be $1.8 million. While spending is in line with planned, actual project completion differs from what was planned:

- **Air compressors**: Toronto Hydro planned to replace six air compressors. By the end of 2019, Toronto Hydro forecasts to replace four of these units at a total cost of $0.4 million. Toronto Hydro cancelled two air compressor replacements due to a change in voltage conversion plans for the MS where they were located.
- **Flood mitigation system:** Toronto Hydro did not plan to install any sump pumps. However, the utility has increasingly focused on storm hardening its system to ensure reliable power supply for its customers. After completing station risk assessments, Toronto Hydro directed $0.1 million for the installation of one sump pump in 2019.
- **Fire Barrier/Suppression Systems**: Toronto Hydro planned to install one fire suppression system and two fire barrier systems during the 2015-2019 period. The utility installed one fire suppression system installation and one fire barrier at a total cost of $1.3 million. The remaining fire barrier installation was cancelled due to a change in conversion plans for the

MS it was intended for. The fire suppression system installed in 2018 cost more than expected with a final spend of $0.9 million compared to its estimate of $0.3 million due to a significant increase in scope discovered during the detailed design phase. However, given the criticality of the assets protected (2 x 230 kV – 27.6 kV transformers at Toronto Hydro's Cavanagh TS) and site specific constraints, an alternative to this increased cost was not available.

Table 51: Other Ancillary Renewal - Historical Actual, Bridge and Forecast Units

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Air Compressor Replacements	-	-	-	4	-	-	2	-	-	-
Sump Pump Installations	-	-	-	-	1[29]	3	-	-	-	-
Fire Barrier/ Suppression System Installations	-	-	-	2	-	NO UNITS PLANNED				

For the 2020-2024 period, Toronto Hydro is proposing $0.5 million to install three sump pumps at TSs identified during risk assessments, and replace two end-of-life air compressors located at Bridgman TS and Ossington MS.

Toronto Hydro prioritizes the replacement of its ancillary systems based on the failure risk and impact posed by each system. The failure risk is assessed qualitatively by considering the following factors.

Table 52: Ancillary System Prioritization

Factor	Prioritization
Failure Impact on a system-by-system basis	Systems that have more far reaching impacts are given higher priority. For example, basement flood would have a more immediate impact on the system compared to failure of an air compressor. On the other hand, air compressor failure could render entire switchgears breakers inoperable, which could cascade into a larger system problem, therefore replacing air

[29] Replacement of this sump pump was not included in Toronto Hydro's 2015-2019 CIR filing. It was installed following the outcome of a station risk assessment.

Factor	Prioritization
	compressor systems will be given a higher priority compared to SSTs.
Age	Older systems are given higher priority.
Number of Customers	The larger the number of customers connected to the station, the higher the priority. For example, ancillary systems located at TSs are given higher priority than those located at MSs.
Failure Rate	Ancillary systems that have frequent SCADA alarms and have a history of repairs will be given higher priority. For example, air compressors that have had a history of problems like motors found smoking, leaking, low air pressure etc., will be prioritized.
Voltage conversion planned? (see Section E6.6.5.3)	Stations with voltage conversion plans do not need any of their assets to be replaced

E6.6.5 Options Analysis

E6.6.5.1 Reactive Replacement

A large portion of station assets are operating beyond their useful life and are obsolete, thus increasing the risk and the impact of failure. As more assets are replaced reactively, the redundancy of the distribution system will continue to degrade and customer outage times and customer outage frequency will increase. Failure rate is expected to increase as assets continue to age without replacement.

Under this option, Toronto Hydro would not perform asset renewal and instead accept the risk of asset failure. This option is therefore not considered and not recommended for stations assets which will be needed well into the future. Generally, this includes all station assets except those at Municipal Stations with voltage conversion plans.

E6.6.5.2 Risk-tolerant Asset Renewal

Under the risk-tolerant option, Toronto Hydro would maintain its 2015-2019 forecast spending and accept an incremental risk given that certain planned projects from 2015-2019 program were not executed.

To maintain spending comparable to its forecast 2015-2019 spending, Toronto Hydro would reduce TS Switchgear renewal plans, and maintain the same level of investment in Municipal Station Assets, and Battery and Ancillary Services (as they have not substantially changed).

The utility is unable to reduce the spend allocated to the Control and Monitoring segment beyond that that forecasted under its proposed plan for the 2020-2024 period due to the critical nature of the assets. Toronto Hydro's DACSCAN and MOSCAD RTUs are functionally obsolete and beyond their useful life and need to be replaced.

Therefore, with the exception of its TS Switchgear renewal plans, the risk-tolerant option is negligibly different from Toronto Hydro's proposed balanced option discussed in Section E6.6.5.4 below and outlined in the Expenditure Plan in Section 4. For this reason, only changes to the TS Switchgear segment are discussed.

1. Transformer Stations

Under the risk-tolerant option, Toronto Hydro would replace two TS switchgear units. With this limited investment, in 2024, 38 percent of Toronto Hydro's TS Switchgear will be operating beyond their useful life, an 11 percent increase from the current baseline of 27 percent. Operating a larger number of these critical assets past their useful life places more downtown customers at risk of outages due to asset failure. Furthermore, the risk would continue to grow because of the demographics are such that with this investment strategy, towards the middle of the 2025-2029, nearly half of Toronto Hydro's 51 TS Switchgear assets will be operating beyond their useful life

As a result, in future rate periods, Toronto Hydro would have to invest more than the entire proposed 2020-2024 Stations Renewal spend ($141.5 million) to reduce the number TS switchgears beyond their useful life to 2019 levels of 27 percent.

Furthermore, and highlighted by Toronto Hydro's historical progress in the TS segment, the complexity of TS Switchgear replacement projects limits the number of replacements Toronto Hydro can perform in a given rate period. Therefore, regardless of an increased budget in future rate periods, the utility would struggle to recover from the consequences of deferred investment now as continued investment deferral would further add to the already existing back-log.

E6.6.5.3 Voltage Conversion

This option is only applicable to work affecting MSs (i.e. Municipal Stations, Control and Monitoring, and Battery and Ancillary Systems Segments). Under the voltage conversion option, Toronto Hydro would decommission MSs with end-of-life and obsolete station assets, thereby eliminating the need for replacement.

For the following two reasons, this option is only pursued when the distribution assets outside the station have also reached end-of-life. First, voltage conversion is fundamentally a renewal option for distribution equipment. Second, the cost of voltage conversion is estimated to be 4 to 8 times the cost of replacing all the station assets. Therefore, voltage conversion only makes sense when justified by the need to renew distribution assets. Where this is the case, voltage conversion would be Toronto Hydro's preferred option. For more information regarding voltage conversion, please see the Area Conversions,[30] Overhead System Renewal,[31] and Underground System Renewal programs.[32]

E6.6.5.4 Balanced Asset Renewal (Proposed Option)

Under the proposed balanced asset renewal option, Toronto Hydro will only replace assets identified as presenting the greatest level of risk and only to the extent required to maintain system reliability. Furthermore, with respect to MSs, Toronto Hydro will only replace assets at stations not targeted for voltage conversion, since conversion will result in decommissioning of the station assets. Toronto Hydro's proposed 2020-2024 work plan is based on this balanced approach and is the recommended option.

A significant portion of Toronto Hydro's station assets have been identified to be at end-of-life and suffer from obsolescence issues. By planning asset replacements based on the needs and pacing detailed in Section E6.6.3, Toronto Hydro is able to reduce failure risk while adhering to resource limitations. This provides a positive outcome for customers by maintaining reliability at a reasonable cost. The targeted pacing also helps maintain sustainability in regards to long-term cost and resource requirements by preventing the number of assets past useful life from increasing beyond a manageable replacement rate.

[30] Exhibit 2B, Schedule E6.1
[31] Exhibit 2B, Schedule E6.5
[32] Exhibit 2B, Schedule E6.2 and E6.3

The pace proposed in this option is the ideal rate of replacement for the assets under this Program. It allows Toronto Hydro to address deteriorating and end-of-life equipment initially considered for the 2015-2019 period asset delayed due to external factors and delayed timelines in addition to the newly deteriorated and end-of-life assets. Therefore, to maintain the age profile of the assets to those in 2017, a slower pace should not be considered.

This option presents the best value to customers, and is consistent with the priorities they have identified: maintaining reliability and minimizing costs.

Toronto Hydro's balanced asset renewal plan with respect to each segment has been presented in detail in Section E6.6.3 and Section E6.6.4.

E6.6.5.5 Complete End-of-Life Asset Renewal

A significant portion of Toronto Hydro's station assets are operating beyond useful life, contain obsolescence related deficiencies, or have been assessed to be in poor condition. Under this renewal option, Toronto Hydro would strive to replace all assets that have reached or surpassed their useful life, in addition to all assets which have been identified as at end-of-life due to condition assessments or obsolescence. In doing so, this would allow the utility to offset past execution limitations.

Although ideal for increased reliability and operational effectiveness, this option is not recommended as it conflicts with customer priorities to contain cost and limit rate increases. It also risks investment in assets which are not required in the longer term. In reality, this option is limited by Toronto Hydro's execution capabilities and customers' price sensitivity.

1. Transformer Stations

This TS asset renewal option would include replacement of all assets operating beyond their useful life, all assets containing PCBs (e.g. KSO breakers), and all legacy assets (e.g. brick switchgear structures, air-blast circuit breakers, etc.).

With significant investment, in 2024, a limited amount of Toronto Hydro's TS Switchgear, TS Outdoor Breakers, or TS Outdoor Switches would be operating beyond their useful life. This would be a significant reduction from current baselines of 27 percent, 4 percent, and 31 percent, respectively.

However, Toronto Hydro would be unable to perform the volume of work required due to the pace required to achieve the desired level of reliability. Transformer station renewal work generally has

long lead times, extensive resource requirement, and requires considerable outages. It is likely the volume of work could not be executed so quickly, highlighting the need to keep demographics within comfortable limits.

This option is not recommended for TS Switchgear, TS Outdoor Breakers, or TS Outdoor Switches due to the cost required relative to the expected return in reliability improvement and its conflict with customer priorities.

2. Municipal Stations

Under this option, asset renewal would include replacement of all station assets operating beyond their useful life or assessed to be in poor condition.

With significant investment, none of Toronto Hydro's MS switchgear, power transformers, or MS primary supplies would be operating beyond their useful life. This would be a significant reduction from current baselines of 43 percent, 46 percent, and 77 percent respectively.

However, Toronto Hydro would be unable to perform the volume of work required due to the pace required to achieve the desired level of reliability. Municipal station renewal work has lead times on the order of months to over a year, extensive resource requirement, and requires considerable outages. The volume of work required would be 550 percent, 750 percent, and 750 percent of the volume proposed in the balanced asset renewal option for the MS switchgear, power transformers, and MS primary supply assets respectively. This volume of work could not be executed to achieve the objective of this option, which only highlights the need to keep demographics within reasonable limits.

This option is not recommended for MS switchgear, power transformers, or MS primary supplies due to the prohibitive cost required relative to the expected incremental return in reliability. Such a result would strongly conflict with customer priorities to manage costs.

3. Control and Monitoring

Under this option, asset renewal for Control and Monitoring systems would including replacing all RTUs operating beyond their useful life, replacing all electromechanical pilot-wire relays, and replacing all copper control circuits.

With large investments, none of Toronto Hydro's RTUs would be operating beyond their useful life. This would be a significant reduction from current baseline of 37 percent. Toronto Hydro would convert all electromechanical pilot-wire systems to differential protection systems and align itself with the new industry standard for critical line protection. This would provide its customers who value reliability above all else with the assurance they have the most reliable system that is feasible. Additionally, the utility would replace all copper control circuits with fiber and align itself with the new industry standard for hard-wired communication systems. This would reduce communication channel failure and the remove the risks that arise from it.

This option is not recommended for RTU renewal, pilot-wire renewal, or copper renewal due to the prohibitive cost and labour resources required. Toronto Hydro would be unable to achieve the execution pace required as the volume of work is simply too large. Additionally, the costs of this alternative would be too high thus contradicting customer desire for cost management.

4. Battery and Ancillary Systems

Under this alternative, asset renewal would include replacing all battery and ancillary systems assets operating beyond their useful life, or containing PCBs.

With significant investment, in 2024, Toronto Hydro would have no DC battery and charger systems, station service transformers, or air compressors operating beyond their useful life. This would be a significant reduction from current baselines of 22 percent, 26 percent, and 20 percent, respectively. Additionally, this would eliminate the risk of PCB release into the environment due to this asset class (as 9 percent of these units currently contain PCBs).

Despite smaller lead times relative to other segments, this option would require an asset renewal pace that surpasses Toronto Hydro's execution limitations. In addition, investments in battery and ancillary systems can be most easily mitigated via operational practices (compared to other segments).

This option is not recommended for DC battery and charger systems, station service transformers, or air compressors due to the required investment required relative to the expected incremental return in reliability.

E6.6.6 Execution Risks & Mitigation

Each segment of the Stations Renewal program faces challenges which can delay or prevent planned renewal work from occurring. Many of these challenges overlap across the four segments of this Program. These challenges are summarized in the table below.

Table 53: Execution Risk Applicability by Segment

Segment	Execution Risks						
	Resource Constraints	Planned outages	Asset Failures	Procurement Lead Times	Project Assessment	Distribution Coordination	Other Risks
Transformer Stations	✓	✓	✓	✓	✓	✓	✓
Municipal Stations	✓	✓	✓	✓	✓	✓	✗
Control and Monitoring	✓	✓	✗	✗	✓	✗	✓
Battery and Ancillary Systems	✓	✓	✓	✗	✓	✗	✗

E6.6.6.1 Resource Constraints

All four segments of the Stations Renewal program use the same pool of stations design and construction resources. Therefore, if there are insufficient resources to complete all the projects planned in the Program, then certain projects will need to be deferred to ensure highest priority projects are completed. Prioritization of projects within this Program is discussed in Section E6.6.4. Toronto Hydro is mitigating this risk with the help of third party providers to complete any projects in excess of Toronto Hydro's resource capacity.

E6.6.6.2 Planned Outages

Most of the renewal work cannot be completed unless a planned outage is arranged. Planned outages are needed to de-energize feeders, power transformers, switchgear, or entire stations without causing power outages to customers, so that Toronto Hydro's crews can safely complete replacement or maintenance work. For Toronto Hydro to de-energize station assets without introducing any undue risk of power outages, Toronto Hydro cannot execute multiple planned outages within the same TS or at two neighbouring MSs. Additionally, projects occurring at

neighbouring MSs are planned to take place in different years, and if possible, at least two years apart.

E6.6.6.3 Asset Failures

Failure of station assets are a source of unplanned station outages which can prevent replacement projects from proceeding due to lack of redundancy. This risk can be mitigated by proactively replacing end-of-life station assets in a timely manner as proposed in this Program.

E6.6.6.4 Procurement Lead Times

Procurement lead times for power transformers, MS switchgear, and TS switchgear range from 6 to 18 months. For this reason, it is difficult and sometimes infeasible to advance or expedite the replacement of a station asset, even if such a change in schedule would result in a more effective execution of the Program. To help mitigate this risk, Toronto Hydro orders this equipment 6-18 months or earlier in advance of expected in-service dates.

E6.6.6.5 Distribution Coordination

Distribution coordination is a challenge commonly affecting the TS and MS segments. All TS switchgear replacement projects and all projects under the MS segment require a distribution project to support the replacement of station assets. A switchgear replacement requires distribution feeders to be removed from the old switchgear and connected to the new switchgear, and replacement of the primary cable within a MS is completed through a distribution project. As a result, if there are delays or resource constraints in the distribution projects, then dependent station projects may also be delayed. Similarly, distribution projects also require planned outages as discussed earlier.

To mitigate the risk relating to distribution coordination, Toronto Hydro engineers strive to clearly define the need for coordination between station and distribution projects at the inception of such projects. On this basis, project managers plan interdependent projects as a single entity so that adequate resources can be allocated and adequate outage planning can be initiated.

E6.6.6.6 Project Assessment

All planned work undergoes a risk assessment by Toronto Hydro's control centre prior to execution. This timeframe is accounted for in the pacing outlined in section E6.6.4.

E6.6.6.7 Other Risks

The risks identified below apply only to their specific segments.

1. Hydro One Coordination (TSs)

One of the most significant risks for the successful completion of projects under the TS segment will be Toronto Hydro's ability to effectively coordinate with Hydro One. For example, when replacing a TS switchgear, close coordination is required to transfer Hydro One's supplying transformers from the existing switchgear to the new switchgear. For TS outdoor breaker replacements, all protection and control wiring needs to be verified by Hydro One prior to the breakers being placed back in-service.

With this need for coordination, there is always a risk Hydro One might not be able to secure resources to align with Toronto Hydro's work plan. Additionally, similar to the discussion in Section E6.6.6.2, Hydro One also requires that its own equipment undergo planned outages. Given the need for such planned outages, there is a risk that Toronto Hydro's replacement work will be prevented from proceeding due to a lack of redundancy.

Toronto Hydro mitigates this risk by sharing its high-level replacement plans with Hydro One years in advance of planned project start date. As project execution draws closer, Toronto Hydro and Hydro One exchange detailed information and communicate more frequently to ensure that work plans and resourcing aligns for both companies. For more information, see Exhibit 2B, Section B.

2. Physical Constraints (TSs)

Space limitations pose a significant risk to the timely completion of TS switchgear renewal projects under the TS segment. In many cases, Toronto Hydro stations do not have space available to install new switchgear. This is a problem because it is usually necessary to install a new switchgear before decommissioning the existing unit, so as to maintain continuous power supply to customers.

The alternative to this approach is to transfer all customers from the existing switchgear to an adjacent switchgear, decommission the existing switchgear, and then install the replacement in the same space. This can only be done if the adjacent switchgear has enough spare capacity to supply these additional customers. Spare capacity on this order is seldom available.

Toronto Hydro mitigates this risk through use of its Station Expansion program,[33] which is intended to ensure capacity requirements are met on the distribution system. Notably, the construction of Copeland TS Phase 1 and Phase 2 will facilitate the replacement of switchgear units at Windsor TS (and other downtown stations in the future). For example, replacement of the Windsor TS A5-6WR switchgear unit will be possible once Copeland TS – Phase 1 has been energized, following which the electrical load on the Windsor TS A5-6WR switchgear will be transferred to the Copeland TS A1-2CX switchgear. Thereafter, A5-6WR can be decommissioned and its space used to install a new switchgear. This in turn will allow capacity for the next Windsor TS switchgear unit to be replaced.

By ensuring a reasonable level of spare capacity at or adjacent to heavily loaded stations, Toronto Hydro will be able to effectively plan and execute switchgear replacement while accommodating new customer connections.

3. Customer Coordination (Control and Monitoring)

For pilot-wire system replacements under the Control and Monitoring segment, a challenge to successful execution is customer coordination. Such replacements require customer relays and associated equipment to be replaced in parallel with Toronto Hydro's equipment. This introduces a risk since projects cannot be scheduled until a time is found which satisfies both the customer's and Toronto Hydro's needs. Toronto Hydro minimizes this risk by informing customers several months ahead of planned work, allowing sufficient time for customers to respond and schedule a time that is feasible.

[33] Exhibit 2B, Schedule E7.4

E6.7 Reactive and Corrective Capital

E6.7.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 267.3	**2020-2024 Cost ($M):** 317.2[1]
Segments: Reactive Capital; Worst Performing Feeders	
Trigger Driver: Failure	
Outcomes: Reliability, Safety, Environment and Customer Service	

The Reactive and Corrective Capital program (the "Program) addresses the replacement of failed and defective assets, and provides for near-term corrective actions on Toronto Hydro's least reliable feeders. The work required under this Program is urgent and non-discretionary. Toronto Hydro carries out the projects and activities in this Program in response to: (1) asset failures, (2) high risk asset deficiencies discovered through planned inspection or in the course of day-to-day work, and (3) feeders exhibiting especially poor reliability.

The Program is grouped into two segments summarized below, and is a continuation the reactive and corrective activities described in Toronto Hydro's 2015-2019 Distribution System Plan.[2]

- **Reactive Capital:** this segment covers the non-discretionary replacement of failed or failing assets across the entire system. Although Toronto Hydro's distribution system has experienced improved reliability overall, there is a significant number of asset failures each year. Between 2013 and 2017, there were approximately 3000 Customer Interruptions ("CI") and 2,300 Customer Hours Interrupted ("CHI") associated with major asset failure across the network. Catastrophic failures of assets can require very large investments by Toronto Hydro – investments that, in the absence of a dedicated reactive capital budget, would deprive other capital and operational programs of resources necessary to maintain the grid. The objective of this segment is to manage unavoidable asset failures and address high-risk deficiencies (or assets approaching imminent failure) in a timely and cost- effective manner to mitigate the impact of failures on customer outcomes such as reliability, safety and the environment for 2020 to 2024 and beyond.

[1] Consistent with the 2015-2019 program, the 2020-2024 program forecast includes allowances for streetlight reactive pole replacement, reactive streetlight replacement and streetlight spot improvement
[2] EB-2014-0116, Exhibit 2B, Section E6.20

- **Worst Performing Feeders:** this segment focuses on improving overall service reliability for customers supplied from poorly performing feeders. The objective of this segment is to identify feeders at risk of experiencing seven or more sustained interruptions (referred to as Feeders Experiencing Sustained Interruptions of 7 of more, or "FESI-7") over a 12-month rolling period and perform mitigation work on deficient assets that could lead to additional interruptions. Although relatively few in number when compared to non-FESI feeders, FESI feeders have a disproportionately negative impact on the system's overall reliability performance. FESI-7 feeders have contributed, on average, to 25 percent of the annual customer interruptions ("CI") and 23 percent of customer hours interrupted ("CHI") since 2013. In response to the reliability and resiliency needs of Toronto Hydro's large customers, and in addition to the FESI-7 metric, the utility has introduced a similar FESI-6 metric specifically for feeders that serve Large Commercial & Industrial class customers across the system.

As the nature of work in this Program is largely unplanned, unpredictable, and can vary significantly from year to year, Toronto Hydro has based its 2020-2024 forecast costs and projected reactive work volumes for this Program on historical trends. The utility forecasts $317 million for the Program during the 2020-2024 period, which is approximately 18 percent increase over projected 2015-2019 spending (including forecasted inflation). Timely reactive work improves safety, avoids depriving other capital programs of planned resources, mitigates environmental impacts, and reduces strain on the distribution system.

E6.7.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Service	• Contributes to Toronto Hydro's customer service obligations and objectives, including the accurate billing of all smart metered customers based on actual usage (also supports compliance with the *Electricity and Gas Inspection Act* and the *Weights and Measures Act*) by restoring metering service as soon as possible.

Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7, System Health (poles)) by: ○ Promptly replacing assets that have failed or are at a very high risk of near – term failure; and ○ Monitoring feeders that are at a high risk of becoming FESI-7 or, for Large Customers, FESI-6, and taking near-term mitigating actions where feasible.
Safety	• Contributes to maintain Toronto Hydro's Total Recorded Injury Frequency measure and safety objectives including TRIF (including compliance with Ontario Regulation 22/4) by replacing failed assets (or high-risk assets approaching imminent failure) to mitigate the risk of catastrophic asset failure events causing injuries to utility employees or members of the public.
Environment	• Contributes to environmental impact reduction of Toronto Hydro's distribution system by avoiding the potential release of harmful chemicals, smoke, or waste (e.g. oil leaks) into the environment through timely replacement of failing or failed assets. • Contributes to improving the Spills of Oil Containing PCBs measure through continuously reducing PCB-contaminated oil leaks by eliminating assets at risk of containing PCBs.[3]

E6.7.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Failure
Secondary Driver(s)	Reliability , Safety, and Environmental Risk

The Reactive and Corrective Capital program is largely driven by the need to address equipment failure. The Program is focused on ensuring assets and system perform at an acceptable standard by: (i) addressing asset deficiencies and failures through like for like replacements; and (ii) executing short term, targeted and small scale mitigation measures to reduce the risk of additional outages on feeders exhibiting poor reliability outcomes. The need for the Reactive Capital segment must be addressed in short order mainly due to asset failure risk, and the Worst Performing Feeders segment

[3] In recent years (2015-2017), the program has replaced an average of 120 transformers per year that contained or were at risk of containing PCBs.

aims largely to improve overall service reliability for customers supplied from poorly performing feeders.

Through the proposed Program, Toronto Hydro would be better able to maintain system performance and reliability, customer satisfaction, and manage or eliminate safety risks to the public and Toronto Hydro employees. The trigger and secondary drivers for this Program are discussed below.

E6.7.3.1 Failure Risk

As the trigger driver of the Reactive and Corrective Capital program, asset failure on Toronto Hydro's distribution system presents reliability risks (which can lead to outages and directly impact customers), environmental risks (e.g. oil spills into the environment), and safety risks (e.g. stemming from electrical contacts, arc flashes, and potentially catastrophic fires). Timely replacements are required to avoid the distribution system being operated under contingency conditions (i.e. with a lack of feeders or assets that can provide backup supply in the event of a subsequent outage).

Table 4 shows the customer reliability impacts of major asset failures between 2013 and 2017. Each failure of overhead switches for example, caused 805 customer interruptions and 359 customer hours of interruption on average between 2013 and 2017.

Table 4: Average CI and CHI Associated with Failures of Major Assets from 2013 - 2017

Asset	Customer Interruptions (CI)	Customer Hours Interrupted (CHI)
Overhead Switches	805	359
Overhead Transformers	190	112
Poles	770	739
Underground Cables	766	729
Underground Transformers	302	292

Timely replacement of failing equipment before an imminent failure can mitigate the frequency and duration of interruptions experienced by the customer. Although Toronto Hydro's distribution system has experienced improved reliability overall, there is a significant number of asset failures each year. Various factors can cause failure including degradation of an asset's condition, foreign interference, and weather. As examples,

Figure 1 shows: (i) a fractured pole caused by a vehicle accident (i.e. foreign interference); and (ii) structural deficiencies of an underground vault as a result of gradual degradation.



Figure 1: Motor vehicle accident on distribution pole (left), underground vault structural deficiencies (right)

Age and condition can also affect the health of an asset, and contribute to asset failure. As an example, Table 5 summarizes Toronto Hydro's Asset Condition Assessment ("ACA") results for underground submersible transformers, which indicate: (i) 227 submersible transformers exhibit material deterioration (HI4 & HI5) and should be considered for replacement as of the end of 2017; and (ii) without any intervention, the number of transformers exhibiting material deterioration is forecasted to more than double by 2024 (554 major assets).

Table 5: Asset Condition for Submersible Transformers[4]

Condition	Submersible Transformers	
	2017	**2024**
HI1 - New or Good Condition	7,816	7,447
HI2 – Minor Deterioration	588	364
HI3 – Moderate Deterioration	271	537
HI4 – Material Deterioration	172	143
HI5 – End of Serviceable Life	55	411
Total	**8,902**	**8,902**

[4] For more details on Asset Condition Assessment see Exhibit 2B, Section D, Appendix A.

Furthermore, as of 2017, 14 percent of Toronto Hydro's overhead transformers have surpassed their useful life and, without any replacement, this is expected to more than double by 2024. With this higher number of end-of-life assets in the system there is a greater likelihood of failure and need for reactive replacement.

Detailed discussions of the condition and age demographics of various asset classes are provided under Toronto Hydro's System Renewal programs.[5]

1. Safety

Another important driver of the Program is the safety and health of both the public and Toronto Hydro employees. Failure modes of equipment, depending on their nature, can have immediate and serious safety and health consequences. For example, transformers in deteriorated condition may experience transformer fires. Overhead lines with cracked or damaged insulators may lead to pole fires. Such fires pose serious risk to workers and the public. Similarly, civil failures and the collapse of structures (such as poles and vaults) can jeopardize the public and Toronto Hydro employees. The Reactive Capital segment can mitigate safety and health risks by replacing assets that have failed or are approaching imminent failure. As examples, Figure 2 below illustrates a pole fire and hazardous conditions found in a network vault.



Figure 2: Pole fire caused by Tracking (left), exposed and rusted rebar in Network Vault (right)

[5] Exhibit 2B, Section E6

2. Environment

Asset failures can also be harmful to the environment. Leaking transformers or cables in underground structures pose a serious environmental risk. Asset failures can also result in the release of harmful contaminants and greenhouse gases into the environment. Timely capital replacements help mitigate such environmental risks. The Reactive Capital segment addresses oil deficiencies by replacing leaking transformers. As an added benefit, during transformer replacement, assets that are at risk of containing PCB are also replaced, thereby reducing the possibility of oil spill containing PCBs.

3. Reliability

Finally, reliability is an important driver of the Program. Depending on the asset and its location within the distribution system, system reliability will be negatively impacted by an asset failure. Asset failures affect the supply of power to Toronto Hydro's customers and strain the system. Historical system reliability impacts are discussed in detail for each segment below.

E6.7.3.2 Reactive Capital

The Reactive Capital segment is comprised of work relating to overhead, underground, secondary network, stations and metering assets. The purpose of this reactive work is to restore service to customers and maintain system reliability by addressing severe asset deficiencies and failures. Reactive work occurs on an unplanned basis in response to an asset failure or the detection of a high risk asset deficiency (e.g. a severely cracked pole). Such issues cannot be addressed by planned capital renewal procedures and timelines, and therefore, must be reactively replaced to maintain the safety and reliability of the distribution system. Reactive work is executed within a short timeframe (e.g. one day to six months) following the detection of an asset requiring replacement. Reactive work covers Toronto Hydro's entire distribution system and affects all asset classes.

Asset deficiencies or substandard conditions across Toronto Hydro's distribution system are identified mainly through the Preventative and Predictive Maintenance programs, but can also be identified either during the normal course of operations or through the Emergency Response program, as shown in Figure 3 and explained in more detail below. Identified deficiencies or

substandard conditions are subsequently addressed through a variety of programs: Preventative and Predictive Maintenance, Corrective Maintenance and the Reactive and Corrective Capital programs.[6]

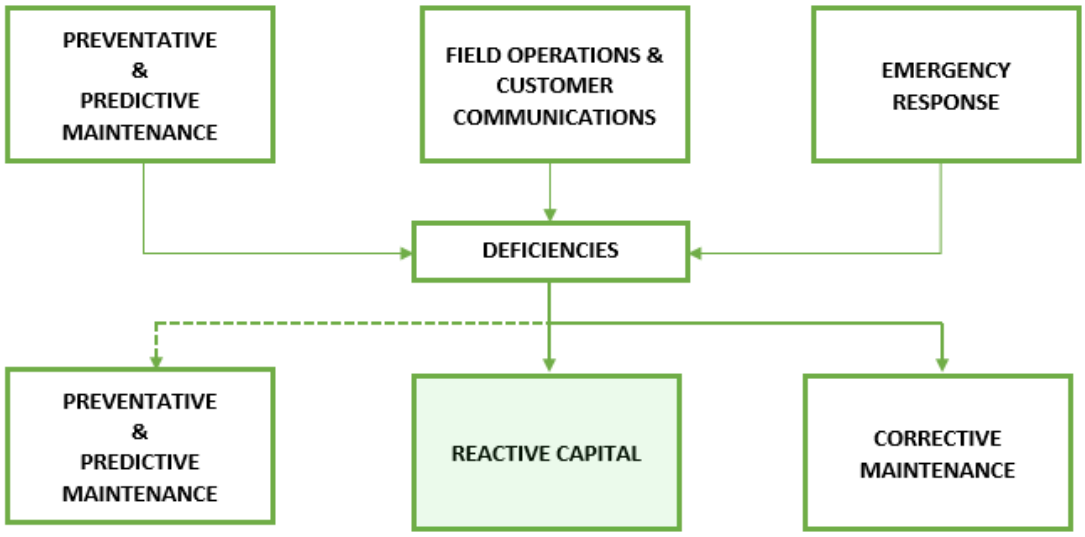


Figure 3: Deficiency Capturing Process[7]

- **Preventative & Predictive Maintenance Activities**: Toronto Hydro's field crews identify asset failures and deficiencies as part of scheduled maintenance and inspection activities.
- **Field Operations & Customer Communications**: issues or actions identified under this category include meter errors collected through Internal Data Collection Systems, phone calls from the customer service team, external emails, and observations by the field crew during the normal course of operations, and customer enquiries requiring field assessment and follow up.
- **Emergency Response:** reactive capital work can also be required as a result of emergencies or unplanned system events. These include asset failures and deficiencies identified outside of Toronto Hydro's daily (planned) operations but requiring immediate remediation and reactive replacements in order to restore power or eliminate safety or environmental risks.

Deficiencies from the above sources are: (i) reviewed to validate the need for reactive intervention; (ii) assessed to determine the nature of reactive intervention required (capital versus maintenance);

[6] Exhibit 4A, Tab 2, Schedules 1-4 for maintenance programs
[7] The deficiency capturing process is described in detail in Exhibit 2B Section D3.

and (iii) the level of urgency/priority to be assigned to each asset deficiency. Toronto Hydro addresses the deficiencies by issuing work requests.[8]

Due to the unpredictable nature of asset failures, the number of corrective work requests from year to year may vary. Catastrophic failures of assets can require very large investments by Toronto Hydro – investments that, in the absence of a dedicated reactive capital budget, would deprive other capital and operational programs of resources necessary to maintain the grid. As such, Toronto Hydro requires the Reactive Capital segment to manage unavoidable asset failures and address high-risk assets approaching imminent failure, in order to continue to provide reliable, safe, and environmentally responsible service to customers from 2020 to 2024 and beyond.

Figure 4 below shows the volume of reactive capital work requests issued between 2013 and 2017.

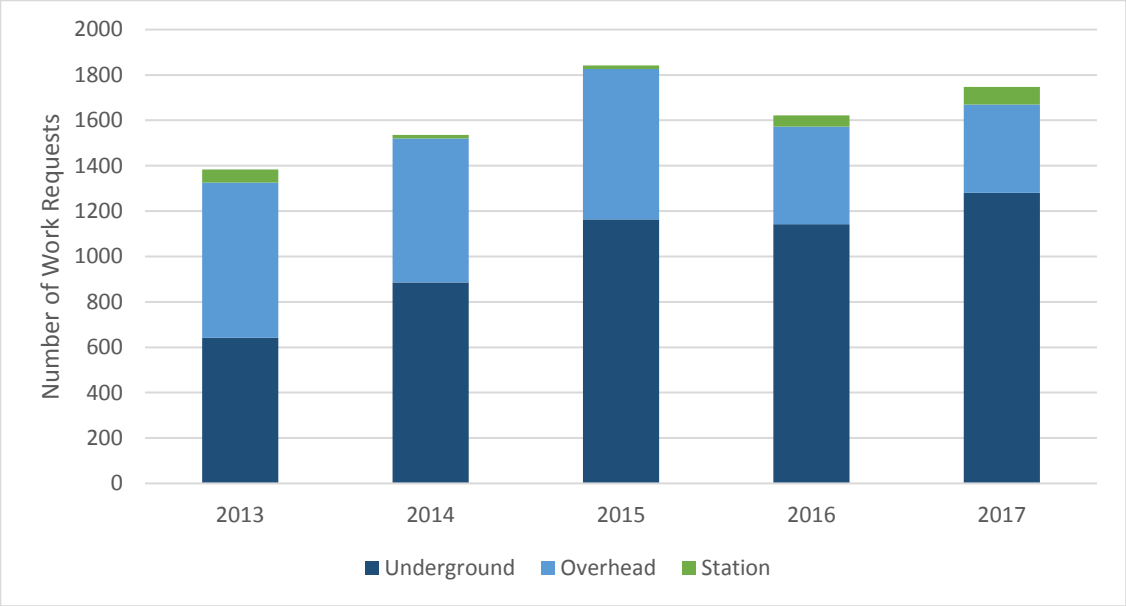


Figure 4: 2013 - 2017 Total Number of Reactive Capital Work Requests by System Type

As shown in Figure 4 above, Toronto Hydro has seen an overall rise in the number of work requests issued to address reactive capital work, primarily due to underground assets with deteriorating age and condition as discussed in the Underground System Renewal programs. Within the stations environment, the volume of requests has varied, but due to the size, operational complexity, and

[8] Work request are forms issued to assign / schedule corrective work addressed by Toronto Hydro crew. Deficiencies identified and work requests raised may have a one to one or many to one relationship (i.e. a single work request may contain more than one deficiency)

criticality of stations assets, station work can contribute significantly to the overall cost of the Reactive Capital segment, despite the relatively low volume of requests.

1. Metering Assets

The Reactive Capital segment also funds reactive meter replacement. Reactive meter replacement capital work consists of the replacement of defective metering equipment in the field including: smart meters, suite meters, interval meters, and primary meters (Including instrument transformers). The loss of communication with a meter is the primary cause of meter replacements. Primary metering units can also fail due to blown instrument transformer fuses which causes customer consumption to be incorrectly read, resulting in incorrect billing. Failed metering equipment not replaced in a timely manner can result in delayed billing and the need to estimate customer consumption.

Table 5 summarizes the estimated number of reactive meter replacements and their estimated costs for the 2020-2024 filing period. The estimated volumes were derived using historical meter failure rates. The year over year increases are due to projected increases in Quadlogic meter failures as the Quadlogic meter population in Toronto Hydro's service area grows. The average percentage of meters failing remains the same but the population is increasing yearly. The meter replacement costs are embedded into the Reactive Capital segment 2020-2024 forecasts in the Expenditure Plan section.

Table 5: Reactive Meter Replacements and Costs (2020 - 2024)

	Projected					
	2020	**2021**	**2022**	**2023**	**2024**	**Total**
Meter Replacements (Units)	5585	5685	5785	5885	5985	28925
Meter Replacement Costs ($ Millions)	2.28	2.30	2.33	2.35	2.38	11.64

E6.7.3.3 Worst Performing Feeders

Toronto Hydro's distribution system contains more than 1,500 feeders that supply power to over 700,000 customers in the City of Toronto. While any one of these feeders is subject to random equipment break-down, foreign interference and environmental effects that can cause unplanned outages, specific feeders experience a disproportionate number of problems and cause an unacceptably high number of sustained interruptions to the residential and commercial customers connected to them. The Worst Performing Feeder ("WPF") segment employs a feeder level analytical

approach that selects feeders experiencing a high number of outages or trending towards increased outages for analysis to determine the cause of outages.

The main objective of Toronto Hydro's WPF segment is to improve overall service reliability for customers supplied from poorly performing feeders. Through this segment, Toronto Hydro identifies feeders which are at risk of experiencing seven or more sustained interruptions over a 12-month rolling period (i.e. FESI-7), excluding planned outages, major event days, outages caused by loss of supply, and interruptions on the secondary side of the distribution transformer. Also, in response to reliability and resiliency needs, the number of sustained interruptions on feeders supplying Toronto Hydro's large customers that are more sensitive to outages (i.e. Commercial and Industrial customers) is reduced to six (i.e. FESI-6). This allows Toronto Hydro to closely monitor these large load feeders and intervene when required, and overall manage the disproportionately negative impact FESI-6 and FESI-7 feeders have on overall system reliability. Despite being relatively few in number compared to the non-FESI feeders, FESI feeders have contributed on average since 2013, about 25 percent of the annual system customer interruptions ("CI") and 23 percent of customer hours interrupted ("CHI").

About 49 percent of outages reviewed during a WPF reliability analysis were caused by defective equipment, and 28 percent by sources outside of Toronto Hydro's control (e.g. animal contacts, severe weather) as shown in Figure 5 below.

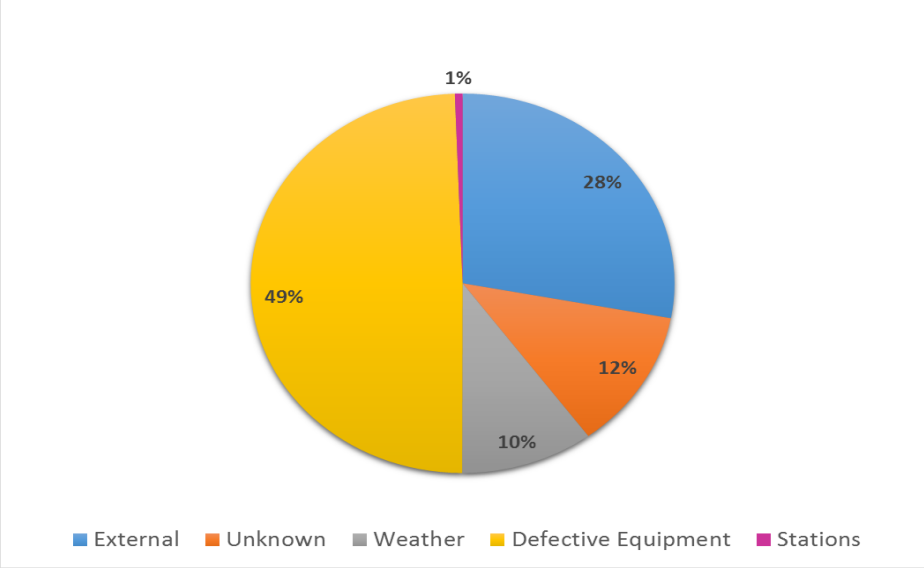


Figure 5: Causes of Sustained Feeder Outages

Following a feeder reliability analysis, field crews patrol and inspect these feeders to assess the condition of equipment and identify quick targeted actions that yield immediate reliability improvements. Some of the deficiencies discovered during these feeder patrols are shown in Figure 6 below.



Figure 6: Rusted Overhead Transformers at Risk of Leaking Oil (Left)/Animal Contact on Metal Switch Bracket (Right)

Figure 7 below shows the historical count of FESI-7 and large load FESI-6 feeders per year. As shown, the annual number of FESI-6 and FESI-7 feeders is small (less than 60) relative to the over 1,500 feeders that make-up Toronto Hydro's distribution system.

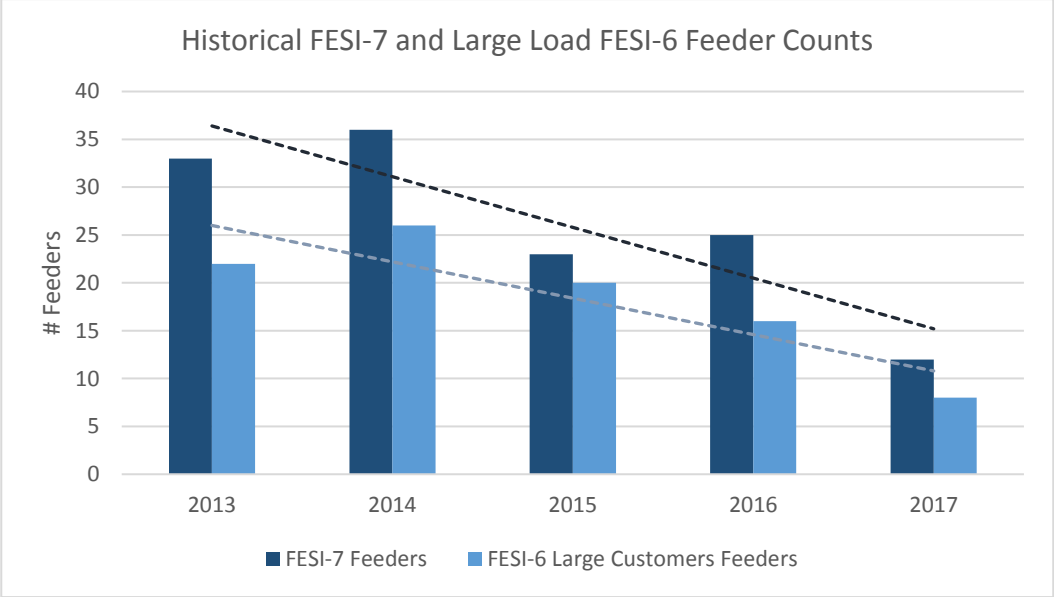


Figure 7: Historical Worst Performing Feeders

As noted above, these feeders have a disproportionately negative impact on the system's overall reliability performance. FESI-7 feeders have contributed, on average, to 25 percent of the annual CI and 23 percent of customer hours interrupted CHI since 2013. Figure 8 shows a comparison of CI and CHI on FESI-7 feeders to non-FESI feeders.

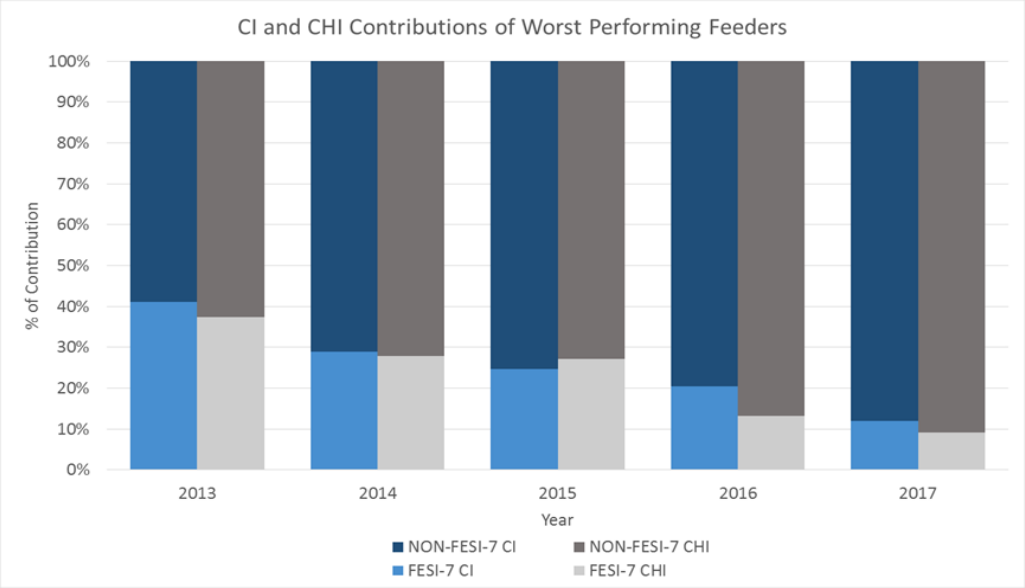


Figure 8: WPF – CI and CHI Contribution

Toronto Hydro has observed improvements to system reliability following the commencement of the WPF segment. As shown in Figure 8, the number of FESI-7 feeders has been trending down since 2013 and there has been a corresponding reduction of approximately 45 percent overall in the cumulative outages on FESI-7 feeders between 2015 and 2017.

The maps that follow compare the locations of large load FESI-6 feeders in 2015 and 2017. WPF mitigation work has led to noticeable improvement in the number of outages that this group of feeders experience in a given year.

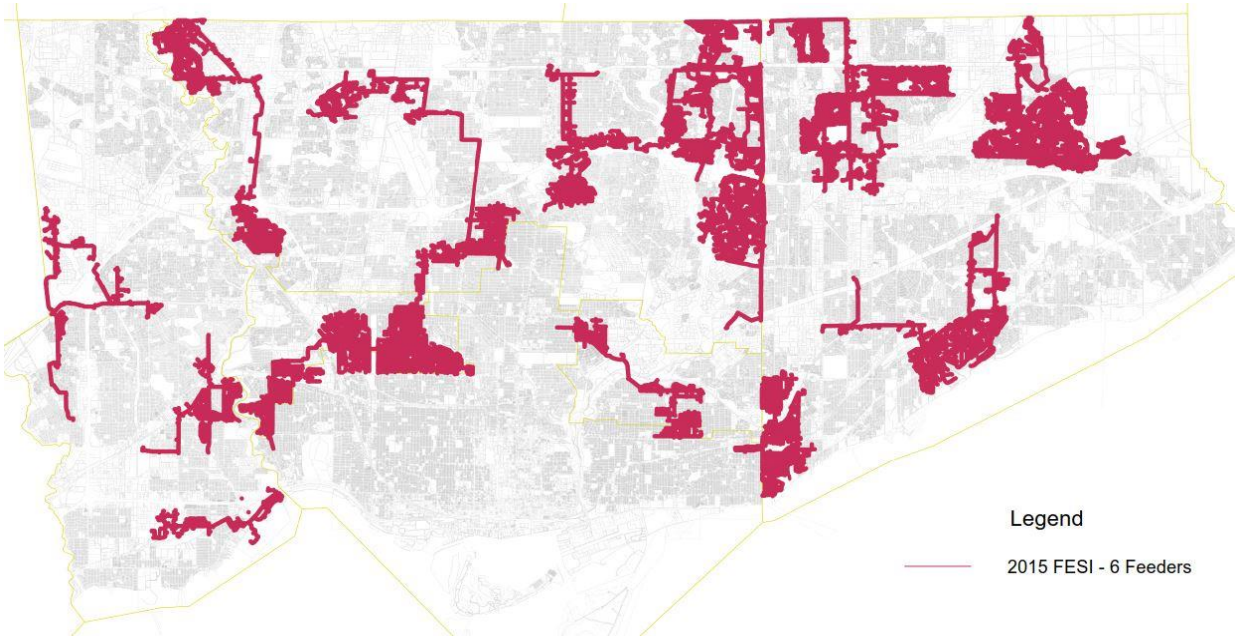


Figure 9: Locations of 2015 FESI-6 Feeders

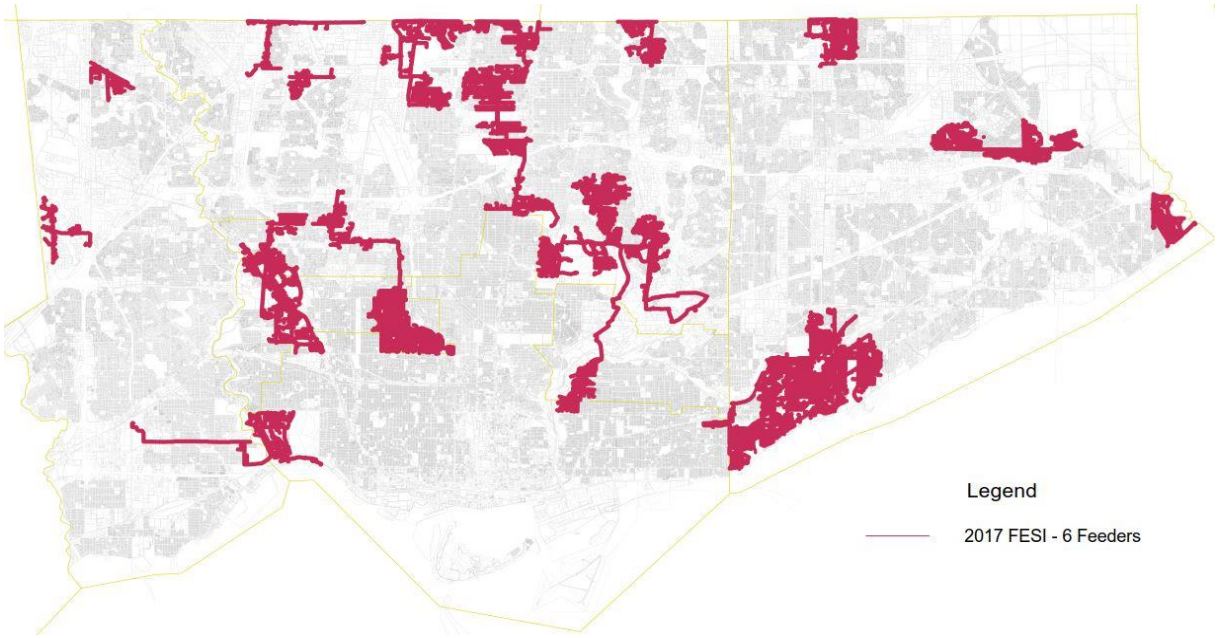


Figure 10: Locations of 2017 FESI-6 Feeders

The WPF segment is designed to be a short term mitigation measure and a complement to the planned renewal capital work. Feeders addressed by the WPF segment still experience unpredictable

failure and power outages, albeit at a lesser frequency until permanent, long-term solutions are implemented. Overall, the WPF segment has been successful in reducing the frequency of power interruptions for customers on feeders that are experiencing especially poor reliability performance.

E6.7.4 Expenditure Plan

Table 6 provides the Historical (2015-2017), Bridge (2018-2019) and Forecast (2020-2024) expenditures for the Reactive and Corrective Capital program.

Table 6: Historical and Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Reactive Capital	39.0	50.2	52.5	54.4	52.6	56.4	57.5	58.5	59.4	60.7
Worst Performing Feeder	3.0	4.1	3.0	4.0	4.5	4.8	4.9	5.0	5.0	5.2
Total	**42.0**	**54.3**	**55.5**	**58.4**	**57.1**	**61.2**	**62.4**	**63.5**	**64.4**	**65.8**

E6.7.4.1 Reactive Capital Segment

Toronto Hydro invested $141.7 million in reactive capital work between 2015 and 2017, and projects to invest $248.7 million by the end of 2019 (approximately $83 million more than the 2015 -2019 forecast of $165.5 million).

The expenditures for Reactive Capital are forecasted based on historic trends in work requests volume and types, equipment failures and reliability. Given the nature of the Reactive Capital segment, actual work volumes and costs vary from year to year. The forecasts for 2015-2019 were developed in early 2014 and represented Toronto Hydro's forecast based on best available information at the time.

The predominant driver for the variance for the 2015-2019 period is that the actual volume and type of assets requiring non-discretionary replacement differed from forecast. This was unavoidable given the unpredictable nature of asset failures and volatile swings in the type and number of equipment failures from year to year. More specifically:

- The increase in reactive capital spending from 2015 to 2016 was driven by a higher number of replacements of underground transformers due to deficiencies such as oil leaks and corrosion. In 2016, Toronto Hydro replaced 601 underground transformers compared with

356 in 2015. A significant portion of the reactive capital spend between 2015 and 2017 was on the replacement of underground transformers, representing approximately half of the reactive capital underground work requests over the same period. This increase has been sustained in 2017 and is expected to be maintained.

- Reactive metering spending increased in 2017 due to a larger quantity of smart meters and suite meters failing, which can be attributed to a larger portion of the metering population being on time-of-use metering and the overall meter population getting older.
- The projected 2018 capital budget is driven by the expected reactive replacement of 353 distribution poles that were condemned based on preventative and predictive maintenance inspections. Historically, Toronto Hydro reactively replaces approximately 200 condemned poles per year.

Toronto Hydro's 2020-2024 forecast for expenditures and work volume under the Reactive Capital segment was based on historical trends, with a total of $292.4 million expenditure forecast over the period and an average annual reactive capital work request volume of 1,700, as shown in Figure 11.

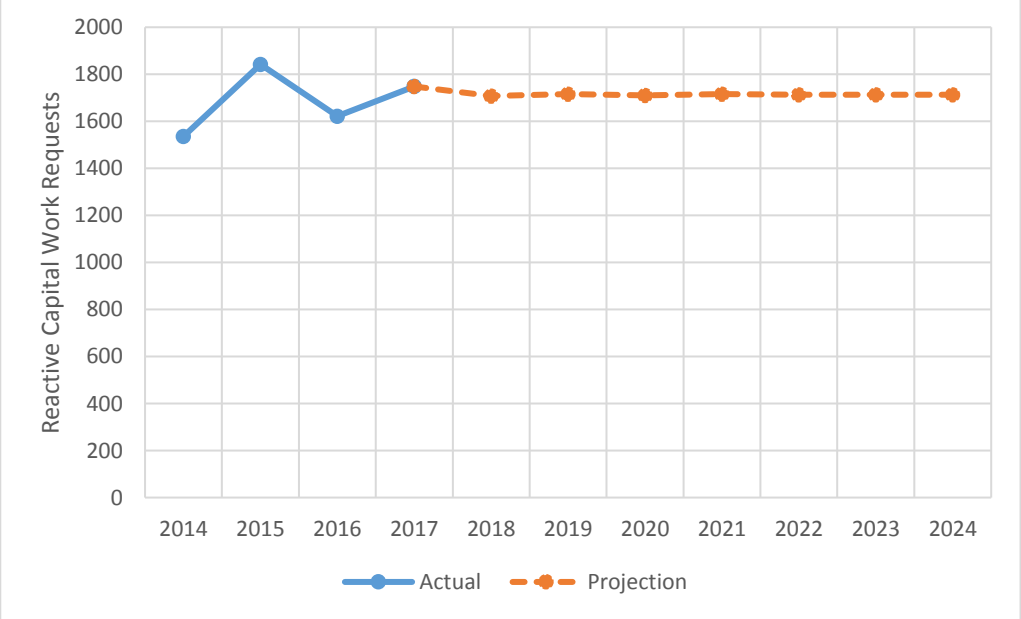


Figure 11: 2018-2024 Reactive Capital Work Request Forecast

As noted in Section 1, the nature of work in this segment is unplanned, unpredictable, non-discretionary, and can vary significantly from year to year. As a result, Toronto Hydro has based the forecast costs and projected work request volumes on historical expenditures and volume of work

requests, using a moving average forecasting methodology. The 2020 to 2024 forecast (cost and volume) is relatively stable and consistent with historical spend.

For the Reactive Capital segment, Toronto Hydro uses a prioritization framework that classifies asset deficiencies into four categories: (i) P1 requires resolution within 15 days; (ii) P2 requires resolution within 60 days; (iii) P3 requires resolutions within 180 days; and (iv) P4 which indicates that conditions are to be monitored and work to be considered at a later date. When an asset exhibiting severe deficiencies is found through maintenance inspections, reported by operations teams or customers, or caused by emergency events, the utility immediately assigns personnel to triage and resolve the issue. Based on the expertise and experience of Toronto Hydro engineers and operation teams, deficiencies are evaluated and prioritized for resolution. Crews are then dispatched to address those assets with the highest safety and environmental risks first, followed by assets with the greatest impact on system reliability.

Contracts with service providers have been negotiated to include rates for both planned and reactive work. When project scheduling allows, P3 reactive work is "bundled" for efficiency purposes and issued as lower-cost planned work (which have lower unit prices). By doing this Toronto Hydro can avoid premium rates attached to reactive work.

Since 2015 Toronto Hydro has also undertaken efforts to maximize the productivity, safety, reliability, and environmental benefits of reduced switching work on the downtown "grid" system. Where possible for P1 and P2 work types, planned maintenance, customer or capital work can be bundled together to align with feeders that are taken out of service to create a safe work zone for repairs or equipment replacement and reduce the required switching costs. Due to lower urgency and more flexible turnaround times, P3 work can be aligned with upcoming maintenance, capital, or customer work.

E6.7.4.2 Worst Performing Feeder Segment

During the 2015-2017 period, Toronto Hydro invested $10.1 million in the WPF Segment, and projects to invest $18.6 million by the end of 2019, which would be $9.6 million above the 2015 - 2019 forecast of $9.0 million.

The overspend over 2015-2019 forecast is largely driven by the unpredictable nature of feeder outages, and the increase in the number of assets requiring intervention to meet the revised

objectives of the segment in response to reliability and resiliency needs of Toronto Hydro's large customers, as explained below.

In 2015, the utility introduced FESI-6 metric specifically for feeders that serve large Commercial & Industrial class customers across the system. This improvement aligns with customer priorities – i.e. larger customers consider system reliability as a top priority. The work completed under the WPF segment from 2015 to 2017 included the replacement of deteriorated or damaged underground cable segments, poles in poor condition, cracked or chipped insulators, flashed over transformers, switches and metal brackets, lighting arrestors, etc. The contribution of the WPF segment to the reliability of the distribution system is evident based on the reduction in the number of FESIs and in their customer impact measured by CI and CHI, as previously shown in Figure 8.

The total number of customers interrupted due to FESI-7 feeders decreased from over 300,000 in 2013 to less than 150,000 in 2017, as shown in Figure 12.

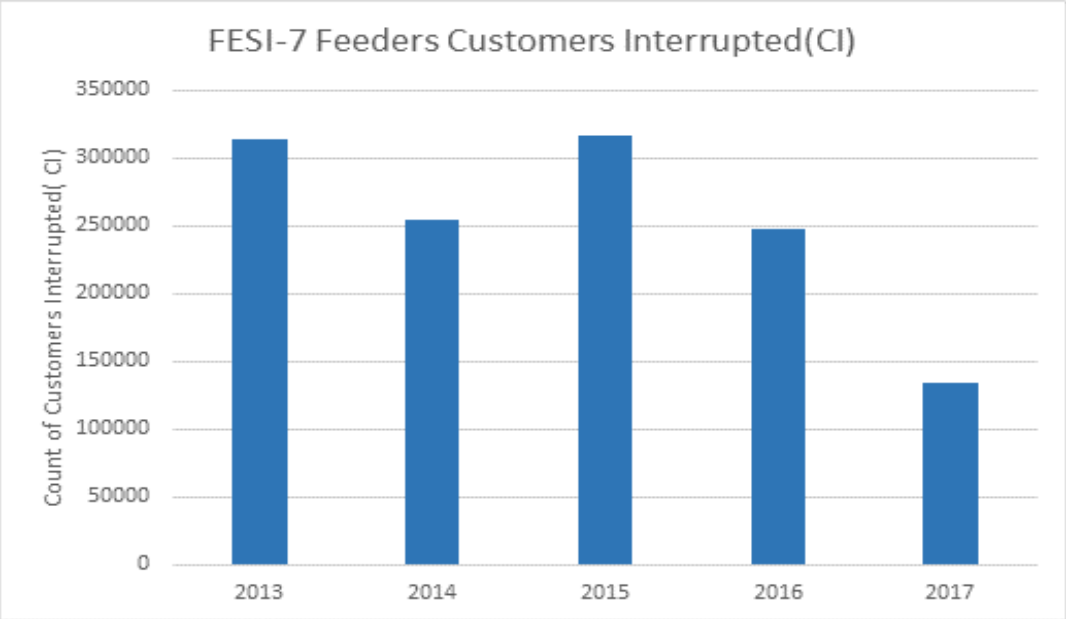


Figure 12: Total Customers Interrupted From FESI-7 Feeders

Toronto Hydro plans to maintain the current levels of performance, and has based its 2020-2024 forecast expenditure and volume for the WPF segment largely on historical trends. This forecast however also accounts for the Program moving into more challenging and expensive underground work which involves civil construction or other asset replacement. In the past, the majority of the

work in the segment was focussed on replacing overhead assets such as pole-top transformers, insulators, and switches. The yearly forecasted expenditure is maintained at an average of $5.0 million for a total spend of $24.9 million over this plan period.

WPF scopes are prioritized based on the reliability performance of each feeder and field patrol findings. The intent of the short term capital work is to mitigate immediate risk to reliability by replacing or upgrading assets that are at high risk of failure that will result in power outages. Most of this work is targeted for completion within a 12 month period so the outcome of reliability improvement is realized immediately thereafter.

E6.7.5 Options Analysis

E6.7.5.1 Reactive Capital Segment

Toronto Hydro considered two alternatives for addressing failed or failing assets:

1) Performing reduced reactive capital work, or
2) Performing the Reactive capital as proposed in this Program.

1. Option 1: Reduced Reactive Capital Work

This option entails a reduction in budget to address reactive capital work during the 2020-2024 CIR period. Implementing this option would result in inadequate funding to meet the demands of required reactive capital work as forecasted based on historical trends. A backlog of work would arise and deprive planned capital or maintenance programs of required resources. Addressing reactive capital work through planned capital rebuilds would also take time to plan, design and execute and do not typically allow for the timely replacement of failed and failing assets. Inadequate funding would also increase environmental risk, and safety risks to the public and Toronto Hydro employees. Ultimately this would lead to more interruptions and longer outages for customers, potentially significant legal consequences (e.g. related to environmental obligations), and risk of worker and public safety incidents.

2. Option 2 (Selected Option): Proposed 2020-2024 Reactive work

Option 2 is the preferred alternative as it accounts for adequate capital funding to effectively replace and repair failed or failing assets over the 2020-2024 planning horizon. The proposed expenditure is

necessary to maintain system performance and reliability, ensure customer satisfaction, eliminate safety risks to the public and Toronto Hydro employees, and mitigate environmental risks.

E6.7.5.2 Worst Performing Feeder Segment

Toronto Hydro considered two alternatives for addressing WPFs:

1) Planned capital rebuild; and
2) Continuation of the current WPF segment (preferred option).

3. Option 1: Planned Capital Rebuild

Addressing WPFs through planned capital rebuilds is the optimal long-term solution. However, rebuild projects take time to plan, design and execute, and do not typically allow for the timely mitigation of worsening reliability trends on poor performing feeders. Without targeted, short-term interventions on poor performing feeders, customers would likely continue to experience a high frequency of sustained interruptions. Further, the number of WPFs would most likely increase, thus negatively impacting SAIFI and SAIDI along with customer satisfaction levels over time. Accordingly, pursuing long-term capital rebuilds without a complementary WPF segment is not recommended.

4. Option 2 (Selected Option): Continue WPF segment

The status-quo and preferred option is to continue the mitigation work under the WPF segment at the pace that has demonstrated results and successes during recent years (i.e. 2015-2017). This option would provide immediate reliability improvements to customers served by poor performing feeders at a reasonable cost, and serves as a “bridge” solution until planned capital rebuilds can be executed.

E6.7.6 Execution Risks & Mitigation

E6.7.6.1 Reactive Capital Segment

Work under the Reactive Capital segment is not pre-planned or scheduled. All asset replacements are made in response to either an asset failure or deficiencies indicating high-risk assets that require immediate replacement and cannot be addressed during planned capital replacement.

Reactive capital work volume can be triggered by activities from Toronto Hydro’s maintenance programs, day-to-day operations, or emergency response. Failed or failing assets are prioritized for

replacements based on engineering assessments of the deficiencies and the potential impact to reliability, safety and the environment. Before reactive capital work can be executed, Toronto Hydro must consider the timing, scheduling, and approval of the work, as well as the asset type, its location and the nature of the failure. Once the failed asset is located, crews are dispatched to the site to perform the replacement. Due to the unpredictable nature of reactively replacing assets, the costs to execute such work can fluctuate.

Depending on the type of asset and the nature and scope of an asset failure, there are various risks that can delay the completion of reactive work such as resource and logistics constraints, and major storm events. In addition, depending on the location and nature of an asset failure, additional design, planning, and approval may be required before the work can be executed. Also, feeders may not be available to be taken out of service to perform the necessary replacements or rebuilds.

Depending on the nature, severity and location of an asset that has failed, coordination with third parties (contractors) may be employed to ensure replacement work can be performed in an efficient and safe manner. Feeders are strategically planned to be taken out in order to maximize the number of asset replacements.

E6.7.6.2 Worst Performing Feeder Segment

Similar to the reactive capital segment, the WPF segment is highly dynamic compared to other, typical planned work programs. Feeder and project prioritization can change quickly and often depend on emerging feeder conditions in the field. Delay in timely intervention may result in additional outages.

To mitigate the risk of project execution, Toronto Hydro has mapped out the WPF process, where feeder patrols scheduling and timelines for project execution have been clearly established. As a result, mitigation work is normally placed on high priority and scheduled for field execution taking into consideration available resources. Emphasis is placed on feeders that have experienced a high number of outages in a 12-month rolling window.

Feeder scheduling/restriction and road work moratoriums may also pose risks to the completion of work in a timely manner. To mitigate risks that might impede timely completion of work under this Program, bi-weekly stakeholder meetings are scheduled to review status of work, emerging issues, as well as alternatives to ensure work is completed in a satisfactory manner and time frame.

E7 System Service Investments



E7.1 System Enhancements

E7.2 Energy Storage Systems

E7.3 Network Condition Monitoring and Control

E7.4 Stations Expansion

E7.1 System Enhancements

E7.1.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 45.5	**2020-2024 Cost ($M):** 27.7
Segments: Contingency Enhancement, Customer-Owned Substation Protection	
Trigger Driver: Reliability	
Outcomes: Reliability, Safety	

The System Enhancements program (the "Program") involves modifying of Toronto Hydro's existing distribution system to strategically address critical issues, including operational constraints, protection enhancement opportunities, security-of-supply risks, and system operational inefficiencies. Both segments of work in this Program, discussed below, are continuations of activities included in Toronto Hydro's 2015-2019 Distribution System Plan ("DSP"). The 2020-2024 proposals are intended to support the utility's objective of maintaining current levels of reliability while improving system resiliency in the face of increasingly frequent adverse weather events.

The System Enhancements program consists of the following two segments:

- **Contingency Enhancement:** This segment is designed to enhance Toronto Hydro's ability to efficiently restore power to customers in the Horseshoe area by: (1) adding remotely operable feeder tie and sectionalizing points on feeders where the number of switching points is currently sub-optimal or where there is an opportunity to facilitate or expand a feeder automation network, (2) upgrading undersized conductors on lateral loops, and (3) upgrading undersized trunk egress cables. Toronto Hydro plans to invest an estimated $24.9 million in 2020-2024 in Contingency Enhancement, which is a 44 percent reduction in segment spending relative to the forecast total for the 2015-2019 period. The reduced pace is influenced by recent improvements in reliability on the overhead system (see Exhibit 2B Section E6.5).
- **Customer-Owned Substation Protection ("COSP"):** This segment is a continuation of Toronto Hydro's plan to install fused protection devices upstream of customer-owned equipment to rectify inadequate protection. In total, Toronto Hydro plans to install protection upstream from approximately 310 customer-owned substations for an estimated total cost of $2.8 million in the 2020-2024 period. This pace of investment will support

Toronto Hydro's objective of maintaining reliability in the Horseshoe over the 2020-2024 period.

Overall, Toronto Hydro plans to spend an estimated $27.7 million in this Program over the 2020-2024 period.

E7.1.2 Outcomes and Measures

Table 2: Outcomes & Measures Summary

Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by: ○ Reducing fault isolation times on targeted feeder trunks by approximately one hour on average through Supervisory Control and Data Acquisition ("SCADA") switches; ○ Reducing the average duration of outages by for targeted feeders by installing SCADA-enabled tie and sectionalizing points; ○ Reducing outages resulting from contingencies by upgrading undersized or de-rated equipment; and ○ Reducing the impact of customer-owned substation equipment failures on the overhead system by installing approximately 930 protection devices.
Safety	• Contributes to maintaining Toronto Hydro's Total Recorded Injury Frequency (TRIF) measure and safety objectives by installing remote switching, which reduces crew exposure to the safety risks associated with manual switching.

E7.1.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Reliability
Secondary Driver(s)	Safety, Operational Constraints, System Efficiency

Toronto Hydro's System Enhancements program is necessary to support the utility's system reliability objectives for 2020-2024. Across the system, Toronto Hydro has identified opportunities

to maintain and improve reliability outcomes, including system resiliency, by implementing targeted system modifications. These system design interventions can cost-effectively reduce the consequences of failure (i.e. the number of customers affected and outage duration), as distinguished from the probability of failure, which is typically addressed by replacing or maintaining aging and poor condition assets. The investments in this Program are intended to reduce the consequence of failures by improving power restoration capabilities during both normal interruption events and adverse weather events, which are becoming increasingly frequent.

Both segments in this Program achieve their objectives by optimizing sections of the distribution system that are not configured or equipped to respond effectively to contingency situations.

E7.1.3.1 Contingency Enhancement

Over the past several years, through customer calls, emails, community meetings and councillor meetings, customers and stakeholders have encouraged Toronto Hydro to find ways to reduce outage frequency and durations on the overhead system. The investments in the Contingency Enhancement segment respond to these concerns by helping to enhance Toronto Hydro's ability to restore power quickly when outages occur in the Horseshoe area of the City, including during high impact contingency events such as major storms.

The Contingency Enhancement segment includes the following four project types, all of which are continuations of activities included in Toronto Hydro's 2015-2019 DSP:

1) installing additional SCADA-enabled tie and sectionalizing points;
2) establishing and expanding feeder automation[1] networks;
3) upgrading under-sized loop conductors; and
4) upgrading the capacity of trunk egress cables.

Each of these activities is discussed in the following sections.

1. Tie and Sectionalizing Points

When a feeder or a section of feeder loses power during a contingency event, customers connected to the failed feeder or section should receive power from an alternate feeder via feeder tie points

[1] Feeder Automation was a stand-alone program in Toronto Hydro's 2015-2019 DSP. Toronto Hydro has grouped Feeder Automation with Contingency Enhancement going forward. This reflects the utility's change in approach to Feeder Automation, discussed in section 3.1.2 below.

and sectionalizing switches. However, if a feeder is not sufficiently equipped with sectionalizing or tie points that can divide the load into smaller sections, re-routing service may not be possible for all customers. This is especially true during peak loading times. Load growth and the addition of new developments can exacerbate this problem. The Contingency Enhancement segment adds tie or sectionalizing points to those feeders lacking sufficient switches.

A secondary issue is the lack of remote operation at some existing tie-points. Before SCADA-controlled devices were available, manual switches were installed. To restore power with manual switches, employees must travel to perform the switching work on-site. Depending on the location of the fault and accessibility of the switches, this typically takes one to two hours. In contrast, SCADA-controlled switches will relay instant loading information to the control room, enabling controllers to remotely re-route power to adjacent feeders within minutes. Remotely controlled switches are also safer than manual switches because employees are not exposed to live equipment during manual switching operations.

To provide appropriate backup supply, Toronto Hydro's standard design practice is that feeders should have at least three strategically located tie points connected to three unique back up feeders as follows:

1) The first tie point connects to another feeder from the same substation bus;
2) The second tie point connects to another feeder on a separate bus located at the same substation; and
3) The third tie point connects to another feeder from a different substation.

This arrangement ensures a contingency power source is available for the faulted feeder regardless of whether the fault occurs at the feeder, bus, or station level. The current average duration for outages on feeders with less than three tie-points is 260 minutes per year per feeder. Upon the completion of this segment, Toronto Hydro estimates this would reduce to 209 minutes per year per feeder, resulting in an approximately 20 percent reduction.

Figure 1 below shows a map of Toronto highlighting those feeders that have less than three feeder ties.

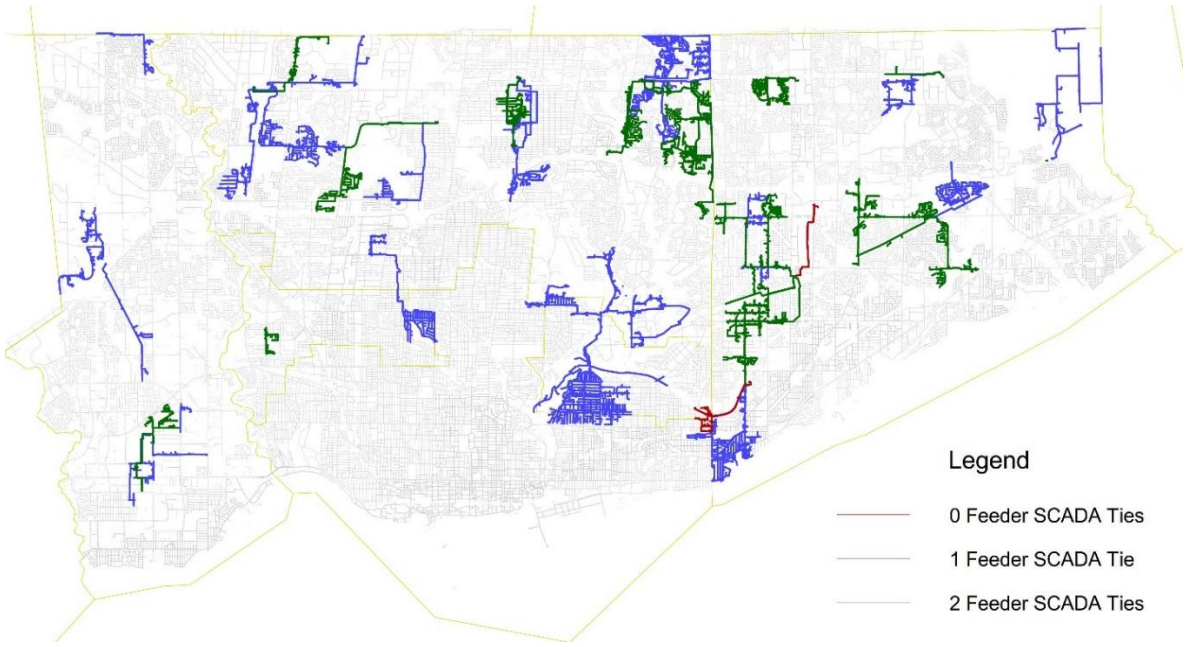


Figure 1: Map of Toronto showing Feeders with less than 3 Tie Points

2. Feeder Automation

Feeder Automation projects replace existing manually operated switches on the main sections of a feeder (i.e. the feeder "trunk") with remotely operable SCADA switches. Automation can then be added to create a network of switches that work together, without manual intervention, to rapidly isolate a fault and minimize the number of customers affected. Feeder Automation is an extension of the tie and sectionalizing point work described above as they both involve the installation of SCADA-enabled switches on feeders. However, while the latter targets feeders with insufficient tie and sectionalizing points, Feeder Automation focuses on strategically installing sufficient SCADA switches on feeder trunks in targeted areas in a way that would enable the eventual creation of a network of automated switches.

Feeder automation has two main components: SCADA switches, and a Fault Location Isolation and Service Restoration application ("FLISR").

1) SCADA switches on feeders allow the remote troubleshooting and sectionalization of feeder faults to achieve more efficient and rapid troubleshooting and restoration, which is the focus of the Feeder Automation work within the Contingency Enhancement segment.

2) FLISR is an application which, together with the Network Management System ("NMS"), can automatically read and process signals from the distribution system to locate a fault. The implementation of Feeder Automation using FLISR would enable Toronto Hydro to rely on autonomous detection and isolation of affected portions of the feeders, further reducing fault isolation time.

During a feeder level outage, control room operators and crews first work to locate the fault and sectionalize the feeder to isolate the faulted section. This will minimize the impact of the outage to a large portion of the customers before crews are able to identify the root cause of the outage and complete repairs. The use of remote operated SCADA switches reduces the fault isolation time by approximately one hour on average. The use of FLISR would further reduce the fault isolation duration to within minutes, which allows crews to focus on the root cause of the outage and reduces the needs for additional troubleshooting and switching crews. It also allows faster restoration of power to all the remaining customers.

Toronto Hydro is focusing on the trunk feeders on the 27.6 kV distribution network in the Horseshoe area as they have the largest impact on customers. As shown by Figure 2, the 27.6 kV system accounts for the largest share of reliability issues in the system, which also means considerable resources are required to restore outages using manual or remote-operated SCADA switches. Trunk outages interrupt the entire feeder and can impact hundreds to thousands of customers. In contrast, lateral or local outages only impact up to a few hundred customers.

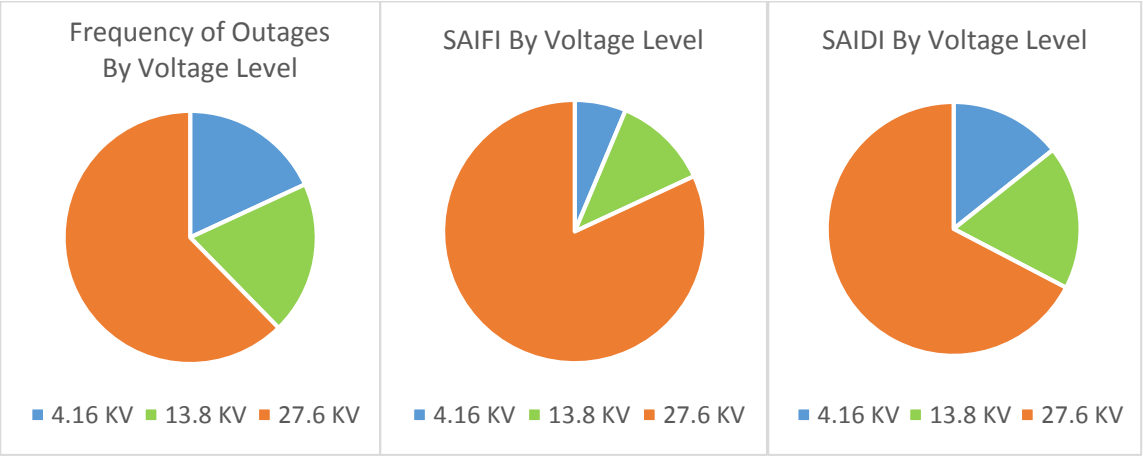


Figure 2: Reliability Impact by Voltage Level

Even though trunk outages make up only a third of the outages that occur on 27.6 kV feeders, they can significantly impact SAIFI and SAIDI (as shown in Figure 3 below). The installation of SCADA switches will allow faster sectionalization and restoration of customers in unaffected sections, thereby reducing the impact of trunk outages and improving the reliability of the system.

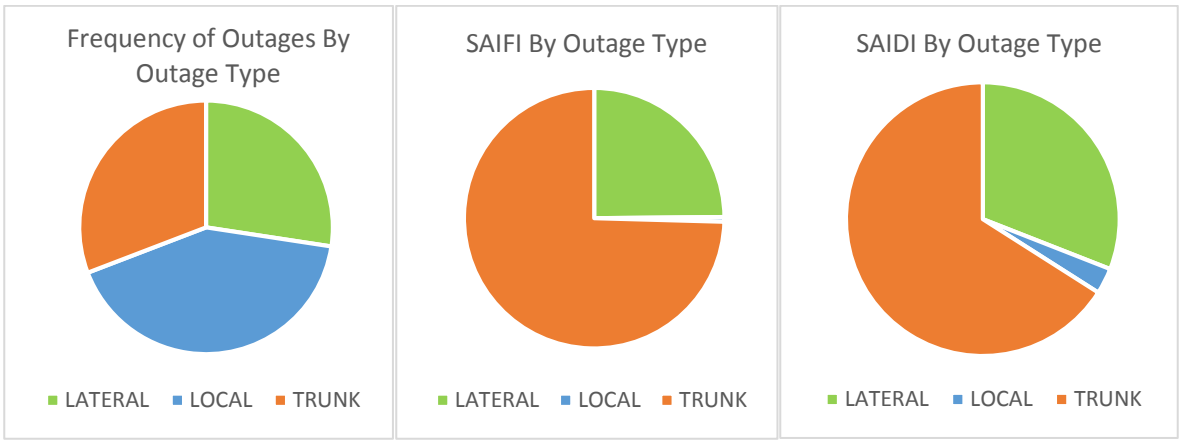


Figure 3: Reliability Impact by Outage Type

As of the end of 2017, 48 feeders are considered to be automation ready (defined as having at least three SCADA sectionalizing switches, and at least two SCADA tie points). The switches on these feeders are ready for the implementation of feeder automation to realize the full benefits of autonomous restoration. Approximately 149 feeders are considered to be partially automated (defined as having at least 1 SCADA sectionalizing switch), and the remainder of the over 60 feeders are without any SCADA switches at all. For these feeders, additional switch installations are required to provide remote restoration capabilities and enable automation to allow for faster outage restorations to customers.

3. Undersized Loop Conductor

Figure 4 depicts a typical looped distribution lateral supplying a series of transformers off the main trunk portion of a feeder. There is an open point near the middle of the loop so that, under normal operating conditions, about half of the load in the loop is supplied from one lateral or the other.

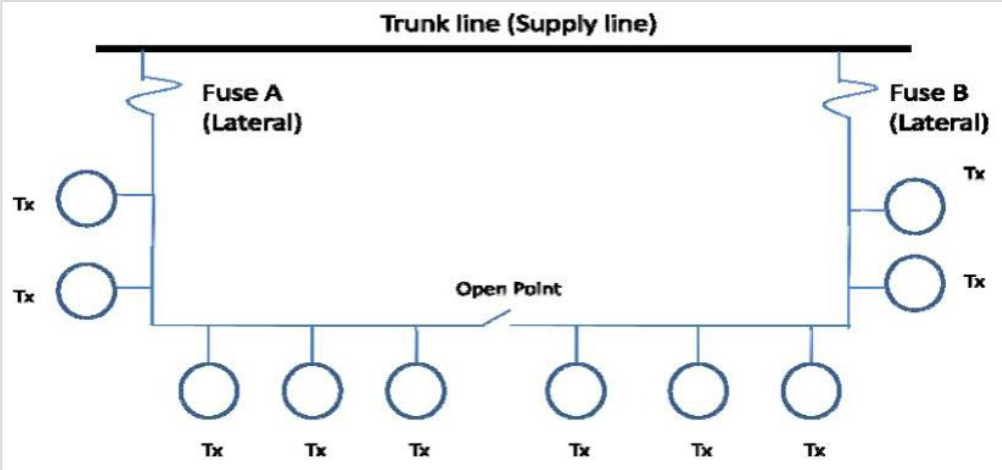


Figure 4: Looped Distribution Design

The conductor on either lateral is designed to be large enough to handle the load of the entire loop if necessary. In a situation where a fault occurs on the first section downstream of Fuse B, the load must be supplied entirely from the other side of the loop, as shown in Figure 5.

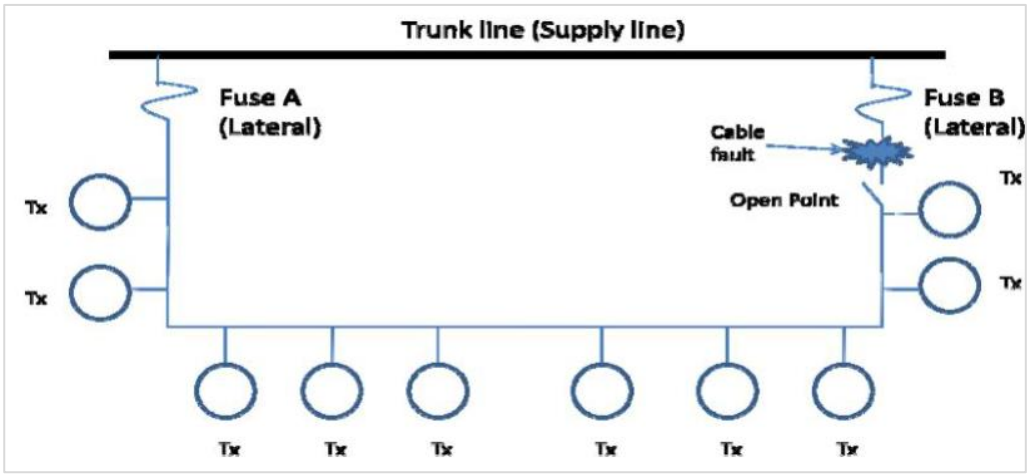


Figure 5: Power restoration in loop after a fault has occurred

Gradual increases in load in certain areas have resulted in existing conductors no longer being able to supply the load of the entire loop. A contingency situation in these locations would cause cascading power outages to the entire loop. Controllers monitor the conductor size and number of transformers transferred to the circuit under contingency; however, the actual load on each transformer may not be known by the controller in real-time. Therefore, if a conductor has previously

withstood a high current during repair work without failing, its integrity may have already been compromised, which could lead to premature failure of the loop conductor requiring reactive repair work.

Toronto Hydro plans to upgrade undersized conductor in lateral loops to ensure that they are rated to carry the load of the entire loop under contingency conditions. Figure 6 shows the locations of undersized loop conductors in Toronto.



Figure 6: Map of Toronto showing undersized loop conductors

4. Insufficient Capacity of Trunk Egress Cable

Toronto Hydro plans to replace existing aluminum cable on feeder trunk egress sections with copper cable. The initial section of a feeder, between the station breaker and the first distribution switch (i.e. the section upstream from any load connections), is called the “egress”. The egress cable must be adequately sized to supply the load of the feeder, plus any additional load from adjacent feeders under contingency, up to the maximum capacity of the feeder breaker (i.e. 600 A).

Some egress cable installed in the 1960s and 1970s on 27.6 kV feeders is 1000 kcmil aluminum, a cable type that is de-rated (i.e. its current carrying capacity is lowered) when installed in an underground environment, to 500 A in summer and 530 A in winter. In some areas, load growth has exceeded the capacity of this existing configuration. Under contingency, a feeder is required to carry the load of adjacent feeder sections that connect to it. Thus, it is critical that the maximum capacity of the feeder is utilized to restore as many customers as possible. This poses a high-risk situation, as failure of the load-carrying feeder to deliver power to its maximum capacity may result in loss of power to two other feeders, causing outages to a large area for four hours (or more) that it would take to make repairs. Due to the limitation of current carrying capability of these trunk egress cables, customers that would otherwise be served by those feeders under a contingency would experience an outage until the work on their normal feeder has been completed. For these reasons, it is critical that the egress portion of the feeder be fully rated to effectively utilize the rated capacity of the breaker.

Under a contingency condition, controllers may not be able to utilize feeders with a 1000 kcmil aluminum egress trunk cable to pick up load lost on adjacent feeders during a fault or planned maintenance. As a result, affected customers will experience prolonged power outage until the faulted asset is repaired or replaced on the normal supply feeder. Toronto Hydro may also be required to defer important scheduled maintenance work until the load on feeders is low enough to be re-routed, resulting in the deterioration of asset conditions and further reducing reliability.

There are 20 stations with a total of 103 km of egress cable considered under-rated (i.e. not 1000 kcmil copper). Table 4 shows the amount of under-rated cable for each of these stations. Toronto Hydro will target feeders with under-rated egress cable that consistently experience high loading, prioritizing them primarily based on loading levels and the reliability of adjacent feeders. These targeted upgrades and installations will better equip the distribution system to meet the needs of customers in contingency scenarios and more effectively maximize the customer value derived from existing feeders by minimizing unnecessary failure risk.

Table 4. Stations with Under-Rated Trunk Egress Cable.

Station	Under-Rated Egress Cable (km)	Total Egress Cable (Circuit km)
Bermondsey TS	24	24
Runnymede TS	1	1
Woodbridge TS	0.1	0.1

Station	Under-Rated Egress Cable (km)	Total Egress Cable (Circuit km)
Leslie TS	18	20
Agincourt TS	6	7
Fairchild TS	18	21
Bathurst TS	16	24
Horner TS	1	2
Rexdale TS	3	6
Cavanaugh TS	6	12
Ellesmere TS	1	3
Fairbanks TS	2	8
Richview TS	0	2
Finch TS	3	16
Scarborough TS	1	6
Warden TS	0.3	4
Malvern TS	0.2	4
Leaside TS	0.1	3
Sheppard TS	0.0	1
Manby TS	0.1	11
Total	**102.6**	**175**

E7.1.3.2 Customer-Owned Substation Protection (COSP)

The COSP segment is primarily designed to mitigate the reliability risks posed by customer-owned substation equipment. To prevent outages to customers upstream from customer-owned substations, Toronto Hydro must ensure that utility-owned protection devices are installed and properly coordinated as safeguards where appropriate.

While Toronto Hydro has protection devices in many places in the Horseshoe area, in some areas these devices are inadequate or absent altogether. There are currently 2,110 customer-owned substations in the Toronto Hydro network: 1,417 substations are located in the Horseshoe area (i.e. the former suburbs) and 693 are in the vicinity of downtown Toronto. During sample substations inspections in the Horseshoe area, 64 of the 185 visited substations were found to be missing upstream utility-owned protection devices. It is estimated that a total of approximately 480 substations could be missing upstream utility-owned protection devices.

There are several reasons as to why this issue and the uncertainty in the number of locations with this issue exist:

- At the time of original construction, the impact that a customer's load could have on the system may have been negligible. However, over time, a customer's load could have risen considerably. Given the increase in customers and associated loads, these substations can now have a significant impact on the reliability of power supply and cannot be neglected.
- Some substations are too large to have upstream fuses and therefore at the time of original construction, these customers would not have upstream protection set up. However, gang-operated load-break SCADA switches can be used today to connect this type of large substation to the feeder trunk as specified in Toronto Hydro's current standards.
- At the time of construction, the manufacturers might not have had the preferred protection devices available (e.g. fuse sizes were limited) for the specific customer-owned substations and loading requirements. As technology evolved, more options are now available (e.g. fuses at higher rating), which would provide better protection to the system.

Toronto Hydro plans to minimize existing and potential impacts associated with its upstream protective devices by ensuring that such devices are in-line with the utility's most recent standards. During a fault, an uncoordinated upstream protection device would fail to act after the customer-owned protection device operates and before the station breaker is triggered. If Toronto Hydro-owned protection devices are improperly configured or absent altogether, the inability for a customer-owned protection device to isolate a fault will trigger the station breakers, which would interrupt the entire feeder. According to Toronto Hydro's Interruption Tracking Information System ("ITIS"), there were 60 interruptions caused by the failure of customer-owned equipment from 2013 to 2017. Figure 7 shows the outage distribution across the City of Toronto and Figure 8 shows the number that occurred in each year.



Figure 7: Historical Reliability Events 2013-2017

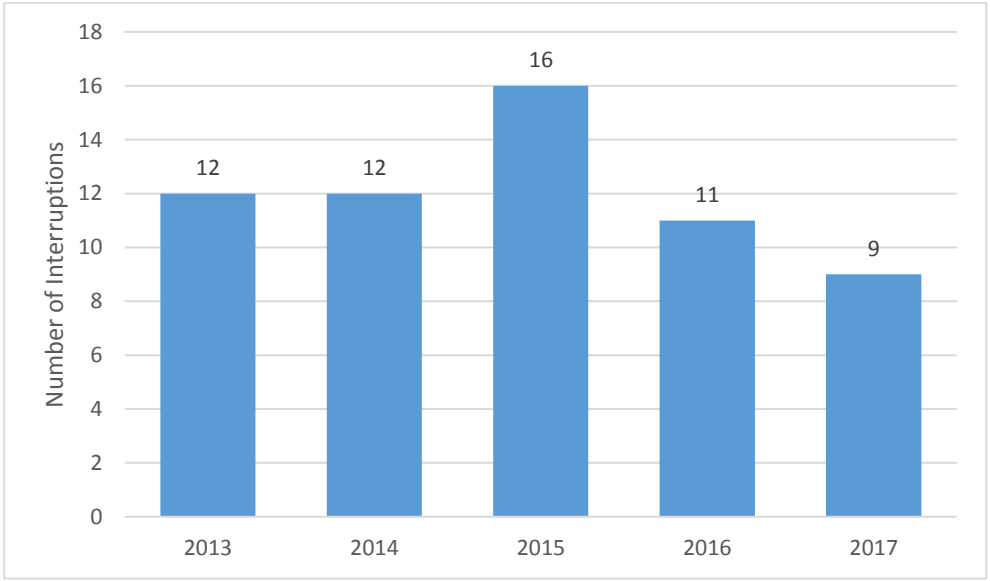


Figure 8: Interruptions due to Failure of Customer-Owned Assets

As a result of inadequate protection, these events interrupted Toronto Hydro customers. If the proper utility protection devices were in place, the impact would be limited to the faulted customer

only. The COSP segment is expected to improve reliability performance in the overhead distribution system caused by customer-owned equipment failures.

E7.1.4 Expenditure Plan

Table 5: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Contingency Enhancement	6.7	15.9	12.1	3.5	6.1	5.5	5.6	5.1	4.3	4.4
Customer-Owned Station Protection	-	-	-	0.6	0.6	0.6	0.5	0.5	0.6	0.6
Total	**6.7**	**15.9**	**12.1**	**4.0**	**6.7**	**6.2**	**6.2**	**5.6**	**4.8**	**4.9**

E7.1.4.1 Contingency Enhancement

Toronto Hydro invested $34.8 million in the Contingency Enhancement segment over the 2015-2017 period and is forecast to spend an additional $9.5 million in 2018-2019, for a total of $44.3 million. This is less than what was initially proposed in Toronto Hydro's 2015-2019 Distribution System Plan. Underspending was due in part to some work that was originally considered part of Contingency Enhancement being completed under renewal program portfolios instead. Further, for the Feeder Automation work, in 2016 Toronto Hydro changed from a decentralized to a centralized automation method which lowered costs. Decentralized automation requires SCADA switch retrofits (which is not needed for centralized automation) and this reduces work and costs required for Feeder Automation.

Between 2015 and 2017, Toronto Hydro added tie points to 10 feeders, added sectionalizing points on 14 feeders, and upgraded one undersized lateral loop. In addition, Toronto Hydro upgraded end-of-life and underrated egress cables at Manby TS, Scarborough TS, Leslie TS, Bathurst TS, and Warden TS, contributing to higher segment expenditures in 2016 and 2017. In 2018 and 2019, Toronto Hydro plans to add tie points on seven distribution feeders, add sectionalizing points on three feeders, and upgrade egress cables at Bathurst TS and Fairchild TS. These investments will benefit customers by reducing the risk of outages and enabling improved restoration and operational efficiency.

For Feeder Automation between 2015 and 2017, Toronto Hydro's implementation included the automation of eight Fairchild TS feeders in the high density areas of North York, expanding on previous implementations of feeder automation in the west end of Toronto. The existing automation infrastructure and switching capabilities in this North York area is modernized with current standard SCADA switches and Remote Terminal Units ("RTUs") to provide ease of integration and a cost-effective means to implement Feeder Automation.

Toronto Hydro plans to invest approximately $24.9 million in similar Contingency Enhancement projects in the 2020-2024 period. The reduction in expenditures, relative to 2015-2019 levels is influenced by improvements in reliability performance in the Horseshoe area of Toronto and the general preference of low-volume customers for price mitigation over additional reliability enhancements.

Toronto Hydro will fund projects in the highest priority locations as determined by analyses of reliability performance, loading statistics, cost-benefit analysis, and other applicable criteria, with the overall objective of maximizing customer value and contributing efficiently to short- and long-term system reliability targets.

E7.1.4.2 Customer-Owned Substation Protection

As seen in Table 5 above, Toronto Hydro deferred capital investment in COSP until 2018. This was a new program in the 2015-2019 DSP and the utility prioritized it behind core renewal work. Toronto Hydro plans to begin investment activities in 2018.

In 2020, Toronto Hydro plans to continue installing protection devices upstream of customer owned substations. In total, Toronto Hydro plans to install 930 fused in-line switches upstream from 310 customer-owned substations for an estimated total all-in cost of $2.8 million in the 2020-2024 period. Toronto Hydro expects 60-70 locations per year to be a pace of work that can be realistically achieved and that will enable the utility to address the majority of the estimated 480 locations without proper protection by the end of 2024.

Toronto Hydro will prioritize locations based on the age and condition of customer-owned equipment, the sufficiency or insufficiency of existing protection equipment and protection coordination, historical reliability performance, and the type of distribution feeder (i.e. locations on the overhead system are given higher priority due to greater exposure to reliability risks). As noted

in the Execution Risks (Section 6.2), the prioritization and pacing of this Program will depend in part on the responsiveness of customers to Toronto Hydro's information and coordination requests.

E7.1.5 Options Analysis

E7.1.5.1 Options for Contingency Enhancement

1. Option 1: No Contingency Enhancement Segment

Maintaining the status quo involves forgoing the Contingency Enhancement segment. Customers served by problematic feeders would continue to experience lengthy outages during contingency conditions. In addition, Toronto Hydro would incur higher costs with respect to reactive work to replace equipment that was damaged due to overloading and manual switching work. For these reasons, the status quo option is not recommended.

2. Option 2 (Selected Option): Contingency Enhancement

Executing the proposed Program strengthens Toronto Hydro's distribution system in contingency conditions, improving reliability for affected customers. The addition of SCADA controlled tie and sectionalizing switches would enable Toronto Hydro to segment a feeder into smaller sections, so that load could be transferred to alternate feeders to reduce the duration of power outages. Customers could expect improved service reliability and Toronto Hydro would gain efficiency advantages by extending the reach of the SCADA system and enabling Feeder Automation networks. As well, upgrading aluminum egress cables to copper would allow feeders to utilize the full rated capacity of the circuit to deliver power during a contingency condition. Although Toronto Hydro will target the highest priority locations over 2020-2024, parts of the distribution system will continue to operate sub optimally in contingency situations. However, this alternative is recommended as it strikes a balance between mitigating risks and cost over the 2020-2024 period.

3. Option 3: Contingency Enhancement at Accelerated Pace

Executing the Program at a faster pace would extend the areas and number of customers benefitting from improved reliability as described for option 2. However, this would increase costs. Mitigating costs has been identified as a high priority, above reliability, by customers in the Horseshoe area of Toronto.

E7.1.5.2 Options for Customer-Owned Substation Protection

1. Option 1: No installation of COSPs

Under the status quo, customer-owned substations with inadequate protection would continue to pose a risk of causing interruptions to other Toronto Hydro customers on the overhead system if customer-owned equipment fails. The inspection of sample substations has indicated that over 22 percent of customer-owned substations in the Horseshoe area are either aged or poorly maintained. Without regular maintenance of the customer-owned substations (which are often neglected), this equipment is increasingly more likely to fail and cause reliability (e.g. outages to upstream customers) problems on Toronto Hydro's distribution system. The failure of customer-owned equipment has already resulted in approximately 12 interruptions per year during the 2013-2017 period. Toronto Hydro expects this number to increase in the near future if the proposed plan is not implemented. For these reasons, Toronto Hydro does not recommend this option.

2. Option 2 (Selected Option): Customer-Owned Substation Protection

By undertaking the COSP segment at the proposed pace, Toronto Hydro expects to improve reliability on the overhead system. Installing utility-owned protection devices will enable Toronto Hydro to isolate faults at customer-owned substations. This will minimize the likelihood that an entire feeder would be affected by a fault at a customer-owned substation, thus reducing the number of customers that will experience power outages. At the proposed pace, Toronto Hydro expects to address the majority of the locations without proper protection by the end of 2024. However, until all the required protection devices are installed, the risk of customer-owned equipment failures causing interruptions to other customers on the overhead system will continue. Nevertheless, this option is the recommended option as it balances risk mitigation and costs.

3. Option 3: COSP at Accelerated Pace

By accelerating the rate at which protection devices are installed, Toronto Hydro would mitigate the impact of faults occurring at customer-owned substations sooner. However, this would come at a higher costs, and in any event a faster pace may not be feasible from a resourcing and execution perspective. Full information on the number of locations and specific work required at each location will not be available until the audits and engineering analysis that are ongoing as of 2018, are fully completed.

E7.1.6 Execution Risks & Mitigation

E7.1.6.1 Contingency Enhancement

Unforeseen site conditions, such as the presence of third party infrastructure (e.g. gas, sewer or water pipes), can necessitate scope changes, and result in cost increases or delays in the completion of the underground work. In these situations, Toronto Hydro will reprioritize or reschedule work after taking all factors into consideration.

As well, Toronto Hydro must take into account city road moratoriums that may be imposed after the scope of work is issued, which could result in delays. However, Toronto Hydro will mitigate this risk by ensuring that it maintains open communication with the City of Toronto and coordinates its activities with those of the city.

Feeder Automation projects, by their nature, require robust communication between switches. Under the decentralized approach to automation, communication between switches created risk for fully implementing automation schemes. Under the proposed centralized approach (FLISR) utilizing the NMS, this risk is expected to be mitigated.

E7.1.6.2 Customer-Owned Substation Protection

One of the main risks of the COSP segment is related to the ongoing assessments and that fact that all substations have yet to be fully audited. The costs associated with the installation of new or replacement protective devices will differ depending on the exact number of stations that require new or replacement protective devices. For example, some locations may already have a switch in place but may be missing a fuse. In this case, as long as the condition of the currently installed equipment is adequate, Toronto Hydro will only install a fuse. The proposed plan is based on information that is available as of 2018 and will be adjusted based on new information that becomes available.

Acquiring all necessary data and documentation is another risk associated with this segment. Some equipment data is not readily available to Toronto Hydro because it is associated with customer-owned substations (e.g. primary protective devices or damaged transformer nameplate). In these instances, Toronto Hydro will need to contact the asset owner to obtain the required information. Since Toronto Hydro has no control over the customer's response time, this process may result in

delays. However, Toronto Hydro will reach out to relevant customers on a timely basis and follow-up with the customer periodically for the requested information to minimize this risk.

An outage may be required in order to complete the protection upgrades. Scheduling outages with the customers may be a challenge requiring active management. While Toronto Hydro has no control over the customer's willingness to schedule an outage, it will consult and work closely with affected customers to reach a mutually agreed solution.

E7.2 Energy Storage Systems

E7.2.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): $0.5 (Rate Base)	**2020-2024 Cost ($M):** $5.8 (Rate Base)
2015-2019 Cost ($M): $7.9 (Net Costs)	**2020-2024 Cost ($M):** $10.5 (Net Costs)
2015-2019 Cost ($M): $35.2 (Gross Costs)	**2020-2024 Cost ($M):** $52.8 (Gross Costs)
Segments: System Service	
Trigger Driver: Category 1- Power Quality; Category 2- Public Policy	
Outcomes: Customer Service, Reliability, Financial Sustainability, Public Policy	

The Energy Storage Systems ("ESS") program was developed to put batteries to use for the benefit of customers where this non-wires option is the best solution to enable or improve distribution service. As is stated in the 2017 Long-Term Energy Plan, "Energy storage can offer benefits throughout the grid, from large-scale facilities that can reduce the need to build new supply, import electricity or use GHG-emitting generation sources, to smaller-scale devices that can provide backup services to buildings."[1]

The Long-Term Energy Plan makes reference to two studies on energy storage that were completed at the request of the Ministry of Energy: (i) a 2016 IESO study on energy storage; and (ii) a 2017 study published by Essex Energy Corporation.

The IESO study, "IESO Report: Energy Storage," was produced in response to a request from the Ministry of Energy in April 2015. This study presents the many benefits of energy storage to the bulk electricity system. Among the benefits the report identifies is the deferral of system upgrades through the use of energy storage to reduce local system peaks.[2] The report states:

> *"Energy storage could also help improve the utilization of existing transmission and distribution assets by deferring some costs associated with their upgrades or refurbishments, as well as improve the quality of electricity supply in certain areas of the system by controlling local voltages."*[3]

[1] 2017 Long-Term Energy Plan, Ministry of Energy, 2017, p.60
[2] IESO Report: Energy Storage, Independent Electricty System Operator, 2016, p.5
[3] IESO Report: Energy Storage, Independent Electricty System Operator, 2016, p.35

Essex Energy Corporation's 2017 study, "The Study of Energy Storage in Ontario's Distribution Systems," was requested by the Ministry of Energy in March 2016. The report describes a number of benefits of energy storage, including distribution system upgrade avoidance, new generation capacity avoidance, redundant power supply (reliability), and power quality improvement.[4] In one of its case studies, the report also identifies the enablement of renewable generation as another benefit of energy storage.[5]

The IESO's 2015 "Central Toronto Area Integrated Regional Resource Plan" also highlights the benefits of energy storage, particularly as a solution to "community level" energy planning, including opportunities to enable renewable generation.[6]

Battery-based Energy Storage Systems are typically comprised of two components: batteries and power electronics. Batteries absorb and supply energy in direct current ("DC"). Power electronics convert battery DC power to alternating current ("AC") (and vice versa) to enable connection to the distribution system. The power electronics also connect and disconnect the batteries from the distribution system. The ability of the ESS to deliver the expected benefits depends not only on the size of the batteries, but also on the capacity ratings, configuration, and switching capabilities of the associated power electronics.

Toronto Hydro's proposed ESS Program includes three investment segments:

1) Grid Performance ESS,
2) Renewable Enabling ESS, and
3) Customer-Specific ESS

Grid Performance ESS projects utilize battery energy storage as integrated components of the traditional distribution system. These projects benefit multiple customers, in the same way as other distribution infrastructure (e.g. poles, wires, and transformers), and can provide specific solutions to distribution problems. Toronto Hydro proposes to use ESS to achieved grid performance enhancements, including to remediate power quality problems (e.g. voltage sags), improve reliability by reducing the number or duration of outages, and increase capacity of a feeder at peak periods. During the 2020-2024 period, $5.5 million is proposed for this category of investment.

[4] The Study of Energy Storage in Ontario's Distribution Systems, Essex Energy Corporation, 2017, p12
[5] The Study of Energy Storage in Ontario's Distribution Systems, Essex Energy Corporation, 2017, p27
[6] Central Toronto Area Integrated Regional Resource Plan, Independent Electricity System Operator, 2015, p90

ESS systems can provide other distribution benefits including local demand response (DR). A local DR solution is being implemented at Cecil TS in the 2015-2019 rate period and is proposed for expansion during the 2020-2024 rate period as described in Section E7.4.

Toronto Hydro is proposing to use ESS connected to the distribution system along the feeder segments where customers would benefit from enhanced grid performance. These needs are diagnosed on a feeder-by-feeder basis having regard to the performance of that part of the grid with respect to capacity, reliability, power quality, and other relevant measures. Where a traditional poles and wires approach is applicable, the solution might be to upgrade the feeder, re-orient feeders, install additional protection and control devices, or undertake other conventional investments. In other instances, a poles and wires option may not be available for a variety of technical or economic reasons. This program will enable Toronto Hydro to pursue ESS options, as may be optimal in a given situation.

A typical example of where a battery solution can be used to cost-effectively improve grid performance would be an area with a relatively high concentration of customers who are sensitive to power quality disturbances. Benefits of such a solution include the following:

- **Voltage Sags:** ESS can offset significant voltage sags and provide ride-through capability.
- **Voltage Support:** ESS can dynamically counteract voltage fluctuations through voltage regulation, thereby minimizing the voltage fluctuations that adversely affect customer equipment and processes.
- **Phase balancing/efficiency**: ESS can help rebalance feeders that exceed the threshold for single phase imbalances, thus decreasing the return current on the neutral conductor and reducing line losses.
- **Reliability and power quality improvements**: ESS can improve the overall power quality for customers by counteracting variations in voltage and harmonics, as well as the effects of switching.

Renewable Enabling ESS investments are distribution investments that support the growth of distributed renewable generation on the system, that in turn offset generation and transmission investments to the benefit of all Ontario rate payers, and that also create environmental benefits. Distributed renewable generation has been supported in Ontario for over a decade through a series of programs offered through the Ontario Power Authority and IESO, including FIT, microFIT, and Net Metering. Customers who do not have contracts through these programs also install renewable

generation. Those customers can receive payments according to hourly market prices or, more often, offset their monthly bill by generating their own electricity behind the meter.

As is the case with other renewable enabling improvements ("REI"), projects in this investment segment are funded 6 percent in the LDC rate base and 94 percent through the provincial REI revenue stream. Over the 2020-2024 period, $5 million is proposed for this segment, with $0.3 million (6 percent) allocated to Toronto Hydro's rate base. These investments are expected to enable the aggregate connection of 5 MW of renewable projects, which would otherwise not be possible due to technical limitations of the grid.

Similarly, ESS can cost-effectively enable electric vehicles ("EVs") to connect to the distribution system by addressing localized system constraints. Toronto Hydro is not proposing any EV ESS projects at this time.

Customer-Specific ESS projects would be installed at the request of the customer, typically behind the customer meter in order to maximize the benefits of the investment. These projects improve traditional distribution service outcomes such as power quality and reliability. By locating these distribution assets behind the meter, they also provide the customer with financial benefits, such as hourly peak-shaving and Industrial Conservation Initiative ("ICI") benefits (i.e. Global Adjustment relief for Class A customers who reduce their demand during provincial peak periods). Thus, the customer-specific behind the meter benefits "stack on top" of the distribution benefits, thereby creating a greater set of benefits associated with the ESS project.

Over the 2020-2024 period, $42.3 million is proposed for this segment. Investments in this segment are driven by the requesting customer's needs. In accordance with the "beneficiary pays" principle, Toronto Hydro will therefore hold these host site customers directly responsible for the costs of the projects that benefit them. As with other capital contributions, payments from the host site customers will offset the amounts that are added to rate base and charged through rates to all ratepayers. Presumptively, the result is that 100 percent of the $42.3 million of planned expenditures are offset by planned capital contributions, such that the net effect of this segment to the Toronto Hydro rate base is $0.

An example of this type of a Customer-Specific ESS project is the Metrolinx Eglinton Crosstown LRT ESS currently underway in 2018/2019. At its request, Metrolinx will receive reliability and emergency services in the event that distribution service from feeders becomes unavailable. The costs of the project are fully allocated to Metrolinx and recoverable through a capital contribution.

The general interconnection schematic for various ESS projects are illustrated in Figure 1 below.

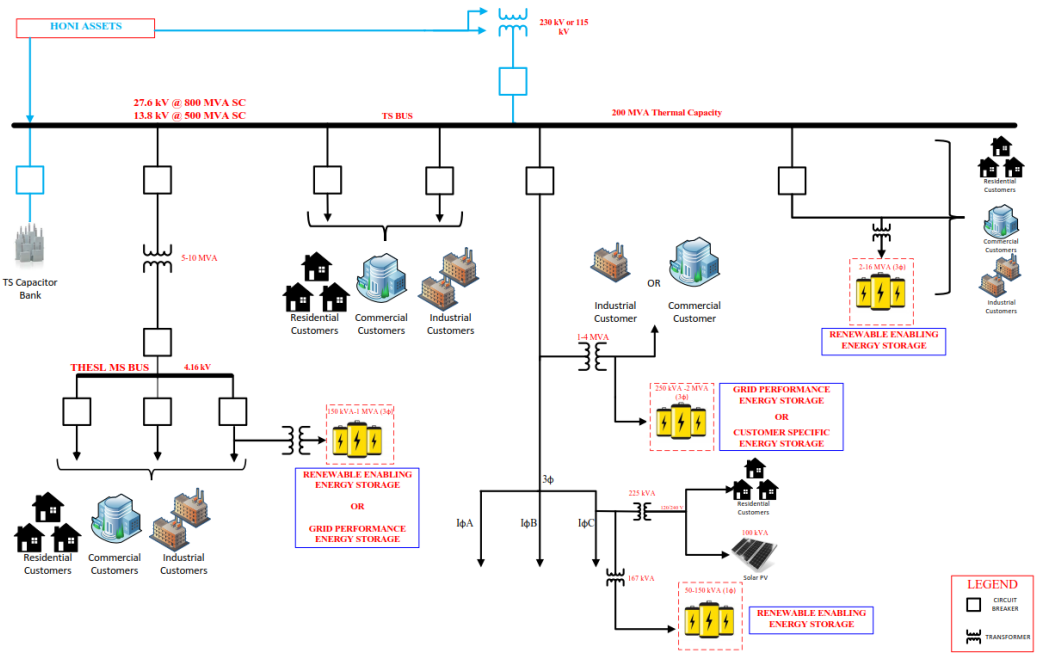


Figure 1: Typical Interconnection for ESS

E7.2.2 Grid Performance ESS

E7.2.2.1 Outcomes and Measures

Table 2: Outcomes & Measures Summary

Customer Service	• Contributes to the reduction of power outages and risk of costly asset failures by mitigating the effects of upstream line disturbances.
Reliability	• Contributes to increased reliability and power quality by mitigating the effects of voltage sags including customer interruptions • Contributes to reliable system performance by enabling dynamic voltage support and reduced harmonics through line voltage regulation.

Financial	• Contributes to Toronto Hydro's financial performance and objectives by: ○ Achieving local, targeted feeder performance improvements to defer the need for conventional infrastructure upgrades. ○ Enabling phase balancing to minimize neutral return currents and improve system efficiency.
Public Policy	• Contribute to Toronto Hydro's public policy objectives by: ○ Creating the stacked benefits of utility battery storage projects that were recognized in the 2017 Long-Term Energy Plan. ○ Reducing greenhouse gas ("GHG") emissions by enabling the proliferation of energy storage, Distributed Energy Resources ("DERs"), and grid-modernization. ○ More effectively utilizing surplus off-peak power, thereby optimizing distribution and infrastructure costs.

E7.2.2.2 Drivers and Need

Table 3: Program Drivers – Grid Performance ESS

Trigger Driver	Reliability
Secondary Driver(s)	System Efficiency

E7.2.2.3 Reliability

Grid Performance ESS can eliminate voltage fluctuations and momentary interruptions, providing ride-through capability for customers and improving reliability of the grid. Grid Performance ESS can also provide the following benefits:

- Supply a feeder segment during an outage, reducing outage impact, improving SAIDI, and making the grid more resilient;
- Reduce peak demand on a feeder, thereby avoiding or deferring feeder or capacity upgrades; and
- Enable renewable generation.

The distribution system must be managed to balance supply and demand and ensure reliability for customers. "Reliability" is often viewed and measured through the lens of traditional factors such as peak capacity, outage avoidance, outage restoration, and grid resilience, which are priority outcomes particularly for customers averse to supply interruptions. At the same time, many customers on the modern distribution system not only value service continuity but also expect reliable supply in terms of high quality power that meets the operational needs of their voltage-sensitive equipment and processes. In this context, and due to an increasingly complex network of distribution assets and loads (including a growing population of DERs), utilities are increasingly having to manage bi-directional power flow, voltage regulation and power quality in addition to traditional reliability factors.

Poor power quality, most easily understood as lights flickering due to voltage fluctuations, can cause interruptions to customer owned equipment. Increasingly, critical customers (advanced manufacturing, information technology service providers, research institutions, hospitals, etc.) are installing sophisticated sensitive electronic equipment, including digital sensing and control equipment that cannot tolerate voltage dips, spikes and harmonics on Toronto Hydro's distribution system. Line disturbances and voltage fluctuations can originate from a number of sources, including traditional loads, switching devices used in the transmission and distribution systems, renewable generation and other distributed generation systems. As their operations evolve, customers, particularly those with loads over 1 MW, are demanding that the performance of the distribution grid keep up with their requirements. This means ensuring sufficient capacity and ride-through functionality to avoid outages and momentary events, regulate voltage within desired operating ranges and address transients generally caused by upstream transmission and distribution equipment. The reliability concerns of customers related to these types of disturbances can be mitigated with ESS.

As part of Toronto Hydro's customer engagement process, key account customers were asked a series of questions and to rank their priorities. Key account customers ranked reliable electrical service as their top priority. Further, in response to this open-ended question, "Is there anything else Toronto Hydro can do?", 13 percent of respondents cited improvements to power quality in their answers. Figure 2 below is a summary of their responses.

Customers other than industrial and institutional customers can also benefit from Grid Performance ESS to meet their reliability needs. Even homes and small businesses can suffer from the effects of voltage fluctuations and momentary outages. For example, overvoltages can damage household

electronics and appliances. Elevators and HVAC equipment used in Toronto's extensive multi-unit residential buildings and large commercial buildings are increasingly sensitive to similar reliability disruptions.

During customer engagement, Toronto Hydro received feedback that customers support improving grid performance in parts of the city that experience lower reliability, particularly where it clearly has a disruptive effect on customers.

Given their experiences, sophistication, and insights, key account customers have made them important advisors to Toronto Hydro as the utility works to identify and better understand reliability issues and related customer needs, especially complex challenges such as poor power quality. As of May 2018, Toronto Hydro has 459 customers with loads above 1 MW, including 251 key account customers with ION meters, which are a special type of revenue meter with built-in power quality monitoring.

The approach and technology used to investigate and solve these reliability challenges have evolved over the years from installing mechanical chart recorders that could only identify gross attributes of power supply, to the current use of digital equipment capable of identifying harmonics, fast rising voltage, current fluctuations, and other line disturbances caused by modern switching equipment not previously available for use on the distribution system. Equipment in use today, along with advanced data and information available from upstream and downstream sources, is also able to identify the cause of the disturbance in most cases. Toronto Hydro has learned that some line disturbances can stem from upstream transmission and distribution equipment, and from disturbances on other feeders sharing a common bus.

Figures 2 and 3 below illustrate several types of voltage disturbances, and their respective contribution to the total disturbances across Toronto Hydro's system.

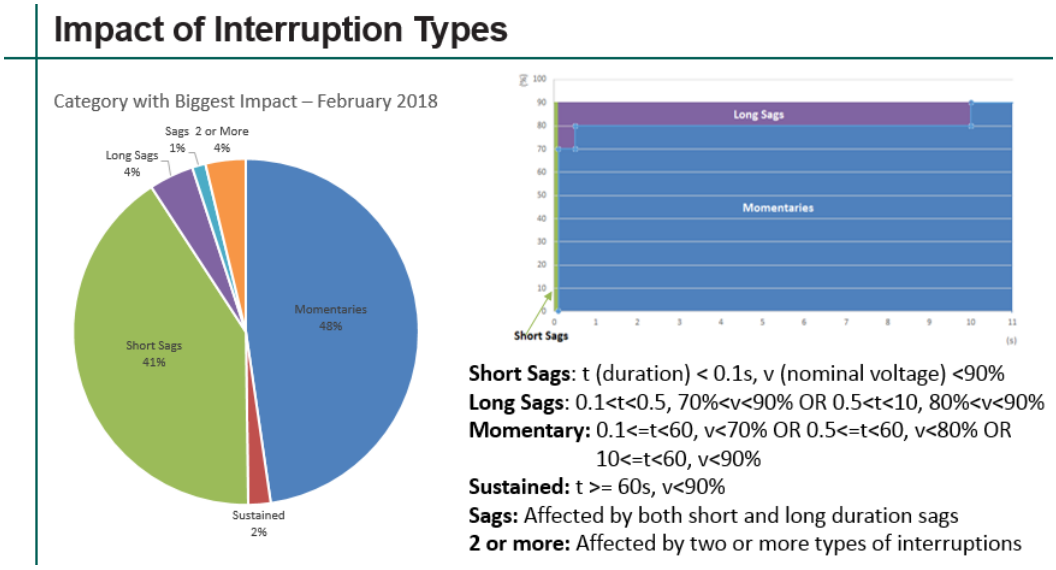


Figure 2: Categories of Line Disturbances

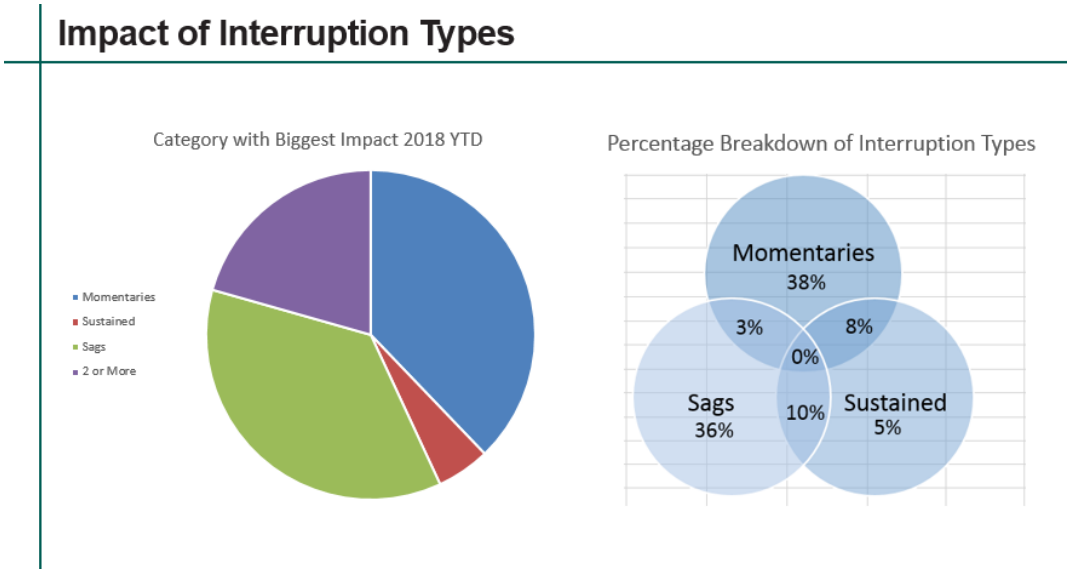


Figure 3: Contribution of Line Disturbances to System Total

Momentary interruptions and voltage sags constitute the vast majority of voltage disturbances on Toronto Hydro's system. These disturbances are typically associated with large current draws on the feeder or bus from large loads coming on line, tree contacts with overhead feeders, and other short duration events such as momentary feeder faults. Toronto Hydro uses an auto-reclose scheme to automatically reclose breakers when they operate due to a fault and then lock out if the fault is not

cleared. This practice allows a momentary outage from temporary faults (which are mainly caused by tree contacts with overhead lines) in favour of increasing the frequency of sustained outages. While this practice does serve to minimize sustained outages, the resulting line disturbance can impact other feeders on the same bus and cause power quality problems and service interruption for customers on those feeders if they cannot ride through the line disturbances.

Table 4 below lists the momentary interruptions (excluding voltage sags) associated with transformer stations from 2013 to 2017. Since their duration do not exceed 60 seconds, these momentary events are not reflected in the sustained duration (SAIDI) or frequency (SAIFI) statistics. Voltage sags are tracked at the feeder level using ION meters at customer locations and are not shown in Table 4. However, voltage sags and momentary interruptions are generally closely linked and correlated. As such, the momentary interruption data shown in Table 4 is a useful screening tool for the purposes of addressing voltage sags for customers and prioritizing efforts on feeders associated with those stations.

1 **Table 4: Stations with Momentary Interruptions 2013-2017 (excluding Major Events)**

STATION NAME	2013	2014	2015	2016	2017	AVERAGE
AGINCOURT TS	24	36	27	20	13	24.0
BASIN TS	6	10	9	7	4	7.2
BATHURST I TS	34	24	25	25	24	26.4
BATHURST II TS	25	36	19	24	19	24.6
BERMONDSEY I TS	17	19	19	21	22	19.6
BERMONDSEY II TS	23	21	10	14	15	16.6
BRIDGMAN TS	2	0	4	8	3	3.4
CARLAW TS	8	14	12	22	18	14.8
CAVANAGH TS	38	51	53	48	26	43.2
CECIL TS	1	0	0	0	0	0.2
DUFFERIN TS	32	36	27	44	41	36.0
DUPLEX TS	7	10	8	20	3	9.6
ELLESMERE TS	37	39	46	44	33	39.8
ESPLANADE TS	0	1	0	0	0	0.2
FAIRBANKS I TS	20	18	25	22	21	21.2
FAIRBANKS II TS	15	19	18	11	23	17.2
FAIRCHILD I TS	17	32	37	36	29	30.2
FAIRCHILD II TS	19	13	17	15	16	16.0
FINCH I TS	20	20	21	11	24	19.2
FINCH II TS	24	25	27	30	22	25.6
GLENGROVE TS	9	8	9	11	7	8.8
HORNER TS	43	23	37	35	30	33.6
LEASIDE TS	23	27	16	21	16	20.6
LESLIE I TS	26	20	19	22	23	22.0
LESLIE II TS	32	59	48	29	21	37.8
MAIN TS	8	7	11	5	10	8.2
MALVERN TS	11	31	23	8	8	16.2
MANBY TS	29	42	38	18	31	31.6
REXDALE TS	33	46	25	46	33	36.6
RICHVIEW TS	44	49	59	42	66	52.0
RUNNYMEDE TS	42	37	50	30	29	37.6
SCARBOROUGH EAST TS	20	15	47	17	19	23.6
SCARBOROUGH WEST TS	27	36	32	27	29	30.2
SHEPPARD EAST TS	22	27	22	26	16	22.6
SHEPPARD WEST TS	32	40	34	24	15	29.0
STRACHAN TS	18	18	18	19	12	17.0
TERAULEY TS	0	1	0	0	0	0.2
WARDEN TS	48	46	46	46	51	47.4
WILTSHIRE TS	2	2	2	2	3	2.2
WOODBRIDGE TS	3	4	8	9	4	5.6

As part of Toronto Hydro's efforts to better understand the nature and cause of unacceptable line disturbances, the utility conducted a series of case studies with a number of large customers. Figure 4 and Figure 5 below summarily illustrate the results of these studies. Three of the four cases of poor power quality were traced to upstream anomalies on the transmission and distribution system.

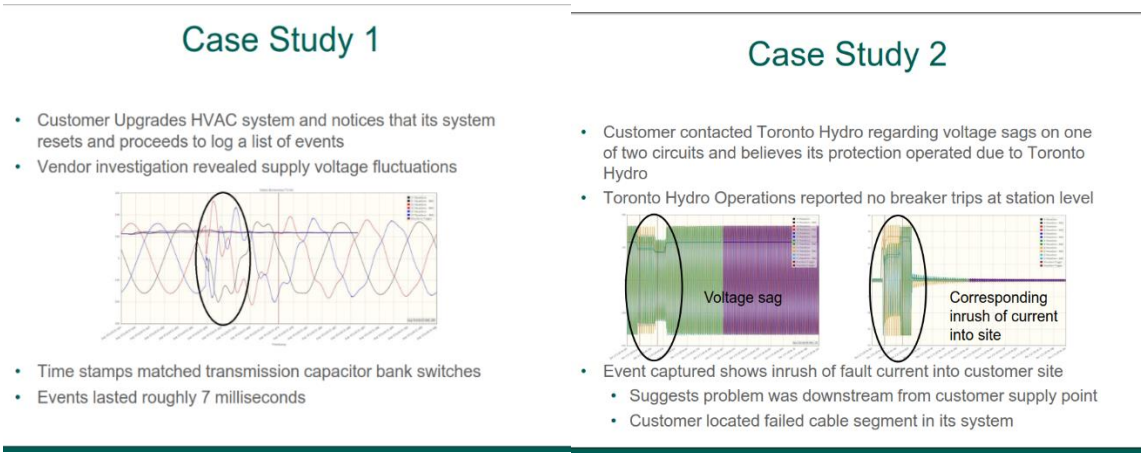


Figure 4: Power Quality Case Studies 1 and 2

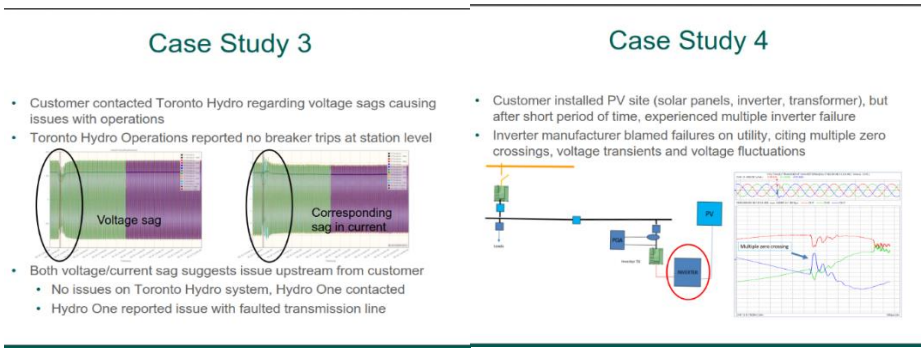


Figure 5: Power Quality Case Studies 3 and 4

In all four case studies, Toronto Hydro deployed power quality monitors to help the customer identify and investigate the disturbances they were experiencing. In particular, with respect to case study 3, power quality monitoring results indicated that voltage sag on the Hydro One transmission system was the root cause of the disturbance that manifested at the customer site. An ESS solution would have been effective in mitigating the impact of such upstream issue on customer operations.

E7.2.2.4 Expenditure Plan

Table 5: Forecast Program Costs- Grid Performance ESS Investments ($ Millions)

	2020	2021	2022	2023	2024
Grid Performance ESS Projects	-	2.7	2.8	-	-

Toronto Hydro proposes to install aggregate capacity of 8 MW/4 MWh of Grid Performance ESS over the forecast period, at a total cost of $5.5 million. These projects will be implemented in 2021 and 2022. Building on the consultations with key account customers and case studies performed to date, Toronto Hydro plans to identify and prioritize suitable sites for Grid Performance ESS investments based on the following screening factors:

1) Feeder has at least one customer with an ION meter (or soon to be installed) that can track the benefits of the Grid Performance ESS;
2) Load criticality, including benefit to vital services and comparative economic contribution;
3) Worst performing feeders; and
4) Benefits to other area customers

To support installations starting in 2021, the screening, customer engagement and selection of key account customers for Grid Performance ESS deployment is proposed to be completed during 2020 along with the required design and procurement. Similarly, the preparatory work necessary to support the 2022 installations is proposed be completed in 2021.

One of the projects considered in this segment involves the 88M43 feeder from Richview TS. As is shown in Table 6 below, between 2015 and 2017, this Richview TS feeder experienced on average 5 momentary interruptions per year (which is the highest out of all transmission stations in Toronto Hydro's service territory) and 11 potential voltage sage events per year. Customers that would benefit from a Grid Performance ESS on this feeder include a manufacturing facility (1-2 MW peak) that has experienced poor reliability. In this example, Grid Performance ESS would eliminate voltage

sags and momentary interruptions, reducing the average number of interruptions for this customer and other customers downstream of the ESS (from 17 to one interruption per year). An ESS could also provide benefits such as outage impact reduction, as described in section E7.2.2.3.

Table 6: Example Customer Reliability (88M43) Prior to Grid Performance ESS

Reliability Statistics	2015	2016	2017	Average
Momentary	5	6	8	**6.3**
Sustained	1	1	2	**1.3**
Hydro One Event	0	0	1	**0.3**
Potential Sag	7	14	22	**14.3**

E7.2.2.5 Options Analysis

1. Option 1: Do nothing

Toronto Hydro has been monitoring and working with key account customers to assess and understand the nature of power quality issues impacting their service and the associated system components. The majority of the feeder disturbances analyzed to date originated upstream of the impacted customers' service entrance equipment. Toronto Hydro has an obligation to address these system issues.

Commercial and industrial customers have informed Toronto Hydro that power quality and reliability are more important considerations than price due to the high cost of service interruptions caused by outages and feeder disturbances[7]. In some cases customers may choose to expand outside the city due to power quality issues, thereby adversely affecting economic growth and employment opportunities within the community.

Toronto Hydro continues to see a rapid pace of DER growth in its service territory, and expects that almost 60 feeders will be unable to support additional renewable generation by 2024. The role of storage in supporting renewable generation is well established. Although the ESS proposed for reliability improvement is not specifically targeted at feeders saturated with DERs, the screening criteria give credit to projects where these synergistic opportunities exist. The candidate feeders and distribution components will benefit from energy storage capacity, through improved reliability, increased efficiency, and expanded capacity for renewable generation.

[7] Exhibit 1B, Schedule 9, Appendix A

The do nothing option is not considered an acceptable solution, since it would not be responsive to customer expectations. Not addressing customer needs will result in continued adverse impact on customer operations (particularly those with sensitive power equipment) and potential economic loss for the customers, utility and local community over time.

2. Option 2: Conventional Wires Options

Conventional wires options can include new feeders, feeder rebuilds, placing lines underground, upgrading stations and building new stations. At the feeder level, a traditional approach is to establish regulated zones on feeders using capacitor banks and reactive power compensators (regulators). Additionally, under load tap changers are often used to increase and decrease line voltage in response to changes in line loading. These traditional approaches to regulation can solve certain power quality issues; however, the dynamic nature of the load along a feeder makes it impossible to achieve adequate regulation in response to load changes and high frequency transients. This technology is too slow to react to line disturbances and voltage can only be adjusted in fixed increments given the design of the tap changers.

Overhead feeders can be placed underground to substantially eliminate momentary interruptions, however such projects are in the order of tens of millions of dollars and cannot be justified based on tree and animal contact avoidance alone. In cases where line disturbances are associated with other feeders on the common bus, more than one overhead feeder may need to be converted to underground. This scale of intervention is inappropriate for solving power quality problems on a feeder segment affecting a relatively small number of customers.

Vegetation management practices, including aggressive cut back, can reduce (not eliminate) tree contacts but must be balanced with City policy and community acceptance given the importance of Toronto's tree canopy. Additionally, animal guards have been applied to reduce animal contacts and resulting feeder disturbances and outages. Different designs have been developed over many years to combat this problem with considerable success. Nevertheless, these designs and activities are insufficient to address the power quality problems these customers experience.

3. Option 3: Conventional Power Electronics Option

The conventional power electronics option involves using regulating devices to mitigate voltage drops (e.g. falling to 50 percent of nominal values for under 10 seconds). Conventional solutions include Static Synchronous Compensator ("STATCOM") and Static VAR Compensator ("SVC").

STATCOMs and SVCs employ power electronics and capacitors to absorb or supply reactive energy in order to regulate voltage. Since capacitors can store a very limited amount of energy, neither STATCOMs nor SVCs are intended to function as energy sources for the purpose of supplying load. As a result, they can provide limited benefit to customers. The differences between STATCOMs and SVCs include stability under varying voltage levels, response speed, and harmonic emissions.

Due to their limited capabilities and benefits, the deployment of STATCOMs and SVCs are not recommended as a solution.

4. Option 4: Do More and Accelerated Spend Options

Grid Performance ESS is an emerging segment based on evolving battery technology functionality, declining ESS costs, and changing customer needs and preferences. There is a risk that these drivers of adoption may prompt more customer interest in Grid Performance ESS than forecasted. There is also a risk that upon closer examination of Customer-Specific ESS projects, one or more of those projects may be reclassified as Grid Performance ESS.

5. Option 5 (Selected Option): Proposed Solution

The installation of appropriately sized Grid Performance ESS on the distribution system offers the best solution to address the upstream line disturbances impacting Toronto Hydro's customers. This solution offers targeted, local line regulation and ride-through capacity for significant reliability events, including voltage sags on feeders. Battery ESS is a "non-wires alternative" that has the ability to offer a lower cost alternative to conventional distribution infrastructure investment. It can also provide additional system and customer benefits that cannot be provided by conventional wires options. These benefits include outage reduction, peak shaving/shifting, and renewable generation enablement.

E7.2.2.6 Execution Risks and Mitigation

These are addressed for the entire ESS program in Section 7.2.5.

E7.2.3 Renewable Enabling ESS

E7.2.3.1 Outcomes and Measures

Table 7: Outcomes & Measures Summary

Customer Service	• Contributes to Toronto Hydro's customer service objectives by enabling customer investments in renewable energy and reducing energy costs.
Reliability	• Contributes to service reliability.
Financial	• Contributes to Toronto Hydro's financial objectives and performance by enabling the deferral of system generation, transmission, and distribution investments.
Public Policy	• Contributes to Toronto Hydro's public policy objectives by: ○ Creating the stacked benefits of utility ESS projects that were recognized in the 2017 Long-Term Energy Plan ("LTEP"); ○ Reducing GHG emissions by enabling the proliferation of energy storage, DERs, and grid-modernization; and ○ More effectively utilizing surplus off-peak power, thereby optimizing distribution and infrastructure costs.

E7.2.3.2 Drivers and Need

Table 8: Program Drivers

Trigger Driver	Public Policy
Secondary Driver(s)	System Efficiency

Applicable policy and economic conditions, together with the preferences of customers and consumers, have facilitated a steady interest in distributed renewable generation projects within Toronto Hydro's service territory. This trend is expected to continue into the foreseeable future. In addition, the decreasing costs of photovoltaic panels, coupled with the end of the IESO's FIT program, have generated growing interest in the net metering initiative, including continued customer investment in renewable energy resources in the distribution system.

Based on historical trends and given the end of the FIT program in 2018, Toronto Hydro anticipates the pace of renewable energy generation ("REG") connections will begin to slow by 2019. However,

forecasted REG installations will be larger in size as compared to years past due to cost reductions in solar photovoltaic panels and net metering benefits. Between 2019 and 2024, Toronto Hydro forecasts that about 830 additional REG connections (totaling 69 MW) will be connected to its distribution system, as shown in Figures 6 and 7 below.

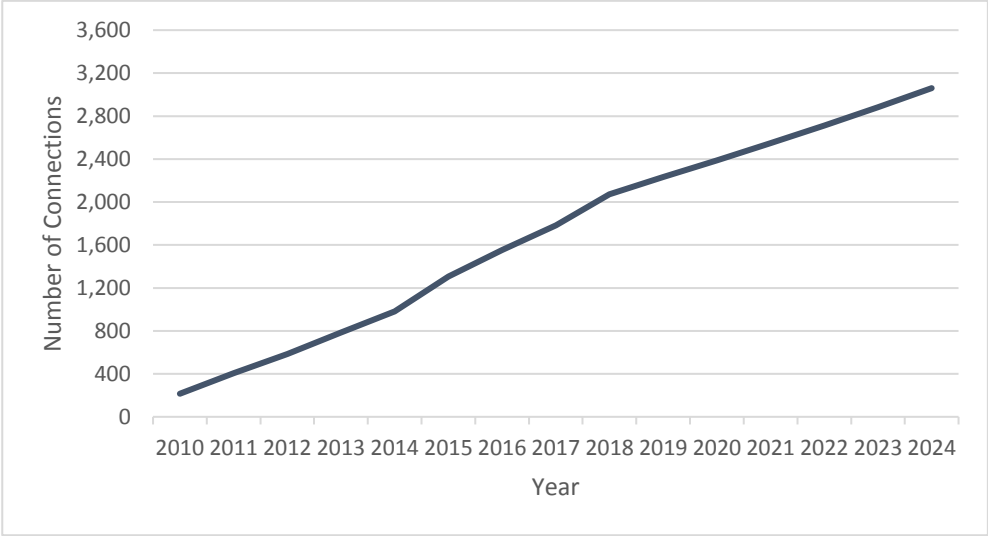


Figure 6: Forecast Renewable Generation Connections

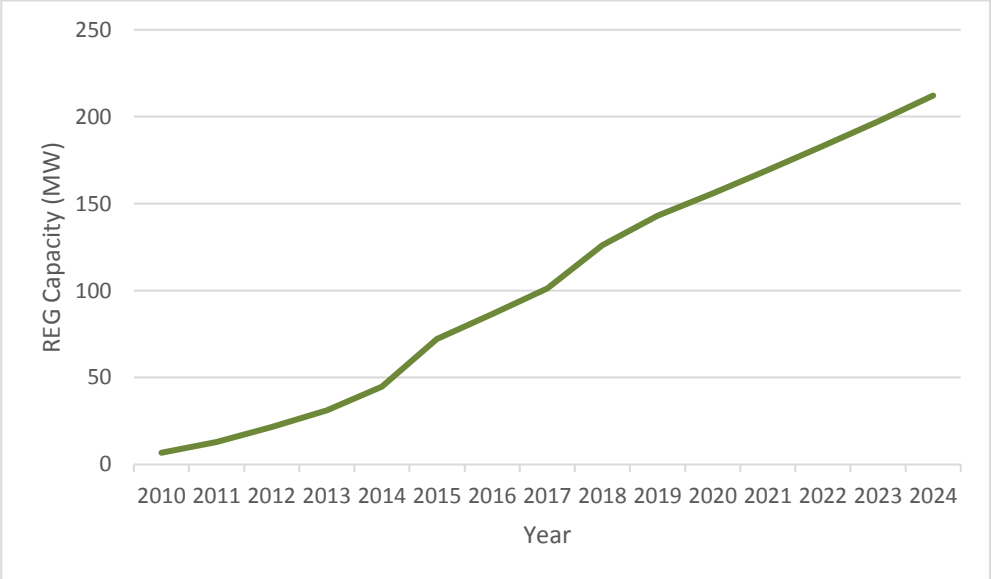
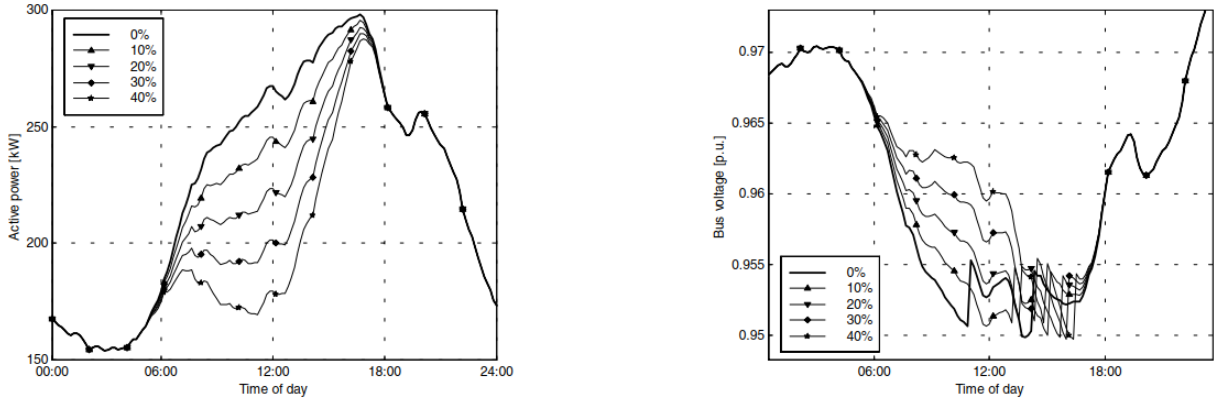


Figure 7: Forecasted Renewable Generation (MW)

Due to the expected demand for renewable generation at the distribution level, there has been a fundamental change in the power flow conditions of the distribution system, which has challenged the conventional radial nature of the grid to accommodate bi-directional power flow. Large scale deployment of REG (e.g. solar PV) causes issues in distribution system planning and operations such as reverse power flow, unintentional islanding and overvoltage on feeders. As a result, Toronto Hydro must proactively manage generation connections on feeders in order to accommodate future growth.

To illustrate the effect of REG on distribution line voltages, Figure 8 shows the load and voltage profiles at a system bus with various levels of REG on the bus.[8] As depicted, bus load begins to rise at the start of the workday at 6am. As generation comes online to support the local load demand, bus load is offset by this generation output and the bus voltage drops. As generation comes offline toward the end of the day, bus loads rise again and line voltages return to their nominal values. The higher the REG to load ratio, the more pronounced these effects become with a higher risk of potential islanding.



a) Active power at bus 53 **b) Voltage at bus 53**

Figure 8: Impacts of Renewable Generation on Bus Voltage

In the past few years, there have been numerous studies, standards and guidelines with respect to REG integration, such as IEEE Standard 1547 (Interconnecting Distributed Resources with Electric

[8] M. Begovic et. al., *Impact of Renewable Distributed Generation on Power Systems*, Proceedings of the 34th Hawaii International Conference on System Sciences (2001), available at <https://pserc.wisc.edu/ecow/get/publicatio/2000public/CSSAR01.PDF>.

Power Systems) and National Renewable Energy Laboratory's ("NREL")[9] High Penetration PV Integration Handbook for Distribution Engineers (NREL Handbook). These documents outline methods and practices to determine the maximum allowable generation on the distribution system (e.g. that DR aggregate capacity is less than one-third of the minimum load of the Local Electric Power System ("EPS")). As the ratio of generation capacity to minimum load[10] increases, the amount of time required by inverters to respond to anti-islanding scenarios increases and the likelihood of effective inverter response to anti-islanding scenarios decreases.

Toronto Hydro conducted an analysis for all feeders in its system to establish generation to minimum load ratios, stiffness factors[11], and fault ratio factors[12] in accordance with applicable guidance of the NREL. The study found that 13 feeders currently exceed the one third generation to minimum load screening ratio outlined by the NREL Handbook. It was also determined that if short circuit capacity constraints at the transformer station were ignored, given the forecast growth in REG, by 2024, an additional 45 feeders would exceed the generation to minimum load ratio.

These findings indicate a high penetration of REG in certain parts of Toronto Hydro's distribution system, which will increase the probability of serious issues such as unintentional islanding conditions. This will adversely affect the utility's ability to safely and reliably connect additional REG to the distribution system and, if not addressed by proactive investments, could ultimately lead to an increase in declined applications for connections in a region with a growing appetite for REG. An overview of these findings, as well as the ESS required to address expected exceedances of the generation-to-minimum load ratio, can be found in Table 9 below.

[9] The National Renewable Energy Laboratory (NREL) specializes in renewable energy and energy efficiency research and development and is a reputable authority on the level of penetration of renewables on electricity systems. It is a government-owned, contractor operated facility that is funded through the United States Department of Energy.
[10] Determined as the ratio of aggregate DG capacity on a particular power system section to the annual minimum load on that power system section.
[11] Determined as available utility fault current divided by DG rated output current in affected area.
[12] Determined as available utility fault current divided by DG fault contribution in affected area.

Table 9: Generation to Minimum Load Ratio Summary for Toronto Hydro Feeders

	Generation to Minimum Load Ratio					
	Existing – Dec 2017			Outlook by 2024		
Description	> 1/3	> 1/2	2/3	> 1/3	> 1/2	2/3
No. of Feeders Exceeding Applicable Ratio	13	0	0	58	51	31
ESS Required to Mitigate All Feeders to Applicable Ratio	5.8 MW/ 23.3 MWh	N/A	N/A	156 MW/ 624 MWh	62.5 MW/ 250 MWh	24.5 MW/ 98 MWh

Renewable Enabling ESS can be deployed on such feeders in order to lower the generation to minimum load ratio. At times during the day when the ratio is high, the ESS can function like a load by absorbing energy; whereas when the ratio is low, the ESS can act like a generator by supplying energy.

An overview of the analysis of seven representative feeders on Toronto Hydro's system can be found in Table 10 below.

Table 10: Generation Screening Ratio - 2024 Outlook Summary for Four Toronto Hydro Feeders

Feeder Name	TS Station - Bus	Region	Minimum Load (MW)	Existing DER (MW)	Gen to Load Ratio (Existing)	DER Outlook (MW)	Gen to Load Ratio (2024 Outlook)
51-M32	*Leslie – Q*	North York	2.39	0.45	0.19	1.09	0.46
51-M25	*Leslie – J*		2.58	1.68	0.17	2.23	0.38
80-M27	*Fairchild – J*		2.01	0.01	0.00	1.03	0.51
63-M6	*Agincourt – Y*	Scarborough	6.88	2.93	0.43	4.10	0.60
47-M1	*Sheppard – B*		3.54	1.76	0.50	2.15	0.61
R29-M36	*Rexdale – Q*	Etobicoke	3.82	0.88	0.23	1.78	0.47
11-M5	*Runnymede - B*	Toronto	2.63	0.39	0.15	1.04	0.39

Table 10 provides the NREL screening ratios for seven feeders in Etobicoke, North York, Scarborough and the former City of Toronto. The assessment indicates the following findings:

- **63-M6 & 47-M1 (Scarborough)**: already exceeds generation to minimum load ratio (in red);
- **51-M32 & 51-M32 (North York), R29-M36 (Etobicoke)**: currently have moderate generation to minimum load ratio for (orange); and
- **51-M32, 51-M25, 80-M27, R29-M36 & 11-M5**: exceeds generation to minimum load ratio for 2024 Outlook

In short, the screening ratios show that by 2024 all seven feeders will have a high penetration of PV generation and that they all will require grid investments or other solutions to ensure the safety of the grid and allow further REG connections.

As part of its DER process, Toronto Hydro offers a pre-application report for its customers, providing information about the proposed point of interconnection so the customer can determine if a DER system installation is worth pursuing. This process also allows Toronto Hydro the opportunity to gauge customer interest in DER and forecast potential DER growth on its distribution system. Pre-application reports help customers prepare successful applications while avoiding the need for Toronto Hydro to perform detailed studies on applications that are not likely to be proceed due to customer concerns.

The pre-application process also allows Toronto Hydro to discover potential distribution system issues that must be addressed to accommodate the proposed DER. In such instances, Toronto Hydro would work with the customer to find the best solution to move the DER installation forward, such as modifying the proposed system to satisfy the pre-application screening. Although Toronto Hydro has been able to manage DER customer expectations to date through this pre-application process, the distribution system is approaching its technical limits and Renewable Enabling ESS investments will be required to accommodate future DER growth.

When assessing the potential to connect a DG project, Toronto Hydro planning engineers determine if a feeder's phase current imbalance exceeds 10 percent of the total load on the feeder (at the station) when DG is added to the feeder. Phase imbalances in general result in a return current on the neutral conductor, causing line losses and, in cases of considerable imbalance, cable splice failures due to overheating. If the DG causes the current imbalance to exceed the 10 percent threshold, the imbalance must be corrected. One such correction method is to redistribute load among the other phases of the feeder, which is technically and operationally complex. Where load distribution is not possible, DG applications must be rejected. Renewable Enabling ESS can address this issue by dynamically balancing phases to respect the 10 percent threshold, without having to redistribute load to different phases. In both the short and long term, this approach is expected to resolve connection barriers for many projects seeking connection in a local area.

ESS is recognized as an effective distribution system solution to increase the PV connection capacity. [13] Not only does ESS present remarkable synergies with REG, Renewable Enabling ESS can also be used to improve system performance by reducing outage impact and shifting/shaving feeder peaks, as described in section 7.2.2.3.

E7.2.3.3 Expenditure Plan

Table 11 and Table 12 below summarize the REI ESS Program plan for 2015-2019.

Table 11: 2015-2019 CIR – Renewable Enabling Investments (Projects)

Assets (Units)	2015	2016	2017	2018	2019	Total (Units)
Local Support Energy Storage (LSES) System *(100 kW × 1 hr)*	1	2	3	3	3	12
Grid Support Energy Storage (GSES) System *(200 kW × 2.5 hrs)*	1	1	2	2	2	8
Municipal Station Energy Storage (MSES) System *(400 kW & 3 hrs)*	0	1	1	1	1	4

Table 12: 2015-2019 CIR – Renewable Enabling Investments ($ Millions)

	2015	2016	2017	2018	2019	Total
REI Investments	**$0.54**	**$1.09**	**$2.16**	**$3.24**	**$3.78**	**$10.8**

Table 13 below summarizes the actual and bridge year investments over the 2015-2019 period.

Table 13: Actual and Bridge Costs- Renewable Enabling Investments ($ Millions)

	Actual			Bridge	
	2015	2016	2017	2018	2019
REI Investments	-	-		**$5.9**	**$2.0**

[13] For example, see:
(i) J. Seuss, M. J. Reno, et al, "Improving distribution network PV hosting capacity via smart inverter reactive power support", Proc. IEEE PES General Meeting, July 2015, pp. 1–5.
(ii) Z. Waclawek, et al, "Sizing of photovoltaic power and storage system for optimized hosting capacity", Proc. IEEE International Conference on Environment and Electrical Engineering, June 2016, pp. 1–5.
(iii) B. P. Bhattarai, et al, "Overvoltage mitigation using coordinated control of demand response and grid-tied photovoltaics", Proc. IEEE SusTech, Jul 2015.
(iv) F. Capitanescu, et al, "Assessing the potential of network reconfiguration to improve distributed generation hosting capacity in active distribution systems", IEEE Transactions on Power Systems, Jan 2015, vol. 30, no. 1, pp. 346–356.
(v) Y. Takenobu, et al, "Maximizing hosting capacity of distributed generation by network reconfiguration in distribution system", Proc. Power Systems Computation Conference (PSCC), June 2016, pp. 1–7.

1. 2015-2019 CIR Energy Storage Systems ("ESS") Program

The 2015-2019 ESS program presented in the 2015-2019 CIR was designed to improve system efficiency, reliability and power quality, and to enable the connection of renewable generation and electric vehicles. Toronto Hydro's original plan involved $10.8 million to support 24 ESS installations. These were spread across 12 Local Support Energy Storage ("LSES") systems, eight Grid Support Energy Storage ("GSES") systems and four Municipal Station Energy Storage ("MSES") systems. The original plan was subsequently modified to reflect technology advancements and emerging customer needs. In the meantime, Toronto Hydro has been implementing various energy storage pilot/innovation projects and connecting customer storage projects. The data, experience and lessons learned from these projects have helped Toronto Hydro to:

- understand the benefits and requirements for safely integrating ESS into the distribution system;
- learn from the experiences of host customers regarding the benefits they derive from ESS;
- plan and design the 2020-2024 ESS projects;
- modernize the grid and prepare for future growth;
- satisfy customer desire to invest in innovative technologies; and
- explore new opportunities for both customers and Toronto Hydro to realize the benefits of DER.

By the end of 2019, Renewable Enabling ESS projects will be completed on two feeders with the highest generation to minimum load ratio, located at Sheppard TS and Agincourt TS, as further discussed below.

a. 2018- 2019 Forecast Expenditures

Based on applicable guidelines and supporting business cases, Toronto Hydro plans to install two Renewable Enabling ESS units totalling approximately $7.9 million with aggregate capacity of 3.75 MW/15 MWh to help mitigate existing generation to minimum load issues for two feeders over the 2018-2019 period. An overview of the candidate feeders, along with the sizing and cost of each ESS unit is detailed in the table below.

Table 14: Renewable ESS

No.	Feeder Name	Station	Bus	Gen to Min Load Ratio	ESS (MW)	ESS (MWh)	ESS Cost ($M)
1	***47-M1***	*Sheppard TS*	B	0.50	1.75	7.0	3.6
2	***63-M6***	*Agincourt TS*	Y	0.43	2.00	8.0	4.3
Total					**3.75**	**15**	**7.9**

2. 2020- 2024 Forecast Expenditures

During 2020-2024, Toronto Hydro plans to install three Renewable Enabling ESS units totalling approximately $5 million and 2.35 MW/9.5 MWh to help mitigate forecasted generation to minimum load levels at three feeders.

Table 15: Forecast Program Costs- Renewable Enabling ESS Investments ($ Millions)

	Forecast				
	2020	**2021**	**2022**	**2023**	**2024**
REI Investments	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**

As mentioned earlier, due to forecasted DER growth by 2024, an additional 45 feeders on Toronto Hydro's distribution system will exceed the generation to minimum load ratio. Therefore, the necessary ESS required to mitigate these issues on all the feeders will range in size from 0.35 MW/1.4 MWh to 9 MW/36 MWh and range in cost from $0.8 million to $19 million. In order to mitigate all these feeders with ESS, it would cost roughly $217 million. As this cost figure indicates, ESS is not always the most economic REI option. Having regard to economics and other benefits, Toronto Hydro has planned wires solutions in most of these instances while proposing $5 million for Renewable Enabling ESS. The table below provides an overview of the proposed ESS projects for the feeders that are suitable for Renewable Enabling ESS investments.

Table 16: Feeders Proposed for Renewable Enabling ESS

No.	Feeder	Station	Bus	Gen to Min Load Ratio	ESS (MW)	ESS (MWh)	ESS Cost ($M)	ESS Start Year	ESS Completion Year
1	***51-M25***	*Leslie TS*	J	0.38	0.35	1.40	$0.8	2020	2020
2	***51-M32***	*Leslie TS*	Q	0.46	0.90	3.60	$1.9	2020	2022
3	***80-M27***	*Fairchild TS*	J	0.51	1.10	4.50	$2.3	2022	2024
TOTAL					**2.35**	**9.50**	**$5.0**	**-**	**-**

Toronto Hydro plans to pace the work uniformly in each year during 2020-2024. To accomplish this pacing, Toronto Hydro will commence work on the 51-M25 Leslie feeder in 2020, the 51-M32 Leslie feeder over three years (2020 to 2022), and the 80-M27 Fairchild feeder over three years (2022 to 2024).

Based on industry studies, Renewable Enabling ESS can be installed anywhere along a feeder in order to help mitigate concerns regarding generation to minimum load ratio. Therefore, to avoid additional costs, the proposed ESS units could potentially be connected to existing Toronto Hydro assets (i.e. padmounted transformers) that can accommodate the nameplate capacity and necessary footprint and layout. If such assets and locations cannot be established, then new assets (i.e. transformer) will be installed to accommodate the proposed ESS.

E7.2.3.4 Options Analysis

1. Option 1: Do nothing

Some feeders in Toronto Hydro's territory currently exceed the acceptable generation to minimum load ratios and more than 50 feeders are forecast to exceed acceptable ratios by 2024. If no action is taken, forecast demand for DG, including REG, cannot be safely accommodated in Toronto. This would put Toronto Hydro in non-compliance with its obligation to connect renewable generation (i.e. pursuant to Section 6.2.4 of the Distribution System Code). Further, customers willing to invest in modernizing the grid will be frustrated, and the associated grid and upstream benefits will not be realized, contrary to the opportunities identified in the Long-term Energy Plan.

2. Option 2: Traditional "poles and wires" solutions

Traditional "poles and wires" solutions include upgrading or constructing additional primary distribution infrastructure (e.g. feeder lines, cables, transformers), modifying protection schemes, implementing direct transfer trip schemes and installing monitoring and control devices. Given the current state of technology and associated costs, traditional solutions are the best option to enable the connection of DER in most cases (but not in all cases). While Toronto Hydro has the Generation Protection Monitoring & Control program to address system-wide issues to enable DER, some localized areas would still experience issues involving generation to minimum load ratio and/or feeder phase imbalances, which can inhibit the connection of a DER project. These specific issues can be addressed with a targeted deployment of ESS.

Feeder re-configurations could also be performed to increase load on forecasted feeders where generation to minimum load ratios are high. However, this method may decrease reliability and may not always be feasible due to the existing network configuration.

3. Option 3: Production Curtailment and Decreasing Operational Margin

With better resource monitoring/forecasting and real-time estimation of the grid capacity, applicable operational margins can be reduced. This in turns allows the existing infrastructure to be used more efficiently and to a greater extent (i.e. with a higher capacity factor). For more detailed information regarding this option, please refer to the Generation Protection, Monitoring, and Control Program.[14]

Curtailment occurs when plants are required to reduce their generation output in order to maintain the operational limits of the grid. This may entail a small gradual decrease of the production (referred to as soft curtailment) or a complete stop to production through measures such as inter-tripping (referred to as hard curtailment). Soft curtailment requires a communication infrastructure and methods to assess the real-time performance of the grid and the appropriate production decrease. In a deregulated market without vertically integrated utilities, it requires willingness from grid users to participate and a legal framework enabling such participation. Moreover, economic arrangements are required to allocate the loss of income stemming from curtailed production.

As such, curtailment is not currently seen as a viable option.

4. Option 4: Do More and Accelerated Spend

Renewable Enabling ESS is customer driven. Spending more or spending more quickly than forecasted is a risk associated with any customer driven program. The proposed option is based on forecasted uptake of distributed renewable generation in the service area.

5. Option 5 (Selected Option): Proposed Solution

The proposed Renewable Enabling ESS program will provide Toronto Hydro with strategic capabilities to address specific issues relating to DG/REG enablement in targeted areas of its distribution system. It will allow Toronto Hydro to mitigate the problems described in sub-section 1 of Section 7.2.3.2 and fulfill its regulatory obligations to connect REG projects pursuant to the DSC. The proposed solution also best positions Toronto Hydro to support the goals of the Long-Term Energy Plan with respect to

[14] Exhibit 2B, Section E5.5

enabling renewable generation and deploying energy storage. It is expected that these investments will enable the aggregate connection of 5 MW of REG which would otherwise be constrained. The overall cost of this option is an estimated $5 million over the 2020 to 2024 period.

E7.2.3.5 Execution Risks and Mitigation

These are addressed for the entire ESS program in Section 7.2.5.

E7.2.4 Customer Driven ESS

E7.2.4.1 Outcomes and Measures

Table 17: Outcomes and Measures Summary

Customer Service	• Contributes to Toronto Hydro's customer service objectives by: ○ Reducing power outages and customer interruption costs. ○ Providing backup power during emergency situations for critical customers (e.g. emergency services, hospitals, government buildings etc.). ○ Enabling Global Adjustment relief for Class A customers. ○ Providing future opportunity to leverage DR and grid capacity relief, thereby avoiding or deferring the need for distribution infrastructure investments.
Reliability	• Contributes to Toronto Hydro's system reliability objectives and performance by enhancing power quality, and ensuring dynamic feeder voltage support, low harmonics and uninterrupted service.
Financial	• Contributes to Toronto Hydro's financial objectives and performance by supporting the satisfaction and retention of load customers and the deferral of conventional infrastructure upgrades.
Public Policy	• Contributes to Toronto Hydro's public policy objectives by: ○ Creating the stacked benefits of utility ESS projects that were recognized in the 2017 Long-Term Energy Plan (LTEP); ○ Reducing GHG emissions by supporting the proliferation of energy storage, DERs, and grid-modernization; and ○ More effectively utilizing surplus off-peak power, thereby optimizing distribution and infrastructure costs.

E7.2.4.2 Drivers and Need

Table 18: Program Drivers

Trigger Driver	Reliability
Secondary Driver(s)	Customer Economics

1. Evaluating Customer-Specific Need

As set out in section 7.2.2 (the Grid Performance ESS segment), ESS can be deployed to mitigate or resolve a number of issues for the benefit of customers. In the case of Grid Performance ESS, each project is expected to benefit multiple customers. In the Customer-Specific ESS segment, each project is expected to predominantly benefit a single customer.

Customer-Specific ESS allows Toronto Hydro to respond to customer-specific needs with a non-wires solution. This approach differs from the common industry practice of pursuing wires solutions (e.g. dedicated transformers, feeders, and transformer stations) to address customer-specific needs. Customer needs are typically made known to Toronto Hydro as part of a new or upgraded connection request or the ongoing dialogue between Toronto Hydro and customers. Customers' needs often involve increased capacity or reliability, which are driven as a function of changes in their operations. In collaboration with Toronto Hydro engineers and other professionals, customers and their advisors carry out options analysis, including cost forecasts. Given its improving functionality and decreasing costs, ESS is becoming an option that is attracting customer inquiry or being recommended by Toronto Hydro as an alternative for customer consideration. Working together with customers, Toronto Hydro ultimately arrives at a plan that will address their needs without adversely affecting grid reliability or other customers connected to the grid.

As options are reviewed with the customer driving the investment, Toronto Hydro examines whether that customer's need will be addressed through wires or non-wires investments already planned on that feeder (e.g. feeder capacity upgrades) or in the area more generally (e.g. feeder reconfigurations). If so, Toronto Hydro consults with the customer whether the timing of the investments and expected service improvements will meet relevant needs. Based on such feedback, adjustments can be made in some cases to the planned project to better address the needs of the customer.

Where a customer-specific investment closely aligns with work required to address the needs of other customers, the investment (whether in an ESS or wires solution) will proceed as a Grid

Performance project, and associated costs are considered part of the regular investment in the distribution system funded through rate base.

In other cases, customer-specific needs require an investment that only benefits that customer. While a wires solution (e.g. a dedicated feeder) is still appropriate in many situations, customers are increasingly interested in considering non-wires alternatives (e.g. Customer-Specific ESS) as part of the options analysis. Alternatives that entail individualized customer benefits result in costs that are outside of the utility's distribution system investment in the normal course. In accordance with the beneficiary pays principle, these costs are presumptively fully allocated to the customer who benefits. The customer pays for these costs through a capital contribution. As a result of the capital contribution, the asset enters rate base with a net $0 value. This is true for both wires and non-wires customer-driven investments.

2. Customer Need for Behind the Meter Investment

In addition to the above-noted customer needs, Toronto Hydro customers who are billed on a non-coincident demand basis have another need: reducing their peak demand in order to reduce their electricity bills. If these customers draw less electricity from the grid during their peak demand hour each month, they lower their electricity bill.

A subset of these customers (i.e. Class A customers) are also eligible for the Industrial Conservation Initiative ("ICI"), which creates a similar but unique need. If these customers can reduce their demand during the top five provincial peak hours of the year, their Global Adjustment charges can be reduced (potentially by a large amount) in the subsequent year. Since those five peak hours are not known until the end of the one year period, customers undertake demand reduction and peak-shaving activities multiple times per year in order to increase their chances of reducing their Global Adjustment charges.

In addition to benefiting specific customers, these load shifting investments could also have the aggregate effect of lowering the overall Ontario peak demand, thus alleviating costs throughout the electricity system for generation, transmission, and distribution. This is the intended result of the hourly price market, demand response programs, and the ICI.

Customer-Specific ESS can help Toronto Hydro customers achieve the desired peak shaving – whether as a stand-alone benefit or in tandem with other customer benefits. ESS can store electricity during non-peak hours and discharge it during peak hours. The same ESS can be used to improve

customer-specific reliability, such as power quality enhancements, momentary outage avoidance, and increased resiliency. As such, the customer can derive both financial and reliability benefits from the same ESS asset. The costs of the investment are presumptively fully allocated to that customer, as discussed above.

Customer reliability needs can be met regardless of whether the ESS is located "in front of the meter" (i.e. traditionally thought of as "grid side") or "behind the meter" (i.e. traditionally thought of as "customer side"). That is, the physics of ESS confers distribution service benefits to the customer in either scenario. For this reason, if reliability were the only customer need that Toronto Hydro needed to address, the distribution asset would typically be located in front of the meter.

However, to meet the customer's financial need, Toronto Hydro has to site the ESS behind the meter, so that it can draw electricity during non-peak hours (for which the customer would incur the associated charges) and discharge during potential peak hours to achieve peak-shaving.

Customers generally prefer to meet both their reliability need and financial need through a single, economically efficient investment. In response, Toronto Hydro proposes to meet that need with Customer-Specific ESS projects that are located where customer benefits can be maximized.

E7.2.4.3 Expenditure Plan

Table 19 shows the gross capital expenditures for the Customer-Specific ESS segment, which is entirely funded by capital contributions from the beneficiary customers. The net impact to Toronto Hydro rate base is $0 over the 2015-2024 period.

Table 19: Bridge & Forecast Customer-Specific ESS ($ Millions)

	Bridge		Forecast					Total
	2018	2019	2020	2021	2022	2023	2024	
Metrolinx ECLRT	9.6	17.7						**27.3**
Metrolinx FWLRT			6.0	10.0				**16.0**
TTC Arrow Garage			12.3					**12.3**
Metrolinx Willowbrook Yard			6.0	2.1	5.9			**14.0**
Total	**9.6**	**17.7**	**24.3**	**12.1**	**5.9**	**0.0**	**0.0**	**69.6**

1. 2018-19 Forecast Expenditure Plan

Metrolinx Eglinton Crosstown Light Rail Transit ("ECLRT") ESS: Currently in construction, this Customer-Specific ESS project will provide emergency power, improve reliability, and reduce emissions for the ECLRT.

The ECLRT ESS is planned to be in-service in 2019, and will consist of a 10 MW/30 MWh battery system and a 100 kW PV system. The total cost of $27.3 million will be fully recovered through customer capital contribution. Located behind the meter, the ESS will enable peak-shaving by reducing coincident and non-coincident peak demand from the grid.

The ECLRT itself will span approximately 20 kilometres, starting at Mt. Dennis, located in the west-end of the city, and terminating at Kennedy station, located in the east-end of the city. The Eglinton Maintenance and Storage Facility Yard ("EMSF") will serve as a supply and charging station and will be fed by two Toronto Hydro feeders at the Mt. Dennis station.

In order to improve system reliability, resiliency and flexibility and to proactively manage power supply during peak demand periods, the ESS is designed to operate during both emergency and non-emergency scenarios. More specifically, it will provide backup power generation with the capability to deliver all the required electricity for the ECLRT traction power, including electricity required for the purposes of emergency ventilation.

ECLRT will be mainly supplied by new feeders originating from the new Runnymede TS bus that is currently in construction. From 2014 through 2017, feeders on the Runnymede TS BY Bus averaged 7.2 sustained interruptions annually. The ESS is expected to reduce the number of sustained interruptions by over 50 percent. Momentary interruptions ("MAIFI") are expected to be minimal with the new underground feeders supplying ECLRT.

2. 2020-24 Forecast Expenditure Plan

Three customers have requested that Toronto Hydro complete ESS projects from 2020-2024 to meet their distribution service needs. These projects will be designed to provide reliability improvements, peak-shaving financial relief and emergency resiliency capacity. Toronto Hydro has determined that satisfying these needs will require discrete projects, the benefits from which are only expected to accrue to each requesting customer. Accordingly, the projects are categorized as Customer-Specific

ESS investments. The requesting customers will make capital contributions such that there will be a zero net effect on rate base in the 2020-2024 period.

The proposed Customer-Specific ESS projects are discussed below.

a. Metrolinx Finch West Light Rail Transit ("FWLRT") ESS

Metrolinx's Finch West Light Rail Transit ("FWLRT") is an 11-kilometre light rail transit line that will connect the TTC's Finch West subway station (on the Yonge-University Line) to Humber College westward along Finch Ave.

The FWLRT ESS will consist of a 8 MW/24 MWh battery system across four sites. The cost of this Customer-Specific ESS project is $16 million with a planned in-service date of 2022. The project is fully funded by the customer who is responsible for capital contributions. It will provide reliability improvement, enhanced resiliency, financial relief through peak-shaving, as well as emergency power to ensure service continuity and support underground station ventilation in a sustained grid outage. During normal operation, the ESS will continuously condition the incoming supply and reduce peak demand for the FWLRT, contributing to lower GHG emissions. The ESS will be located behind the meter, enabling peak-shaving by reducing coincident and non-coincident peak demand from the grid.

FWLRT will be supplied by feeders originating from the Finch TS BY Bus. According to Toronto Hydro's feeder reliability estimate (based on the ten feeders served by that bus), feeders on the Finch TS BY Bus averaged 5.1 sustained interruptions annually between 2014 through 2017. The ESS is expected to reduce sustained interruptions, momentary interruptions, and voltage sags by over 50 percent.

b. TTC Arrow Road Garage ESS

This large TTC public transit garage is located on Arrow Road near Finch Avenue and Highway 400 in the north end of Toronto. The TTC is investing in the facility such that it is expected to eventually support approximately 250-300 electric buses.

The TTC Arrow Road Garage ESS project will provide reliability improvements, resiliency, financial relief through peak-shaving, and emergency capacity. The cost of this Customer-Specific ESS project is $12.3 million with a planned in-service date of 2020. The project is fully funded by the customer through capital contributions. The ESS will be located behind the meter, enabling peak-shaving by reducing coincident and non-coincident peak demand from the grid.

The TTC Arrow Garage ESS will consist of a 5 MW/20 MWh battery system. The ESS will augment planned feeder upgrades at this site as part of the customer's project to deploy electric buses. During normal operation, the ESS will continuously condition the incoming supply and reduce peak demand for the TTC Arrow Garage.

Arrow Road Garage is supplied by a feeder (55-M29) originating from the Finch TS JQ Bus. During 2014-2017, 55-M29 averaged 4.5 sustained interruptions annually. The ESS is expected to reduce sustained interruptions, momentary interruptions, and voltage sags by over 50 percent.

3. Metrolinx Willowbrook Yard ESS

Metrolinx operates a large rail maintenance yard at Willowbrook in Etobicoke which services the busy regional rail lines on the lakeshore corridor.

The Willowbrook Yard ESS consists of a 8 MW/24 MWh battery system. The cost of this Customer-Specific ESS project is $14 million with a planned in-service date of 2022. The project is fully funded by the customer through capital contributions. It will provide reliability improvements, resiliency, financial relief through peak-shaving and emergency power.

During normal operation, the ESS will continuously condition the incoming supply and reduce peak demand for Willowbrook. The ESS will be located behind the meter and enable peak-shaving by reducing coincident and non-coincident peak demand from the grid.

Willowbrook Yard is supplied by a feeder (R30-M8) originating from the Horner TS BY Bus. During 2014-2017, R30-M8 averaged 5.1 sustained interruptions annually. The ESS is expected to reduce sustained interruptions, momentary interruptions, and voltage sags by over 50 percent.

E7.2.4.4 Options Analysis

This section examines other potential options for addressing the issues.

1. Option 1: On-Site Generation Options

Customers can consider on-site generation to provide some degree of reliability, financial benefits (i.e. behind the meter peak shaving), and emergency power. The on-site generator can be diesel or natural-gas fired and will operate either: (i) in parallel with the distribution grid and require emissions controls and protections or (ii) during an emergency only when the distribution grid is unavailable for extended periods (i.e. in an islanded configuration). On-site generation can address extended

outages, but due to limited generator response and protection settings, does not generally address momentary interruptions or large voltage sags. As such, reliance on this solution generally involves a "bump" in supply until the generator can re-supply the load.

Further, the use of diesel or natural-gas fired generation will lead to an increase in local air/noise emissions. Cost for on-site generation (excluding cogeneration applications) is estimated at $10 million for a 10 MW facility, including interconnection and maintenance costs over the service life of the asset.

The customers driving the proposed Customer-Specific ESS projects have rejected this option.

2. Option 2: Conventional Wires Options

Conventional wires options can include new feeders, feeder rebuilds, placing lines underground, upgrading stations and building new stations. At a feeder level, a traditional approach is to establish regulated zones on feeders using capacitor banks and reactive power compensators (i.e. regulators). Additionally, under load tap changers are often used to increase and decrease line voltage in response to changes in line loading. These traditional approaches to regulation can solve certain issues associated with coarse power quality; however, the dynamic nature of the load along a feeder makes it impossible to achieve adequate regulation in reaction to changes in load and high frequency transients. This technology is too slow to react to line disturbances, and voltage can be adjusted only in fixed increments due to the design of the tap changer.

Overhead feeders can be placed underground to substantially eliminate momentary interruptions; however, the costs of such projects are in the order of millions of dollars and cannot be justified based on tree and animal contact avoidance alone. In cases where line disturbances are associated with other feeders on the common bus, more than one overhead feeder may need to be converted to underground. This scale of intervention is costly, takes a long time to build out, and is disruptive to the community.

Vegetation management practices, including aggressive cut backs, can reduce (not eliminate) tree contacts but must be balanced with City policy and community acceptance given the importance of Toronto's tree canopy. Additionally, animal guards have been applied to help reduce animal contacts and resulting feeder disturbances and outages. Different designs have been developed over many years to combat this problem with considerable success. However, it remains difficult to eliminate animal contact.

None of the conventional wires options provide comprehensive protection (i.e. against momentaries, voltage sags and extended outages) or demand management and cost control, which are all benefits associated with on-site ESS.

The customers driving the proposed Customer-Specific ESS projects have rejected this option.

3. Option 3: Conventional Power Electronics

The conventional power electronics option involves using regulating devices to mitigate voltage drops (e.g. falling to 50 percent of nominal value for under 10 seconds). Conventional solutions include STATCOM and SVC, which employ power electronics and capacitors to absorb or supply reactive energy in order to regulate voltage . Since capacitors can store a very limited amount of energy, STATCOMs and SVCs are not intended to function as energy sources for the purpose of supplying load. As a result, they provide limited benefit to customers. The differences between STATCOMs and SVCs include stability under varying voltage levels, response speed, and harmonic emissions.

The installed cost for conventional power electronics ranges between $10 million to $15 million for a 10 MW facility.

Due to their limited capabilities and benefits, the deployment of STATCOMs and SVCs is not recommended in this case. Additionally, customers driving the proposed Customer-Specific ESS projects have rejected this option.

4. Option 4: Do More and Accelerated Spend Options

Customer-Specific ESS is customer driven. Spending more or spending more quickly than forecasted is a risk associated with any customer driven program. The proposed option is based on negotiation with several customers planning energy storage in the service area. This program can be expanded if necessary given the projects are funded with customer contributions.

5. Option 5 (Selected Option): Proposed Solution

Customer-Specific ESS provides Toronto Hydro with a more focused option for improving power quality and providing customers with emergency capacity. This non-wires solution can offer a lower cost alternative to conventional distribution infrastructure investment, can be executed quickly, and is less disruptive to the community than traditional wires solutions. Additionally, it can also provide

additional system and customer benefits that are not available from conventional wires options or conventional on-site generation, including future control and capacity opportunities and deferral of traditional generation, transmission, and distribution upgrades.

Since the individual customers who benefit from these projects fund 100 percent of the cost through capital contributions, the size of the Customer-Specific ESS segment can scale-up relatively easily based on customer interest. That is, the proposed option also encompasses "Do More" and "Accelerated Spend" options.

E7.2.5 Execution Risks and Mitigation

Project execution risks may impact project design, project siting, approvals, construction, project schedule and commissioning.

Compared to traditional technologies, there are many fewer technical resources in the sector with knowledge on ESS are available to design, install and commission the systems, which can lead to a delay in program implementation and increased costs. Toronto Hydro will manage this risk by researching and applying relevant experiences from other jurisdictions and investing in training and staff development for engineering and skilled trades.

Project siting and approvals risk is generally limited because ESS involves electronics technology with minimal air/noise emissions and is therefore subject to standard building permit approvals (without extensive environmental assessment requirements) on utility or customer-hosted sites.

Construction cost variance is mitigated through a competitive procurement system for ESS projects and standard contract provisions which provide fixed price responsibility and liquidated damages for non-performance. Based on market projections, battery ESS technology will mature and prices fall providing some protection against year-over-year inflation and a degree of budget contingency. Battery costs represent approximately half the cost of ESS, while converters, switchgear, transformation, controls, conditioning, civil work and enclosures make up the balance. Costs for ESS continue to decline with average battery prices moving from US$300/kWh in 2015 to an expected US$110/kWh in 2024.[15] As such, over the 2020-2024 period, the cost/benefit value proposition of ESS will likely continue to improve, thereby facilitating increased use of this solution to address customer needs.

[15] Lithium-ion Battery Costs and Market, Bloomberg New Energy Finance, July 5, 2017.

Project schedule risk can be effectively managed by dedicated project teams that provide short-interval control and regular coordination between the utility and customers. Toronto Hydro will dedicate its efforts in the first year of the program to selecting suitable locations and obtaining lease/easement agreements for all feeder projects. Labour availability and project prioritization with other capital project and planned maintenance work will be managed to implement this program on-schedule.

ESS projects are complex due to bi-directional power flow and interface protections between project locations and their associated feeder/station supply point. Commissioning risk can be mitigated by using a standard requirements matrix and site acceptance testing protocol. Further, in-depth training in advance of actual field work is planned for crew members and operations staff who will take part in ESS installation and commissioning.

E7.2.6 Appendix A: EPRI Benefits of Energy Storage

Energy storage can provide a rich spectrum of economic, reliability, and environmental benefits to the electric grid, to electricity end-users and to society as a whole. Electric Power Research Institute (EPRI) studied benefits of energy storage using in their 2010 report: ***Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects***.

Table 21: EPRI Smart Grid Technology Benefits: Energy Storage

Benefit Category	Benefit Sub-Category	Benefit
Economic	*Improved Asset Utilization*	1) Optimized Generator Operation
		2) Deferred Generation Capacity Investments
		3) Reduced Ancillary Service Cost
		4) Reduced Congestion Cost
	T&D Capital Savings	5) Deferred Transmission Capacity Investments
		6) Deferred Distribution Capacity Investments
	Energy Efficiency	7) Reduced Electricity Losses
	Electricity Cost Savings	8) Reduced Electricity Costs
Reliability	*Power Interruptions*	9) Reduced Sustained Outages
	Power Quality	10) Reduced Momentary Outages
		11) Reduced Sags and Swells
Environmental	*Air Emissions*	12) Reduced CO_2 Emissions
		13) Reduced SOx, NOx, and PM-10 Emissions

1) **Optimized Generator Operation:** The ability to respond to changes in load would enable grid operators to dispatch a more efficient mix of generation that could be optimized to reduce cost, including the cost associated with polluting emissions. Electricity storage can be used to absorb generator output as electrical load decreases, allowing the generators to remain in their optimum operating zone. The stored electricity could then be used later so that dispatching additional, less efficient generation could be avoided. The storage can have the effect of smoothing the load curve that the generation fleet must meet. This benefit includes two components: (1) avoided generator start-up costs and (2) improved performance due to improved heat rate efficiency and load shaving.

2) **Deferred Generation Capacity Investments:** Electricity storage can be used to reduce the amount of central station generation required during peak times. This would tend to improve the overall load profile and allow a more efficient mix of generation resources to be dispatched. This can save utilities money on their generation costs.
3) **Reduced Ancillary Services Cost:** Ancillary services including spinning reserve and frequency regulation can be provided by energy storage resources. The reserve margin is a required capacity above the peak demand that must be available and is typically +15 percent of peak demand. If peak demand is reduced, reserve margin would be reduced.
4) **Reduced Congestion Cost:** Distributed energy resources provide energy closer to the end use, so less electricity must be passed through the transmission and distribution lines, which reduces congestion.
5) **Deferred Transmission Capacity Investments:** Utilities build transmission with capacity sufficient to serve the maximum amount of load that planning forecasts indicate. The trouble is, this capacity is only required for very short periods each year, when demand peaks. Providing stored energy capacity closer to the load reduces the power flow on transmission lines, potentially avoiding or deferring capacity upgrades. This may be particularly effective during peak load periods.
6) **Deferred Distribution Capacity Investments:** Electricity storage can also be used to relieve load on overloaded stations and feeders, potentially extending the time before upgrades or additions are required.
7) **Reduced Electricity Losses:** By managing peak feeder loads with electricity storage, peak feeder losses, which are higher than at non-peak times, would be reduced.
8) **Reduced Electricity Costs:** Electricity storage can be used to reduce the cost of electricity, particularly during times when the price of "grid power" is very high. A consumer or the owner of an enabled DER realizes savings on his electricity bill.
9) **Reduced Sustained Outages:** Electricity storage can be used as a backup power supply for one or more customers until normal electric service can be restored. However, the backup would only be possible for a limited time (a few hours) depending on the amount of energy stored.
10) **Reduced Momentary Outages:** When combined with the necessary control system, energy storage could act like an uninterruptible power supply (“UPS”), supporting end use load during a momentary outage.

11) **Reduced Sags and Swells**: The same UPS capability could be used to enable load to ride through voltage sags and swells.
12) **Reduced CO_2 Emissions**: Electricity storage can reduce electricity peak demand. This translates into a reduction in CO_2 emissions produced by fossil-based electricity generators. However, since electricity storage has an inherent inefficiency associated with it, electricity storage could increase overall CO_2 emissions if fossil fuel generators are used for charging.
13) **Reduced SOx, NOx, and PM-10 Emissions**: Electricity storage can reduce electricity peak demand. This translates into a reduction in polluting emissions produced by fossil-based electricity generators. However, since electricity storage has an inherent inefficiency associated with it, electricity storage could increase overall emissions if fossil fuel generators are used for charging.

E7.3 Network Condition Monitoring and Control

E7.3.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): -	**2020-2024 Cost ($M**): 63.0
Segments: Network Condition Monitoring and Control	
Trigger Driver: Reliability	
Outcomes: Customer Service, Reliability, Environment, Safety, Financial	

The Network Condition Monitoring and Control program is designed to introduce real-time, Supervisory Control and Data Acquisition ("SCADA")-enabled monitoring and control to Toronto Hydro's low voltage secondary network distribution system. The network system supplies 13 percent of the peak load in downtown Toronto, including key customers like banks and hospitals that are highly sensitive to service interruptions. SCADA-enabled monitoring and control will benefit these customers by introducing remote operating and switching capabilities that are already utilized in many other parts of the system. It will also introduce real-time monitoring capabilities with respect to the following types of operating parameters:

- Air temperature and water level in the vault;
- Oil level, oil temperature and tank pressure of the network transformer; and
- Current, voltage, open/closed status and water level of the network protector, which is essential to the automatic transfer capabilities that allow the reliability benefits of the network design to materialize.

These capabilities will support continuous improvement on a number of key outcomes for downtown customers, the public, and the environment. More specifically, such capabilities include: remote identification of active failure risks (e.g. floods) and prevention of subsequent outages; the ability to sustain service for substantially more customers during multiple contingency events; early identification of potential safety risks (e.g. vault fires); early identification of oil leaks; and improved loading data accuracy, which will help Toronto Hydro to connect more customers to the network system in a more timely and cost effective manner overall. Finally, Toronto Hydro expects remote sensing capabilities to result in approximately $0.1 million in annual system operation and maintenance savings by 2024, as the need for certain types of inspections will be eliminated.

The low voltage network distribution system has historically been Toronto Hydro's most reliable system. Toronto Hydro recently began deploying new, higher voltage network units to better accommodate growth in the core and help reverse a gradual decline in the number of customers connected to the network. At the same time, the existing network is aging as vaults experience floods and transformers corrode and leak oil, as evidenced by the hundreds of deficiencies observed in recent years. Several catastrophic and highly disruptive failures affecting customers have also occurred in recent years. Given these constraints and pressures, Toronto Hydro is prioritizing the Network Condition Monitoring and Control program as a means of improving reliability, system resiliency, and efficiency of operations on the network. The utility plans to invest $63 million between 2020 and 2024 with the objective of installing monitoring equipment and fibre optic cable in approximately 90 percent of the 1,055 network vaults by the end of 2024. This will support the outcomes summarized above and described in more detail below.

E7.3.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Service	• Contributes to Toronto Hydro's customer service objectives (e.g. OEB's ESQR targets, which require new services to be connected on time 90 percent of the time) by enabling more efficient connections through use of live loading data for power flow modeling.
Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by: o Reducing flooding-related equipment damage; o Enabling the early detection of conditions that can cause vault fires to improve response time and mitigate damage; o Providing real-time loading data and remote switching capabilities to allow controllers to drop approximately one-third fewer customers from the network during multiple contingency events.
Environment	• Contributes to Toronto Hydro's environmental objectives by reducing oil leaks through monitoring of transformer oil levels.
Safety	• Contributes to maintaining Toronto Hydro's Total Recorded Injury Frequency measure and safety objectives by enabling early warning of potential risks associated with vault loading, flooding and fire.

Financial	• Contributes to Toronto Hydro's financial objectives by eliminating the need for crews to perform inspections and obtain summer load readings.

E7.3.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Reliability
Secondary Driver(s)	Safety, Failure Risk, System Efficiency

The Network Condition Monitoring and Control program aims to improve the reliability of Toronto Hydro's low voltage secondary network system by introducing real-time SCADA-enabled monitoring and control. The installed equipment and fibre optic communication cables will provide live condition and loading data and remote control capabilities that will enable Toronto Hydro to respond proactively and more effectively to emerging hazards and multiple contingency events, leading to fewer and shorter interruptions for sensitive downtown customers.

Toronto Hydro's network distribution system peak load is about 13 percent of the total downtown load (e.g. 230 MVA of 1800 MVA in total). Although network distribution provides the most reliable service offered by Toronto Hydro, it has not been available for some important customer classes. Typically, larger downtown customers could only be supplied with a dual radial connection. However, as of 2017, a 600V secondary network option became available.[1] This means larger customers, such as condos and large commercial and mixed-use buildings, can choose a more reliable network service. With this new option, Toronto Hydro is expecting to reverse a recent decline in network system load. For example, network load experienced a steady decline over the 10-year period between 2006 and 2015 from 308 MVA to 234 MVA. However, the existing network system is aging and susceptible to flooding and oil leaks, resulting in several catastrophic failures in recent years. In response, Toronto Hydro plans to improve the network system's resiliency, reliability and operation efficiency through SCADA-enabled monitoring and control.

[1] With the older, lower rated equipment, only buildings up to about 25 stories could be connected to the network system due to excessive voltage drop for taller buildings. The 600 V option enables connection of buildings up to at least 70 stories.

The components required to enable monitoring and control of a network vault and unit are depicted in Figure 1. Vault sensors include a water level sensor and a vault temperature sensor, which are connected directly to the communication box. Transformer mounted sensors include oil temperature, oil level and tank pressure. Protector monitoring and control are all enabled through a special communication-ready network protector relay mounted inside the network protector. [2] Network units manufactured after 2010 have the required sensors built-in, while older units need retrofit packages to be installed.

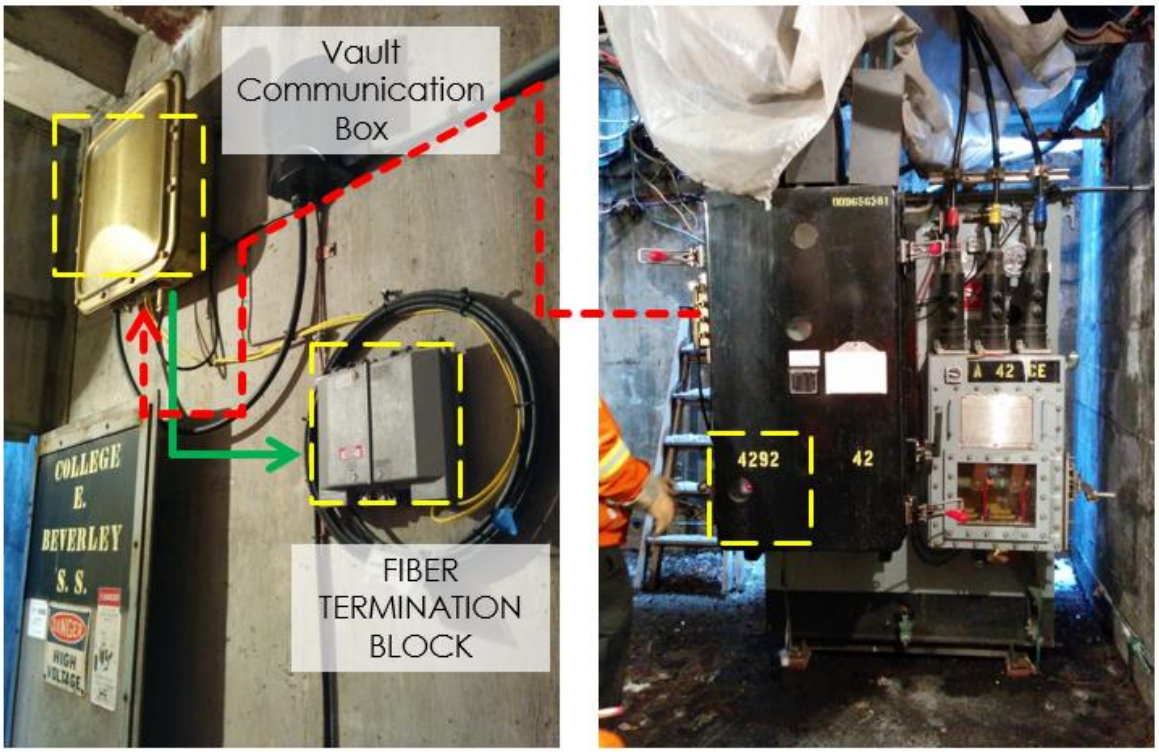


Figure 1: Vault Layout with Network Condition Monitoring and Control Equipment Installed

Once work inside the vault is completed, Toronto Hydro can monitor and control the automated vaults through a SCADA screen from the control room, an example of which is shown in Figure 2 below.

[2] The network protector automatically connects and disconnects individual transformers from the secondary grid to compensate for primary feeder switching and equipment failures.

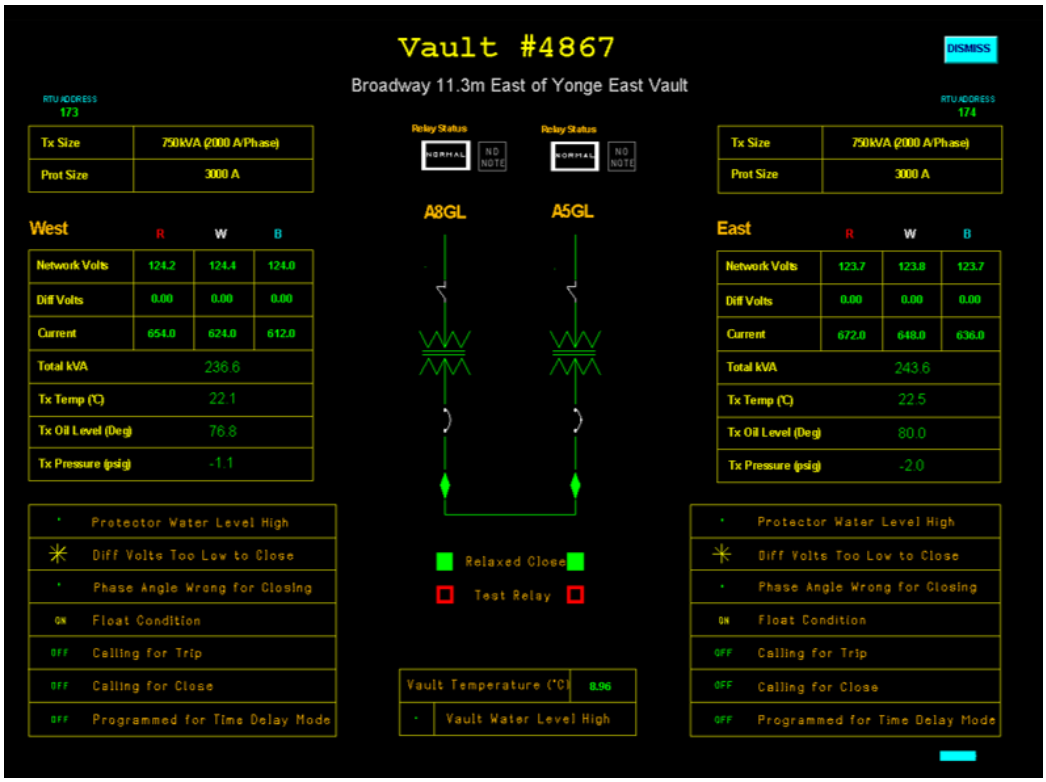


Figure 2: SCADA Screen for a Vault with Network Condition Monitoring and Control

E7.3.3.1 Network Vault Condition Monitoring

The Network Condition Monitoring and Control program will provide live condition data of the vault and network units. This will give the Control Room access to important information on developing hazardous conditions such as flooding, fire, and oil leaks, allowing proactive measures to be taken to prevent equipment failure and mitigate safety and environmental risks. Such data includes vault temperature and water level, network transformer operating temperature, oil level and tank pressure, and the presence of water inside network protectors.

The proposed use of water level sensors would mitigate the risk of equipment damage and reduce customer service interruptions due to vault flooding. In 2018, there are approximately 750 protectors that are not designed to operate when submerged under water. From 2015 to 2017, inspections found 76 incidents of protector internal water stains and 370 incidents of vault flooding. It is estimated that half of these occurrences can be proactively addressed through the installation of flood level sensor alarms by 2024. Once installed (approximately 30 cm above the vault floor), water level sensors would trigger alarms in the Control Room when rising water reaches the sensor.

Toronto Hydro will then dispatch a crew to address the flooding prior to water levels reaching a point where equipment is damaged or at risk of failure.

Monitoring of the network system will also enable Toronto Hydro to detect fires earlier, improving response time and mitigating any damage to equipment and safety risks that may result. If a fire occurs, the Control Room will be informed and can remotely operate vault equipment to prevent catastrophic failures. This would help lessen the impact to the customers directly connected to a given vault, as well as minimize potential widespread network outages that impact all customers connected to the network grid.

Oil leaks are another concern which can be addressed through network vault monitoring. If a serious transformer oil leak is not promptly identified, transformer failure could occur shortly after the oil level drops below the windings or upper cooling tubes. This could result in a catastrophic transformer fire causing widespread and prolonged customer interruptions. In addition, leaking oil within a vault may enter the vault drainage system and discharge into the environment. Figure 3 shows the volume distribution of 223 network transformer oil leaks identified by Toronto Hydro from 2015 to 2017.

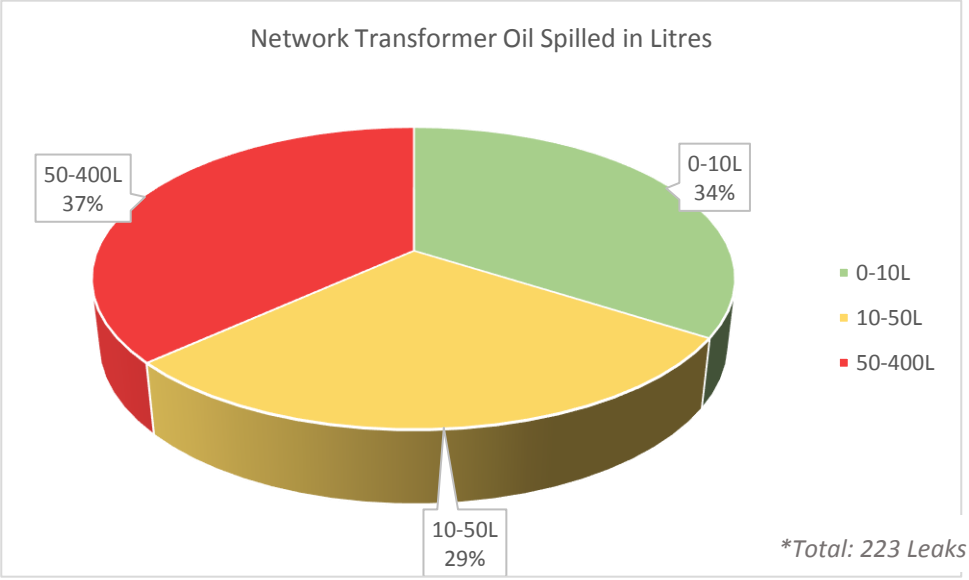


Figure 3: Network Transformer Oil Leaks 2015-2017

The proposed condition monitoring equipment will alert Toronto Hydro to a leaking transformer, so that crews can be dispatched to contain the leak and minimize environmental damage until the unit can be replaced. Toronto Hydro expects this measure to limit the larger leaks to 50 litres, reducing

the volume of the largest spills (which make up over a third of those reported in 2015-2017) by 95 litres. Oil level monitoring data will also support the accurate reporting of oil quantities to the Ministry of the Environment and Climate Change and the City if a spill occurs.

E7.3.3.2 Network Unit Control and Loading Data

The monitoring and control equipment also provides remote control capabilities and loading data required for emergency operations as well as normal analysis and planning. When live condition data is not available, it is acquired through estimates or field inspections, which are both less accurate and more resource intensive. Real-time loading data will allow controllers to more effectively respond to multiple contingency events and emergency situations resulting in fewer and shorter customer interruptions. Remote monitoring and control would also reduce the need for crews to visit vaults. This benefits customers by both expediting service restoration during network emergencies, as well as reducing costs associated with normal network system operations. Features that will provide these benefits include:

- monitoring of operating voltages and currents;
- monitoring of the open/closed status of network protectors;
- ability to remotely open or close protectors;
- automatic reporting of conditions preventing equipment from automatically operating as desired (e.g. voltage too low to reclose); and
- ability to temporarily alter equipment settings to facilitate automatic operation (e.g. “relaxed close”) that would otherwise not occur.

The loads for the low voltage secondary networks targeted for Network Condition Monitoring and Control in 2020-2024 are shown in Table 4 below. Through this program, Toronto Hydro expects to avoid dropping one third of the total network load (which would otherwise have to be dropped in multiple contingency events). Approximately once every three years, a multiple contingency event results in a forced widespread outage. These networks are designed to handle first contingency (N-1) outages at both the feeder and network unit levels without causing customer interruptions. However, second contingency (N-2) or higher events require network analysis to determine whether customer loads can be sustained or must be dropped in order to avoid excessive equipment loading levels. In the absence of live loading data, conservative load estimates are made for this analysis. Toronto Hydro derives these estimates using loading data from summer inspections, which may not be accurate due to variances in season, ambient temperature, time of day, and day of the week. In

contrast, accurate real-time loading information will allow the Control Room to operate network equipment according to the actual limits during multiple contingency events.

Table 4: Potential Customer Load Saved From Monitoring and Control

Network	Total Load on Feeders (MVA)	Network Load (MVA)	Proposed Automation Year	Expected Load Saved During Multiple Contingency Events (MVA)
GD Phase 1	49	11.6	2019	3.9
GD Phase 2		17.4	2020	5.8
CS-West Phase 1	45	11	2020	3.7
CS-West Phase 2		11	2022	3.7
Bridgman Total	29.2	14.6	2022	4.9
Highlevel Total	112	56	2023	18.7
Glengrove Total	28	14	2024	4.7
Duplex Total	69.6	34.8	2024	11.6
Gerrard Total	12	6	2023	2.0
Dufferin Phase 1	5.5	4	2023	1.3
Dufferin Phase 2	15.7	12	2024	4.0
Wiltshire Total	1	1	2024	0.3
Leaside Total	3	2	2024	0.7
Main Total	9	7	2024	2.3
Carlaw Total	9	7	2024	2.3
Strachan Total	9	7	2024	2.3

Table 4 also shows the potential customer load that may be saved for each of these networks during a multiple contingency event. These savings are estimated based on the avoidance of dropping one third of the network load. The targeted networks in Table 4 represent about 72 percent of total network system load based on non-concurrent peaks. On average, multiple contingency events occur once every three years.

In addition to the aforementioned benefits, the availability of live loading data has other benefits, including customer service improvement and operating cost avoidance, as discussed below.

Deployment of the Network Condition Monitoring and Control program will provide more accurate peak readings of Toronto Hydro's network assets than can be achieved through summer vault inspections. From a planning perspective, engineers will be able to model the various parts of the system with greater accuracy and plan based on more accurate power flow models. Network customer requests can be challenging to handle, and accurate power flow models are essential for efficiently connecting customers. More efficient connections will result in lower-cost and faster

customer connection, contributing to the utility's compliance with OEB-prescribed objective to connect new services on time 90 percent of the time.

Regarding operating cost avoidance, Toronto Hydro conducts three inspections per year of all network vaults in the system, one of which is also used to collect summer peak vault loading data. When a network vault is automated, the summer peak reading inspection can be eliminated as peak loading data can be extracted from the SCADA system instead. Figure 4 shows the annual operating costs that may be avoided as this program progresses and additional vaults are automated each year

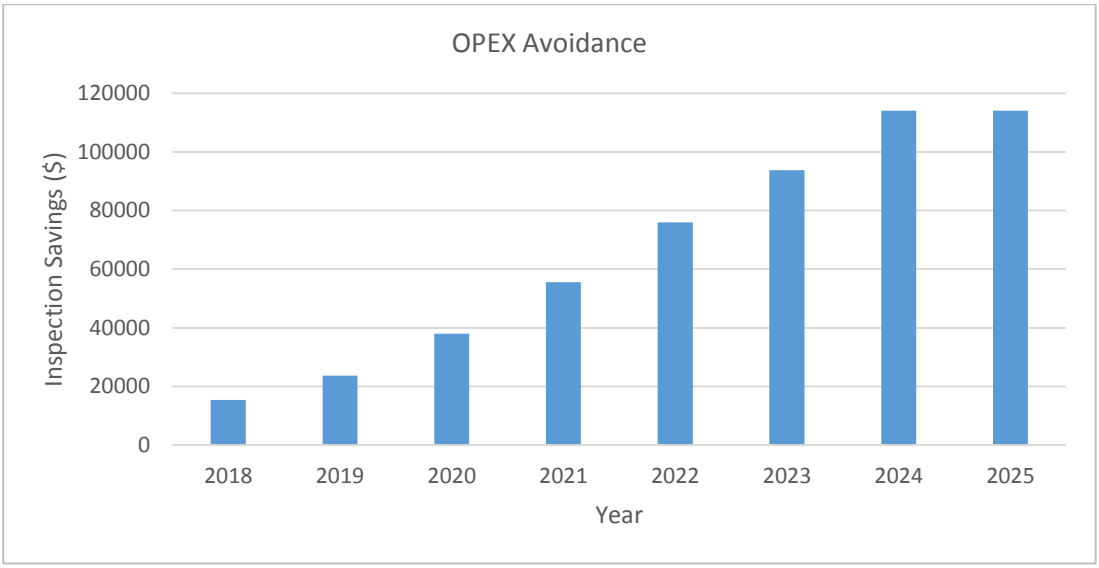


Figure 4: Expected Operating Expenditure Avoidance by Year

E7.3.4 Expenditure Plan

The Network Condition Monitoring and Control program aims to improve issues related to reliability, safety, failure risk, and system efficiency primarily by investing in monitoring and control equipment installations inside network vaults, as well as a fibre optic communications backbone installed under city streets. Table 5 below depicts the forecast (2020-2024) spending for this program.

Table 5: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Network Condition Monitoring and Control	-	-	-	-	-	7.6	10.2	12.6	15.3	17.4

There are no historical (2015-2017) or bridge (2018-2019) expenditures associated with this program. Toronto Hydro funded the work done in 2015-2019 (averaging $2.2 million per year) as part of the Network Unit Renewal Program (now a segment within Network System Renewal program)[3] as there were synergies between the types of work undertaken in that program and this one.

Table 6 summarizes the 2015-2019 projects and their estimated costs. Two stations, Windsor and Cecil, which supply the Spadina network area south of College were chosen as the pilots for this program. By the end of 2019, Toronto Hydro expects to have commissioned 204 of the vaults for which necessary equipment and fibre will have been installed. Completion of this work will result in the first substantial addition to Toronto Hydro's facilities to remotely monitor and control its network system.

Table 6: 2015-2019 Projects.

Network	Total Load on Feeders (MVA)	Network Load (MVA)	Proposed Automation Year	Actual or Estimated Costs ($Millions)
WR-West Phase 1	55	12.5	2017	3.4
WR-West Phase 2		12.5	2018	1.1
A-North Phase 1	44	13.5	2018	2.0
A-North Phase 2		13.5	2019	3.0
CE-South Phase 1	32	6.5	2017	2.3
CE-South Phase 2		6.5	2018	

For 2020-2024, Toronto Hydro plans to spend $63 million to automate another 13 networks by completing the fibre and equipment installation and commissioning for 750 vaults. Table 7 provides the proposed timing by network.

[3] See: Exhibit 2B Section E6.4.

Table 7: 2020-2024 Projects.

Network	Total Load on Feeders (MVA)	Network Load (MVA)	Proposed Automation Year
GD Phase 1	49	11.6	2019
GD Phase 2		17.4	2020
CS-West Phase 1	45	11	2021
CS-West Phase 2		11	2021
Bridgman Total	29.2	14.6	2022
Highlevel Total	112	56	2022
Duplex Total	69.6	34.8	2023
Gerrard Total	12	6	2023
Dufferin Phase 1	5.5	4	2023
Dufferin Phase 2	15.7	12	2024
Glengrove Total	28	14	2024
Wiltshire Total	1	1	2024
Strachan Total	9	7	2024
Carlaw Total	9	7	2024
Main Total	9	7	2024
Leaside Total	3	2	2024

The planned pacing of execution is the fastest practical rate that Toronto Hydro is realistically able to achieve given available resources. By enabling monitoring and control of approximately 90 percent of the network system by 2024, this program will improve reliability for downtown customers, saving them from multiple contingency events, and contributes to the utility's system reliability objectives. Customers will also benefit from faster and less expensive connections and reduced safety and environmental risks.

The prioritization and scheduling of projects in this program are based on the proposed fiber optic installation plan shown in Figure 5. Installation of the necessary fiber backbone is a prerequisite for testing and commissioning monitoring and control equipment installed in individual vaults. Therefore, equipment installation in vaults is planned for the year following the completion of fiber installation. In addition, network units installed after 2010, including those to be replaced through the Network System Renewal program, will be equipped with the necessary relays and sensors required for monitoring and control. Network units installed prior to 2010 need to be retrofitted, which is a need that is accounted for during project prioritization.

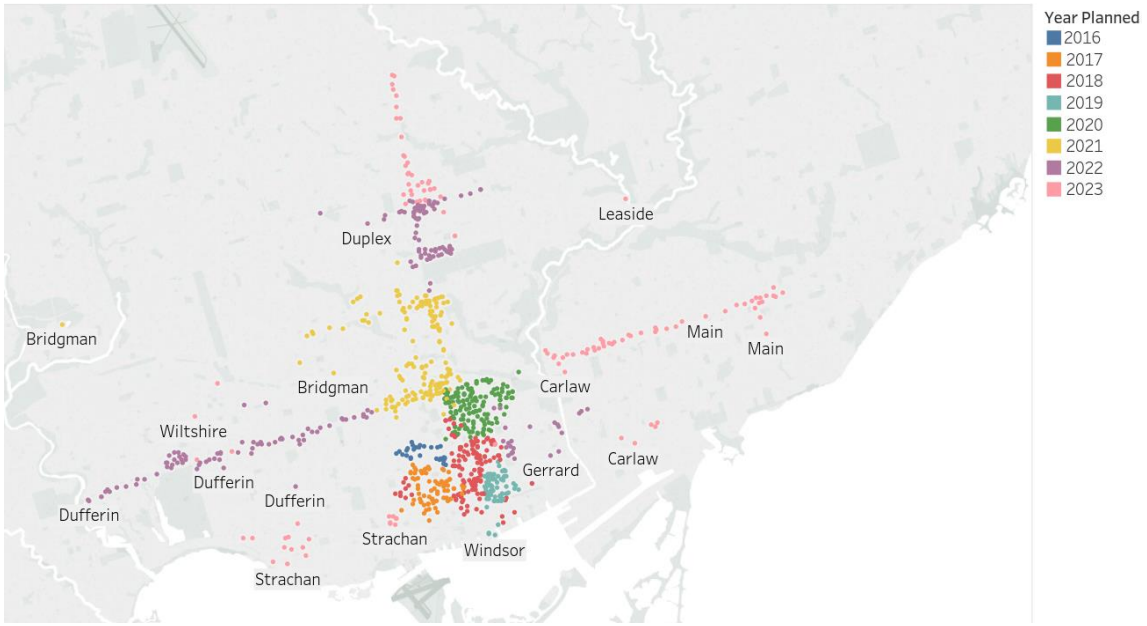


Figure 5: Fibre Optic Cable Deployment by Year and Station

Toronto Hydro chose Windsor and Cecil as the first networks to be automated for two reasons. First, their mutual proximity permits the same fibre backbone to be used for both networks. Second, these are particularly important networks based on loading and critical customers. Next, Toronto Hydro plans to branch out to other downtown stations, starting with Terauley and taking into account the City's King Street Pilot Project and related road moratoriums affecting execution at other adjacent stations. During the 2020-2024 period, Toronto Hydro plans to complete automation of the remaining portions of the downtown core prior to proceeding with the more distant network areas.

E7.3.5 Options Analysis

E7.3.5.1 Option 1: No Automation at the Remaining Network System Vaults

Under this option, the network system would remain unmonitored. Oil leaks, vault flooding, vault fires, protector failures, and protector flooding would continue to be addressed on a reactive basis, leading to potential outages for customers and potentially serious environmental consequences. Replacement units will continue to be provided with sensors; however, SCADA connection will not be implemented. With no live loading data available, Toronto Hydro will continue to rely on less accurate loading information acquired through estimates or field inspections for the purposes of

planning for and responding to multiple contingency events. Therefore, this program is not recommended.

E7.3.5.2 Option 2: Network Condition Monitoring and Control at Reduced Rate

Automation of the seven of the 13 remaining networks (approximately 70 percent of network vaults) over 2020-2024 would result in reliability improvements for customers on those networks by 2024. Although this would cost approximately $20 million less than the proposed plan, the benefits of monitoring and control would be delayed to beyond 2024 for the remaining six networks (approximately 20 percent of network vaults). The Network Condition Monitoring and Control program provides good value for the money spent and not proceeding with monitoring and control of all of the remaining networks does not align with customer engagement results, which favour faster implementation of monitoring and control on the network system.[4] This option is therefore not recommended.

E7.3.5.3 Option 3 (Selected Option): Condition Monitoring and Control of 13 Networks

Automation of the 13 proposed networks means Toronto Hydro will have live access to the following for all networks in the secondary network system: vault temperature, vault water level, network unit loading, transformer oil level, transformer top oil temperature, transformer tank pressure, protector status, protector water level, and protector remote control. This option is preferred as it is expected to lead to reliability and safety improvements, including fewer and shorter customer interruptions, quicker responses to emerging hazardous situations, reduced environmental impacts, and reductions in reactive capital and operating costs. These benefits result from the ability to identify developing problems before equipment failure occurs, improved ability to operate networks under multiple contingency events, as well the ability to remotely monitor and operate equipment resulting in quicker and more cost-effective responses. This option is also consistent with customer engagement results prioritizing monitoring and control of the network system.

[4] Exhibit 1B, Tab 4, Schedule 1, Appendix A,

E7.3.6 Execution Risks & Mitigation

E7.3.6.1 Fibre Installation

Fibre optic cable is the first asset that must be installed as part of the Network Condition Monitoring and Control program. Installation of fibre under city streets poses a number of risks that may cause program delays and increase costs, including:

- Lack of existing duct capacity for the fibre optic cable;
- Road construction moratoriums and road work restrictions;
- Construction blocking access to cable chambers and vaults; and
- Leaking feeders posing hazards that prevent workers from entering cable chambers and vaults.

If a problem is only identified once construction begins, it results in reactive work, increased cost, and program delays. Toronto Hydro mitigates these risks by performing detailed field inspections during the design phase of the program and then designing solutions that avoid problem locations altogether. Alternatively, the utility can plan ahead for necessary construction work to avoid impacting the program's critical path timeline.

E7.3.6.2 Vault Equipment Installation

Certain risks can delay the installation of equipment inside network vaults and increase costs, including:

- Flooded vaults;
- Lack of suitable available space to install equipment; and
- Existing primary feeder installation interfering with the installation of transformer sensors.

Toronto Hydro mitigates all of these risks by performing a detailed field inspection during the design phase. The utility can complete corrective work on flooded vaults prior to starting construction work for this program. To address a lack of suitable available space to install equipment, such issues will be proactively identified, and the relevant project will be designed to include the necessary equipment relocation work and scheduled to avoid impacting the program's critical path timeline. Where existing primary feeder installations interfere with installation of a particular transformer sensor, Toronto Hydro may omit the sensor and adjust the Control Room SCADA display to compensate.

E7.4 Stations Expansion

E7.4.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 180.1	**2020-2024 Cost ($M):** 136.4
Segments: Copeland TS – Phase 2, Hydro One Contributions, Local Demand Response ("DR")	
Trigger Driver: Capacity Constraints	
Outcomes: Customer Service, Reliability, Public Policy, Environment, Financial	

Toronto Hydro's Stations Expansion program (the "Program") addresses medium- to long-term system capacity needs. The Program is driven by capacity constraints on the distribution system. Increased and continued densification and population growth are driving the need to relieve the loading on the distribution system and create additional capacity. If not dealt with proactively, this will impact Toronto Hydro's ability to connect customers to its distribution system. The primary focus of the work planned in the 2020-2024 period is on the downtown and south-west area of the system, where growth continues to be concentrated.

The Stations Expansion program consists of the three segments summarized below, and is a continuation of the expansion activities described in Toronto Hydro's 2015-2019 Distribution System Plan.[1]

- **Copeland TS – Phase 2**: this segment will expand the capacity of Toronto Hydro's Copeland Transformer Station ("TS"), located in the centre of Toronto's financial district. The project will provide additional capacity of 144 MVA. The additional capacity is needed to support forecasted growth and development in the City's Central Waterfront area while maintaining and enhancing system reliability and resiliency for outage-sensitive customers in the downtown core. Toronto Hydro's 2015-2019 Distribution System Plan included a high-level proposal to begin work on the Copeland TS – Phase 2 project in 2019. Toronto Hydro developed a more detailed plan in 2016 which included advancing some work into the 2017-2019 timeframe to account for expected project lead times. In total, Toronto Hydro expects the Copeland TS – Phase 2 project will cost an estimated $89 million, with $79 million of those expenditures occurring in the 2020-2024 period. The estimated in-service date is 2024.

[1] EB-2014-0116, Exhibit 2B, Section E7.9

- **Hydro One Contributions:** this segment covers Toronto Hydro's forecasted capital contributions to Hydro One for work related to:
    - Expansion of Horner TS, which will provide an additional capacity of 192 MVA in South-West Toronto to enable medium-to-long term load and customer growth as anticipated based on the Toronto Integrated Regional Resource Plan ("IRRP") process;
    - Cost-effective capacity upgrades of end-of-life ("EOL"), Hydro One-owned power transformers as anticipated based on the IRRP process;

  Toronto Hydro plans to invest an estimated $53 million in this segment in the 2020-2024 period compared to a forecasted $99 million in 2015-2019.
- **Local DR:** this segment includes cost-effective non-wires investments to manage local capacity constraints while deferring larger, traditional wires investments. Toronto Hydro is proposing targeted DR strategies to reduce peak demand by approximately 10 MW, supporting the deferral of approximately $135 million in capital investment at Cecil TS and Basin TS for 5 to 6 years. The capital budget for this Program in the 2020-2024 period consists of an estimated $4.6 million in 2023-2024 for a battery storage project in the Basin TS area. Under the Asset and Program Management program[2], Toronto Hydro plans to allocate operational expenditures associated with this segment.

The investments summarized above and in the remainder of this narrative are informed by, and fully aligned with, IRRP activities conducted in coordination with the IESO and Hydro One. The most recent planning document from this process is the Needs Assessment Report for the Toronto Region ("Needs Assessment"). A high level reconciliation of the Needs Assessment with Toronto Hydro's Stations Expansion program is found in Section E7.4.7 of this narrative.

The Stations Expansion program also responds to the need for maintained system reliability and increased grid resiliency to support Ontario public policy drivers. To this end, the Program focuses on Toronto Hydro's broad strategy of grid modernization within the context of an aging, dense urban infrastructure, aiming to support customers and load growth and both mitigating and adapting to climate change through grid resiliency and innovation.

[2] Exhibit 4A, Tab 2, Schedule 9, Section 7

In total, Toronto Hydro plans to invest an estimated $136.4 million in stations-level capacity expansion in the 2020-2024 timeframe compared to a forecasted $180.1 million in the 2015-2019 timeframe. The utility expects to add or free-up over 400 MVA in capacity on the system as a result.

E7.4.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Service	• Contributes to Toronto Hydro's customer service objectives by: ○ Reducing the number of stations unable to connect new large customers in the downtown and Horseshoe areas by investing in 415 MVA in additional supply capacity by 2025; ○ Increasing supply capacity using DR measures; and ○ Alleviating feeder position limitations that prevent customer connections.
Reliability	• Contributes to maintaining Toronto Hydro's System Capacity Measure and system reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by: ○ Providing redundancy and operational flexibility by upgrading capacity at supply points to keep the number of highly loaded stations (with loads > 90 percent capacity) at a minimum for the downtown and Horseshoe areas; and ○ Managing peak loads and alleviating capacity constraints to reduce the risk of outages by maximizing the use of existing capacity through targeted DR initiatives, • Investing in climate-resilient station infrastructure and equipment, in particular at Copeland TS which has flood defenses, seismic protections (i.e. earthquake resistant), and is protected from exposure to storms.
Public Policy	• Contributes to Toronto Hydro's public policy objectives by: ○ Supporting the IRRP and the Ontario Long-Term Energy Plan ("LTEP") by meeting local needs through a mix of traditional infrastructure, energy storage, conservation and DR; ○ Enabling electrification by investing in additional capacity and operational flexibility; ○ Supporting Ontario's Conservation First Framework by investing in non-wires alternatives.

Environment	• Contributes to Toronto Hydro's environmental objectives by investing in capacity to support operational flexibility, enable electrification, and support the proliferation of distributed energy resources (DERs).
Financial	• Contributes to Toronto Hydro's financial objectives by deferring approximately $135 million in capital investment through the use of targeted DR strategies.

E7.4.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Capacity Constraints
Secondary Driver(s)	Reliability

The Stations Expansion program is driven by capacity constraints on the distribution system. Increased and continued densification and population growth are driving the need to relieve loading on the distribution system and create additional capacity. These conditions are only expected to intensify beyond 2024 as supported by the City of Toronto's long-term Precinct Plans[3] for both the downtown and the Horseshoe areas and by Toronto Hydro's 10-Year Station Load forecast (see Section D of the DSP). Toronto Hydro anticipates that the significant redevelopment and load growth associated with planned projects[3] in the downtown and central waterfront will result in 208 MVA of incremental load in the City's core over the 2020-2024 period or shortly thereafter. Similar to the downtown region, the Horseshoe area continues to experience concentrated load growth. The City of Toronto's "Precinct Plans" [4] for the region, including the South-West Toronto area, shows a load growth of 252 MVA, which includes all planned projects forecasted to materialize over the 2020-2024 period, or shortly thereafter. The Load Demand program[5] includes a more detailed discussion of the proposed Precinct Plans and how they factor into Toronto Hydro's capacity investment plans. Continued densification and population growth are expected to continue driving up system loading up to and beyond 2024. If not dealt with proactively, this trend will impact Toronto Hydro's ability to connect customers to the distribution system.

[3] City of Toronto, *How Does The City Grow?* (April 2017), available <https://web.toronto.ca/wp-content/uploads/2017/08/9014-How-Does-the-City-Grow-April-2017.pdf>.
[4] *Supra* note 4.
[5] Exhibit 2B, Section E5.3.

Addressing capacity constraints in the downtown core is crucial as stations primarily serve institutional, commercial, and large residential condominium customers experiencing rapid, large-scale growth, including electric transportation infrastructure (e.g. subways, streetcars). Given the importance of loads associated with essential services in all these station areas, resiliency and reliability are extremely important. The work under this Program responds to the need for resiliency and reliability in these areas by relieving highly loaded station buses and ensuring availability of feeder positions to connect new customers. This provides an overall benefit to all ratepayers by connecting new customers to their optimal supply point within the station service area and thus maintaining low connection costs. Ensuring reliable and resilient power supplies to these essential services is important to all Toronto Hydro customers, regardless of their rate class.

Toronto Hydro's 10-year Station Load forecast predicts an increase in load which will reduce capacity availability at the following stations: Carlaw, Esplanade, Windsor, Terauley, Cecil, Manby, Richview, Fairbank, Strachan, Duplex, Charles, Basin, and Horner. Most of these stations are highly loaded and have either limited or no spare feeder positions available to enable load transfers or enable additional capacity. As a result, this reduces Toronto Hydro's ability to connect customers and large DERs to the distribution system efficiently within the station service areas.

The work planned under the Stations Expansion program is aligned with system needs identified in the Needs Assessment and in the Regional Infrastructure Plan ("RIP") report.[6] Table 4, Table 5, and Table 6 below highlight the needs and how they are addressed through the Stations Expansion program.

Table 4: New Needs

New Needs	NA Report Section	Stations Expansion Narrative
End-of-Life Assets	*7.1.1*	See *Table 8*.

Table 5: Needs Identified in Previous RIP

Needs Identified in Previous RIP	NA Report Section	RIP Report Section	Stations Expansion Narrative
South-West Toronto – Station Capacity	*7.2.1*	*7.2*	Addressed with Horner expansion in 2020-2024 Stations Expansion plan.

[6] Exhibit 2B, Section B, Appendix A, B, C, D, and E

Needs Identified in Previous RIP	NA Report Section	RIP Report Section	Stations Expansion Narrative
Downtown District – Station Capacity	*7.2.2*	*7.3*	Addressed with Copeland TS - Phase 2 expansion in 2020-2024 Stations Expansion plan.

Table 6: End-of-Life Assets – Metro Toronto Region

EOL Asset	Replacement/ Refurbishment Timing	Details	Stations Expansion Narrative
Charles TS T3/T4 Transformers	*2024-2025*	EOL Transformers and other HV equipment are identified at these stations for replacement with higher rated equipment, and are discussed further in Section 7.1.1.2 of NA report	Included in 2020-2024 Stations Expansion plan.
Duplex TS: T1/T2 Transformers	*2023-2024*		Included in 2020-2024 Stations Expansion plan.
John TS: T1, T2, T3, T4, T6 Transformers and 115 kV breakers	*2024-2025*	EOL Transformers and other HV equipment are identified at these stations where scope for replacement is to be further assessed, and are discussed further in Section 7.1.1.3 of NA report.	Included in 2020-2024 Stations Expansion plan.

The Stations Expansion program also responds to the need for maintained system reliability and increased grid resiliency to support public policy drivers. To this end, the Program focuses on Toronto Hydro's broad corporate strategy of grid modernization within the context of aging, dense urban infrastructure, supporting customers and load growth, and mitigating and adapting to climate change through grid resiliency and innovation.

The system needs are addressed through three segments: Copeland TS – Phase 2, Hydro One Contributions, and Local DR, as further discussed below.

E7.4.3.1 Copeland TS – Phase 2

The Copeland TS – Phase 2 is required to address capacity constraints in the downtown core, which continues to experience a high degree of densification and growth as identified in the most recent Regional Planning Needs Assessment report (i.e. IRRP, see Table 5 and Table 32). The Copeland TS - Phase 2 project is incremental to Phase 1 and is intended to make full use of potential capacity at the Copeland TS site. This will: (i) reduce loading on highly loaded buses at surrounding stations, allowing Toronto Hydro to continue to connect customers efficiently within the station service areas; and (ii) create 40 spare feeder positions, enabling load transfers through switching operations and new customer connections. Copeland TS - Phase 2 will provide an additional 144 MVA in the downtown area by 2024. This includes the installation of two additional 72 MVA busses, three gas insulated power transformers (two load-serving and one back-up) and the installation of a transfer bus.

Based on Toronto Hydro's most recent 10-year station load forecast[7] three downtown stations will require capacity relief in the 2020-2024 period: Windsor TS, Cecil TS, and Terauley TS. Figure 1 below provides a visual overview of these stations with an indication of when the busses are projected to require capacity relief. Typically, load relief on a 13.8 kV downtown station bus is required when the forecasted peak load of the bus reaches 95 percent of the bus firm capacity.

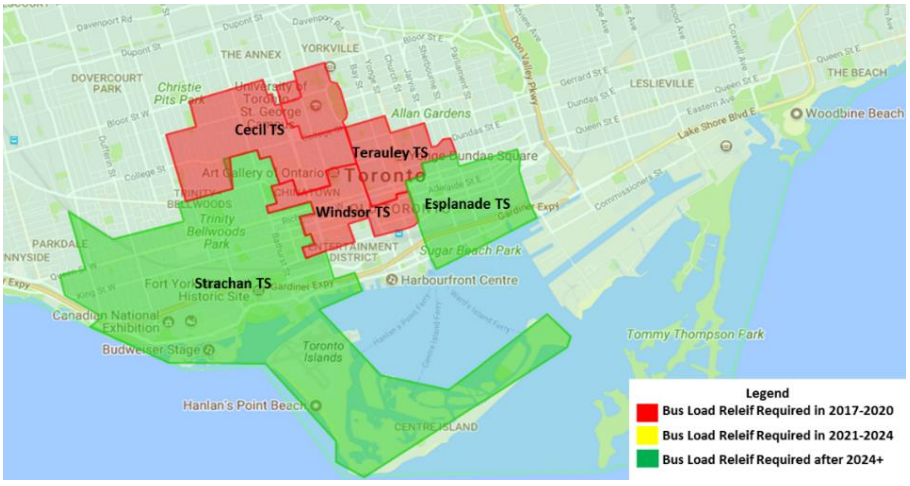


Figure 1: Geographical spread of Downtown Core Stations with a visual overview of bus load relief requirements

[7] Described in Exhibit 2B, Section D2.3 System Utilization

Continued investment in Copeland TS – Phase 2 will create forty spare feeder positions. Spare feeder positions are available unused feeders on a bus that enable: (i) the connection of new customers who cannot be connected via existing feeders and (ii) load transfers between and within stations. As seen in Table 7 below, Toronto Hydro faces a limited and decreasing number of spare feeder positions in the downtown area as evidenced by the fact that Cecil TS and Windsor TS do not have any spare positions remaining. This issue is of particular concern in the downtown core, because the design of the distribution system is such that feeder loading cannot be relieved through switching operations and can only be relieved through bus transfers (as described in more detail in Option 3 in section E7.4.5 Options Analysis).

Table 7: Downtown Core Station Load Profile (2017 vs. 2024)

Column A	Column B	Column C	Column D	Column E	Column F	Column H
Station	**Bus ID**	**2017 Bus Loading (%)**	**Spare Feeder Position – 2017**	**2020 Bus Loading (%)**	**2024 Bus Loading (%)**	**Potential # of CI[8] due to bus failure**
Cecil TS	*A1-2CE* [9]	57%	0	57%	60%	1
	A3-4CE	77%	0	79%	81%	2244
	A5-6CE	79%	0	99%	103%	3466
	A7-8CE	79%	0	83%	86%	4576
Esplanade TS	*A1-2X*	74%	0	67%	68%	758
	A1-2GD	90%	6	78%	81%	5095
	A3-4GD	83%	0	88%	90%	2898
Strachan TS	*A1-2T*	86%	0	89%	93%	5207
	A5-6T	65%	3	78%	80%	4165
	A7-8T	88%	1	88%	90%	7600
	A9-10T	78%	0	88%	90%	2160
Terauley TS	*A1-2A*	79%	1	91%	89%	772
	A3-4A	77%	1	98%	102%	982
	A5-6A	82%	7	90%	92%	1331
	A9-10A	70%	1	75%	68%	184

[8] "CI": Customers Interrupted
[9] Dedicated bus feeding University of Toronto

Column A	Column B	Column C	Column D	Column E	Column F	Column H
Station	**Bus ID**	**2017 Bus Loading (%)**	**Spare Feeder Position – 2017**	**2020 Bus Loading (%)**	**2024 Bus Loading (%)**	**Potential # of CI[8] due to bus failure**
Windsor TS	*A3-4WR* [10]	88%	0	90%	0%	5838
	A5-6WR [11]	90%	0	14%	93%	434
	A11-12WR	77%	0	77%	80%	21
	A13-14WR	95%	0	85%	88%	21
	A15-16WR	87%	0	88%	74%	468
	A17-18WR	88%	0	73%	76%	227
Copeland TS [12]	*A1-2CX*	81% [13]	1	81%	82%	--
	A3-4CX	63% [13]	3	0%	64%	--

Note: Red is ≥ 95 percent and orange is ≥ 90 percent.

Highly loaded station buses and a lack of spare feeder positions, as shown in Table 7, also limit contingency operation capabilities, making it more difficult for Toronto Hydro to restore service to customers in the event of an outage. When the supply at a station is lost, the impacted load needs to be re-distributed to nearby feeders to maintain service to at-risk customers. If the nearby feeders are also highly loaded or have no spare positions, they will not be able to pick up additional load. This will result in longer interruptions and a more difficult and costly restoration process.

The current shortage of feeder positions or bus capacity makes it difficult to connect new customers to an optimal supply point within the station service area. In this case, feeders are extended outside the boundary of the station service area, which may require the construction of additional civil infrastructure. Furthermore, load transfers between feeders could also be required to accommodate new customer connection from the nearest available feeder. All these additional factors can add considerable cost and time to the connection project. Table 7 shows the percentage bus loading, the

[10] A3-4WR will be out of service in 2024 for Switchgear replacement
[11] A5-6WR will be replaced by a new Switchgear A11-12WR by 2024
[12] Copeland TS will be in-service by Q4 2018
[13] A1-2CX bus will be loaded in 2020 and A3-4CX in 2021

number of spare feeder positions at Cecil TS, Esplanade TS, Strachan TS, Terauley TS, Windsor TS and Copeland TS as well as the number of customers that could be affected by the failure of each bus.

Therefore, by introducing an additional 144 MVA capacity into the Toronto Hydro System, Copeland TS will help relieve the heavily loaded stations (as identified in Table 7), thus allowing new customers to be connected to their service areas, which would otherwise be difficult and expensive to connect.

It is important to note that the impact of electric vehicle ("EV") deployment has not been accounted for in this forecast. Following the release of the LTEP in the fall of 2017, Toronto Hydro is working with regional planning stakeholders to develop a 25 year load forecast that includes an assessment of different EV deployment scenarios. Large-scale EV deployment may increase the peak load demand at certain stations, thus triggering the need for additional capacity.

E7.4.3.2 Hydro One Contributions

As a part of the IRRP process and Hydro One's long-term investment planning process, the Toronto Region needs are reviewed and agreed upon as a part of the Needs Assessment led by the IESO. The results of the most recent Needs Assessment highlight new emerging needs identified by Hydro One since the previous regional plan and reaffirm needs that were previously identified. These needs are summarized in Table 31, Table 32, and Table 33 in Section E7.4.7.

In response, Toronto Hydro is making capital contributions to Hydro One to carry out upgrades at Hydro One stations during the 2020-2024 period. This is done for large projects where a Toronto Hydro need requires Hydro One to perform a large capital project, such as the Horner expansion, or for projects where Toronto Hydro identifies an opportunity to enable incremental capacity upgrade in coordination with a Hydro One initiated project, such as the identified Hydro One EOL transformer upgrades. Contributing capital to Hydro One allows Toronto Hydro to alleviate capacity constraints on the distribution system by increasing bus firm capacity and increasing available load through transformer upgrades. This enables both customer connections to the system and load transfers which can reduce the risk and duration of outages. Table 8 below provides a summary of these Hydro One contribution projects included in the 2020-2024 filling:

Table 8: 2020-2024 Hydro One Contribution Projects based on the most recent Needs Assessment report

Project	Project Type
Horner Expansion	Station Capacity Expansion
Charles TS – T3/T4 Upgrade	Transformer Upgrade
Duplex TS – T1/T2 Upgrade	Transformer Upgrade
Windsor TS – T1/T2/T3/T4 Upgrades	Transformer Upgrade
Finch TS B-Y Replacement	Bus Replacement

1. Horner TS Expansion

Toronto Hydro plans to make a capital contribution to Hydro One of $34.4 million over the 2020-2024 period for a large-scale expansion project at Horner TS. The result will be an additional capacity of 192 MVA to alleviate forecasted capacity constraints at Manby TS in the South-West area of Toronto. This need has been identified in the Needs Assessment report as shown in Table 32 and as discussed in detail in the IRRP, Section 7.2.3.[14] **/C**

Figure 2 below shows the four stations in this area that require capacity relief in the near future: Manby TS, Horner TS, Runnymede TS, and Fairbank TS.

[14] Exhibit 2B, Section B, Appendix E

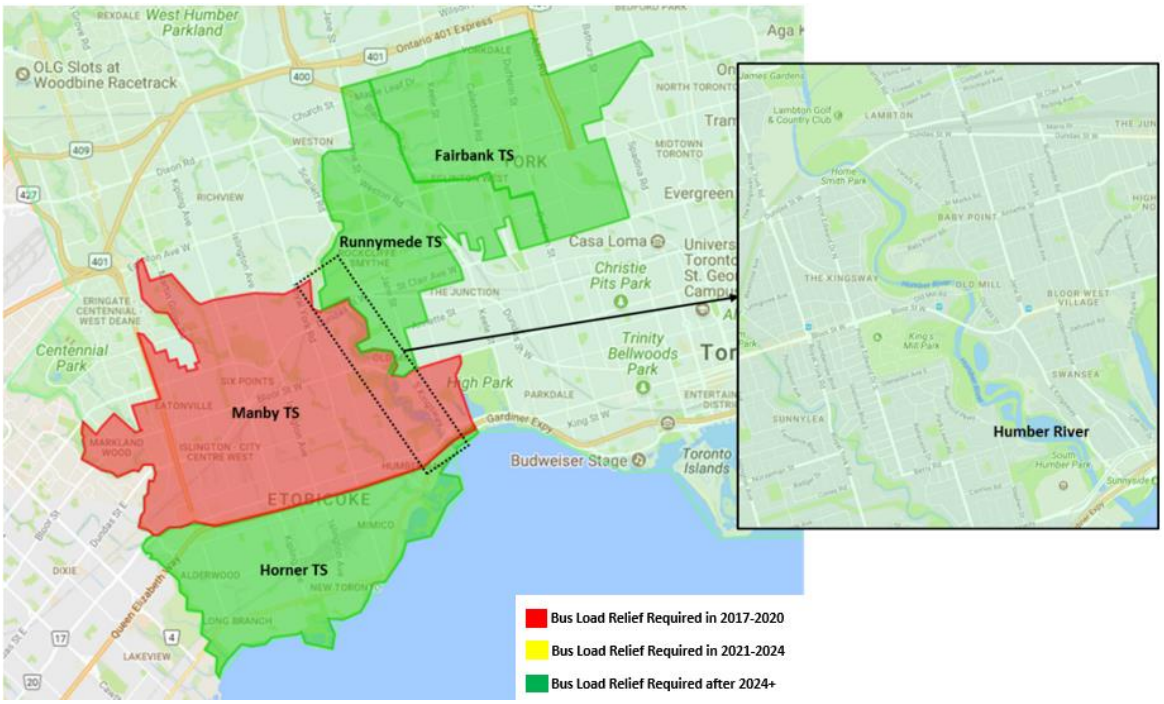


Figure 2: Geographical Spread of South-West Toronto Stations with a visual overview of bus load relief requirements

As shown in Table 9, loading on most station buses identified in Figure 2 above is 75 percent as of 2017. Typically, a 27.6 kV Horseshoe station bus requires relief when the forecasted peak load of a bus reaches 100 percent of the bus firm capacity. Loading is expected to increase at all stations by 2024 if no actions are taken (as seen in Column E). Hydro One is currently installing a new bus (J-Q) at Runnymede TS with an expected in-service date of Q4 2018. This bus will provide an additional 117 MVA capacity to the South-West Toronto area. However, because of the physical barriers posed by the Humber River (see Figure 2), the additional capacity cannot be efficiently utilized to relieve constraints at Manby TS or Horner TS.

As seen in Table 9 below, currently Manby TS and Horner TS have no spare feeder positions available, and by 2020 Manby TS is expected to reach 100 percent capacity and become overloaded. Customers with large loads (14 MVA or more) or DERs introduced into the system require dedicated feeders, which can only be provided if there are spare feeders on a bus. Even if the existing feeders on a bus have capacity, load from large customers cannot be aggregated along these feeders due to the configuration and design of the feeder protection system and the contingency plans. For example, a large customer has enough load that requires supply from two feeders. However, due to contingency

setup, this customer will require 3 feeders (two on-load and one standby) so that if any of the on-load feeders fail, the standby feeder can pick up the load. The lack of spare feeder positions prevents Toronto Hydro from implementing this contingency setup for any new large customer connections.

Due to a lack of spare feeder positions, there is a high risk of connection rejection if and when Toronto Hydro receives large customer or DER connection requests in the Manby or Horner TS service areas. In that Toronto Hydro has a statutory obligation to provide access to the grid, Toronto Hydro will be forced to implement expensive load transfers, which cost at least two times more than regular load transfers, to enable the connections.

As seen in column H in Table 9, bus failures at Manby TS or Horner TS would affect an average of 3,560 and 18,312 customers respectively. Investments in this Program would alleviate the risk of bus failure therefore increasing service reliability for these customers.

Table 9: 2017 Summer Load Forecast (South-West Toronto) with no investments

Column A	Column B	Column C	Column D	Column E	Column F	Column H
Station Name	**Bus ID**	**2017 Bus Loading (%)**	**Spare Feeder Position 2017**	**2020 Bus Loading (%)**	**2024 Bus Loading (%)**	**Potential # of CI[15] due to bus failure**
Fairbank TS	*B-Q*	67%	0	64%	76%	17978
	Y-Z	89%	0	88%	91%	11471
Horner TS	*B-Y*	75%	0	80%	83%	18312
Manby TS	*B-Y*	91%	0	95%	98%	4942
	Q-Z	95%	0	103%	106%	2921
	V-F	76%	0	91%	99%	2824
Runnymede TS	*B-Y*	90%	0	61%	63%	21205
	J-Q [1]	--	0	73%	75%	--
Richview TS	*B-Y*	40%	0 [2]	43%	44%	248
	J-E	70%	0	60%	62%	2914
	Q-Z	43%	0	47%	49%	2059

Note: Red ≥ 100 percent and orange is ≥ 95 percent

To provide capacity relief at Manby TS, Toronto Hydro has performed several load transfers to Horner TS and Richview TS as summarized in Table 10 below.

[15] "CI": Customers Interrupted
[1] J-Q is the new Runnymede TS bus. It is expected to be in-service by Q4 2018
[2] B-Y bus has feeders that are owned by Alectra utility

Table 10: Load transfer from Manby TS to Horner TS and Richview TS

Load Transfer	2015	2016	2017	Total
Manby TS to Richview TS (MVA)	13	8	--	**21**
Manby TS to Horner TS (MVA)	--	--	3	**3**

Toronto Hydro assessed several capacity relief alternatives, including DR and using Richview TS to pick up additional load from Manby TS. It was found that an upgrade of Hydro One's Horner TS transformation capacity is the most feasible and cost-effective option. A detailed options analysis can be found in Section E7.4.5.2. For additional details on the Richview TS option, please refer to section 7.2.3 of the IRRP report for the Central Toronto area.[16]

2. Hydro One Transformer Upgrades

Toronto Hydro is planning to contribute capital to Hydro One to upgrade three transformers during the 2020-2024 period to alleviate capacity constraints. Initiated by Hydro One's sustainment plans and included in the Needs Assessment report (see Table 32), the proposed investments will enable incremental capacity upgrades at Hydro One-owned transformer stations to enable customer connections and to mitigate capacity constraints at the same time that Hydro One is replacing EOL equipment in its stations.

Based on the RIP report[17] Charles TS, Duplex TS, and Windsor TS are expected to reach above 95 percent station capacity[18] within 15-20 years from 2020. When these stations are overloaded, Toronto Hydro will be unable to connect new customers within these service areas or to provide reliable service to its existing customers. As mentioned earlier, the downtown core stations serve primarily institutional, commercial, and large residential condominium customers, who prioritize reliability and resiliency over all other factors given the essential services they provide. For such customers, the cost of power interruptions outweighs the cost of distribution rate increases, and it is crucial to avoid interruptions by adding capacity to the system.

In response, Toronto Hydro plans to provide capital contributions to Hydro One to upgrade the transformers identified in Table 11. For each project, Toronto Hydro plans to request transformer

[16] Exhibit 2B, Section B, Appendix E
[17] Exhibit 2B, Section B, Appendix C
[18] A 13.8 kV downtown station bus load relief is required when the forecasted peak load of a bus reaches 95% of the bus firm capacity.

upgrades (from the current 75 MVA to 100 MVA). These investments are estimated to add approximately 188 MVA of capacity (see Table 11 Column C) to the system over the next 10-15 years. The geographical distribution of these transformers can be seen in Figure 3.

Table 11: Hydro One Transformer Replacement

Column A	Column B		Column C
Project	**Transformer Ratings (MVA)**		**Final Post-Replacement Capacity Additions [19]**
	Existing	**New**	
Charles TS – T3/T4 Upgrade	75	100	54 MVA
Duplex TS – T1/T2 Upgrade	75	100	54 MVA
Windsor TS – T1/T2/T3/T4 Upgrades	75	100	80 MVA
Total			**188 MVA**

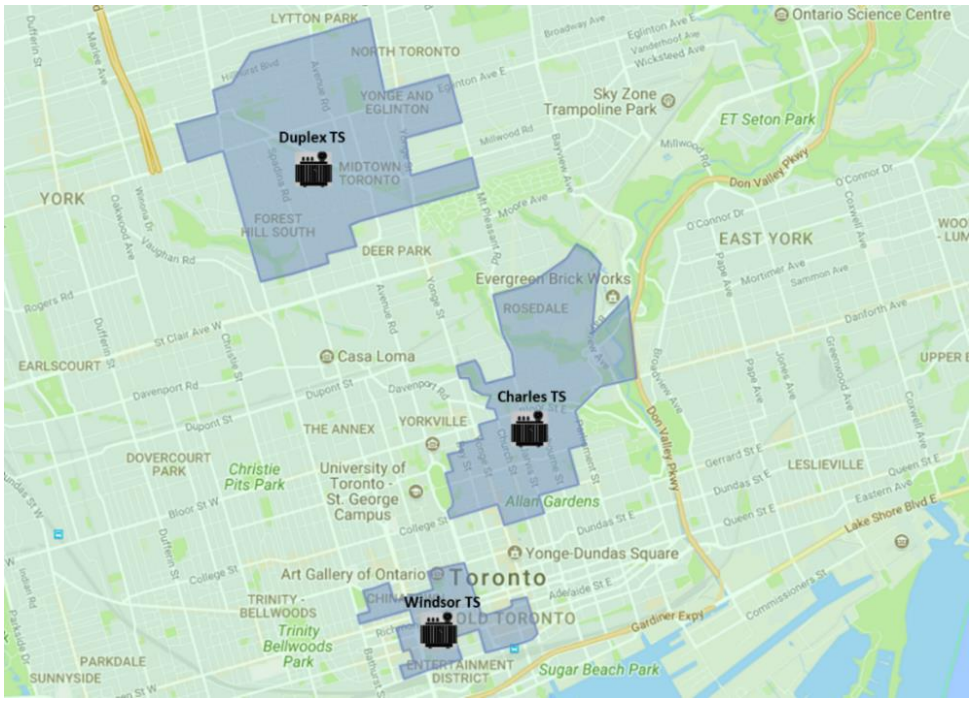


Figure 3: 2020-2024 Hydro One Transformer Upgrade Projects

[19] Following a Hydro One transformer upgrade, additional investments may need to be made to realize all of the available capacity. For example, the station switchgear may need to be replaced or the transformer's pair may need to be upgraded. Toronto Hydro replaces end-of-life transformer station switchgear in the Station Renewal program (See Exhibit 2B, Section E6.6 Station Renewal – Section E6.6.3.1 sub-section 1 TS Switchgear).

Upgrading these transformers in tandem with Hydro One's renewal and sustainment plans would alleviate capacity constraints on the system and result in avoided costs of up to $20 million (as shown in Table 12) thus reducing the burden on ratepayers. This benefit is possible given the Transmission System Code cost allocation rules: when work is being undertaken by the transmitter in the normal course, the distributor is only responsible for paying the incremental cost of an equipment upgrade; on the other hand, if the work is initiated by the distributor, the rules shift much of the cost burden onto the distributor.[20] For example, Hydro One will invest $5.5 million to replace and upgrade the existing T3 and T4 transformers at Charles TS. Of the $5.5 million, $0.5 million is paid by Toronto Hydro in the form of capital contribution for requesting capacity increase of the new transformers from 75 MVA to 100 MVA. In this scenario, Toronto Hydro benefits from capacity gains due to higher transformer ratings. At the same time, it is able to avoid an additional $5 million in costs (as shown in Table 12 below) as a result of not having to pay for the entire transformer replacement cost.

Table 12: Avoided Costs by aligning with Hydro One sustainment plans ($ Millions)

Project	Cost if independent of Hydro One sustainment plans	Cost if undertaken with Hydro One sustainment plan	Avoided Cost
Charles TS – T3/T4 Upgrade	5.5	0.5	5.0
Duplex TS – T1/T2 Upgrade	5.5	0.5	5.0
Windsor TS – T1/T2/T3/T4 Upgrades	11	1.0	10.0
Total	**22.0**	**2.0**	**20.0**

Additionally, when Hydro One replaces a transformer, the incremental cost of installing a larger unit is relatively small in relation to the incremental capacity derived from the investment, resulting in considerable savings per MVA of installed capacity. Section E7.4.5.2 sub-section two outlines the typical differences between replacing a 75 MVA transformer with a like-for-like transformer and a higher rated 100 MVA transformer.

If the transformers identified in Table 11 are not upgraded and are instead replaced on a like-for-like basis (i.e. 75 MVA to 75 MVA) during the 2020-2024 period, the capacity of the existing buses connected to these transformers will be stranded (i.e. limited), as seen in Table 13 below. This will

[20] Transmission System Code, Section 6.3 - Cost Responsibility for New and Modified Connections.

result in increased capacity constraints on the system. Additionally, if the transformer upgrades are not carried out in the 2020-2024 period, Hydro One is unlikely to replace them again within the next 45 years[21] and Toronto Hydro would need to replace these busses as part of the Stations Renewal program[22] within the next 15 years due to increased loading as indicated in Appendix C (Metro Toronto Regional Load Forecast) of the RIP report.

Table 13: List of Toronto Hydro Owned Busses Connected to Hydro One Transformers

Column A	Column B	Column C	Column D	Column E	Column F	Column G	Column I
Station – Transformer	**Connected Bus**	**Existing Bus Capacity**	**2017 Bus Loading (%)**	**Spare feeder position 2017**	**2020 Bus Loading (%)**	**2024 Bus Loading (%)**	**Potential # of CI[23] due to bus failure**
Charles TS – T3/T4	*A1-2CS*	45 MVA	67%	1	73%	76%	3044
	A3-4CS	45 MVA	76%	0	89%	91%	3254
Duplex TS – T1/T2	*A1-2DX*	45 MVA	69%	0	82%	84%	5767
	A3-4DX	45 MVA	69%	0	78%	80%	1723
Windsor TS – T1/T2/T3/T4	*A5-6WR*	59 MVA	90%	0	14%	93%	434
	A3-4WR	59 MVA	88%	0	90%	0%	5838
	A13-14WR	41 MVA	95%	0	85%	88%	21
	A17-18WR	49 MVA	88%	0	73%	76%	227

Note: For Bus Loading, red represents ≥85 percent and orange ≥80 percent.

3. Finch B-Y Bus Replacement

Finch TS is a Hydro One owned station located in the Finch Avenue and Weston Road area. Hydro One intends to replace its legacy air-insulated 27.6 kV outdoor B-Y bus and rebuild the switchgear yard at Finch TS in 2024. This rebuild work will include the installation of a new 27.6 kV outdoor metalclad switchgear with twelve circuit breaker positions (or more) to replace the existing B-Y bus. The existing B-Y bus has 12 EOL bulk oil circuit breakers and Toronto Hydro owns six of them. Toronto Hydro intends to make a total capital contribution of $4.1 million to Hydro One to replace the existing six breakers on B-Y bus with six new ones on a new bus.

[21] Kinectrics "Useful Life of Assets" Report, filed in the EB-2010-0142 application (Exhibit Q1, Tab 2)
[22] Exhibit 2B, Schedule E6.5, Section E6.5.3.1 sub-section 1
[23] "CI": Customers Interrupted

Typically, Toronto Hydro would replace these obsolete oil circuit breakers with vacuum circuit breakers through its Stations Renewal program.[24] However, in this case, since Hydro One is replacing the entire B-Y bus along with all its circuit breakers, Toronto Hydro will make a capital contribution to Hydro One to transfer ownership from the existing 6 circuit breakers on the B-Y bus to six new circuit breakers on the new Hydro One-owned 27.6 kV bus.

The outdoor oil circuit breakers at Finch TS were installed in the 1960s and 1970s and are past their 45 year useful life. These legacy units show signs of moderate and accelerated deterioration, and need to be replaced to mitigate the failure risk associated with their obsolete oil-based technology. Although a fault would normally only cause a localized outage on the feeder protected by the breaker, when a TS outdoor circuit breaker fails, thousands of customers will be affected because a fault would extend the outage to all customers supplied by the station bus. If the B-Y bus at Finch TS experienced a failure, the outage could last between one to two hours and could potentially impact around 13,000 customers in the service area.

Toronto Hydro experienced an outage of this nature on August 4, 2017, when an outdoor breaker at Finch TS failed to open during a fault. Bus protection was forced to operate, interrupting power to nearly 5,000 customers. The majority of customers were restored within an hour of the initial incident; however, all of those customers were supplied by feeders that would not have suffered an outage had the outdoor breaker operated as designed.

E7.4.3.3 Local Demand Response

The Local DR segment includes conservation programs and technological solutions that encourage load curtailment and load-shifting, including targeted DR resource procurement at two stations: Cecil TS (a continuation of the current local DR program) and Basin TS. Locally targeted, customer-centric initiatives promote the adoption of existing and new DR technologies.[25] These investments enable the utility to address capacity constraints using targeted deployment of DR, expanding the planning toolbox beyond conventional wires solutions when evaluating options to address medium term capacity needs. DR strategies do not permanently replace the need for traditional wires solutions, but rather provide the utility with far more flexibility in terms of the timing of capacity upgrades and the ability to decide what parts of the station will be upgraded versus which parts can be deferred. This enables optimal deferral of investment costs, while allowing for re-allocation and optimization

[24] See Exhibit 2B, Section E6.6 Stations Renewal, Section E6.6.3.1 sub-section 2 TS Outdoor Breakers for more detail.
[25] See Exhibit 4A, Tab 2, Schedule 9 – Asset and Program Management, 7. Local Demand Response

of capital as medium-term investment options are considered. Local DR also supports the goals of the Toronto IRRP and the LTEP to meet local needs with DERs, conservation programs and DR strategies.

Local DR is most appropriate in service areas requiring non-urgent load relief to provide sufficient time to penetrate the market. Suitable candidate stations must have adequate lead-time (two to three years) for the implementation of a DR solution before a capacity constraint is expected to materialize. Toronto Hydro targets stations that exhibit physical or logistical barriers for pursuing conventional station expansion solutions, making the DR option significantly more cost-effective in the short-to-medium term. Further, DR works best at stations with load profiles that demonstrate short and infrequent system peaks. In Toronto Hydro's service area, these temporary "spikes" in customer demand typically occur during the hottest weekday afternoons in the summer when maximum cooling loads amplify the normal daily peaks that result from electrical building system and operational end-uses. Stations that serve a range of larger customers (greater than 3 MW average monthly peak demand) that have flexible operational profiles are best suited to DR solutions.

Local DR is needed to address capacity constraints that are forecast to start affecting the identified stations by as early as 2022**.** Implementing this program is expected to mitigate the risks of operating the system beyond its capacity and avoid the need to undertake complex and impractical load transfer projects to free up capacity for new customers. Failing to address capacity constraints can lead to operational and reliability risks by 2022, as shown in Table 14 below.

As can be seen in Table 14, Basin TS will reach 85 percent loading by 2020, and approach 90 percent by 2024. As such, Toronto Hydro has adequate lead-time to implement DR measures that can help defer the need for costly capital investments, while also providing sufficient buffer to allow for the implementation of wires solutions if needed. In the case of Cecil TS, which will reach 85 percent loading by 2024, there is no lead-time required as the proposal is to continue the current Local DR program, which was developed, implemented, and tested during the 2015-2019 period. Failure to implement Local DR could result in reduced reliability, costly short-term load transfer projects, reduced flexibility to schedule maintenance outages, inability to accommodate distributed generation (e.g. combined heat and power), increased risk of equipment failure, and inability to connect new loads. Operating station busses at high capacity puts the system at risk of violating design parameters, which could result in rotating blackouts and voltage reductions.

Table 14: 2016 Station Load Forecast for Selected Stations

Station/Bus	Firm Capacity (MVA)		Year								
	100%	95%	2016	2017	2018	2019	2020	2021	2022	2023	2024
Cecil (115 kV/13.8 kV) TS (Weather corrected busses to 32°C)											
A1-2	47	45	27	27	27	27	27	27	27	28	28
A3-4	47	45	35	36	36	37	37	37	38	38	38
A5-6	72	68	53	57	61	67	71	73	73	74	74
A7-8	72	68	56	57	57	59	60	60	61	61	62
Total of all Busses	238	226	171	177	181	190	195	197	199	201	202
Surplus MVA			67	61	57	48	43	41	39	37	36
% Loading (Load/2016 Firm Cap)			72%	74%	76%	80%	82%	83%	84%	84%	85%
Basin (115 kV/13.8 kV) TS (Weather corrected busses to 32°C)											
A5-6	49	47	32	35	44	47	49	49	50	50	50
A7-8	49	47	21	27	28	32	34	36	36	36	37
Total of all Busses	98	94	53	62	72	79	83	85	86	86	87
Surplus MVA			45	36	26	19	15	13	12	12	11
% Loading (Load/2016 Firm Cap)			54%	63%	73%	81%	85%	87%	88%	88%	89%

Toronto Hydro proposes to continue Local DR at Cecil TS. That project has had considerable uptake from several large (>1 MW) customers with an interest in longer-term DR contracts (beyond the current 2019 program end date, preferably for 3-5 year terms). There are also numerous smaller commercial customers (500 kW to 1 MW) interested in DR to support customer-funded storage projects. The station load forecast (see above) shows a continued need for load reduction at Cecil TS. DR remains a more cost-effective and customer-friendly approach compared to conventional wires solutions.[26]

The next phase of the Local DR program is expected to achieve a total of 11 MVA (about 10 MW) of peak demand reduction between 2020 and 2024 at an all-in projected cost of $10.3 million (60percent operational expenditures, 40 percent capital expenditures). The operational

[26] For the cost-effectiveness analysis of DR versus wires, please see section E7.4.5.3.

expenditures will fund the cost of program administration, customer incentives, and consultant and technology fees (e.g. the cost of procuring DR software).[27] The capital expenditures will fund the cost of Toronto Hydro-owned battery storage at Basin TS.

By curtailing 10 MW of peak load, Toronto Hydro can defer capital investment that would otherwise be required in 2022-2024 or shortly thereafter to provide bus relief at these stations by five to six years. Without investment in this Local DR solution, conventional wires solutions would be required at a cost of $135 million to avoid reliability risks and meet Toronto Hydro's obligations to customers (see Section E7.4.5.3).

Both Cecil TS and Basin TS serve primarily institutional and commercial customers. The demand at Cecil TS is 43 percent institutional customers (e.g. hospitals and universities) and 25 percent commercial customers, with the remaining demand being residential. Basin TS serves 35 percent institutional customers (e.g. City of Toronto waste water treatment plants, healthcare facilities, Metrolinx/Go Transit), 30 percent commercial customers, 3 percent industrial, with the remaining being residential.

Given the criticality of loads associated with critical services, resiliency and reliability are extremely important at both stations. Local DR responds to the need for resiliency and reliability in these areas while incentivizing customers to change their behaviour and contributing to an overall benefit to all ratepayers. Keeping these essential services running smoothly is important to all Toronto Hydro customers, regardless of their rate class.

E7.4.4 Expenditure Plan

Table 15: Historical & Forecast Program Costs by Segments ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Copeland TS Expansion	20.5	19.1	22.0	7.4	7.8	8.9	29.7	38.8	1.0	--
Hydro One Contributions	2.5	15.3	37.4	22.7	21.5	10.6	10.3	10.5	10.2	11.7
Local Demand Response	--	--	0.1	0.5	3.6	--	--	--	1.2	3.4
Total	**23.0**	**34.4**	**59.4**	**30.6**	**32.8**	**19.5**	**40.0**	**49.3**	**12.5**	**15.2**

[27] Exhibit 4A, Tab 2, Schedule 9 – Asset and Program Management.

Spending in the Stations Expansion program over the 2015-2019 period is projected to be $180.1 million.

Toronto Hydro proposes to spend $136.4 million over the 2020-2024 period to add or free up 415 MVA of capacity on its system. This is $43.7 million less than what is forecasted to be spent over the 2015-2019 period. The proposed projects in the Stations Expansion program are based on Hydro One sustainment plans and the IRRP Needs Assessment report. Given the complexity and size of these individual projects, their expenditures are discrete and not conducive to smoothing over the rate period. Moreover, these projects entail extensive coordination with Hydro One and other stakeholders (such as contractors, vendors, public etc.), long lead times for ordering equipment, and logistical challenges in heavy electrical equipment delivery. Due to these challenges, the Stations Expansion program is susceptible to fluctuations in spending from year-to-year. As such, the historical and proposed spending reflect significant variations from year to year.

E7.4.4.1 Copeland TS – Phase 2

Toronto Hydro forecasts to spend $76.8 million on Copeland TS – Phase 1 and 2 over the 2015-2019 rate period, and $78.4 million during 2020-2024 rate period on completing Copeland TS - Phase 2. A breakdown of the budget is shown below in Table 16.

Table 16: 2015-2024 Budget (Actual/Bridge/Forecast): Copeland TS – Phase 1 and Phase 2 ($ Millions)

Asset Class	Actuals			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Copeland TS – Phase 1	20.5	19.1	21.5	5.6	--					
Copeland TS – Phase 2	--	--	0.5	1.8	7.8	8.9	29.7	38.8	1.0	--
Total	**20.5**	**19.1**	**22.0**	**7.4**	**7.8**	**8.9**	**29.7**	**38.8**	**1.0**	**-**

1. Copeland TS – Phase 1

Copeland TS – Phase 1 is a large and complex project of unprecedented scale for Toronto Hydro. It is a uniquely challenging project in the dense urban core of the City. The Copeland TS design places most of the equipment underground and includes a tunnel connection to Hydro One's Front Street tunnel.

Due to several unforeseen events and factors, including the effect of unusually adverse weather events, challenging site conditions, logistical challenges, and contractor performance, construction

of Copeland TS – Phase 1 has encountered schedule and spending delays. Construction is expected to be completed in 2018 at a projected cost $66.7 million, which is $15.1 million higher than forecasted in the 2015-2019 rate filing for 2018. However, the overall Copeland TS – Phase 1 budget from project inception to project completion in 2018 has not materially changed. Furthermore, the timing of the expenditures proposed in the 2015-2019 CIR filing have shifted as a result of the delay to the construction schedule.

2. Copeland TS – Phase 2

Copeland TS – Phase 2 is expected to be completed by late 2023 or early 2024. Certain limited pre-construction work related to this project commenced in 2017. This project has to start in the 2017-2019 period to meet the long lead times associated with manufacturing, delivery, and assembly of power transformers and switchgear. There are three major activities to be completed in the 2017-2019 timeframe: contractor Request for Proposal ("RFP")-related activities, design and engineering, and certain pre-construction work. These major activities are forecasted to cost $10.0 million during the 2017-2019 period.

In 2017, Toronto Hydro developed and issued contractor RFPs for competitive bids. Based on the responses from bidders, budget and schedule for Copeland TS – Phase 2 will be updated in late 2018 or early 2019. In 2018, at least two contractors are expected to be selected: a primary Engineering, Procurement, and Construction ("EPC") contractor, an engineering consulting firm, and potentially one or more specialist firms to carry out inspections, audits, and payment verification. The selected EPC contractor is also expected to complete design and engineering work ahead of 2020 so that the major electrical equipment can be purchased following the issuance of the OEB's decision in respect of this application. Some pre-construction work, along with development of logistical and transportation plans, acquisition of permits, and public engagement plans are also expected to be carried out in 2018 and 2019.

The expenditure plan for Copeland TS – Phase 2 was developed based on the actual costs of Copeland TS - Phase 1, plus additional considerations based on lessons learned from Copeland TS - Phase 1 (detailed in Section E7.4.6 Execution Risks & Mitigation) as well as certain unique attributes and challenges of Copeland TS - Phase 2 that were not applicable to Copeland TS - Phase 1, including:

- **Construction within an energized station:** Copeland TS - Phase 2 requires construction, testing, and commissioning of equipment in an already energized Copeland TS. In addition

to safety issues related to working near live equipment, contractors must coordinate work with Toronto Hydro and Hydro One personnel working in the station. Increased logistics limitations also exist due to the presence of cable racking and HVAC and mechanical equipment.

- **Public access and stakeholder relations:** The public and neighbouring businesses will be utilizing the roof and surrounding sidewalk areas of Copeland TS while Copeland TS - Phase 2 construction is in process.
- **Roof opening**: A roof opening needs to be made to transport large equipment into the station and then be re-constructed after the work is completed.
- **Cable installation***:* Copeland TS - Phase 2 involves the installation and routing of additional High Voltage ("HV"), Medium Voltage ("MV"), and control cables in the station basement, utilizing existing cable racks and trays. Since existing cable racks and trays will already be carrying cables installed during Copeland TS - Phase 1, it would be challenging to pull cables through the limited basement space.
- **Utilization of EPC contractor**: Schedule and budget will be developed and managed by the EPC contractor.

The 2017-2024 budget for Copeland TS – Phase 2 includes the following tasks:

- Design and Pre-Construction
- Major Electrical Equipment:
- Procurement of 3 power transformers, 3 switchgears, and HV/MV/control cable
- Installation, testing and commissioning of major electrical equipment
- Cable installation, termination, testing and commissioning
- Installation of Protection and Control, and metering equipment
- Construction:
- Including civil, facilities, station services, landscaping, room finishes, and enhancements to IT, SCADA and communications systems
- Project Management and Ancillary Cost:
- Third-party review and verification, including payment verification
- Acquisition of permits, insurance, public relations, liaison and coordination with relevant stakeholders, including the City, Ministry of Labour, other authorities, and Hydro One

A summary of the Copeland TS – Phase 2 schedule and annual cost is shown below in Table 17:

Table 17: Summary Schedule and Annual Cost of Copeland TS – Phase 2

Year	Budget ($ Millions)	Work Schedule
2017	0.5	Design
2018	1.8	Design
2019	7.8	Design and Pre-Construction
2020	8.9	Pre-construction Project Management and Ancillary Cost Major Electrical Equipment
2021	29.7	Project Management and Ancillary Cost Major Electrical Equipment
2022	38.8	Project Management and Ancillary Cost Major Electrical Equipment Construction
2023	1.0	Project Management and Ancillary Cost Major Electrical Equipment Construction

E7.4.4.2 Hydro One Contribution

Toronto Hydro forecasts to spend $99.4 million on Hydro One capital contributions over the 2015-2019 rate period, and $53.3 million over the 2020-2024 rate period. The expenditures include contributions to Hydro One for stations expansions (i.e. Runnymede TS and Horner TS), transformer upgrades and related work, and bus replacements. These projects are planned based on the Needs Assessment (see Table 31, Table 32, Table 33 in Section E7.4.7).

Table 18: 2015-2024 Budget (Actual/Bridge/Forecast): Hydro One Contribution ($ Millions)

Asset Class	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Runnymede TS Expansion	0.08	13.6	36.0	5.8	--	--	--	--	--	--
Horner TS Expansion	0.05	0.3	--	15.0	19.4	10.6	7.8	8.0	8.0	--
Hydro One Transformer Upgrades and Related Work	2.3	1.4	1.4	1.9	2.1	--	0.5	0.5	0.1	2.0
Finch TS B-Y Bus Replacement	--	--	--	--	--	--	--	--	0.1	4.0
Reactive Hydro One Contribution	--	--	--	--	--	--	2.0	2.0	2.0	5.7
Total	**2.5**	**15.3**	**37.4**	**22.7**	**21.5**	**10.6**	**10.3**	**10.5**	**10.2**	**11.7**

1. 2015-2019 Expenditure Costs

Over the 2015-2019 rate period, Toronto Hydro expects to spend $99.4 million on Hydro One contributions, which is approximately $7.4 million less than forecasted. This variance is attributable to: Runnymede TS expansion cost estimate changes, South-West Toronto needs and scope changes, Hydro One transformer upgrades and related projects, and Hydro One cost reconciliation. A more detailed comparison is shown in Table 19 and further discussed below.

Table 19: Hydro One Contribution – Historical Spending Analysis ($ Millions)

Projects	2015-2019 Filed Cost	2015-2019 Actual/Forecast Cost	Variance
Horner Expansion	72.0	34.8	(37.2)
Runnymede Expansion	33.0	55.5	22.5
Hydro One Transformer Upgrades & Related Work	1.8	9.1	7.3
Total	**106.8**	**99.4**	**(7.4)**

a. Runnymede TS Expansion Cost Estimate Changes:

In the 2015-2019 rate application, Toronto Hydro forecasted a $33 million capital contribution to Hydro One for the Runnymede TS expansion based on high level equipment and construction costs available at the time. In Q2 2016, Hydro One made available a Class C (+50 percent/-20 percent) cost estimate of $37 million, which included an expansion to the 115-27.6 kV Runnymede TS consisting of two new 50/83 MVA transformers and the re-conductoring of the 115 kV transmission circuits (K1W, K3W, K11W and K12W), each of which is approximately 10 kilometres long between Manby TS and Wiltshire TS. In Q4 2016, Hydro One provided Toronto Hydro with a Class B estimate (+/-20 percent) of $55.5 million, noting that the original Class C estimate for the circuit re-conductoring work did not consider and include:

- Replacement of steel members (required on 90 percent of structures) in the circuit conductors;
- Construction complexities due to working in a congested corridor in the City; and
- More complex outage requirements at Manby TS, Runnymede TS, and Wiltshire TS than originally expected.

b. South-West Toronto Needs/Scope Change:

In the 2015-2019 rate application, Toronto Hydro proposed to construct and own a 100 MVA transformer station in the Manby TS area for $72 million. However, once the feasibility study was completed in 2014, Toronto Hydro determined that building a new station would require longer implementation time and higher cost compared to other options (see section E7.4.5.2 sub-section 1 for additional details). The preferred option of Horner TS expansion will cost $30.4 million during 2015-2019 and $34.8 million during 2020-2023. This option allows Toronto Hydro to avoid approximately $7.2 million while addressing the capacity needs in the South-West Toronto region.

As noted in section E7.4.3.2 sub-section 1 (Table 10), pending the completion of the Horner TS expansion, Toronto Hydro undertook several much needed load transfer projects to relieve capacity constraints at Manby TS. These investments resulted in increased flexibility with respect to the need date for the Horner TS expansion.

c. Hydro One projects:

Over the 2015-2019 period, Toronto Hydro expects to undertake several projects that were not included in the 2015-2019 DSP at a total cost of $2.3 million. These projects are driven by Hydro One sustainment plans.

- **Transformer upgrades:** $0.8 million capital contribution to Hydro One to upgrade transformers at Cecil TS, Dufferin TS, and Main TS from 75 MVA to 100 MVA. These projects were not included in the 2015-2019 DSP due to the timing of Hydro One's sustainment plans.
- **Bridgman TS cable replacement**: $0.7 million capital contribution to Hydro One in support of the replacement of Toronto Hydro-owned 13.8 kV LV cables between Bridgman TS and High Level TS to mitigate reliability issues. This work carried out by Hydro One addressed Toronto Hydro's needs by modifying the incoming circuit breakers at High Level TS to enable the connection of the new cables.
- **Bridgeman TS potential transformer and metering upgrade:** $0.8 million capital contribution to Hydro One for the replacement of EOL, legacy oil-filled potential transformers ("PTs"). To ensure the proper function of Toronto Hydro's protection and control system at Bridgman TS, Hydro One was required to perform certain modifications for Toronto Hydro.

d. Hydro One Cost Reconciliations:

Pursuant to applicable cost recovery agreements (including criteria regarding cost reconciliation review), Toronto Hydro incurred $2.3 million to reconcile past Hydro One capital contributions. Such reconciliations are typically based on actual asset or station loading and project in-service anniversaries, making the costs difficult to forecast in advance.

- **Cecil TS 10-Years True-Up:** $1.8 million in capital contributions to Hydro One for the 10-year economic evaluation period ("EEP") of the 2005 Cecil TS T3/T4 transformer upgrade. This payment accounted for the variance between the forecasted load at the time of the transformer upgrade and the actual load at the end of the EEP.
- **Richview TS 10-Years True-Up:** $0.5 million in capital contributions to Hydro One for the 10-year EEP of the 2006 installation of two feeder breaker positions at Richview TS. This payment accounted for the variance between the forecasted load at the time of the breaker installations and the actual load at the end of the EEP.

2. 2020-2024 Forecast Expenditures

As evidenced in the 2015-2019 period, given the nature of work performed under the Hydro One Contribution segment, expenditures are susceptible to large fluctuations from year-to-year. This is due to the dependency on Hydro One's sustainment plans and the complexity and size of individual projects which make the spending discrete and irregular. For 2020-2024, Toronto Hydro's proposals are based on the best available information as of 2018.

a. Horner TS Expansion

Toronto Hydro anticipates that the cost to complete the Horner TS Expansion will be $69.2 million, mostly in the form of capital contribution to Hydro One. The forecast includes $45.4 million to complete the Horner expansion work by 2020 and is based on the Class C estimate provided by Hydro One. The remainder $23.8 million is required for civil infrastructure enhancement work within Hydro One's yard to enable feeder transfers from Manby TS. Table 20 below outlines the payment breakdown to Hydro One by year.

Table 20: Horner TS Expansion Hydro One Payment Breakdown

Project	Cost ($ Millions)	Payment Year
Horner TS Expansion	0.4	2015-2016
	34.4	2018-2019
	34.4	2020-2023

b. Hydro One Transformer Upgrades

As noted in section E7.4.3.2 sub-section 2 above, Toronto Hydro plans to make capital contribution to Hydro One to upgrade certain EOL transformers from 75 MVA to 100 MVA. Table 21 below outlines the payment breakdown to Hydro One by years. Toronto Hydro forecasts that the cost to complete this work will be $3.1 million. The forecast is based on:

- **Hydro One's sustainment plans**: Total number of transformer upgrade projects during the 2020-2024 period are based on this plan which aligns with the Needs Assessment (see Table 33).
- **Actual project costs**: Unit cost of forecasted projects are based on completed and ongoing transformer upgrade projects executed between 2015 and 2018.

Table 21: Transformer Upgrades Hydro One Payment Breakdown

Hydro One Transformer Upgrades	Cost ($ Millions)	Payment Year
Charles TS – T3/T4	0.1	2018
	0.5	2021
Duplex TS – T1/T2	0.1	2019
	0.5	2022
Windsor TS – T1/T2/T3/T4	0.1	2023
	2.0	2024

c. Hydro One Bus Replacement: Finch TS B-Y Bus

As noted in section E7.4.3.2 sub-section three, Toronto Hydro plans to make capital contributions to Hydro One to replace six EOL bulk oil circuit breakers connected to Hydro One's legacy air-insulated 27.6 kV outdoor B-Y bus at Finch TS. This is part of Hydro One's Finch TS switchgear refurbishment plan where Hydro One plans to install a new bus to replace the existing B-Y bus. Toronto Hydro estimates that its cost to complete this work will be $4.1 million, all in the form of capital contribution to Hydro One. This project is at its preliminary stage and Hydro One has yet to share detailed plans

regarding the installation of the new metalclad switchgear. Therefore, the forecast is based on historical Hydro One owned bus replacement work, where Toronto Hydro has contributed toward upgrades. Table 22 below outlines the payment breakdown to Hydro One by year.

Table 22: Finch TS B-Y Bus Replacement Hydro One Payment Breakdown

Project	Cost ($ Millions)	Payment Year
Finch TS: B-Y Bus Replacement	0.1	2023
	4.0	2024

d. Reactive Hydro One Contribution

As noted above, Toronto Hydro incurred an additional $4.6 million in the form of capital contribution for several Hydro One projects that were not included in the 2015-2019 DSP. To account for any anticipated but yet to be identified Hydro One projects, Toronto Hydro has allocated $11.7 million as "Reactive Hydro One Contribution" during the 2020-2024 rate period. This budget is required to support projects triggered by Hydro One sustainment plans such as cable, switchgear or transformer replacements or upgrades. For example, Hydro One currently plans to upgrade three transformers (T11, T12, and T13) at Bridgman TS from 66.6 MVA to 100 MVA in 2020. Following the upgrades, additional capital contributions may be required from Toronto Hydro (e.g. to support switchgear replacements) so as to realize all of the additional available capacity.

This forecasted amount will enable Toronto Hydro to account for any cost reconciliations, which are typically based on actual asset or station loading and project in-service anniversaries, and are difficult to forecast in advance. True-up payments may result from variances between forecasted load at the time of asset upgrade and the actual load at the end of the EEP.

This amount would also enable Toronto Hydro to account for any policy changes pending more detailed planning and coordination with Hydro One.

E7.4.4.3 Local Demand Response

Table 23: 2015-2024 Budget (Actual/Bridge/Forecast): Local Demand Response ($ Millions)

Asset Class	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Local DR Program	--	--	--	0.5	3.6	--	--	--	1.2	3.4
Total	**--**	**--**	**--**	**0.5**	**3.6**	**--**	**--**	**--**	**1.2**	**3.4**

Over the 2015-2019 period, Toronto Hydro forecasts to spend $4.1 million in the Local DR segment for the purchase and installation of a battery for Cecil TS. The battery storage costs are estimated based on market costs for utility grade equipment, and installation estimates based on utility scale projects underway in Toronto over the 2015-2018 period.

Over the 2020-2024 period, Toronto Hydro forecasts to spend $4.6 million for the battery storage project in the Basin TS area. Similarly to the Local DR at Cecil TS, the capital cost of the battery and its installation is estimated based on the same assumptions regarding market costs and comparable projects.

The bulk of the total 2020-2024 Local DR program cost (e.g. incentives, labour) is not capitalized and therefore not included in Table 23. 60 percent of the $10.3 million total program cost is operating expenditures relating to program administration, customer incentives for DR activities, marketing and legal costs, and measurement and verification costs, as detailed in the Asset and Program Management program.[28]

E7.4.5 Options Analysis

Toronto Hydro has identified and evaluated various options based on current and future needs of the system.

E7.4.5.1 Options for Copeland TS

1. Option 1: Do Nothing

Do nothing is not a feasible option as it does not provide the necessary load relief and feeder positions required at downtown core stations (see Table 7 Columns D and E). This option would result in most busses being heavily loaded by 2024, including eight at 90 percent or above and two at more than 100 percent capacity. Toronto Hydro anticipates the remaining spare feeder positions will also be used up by 2024, which means that it will be very difficult, and in some cases impossible, for Toronto Hydro to connect new customers, including DERs, at these stations.

[28] See Exhibit 4A, Tab 2, Schedule 9 – Asset and Program Management

2. Option 2 (Selected Option): Copeland TS – Phase 2

Incremental to Copeland TS - Phase 1, construction and procurement for the Copeland TS - Phase 2 project is proposed to commence in early 2020 (with design expected to be completed over 2017-2019), providing an additional 144 MVA capacity in the area by 2024. Copeland TS - Phase 2 includes the installation of 2 additional 72 MVA busses, 3 gas insulated power transformers (two load-serving and one back-up), and a transfer bus to allow use of the spare transformer to back-up Copeland TS and other stations through the installation of ties.

This option includes a spare transformer and a transfer bus. This would allow Toronto Hydro to fully utilize the space and infrastructure installed in Copeland TS - Phase 1, while minimizing the need and cost associated with re-entering the station (i.e. equipment delivery and redoing the landscaping). The cost associated with the installation of these assets is estimated to be $1.5 million. Additionally, the spare transformer is required given the uniqueness of the SF_6 transformers that will be installed at the station and the long lead times (over a year) to procure replacement units. The failure risk of a SF_6 transformer is very low. However, if a failure were to happen, the Copeland station load supplied by the failed transformer would be under contingency without any outage to the customer. The contingency state would exist until the load at risk can be transferred to nearby stations.

This option would also provide a significant number of feeder positions to allow for bus load rebalancing in the area, facilitate future switchgear replacements (particularly at Windsor TS), and provide additional security of supply to critical downtown customers.

Regardless of whether one or two 72 MVA busses are installed, Toronto Hydro will still require the installation of two power transformers for contingency purposes. Through the installation of the second bus, Toronto Hydro is able to utilize the stranded transformation capacity which would otherwise remain unused. Other benefits of Copeland TS – Phase 2 include the following:

- Additional support for adjacent station (Windsor TS, Esplanade TS, Terauley TS, Strachan TS, and Cecil TS) through load transfers.
- Execution of work without streetscape impact, traffic congestion, or permanent visual disturbance to the area since all civil work will be completed as part of Copeland TS - Phase 1.
- Additional capacity for the proposed developments of the West Donlands, East Waterfront and the Portland's areas.

- Minimal additional HV connection work beyond what was completed as part of Copeland TS - Phase 1.

3. Option 3: Expansion of Esplanade TS

This option would involve working with Hydro One to construct a new building on the existing Esplanade TS site, perform necessary transmission upgrades (as determined by Hydro One), install two new power transformers, install two new 72 MVA distribution busses, carry out civil work including building expansion, and complete the requisite HV connection work. More specifically:

- This project would involve construction of a new facility on Hydro One property to a downtown residential area and urban parkland, giving rise to a host of potential challenges in terms of obtaining community acceptance and municipal approval.
- This option cannot be executed in time by 2024 to facilitate load transfers , relieve heavily loaded busses and enable near-term customer connections (including DER connections) in the downtown area, due to the extensive civil construction and equipment installation as well as coordination with Hydro One that are required.
- This option is estimated to cost $90 million (see Table 24 for cost breakdown), including required contributions to Hydro One. This estimate would be subject to significant uncertainty given the project scope will include complex work on the transmission system that is yet to be determined and scoped.

Table 24: Cost Breakdown of Esplanade TS expansion ($ Millions)

Item	Cost
Building Expansion	20
Transformers x2	20
Switchgear (Contribution to Hydro One) x2	26
Service Busses x2	14
Civil egress	10
Total Cost	**90**

4. Option 4: Load Transfers

This option includes the installation of feeder ties between busses within the same or different stations and significant civil construction to enable load transfer from heavily loaded busses. For this solution to work, the load receiving bus must have sufficient capacity and feeder positions to accept

the new load. Furthermore, for inter-station load transfer, it must be feasible to construct the necessary distribution infrastructure to permanently transfer the load.

Given these requisite conditions, there are various technical barriers that would make this a costly and extremely complex option for 13.8 kV downtown core stations, which include:

- Most downtown station busses are heavily loaded (as shown in Table 7) and thus unable to accept intra- or inter-station load transfer.
- As shown in Table 7, spare feeder positions are increasingly scarce at certain stations as Toronto Hydro continues connecting new customers.
- The downtown core distribution system was not designed with the capability to transfer load through switching operations. Much of the load to be transferred in downtown stations (i.e. secondary network load and large office or condo buildings) comes in discrete chunks that cannot be further divided, and requires dedicated feeder positions. The busses that have capacity may not have sufficient feeder positions available to provide the dedicated feeders needed to supply these discrete loads. For example, if Bus A is overloaded and Bus B has 10 MVA in spare capacity, and the smallest discrete chunk of load on Bus A exceeds 10 MVA, Bus B cannot be utilized to offload Bus A.

As mentioned in Section E7.4.3.1, the City of Toronto's long term Precinct Plans[29] forecast 208 MVA of incremental load over or shortly after the 2020-2024 period in the downtown core. In addition, Table 7 shows the need for spare feeder positions to enable connection of new downtown customers. This option is not a technically feasible alternative to meet these medium to long term needs.

E7.4.5.2 Options for Hydro One Contribution

1. South-West Toronto System Need – Alternatives Evaluation

a. Option 1: Do Nothing

Do nothing is not a feasible option as it does not provide the necessary load relief and feeder positions required at Manby TS.

[29] *Supra* Note 2

b. Option 2 (Selected Option): Expansion of Horner TS

This option involves the expansion of Horner TS to provide an additional 192 MVA capacity in the Manby TS and Horner TS service areas. The project scope includes the installation of two 75/100/125 MVA power transformers, four transformer breakers, one bus-tie breaker, 12 feeder breakers with up to six tie switchgears, and up to two capacitors with breakers. As Horner TS is a Hydro One-owned station, the work will be completed by Hydro One. Toronto Hydro submitted a formal Connection Application to Hydro One in 2013 to assess the cost and feasibility of this option. Further, an engineering study performed by Hydro One concluded that this option is technically feasible. The planned in-service date for Horner TS expansion is 2020. Civil infrastructure enhancement work within the Hydro One yard is planned to be completed by 2023. Further project details and benefits are set out below:

- The Manby and Horner TS service areas border Etobicoke creek and the Alectra utility service area on the west, Lake Ontario on the south and Humber River on the East. Toronto Hydro will address these distribution challenges in the detailed design and build civil infrastructure as required.
- The project will help relieve Manby TS, which is expected to reach 100 percent station capacity and become overloaded late in the 2020-2024 period.
- The project will provide additional feeder positions to enable the connection of large new customer connections, including large DER, in the Horner TS service area in the medium to long term.

c. Option 3: Load Transfer to Richview TS

This option would utilize spare capacity at Richview TS, a Hydro One owned station, to relieve the heavily loaded Manby TS, which is located approximately 8 kilometres from Richview TS feeders. This is a significant distance to run 27.6 kV distribution feeders, especially due to physical obstacles and barriers that require crossings such as railway corridors and cables cutting through treed areas. The estimated cost of this option is $77 million, which is subject to significant uncertainty due to the aforementioned challenges. Moreover, running overhead feeders along residential areas would affect the overall aesthetics of the neighbourhood. Another option would be to run underground cables; however, that will require additional civil infrastructure to be built at even greater cost. Lastly, this option will not add additional capacity at the transmission level.

d. Option 4: Build new TS near Manby TS

This option involves Toronto Hydro purchasing land near Manby TS and building a new TS. This new TS would provide at least 100 MVA in capacity to support the long-term growth of the Manby TS and Horner TS service areas. Toronto Hydro performed a feasibility study in 2014 to identify suitable sites for such a new TS and the associated cost. The study concluded that this option would entail a lengthy approval process and long lead times, and may not be implemented in time to help relieve the highly-loaded Manby TS. Moreover, the estimated cost to building a new TS near Manby TS is approximately $72 million, four percent higher than the chosen option ($69.2 million).

2. Hydro One Transformer/Bus Upgrades – Alternatives Evaluation

a. Option 1: Do nothing and Hydro One replaces its transformer/bus like-for-like.

Under this alternative, Toronto Hydro would not have to bear any costs over the forecast 2020-2024 period. When Toronto Hydro determines that additional capacity or feeder positions are required, Toronto Hydro would be responsible for the entire replacement cost of both the transformers supplying the bus and/or the bus upgrade, which is estimated at $30 million. This option is not preferable given: (i) the relatively low incremental cost of the upgrade at this time; and (ii) the likelihood of additional capacity being required in the medium to longer term.

b. Option 2 (Selected Option): Request that Hydro One replace existing transformers with a higher MVA rating unit or add new feeder positions; and contribute to the incremental cost.

The preferred option is requesting that Hydro One replace existing transformers with a higher MVA rating unit or add new feeder positions, and contributing to the incremental cost. In this case, Toronto Hydro would be responsible for the incremental cost difference for the capacity upgrade or addition of new feeder positions. Given the long-term need for additional capacity, this represents an opportunity to align Toronto Hydro plans with Hydro One plans. As a result, capacity would be increased when the other transformer paired with the upgraded transformer is upgraded as well in the future.

The total estimated cost to Toronto Hydro is $10.2 million for transformer upgrades and for replacing existing EOL breakers and adding new feeder positions, with an avoided cost of $20 million as set out in detail below (this avoided cost excludes the costs avoided for breaker replacements). Additionally, when Hydro One is replacing a transformer, the incremental cost of installing a larger unit is relatively

small in relation to the incremental capacity derived from the investment, resulting in considerable savings per MVA of additional installed capacity. Table 25 below shows the typical difference between replacing a 75 MVA transformer with a like-for-like transformer versus a higher rated 100 MVA transformer.

Table 25: Cost difference between 75 MVA vs 100 MVA Transformer Installation

Job	Like-for-Like Replacement	Higher Rating Replacement	% Difference
Capacity	75 MVA	100 MVA	25%
Transformer Replacement Cost	$2.5 M	$2.8M	9%
Cost per MVA	$33,333	$27,500	(18%)

E7.4.5.3 Options for Local Demand Response

1. Option 1: Do nothing

Without Local DR, the identified stations, Cecil TS and Basin TS, could be exposed to some operational and reliability risks as early as 2022. Failure to implement Local DR could result in:

- Reduced reliability;
- Costly short-term load transfer projects;
- Reduced flexibility to schedule maintenance outages;
- Inability to accommodate distributed generation (e.g. CHP, solar); and,
- Increased risk of equipment failure, and inability to connect new loads.

Not addressing the identified station constraints and highly-loaded station busses puts the system at risk of violating design parameters, which could result in rotating blackouts and voltage reductions. Lack of spare capacity limits Toronto Hydro's ability to perform planned maintenance and increases the likelihood of customer outages.

Further, without pursuing Local DR at Cecil TS and expanding the program to include Basin TS, Toronto Hydro would lose a valuable opportunity to build relationships with large and residential customers through this program, mitigate short- and long-term electricity rates, and cost-effectively accommodate new customer connections in the medium-term.

2. Option 2 (Selected Option): Implement Local DR Program as Proposed

Local DR includes programs and technological solutions that encourage load curtailment and load-shifting, allowing for capacity constraints to be addressed over the medium-term (i.e. 5 years) using targeted deployment of DR. Local DR enables the deferral of asset upgrades and optimization of capital allocation.

This option supports the goals of the IRRP, LTEP, the Conservation First Framework, and Ontario's greenhouse gas emissions reduction targets. It also entails partnership/relationship building to not only help resolve medium-term capacity issues but also more effectively leverage load-reduction activities already taking place by the private sector. It represents an opportunity for a win-win arrangement between the utility and its customers.

While stations expansion activities could solve the capacity issues at the identified stations, Toronto Hydro would lose the opportunity afforded by Local DR to mitigate customer rates and to cost-effectively accommodate new customer connections in the short-to-medium-term. (See sub-section five for cost-effectiveness comparison relative to wires alternative.)

3. Option 3: Conventional station capacity expansion

Foregoing Local DR in favour of additional station expansion at the identified stations is a more expensive alternative due to the need for property purchase and project design. This option is expected to cost $57 million for Cecil TS and $78 million for Basin TS. Table 26 and Table 27 set out the relevant high level cost breakdowns.

Cecil TS has no room for additional capacity due to land restrictions. Further, installing new transformers in the Cecil TS area would not increase capacity as they are limited by applicable bus ratings and the existing busses are already overloaded. A wires solution would involve Toronto Hydro acquiring a new building in the area and installing new switchgear to transfer load from Cecil TS to new busses. A wires solution at Basin TS would require significant construction to expand the building and the acquisition of new transformers, busses, and switchgear.

4. Cost Breakdown

As outlined in Table 26 and Table 27 below, the total cost of the conventional investment under this option is expected to be $135 million. Based on the 2017 10-Year Station Load forecast, this spending could be deferred to the late 2020s through local DR strategies.

Table 26: Cost Breakdown of Wires Solution at Cecil TS ($ Millions)

Item	Cost
Property and Building Acquisition	19
Switchgear	13
Transformer and Cabling	13
Civil Construction and Feeder Transfers	11
Project Management & Ancillary	1
Total	**57**

Table 27: Cost Breakdown of Wires Solution at Basin TS ($ Millions)

Item	Cost
Building Expansion	10
Transformer x2	20
Switchgear (Contribution to Hydro One) x2	26
Service Busses x 2	14
Civil Construction Work	6
Project Management & Ancillary	2
Total	**78**

5. Cost-effectiveness

To analyze the cost-effectiveness of applying Local DR at a station, Toronto Hydro used a financial model developed by ICF international for evaluating the business case for DR initiatives. The model was explicitly designed to support Ontario LDCs in making the decision to use Local DR for the purpose of distribution system asset upgrade deferral. It assesses the value of such deferral for the ratepayer, the utility, and the Province.

The model incorporates a series of cost-effectiveness tests that assess the business case and financial impact of Local DR from the perspective of all stakeholders (e.g. ratepayer, utility, Province, program participants). The choice to use this external model was based on the fact that it captures the avoided transmission and generation costs that result from the use of Local DR. The applicable tests are outlined in Table 28 below. Each test assesses the ratio of benefits to costs, and thus the higher the number, the more cost-effective the program is from the perspective of each stakeholder.

Table 28: Definition of Cost-effectiveness Tests used to assess the benefit of Local DR over conventional wires solutions

Test	Perspective	Purpose
Total Resource Cost Test ("TRC")	All ratepayers	To assess the long-term rate impact associated with using DR measure over supply-side option. Accounts for the deferral of local distribution and transmission asset upgrades.
Program Administrator Cost Test ("PAC")	In this case, the LDC	To assess whether DR is cost-effective to administer as compared to supply-side options
Participant Cost Test ("PCT")	Ratepayers participating in Local DR	To assess whether participating in the program will yield more benefits overtime for the participating ratepayers than it will cost them, accounting for any cash incentive, bill credit or direct-install they will benefit from when they sign up in the program and/or as they stay in the program
Rate-Impact Measure Test ("RIM")	Non-participating ratepayers	To asses if rates will go up in the short term as a consequence of Local DR being preferred to supply-side options to refund incentive being handed out, program administration cost, and lost revenues; accounting for the deferral of local distribution and transmission asset upgrades
Net benefit for distribution under the RIM test ("RIM-d")	Non-participating ratepayers	To asses if the distribution portion of the rates will increase in the short term in relation to Local DR
Local Distribution Company Test ("LDCT")	LDC's shareholders	To asses if utilizing Local DR and deferring the local asset upgrades optimizes the LDC shareholder's capital allocation strategy

The cost-effectiveness test results for Cecil TS and Basin TS are outlined in Table 29 and Table 30.

Table 29: Cost-effectiveness Test Results for Local DR at Cecil TS

Test Results	Benefit to Cost ("B/C") Ratio	Net Present Value ("NPV") ($ Millions)
Total Resource Cost Test (TRC)	2.0	6.1
Program Administrator Cost Test (PAC)	1.6	4.5
Participant Cost Test (PCT)	2.0	2.1
Rate-Impact Measure Test (RIM)	1.5	4,1
Local Distribution Company Test (LDCT)	N/A	(5.3)

Table 30: Cost-effectiveness Test Results for Local DR at Basin TS

Test Results	Benefit to Cost ("B/C") Ratio	Net Present Value ("NPV") ($ Millions)
Total Resource Cost Test (TRC)	1.9	3.8
Program Administrator Cost Test (PAC)	1.6	2.9
Participant Cost Test (PCT)	1.9	1.2
Rate-Impact Measure Test (RIM)	1.5	2.6
Local Distribution Company Test (LDCT)	N/A	(3.6)

The results of the cost-effectiveness test show that, overall, Local DR for the purpose of asset upgrade deferral over the next 5 years is cost-effective at both Cecil TS and Basin TS. The Total Resource Cost and Rate-Impact Measure tests are both highly positive, indicating that the use of Local DR to defer asset upgrades will have the effect of lowering rates over the short- and long-term. This means that even ratepayers who are not participating in Local DR will see benefit from its implementation. The Program Administrator Cost Test shows that for both stations, the program is cost-effective in terms of its administration costs as compared to the cost of administering asset upgrades. The Participant Cost Test shows that in both cases, participating ratepayers will benefit overall from Local DR, even when accounting for any costs they may incur (e.g. equipment costs related to enabling DR capability).

Notably, for both Cecil TS and Basin TS, the LDC test yields a negative net present value, which represents the cash value that must be recovered by the LDC to remain "whole" when compared to the wires solution option. By deferring these capital investments, the creation of a new revenue stream and a new component of regulated rate of return are also deferred by Toronto Hydro.

6. Station Selection

The selection of Basin TS for implementing Local DR was based on a ranking system that assessed the following criteria:

- Adequate lead-time to implement DR solution: capacity relief must be approximately 5 years in the future (measure based on busses with above 95 percent loading);
- Difficulty of performing bus level load transfers;
- Limited ability to connect new loads;
- High potential for load growth in area; and
- No wires solution planned: If a wires solution is already planned or underway, consideration is given to the potential role for DR to support the implementation of a wires solution by providing additional flexibility.

Basin TS ranked high amongst the stations that were potential candidates for Local DR. Discussions with the IESO also indicated that providing capacity relief at Basin would also help reduce projected strain on the transmission system. Other stations that were considered include: Dufferin, Strachan, Carlaw, Windsor, Main, Manby, and Duplex. These stations were not chosen because capacity relief is required within the short term, making the use of DR measures inappropriate from a reliability perspective given the need to leave a buffer period in case wires solutions are required (i.e. if DR measures are not adequate for providing required capacity).

E7.4.6 Execution Risks & Mitigation

E7.4.6.1 Copeland TS – Phase 2

The Copeland TS – Phase 2 segment is a large undertaking and involves multiple execution risks, which include:

- Given the complex nature of these projects, a host of inherent planning challenges and risks can impact overall project cost and execution, such as the length of time required to acquire permits;
- Road moratoriums established by the City of Toronto;
- Logistical challenges in delivering electrical equipment into the downtown core; and
- Coordination with distribution planners as well as with third parties.

Toronto Hydro will communicate key lessons learned from past projects to Copeland TS - Phase 2 bidders during the RFP procurement process to mitigate project execution risks. In particular, Toronto Hydro will provide risk information associated with facility conditions and restrictions, logistical and transportation issues, unique specifications of major electrical equipment, and permitting issues.

Financial risks will be mitigated by pursuing a fixed-price, turn-key, EPC contract. A competitive bid process will result in a selection of one general contractor responsible for all the major tasks. This is expected to be completed in 2018.

Quality control risks will be mitigated via the use of reputable third party firms with extensive electrical station construction experience to carry out verification and payment review/billing certification. A consulting engineering firm will be utilized to investigate and resolve emerging site issues and ensure that construction is carried out according to specifications.

E7.4.6.2 Hydro One Contribution

The following risks are associated with the execution of Hydro One contribution projects:

- Schedule depends on Hydro One's ability to execute the work;
- Overall project cost is highly dependent on Hydro One estimates; and
- Additional tasks (such as installation of bus and feeder ties or other safeguard measures to protect Toronto Hydro assets during Hydro One asset replacement) maybe identified during detailed equipment outage planning. If an identified task is performed by Toronto Hydro, it will increase the project's cost for Toronto Hydro.

To mitigate these risks, Toronto Hydro engages in active coordination with Hydro One through bi-monthly meetings and as-required on-site meetings with relevant stakeholders to remain aligned with Hydro One's latest sustainment plans.

E7.4.6.3 Local Demand Response

The Local DR program faces certain unique challenges. However, the utility's experience with the current Local DR program will help inform and establish its future risk mitigation strategies.

Some customer types may not be well suited to DR activities. Depending on the market segments applicable in the station area, a customer mismatch may lead to lower than expected program

uptake. For example, through the current Local DR program at Cecil TS, it has become apparent that some institutional customers, such as hospitals, are not ideally suited to conventional DR. Toronto Hydro is currently working with one of the largest hospitals in the area to develop a best practices guide to help encourage this sector's participation. This is expected to be a valuable tool from a customer engagement perspective in the next round of Local DR efforts.

Experience gained through the current Local DR program has enabled more effective stations selection, ensuring that the choice reflects a customer mix that is well-suited to Local DR. Basin TS has a relatively large number of industrial and institutional customers that are well-suited to a DR solution (including, for example, a City of Toronto waste treatment plant that already participates in provincial DR).

Higher-than-expected uptake could lead to budget pressures in terms of customer incentives. To manage this, it will be important to track spending closely and set caps on customer uptake. Storage projects often have upside budget risks due to the cost of exploring and installing the technology, the acquisition of land or space for the battery, and the time requirements for permitting. These budgetary risks can be managed by exploring different storage technologies in partnership with commercial customers who are interested in installing (customer-funded) storage. In the current Local DR program at Cecil TS, there has been significant interest from customers in such smaller-scale storage opportunities, which are made viable through participation in the Large DR program. Budget risk can also be managed by leveraging available external funding opportunities (e.g. the Smart Grid Fund).

Certain highly technical projects (e.g. voltage optimization, battery storage) can take longer than expected to implement. It will be important to manage this timing risk closely to mitigate project delaying risk.

E7.4.7 Regional Planning Needs

The following tables, Table 31, Table 32, and Table 33 (from the IRRP Needs Assessment Report), highlights the emerging needs that have been identified in the Toronto Region since the previous regional planning cycle, and reaffirms the near, medium, and long-term needs already identified in the previous RIP.[30] The tables below also highlight how the Stations Expansion program is expected to address these needs.

Table 31: New Needs identified in the Needs Assessment

New Needs	NA Report Section	Stations Expansion Program
End-of-Life (EOL) Assets	*7.1.1*	See *Table 8*.
East Harbor / Port Lands Area and Basin TS – Transformation Capacity	*7.1.2*	NA report identified this need by around 2025+. Therefore, no projects are included in this Program to address this need.
Load Restoration – C14L+C17L, C5E+C7E, K3W+K1W	*7.1.3*	Transmission network constraint. Not applicable to Toronto Hydro.

Table 32: Needs Identified in Previous RIP

Needs Identified in Previous RIP	NA Report Section	RIP Report Section	Stations Expansion Program
South-West Toronto – Station Capacity	*7.2.1*	*7.2*	Addressed with Horner expansion in 2020-2024 Stations Expansion plan.
Downtown District – Station Capacity	*7.2.2*	*7.3*	Addressed with Copeland TS - Phase 2 expansion in 2020-2024 Stations Expansion plan.
230 kV Richview x Manby Corridor – Line Capacity	*7.2.3*	*7.4*	Transmission network constraint. Not applicable to Toronto Hydro.
Supply Security – Breaker Failure at Manby West & East TS	*7.2.4*	*7.6*	Transmission network constraint. Not applicable to Toronto Hydro.
230/115 kV Leaside Autotransformer – Transformation Capacity	*7.2.5*	*7.10*	Transmission network constraint. Not applicable to Toronto Hydro.

[30] See Exhibit 2B, Section B, Appendix A, B, C, D, and E for Regional Planning Reports.

Needs Identified in Previous RIP	NA Report Section	RIP Report Section	Stations Expansion Program
Voltage Instability of 115 kV Leaside Subsystem	*7.2.5*	*Identified in Central Toronto Area IRRP report – Appendix E*	Transmission network constraint. Not applicable to Toronto Hydro.
115 kV Leaside x Wiltshire Corridor – Line Capacity	*7.2.6*	*7.10*	Transmission network constraint. Not applicable to Toronto Hydro.
230/115 kV Manby Autotransformers – Transformation Capacity	*4.2.7*	*7.10*	Transmission network constraint. Not applicable to Toronto Hydro.
115 kV Manby West x Riverside Junction – Line Capacity	*7.2.8*	*7.10*	Transmission network constraint. Not applicable to Toronto Hydro.
115 kV Don Fleet JCT x Esplanade TS – Line Capacity	*7.2.9*	*Identified in Central Toronto Area IRRP report – Appendix E*	Transmission network constraint. Not applicable to Toronto Hydro.

1 **Table 33: End-of-Life Assets – Metro Toronto Region**

EOL Asset	Replacement/ Refurbishment Timing	Details	Stations Expansion Program
Fairbank TS: T1/T3, T2/T4 Transformers	*2022-2023*	EOL transformers and other HV equipment are identified at these stations for replacement with similar type equipment of the same ratings (discussed further in Section 7.1.1.1 of NA report).	Current 50/83 MVA transformer is largest 115-27.6 kV standard size.
Fairchild TS: T1/T2 Transformers	*2023-2024*		Current 75/125 MVA transformer is largest 230-27.6 kV standard size.
Leslie TS: T1 Transformer	*2023-2024*		Current 75/125 MVA transformer is largest 230-27.6 kV standard size.
Runnymede TS: T3/T4 Transformers	*2021-2022*		Proposed 50/83 MVA transformer is largest 115-27.6 kV standard size.
Sheppard TS: T3/T4 Transformers	*2019-2020*		Toronto Hydro determined increase in capacity to larger 75/125 MVA transformer was not required.

EOL Asset	Replacement/ Refurbishment Timing	Details	Stations Expansion Program
Bridgman TS: T11/T12/T13 Transformers	*2022-2023*	EOL Transformers and other HV equipment are identified at these stations for replacement with higher rated equipment, and are discussed further in Section 7.1.1.2 of NA report	Included in 2015-2019 Stations Expansion plan.
Charles TS T3/T4 Transformers	*2024-2025*		Included in 2020-2024 Stations Expansion plan.
Duplex TS: T1/T2 Transformers	*2023-2024*		Included in 2020-2024 Stations Expansion plan.
Strachan TS: T12 Transformer	*2020-2021*		Included in 2015-2019 Stations Expansion plan.
Bermondsey TS: T3/T4 Transformers	*2022-2023*	EOL Transformers and other HV equipment are identified at these stations where scope for replacement is to be further assessed, and are discussed further in Section 7.1.1.3 of NA report.	Identified as consideration for downsizing, therefore Not Applicable to Toronto Hydro. See section 7.1.1.3 of NA report for details.
John TS: T1, T2, T3, T4, T6 Transformers and 115 kV breakers	*2024-2025*		Included in 2020-2024 Stations Expansion plan.
Main TS: T3/T4 Transformers and 115 kV line disconnect switches	*2021-2022*		Included in 2015-2019 Stations Expansion plan.
Manby TS: T7, T9, T12 Autotransformers, T13 Step-Down Transformer and rebuild 230 kV yard	*2024-2025*		Transmission network constraint. Not applicable to Toronto Hydro.
115 kV C5E/C7E Underground Cable: Esplanade TS to Terauley TS	*2024-2025*	EOL Line section is identified for replacement with similar type equipment, and is discussed further in Section 7.1.1.4 of NA report.	Transmission network constraint. Not applicable to Toronto Hydro.
115 kV H1L/H3L/H6LC/H8LC: Bloor Street JCT to Leaside JCT	*2020-2021*		Transmission network constraint. Not applicable to Toronto Hydro.
115 kV L9C/L12C: Leaside TS to Balfour JCT	*2020-2021*		Transmission network constraint. Not applicable to Toronto Hydro.

E8 General Plant Investments



E8.1 Control Operations Reinforcement

E8.2 Facilities, Management, and Security

E8.3 Fleet and Equipment Services

E8.4 Information Technology and Operational Technology System

E8.1 Control Operations Reinforcement

E8.1.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): N/A	**2020-2024 Cost ($M):** 40.2
Segments: Control Operations Reinforcement	
Trigger Driver: Operational Resilience	
Outcomes: Reliability, Safety, Customer Service, Public Policy	

The Control Operations Reinforcement program (the "Program") will increase Toronto Hydro's operational resiliency and improve the utility's ability to safely operate the distribution grid by creating a fully functional dual Control Centre at its [redacted] work centre. The dual Control Centre at Toronto Hydro will be designed to withstand evolving hazards and threats, deliver reliable electricity, and support the capability to restore electricity as efficiently as possible.

Toronto Hydro's existing Control Centre is a critical infrastructure that acts as a control authority and real-time operator of the distribution system within the City of Toronto. Control Centre operations are hosted from Toronto Hydro's 500 Commissioners work centre and include the following two primary responsibilities:

1) maintain real-time control of Toronto Hydro's distribution plant through telemetry and remote operation of station breakers and field devices; and
2) coordinate all activities involving field crew workers within the "safe limits of approach" to Toronto Hydro plant that is energized above 750 Volts, as prescribed by the Ontario Electrical Safety Code and Electrical Utility Safety Rules.

Failure of Toronto Hydro's existing Control Centre can have substantial financial and economic consequences for Toronto, the largest city in Canada, the fourth largest in North America, and the economic and financial centre of the country.

The proposed dual Control Centre at [redacted] will replace the existing back-up Control Centre at Toronto Hydro's [redacted] location and will be used to operate and control Toronto Hydro's distribution grid in parallel with the primary Control Centre. [redacted]

[redacted]

The development of a dual Control Centre will allow Toronto Hydro to more effectively safeguard, manage, and operate its distribution system, minimize potential safety hazards to the public and employees, and minimize business interruption impacts on its customers, should the primary Control Centre be compromised.

As energy policy changes, bringing innovation and new technology, the evolution of the smart grid is changing the value proposition of Control Centres. Control Centres are becoming more integrated with the technology, not only from a monitoring and control of energy delivery perspective but also from an energy management perspective, elevating their role and importance. The growth of distributed generation has also given distributors some of the reliability responsibilities traditionally reserved for transmission utilities.[1] [redacted] As such, as part of the Program, Toronto Hydro intends to build its dual Control Centre with the technology required to manage this growing system requirement.

In addition, over the last five years, Toronto Hydro's operations have been disrupted by several large-scale environmental and other hazard events. These large scale environmental and hazard events are becoming increasingly more common within Toronto Hydro's service territory and across the industry.[2] For instance, in 2018 alone, Toronto Hydro has experienced four severe weather-related events that caused wide-spread damage and outages.[3] Further, in addition to more frequent and severe weather events, there continues to be an escalation of terrorist attacks on people and property, cyber terrorist attacks, as well as system attacks from increasingly sophisticated hackers. The impact of these events on the distribution system has already been experienced in Ukraine, as demonstrated by the 2015 cyber-attack on three separate distribution companies where continuity

[1] London Economics International LLC, Jurisdictional Review and Economic Case for a Dual Distribution Control Center in Toronto Hydro Territory (June 22, 2018), at p. 15.
[2] AECOM Environment, Toronto Hydro-Electrical Systems Limited Climate Change Vulnerability Assessment filed in EB-2014-0116, Toronto Hydro-Electric System Limited, Exhibit 2B, E8.8, Appendix A (Filed July 31, 2014, Updated February 6, 2015).
[3] See Table 6 for examples of recent severe weather events in Toronto.

of service was disrupted for up to 225,000 customers.[4] Canada is not immune to such threats. Public Safety Canada issued a report titled "The 2017 Public Report on The Terrorist Threat to Canada" indicating that since 2014, Canada's terrorism threat level is Medium, meaning that a violent act of terrorism could occur.[5]

Toronto Hydro has examined its existing operational capabilities in light of these emerging challenges and needs. The plans contained in this Program address the shortcomings of Toronto Hydro's current back-up Control Centre. To assess Toronto Hydro's investment in a dual Control Centre, the utility retained London Economics International ("LEI") to undertake a review of comparator utilities with fully functional dual control centres as well as an economic analysis determining whether this investment is justifiable, see Appendix A.[6] LEI found that utilities expressed similar rationales for requiring a dual control centre, including supporting resiliency, increasing reliability, and ensuring quick recovery from terrorist threats and natural disasters, for example earthquakes, storms, and floods.[7] LEI also found that the growth in distributed energy resources, as is the case in Toronto, has caused distribution utility operations to be more complex and take on some of the traditional responsibilities associated with the Bulk Electricity System, including managing interconnected generation and greater responsibility over bulk system reliability.[8] The review concludes that based on the estimated cost of an outage, the investment in a dual control centre can be economically justified if it can reduce the duration of such an outage.[9]

[4] Electricity Information Sharing and Analysis Center, White Analysis of the Cyber Attack on the Ukrainian Power Grid (March 18, 2016) at p. 1, found at <https://www.nerc.com>.
[5] 2017 Public Report on the Terrorist Threat to Canada (December 17, 2017), found at <https://www.publicsafety.gc.ca/cnt/rsrcs/pblctns/pblc-rprt-trrrst-thrt-cnd-2017/index-en.aspx>.
[6] Supra note 1.
[7] Ibid at pp. 5-14.
[8] Ibid at p.16.
[9] Ibid at pp. 24-26.

E8.1.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Reliability	• Contributes to Toronto Hydro's reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: ○ Reducing the likelihood of a complete or partial stand-down of field work and the likelihood of cascading outages resulting from interruption to visibility over the distribution system; and ○ Ensuring compliance with requirements relating to system restoration planning outlined in Chapter 5, Section 11 of the Market Rules.
Safety	• Contributes to Toronto Hydro's safety objectives as measured by Total Recordable Injury Frequency ("TRIF") by: ○ Providing seamless visibility over the distribution system, thereby reducing the likelihood of worker/public injury resulting from loading issues and inadvertent energizing of equipment; ○ Ensuring efficient administration and application of the Toronto Hydro Work Protection Code; and ○ Maintaining compliance with Ontario Regulation 22/04 (Electrical Distribution Safety) through timely reporting of serious electrical incidents involving Toronto Hydro plant.
Customer Service	• Contributes to Toronto Hydro's customer service objectives by: ○ Ensuring continued capability to receive and respond to trouble calls from customers and/or external stakeholders; ○ Maintaining the capability to effectively manage, prioritize and resolve multiple concurrent system issues impacting customers; and ○ Providing relevant and timely outage information to customers, such as estimated outage restoration times and other situational information relating to system outages.
Public Policy	• Contributes to Toronto Hydro's public policy objectives by consistently meeting OEB-mandated service quality targets with respect to Emergency Response (Distribution System Code, s. 7.9).

E8.1.3 Drivers and Need

Table 3: Program Drivers

Trigger Drivers	Operational Resilience
Secondary Driver(s)	Reliability, Safety

E8.1.3.1 Program Drivers

The primary driver for the Program is Operational Resilience and the secondary drivers are Reliability and Safety. As discussed below, the Control Centre is the control authority for Toronto Hydro and is the real-time operator of Toronto Hydro's distribution system. The Control Centre executes most of the critical functions required to successfully operate the distribution system. [redacted]

Table 4: Minimum Space Requirements for a Control Centre – [redacted]

	500 Commissioners	[redacted]	Gap (%)
Control Room Space Requirements (ft²)	[redacted]	[redacted]	[redacted]

In November 2017, Toronto Hydro Power System Controllers executed a pilot whereby part of the distribution grid would be controlled entirely by the [redacted], as part of an effort to simulate the loss of the primary Control Centre. Within the scope of this pilot, key systems that are required to maintain full operational control of the system were identified as follows:

[redacted]

[redacted]

Table 5: Summary of Technological Restrictions at [redacted] Facility

	500 Commissioners	[redacted]	Gap (%)
[redacted]			

[redacted] Orders to Operate ("OTO") are the final output of the system operation planning process to the field staff to receive step by step instructions on real time operation of equipment from Power System Controllers. These include orders which are executed in sequence to isolate, de-energize, and ground work areas to make them safe for work, change system state, test continuity, hipot test, and restore power. [redacted]

[redacted]



[redacted]

[redacted] the primary Control Centre located at Toronto Hydro's 500 Commissioners site may be vulnerable to certain hazards, such as extreme weather events. Since the primary Control Centre is located within the flood plain, the most probable and consequential hazard or threat [redacted] The flooding is most likely to cause catastrophic damage to the building and various facilities that house the primary Control Centre, [redacted]

As discussed above, Canada's current terrorism threat level is "Medium," meaning that a violent act of terrorism could occur.[10] [redacted] Electrical hazards are, to a large extent, limited through constant system oversight via Control Centre operations.[11]

[redacted]

Moreover, with the introduction of renewable and other distributed energy resources, the nature of Control Centre operations continues to evolve. The growth of distributed energy resources has led to utilities being required to manage bi-directional flow of electricity, managing more complex operations and taking on increasing responsibility that has traditionally been reserved for transmission utilities.[12] This evolution changes the manner in which the power is managed and delivered throughout the grid. With the forecasted increase of distributed generation connections, which is expected to reach 800MW by the end of 2024, Toronto Hydro requires real-time monitoring and control in order to ensure distribution system safety and the adequate management of distributed energy connections.

Lastly, as part of its report, filed at Appendix A, LEI completed a review of various utilities in North America that have distribution operations with more than one Control Centre. These facilities were fully functional and were able to take over full operational functions from the primary Control Centre. The review confirms that utilities serving a critical load in North America invest in more than one fully functioning Control Centre to support resiliency, increase reliability, and ensure quick recovery

[10] Supra note 4.
[11] See Exhibit 4A, Tab 2, Schedule 7, for a discussion of the roles and responsibilities of Power System Controllers.
[12] Supra note 1 at p. 15.

from terrorist threats and natural disasters, for example earthquakes and floods. These same justifications are driving the need for Toronto Hydro's dual Control Centre.

E8.1.3.2 Control Centre Operations & Criticality

The Control Centre's Power System Controllers coordinate and monitor the safe distribution of electricity across Toronto Hydro's service territory and support most of its crtical functions. Power System Controllers maintain real-time control of Toronto Hydro's distribution plant and coordinate all activities involving field crew workers. This real-time control includes monitoring of grid operation, system loading, and response to system or asset failures.

[redacted]

Under normal operating conditions, Power System Controllers prepare and execute OTO (switching instructions), enabling planned capital, and operation and maintenance activities for Toronto Hydro's workforce. Control Centre personnel are involved in developing necessary OTO, dispatch of crews, and conducting isolation and switching functions for each capital construction project or maintenance task that is being performed in order to enable a safe work zone. Each OTO comprises a list of switching instructions which enable operations crews to safely transfer customer load and/or establish suitable work protection over a specified range of system devices, which, in turn, allows crews to work in accordance with applicable safety legislation and protects the security of supply to Toronto Hydro's customers. Work involved in the development of OTO is extremely detailed, drawing on multiple system records in conjunction with current system state/loading and is critical to crew and public safety. Where restoration is not possible, crews work directly with the Control Centre to switch equipment in order to restore power to the extent possible prior to continuing with the root cause.

During abnormal system conditions, which are typically caused by extreme weather events, defective equipment, or heat stress to distribution assets, Power System Controllers coordinate Toronto Hydro's response to these system contingencies. During the abnormal system conditions, the restoration efforts must be undertaken immediately as these conditions might pose a significant

safety hazard. The emergency activities might include quick and safe restoration of the downed conductors, failed equipment, electrical/vault fires, environmental hazards and etc. Power System Controllers and Trouble Dispatchers direct the response efforts of Toronto Hydro's Grid Response (emergency maintenance) crews during system contingencies and abnormal conditions.

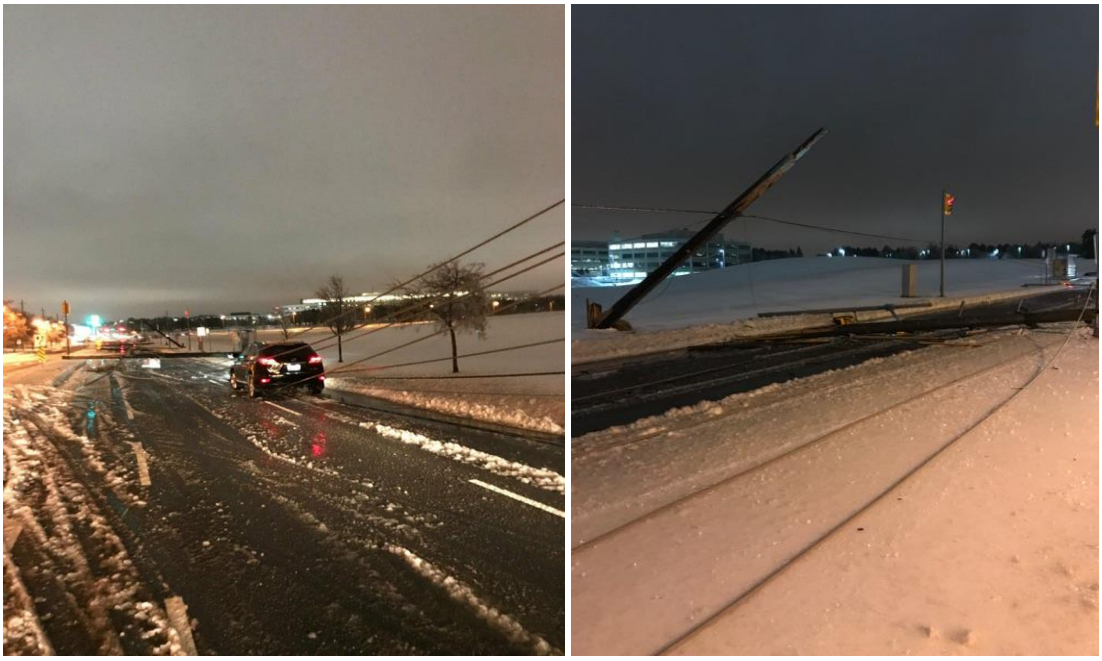


Figure 2: Damage from City of Toronto Ice Storm in April 2018

Toronto Hydro has defined a list of critical functions that are necessary for successful operation of the distribution system. A more detailed description of each these functions is provided in Appendix B. Notably, a number of these critical functions have a maximum tolerable downtime of zero hours.

The North American Electric Reliability Corporation ("NERC") have issued directives and rules concerning the "Loss of Control Room Functionality" which ensure continued reliable operation of the Bulk Electric System in the event that a Control Centre becomes inoperable.[13] NERC standards require the facility containing the Control Centre to be resilient enough to survive, to some extent, the hazards and threats it faces. With respect to criticality relative to their purpose or function, the assets that are subject to NERC requirements are similar in nature to Toronto Hydro's assets. Toronto Hydro serves the largest city in Canada and is also the Country's financial and business capital. As

[13] NERC, Reliability Standards for the Bulk Electric Systems of North America, Standard EOP-008-1 and EOP-008-2- Loss of Control Center Functionality (Updated February 15, 2018).

such, given the criticality of Toronto Hydro distribution system, NERC directives and rules are indicative of the measures that must be taken with respect to critical assets, such as the Control Centre.

E8.1.3.3 Continuity of Operations Capabilities

Control Centers have become increasingly more sophisticated over the past 30 years from simple analogue tone-based telemetry and control based on electromechanical devices to digital electronic monitoring, data acquisition and control. Paper-based records have been replaced with geo-referenced graphical information systems and outage management systems and crew dispatch and coordination can be accomplished through tablets and crew resource management systems. Control Centers have always been considered critical infrastructure for the management of the distribution system mainly for monitoring and control of substations, transformers, and feeders. However, their purpose continues to evolve to support the new smart grid ecosystem, comprising renewable and other distributed energy resources, micro-grids, electric vehicles, and growing interest in energy storage on the system for power quality, off-peak storage, and grid resilience. As this new paradigm comes into focus, the manner in which power is managed and delivered evolves. Smart grid development requires a completely new concept of a smart grid Control Center, one which is not only critical to distribution system management, but also critical to energy management within the City, and ultimately the Bulk Electric System.

LEI, in its review, concludes that as distribution utilities evolve towards more complex operations and greater responsibility for reliability within the bulk electricity system, fully functioning dual Control Centres will become increasingly necessary.[14] See Figure 3, below, for LEI's depiction of industry trends such as distributed energy resources, smart grids, and electric vehicles that will inevitably challenge the traditional role of the distributor. The fundamental shift to managing bi-directional flow of electricity adds a layer of complexity to Control Centre operations necessitating more active involvement in forecasting intermittent generation, energy scheduling or dispatching generation to manage outages.[15]

14 Supra note 1 at p. 15.
15 Supra note 1 at p. 16.

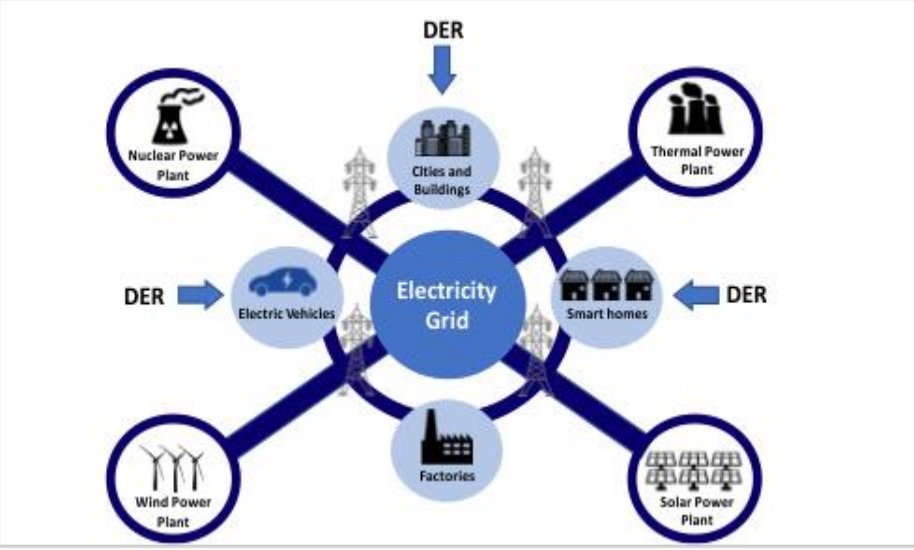


Figure 3: Distributed Energy Resources Interacting with the Electricity Grid[16]

In 2017, Toronto Hydro responded to over 8,000 inquiries from customers and developers seeking to connect generation under various programs. A wide range of proponents have submitted project applications, including many schools, housing managers, large grocery stores, condominium corporations, and department stores. As of the end of 2017, Toronto Hydro has connected over 1,780 Distributed Generators of various sizes representing approximately 225MW. Based on internal forecasts, Distributed Generation connections in Toronto are expected to increase and to reach 800 MW by the end of 2024.[17]

[redacted] As such, as part of the Program, Toronto Hydro intends to build its dual Control Centre with the technology required to manage this growing system requirement. The dual Control Centre will have the capability to monitor and control distributed energy resources. In the event that primary control is lost, it is critical to understand which sources on the system have tripped off, and which have not, both for work protection, but also for power restoration efforts. In accordance with Rule 149 of the Electrical Utility Safety Rules, Toronto Hydro must identify backfeed hazards and eliminate where possible, or control using approved temporary grounding procedures. Although modern inverters

16 Supra note 1 at p. 15.
17 See Exhibit 2B, Section E5.1.

have anti-islanding capabilities, it has been known to fail, and, therefore, do not completely eliminate the back feed hazard, as required by the Electrical Utility Safety Rules.

E8.1.3.4 Risk Exposures

1. Extreme Weather Events

Toronto Hydro evaluates its state of operational preparedness for managing large-scale events on a periodic basis. As part of the evaluation, significant weather events are reviewed along with system resilience, system and customer impacts, and organizational response. Over the last five years, Toronto Hydro experienced several incidents, and some of the more extreme examples include:

- Hurricane Sandy (2012);
- Ice Storm (2013);
- City of Toronto Flooding Event (2013);
- Manby Station Flooding (2013);
- Freezing Rain Event (2017);
- City of Toronto High-water/flooding event (2017);
- Ice Storm (2018); and
- Wind Storm (2018).



Figure 4: Damage from City of Toronto Wind Storm in May 2018

Table 6, below, provides examples of extreme weather events occurring in the first half of 2018 in the City that exceeded Toronto Hydro's standard response practices and triggered the deployment of additional planning and response resources under the utility's Disaster Preparedness Management program.[18]

Table 6: Examples of Recent Severe Weather Events in the City of Toronto

Event	Description
Wind storm (April 2018)	• Sustained 65km/h winds, with gusts approaching 90km/h. • Estimated 24,000 customers out at peak; all customers restored within 48 hours of the end of the event.
Ice storm (April 2018)	• Approximately 10-20mm of freezing rain, 20-25mm rain, sustained winds of 70km/h with gusts up to 110km/h. • Estimated 51,000 customers out at peak. • 99 percent of customers restored within first two days of response; all impacted customers restored within 5 days of the start of the event.
Wind storm (May 2018)	• High winds reported throughout service territory with gusts reaching approximately 120km/h. • Estimated 68,000 customers out at peak. • 96 percent of customers restored within 48 hours of the start of the event
Flash storm (June 2018)	• High winds reported throughout service territory with gusts reaching approximately 90-100km/h. • Estimated 16,500 customers out at peak. • 86 percent of customers restored within the first 12 hours and 97 percent of customers restored within the first 24 hours of the event's occurrence

These events, some of which had significant impacts on Toronto Hydro operations, have highlighted a need for increased emergency preparedness and operational resilience of Toronto Hydro's distribution system. Toronto Hydro's distribution system and facilities continue to be exposed to ever-increasing hazards due to the increase in severe environmental events introduced as a result of

18 See Exhibit 4A, Tab 2, Schedule 6.

climate change.[19] It has been identified that global and regional climate has changed and will continue to change within the City of Toronto, including continued increases in average and extreme maximum temperatures, increases in total annual rainfall, and increases in the intensity of rainfall events.[20]

As illustrated in Figures 5 and 6 below, the 500 Commissioners work centre, which houses the primary Control Centre, is situated along the path of the Don flood plain and is adjacent to Lake Ontario. The last known major flooding disaster – brought on by Hurricane Hazel – occurred in 1953, affecting an extensive portion of Toronto and the Greater Toronto Area ("GTA"), and in particular introducing widespread flooding at the location where the 500 Commissioners facility currently exists. In recent years, including 2013 and 2017, there have been additional flooding events within the City of Toronto, brought on by ongoing climate changes. Global climate change is expected to continue to introduce observable impacts to the environment, including changes in precipitation patterns.[21] [redacted]

19 AECOM Environment, Toronto Hydro-Electrical Systems Limited Climate Change Vulnerability Assessment filed in EB-2014-0116, Toronto Hydro-Electric System Limited, Exhibit 2B, E8.8, Appendix A (Filed July 31, 2014, Updated February 6, 2015).
20 Ibid.
21 This is a consequences of climate change, see National Aeronautics and Space Administration (NASA), URL: https://climate.nasa.gov/effects/, 2018.

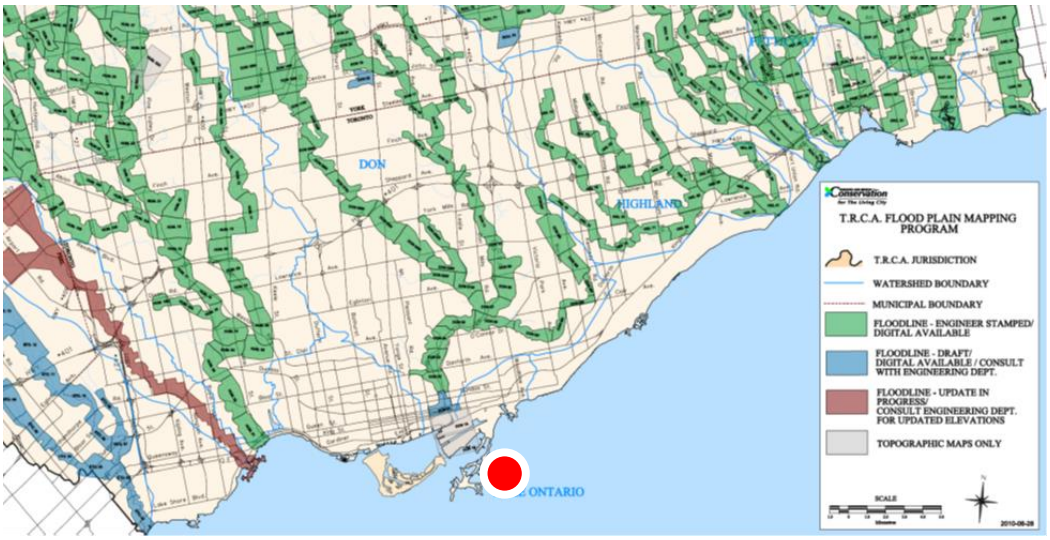


Figure 5: City of Toronto Flood Plain Mapping Program[22]

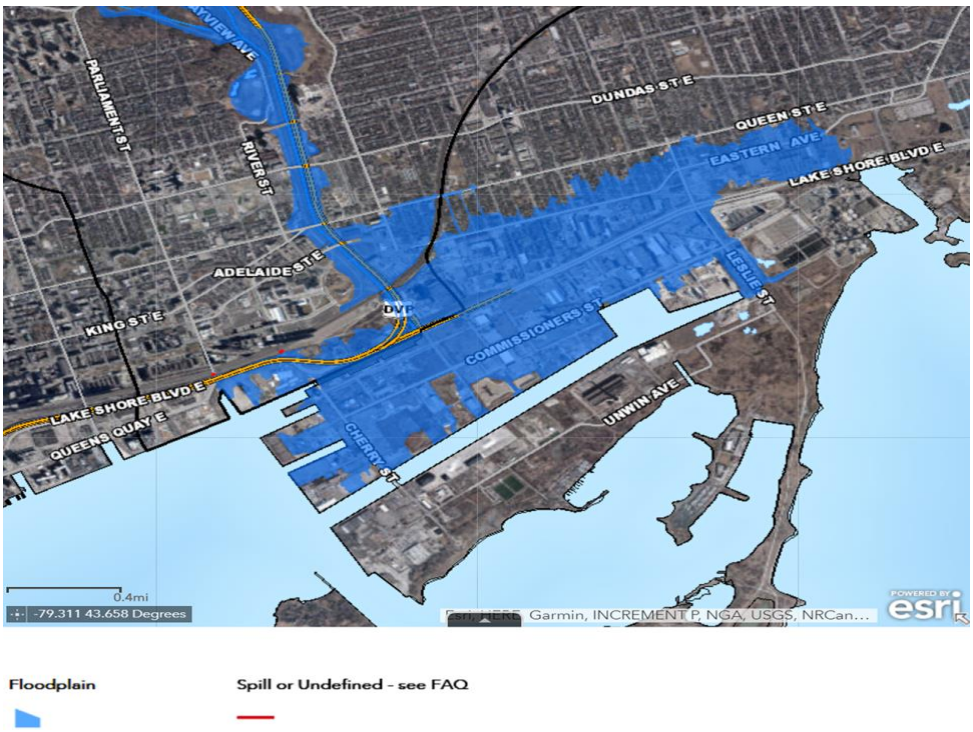


Figure 6: View of 500 Commissioners Street within path of Don Valley

22 The primary Control Centre located at 500 Commissioners is represented by red dot on the map.

Lastly, Public Safety Canada has consistently identified that severe weather poses one of the greatest threats to the Canadian electricity industry.[23] The report specifies that global warming has augmented the risk from natural hazards as it has increased the frequency and intensity of extreme weather events. Indeed, Toronto Hydro's service territory, as well as some of its facilities, have already experienced several weather-related hazard events and further exploration of post-incident reviews has underscored the need for reducing Toronto Hydro's operational risk exposures.

2. Deliberate Threats

In 2017, Public Safety Canada issued a report Canada's terrorist threat levels, in which it discussed the likelihood of a violent act of terrorism occurring in Canada, based on information and intelligence. Canada's current terrorism threat level is "Medium," meaning that a violent act of terrorism could occur, and has been at this level since October 2014."[24] In the same report, Public Safety Canada also identified the potential of cyber security terror attack on essential services, including the electric distribution grid.[25] [redacted] The report further outlines "…terrorist entities aspire to use cyber-tools as weapons that can cause physical harm to computer networks and systems, which would be a far more sophisticated type of cyberattack. Possessing sufficiently advanced capabilities would enable them to successfully disrupt essential services and critical infrastructure (such as the electrical grid).[26]

23 Public Safety Canada, Threats Analysis: Threats to Canada's Critical Infrastructure Report, March 12, 2003 (available at https://www.publicsafety.gc.ca/lbrr/archives/cn000034012674-eng.pdf); Public Safety Canada, National Strategy for Critical Infrastructure Report, 2009 (available at https://www.publicsafety.gc.ca/cnt/rsrcs/pblctns/srtg-crtcl-nfrstrctr/srtg-crtcl-nfrstrctr-eng.pdf)
24 Ibid at p.5.
25 Ibid.
26 Supra note 23 at p.9.

[redacted]

E8.1.4 Expenditure Plan

Toronto Hydro requires $40.2 million over the 2020-2024 plan period to construct a dual Control Centre that will be built with hazard and threat resilience in mind. The expenditure plan for the dual Control Centre is separated into four categories (non-direct construction costs, alterations & demolition, building construction and site works), which spans over a three year period between 2020 and 2022.

Table 7: Forecast Program Costs ($ Millions)

	Forecast				
	2020	**2021**	**2022**	**2023**	**2024**
Non-direct Construction Costs	3.4	2.6	4.8	-	-
Alterations and Demolitions	-	14.1	11.8	-	-
Building	-	0.3	0.6	-	-
Site-works	0.5	0.4	1.7	-	-
Total	**3.9**	**17.4**	**18.9**	**-**	**-**

Work associated with non-direct construction costs begins in 2020 and includes feasibility cost planning, design, and permitting. Deliverables include a detailed drawing package for the dual Control Centre. Once deliverables are finalized, the building permit application process and any Preliminary Project Reviews or Site Plan approval applications with the City of Toronto will commence. A team of experienced project managers will then manage the construction of the dual Control Centre from inception to completion. The construction phases will include regular construction inspections, shop drawing reviews & approvals, payment certifications, and overall construction support. The expenditure plan will conclude in Q4 2022 with closeout document preparations, deficiency reviews, and asset testing and commissioning.

The alterations and demolition expenditure plan will occur in the early phases of construction and will include removal of existing concrete footings & structural steel in preparation for the build out of the second floor. In order to accommodate the installation of large equipment during building construction, the concrete exterior wall will be demolished and replaced with modular louvered wall system. Existing mechanical, electrical infrastructure will also be removed in preparation for new installations.

The majority of the costs in the expenditure plan are for building construction. Architectural plans will be constructed with provisions for the second floor build out, separate mechanical, electrical and IT hub rooms. These provisions will be formed by two storey masonry block walls, concrete foundations, interior wall finishes, and structural steel. Mechanical and electrical equipment will be purchased and installed once architectural components have sufficiently progressed. The mechanical equipment is comprised of HVAC systems used to heat and cool office spaces, plumbing for washroom facilities, air extraction for generator equipment, cooling capacity for IT & UPS rooms, and fire sprinkler systems. The electrical building cost expenditure is a large portion of the building construction costs due to the dual generators and dual UPSs (Uninterruptible Power Supply) that will be installed as per control centre requirements based on TIER 1 utility, TIER 2 generator, TIER 3 UPS and TIER 3 EPS and UPS distribution. As the project progresses into the final years of construction, interior finishes will be installed in the office spaces such as ceiling tiles, carpet, tiling, office furniture, audio visual equipment, and IT hardware.

The expenditure plan for site works will begin once a site plan approval has been granted for the expansion of the parking lot. This will include new asphalt, walkways, curbs, and modification to the storm water management system. Due to site conditions, a retaining wall will be constructed to allow for additional parking spots. Also included in the site works expenditure plan are new light standards and security equipment. This equipment will ensure that the parking lot is appropriately lit during dark hours and employees are safe coming to and leaving the facility.

All of the above details surrounding the expenditure plan for the dual Control Centre comes with potential additional costs due to the construction work occurring in an occupied work centre. Considerations for noise and disruption will have to be taken into account when scheduling construction work. This could result in after-hours work, fire panel bypass, fire watch, and contingencies to maintain business continuity. Contingencies for these items have been included in the construction estimate and represent $1.0 million of the expenditure plan.

E8.1.4.1 Implementation Strategy

The construction of the Control Centre will be managed by Toronto Hydro. The dual Control Centre will be constructed in three stages, as displayed below:

Table 8: Phase One Objectives

Responsibility Group	Description	Proposed Deadline
Toronto Hydro	Develop and procure contracts for construction manager, project management and contract administrator	Q3 2020
Design Team	Complete the design tender drawings	Q3 2020
Design Team	Begin obtaining City approvals in order to proceed with construction (site plan approval, permits, etc.)	Q3 2020
Toronto Hydro	Review and approve design drawing for the Control Centre	Q4 2020

Table 9: Phase Two Objectives

Responsibility Group	Description	Proposed Deadline
All	Once drawing are ready for tender, work with the team to develop project schedule and critical path	Q4 2020
Construction Manager	Tender the construction work	Ongoing
Construction Manager	Begin construction at [redacted] and ensure adherence to the project schedule.	Q4 2020
Toronto Hydro	Procure Furniture / Equipment for Office Space	Q2 2022
All	[redacted] Dual Control Centre's substantial completion	Q3 2022

Table 10: Phase Three Objectives

Responsibility Group	Description	Proposed Deadline
All	Work with team to identify and address all construction deficiencies	Q4 2022
Design Team	Create and deliver close out documentation to Toronto Hydro	Q4 2022
Toronto Hydro	"Go Live" with Control Centre	Q4 2022
Toronto Hydro	Pay all vendors and close the project	Q4 2022

E8.1.4.2 Planned Project Timeline

Table 11: Planned Project Timeline

	2020				2021				2022			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Non-Direct Construction Cost												
Interior Demolition												
Building Construction												
Site work												

E8.1.5 Options Analysis / Business Case Evaluation ("BCE")

E8.1.5.1 Option 1: Status Quo

The status quo option will entail continuing with the existing Control Centre set-up, i.e. the Control Centre located in 500 Commissioners serves as the primary Control Centre, while the facility located in [redacted] serves as the backup Control Centre. There will be no incremental spending to further safeguard the 500 Commissioners location from the threat of flooding or other catastrophic events. Under this scenario, the primary Control Centre would remain vulnerable to severe weather-related events, due to its location that is adjacent to Lake Ontario and along the path of the Don Valley flood plain. [redacted]

E8.1.5.2 Option 2: Fortification of 500 Commissioners Street Work Site

One option in mitigating some of the risks associated with the primary Control Centre would be to introduce enhanced fortification of the current 500 Commissioners facility such that the risk of catastrophic failure is reduced. As described above, the primary Control Centre at Toronto Hydro's 500 Commissioners facility is located along the path of the Don flood plain and is adjacent to Lake

Ontario. This places the facility at a significantly elevated risk of flooding, which would result in the catastrophic failure of the primary Control Centre. There are several methods available in order to safeguard office buildings and structures from potential flooding events. As described by the Federal Emergency Management Agency ("FEMA") within their study "Floodproofing for Non-Residential Structures", recommended actions for safeguarding commercial facilities such as 500 Commissioners include:[27]

- Elevating the existing structure using posts, piles, piers or walls;
- Installation of flood shields and closures; and
- Installation of floodwalls and levees.

However, elevating the current Commissioners structure would be infeasible due to the multiple levels of structure and materials utilized as part of the construction. It would be possible to install flood shields and closures around the primary control centre location, coupled with floodwalls and levees along the entire length of the Commissioners facility that faces Lake Ontario.

Using the suggested cost estimate data provided by FEMA in its Floodproofing for Non-Residential Structures study,[28] coupled with the square footage and dimensions of the 500 Commissioners facility, total costs to perform full flood-proofing of the Commissioners facility are estimated to exceed $10 million. This includes secondary costs including the extension of fibre to support the Control Centre functions, waterproofing of walls and floors, installation of subfloor drainage systems as well as backflow prevention devices and testing of flooding shield systems. These costs do not account for the loss of usable space that may be incurred due to the installation of flood shields, closures, floodwalls, and levees respectively. These costs would only contribute towards the protection of a flooding event. However, other risks (e.g. terrorist attack) and natural disaster events could also compromise the Commissioners location and would not be at all addressed by this option, leaving Toronto Hydro and its customers vulnerable to many of the same risks discussed in the option above.

Furthermore, under this scenario, the backup Control Centre at [redacted] would continue to operate in parallel with the primary control centre. [redacted]

[27] "FEMA 102: Floodproofing for Non-Residential Structures", Federal Emergency Management Agency, 1986, available at: <https://www.fema.gov>.
[28] Ibid.

[redacted]

For these reasons, Toronto Hydro does not consider fortification of the 500 Commissioners location to be a viable option.

E8.1.5.3 Option 3: Development of a Dual Control Centre at [redacted]

The third option assessed entails the development of a dual Control Centre at [redacted] The subsequent sub-sections will individually examine each facility to assess the feasibility of developing a fully-operational dual Control Centre within.

1. Option 3.1: Dual Control Centre at [redacted] Work Centre

[redacted]

2. Option 3.2 (Selected Option): Dual Control Centre at [redacted] Work Centre

[redacted]

This location possesses a total of 12,000 square feet of available space to accommodate a fully-functioning dual Control Centre. SCADA and telecom facilities already exist at this location, making this location the most cost efficient for installation and set-up, when compared to other existing facilities. In addition, the facility will be able to perform all operations that can be executed by the primary Control Centre, including monitoring distributed generation and renewable connections.

By far, the greatest advantage of the [redacted] location is that it has the space and other requirements necessary to accommodate a fully functioning dual Control Centre. Employees at both Control Centres will be responsible for different areas of the City, to ensure there is no duplication in work. Since it would be operating in parallel to the primary Control Centre, under an emergency scenario, there will be virtually no impact on operations as the dual Control Centre will be able to resume all functions of the primary Control Centre.



Figure 7: Fiber Cable Routing to [redacted]

3. Option 3.3: Dual Control Centre at [redacted]

It should be stated that many of the advantages associated with the [redacted] location are also associated with their [redacted] location. [redacted]

[redacted]

E8.1.5.4 Option 4: Development of a Dual Control Centre with Limited Functionalities at [redacted]

This option would involve the development of a dual Control Centre with limited functionalities (i.e. not a fully functioning Control Centre) at [redacted] This limited Control Centre would operate in a similar manner [redacted] This option would only be available at [redacted] due to the available space at this location in order to accommodate the requirements, as previously noted above.

[redacted]

[redacted]

[redacted]

While space requirements for this backup facility would be reduced by approximately 50-60 percent when compared to a fully functioning Control Centre, the funding requirements would not be reduced proportionally. This is due to the fact that certain components, such as the Uninterruptible Power Supply, data centre, electrical room, and generators must be fully built at the time of construction. These components cannot be constructed in an incremental manner, even if the Control Centre is utilized only for partial, backup purposes.

E8.1.5.5 Option 5: Development of a Dual Control Centre at a Newly Acquired or Leased Facility

The development of a dual Control Centre at a newly acquired or leased facility would allow Toronto Hydro to select an optimal location of its choice based on a host of considerations, such as risk and cost. This option would allow the utility to custom design a Control Centre to fit all its requirements rather than to design a facility to fit existing infrastructure and space. Since the new location will house all new IT-related infrastructure, it will present a lower risk of failure. In addition, existing Toronto Hydro operations would not be disrupted by construction issues (noise-related or otherwise) since no other Toronto Hydro functions would be co-located on the premises.

However, the utility will incur costs to construct fiber-optic infrastructure to enable SCADA capabilities. There will be added costs of additional support services required for the dual Control Centre at a newly acquired or leased site. For instance, IT personnel will need to be either located within the new site or travel from Toronto Hydro's existing sites to the new Control Centre in case of IT-related issues.

E8.1.5.6 Evaluation of Options

The evaluation criteria used to assess the various options available to Toronto Hydro include the following:

1) Current weather related risks associated with the proposed location (for instance, is it located within the path of a flood plain);

2) Available space within the proposed location (when compared to minimum space requirements for a fully functioning Control Centre);
3) Available technological capabilities within the proposed location (when compared to minimum technological requirements for a dual Control Centre);
4) Impact associated with a terrorist event, and whether the event would prevent the full enablement of the dual Control Centre; and
5) Total cost impact to ratepayers.

Each of the above criteria were taken into consideration when selecting the best overall option for Toronto Hydro.

Table 12, below, illustrates the results of the options analysis, comparison and final recommendations, based upon what has already been discussed for each of the options above.

Table 12: Results of Option Analysis

Criteria / Location	[redacted]	Newly Acquired or Leased Facility
Weather Risks		
Available Space		
Available Technological Capabilities		
Dual Control Centre Enablement		
Impact of Terrorism Attack		
Total Costs		

Legend
Does not meet criteria
Partially meets criteria
Meets or Exceeds Criteria

When assessing current-state risks, availability of space and technological capabilities, costs, as well as overall ability to meet the objectives of dual control centre enablement, this comparison indicates that both the development of a dual Control Centre at [redacted] and at a newly acquired or leased facility satisfies all the criteria. However, the differentiating factor between the two options is cost.

Building a dual Control Centre at Toronto Hydro's existing facility at [redacted] is the most effective solution and the primary reason for why the utility has opted to adopt this approach.

Furthermore, Toronto Hydro performed a comparative analysis of how each of the various Control Centre locations (alternatives considered), including the proposed at [redacted], are equipped to handle critical emergency functions. Appendix B presents the results of these analysis. It must be noted that all of these functions can be supported through the primary Control Centre at 500 Commissioners facility, as well as the proposed dual Control Centre at the [redacted] location. However, notable constraints exist under the current configuration where [redacted] location acts as the backup Control Centre, as described above.

E8.1.6 Execution Risks & Mitigation

The largest risk to the successful execution of the Program involves timing and costs. The expenditure plan is based on estimates of external labour, external labour and material costs over the 2020 to 2022 period. Material costs are generally subject to greater price fluctuations over time and therefore cost-overruns may transpire. However, through the expertise of experienced project management leadership, and industry experts a proactive approach will be taken to manage these costs.

In addition, there are also construction related risks associated with the Program, including:

- Unexpected construction conditions
- Occupational health and safety
- Disruption to Toronto Hydro employees at [redacted]
- Design change approvals
- Budget shortfalls
- City approval delays
- Procurement / Tender delays
- Design changes

These issues can be mitigated with proper communication, leveraging the expertise of the consultants and proper project planning, see Table 13, below. Overall, leading project management tools and practices will be utilized and the expertise of highly qualified project management leadership and industry experts will be leveraged in order to take a proactive approach to managing unknown conditions.

Table 13: Phase One Risk and Mitigation Strategy

Risk Description	Impact Level	Mitigation Strategy
City Approval Delay	*High*	Leverage the experience and expertise of the design consultants to work with the City to obtain approvals.
Procurement / Tender Delays	*Medium*	Ensure drawings are complete and involve the design team during the tender process.
Design Changes	*Medium*	Toronto Hydro to work internally to limit the amount of changes on the project after tender process.
Unexpected Construction Conditions	*High*	Leverage the expertise of the Design team to ensure that unknown construction conditions are addressed in the most efficient manner.
Occupational Health and safety	*High*	Have a metric in place that tracks safety infractions. Ensure construction manager adheres to Toronto Hydro safety standards.
Disruption to Toronto Hydro Staff at [redacted]	*High*	Ensure proper communication with Toronto Hydro employees. Work that can have high impact on Toronto Hydro employees to occur after hours.
Design Change Approval	*Medium*	Ensure proper process is in place to ensure changes are approved in a timely manner.
Budget Shortfalls	*High*	Develop a budget with some contingency and work with team to ensure value engineered savings.
Major Deficiency Discovered	*High*	Have the design team review the progress of construction regularly to ensure work is completed has per plan
Unpaid invoices	*Medium*	Ensure proper communication with all vendors to ensure they are paid in a timely manner

Jurisdictional review and economic case for a dual distribution control center in Toronto Hydro territory

prepared by London Economics International LLC

June 22nd, 2018

Distribution control centers ("DCC") support reliability, resiliency, and the ability to recover quickly from deliberate attacks and natural disasters. LEI has found that there is a precedent for utilities across North America to build fully functional backup control centers, at similar costs to those proposed by Toronto Hydro. Justifications included increasing reliability and resiliency, with certain utilities citing specific situations such as natural disasters or terrorism threats. Growth in distributed energy resources has also caused distribution utility operations to be more complex and take on some of the responsibilities traditionally required in the Bulk Electricity System, including dealing with interconnected generation and taking greater responsibility for bulk system reliability. LEI believes that the evolution of these responsibilities also support the need for Toronto Hydro's proposed dual DCC. Finally, LEI's analysis indicates that the proposed costs can be justified economically, given the significant costs of outages in the city of Toronto, and the potential for the dual control center to reduce the duration of high-impact outages.

Table of contents

1 EXECUTIVE SUMMARY 4

1.1 SCOPE OF SERVICES 4
1.2 SUMMARY OF FINDINGS 4

2 ROLE OF DISTRIBUTION CONTROL CENTERS 5

3 CONTROL CENTER OPERATIONS IN OTHER JURISDICTIONS 5

3.1 HYDRO ONE 9
3.2 CONSOLIDATED EDISON 10
3.3 PACIFIC GAS AND ELECTRIC 11
3.4 FLORIDA POWER & LIGHT COMPANY 12
3.5 SAN DIEGO GAS & ELECTRIC 14

4 IMPACT OF DISTRIBUTED ENERGY RESOURCES ON THE ROLE OF DISTRIBUTION UTILITIES 15

4.1 CHANGING ROLE OF THE DISTRIBUTION UTILITY 15
4.2 GROWTH OF DISTRIBUTED ENERGY RESOURCES IN ONTARIO 16
4.3 ROLE OF THE DISTRIBUTION SYSTEM IN RELIABILITY 18

5 ECONOMIC CASE ANALYSIS FOR PROPOSED CONTROL CENTER 21

5.1 VALUE OF LOST LOAD 21
5.2 ECONOMIC COSTS OF AN EXTRAORDINARY EVENT 24

6 CONCLUDING REMARKS 27

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Table of figures

FIGURE 1. LIST OF ACRONYMS....3
FIGURE 2. ELECTRICITY DELIVERED BY UTILITIES....6
FIGURE 3. CONTROL CENTER CONSTRUCTION COSTS....6
FIGURE 4. SUMMARY OF IDENTIFIED UTILITY DISTRIBUTION OPERATIONS....8
FIGURE 5. ALTERNATIVE BUCC REPLACEMENTS INITIALLY PRESENTED BY HYDRO ONE....9
FIGURE 6. FPL DCC LOCATIONS....13
FIGURE 7. DISTRIBUTED ENERGY RESOURCE INTERACTION WITH THE ELECTRICITY GRID....15
FIGURE 8. CONTRACTED AND INSTALLED DER IN ONTARIO AS OF FEBRUARY 2017 (MW)....16
FIGURE 9. TYPE & DURATION OF OUTAGE EVENT EQUIVALENT TO $40.2 MILLION DUAL CONTROL CENTER COST....21
FIGURE 10. SUMMARY OF VOLL BY JURISDICTION....23
FIGURE 11. TORONTO HYDRO HISTORICAL SAIDI (2012-2016)....25
FIGURE 12. ASSUMED CUSTOMER DEMAND IN DUFFERIN TS EXAMPLE....25
FIGURE 13. ASSUMED CUSTOMER DEMAND IN WINDSOR TS EXAMPLE....26

Figure 1. List of Acronyms

BEA	U.S. Bureau of Economic Analysis
BUCC	Backup Control Centers
CAD	Canadian Dollars
CECONY	Consolidated Edison Company of New York
DCC	Distribution Control Center
DER	Distributed Energy Resource
EIA	US Energy Information Administration
EMP	Electromagnetic Pulse
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FPL	Florida Power & Light Company
GDP	Gross Domestic Product
HECO	Hawaiian Electric
HMCC	Hardened Mobile Control Center
HVAC	Heating, Ventilation, and Air Conditioning
IESO	Independent Electricity System Operator
ISO	Independent System Operator
ISOC	Integrated System Operations Center
IT	Information Technology
LDC	Local Distribution Company
LEI	London Economics International LLC
LTEP	Long Term Energy Plan
NERC	North American Electric Reliability Corporation
OEB	Ontario Energy Board
PG&E	Pacific Gas and Electric
RDGI	Renewable Distributed Generation Integration
SAIDI	System Average Interruption Duration Index
SCADA	Supervisory Control and Data Acquisition
SDG&E	San Diego Gas & Electric
TCC	Transmission Control Center
THESL	Toronto Hydro Electric System Limited
TS	Transformer Station
TSX	Toronto Stock Exchange
UPS	Uninterrupted Power Supply
US	United States
USD	US Dollars
VoLL	Value of Lost Load

1 Executive Summary

1.1 Scope of services

LEI was engaged by Toronto Hydro to undertake an independent study of comparator utilities with fully functional backup control centers ("BUCCs") in other jurisdictions. The utilities were reviewed and analyzed in terms of their functionality as well as cost. LEI also considered the proposed dual control center from an economic perspective by estimating economic costs of a high-impact outage on Toronto Hydro's service territory.

1.2 Summary of findings

LEI has identified five utilities that have built fully functional BUCCs— Hydro One, Consolidated Edison, Pacific Gas & Electric, Florida Light & Power, and San Diego Gas & Electric. These utilities identify various justifications for their investment, including supporting resiliency, increasing reliability, and ensuring quick recovery from terrorist threats and natural disasters, for example earthquakes and floods. Integration of Distributed Energy Resources ("DERs") was also cited.

All reviewed BUCCs were fully functional and were able to take over operations from the primary control center. However, different utilities varied in terms of their mode of operation: the number of backups, whether they were manned or unmanned, and whether they ran in parallel or not. Toronto Hydro's current BUCC has only [redacted] of the functionalities of the primary control center; the proposed dual control center is to be fully functional and run in parallel with the primary control center.

In its study of comparator utilities, LEI found that the cost of BUCCs built in the past 5 years are aligned with the cost of Toronto Hydro's proposed dual control center. Moreover, the justifications of costs, and challenges faced by comparator utilities are comparable. Compared to the utilities reviewed, Toronto Hydro serves a uniquely important load in terms of political and economic significance, as well as a large base of customers with significant population density.

LEI also reviewed the impact of DERs on the role of the distribution utility. The growth of distributed generation has given distributors some of the reliability responsibilities traditionally reserved for transmission utilities, such as forecasting and dispatching generation. In California, Texas and Hawaii, as well as Ontario, utilities, regulators and reliability authorities have recognized the threat of high DER penetration to the reliability of the bulk transmission system. Bulk system utilities are governed by NERC safety requirements, including the requirement for backup functionality of its control center. LEI believes as distribution utilities evolve towards more complex operations with greater responsibility for reliability, fully functional backup distribution control centers will become increasingly necessary.

Finally, LEI conducted a high-level review of the economic cost of a high-impact outage on Toronto Hydro's service territory, which covers the financial and economic capital of Canada. Extraordinary events such as natural disasters or terrorist attacks could cause the inability to operate Toronto Hydro's primary control center, resulting in delayed service recovery time following an outage. LEI's analysis shows that the proposed costs for the dual control center can be justified economically, given the significant costs of outages in the city of Toronto, and the dual control center's potential to reduce the duration of these outages.

2 Role of distribution control centers

Electricity distribution control centers ("DCCs") are used to control, coordinate, and monitor the distribution of electricity. Utilities in North America are upgrading their control centers to support reliability, resiliency, and to recover more quickly from natural disasters – and in order to further increase reliability, some utilities have built fully functional BUCCs.

DCCs provide real-time management of the grid. Supervisory Control and Data Acquisition ("SCADA") systems are used to obtain data about the distribution system via sensors and operate station breakers and field devices to manage the system. From the DCC, operators are able to monitor grid operation, manage planned and unplanned outages, manage system loading, as well as determine areas to improve grid performance and reliability. Key tasks at a DCC include clearance management and developing switching orders for planned maintenance.[1] Clearance management is the process by which the DCC determines periods that equipment can be taken out of service by asset management for planned work. Operators need to consider the outage length, system conditions and other clearance requests to determine when clearance can be taken. After clearance is approved, a switching order must be developed, which involves deenergizing equipment before any work is performed for safety, as well as reconfiguring the power system to perform reliably during this period. These responsibilities are critical to enable the reliable operation of the distribution system and ensure the safety of the public and utility employees.

Given their important role, DCCs are typically set up to run on a 24/7 basis with multiple levels of redundancy. Electrically they may be supported with an uninterrupted power supply ("UPS"), battery storage and/or a backup diesel generator, while SCADA systems will have multiple communication feeds, and technology systems will be designed to withstand application or hardware failures. BUCCs are used as a type of physical redundancy, where utilities have a separate facility that can take over the responsibilities of the primary DCC, if the primary DCC is inoperable or inaccessible.

Hot vs. Cold Backup Control Centers

Redundancy in BUCCs can be applied in various ways. Cold BUCCs are secondary backups that are only called upon when the primary system experiences a significant failure. Hot backups are a method of redundancy in which both primary and secondary systems are running, so that the secondary BUCC is receiving and processing the same information so that it can assume operations quickly and smoothly.

3 Control center operations in other jurisdictions

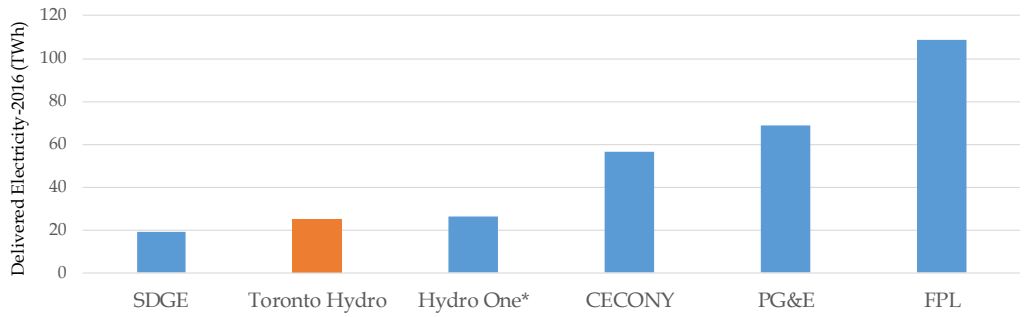
This section provides case studies of control centers in other jurisdictions, all of which are for utilities that have distribution operations. These utilities have sought to bolster their backup plans

[1] Vadari, Mani. *Electric System Operations: Evolving to the Modern Grid*. 2013.

to improve reliability and resiliency against severe weather events such as hurricanes and floods, as well as attacks including cyber-attacks.

LEI reviewed large Canadian and US utilities and identified four utilities that publicly disclose they utilize fully functional BUCCs to improve reliability in their distribution operations.[2] Hydro One has also been included, as they are developing a new 'dual primary' control center to replace their current BUCC, as discussed in its most recent distribution rate application.

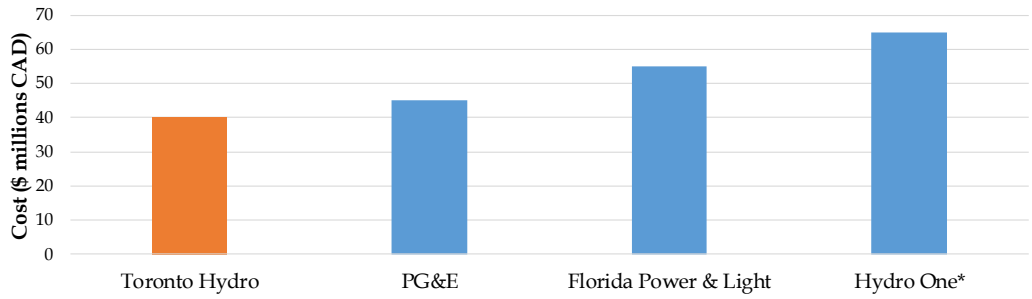
Figure 2. Electricity delivered by utilities



* Note: Electricity delivered to Hydro One distribution customers only
Source: Company reports and websites

In terms of the capabilities of the backup controls centers, all five case studies are fully functional and can completely take over operations from the primary control center. Toronto Hydro has estimated that the existing BUCC at [redacted] of the functionalities of the primary control center. Toronto Hydro's proposed dual control center at [redacted] would be fully functional, and costs are in line with (and slightly lower than) the identified utilities that had publicly available control center construction costs. A comparison of costs is shown below in Figure 3.

Figure 3. Control center construction costs



[2] LEI reviewed the 20 largest US utilities and 5 largest Canadian distribution utilities by number of customers. The excluded utilities may also use a backup control center, however were excluded from this review as no public information was found.

* Note: Budget of distribution portion of control center only, not the total cost

A comparative summary of the profiles and functionalities associated with the selected utilities is shown below in Figure 4. Toronto Hydro falls within the range of the selected utilities in terms of electricity delivered annually, as shown in Figure 2. Although certain selected utilities serve a larger load or area, Toronto Hydro serves a uniquely important load. Toronto Hydro serves the provincial capital as well as the economic and financial center of Canada; in fact, it serves the highest proportion of national economic activity out of all the identified utilities. In addition, Toronto Hydro has amongst the highest customer densities of the identified utilities and distributes approximately 19% of electricity consumed in Ontario.[3]

[3] Toronto Hydro. *About Us.* <https://www.torontohydro.com/sites/corporate/AboutUs/Pages/AboutUs.aspx>

Figure 4. Summary of identified utility distribution operations

	Metric	Toronto Hydro	Hydro One	FPL	PG&E	CECONY	SDGE
	Province/State of utility service territory	Ontario	Ontario	Florida, US	California, US	New York, US	California, US
Load Significance	**Delivered electricity (GWh, 2016)**	25,373	26,289*	108,871	68,820	45,745	19,200
	Number of customers ('000)	768	1,355	4,900	5,400	3,400	1,400
	Service area (km^2)	630	962,774	71,613	181,299	1,564	10,619
	Service area density (customers/km^2)	1,219	1	68	30	2,174	132
	Population of largest city served ('000)	2,732	<80	454	1,025	8,538	1,406
	Serving provincial/state capital?	✓	-	-	-	-	-
	Serving national financial center?	✓	-	-	-	✓	-
	% of national economic activity in utility's service territory**	10.0%	<6%***	3.3%	6.2%	4.0%	1.2%
Control center operations	**Qualitative Justification**	Withstand extreme weather events, climate adaptation, terror threat	Reduce financial risk, customer impacts and reputational harm	Increase reliability, reduce time required to recover from storms	Strengthen grid resiliency and reliability, particularly for natural disasters; DER integration	Withstand and rapidly recover from an EMP attack	Maintain reliability, DER related reliability concerns
	Mode of operation	One backup, Proposed: dual control centre	One backup, Proposed: dual primary control centre	Two backups	Parallel Three centers co-run	Parallel Four centers co-run + mobile backup	One backup
	Manned/Unmanned	Unmanned, Proposed: Manned	Manned	Unmanned	Manned	Manned	Unmanned
	Functionality	[redacted] proposed: [redacted]	Equivalent	Equivalent	Equivalent	Equivalent	Equivalent
	Cost (Canadian $ million)****	$40 (estimated cost of the proposed dual CC)	$65 (for proposed ISOC)	$55 (for one DCC)	$45 (average cost across three control centres)	n.a.	n.a.

* A total of 36,525 GWh were delivered through Hydro One distribution lines in 2016 - this includes electricity distributed to consumers who purchased power directly from the IESO

** Economic activity in Toronto Hydro service territory measured by comparing the 2016 annual GDP for the city of Toronto to Canada as a whole, using GDP estimates available from the city of Toronto's website. Economic activities in US utility's service territory was measured using county-level Personal Income data published by the US Bureau of Economic Analysis. Economic activity in counties the US utilities serve were then summed up and compared to total national Personal Income

*** Economic activity in Hydro One's distribution service territory is very difficult to estimate. Data available on Statistics Canada's website [CANSIM Table 381-5000] from 2009 provides GDP estimates for 15 metropolitan areas in Ontario, as well an estimate for 'non-census metropolitan areas' in Ontario. Assuming all economic activity in Ontario's 'non-census metropolitan areas' falls under Hydro One service territory, then this value divided by the total Canadian GDP estimate from the same data source indicates that 5.7% of Canada's economic activity falls within Hydro One's distribution service territory

**** Costs of US control rooms converted to Canadian dollars using an exchange rate of 1.3 CAD:1 USD (as of June 1st, 2018)

Sources: FERC, EIA, BEA, US Census Bureau, Statistics Canada, City of Toronto, Company reports and websites

3.1 Hydro One

Hydro One's primary power control center was opened in 2005 and cost $118 million.[4] The control center monitors both Hydro One's distribution and transmission networks in Ontario. Named the "Ontario Grid Control Centre", it consolidated monitoring and control functions under one roof, instead of the previously isolated regional control centers.

Hydro One also maintains a BUCC in Toronto originally commissioned in 1956 and is seeking to upgrade its control center capabilities (including both distribution and transmission) under its ongoing custom Incentive Rate-setting application for 2018-2022 electricity distribution rates [EB-2017-0049]. Hydro One has stated that its current BUCC requires upgrading due to an increased risk of facility failure. Hydro One has cited the main reasons to upgrade the facility as:

(i) regulatory compliance;
(ii) financial risk;
(iii) customer impacts; and
(iv) reputational harm.[5]

Hydro One presented a number of alternative approaches to replace/upgrade the existing BUCC operations, which are summarized in Figure 5 below (along with the costs associated with the distribution portion of these alternatives).

Figure 5. Alternative BUCC replacements initially presented by Hydro One

Alternative	Description	Distribution portion of costs ($ million)
1	Maintain status quo and use offsite leased space	$39
2	Build Network Operating Division ("NOD") BUCC and Data Centre ("DC") exclusively	$52
3	Build Integrated System Operations Center ("ISOC") as BUCC and Backup IT Management Center ("BUITMC"), with back office support areas and an integrated DC	$62
4	Acquire an existing facility for BUCC and BUITMC and integrated DC	N/A
5	Build Primary NOD Control Centre, primary SOC, and BUITMC	$71
6	Build ISOC capable of "dual primary" operations ***[Recommended by Hydro One]***	$65

Note: The above values represent only the distribution portion of costs. Total cost estimates for these listed alternatives are approximately double the values shown above.
Source: Hydro One exhibit B1-2 (OEB case EB-2017-0049) from April 4, 2017, pdf page 1314-1315

Of the approaches presented, Hydro One recommended the construction of a new Integrated System Operations Center ("ISOC"). Importantly, the ISOC would eventually allow Hydro One

[4] Hydro One. *Exhibit B1-2 from OEB case EB-2017-0049.* April 4, 2017 <http://www.rds.oeb.ca/HPECMWebDrawer/Record/569822/File/document>

[5] According to Hydro One's rate application for the 2015-2019 period

to operate a "dual primary" scenario, where both the current and new control centers can operate in parallel. Hydro One's distribution rate application is currently still ongoing.

3.2 Consolidated Edison

Consolidated Edison Company of New York ("CECONY") is a regulated utility which provides electric service to 3.4 million customers in New York City and Westchester County.[6] In addition to servicing a 604 square mile electric service territory, it also distributes natural gas and district energy steam. CECONY is divided into four different operating regions (Bronx/Westchester, Brooklyn/Queens, Manhattan, and Staten Island), each with an Electric Distribution Control Center which is responsible for coordinating switching operations and feeder processing for restoration of outages.[7] These DCCs are staffed 24/7. CECONY has highly concentrated underground distribution networks, which typically witness fewer interruptions in the face of weather events, in comparison to overhead systems common elsewhere.[8]

In recent years, CECONY has undertaken significant expense to upgrade its DCCs. A review of its reported annual capital expenditures from 2011-2016 shows total actual costs for "Electric Distribution Control Center Upgrades" of $23.7 million USD. [9,10,11,12,13,14] This work includes a project to upgrade the IT server, network, UPS infrastructure, and enhance the electrical and HVAC design of all DCCs. CECONY's justification for the project was that the DCCs are "vital to maintaining [their] ability to deliver safe and efficient services".[15] CECONY's

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[6] ConEdison. *Company History and Statistical Information.* <https://www.coned.com/en/about-us/corporate-facts>

[7] NYDPS. *ELECTRIC INFRASTRUCTURE AND OPERATIONS PANEL.* Jan 29, 2015. <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B4BEE2FD7-6E49-40AE-B007-3B76085F31AC%7D>

[8] NYDPS. Office of Electric, Gas, and Water. *2016 Electric Reliability Performance Report*. June 2017. <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BBBCBF3C3-1812-4EEC-9E31-6901AED885D3%7D>

[9] ConEdison. *Report on 2011 Capital Expenditures*. February 28, 2012.

[10] ConEdison. *Report on 2012 Capital Expenditures*. February 28, 2013.

[11] ConEdison. *Report on 2013 Capital Expenditures*. February 28, 2014.

[12] ConEdison. *Report on 2014 Capital Expenditures and 2015-2019 Electric Capital Forecast*. March 2, 2015.

[13] ConEdison. *Report on 2015 Capital Expenditures and 2016-2020 Electric Capital Forecast*. February 29, 2016.

[14] ConEdison. *Report on 2016 Capital Expenditures and 2017-2021 Electric Capital Forecast*. February 28, 2017.

[15] NYDPS. *Electric Infrastructure and Operations Panel*. Jan 29, 2015. <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B4BEE2FD7-6E49-40AE-B007-3B76085F31AC%7D>

decision to invest in the project was to provide "a high level of availability to allow the operators, designers and engineers to make proper decisions during major distribution system events".[16] CECONY continues to invest in updating its distribution management; a multi-year outage management system integration project was initiated in 2018.[17]

In addition to multiple DCCs, CECONY is building the world's first utility Hardened Mobile Control Center ("HMCC") to enhance its ability to withstand and rapidly recover from an Electromagnetic Pulse ("EMP") attack. An EMP would potentially destroy many key control center systems and devices, leaving the utility operating with limited visibility, vulnerable to multiple contingencies, and possibly requiring reduced load and extended outages.[18] The HMCC is a modular backup system consisting of completely self-sufficient and self-contained elements that have their own power supplies. It would take over system operations in less than one day after an EMP attack, down from weeks or months. The system will be on a mobile platform consisting of three tractor trailers enclosures that can be deployed to one or several locations, that can support workstations for 16 operators in total. The contract to build the HMCC was awarded in December 2017.

As justification for the HMCC, CECONY cited growing tensions in world events and findings from a commission established by US Congress to assess threats of an EMP attack.[19] This commission concluded several potential adversaries would have the capability to attack the US with an EMP, even without a high level of sophistication, and that an "EMP is one of a small number of threats that can hold our society at risk of catastrophic consequences". CECONY describes the HMCC as a proactive and sensible approach to prepare for this threat.

3.3 Pacific Gas and Electric

Pacific Gas and Electric ("PG&E"), which serves around 5.4 million customers in California and has 140,000 miles of lines, operates three electric distribution control centers (Fresno, Rocklin, and Concord) over an entire service area exceeding 180,000 km^2. PG&E consolidated its 15 existing electric operations centers into these three centers in 2016, as part of its effort to create a "smart, more resilient grid". Each of the three centers monitor and control approximately one-third of PG&E's service region, also known as a parallel mode of operation. The centers provide the ability

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[16] ConEdison. Exhibit IIP-13. <https://legacyold.coned.com/documents/2013-rate-filings/Electric/Exhibits/076-IIP-13-ITCategory.pdf>

[17] GridBright. *ConEd Selects GridBright for Distribution Management Integration*. August 2017. <https://gridbright.com/coned-integration>

[18] Consolidated Edison. *Case 16-E-0060 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*. Feb 28, 2018 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B105D820F-4CE5-4E84-9E28-CC4F813E6158%7D>

[19] Ibid.

"to shift operations to the two other regional control centers if support is needed at one in the event of a major storm or natural disaster."[20] The centers were constructed with redundant data feeds and emergency back-up capabilities to be able enhance resiliency in the face of unforeseen events such as major storms or natural disasters.

PG&E's three DCCs cost a total of approximately $105 million USD. The first control center in Fresno opened in late 2014, at a total cost of $28.5 million USD. The second control center in Concord cost $40 million USD and was opened in August 2015. The third control center in Rocklin opened in February 2016, at a total cost of $36 million USD.[21]

According to PG&E, investment in these control centers will "strengthen resiliency of the grid, while enhancing electric reliability",[22] as well as advancing the integration of DERs into its distribution system. Smart grid technologies were also piloted and deployed alongside the control center consolidation.[23]

3.4 Florida Power & Light Company

FPL is one of the largest US electric utilities, serving approximately 4.9 million customers in Florida.[24] FPL operates three DCCs and maintains two backups near two of its control centers, and has "implemented multiple levels of resiliency and redundancy in both its transmission and distribution substations and control centers".[25] Not only is each facility equipped with redundant energy management systems, but each backup facility is geographically diverse, fully functional, and has dedicated and redundant communication links. This allows a BUCC to quickly and effectively take over if the primary control center loses functionality. The BUCCs closely replicate the main control centers and can also be accessed remotely from the nearby DCC. The BUCCs are

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[20] PG&E. *PG&E Opens New $40 Million State-Of-The-Art Electric Control Center in Concord.* August 20, 2015. <https://www.pge.com/en/about/newsroom/newsdetails/index.page?title=20150820_pge_opens_new_40_million_state-of-the-art_electric_control_center_in_concord>

[21] PG&E. With Opening of New Rocklin Facility, PG&E Completes Move to Industry-Leading, High-Tech Electric Distribution Control Centers. February 03, 2016. <https://www.pge.com/en/about/newsroom/newsdetails/index.page?title=20160203_with_opening_of_new_rocklin_facility_pge_completes_move_to_industry-leading_high-tech_electric_distribution_control_centers>

[22] Ibid.

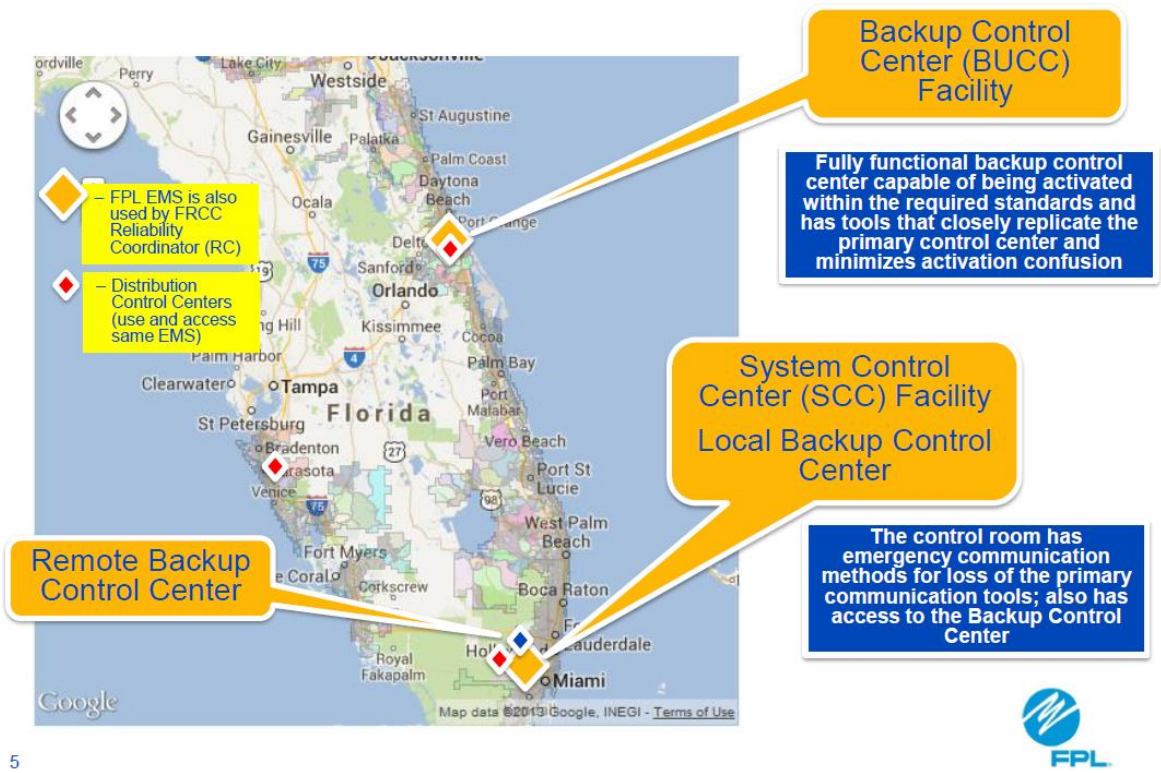
[23] PG&E. *Smart Grid Annual Report – 2017.* September 29, 2017. https://www.pge.com/pge_global/common/pdfs/safety/how-the-system-works/electric-systems/smart-grid/Annual-Report-2017.pdf>

[24] Florida Power & Light. *Company Profile.* <https://www.fpl.com/about/company-profile.html>

[25] State of Florida Public Service Commission. *Review of Physical Security Protection of Utility Substations And Control Centers.* December 2014. P. 29 <http://www.psc.state.fl.us/Files/PDF/Publications/Reports/General/Electricgas/Physical_Security_2014.pdf>

unmanned, so they do not run in parallel,[26] and can be considered "cold" backups. These DCCs support FPL's business continuity and recovery plans, and increase reliability and reduce time required to recover from storms.

Figure 6. FPL DCC locations



Source: NERC. *NERC Monitoring and Situational Awareness Conference: Loss of Control Center Procedures and Testing Practices*. September 19, 2013

In January 2017, FPL began construction on a $42 million USD DCC in West Palm Beach. It is located next to FPL's command center, a hub opened in 2012 that coordinates overall storm response.[27] The new center will be built to withstand Category 5 hurricanes, and will consolidate the two existing distribution control centers located in Miami and Sarasota. These enhancements come as part of FPL's $2 billion USD plan to harden its infrastructure against natural disasters.

[26] NERC. *NERC Monitoring and Situational Awareness Conference: Loss of Control Center Procedures and Testing Practices*. September 19, 2013 <https://www.nerc.com/pa/rrm/Resources/MonitoringSituationalAwarenessDL/9.%20FPL_Loss_of_CC_Testing%20-%20Ed%20Batalla.pdf>

[27] Palm Beach Post. *"FPL breaks ground on distribution center to be Cat-5 storm ready"*. January 18, 2017. <https://www.palmbeachpost.com/business/fpl-breaks-ground-distribution-center-cat-storm-ready/n5kRoKXSks4jcUpGRbz9SN/>

3.5 San Diego Gas & Electric

San Diego Gas & Electric ("SDGE") is a regulated utility which provides electric service to 1.4 million customers in San Diego County and a portion of Orange County, California, over a total area of around 10,600 km^2. SDGE owns 21,000 miles of distribution lines serving 25 communities and operates transmission lines as well as two generating stations. The monitoring, operation and dispatch for the entire SDGE electric network occurs from the Mission Control facility. A project to modernize these operations in terms of data infrastructure and workstations was forecast to cost $16.3 million USD;[28] justifications included "reducing time to identify abnormal or adverse system conditions" allowing for better and faster decisions.

SDGE also has a fully-functional backup DCC located 10 miles away from its primary control center which is used to continue to maintain reliability under emergency scenarios such as loss of the primary facility or any failure of computer or communications systems.[29] The "cold" backup center has redundant connectivity allowing for operators to virtually connect to the BUCC in the case of a failure of the primary energy management system, while physically remaining in the primary control center. The BUCC is also able to handle the situation where a total failure of connectivity means operators must relocate physically to the BUCC.

Note that SDGE is one of the leading utilities in incorporating DERs – in 2016 they were the first California utility to reach their net metering cap of 617 MW (though they continue to install solar capacity through the NEM 2.0 program).[30] In their control centers, SDGE has recognized that the high penetration of DER has contributed to greater risk of safety and reliability incidents.[31] Specific challenges identified include: reverse power flow, increased voltage variability, reduced switching flexibility, and a lack of visibility of actual circuit loads, among others.[32] For their operators, these challenges have added complexity to decision making and switching requirements.

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[28] SDGE. *Direct Testimony of R. Dale Tattersall (Real Estate, Land Services and Facilities)*. October 6, 2017.

[29] SDGE. *Prepared Direct Testimony of Don Akau on Behalf of San Diego Gas & Electric Company*. Sept 25, 2015. <https://www.sdge.com/sites/default/files/FINAL%2520Akau%2520Testimony.pdf >

[30] Utility Dive. *As SDG&E edges closer to net metering cap, solar installations not expected to slow*. June 22, 2016 <https://www.utilitydive.com/news/as-sdge-edges-closer-to-net-metering-cap-solar-installations-not-expected/421312/>

[31] SDGE. *Revised San Diego Gas & Electric Company Direct Testimony of William H. Speer (Electric Distribution O&M)*. December 2017. <https://www.sdge.com/sites/default/files/SDG%2526E-15-R%2520Speer%2520Revised%2520Prepared%2520Direct%2520Testimony.pdf>

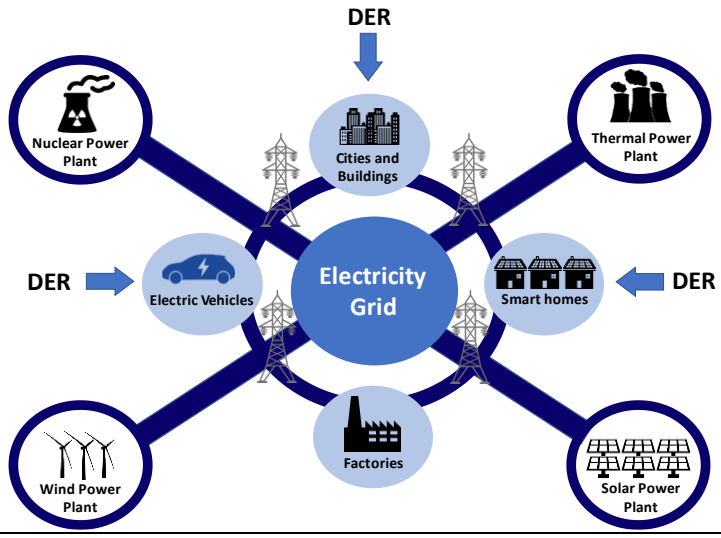
[32] Utility Dive. *How SDG&E is dealing with high penetrations of rooftop solar*. July 25, 2014 <https://www.utilitydive.com/news/how-sdge-is-dealing-with-high-penetrations-of-rooftop-solar/290227/>

4 Impact of distributed energy resources on the role of distribution utilities

The following section discusses how the growth of DER has led distribution utilities to manage more complex operations. Ontario has seen significant DER growth, which has impacted distributor operations across the province in terms of monitoring and control of energy delivery as well as energy management. The growth of distributed generation has also given distributors some of the reliability responsibilities traditionally reserved for transmission utilities. Transmission utilities are part of the bulk electricity system and thus governed by NERC safety requirements, including the requirement for backup functionality of its control center. LEI believes as distribution utilities evolve towards more complex operations and greater responsibility for reliability, fully functional BUCCs will become increasingly necessary.

4.1 Changing role of the distribution utility

Figure 7. Distributed Energy Resource interaction with the electricity grid



Electricity distribution grids are undergoing fundamental changes with the advancement of industry trends such as DERs, smart grids, and integration of electric vehicles. These trends are challenging the traditional role of the distributor and the DCCs. The traditional power grid delivered power from large scale, centralized generation, through the transmission system and the distribution system to consumers. Therefore, DCCs only handled flows of electricity in a single direction: to electricity consumers. However, small scale generation and other DERs can now be found in the distribution side of the grid, as illustrated in Figure 7. Their growth means that distributors at times need to manage bi-directional flow of electricity between the utility and consumers. This fundamental change in utility operations adds a layer of complexity to control

center operations, as they try to integrate, interpret, and act on this new information.[33] This evolution has caused DCCs to take on more operations which are more typically associated with TCCs, such as forecasting intermittent generation, energy scheduling, or dispatching generation to manage outages.

4.2 Growth of Distributed Energy Resources in Ontario

The definition for DERs can vary across jurisdictions, but generally they are decentralized, often modular, distribution grid-connected power supplying devices with smaller installed capacity. They often include power generation, storage, and demand response. In certain jurisdictions they may also have specific renewable, interconnection voltage or capacity requirements. The IESO definition of DERs is introduced in the textbox below.

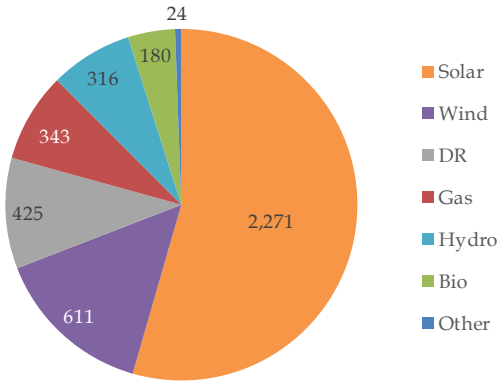
IESO definition of DERs

Distributed Energy Resources (DERs) are any electricity producing resources or controllable (dispatchable) loads connected to a distribution system that can serve electricity demand.

- DERs include, but are not limited to, generation, storage, and controllable load resources, but exclude persistent load reduction
- DERs may operate individually or be aggregated into virtual units
- DERs may connect directly to the distribution system or be integrated into a load

Source: IESO. *Grid-LDC Coordination and Interoperability Initiatives*. September 26, 2017. <http://www.ieso.ca/-/media/files/ieso/document-library/tp/2017/iesotp-20170926-6-grid-ldc-distributed-energy-resources-presentation.pdf?la=en&hash=50850B963ECB5B17141A7BB7F740444DE777F3EF>

Figure 8. Contracted and Installed DER in Ontario as of February 2017 (MW)



Source: IESO. Grid-LDC Coordination and Interoperability Initiatives. September 26, 2017.

[33] Stevens-Adams, Susan Marie, Cole, Kerstan Suzanne, Haass, Michael Joseph, Jeffers, Robert Fredric, Warrender, Christina E., Burnham, Laurie, and Forsythe, James C. *Situation awareness and automation in the electric grid control room*. United States: N. p., 2015. Web.

In Ontario, the growth of DER has been significant – as of 2017, there is 4,169 MW of contracted and installed DER capacity,[34] which is broken down in Figure 8. This includes over 2,000 MW of solar and 600 MW of wind connected to the distribution system. Solar and wind DER capacity is expected to grow to a total of over 3,000 MW by the early 2020s, and 34 MW of storage is also expected.[35] Between 2009 and 2016, Toronto Hydro has enabled approximately 81.9 MW of renewable generation, or over 1,572 interconnections.[36] Toronto's 2009 Sustainable Energy Strategy calls for an increase of 550 MW of renewable generation,[37] which is estimated to result in an additional 9,000 interconnections.[38] In the 2017 Long Term Energy Plan ("LTEP"), the Government of Ontario also refers to the future growth of DERs, including energy storage, microgrids, electric vehicles, in addition to renewable generation.[39] Although the 2017 LTEP does not explicitly state procurement targets, it has led to the development of the IESO's Renewable Distributed Generation Integration ("RDGI") Fund which will fund DER and smart-grid integration demonstration projects.[40]

The IESO has recognized impacts of DER to distributors and the broader bulk electric system. In 2017 it convened the Grid-LDC Inter-Operability Standing Committee, with the objectives of discussing issues and opportunities to coordinate management of the system.[41] Parties have discussed DER integration challenges, issues in forecasting, and data availability and sharing, with the goal of initiating pilot projects enabling greater coordination between LDCs and the IESO.[42]

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[34] IESO. *Grid-LDC Coordination and Interoperability Initiatives*. September 26, 2017. <http://www.ieso.ca/-/media/files/ieso/document-library/tp/2017/iesotp-20170926-6-grid-ldc-distributed-energy-resources-presentation.pdf?la=en&hash=50850B963ECB5B17141A7BB7F740444DE777F3EF>

[35] Ibid.

[36] Toronto Hydro. *2016 Toronto Hydro Environmental Performance Report*. 3/3/2017. <https://www.torontohydro.com/sites/electricsystem/corporateresponsibility/Documents/2016%20Toronto%20Hydro%20Environmental%20Report%20-%202017-03-09.pdf>

[37] City of Toronto. *The Power to Live Green: Toronto's Sustainable Energy Strategy*. October 19, 2009 <https://www.toronto.ca/legdocs/mmis/2009/ex/bgrd/backgroundfile-24583.pdf>

[38] Assuming 2009-2016 average rate of 52 kW per interconnection.

[39] Government of Ontario. *2017 Long-Term Energy Plan: Delivering fairness and choice*. <https://www.ontario.ca/document/2017-long-term-energy-plan>

[40] IESO. *Renewable Distributed Generation Integration (RDGI) Fund*. March 29, 2018. http://www.ieso.ca/-/media/files/ieso/document-library/engage/rdgif/rdgif-20180329-presentation.pdf?la=en

[41] IESO. *Grid-LDC Inter-Operability Standing Committee Terms of Reference*. March 2017. <http://www.ieso.ca/-/media/files/ieso/document-library/standing-committee/gli/gldc-20170327-terms-of-reference.pdf?la=en>

[42] IESO. *Where Do We Go From Here*. Feb 8, 2018. <http://www.ieso.ca/-/media/files/ieso/document-library/standing-committee/gli/gldc-20180208-planning-discussion.pdf?la=en>

4.3 Role of the Distribution System in Reliability

Potential DER impact to bulk system reliability

The bulk electricity system (including the transmission system) in the Continental US and Canada is under the regulatory authority of NERC, which develops and enforces reliability standards. NERC has studied the potential impacts to the bulk system from high levels of DER. NERC noted the operations at wholesale and retail, and transmission and distribution "may be increasingly blurred" and that additional communication and controls infrastructure will be required to handle the operational challenges associated with coordinating distribution and bulk data. Bulk system reliability impacts identified include:

- Non-dispatchable ramping/variability of certain DER
- Response to faults: lack of low voltage ride through, lack of frequency ride-through and coordination with the IEEE 1547 interconnection standards for distributed generation
- Potential system protection considerations
- Under Frequency Load Shedding (UFLS) and Under Voltage Load Shedding (UVLS) disconnecting generation and further reducing frequency and voltage support
- Visibility/controllability of DER
- Coordination of system restoration
- Scheduling/forecasting impacts on base load/cycling generation mix
- Reactive power and voltage control
- Impacts on forecast of apparent load seen by the transmission system

Source: NERC. *Potential Bulk System Reliability Impacts of Distributed Resources*. August 2011. https://www.nerc.com/docs/pc/ivgtf/IVGTF_TF-1-8_Reliability-Impact-Distributed-Resources_Final-Draft_2011.pdf

The growth of DERs has not only shifted the role and responsibilities of distributors and their DCCs, but the distribution system has also taken on greater importance from a bulk system reliability perspective. Traditionally, DCCs and TCCs have been managed separately and there has been minimal coordination between them. This is because the impact of the distribution system on the transmission system was previously assumed to be trivial.[43] This is generally true at lower DER penetration rates, as any impacts can be managed by bulk power system

[43] Li, Zhengshuo. *Distributed Transmission-Distribution Coordinated Energy Management Based on Generalized Master-Slave Splitting Theory*. January 24, 2018. P. 1.

resources.[44] However, a distribution system with significant DER integration can cause issues in transmission line loading, grid voltage, and system frequency,[45] and may change its operating state more often which can impact bulk system reliability.[46]

Utilities, Independent System Operators ("ISOs"), and their respective regulatory authorities also recognize issues caused by DERs. Utilities located within the Electric Reliability Council of Texas ("ERCOT") had interconnected nearly 900 MW of DERs in their service territories (at or below 60 kV) as of 2015. Although these resources do not pose an immediate concern at the transmission level, ERCOT noted several potential reliability issues for the bulk system with higher DER penetration. These include increased error in load forecasting resulting in excessive reliance on regulation and other ancillary services, and uncoordinated system restoration after a load shed event potentially causing large voltage or frequency swings. [47]

In Hawaii, over 10% of Hawaiian Electric's ("HECO") Oahu customers utilize rooftop solar. This high rate of DER penetration has resulted in distribution circuits exceeding 100% of daytime minimum load.[48] HECO implemented restrictions on PV interconnections, citing that additional PV may cause distribution circuits to become dangerous and unreliable due to overvoltage, voltage variations, and islanding issues. Impacts to the transmission system include magnifying transients, accelerating transients, degrading control measures and frequency instability.[49]

The distribution system was found to be one of the contributing factors in the Arizona-Southern California 2011 outages, where an 11-minute system disturbance in the Pacific Southwest caused cascading outages impacting an estimated 2.7 million customers.[50] A Federal Energy Regulatory Commission ("FERC")/ North American Electric Reliability Corporation ("NERC") study on this outage found that "the separate management over [transmission power subsystems] and

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[44] NERC. *Distributed Energy Resources Connection Modeling and Reliability Considerations*. February 2017. <http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf

[45] Ibid.

[46] Li, Zhengshuo. *Distributed Transmission-Distribution Coordinated Energy Management Based on Generalized Master-Slave Splitting Theory*. January 24, 2018. P. 1.

[47] ERCOT. Distributed Energy Resources (DERs) Reliability Impacts and Recommended Changes. March 2017. <http://www.ercot.com/content/wcm/lists/121384/DERs_Reliability_Impacts_FINAL.pdf>

[48] Greentech Media. *How Much Solar Can HECO and Oahu's Grid Really Handle?*. February 2014. <https://www.greentechmedia.com/articles/read/how-much-solar-can-heco-and-oahus-grid-really-handle#gs.1tYivlI>

[49] HECO. *Renewables in Hawaii*. February 6, 2014. < https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_of_Trustees_Presentations-February_6_2014.pdf>

[50] FERC. *Arizona-Southern California Outages on September 8, 2011*. April 2012. <https://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf>

[distribution power subsystems] is insufficient to ensure the operational security of an integrated T-D power system".[51] The NERC Distributed Energy Resources Task Force has also highlighted the importance of data sharing and coordination between distribution and transmission utilities.[52]

These examples, as well as the IESO's Grid-LDC Inter-Operability Standing Committee that was introduced in Section 4.2, show that the operation of the distribution system is becoming more important to bulk system reliability. Bulk system utilities are required by NERC to have backup functionality for their control center. LEI believes that the case for a fully functional backup distribution control center is further supported by the evolving challenges of integrating DERs, and the importance of coordination between the distribution and transmission utility.

[51] Li, Zhengshuo. *Distributed Transmission-Distribution Coordinated Energy Management Based on Generalized Master-Slave Splitting Theory*. January 24, 2018. P. 1.

[52] NERC. *Distributed Energy Resources Connection Modeling and Reliability Considerations*. Feb 2017. <https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf>

5 Economic case analysis for proposed control center

This section summarizes LEI's analysis of an economic case for the proposed dual control center, utilizing the concept of Value of Lost Load ("VoLL"). As demonstrated below, based on estimates of VoLL for Toronto, the proposed dual control center could pay for itself if it could reduce the duration of relatively short high impact outages; examples of the type and duration of such outages are presented in Figure 9. Given that the dual control center provides operational benefits beyond reducing outage durations, this suggests that the investment is economically justified.

Figure 9. Type & duration of outage event equivalent to $40.2 million dual control center cost

Extraordinary outage event	Duration of outage
System-wide outage at average 2016 peak load (3,961 MW)	**20 minutes**
System-wide outage at average 2016 load (2,913 MW)	**28 minutes**
Outage at Windsor Transformer Station (300 MW peak)	**4.5 hours**

Note: This figure summarizes analysis covered in Section 5.2.

Toronto Hydro's service area covers the city of Toronto. With a population of 2.9 million as of July 2017 and a GDP of $193 billion CAD in 2016, [53,54] Toronto is Canada's largest city; it is comparable to entire provinces in terms of population and economic activity. Toronto is also Canada's economic and financial center; the Toronto Stock Exchange ("TSX") is the 9th largest exchange in the world by market capitalization. The city's continued economic functionality is highly dependent on maintaining reliable and resilient grid operations and continuous electricity distribution by Toronto Hydro.

5.1 Value of Lost Load

LEI believes that analysis based on VoLL is an effective method to estimate the economic cost of outages in the city of Toronto. If the cost of outages can be estimated, we can determine whether a particular investment intended to avoid or reduce the duration of such outages is economically worthwhile. VoLL is a socio-economic monetary indicator of the economic consequences of a power outage; it is an indicator of the economic value of sustained electricity supply. As with any investment or consumption choice, if cost is less than value, the optimal investment has been chosen, and resources are available, the investment should be made, or the item consumed. In the case of a utility, if an investment is cost-effective and costs less to achieve than the Value of Lost Load, then the investment should be pursued.

[53] City of Toronto. <https://www.toronto.ca/city-government/data-research-maps/toronto-at-a-glance/>

[54] Toronto city GDP was $168 billion in 2016 measured in 2007 Canadian dollars. This value was inflated to 2016 dollars using inflation rate for Toronto based on StatsCan data [CANSIM Table 326-0021].

What is VoLL?

VoLL—usually measured in dollars per MWh—represents an indication of society's willingness to pay for electricity service (or to avoid curtailment). It is important to recognize that VoLL will vary depending on the type of outage considered. Generally, there are three broad classes of outages that can occur on an electricity grid:

- large-scale, long-term outages in which power is interrupted across a wide area for days or possibly even weeks due to a catastrophic event that causes a system-wide blackout and requires system restart and in some cases, extensive infrastructure repairs;
- more localized outages in which electricity service is unavailable for hours at a time (e.g., as a result of distribution service event or a more localized weather event, such as a tornado or a flood); and
- targeted, short-duration outages of select customers over more discrete timeframes. Long duration, system-wide outages will likely have the highest VoLL as the indirect and induced costs of the outage increase over time (loss of wages, loss of perishable goods, etc.).

Sources: adapted from London Economics International. *Estimating the Value of Lost Load*. June 17th, 2013; Schroder and Kuckshinrichs. *Value of Lost Load: An Efficient Economic Indicator for Power Supply Security? A Literature Review*. December 24th, 2015

Accurately estimating VoLL for a given region and a specific type of outage depends on multiple factors such as the type of customer affected, regional economic conditions and demographics, time and duration of outage, and other specific traits of an outage. It is important to note that VoLL is a region-specific average representing what society as a whole would be willing to pay to avoid an outage; VoLL for specific customers may be higher or lower, and VoLL in specific hours of the day will be higher or lower than the overall reported average. VoLL is not a line item on any individual customer's bill. Instead, it is used for planning purposes to determine at what point society is better off to forgo the use of electricity rather than to make an investment that contributes to additional reliability.

Four key methodologies are used in the estimation of VoLL: (i) macroeconomic analysis; (ii) a survey of stated choices; (iii) a survey of revealed preferences; and (iv) case studies. Macroeconomic analysis and surveying stated choices are more common due to the relative ease of data acquisition.[55]

[55] Surveying revealed preferences is based on actual investments made by customers that install or procure back up power, meaning that a significant portion of customers will not be surveyed. Case studies depend on data obtained from an actual outage, which is difficult to obtain for a significant portion of customers; moreover, the available case studies may not be representative of forthcoming outages, particularly in other jurisdictions.

The macroeconomic approach involves the application of an electricity intensity ratio, such as GDP/kWh, based on the assumption that a power cut would result in a proportionate drop in economic activity. On the other hand, customers' perceived values can be surveyed to ask about the cost that a customer is willing to incur to avoid a power outage—or the amount of money a customer would need to be compensated to accept a power outage. Whether it is willingness to pay or willingness to accept payment, both approaches are used to estimate the direct cost that a customer would incur as a result of an outage.

LEI previously performed for Electric Reliability Council of Texas ("ERCOT") an extensive review of VoLL calculations in different jurisdictions; the studied jurisdictions all used one of the techniques discussed above.[56] LEI's study found that average VoLL for a developed, industrial economy ranges from approximately US$9,000/MWh to US$45,000/MWh, shown in Figure 10 below.[57]

Figure 10. Summary of VoLL by jurisdiction

Region/Market	Methodology	VoLL (CAD)	VoLL (USD)
New Zealand	Survey	$42,503	$41,269
Australia - Victoria	Survey	$45,767	$44,438
Australia	Survey	$47,075	$45,708
Republic of Ireland	Macroeconomic analysis	$9,823 - $16,751	$9,538 - $16,265
US - Northeast	Macroeconomic analysis	$9,561 - $14,341	$9,283 - $13,925

Sources: "Investigation into VOLL in New Zealand", "Assessment of the Value of Customer Reliability (VCR)", "Valuing Reliability in the National Electricity Market", "An Estimate of the Value of Lost Load for Ireland", "The Economic Cost of the Blackout"
Note: USD to CAD conversion rate is 1:1.0299, based on the 2013 average annual exchange rate

IESO utilized the concept of VoLL in its 2015 Central Toronto Integrated Regional Resource Plan. As part of this 25-year plan, IESO conducted a Probabilistic Reliability Assessment to estimate the economic impact of the risk of outages,[58] using a VoLL assumption of CAD$30,000/MWh.[59,60]

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[56] London Economics International. *Estimating the Value of Lost Load*. June 17, 2013. <http://www.ercot.com/content/gridinfo/resource/2015/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf>

[57] Ibid.

[58] IESO. *Central Toronto Area Integrated Regional Resource Plan*. April 28, 2015. <http://www.ieso.ca/-/media/files/ieso/document-library/regional-planning/central-toronto/2015-central-toronto-irrp-report.pdf?la=en>

[59] Independent Electricity System Operator. *Central Toronto Area Integrated Regional Resource Plan – Appendices*. April 28, 2015. <http://www.ieso.ca/-/media/files/ieso/document-library/regional-planning/central-toronto/2015-central-toronto-irrp-report-appendices.pdf?la=en>

[60] This assumption is similar to a 2004 estimate of USD 22,600/MWh which used a survey-based methodology. (Bhavaraju, M., *Variable Resource Requirement*, PJM Stakeholder Meeting. 2004.)

As this assumption falls within LEI's previous study ranges for VoLL, LEI believes a $30,000/MWh is an appropriate VoLL assumption in Toronto Hydro's service territory.

5.2 Economic costs of an extraordinary event

Low-probability events such as terrorist attacks or extraordinary weather events can have significant system impacts – for example, flooding could cause outages and result in the inability to operate Toronto Hydro's primary control center. Note that extraordinary weather events are predicted to become more frequent due to climate change – for example, maximum daily rainfall in Toronto is expected to more than double by 2040, increasing the risk of flooding near critical components.[61] To the extent the primary control center cannot be used at the same time that significant system outages occur, Toronto Hydro's ability to restore service would be significantly delayed – the control center plays a vital role during recovery, including coordinating with field personnel, data analysis, switching, isolation, and facilitation of emergency reactive work.

The most beneficial case would be reducing the duration of a system wide outage. Toronto Hydro supplied a total of 25,588 GWh in 2016, which averages to about 2,913 MWh delivered per hour, and had an average peak load of 3,961 MW.[62] Taking Toronto Hydro's average load per hour of 2,913 MWh, and assuming a VoLL price of $30,000/MWh, the $40.2 million cost for the dual control center represents reducing the duration of a system-wide outage by 28 minutes at VoLL prices.[63] Assuming the outage occurs during an average peak load hour, the representative cost of the control center drops to reducing the duration a system-wide outage by 20 minutes. This shows that it would only take the reduction in duration of a single system-wide outage of these lengths over the lifetime of the control center investment to recover the construction costs.

To put these outage times in context, Toronto Hydro's System Average Interruption Duration Index ("SAIDI") has averaged 0.98 hours from 2012-2016, or 58.8 minutes; Figure 11 presents Toronto Hydro's historical SAIDI from 2012 to 2016.

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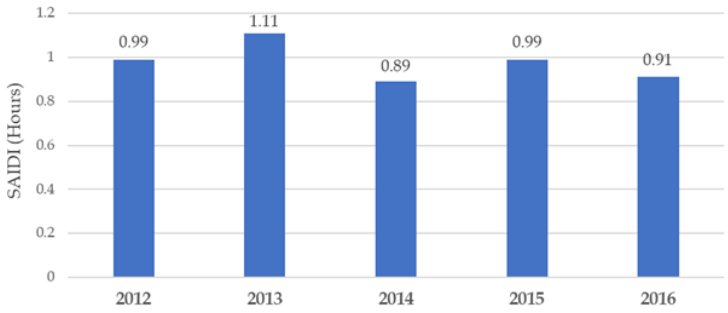
[61] City of Toronto. *TransformTO: Resilience and Adaptation to Extreme Weather.* < *https://www.toronto.ca/wp-content/uploads/2017/10/9801-TransformTO-Resilience-and-Adaption-to-Extreme-Weather-Workbook-Results-Summary-AODA-Compliant.pdf*>

[62] Data taken from the OEB's 2016 Yearbook on Electricity Distributors. Toronto Hydro's "average load per hour" estimated by dividing its 'Total kWh Supplied' from the OEB yearbook by the total number of hours in the year (8,784). Toronto Hydro's 'average peak load' taken from the OEB's yearbook (page 62, line 15). Source: Ontario Energy Board. *2016 Yearbook of Electricity Distributors*. August 17, 2017.

[63] Toronto Hydro delivered a total of 25,588 GWh in 2016, which is an average of about 49 MWh delivered per minute. At a VoLL of $30,000/MWh, each average minute of a Toronto Hydro outage would cost around $1.46 million CAD. Therefore, an outage of 28 minutes would cover the full value of the new control center ($40.2 million CAD).

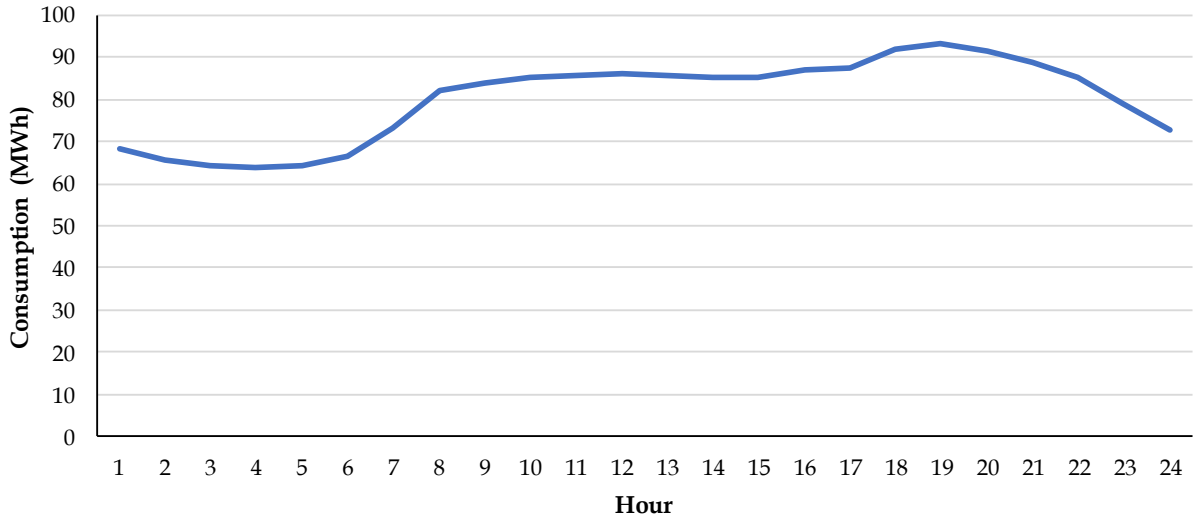
Figure 11. Toronto Hydro historical SAIDI (2012-2016)



Source: Toronto Hydro. *Scorecard - Toronto Hydro-Electric System Limited*. 9/24/2017.

More conservative cases involve the dual control center reducing the impact of losing a Transformer Station ("TS") at the same time as the primary control center, which could happen for example due to flooding which impacts both the control center and a TS. An example of the scale of TS losses occurred on January 15th, 2009, when the failure of the deluge system at the Dufferin TS caused an outage that lasted around 24 hours. Multiplying the $30,000/MWh VoLL assumption discussed previously, by an assumed customer demand profile over the 24-hour period as shown in Figure 12, the economic impact of such an outage is estimated to be $57.6 million, about 43% higher than the cost of the dual control center.

Figure 12. Assumed customer demand in Dufferin TS example

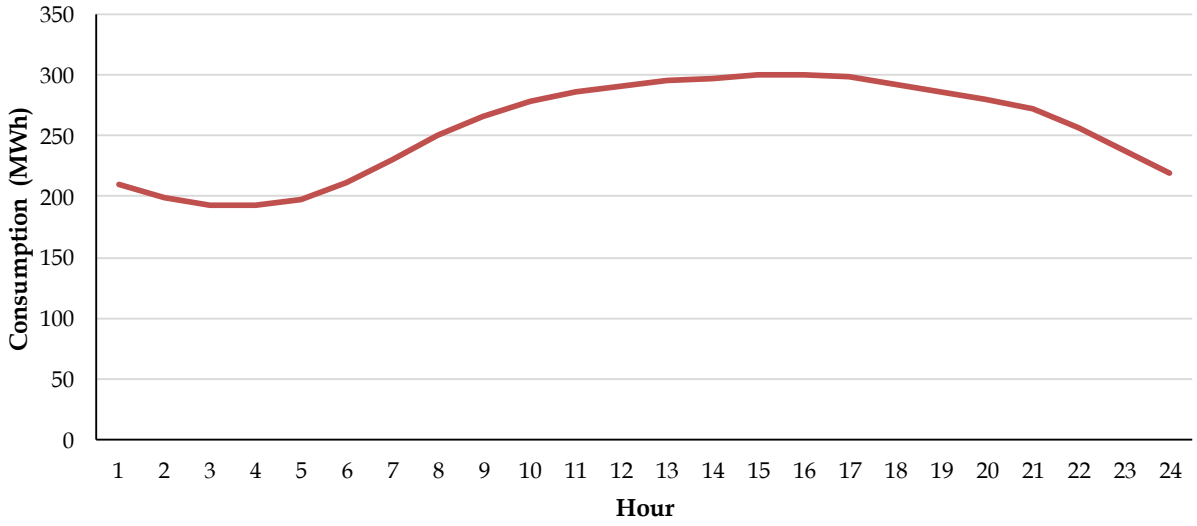


LEI estimated this demand shape in the outage location using the IESO's zonal demand for the Toronto Transmission Zone on January 15th, 2009. The outage to customers with an annual peak load of 113 MW was then fitted to the demand shape of the Toronto Transmission Zone on that day
Source: IESO 2009 zonal demand

Extended outages at larger Transformer Stations, such as the Windsor TS, are also possible and would have even greater effects including outages to Canada's economic and financial center. If a terrorist attack, fire, or flood causes the loss of the primary control center and the entire Windsor

TS, it could cause a loss of 300 MW at peak load. Assuming a VoLL of $30,000/MWh, a 300 MW peak load, and the demand profile shown in Figure 13 below, the $40.2 million cost for the control center represents in this example an outage duration of around 4.5 hours.[64]

Figure 13. Assumed customer demand in Windsor TS example



LEI estimated this demand shape in the outage location using the IESO's zonal demand for the Toronto Transmission Zone on its peak day for 2016, August 12th. The outage to customers with an annual peak load of 300 MW was then fitted to the demand shape of the Toronto Transmission Zone on that day

These examples show the potentially high economic impact of outages. LEI has estimated the loss of load possible during certain extraordinary events and using a VoLL of $30,000/MWh has estimated the economic cost of outages in the city of Toronto. The examples in this section show that relatively short duration outages would end up costing the equivalent of the $40.2 million cost of the dual control center. Therefore, if the dual control center could reduce the duration of potential outages or allow for a fully functional alternative in the event that the main control center needs to be evacuated, the avoided outage effects mean that the dual control center could essentially pay for itself.

[64] Duration reflects outage occurring at the highest demand hours (hours 13-17).

6 Concluding remarks

LEI believes there is a strong case to support a dual distribution control center for Toronto Hydro, based on the key points identified below:

- research in Section 3 shows a precedent for North American distribution utilities to build new fully functional backup distribution control centers to help alleviate reliability and resiliency concerns;

- observed construction costs for fully functional BUCCs are similar to those proposed by Toronto Hydro—see Figure 3;

- the importance of the load served by Toronto Hydro compares favourably to these examples;

- many of the justifications presented by other North American distribution utilities to add or enhance backup operations are equally applicable to Toronto Hydro—see Figure 4;

- an increase in adverse weather events, particularly maximum daily rainfall and flooding risks, further justify the need the need for a more capable alternative to the main control center in the case of a prolonged failure;

- the responsibilities of distribution utilities are evolving due to the proliferation of DERs, and with greater responsibility for reliability, alternate control centers will become increasingly necessary as discussed in Section 4; and

- from an economic perspective, the proposed cost of the dual control center can be justified given the significant costs associated with outages in the city of Toronto, and the potential for the dual control center to reduce the duration of high impact outages.

Appendix: List of Works Consulted

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Appendix B - List of Emergency Critical Functions

[redacted]









E8.2 Facilities Management and Security

E8.2.1. Summary

Table 1: Program Overview

2015-2019 Cost ($M): 35.3	**2020-2024 Cost ($M):** 60.4
Segments: Facilities Management and Security	
Trigger Driver: System Maintenance and Capital Investment Support	
Outcomes: Public Policy, Environment, Safety, Financial	

Through the Facilities Management and Security Program (the "Program"), Toronto Hydro will invest in building improvements that are critical to the proper functioning of Toronto Hydro's electricity distribution system. The operation centres covered by the Program include four Toronto Hydro-owned work centres, that have unique footprints and functions, and 207 stations, the majority of which serve a critical role in the distribution of electricity.

The main objective of the Program is to maintain the infrastructure that supports critical operations of Toronto Hydro's distribution system, and to replace assets that are end of life and in poor condition. The Program addresses the following three areas:

1) **Work Centres:** includes repairs and improvements identified in detailed condition assessments of the four work centres located at 500 Commissioners Street, 14 Carlton Street, 71 Rexdale Boulevard and 715 Milner Avenue;
2) **Stations**: includes facilities-related repairs and improvements identified in detailed condition assessments for Toronto Hydro's distribution stations that are in poor condition and past useful life; and
3) **Security Improvements:** covers security enhancements necessary to protect Toronto Hydro's assets, employees and the public with up-to-date security equipment and technologies (i.e. installation of advanced Video Management System ("VMS"), upgraded card-access, and key management equipment). Toronto Hydro also plans to upgrade its Security Operations Centre ("SOC") to new security software standards to provide [redacted]

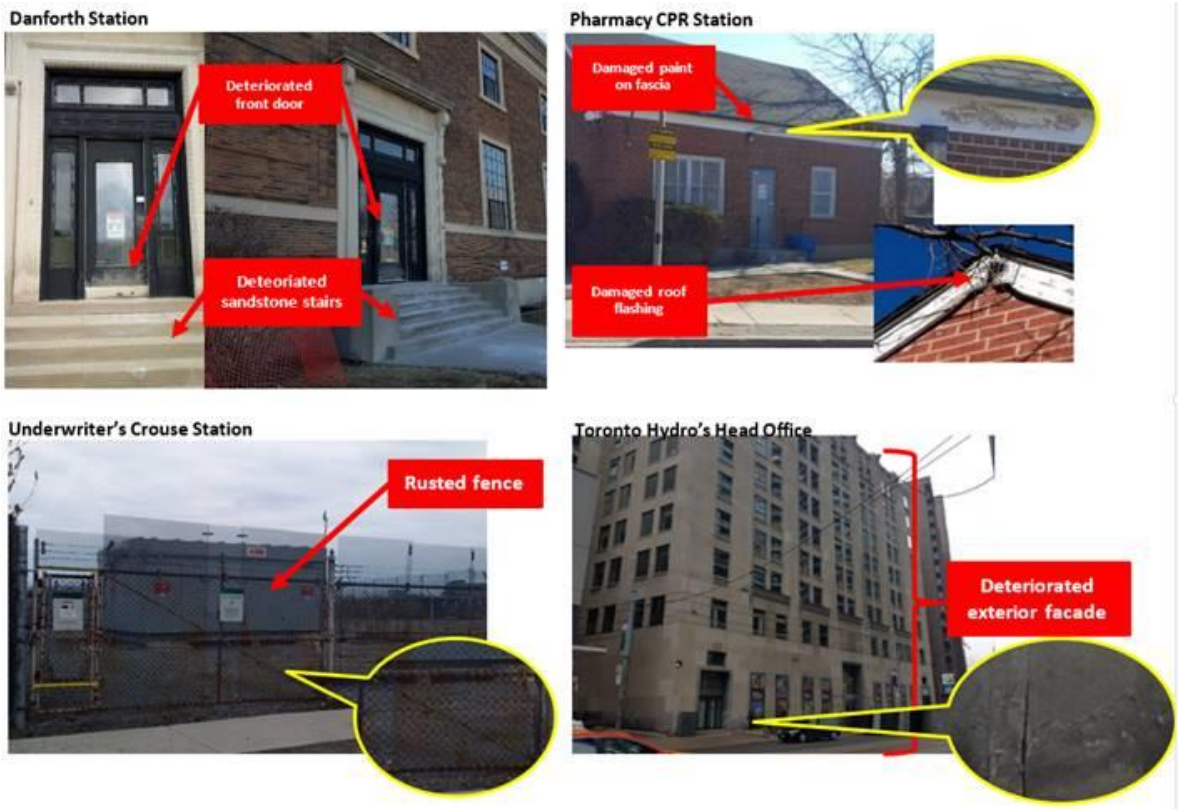

Figure 1: Examples of Toronto Hydro infrastructure that will be addressed through the Program

Maintenance investments that are part of the Program are prioritized to address critical assets that are at end of life and in poor condition. This is expected to lead to safe and reliable distribution of electricity as well as reduced lifecycle asset costs. Toronto Hydro selects candidates for repair and improvement based on detailed building asset condition assessments. The deficiencies identified as part of these assessments are classified into the following five categories:

- **Architectural***:* The volumes and functions of a building such as building foundation, roof, exterior enclosure and envelope;
- **Fire & Life Safety***:* Key components of the overall safety of the building. These ensure that the building is in compliance with the Ontario Building Code, Ontario Fire Code and other applicable regulations;
- **Mechanical & Electrical***:* The interior building systems and power distribution system required for the overall functionality of the building;

- **Civil***:* Core building infrastructure including storm drainage, access ways, walk ways, windows; and
- **Plumbing***:* The pipes, tanks, fittings and other apparatus required for the water supply, hot water heating, and sanitation in a building.

The Program also includes security improvement investments that will support Toronto Hydro's operations and improve physical security infrastructure. These security investments are also part of Toronto Hydro's efforts to continue alignment with the OEB's Cyber Security Framework.[1] This will be achieved by installing modern security equipment and technology, such as advanced access-control equipment and intercom devices at all of Toronto Hydro's buildings and stations. [redacted]

The Program is a continuation of the activities described in Toronto Hydro's 2015-2019 Rate Application.[2] However, in the 2015-2019 Rate Application, the funding requested for the Facilities Management and Security program covered building-related asset replacements for only 11 out of 207 stations. Since 2015, Toronto Hydro has created a robust facilities management system that records assessments and maintenance plans for all assets located in Toronto Hydro's work centres and stations. This repository system identifies the condition of all facilities-related assets (e.g. poor, fair, good) owned by Toronto Hydro, thereby ensuring that the utility efficiently performs the necessary maintenance work where required. As further described below, a number of Toronto Hydro's facilities assets are at end of life and in poor condition and will require extensive maintenance or replacement.

[1] Ontario Cyber Security Framework (December 6, 2017), available at: < https://www.oeb.ca/sites/default/files/Ontario-Cyber-Security-Framework-20171206.pdf>.
[2] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015), Exhibit 2B, Schedule 8.2.

E8.2.2. Program Outcomes

Table 2. Outcomes and Measures Summary

Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: ○ Investing in stations and work centres' building-related improvements that are critical to the proper functioning of Toronto Hydro's electricity distribution; and ○ Mitigating the risk of damage to critical infrastructure housed within the stations (e.g. a sump pump failure could cause flooding and damage electrical equipment).
Public Policy	• Contributes to Toronto Hydro's public policy objectives by ensuring compliance with applicable regulatory and legislative requirements such as the OEB's Cyber Security Framework by: ○ leading the implementation, maintenance and continuous lifecycle management of modern commercial security systems and technology in partnership with security subject matter experts; ○ applying security management policies and procedures across all Toronto Hydro sites; and ○ Investing in physical security measures that helps safeguard private information. This is accomplished through measures that prevent unauthorized physical access to work centres.
Environment	• Contributes to Toronto Hydro's environmental objectives by: ○ Assisting with the achievement of goals outlined in Ontario's Climate Change Action Plan by reducing greenhouse gas emissions. This will be achievable through the use of new HVAC units that will consume less electricity and natural gas; and ○ Ensuring compliance with Ontario's Conservation First Framework by working towards decreasing Toronto Hydro's average electricity consumption across its buildings and work stations. This will be achieved through the use of new lighting that will consume less electricity.
Safety	• Contributes to Toronto Hydro's safety objectives, measured through metrics such as the Total Recordable Injury Frequency ("TRIF") by:

	○ Ensuring compliance with the Ontario Building Code and the Fire Code; ○ Repairing deficiencies which cause trip and fall hazards; ○ Addressing stations-related deficiencies such as absence of secondary exits, non-compliant stairs, and inaccessible doors along pathways; ○ Improving internal lighting conditions and repair external damaged lighting in work areas; and ○ Reducing the risk of unauthorized access into Toronto Hydro work centres and stations.
Financial	• Contributes to Toronto Hydro's financial objectives as measured by the total cost and efficiency measures by: ○ Utilizing detailed asset condition assessments in order to only replace those assets that are end of life and in poor condition; ○ Undertaking security enhancements at only certain work centres and stations, according to highest level of need and risk; ○ Prioritizing preventative maintenance of end of life assets that are in poor condition to mitigate against costly reactive repairs; ○ Deterring theft and vandalism through the installation of enhanced security systems; ○ Reducing utility costs at Toronto Hydro's work centres via the use of energy efficient HVAC and lighting systems; and ○ Eliminating unnecessary costs associated with the need to maintain obsolete fire systems by installing fire alarm systems that can be readily maintained using commercially available parts.

E8.2.3. Program Drivers and Need

Table 3. Program Drivers

Trigger Driver	System Maintenance and Capital Investment Support
Secondary Driver(s)	Safety and Failure Risk

The sections below provide a summary of the deficiencies inherent within work centres and stations, and the proposed work program for remediating those deficiencies.

E8.2.3.1 Aging and Deteriorating Assets

In 2016, Toronto Hydro conducted a thorough review of all assets and building systems located within all of its work centres and distribution stations. The objective of this review was to identify the infrastructure that was at greatest risk of requiring substantial repairs or replacement within the next ten years. The reviews are updated annually, based on field observations and capital work completed in the fiscal year. The assessments indicated that a number of critical building assets within Toronto Hydro's work centres and stations (e.g. foundation walls, sump pumps, roofs, fire alarm systems etc.) are in poor condition, obsolete or require substantial investments to maintain. Failure of these critical assets could have an adverse impact on the reliability of Toronto Hydro's system, as well as the safety of employees and the public. It also affects the ability to effectively respond to power interruptions or emergency situations.

Toronto Hydro used the methodology formulated in the Facilities Asset Management Strategy (the "Strategy", filed at Exhibit 2A, Section D5) to form the basis for its annual assessments. The Strategy was developed by Toronto Hydro on the basis of industry standards and knowledge sharing with subject matter experts, consultants, and service providers. Based on the Strategy, assets that receive a poor condition rating were to be addressed within one to five years. Assets that received a fair condition rating were to be closely monitored and/or maintained under a preventative maintenance program.[3] Finally, assets with a good condition rating did not require any repairs within the next one to ten years. Figure 2, below, illustrates the number of work centres and stations in need of some form of repair or remediation, both historical and forecast. A trend illustrating increasing stations-

[3] Preventive maintenance is performed under Facilities Management. For more information, refer to Exhibit 4A, Tab 2, Schedule 12.

related work to address building infrastructure (for instance, a damaged roof) that houses critical distribution equipment can be observed.

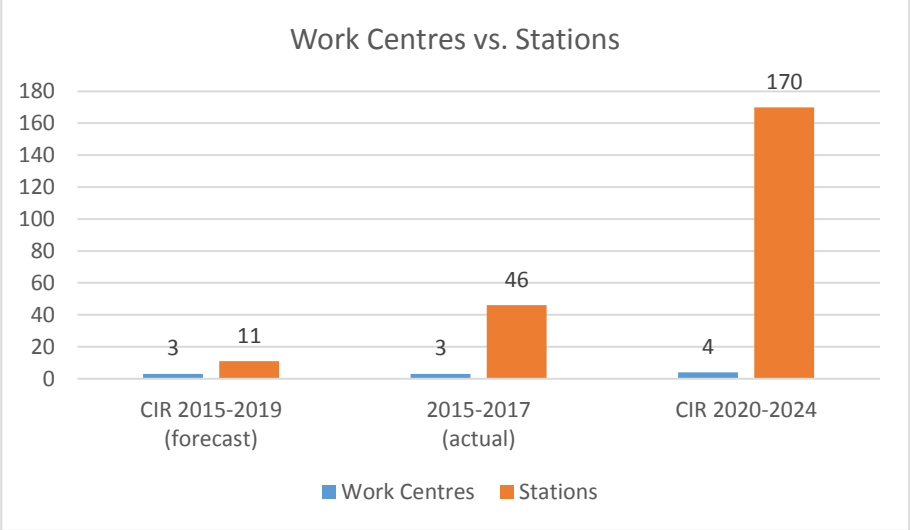

Figure 2: Forecast and Actual Program Work Volumes

Projects that are expected to be undertaken as part of the Program during the 2020-2024 plan period, along with their costs and high-level rationale are provided in Table 4, below.

Table 4: List of Program Projects Expected to be completed over the 2020-2024 Plan Period

Project Category	Cost ($M)	Rationale
Architectural repairs and remediation at work centres and stations (e.g. Trades Training Area upgrades, structural repairs, repair, or replacement of stations building envelope, etc.)	24.4	Addresses safety issues and prevents structural damage.
Fire and Life Safety (e.g. stations fire alarm system upgrades, signage and emergency lighting, etc.)	10.5	Replaces obsolete fire alarm systems and addresses safety and compliance issues.
Mechanical and Electrical (e.g. HVAC system replacement, supplementing cooling system, upgrading and replacement of lighting, sump pump replacement, etc.)	5.1	Addresses assets in poor condition, equipment overloading and capacity issues, safety concerns, and compliance with mandated requirements.

Project Category	Cost ($M)	Rationale
Civil (e.g. exterior access ways and walkways, including pavement, driveways, and parking spaces, etc.)	4.5	Addresses safety-related concerns.
Plumbing (e.g. plumbing fixtures, hot water tanks, etc.)	1.3	Addresses assets in poor condition.
Security Improvements (e.g. access control upgrades, video management system, cameras, etc.)	14.6	Addresses assets in poor condition, safety, and security concerns.

1. Architectural

Architectural systems refer to the functions of a building. Within work centres and stations, Toronto Hydro plans to address issues related to the foundation and building envelope (e.g. brick masonry walls, windows and roofs) and interior finishes (e.g. carpets, walls, ceiling tiles, baseboards, office furniture, office cubicles etc.). Examples of repair work to be undertaken under this category include the renovation of the Trades Training Area, superstructure and concrete/masonry repairs at 500 Commissioners and architectural repairs and remediation work at distribution stations.

a. Renovating the Trades Training Area at 500 Commissioners Work Centre

The Trades Training area at 500 Commissioners will be renovated to accommodate increased class sizes and to permanently remove the slip-trip-and-fall hazards, as demonstrated in Figure 3 (left picture), below. Currently, Trades Training classes are over-crowded due to the size and design of the current training area. This issue is likely to be exacerbated in the next few years due to the increase in Trades recruitment resulting from retirements.[4] In addition, the audio visual equipment is inadequate and non-functional as the wiring is breached behind the training room walls and training time is lost, reducing productivity, due to attempts to revive this equipment or to bring in the portable projectors/learning aids to continue the training.

b. Superstructure and Concrete/Masonry Repairs at 500 Commissioners Work Centre

Superstructure and concrete/masonry repairs at 500 Commissioners work centre are required for improved safety since there is extensive corrosion in and around its welded joints (see Figure 3 – right picture). The work centre at 500 Commissioners is almost 25 years old. As the building gets

[4] See Exhibit 4A, Tab 4, for a discussion of Toronto Hydro's staffing and recruitment efforts

older, corrosion affects the integrity of the structure which could lead to permanent and irreparable damage.



Figure 3: Tripping Hazard caused by AV Equipment in Trades Training Area (Left) and Rusted Loading Dock Super Structure at 500 Commissioners, Architectural Repairs and Remediation at Distribution Stations (Right)

In 2017, a third party conducted a review of five Toronto Hydro transformer stations (the "Stations Review").[5] The five stations were selected as being representative of Toronto Hydro's other stations, based on size and complexity. The result of the Stations Review revealed that remediation work was required at all five stations to bring them up to the standards mandated by the 2012 Ontario Building Code ("OBC") and the Ontario Fire Code ("OFC"). For instance, deficiencies that were noted include exits signs not being well-defined, stairs non-compliant with safety standards, and inaccessible doors along pathways that pose tripping hazards. The Stations Review concluded that remedial work should be undertaken in order to remediate safety hazards for employees and comply with the OBC and OFC.

Apart from the five stations assessed by the Stations Review, the condition assessments conducted by Toronto Hydro found that a number of other stations also require repair or replacement of their building envelope (e.g. roof, windows, masonry walls, and doors) in order to address risks of water and pest infiltration and structural damage from external elements, all of which could impact the distribution equipment located within. For example, Figure 4, below, illustrates a damaged wall at Etobicoke Neilson Drive Station, which is located directly adjacent to critical distribution grid equipment. If the wall is not repaired, water infiltration will accelerate the corrosion of the distribution grid equipment. Delaying some repairs or replacements may lead to higher operational

[5] Review conducted on Toronto Hydro's Flemingdon, Junction, Allenby, Terauley, and Mountbatten stations.

costs as frequent, repetitive patch-up work may be required to prevent failure of distribution equipment.



Figure 4: Damaged Wall at Etobicoke Neilson Drive Station

2. Fire & Life Safety

Currently, there are 20 stations with Cerberus Pyrotronics – System 3 fire alarm panels (Figure 5), installed in the early 1990s. These fire panels need to be replaced prior to failure as parts for this system are obsolete and difficult to obtain, which may result in increased wait times and additional repair costs. For instance, in May 2016, the power supply to the fire panel located at Wiltshire Station required replacement and took over a week to complete due to the lack of requisite parts. This resulted in additional costs stemming from required personnel keeping watch for fire hazards until repairs could be completed. This additional expense was more than the total cost for parts and labour combined, expenses which could have been avoided through a proactive, scheduled replacement of these outdated fire panels. To address these concerns, five of the 20 Cerberus Pyrotronics – System 3 fire panels are planned to be replaced as part of a planned replacement program during the 2020-2024 period, and their parts will be retained to be used for reactive repairs pending replacement of the 15 remaining panels as part of work programs for future years.



Figure 5: Cerberus Pyrotronics - Fire Panel at Carlaw Station

3. Mechanical and Electrical

Mechanical and electrical assets include Heating, Ventilation and Air Conditioning ("HVAC") systems, elevators, site lighting, electrical panels, building automation system, and power distribution systems in Toronto Hydro's buildings.

The proposed mechanical and electrical work includes replacing the HVAC systems at 500 Commissioners work centre, supplementing the computer room with air conditioners at 14 Carlton, upgrading the lighting at 500 Commissioners, and replacing lighting and sump pumps at certain stations.

a. Replacement of HVAC Systems at 500 Commissioners

Toronto Hydro will replace the original HVAC systems, installed in 1996, on the north side of Building B at 500 Commissioners that are past their useful life and in poor condition (see Figure 6, below). These HVAC systems frequently break down and consume an excessive amount of energy. Failure of building assets such as HVAC systems jeopardizes the functionality of vital operations due to critical equipment not being maintained at required temperatures. Furthermore, the new HVAC systems are much more efficient in regards to electricity consumption. Previously, Toronto Hydro replaced an HVAC system on the south side of the building and, as a result, electricity consumption dropped by 60 percent. Since the original HVAC systems on the north side of the building are past their useful life and in poor condition, they would need major repairs in the future.



Figure 6: Rusted HVAC units at 500 Commissioners

b. Supplementing Air Conditioners at 14 Carlton

The Computer Room Air Conditioners ("CRAC") at 14 Carlton's Data Centre require supplementation due to an increase in Data Centre equipment over the last five years. On extremely hot summer days, these CRAC units are showing signs of overloading and lack of capacity.

c. Upgrading the Lighting at 500 Commissioners

The interior lighting at 500 Commissioners must be upgraded in order to meet the requirements of the OBC, and damaged exterior lighting fixtures at the 500 Commissioners work centre need to be replaced as they pose a risk of falling on pedestrians and fleet vehicles (see Figure 7, below).



Figure 7: Blown yard light hanging by an electrical wire

In 2017, a third party conducted a review of the lighting at the 500 Commissioners work centre. The review concluded that the lighting in most of the covered parking areas, the warehouse and fleet garage does not meet the requirements set out in the OBC, as illustrated in Table 5 below, and therefore must be upgraded or replaced.

Table 5: OBC Lighting Requirements and Current Lighting Levels at 500 Commissioners

Location of Lighting at 500 Commissioners	Existing Lighting Levels	OBC-Required Lighting Levels
Building A - Warehouse	193 Lux	300 Lux
Building D - Fleet Garage	230 Lux	300 Lux
Building C-Lower Level Parking	37.4 Lux	50 Lux

d. Lighting Replacement at Stations

In addition to the work centres-related mechanical and electrical repairs, damaged or rusted lighting will also need to be replaced at various stations. Stations' lighting poses safety (i.e. trip-and-fall) hazards due to inadequate lighting levels and security concerns (e.g. trespassing, vandalism, and graffiti). Inadequate or damaged lighting as demonstrated in Figure 8, below, also attracts wildlife, which can lead to pest infestation and damage to distribution grid equipment.



Figure 8: Damaged Exterior Light at Etobicoke Hartsdale Station

e. Sump Pump Replacement at Six Stations

In 2017, a third party completed an assessment of the existing water infiltration and sump pump systems at various Toronto Hydro stations (the "Sump Pump Review"). The Sump Pump Review

concluded that 15 sump pumps will need to be replaced at six stations. In addition, the Sump Pump Review also identified that several of the existing sump-pumps are of a residential-grade and not suitable for commercial use. Failure of these non-commercial grade/poor condition sump pump systems (see Figure 9 – left, below) could lead to station flooding, resulting in significant reactive repair costs and power outages for thousands of customers. For instance, in January 2018, Dupont Station was flooded due to a residential-duty sump pump failure (see Figure 9 - right, below). The sump pump was similar to the ones reviewed as part of the Sump Pump Review, and the pump has since been replaced with a commercial-duty sump pump. Toronto Hydro plans to take a proactive approach to replacing the remaining at-risk residential grade sump pumps to avoid damage to the station or grid distribution assets located within the stations.



Figure 9: Heavily Corroded Sump Pump at Toronto Main Station (Left) and Dupont Station Flood due to Sump Pump Failure in January 2018

4. Civil

Civil work refers to exterior access ways and walkways, including pavement, driveways, and parking spaces. Many surfaces at both work centres and stations are in poor condition and in urgent need of repair to prevent tripping hazards (see examples in Figure 10).

Examples of the major work proposed under this category include asphalt/concrete pavement and driveway repairs at more than 20 distribution stations, truck parking garage ramp repairs, and fleet vehicle parking repaving at the 500 Commissioners work centre.




Figure 10: Damaged Pavement at Junction Station (Left) and Damaged Concrete at 500 Commissioners Gate Entrance (Right)

5. Plumbing

Plumbing assets include fixtures, showers, drinking water units, and water heaters. Some of the major proposed work in this category includes replacement of corroded or damaged water heaters at ten stations that have both surpassed their useful life and are in poor condition. Any further delays on replacement may result in leakage or asset damage given their close proximity to grid distribution assets. In addition, the plumbing fixtures in Buildings A and D at 500 Commissioners require replacement as they are past their useful life, in poor condition, frequently break-down and consume high volumes of water.

E8.2.3.2 Security Improvements

This section sets out the work to be undertaken to improve the physical security infrastructure at Toronto Hydro.

1. Security Improvements

With extensive focus on the Smart Grid across Ontario, information technology ("IT") infrastructure is becoming increasingly critical in grid distribution equipment. Toronto Hydro's stations contain Smart Grid/Supervisor Control and Data Acquisition ("SCADA") assets in areas with the highest population density in Canada, posing heightened security risks of hacker infiltration. Utility companies are targets for security breaches because of the critical role they play in the operation of essential services (e.g. hospitals, public transit, and traffic management) and the vast databases of confidential customer information they possess.

In 2016, the OEB conducted a review of the state of cybersecurity of the (non-bulk) electrical grid and associated business systems.[6] As a result of this review, the OEB issued the Cyber Security Framework (the "Framework") which is designed to allow licensed utilities, such as Toronto Hydro to assess their inherent cyber security risk, define their benchmark objectives, and measure progress towards those objectives and report back to the OEB. To ensure mandatory compliance with the Framework, on March 15, 2018, the OEB amended its Distribution System Code to require all licensed distributors to report on the status of cyber security readiness.

To ensure continued compliance with the Framework, Toronto Hydro requires investments in physical security infrastructure. The Framework recommends a number of controls to be in place to limit access to assets and associated facilities to authorized users only.[7] Toronto Hydro plans to implement the Framework controls through a two-pronged approach: (1) [redacted] (2) [redacted] Therefore, the security improvement work performed under the Program ensures the protection of Toronto Hydro assets (i.e. employees, information, equipment, business operations and building infrastructure) through the implementation and administration of new and enhanced security standards, including:

- the implementation, maintenance and continuous lifecycle management of modern commercial security systems and technology as per standards developed by Toronto Hydro and security subject matter experts;
- the proactive monitoring and control of these systems and technology; and
- the systematic and phased application of security management policies and procedures across all Toronto Hydro sites. In the 2020-2024 plan period, two work centres, and ten stations will receive the [redacted]

[6] EB-2016-0032, OEB Letter, "Protecting Privacy of Personal Information and the Reliable Operation of the Smart Grid in Ontario (February 11, 2016), available at: < https://www.oeb.ca/industry/policy-initiatives-and-consultations/protecting-privacy-personal-information-and-reliable>.
[7] Supra note 6, Appendix E, page 5.

a. CCURE System Expansion

[redacted]

b. Video Management System

[redacted]

c. Automatic Key Management System

[redacted]

[8] Certain employees are provided with secondary roles in the case of emergencies. These roles dictate access-levels.
[9] The sites proposed to receive the Key Management System were chosen to provide the best control of issued keys for station assets.

[redacted]

d. Enhancement of the Security Operations Centre

[redacted]

These improvements will help Toronto Hydro achieve the physical security and continuous monitoring controls identified in the Framework, thereby reducing the risk of an unauthorized user gaining access to physical IT equipment and secure sites.[10] For instance, the enhanced SOC will contain automatic alarm capabilities for physical security alerts in response to unidentified or unverifiable access to information technology assets, e.g. server rooms. In addition, the SOC enhancement will allow for monitoring of the Building Automation System ("BAS") to ensure that critical system alarms will be immediately communicated to the relevant employees. For instance, a high sump pit level due to sump pump failure is a critical notice and would be communicated

[10] Supra note 6, Appendix E, page 18.

immediately to the appropriate stakeholders so that it can be addressed in a prompt and efficient manner.

E8.2.4. Expenditure Plan

The historical and forecast program costs for the Program are set out in Table 6, below. The work performed under the work centres and stations categories will be completed based on priority and balancing of the workload over the 2020-2024 plan period. Specifically, for the work centre category, projects will take place primarily in 2020 and 2021 as these projects involve like-for-like replacements which do not require construction permits. For the stations category, approvals and permits will be obtained in 2020 and 2021 for projects that will take place in 2022, 2023 and 2024. These will typically be larger projects requiring extensive design, permits, and stakeholder approvals (e.g. Hydro One, City of Toronto, TTC, etc.). Overall, the largest expenditure in both the work centres and stations categories will be in the areas of Architectural and Fire & Life Safety, which accounts for 75 percent of the required capital expenditure, primarily due to the fact that more than 80 percent of Toronto Hydro's stations are over 40 years old and require significant Architectural and Fire & Life Safety renovations to maintain functional operation.

2021 will be the highest spending year in the security improvements category to ensure that the outlined security concerns are addressed as quickly as possible while also allowing for time in 2020 to plan for the required work.

Table 6. Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Work Centres	11.4	5.3	4.2	0.7	1.1	7.2	2.9	0.2	1.1	1.7
Stations	3.2	2.8	1.6	1.1	1.1	2.9	3.8	8.3	9.0	8.7
Security Improvements	0.7	0.9	0.5	0.4	0.4	1.5	5.1	3.6	2.2	2.2
Total	**15.3**	**9.0**	**6.3**	**2.2**	**2.6**	**11.6**	**11.8**	**12.1**	**12.3**	**12.6**

E8.2.4.1 Work Centre and Stations

Starting in 2016, work centres and stations building assets were assessed and received a condition rating of poor, fair or good. Assets that received a poor condition rating will be addressed within the 2020-2024 plan period. Assets in fair condition will be closely monitored and/or maintained under a preventative maintenance program. Finally, assets in good condition are not planned for any repairs

in the 2020-2024 period. Toronto Hydro will only replace assets that are past their useful life and are in poor condition. This means that assets that are past their useful life but are in fair or good condition or are "run-to-fail" will defer $11.3 million in asset lifecycle costs.

The assets categorized as being in poor condition are assigned a priority rating based on the Facilities Asset Management Strategy.[11] The priority ratings are used to ensure that the Program is targeted on the most critical assets first:

- **Priority Rating 1:** Critical life safety assets (e.g. Fire & Life Safety systems, sump pumps).
- **Priority Rating 2:** Assets that provide building functionality (e.g. doors, windows, roofs).
- **Priority Rating 3:** Assets that are run-to-fail and/or low impact (e.g. baseboard heaters). These assets are to be replaced only when they fail even if they are past their useful life and are readily available for replacement as needed.
- **Priority Rating 4:** Assets that provide cost effective upgrades to existing systems and should be planned if there is an existing project going on in the area.

E8.2.4.2 Security Improvements

There is an increase in spending over the 2020-2024 plan period as compared with the 2015-2019 plan period. [redacted]

Security improvements can be broken down into four key areas: access control (including intercom and duress stations), Security Operations Centre, physical security improvements, and CCTV improvements. A breakdown of the required capital spending in each of these areas can be viewed in Figure 11, below. The majority of the security improvements funding is planned for 2021 since that is the primary year of the access-control conversion (i.e. ISL to CCURE). The remaining items will be addressed throughout the plan period.

[11] See Exhibit 2B, Section D5 for more details

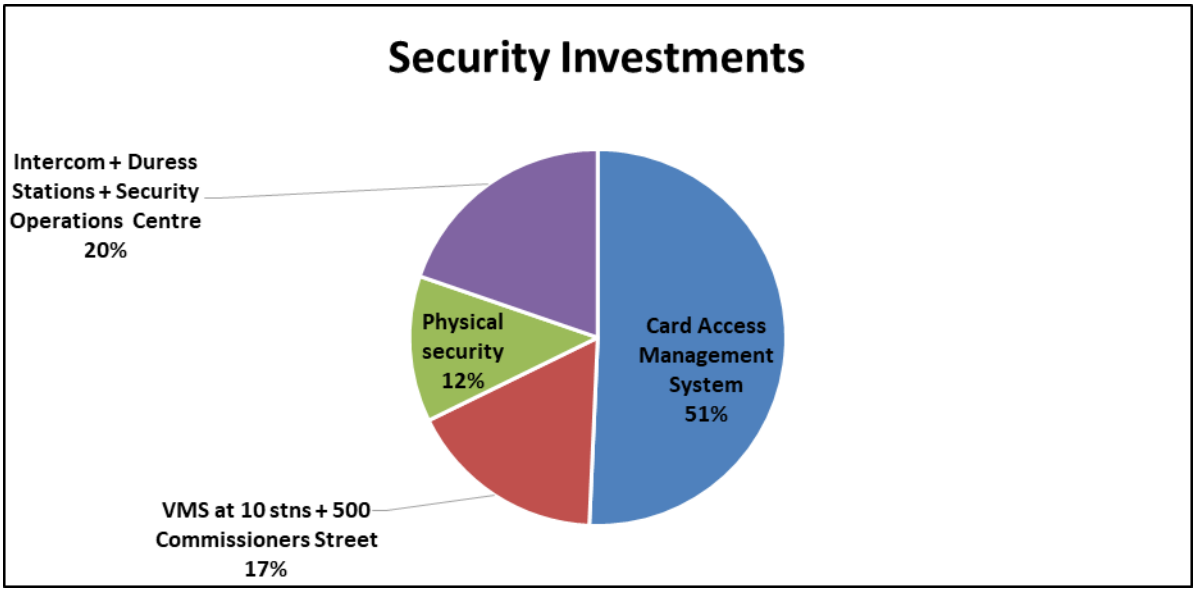

Figure 11: Security Related Investments

The Program's work sequencing will be driven by the following factors, in order of priority:

1) **Health & Safety**: Upon review, should a project be deemed a risk to the health or safety of employees or customers, it will become priority.
2) **Protecting Critical Functions and Assets:** Toronto Hydro's stations house electrical distribution equipment, which are critical to distributing electricity to customers. Toronto Hydro's work centres are critical to maintaining business continuity. Critical business functions housed within Toronto Hydro-owned facilities include Customer Care Call Centre, Control Centre, and IT Infrastructure (Data Centres).
3) **Lifecycle Costs:** Assets which incur high-operational costs will be replaced so long as their replacement is expected to provide operational savings in future years. For example, HVAC components in fair condition which breakdown frequently incur high-operational inspection and repair costs. Replacement would be considered in these cases.
4) **Cost-efficiency and Grid Management:** Remediation work in stations frequently require the assets to be fully de-energized in order for employees to work safely. Therefore, projects in this Program will be planned and executed alongside capital projects in the stations in order to minimize the number of outage requests at a station and its overall downtime.
5) **Planning and Risk Assessments**: Some of the work within the Program involves design and construction around high-voltage equipment in buildings with heritage preservation status.

Due to these complexities, these projects need to be planned accordingly, with risks identified and mitigation plans created.

E8.2.5. Options Analysis / Business Case Evaluation ("BCE")

E8.2.5.1 Option 1: Run-to-Fail Approach

Under the run-to-fail approach, Toronto Hydro would delay necessary investments in work centres and stations and would perform replacements and repairs on a reactive basis, once an asset fails. Since the majority of assets that are end of life and in poor condition are categorized as Priority 1 (critical) and Priority 2 (building functionality), this approach would significantly impact Toronto Hydro's operations should they fail. Furthermore, the OEB's Cyber Security Framework stresses the importance of physical security to support the objectives of cyber security for utilities. Some of the effects of instituting a run-to-fail strategy include:

- **Business Disruptions:** Fire alarm panels, large HVAC units and heritage station assets can only be addressed through planned replacements as they involve engineered design, analysis, long-lead material purchases, and/or custom built materials (i.e. in support of heritage preservation). This strategy will lead to business disruption as facilities-related assets support the work environment of Toronto Hydro employees and are essential to business continuity (i.e. Control Centre, Data Centre, and Grid Response). For instance, an unexpected asset failure in the main Control Centre could halt the ability of crews to work safely.

  Further, failure to improve and enhance the current security standard could increase the risk of the following: [redacted]

- **Failure of Toronto Hydro Grid Distribution Assets:** Failure of Priority 2 assets (i.e. building functionality such as roofs and windows) could directly affect grid reliability. For instance, proactively maintaining the integrity of station roof surfaces protects grid distribution equipment from water infiltration. Distribution equipment is highly susceptible to water damage and can lead to outages if compromised, directly affecting Toronto Hydro

customers. The top priority for Toronto Hydro's Key Account customers, as per the 2017 Customer Engagement Survey, is reliable power supply.

- **Asset Lifecycle Management:** Without proactive replacement, Priority 1 and 2 assets that are in poor condition will fail unexpectedly. The cost associated with unexpected failures and reactive repairs often outweighs the cost of proactive repairs due to the fact that reactive repairs generally require additional scope and premium time. For example, damage to Annabelle Station's shingles was not addressed proactively or in a timely manner and led to the necessity for mold abatement, which on its own cost 1.8 times more than the cost to replace the roof shingles.

Figure 12, below, shows the progression of asset condition if no action is taken in the 2020-2024 plan period. As more assets transition from good and fair to poor condition, there is increasing risk that lifecycle management costs will rise as well.

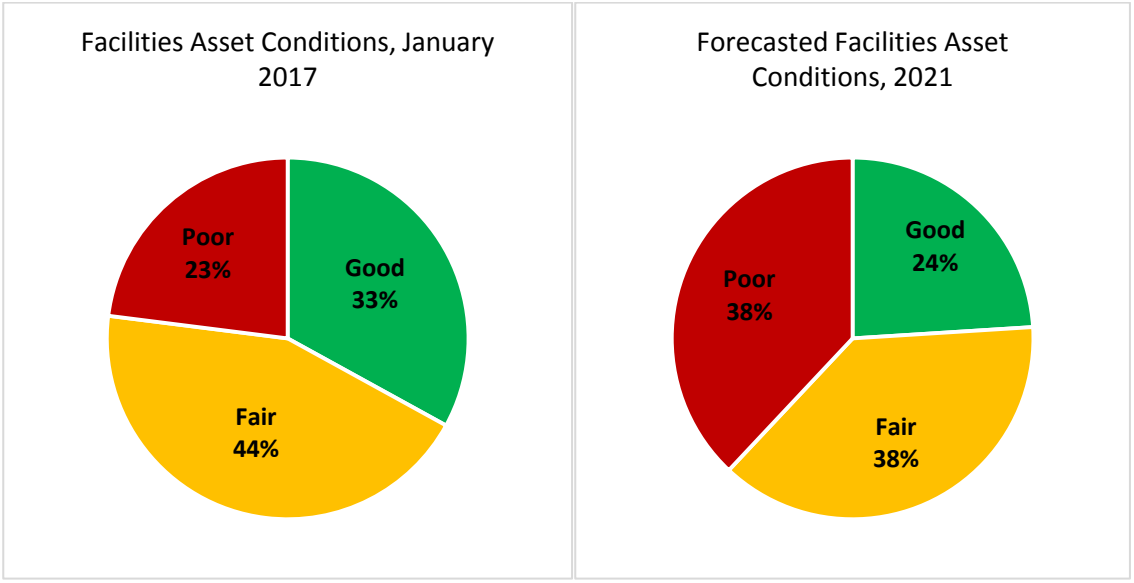

Figure 12: Progression of Asset Conditions under "Run-to-Fail" Approach

- **Safety Hazards:** There are increased safety hazards under this approach due to assets in poor condition and unexpected failure. For example, the Stations Review identified safety gaps directly contradicting requirements under the current OBC. For instance, in the event of an emergency, the exit routes are not easily identifiable and may result in entrapment. In addition, water infiltration in stations creates a risk of electrocution hazards to on-site personnel, health and safety considerations with standing water and mould, and

compromises the integrity of the building. Lastly, lighting in various areas at 500 Commissioners is in poor condition and beyond useful life. Some areas do not provide minimum lighting levels required under the OBC.

[redacted]

E8.2.5.2 Option 2 (Selected Option): Preventative Maintenance and Planned Replacements of End of Life and Poor Condition Assets and Investing in Security Improvements at Certain Toronto Hydro Work Sites

This option will cost Toronto Hydro approximately $60.4 million. The benefits of implementing this option include:

- **Utilizing Capital Funds for Priority Assets:** More than 90 percent of capital funds will be spent on addressing Priority 1 (critical) and 2 (building functionality) assets.
- **Minimized Asset Lifecycle Costs:** Assets that have surpassed their useful life, but are in good or fair condition, or are run-to-fail will not be replaced. This strategy will defer $11.3 million in asset lifecycle costs.
- **Legislative Compliance:** Toronto Hydro can maintain compliance with mandated requirements by ensuring that lighting, HVAC, flooring and stairs hazards, etc. and other deficiencies are addressed.
- **Competitive Procurement Pricing:** Planned replacements will help Toronto Hydro by utilizing a competitive bids process, resulting in favorable acquisition costs for goods and services while maintaining quality of work and process integrity.

- **Stakeholder Management:** The planned replacement policy would provide sufficient time to identify and involve all stakeholders to the planned work. This would also include obtaining appropriate approvals and permits for the work involved.
- **Proactive and Responsive Security Monitoring and Control Systems:** By having a proactive approach to security systems, the physical threats to Toronto Hydro's assets can be minimized by having a real-time response to threats as they occur. This would also aid in providing recorded visual evidence.
- **Quick Response to Grid Emergencies:** The capability for emergency activation of access-levels would support automatic-access to predefined areas in work centres or stations. This is expected to result in faster response times and more efficient organizational coordination when addressing grid emergencies.

[redacted]

E8.2.5.3 Option 3: Preventative Maintenance of Assets and Replacements of All End of Life Assets and Investing in Security Improvements at all Toronto Hydro Work Sites

This option considers replacement of all assets that are end of life, irrespective of asset condition as well as replacing Video Management System hardware and software at all stations. This approach also conducts preventative maintenance on all assets, without a regard for asset function or criticality. This option will require approximately $113.5 million in funding.

Some of the main cost drivers under this option include:

- All assets at the end of life will be replaced at a cost of $53 million irrespective of asset condition;
- Emergency exits and lighting will be remediated at all stations and work centres at a cost of $38 million; and
- Security upgrades across all Toronto Hydro properties at a cost of $22.5 million.

Some of the consequences of instituting this approach include:

- **Increased Funding Request:** Funding required to implement this approach is $113.5 million and this will increase costs for ratepayers.
- **Increased Reliability of Assets**: Since all assets will be replaced at their end of life, replacement will improve their reliability and reduce the financial burden of reactive maintenance.
- **Operational Savings**: When assets require reactive maintenance less often, operational spending would decrease.
- **Optimized Working Environments:** Advanced lighting systems across all sites, HVAC retrofits, and renovations would refine controls and offer greater employee comfort.
- **Improved Security Monitoring and Control Systems:** [redacted]

E8.2.5.4 Evaluation of Options

When comparing the different options available to Toronto Hydro, the utility has chosen Option 2 as the prudent and preferred approach since it ensures continued reliability of the grid, reduces overall asset lifecycle costs, and the safety of employees and the public. It also ensures the necessary security infrastructure is in place to continue compliance with the OEB Cyber Security Framework. In addition, reactive repairs of assets under Option 1 is not cost-effective since failure would affect public and employee safety, and Toronto Hydro's business continuity. Option 3, on the other hand, does not have the same flaws and would provide a number of benefits such as decreased operational costs, optimal work environment, and an increase in reliability of assets. However, the significant cost escalation for ratepayers does not make this a viable option.

Option 2 is also the most cost-effective solution that ensures Toronto Hydro continues to maintain the level of security required to safeguard an essential service. The majority of assets planned for replacement in the 2020–2024 plan period are at the end of their useful life and in poor condition. These assets are related to critical systems and building functionality, and therefore utilizing a run-to-fail approach would not be acceptable since these critical assets are design-heavy and require engineered solutions, long lead times, and City permits.

On the other hand, proper project planning and constrained spending (i.e. the proposed approach) over the 2020-2024 plan period is expected to provide many benefits, including:

1) A balanced investment approach to align with resource capacity;
2) Minimization of business interruptions;
3) Optimization of Toronto Hydro Procurement Strategy in order to receive competitive prices for services; and
4) Sufficient time for comprehensive design, permit, and purchasing.

Lastly, applying a restrained approach under Option 2 and utilizing the Facilities Asset Management Strategy to only replace assets that are end of life and in poor condition would be the more cost-effective solution for ratepayers.

E8.2.6. Execution Risks & Mitigation

The Program is vulnerable to several risks that could affect the planning and timing of repairs and replacements. The risks include:

- Delays in obtaining the necessary approvals and permits to begin executing the work programs may delay the start or completion of projects. To mitigate against this risk, Toronto Hydro will utilize subject matter experts to work with the necessary stakeholders in order to obtain approvals and permits in a timely manner. In addition, Toronto Hydro will initiate the process as early as possible to ensure permits are obtained for the project's scheduled execution timing, mitigating delays.
- Legacy environmental conditions (e.g. asbestos or PCBs) might require further testing and analysis, which may affect project budget and execution schedule. To mitigate against this risk, Toronto Hydro will seek subject matter expertise (consultants and/or engineers) for a thorough review of actual field conditions in high-risk locations prior to developing a project plan and incorporate these findings during the procurement process to limit the cost escalation of abatement work through time and material.

E8.3 Fleet and Equipment Services

E8.3.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 19.1	**2020-2024 Cost ($M):** 42.5
Segments: Fleet and Equipment Services	
Trigger Driver: System Maintenance and Capital Investment Support	
Outcomes: Reliability, Environment, Safety, Financial	

The Fleet and Equipment Services program (the "Program") is responsible for the procurement, maintenance, and disposal of vehicles and equipment that are needed to support Toronto Hydro's functional and operational needs. The Program's primary objective is to manage the Program's assets to the lowest overall lifecycle cost, while ensuring asset reliability and employee and public safety. Capital investments within the Program are grouped into two categories: (1) vehicles: which includes, (a) heavy duty vehicles, used as a primary tool to perform distribution work, and to transport operators and equipment; and (b) light duty vehicles, which are fully equipped for employees to inform, manage and monitor distribution work; and (2) vehicle and employee equipment (e.g. forklifts, trailers, telematics systems, boom lifts, protective gear, etc.). The Program and its constituent segments are a continuation of the activities described in the Fleet and Equipment Services program in Toronto Hydro's 2015-2019 Rate Application.[1]

Toronto Hydro relies on its fleet of vehicles to support functional needs and performance requirements associated with executing a complex and dynamic capital and maintenance program. An insufficient or unreliable fleet can negatively impact utility performance, such as reliability and employee productivity. In addition, as vehicle fleets age, they incur higher operating expenses due to increasing levels of reactive repairs. Therefore, the Program ensures that capital investments are made at a level and pace that allow asset maintenance, repair and capital costs to be minimized. An optimally timed vehicle replacement strategy also ensures that the appropriate level of vehicles are available to support system maintenance and capital investment plans.

[1] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015), Exhibit 2B, Schedule 8.1.

To ensure that the vehicles are replaced in a cost-effective manner, Toronto Hydro utilizes the Life Cycle Analysis ("LCA") approach to identify the capital investment candidates for future replacements and bases its decision to replace or dispose of the vehicle on the actual asset condition assessment. The LCA provides empirical justification to identify the best time to replace vehicles in terms of age, mileage or other pertinent factors. As the age of a vehicle increases, ownership costs decline and operating costs increase. As such, the optimal time to replace a vehicle is before the point where the operating costs begin to outweigh the decline in ownership costs. To assist with determining the LCA, Toronto Hydro retained a third party consultant to undertake a comprehensive study of Toronto Hydro on-road vehicle fleet and to provide recommendations regarding the optimal replacement age of the fleet vehicles. Toronto Hydro leverages the analysis to plan its future capital replacements during the 2020-2024 plan period.



Figure 1: Toronto Hydro Fleet

Although the LCA identifies the optimal age for vehicle replacements for the purposes of expenditure planning, Toronto Hydro replaces vehicles according to the results of vehicle condition assessments. Because a replacement cycle varies depending on the vehicle make, model year, equipment design, operating environment or even by how the operator uses the vehicle, some vehicles that are in poor condition or unsafe may require replacement before the criteria is met, and alternatively, some vehicles that exceed the criteria may be in good condition and not warrant replacement. As such, the vehicles forecasted for replacement in accordance with the LCA, also undergo condition

assessments performed as part of the regular vehicle inspections. This forms the basis of Toronto Hydro's vehicle replacement and disposal decision-making.

Prioritization within the Program reflects the importance of the vehicle class to performing core distribution work, the lead time required to procure the asset, cost, and the level of customization required. As such, capital plans are created by first scheduling the heavy duty vehicle replacements in their recommended replacement year, followed by light duty vehicles. Equipment is scheduled on a more ad-hoc basis. It is more economical and efficient to procure vehicles in batches of approximately five to ten units, therefore asset replacements are shuffled between years within a five year plan to assist with balanced spending during the years.

Over the 2020-2024 plan period, Toronto Hydro will focus primarily on the replacement of heavy duty vehicles that are or will be due for replacement. Owing primarily to the fact that heavy duty vehicles are eight to ten times more expensive than light duty vehicles and due to the increase in foreign exchange rates that has led to an escalation in asset price, the requested Program funding over the 2020-2024 plan period is higher than the 2015-2019 period. Nevertheless, Toronto Hydro continues to implement various mitigation measures to minimize the impact of these costs. For instance, Toronto Hydro has taken steps to reduce its overall fleet size from 660 units[2] down to 588, thereby, reducing the operating costs of running a larger fleet.

In addition, the investments in Toronto Hydro vehicle fleet can produce the following benefits:

- Minimization of total vehicle costs;
- Minimization of fleet downtime due to repairs, and a corresponding increase in fleet reliability;
- Increase in vehicle efficiency, i.e. lower fuel consumption and idle reduction;
- Improvements in shop efficiency as less labour will be required to maintain new vehicles and focus can be on older vehicles;
- Reduction in environmental impacts such as reduction in greenhouse gases emitted as well as a reduction in the maintenance fluids used; and
- Increased employee and field safety as newer vehicles are equipped with new safety technology.

[2] I in EB-2014-0116, Toronto Hydro reported a fleet size of 660 units, including cars, pickups, bucket trucks, and other vehicles. See EB-2014-0116 Exhibit 2B, Section E8.1 at page 5.

E8.3.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: ○ Ensuring work crews have the necessary vehicles and equipment to perform distribution work when required; and ○ Ensuring that the fleet is in good running order and the assets are replaced before critical equipment failures arise that necessitate lengthy and costly offsite repairs.
Environment	• Contributes to Toronto Hydro's environmental objectives by aiming to reduce GHG emissions associated with fleet fuel consumption by: ○ Utilizing hybrid and electric vehicles and biofuels where possible; and ○ Implementing anti-idling technology, GPS reporting used to drive changes in driver behaviour, and the use of biofuels.[3]
Safety	• Contributes to Toronto Hydro's safety objectives, measured through metrics such as the Total Recordable Injury Frequency ("TRIF") by helping to ensure employees are working safely with minimal exposure to hazards.
Financial	• Contributes to Toronto Hydro's financial objectives as measured by the total cost and efficiency measures by: ○ Managing fleet and equipment assets to the lowest overall lifecycle cost; and ○ Mitigating fuel expense by aiming to reduce fuel consumption through a combination of utilizing hybrid and electric vehicles; idle-reduction technologies; and adhering to recommended vehicle lifespans.

[3] The use of technology to drive these results is limited by funding and classes of vehicles where the Return on Investment is justifiable.

E8.3.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	System Maintenance and Capital Investment Support
Secondary Driver(s)	Safety, Reliability, Business Operations Efficiency

E8.3.3.1 System Maintenance and Capital Investment Support

The trigger driver for this Program is the need to ensure that Toronto Hydro continues to have access to vehicles that support system maintenance and capital investment activities during the 2020-2024 plan period and beyond. Toronto Hydro requires access to vehicles and equipment that meet current and future functional requirements to transport employees and materials to and from job sites, to perform work onsite, and provide onsite working area and shelter. Toronto Hydro's fleet consists of many types of vehicles that are designed for multiple purposes. On the job-site vehicle uses include, but are not limited to, lifting and positioning material, storing material, preparing material for installation, acting as a planning station and serving as shelter. Fleet vehicles must be available to support these functions in a safe, reliable, and operationally efficient manner.

Heavy duty vehicles are a primary means of transporting equipment for distribution work. Light duty vehicles facilitate the engineering and management functions of distribution work. Associated equipment assets are used to perform lifting and towing, and include operator safety implements, such as network protection relays, rubber gloves, and gas monitors. Over time, these units are subject to wear and tear that impact vehicle safety, reliability, and operational efficiency. In addition, operational needs and requirements change over time in a manner that necessitates certain vehicle and equipment types, technologies and configurations that are not found in the utility's existing fleet.

If the age profile of the fleet surpasses the target age identified in the LCA, reliability of these assets may become compromised, posing risks to the timeliness and reliability of distribution work. When the average age of the fleet exceeds the target age, the vehicle-related parts and services operating costs also begin to increase significantly. It is expected that the vehicle-related operating costs will also continue to escalate as the average age of the fleet increases.

E8.3.3.2 Safety

As vehicles age, there is an increased risk of safety issues such as structural and component failure, and electrical faults, caused by a number of factors, including corrosion. Toronto Hydro vehicles are

continuously used throughout the year and spend the majority of the time outdoors in direct exposure to the weather and external elements. In addition to high levels of humidity throughout the year which can cause corrosion, road salt used on city streets and highways is of particular concern as it can lead to corrosion that damages and weakens the frame of the unit over time. The frame is the main structure of a vehicle to which all running gears are fastened, and supports the entire weight of the vehicle excluding the wheels, suspension, and some steering components. Severe rust to the frame can lead to breaks while under load, e.g. during a lift operation, cable pull, or material loading. Frame weakness can also decrease the ability of the vehicle to withstand crashes, thus jeopardizing the safety of the operators and the general public.

As shown in Figure 2 and Figure 3 below, corrosion can also appear on vehicle body panels, causing them to be weak and brittle. Brittle panels are subject to breaking, leaving sharp edges or presenting a potential fall hazard if the rusting occurs on a step, handle, or vehicle floor.



Figure 2: Corrosion on Cube Van Steps

Corrosion may also occur on components that are critical to the operation of the vehicle, such as transmission and brake lines, that are often not observable between vehicle services. Rust on these components results in weak spots that have the potential to rupture and leak, and/or cause failures while in use. For example, a transmission line rupture could result in a seized transmission. If this

occurs while in motion, the operator is at risk of losing control of the vehicle. Further, brake line leaks can result in brake failure, possibly leading to a loss of control.

Costly transmission replacements are a determining factor in taking a vehicle out of service as the repair costs can exceed the netbook value and market value of the vehicle.



Figure 3: Underbody Corrosion on Bucket Truck

As mentioned above, regular use of the fleet over time can lead to the failure of critical components that are not readily serviceable or observable by maintenance staff. Components such as the hydraulic hoses running through an aerial cannot be directly inspected at service intervals. As the hoses age, they become less flexible and more brittle. Hose failure results in hydraulic fluid leaks to the environment, and could also result in an inability to lower an employee operating a bucket to the ground. Rescuing an employee from an aerial bucket presents a potential risk to the employee in the bucket, other field employees who are assisting with the operation and the public.

Lastly, components designed to protect electrical circuitry can become compromised as a vehicle ages and wear down with regular use, leading to potential electrical failures. The longer a vehicle is in service, the more inevitable this failure becomes. Electrical failures could lead to the disabling of auxiliary safety lighting systems and onboard equipment which are required as field staff perform their distribution functions.

E8.3.3.3 Reliability

Unreliable or unavailable vehicles adversely impact Toronto Hydro's ability to provide acceptable levels of reliable service, and could also result in lost productivity or a disruption to construction and/or maintenance plans. As is discussed elsewhere in this Program, Toronto Hydro vehicles generally require increasing maintenance as they age. In addition, even with regular maintenance, as part of regular wear and tear activities, vehicles are more likely to fail while in use or will need to be held out of service for repairs following an inspection. Furthermore, parts availability decreases over time, and there is a risk of make and model obsolescence. As a result, there is an increased probability that the vehicle will be taken out of service for longer periods of time, while Toronto Hydro procures the requisite parts.

E8.3.3.4 Business Operations Efficiency

Toronto Hydro's utilization of a vehicle's LCA is intended to minimize the operating costs of the fleet relative to the cost of ownership. As vehicles age, ownership costs (such as purchase costs and cost of capital) decrease as operating costs (such as fuel, maintenance costs, downtime) increase. At some point in the asset's life cycle, the operating costs begin to outweigh ownership costs. The total life cycle vehicle costs are at their lowest at a point in time just before operating costs exceed ownership costs. Vehicle replacement at that point in time minimizes total vehicle costs. As vehicles age, performance such as fuel economy and lifting efficiency tend to decline while emission tends to increase. New vehicles generally entail lower maintenance costs in early years, as they tend to experience less failures requiring repairs.

E8.3.4 Expenditure Plan

Table 4: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Heavy Duty Vehicles	2.2	2.9	3.3	1.7	1.7	5.8	6.6	7.2	7.4	6.5
Light Duty Vehicles	1.3	0.8	0.3	1.5	1.5	2.7	2.2	1.2	1.2	1.1
Equipment	0.6	0.1	1.1	0.1	0.1	0.1	0.1	0.2	0.1	0.1
Total	**4.1**	**3.7**	**4.7**	**3.3**	**3.3**	**8.6**	**8.9**	**8.5**	**8.7**	**7.8**

Toronto Hydro's expenditure and asset replacement planning begins several years in advance, primarily due to the lead time required to procure vehicles. To identify the candidates for future replacements, Toronto Hydro utilizes LCA and asset condition assessments collected during vehicles inspections. As mentioned previously, a LCA enables determination of the optimal time to replace vehicles and equipment based on age, mileage or other pertinent factors.

As vehicles age, ownership costs decrease, and operating costs increase. In this context, operating costs includes maintenance, loss in driver productivity from reduced vehicle reliability and the impact of increased fuel consumption by older vehicles. As the summation of all ownership and operating costs, life cycle costs are determined by modeling actual and anticipated ownership and operating cash flows for a particular vehicle over the life of a vehicle. The projected costs are then used to determine the replacement cycle that results in the lowest overall life cycle costs. The time window in the cycle in which this occurs is the optimal point at which to replace a vehicle. This optimal replacement point is given primarily in terms of age in years.



Figure 4: Toronto Hydro Heavy Duty Vehicles

To assist with the LCA, Toronto Hydro retained a third party consultant to undertake a review of Toronto Hydro's on-road vehicle fleet and to provide recommendations regarding the optimal

replacement age of the fleet vehicles. The review identified: (i) the age at which a vehicle should be replaced; and (ii) when replacement should occur (i.e. ideally before costs rise and reliability/safety is reduced and before major capital investment is required).

Using Toronto Hydro's historical costs from 2013 to 2016, the review provided its life cycle analysis recommendations for Toronto Hydro's vehicle fleet, which are summarized in Table 6, below. The conclusions reached in the review include an increase in the lifespans of many light duty vehicles, and a decrease in the lifespans of some heavy duty vehicles.

Table 5: Life Cycle Analysis Replacement Criteria

Priority	Segment	Vehicle Type	2013 LCA (Years)	2017 LCA (Years)	Net	Considerations
1	*Heavy Duty (HD)*	Cube Van	12	12-15	↑	Heavy duty vehicle replacements are routinely evaluated on an individual basis.
1	*Heavy Duty (HD)*	Single Bucket	14	12-16	→	
1	*Heavy Duty (HD)*	Single Bucket -Van Mount	8	11	↑	
1	*Heavy Duty (HD)*	Cable Truck	16	11-14	↓	
1	*Heavy Duty (HD)*	Crane Truck	14	10-14	↓	
1	*Heavy Duty (HD)*	Dump Truck	14	8-12	↓	
1	*Heavy Duty (HD)*	Line Truck	13	13	→	
1	*Heavy Duty (HD)*	Double Bucket Truck	14	14	→	
1	*Heavy Duty (HD)*	Digger-Derrick	13	13	→	
2	*Light Duty (LD)*	Car	6	9	↑	Exceptions: Above average maintenance costs, obsolescence, and usability for the task, poor reliability, excessive downtime, and lack of parts.
2	*Light Duty (LD)*	Cargo Minivan	7	7	→	
2	*Light Duty (LD)*	Passenger Minivan	6	9	↑	
2	*Light Duty (LD)*	Full-size Van	9	10	↑	
2	*Light Duty (LD)*	Pick-Up Truck	9	9	→	
2	*Light Duty (LD)*	SUV	6	8	↑	
3	*Equipment (Eq)*	Trailers	20	20	→	Equipment replacement is on a run-to-failure and/or ad-hoc request basis.

Total life cycle costs and the optimal time for replacement will differ from vehicle to vehicle due to variability in factors such as the vehicle's make, model year, equipment design, initial cost, maintenance costs, and operator usage. Due to this variability, the optimal period is an estimation

of the optimal replacement time for most units within the class. Nevertheless, an asset's condition is the final determinative factor in deciding whether or not it will be replaced.

Further, exceptions to the above recommended lifespans may arise depending on specific considerations that may necessitate vehicle replacement ahead of schedule. These considerations include, but are not limited to, average maintenance costs, obsolescence, and unsuitability for the task, poor reliability, excessive downtime and non-availability of parts or accident damage beyond repair. In addition, specialized heavy vehicle replacements are routinely evaluated on an individual basis, irrespective of the schedule. This is primarily due to the critical role heavy duty vehicles play, their costs and the longer lead times required for their procurement.

Expenditure planning for capital replacements begin several years in advance due to the lead time required to procure vehicles. The lead time for heavy duty vehicles, which are of the highest priority and costliest type, is the longest at 1.5-2 years. This is due to the high degree of complexity and specialization required to be responsive to utility functions, as well as the involvement of multiple vendors.

E8.3.4.1 Heavy and Light Duty Vehicles

The number of light and heavy duty vehicles Toronto Hydro is proposing to replace in the current plan period is virtually identical to what was proposed in the 2015-2019 plan period (260 vehicles versus 261 vehicles, respectively).[4] However, in the 2015-2019 period, Toronto Hydro required funding for 62 heavy duty and 199 light duty vehicles. In the current 2020-2024 plan period, Toronto Hydro requires funding for 101 heavy duty and 159 light duty vehicles. In other words, in the 2020-2024 period, Toronto Hydro requires 63 percent more heavy duty vehicles.

For the 2015-2019 period, Toronto Hydro requested funding of $16.9 million for fleet vehicles, $11 million on heavy duty and $5.9 million on light duty vehicles. In the current plan period, Toronto Hydro plans to invest $32.8 million on heavy duty, and $8.2 million on light duty vehicles. Heavy duty vehicles are typically five to ten times more costly than light duty vehicles. As can be seen in Tables 6 and 7, below, an average bucket truck (a heavy duty vehicle) costs $350,000-$450,000, whereas a pick-up or SUV (a light duty vehicle) will cost $35,000-$45,000. In addition, heavy duty vehicles have

[4] EB-2014-0116, Toronto Hydro-Electric System Limited Application (Filed July 31, 2014), Exhibit 2B, Section E8.1, p. 9.

been more significantly impacted by exchange rate fluctuations given that some of the customization requirements are sourced from the U.S.

Table 6: Replacement Costs[5] For Heavy Duty Vehicles for the 2020 to 2024 Period ($ Millions)

Description	2020		2021		2022		2023		2024		Total Cost
	No.	Cost	No.	Cost	No.	Cost	No.	Cost	No.	Cost	
Cube Van	4	0.5	2	0.3	5	0.7	0	0	7	1.0	**2.5**
Van With Aerial Device	3	0.3	0	0	3	0.4	0	0	0	0	**0.7**
Line Truck	2	0.3	0	0	0	0	1	0.1	0	0	**0.4**
Single Bucket Truck	7	2.6	10	3.8	6	2.4	5	1.9	4	1.6	**12.3**
Double Bucket Truck	3	1.3	2	0.9	7	3.1	5	2.3	6	2.7	**10.2**
Cable Truck	0	0	2	1.0	0	0	0	0	0	0	**1.0**
Small Crane Truck	0	0	1	0.3	1	0.3	2	0.5	0	0	**1.0**
Large Crane Truck	0	0	0	0	0	0	1	0.5	0	0	**0.5**
Small Derrick Truck	1	0.4	1	0.4	1	0.4	1	0.4	0	0	**1.6**
Large Derrick Truck	1	0.4	0	0	0	0	2	0.9	1	0.4	**1.7**
Dump Truck	0	0	0	0	0	0	3	0.7	3	0.8	**1.5**
Total	**21**	**5.8**	**18**	**6.6**	**23**	**7.2**	**20**	**7.4**	**21**	**6.5**	**33.5**

Table 7: Replacement Costs[6] For Light Duty Vehicles for the 2020 to 2024 Period ($ Millions)

Description	2020		2021		2022		2023		2024		Total Cost
	No.	Cost	No.	Cost	No.	Cost	No.	Cost	No.	Cost	
Sports Utility Vehicle	25	1.1	0	0	0	0	0	0	0	0	**1.1**
Pick-Up Truck	15	0.8	15	0.7	15	0.9	15	0.9	13	0.8	**4.1**
Minivan - Passenger	3	0.1	0	0	0	0	0	0	0	0	**0.1**
Minivan - Cargo	3	0.1	17	0.8	0	0	0	0	0	0	**1.0**
Full Size Van - Cargo	10	0.5	12	0.6	5	0.3	5	0.3	6	0.3	**2.0**
Total	**56**	**2.7**	**44**	**2.2**	**20**	**1.2**	**20**	**1.2**	**19**	**1.1**	**8.3**

[5] These costs are inclusive of all up-fitting necessary for the job, such as storage bins, partitions, racking, lighting, additional power supply; and any other aftermarket additions required in a particular light duty vehicle.
[6] Ibid.

As vehicles age, they incur higher operating expenses due to increasing levels of reactive repairs. Therefore, if the recommended replacements are not completed during the 2020-2024 period, operating costs for repairs will increase with the escalating average age of the fleet.

E8.3.4.2 Equipment

On-vehicle equipment includes anti-idling technology, GPS units, and laptop mounts installed in vehicles and equipment such as trailers and lifts (scissor lift, forklift, boom lift, vehicle lift). Toronto Hydro currently has 52 trailers and 45 lifts, ranging in age from one to 30 years (average age for both is 12 years). Replacement of this equipment is done on a reactive, or 'run-to-fail' model for the following reasons:

- Equipment generally has long lifespans;
- The variability in frequency of use makes it difficult to forecast replacement based on age or usage;
- Equipment procurement requires short lead times;
- There is little to no customization of equipment required so procurement is prompt;
- There is low safety risk of critical equipment failure; and
- There are similar units available for immediate use if a unit fails critically.

Table 8, below, shows the forecasted costs associated with replacement of equipment on a reactive basis. Equipment is assessed at every preventative maintenance review within a six month period and respective replacement is determined based on unit condition and performance.

Table 8: Equipment Replacement Costs For 2020 To 2024 Period ($ Millions)

	2020	2021	2022	2023	2024	Total
Equipment	0.1	0.1	0.2	0.1	0.1	0.6
Total	**0.1**	**0.1**	**0.2**	**0.1**	**0.1**	**0.6**

Telematics and anti-idling systems helps the Program monitor and continuously improve idling, utilization, driver safety, and diagnostic maintenance. The anti-idle system manages, monitors and provides real-time data to the user on battery voltage, coolant, temperature, idling, anti-theft mode, and engine start/stop. It also provides exceptions reporting on driver behaviour that helps reduce speeding and harsh braking. The use of telematics GPS hardware and software provides benefits in

a number of areas, including: real-time tracking of vehicle locations and maintenance indicators[7]; customer complaints investigations and claims (by enabling access to historical tracking of the entire fleet and history of vehicle location); speed profile (notification of speeding based on local speed limit and set data); zone management (home zones based on location of vehicles parked when not in use); and zone creation based on work centre locations to track and optimize arrival and departure of vehicles. Most newly purchased heavy duty diesel vehicles are now equipped with GRIP anti-idling technology to aid in the reduction of idling which will increase lifespan (as it is directly related to the wear and tear of the engines) and decrease GHG emissions. These systems are included in the specifications which the vendors must comply with for purposes of the purchase contract.

Other onboard equipment includes laptop mount kits, for ruggedized laptops used in the field, equipped with pedestal, docking station and wiring needed to power laptops. These mounts are installed in most vehicles (light and heavy duty) to facilitate ergonomically safe use of laptops for onsite crew inspections, site visits and other situations without the need to drive back to the work centre and file paperwork. Ergonomic features (such as dock tilt, spring loaded, telescopic and adjustable base) along with a risk assessment help enhance user safety and performance over time.

Figure 5, below, shows views of a steel lap mount installed in an underground cube van which include a pedestal bolted to the base of the cab along with a docking station, battery protector, and antenna.



Figure 5: Lap Top Mount Installed In Cube Van

[7] For example, engine light on, fuel tank, battery voltage, tire air, GPS not reporting/working, unplugged devices, idling, zoning, trip history, PTO (power off take-off) used for CVOR units (commercial vehicle operation registration).

Prioritization within the Program reflects the importance of the vehicle class to performing core distribution work, the lead time required to procure the asset, the level of customization and/or specialization required, and the cost. Capital plans are created by first scheduling the heavy duty vehicle replacements in their recommended replacement year, followed by light duty vehicles. Asset condition assessment is used to prioritize the replacement of vehicles. Equipment is scheduled on a more ad-hoc basis.

It is more economical and efficient to procure vehicles in batches of approximately five to ten vehicles, therefore asset replacements are shuffled between years within a five-year plan to assist with balanced spending during the year. Replacing in batches and leveling spending in a given year makes it easier for the administration and maintenance teams to ensure work is balanced throughout the lifecycle of the vehicle. The parameters or factors affecting prioritization in long-term capital planning are shown in Table 9, below, by vehicle class.

Table 9: Factors Influencing Capital Planning By Asset Class

	Functional Criticality	Procurement Time	Average Cost/Unit ($M)	Degree of Customization
Heavy Duty Vehicles	High	18-24 months	$0.26	High
Light Duty Vehicles	Medium	6-12 months	$0.04	Medium
Equipment	Low	3-6 months	$0.01	Low

E8.3.5 Options Analysis / Business Case Evaluation ("BCE")

Toronto Hydro considered three options for investments in the Program over the current plan period: (i) run to failure; (ii) managed fleet replacement (the proposed approach); and (iii) replacement of all assets as per the results of the LCA.

E8.3.5.1 Option 1: Run-to-Fail Approach

In the run-to-fail approach, a vehicle would only be replaced once it has completely failed and can no longer perform its intended function. To provide an estimate of the cost impact of this option, Toronto Hydro assumes the average age of the fleet continues to increase by one year for each calendar year. In other words, all fleet assets that are currently owned are assumed to remain in the fleet without turnover. Using Toronto Hydro's current data from 2012-2017, which connects the average age of the fleet with the total vehicle-related parts and services costs, a projection of future

vehicle-related costs is forecasted. As shown in Figure 6, below, by year 2024 the average fleet age would be approximately 13.2 years and the corresponding vehicle operating costs would be approximately $11.8 million. This represents a 121 percent increase in operating costs compared to 2017 ($11.8 million versus $5.3 million) – this is more than double the current vehicle related maintenance and repair costs. These cost increases over and above 2017 levels include fuel, parts, labour for maintenance that could have been mitigated with a newer vehicle.

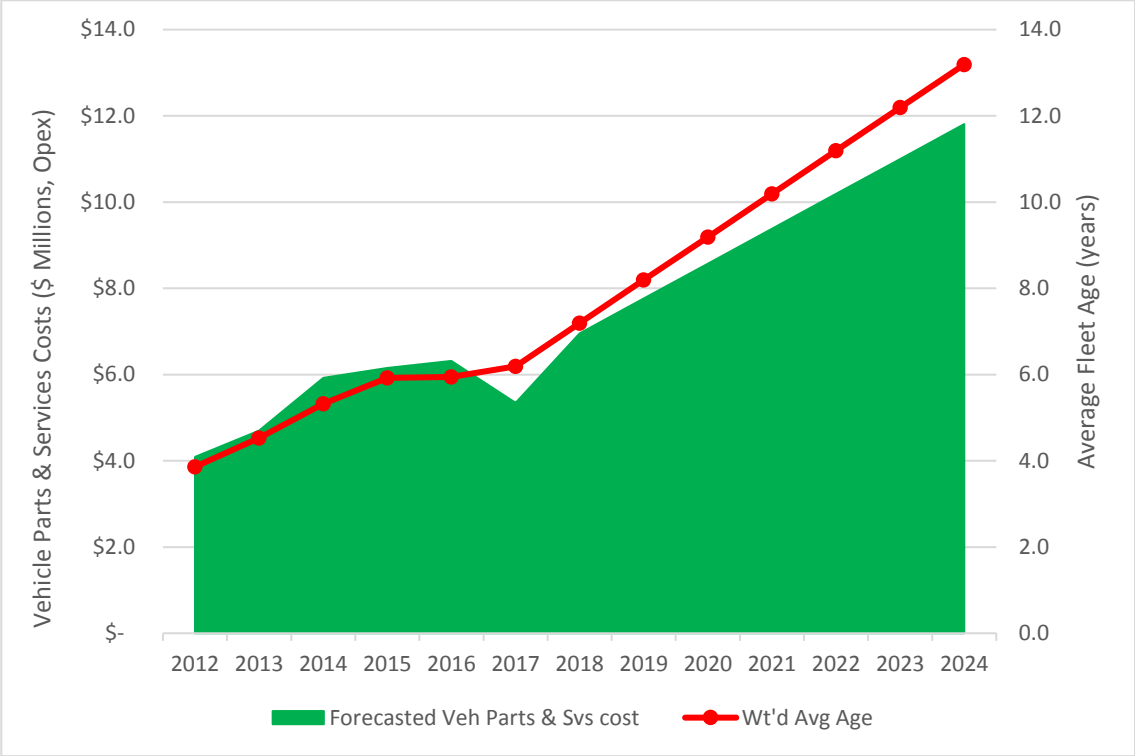

Figure 6: Run-to-Fail Approach - Vehicle OPEX Costs

This option would have the following consequences:

- Unit field failures will likely increase as vehicles age – these field failures will adversely affect field crew productivity and, in some cases, result in Toronto Hydro's inability to conduct system maintenance and capital investment as planned. This will lead to higher labour and support costs (such as permits, penalties for late work completion, additional fuel on account of more frequent trips to and from a work location, etc.).
- The severity of failures is likely to increase, and these failures could potentially become more catastrophic, leading to safety risks, injuries, damage to property or equipment and

environmental spills. For example, hydraulic hoses are more prone to failure over time. A catastrophic hydraulic line failure could, at minimum, result in an employee becoming trapped in a bucket, as well as result in a significant hydraulic fluid spill on to a roadway.

- Running a vehicle to failure would mean that the replacement date is somewhat unpredictable. This would mean being without a specific type of critical fleet vehicle for several months before a replacement is available, given the lead time of a vehicle is between three and 24 months. Distribution work would not be able to be carried out reliably if vehicles are not readily available and in a state of good repair.
- Toronto Hydro operating costs for repairs are likely to increase as parts fail and are replaced. As a vehicle ages, parts will likely become less available, resulting in increasing costs with respect to their purchase. Furthermore, to keep pace with increasing failures, it may be necessary for Toronto Hydro to increase the frequency of preventative maintenance tasks, as well as the number of mechanics it employs and/or the additional external resources it relies on.
- Toronto Hydro may have to increase its vehicle count to maintain similar vehicle availability levels to deliver equivalent service levels to customers. This is because as vehicles age, out of service time will likely also increase due to increasing repair challenges that result from an aging fleet (such as rusted bolts and more significant repairs). To ensure that vehicles are available for use, Toronto Hydro would likely require the use of 'spare' vehicles should the main service vehicles become unavailable on account of maintenance or repairs. In addition, Toronto Hydro may have to rent new equipment for vehicles at a significant cost.
- Replacement for vehicles that have reached total failure require a lead times of up to 24 months for purchase and delivery of specialized vehicles. During this time, Toronto Hydro's ability to perform system maintenance and capital investment may be impaired and/or delayed if alternate vehicles cannot be sourced internally, or via a temporary path such as renting or leasing.

E8.3.5.2 Option 2 (Selected Option): Managed Fleet Replacement

The managed fleet replacement is the proposed approach under the Program. Under this option, Toronto Hydro would undertake a like-for-like replacement of vehicles in line with the fleet replacement considerations outlined in the Expenditure Plan. Utilizing this option, Toronto Hydro is able to bring the average fleet age within +/- 0.5 years of the target average age of five years during the 2020 to 2024 period. By using this approach, Toronto Hydro is able to ensure vehicle-related

operating costs do not escalate as a result of equipment failure and other more costly repairs while also having greater assurance that vehicles operate predictably and safely.

This approach will have the following consequences:

- By utilizing this option, Toronto Hydro ensures that replacement of vehicles according to the applicable criteria will optimize the total cost of vehicle ownership on average over time, which translates into savings for ratepayers.
- The managed approach will improve overall vehicle reliability, translating to less downtime, fewer vehicle failures, and resulting in improved field crew productivity;
- Increase in fleet vehicle and equipment performance;
- Improved overall safety of fleet vehicles due to new/improved safety systems; and
- Improved fuel efficiency leading to reduced GHG emissions and fuel costs.

E8.3.5.3 Option 3: Replacement of all Assets According to the Life Cycle Analysis

This option entails replacing all vehicle types according to the exact replacement ages provided for in the LCA review and replacing all trailers over 20 years of age, without taking into account asset condition assessments gathered during routine inspections. Trailers are usually replaced reactively once failure or breakdown occurs. This option would require $56.5 million in funding over the 2020-2024 period.

This option will have the following consequences:

- Pre-emptive mitigation of age-related safety risks and corresponding escalation of repair costs;
- Ensuring adequate availability of similar vehicles to maintain reliability during weather and other emergency events;
- Ensuring adequate availability of vehicles due to an increase in the use of external repair services, which causes vehicles to be out of service for longer durations;
- The overall funding required to implement this option is $14 million more than needed under the managed fleet approach, Option 2, above;
- The number of vehicles to be replaced would also vary greatly year to year, creating logistical challenges with in-servicing and disposing of decommissioned vehicles. In contrast, in Toronto Hydro's proposed approach, the LCA is used as a tool to forecast which assets will

become due for replacement and condition assessments determine exactly which vehicles need to be replaced; and

- Less reliance on condition based assessments. As explained above, there could be an instance when a vehicle that has not met its replacement criteria will need to be replaced due to its poor or unsafe condition. Alternatively, there could be a vehicle that has exceeded its replacement criteria but may be in good condition and, as such may not warrant replacement.

E8.3.5.4 Evaluation of Options

Toronto Hydro has opted to proceed with Option 2, the managed fleet replacement approach, as it is the most cost-effective solution to manage Toronto Hydro's vehicle fleet to the lowest overall lifecycle cost, while ensuring asset reliability and employee and public safety.

Replacing vehicle fleet on a run to failure basis (Option 1) will not only adversely affect field crew productivity and inability to conduct planned system maintenance and capital investment, but it will also more than double the current vehicle related maintenance and repair costs. In addition, Toronto Hydro could have chosen to replace its vehicle fleet according to the exact replacement ages provided for in the LCA review, as per Option 3, without taking into consideration the asset condition. Option 3 would increase vehicle reliability and provide assurance of vehicle availability more so than the other two options. However, Option 3, among other things, would require more capital funding over the 2020-2024 plan period and would not be the most cost-effective solution.

The managed fleet replacement approach ensures that capital investments are made at a level and pace that minimizes asset maintenance, repair, and capital costs. An optimally timed vehicle replacement strategy also ensures that the appropriate level of vehicles are available to support system maintenance and capital investment plans. As such, Option 2 provides maximum value for ratepayers.

E8.3.6 Execution Risks & Mitigation

There are two primary execution risks inherent in the Program. The first is the fluctuating exchange rate between Canadian and American currency. Most heavy duty and specialized vehicle manufacturers are located in the United States. The weakening of the Canadian dollar in recent years increased the cost of cab and chassis for bucket trucks, line trucks and other specialized trucks, as well as lift equipment and parts. The value of the Canadian dollar has dropped since 2012. As a

mitigation strategy, Toronto Hydro has secured multi-year tenders with limitations on cost increases per year (1.8 percent maximum). In addition, where possible, Canadian supplies are chosen since total costs per unit are approximately 10-15 percent less when compared to vendors based in the United States.

Vehicle lead time is another critical execution risk. Once the vehicle specifications have been drafted, and the procurement process has been completed, vendors must be awarded the bid and a purchase order must be issued with sufficient time for the vehicle to be delivered in the current plan year. While unit order size and relationship with the vendor can sometimes reduce product lead time, many variables such as the manufacturer's inventory of the requested vehicle, vendor time availability to perform up-fits/customizations, and specification complexity, are not controlled by the successful bidder. For instance, the successful bidder may only perform the up-fit portion of the delivery in-house, and may order all other parts of the unit specified in the tender from another vendor. The lead-time risk can be mitigated by awarding plan submissions well in advance of the calendar year of purchase. In order to do so, Toronto Hydro will need to ensure that vehicle reviews, specifications, and request for proposal/quotation are largely completed in the first half of the prior calendar year. Multi-year contracts for bucket truck tenders is another strategy utilized to lock in pricing of a completed unit and guarantee truck deliveries and forecasted in-servicing of new bucket trucks.

E8.4 Information Technology and Operational Technology Systems

E8.4.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 231.2	**2020-2024 Cost ($M):** 281.4
Segments: IT Hardware, IT Software, and Communication Infrastructure	
Trigger Driver: System Maintenance and Capital Investment Support	
Outcomes: Customer Service, Public Policy, and Financial	

The Information Technology and Operational Technology [1] Systems ("IT/OT") program (the "Program") proposes to invest in hardware, software, and communication assets that provide critical support to Toronto Hydro's customer and business-facing services. Toronto Hydro relies on IT/OT systems to execute capital and operational programs, including customer-facing and operationally-critical functions. The investments proposed in this Program were developed in accordance with Toronto Hydro's IT Asset Management Strategy,[2] which mitigates risks to reliability, cybersecurity, and the utility's business operations.

The Program's objective is to provide reliable technology solutions and services to support Toronto Hydro's business functions, including effective and reliable service to customers, safe and efficient management, and operation of the distribution system, compliance with legal and regulatory requirements, and sustainment of the utility's long-term financial viability.

The Program consists of the following three segments:

- **IT Hardware**: includes the core back end infrastructure assets (e.g. servers, local area networks and data storage/centres) and endpoint assets (e.g. desktop computers, laptops, printers, smart phones, and tablets) that support Toronto Hydro's day-to-day operations and core systems;
- **IT Software**: includes software applications that provide process improvements to a range of customer-facing and business functions; and,

[1] Operational Technology refers to hardware and software that detect or cause a change through the direct monitoring and/or control of physical devices, processes, and events in the enterprise (https://www.gartner.com/it-glossary/operational-technology-ot/).
[2] Provided at Exhibit 2B, Section D5.

- **Communication Infrastructure**: includes assets that enable the monitoring and control of distribution communication infrastructure, including fibre-optic assets and wireless Supervisory Control and Data Acquisition ("SCADA") infrastructure.

E8.4.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Service	• Contributes to Toronto Hydro's customer service objectives by: ○ Improving the customer experience of interacting with the utility through digital platform; and ○ Supporting accurate and timely communication with customers during prolonged power outages.
Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: ○ Maintaining the availability of modern, reliable and secure enterprise-wide IT/OT systems that support efficient distribution system management; ○ Supporting outage restoration efforts by ensuring that system operators have the necessary IT/OT tools to promptly identify incidents, develop effective resolution plans and communicate with operational teams; and ○ Enhancing IT/OT systems to enable remote equipment monitoring and operations capabilities.
Public Policy	• Contributes to Toronto Hydro's public policy objectives by: ○ Providing the technological infrastructure framework required to achieve conservation and demand management targets, enable grid-modernization, and support energy storage and distributed energy resources; and ○ Ensuring the effectiveness and availability of IT/OT systems that are required to support the utility's implementation of new policy initiatives and compliance with regulatory requirements, including those arising out of the OEB's Cyber Security Framework.

Safety	• Contributes to Toronto Hydro's safety objectives, measured through metrics such as the Total Recordable Injury Frequency ("TRIF") by: ○ Enabling the constant monitoring of substation and field assets; and ○ Maintaining the effectiveness and availability of IT/OT Systems that support the utility's safety performance (such as Intelex, Learning Management System, SCADA, Automated Vehicle Locator, Field Mobility System, Radio, and Network Management System).
Financial	• Contributes to Toronto Hydro's financial objectives by ensuring that the Tier 1 IT systems are available and reliable in support of efficient and accurate financial reporting.

E8.4.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	System Maintenance and Capital Investment Support
Secondary Driver(s)	Cyber Security Risks, Regulatory Compliance, and Functional Obsolescence

The Program supports Toronto Hydro's core operations and business processes, and enables the safe and efficient execution of the utility's capital and operational programs. The utility relies on its IT/OT systems to manage and operate the electricity distribution system, satisfy its obligations to customers, and comply with existing and emerging regulatory requirements.

E8.4.3.1 IT Hardware

Toronto Hydro's IT hardware must be renewed on a regular basis to ensure that systems that support customer-facing services, core distribution operations and other important processes continue to function reliably with a low risk of failure. Toronto Hydro employs many software applications to automate processes and efficiently execute required tasks such as preparing customers' bills and dispatching crews to respond to outages. These applications run on IT hardware, the building blocks of the overall IT System that must be reliable to ensure that the software applications it houses remain available.

IT hardware infrastructure assets support a number of customer service functions. Currently, approximately 224,420[3] customers use the online electronic billing function and approximately 282,000[4] customers have accounts that provide key self-serve functions, such as management of account details, customer moves, payment options, and landlord information. Hardware assets also support a number of customer interfacing applications and processes delivered via telephony through the Toronto Hydro Call Centre. If the hardware assets supporting these functions were to fail, customers would be unable to access these systems, and could experience significant delays in completing routine transactions. This would impact customer service satisfaction and likely lead to increased volume of calls and complaints to Toronto Hydro's Call Centre.

Hardware assets support systems that are used to manage field crews and respond to outages, and thus are critical to the utility's ability to meet operational outcomes, including reliability. By providing distribution grid management employees real-time access to crew availability, geographic outage location and crew location, these systems enable Toronto Hydro to efficiently and effectively deploy crews to restore power to customers in a timely fashion. In the event of core backend infrastructure failure, the functionality of these applications would be impaired, and as a result, Toronto Hydro's outage response time would be negatively affected.

IT hardware also underpins the utility's environmental, health, and safety processes across its work centres and job sites. Such processes range from completion of site conditions and safety forms, review of Material Safety Data Sheets, safety and environmental audits, and incident and claims investigations. In the event of an IT hardware or software failure, employees may not have access to the information required to make informed decisions about environmental and health and safety issues that may be serious and time-sensitive, thus potentially compromising work safety or contributing to inadvertent breaches of applicable compliance requirements.

IT hardware investments are planned and implemented with regard to both current and future utility needs and operational requirements in order to enable Toronto Hydro to execute its plans and programs securely and efficiently in pursuit of its short- and long-term objectives. IT hardware standards are regularly reviewed, assessed, and implemented based on the utility's requirements from operational, regulatory and customer service perspectives. This requires Toronto Hydro to continuously invest in its IT hardware assets.

[3] As at the end of 2017.
[4] Ibid.

IT hardware assets are classified as either Endpoint Assets or Core Backend Infrastructure Assets. Endpoint Assets are the assets that the end-user interfaces with to execute, process, complete and review business tasks and operations. These include computing assets (e.g. desktops, laptops, and tablets) that support the execution of business processes, data transactions and analysis, as well as printing assets (e.g. printers, plotters, and photocopiers) that translate electronic documents like engineering drawings and contracts onto paper. Both are relied upon extensively by Toronto Hydro's IT users to execute daily work across the utility.

Core Backend Infrastructure Assets are responsible for the computation, storage, and communication necessary to support IT systems. Servers manage access to centralized resources and services in the network and security appliances secure the network from unwanted traffic. Storage assets enable the secure retention of digital data such as customer information, and include disk and flash arrays, which store records for access by servers. Communication assets facilitate the exchange of data within and between the core backend assets and the endpoint assets, so that users can access information from a central IT system. Network and telephony assets enable computers, services, and storage devices to exchange data and manage communication services.

Figure 1 depicts the typical structure and dependency of IT hardware assets.

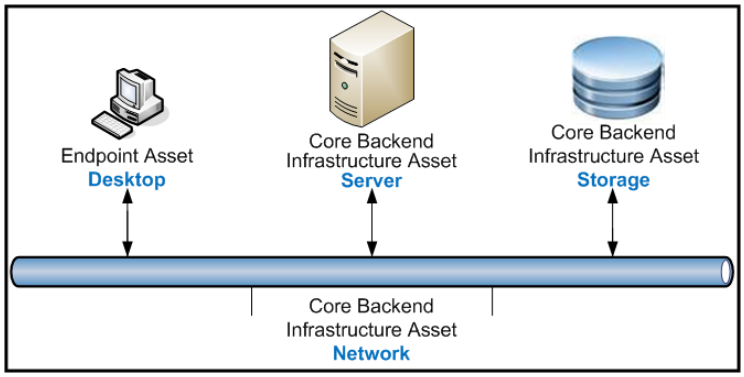

Figure 1: Typical Endpoint Asset to Core Infrastructure Relationships

Toronto Hydro currently manages its renewal of over 2,000 endpoint assets and over 1,500 core backend infrastructure assets using a structured IT Asset Management approach, which can be found in Exhibit 2B, Section D5. Toronto Hydro's IT Asset Management Strategy is aligned with industry best practices, vendor lifecycle recommendations, and Toronto Hydro empirical data.

The lifespans of hardware assets range from four to seven years, which are considered to be within industry norms. At the end of its lifecycle, hardware assets' risk of failure increases significantly, potentially impacting core business processes.

To determine the refresh cycle for existing hardware, Toronto Hydro maintains an inventory of hardware assets that includes technical details and lifecycle information such as date of implementation and end of vendor support. This approach ensures that IT hardware assets are available to support the effective and efficient execution of the utility's operations.

Adhering to this approach, approximately 90 percent of Toronto Hydro's core backend infrastructure, and 100 percent of its endpoints assets will need to be replaced during 2020 to 2024. These include data and voice network routers, switches and appliances, storage network switches, storage arrays, data backup appliances, file storage appliances, UNIX and Windows servers, security, and monitoring appliances, and uninterruptable power supplies.

E8.4.3.2 IT Software

Investment in IT software is required to:

- ensure that current applications can continue to operate reliably and with minimal risk exposure to cyber threats;
- make targeted and prudent IT enhancements to current functionality in response to core business needs or risks; and,
- respond to evolving regulatory or compliance obligations.

IT software is omnipresent in the modern utility. Toronto Hydro relies upon, and must maintain, various IT software systems to efficiently manage core operations and business processes and to execute planned programs relating to Distribution Grid Infrastructure Design and Construction, Distribution Grid Operations, Customer Billing and Service and Corporate Services.

Without these systems, a utility of Toronto Hydro's size and complexity would encounter significant challenges in operating its electricity distribution system, delivering capital programs and satisfying obligations to customers and other parties with which it interacts. Moreover, in the absence of incremental funding to build additional capabilities, the utility could be forced to bypass opportunities to improve productivity or innovate service offerings to meet customers' evolving needs and preferences.

Software applications deliver tangible value to customers directly through customer-facing IT services, and indirectly through the improved performance (or avoided risks) of business-facing platforms and solutions. To maintain a reliable and productive suite of IT Software, Toronto Hydro makes three types of investments:

- Software Upgrades
- Software Enhancements
- Regulatory Compliance

1. Software Upgrades

Over the 2020 to 2024 period, Toronto Hydro plans to upgrade all of its software applications. These upgrades will ensure that Toronto Hydro's software systems receive support from vendors, keep pace with technology changes, remain integrated with other relevant software systems, and are protected against cyber security threats.

When IT systems are beyond the period of extended vendor support, the vendor and the marketplace do not guarantee availability of qualified resources and expertise needed to resolve any potential issues. As a result, the failure of these systems may result in prolonged restoration, which can significantly affect the utility's operations and its ability to execute planned work programs and deliver service to customers.

In addition, legacy IT systems no longer receive security patches and performance upgrades or fixes, rendering the applications more vulnerable to cyber-attacks. Every month, Toronto Hydro's IT security team successfully blocks as many as 20 million internet-based attacks. These attacks attempt to tamper with normal IT system operations, gain unauthorized access to confidential information, or cause a machine or network resource to be unavailable to its intended authorized users.

A successful cyber-attack on the Customer Information System ("CIS"), for example, would compromise customer usage and billing data, including confidential customer information. Stolen customer data can be used in fraud and identity theft, as was the case in the January 2018 cyber-attack on Metrolinx by hackers.[5] This event highlights the real risk and consequences of cyber intrusions and the ongoing need for Toronto Hydro to regularly upgrade its software and hardware

[5] Toronto Star, Metrolinx Targeted by North Korean Cyber Attack (January 23, 2018), available at <https://www.thestar.com/news/gta/2018/01/23/metrolinx-targeted-by-north-korean-cyberattack.html>.

in order to protect its systems from external attacks.[6] Similarly, a leak of Toronto Hydro's sensitive operational information could lead to and assist in malicious attempts to jeopardize day-to-day operations and, in extreme cases, the successful exploitation of a system vulnerability that can cause mass outages across the grid.

The ongoing use of applications past end of useful life leads to retention and maintenance of standalone underlying components that lag vendor support lifecycles. This exposes the IT systems to security and failure risks from the underlying components.

Toronto Hydro must address these risks by upgrading its applications to maintain compatibility with underlying infrastructure.

Table 4 below sets out all major IT systems (known as "Tier 1" systems) and their underlying infrastructure that will reach their end of life in the 2020 to 2024 period and must be upgraded. Tier 1 applications support utility-wide processes, are functionally integrated with other applications, and are supported by a host of databases, middleware, storage and network devices. In a disaster scenario, Toronto Hydro requires that a Tier 1 system be recovered in four hours or less.

Table 4: Toronto Hydro's Tier 1 IT Systems

Tier 1 System Name	Expected System Age at end of 2024	System Lifecycle (in years)
Warehouse Management System	6	4 to 5
Geospatial Information System	6	4 to 5
Supervisory Control and Data Acquisition System	7	4 to 5
Distribution Network Management System	6	4 to 5
Outage Management System	6	4 to 5
Operational Data Store	5	4
Meter Management System	6	3
Customer Information System	13	5 to 7
Enterprise Resource Planning System	6[7]	5 to 10

[6] In March 2018, the United States Computer Emergency Readiness Team issued an alert on Russian government actors targeting U.S. Government entities and organizations in the energy section. See https://www.us-cert.gov/ncas/alerts/TA18-074A.

[7] The version of SAP used for Toronto Hydro's ERP was three years old at the time of implementation in 2018, and will be out of support in 2025. The lead time required to implement an ERP requires more than 12 months of active preparation

The Enterprise Resource Planning ("ERP") and CIS upgrades are the most significant upgrades based on size and complexity, and are discussed in greater detail in the Expenditure Plan. Both are fundamental to the utility's ongoing operations. Without full vendor support, any disruption caused by a system failure is likely to take longer to resolve resulting in additional costs and delays to correct the failure. For the ERP, this could disrupt Toronto Hydro's financial processes and the ability to report accurate information in line with regulatory requirements.

Toronto Hydro's CIS currently processes approximately $18 million per day in electricity costs. Billing delays due to CIS issues can give rise to major customer and financial impacts, and would put at risk Toronto Hydro's ability to meet OEB-established metric on billing accuracy. The current legacy system entails increased security risks because it no longer receive security patches from the vendor. This is an especially serious issue as security breaches can compromise confidential customer information, such as customer bank accounts and Social Insurance Numbers.

Functional obsolescence is an additional consideration driving the need to invest in software upgrades. Finding skilled resources to ensure ongoing support optimization for legacy systems is and will become more challenging. This was previously a challenge with respect to Toronto Hydro's legacy ERP System Ellipse, as outlined in Toronto Hydro's 2015 CIR application (Exhibit 2B, E8.6), and is now a particular concern for the CIS system.

Over time, Toronto Hydro customized its CIS, often in response to new regulatory requirements. Integrating such customizations into the architecture of the utility's overall IT infrastructure has become increasingly complex and time consuming. In the interim, Toronto Hydro is managing this risk by incurring additional IT operating costs and additional testing of modifications to the system. However, these costs are expected to continue escalating as customizations become more complex and costly to implement, test, and maintain.

Toronto Hydro's other Tier 1 applications also require upgrades to mitigate reliability and cybersecurity risks. Control room operators and dispatchers rely extensively on the Outage and Distribution Management System and Mobile Network Management System to access real-time outage data and to view the location and status of field crews. Upgrading these systems ensures Toronto Hydro's continued ability to respond to outages in a safe, timely, and efficient manner. In addition, system enhancements and analytics in relation to these applications can provide Toronto

with a System Integrator. The timing of the expenditure to upgrade the ERP prior to losing support therefore falls within the 2020 to 2024 period.

Hydro with critical information about managing resources and restoring power to customers in emergency events.

Engineers, designers, and field crews depend on IT systems such as the Geospatial Information System ("GIS") and the Distribution Network Analytical Tool to access important information about assets across the distribution system, and to develop asset replacement plans, determine project detail estimates and review the conditions of assets prior to physical intervention.

Toronto Hydro's construction project teams and outage response teams rely on IT solutions to execute work plans and respond to outages. The inventory management system facilitates this function by managing asset inventory levels across multiple warehouse locations, and enabling the delivery of materials at job sites and key locations across the system. A failure of this system could lead to errors in materials information that could affect asset costing information, or even worse, jeopardize the safety of employees using these materials. Delays in the delivery of materials to project sites could also hamper the utility's ability to respond to outages and execute planned work in a timely and efficient manner.

In addition, Toronto Hydro is proposing to upgrade its suite of Tier 2 IT software applications, which support targeted processes and have little or no integration with other enterprise applications. Compared to Tier 1 applications, Tier 2 applications generally have lower maintenance costs and support a smaller user base. As such, both the risks and corresponding investment costs associated with Tier 2 software upgrades are lower. Examples of such applications are the data analytics software application, power quality application, and the fuel data system. Lifecycles developed in accordance with Toronto Hydro's IT Asset Management Strategy are five years or less for these applications. Accordingly, all Tier 2 systems will require one or more upgrades during the 2020 to 2024 period.

2. Software Enhancements

Over the 2020 to 2024 period, Toronto Hydro plans to undertake software enhancement projects in alignment with its IT Asset Management Strategy, located at Exhibit 2B, Section D5. Whereas software upgrades are typically triggered by emerging reliability or cybersecurity risks, software enhancements are driven by risks to a particular customer-facing or business process. A specific type of risk driven by compliance requirements is discussed more thoroughly in the following section.

Toronto Hydro expects increasing demands to continue from customers and internal clients. External facing enhancements, such as initiatives related to the web portal and customer billing, aim to ensure customers can access information and interact with Toronto Hydro securely and efficiently, such as by expanding payment options to include credit card processing. Data analytics expansions could enable the development of descriptive and predictive analysis data models to assist in areas such as long-term strategy and planning, generation and capacity planning, asset maintenance planning, outage prediction, system planning, and power quality and reliability planning.

Just as software enhancements address a range of emerging business risks, they can be implemented using a variety of different IT approaches. Previously independent systems can be integrated to mitigate the risk of data errors stemming from manual work-around processes. Incremental reporting capability can be built to fills gaps in management processes and decision making. Adding functionality or new software tools can add capabilities that meet emerging customer needs and preferences or mitigate cost pressures.

Toronto Hydro employs a rigorous and comprehensive methodology, as described in the IT Asset Management Strategy (Exhibit 2B, Section D5). Projects undergo a stringent review process and are operationalized through a strictly governed implementation process, summarized below.

- **Evaluate**: The utility validates the proposed initiative and works with the relevant business unit(s) to determine the project scope, business requirements, current state business processes, future state business processes, the options to achieve the future state, and the preferred approach, costs, and benefits.
- **Align**: Toronto Hydro reviews the proposed project to help ensure the following:
    - Governance, due-diligence, rationale, and accuracy of the project costs and benefits;
    - Strategic alignment with Toronto Hydro's objectives (e.g. value for money);
    - Alignment with Toronto Hydro's risk profile (e.g. cyber security); and
    - Alignment with existing technology investments and standards.
- **Prioritize**: Toronto Hydro prioritizes the project based on a combination of factors, including project dependencies, costs, benefits, strategic alignment, and risk assessment.
- **Execute**: Project execution typically consists of the following steps:
    - Gathering more detailed user and technical requirements;
    - Mapping the relevant business processes;
    - Developing and/or procuring the application as needed;

- Provisioning the infrastructure to host the application;
- Configuring the application to meet business requirements;
- Testing the application for compatibility with Toronto Hydro's infrastructure;
- Engaging users to test that the application meets their business and functional requirements;
- Training users on the features and functionality of the application; and
- Implementing the application across the appropriate departments.

3. Regulatory Compliance

Each year, Toronto Hydro must make changes to its business processes in order to comply with emerging regulatory requirements and be responsive to public policy priorities. Among the many drivers of new policy, requirements are accessibility obligations and requirements of Measurement Canada, the OEB, the IESO, the Ontario Securities Commission, and the Ministry of Labour. Failing to meet regulatory compliance obligations exposes Toronto Hydro to financial risk, in the form of penalties, and reputational harm.

In 2015 to 2017, Toronto Hydro implemented a number of software changes to respond to evolving regulatory compliance matters, including the cessation of the Ontario Clean Energy Benefit, the implementation of the Ontario Electricity Savings Program and the Ontario Rebate for Electricity Consumers, and the move to monthly billing. For more on monthly billing, please see Exhibit 9, Tab 1, Schedule 1.

Toronto Hydro anticipates this policy-driven investment to continue in the 2020 to 2024 period. To minimize risk and optimize benefits realization, Toronto Hydro follows the same four-step "Evaluate-Align-Prioritize-Execute" process used to govern the development of Software Enhancements.

E8.4.3.3 Communication Infrastructure

Toronto Hydro has four discrete communication infrastructure needs in the 2020 to 2024 period. Communications infrastructure is relied upon by core utility operations to maintain and operate the distribution system in a safe and reliable manner. The proposed investments address functional obsolescence in Toronto Hydro's current communications infrastructure footprint, address safety and reliability risks, and support the monitoring and control of future smart grid technologies.

Over the 2020-2024 period, Toronto plans to undertake the following types of work in this segment:

- Distribution system communication technology upgrade;
- Distribution system fibre-optic plant replacement and expansion;
- Wireless SCADA infrastructure upgrade; and
- Underground radio expansion.

1. Communication Technology Upgrade: SONET migration and decommissioning

Toronto Hydro relies on SONET communication technology at substations on the 13.8 kV system for SCADA communication to operate remote terminal units ("RTU"), which provide automated control of station assets such as circuit breakers. SONET is a legacy communication technology, developed in the 1980s. It is no longer supported by the manufacturer and has limited capacity to support increased automation at additional substations. If not replaced, SONET would become more expensive to maintain and limit Toronto Hydro's ability to leverage communications-based innovations to improve performance. The modern replacement for SONET is the routed IP network, supported by Multi-Protocol Label Switching ("MPLS") technology.

2. Fibre-Optic Plant Replacement and Expansion

Currently, approximately 300 kilometres of fibre-optic cable connect various in-field communication technologies to Toronto Hydro's Control Centre. For example, SCADA equipment that can be remotely operated from the Control Centre relies on fibre-optic cable to convey instructions. During 2015 to 2019, Toronto Hydro deployed approximately 70 kilometres of fibre-optic cable to remediate reliability concerns with the current plant and to expand SCADA capabilities to more locations. Toronto Hydro needs to install approximately 10 kilometres of additional fibre-optic cable to target areas of fibre, that are failing more frequently.

3. Wireless SCADA Infrastructure Upgrade

Wireless SCADA infrastructure is required to enable SCADA monitoring and control functionality for field assets where it is more cost effective than fibre-optic plant, such as smaller municipal station RTUs and pole-top distribution grid assets. Wireless SCADA infrastructure is a critical service responsible for monitoring and control of distribution grid assets, and failure to maintain adequately supported telecommunications infrastructure in this space could negatively impact service restoration times, crew safety and operational efficiency.

In 2015, Toronto Hydro operated five different legacy wireless SCADA technologies, which it proposed to address as part of the 2015 to 2019 Distribution System Communication Infrastructure ("DSCI") Program (see 2015 CIR Application, Exhibit 2B, E6.22). During the course of the upgrade, the underlying GE SD9 technology reached end of life and became functionally obsolete, meaning that it would no longer be vendor-supported and thus be prone to longer outages that impede restoration efforts. Toronto Hydro plans to replace GE SD9 with GE Orbit, the current technology that is supported by the vendor.

4. Underground Radio Expansion

This initiative is intended to address gaps in Toronto Hydro's radio coverage at certain underground vaults that are located well below ground level (i.e. parking level 2, "P2", or lower). Based on operational experience, current radio technology has connectivity challenges at specific locations, which create safety and operational concerns. To mitigate these risks, Toronto Hydro intends to procure and deploy powered wall-mounted units with wireless Bluetooth microphones, which pair to standard radio units so they can be used in locations where they otherwise could not receive a signal.

E8.4.4 Expenditure Plan

Table 5: Historical & Forecast Program Costs ($ Millions)

Segments	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
IT Hardware	7.5	9.3	10.1	7.8	7.8	11.5	10.3	11.6	14.0	14.5
IT Software	14.8	21.7	40.3	50.8	19.7	41.0	43.0	35.8	40.5	48.2
Communication Infrastructure	6.1	17.6	4.9	6.0	6.9	2.2	2.4	2.1	2.1	2.1
Total	**28.4**	**48.6**	**55.4**	**64.6**	**34.4**	**54.8**	**55.7**	**49.5**	**56.6**	**64.8**

Over the 2020 to 2024 period, Toronto Hydro forecasts spending $281.4 million across the three IT/OT Program segments. This represents an increase of $50.2 million (or approximately 22 percent) compared to 2015 to 2019 spending, which is inclusive of the following programs from Toronto Hydro's 2015 Distribution System Plan:

- E8.4 (IT Hardware)
- E8.5 (IT Software)

- E8.6 (Enterprise Resource Planning Program)
- E8.7 (Voice Radio System Upgrade Program)
- E6.22 (Distribution System Communication Infrastructure)

In addition, capital expenditures discussed in the Monthly Billing DVA in this application (see Exhibit 9, Tab 1, Schedule 1) map to the IT software segment.

IT/OT systems perform vital functions that are central to the safe and reliable operation of the distribution system and effective interaction between the utility and customers. The level of proposed spending is required to (i) refresh IT hardware systems at the end of their useful life, including data centre assets that were last upgraded just prior to the 2015 to 2019 period; (ii) upgrade Toronto Hydro's IT software applications that require remediation during the period, including the ERP and CIS, and make targeted investments to provide software enhancements that address business risks or compliance matters; and (iii) address specific OT system needs to mitigate risks such as functional obsolescence.

A number of controls and practices are in place to ensure that IT expenditures are prudently incurred and deliver value to customers either directly, through improved customer service, or indirectly from the performance or cost improvements enabled by certain investments. IT/OT expenditures are subject to Toronto Hydro's procurement policy, which can be found in Exhibit 4A, Tab 3, Schedule 1. For IT software investment, this applies to both the application itself and the system integration support services that are required to implement the solution efficiently and cost-effectively. Where feasible, Toronto Hydro makes efforts to time the procurement process during periods of the year when it is more likely to obtain discounts, such as year-end. Toronto Hydro also seeks to leverage existing vendors of record lists at the municipal or provincial level in order to leverage any potential volume discount that would allow the utility to obtain IT products at lower price points.

An independent benchmarking study performed by Gartner Consulting (see Appendix A) concluded that Toronto Hydro's total IT expenditures per user in both 2017 and 2020 benchmark competitively against industry peers.[8] Gartner also concluded that in both years that the distribution of Toronto Hydro's IT investments "by cost category, investment category and functional area are all comparable to the peer group, with some variation but no significant issues identified."[9]

[8] Gartner Consulting (2018), *IT Budget Assessment Final Report* found in Exhibit 2B, Section E8.4, Appendix A. pg. 1.
[9] Ibid.

Gartner further assesses Toronto Hydro's spending in a Run-Grow-Transform paradigm,[10] defined as:

- **Run**: "an indicator of how much of the IT resource is consumed and focused on the continuing operation of the business."
- **Grow**: "an indicator of how much of the IT resource is consumed and focused on developing and enhancing IT systems in support of business growth (typically organic growth) or improvement."
- **Transform**: "an indicator of how much of the IT resource is consumed and focused on implementing technology systems that enable the enterprise to enact new business models."

In both 2017 and 2020, Toronto Hydro IT investments are primarily directed at maintaining current business capabilities ("run") with the remainder directed at expanding existing business capabilities or driving new ones ("grow" and "transform" respectively).[11] The resulting split among the three categories is comparable to the peer group average, with slightly more focus on the "run" category. Toronto Hydro interprets this result as confirmation that its IT expenditures are appropriately balanced.

E8.4.4.1 IT Hardware

The table below outlines the approximate volume of hardware assets that Toronto Hydro plans to upgrade or replace during the 2020-2024 plan period.

Table 6: Hardware Volumes

Asset Category	IT Hardware	2015-2019 Actuals/Bridge		2020-2024 Plan	
		Capacity /Units	Total Cost ($M)	Capacity/ Units	Total Cost ($M)
Core Backend Infrastructure Assets (Capacity)	*Unix Virtual Servers*	440	33.4	560	50.8
	Linux x86 Virtual Servers	250		350	
	Windows Virtual Servers	1460		2660	
Endpoint Assets (Units)	*Personal Computing Devices*	2310	9.1	2310	11.1
	Printers & Plotters	180		180	

[10] Ibid, pg. 6
[11] Ibid, pg. 16

IT hardware cost estimates are derived by forecasting the number of hardware assets that are past their useful life and that are needed for incremental needs over the 2020 to 2024 period.

Toronto Hydro's IT Asset Management Strategy (Exhibit 2B, Section D5) details the utility's approach to replacing IT hardware assets. The timing and pacing of investment in each asset sub-type is driven by the asset lifecycle defined in the applicable standard, which are based on factors such as the criticality of the infrastructure, industry best practice, and vendor specifications. These standards are designed to extract the maximum value from hardware assets and minimize the negative impact of potential asset failures.

Toronto Hydro also considers forecast capacity requirements to ensure it has the necessary IT hardware to support general business growth and associated increased data storage and data processing requirements. The forecasts are based on the analysis of the following factors:

- Historical trends of current assets capacity versus utilization by existing IT systems;
- Asset resource requirements to support system enhancements and new initiatives; and
- New operational requirements that necessitate increased hardware resources.

Based on this approach, Toronto Hydro will require $61.9 million to replace its IT hardware with upgraded assets. Of Toronto Hydro's current assets, approximately 90 percent of existing core backend infrastructure (e.g. network, storage, and server assets) are forecast to require replacement in order to address reliability risks associated with those assets and provide the incremental capacity needed to support Toronto Hydro's IT footprint. The utility anticipates that all endpoint assets will need to be replaced between 2020 and 2024, at a pace that will address an approximately equal number of assets each year.

The main drivers of variance in spending are attributable to the timing of the asset lifecycles within the 2020 to 2024 period. During 2015 to 2019, only 50 percent of Toronto Hydro's core backend infrastructure assets needed to be replaced, whereas this is expected to rise to 90 percent during 2020 to 2024. The largest contributing factor is Toronto Hydro's two data centres, which were last renewed in 2014 and are scheduled for replacement during the next rate period. This scheduled refresh accounts for a majority (approximately $12 million) of the variance in spending between the two periods.

E8.4.4.2 IT Software

1. Software Upgrades

Over the 2020 to 2024 period, Toronto Hydro plans to spend $208.5 million on IT software upgrades, enhancements and regulatory compliance initiatives.

As discussed in the driver's section, Toronto Hydro plans to upgrade its Tier 1 software applications. Table 7, below, outlines the historical and forecast spending for the Tier 1 software applications.

Table 7: Tier 1 IT Systems Upgrades Costs ($ Millions)

IT Systems	2015 - 2019 Actual & Bridge	2020 - 2024 Plan
ERP	62.8	46.3
CIS	10.0	38.5
Tier 1 Systems excluding CIS & ERP	**36.7**	**40.2**
Tier 1 Systems Total	**109.5**	**125.0**

a. Enterprise Resource Planning

Compared to the 2015 to 2019 period, Toronto Hydro is proposing to decrease its spend in relation to the ERP system. As discussed in the 2015-2019 DSP (Exhibit 2B, E8.6), the utility detailed its need to replace the legacy system, Ellipse, in favour of a modern application to address significant reliability and cybersecurity risks. Through a competitive process, Toronto Hydro procured an independent System Integrator services provider for SAP implementation. In addition, the approved ERP program entailed the consolidation of 30 other legacy systems into the new ERP to streamline the effort required to administer and support those functions over the long run and minimize business risks.

In the 2020 to 2024 period, the scope of Toronto Hydro's planned investment in its ERP is reduced and paced more consistently across the five years. Toronto Hydro plans to upgrade its ERP database and application, referred to as ECC, to the current version of SAP's system, referred to as HANA. This upgrade is required because SAP will no longer provide vendor support to the ECC version by 2025. Without the proposed upgrade, this core IT system would be exposed to unacceptable reliability and cybersecurity risks, as detailed in Section E8.4.3. In addition to this upgrade, Toronto Hydro expects to implement ongoing security patches while vendor support is still available and incur data archiving and decommissioning costs from previous legacy programs.

The most opportune time to upgrade to HANA is expected to be later in the 2020 to 2024 window. By that time, SAP is more likely to have developed patches to address defects and performance issues that decrease system reliability and increase integration costs for early adopters. A more complex upgrade to HANA that would include more real-time analytics and logistics, and other required upgrades, was considered as part of the options analysis but ultimately determined to be sub-optimal. Please see the next section for a more detailed discussion.

In addition to the upgrade to the HANA platform, Toronto Hydro is proposing to make incremental improvements to the capability of its ERP system. These enhancements would build functionality within the ERP to address business risks (i.e. by minimizing manual processes or standalone systems) and/or mitigate cost pressures. Twelve different enhancements are proposed for the 2020 to 2024 period, addressing core processes such as regulatory compliance, timekeeping, health and safety functionality, and asset analytics.

Over the 2020 to 2024 period, Toronto Hydro also plans to integrate the ERP with other core IT systems. Integration enhancements would allow for the seamless exchange of information between systems, helping to mitigate the risks inherent to manual efforts that are otherwise necessary, or to improve reporting capabilities to assist decision making. The four applications planned for integration are the Document Management System, Customer Care & Billing (CIS), NMS/Oracle MWP, and GIS.

Toronto Hydro is proposing to stagger these investments over the course of the rate period in order to generate incremental benefits for IT operations. Sequencing the expenditures in this way will increase the likelihood that experience gained from the current ERP implementation during 2015 to 2019 could be leveraged to reduce the scope and cost of future System Integration services for ERP-related activities. In addition, pacing investment in the ERP helps to reduce the likelihood that more lumpy investments will be necessary in the future, such as what was required to replace Toronto Hydro's legacy ERP, Ellipse.

b. Customer Information System

Since April 2016, Toronto Hydro's legacy CIS has been without vendor support from Oracle, leaving it exposed to reliability and cybersecurity risks, as detailed above in Section E8.4.3. CIS is the foundation of a range of customer service functions, and any disruptions would likely have significant implications for the utility's customers. It is a highly connected application (33 major integration

points with other systems), the result of emerging compliance-related, and business or customer-driven adaptations.

To maintain the current CIS after the expiration of vendor support, Toronto Hydro invested in customizations (e.g. the provision of self-service options through *mytorontohydro.com*) that are increasingly difficult to administer and maintain. At present, there are about 1,000 separate interfaces, configurations, and customizations to the original Customer Care & Billing product, which can impede the ability to integrate the CIS with other systems, and thus limit their ability to improve business processes.

Toronto Hydro plans to upgrade to a fully supported version of Oracle's CIS, including the application, integration, reporting, middleware, and database. New "out of the box", functionalities are more technically capable to meet modern billing demands. Maintaining an Oracle-based solution (common among LDCs in Ontario) would allow Toronto Hydro to work collaboratively with its peers to find solutions to new compliance-related requirements. Functions that are currently carried out by customized code developed to provide functionality in relation to compliance requirements or other similar drivers will be embedded within the new system. This will make it easier and more cost-effective to adapt to new customer service or billing-related requirements, such as those related to the Long Term Energy Plan or Implementation Plans. The planned upgrade to the CIS would be optimized by using a two-phase process, with "go-live" dates currently scheduled for 2021 and 2024 respectively. This reduces implementation risks, optimizes the use of IT resources, and maintains vendor support for performance and security upgrades.

The upgraded CIS is expected to deliver considerably more flexibility to execute highly specific operations that will improve customers' experience (including with the Call Centre, billing, customer connections, and other customer-facing services) or reduce their transaction costs.

c. Other Tier 1 Systems

During the 2020 to 2024 period, Toronto Hydro plans to upgrade its other Tier 1 applications (listed above in Section E8.4.3) in line with lifecycles developed pursuant to its IT Asset Management Strategy. Cost variances for these upgrades, as shown in Table 7, are primarily due to inflation.

d. Tier 2 Systems

Table 8: Planned Tier 2 Application Upgrades

	2015-2019 Actuals/Bridge		2020-2024 Plan	
	Number of Applications	Cost ($M)	Number of Applications	Cost ($M)
Tier 2 Systems	61	8.0	72	13.4

The forecasts in the table above were derived by analyzing the lifecycles of all Tier 2 applications. Applications must be upgraded before reaching the end of their useful lives to mitigate the risk of failure and disruption to the processes they support. Increasingly, vendors are reducing the lifecycles of Tier 2 applications, meaning an increasing number will require more than one upgrade over the 2020 to 2024 period. The increased cost of upgrading on shorter intervals, the additional number of Tier 2 Systems anticipated to be in use and general price inflation are the primary drivers of the variance between the two rate periods.

2. Software Enhancements

Whereas software upgrades are triggered by a need to address reliability or cybersecurity risks, software enhancements mitigate core business risks that would not be technically feasible or cost-effective to address through a non-IT solution. The table below presents the number of planned software enhancements initiatives and their associated costs in the 2020 to 2024 period. The table also presents the number of enhancement initiatives that are expected to be completed over the 2015 to 2019 period and their associated costs.

Table 9: Software Enhancements Volumes and Cost

	2015-2019 Actuals/Bridge		2020-2024 Plan	
	Number of Enhancements	Cost ($M)	Number of Enhancements	Cost ($M)
Software Enhancements	26	22.0	45	60.9

As discussed in the Drivers section, software enhancements can take a number of different forms: adding an additional function to an existing Tier 1 application (aside from ERP and CIS, which are discussed above); integrating two systems to leverage otherwise independent data sets;

enhancement of reporting capabilities to make better use of existing data; or adding a new application.

The increase in cost for enhancements between 2015-2019 and 2020-2024 is a result of multiple factors. In 2015-2019, significant resources were dedicated to implementing the new ERP system, which represented a significant improvement over the legacy Ellipse system. A number of enhancements were included within the scope of that project that would have otherwise contributed to spending in this category during the period. Additionally, Toronto Hydro expects that customer and operationally-driven enhancements will be necessary to address risks or respond to changing consumer preferences. Inflation also contributes to the increase in Toronto Hydro's proposed planned expenditures.

A reduction in funding for software enhancements would leave Toronto Hydro behind its peer group, and less capable of responding to emerging customer and business-driven risks. The $60.9 million in software enhancements planned for the 2020-2024 plan period accounts for approximately 30 percent of Toronto Hydro's IT software segment. Toronto Hydro's total IT expenditures, of which Software Enhancements is one component, are generally consistent with its peer group in terms of the Run-Grow-Transform paradigm articulated in the Gartner IT benchmarking study (as discussed at the outset of this section).

3. Regulatory Compliance

The table below presents the anticipated number of regulatory compliance initiatives Toronto Hydro will need to complete in the 2020-2024 period and the associated budget. Also included in the table are the number of regulatory compliance initiatives that will be completed over the 2015-2019 plan period with their associated cost.

Table 10: Regulatory Compliance Volumes and Cost

	2015-2019 Actuals/Bridge		2020-2024 Planned	
	Number of Initiatives	Cost ($M)	Anticipated Number of Initiatives	Cost ($M)
Regulatory Compliance	5	7.8	6	9.3

Toronto Hydro anticipates it will require a small increment in funding for new compliance-related initiatives in the 2020 to 2024 period, in relation to a range of public policy initiatives such as those

listed in the provincial Long-Term Energy Plan, the LTEP Implementation Plans, and other important matters (e.g. cybersecurity).

E8.4.4.3 Communication Infrastructure

As detailed in Section E8.4.3, over the 2020-2024 period Toronto plans to undertake work in four discrete projects in this segment:

- Distribution system communication technology upgrade;
- Distribution system fibre-optic plant replacement and expansion;
- Wireless SCADA Infrastructure; and
- Underground radio expansion.

1. Distribution System Communication Technology Upgrade

The table below outlines the expected volume of work and associated costs over the 2020-2024 plan period to upgrade Toronto Hydro's distribution system communication technology.

Table 11: Distribution System Communication Technology Upgrade Volumes and Cost

	2020-2024 Volume (# of SONET Sites)	Total Cost ($M)
SONET Migration and Decommissioning	45	2.8

By the end of 2024, Toronto Hydro expects to eliminate the entire legacy SONET footprint and to convert all of its IT/OT station assets (e.g. RTUs) to the IP Stations Network. To achieve this plan, Toronto Hydro expects to spend approximately $0.6 million per year to engineer and execute the migration from SONET and to decommission the SONET environment. The availability of the modern IP Stations Network, delivered as part of the DSCI Program (see Toronto Hydro's 2015 CIR, Exhibit 2B, E6.22), is expected to be leveraged to carry out the planned migration and decommissioning work.

2. Distribution System Fibre-Optic Plant Replacement and Expansion

The table below outlines the expected volumes of work and associated costs over the 2020-2024 plan period to replace and expand distribution system fibre-optic plant.

Table 12: Distribution System Fibre-Optic Plant Expansion Volumes and Cost

	2020-2024 Volume (km of cable)	Total Cost ($M)
Fibre-Optic Cable	10	1.1

With the majority of fibre-optic installation completed between 2015 and 2019, Toronto Hydro expects to spend approximately $1.1 million in 2020-2024 on fibre-optic plant replacement and expansion to install approximately 2 kilometres of fibre per year. Historically, Toronto Hydro incurred costs of approximately $90,000 per kilometre, which is consistent with 2020 to 2024 forecasts after accounting for inflation.

3. Wireless SCADA Infrastructure Upgrade

The table below outlines the expected volumes of work and associated costs over the 2020-2024 period to upgrade the wireless SCADA infrastructure.

Table 13: Wireless SCADA Infrastructure Upgrade Volumes and Cost

	2020-2024 Volume (# of Radio Sites/ Endpoints)	Total Cost ($M)
SCADA High-Site Capacity Upgrade	12	0.8
Wireless SCADA Endpoint Radio Migration	885	3.0
Radio Installation	46	0.4

Toronto Hydro expects that by the end of 2024, all remaining end-of-life wireless SCADA assets will be upgraded or replaced. This work will be paced uniformly from year to year over the 2020-2024 period, taking into account the available resource capacity to perform the required tasks.

4. Underground Radio Expansion

The table below outlines the expected volumes of work and associated costs over 2020 to 2024 to expand the radio network to reach underground vaults.

Table 44: Underground Radio Expansion Volumes and Cost

	2020-2024 Volume (# of Radio Sites)	Total Cost ($M)
Underground Radio Sites	42	2.8

Toronto Hydro estimates that 42 underground vaults will require underground radio technology. This represents the number of vaults that are located underground at or below the P2 level. Each location requires radio equipment and associated installation costs, which includes drilling conduit through concrete to connect the radio equipment to an above-grade antenna.

E8.4.4.4 Project Prioritization

As detailed in the IT Asset Management Strategy (see Exhibit 2B, Section D5), Toronto Hydro has a robust decision making process to govern its IT/OT program. In accordance with this strategy, the utility ranks and prioritizes candidate initiatives in this program by weighing and balancing the following considerations and their impact on the utility's operations and customers:

- Compliance with applicable regulatory requirements;
- Required availability of the IT/OT systems to support core business operations and planned work programs. As described above, enterprise software applications are categorized into two tiers based on their criticality. Upgrades to Tier 1 applications take priority over Tier 2;
- Ensuring data in the IT/OT systems are secure and protected from cyber-attacks;
- Sustaining and improving current levels of customer service; and
- Other considerations such as application complexity, resource balancing, and co-ordination with other programs.

E8.4.5 Options Analysis/Business Case Evaluation ("BCE")

E8.4.5.1 Options Analysis/BCE for IT Hardware Segment

1. Option 1: Do Nothing

Under this option, IT hardware assets (both core backend infrastructure and endpoint assets) will be run to failure and replaced on a reactive basis. This option would introduce substantial risks to business continuity, information security, and service quality of Toronto Hydro's customer-facing and business-focused applications. Any disruptions or breaches of hardware assets would directly impact

IT software and by extension business processes reliant on the software, including critical grid services (e.g. SCADA) and customer-facing channels (e.g. Contact Centre).

Hardware beyond its useful life is more prone to failures without warning, potentially resulting in prolonged service outages and significant impact on business continuity. Old hardware is less likely to be supported by the vendor, extending the length of an outage and increasing the cost of restoration. Unsupported hardware failures may result in data losses and inability to recover lost data, posing an unacceptable risk to Toronto Hydro's ability to provide its core services to ratepayers and comply with legislative and regulatory obligations. Unsupported hardware is also more prone to cybersecurity breaches, as vendors stop issuing security patches to mitigate critical gaps once hardware becomes unsupported.

2. Option 2: Externally Hosted Solution for Core Backend Infrastructure Assets; Endpoint Asset Replacements Based on IT Asset Management Strategy

Under this option, the entirety or a portion of Toronto Hydro's core infrastructure assets would be migrated to a managed services provider, such as a data centre co-location facility or a public cloud. Toronto Hydro is concerned that externally hosted services would introduce too much risk and uncertainty at this time. Public cloud facilities are primarily tailored to corporate users operating generic web-centric applications using commodity hardware. Critical production applications, such as SCADA, NMS, and CIS, are not readily deployed through public cloud infrastructure, due to the lack of support by external providers for these types of technologies. The need for tight functional coupling between in-house infrastructure hardware, telecommunications, and in-field O/T facilities further limits the feasibility of hosting core infrastructure hardware assets externally. Cyber security is also a critical factor with externally managed infrastructure, as secure links, interfaces, and perimeter would otherwise need to be established and maintained between internal and external facilities, at significant cost.

3. Option 3: Internally Hosted Solution for Core Backend Infrastructure Assets; Endpoint Asset Replacements Based on IT Asset Management Strategy

This option would continue the status quo approach. Adherence to the established architectural standards, capacity, and lifecycle models based on industry norms will ensure a supported, scalable, available, and secure IT hardware asset base, capable of adequately supporting core business applications and processes. Operating a vendor-supported hardware base minimizes the risks to

business continuity, enabling Toronto Hydro to focus on its core business functions and provide the levels of service expected by ratepayers.

This option leverages the existing investment in data centres and telecommunications facilities (e.g. fibre-optic plant) and provides purpose built IT/OT ecosystem tailored to the specific business functions provided by Toronto Hydro.

4. Option Evaluation

Option 3 is preferred. With respect to core backend infrastructure, Option 3 entails the least risk and disruption to business operations. This approach provides flexibility to modify hardware asset maintenance windows on an as-needed basis and to quickly respond to hardware outages (i.e. internally escalate hardware asset issues for resolution). Option 3 obviates the need of a secure connection between Toronto Hydro's network and externally hosted infrastructure, thus mitigating cyber security risks and avoiding incremental network connectivity costs. Option 3 also mitigates the data residency risk associated with Option 2, where Toronto Hydro would be restricted to selecting an externally hosted and managed solution within the province/country.

With respect to endpoint assets, Option 3 (which is equivalent to Option 2 for purposes of endpoint assets) is preferable because it would allow proactive replacements before asset performance deteriorates or fails. This would mitigate the risk of employee downtime, as well as re-work and data loss from failure of endpoint assets. With access to reliable and updated endpoint assets, employees will be able to perform their duties more efficiently and ultimately ensure the effective delivery of customer service and experience. Lastly, this option would also reduce the need to procure new endpoint assets on an expedited basis from vendors, or to maintain a large number of spare devices to address potential failure.

E8.4.5.2 Options Analysis/BCE for IT Software

1. Option 1: Do nothing

Under this option, Toronto Hydro would not upgrade its Tier 1 and Tier 2 applications (including the ERP and CIS), allowing them to operate without vendor support on an ongoing basis. Toronto Hydro would be responsible for maintaining and further customizing applications using manual work-arounds, which become increasingly complex, risky, and costly over time. Without vendor support

for security-related patches, this option poses significant cyber security risk because outdated systems would be more vulnerable to cyber-attacks and compromises.

With respect to the ERP, the do nothing option would mean that it would become a legacy system in Toronto Hydro's IT landscape and lose vendor support by the end of the rate period. The ERP and underlying technology would no longer receive patches to fix new security or functional defects, leaving it exposed to cyber threats. The processes proposed to be integrated with the ERP would remain manual work-arounds, leaving data in silos across the organization, increasing the risk of data errors and limiting the reporting capability of the systems. Other Tier 1 systems would not be integrated, creating a barrier to more efficient and effective management of Toronto Hydro's distribution system.

With respect to the CIS, which is already without vendor support, the do nothing option would mean that the system would not gain vendor support, including patches to fix new security or functional defects. This option would also fail to integrate new process customizations, such as those relating to recent public policy changes. Continued reliance on the current CIS would significantly impede the company's ability to modify the CIS in response to future changes in public policy, customer service expectations, and industry best practices.

2. Option 2: Software Upgrades - Outsourced Management of IT Applications

Under this option, Toronto Hydro would engage a third-party service provider to manage its IT applications, including with respect to the pursuit of any required software upgrades.

This option presents a number of operational and cost risks. If significant volumes of IT-related incidents require support (e.g. due to major events like storms or flooding), third parties may not be sufficiently responsive or capable to deal with extraordinary circumstances that require intensive effort. This would also leave Toronto Hydro more exposed to vendor-related cybersecurity risks due to the change in responsibilities and direct controls over Toronto Hydro's data. This option could result in prolonged outages to the distribution system or to customer services.

Procuring contracts of this nature would exert significant cost pressures on Toronto Hydro's operational budget.

3. Option 3: Software Upgrades and Expansions Based on IT Asset Management Strategy; Simple Scope Enhancement of the ERP; and Technical upgrade of the CIS

Under option 3, Toronto Hydro would pursue standards-based asset lifecycle management of software upgrades and enhancements to meet business needs in alignment with its IT Asset Management Strategy. This option would proceed with the software upgrades to Tier 1 and Tier 2 applications. With respect to the ERP and CIS, Option 3 would entail a relatively limited level of investments, as explained below.

The simple scope enhancement of the ERP would consist of a limited one-way integration with other systems and less-capable enhancements than those proposed in the Expenditure Plan. While some benefits can be realized under this option at slightly less than 60 percent of the cost of the preferred plan, there would be minimal integration achieved with other non-ERP IT systems, and little to no new ERP functionalities (including new reporting features). Under this option, most manual work and duplicate processes will remain unchanged, and most data will be scattered across different repositories without interface with the ERP.

A technical upgrade of the CIS would provide a system that is vendor supported, and allow Toronto Hydro to adapt more easily to evolving regulatory or business requirements. Vendor support will more readily enable modifications and enhancements to the CIS in response to evolving market trends, public policy requirements, and security risks. However, customizations already built to address recent modifications would not be integrated into the software. As evolving business needs drive further changes within the new system, higher costs will be incurred under Option 3 due to the legacy process and architecture complexity and, at some point, may be technically infeasible to support. This investment is expected to cost approximately half of the proposed $38.5 million.

4. Option 4: Software Upgrades and Expansions Based on IT Asset Management Strategy; Moderate Scope Enhancement of the ERP; and Enhanced Implementation of the CIS

The main difference between Option 3 and Option 4 is the incrementally expanded, moderate scope of investments proposed for the ERP and CIS under Option 4. This option is described at length in the Expenditure Plan.

5. Option 5: Software Upgrades and Expansions Based on IT Asset Management Strategy; Complex Scope Enhancement of the ERP; and New Implementation of the CIS

The main difference between Option 4 and Option 5 is the incrementally expanded, large scope of investments proposed for the ERP and CIS under Option 5.

A complex scope solution with respect to the ERP entails a broader integration with the non-ERP IT systems and the full extent of the enhancements proposed in Option 4. It would also entail implementing a newer version of HANA that is current at the outset of its product life. This approach would yield new ERP functionalities, including many new reporting features, but is expected to cost more than double the $46.3 million proposed for Option 4.

A new implementation of the CIS entails decommissioning the current CIS and implementing an entirely new system to be selected, at a cost of approximately 30 percent more than Option 4. It would also likely require a lengthier implementation timeline to sufficiently architect the data flows and interface. Implementing a new Tier 1 system is not expected to deliver any material incremental benefits to an upgraded Oracle CIS application.

6. Option Evaluation

Option 4 is the preferred option. Compared to Options 1 and 2, this approach minimizes risks to the reliability and cybersecurity of Toronto Hydro's IT software applications. In very limited and targeted circumstances, Option 2 (externally hosted solution) would be considered for a particular software solution if it can be implemented more quickly, reduce operational risk, simplify any required change management processes, and have sufficient cyber security protections in place.

Option 3 does address the cybersecurity concerns of continuing to operate applications without vendor support, such as security patches. However, it leaves legacy customizations to the CIS unaddressed, creating operation cost and logistics challenges (which can be mitigated by Option 4). For the ERP, integration with the four systems listed in the Expenditure Plan would be limited to a single direction, significantly constraining the potential value of integration, and enhancements would not sufficiently streamline work processes in response to business needs, regulatory requirements, or customer expectations.

Option 5 would require a significant amount of additional funding for the ERP and CIS without sufficient incremental benefits. The benefits of the ERP approach in this Option would be significant,

but not significantly so. There is little incremental benefit to the Option 5 approach for the CIS. On this basis, Option 5 is not preferred.

E8.4.5.3 Options/BCE for Communication Infrastructure

Toronto Hydro evaluated the following options:

- Option 1: Do nothing.
- Option 2 (Selected Option): Implement the proposed approach.

For the SONET migration and decommissioning and the wireless SCADA infrastructure upgrade, the do nothing option would leave in place the current obsolete technology. While this would temporarily defer replacement, Toronto Hydro would likely incur additional costs to maintain these assets in the absence of vendor support and/or experience longer system outages. Option 2 is preferred, as it would cost-effectively address the associated failure risks.

For the fibre-optic plant replacement and expansion, the do nothing option would leave parts of Toronto Hydro's system without requisite infrastructure to support SCADA penetration and network innovation. The proposed approach is cost effective and leverages existing plant installed under an approved program from the 2015 CIR application.

For the Underground Radio Expansion, the do nothing option would not resolve the existing safety and operational issues in vaults located underground, at levels P2 or below. As an alternative to radio expansion, Toronto Hydro considered using bi-directional amplifiers to enhance the radio signal into the vault and installing a permanent radio similar to that used in Toronto Hydro's truck fleet. The proposed approach, a solution that leverages existing portable radios, was found to address the operational and safety risks more cost-effectively than the alternatives.

E8.4.6 Execution Risks & Mitigation

This section discusses various potential risks to the execution of the IT/OT program, and Toronto Hydro's corresponding mitigation measures:

- **Internal Resource Availability:** There may be insufficient resources to complete the planned program tasks and activities, which could delay interdependent and downstream work activities and lead to escalations in project costs due to the need to procure temporary skilled resources at a premium. In response, Toronto Hydro will: (i) adopt a long term

resource plan based on project tasks and activities that the utility plans to undertake over the 2020-2024 period; and (ii) ensure appropriate responsibility overlaps between labour resources to minimize impact from attrition.

- **Vendor Management:** Vendors may not meet program delivery obligations or may change the product cost structure. More specifically, a vendor may be unable to provide the product according to project schedule or in compliance with Toronto Hydro's specifications, thereby leading to delays or cost overruns to address the issue. In this regard, Toronto Hydro will adopt the following mitigation measures to ensure contractual mechanisms are available as well as to oversee and enforce contract terms and conditions:
    - Clearly state expected timelines and have resolution clauses to address delays.
    - Identify an escalation path to quickly resolve conflicts and discrepancies.
    - Enforce short interval control through vendor project status updates and reports.
    - Complete comprehensive due-diligence of scope and requirements prior to undertaking projects and incorporate findings in the tender documentation.
    - Enter into long term contracts, where appropriate, with vendors and suppliers to ensure costs are fixed over a long period of time.
    - Solicit vendor responses to competitive bids from qualified parties.
- **Technology Change:** New technology may be introduced after previous assets were refreshed during the asset's lifecycle. This risk may impact project cost, as new technology may need to be procured to meet business requirements. Toronto Hydro closely monitors the latest trends to determine how technology fits into existing Toronto Hydro IT standards and business requirements.
- **Adherence to Budget & Timelines:** If a project tracks above budget or falls behind schedule, this could take resources away from other important IT projects and delay their implementation. To address this risk, Toronto Hydro uses modern project management methods, tools, and vendor agreements to ensure on-time and on-budget project execution. Moreover, Toronto Hydro's experienced project managers will control the implementation timing of projects in accordance with each project plan and emerging risks. Contract tools and incentives will also be incorporated to aid the management of timelines.
- **Project Delivery**: A new IT/OT System version could cause established core business processes to change and, without proper integration, could disrupt, and cause inefficiencies in these processes. Toronto Hydro undertakes extensive regression testing and user testing prior to rolling out the final upgrade to the business units. In addition, risks are mitigated

through appropriate user engagement and communication, change management, and project governance including contingencies to minimize the impact to the business users in the final implementation.

- **Regulatory Requirements:** Currently unknown new regulatory requirements can require additional resources and time to implement. If new regulatory requirements emerge at a higher than expected rate, resources will be re-allocated to ensure that Toronto Hydro complies with application requirements. Projects will be rescheduled as necessary in accordance with the project prioritization considerations outlined in section E8.4.4.4 above.
- **IT/OT Systems Integration:** Different systems may not be properly integrated with each other when a system or group of systems are upgraded or replaced. If the current level of integration is not maintained, business processes could be impeded and process inefficiencies could be introduced from manual data updates. Toronto Hydro considers and analyzes new component configurations in defining project scopes, and conducts thorough due diligence during technical feasibility studies.
- **Software Release Dates:** Changes to application version release dates will impact the project schedule and potentially impact downstream projects in the program. If one or more software upgrades require another software upgrade to be completed first, any delay in the release of the first software upgrade will delay the upgrade of the dependent software system(s). To address this risk Toronto Hydro monitors release dates, ensures that all impacted projects are properly sequenced, follows best practices in project management, and maintains a holistic view of IT environment/architecture to identify interdependencies.
- **Solution Fit to Utility Requirements**: A design approach that considers functionalities in isolation is particularly risky. The solutions proposed for incorporation into the upgraded and expanded IT systems must be able to deliver the functionality Toronto Hydro requires to meet its operational, regulatory, and customer obligations. Toronto Hydro will fully consider all areas of its operations before any configuration or coding has taken place. All processes and system requirements will be defined and documented by Toronto Hydro prior to tools, components and modules selection, and integration. End-to-end operational process scenarios will be used in the testing phase of the system.

Toronto Hydro-Electric System Limited
EB-2018-0165
Exhibit 2B
Section E8.4
Appendix A
ORIGINAL
(35 pages)

IT Budget Assessment Final Report

16 March 2018

Prepared for: Torys LLP

Project Number: 330045299

GARTNER CONSULTING



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Executive Summary

- In connection with THESL's upcoming distribution rate application, Gartner completed a peer benchmark of the THESL IT budget.
  - The assessment included a comparison of high level IT metrics and spending and staffing distributions with a view to providing insight into how IT spending aligns with peer organizations.
- For 2017, THESL IT Spending as a Percentage of Revenue and of Operational Expense are both lower than the peer group (2.2% vs 2.5% and 2.4% vs 3.1% respectively).
  - Infrastructure support cost is also less than other peer organizations would spend to support the same workload – $32.4M compared to $37.1M (12.6% or 4.5M less).
- Distribution of spending by cost category, investment category and functional area are all comparable to the peer group, with some variation but no significant issues identified.
- THESL also provided Gartner a forecast for 2020 spending and staffing in addition to 2017 data.
- Results of the comparison of the 2020 forecast to the 2017 peer group show similar results.
  - For 2020, THESL IT Spending as a Percentage of Revenue and of Operational Expense are both lower than the peer group (2.3% vs 2.5% and 2.7% vs 3.1% respectively).
- As in 2017, the distribution of spending by cost category, investment category and functional area are all comparable to the peer group, with some variation but no significant issues identified.
- THESL did not forecast infrastructure workload or users, so Gartner did not calculate comparable infrastructure efficiency or employee-based metrics for 2020 data.

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Contents

- Project Background and Objectives
- Benchmark Analysis Methodology
- Results for Fiscal Year 2017
- Projected Results for Fiscal Year 2020

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Project Background and Objectives

- In connection with THESL's upcoming distribution rate application, Gartner has conducted an assessment of the THESL IT budget.
  - The assessment includes a comparison of high level IT metrics and spending and staffing distributions with a view to providing insight into how IT spending aligns with peer organizations.

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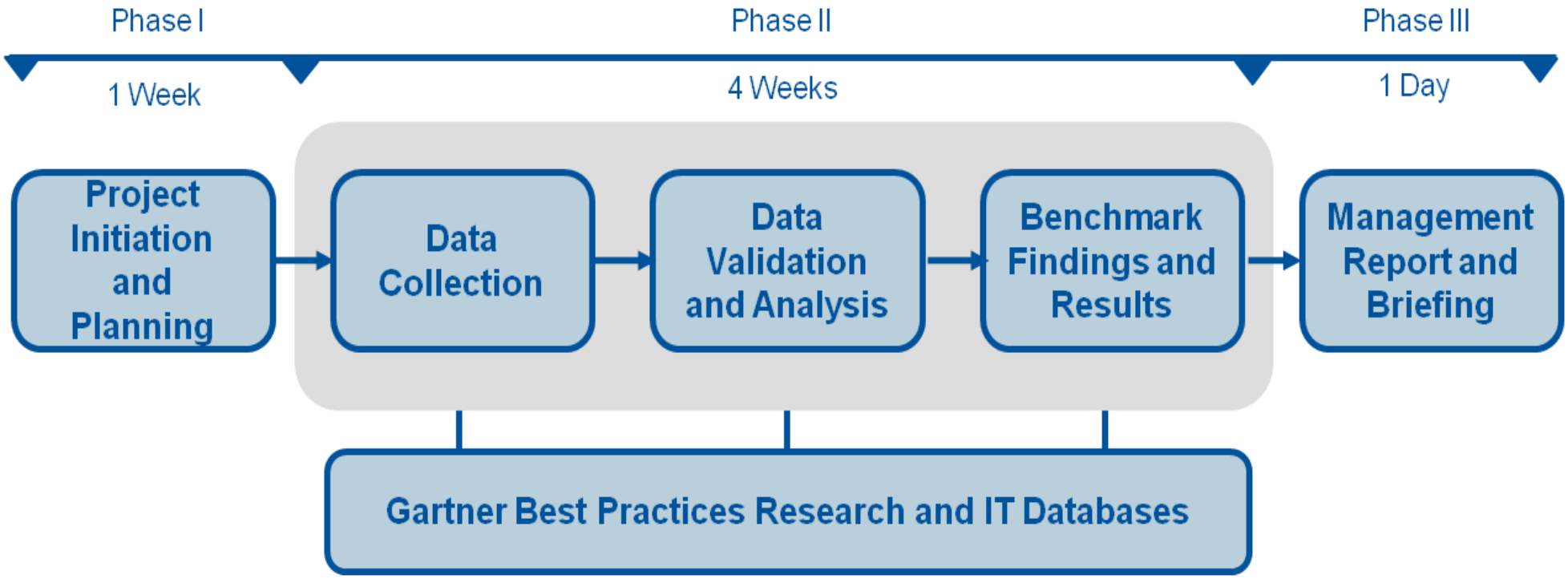
Benchmark Analysis Methodology
IT Budget Assessment Project Schedule

At a high level, the project specific tasks and timeline are shown in the figure below:



Torys provided data collected by THESL staff based on Gartner data definitions. Gartner conducted a data validation with the teams to ensure data definitions were followed and the comparative results are accurate.

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Benchmark Analysis Methodology
Key Concepts

- **Revenue**: The enterprise revenue associated with the business units supported by the IT organization.
- **Operational Expense**: Enterprise expense equals the expense associated with the business units supported by the IT organization.
- **IT Budget /Spend**: The best estimate of total spend at the end of the twelve month budget period for information technology to support the enterprise. IT Budget/Spending can come from anywhere in the enterprise that incurs IT costs, and it is not limited to the IT organization. It is calculated on an annualized “cash out” basis and therefore contains capital spending, and operational expenses, but not depreciation and amortization. IT budget/spending information collected from clients typically does not include:
  - Costs for technology or services that are resold - An example of this is salaries for developers involved in building commercially packaged software.
  - Operational technology that is equipment built or purchased for non data processing purposes but which has computerized components – Examples of this include robotic manufacturing machines, Automated Teller Machines, specialized point of sale devices, scanners, blood pressure monitors etc.
  - Depreciation or amortization expenses as that could lead to double counting from an accounting perspective.
  - Internal “cross charges” and corporate allocations related to expenses such as, early retirement, incentive bonuses, human resources, and chairperson's salary etc.
  - Business data subscriptions and services (such as Bloomberg), even if they are managed by the IT organization.

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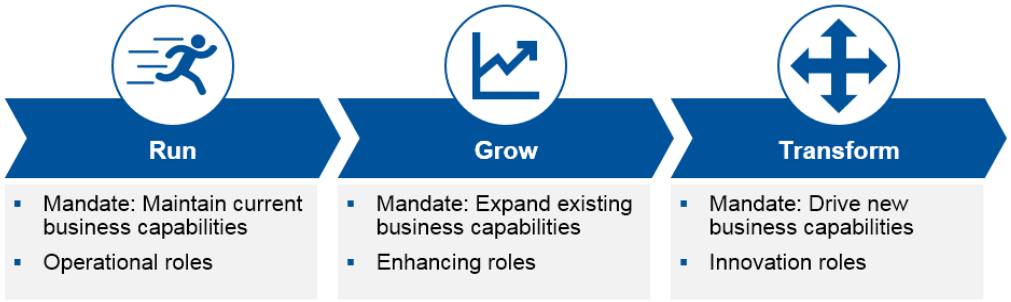
Benchmark Analysis Methodology
Definitions for Run, Grow and Transform Allocation

Business Value Category Decision Tree for Run, Grow and Transform the Business IT Spending Allocation



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- **Transform the Business**: This is an indicator of how much of the IT resource is consumed and focused on implementing technology systems that enable the enterprise to enact new business models. This is very much a "venture" category and would be represented by activities such as an insurer introducing usage-based insurance products such as telematics or a supermarket combining real time analytic monitoring with in-store task management to provide automated alerts to store staff to perform preemptive tasks.
- **Run the Business**: This is an indicator of how much of the IT resource is consumed and focused on the continuing operation of the business. It includes all non-discretionary expense as part of the Run the Business Cost.
- **Grow the Business**: This is an indicator of how much of the IT resource is consumed and focused on developing and enhancing IT systems in support of business growth (typically organic growth) or improvement. Discretionary investments are included in the Grow/Improve the Business Cost.

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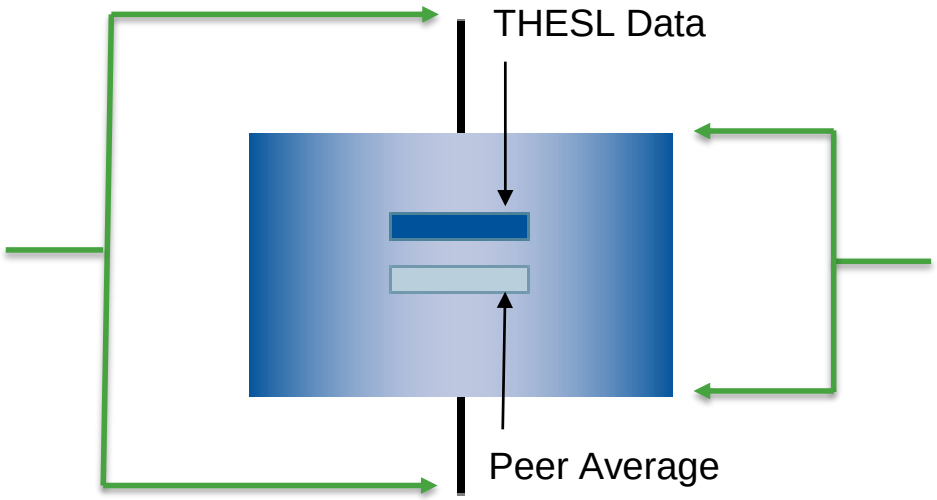
Benchmark Analysis Methodology
Peer Comparisons

THESL's results are displayed in comparison with the following reference points:

Peer Range: the 10th percentile to 90th percentile range of results for the comparison group



Peer Middle quartile range between the 25th and 75th percentiles for the comparison group.

Differences in spending and staffing metrics derived from this analysis provide insight into current strategic IT investment levels relative to business performance and scale vs. the competitive landscape.

These measures should also be considered within the context of future state business objectives.

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Benchmark Analysis Methodology
Peer Comparisons

- A peer group of 15 Utilities was selected based on industry and revenue.
  - The same peer group is used for both the 2017 and projected 2020 results.

	THESL 2017	THESL 2020	Peer Average
Revenue (millions)	$4,016.9	$4,042.5	$4,477.8
Operational Expense (millions)	$3,572.7	$3,447.5	$3,659.8
Organization Employees	1,390	1,467	4,730
Organization Users (from Active Directory)	3,430	N/A	N/A
IT FTEs	214	200	305
IT Capital and Operational Expense (millions)	$87.1	$92.9	$110.4
Customers	758,193	784,095	1,233,000

  - Peer geographic distribution is 7 United States, 4 Canada and 4 Western Europe.
  - All serve major urban locations.
  - THESL 2017 data is based on 11 months of actuals plus one month estimate to complete.

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Results for Fiscal Year 2017

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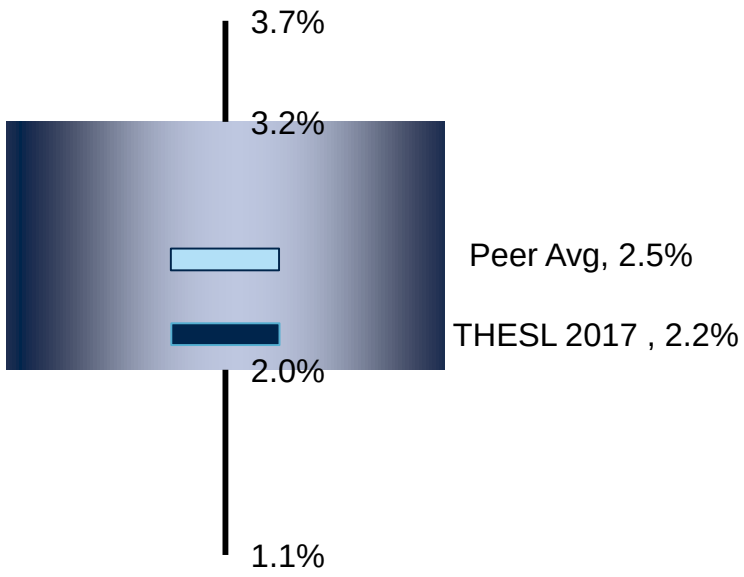
2017 IT Spending as % of Revenue



- IT Spending as a Percentage of Revenue for THESL is about 14% less than the peer group, 2.2% compared to 2.5%.
  - IT Spending as a Percentage of Revenue is a common measure of IT's role in the business, and a measure to assess the comparative level of spending with industry peers.
- Being above or below average does not necessarily mean spending is "too high" or "too low."

Cylinder denotes the median 50% of responses

= Peer Range
= Peer Middle Quartiles
= Peer Average
= THESL 2017

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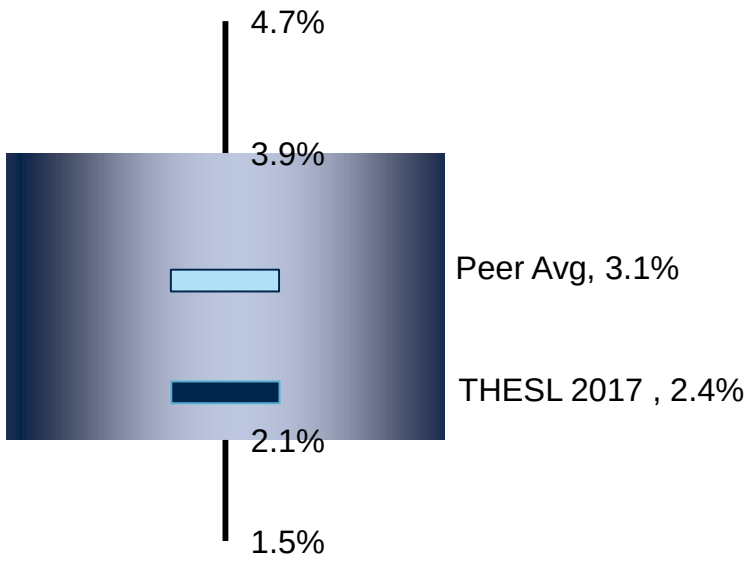
2017 IT Spending as % of Operational Expense



- IT Spending as a Percentage of Operational Expense for THESL is about 22% less than the peer group, 2.4% compared to 3.1%.
  - IT Spending as a Percentage of Operational Expense provides a view of the role IT plays in business spending patterns: the greater the amount of operating expenses is dedicated to IT, the greater the business generally requires visibility into IT investments.

Cylinder denotes the median 50% of responses

= Peer Range **= Peer Middle Quartiles**

= Peer Average **= THESL 2017**

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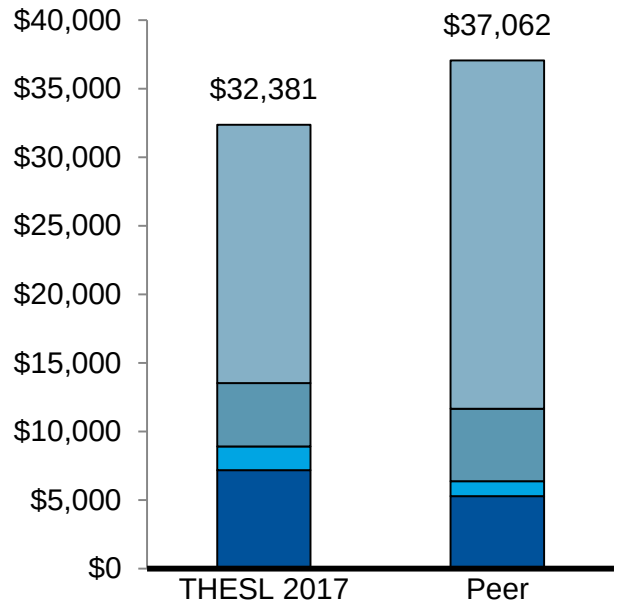
Infrastructure Support Efficiency

THESL 2017 IT infrastructure spending is 13% ($4.7M) less than organizations of similar size would spend to support the same workload, $32.4M compared to $37.1M.



	THESL 2017	Peer
Data Center	$18,849	$25,412
End-User Computing	$4,625	$5,274
IT Service Desk	$1,724	$1,097
Voice & Data Networking	$7,183	$5,279
Total	$32,381	$37,062

- THESL provided 2017 infrastructure workload measures in addition to IT spending and staffing budgets and distributions, allowing this comparison of infrastructure costs to Gartner benchmark database averages.
  - 441 Unix OS Instances
  - 1,464 Windows OS Instances
  - 252 Linux x86 OS Instances
  - 4,041 TBs Raw Storage
  - 4,038 Personal Computing Devices
  - 49,301 IT Service Desk Contacts
  - 3,430 Active Directory User Accounts (Voice & Data Users)
- Gartner allocated 48% of THESL Corporate IT Management and IT Finance & Administration to infrastructure spending (infrastructure is 48% of total infrastructure and applications).
  - Within the Gartner database, these costs are included in the detailed infrastructure metrics but not broken out separately.

- *Note that 2020 infrastructure workload measures have not been forecast so there is no comparison for the 2020 period.*

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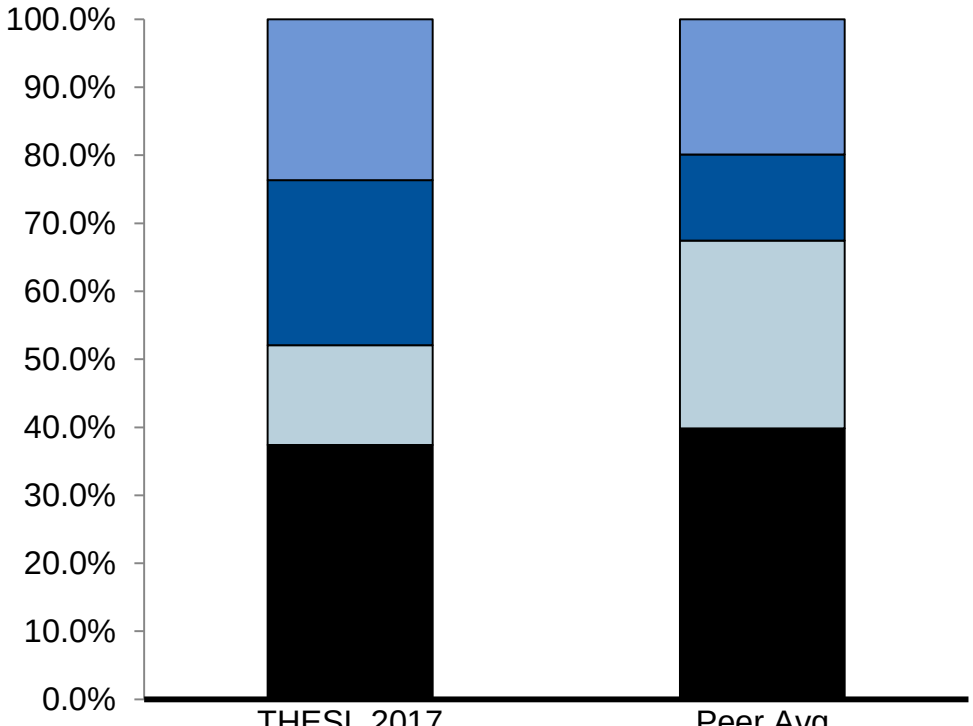
2017 Spending Distribution by Cost Category



	THESL 2017	Peer Avg
Outsourcing	23.6%	19.9%
Hardware	24.3%	12.7%
Software	14.7%	27.6%
Personnel	37.4%	39.8%

- The distribution of spending between hardware, software, personnel and outsourcing shows a lower distribution of spending for Software than the peers, but higher for Outsourcing and Hardware.
  - The distribution of spending for Personnel is also slightly lower.
- This distribution represents a “capital view” of IT spend which includes current-year capital and operational spending (and excludes depreciation and amortization).

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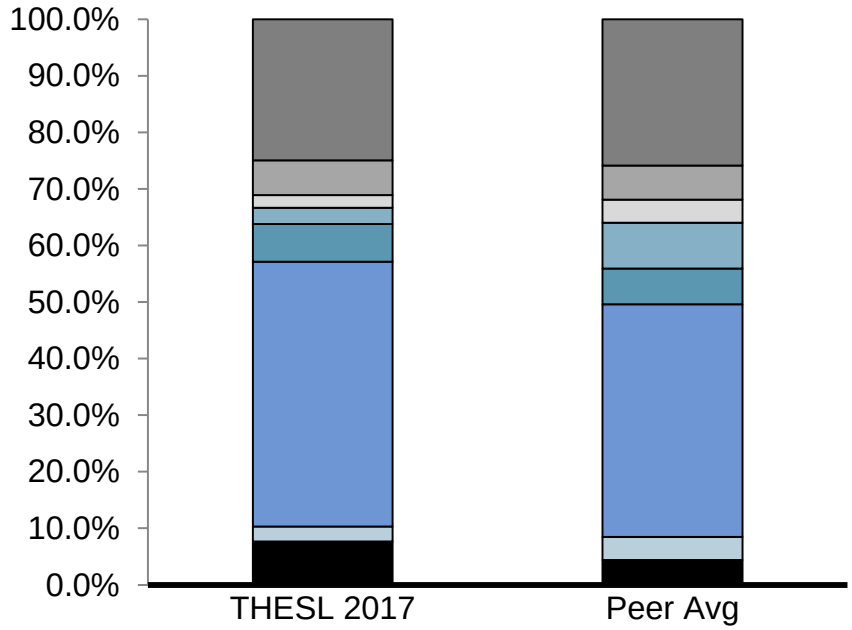
2017 Spending Distribution by IT Functional Area



	THESL 2017	Peer Avg
Data Center	25.0%	25.9%
End-User Computing	6.1%	6.0%
IT Service Desk	2.3%	4.1%
Voice Services	2.8%	8.1%
Data Networking	6.7%	6.3%
App Dev & Support	46.9%	41.2%
Corporate IT Mgmt	2.6%	4.1%
Finance & Admin	7.7%	4.4%

- The distribution of spending by functional area provides a view of key IT resource consumption.
- The distribution of spending for IT Service Desk and Voice Services are lower than the peer group, while Applications is slightly higher.
  - Combined Corporate IT Management, Finance & Administration is also slightly higher than the peer group.
- This distribution represents an “expense view” of IT spend which includes current-year operational expense as well as current-year lease, maintenance, depreciation and amortization expense.

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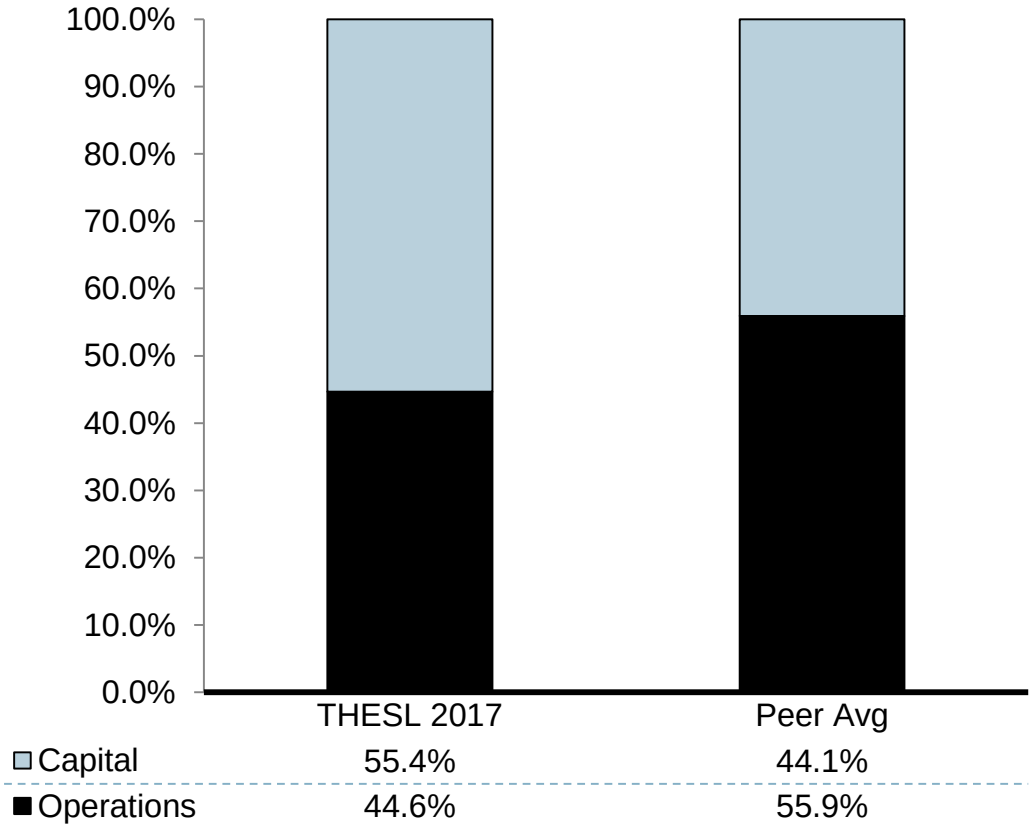
2017 Spending Distribution – Capital and Operational Spend



- For 2017, the percentage of the IT budget for Capital is greater than the peer group, while the percentage of spending for Operations Expense is lower.
- IT capital expenses vs. operational expenses helps to portray the investment profile for an organization in a given year.
  - In 2017, an ERP replacement project contributes to a high percentage of spending on capital projects.

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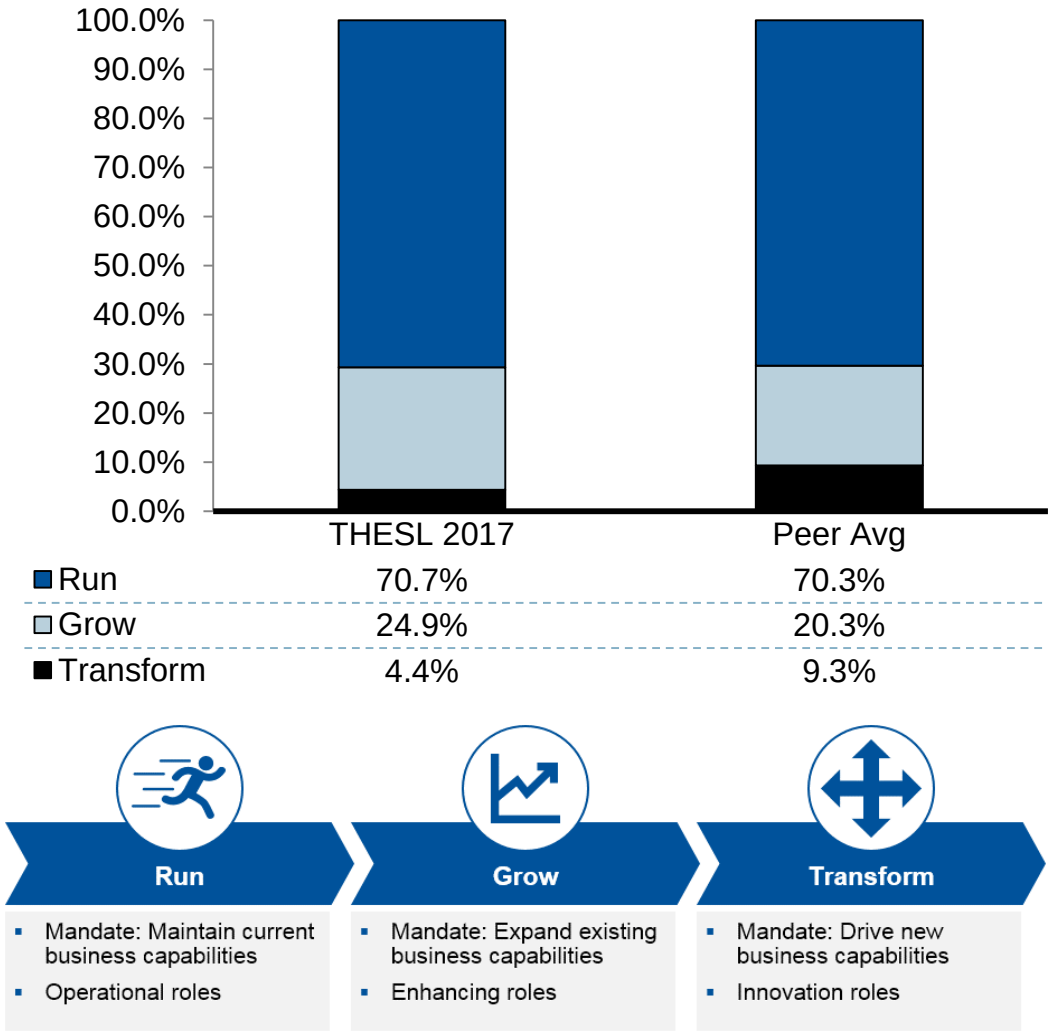
2017 Spending Distribution – Run, Grow, Transform



- The distribution of the IT Budget categorized as Run, Grow and Transform is similar to the peer group.
- The distribution of IT spending to “run,” “grow” and “transform” the business provides a view of the investment profile in business terms.

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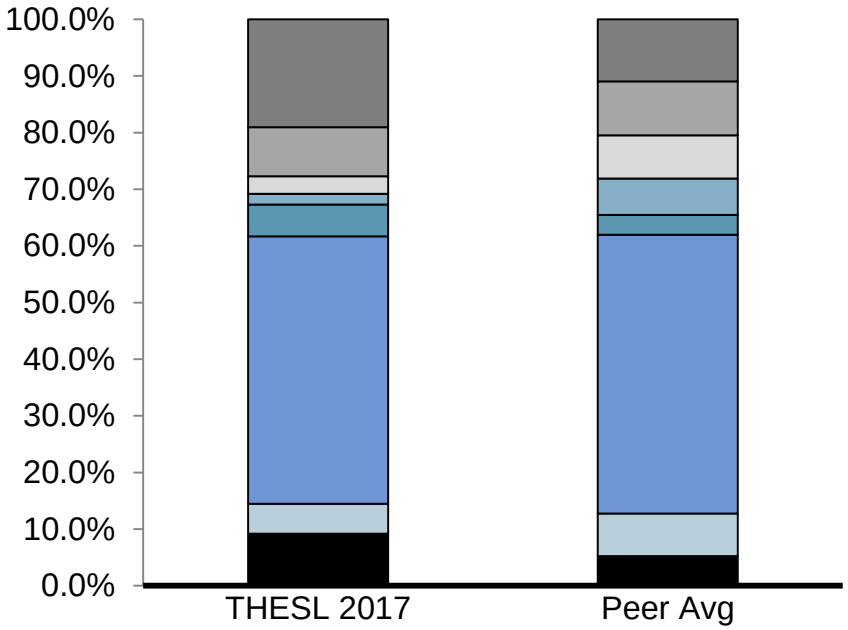
2017 Staffing Distribution by IT Functional Area



	THESL 2017	Peer Avg
Data Center	19.0%	10.9%
End-User Computing	8.7%	9.5%
IT Service Desk	3.1%	7.6%
Voice Services	1.9%	6.4%
Data Networking	5.6%	3.5%
App Dev & Support	47.2%	49.2%
Corporate IT Mgmt	5.3%	7.5%
Finance & Admin	9.2%	5.2%

- Data Center and Data Networks have a higher percentage of staffing than the peer group.
- The percentage of Finance & Admin staffing is also higher.

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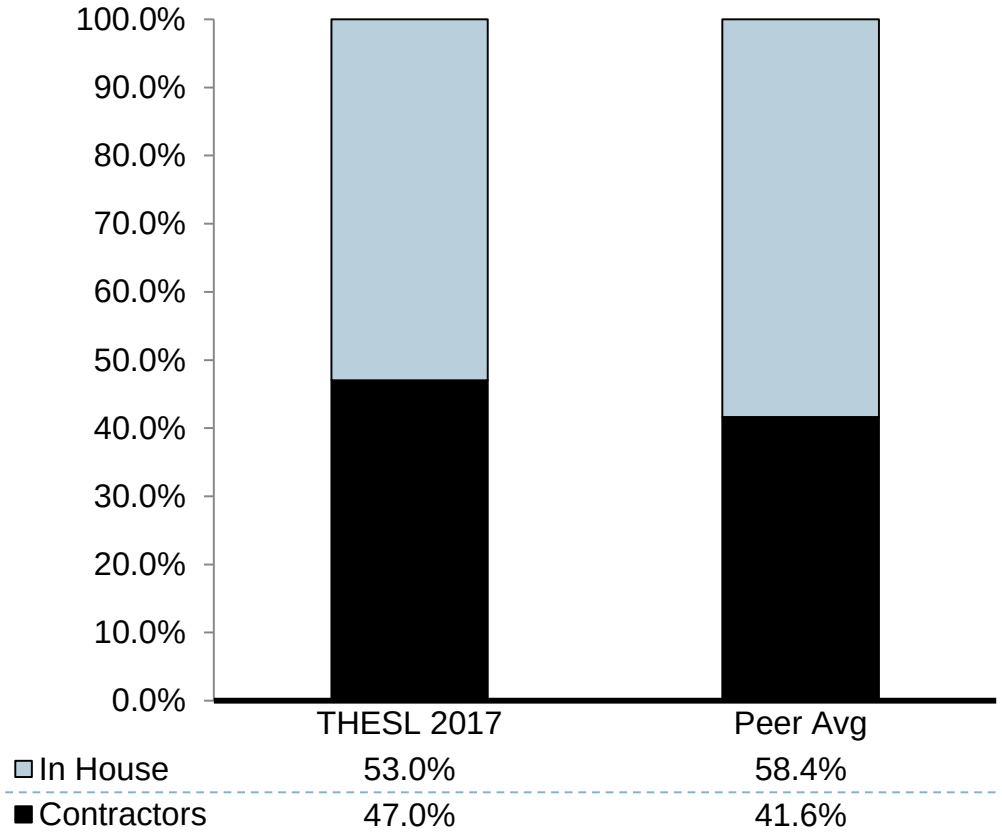
2017 IT Contractor Usage



- THESL and the peer group both rely on a high percentage of contractor IT staff.
  - This distribution provides a reflection of the IT staffing strategy and can be useful in managing support when there are fluctuating demands for IT services.

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Employees versus Users at THESL

- Gartner typically collects the number of employees for an IT Budget Assessment, and bases three standard metrics on employee count: Revenue per Employee, IT Spending per Employee and IT FTEs as a Percentage of Employees.
  - Many of the IT departments Gartner works with and has in our peer benchmark database typically do not know the number of contractor labour or level of outsourcing in the lines of business, and Gartner does not normally collect a number of users.
- As with other measures comparing IT spending to business measures, these three metrics can be influenced by both the numerator and denominator.
- For THESL, these three metrics appear to be skewed compared to the peer group based on the employee count, rather than by IT spending and staffing.
- As a test of this assumption, Gartner computed metrics using THESL number of Users rather than Employees and compared results.
- While metrics based on Employees are about 2.2 to 2.5 times greater than the peer group, the results based on Users are between 0 and 10% less than the peer group.
  - The metrics based on Users are in line with the other metrics (IT Spending as a Percentage of Revenue and Operational Expense), supporting the assumption that it is THESL employee count not IT spending or staffing that drives the results on the next three slides.

Note that the number of Users has not been forecast for the 2020 period, so Gartner has not reported 2020 results for these metrics.

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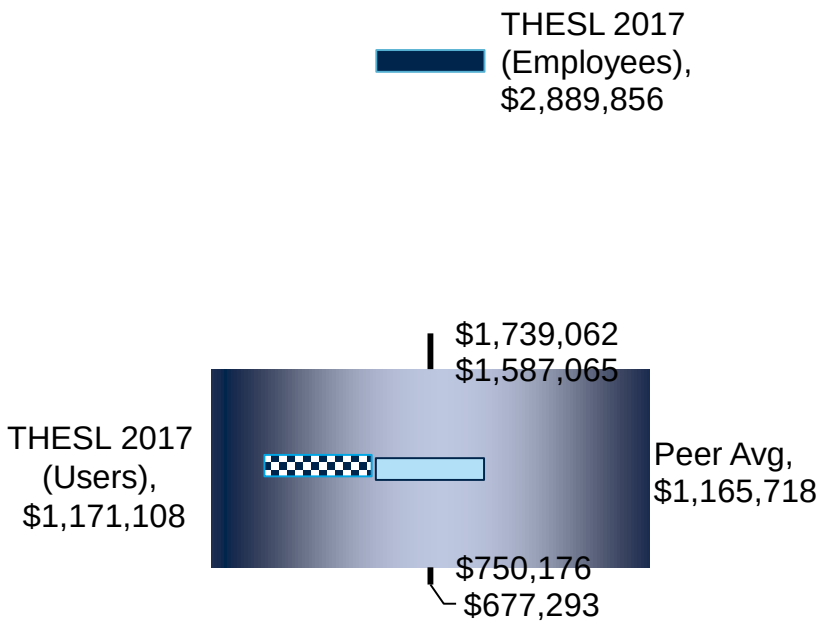
2017 Revenue Per Employee



- THESL Employee count is comparatively lower than the peer group, reflected in Revenue per Employee.
- Based on 3,430 Users from THESL Active Directory, Revenue per User is roughly equivalent to the peer group Revenue per Employee.
  - This suggests that THESL lines of business may have a higher reliance on contract or outsource support than the peer group.

Cylinder denotes the median 50% of responses

= Peer Range

= Peer Average

= Peer Middle Quartiles

= THESL 2017 based on Employee Count

= THESL 2017 based on User Count

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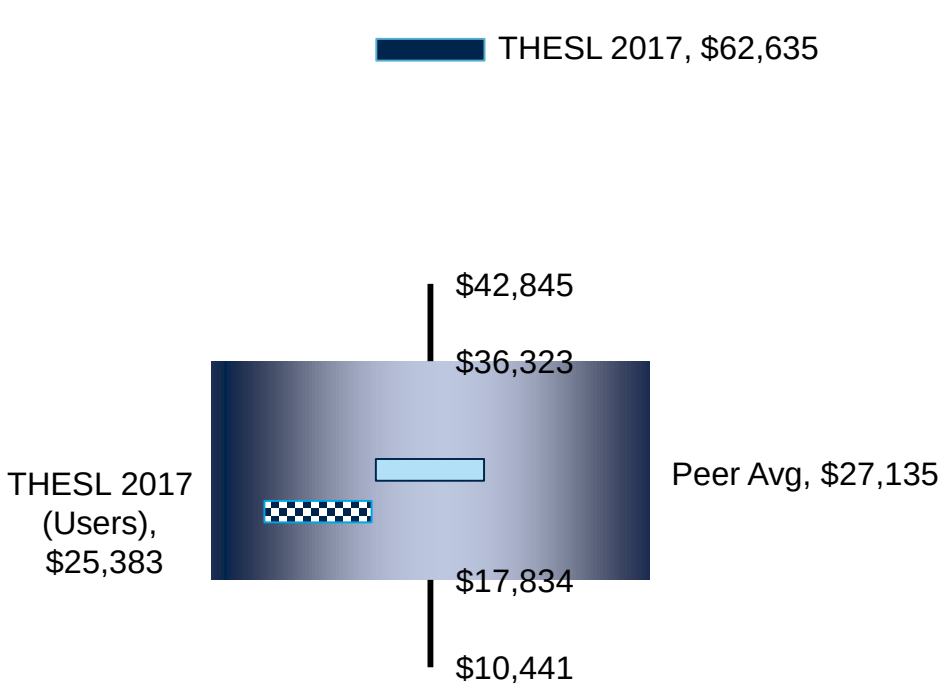
2017 IT Spending Per Employee



Cylinder denotes the median 50% of responses

= Peer Range

= Peer Average

= Peer Middle Quartiles

= THESL 2017 based on Employee Count

= THESL 2017 based on User Count

- While IT Spending per Employee is about 2.3 times greater than the peer group, IT Spending per User is about 6.5% less.
  - Based on the comparison of Revenue per Employee and Revenue per User to the peer group, Gartner believes that IT Spending per User represents a better comparison for THESL.
  - Gartner believes that a relatively lower employee count skews results for IT Spending per Employee, not higher IT spending.

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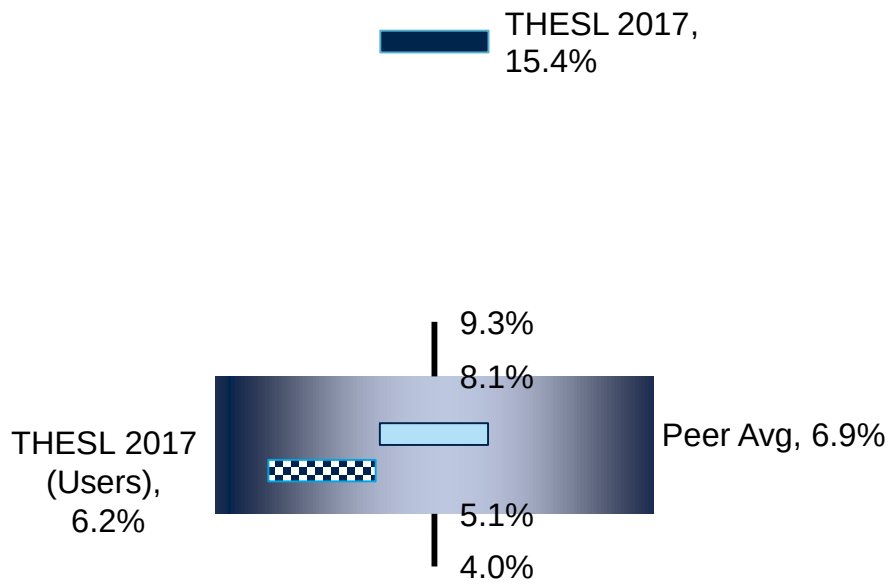
2017 IT FTEs as % of Total Employees



- While IT FTEs as a Percentage of Total Employees is about 2.2 times greater than the peer group, IT FTEs as a Percentage of Total User is about 9.6% less.
  - Based on the comparison of Revenue per Employee and Revenue per User to the peer group, Gartner believes that IT FTEs as a Percentage of Total User represents a better comparison.
  - Gartner believes that a relatively lower employee count skews results for IT FTEs as a Percentage of Total Employees, not higher IT staffing.

Cylinder denotes the median 50% of responses

= Peer Range
= Peer Average
= Peer Middle Quartiles
= THESL 2017 based on Employee Count
= THESL 2017 based on User Count

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Projected Results for Fiscal Year 2020

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Projected IT Budget Results for 2020

- THESL provided a forecast for business and IT measures for 2020.
- Gartner has compared these forecasts to the IT spending and staffing metrics for the 2017 peer group.
  - Gartner does not have comparable forecasts for the peers.
- Results for this forecast may differ from actual results for THESL based on the accuracy of the forecast.
- Not all measures were forecast, so not all metrics for the projected 2020 period can be reported.
  - Infrastructure workload measures were not forecast for 2020 so no comparison of efficiency for infrastructure support is provided.
  - User count was not forecast for 2020. As discussed in 2017 results, THESL has a comparatively low number of employees which skews results for employee-based metrics. As such, Gartner has not calculated or reported results for Revenue per Employee and per User, IT Spending per Employee and per User, or IT FTEs as a Percentage of Employees and Users.

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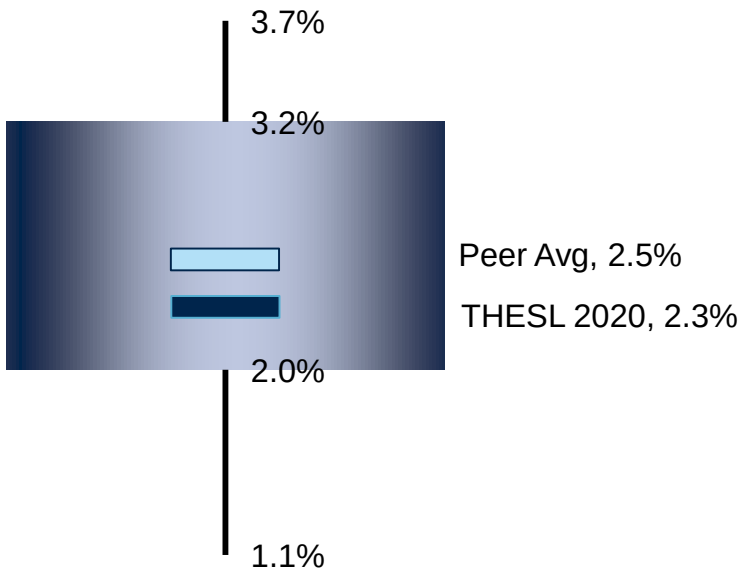
Projected 2020 IT Spending as % of Revenue



- Forecast IT Spending as a Percentage of Revenue for THESL in 2020 is about 9% less than the 2017 peer group, 2.3% compared to 2.5%.

Cylinder denotes the median 50% of responses

= Peer Range

= Peer Middle Quartiles

= Peer Average

= THESL 2020

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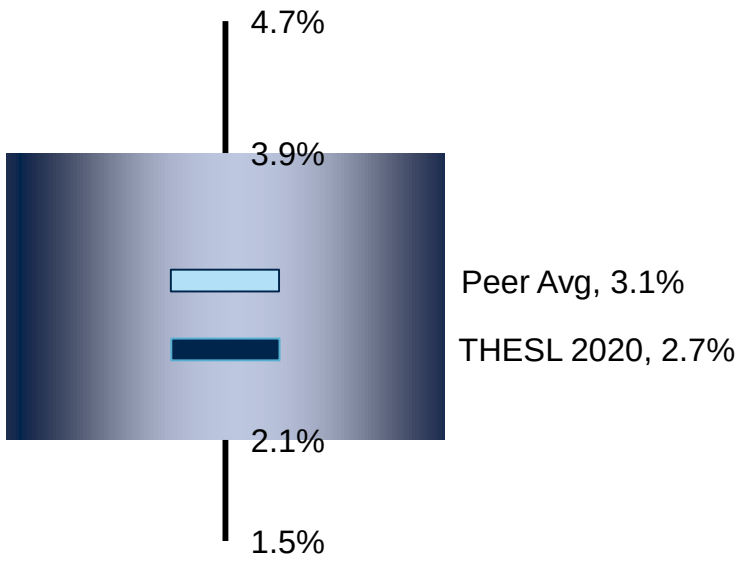
Projected 2020 IT Spending as % of Operational Expense



- IT Spending as a Percentage of Operational Expense for THESL is about 13% less than the 2017 peer group, 2.7% compared to 3.1%.

Cylinder denotes the median 50% of responses

= Peer Range **= Peer Middle Quartiles**

= Peer Average **= THESL 2020**

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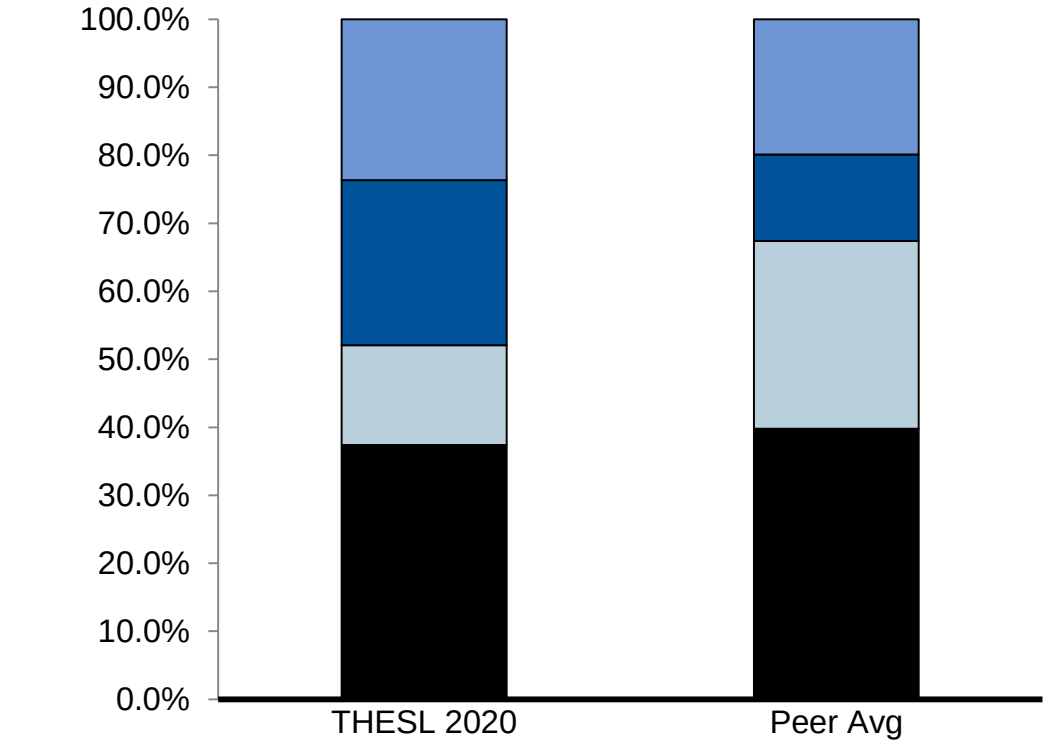
Projected 2020 Spending Distribution by Cost Category



	THESL 2020	Peer Avg
Outsourcing	23.6%	19.9%
Hardware	24.3%	12.7%
Software	14.7%	27.6%
Personnel	37.4%	39.8%

- The distribution of spending between hardware, software, personnel and outsourcing forecast for 2020 is the same as in 2017, and shows a lower distribution of spending for Software than the peers, but higher for Outsourcing and Hardware.
  - The distribution of spending for Personnel is also slightly lower.

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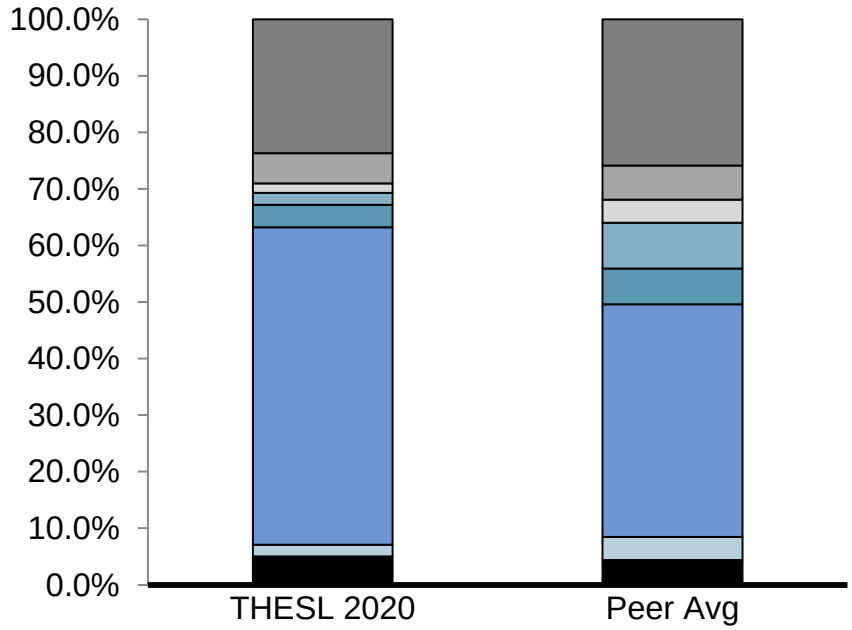
Projected 2020 Spending Distribution by IT Functional Area



	THESL 2020	Peer Avg
Data Center	23.7%	25.9%
End-User Computing	5.3%	6.0%
IT Service Desk	1.6%	4.1%
Voice Services	2.1%	8.1%
Data Networking	4.0%	6.3%
App Dev & Support	56.1%	41.2%
Corporate IT Mgmt	2.1%	4.1%
Finance & Admin	5.0%	4.4%

- The forecast distribution of spending for Applications is slightly higher than in 2017, while all other areas are slightly lower.
- Compared to the 2017 peer group, the percentage of spending for Applications and for Finance & Administration are higher while all other areas are lower.
- This distribution represents an “expense view” of IT spend which includes current-year operational expense as well as current-year lease, maintenance, depreciation and amortization expense.

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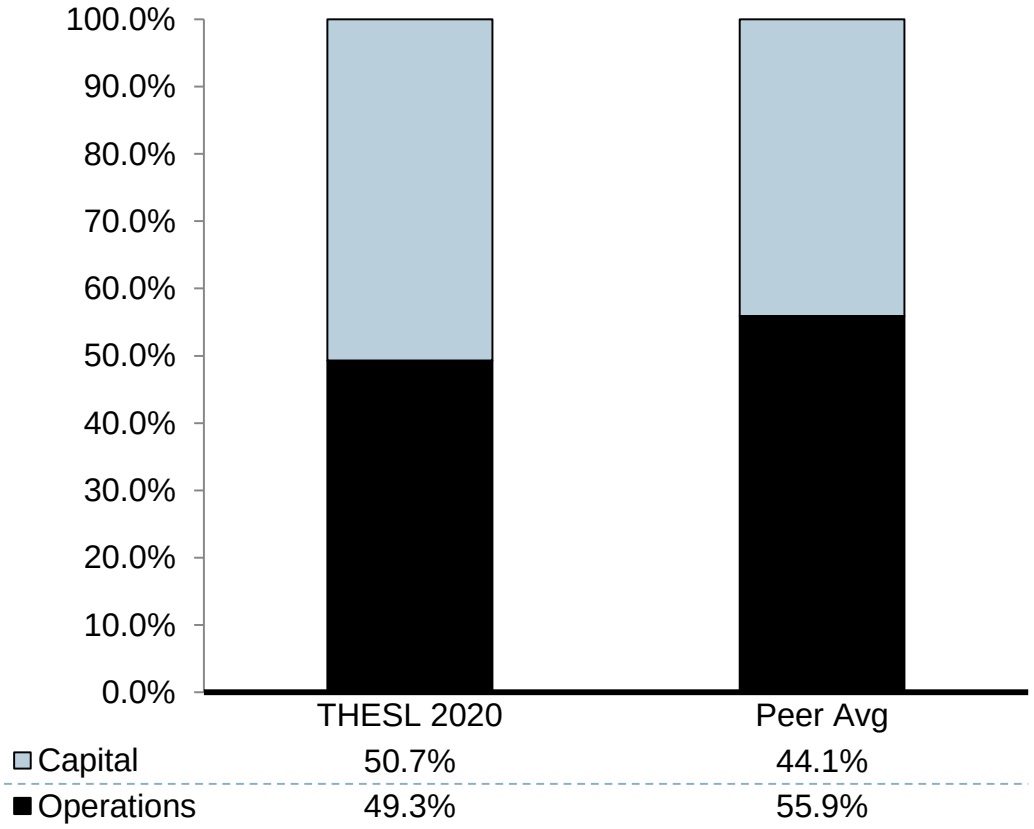
Projected 2020 Spending Distribution – Capital and Operational Spend



- For 2020, the percentage of the IT budget forecast as Capital is greater than the peer group, while the percentage of spending for Operations Expense is lower.
- The difference forecast for 2020 is slightly less than in 2017.
- IT capital expenses vs. operational expenses helps to portray the investment profile for an organization in a given year.

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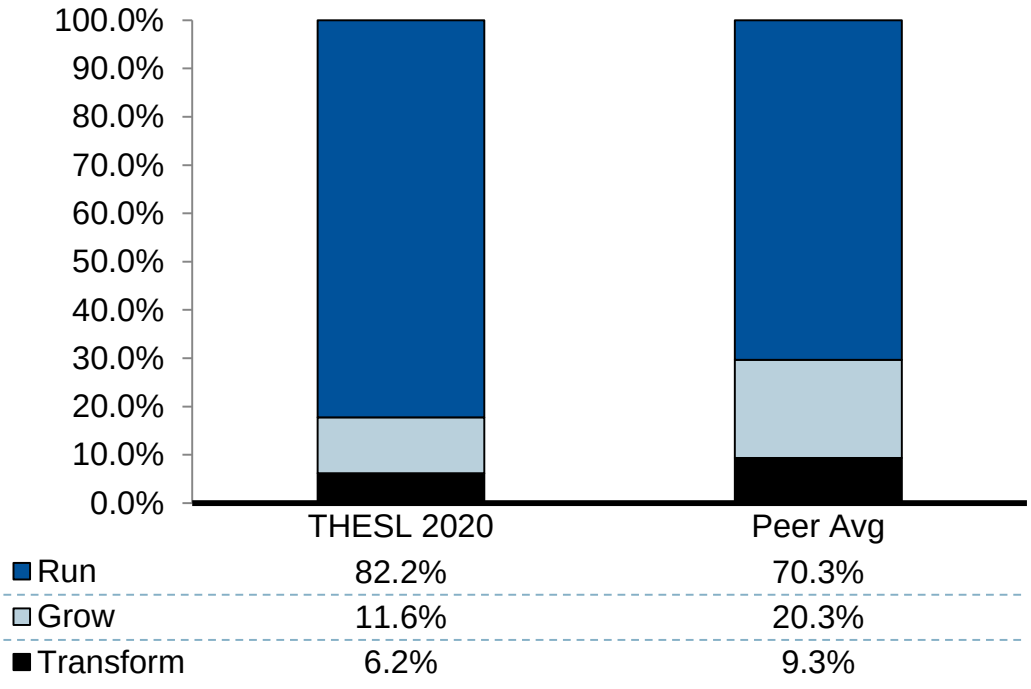
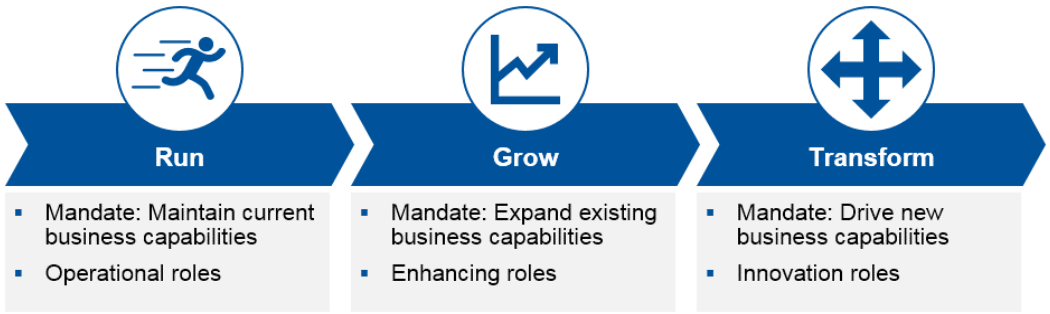
Projected 2020 Spending Distribution – Run, Grow, Transform





- The 2020 forecast for IT spending allocated to “Run” is greater than in 2017, and greater than the peer group.

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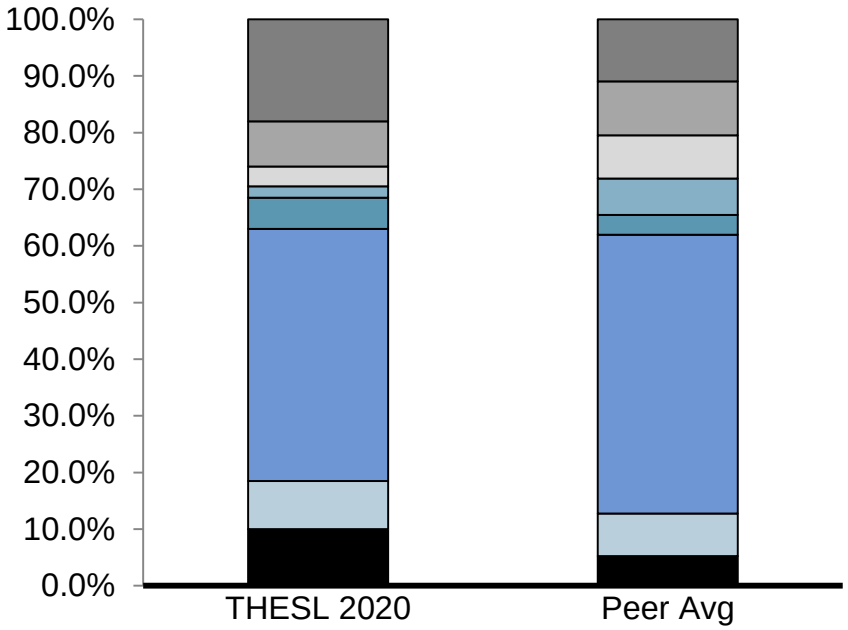
Projected 2020 Staffing Distribution by IT Functional Area



	THESL 2020	Peer Avg
Data Center	18.0%	10.9%
End-User Computing	8.0%	9.5%
IT Service Desk	3.5%	7.6%
Voice Services	2.0%	6.4%
Data Networking	5.5%	3.5%
App Dev & Support	44.5%	49.2%
Corporate IT Mgmt	8.5%	7.5%
Finance & Admin	10.0%	5.2%

- As in 2017, Data Center and Data Networks are forecast to have a higher percentage of staffing than the 2017 peer group.
- The percentage of Finance & Admin staffing is also higher.

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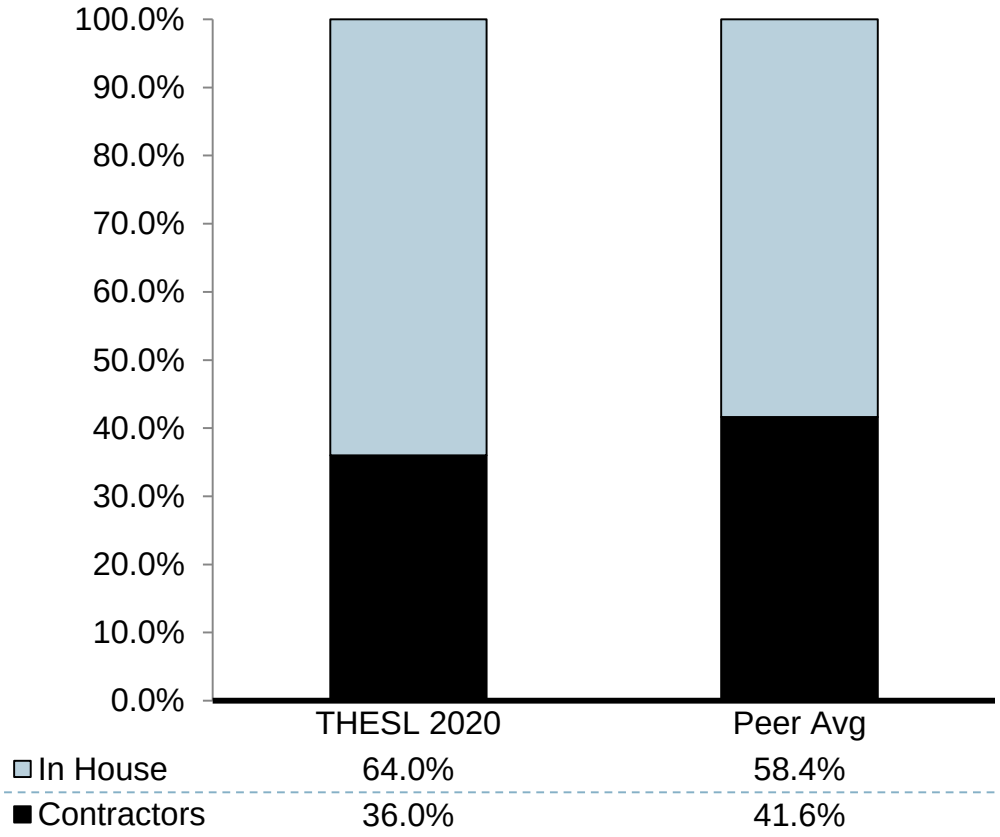
Projected 2020 IT Contractor Usage



- 2020 projected reliance on contractors for THESL is less than in 2017, and is lower than the 2017 peer group.

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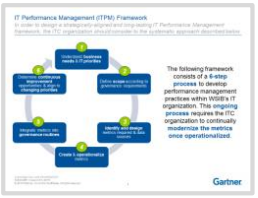
IT Performance Management (ITPM) Lifecycle

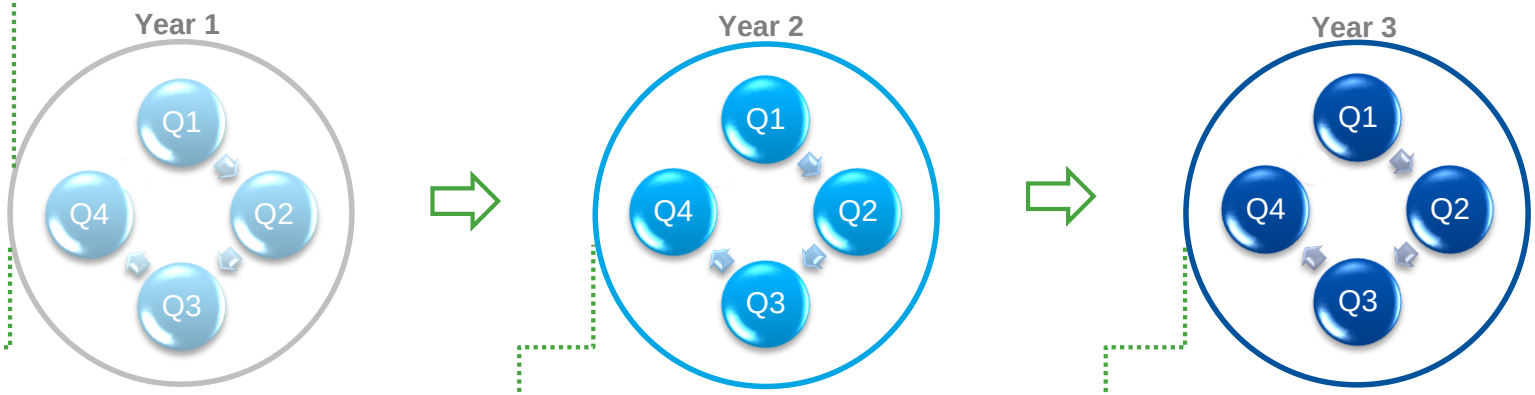
A 3-year timeframe provides both the perspective required for a comprehensive IT performance management lifecycle, with a focus on periodic benchmarking and help desk sourcing.

IT Performance Metrics

*(**Quarterly**) Execution and management of the IT Performance Management metrics portfolio and associated governance activities.*



3-Year IT Performance Management Cycle



Comprehensive Benchmark

*(**Year 1**) Consolidated and comprehensive benchmark analysis, including historical and peer group comparison*

Focused Benchmark: (e.g., *Data Center)*

*(**Year 2**) Based on the results from the Year 1 Comprehensive Benchmark, perform a detailed review and benchmark in a focus area*

Focused Benchmark: (e.g., *Help Desk Sourcing)*

*(**Year 3**) Based on the results from the Year 1 Comprehensive Benchmark, perform a detailed review and benchmark in a focus area*

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LOAD, CUSTOMERS, AND REVENUE

Toronto Hydro's total load, customer, and distribution revenue forecast is summarized in Table 1. The revenue forecast is calculated based on proposed distribution rates, excluding commodity, rate riders, and all other non-distribution rates.

Table 1: Total Load, Revenues, and Customers

Year		Total Normalized GWh	Total Normalized MVA	Total Distribution Revenue ($M)	Total Customers
2013	Actual	25,245.1	42,737.5	531.9	724,144
2014	Actual	25,132.0	41,866.4	536.6	735,262
2015	Actual	25,031.1	41,320.7	628.0	747,811
2016	Actual	24,909.3	41,335.6	661.4	759,031
2017	Actual	24,427.6	40,731.3	693.6	765,559
2018	Bridge	24,378.2	40,925.0	740.7	771,079
2019	Bridge	24,123.8	40,761.1	771.5	776,786
2020	Forecast	24,036.0	40,408.1	796.9	784,330
2021	Forecast	23,818.0	40,275.5	824.2	790,944
2022	Forecast	23,651.8	40,200.6	846.8	798,591
2023	Forecast	23,475.3	40,104.6	885.2	806,238
2024	Forecast	23,396.7	40,166.6	924.2	813,886

Notes:

1. Total Normalized GWh are purchased GWh (before losses), and are weather normalized to the Test Year heating and cooling degree day assumptions.
2. Total Normalized MVA are weather normalized MVA.
3. Total Distribution Revenue is weather normalized and includes an adjustment for the Transformer Allowance.
4. Total Customers are as of mid-year and exclude street lighting devices and unmetered load connections.

Toronto Hydro's detailed load forecasts by rate class, customer forecast by rate class and forecast of distribution revenues by rate class (OEB Appendix 2-IB) are shown in Exhibit 3, Tab 1, Schedule 2.

The information provided for the Load, Customers, and Revenue exhibit has been prepared according to the Board's Filing Requirements for Electricity Distribution Rate Applications (July 12, 2018).

1. HISTORICAL LOADS

Toronto Hydro's historical total system load (actual and weather-normalized) is illustrated in Figure 1 below.

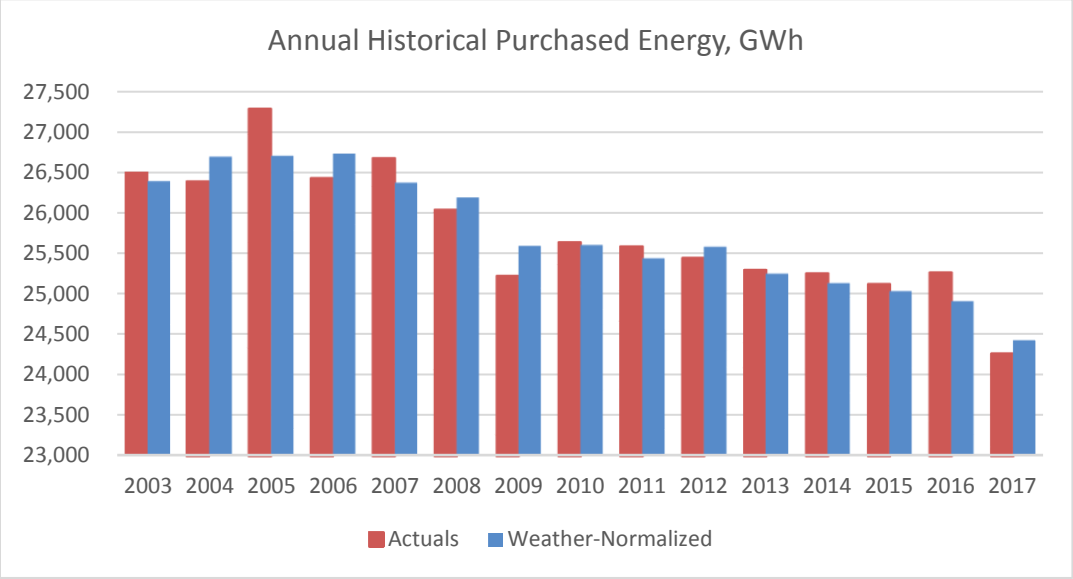


Figure 1: Historical Purchased Energy

Since 2006, Toronto Hydro has experienced a significant decrease in total energy consumption. Essentially flat growth over the 2004-2006 period has been replaced by

declining loads over the 2007-2017 period. The utility believes that conservation activities – both program driven and naturally occurring – continue to have a significant impact on the overall load change. Table 2, below, shows a summary of the total historical normalized annual loads and growth.

Table 2: Historical Annual Load

Year	Total Normalized GWh	Growth GWh	Percentage Change (%)
2003	26,383.5		
2004	26,686.7	303	1.1%
2005	26,697.1	10	0.0%
2006	26,721.5	24	0.1%
2007	26,368.4	(353)	-1.3%
2008	26,186.4	(182)	-0.7%
2009	25,587.8	(599)	-2.3%
2010	25,599.2	11	0.0%
2011	25,435.4	(164)	-0.6%
2012	25,578.6	143	0.6%
2013	25,245.1	(334)	-1.3%
2014	25,132.0	(113)	-0.4%
2015	25,031.1	(101)	-0.4%
2016	24,909.3	(122)	-0.5%
2017	24,427.6	(482)	-1.9%

2. LOAD AND CUSTOMER FORECAST METHODOLOGY

Toronto Hydro's load and customer forecast methodologies are unchanged from those approved by the OEB in the utility's 2015-2019 Rate Application.[1] Forecasting models have been updated to reflect the most recently available information.

1 EB-2014-0116, Toronto Hydro-Electric System Limited Decision and Order (December 29, 2015).

Toronto Hydro's load forecast methodology consists of a three-step process which explicitly takes into account historical and forecast Conservation and Demand Management ("CDM") impacts. First, the actual historical cumulative CDM impacts are added to metered loads. Second, the load (gross of CDM) is forecasted based on multifactor regression techniques. Third, the cumulative forecast CDM impacts are deducted from the gross load forecast to derive the load forecast (net of CDM).

Toronto hydro has developed separate energy forecasts for each rate class; total system load is a summation of the individual rate class loads. For rate classes whose billing units are monthly peak demand, the forecasted monthly non-coincident peak by class is forecast based on historical relationships between energy and demand. The forecast of customers by rate class is determined using time-series econometric methodologies. Revenues are determined by applying the proposed distribution rates to the rate class billing determinants for the forecast period.

3. kWh LOAD FORECAST

3.1 Multivariate Regression Model

Toronto Hydro's process of developing a model of energy usage for each rate class involves estimating multifactor models using different input variables to determine the best fit. Different models were fit based on *a priori* assumptions about which input variables impact energy use. Using stepwise regression techniques, numerous explanatory variables were tested with the ultimate model being determined based on model statistics and judgment.

Models are developed separately for each rate class; this methodology allows for greater detail in modelling loads and allows for the different interactions to be modelled

independently. All of Toronto Hydro's regression models use monthly kWh per day as the dependent variable and monthly values of independent variables from July, 2002 through to the latest actual values (December 2017) to determine the monthly regression coefficients.

The main drivers of energy consumption over time are weather and energy conservation activities – both program and naturally occurring, as well as calendar, economic, and demographic conditions. While load impacts related to the CDM program activities are explicitly taken into account prior to and after the modelling (see section below on CDM forecast), the remainder of the effects are captured through the multivariate regression model.

The primary driver of consumption variance between years is weather. Weather impacts on load are apparent in both the winter heating season and in the summer cooling season. For that reason, both Heating Degree Days ("HDD" – a measure of coldness in winter) and Cooling Degree Days ("CDD" – a measure of summer heat) are captured in the multifactor regression model. In previous rate filings, Toronto Hydro had indicated that the standard definition of HDD, which uses 18 degrees Celsius as the point at which loads start to be impacted by temperature, was not as effective as a measure which uses 10 degrees Celsius as the "balance point" for the HDD measure. Figure 2, below, shows the relationship between temperatures and loads for the period of July 2002 to December 2017. It is clear that the relationship between heating loads and temperature changes at 10 degrees Celsius. Toronto Hydro uses this 10 degrees Celsius "balance point" for construction of its HDD measure.

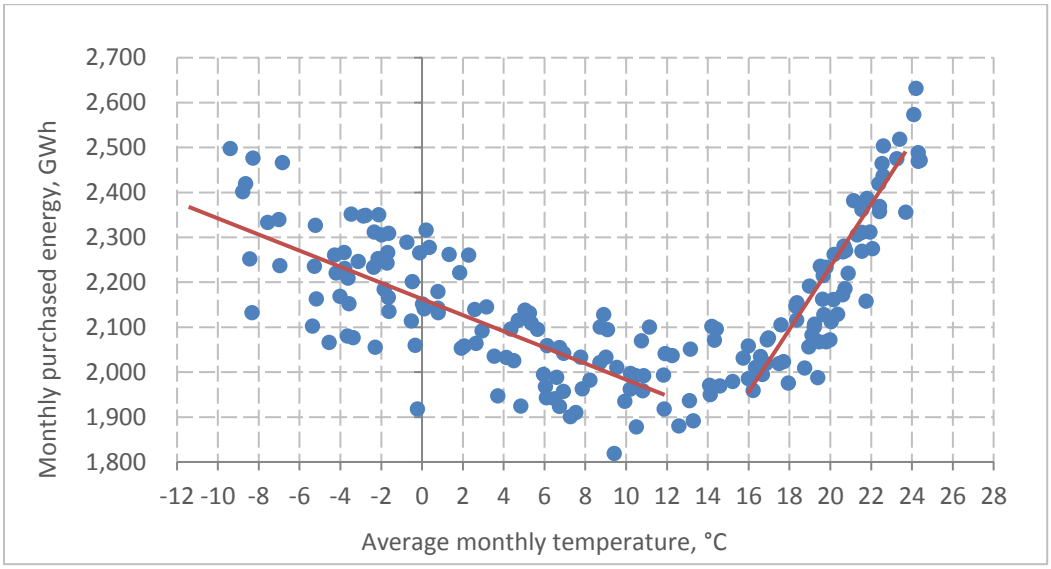


Figure 2: Purchased Energy versus Average Temperature

Dew point temperature is another type of weather factor, included as an explanatory variable for the Competitive Sector Multi-unit Residential ("CSMUR"), General Service ("GS") 50-999 kW, GS 1000-4999 kW, and Large Use customer classes. This variable captures the impact of humidity on consumption and shows the positive impact of temperature on loads during summer months and negative impact during winter months.

Demographic, economic conditions, and naturally occurring conservation activities are captured within the model by customer, Toronto Gross Domestic Product ("GDP"), and Toronto unemployment rate and time trend variables. The Toronto unemployment rate and Toronto GDP reflect the level of economic fluctuations, and were found to be statistically significant in the GS <50 kW, GS 50-999 kW, GS 1000-4999 kW, and Large Use class models. Customer variables capture overall levels of demographic

fluctuations, and were found to be statistically significant in the CSMUR, GS <50 kW, GS 50-999 kW, and Large Use class models.

The time trend variables used in the models are intended to capture trends which are not otherwise explained by the other driver variables. The Residential model uses a simple time trend variable which captures an increase in downward trend in consumption over the historical period from 2008 onward. The model is based on consumption with approved CDM loads "added back" to loads. Approved CDM activities alone do not account for additional natural conservation which seems most apparent in 2008 and onward. The GS<50 kW and GS 50-999 kW models use simple time trends over historical 2002 to 2017 in order to help account for trending that other driver variables and CDM adjustments do not fully speak to, as well as to improve overall model fit over the period.

For the Large Use customers, a clear change in trend has occurred. For this class, Toronto Hydro has incorporated a linear spline time trend. Consumption for this class displays a change in trend in the 2010 to 2017 period, which is captured by this type of time trend.

One additional factor determining energy use in the monthly model can be classified as "calendar factors." For example, the number of business days in a month will impact total monthly load. To capture the different number of days in the calendar months, the modelling of purchased energy was performed on a per-day basis. To reflect different numbers of business days in the month and, consequently, different number of peak hours, business day percentage was used in those class models. A dummy variable was also included to reflect the impact of the 2003 August blackout on energy use in

that month. Lastly, in several models a variable has been used to indicate shoulder months where electricity usage is typically the lowest and most difficult to forecast using other variables alone.

Exhibit 3, Tab 1, Schedule 1, Appendix A-1 contains the historical and forecast load and input variable details. The model statistics for each class model are shown in Exhibit 3, Tab 1, Schedule 1, Appendix A-2.

From the regression models, the forecast of energy usage is determined by applying the model coefficients to forecasts of the input variables.

The forecast for heating and cooling degree-days, and dew-point temperature inputs is based on a ten-year historical average of HDD, CDD, and Dew. A ten-year average was chosen over the 20-year average based on analysis of the annual HDD and CDD data that shows a definite trend in HDD and CDD (see Figure 3, below). Using an average over the longer time period would therefore be less reflective of the most recent data and an inferior forecast of HDD and CDD. Toronto Pearson International Airport station was used as the climatological measurement point for establishing monthly HDD and CDD.

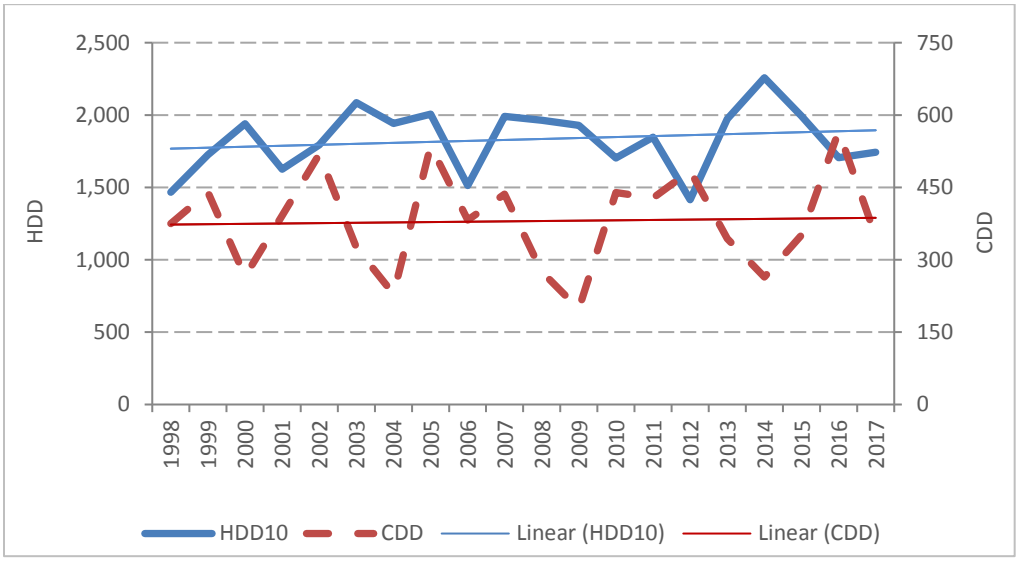


Figure 3: Historical CDD and HDD

As per The OEB Filing Requirements, a comparison of load forecasts based on ten-year average and 20-year trends in HDD and CDD can be found in Exhibit 3, Tab 1, Schedule 1, Appendix B.

The forecast of the City of Toronto's unemployment rate and population was derived based on the Conference Board of Canada forecast of the Toronto Census Metropolitan Area ("CMA") unemployment rate and population using a pair regression model.

Table 3 summarizes the variables included in each of the rate class energy models.

Table 3: Regression Variables by Rate Class

Residential	Competitive Sector Multi-unit Residential	General Service <50 kW	General Service 50-999 kW	General Service 1,000-4,999 kW	Large Use	Street Lighting	Unmetered Load
HDD 10 per day	HDD 10 per day	HDD 10 per day	HDD 10 per day	HDD 10 per day	HDD 10 per day	Average use per device	Simple extrapolation
CDD per day	CDD per day	CDD per day	CDD per day	CDD per day	CDD per day		
Blackout dummy	Dew point temp.	Business days percent	Dew point temp.	Dew point temp.	Dew point temp.		
Time trend	Number of CSMUR customers	GDP	Business days percent	Business days percent	Business days percent		
Shoulder month	Intercept term	Black out dummy	GDP	GDP	GDP		
Intercept term		Time trend	Black out dummy	Toronto Unemployment Rate	Black out dummy		
		Shoulder month	Shoulder month	Black out dummy	Time trend		
		Number of GS<50 kW customers	Number of GS 50-999 kW customers	Time trend	Numbers of LU customers		
		Intercept term	Intercept term	Intercept term	Intercept term		

3.2 Electric Vehicles and Distributed Generation

The markets for Electric Vehicles ("EVs") and widespread Distributed Generation ("DG") are fairly new in Ontario. To date, any impacts on overall loads and demands on the Toronto Hydro system have not been determined to be material. Government policy in these areas has the potential to increase the amounts of loads associated with EVs and DG, including over the 2020-2024 forecast period.

Toronto Hydro does not have enough information about these markets to be able to confidently include any impacts on loads or demands at the time of filing. There has

been no explicit incorporation of the potential load impacts into the load forecast, other than trends that would be part of measured loads to date, and would be captured in the multivariate regression models.

4. CLASS DEMAND (kVA) FORECAST

Toronto Hydro's forecast of monthly peak demand by customer class, which is used to determine revenue for those customers billed on a demand basis (GS 50-999 kW, GS 1000-4999 kW, Large User, and Street Lighting), is established using historical relationships between energy and demand. The utility uses the latest three-year average of this relationship for forecasting purposes. The resulting kW demand forecast is explicitly adjusted to reflect the impacts from the cumulative estimated CDM activities and subsequently converted based on the latest three-year average power factors to the peak kVA demand forecast (net of CDM). The cumulative CDM demand forecast consists of the incremental CDM forecast as well as persistence of historical CDM demand savings.

5. CDM FORECAST

Toronto Hydro confirms that it has explicitly included the impacts of CDM into its load forecast, consistent with the Board's CDM Guidelines (EB-2012-0003). The cumulative CDM forecast deducted from the gross load (step three of the three-step process described previously) includes the CDM savings for programs delivered in each year.

Toronto Hydro's actual and forecasted CDM savings for the 2006 to 2024 period can be separated into three separate components:

1) 2006 to 2016 verified historical savings;

2) 2017 to 2020 forecast savings under the existing Conservation First Framework ("CFF"); and
3) 2021 to 2024 forecast savings beyond the CFF.

5.1 2006 to 2016 Verified Historical Savings

Toronto Hydro's CDM forecast includes the impacts of historical CDM achievement. The annual impacts of CDM completed between 2006 and 2016 have been verified by the Independent Electricity System Operator ("IESO"), and represent the full suite of energy efficiency and demand response programs offered to Toronto Hydro's residential and business customer segments. For each year, and for each program, impacts are allocated to the appropriate rate classes. Where program-level data is available, rate class allocations are estimated based on best available knowledge of the program participant profile. Where project-level detail is available, rate class allocation estimates improve based on the ability to assign a rate class to each contribution of program savings.

5.2 2017 to 2020 Forecasted Savings

The second component of Toronto Hydro's CDM forecast includes unverified 2017 and 2018 achievement as well as the remaining forecasted savings through 2020. This contribution toward the load forecast is consistent with the utility's recently approved 2015 to 2020 CDM Plan and represents the full suite of energy efficiency programs, both local and provincial, currently being offered to Toronto Hydro customers, as well as planned program offerings.

The 2017 and 2018 savings are based on completed projects, where the savings remain subject to third-party evaluation and subsequent IESO verification. The forecasted

portion of 2018 savings, as well as the 2019 and 2020 forecasted impacts are based on a combination of projects already pre-approved and scheduled for completion within this timeframe as well as the application of historical trends and anticipated future penetration for programs without natural funnels. At this time, Toronto Hydro forecasts a moderate reduction in annual savings in future years to account for common measure saturation, such as LED lighting. However, the total forecast currently surpasses Toronto Hydro's 2015 to 2020 CFF-assigned target of 1,556 GWh.

The 2017 to 2020 forecasted savings include a higher degree of accuracy with respect to rate class allocation as rate class forecasting has been integrated within internal CDM reporting. Each month, project-level detail is matched against billing system data to ensure all savings are allocated correctly.

5.3 2021 to 2024 Forecasted Savings

Toronto Hydro's annual forecasted savings for 2021 to 2024 were developed based on the assumption that there will be a continuation of CDM programs. However, in the absence of a new framework, the projected impact is based on the anticipated "status quo" CDM delivery objectives and expectations assigned for the post 2020 conservation planning period. In terms of estimating impact, the effects of the 2011 to 2020 program build-up and the expected market saturation determined the basic assignment of annual savings. This is demonstrated by the fact that 2020 forecast CDM savings, and the subsequent consistent application of the same level of annual savings beyond 2020, are lower than current realized savings. Due to the absence of conservation planning detail, Toronto Hydro has determined this to be the best estimate at this time given the absence of conservation planning detail for this period; this method is consistent with other CDM forecasts used internally and externally for other planning objectives.

Historical and estimated CDM savings used in Toronto Hydro's load forecast are "gross" numbers and hence, include "free riders". Toronto Hydro believes that "gross" CDM savings are the correct values to apply to the load forecast used to determine billing units. The OEB approved this treatment in its EB-2011-0116 decision. In regard to the Future Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA") however, Toronto Hydro agrees that the CDM applied in this forecast will be the basis for the LRAMVA, and Toronto Hydro's LRAMVA balance will reflect the difference between estimated and actual CDM savings on a net basis. Exhibit 3, Tab1, Schedule 1, Appendix C has been created as an alternative to the OEB's Appendix 2-I, and provides a reconciliation between gross CDM used for load forecast purposes and net CDM used for LRAMVA proposes.

Tables 4 and 5 represent the summaries of the cumulative forecast CDM consumption and demand impacts by class used for establishing the load forecast (net of CDM).

Table 4: Cumulative Forecast CDM Consumption Impacts, MWh (Gross)

MWh	Residential	CSMUR	GS <50 kW	GS 50-999 kW	GS 1000-4999 kW	Large Use	Total
2017	596,898	6,010	438,492	923,127	553,270	451,787	**2,969,583**
2018	638,045	10,300	460,258	1,114,418	632,036	499,874	**3,354,930**
2019	659,746	16,846	482,220	1,260,549	719,557	565,421	**3,704,337**
2020	670,817	23,205	502,468	1,383,783	790,685	624,077	**3,995,036**
2021	680,526	29,504	521,954	1,504,060	859,429	654,166	**4,249,639**
2022	690,234	35,804	541,440	1,624,336	928,173	684,255	**4,504,242**
2023	699,943	42,103	560,926	1,744,613	996,916	714,344	**4,758,845**
2024	709,651	48,403	580,411	1,864,890	1,065,660	744,433	**5,013,449**

Table 5: Cumulative Forecast CDM Demand Impacts, MW (Gross)

MW	GS 50-999 kW	GS 1000-4999 kW	Large Use	Total
2017	1,879	1,132	1,096	**4,107**
2018	2,178	1,212	1,159	**4,549**
2019	2,402	1,306	1,263	**4,971**
2020	2,594	1,379	1,354	**5,328**
2021	2,781	1,451	1,404	**5,636**
2022	2,969	1,523	1,454	**5,945**
2023	3,156	1,595	1,503	**6,254**
2024	3,344	1,666	1,553	**6,563**

Tables 6 and 7 include the 2020-2024 total net forecast CDM consumption and demand impacts per year with no prior persistence, which correspond to the gross cumulative numbers above, and will be used for future LRAMVA filings. Please refer to Exhibit 3, Tab 1, Schedule 1, Appendix C for a breakdown by class.

Table 6: 2020-2024 Total Net Forecast CDM Consumption Impact, MWh

CDM Forecast Year	2020	2021	2022	2023	2024	*Total*
2020	144,167					**144,167**
2021	140,936	144,167				**285,104**
2022	140,833	140,936	144,167			**425,936**
2023	140,564	140,833	140,936	144,167		**566,500**
2024	140,046	140,564	140,833	140,936	144,167	**706,547**

Table 7: 2020-2024 Total Net Forecast CDM Demand Impact, MW

CDM Forecast Year	2020	2021	2022	2023	2024	Total
2020	233.58					**233.58**
2021	229.17	233.58				**462.76**
2022	229.03	229.17	233.58			**691.78**
2023	228.93	229.03	229.17	233.58		**920.72**
2024	228.89	228.93	229.03	229.17	233.58	**1,149.61**

6. CUSTOMER FORECAST

Customer additions in Toronto Hydro's service territory have been fairly steady over the recent period, driven mainly by Residential and CSMUR customer additions, while General Service classes remain more flat year over year. The utility's forecast of new customers is primarily based on extrapolation models for each rate class with the exception of the CSMUR rate class (implemented on June 1, 2013), whose forecast customer additions are based on market knowledge of suite metering and multi-unit dwelling construction in Toronto Hydro's service area, as well as an application of expert judgement.

Toronto Hydro's detailed forecast of customers by rate class is found in Exhibit 3, Tab 1, Schedule 2 (OEB Appendix 2-IB).

7. ACCURACY OF LOAD FORECAST AND VARIANCE ANALYSES

Table 8 summarizes the variances between Toronto Hydro's actual loads and the last OEB-approved loads (filed in Toronto Hydro's EB-2014-0116 rate filing).

Table 8: Forecast versus Actual Purchased Energy

Year	Board-Approved Load Forecast	Actual Load		Weather Normalized Actual	
	GWh	GWh	Variance	GWh	Variance
2015	25,018.45	25,122.15	0.41%	25,031.07	0.05%
2016	24,993.28	25,265.00	1.09%	24,909.27	-0.34%
2017	25,027.38	24,268.56	-3.03%	24,427.62	-2.40%

Year to year variances in Toronto Hydro's historical loads reflect the impacts of weather, economic conditions, CDM, and normal customer growth. For the forecast periods, year

to year variances in loads reflect the impact of model driver variables and CDM assumptions.

Tables showing Toronto Hydro's year-over-year actual versus Board-approved loads and customers can be found in Exhibit 3, Tab 1, Schedule 2 (OEB Appendix 2-IB).

Model Input Data

Month	Purchased Energy per day, kWh (by customer class)								Cumulative CDM impacts per day, kWh						HDD10 per day	CDD18 per day	GDP	Time Trend			Blackout Dummy	DewPoint Temperature	Business Days Percent	Shoulder Flag	Toronto Unemployment Rate	Customer Numbers		
	Residential	Competitive Sector Multi-Unit Residential (CSMUR)	GS<50 kW	GS 50-999 kW	GS 1000-4999 kW	Large Use	Street lighting	Unmetered Scattered Load	Residential	CSMUR	GS<50 kW	GS 50-999 kW	GS 1000-4999 kW	Large Use				Residential	GS<50 kW & GS 1,000-4,999 kW	Large Use						CSMUR	GS<50 kW (excluding FIT)	GS 50-999 kW	Large Use
Jul 2002	19,204,876		8,649,128	31,276,255	16,527,279	8,820,370	256,949	166,002							0.00	6.21	241,881	0	1	1	0	15.57	71.0	1	7.8		66,908	10,576	46
Aug 2002	18,511,523		8,183,954	29,604,261	15,721,190	8,346,209	246,772	159,547							0.00	4.60	242,337	0	2	2	0	22.06	67.7	1	9.6		66,827	10,586	46
Sep 2002	16,114,720		7,687,179	28,298,565	14,984,372	7,895,845	269,652	158,251							0.00	2.92	242,794	0	3	3	0	13.55	66.7	1	8.7		66,826	10,619	46
Oct 2002	14,513,865		6,947,084	25,956,564	13,645,056	7,127,650	306,016	155,740							2.96	0.32	243,074	0	4	4	0	4.79	71.0	0	8.5		66,859	10,669	46
Nov 2002	15,395,003		7,232,335	27,256,662	13,902,998	7,204,315	363,235	158,333							7.14	0.00	243,354	0	5	5	0	-0.53	70.0	0	7.8		66,838	10,680	46
Dec 2002	17,264,325		7,335,346	28,296,964	13,783,673	7,157,154	373,118	162,451							11.98	0.00	243,634	0	6	6	0	-5.56	64.5	1	8.7		66,934	10,708	46
Jan 2003	18,311,915		7,916,178	30,509,950	14,995,396	7,598,243	403,495	163,775							18.27	0.00	244,287	0	7	7	0	-11.63	71.0	1	9.4		66,987	10,732	46
Feb 2003	17,946,872		8,123,903	30,717,592	14,953,503	7,633,376	371,971	162,553							16.96	0.00	244,940	0	8	8	0	-11.31	71.4	1	8.4		67,139	10,786	46
Mar 2003	16,306,690		7,612,193	28,018,838	14,110,408	7,296,898	339,070	159,786							10.79	0.00	245,594	0	9	9	0	-5.52	67.7	1	7.4		67,113	10,794	46
Apr 2003	14,622,587		7,121,777	26,707,917	13,805,589	7,149,673	288,109	160,638							5.34	0.08	245,594	0	10	10	0	-1.84	66.7	0	8.7		67,040	10,809	46
May 2003	13,572,543		6,652,815	24,857,765	13,226,484	7,017,781	236,326	153,861							0.17	0.00	245,594	0	11	11	0	6.50	67.7	0	9.1		67,126	10,828	46
Jun 2003	14,771,959		7,206,195	27,040,865	14,519,362	7,638,136	232,369	158,462							0.00	1.76	245,595	0	12	12	0	11.94	70.0	1	8.8		66,958	10,845	46
Jul 2003	16,298,890		7,827,787	29,154,832	15,538,655	7,771,092	252,559	163,533							0.00	3.82	245,389	0	13	13	0	14.71	71.0	1	9.6		67,046	10,848	46
Aug 2003	15,735,506		7,524,161	27,792,398	14,449,168	7,483,754	238,901	159,766							0.00	4.13	245,182	0	14	14	1	16.04	64.5	1	9.0		67,040	10,850	46
Sep 2003	14,015,178		6,905,035	26,228,274	14,274,728	7,348,513	279,868	157,630							0.04	0.80	244,976	0	15	15	0	11.65	70.0	1	9.3		66,964	10,851	46
Oct 2003	13,928,118		6,717,373	25,744,347	13,778,426	6,912,996	326,382	159,766							2.26	0.00	246,159	0	16	16	0	4.73	71.0	0	8.2		67,018	10,892	46
Nov 2003	15,092,616		6,999,278	26,923,503	13,922,169	7,029,585	383,778	161,194							5.35	0.00	247,341	0	17	17	0	1.60	66.7	0	8.6		66,892	10,874	46
Dec 2003	16,844,234		7,272,589	27,677,189	13,794,288	6,932,811	400,325	161,702							10.11	0.00	248,524	0	18	18	0	-3.98	67.7	1	7.6		67,064	10,908	47
Jan 2004	17,978,692		7,904,747	30,816,801	15,143,333	8,177,818	405,204	167,312							19.39	0.00	248,793	0	19	19	0	-13.06	67.7	1	8.6		66,973	10,939	47
Feb 2004	17,170,190		7,700,344	29,663,529	14,662,859	7,211,845	356,252	163,516							13.78	0.00	249,063	0	20	20	0	-8.28	69.0	1	7.8		67,046	10,971	47
Mar 2004	15,629,667		7,263,222	27,958,514	14,414,022	7,168,856	341,915	162,663							7.90	0.00	249,333	0	21	21	0	-2.07	74.2	1	8.5		67,001	10,986	47
Apr 2004	14,026,791		6,860,879	26,007,834	13,599,975	7,142,223	284,717	160,004							3.88	0.00	250,426	0	22	22	0	0.57	66.7	0	8.1		66,920	11,007	47
May 2004	13,190,260		6,697,193	25,467,554	13,536,594	6,883,795	236,779	158,600							0.61	0.28	251,519	0	23	23	0	7.92	64.5	0	8.8		66,875	11,018	47
Jun 2004	13,682,848		6,996,090	26,877,869	14,725,457	7,501,466	230,928	161,946							0.00	1.05	252,612	0	24	24	0	11.15	73.3	1	8.2		66,789	11,038	47
Jul 2004	14,728,572		7,410,303	28,203,152	15,020,716	7,789,243	247,688	164,679							0.00	2.79	253,259	0	25	25	0	15.50	67.7	1	8.7		66,753	11,045	47
Aug 2004	14,329,725		7,313,804	27,825,836	14,779,013	7,491,884	232,359	160,171							0.00	1.92	253,906	0	26	26	0	14.06	67.7	1	8.2		66,715	11,076	47
Sep 2004	13,952,065		7,074,372	27,537,276	15,242,637	7,559,001	287,188	163,732							0.00	1.37	254,553	0	27	27	0	12.85	70.0	1	8.2		66,658	11,104	47
Oct 2004	13,466,693		6,596,275	25,678,284	13,594,246	6,960,710	322,754	159,158							0.83	0.05	255,037	0	28	28	0	6.00	64.5	0	9.0		66,496	11,097	47
Nov 2004	14,734,158		6,925,586	26,942,928	14,049,875	7,104,274	380,877	161,489							4.67	0.00	255,522	0	29	29	0	0.48	73.3	0	8.1		66,585	11,119	47
Dec 2004	16,962,969		7,498,072	29,200,693	14,274,620	7,287,318	393,686	167,781							12.75	0.00	256,006	0	30	30	0	-6.05	67.7	1	8.7		66,505	11,146	47
Jan 2005	17,644,488		7,884,202	31,067,950	14,884,092	7,502,345	415,029	163,047							16.84	0.00	256,735	0	31	31	0	-10.68	64.5	1	8.0		66,464	11,167	47
Feb 2005	16,986,994		7,790,034	29,965,306	14,769,846	7,412,682	380,503	159,982							14.01	0.00	257,464	0	32	32	0	-7.08	71.4	1	9.1		66,628	11,184	47
Mar 2005	15,704,996		7,441,105	28,955,758	14,554,549	7,319,912	357,292	157,327							11.65	0.00	258,194	0	33	33	0	-6.16	67.7	1	8.3		66,630	11,198	47
Apr 2005	13,765,854		6,766,118	26,139,356	13,762,751	6,903,337	296,587	153,933							2.77	0.00	258,554	0	34	34	0	-0.56	70.0	0	8.8		66,556	11,426	48
May 2005	13,739,592		6,518,052	25,117,342	13,271,845	6,822,412	231,600	149,054							0.92	0.03	258,914	0	35	35	0	4.06	67.7	0	8.2		66,482	11,185	47
Jun 2005	17,351,693		7,803,803	30,831,062	16,622,447	8,214,883	239,904	151,947							0.00	4.88	259,274	0	36	36	0	15.35	73.3	1	8.6		66,668	11,214	47
Jul 2005	18,839,649		8,166,152	31,728,614	16,122,802	7,757,701	249,964	158,882							0.00	6.09	260,122	0	37	37	0	15.96	64.5	1	7.9		66,741	11,233	47
Aug 2005	17,458,775		7,764,782	30,249,616	16,074,354	7,558,624	245,451	155,642							0.00	4.54	260,970	0	38	38	0	15.82	71.0	1	7.9		66,807	11,242	47
Sep 2005	14,755,814		7,084,612	28,045,770	15,354,144	7,374,681	280,008	153,375							0.00	1.74	261,817	0	39	39	0	12.99	70.0	1	7.4		66,885	11,255	47
Oct 2005	13,612,493		6,553,620	26,087,500	14,169,462	6,868,355	320,937	152,229							1.33	0.25	262,448	0	40	40	0	7.19	64.5	0	7.6		66,923	11,267	47
Nov 2005	14,817,652		6,910,069	27,534,293	14,466,500	7,025,394	380,230	149,728							5.37	0.00	263,079	0	41	41	0	1.10	73.3	0	6.6		67,066	11,286	47
Dec 2005	16,564,476		7,437,910	29,721,095	14,596,020	7,011,795	390,672	156,298							13.46	0.00	263,709	0	42	42	0	-6.47	64.5	1	8.1		67,147	11,498	47
Jan 2006	16,528,280		7,352,899	28,878,874	14,408,784	6,987,662	407,562	155,071	919						9.80	0.00	264,775	0	43	43	0	-2.82	67.7	1	8.0		67,209	11,349	47
Feb 2006	16,386,367		7,542,777	29,982,830	15,093,663	7,321,461	384,419	156,294	1,743						13.58	0.00	265,840	0	44	44	0	-7.75	71.4	1	8.1		67,183	11,358	46
Mar 2006	15,149,542		7,166,823	28,307,388	14,682,471	7,162,165	354,233	153,057	2,657						8.67	0.00	266,905	0	45	45	0	-5.33	74.2	1	7.1		67,145	11,358	47
Apr 2006	13,403,678		6,457,396	25,422,610	13,533,302	6,820,677	292,933	150,215	11,562						2.58	0.00	267,051	0	46	46	0	0.65	60.0	0	7.6		67,108	11,375	47
May 2006	13,406,038		6,470,721	25,888,725	14,286,344	7,184,146	237,248	150,833	11,607						0.31	0.84	267,197	0	47	47	0	7.88	71.0	0	7.1		67,030	11,377	46
Jun 2006	15,451,889		7,089,496	28,261,902	15,667,781	7,630,593	229,557	164,514	31,915						0.00	2.45	267,342	0	48	48	0	12.56	73.3	1	6.9		67,004	11,397	48
Jul 2006	17,364,157		7,803,803	31,081,220	16,376,057	8,226,171	250,990	173,228	34,836						0.00	5.40	267,080	0	49	49	0	17.38	64.5	1	6.8		67,009	11,389	48
Aug 2006	16,091,564		7,335,937	29,427,040	15,969,371	7,769,925	246,501	167,021	158,787						0.00	3.28	266,818	0	50	50	0	14.60	71.0	1	7.8		67,089	11,417	49
Sep 2006	13,630,376		6,438,984	25,986,422	14,337,632	7,055,393	275,432	158,610	172,383						0.05	0.43	266,555	0	51	51	0	11.65	66.7	1	8.1		67,095	11,430	49
Oct 2006	13,539,048		6,406,677	26,187,123	14,215,738	6,993,313	327,134	162,871	77,339						2.42	0.04	267,425	0	52	52	0	4.76	67.7	0	7.6		67,051	11,441	49
Nov 2006	14,672,055		6,757,402	27,548,591	14,482,704	7,137,127	385,452	162,055	83,731						4.78	0.00	268,295	0	53	53	0	2.07	73.3	0	8.5		67,068	11,426	49
Dec 2006	15,905,045		6,862,288	27,901,327	13,823,127	6,798,357	386,505	161,258	174,399						8.15	0.00	269,164	0	54	54	0	-2.39	61.3	1	7.0		67,017	11,444	49
Jan 2007	16,860,559		7,271,758	29,655,760	14,728,039	6,827,632	411,032	163,099	176,259		619	662	620	612	12.87	0.00	269,573	0	55	55	0	-6.55	71.0	1	7.5		66,920	11,426	49
Feb 2007	17,559,799		7,779,608	31,920,692	15,448,530	7,368,713	389,657	166,716	200,651		2,518	2,695	2,521	2,491	18.43	0.00	269,981	0	56	56	0	-12.36	71.4	1	8.0		66,923	11,452	49
Mar 2007	15,835,887		7,080,110	28,724,776	14,455,093	7,075,744	353,562	161,555	188,952		4,843	5,183	4,849	4,791	9.77	0.00	270,390	0	57	57	0	-5.63	71.0	1	8.5		66,853	11,502	48
Apr 2007	14,015,794		6,614,987	26,882,009	13,826,905	6,949,028	299,516	161,255	95,044		2,683	2,871	2,686	2,654	4.86	0.00	271,023	0	58	58	0	0.02	63.3	0	7.9		66,814	11,476	49
May 2007	13,193,769		6,358,708	26,056,580	14,129,655	6,799,020	234,356	156,695	95,629		3,811	4,079	3,816	3,770	0.19	0.72	271,657	0	59	59	0	5.76	71.0	0	7.7		66,682	11,469	48
Jun 2007	15,356,634		7,195,126	29,659,946	15,737,686	7,646,739	236,262	164,442	254,264		13,610	14,564	13,626	13,462	0.00	3.31	272,290	0	60	60	0	12.19	70.0	1	7.8		66,617	11,440	49
Jul 2007	15,996,572		7,165,386	29,130,163	15,095,627	6,920,126	242,518	159,383	257,753		17,062	18,259	17,082	16,876	0.00	3.42	273,157	0	61	61	0	14.04	67.7	1	8.2		66,486	11,497	49
Aug 2007	16,310,745		7,397,334	30,383,785	16,092,603	7,888,869	250,774	164,834	304,934		32,765	35,063	32,803	32,408	0.00	4.55	274,023	0	62	62	0	14.51	71.0	1	7.7		66,386	11,537	49
Sep 2007	14,648,448		6,773,727	27,726,373	14,881,515	7,365,566	279,044	159,347	674,015		153,311	164,063	153,492	151,644	0.01	1.58	274,890	0	63	63	0	11.56	63.3	1	7.5		66,288	11,556	49
Oct 2007	13,669,553		6,417,306	26,458,053	14,461,056	6,811,240	323,853	159,820	268,201		61,247	65,542	61,319	60,581	0.49	0.64	274,912	0	64	64	0	9.24	71.0	0	7.9		66,199	11,550	49
Nov 2007	14,885,977		6,793,426	27,999,981	14,498,871	7,138,206	383,672	162,357	288,148		66,952	71,647	67,031	66,224	7.43	0.00	274,934	0	65	65	0	-1.40	73.3	0	8.1		66,143	11,586	49
Dec 2007	16,952,892		7,162,973	29,656,733	14,288,028	7,134,747	389,185	164,376	605,243		143,393	153,450	143,563	141,834	12.35	0.00	274,956	0	66	66	0	-5.84	61.3	1	7.8		66,245	11,590	49
Jan 2008	17,303,880		7,255,567	30,117,118	14,544,582	7,290,645	411,876	163,183	633,137		160,550	170,632	161,928	159,978	12.25	0.00	274,378	1	67	67	0	-6.16	71.0	1	7.6		66,054	11,754	49
Feb 2008	17,133,169		7,467,772	31,053,285	14,825,175	7,423,436	384,450	164,250	678,466		172,647	183,425	174,191	172,094	15.27	0.00	273,799	2	68	68	0	-9.12	69.0	1	6.9		66,150	11,863	48
Mar 2008	15,932,255		7,025,212	29,231,992	14,423,553	7,278,631	358,313	163,413	639,628		164,543	174,630	166,201	164,200	11.68	0.00	273,220	3	69	69	0	-7.00	61.3	1	7.4		66,093	11,929	48
Apr 2008	13,569,578		6,232,617	26,561,762	13,834,762	7,030,859	295,774	159,698	324,908		85,690	90,726	86,772	85,727	2.60	0.00	273,460	4	70	70	0	0.71	73.3	0	6.5		66,152	11,977	48
May 2008	12,997,465		6,008,337	25,595,505	13,402,257	6,551,008	234,952	157,052	317,449		84,784	89,660	85,962	84,927	0.45	0.08	273,699	5	71	71	0	3.87	67.7	0	7.1		66,094	12,016	49
Jun 2008	15,225,099		6,815,681	28,778,432	15,179,681	7,389,078	232,922	161,925	813,778		220,513	232,882	223,893	221,197	0.00	2.38	273,939	6	72	72	0	13.65	70.0	1	7.5		66,311	12,066	49
Jul 2008	16,372,787		7,450,989	30,676,433	15,600,581	7,729,728	248,421	162,898	908,779		286,221	298,051	294,357	290,812	0.00	3.58	274,129	7	73	73	0	14.83	71.0	1	7.6		66,286	12,063	49
Aug 2008	14,994,056		6,974,675	29,212,172	14,708,074	7,223,683	239,612	156,724	909,700		286,788	298,618	294,964	291,411	0.00	2.06	274,319	8	74	74	0	13.64	64.5	1	7.6		66,226	12,077	49
Sep 2008	14,475,170		6,546,746	27,751,953	14,836,876	7,147,376	286,630	161,934	943,560		300,340	312,825	309,341	305,616	0.00	0.89	274,509	9	75	75	0	12.06	70.0	1	7.8		66,293	12,105	48
Oct 2008	13,520,793		5,978,109	26,183,884	13,787,466	6,468,382	329,428	161,317	373,320		119,150	124,076	122,748	121,270	2.00	0.00	272,636	10	76	76	0	3.37	71.0	0	8.2		65,867	12,095	48
Nov 2008	15,034,483		6,371,458	27,954,158	13,933,968	6,742,182	386,520	162,065	387,824		124,389	129,481	128,195	126,651	7.31	0.00	270,763	11	77	77	0	-1.22	66.7	0	8.1		66,084	12,128	47
Dec 2008	16,999,100		6,908,000	29,515,695	13,697,348	6,569,481	380,803	159,641	779,203		250,395	260,606	258,097	254,989	13.12	0.00	268,890	12	78	78	0	-7.49	67.7	1	8.3		65,917	12,156	47
Jan 2009	18,085,185		7,449,537	31,830,068	14,394,725	6,916,937	417,231	166,009	781,102		251,871	262,083	259,798	256,669	18.78	0.00	266,851	13	79	79	0	-12.88	67.7	1	9.1		65,700	12,147	47
Feb 2009	17,161,688		7,141,790	30,274,266	14,137,187	7,032,492	382,752	169,699	872,447		284,810	296,115	294,488	290,941	13.66	0.00	264,811	14	80	80	0	-8.48	67.9	1	9.4		66,133	12,181	47
Mar 2009	15,537,631		6,762,608	28,734,524	13,853,001	6,706,802	356,765	163,022	790,907		259,495	269,706	268,577	265,342	9.22	0.00	262,772	15	81	81	0	-6.38	71.0	1	9.6		66,140	12,189	47
Apr 2009	13,566,489		6,184,048	26,569,259	13,069,631	6,464,118	303,012	163,555	397,096		131,467	136,560	136,306	134,664	3.20	0.04	262,713	16	82	82	0	-1.44	66.7	0	9.2		65,846	12,163	47
May 2009	12,630,467		5,839,741	25,359,410	12,918,815	6,198,502	236,904	158,517	387,135		129,441	134,369	134,459	132,840	0.41	0.22	262,653	17	83	83	0	4.55	64.5	0	10.5		65,798	12,208	47
Jun 2009	13,893,747		6,355,969	27,601,047	14,186,123	7,154,419	235,165	164,224	985,442		331,318	343,812	344,526	340,377	0.00	1.14	262,594	18	84	84	0	11.08	73.3	1	10.9		66,074	12,231	47
Jul 2009	14,421,549		6,433,052	27,746,366	14,098,867	7,580,400	242,648	158,771	1,037,877		386,003	415,213	477,200	657,619	0.00	1.41	263,931	19	85	85	0	13.43	67.7	1	11.1		65,854	12,287	47
Aug 2009	15,905,277		6,889,464	30,110,671	15,188,108	7,600,951	251,837	163,149	1,048,339		394,137	423,347	486,567	666,873	0.00	2.94	265,268	20	86	86	0	15.53	64.5	1	10.8		66,047	12,295	47
Sep 2009	14,229,368		6,247,215	27,597,638	14,339,546	7,169,548	285,097	152,004	1,087,499		410,672	423,166	435,904	430,655	0.04	0.70	266,605	21	87	87	0	11.96	70.0	1	10.0		66,100	12,337	47
Oct 2009	13,259,207		5,848,091	26,632,728	13,429,029	6,599,010	333,095	154,586	431,076		163,607	168,536	173,803	171,709	1.96	0.00	267,462	22	88	88	0	4.55	67.7	0	9.9		65,873	12,316	47
Nov 2009	14,141,377		5,944,597	27,039,912	13,455,181	6,448,557	388,982	155,243	446,923		170,210	175,303	180,919	178,740	4.15	0.00	268,320	23	89	89	0	2.75	70.0	0	10.8		65,835	12,384	47
Dec 2009	17,105,627		6,581,682	29,804,165	13,785,518	6,547,808	391,443	156,359	912,966		354,401	364,612	377,863	373,313	12.36	0.00	269,177	24	90	90	0	-5.94	67.7	1	9.7		65,883	12,444	47

Month	Purchased Energy per day, kWh (by customer class)								Cumulative CDM impacts per day, kWh						HDD10 per day	CDD18 per day	GDP	Time Trend			Blackout Dummy	DewPoint Temperature	Business Days Percent	Shoulder Flag	Toronto Unemployment Rate	Customer Numbers			
	Residential	Competitive Sector Multi-Unit Residential (CSMUR)	GS<50 kW	GS 50-999 kW	GS 1000-4999 kW	Large Use	Street lighting	Unmetered Scattered Load	Residential	CSMUR	GS<50 kW	GS 50-999 kW	GS 1000-4999 kW	Large Use				Residential	GS<50 kW & GS 1,000-4,999 kW	Large Use						CSMUR	GS<50 kW (excluding FIT)	GS 50-999 kW	Large Use
Jan 2010	17,925,087		6,976,489	31,213,851	14,241,927	6,887,447	418,962	161,385	977,480		452,876	463,088	476,339	470,602	15.23	0.00	269,840	25	91	90	0	-8.41	64.5	1	9.8		65,607	12,597	47
Feb 2010	17,226,367		7,008,404	31,220,039	14,309,991	6,940,328	386,994	160,271	1,087,785		509,908	521,214	535,885	529,431	13.37	0.00	270,503	26	92	90	0	-7.22	67.9	1	9.9		66,056	12,574	47
Mar 2010	14,736,453		6,346,872	28,434,506	13,753,175	6,649,951	357,966	157,363	989,603		471,380	481,592	494,843	488,883	5.73	0.00	271,166	27	93	90	0	-3.39	74.2	1	9.9		66,156	12,703	47
Apr 2010	12,477,945		5,668,814	26,385,078	12,962,135	6,020,159	301,056	151,092	496,327		239,312	244,405	251,014	247,991	1.01	0.00	271,909	28	94	90	0	0.83	66.7	0	10.4		65,995	12,826	47
May 2010	13,534,105		5,880,439	27,651,525	13,731,092	6,523,040	245,168	148,588	481,330		233,140	238,069	244,465	241,520	0.58	1.47	272,652	29	95	90	0	8.64	64.5	0	10.6		65,681	12,829	47
Jun 2010	15,798,951		6,509,870	29,271,559	14,797,280	7,140,037	236,789	146,396	1,243,095		626,096	638,589	654,802	646,915	0.00	1.96	273,395	30	96	90	0	13.92	73.3	1	10.1		65,799	12,873	47
Jul 2010	19,201,994		7,334,336	33,143,019	16,003,517	7,951,562	251,509	146,894	1,210,497		616,977	659,050	764,735	1,081,536	0.00	5.32	274,129	31	97	90	0	17.44	67.7	1	9.0		66,029	12,906	46
Aug 2010	17,547,294		6,982,607	32,038,088	15,859,128	7,873,418	250,633	145,629	1,221,759		634,169	676,241	781,927	1,098,521	0.00	4.48	274,862	32	98	90	0	17.11	67.7	1	11.1		65,895	12,916	46
Sep 2010	14,247,334		6,223,711	28,280,503	14,471,605	6,895,759	287,534	139,740	1,288,108		694,803	707,297	723,509	714,796	0.00	1.05	275,596	33	99	90	0	12.14	70.0	1	10.7		65,794	12,978	46
Oct 2010	12,717,963		5,531,417	26,622,018	13,346,604	6,100,189	333,276	141,068	510,205		277,215	282,143	288,539	285,064	1.15	0.00	276,406	34	100	90	0	5.44	64.5	0	9.9		66,041	12,980	46
Nov 2010	14,323,111		5,940,283	28,209,136	13,648,666	6,455,800	388,390	140,793	533,758		296,447	301,540	308,149	304,438	5.58	0.00	277,216	35	101	90	0	0.43	73.3	0	10.0		65,976	13,021	46
Dec 2010	17,371,384		6,756,711	30,994,786	13,745,428	7,095,603	392,178	139,025	1,077,841		606,068	616,279	629,531	621,949	13.81	0.00	278,026	36	102	90	0	-7.07	67.7	1	9.9		66,167	13,168	50
Jan 2011	17,965,722		6,927,706	32,102,324	14,127,492	7,206,767	418,421	129,836	1,080,199		608,984	620,949	631,788	623,882	17.01	0.00	278,917	37	103	90	0	-10.16	64.5	1	9.5		65,996	13,266	50
Feb 2011	17,529,718		7,001,224	32,127,223	14,366,131	7,338,692	388,767	127,365	1,198,162		676,987	691,889	701,611	692,552	15.36	0.00	279,808	38	104	90	0	-9.13	67.9	1	8.7		65,942	13,314	50
Mar 2011	15,874,698		6,666,296	30,212,639	14,022,035	7,223,723	360,148	125,860	1,091,229		622,622	642,788	642,345	632,921	10.48	0.00	280,700	39	105	90	0	-5.22	74.2	1	9.8		65,945	13,246	50
Apr 2011	13,373,990		5,903,378	27,529,068	12,896,382	6,751,637	303,774	125,469	548,555		315,851	329,105	324,487	319,195	3.56	0.00	280,499	40	106	90	0	0.87	63.3	0	9.4		65,856	12,938	50
May 2011	12,445,804		5,576,218	26,949,696	12,907,795	6,939,061	242,522	118,094	536,067		312,102	328,800	319,004	313,167	0.23	0.42	280,298	41	107	90	0	9.25	67.7	0	9.6		66,224	12,795	50
Jun 2011	15,136,753		6,572,708	29,598,323	14,434,130	7,817,235	234,769	117,692	1,379,505		816,689	874,392	828,408	810,765	0.00	1.74	280,098	42	108	90	0	12.47	73.3	1	9.2		66,681	12,845	50
Jul 2011	19,602,685		7,463,933	33,339,926	15,288,480	8,098,236	253,286	127,864	1,351,454		810,646	879,941	818,566	806,564	0.00	6.41	281,640	43	109	90	0	15.75	64.5	1	8.9		66,723	12,824	50
Aug 2011	16,685,563		7,202,622	32,002,632	14,932,366	7,864,672	246,519	118,097	1,355,949		816,204	888,842	822,868	810,248	0.00	3.94	283,183	44	110	90	0	15.21	71.0	1	8.9		66,900	12,824	50
Sep 2011	14,050,928		6,525,256	29,338,960	14,168,647	7,607,759	285,201	115,240	1,408,008		851,934	930,830	855,690	834,124	0.00	1.32	284,726	45	111	90	0	13.04	70.0	1	9.0		67,017	12,791	51
Oct 2011	12,942,916		5,749,056	27,142,008	12,995,599	6,701,139	334,303	116,146	560,131		341,858	376,449	342,037	332,888	1.61	0.08	285,467	46	112	90	0	6.66	64.5	0	9.0		67,039	12,701	51
Nov 2011	14,150,205		6,135,836	28,148,932	13,177,997	7,001,090	390,581	117,427	591,888		369,435	414,910	365,965	354,710	3.86	0.00	286,208	47	113	90	0	2.40	73.3	0	9.2		67,161	12,562	51
Dec 2011	16,454,254		6,761,035	30,000,329	13,449,926	6,123,030	402,229	119,781	1,227,687		791,359	912,988	772,958	744,755	9.23	0.00	286,949	48	114	90	0	-2.70	64.5	1	9.0		67,244	12,587	52
Jan 2012	17,174,792		7,144,806	30,695,643	13,908,384	7,139,903	423,256	121,978	1,303,764		836,072	965,292	720,231	684,942	11.71	0.00	287,250	49	115	90	0	-5.43	67.7	1	10.6		67,442	12,357	52
Feb 2012	16,154,623		6,947,917	30,512,034	13,901,953	7,211,778	391,701	115,971	1,337,448		812,615	944,909	712,541	679,535	10.33	0.00	287,552	50	116	90	0	-4.71	69.0	1	8.8		67,517	12,195	51
Mar 2012	14,005,750		6,610,859	28,422,720	13,508,521	7,082,769	360,155	117,866	1,020,233		786,006	908,214	710,011	679,960	4.68	0.01	287,854	51	117	90	0	0.49	71.0	1	9.8		67,517	12,125	51
Apr 2012	13,382,570		6,349,302	27,018,615	12,783,012	6,973,938	315,028	117,376	962,159		710,404	836,123	684,005	658,279	3.36	0.00	288,391	52	118	90	0	-1.32	63.3	0	10.3		67,507	12,037	52
May 2012	13,196,648		6,298,511	27,692,383	14,562,374	7,173,182	238,309	113,581	1,019,145		703,273	830,149	695,312	665,093	0.00	1.18	288,929	53	119	90	0	8.69	71.0	0	10.2		67,473	12,116	52
Jun 2012	16,561,872		6,920,097	29,902,284	15,260,333	7,435,603	236,599	112,514	1,223,706		755,347	894,989	732,970	695,829	0.00	3.39	289,466	54	120	90	0	13.08	70.0	1	9.7		67,360	12,129	52
Jul 2012	19,470,962		7,859,086	33,204,717	15,803,217	7,859,646	251,219	120,795	1,318,391		822,993	964,028	753,793	706,725	0.00	6.35	289,788	55	121	90	0	15.46	67.7	1	10.0		67,365	12,159	52
Aug 2012	17,030,834		7,106,497	30,946,407	15,510,410	7,844,743	250,899	115,291	1,318,391		796,357	953,599	754,567	715,161	0.00	3.62	290,109	56	122	90	0	15.18	71.0	1	9.8		67,464	12,175	52
Sep 2012	14,190,379		6,507,065	28,041,122	14,413,408	7,400,939	287,762	116,419	1,198,231		736,874	892,580	728,442	689,919	0.02	1.19	290,430	57	123	90	0	10.73	63.3	1	9.6		67,607	12,183	52
Oct 2012	13,452,026		6,120,351	26,747,742	14,156,852	7,215,166	334,221	113,648	1,140,115		687,461	831,331	697,376	669,654	1.58	0.04	290,058	58	124	90	0	6.55	71.0	0	10.1		67,845	12,184	52
Nov 2012	14,733,223		6,720,953	28,210,768	14,268,733	7,099,911	387,559	118,414	995,338		739,498	873,810	712,907	688,378	6.59	0.00	289,687	59	125	90	0	-1.36	73.3	0	9.4		67,924	12,205	52
Dec 2012	15,877,642		6,849,194	28,845,414	13,587,706	6,820,260	390,271	115,694	955,687		780,716	919,585	691,460	674,899	8.36	0.00	289,315	60	126	90	0	-2.73	61.3	1	9.6		67,904	12,225	52
Jan 2013	16,869,730		7,418,918	30,634,099	14,654,377	6,999,072	416,577	117,661	1,122,390		970,137	1,193,051	769,875	714,709	12.14	0.00	290,031	61	127	90	0	-6.04	67.7	1	9.5		67,921	12,259	53
Feb 2013	17,186,593		7,505,143	31,515,432	14,769,561	7,151,305	388,030	116,401	1,506,666		976,595	1,209,568	788,857	734,391	14.55	0.00	290,746	62	128	90	0	-7.66	67.9	1	9.1		67,944	12,262	53
Mar 2013	15,557,849		6,950,574	28,834,801	14,484,705	7,204,746	365,740	118,337	1,305,953		912,043	1,122,506	758,951	709,511	9.90	0.00	291,461	63	129	90	0	-5.16	67.7	1	8.8		68,017	12,206	53
Apr 2013	13,842,982		6,522,542	27,541,803	14,314,929	6,964,996	307,864	115,232	1,100,408		824,318	1,033,405	731,153	686,888	4.51	0.00	292,650	64	130	90	0	0.13	66.7	0	9.0		68,028	12,199	53
May 2013	12,953,193	344,895	6,668,233	26,598,975	13,945,479	7,219,587	253,838	119,480	971,898	2,529	816,044	1,026,021	743,239	693,998	0.46	0.75	293,838	65	131	90	0	7.63	71.0	0	8.0	35,811	68,025	12,074	53
Jun 2013	14,594,000	357,407	6,725,082	28,830,756	15,242,080	7,057,222	227,370	110,637	1,099,235	2,665	876,469	1,106,160	783,493	726,069	0.00	2.04	295,026	66	132	90	0	12.91	70.0	1	8.6	36,156	68,220	11,885	52
Jul 2013	17,471,738	416,782	7,755,732	31,685,524	15,690,543	7,582,708	251,581	122,290	1,236,093	2,898	954,961	1,191,489	805,751	737,439	0.00	4.45	295,485	67	133	90	0	16.14	67.7	1	8.4	36,777	68,313	11,924	51
Aug 2013	15,840,794	395,994	7,236,754	29,939,148	15,420,682	7,467,652	250,283	113,167	1,376,127	2,845	924,054	1,178,599	806,578	746,241	0.00	3.03	295,943	68	134	90	0	14.20	71.0	1	7.6	37,407	68,386	11,913	51
Sep 2013	13,935,176	375,382	6,617,045	27,711,973	14,725,710	7,303,334	289,793	114,468	1,421,998	2,940	855,033	1,103,183	778,653	719,903	0.00	0.91	296,401	69	135	90	0	11.10	63.3	1	8.9	37,871	68,468	11,923	51
Oct 2013	13,257,217	370,333	6,324,728	26,756,973	14,431,234	7,172,470	333,570	112,883	1,210,359	2,501	797,696	1,027,482	745,445	698,757	1.60	0.01	297,125	70	136	90	0	6.51	71.0	0	9.5	38,174	68,558	11,890	51
Nov 2013	15,183,996	401,593	7,027,372	28,607,657	14,515,063	7,034,718	392,104	116,709	1,229,712	2,609	858,077	1,079,984	762,047	718,295	8.12	0.00	297,850	71	137	90	0	-2.60	73.3	0	9.4	38,253	68,586	11,904	51
Dec 2013	16,787,468	447,159	7,426,893	30,015,008	14,019,970	6,930,693	392,785	113,251	1,005,413	2,191	905,905	1,136,559	739,122	704,230	14.20	0.00	298,574	72	138	90	0	-7.70	61.3	1	9.9	38,602	68,595	11,914	51
Jan 2014	18,435,372	504,099	8,361,578	32,856,648	15,384,687	7,305,565	414,695	119,065	1,059,543	2,954	1,105,254	1,469,230	892,020	775,178	18.64	0.00	298,622	73	139	90	0	-12.65	71.0	1	9.9	39,542	68,617	11,904	51
Feb 2014	17,522,686	463,639	7,942,666	32,327,026	15,725,432	7,343,275	392,326	114,207	1,319,385	3,470	1,112,612	1,489,571	914,013	796,525	18.33	0.00	298,671	74	140	90	0	-12.29	67.9	1	9.8	40,438	68,570	11,913	52
Mar 2014	16,547,163	448,759	7,755,827	30,889,035	15,109,353	7,265,254	359,544	117,291	1,445,447	3,609	1,039,069	1,382,354	879,362	769,540	14.28	0.00	298,720	75	141	90	0	-9.74	67.7	1	9.2	41,224	68,638	11,970	50
Apr 2014	14,338,732	384,490	6,757,393	27,748,580	13,512,498	6,922,563	317,075	116,254	1,433,365	3,708	939,126	1,272,628	847,154	745,003	4.22	0.00	300,527	76	142	90	0	-1.06	66.7	0	9.4	42,022	68,723	11,931	45
May 2014	12,264,924	378,283	6,456,053	27,615,367	14,267,478	6,635,438	237,737	110,813	1,131,103	3,354	929,699	1,263,534	861,157	752,714	0.23	0.38	302,335	77	143	90	0	6.75	67.7	0	9.1	42,409	68,856	11,886	48
Jun 2014	14,197,191	432,398	7,149,021	29,879,885	14,952,039	7,224,040	236,512	114,787	1,066,719	3,310	998,540	1,362,225	907,798	787,499	0.00	2.27	304,143	78	144	90	0	12.44	70.0	1	10.2	43,022	68,952	11,852	47
Jul 2014	14,637,417	447,373	7,370,333	30,444,359	14,971,891	7,039,103	250,699	117,902	1,129,897	3,267	1,087,965	1,467,307	933,587	799,830	0.00	2.29	305,403	79	145	90	0	13.11	71.0	1	11.1	43,554	69,058	11,767	46
Aug 2014	14,566,973	452,405	7,244,454	29,857,989	14,917,851	6,974,513	250,712	113,340	1,312,925	3,671	1,052,753	1,451,433	934,546	809,378	0.00	2.64	306,663	80	146	90	0	14.34	64.5	1	10.2	44,190	69,002	11,779	46
Sep 2014	13,830,633	452,630	7,212,466	28,769,812	14,765,173	6,735,691	291,310	118,367	1,510,385	3,725	974,119	1,358,559	902,190	780,811	0.03	1.00	307,924	81	147	90	0	16.91	70.0	1	9.5	44,785	69,896	10,845	45
Oct 2014	13,167,334	448,538	6,822,813	26,973,630	14,096,481	6,612,483	334,641	118,446	1,461,663	3,605	908,797	1,265,334	863,714	757,876	1.16	0.04	308,803	82	148	90	0	6.71	71.0	0	9.0	45,725	70,194	10,622	46
Nov 2014	15,199,103	491,197	7,624,443	29,138,565	14,300,736	6,565,947	389,010	116,963	1,328,445	3,273	977,587	1,329,989	882,949	779,067	8.14	0.00	309,683	83	149	90	0	-2.38	66.7	0	8.7	46,681	70,190	10,632	43
Dec 2014	16,070,480	509,971	7,772,586	29,527,730	13,985,411	6,381,559	392,326	114,542	1,264,014	3,199	1,032,076	1,399,661	856,387	763,812	9.98	0.00	310,562	84	150	90	0	-3.56	67.7	1	8.1	47,754	70,354	10,537	43
Jan 2015	17,432,428	613,004	8,755,477	32,578,684	14,905,936	6,918,672	415,927	117,177	1,160,820	4,375	1,238,964	1,898,364	1,172,073	962,505	17.56	0.00	311,008	85	151	90	0	-12.09	67.7	1	7.3	48,980	70,387	10,502	44
Feb 2015	18,213,200	630,507	9,034,645	34,196,368	15,585,626	7,386,210	393,044	118,223	1,275,129	5,155	1,247,212	1,924,646	1,200,972	989,010	22.60	0.00	311,454	86	152	90	0	-16.85	67.9	1	8.0	49,914	70,351	10,492	44
Mar 2015	15,450,965	552,893	8,150,363	30,437,162	14,738,532	7,052,843	362,171	116,102	1,295,878	4,939	1,164,772	1,786,114	1,155,442	955,505	11.85	0.00	311,901	87	153	90	0	-8.04	71.0	1	7.5	50,816	70,390	10,478	44
Apr 2015	13,615,457	483,751	7,175,282	27,620,897	14,110,170	6,748,035	308,340	113,366	1,623,582	5,878	1,052,738	1,644,338	1,113,122	925,038	3.15	0.00	312,735	88	154	90	0	-0.29	66.7	0	7.5	51,933	70,376	10,435	44
May 2015	12,893,612	522,710	7,324,403	27,517,517	14,272,460	6,713,491	244,319	116,240	1,507,814	5,655	1,042,171	1,632,588	1,131,521	934,613	0.05	1.10	313,569	89	155	90	0	7.72	64.5	0	7.4	53,094	70,421	10,380	44
Jun 2015	13,526,018	538,092	7,396,213	28,690,279	14,945,000	6,990,828	236,354	113,937	1,270,499	5,462	1,119,340	1,760,104	1,192,805	977,804	0.00	1.08	314,404	90	156	90	0	12.16	73.3	1	7.4	54,516	70,436	10,364	44
Jul 2015	16,162,602	638,169	8,443,272	31,721,940	15,499,639	7,045,692	251,098	119,626	1,122,125	5,049	1,219,583	1,895,879	1,226,691	993,115	0.00	3.69	315,467	91	157	90	0	13.78	71.0	1	7.2	57,061	70,393	10,368	44
Aug 2015	15,501,218	605,142	7,812,268	30,454,341	15,296,240	7,281,703	252,434	110,850	1,228,204	5,148	1,180,111	1,875,369	1,227,950	1,004,970	0.00	2.86	316,531	92	158	90	0	14.46	64.5	1	7.5	58,994	70,324	10,376	44
Sep 2015	15,242,279	644,023	7,913,628	30,797,004	15,364,642	7,284,231	289,680	121,494	1,474,728	5,979	1,091,965	1,755,368	1,185,437	969,500	0.00	2.73	317,595	93	159	90	0	13.76	70.0	1	7.8	60,600	70,329	10,388	44
Oct 2015	13,028,478	566,686	6,884,418	27,154,492	14,152,389	6,776,812	334,582	112,578	1,588,836	5,681	1,018,740	1,634,913	1,134,880	941,022	1.55	0.00	318,413	94	160	90	0	4.21	67.7	0	7.5	61,353	70,308	10,425	44
Nov 2015	13,879,865	576,623	7,371,379	27,973,035	14,253,763	6,881,869	391,355	115,988	1,641,797	5,870	1,095,853	1,718,454	1,160,155	967,334	4.06	0.00	319,232	95	161	90	0	1.95	70.0	0	8.3	62,050	70,331	10,446	44
Dec 2015	14,546,231	590,321	7,546,322	28,615,437	13,703,500	6,629,043	390,109	115,720	1,397,445	4,992	1,156,933	1,808,476	1,125,254	948,393	5.87	0.00	320,050	96	162	90	0	0.61	67.7	1	8.7	62,647	70,300	10,475	44
Jan 2016	16,655,426	701,103	8,296,079	31,214,699	14,546,198	7,048,509	424,021	117,777	1,522,926	10,156	1,301,189	2,284,273	1,401,007	1,122,214	13.63	0.00	322,130	97	163	90	0	-7.88	64.5	1	8.6	63,370	70,280	10,496	44
Feb 2016	15,745,546	682,910	8,259,392	31,271,816	14,774,969	7,107,722	391,053	115,831	1,375,384	9,421	1,264,684	2,236,039	1,386,068	1,113,355	12.29	0.00	324,210	98	164	90	0	-7.42	69.0	1	8.2	63,732	70,271	10,510	44
Mar 2016	14,130,466	609,475	7,791,251	29,466,784	14,399,638	6,975,541	362,703	115,865	1,276,573	9,379	1,223,271	2,149,203	1,381,147	1,114,053	7.51	0.00	326,290	99	165	90	0	-2.61	67.7	1	8.1	64,294	70,233	10,510	44
Apr 2016	13,462,734	584,662	7,362,053	28,265,045	14,241,159	6,971,263	306,864	117,208	1,484,225	10,283	1,105,610	1,978,607	1,330,560	1,078,530	5.59	0.00	325,858	100	166	90	0	-4.20	70.0	0	8.0	64,680	70,214	10,508	44
May 2016	13,586,272	585,686	7,199,493	27,956,249	14,350,246	7,079,655	246,533	113,804	1,741,522	11,460	1,094,512	1,964,469	1,352,554	1,089,694	0.41	1.19	325,426	101	167	90	0	5.65	67.7	0	7.9	64,917	70,165	10,502	44
Jun 2016	15,893,502	651,576	7,859,698	30,019,277	15,091,646	7,299,372	235,732	115,825	1,726,965	11,772	1,175,557	2,117,907	1,425,809	1,140,051	0.00	2.79	324,995	102	168	90	0	8.94	73.3	1	5.9	65,685	70,122	10,475	42
Jul 2016	18,168,911	717,337	8,624,328	32,919,028	15,672,908	7,570,955	252,779	117,703	1,362,791	10,649	1,280,835	2,281,282	1,466,314	1,157,903	0.00	5.71	325,537	103	169	90	0	14.33	64.5	1	7.4	65,758	70,175	10,359	44
Aug 2016	18,965,473	766,857	9,296,071	34,482,058	16,233,846	7,724,869	251,938	120,594	1,243,760	10,171	1,239,380	2,256,603	1,467,820	1,171,725	0.00	6.30	326,079	104	170	90	0	16.42	71.0	1	8.0	66,456	70,149	10,318	44
Sep 2016	14,834,011	675,998	7,668,335	30,439,450	15,255,360	7,279,878	291,217	114,998	1,406,715	10,717	1,146,806	2,112,208	1,417,001	1,130,370	0.00	2.31	326,621	105	171	90	0	12.53	70.0	1	7.5	66,796	70,128	10,318	44
Oct 2016	12,507,819	616,107	7,015,900	27,473,551	14,252,560	6,945,451	335,878	113,952	1,581,855	11,656	1,069,904	1,967,267	1,356,569	1,097,166	1.46	0.13	327,193	106	172	90	0	7.36	64.5	0	7.5	67,351	70,106	10,333	44
Nov 2016	13,882,560	631,317	7,355,425	28,243,072	14,285,296	7,009,706	390,978	115,363	1,819,762	11,826	1,150,890	2,067,790	1,386,781	1,127,844	3.62	0.00	327,765	107	173	90	0	2.35	73.3	0	7.5	67,985	70,068	10,343	44
Dec 2016	15,925,577	717,638	7,959,909	30,503,566	14,046,245	6,980,304	393,775	117,739	1,761,060	11,444	1,215,038	2,176,112	1,345,062	1,105,760	11.61	0.00	328,336	108	174	90	0	-5.55	64.5	1	7.0	68,472	70,109	10,352	44
Jan 2017	16,051,806	743,854	8,285,734	31,324,570	14,429,390	7,253,903	420,963	116,559	1,725,595	15,996	1,349,869	2,781,323	1,565,235	1,257,230	11.64	0.00	330,257	109	175	90	0	-5.38	67.7	1	7.2	69,066	70,064	10,364	44
Feb 2017	15,428,493	708,935	8,152,908	30,999,520	14,546,736	7,247,730	392,596	115,453	1,878,414	17,883	1,358,856	2,819,829	1,603,827	1,291,852	10.26	0.00	332,178	110	176	90	0	-5.22	67.9	1	7.4	69,376	70,097	10,386	44
Mar 2017	14,725,175	702,747	8,096,407	30,648,678	14,564,653	7,217,675	362,401	118,682	1,433,

Month	Purchased Energy per day, kWh (by customer class)								Cumulative CDM impacts per day, kWh						HDD10 per day	CDD18 per day	GDP	Time Trend			Blackout Dummy	DewPoint Temperature	Business Days Percent	Shoulder Flag	Toronto Unemployment Rate	Customer Numbers			
	Residential	Competitive Sector Multi-Unit Residential (CSMUR)	GS<50 kW	GS 50-999 kW	GS 1000-4999 kW	Large Use	Street lighting	Unmetered Scattered Load	Residential	CSMUR	GS<50 kW	GS 50-999 kW	GS 1000-4999 kW	Large Use				Residential	GS<50 kW & GS 1,000-4,999 kW	Large Use						CSMUR	GS<50 kW (excluding FIT)	GS 50-999 kW	Large Use
Jan 2018									2,097,174	31,193	1,416,876	3,357,672	1,788,067	1,391,046	14.86	0.00	343,312	121	187	90	0	-8.71	71.0	1	6.9	73,641	70,709	10,401	44
Feb 2018									2,042,179	30,351	1,426,308	3,404,158	1,832,153	1,429,352	14.60	0.00	343,614	122	188	90	0	-8.81	67.9	1	6.9	74,093	70,717	10,400	44
Mar 2018									1,813,589	27,681	1,332,030	3,159,133	1,762,695	1,380,929	9.59	0.00	343,917	123	189	90	0	-5.37	67.7	1	7.0	74,434	70,725	10,399	44
Apr 2018									1,583,291	24,823	1,203,908	2,908,372	1,698,133	1,336,897	3.31	0.00	344,604	124	190	90	0	-0.33	66.7	0	6.9	74,760	70,733	10,398	44
May 2018									1,520,218	25,565	1,191,824	2,887,590	1,726,202	1,350,735	0.35	0.71	345,292	125	191	90	0	6.91	71.0	0	6.9	75,090	70,741	10,397	44
Jun 2018									1,767,503	28,027	1,280,074	3,113,130	1,819,695	1,413,156	0.00	2.11	345,979	126	192	90	0	12.27	70.0	1	6.9	75,371	70,749	10,396	44
Jul 2018									2,073,907	31,235	1,394,712	3,353,277	1,871,390	1,435,285	0.00	4.30	346,654	127	193	90	0	14.92	67.7	1	6.9	75,651	70,757	10,395	44
Aug 2018									1,990,230	31,053	1,349,571	3,317,001	1,873,311	1,452,417	0.00	3.43	347,328	128	194	90	0	15.01	71.0	1	6.9	75,932	70,766	10,394	44
Sep 2018									1,676,988	29,994	1,248,767	3,104,753	1,808,454	1,401,155	0.01	1.45	348,003	129	195	90	0	12.66	63.3	1	6.9	76,213	70,774	10,393	44
Oct 2018									1,481,142	27,724	1,165,028	2,891,702	1,731,327	1,359,997	1.49	0.06	348,672	130	196	90	0	5.95	71.0	0	6.8	76,494	70,782	10,392	44
Nov 2018									1,675,199	29,212	1,253,214	3,039,462	1,769,885	1,398,024	5.79	0.00	349,341	131	197	90	0	0.08	73.3	0	6.8	76,774	70,790	10,391	44
Dec 2018									1,883,766	31,771	1,323,065	3,198,685	1,716,641	1,370,650	11.37	0.00	350,009	132	198	90	0	-5.16	61.3	1	6.8	77,055	70,798	10,391	44
Jan 2019									2,168,501	51,019	1,484,483	3,797,957	2,035,669	1,573,449	14.86	0.00	350,629	133	199	90	0	-8.71	71.0	1	6.8	77,336	70,806	10,390	44
Feb 2019									2,111,636	49,642	1,494,365	3,850,537	2,085,860	1,616,778	14.60	0.00	351,248	134	200	90	0	-8.81	67.9	1	6.8	77,652	70,814	10,389	44
Mar 2019									1,875,271	45,274	1,395,589	3,573,383	2,006,783	1,562,006	9.59	0.00	351,867	135	201	90	0	-5.37	67.7	1	6.8	78,023	70,822	10,388	44
Apr 2019									1,637,140	40,600	1,261,353	3,289,741	1,933,281	1,512,200	3.31	0.00	352,553	136	202	90	0	-0.33	66.7	0	6.8	78,429	70,830	10,387	44
May 2019									1,571,922	41,814	1,248,693	3,266,234	1,965,238	1,527,852	0.35	0.71	353,239	137	203	90	0	6.91	71.0	0	6.8	78,870	70,838	10,386	44
Jun 2019									1,827,617	45,841	1,341,153	3,521,348	2,071,677	1,598,458	0.00	2.11	353,925	138	204	90	0	12.27	66.7	1	6.8	79,347	70,846	10,385	44
Jul 2019									2,144,442	51,087	1,461,261	3,792,985	2,130,530	1,623,489	0.00	4.30	354,614	139	205	90	0	14.92	71.0	1	6.8	79,860	70,854	10,384	44
Aug 2019									2,057,920	50,789	1,413,967	3,751,952	2,132,717	1,642,868	0.00	3.43	355,303	140	206	90	0	15.01	67.7	1	6.8	80,373	70,862	10,383	44
Sep 2019									1,734,024	49,058	1,308,353	3,511,872	2,058,879	1,584,884	0.01	1.45	355,992	141	207	90	0	12.66	66.7	1	6.8	80,886	70,870	10,382	44
Oct 2019									1,531,517	45,344	1,220,618	3,270,885	1,971,072	1,538,329	1.49	0.06	356,695	142	208	90	0	5.95	71.0	0	6.7	81,398	70,878	10,381	44
Nov 2019									1,732,174	47,779	1,313,012	3,438,020	2,014,969	1,581,342	5.79	0.00	357,397	143	209	90	0	0.08	70.0	0	6.7	81,911	70,886	10,380	44
Dec 2019									1,947,835	51,963	1,386,196	3,618,122	1,954,353	1,550,379	11.37	0.00	358,099	144	210	90	0	-5.16	64.5	1	6.7	82,424	70,894	10,380	44
Jan 2020									2,204,891	70,278	1,546,817	4,169,252	2,236,896	1,736,678	14.86	0.00	358,831	145	211	90	0	-8.71	71.0	1	6.7	82,937	70,902	10,379	44
Feb 2020									2,073,035	66,024	1,503,421	4,081,216	2,213,012	1,722,968	14.60	0.00	359,563	146	212	90	0	-8.81	65.5	1	6.6	83,430	70,910	10,378	44
Mar 2020									1,906,741	62,365	1,454,190	3,922,724	2,205,155	1,724,048	9.59	0.00	360,296	147	213	90	0	-5.37	71.0	1	6.6	83,892	70,918	10,377	44
Apr 2020									1,664,614	55,927	1,314,318	3,611,352	2,124,387	1,669,075	3.31	0.00	361,026	148	214	90	0	-0.33	66.7	0	6.6	84,335	70,926	10,376	44
May 2020									1,598,301	57,598	1,301,126	3,585,547	2,159,502	1,686,351	0.35	0.71	361,756	149	215	90	0	6.91	64.5	0	6.6	84,758	70,934	10,375	44
Jun 2020									1,858,287	63,145	1,397,469	3,865,602	2,276,463	1,764,282	0.00	2.11	362,486	150	216	90	0	12.27	73.3	1	6.6	85,161	70,942	10,374	44
Jul 2020									2,180,429	70,372	1,522,620	4,163,794	2,341,134	1,791,909	0.00	4.30	363,213	151	217	90	0	14.92	71.0	1	6.6	85,544	70,950	10,373	44
Aug 2020									2,092,455	69,961	1,473,340	4,118,750	2,343,537	1,813,298	0.00	3.43	363,940	152	218	90	0	15.01	64.5	1	6.6	85,927	70,958	10,372	44
Sep 2020									1,763,123	67,577	1,363,291	3,855,200	2,262,400	1,749,299	0.01	1.45	364,666	153	219	90	0	12.66	70.0	1	6.5	86,310	70,966	10,371	44
Oct 2020									1,557,218	62,461	1,271,872	3,590,653	2,165,914	1,697,915	1.49	0.06	365,399	154	220	90	0	5.95	67.7	0	6.5	86,693	70,974	10,370	44
Nov 2020									1,761,243	65,815	1,368,146	3,774,128	2,214,149	1,745,391	5.79	0.00	366,132	155	221	90	0	0.08	70.0	0	6.5	87,076	70,982	10,369	44
Dec 2020									1,980,522	71,579	1,444,403	3,971,837	2,147,542	1,711,215	11.37	0.00	366,865	156	222	90	0	-5.16	67.7	1	6.5	87,459	70,990	10,369	44
Jan 2021									2,236,802	89,357	1,606,803	4,531,639	2,431,376	1,820,409	14.86	0.00	367,598	157	223	90	0	-8.71	64.5	1	6.5	87,842	70,998	10,368	44
Feb 2021									2,178,146	86,945	1,617,499	4,594,377	2,491,323	1,870,540	14.60	0.00	368,332	158	224	90	0	-8.81	67.9	1	6.5	88,241	71,006	10,367	44
Mar 2021									1,934,337	79,296	1,510,584	4,263,683	2,396,875	1,807,171	9.59	0.00	369,066	159	225	90	0	-5.37	74.2	1	6.5	88,667	71,014	10,366	44
Apr 2021									1,688,705	71,109	1,365,288	3,925,246	2,309,086	1,749,547	3.31	0.00	369,822	160	226	90	0	-0.33	66.7	0	6.5	89,109	71,022	10,365	44
May 2021									1,621,433	73,235	1,351,584	3,897,198	2,347,254	1,767,656	0.35	0.71	370,578	161	227	90	0	6.91	64.5	0	6.5	89,569	71,031	10,364	44
Jun 2021									1,885,181	80,288	1,451,663	4,201,595	2,474,383	1,849,345	0.00	2.11	371,334	162	228	90	0	12.27	73.3	1	6.5	90,045	71,039	10,363	44
Jul 2021									2,211,986	89,477	1,581,668	4,525,706	2,544,076	1,878,303	0.00	4.30	372,088	163	229	90	0	14.92	67.7	1	6.5	90,538	71,047	10,362	44
Aug 2021									2,122,738	88,954	1,530,476	4,476,747	2,547,289	1,900,724	0.00	3.43	372,842	164	230	90	0	15.01	67.7	1	6.5	91,031	71,055	10,361	44
Sep 2021									1,788,640	85,922	1,416,160	4,190,289	2,459,098	1,833,639	0.01	1.45	373,597	165	231	90	0	12.66	70.0	1	6.5	91,524	71,063	10,360	44
Oct 2021									1,579,755	79,418	1,321,195	3,902,748	2,354,222	1,779,778	1.49	0.06	374,359	166	232	90	0	5.95	64.5	0	6.5	92,017	71,071	10,359	44
Nov 2021									1,786,732	83,682	1,421,202	4,102,170	2,406,652	1,829,542	5.79	0.00	375,121	167	233	90	0	0.08	73.3	0	6.5	92,510	71,079	10,359	44
Dec 2021									2,009,186	91,011	1,500,417	4,317,064	2,334,253	1,793,719	11.37	0.00	375,884	168	234	90	0	-5.16	67.7	1	6.5	93,003	71,087	10,358	44
Jan 2022									2,268,713	108,435	1,666,788	4,894,025	2,625,856	1,904,141	14.86	0.00	376,449	169	235	90	0	-8.71	64.5	1	6.5	93,497	71,095	10,357	44
Feb 2022									2,209,220	105,509	1,677,884	4,961,780	2,690,599	1,956,577	14.60	0.00	377,014	170	236	90	0	-8.81	67.9	1	6.5	93,990	71,103	10,356	44
Mar 2022									1,961,932	96,227	1,566,977	4,604,641	2,588,595	1,890,293	9.59	0.00	377,580	171	237	90	0	-5.37	74.2	1	6.5	94,483	71,111	10,355	44
Apr 2022									1,712,797	86,292	1,416,257	4,239,140	2,493,784	1,830,019	3.31	0.00	378,145	172	238	90	0	-0.33	63.3	0	6.5	94,976	71,119	10,354	44
May 2022									1,644,565	88,871	1,402,041	4,208,850	2,535,005	1,848,961	0.35	0.71	378,710	173	239	90	0	6.91	67.7	0	6.4	95,469	71,127	10,353	44
Jun 2022									1,912,076	97,430	1,505,857	4,537,588	2,672,303	1,934,407	0.00	2.11	379,276	174	240	90	0	12.27	73.3	1	6.4	95,962	71,135	10,352	44
Jul 2022									2,243,542	108,581	1,640,715	4,887,618	2,748,219	1,964,698	0.00	4.30	379,841	175	241	90	0	14.92	64.5	1	6.4	96,455	71,143	10,351	44
Aug 2022									2,153,022	107,947	1,587,613	4,834,743	2,751,041	1,988,150	0.00	3.43	380,406	176	242	90	0	15.01	71.0	1	6.4	96,948	71,151	10,350	44
Sep 2022									1,814,157	104,268	1,469,029	4,525,378	2,655,795	1,917,979	0.01	1.45	380,972	177	243	90	0	12.66	70.0	1	6.4	97,441	71,159	10,349	44
Oct 2022									1,602,292	96,375	1,370,519	4,214,843	2,542,531	1,861,640	1.49	0.06	381,537	178	244	90	0	5.95	64.5	0	6.4	97,934	71,167	10,348	44
Nov 2022									1,812,222	101,550	1,474,259	4,430,213	2,599,154	1,913,694	5.79	0.00	382,102	179	245	90	0	0.08	73.3	0	6.4	98,427	71,175	10,348	44
Dec 2022									2,037,849	110,443	1,556,432	4,662,291	2,520,964	1,876,223	11.37	0.00	382,667	180	246	90	0	-5.16	64.5	1	6.4	98,920	71,183	10,347	44
Jan 2023									2,300,623	127,514	1,726,774	5,256,411	2,820,336	1,987,872	14.86	0.00	383,233	181	247	90	0	-8.71	67.7	1	6.4	99,414	71,191	10,346	44
Feb 2023									2,240,293	124,073	1,738,270	5,329,183	2,889,874	2,042,615	14.60	0.00	383,798	182	248	90	0	-8.81	67.9	1	6.4	99,907	71,199	10,345	44
Mar 2023									1,989,528	113,157	1,623,371	4,945,599	2,780,316	1,973,416	9.59	0.00	384,363	183	249	90	0	-5.37	74.2	1	6.4	100,400	71,207	10,344	44
Apr 2023									1,736,888	101,475	1,467,227	4,553,035	2,678,482	1,910,491	3.31	0.00	384,929	184	250	90	0	-0.33	60.0	0	6.4	100,893	71,215	10,343	44
May 2023									1,667,696	104,508	1,452,499	4,520,501	2,722,756	1,930,266	0.35	0.71	385,494	185	251	90	0	6.91	71.0	0	6.3	101,386	71,223	10,342	44
Jun 2023									1,938,970	114,573	1,560,051	4,873,582	2,870,223	2,019,469	0.00	2.11	386,059	186	252	90	0	12.27	73.3	1	6.3	101,879	71,231	10,341	44
Jul 2023									2,275,099	127,685	1,699,763	5,249,530	2,951,762	2,051,092	0.00	4.30	386,625	187	253	90	0	14.92	64.5	1	6.3	102,372	71,239	10,340	44
Aug 2023									2,183,305	126,940	1,644,749	5,192,740	2,954,793	2,075,575	0.00	3.43	387,190	188	254	90	0	15.01	71.0	1	6.3	102,865	71,247	10,339	44
Sep 2023									1,839,674	122,613	1,521,897	4,860,468	2,852,492	2,002,319	0.01	1.45	387,755	189	255	90	0	12.66	66.7	1	6.3	103,358	71,255	10,338	44
Oct 2023									1,624,829	113,332	1,419,842	4,526,939	2,730,840	1,943,503	1.49	0.06	388,321	190	256	90	0	5.95	67.7	0	6.3	103,851	71,263	10,337	44
Nov 2023									1,837,712	119,417	1,527,316	4,758,255	2,791,657	1,997,845	5.79	0.00	388,886	191	257	90	0	0.08	73.3	0	6.3	104,344	71,271	10,337	44
Dec 2023									2,066,512	129,875	1,612,446	5,007,518	2,707,676	1,958,727	11.37	0.00	389,451	192	258	90	0	-5.16	61.3	1	6.3	104,837	71,279	10,336	44
Jan 2024									2,332,534	146,593	1,786,760	5,618,797	3,014,817	2,071,604	14.86	0.00	390,017	193	259	90	0	-8.71	71.0	1	6.3	105,331	71,287	10,335	44
Feb 2024									2,193,044	137,719	1,736,632	5,500,153	2,982,626	2,055,250	14.60	0.00	390,582	194	260	90	0	-8.81	69.0	1	6.3	105,824	71,295	10,334	44
Mar 2024									2,017,123	130,088	1,679,765	5,286,557	2,972,036	2,056,538	9.59	0.00	391,147	195	261	90	0	-5.37	64.5	1	6.3	106,317	71,304	10,333	44
Apr 2024									1,760,980	116,658	1,518,196	4,866,929	2,863,181	1,990,963	3.31	0.00	391,712	196	262	90	0	-0.33	70.0	0	6.3	106,810	71,312	10,332	44
May 2024									1,690,828	120,144	1,502,957	4,832,152	2,910,508	2,011,571	0.35	0.71	392,278	197	263	90	0	6.91	71.0	0	6.3	107,303	71,320	10,331	44
Jun 2024									1,965,865	131,715	1,614,245	5,209,575	3,068,143	2,104,532	0.00	2.11	392,843	198	264	90	0	12.27	66.7	1	6.2	107,796	71,328	10,330	44
Jul 2024									2,306,655	146,790	1,758,810	5,611,442	3,155,304	2,137,486	0.00	4.30	393,408	199	265	90	0	14.92	71.0	1	6.2	108,289	71,336	10,329	44
Aug 2024									2,213,589	145,932	1,701,885	5,550,737	3,158,544	2,163,001	0.00	3.43	393,974	200	266	90	0	15.01	67.7	1	6.2	108,782	71,344	10,328	44
Sep 2024									1,865,191	140,959	1,574,766	5,195,557	3,049,190	2,086,659	0.01	1.45	394,539	201	267	90	0	12.66	66.7	1	6.2	109,275	71,352	10,327	44
Oct 2024									1,647,367	130,288	1,469,166	4,839,034	2,919,148	2,025,365	1.49	0.06	395,104	202	268	90	0	5.95	71.0	0	6.2	109,768	71,360	10,326	44
Nov 2024									1,863,202	137,284	1,580,373	5,086,298	2,984,159	2,081,997	5.79	0.00	395,670	203	269	90	0	0.08	70.0	0	6.2	110,261	71,368	10,326	44
Dec 2024									2,095,176	149,307	1,668,460	5,352,745	2,894,387	2,041,230	11.37	0.00	396,235	204	270	90	0	-5.16	64.5	1	6.2	110,754	71,376	10,325	44

Residential Model

Dependent Variable: RES_DAY
Method: Least Squares
Date: 04/19/18 Time: 13:45
Sample: 2002M07 2017M12
Included observations: 186
White Heteroskedasticity-Consistent Standard Errors & Covariance

Variable	Coefficient	Std. Error	t-Statistic	Prob.
BLACKOUT	**(1,368,157)**	104,109	-13.14	0.000
CDD18_DAY	**945,817**	36,776	25.72	0.000
HDD10_DAY	**283,397**	8,639	32.81	0.000
SHOULDER_FLAG	**278,374**	89,156	3.12	0.002
TREND_2008	**(6,174)**	860	-7.18	0.000
C	**12,919,065**	64,713	199.64	0.000

R-squared	**93.1%**	Mean dependent var	15307812.02
Adjusted R-squared	**93.0%**	S.D. dependent var	1731532.16
S.E. of regression	459,496.5	Akaike info criterion	28.95
Sum squared resid	38,004,671,942,128.3	Schwarz criterion	29.05
Log likelihood	(2,685.9)	Hannan-Quinn criter.	28.99
F-statistic	489.4	Durbin-Watson stat	1.23
Prob(F-statistic)	0.0		

CSMUR Model

Dependent Variable: CSMUR_PERDAY
Method: Least Squares
Date: 04/19/18 Time: 13:49
Sample: 2013M05 2017M12
Included observations: 56
White Heteroskedasticity-Consistent Standard Errors & Covariance

Variable	Coefficient	Std. Error	t-Statistic	Prob.
CUST_NUM	**9**	0	51.56	0.000
DEW	**5,010**	898	5.58	0.000
CDD18_DAY	**17,297**	2,262	7.65	0.000
HDD10_DAY	**13,907**	1,257	11.06	0.000
C	**(66,858)**	13,530	(4.94)	0.000

R-squared	**98.1%**	Mean dependent var	568796.79
Adjusted R-squared	**98.0%**	S.D. dependent var	125885.39
S.E. of regression	17,911.5	Akaike info criterion	22.51
Sum squared resid	16,361,900,917.6	Schwarz criterion	22.69
Log likelihood	(625.3)	Hannan-Quinn criter.	22.58
F-statistic	666.4	Durbin-Watson stat	1.33
Prob(F-statistic)	0.0		

GS <50 kW Model

Dependent Variable: LESS50_DAY
Method: Least Squares
Date: 05/15/18 Time: 12:40
Sample: 2002M07 2017M12
Included observations: 186
White Heteroskedasticity-Consistent Standard Errors & Covariance

Variable	Coefficient	Std. Error	t-Statistic	Prob.
BLACKOUT	**(279,127)**	39,936	(6.99)	0.000
CDD18_DAY	**274,086**	10,648	25.74	0.000
BUS_DAYS_PERCENT	**9,277**	3,330	2.79	0.006
HDD10_DAY	**78,282**	3,059	25.59	0.000
NUMCUSTNETFIT	**344**	15	22.48	0.000
GDP	**8**	2	3.65	0.000
SHOULDER_FLAG	**168,473**	30,534	5.52	0.000
TREND_JUL2002	**(9,274)**	919	(10.09)	0.000
C	**(19,083,862)**	751,889	(25.38)	0.000

R-squared	**95.1%**	Mean dependent var	7126026.75
Adjusted R-squared	**94.9%**	S.D. dependent var	680626.33
S.E. of regression	154,047.1	Akaike info criterion	26.78
Sum squared resid	4,200,299,243,690.2	Schwarz criterion	26.93
Log likelihood	(2,481.1)	Hannan-Quinn criter.	26.83833286
F-statistic	429.3	Durbin-Watson stat	1.126856313
Prob(F-statistic)	0.0		

GS 50-999kW model

Dependent Variable: GS350_DAY
Method: Least Squares
Date: 05/15/18 Time: 12:14
Sample: 2002M07 2017M12
Included observations: 186
White Heteroskedasticity-Consistent Standard Errors & Covariance

Variable	Coefficient	Std. Error	t-Statistic	Prob.
BLACKOUT	**(1,619,190)**	88,796	(18.23)	0.000
BUS_DAYS_PERCENT	**40,283**	7,792	5.17	0.000
CDD18_DAY	**925,140**	28,836	32.08	0.000
CUST_NUMBERS	**371**	35	10.67	0.000
DEW	**75,495**	14,310	5.28	0.000
GDP	**30**	1	29.20	0.000
HDD10_DAY	**384,292**	19,463	19.74	0.000
SHOULDER_FLAG	**394,315**	85,109	4.63	0.000
C	**10,108,937**	823,806	12.27	0.000

R-squared	**96.8%**	Mean dependent var	28958549.08
Adjusted R-squared	**96.7%**	S.D. dependent var	2003070.55
S.E. of regression	366,324.8	Akaike info criterion	28.51
Sum squared resid	23,752,319,343,272.3	Schwarz criterion	28.66
Log likelihood	(2,642.2)	Hannan-Quinn criter.	28.57085727
F-statistic	669.3	Durbin-Watson stat	1.382071664
Prob(F-statistic)	0.0		

GS 1000-4999kW Model

Dependent Variable: GS450_DAY
Method: Least Squares
Date: 03/28/18 Time: 18:26
Sample: 2002M07 2017M12
Included observations: 186
White Heteroskedasticity-Consistent Standard Errors & Covariance

Variable	Coefficient	Std. Error	t-Statistic	Prob.
BLACKOUT	**(921,318)**	69,526	(13.25)	0.000
BUS_DAYS_PERCENT	**51,112**	6,835	7.48	0.000
DEW	**85,824**	10,758	7.98	0.000
GDP	**17**	5	3.42	0.001
HDD10_DAY	**154,397**	12,559	12.29	0.000
UNEMPL_RATE	**(61,364)**	29,726	(2.06)	0.040
TREND_JUL2002	**(7,190)**	2,395	(3.00)	0.003
CDD18_DAY	**282,486**	30,037	9.40	0.000
C	**6,071,213**	1,528,203	3.97	0.000

R-squared	**83.4%**	Mean dependent var	14494483.10
Adjusted R-squared	**82.6%**	S.D. dependent var	772304.11
S.E. of regression	321,838.8	Akaike info criterion	28.25
Sum squared resid	18,333,698,235,852.4	Schwarz criterion	28.40
Log likelihood	(2,618.1)	Hannan-Quinn criter.	28.31191789
F-statistic	111.0	Durbin-Watson stat	1.0499286
Prob(F-statistic)	0.0		

Large Use Model

Dependent Variable: LU_DAY
Method: Least Squares
Date: 03/28/18 Time: 18:43
Sample: 2002M07 2017M12
Included observations: 186
White Heteroskedasticity-Consistent Standard Errors & Covariance

Variable	Coefficient	Std. Error	t-Statistic	Prob.
BLACKOUT	**(386,736)**	60,953	(6.34)	0.000
BUS_DAYS_PERCENT	**16,141**	5,325	3.03	0.003
CDD18_DAY	**152,034**	25,373	5.99	0.000
CUST	**38,289**	9,321	4.11	0.000
DEW	**33,479**	9,481	3.53	0.001
GDP	**6**	1	4.82	0.000
HDD10_DAY	**62,120**	10,565	5.88	0.000
TREND_SPLINE_2010	**(8,899)**	1,172	(7.59)	0.000
C	**2,525,042**	785,144	3.22	0.002

R-squared	**71.6%**	Mean dependent var	7160800.52
Adjusted R-squared	**70.3%**	S.D. dependent var	430957.28
S.E. of regression	234,983.7	Akaike info criterion	27.62
Sum squared resid	9,773,466,740,053.2	Schwarz criterion	27.78
Log likelihood	(2,559.6)	Hannan-Quinn criter.	27.68284833
F-statistic	55.7	Durbin-Watson stat	1.243705295
Prob(F-statistic)	0.0		

Table 1: Alternative Weather Forecast - 20-Year Trend

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
1					
2					
3		Heating Degree Days 10		Cooling Degree Days	
		10-Year	20-Year	10-Year	20-Year
4	Year	Average	Trend	Average	Trend
5	2018	1,849.5	1,898.4	370.0	388.0
6	2019	1,849.5	1,905.2	370.0	388.8
7	2020	1,864.1	1,928.0	370.0	389.6
8	2021	1,849.5	1,918.8	370.0	390.5
9	2022	1,849.5	1,925.6	370.0	391.3
10	2023	1,849.5	1,932.4	370.0	392.1
11	2024	1,864.1	1,955.8	370.0	392.9
12	Notes:				
13	1. 10-Year Average calculated over 2008-2017				
14	2. Trend forecast based on linear trend from 1998-2017				
15					

Table 2: Alternative Weather Forecast - Load Forecast

	Col. 1	Col. 2	Col. 3	Col. 4
1				
2				
3		Assuming 10-Year Average HDD & CDD	Assuming 20-Year Trend HDD & CDD	Variance
4	Year	GWh	GWh	%
5	2018	24,378.2	24,472.7	0.4%
6	2019	24,123.8	24,227.1	0.4%
7	2020	24,036.0	24,149.5	0.5%
8	2021	23,818.0	23,938.9	0.5%
9	2022	23,651.8	23,781.5	0.5%
	2023	23,475.3	23,613.8	0.6%
10	2024	23,396.7	23,545.9	0.6%
11				

Load Forecast Energy Impacts

	A	B	C	D D=B+C	E	F F=D+E	G	H H=FxG	I	J	K	L	M	N	O
	RESIDENTIAL		**Cumulative 2019 Persistence**	**Cumulative Incremental Gross (For Load Forecast)**	**2020-2024 Load Forecast/LRAM Methodology Variance**	**Cumulative Incremental Gross (For LRAM)**	**Gross to Net Ratio**	**Net Cumulative**	**MWh**	**2020**	**2021**	**2022**	**2023**	**2024**	**Total**
1	2020 CDM Forecast	670,817	(665,659)	5,157.64	4,550.86	9,709	84.7%	8,221	2020 CDM Forecast	8,221					**8,221**
2	2021 CDM Forecast	680,526	(665,659)	14,866.15	4,550.86	19,417	84.7%	16,443	2021 CDM Forecast	8,221	8,221				**16,443**
3	2022 CDM Forecast	690,234	(665,659)	24,574.65	4,550.86	29,126	84.7%	24,664	2022 CDM Forecast	8,221	8,221	8,221			**24,664**
4	2023 CDM Forecast	699,943	(665,659)	34,283.16	4,550.86	38,834	84.7%	32,886	2023 CDM Forecast	8,221	8,221	8,221	8,221		**32,886**
5	2024 CDM Forecast	709,651	(665,659)	43,991.66	4,550.86	48,543	84.7%	41,107	2024 CDM Forecast	8,221	8,221	8,221	8,221	8,221	**41,107**
6									**Total**	**41,107**	**32,886**	**24,664**	**16,443**	**8,221**	**123,322**

	CSMUR		**Cumulative 2019 Persistence**	**Cumulative Incremental Gross (For Load Forecast)**	**2020-2024 Load Forecast/LRAM Methodology Variance**	**Cumulative Incremental Gross (For LRAM)**	**Gross to Net Ratio**	**Net Cumulative**	**MWh**	**2020**	**2021**	**2022**	**2023**	**2024**	**Total**
7	2020 CDM Forecast	23,205	(19,858)	3,347	2,952.91	6,300	101.2%	6,378	2020 CDM Forecast	6,378					**6,378**
8	2021 CDM Forecast	29,504	(19,858)	9,646	2,952.91	12,599	101.2%	12,755	2021 CDM Forecast	6,378	6,378				**12,755**
9	2022 CDM Forecast	35,804	(19,858)	15,946	2,952.91	18,899	101.2%	19,133	2022 CDM Forecast	6,378	6,378	6,378			**19,133**
10	2023 CDM Forecast	42,103	(19,858)	22,245	2,952.91	25,198	101.2%	25,510	2023 CDM Forecast	6,378	6,378	6,378	6,378		**25,510**
11	2024 CDM Forecast	48,403	(19,858)	28,545	2,952.91	31,498	101.2%	31,888	2024 CDM Forecast	6,378	6,378	6,378	6,378	6,378	**31,888**
12									**Total**	**31,888**	**25,510**	**19,133**	**12,755**	**6,378**	**95,663**

	GS<50		**Cumulative 2019 Persistence**	**Cumulative Incremental Gross (For Load Forecast)**	**2020-2024 Load Forecast/LRAM Methodology Variance**	**Cumulative Incremental Gross (For LRAM)**	**Gross to Net Ratio**	**Net Cumulative**	**MWh**	**2020**	**2021**	**2022**	**2023**	**2024**	**Total**
13	2020 CDM Forecast	502,468	(492,116)	10,352	9,133.97	19,486	83.95%	16,358	2020 CDM Forecast	16,358					**16,358**
14	2021 CDM Forecast	521,954	(492,116)	29,838	7,883.62	37,721	83.95%	31,667	2021 CDM Forecast	15,309	16,358				**31,667**
15	2022 CDM Forecast	541,440	(492,116)	49,323	6,580.08	55,904	83.95%	46,931	2022 CDM Forecast	15,264	15,309	16,358			**46,931**
16	2023 CDM Forecast	560,926	(492,116)	68,809	5,011.79	73,821	83.95%	61,973	2023 CDM Forecast	15,042	15,264	15,309	16,358		**61,973**
17	2024 CDM Forecast	580,411	(492,116)	88,295	2,874.18	91,169	83.95%	76,537	2024 CDM Forecast	14,564	15,042	15,264	15,309	16,358	**76,537**
18									**Total**	**76,537**	**61,973**	**46,931**	**31,667**	**16,358**	**233,466**

	GS 50-1000kW		**Cumulative 2019 Persistence**	**Cumulative Incremental Gross (For Load Forecast)**	**2020-2024 Load Forecast/LRAM Methodology Variance**	**Cumulative Incremental Gross (For LRAM)**	**Gross to Net Ratio**	**Net Cumulative**	**MWh**	**2020**	**2021**	**2022**	**2023**	**2024**	**Total**
19	2020 CDM Forecast	1,383,783	(1,319,886)	63,897	56,379.70	120,277	75.5%	90,777	2020 CDM Forecast	90,777					**90,777**
20	2021 CDM Forecast	1,504,060	(1,319,886)	184,174	54,099.14	238,273	75.5%	179,833	2021 CDM Forecast	89,056	90,777				**179,833**
21	2022 CDM Forecast	1,624,336	(1,319,886)	304,450	51,800.60	356,251	75.5%	268,875	2022 CDM Forecast	89,042	89,056	90,777			**268,875**
22	2023 CDM Forecast	1,744,613	(1,319,886)	424,727	49,474.59	474,202	75.5%	357,896	2023 CDM Forecast	89,021	89,042	89,056	90,777		**357,896**
23	2024 CDM Forecast	1,864,890	(1,319,886)	545,004	47,097.50	592,101	75.5%	446,879	2024 CDM Forecast	88,983	89,021	89,042	89,056	90,777	**446,879**
24									**Total**	**446,879**	**357,896**	**268,875**	**179,833**	**90,777**	**1,344,259**

	GS1-5MW		**Cumulative 2019 Persistence**	**Cumulative Incremental Gross (For Load Forecast)**	**2020-2024 Load Forecast/LRAM Methodology Variance**	**Cumulative Incremental Gross (For LRAM)**	**Gross to Net Ratio**	**Net Cumulative**	**MWh**	**2020**	**2021**	**2022**	**2023**	**2024**	**Total**
25	2020 CDM Forecast	790,685	(754,165)	36,520	32,223.61	68,744	75.8%	52,090	2020 CDM Forecast	52,090					**52,090**
26	2021 CDM Forecast	859,429	(754,165)	105,264	30,801.61	136,065	75.8%	103,103	2021 CDM Forecast	51,013	52,090				**103,103**
27	2022 CDM Forecast	928,173	(754,165)	174,007	29,364.48	203,372	75.8%	154,104	2022 CDM Forecast	51,001	51,013	52,090			**154,104**
28	2023 CDM Forecast	996,916	(754,165)	242,751	27,918.89	270,670	75.8%	205,099	2023 CDM Forecast	50,995	51,001	51,013	52,090		**205,099**
29	2024 CDM Forecast	1,065,660	(754,165)	311,495	26,469.02	337,964	75.8%	256,090	2024 CDM Forecast	50,992	50,995	51,001	51,013	52,090	**256,090**
30									**Total**	**256,090**	**205,099**	**154,104**	**103,103**	**52,090**	**770,486**

	LARGE USE		**Cumulative 2019 Persistence**	**Cumulative Incremental Gross (For Load Forecast)**	**2020-2024 Load Forecast/LRAM Methodology Variance**	**Cumulative Incremental Gross (For LRAM)**	**Gross to Net Ratio**	**Net Cumulative**	**MWh**	**2020**	**2021**	**2022**	**2023**	**2024**	**Total**
31	2020 CDM Forecast	624,077	(608,092)	15,985	14,104.21	30,089	74.6%	22,433	2020 CDM Forecast	22,433					**22,433**
32	2021 CDM Forecast	654,166	(608,092)	46,074	13,486.80	59,561	74.6%	44,406	2021 CDM Forecast	21,973	22,433				**44,406**
33	2022 CDM Forecast	684,255	(608,092)	76,163	12,808.40	88,971	74.6%	66,333	2022 CDM Forecast	21,927	21,973	22,433			**66,333**
34	2023 CDM Forecast	714,344	(608,092)	106,252	12,095.95	118,348	74.6%	88,235	2023 CDM Forecast	21,902	21,927	21,973	22,433		**88,235**
35	2024 CDM Forecast	744,433	(608,092)	136,341	11,381.68	147,722	74.6%	110,136	2024 CDM Forecast	21,901	21,902	21,927	21,973	22,433	**110,136**
36									**Total**	**110,136**	**88,235**	**66,333**	**44,406**	**22,433**	**331,544**

	Total		**Cumulative 2019 Persistence**	**Cumulative Incremental Gross (For Load Forecast)**	**2020-2024 Load Forecast/LRAM Methodology Variance**	**Cumulative Incremental Gross (For LRAM)**	**Gross to Net Ratio**	**Net Cumulative**	**MWh**	**2020**	**2021**	**2022**	**2023**	**2024**	**Total**
37	2020 CDM Forecast	3,995,036	(3,859,778)	135,258	119,345.26	254,603	77.1%	196,258	2020 CDM Forecast	144,167					**144,167**
38	2021 CDM Forecast	4,249,639	(3,859,778)	389,861	113,774.95	503,636	77.1%	388,206	2021 CDM Forecast	140,936	144,167				**285,104**
39	2022 CDM Forecast	4,504,242	(3,859,778)	644,464	108,057.33	752,522	77.1%	580,040	2022 CDM Forecast	140,833	140,936	144,167			**425,936**
40	2023 CDM Forecast	4,758,845	(3,859,778)	899,068	102,005.00	1,001,073	77.1%	771,599	2023 CDM Forecast	140,564	140,833	140,936	144,167		**566,500**
41	2024 CDM Forecast	5,013,449	(3,859,778)	1,153,671	95,326.16	1,248,997	77.1%	962,637	2024 CDM Forecast	140,046	140,564	140,833	140,936	144,167	**706,547**

Load Forecast Demand Impacts

	A	B	C	D D=(B+C)	E	F F=D+E	G	H H=FxG	I	J	K	L	M	N	O
	GS 50-1000MW		**Cumulative 2019 Persistence**	**Cumulative Incremental Gross (For Load Forecast)**	**2020-2024 Load Forecast/LRAM Methodology Variance**	**Cumulative Incremental Gross (For LRAM)**	**Gross to Net Ratio**	**Net Cumulative**	**MW**	**2020**	**2021**	**2022**	**2023**	**2024**	**Total**
1	2020 CDM Forecast	2,594	(2,492)	102	86	188	75.59%	142	2020 CDM Forecast	141.76					**141.76**
2	2021 CDM Forecast	2,781	(2,492)	289	83	372	75.59%	281	2021 CDM Forecast	139.20	141.76				**280.96**
3	2022 CDM Forecast	2,969	(2,492)	477	79	556	75.59%	420	2022 CDM Forecast	139.15	139.20	141.76			**420.11**
4	2023 CDM Forecast	3,156	(2,492)	664	76	740	75.59%	559	2023 CDM Forecast	139.11	139.15	139.20	141.76		**559.23**
5	2024 CDM Forecast	3,344	(2,492)	852	72	924	75.59%	698	2024 CDM Forecast	139.07	139.11	139.15	139.20	141.76	**698.30**
6									**Total**	**698.30**	**559.23**	**420.11**	**280.96**	**141.76**	**2,100.36**

	GS1-5MW		**Cumulative 2019 Persistence**	**Cumulative Incremental Gross (For Load Forecast)**	**2020-2024 Load Forecast/LRAM Methodology Variance**	**Cumulative Incremental Gross (For LRAM)**	**Gross to Net Ratio**	**Net Cumulative**	**MW**	**2020**	**2021**	**2022**	**2023**	**2024**	**Total**
7	2020 CDM Forecast	1,379	(1,341)	39	33	72	76.07%	55	2020 CDM Forecast	54.59					**54.59**
8	2021 CDM Forecast	1,451	(1,341)	111	31	142	76.07%	108	2021 CDM Forecast	53.51	54.59				**108.10**
9	2022 CDM Forecast	1,523	(1,341)	182	30	212	76.07%	162	2022 CDM Forecast	53.49	53.51	54.59			**161.59**
10	2023 CDM Forecast	1,595	(1,341)	254	29	283	76.07%	215	2023 CDM Forecast	53.48	53.49	53.51	54.59		**215.07**
11	2024 CDM Forecast	1,666	(1,341)	326	27	353	76.07%	269	2024 CDM Forecast	53.47	53.48	53.49	53.51	54.59	**268.54**
12									**Total**	**268.54**	**215.07**	**161.59**	**108.10**	**54.59**	**807.89**

	LARGE USE		**Cumulative 2019 Persistence**	**Cumulative Incremental Gross (For Load Forecast)**	**2020-2024 Load Forecast/LRAM Methodology Variance**	**Cumulative Incremental Gross (For LRAM)**	**Gross to Net Ratio**	**Net Cumulative**	**MW**	**2020**	**2021**	**2022**	**2023**	**2024**	**Total**
13	2020 CDM Forecast	1,354	(1,328)	27	23	50	75.02%	37	2020 CDM Forecast	37.23	-	-	-	-	**37.23**
14	2021 CDM Forecast	1,404	(1,328)	76	22	98	75.02%	74	2021 CDM Forecast	36.47	37.23	-	-	-	**73.69**
15	2022 CDM Forecast	1,454	(1,328)	126	21	147	75.02%	110	2022 CDM Forecast	36.39	36.47	37.23	-	-	**110.08**
16	2023 CDM Forecast	1,503	(1,328)	176	19	195	75.02%	146	2023 CDM Forecast	36.34	36.39	36.47	37.23	-	**146.42**
17	2024 CDM Forecast	1,553	(1,328)	225	18	244	75.02%	183	2024 CDM Forecast	36.34	36.34	36.39	36.47	37.23	**182.76**
18									**Total**	**182.76**	**146.42**	**110.08**	**73.69**	**37.23**	**550.19**

	Total		**Cumulative 2019 Persistence**	**Cumulative Incremental Gross (For Load Forecast)**	**2020-2024 Load Forecast/LRAM Methodology Variance**	**Cumulative Incremental Gross (For LRAM)**	**Gross to Net Ratio**	**Net Cumulative**	**MW**	**2020**	**2021**	**2022**	**2023**	**2024**	**Total**
19	2020 CDM Forecast	5,328	(5,160)	167	142	309	75.61%	234	2020 CDM Forecast	233.58					**233.58**
20	2021 CDM Forecast	5,636	(5,160)	476	136	612	75.61%	463	2021 CDM Forecast	229.17	233.58				**462.76**
21	2022 CDM Forecast	5,945	(5,160)	785	130	915	75.61%	692	2022 CDM Forecast	229.03	229.17	233.58			**691.78**
22	2023 CDM Forecast	6,254	(5,160)	1,094	124	1,218	75.61%	921	2023 CDM Forecast	228.93	229.03	229.17	233.58		**920.72**
23	2024 CDM Forecast	6,563	(5,160)	1,403	117	1,520	75.61%	1,150	2024 CDM Forecast	228.89	228.93	229.03	229.17	233.58	**1,149.61**
24									**Total**	**1,149.61**	**920.72**	**691.78**	**462.76**	**233.58**	**3,458.44**

OEB Appendix 2-IB
Customer, Connections, Load Forecast and Revenues Data and Analysis

This sheet is to be filled in accordance with the instructions documented in section 2.3.2 of Chapter 2 of the Filing Requirements for Distribution Rate Applications, in terms of one set of tables per customer class.

Color coding for Cells: Data input | Drop-down List | No data entry required | Blank or calculated value

Distribution System (Total)

	Calendar Year (for 2020 Cost of Service		Consumption (kWh) [3]				
				Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2013*		Actual	24,602,483,277	24,549,317,998		
Historical	*2014*		Actual	24,558,531,773	24,438,073,165		
Historical	*2015*		Actual	24,428,042,829	24,339,499,672	Board-approved	
Historical	*2016*		Actual	24,567,033,429	24,221,254,752		
Historical	*2017*		Actual	23,598,825,424	23,753,435,105		
Bridge Year	*2018*		Forecast		23,704,588,481		
Bridge Year	*2019*		Forecast		23,456,901,501		
Test Year	*2020*		Forecast		23,371,287,137		
Test Year	*2021*		Forecast		23,159,331,182		
Test Year	*2022*		Forecast		22,997,724,093		
Test Year	*2023*		Forecast		22,826,104,359		
Test Year	*2024*		Forecast		22,749,647,312		

Variance Analysis	Year	Year-over-year		Versus Board-approved
	2013			
	2014	-0.2%	-0.5%	
	2015	-0.5%	-0.4%	
	2016	0.6%	-0.5%	
	2017	-3.9%	-1.9%	
	2018		-0.2%	
	2019		-1.0%	
	2020		-0.4%	
	2021		-0.9%	
	2022		-0.7%	
	2023		-0.7%	
	2024		-0.3%	
	Geometric Mean	-1.4%	-0.8%	

Customer Class Analysis (one for each Customer Class, excluding MicroFIT and Standby)

1 Customer Class: Residential — Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2020 Cost of Service)	Customers				Consumption (kWh) [3]				Consumption (kWh) per Customer			
							Actual (Weather actual)	Weather-normalized	Weather-normalized		Actual (Weather actual)	Weather-normalized	Weather-normalized
Historical	*2013*	Actual	606,350			Actual	4,988,814,396	4,978,747,000		Actual	8,228	8,211	
Historical	*2014*	Actual	609,928			Actual	4,879,959,207	4,864,760,386		Actual	8,001	7,976	
Historical	*2015*	Actual	610,961	Board-approved	612,985	Actual	4,807,191,038	4,785,012,315	4,909,898,145	Actual	7,868	7,832 Board-approved	8,010
Historical	*2016*	Actual	611,021			Actual	4,903,931,991	4,766,987,170		Actual	8,026	7,802	
Historical	*2017*	Actual	611,660			Actual	4,464,337,173	4,513,182,843		Actual	7,299	7,379	
Bridge Year	*2018*	Forecast	612,675			Forecast		4,579,985,785		Forecast		7,475	
Bridge Year	*2019*	Forecast	614,320			Forecast		4,532,014,707		Forecast		7,377	
Test Year	*2020*	Forecast	615,965			Forecast		4,510,636,914		Forecast		7,323	
Test Year	*2021*	Forecast	617,609			Forecast		4,458,695,848		Forecast		7,219	
Test Year	*2022*	Forecast	619,254			Forecast		4,422,717,979		Forecast		7,142	
Test Year	*2023*	Forecast	620,899			Forecast		4,386,740,109		Forecast		7,065	
Test Year	*2024*	Forecast	622,544			Forecast		4,366,437,563		Forecast		7,014	

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2013			*2013*				*2013*			
	2014	0.6%		*2014*	-2.2%	-2.3%		*2014*	-2.8%	-2.9%	
	2015	0.2%		*2015*	-1.5%	-1.6%		*2015*	-1.7%	-1.8%	
	2016	0.0%		*2016*	2.0%	-0.4%		*2016*	2.0%	-0.4%	
	2017	0.1%		*2017*	-9.0%	-5.3%		*2017*	-9.1%	-5.4%	
	2018	0.2%		*2018*		1.5%		*2018*		1.3%	
	2019	0.3%		*2019*		-1.0%		*2019*		-1.3%	
	2020	0.3%		*2020*		-0.5%		*2020*		-0.7%	
	2021	0.3%		*2021*		-1.2%		*2021*		-1.4%	
	2022	0.3%		*2022*		-0.8%		*2022*		-1.1%	
	2023	0.3%		*2023*		-0.8%		*2023*		-1.1%	
	2024	0.3%	0.5%	*2024*		-0.5%	-8.1%	*2024*		-0.7%	-8.6%
	Geometric Mean	0.3%		Geometric Mean	-3.6%	-1.3%		Geometric Mean	-3.9%	-1.6%	

	Calendar Year (for 2020 Cost of Service)	Revenues			
Historical	*2013*	Actual	$ 211,842,738		
Historical	*2014*	Actual	$ 213,303,103		
Historical	*2015*	Actual	$ 250,146,122	Board-approved	$ 252,506,394
Historical	*2016*	Actual	$ 262,006,434		
Historical	*2017*	Actual	$ 273,565,974		
Bridge Year	*2018*	Forecast	$ 291,916,203		
Bridge Year	*2019*	Forecast	$ 305,001,252		
Test Year	*2020*	Forecast	$ 315,807,309		
Test Year	*2021*	Forecast	$ 326,944,706		
Test Year	*2022*	Forecast	$ 335,877,177		
Test Year	*2023*	Forecast	$ 351,046,981		
Test Year	*2024*	Forecast	$ 365,837,982		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2013		
	2014	0.7%	
Note 2	*2015*	17.3%	
	2016	4.7%	
	2017	4.4%	
	2018	6.7%	
	2019	4.5%	
	2020	3.5%	
	2021	3.5%	
	2022	2.7%	
	2023	4.5%	
	2024	4.2%	25.1%
	Geometric Mean	5.6%	

2 Customer Class: CSMUR Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2020 Cost of Service)	Customers				Consumption (kWh) [3]				Consumption (kWh) per Customer				
							Actual (Weather actual)	Weather-normalized		Weather-normalized		Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2013*	Actual	36,156			Actual	133,317,285	130,463,404			Actual	3,687	3,608		
Historical	*2014*	Actual	43,022			Actual	158,440,481	154,703,464			Actual	3,683	3,596		
Historical	*2015*	Actual	54,516	Board-approved	54,122	Actual	203,724,686	202,105,727	Board-approved	213,116,822	Actual	3,737	3,707	Board-approved	3,938
Historical	*2016*	Actual	65,685			Actual	231,489,091	230,324,614			Actual	3,524	3,507		
Historical	*2017*	Actual	71,041			Actual	243,307,958	245,098,022			Actual	3,425	3,450		
Bridge Year	*2018*	Forecast	75,371			Forecast		256,193,965			Forecast		3,399		
Bridge Year	*2019*	Forecast	79,347			Forecast		263,912,886			Forecast		3,326		
Test Year	*2020*	Forecast	85,161			Forecast		277,127,203			Forecast		3,254		
Test Year	*2021*	Forecast	90,045			Forecast		286,903,886			Forecast		3,186		
Test Year	*2022*	Forecast	95,962			Forecast		300,278,055			Forecast		3,129		
Test Year	*2023*	Forecast	101,879			Forecast		313,817,857			Forecast		3,080		
Test Year	*2024*	Forecast	107,796			Forecast		328,419,229			Forecast		3,047		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2013			*2013*				*2013*			
Note 3	*2014*	19.0%		*2014*	18.8%	18.6%		*2014*	-0.1%	-0.3%	
Note 3	*2015*	26.7%		*2015*	28.6%	30.6%		*2015*	1.5%	3.1%	
Note 3	*2016*	20.5%		*2016*	13.6%	14.0%		*2016*	-5.7%	-5.4%	
	2017	8.2%		*2017*	5.1%	6.4%		*2017*	-2.8%	-1.6%	
	2018	6.1%		*2018*		4.5%		*2018*		-1.5%	
	2019	5.3%		*2019*		3.0%		*2019*		-2.1%	
	2020	7.3%		*2020*		5.0%		*2020*		-2.2%	
	2021	5.7%		*2021*		3.5%		*2021*		-2.1%	
	2022	6.6%		*2022*		4.7%		*2022*		-1.8%	
	2023	6.2%		*2023*		4.5%		*2023*		-1.6%	
	2024	5.8%	57.4%	*2024*		4.7%	30.0%	*2024*		-1.1%	-17.4%
	Geometric Mean	11.5%		Geometric Mean	22.2%	9.7%		Geometric Mean	-2.4%	-1.7%	

	Calendar Year (for 2020 Cost of Service)	Revenues			
Historical	*2013*	Actual	$ 11,000,234		
Historical	*2014*	Actual	$ 13,227,973		
Historical	*2015*	Actual	$ 17,829,628	Board-approved	$ 18,002,535
Historical	*2016*	Actual	$ 21,941,819		
Historical	*2017*	Actual	$ 25,460,359		
Bridge Year	*2018*	Forecast	$ 28,744,247		
Bridge Year	*2019*	Forecast	$ 31,732,336		
Test Year	*2020*	Forecast	$ 34,606,592		
Test Year	*2021*	Forecast	$ 37,785,433		
Test Year	*2022*	Forecast	$ 41,260,781		
Test Year	*2023*	Forecast	$ 45,664,205		
Test Year	*2024*	Forecast	$ 50,218,024		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2013		
Note 3	*2014*	20.3%	
Note 3	*2015*	34.8%	
Note 3	*2016*	23.1%	
Note 3	*2017*	16.0%	
Note 3	*2018*	12.9%	
Note 3	*2019*	10.4%	
	2020	9.1%	178.9%
	2021	9.2%	
	2022	9.2%	
Note 3	*2023*	10.7%	
Note 3	*2024*	10.0%	
	Geometric Mean	16.4%	

3 Customer Class: GS < 50 kW Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2020 Cost of Service)	Customers				Consumption (kWh) [3]				Consumption (kWh) per Customer			
							Actual (Weather actual)	Weather-normalized	Weather-normalized		Actual (Weather actual)	Weather-normalized	Weather-normalized
Historical	*2013*	Actual	68,312			Actual	2,171,642,035	2,169,187,101		Actual	31790.1	31,754	
Historical	*2014*	Actual	69,078			Actual	2,253,840,657	2,250,960,065		Actual	32627.5	32,586	
Historical	*2015*	Actual	70,628	Board-approved	69,131	Actual	2,366,876,161	2,360,983,568	Board Approved 2,118,402,162	Actual	33511.9	33,428	Board Approved
Historical	*2016*	Actual	70,499			Actual	2,371,216,399	2,330,941,187		Actual	33634.8	33,063	
Historical	*2017*	Actual	71,116			Actual	2,306,089,650	2,319,849,458		Actual	32427.2	32,621	
Bridge Year	*2018*	Forecast	71,306			Forecast		2,307,381,246		Forecast		32,359	
Bridge Year	*2019*	Forecast	71,403			Forecast		2,281,497,648		Forecast		31,952	
Test Year	*2020*	Forecast	71,499			Forecast		2,267,638,936		Forecast		31,716	
Test Year	*2021*	Forecast	71,596			Forecast		2,238,780,453		Forecast		31,270	
Test Year	*2022*	Forecast	71,692			Forecast		2,214,262,866		Forecast		30,886	
Test Year	*2023*	Forecast	71,788			Forecast		2,187,481,667		Forecast		30,471	
Test Year	*2024*	Forecast	71,885			Forecast		2,169,915,395		Forecast		30,186	

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2013			*2013*				*2013*			
	2014	1.1%		*2014*	3.8%	3.8%		*2014*	2.6%	2.6%	
	2015	2.2%		*2015*	5.0%	4.9%		*2015*	2.7%	2.6%	
	2016	-0.2%		*2016*	0.2%	-1.3%		*2016*	0.4%	-1.1%	
	2017	0.9%		*2017*	-2.7%	-0.5%		*2017*	-3.6%	-1.3%	
	2018	0.3%		*2018*		-0.5%		*2018*		-0.8%	
	2019	0.1%		*2019*		-1.1%		*2019*		-1.3%	
	2020	0.1%		*2020*		-0.6%		*2020*		-0.7%	
	2021	0.1%		*2021*		-1.3%		*2021*		-1.4%	
	2022	0.1%		*2022*		-1.1%		*2022*		-1.2%	
	2023	0.1%		*2023*		-1.2%		*2023*		-1.3%	
	2024	0.1%	3.4%	*2024*		-0.8%	7.0%	*2024*		-5.5%	
	Geometric Mean	0.5%		Geometric Mean	2.0%	0.0%		Geometric Mean	0.7%	-0.5%	

	Calendar Year (for 2020 Cost of Service)	Revenues			
Historical	*2013*	Actual	$ 69,640,444		
Historical	*2014*	Actual	$ 72,523,701		
Historical	*2015*	Actual	$ 89,457,689	Board-approved	$ 82,174,475
Historical	*2016*	Actual	$ 93,027,753		
Historical	*2017*	Actual	$ 97,989,286		
Bridge Year	*2018*	Forecast	$ 103,423,556		
Bridge Year	*2019*	Forecast	$ 106,600,964		
Test Year	*2020*	Forecast	$ 110,004,699		
Test Year	*2021*	Forecast	$ 112,620,337		
Test Year	*2022*	Forecast	$ 114,543,206		
Test Year	*2023*	Forecast	$ 118,435,994		
Test Year	*2024*	Forecast	$ 122,461,164		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2013		
	2014	4.1%	
Note 2	*2015*	23.3%	
	2016	4.0%	
	2017	5.3%	
	2018	5.5%	
	2019	3.1%	
	2020	3.2%	
	2021	2.4%	
	2022	1.7%	
	2023	3.4%	
	2024	3.4%	33.9%
	Geometric Mean	5.8%	

4 **Customer Class:** GS 50-999 kW Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kVA

	Calendar Year (for 2020 Cost of Service)	Customers				Consumption (kWh) [3]				Consumption (kWh) per Customer				
							Actual (Weather actual)	Weather-normalized	Weather-normalized		Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2013*	Actual	11,885			Actual	9,901,798,273	9,879,064,931		Actual	833,134	831,221		
Historical	*2014*	Actual	11,852			Actual	10,026,512,948	9,969,187,148		Actual	845,976	841,140		
Historical	*2015*	Actual	10,364	Board-approved	12,054	Actual	9,931,112,876	9,894,525,368	Board-approved	9,848,614,894	Actual	958,232	954,701	Board-approved	817,041
Historical	*2016*	Actual	10,475			Actual	9,975,508,523	9,858,005,611			Actual	952,316	941,098		
Historical	*2017*	Actual	10,407			Actual	9,672,125,164	9,730,910,630			Actual	929,386	935,035		
Bridge Year	*2018*	Forecast	10,396			Forecast		9,654,315,225			Forecast		928,657		
Bridge Year	*2019*	Forecast	10,385			Forecast		9,589,676,796			Forecast		923,416		
Test Year	*2020*	Forecast	10,374			Forecast		9,587,728,582			Forecast		924,207		
Test Year	*2021*	Forecast	10,363			Forecast		9,526,101,781			Forecast		919,242		
Test Year	*2022*	Forecast	10,352			Forecast		9,482,679,716			Forecast		916,024		
Test Year	*2023*	Forecast	10,341			Forecast		9,432,138,729			Forecast		912,111		
Test Year	*2024*	Forecast	10,330			Forecast		9,419,379,152			Forecast		911,847		

Variance Analysis	Year	Customers Year-over-year	Customers Test Year Versus Board-approved	Consumption (kWh) Year	Consumption (kWh) Year-over-year: Actual (Weather actual)	Consumption (kWh) Year-over-year: Weather-normalized	Consumption (kWh) Test Year Versus Board-approved	Consumption (kWh) per Customer Year	Consumption (kWh) per Customer Year-over-year: Actual (Weather actual)	Consumption (kWh) per Customer Year-over-year: Weather-normalized	Consumption (kWh) per Customer Test Year Versus Board-approved
	2013			*2013*				*2013*			
	2014	-0.3%		*2014*	1.3%	0.9%		*2014*	1.5%	1.2%	
Note 2	*2015*	-12.6%		*2015*	-1.0%	-0.7%		*2015*	13.3%	13.5%	
	2016	1.1%		*2016*	0.4%	-0.4%		*2016*	-0.6%	-1.4%	
	2017	-0.6%		*2017*	-3.0%	-1.3%		*2017*	-2.4%	-0.6%	
	2018	-0.1%		*2018*		-0.8%		*2018*		-0.7%	
	2019	-0.1%		*2019*		-0.7%		*2019*		-0.6%	
	2020	-0.1%		*2020*		0.0%		*2020*		0.1%	
	2021	-0.1%		*2021*		-0.6%		*2021*		-0.5%	
	2022	-0.1%		*2022*		-0.5%		*2022*		-0.4%	
	2023	-0.1%		*2023*		-0.5%		*2023*		-0.4%	
	2024	-0.1%	-13.9%	*2024*		-0.1%	-2.6%	*2024*		0.0%	13.1%
	Geometric Mean	-1.4%		Geometric Mean	-0.8%	-0.5%		Geometric Mean	3.7%	0.9%	

	Calendar Year (for 2020 Cost of Service)	Transformer Allowance kVa		
Historical	*2013*	Actual	5,677,788	
Historical	*2014*	Actual	6,043,033	
Historical	*2015*	Actual	6,255,491	
Historical	*2016*	Actual	6,426,851	
Historical	*2017*	Actual	6,387,212	
Bridge Year	*2018*	Forecast	6,347,645	
Bridge Year	*2019*	Forecast	6,339,037	
Test Year	*2020*	Forecast	6,256,401	
Test Year	*2021*	Forecast	6,244,728	
Test Year	*2022*	Forecast	6,242,677	
Test Year	*2023*	Forecast	6,235,946	
Test Year	*2024*	Forecast	6,250,759	

	Calendar Year (for 2020 Cost of Service)	Revenues				Demand (kVA)				Demand (kVA) per Customer				
							Actual (Weather actual)	Weather-normalized	Weather-normalized		Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2013*	Actual	$ 150,194,118			Actual	25,938,018	25,882,337		Actual	2182	2178		
Historical	*2014*	Actual	$ 150,772,038			Actual	25,788,227	25,679,509		Actual	2176	2167		
Historical	*2015*	Actual	$ 172,375,420	Board-approved	$ 180,346,188	Actual	25,388,280	25,324,534	Board-approved	26,395,826	Actual	2450	2444	Board-approved	2,190
Historical	*2016*	Actual	$ 181,645,982			Actual	25,684,305	25,373,258			Actual	2452	2422		
Historical	*2017*	Actual	$ 188,108,963			Actual	24,821,587	24,967,767			Actual	2385	2399		
Bridge Year	*2018*	Forecast	$ 202,001,465			Forecast		25,259,133			Forecast		2430		
Bridge Year	*2019*	Forecast	$ 209,647,074			Forecast		25,224,716			Forecast		2429		
Test Year	*2020*	Forecast	$ 213,897,609			Forecast		24,899,249			Forecast		2400		
Test Year	*2021*	Forecast	$ 220,563,142			Forecast		24,849,478			Forecast		2398		
Test Year	*2022*	Forecast	$ 226,003,812			Forecast		24,840,867			Forecast		2400		
Test Year	*2023*	Forecast	$ 235,495,164			Forecast		24,813,648			Forecast		2400		
Test Year	*2024*	Forecast	$ 245,490,240			Forecast		24,875,671			Forecast		2408		

Variance Analysis	Year	Revenues Year-over-year	Revenues Test Year Versus Board-approved	Demand (kVA) Year	Demand (kVA) Year-over-year: Actual (Weather actual)	Demand (kVA) Year-over-year: Weather-normalized	Demand (kVA) Test Year Versus Board-approved	Demand (kVA) per Customer Year	Demand (kVA) per Customer Year-over-year: Actual (Weather actual)	Demand (kVA) per Customer Year-over-year: Weather-normalized	Demand (kVA) per Customer Test Year Versus Board-approved
	2013			*2013*				*2013*			
	2014	0.4%		*2014*	-0.6%	-0.8%		*2014*	-0.3%	-0.5%	
Note 2	*2015*	14.3%		*2015*	-1.6%	-1.4%		*2015*	12.6%	12.8%	
	2016	5.4%		*2016*	1.2%	0.2%		*2016*	0.1%	-0.9%	
	2017	3.6%		*2017*	-3.4%	-1.6%		*2017*	-2.7%	-1.0%	
	2018	7.4%		*2018*		1.2%		*2018*		1.3%	
	2019	3.8%		*2019*		-0.1%		*2019*		0.0%	
	2020	2.0%		*2020*		-1.3%		*2020*		-1.2%	
	2021	3.1%		*2021*		-0.2%		*2021*		-0.1%	
	2022	2.5%		*2022*		0.0%		*2022*		0.1%	
	2023	4.2%		*2023*		-0.1%		*2023*		0.0%	
	2024	4.2%	18.6%	*2024*		0.2%	-5.7%	*2024*		0.4%	9.6%
	Geometric Mean	5.0%		Geometric Mean	-1.5%	-0.4%		Geometric Mean	3.0%	1.0%	

5 Customer Class: GS 1000-4999 kW Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kVA

	Calendar Year (for 2020 Cost of Service)	Customers				Consumption (kWh) [3]				Consumption (kWh) per Customer				
							Actual (Weather actual)	Weather-normalized		Weather-normalized		Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2013*	Actual	516			Actual	4,933,804,363	4,922,403,921			Actual	9,561,636	9,539,542		
Historical	*2014*	Actual	447			Actual	4,882,286,646	4,850,090,381			Actual	10,922,341	10,850,314		
Historical	*2015*	Actual	432	Board-approved	440	Actual	4,807,842,082	4,791,516,663	Board-approved	4,654,535,571	Actual	11,129,264	11,091,474	Board-approved	10,578,490
Historical	*2016*	Actual	443			Actual	4,753,125,810	4,722,938,583			Actual	10,729,404	10,661,261		
Historical	*2017*	Actual	431			Actual	4,608,797,465	4,630,556,212			Actual	10,693,266	10,743,750		
Bridge Year	*2018*	Forecast	430			Forecast		4,660,641,682			Forecast		10,838,702		
Bridge Year	*2019*	Forecast	430			Forecast		4,591,708,574			Forecast		10,678,392		
Test Year	*2020*	Forecast	430			Forecast		4,561,528,177			Forecast		10,608,205		
Test Year	*2021*	Forecast	430			Forecast		4,500,819,338			Forecast		10,467,022		
Test Year	*2022*	Forecast	430			Forecast		4,444,016,815			Forecast		10,334,923		
Test Year	*2023*	Forecast	430			Forecast		4,387,143,302			Forecast		10,202,659		
Test Year	*2024*	Forecast	430			Forecast		4,351,721,474			Forecast		10,120,282		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2013			*2013*				*2013*			
Note 4	*2014*	-13.4%		*2014*	-1.0%	-1.5%		*2014*	14.2%	13.7%	
	2015	-3.4%		*2015*	-1.5%	-1.2%		*2015*	1.9%	2.2%	
	2016	2.5%		*2016*	-1.1%	-1.4%		*2016*	-3.6%	-3.9%	
	2017	-2.7%		*2017*	-3.0%	-2.0%		*2017*	-0.3%	0.8%	
	2018	-0.2%		*2018*		0.6%		*2018*		0.9%	
	2019	0.0%		*2019*		-1.5%		*2019*		-1.5%	
	2020	0.0%		*2020*		-0.7%		*2020*		-0.7%	
	2021	0.0%		*2021*		-1.3%		*2021*		-1.3%	
	2022	0.0%		*2022*		-1.3%		*2022*		-1.3%	
	2023	0.0%		*2023*		-1.3%		*2023*		-1.3%	
	2024	0.0%	-2.3%	*2024*		-0.8%	-2.0%	*2024*		-0.8%	0.3%
	Geometric Mean	-1.8%		Geometric Mean	-2.2%	-1.2%		Geometric Mean	3.8%	0.6%	

	Calendar Year (for 2020 Cost of Service)	Transformer Allowance kVa			
Historical	*2013*	Actual	8,869,214		
Historical	*2014*	Actual	8,796,124		
Historical	*2015*	Actual	8,758,785		
Historical	*2016*	Actual	8,807,222		
Historical	*2017*	Actual	8,576,556		
Bridge Year	*2018*	Forecast	8,677,265		
Bridge Year	*2019*	Forecast	8,628,165		
Test Year	*2020*	Forecast	8,635,125		
Test Year	*2021*	Forecast	8,586,979		
Test Year	*2022*	Forecast	8,545,146		
Test Year	*2023*	Forecast	8,502,657		
Test Year	*2024*	Forecast	8,498,730		

	Calendar Year (for 2020 Cost of Service)	Revenues				Demand (kVA)				Demand (kVA) per Customer				
							Actual (Weather actual)	Weather-normalized		Weather-normalized		Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2013*	Actual	$ 49,204,688			Actual	11,071,372	11,046,389			Actual	21,456	21,408		
Historical	*2014*	Actual	$ 47,856,241			Actual	10,765,500	10,703,390			Actual	24,084	23,945		
Historical	*2015*	Actual	$ 55,006,263	Board-approved	$ 55,588,622	Actual	10,620,705	10,591,944	Board-approved	10,671,871	Actual	24,585	24,518	Board-approved	24,254
Historical	*2016*	Actual	$ 57,374,752			Actual	10,586,541	10,515,476			Actual	23,897	23,737		
Historical	*2017*	Actual	$ 59,842,095			Actual	10,256,881	10,303,604			Actual	23,798	23,906		
Bridge Year	*2018*	Forecast	$ 64,459,918			Forecast		10,442,958			Forecast		24,286		
Bridge Year	*2019*	Forecast	$ 66,800,371			Forecast		10,383,836			Forecast		24,148		
Test Year	*2020*	Forecast	$ 69,156,857			Forecast		10,392,864			Forecast		24,169		
Test Year	*2021*	Forecast	$ 71,212,854			Forecast		10,334,297			Forecast		24,033		
Test Year	*2022*	Forecast	$ 72,765,117			Forecast		10,283,783			Forecast		23,916		
Test Year	*2023*	Forecast	$ 75,726,989			Forecast		10,232,645			Forecast		23,797		
Test Year	*2024*	Forecast	$ 78,883,982			Forecast		10,228,471			Forecast		23,787		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2013			*2013*				*2013*			
	2014	-2.7%		*2014*	-2.8%	-3.1%		*2014*	12.2%	11.9%	
Note 2	*2015*	14.9%		*2015*	-1.3%	-1.0%		*2015*	2.1%	2.4%	
	2016	4.3%		*2016*	-0.3%	-0.7%		*2016*	-2.8%	-3.2%	
	2017	4.3%		*2017*	-3.1%	-2.0%		*2017*	-0.4%	0.7%	
	2018	7.7%		*2018*		1.4%		*2018*		1.6%	
	2019	3.6%		*2019*		-0.6%		*2019*		-0.6%	
	2020	3.5%		*2020*		0.1%		*2020*		0.1%	
	2021	3.0%		*2021*		-0.6%		*2021*		-0.6%	
	2022	2.2%		*2022*		-0.5%		*2022*		-0.5%	
	2023	4.1%		*2023*		-0.5%		*2023*		-0.5%	
	2024	4.2%	24.4%	*2024*		0.0%	-2.6%	*2024*		0.0%	-0.3%
	Geometric Mean	4.8%		Geometric Mean	-2.5%	-0.8%		Geometric Mean	3.5%	1.1%	

6 Customer Class: Large Use — Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kVA

	Calendar Year (for 2020 Cost of Service)	Customers			Consumption (kWh) [3]				Consumption (kWh) per Customer				
						Actual (Weather actual)	Weather-normalized		Weather-normalized		Actual (Weather actual)	Weather-normalized	Weather-normalized
Historical	*2013*	Actual	52		Actual	2,317,813,992	2,314,158,707			Actual	44,573,346	44,503,052	
Historical	*2014*	Actual	47		Actual	2,202,455,832	2,193,335,719			Actual	46,860,762	46,666,717	
Historical	*2015*	Actual	44	Board-approved	Actual	2,156,018,802	2,150,078,846	Board-approved	2,228,386,374	Actual	49,000,427	48,865,428	Board-approved	45,477,273
Historical	*2016*	Actual	42		Actual	2,175,392,445	2,155,688,415			Actual	51,795,058	51,325,915	
Historical	*2017*	Actual	44		Actual	2,148,489,979	2,158,159,906			Actual	48,829,318	49,049,089	
Bridge Year	*2018*	Forecast	44		Forecast		2,090,235,503			Forecast		47,505,352	
Bridge Year	*2019*	Forecast	44		Forecast		2,042,069,343			Forecast		46,410,667	
Test Year	*2020*	Forecast	44		Forecast		2,009,923,443			Forecast		45,680,078	
Test Year	*2021*	Forecast	44		Forecast		1,991,635,383			Forecast		45,264,441	
Test Year	*2022*	Forecast	44		Forecast		1,977,187,697			Forecast		44,936,084	
Test Year	*2023*	Forecast	44		Forecast		1,962,015,257			Forecast		44,591,256	
Test Year	*2024*	Forecast	44		Forecast		1,956,322,242			Forecast		44,461,869	

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2013			*2013*				*2013*			
	2014	-9.6%		*2014*	-5.0%	-5.2%		*2014*	5.1%	4.9%	
	2015	-6.4%		*2015*	-2.1%	-2.0%		*2015*	4.6%	4.7%	
	2016	-4.5%		*2016*	0.9%	0.3%		*2016*	5.7%	5.0%	
	2017	4.8%		*2017*	-1.2%	0.1%		*2017*	-5.7%	-4.4%	
	2018	0.0%		*2018*		-3.1%		*2018*		-3.1%	
	2019	0.0%		*2019*		-2.3%		*2019*		-2.3%	
	2020	0.0%		*2020*		-1.6%		*2020*		-1.6%	
	2021	0.0%		*2021*		-0.9%		*2021*		-0.9%	
	2022	0.0%		*2022*		-0.7%		*2022*		-0.7%	
	2023	0.0%		*2023*		-0.8%		*2023*		-0.8%	
	2024	0.0%	-10.2%	*2024*		-0.3%	-9.8%	*2024*		-0.3%	0.4%
	Geometric Mean	-1.7%		Geometric Mean	-2.5%	-1.7%		Geometric Mean	3.1%	0.0%	

	Calendar Year (for 2020 Cost of Service)	Transformer Allowance kVa	
Historical	*2013*	Actual	5,297,783
Historical	*2014*	Actual	5,037,228
Historical	*2015*	Actual	4,961,605
Historical	*2016*	Actual	5,040,441
Historical	*2017*	Actual	4,991,727
Bridge Year	*2018*	Forecast	4,775,971
Bridge Year	*2019*	Forecast	4,706,855
Test Year	*2020*	Forecast	4,670,713
Test Year	*2021*	Forecast	4,646,613
Test Year	*2022*	Forecast	4,630,773
Test Year	*2023*	Forecast	4,613,066
Test Year	*2024*	Forecast	4,616,690

	Calendar Year (for 2020 Cost of Service)	Revenues			Demand (kVA)				Demand (kVA) per Customer				
						Actual (Weather actual)	Weather-normalized		Weather-normalized		Actual (Weather actual)	Weather-normalized	Weather-normalized
Historical	*2013*	Actual	$ 25,251,423		Actual	5,493,794	5,485,574			Actual	105,650	105,492	
Historical	*2014*	Actual	$ 23,989,999		Actual	5,177,346	5,159,660			Actual	110,156	109,780	
Historical	*2015*	Actual	$ 27,721,665	Board-approved	Actual	5,090,547	5,080,088	Board-approved	5,305,030	Actual	115,694	115,457	Board-approved	108,266
Historical	*2016*	Actual	$ 29,318,163		Actual	5,170,992	5,122,203			Actual	123,119	121,957	
Historical	*2017*	Actual	$ 31,351,056		Actual	5,113,057	5,134,769			Actual	116,206	116,699	
Bridge Year	*2018*	Forecast	$ 31,915,699		Forecast		4,897,235			Forecast		111,301	
Bridge Year	*2019*	Forecast	$ 32,812,359		Forecast		4,826,374			Forecast		109,690	
Test Year	*2020*	Forecast	$ 33,795,038		Forecast		4,789,334			Forecast		108,849	
Test Year	*2021*	Forecast	$ 34,823,821		Forecast		4,764,614			Forecast		108,287	
Test Year	*2022*	Forecast	$ 35,638,447		Forecast		4,748,366			Forecast		107,917	
Test Year	*2023*	Forecast	$ 37,139,549		Forecast		4,730,195			Forecast		107,504	
Test Year	*2024*	Forecast	$ 38,741,455		Forecast		4,733,922			Forecast		107,589	

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2013			*2013*				*2013*			
	2014	-5.0%		*2014*	-5.8%	-5.9%		*2014*	4.3%	4.1%	
Note 2	*2015*	15.6%		*2015*	-1.7%	-1.5%		*2015*	5.0%	5.2%	
	2016	5.8%		*2016*	1.6%	0.8%		*2016*	6.4%	5.6%	
	2017	6.9%		*2017*	-1.1%	0.2%		*2017*	-5.6%	-4.3%	
	2018	1.8%		*2018*		-4.6%		*2018*		-4.6%	
	2019	2.8%		*2019*		-1.4%		*2019*		-1.4%	
	2020	3.0%		*2020*		-0.8%		*2020*		-0.8%	
	2021	3.0%		*2021*		-0.5%		*2021*		-0.5%	
	2022	2.3%		*2022*		-0.3%		*2022*		-0.3%	
	2023	4.2%		*2023*		-0.4%		*2023*		-0.4%	
	2024	4.3%	16.3%	*2024*		0.1%	-9.7%	*2024*		0.1%	0.5%
	Geometric Mean	4.4%		Geometric Mean	-2.4%	-1.5%		Geometric Mean	3.2%	0.2%	

7 Customer Class: Street Lighting Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kVA

	Calendar Year (for 2020 Cost of Service)	Connections				Consumption (kWh) [3]				Consumption (kWh) per Connection				
							Actual (Weather actual)	Weather-normalized		Weather-normalized		Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2013*	Actual	163,426			Actual	114,205,296	114,205,296			Actual	699	699		
Historical	*2014*	Actual	163,810			Actual	114,087,684	114,087,684			Actual	696	696		
Historical	*2015*	Actual	164,008	Board-approved	164,098	Actual	114,178,674	114,178,674	Board-approved	114,092,929	Actual	696	696	Board-approved	695
Historical	*2016*	Actual	164,296			Actual	114,988,504	114,988,504			Actual	700	700		
Historical	*2017*	Actual	164,537			Actual	114,477,435	114,477,435			Actual	696	696		
Bridge Year	*2018*	Forecast	164,756			Forecast		114,634,473			Forecast		696		
Bridge Year	*2019*	Forecast	165,024			Forecast		114,820,946			Forecast		696		
Test Year	*2020*	Forecast	165,292			Forecast		115,390,403			Forecast		698		
Test Year	*2021*	Forecast	165,560			Forecast		115,193,891			Forecast		696		
Test Year	*2022*	Forecast	165,828			Forecast		115,380,364			Forecast		696		
Test Year	*2023*	Forecast	166,096			Forecast		115,566,836			Forecast		696		
Test Year	*2024*	Forecast	166,364			Forecast		116,138,779			Forecast		698		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2013			*2013*				*2013*			
	2014	0.2%		*2014*	-0.1%	-0.1%		*2014*	-0.3%	-0.3%	
	2015	0.1%		*2015*	0.1%	0.1%		*2015*	0.0%	0.0%	
	2016	0.2%		*2016*	0.7%	0.7%		*2016*	0.5%	0.5%	
	2017	0.1%		*2017*	-0.4%	-0.4%		*2017*	-0.6%	-0.6%	
	2018	0.1%		*2018*		0.1%		*2018*		0.0%	
	2019	0.2%		*2019*		0.2%		*2019*		0.0%	
	2020	0.2%		*2020*		0.5%		*2020*		0.3%	
	2021	0.2%		*2021*		-0.2%		*2021*		-0.3%	
	2022	0.2%		*2022*		0.2%		*2022*		0.0%	
	2023	0.2%		*2023*		0.2%		*2023*		0.0%	
	2024	0.2%	0.7%	*2024*		0.5%	1.1%	*2024*		0.3%	0.4%
	Geometric Mean	0.2%		Geometric Mean	0.1%	0.2%		Geometric Mean	-0.1%	0.0%	

	Calendar Year (for 2020 Cost of Service)	Revenues				Demand (kVA)				Demand (kVA) per Connection				
							Actual (Weather actual)	Weather-normalized		Weather-normalized		Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2013*	Actual	$ 12,108,215			Actual	323,205	323,205			Actual	2.0	2.0		
Historical	*2014*	Actual	$ 12,259,078			Actual	323,887	323,887			Actual	2.0	2.0		
Historical	*2015*	Actual	$ 12,269,663	Board-approved	$ 12,281,306	Actual	324,136	324,136	Board-approved	324,479	Actual	2.0	2.0	Board-approved	2.0
Historical	*2016*	Actual	$ 12,793,477			Actual	324,629	324,629			Actual	2.0	2.0		
Historical	*2017*	Actual	$ 13,706,308			Actual	325,116	325,116			Actual	2.0	2.0		
Bridge Year	*2018*	Forecast	$ 14,472,669			Forecast		325,652			Forecast		2.0		
Bridge Year	*2019*	Forecast	$ 15,053,386			Forecast		326,138			Forecast		2.0		
Test Year	*2020*	Forecast	$ 15,570,015			Forecast		326,622			Forecast		2.0		
Test Year	*2021*	Forecast	$ 16,093,607			Forecast		327,106			Forecast		2.0		
Test Year	*2022*	Forecast	$ 16,510,255			Forecast		327,591			Forecast		2.0		
Test Year	*2023*	Forecast	$ 17,227,775			Forecast		328,076			Forecast		2.0		
Test Year	*2024*	Forecast	$ 17,928,726			Forecast		328,561			Forecast		2.0		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2013			*2013*				*2013*			
	2014	1.2%		*2014*	0.2%	0.2%		*2014*	0.0%	0.0%	
	2015	0.1%		*2015*	0.1%	0.1%		*2015*	0.0%	0.0%	
	2016	4.3%		*2016*	0.2%	0.2%		*2016*	0.0%	0.0%	
	2017	7.1%		*2017*	0.1%	0.1%		*2017*	0.0%	0.0%	
	2018	5.6%		*2018*		0.2%		*2018*		0.0%	
	2019	4.0%		*2019*		0.1%		*2019*		0.0%	
	2020	3.4%		*2020*		0.1%		*2020*		0.0%	
	2021	3.4%		*2021*		0.1%		*2021*		0.0%	
	2022	2.6%		*2022*		0.1%		*2022*		0.0%	
	2023	4.3%		*2023*		0.1%		*2023*		0.0%	
	2024	4.1%	26.8%	*2024*		0.1%	0.7%	*2024*		0.0%	-0.1%
	Geometric Mean	4.0%		Geometric Mean	0.2%	0.2%		Geometric Mean	0.0%	0.0%	

8 Customer Class: Unmetered Scattered Load Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2020 Cost of Service)	Customers				Consumption (kWh) [3]				Consumption (kWh) per Customer			
							Actual (Weather actual)	Weather-normalized	Weather-normalized		Actual (Weather actual)	Weather-normalized	Weather-normalized
Historical	*2013*	Actual	873			Actual	41,087,638	41,087,638		Actual	47,065	47,065	
Historical	*2014*	Actual	888			Actual	40,948,317	40,948,317		Actual	46,113	46,113	
Historical	*2015*	Actual	866	Board-approved	898	Actual	41,098,509	41,098,509	Board-approved 41,132,354	Actual	47,458	47,458	Board-approved 45,804
Historical	*2016*	Actual	866			Actual	41,380,666	41,380,666		Actual	47,784	47,784	
Historical	*2017*	Actual	860			Actual	41,200,600	41,200,600		Actual	47,908	47,908	
Bridge Year	*2018*	Forecast	857			Forecast		41,200,600		Forecast		48,075	
Bridge Year	*2019*	Forecast	857			Forecast		41,200,600		Forecast		48,075	
Test Year	*2020*	Forecast	857			Forecast		41,313,479		Forecast		48,207	
Test Year	*2021*	Forecast	857			Forecast		41,200,600		Forecast		48,075	
Test Year	*2022*	Forecast	857			Forecast		41,200,600		Forecast		48,075	
Test Year	*2023*	Forecast	857			Forecast		41,200,600		Forecast		48,075	
Test Year	*2024*	Forecast	857			Forecast		41,313,479		Forecast		48,207	

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2013			*2013*				*2013*			
	2014	1.7%		*2014*	-0.3%	-0.3%		*2014*	-2.0%	-2.0%	
	2015	-2.5%		*2015*	0.4%	0.4%		*2015*	2.9%	2.9%	
	2016	0.0%		*2016*	0.7%	0.7%		*2016*	0.7%	0.7%	
	2017	-0.7%		*2017*	-0.4%	-0.4%		*2017*	0.3%	0.3%	
	2018	-0.3%		*2018*		0.0%		*2018*		0.4%	
	2019	0.0%		*2019*		0.0%		*2019*		0.0%	
	2020	0.0%		*2020*		0.3%		*2020*		0.3%	
	2021	0.0%		*2021*		-0.3%		*2021*		-0.3%	
	2022	0.0%		*2022*		0.0%		*2022*		0.0%	
	2023	0.0%		*2023*		0.0%		*2023*		0.0%	
	2024	0.0%	-4.6%	*2024*		0.3%	0.4%	*2024*		0.3%	5.2%
	Geometric Mean	-0.2%		Geometric Mean	0.1%	0.1%		Geometric Mean	0.6%	0.2%	

	Calendar Year (for 2020 Cost of Service)	Connections				Consumption (kWh) per Connection			
						Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2013*	Actual	11,784			Actual	3,487	3,487	
Historical	*2014*	Actual	11,754			Actual	3,484	3,484	
Historical	*2015*	Actual	11,942	Board-approved	11,720	Actual	3,442	3,442	Board-approved 3,510
Historical	*2016*	Actual	12,056			Actual	3,432	3,432	
Historical	*2017*	Actual	12,196			Actual	3,378	3,378	
Bridge Year	*2018*	Forecast	12,272			Forecast		3,357	
Bridge Year	*2019*	Forecast	12,272			Forecast		3,357	
Test Year	*2020*	Forecast	12,272			Forecast		3,366	
Test Year	*2021*	Forecast	12,272			Forecast		3,357	
Test Year	*2022*	Forecast	12,272			Forecast		3,357	
Test Year	*2023*	Forecast	12,272			Forecast		3,357	
Test Year	*2024*	Forecast	12,272			Forecast		3,366	

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2013			*2013*			
	2014	-0.3%		*2014*	-0.1%	-0.1%	
	2015	1.6%		*2015*	-1.2%	-1.2%	
	2016	1.0%		*2016*	-0.3%	-0.3%	
	2017	1.2%		*2017*	-1.6%	-1.6%	
	2018	0.6%		*2018*		-0.6%	
	2019	0.0%		*2019*		0.0%	
	2020	0.0%		*2020*		0.3%	
	2021	0.0%		*2021*		-0.3%	
	2022	0.0%		*2022*		0.0%	
	2023	0.0%		*2023*		0.0%	
	2024	0.0%	4.7%	*2024*		0.3%	-4.1%
	Geometric Mean	0.4%		0	-1.0%	-0.4%	

	Calendar Year (for 2020 Cost of Service		Revenues			
Historical	*2013*	Actual	$ 2,616,211			
Historical	*2014*	Actual	$ 2,661,624			
Historical	*2015*	Actual	$ 3,170,482	Board-approved	$	3,173,355
Historical	*2016*	Actual	$ 3,314,179			
Historical	*2017*	Actual	$ 3,541,144			
Bridge Year	*2018*	Forecast	$ 3,734,078			
Bridge Year	*2019*	Forecast	$ 3,878,054			
Test Year	*2020*	Forecast	$ 4,022,917			
Test Year	*2021*	Forecast	$ 4,143,857			
Test Year	*2022*	Forecast	$ 4,246,058			
Test Year	*2023*	Forecast	$ 4,425,373			
Test Year	*2024*	Forecast	$ 4,610,813			

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2013		
	2014	1.7%	
Note 2	*2015*	19.1%	
	2016	4.5%	
	2017	6.8%	
	2018	5.4%	
	2019	3.9%	
	2020	3.7%	
	2021	3.0%	
	2022	2.5%	
	2023	4.2%	
	2024	4.2%	26.8%
	Geometric Mean	5.8%	

Notes:

1 2015 Revenues are calculated on the rates that would have been applied if test year rate implementation was January 1, 2015.
2 Variances due to 2015 test year rate increases
3 CSMUR variances driven mainly strong rate of growth in number of customer and resulting electricity sales to the class.
4 Variance driven mainly by customer rate-class reclassification

OTHER REVENUE

1. INTRODUCTION

In addition to revenues recovered through distribution rates, Toronto Hydro earns other revenue from non-distribution related services, property and facility rentals, Specific Service Charges, and short-term investments. Toronto Hydro also receives income and recoveries from shared services that it provides to its affiliates. Together, these revenues constitute Toronto Hydro's Other Revenue and reduce the costs recovered through distribution rates. The Other Revenues are broken out into the sub-categories as summarized in Table 1, below.

Table 1: Other Revenue Summary

Description	Actual Year 2015	Actual Year 2016	Actual Year 2017	Bridge Year 2018	Bridge Year 2019	Test Year 2020
Specific Service Charges	$6.8	$9.5	$7.2	$6.5	$6.5	$6.6
Late Payment Charge	$4.1	$4.5	$3.7	$3.7	$3.7	$3.8
Other Operating Revenues	$10.8	$12.0	$13.4	$12.3	$12.4	$12.0
Other Income or Deductions	$16.1	$18.7	$21.4	$21.4	$24.0	$25.4
Total Revenue Offset	**$37.8**	**$44.7**	**$45.7**	**$43.9**	**$46.7**	**$47.7**

A complete breakdown of the Other Revenue accounts is shown in OEB Appendix 2-H – Other Operating Revenue (Exhibit 3, Tab 2, Schedule 2).

2. REVENUE FROM SPECIFIC SERVICE CHARGES

Toronto Hydro charges user fees for certain services. Some of these services, such as account setup, are provided at the customer's request. Other fees result from Toronto Hydro's business operations, such as customers' non-payment of bills.

Variance Explanation

The historical variance between Toronto Hydro's 2015 and 2016 actuals from $6.8 million to $9.5 million is primarily due to the implementation in 2016 of Specific Service Charges approved as part of the utility's 2015-2019 Rate Application.[1] The historical variance between 2016 and 2017 actuals from $9.5 million to $7.1 million is primarily due to lower collection service charges due to the Winter Reconnection initiative which suspended disconnections for customers in arrears during winter time.

3. LATE PAYMENT CHARGES

Toronto Hydro applies late payment charges on overdue customer balances in accordance with all applicable regulations.

Variance Explanation

The historical variance between 2016 and 2017 actuals from $4.5 million to $3.7 million is primarily due to lower average electricity bill partly due to Ontario Fair Hydro Plan.

The annual late payment charges for 2020 are expected to be stable and remain generally consistent with 2017 amounts.

4. OTHER OPERATING REVENUES

Other Operating Revenue includes revenues from Standard Supply Service ("SSS") Administration Charges, Retail Service Charges, and Maintenance of third-party facilities located within Toronto Hydro. It also includes revenues allocated from Toronto Hydro's contract with the City of Toronto for the maintenance of street-lighting assets which

[1] EB-2014-0116, Toronto Hydro-Electric System Limited Decision and Order (December 29, 2015).

were moved into Toronto Hydro rate base as a result of the Decision from the utility's 2015-2019 Rate Application.[2]

Variance Explanation

The historical variance between 2015 and 2016 actuals from $10.8 million to $12.0 million and 2016 and 2017 actuals from $12.0 million to $13.4 million are primarily due to an increase in the revenues related to street-lighting assets as a result of incremental operating costs. The forecast for 2020 is expected to be in line with historical revenues.

5. OTHER INCOME OR DEDUCTIONS

Toronto Hydro earns revenue by providing services to customers and third parties, through gains on the sale of scrap metal, and gains on the disposal of utility property. Toronto Hydro also earns income and recoveries by providing shared services to its affiliates and through interest income from the short-term investment of idle cash balances.

Toronto Hydro divides its Other Income into the following four categories:

- Merchandise and Jobbing;
- Gains from Sale of Utility Properties;
- Shared Services Income and Recoveries; and
- Interest Income from Short-Term Investment.

Variance Explanation

The historical variance for Other Income program between 2015 and 2016 actuals from $16.1 million to $18.7 million is due to an increase in the pole attachment program

[2] Ibid.

offset by lower gain on sale of properties. The historical variance between 2016 and 2017 actuals from $18.7 million to $21.4 million is due to an increase in pole attachment program and shared service recovery offset by lower gain on sale of properties. The variance from 2017 to 2020 is due to higher revenues from the pole attachment program.

5.1 Merchandise and Jobbing

Toronto Hydro offers some services to customers and third parties for a fee. These services generally exclude those covered by the various OEB-approved Specific Service Charges, and are comprised of the following activities:

- Customer requests for isolation, protection, and temporary removals of lines to allow work on customer equipment;
- Repair of damaged distribution plant to be reimbursed by third parties;
- Rental income charged for pole attachments;
- Rental income derived from Toronto Hydro properties such as ducts;
- Gains on sale of scrap metal; and
- Revenues from sale of inventory to third parties.

The revenues and expenses from Merchandise and Jobbing vary significantly from year to year, depending on the number and type of activities requested by customers. As such, forecast of the activities, revenues and expenses from 2018 to 2020 are based primarily on historical trends.

For 2020, Toronto Hydro proposes an increase to its current pole attachment rental fee from $42.00 to $44.15, in accordance with the OEB's EB-2015-0304 decision, and as further detailed in Exhibit 8, Tab 2, Schedule 1.

Toronto Hydro also generates income from the sale of scrap metal materials. Scrap metals are sold at market rates and any revenue depends on the strength of the market at the time of disposition and the volume of scrap that is available for processing. Toronto Hydro currently outsources the processing and selling of scrap metal materials to a third party. Proceeds of the sale net of the vendor's cost of disposing the scrap metal materials are remitted to Toronto Hydro.

5.2 Gains from Sale of Utility Properties

Toronto Hydro disposes of surplus facilities and equipment on a periodic basis. Over the 2015 to 2017 period, total net gains on sale was $6.7 million. For the forecast period 2018-2020, Toronto Hydro does not forecast any additional sales, with the exceptions noted below.

In 2017 Toronto Hydro sold its property located at 50/60 Eglinton Ave. W. Net after tax gains on this sale has been proposed to be returned to customers through a rate rider, further explained in Exhibit 8, Tab 1, Schedule 1.

In 2018 Toronto Hydro sold its property at 5800 Yonge St. The sale of this property was contemplated in the utility's 2015-2019 Rate Application, and forecasted gains were included in a rate rider approved for disposition over the 2016-18 period. The variance between the forecasted amount and the final after-tax gains has been recorded in the variance account. Further details can be found in Exhibit 9, Tab 1, Schedule 1.

Neither of the 5800 Yonge St. or 50/60 Eglinton Ave. W sales have been reflected in the Other Revenue tables, since they are being disposed of through separate rate riders.

5.3 Shared Services Income and Recoveries

Toronto Hydro provides shared services to its affiliates and receives income and recoveries through transfer prices determined based on Affiliate Relationship Code ("ARC") requirements. Details on shared services are further provided in Exhibit 4A, Tab 5, Schedule 1.

5.4 Interest Income from Short-Term Investment

Toronto Hydro invests its working capital cash balances at a competitive market rate with its cash management bank to generate additional interest income. The interest earned from these short-term investment activities are an offset to Toronto Hydro's interest expense, which reduce the overall distribution revenue requirement and result in lower distribution rates, benefitting ratepayers.

OEB Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2015 Actual	2016 Actual	2017 Actual	Bridge Year	Bridge Year	Test Year
		2015	2016	2017	2018	2019	2020
	Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
4235	Specific Service Charges	$6,786,826	$9,497,848	$7,186,822	$6,508,368	$6,544,885	$6,581,270
4225	Late Payment Charges	$4,126,310	$4,540,398	$3,696,196	$3,714,184	$3,732,947	$3,751,641
4082	Retailers' Fixed charge	$5,320	$5,280	$5,520	$5,420	$5,420	$5,420
4082	Retailers' Variable Charge	$257,269	$225,343	$178,662	$181,017	$171,386	$162,420
4082	Distributor Consolidated Billing (DCB) Charges	$143,718	$125,603	$106,118	$104,725	$99,207	$94,067
4082	Retail Consolidated Billing (RCB) Credit	-$9,072	-$8,351	-$635	$0	$0	$0
4084	Retailer Service Transaction Request	$13,764	$12,656	$10,350	$9,780	$9,282	$8,816
4084	Retailer Service Transaction Processing	$6,344	$5,722	$4,485	$4,474	$4,271	$4,081
4090/4086	SSS Admin Charge	$2,196,126	$2,317,539	$2,269,960	$2,370,591	$2,389,560	$2,407,409
4210	Parking Rental	$3,790	$1,200	$1,200	$0	$0	$0
4210	Property Rental	$41,516	$46,854	$53,414	$0	$0	$0
4215	TTC Rectification	$253,250	$303,900	$303,900	$303,900	$303,900	$303,900
4215	Settlement Discounts Taken	$404,384	$381,359	$523,847	$389,382	$389,382	$389,382
4215	Stale Dated Cheques	$453,706	$417,078	$736,416	$533,368	$533,368	$533,368
4220	Street Lighting	$7,055,723	$8,200,259	$9,229,601	$8,368,642	$8,536,375	$8,076,074
4325	Merchandise and Jobbing Revenue	$23,108,588	$32,769,384	$45,929,144	$34,458,054	$36,014,502	$37,732,615
4330	Merchandise and Jobbing Costs	-$14,047,565	-$19,805,704	-$29,913,621	-$18,641,067	-$17,651,688	-$17,991,088
4335	Gain/Loss on disposals	$211,338	$0	$0	$0	$0	$0
4375	Shared Services Recovery[1]	$2,927,027	$3,212,613	$4,829,010	$5,430,108	$5,494,615	$5,507,706
4355	Gain on Disposition of Utility and Other Property	$4,062,681	$2,132,160	$515,158	$0	$0	$0
4398	Foreign Exchange Gain/(Loss)	-$1,500,430	$162,383	$54,784	$0	$0	$0
4405	Investment Interest Income	$1,298,537	$186,388	$9	$120,000	$120,000	$120,000
Specific Service Charges		$6,786,826	$9,497,848	$7,186,822	$6,508,368	$6,544,885	$6,581,270
Late Payment Charges		$4,126,310	$4,540,398	$3,696,196	$3,714,184	$3,732,947	$3,751,641
Other Operating Revenues		$10,825,837	$12,034,443	$13,422,839	$12,271,299	$12,442,150	$11,984,936
Other Income or Deductions		$16,060,177	$18,657,224	$21,414,483	$21,367,095	$23,977,430	$25,369,233
Total		**$37,799,149**	**$44,729,912**	**$45,720,340**	**$43,860,946**	**$46,697,412**	**$47,687,080**

Description	Account(s)
Specific Service Charges:	4235
Late Payment Charges:	4225
Other Distribution Revenues:	4080, 4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Income and Expenses:	4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4375, 4380, 4385, 4390, 4395, 4398, 4405, 4415

Account Breakdown Details

Account 4235 -Specific Service Charges

	2015 Actual	2016 Actual	2017 Actual	Bridge Year	Bridge Year	Test Year
				2018	2019	2020
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Account Set Up Charge	$3,163,196	$3,315,852	$3,132,490	$2,994,278	$3,010,922	$3,027,508
NSF Collection Charges	$59,445	$111,704	$106,825	$107,417	$107,980	$108,541
Collection Service Charges	$2,986,342	$5,165,058	$3,130,010	$2,859,179	$2,875,286	$2,891,331
Connection-Reconnection Charge	$554,565	$873,835	$644,708	$547,494	$550,698	$553,890
Easement Letter	$24,978	$29,773	$39,955	$0	$0	$0
Misc Revenue	-$1,700	$1,625	$132,834	$0	$0	$0
Total	**$6,786,826**	**$9,497,848**	**$7,186,822**	**$6,508,368**	**$6,544,885**	**$6,581,270**

Account 4325 -Merchandise and Jobbing Revenue

	2015 Actual	2016 Actual	2017 Actual	Bridge Year	Bridge Year	Test Year
				2018	2019	2020
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Inventory Sales	$88,900	$1,722,500	$5,447,129	$2,200,000	$2,200,000	$2,200,000
Isolation	$425,900	$723,600	$3,245,726	$1,317,200	$1,326,800	$1,336,600
Customer and Temp Services	$4,787,700	$5,712,240	$4,771,188	$6,692,200	$6,344,800	$6,528,800
MicroFIT	$93,500	$71,060	$157,066	$40,000	$50,000	$62,500
Scrap Sales	$2,351,600	$3,264,400	$3,198,906	$2,930,000	$2,988,600	$3,048,400
Accident Claims	$2,422,022	$1,683,500	$3,281,539	$2,450,900	$2,502,500	$2,562,600
Pole & Duct Rental	$11,145,300	$18,051,800	$23,106,399	$17,465,700	$19,236,165	$20,624,017
Streetlighting[1]	$520,678	$459,415	$332,279	$669,103	$669,103	$669,103
Other[2]	$1,272,988	$1,080,868	$2,388,913	$692,951	$696,534	$700,595
Total	**$23,108,588**	**$32,769,384**	**$45,929,144**	**$34,458,054**	**$36,014,502**	**$37,732,615**

Account 4330 -Merchandise and Jobbing Costs

	2015 Actual	2016 Actual	2017 Actual	Bridge Year	Bridge Year	Test Year
				2018	2019	2020
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Inventory Sales	-$110,700	-$1,661,500	-$5,240,465	-$2,000,000	-$2,000,000	-$2,000,000
Isolation	-$393,900	-$611,300	-$3,681,121	-$1,779,600	-$1,793,200	-$1,806,800
Customer and Temp Services	-$3,907,893	-$4,675,909	-$3,751,142	-$6,205,000	-$5,930,600	-$6,108,600
MicroFIT	-$47,007	-$78,191	-$25,354	-$40,000	-$50,000	-$62,500
Scrap Sales	-$1,131,000	-$863,200	-$1,048,740	-$1,275,000	-$1,300,500	-$1,326,500
Accident Claims	-$2,267,530	-$2,321,000	-$3,026,630	-$2,218,200	-$2,265,600	-$2,320,800
Pole & Duct Rental	-$4,771,400	-$8,416,600	-$10,670,064	-$4,317,900	-$3,502,950	-$3,553,027
Streetlighting[1]	-$476,270	-$380,939	-$302,663	-$569,180	-$569,180	-$569,180
Other[2]	-$941,865	-$797,065	-$2,167,443	-$236,187	-$239,658	-$243,681
Total	**-$14,047,565**	**-$19,805,704**	**-$29,913,621**	**-$18,641,067**	**-$17,651,688**	**-$17,991,088**

Account 4405 - Investment Interest Income

	2015 Actual	2016 Actual	2017 Actual	Bridge Year	Bridge Year	Test Year
				2018	2019	2020
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Investment Interest Income	$1,298,537	$0	$9	$120,000	$120,000	$120,000
Regulated Assets Charges-Revenue	$0	$186,388	$0	$0	$0	$0
Total	**$1,298,537**	**$186,388**	**$9**	**$120,000**	**$120,000**	**$120,000**

Notes

1 The amounts reported as shared services recovery in account 4375 do not include the cost recovery associated with fleet, occupancy and IT services provided by THESL to THESI, THESU and THC presented as part of Appenix 2N. The recovery of these costs is included in the OM&A evidence as part of the Allocation and Recoveries program for an average annual value of $1.1M for the period 2015-2020.
Streetlighighting recoveries and costs related to emergency response, engineering and planning included in Appendix 2N are shown under the merchandising and jobbing section (4325 & 4330).

2 The "Other" category is composed of IT services related to Hydro One Telecom and other various adhoc services.

OVERVIEW OF OPERATING, MAINTENANCE, AND ADMINISTRATION EXPENDITURES

This schedule provides a summary of Toronto Hydro's Operations, Maintenance, and Administration ("OM&A") plan and the process and considerations that informed the establishment of the plan.

1. CONCORDANCE WITH CHAPTER 2 FILING REQUIREMENTS

Consistent with applicable OEB guidance,[1] Toronto Hydro presents its Historical, Bridge, and Test Year OM&A expenditures as the sum of a series of discrete programs. The descriptions and variance analysis for these programs and associated expenditures and adjustments can be found in Exhibit 4A, Tab 2, Schedules 1 through 21. In an effort to balance the OEB's guidance on program-based OM&A cost review with the objective of providing a thorough cost analysis, Toronto Hydro has further broken down a number of OM&A programs into segments – i.e. discrete activity-based areas that address the constituent components of a single program.

2. OVERVIEW OF THE OM&A PROGRAMS AND EXPENDITURES

Toronto Hydro's forecast OM&A expenditures for 2020 are $277.5 million, which represents a compounded average increase of 2.6 percent per year from 2015 Board-approved and 2015 historical actuals. When normalized for customer count, the compound growth rate in OM&A costs per customer is 1.6 percent over the rate period. Normalized for full time equivalent ("FTE"), the compound growth rate is 2.5 percent.

[1] Including, for example, Ontario Energy Board, Filing Requirements for Electricity Distribution Rate Applications, Chapter 2 (July 12, 2018), s. 2.4; and the Handbook for Utility Rate Applications (October 13, 2016), p. 19.

Detailed trend analyses are included in OEB Appendices 2-JA, 2-JB, 2-JC, and 2-L to this schedule.

Table 1, below, provides a breakdown of Toronto Hydro's Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) OM&A expenditures, by program. Descriptions of each program, including details about cost drivers, cost control measures taken by Toronto Hydro, and year-over-year variance analyses, are contained in Exhibit 4A, Tab 2, Schedules 1 through 21.

Table 1: Historical, Bridge, and Test Year OM&A Expenditures by Program ($ Millions)[2]

OM&A Program	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Preventative and Predictive Overhead Line Maintenance	6.3	7.6	6.7	6.6	6.8	6.0
Preventative and Predictive Underground Line Maintenance	2.6	2.9	3.2	4.5	5.2	5.5
Preventative and Predictive Station Maintenance	5.6	5.3	5.6	5.4	5.6	5.6
Corrective Maintenance	16.1	16.8	20.3	17.0	17.0	17.2
Emergency Response	16.4	15.2	15.9	16.4	16.5	16.6
Disaster Preparedness Management	2.3	2.4	2.2	2.6	2.8	2.7
Control Centre Operations	5.4	5.4	6.3	7.8	8.7	8.7
Customer-Driven Work	10.2	10.0	11.6	9.9	9.6	9.6
Asset and Program Management	11.2	18.1	11.5	14.8	14.7	13.1
Work Program Execution	19.5	19.5	20.5	19.1	20.3	21.8
Fleet and Equipment Services	10.1	9.8	11.0	10.9	11.0	11.0
Facilities Management	27.4	27.8	25.3	23.2	23.4	24.0
Supply Chain Services	10.4	13.4	11.4	11.7	12.3	12.6
Customer Care	41.0	38.1	39.6	43.0	44.0	49.4
Human Resources and Safety	14.1	15.2	14.7	15.2	15.5	15.9
Finance	16.1	15.0	13.6	15.9	16.2	16.2

[2] Numbers may not sum due to rounding.

OM&A Program	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Information Technology	34.4	35.0	38.4	41.7	43.5	44.0
Legal and Regulatory	12.1	13.4	14.0	15.3	15.1	15.9
Charitable Donations and LEAP	0.7	0.9	0.8	0.8	0.8	0.9
Common Costs and Adjustments	1.1	(0.1)	1.6	(0.7)	(1.3)	0.8
Allocations and Recoveries	(19.0)	(21.9)	(18.9)	(20.1)	(20.0)	(19.9)
Total OM&A	**244.0**	**249.8**	**255.3**	**261.2**	**267.6**	**277.5**

Toronto Hydro's 2020 OM&A plan was an output of its outcomes-oriented, customer-focused business planning activities. The development of the OM&A plan was informed by a number of factors, including operational needs (e.g. requirements relating to asset investment, maintenance, and staffing), legislative and regulatory obligations, the Outcomes Framework, and Customer Engagement. The OM&A plan was constrained by the strategic parameters established for the business plan, including upper limits on the 2020 OM&A budget and the cap on the average annual increase to base distribution rates (see Exhibit 1B, Tab 1, Schedule 1).

Toronto Hydro's OM&A plan was developed in accordance with the utility operating under an Incentive Regulation Mechanism ("IRM") framework for non-capital expenditures. For 2021 to 2024, funding for OM&A is constrained by the proposed rate framework, which includes the OEB's current inflation factor methodology, stretch factor methodology set on the basis of PSE's cost benchmarking study,[3] and current productivity factor policy.

Toronto Hydro used both general and specific cost and economic assumptions in its forecast of 2020 OM&A costs. The forecast for compensation costs considered previous

[3] See Exhibit 1B, Tab 4, Schedule 2.

and current collective agreement parameters, adjustments to reflect market-competitive pay increases for non-unionized employees, and the proposal to use the accrual method to account for Other Post-Employment Benefits. For more information on compensation costs, see Exhibit 4A, Tab 4, Schedules 2 and 4. Otherwise, a general inflation factor of 2.0 percent was applied, consistent with the OEB's inflation factor at the time of 1.9 percent.

The programs that constitute Toronto Hydro's plan are largely a continuation of its 2015-2019 OM&A programs, which are critical to the ongoing performance of the utility. They provide functions that support the safe and reliable operation of the distribution system, deliver customer-facing services that respond to customer expectations and improve ratepayer value, and provide critical corporate functions that allow the utility to operate in a financially responsible and policy-responsive manner.

Toronto Hydro's OM&A expenditures contribute to the achievement of the Outcomes Framework (see Exhibit 1B, Tab 2, Schedule 1) and the Electricity Service Quality Requirements (see Exhibit 1B, Tab 2, Schedule 3). Each OM&A program contains outcomes that Toronto Hydro expects to be attained as a result of the proposed investment, and are categorized into the six outcome categories under the Outcomes Framework.[4] This results-driven approach underscores the customer value generated by the proposed OM&A programs.

Toronto Hydro's OM&A programs detail the applicable cost drivers and the steps taken by the utility to reduce those costs on a program-specific basis. For example, in the

[4] The outcomes listed in each program are directly connected to, and dependent on, the forecasted funding needs for the program. Any change in overall rates funding for the term of the plan would require Toronto Hydro to reforecast cost allocation to each program and re-examine the corresponding outcomes.

Customer Care program (Exhibit 4A, Tab 2, Schedule 14) the annual cost of moving to monthly billing is being mitigated by increasing the penetration of eBilling, which is significantly less expensive than paper billing. The utility is proposing to drive further eBilling adoption through 2020 to 2024, and track its progress through a "Customers Receiving eBills" metrics in its Custom Performance Measures and Targets framework (see Exhibit 2B, Section C2).

Other programs experiencing significant cost pressures include: (i) Information Technology (Exhibit 4A, Tab 2, Section 17), which is an area where Toronto Hydro must adapt to externally-driven increases in maintenance costs and fees; and (ii) Control Centre Operations (Exhibit 4A, Tab 2, Schedule 7), which is an area where the utility must make non-discretionary workforce renewal investments in light of demographic challenges (as outlined in the Workforce Staffing Plan and Strategy at Exhibit 4A, Tab 4, Schedule 3). Both programs detail the specific actions Toronto Hydro is taking to control costs.

As discussed in detail in each OM&A program, the efficiencies expected to be achieved through Toronto Hydro's actions are partially offsetting program costs. For example, annual Facilities Management program costs (Exhibit 4A, Tab 2, Schedule 12) are expected to decrease by $3.4 million (12.4 percent) between 2015 and 2020, primarily due to Toronto Hydro's move from leased to owned facilities. The cost of other OM&A programs, such as Finance (Exhibit 4A, Tab 2, Schedule 16) and Emergency Response (Exhibit 4A, Tab 2, Schedule 5) are expected to decrease or remain virtually unchanged from 2015 to 2020 as a result of specific steps taken by the utility.

OEB Appendix 2-D (filed as Appendix A to Exhibit 2A, Tab 5, Schedule 2) details overall levels of, and changes to, Total Capitalized OM&A for 2015 to 2020. Annual variances are a function of the overall type and nature of the capital work being executed by Toronto Hydro. There have been no changes in the utility's overhead expense capitalization policy since its last rebasing application.

OEB Appendix 2-JA
Summary of Recoverable OM&A Expenses

(in $ Millions)

	Last Rebasing Year (2015 Board-Approved)	2015 Actuals	2016 Actuals	2017 Actuals	2018 Bridge Year	2019 Bridge Year	2020 Test Year
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Operations	-	$ 48.6	$ 56.9	$ 55.1	$ 56.3	$ 60.2	$ 59.4
Maintenance	-	$ 67.1	$ 63.1	$ 64.3	$ 65.9	$ 67.1	$ 67.7
SubTotal	**-**	**$ 115.7**	**$ 120.0**	**$ 119.3**	**$ 122.2**	**$ 127.3**	**$ 127.1**
%Change (year over year)			3.7%	-0.5%	2.4%	4.1%	-0.1%
%Change (Test Year vs Last Rebasing Year - Actual)							9.9%
Billing and Collecting	-	$ 36.7	$ 33.4	$ 34.9	$ 37.8	$ 38.4	$ 38.8
Community Relations	-	$ 3.5	$ 2.5	$ 2.3	$ 2.6	$ 2.7	$ 2.8
Administrative and General	-	$ 81.9	$ 88.3	$ 92.5	$ 92.1	$ 93.4	$ 95.0
Taxes Other Than Income Taxes	-	$ 5.2	$ 4.6	$ 5.3	$ 5.6	$ 5.4	$ 5.5
Donations	-	$ 1.0	$ 1.0	$ 1.0	$ 0.9	$ 0.9	$ 1.0
SubTotal	**-**	**$ 128.3**	**$ 129.9**	**$ 135.9**	**$ 139.0**	**$ 140.9**	**$ 143.1**
%Change (year over year)			1.2%	4.7%	2.2%	1.4%	1.5%
%Change (Test Year vs Last Rebasing Year - Actual)							11.5%
Total	**$ 243.9**	**$ 244.0**	**$ 249.8**	**$ 255.3**	**$ 261.2**	**$ 268.2**	**$ 270.2**
%Change (year over year)			2.4%	2.2%	2.3%	2.7%	0.8%
Cash vs. Accrual OPEB and Monthly Billing	-	-	-	-	-	-	$ 7.3
Total - including Cash vs. Accrual OPEB and Monthly Billing	**$ 243.9**	**$ 244.0**	**$ 249.8**	**$ 255.3**	**$ 261.2**	**$ 268.2**	**$ 277.5**
%Change (year over year)			2.4%	2.2%	2.3%	2.7%	3.5%

	Last Rebasing Year (2015 Board-Approved)	2015 Actuals	2016 Actuals	2017 Actuals	2018 Bridge Year	2019 Bridge Year	2020 Test Year
Operations	-	$ 48.6	$ 56.9	$ 55.1	$ 56.3	$ 60.2	$ 59.4
Maintenance	-	$ 67.1	$ 63.1	$ 64.3	$ 65.9	$ 67.1	$ 67.7
Billing and Collecting	-	$ 36.7	$ 33.4	$ 34.9	$ 37.8	$ 38.4	$ 38.8
Community Relations	-	$ 3.5	$ 2.5	$ 2.3	$ 2.6	$ 2.7	$ 2.8
Administrative and General	-	$ 81.9	$ 88.3	$ 92.5	$ 92.1	$ 93.4	$ 95.0
Taxes Other Than Income Taxes	-	$ 5.2	$ 4.6	$ 5.3	$ 5.6	$ 5.4	$ 5.5
Donations	-	$ 1.0	$ 1.0	$ 1.0	$ 0.9	$ 0.9	$ 1.0
Cash vs. Accrual OPEB and Monthly Billing	-	-	-	-	-	-	$ 7.3
Total	**$ 243.9**	**$ 244.0**	**$ 249.8**	**$ 255.3**	**$ 261.2**	**$ 268.2**	**$ 277.5**
%Change (year over year)			2.4%	2.2%	2.3%	2.7%	3.5%

OEB Appendix 2-JA
Summary of Recoverable OM&A Expenses

	Last Rebasing Year (2015 Board-Approved)	2015 Actuals	Variance 2015 BA - 2015 Actuals	2016 Actuals	Variance 2016 Actuals vs. 2015 Actuals	2017 Actuals	Variance 2017 Actuals vs. 2016 Actuals	2018 Bridge Year	Variance 2018 Bridge vs. 2017 Actuals	2019 Bridge Year	Variance 2019 Bridge vs. 2018 Bridge	2020 Test Year	Variance 2020 Test vs. 2019 Bridge
Operations	-	$ 48.6	$ (48.6)	$ 56.9	$ 8.3	$ 55.1	$ (1.9)	$ 56.3	$ 1.2	$ 60.2	$ 3.9	$ 59.4	$ (0.8)
Maintenance	-	$ 67.1	$ (67.1)	$ 63.1	$ (4.1)	$ 64.3	$ 1.2	$ 65.9	$ 1.7	$ 67.1	$ 1.1	$ 67.7	$ 0.6
Billing and Collecting	-	$ 36.7	$ (36.7)	$ 33.4	$ (3.4)	$ 34.9	$ 1.5	$ 37.8	$ 2.9	$ 38.4	$ 0.7	$ 38.8	$ 0.4
Community Relations	-	$ 3.5	$ (3.5)	$ 2.5	$ (1.0)	$ 2.3	$ (0.2)	$ 2.6	$ 0.3	$ 2.7	$ 0.1	$ 2.8	$ 0.1
Administrative and General	-	$ 81.9	$ (81.9)	$ 88.3	$ 6.4	$ 92.5	$ 4.1	$ 92.1	$ (0.4)	$ 93.4	$ 1.3	$ 95.0	$ 1.5
Taxes Other Than Income Taxes	-	$ 5.2	$ (5.2)	$ 4.6	$ (0.5)	$ 5.3	$ 0.6	$ 5.6	$ 0.3	$ 5.4	$ (0.2)	$ 5.5	$ 0.1
Donations	-	$ 1.0	$ (1.0)	$ 1.0	$ (0.0)	$ 1.0	$ (0.0)	$ 0.9	$ (0.0)	$ 0.9	$ 0.0	$ 1.0	$ 0.0
Cash vs. Accrual OPEB and Monthly Billing	-	-	-	-	-	-	-	-	-	-	-	$ 7.3	$ 7.3
Total OM&A Expenses	$ 243.9	$ 244.0	$ (244.0)	$ 249.8	$ 5.8	$ 255.3	$ 5.4	$ 261.2	$ 6.0	$ 268.2	$ 6.9	$ 277.5	$ 9.3
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Recoverable OM&A Expenses	$ 243.9	$ 244.0	$ (244.0)	$ 249.8	$ 5.8	$ 255.3	$ 5.4	$ 261.2	$ 6.0	$ 268.2	$ 6.9	$ 277.5	$ 9.3
Variance from previous year					$ 5.8		$ 5.4		$ 6.0		$ 6.9		$ 9.3
Percent change (year over year)					2.4%		2.2%		2.3%		2.7%		3.5%
Percent Change: Test year vs. Most Current Actual													3.7%
Simple average of % variance for all years													2.6%
Compound Annual Growth Rate for all years													2.6%

Note:

1 Recoverable OM&A that is included on these tables should be identical to the recoverable OM&A that is shown for the corresponding periods on Appendix 2-JB.

OEB Appendix 2-JB
Recoverable OM&A Cost Driver Table

OM&A	Last Rebasing Year (2015 Board-Approved)	2016 Actuals	2017 Actuals	2018 Bridge Year	2019 Bridge Year	2020 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Opening Balance	**$243.9**	**$244.0**	**$249.8**	**$255.3**	**$261.2**	**$268.2**
Distribution Operations						
Predictive and Preventative Maintenance Overhead	-	$1.3	($0.9)	($0.1)	$0.1	($0.7)
Predictive and Preventative Maintenance Underground	-	$0.3	$0.3	$1.3	$0.7	$0.2
Predictive and Preventative Maintenance Stations	-	($0.3)	$0.3	($0.1)	$0.2	($0.1)
Corrective Maintenance	-	$0.7	$3.5	($3.3)	($0.0)	$0.2
Emergency Response	-	($1.2)	$0.7	$0.4	$0.2	$0.1
Disaster Preparedness Management	-	$0.0	($0.2)	$0.4	$0.2	($0.1)
Control Centre Operations	-	$0.0	$0.8	$1.5	$0.9	$0.1
Customer Driven Work	-	($0.2)	$1.7	($1.7)	($0.4)	$0.0
Asset and Program Management	-	$6.9	($6.6)	$3.4	$0.4	($2.2)
Work Program Execution	-	($0.0)	$1.0	($1.4)	$1.1	$1.5
Fleet and Equipment	-	($0.3)	$1.2	($0.1)	$0.0	$0.0
Supply Chain	-	$3.0	($2.0)	$0.3	$0.6	$0.3
Customer Service and Communications						
Billing, Remittance & Meter Data Management	-	($2.3)	$2.2	$0.3	$0.4	$4.5
Collections	-	($0.5)	($1.0)	$2.9	$0.3	$0.1
Customer Relationship Management	-	$0.2	($0.1)	($1.1)	$0.1	$0.7
Communications & Public Affairs	-	($0.2)	$0.4	$1.3	$0.2	$0.1
LEAP	-	$0.2	($0.1)	$0.0	$0.0	$0.0
Human Resources and Safety						
Human Resource Services and Employee Labour Relations	-	$0.6	($0.0)	($0.3)	$0.0	$0.1
Environment Health and Safety	-	$0.1	($0.2)	$0.2	$0.1	$0.1
Talent Management & Organizational Effectiveness	-	$0.3	($0.3)	$0.7	$0.1	$0.2
Information Technology						
IT Governance	-	$0.2	$0.0	$0.3	$0.0	$0.1
IT Operations	-	$0.4	$2.6	$2.9	$1.5	$0.3
Project Execution	-	$0.2	$0.2	$0.0	$0.0	$0.1
Security & Enterprise Architecture	-	($0.2)	$0.4	$0.1	$0.3	$0.1
Common Corporate Costs						
Common Corporate Costs	-	($1.2)	$1.7	($2.3)	($0.6)	$2.1

OEB Appendix 2-JB
Recoverable OM&A Cost Driver Table

OM&A	Last Rebasing Year (2015 Board-Approved)	2016 Actuals	2017 Actuals	2018 Bridge Year	2019 Bridge Year	2020 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Facilities Management						
Facilities Maintenance Services	-	$0.9	($0.1)	($1.2)	$0.5	$0.4
Rentals & Leases	-	$0.1	($3.6)	($1.4)	$0.0	$0.0
Utilities & Communications	-	($0.1)	$0.3	$0.5	($0.1)	$0.1
Property Taxes	-	($0.6)	$1.0	$0.0	($0.2)	$0.1
Other Various						
Finance	-	($1.1)	($1.4)	$2.3	$0.3	$0.0
Legal and Regulatory	-	$1.3	$0.6	$1.4	($0.2)	$0.7
Allocations and Recoveries	-	($2.9)	$3.0	($1.1)	$0.1	$0.0
Closing Balance	**$244.0**	**$249.8**	**$255.3**	**$261.2**	**$268.2**	**$277.5**

Notes:

1 For each year, a detailed explanation for each cost driver and associated amount is required in Exhibit 4.

2 For purposes of assessing incremental cost drivers, the closing balance for each year becomes the opening balance for the next year.

3 Opening Balance for "Last Rebasing Year" (cell B15) should be equal to the Board-Approved amount.

OEB Appendix 2-JC
OM&A Programs Table

(in $ Millions)

Programs	Last Rebasing Year (2015 Board-Approved)	2015 Actuals	2016 Actuals	2017 Actuals	2018 Bridge Year	2019 Bridge Year	2020 Test Year	Variance (Test Year vs. 2017 Actuals)	Variance (Test Year vs. Last Rebasing Year (2015 Board-Approved)
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**		
Distribution Operations									
Predictive and Preventative Maintenance Overhead	-	6.3	7.6	6.7	6.6	6.8	6.0	(0.7)	6.0
Predictive and Preventative Maintenance Underground	-	2.6	2.9	3.2	4.5	5.2	5.5	2.2	5.5
Predictive and Preventative Maintenance Stations	-	5.6	5.3	5.6	5.4	5.6	5.6	0.0	5.6
Corrective Maintenance	-	16.1	16.8	20.3	17.0	17.0	17.2	(3.1)	17.2
Emergency Response	-	16.4	15.2	15.9	16.4	16.5	16.6	0.7	16.6
Disaster Preparedness Management	-	2.3	2.4	2.2	2.6	2.8	2.7	0.5	2.7
Control Centre Operations	-	5.4	5.4	6.3	7.8	8.7	8.7	2.5	8.7
Customer Driven Work	-	10.2	10.0	11.6	9.9	9.6	9.6	(2.1)	9.6
Asset and Program Management	-	11.2	18.1	11.5	14.8	15.3	13.1	1.6	13.1
Work Program Execution	-	19.5	19.5	20.5	19.1	20.3	21.8	1.3	21.8
Fleet and Equipment	-	10.1	9.8	11.0	10.9	11.0	11.0	(0.1)	11.0
Supply Chain	-	10.4	13.4	11.4	11.7	12.3	12.6	1.2	12.6
Sub-Total	-	116.1	126.5	126.3	126.9	131.0	130.4	4.1	130.4
Customer Care									
Billing, Remittance & Meter Data Management	-	15.7	13.4	15.5	15.9	16.2	20.7	5.2	20.7
Collections	-	10.8	10.3	9.2	12.1	12.4	12.6	3.3	12.6
Customer Relationship Management	-	11.4	11.6	11.5	10.4	10.6	11.3	(0.2)	11.3
Communications & Public Affairs	-	3.1	2.9	3.3	4.6	4.7	4.9	1.6	4.9
Sub-Total	-	41.0	38.1	39.6	43.0	44.0	49.4	9.8	49.4
Charitable Donations and LEAP									
LEAP	-	0.7	0.9	0.8	0.8	0.8	0.9	0.1	0.9
Sub-Total	-	0.7	0.9	0.8	0.8	0.8	0.9	0.1	0.9

OEB Appendix 2-JC
OM&A Programs Table

(in $ Millions)

Programs	Last Rebasing Year (2015 Board-Approved)	2015 Actuals	2016 Actuals	2017 Actuals	2018 Bridge Year	2019 Bridge Year	2020 Test Year	Variance (Test Year vs. 2017 Actuals)	Variance (Test Year vs. Last Rebasing Year (2015 Board-Approved)
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**		
Human Resources and Safety									
Human Resource Services and Employee Labour Relations	-	4.6	5.2	5.1	4.8	4.8	5.0	(0.2)	5.0
Environment Health and Safety	-	2.5	2.7	2.5	2.7	2.8	2.9	0.4	2.9
Talent Management & Organizational Effectiveness	-	7.0	7.3	7.0	7.8	7.9	8.1	1.1	8.1
Sub-Total	-	14.1	15.2	14.7	15.2	15.5	15.9	1.2	15.9
Information Technology									
IT Governance	-	2.7	2.9	3.0	3.2	3.3	3.4	0.4	3.4
IT Operations	-	27.9	28.3	30.9	33.8	35.3	35.6	4.7	35.6
Project Execution	-	1.2	1.4	1.6	1.6	1.6	1.7	0.1	1.7
Security & Enterprise Architecture	-	2.7	2.4	2.9	3.0	3.3	3.4	0.5	3.4
Sub-Total	-	34.4	35.0	38.4	41.7	43.5	44.0	5.7	44.0
Common Costs and Adjustments									
Common Corporate Costs	-	1.1	(0.1)	1.6	(0.7)	(1.3)	0.8	(0.8)	0.8
Sub-Total	-	1.1	(0.1)	1.6	(0.7)	(1.3)	0.8	(0.8)	0.8
Facilities Management									
Facilities Maintenance Services	-	14.6	15.4	15.3	14.1	14.7	15.1	(0.3)	15.1
Rentals & Leases	-	5.2	5.3	1.7	0.3	0.4	0.4	(1.4)	0.4
Utilities & Communications	-	2.4	2.4	2.6	3.1	3.0	3.1	0.4	3.1
Property Taxes	-	5.2	4.6	5.6	5.6	5.4	5.5	(0.0)	5.5
Sub-Total	-	27.4	27.8	25.3	23.2	23.4	24.0	(1.3)	24.0
Finance									
Controllership	-	8.4	7.3	6.4	7.2	7.2	7.0	0.6	7.0
External Reporting	-	2.5	2.7	2.7	3.0	3.1	3.2	0.5	3.2
Financial Services	-	5.2	5.0	4.6	5.7	5.9	6.1	1.5	6.1
Sub-Total	-	16.1	15.0	13.6	15.9	16.2	16.2	2.6	16.2

OEB Appendix 2-JC
OM&A Programs Table

(in $ Millions)

Programs	Last Rebasing Year (2015 Board-Approved)	2015 Actuals	2016 Actuals	2017 Actuals	2018 Bridge Year	2019 Bridge Year	2020 Test Year	Variance (Test Year vs. 2017 Actuals)	Variance (Test Year vs. Last Rebasing Year (2015 Board-Approved)
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**		
Legal and Regulatory									
Legal and Regulatory Program	-	12.1	13.4	14.0	15.3	15.1	15.9	1.9	15.9
Sub-Total	-	12.1	13.4	14.0	15.3	15.1	15.9	1.9	15.9
Allocations and Recoveries									
On-cost recovery	-	(10.6)	(11.5)	(11.3)	(11.9)	(11.8)	(11.8)	(0.5)	(11.8)
Fleet Recovery Offset	-	(12.5)	(12.4)	(11.5)	(11.4)	(11.4)	(11.6)	(0.1)	(11.6)
IT and Occupancy Charges	-	(0.7)	(1.1)	(1.0)	(1.0)	(1.0)	(1.0)	(0.0)	(1.0)
Shared Services	-	4.8	2.9	4.8	4.3	4.4	4.6	(0.2)	4.6
Other Allocated Costs	-	0.0	0.1	0.2	(0.1)	(0.1)	(0.1)	(0.3)	(0.1)
Sub-Total	-	(19.0)	(21.9)	(18.9)	(20.1)	(20.0)	(19.9)	(1.0)	(19.9)
Miscellaneous	-	-	-	-	-	-	-	-	-
Total	**243.9**	**244.0**	**249.8**	**255.3**	**261.2**	**268.2**	**277.5**	**22.2**	**33.6**

Notes:

1 Please provide a breakdown of the major components of each OM&A Program undertaken in each year. Please ensure that all Programs below the materiality threshold are included in the miscellaneous line. Add more Programs as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the OM&A budget in the miscellaneous category

OEB Appendix 2-L
Recoverable OM&A Cost per Customer and per FTE [1]

	Last Rebasing Year (2015 Board-Approved)	2015 Actuals	2016 Actuals	2017 Actuals	2018 Bridge Year	2019 Bridge Year	2020 Test Year
Reporting Basis							
OM&A Costs							
O&M	-	$ 115.7	$ 120.0	$ 119.3	$ 122.2	$ 127.3	$ 127.1
Admin Expenses	-	$ 128.3	$ 129.9	$ 135.9	$ 139.0	$ 140.9	$ 150.4
Total Recoverable OM&A from Appendix 2-JB [5]	**$ 243.9**	**$ 244.0**	**$ 249.8**	**$ 255.3**	**$ 261.2**	**$ 268.2**	**$ 277.5**
Number of Customers [2,4]	**747,812**	**747,812**	**759,032**	**765,560**	**771,080**	**776,787**	**784,331**
Number of FTEs [3,4,6]	**1,630**	**1,630**	**1,605**	**1,589**	**1,621**	**1,646**	**1,639**
Customers/FTEs	**458.89**	**458.89**	**472.96**	**481.92**	**475.66**	**472.04**	**478.52**
OM&A cost per customer							
O&M per customer	**-**	**154.7**	**158.0**	**155.8**	**158.5**	**163.8**	**162.1**
Admin per customer	**-**	**171.6**	**171.1**	**177.6**	**180.3**	**181.4**	**191.7**
Total OM&A per customer	**326.2**	**326.3**	**329.1**	**333.4**	**338.8**	**345.2**	**353.8**
OM&A cost per FTE							
O&M per FTE	**-**	**70,984.6**	**74,748.3**	**75,105.8**	**75,396.7**	**77,339.4**	**77,563.5**
Admin per FTE	**-**	**78,732.1**	**80,913.3**	**85,579.5**	**85,739.7**	**85,617.0**	**91,737.1**
Total OM&A per FTE	**149,666.7**	**149,716.7**	**155,661.6**	**160,685.4**	**161,136.5**	**162,956.4**	**169,300.6**

Notes:

1 If it has been more than four years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than four years ago, a minimum of three years of actual information is required.

2 The method of calculating the number of customers is the year end method

3 The method of calculating the number of FTEs is the mid year average

4 The number of customers and the number of FTEs should correspond to mid-year or average of January 1 and December 31 figures.

5 For the test year, the applicant should take into account the system O&M (line 22 of Appendix 2-AB) in developing its forecasted OM&A.

6 Difference to compensation table (appendix 2-K) FTE figures due to students

PREVENTATIVE AND PREDICTIVE OVERHEAD LINE MAINTENANCE

1. OVERVIEW

Table 1: Preventative and Predictive Overhead Line Maintenance Program Summary

2015-2017 Average Annual Cost ($M): 6.9	**2020 Cost ($M):** 6.0
Segments: • Overhead Line Patrols & Pole Inspections • Overhead Switch Maintenance & Insulator Washing • Vegetation Management • Metering Services	
Outcomes: Reliability, Environment, Safety, and Customer Service	

The Preventative and Predictive Overhead Line Maintenance program (the "Program") funds maintenance activities on: (i) Toronto Hydro's overhead line assets; and (ii) metering assets and associated communication systems that enable meter data collection and tracking to ensure compliance with applicable legislative and regulatory requirements. This Program involves inspection and maintenance tasks typically conducted on a fixed cycle, and inspection of equipment for indications of potential failure. The segments in this Program are focused on preserving and maximizing an asset's performance over its expected useful life while mitigating a wide variety of system risks. The Program is also designed to minimize overall lifecycle costs, account for factors such as the safety of Toronto Hydro work crews and the public, responsible environmental stewardship and associated obligations, and compliance with statutory and regulatory requirements.[1]

The Preventative and Predictive Overhead Line Maintenance program is comprised of the following four segments:

[1] Including the OEB's Minimum Inspection Requirements under Appendix C of the *Distribution System Code*.

- **Overhead Line Patrols & Pole Inspections:** this segment funds periodic line patrols to inspect all overhead distribution equipment, including pole-mounted transformers, switches, auxiliary equipment, and conductor wire. In addition to line patrols, the segment also includes dedicated pole inspections and wood pole treatment.
- **Overhead Switch Maintenance & Insulator Washing**: this segment funds two general sets of maintenance activities on the overhead distribution system: (i) the periodic inspection and maintenance of overhead switches such as SCADA-Mate and Three Phase Gang-Operated Switches; and (ii) the washing of porcelain insulators located at high-risk locations prone to contamination build-up.
- **Vegetation Management**: this segment funds the trimming of vegetation near overhead feeders to minimize the impact of tree-caused power interruptions on system reliability.
- **Metering Services:** this segment funds the inspection and maintenance of metering assets and associated communication technologies to ensure proper functionality and compliance with applicable legislative and regulatory requirements.

The proposed 2020 expenditures for this Program are based on historical levels. By preserving and maximizing the performance of overhead line and metering assets and ensuring these assets are fully operational, this Program contributes to maintaining safety, the environment, and overall system reliability at reasonable costs to Toronto Hydro's customers.

In addition, the Program contributes to customer experience and satisfaction by facilitating: (i) the tracking of accurate and timely electricity consumption information

for customer billing purposes; and (ii) the use of up-to-date communication technology that enables remote reading and processing of customer meter information.

2. OUTCOMES AND MEASURES

Table 2: Preventative and Predictive Overhead Line Maintenance Program Outcomes and Measures Summary

Reliability	• Contribute to the overall system performance and reliability – as measured by performance metrics like SAIFI, SAIDI, Customers Interrupted ("CI"), and Customer Hours Interrupted ("CHI") – by promptly identifying potential asset failure or assets in substandard conditions before failure occurs, through planned inspections in compliance with the Ontario Energy Board's ("OEB") Distribution Systems Code ("DSC"). • On average, a trimmed feeder after experiencing three to four years of growth shows a 20 percent to 40 percent reduction in tree caused interruptions.
Environment	• Contribute to reducing the environmental impact of Toronto Hydro's distribution system by proactively identifying transformers exhibiting signs of oil deficiencies for replacement, thereby reducing the likelihood of oil spills into the environment.
Safety	• Contribute to Toronto Hydro's safety objectives (including compliance with Ontario Regulation 22/4, and safety performance as reflected by metrics like the Serious Electrical Incidents Index and Total Recordable Injury Frequency) through proactive inspections to identify and reduce the likelihood of equipment malfunction (e.g. porcelain switch breaking) and asset failures (e.g. collapse of a pole or flashovers on electrical equipment) which, if not prevented, may lead to injury of the general public and Toronto Hydro's crew.
Customer Service	• Contribute to Toronto Hydro's customer service performance and objectives by ensuring the accurate billing of all smart metered customers based on actual usage, and mitigating the risk of meter seals expiring before their testing and re-validation (which also supports compliance with applicable regulatory requirements like the *Electricity and Gas Inspection Act* and the *Weights and Measures Act*).

3. PROGRAM DESCRIPTION

The Preventative and Predictive Overhead Line Maintenance program funds all maintenance activities with respect to Toronto Hydro's overhead distribution system and metering assets, including meters and communication systems that enable meter data collection and tracking. This Program involves inspection and maintenance tasks typically conducted on a fixed cycle and inspection of equipment for predetermined conditions indicative of a potential failure. The segments in the Program focus on preserving and maximizing an asset's performance over its expected useful life while mitigating a wide variety of system risks. The Program is also designed to minimize overall costs and account for factors such as the safety of Toronto Hydro's work crews and the public, responsible environmental stewardship and associated obligations, and compliance with applicable statutory and regulatory requirements.

The Preventative and PredictiveOverhead Line Maintenance program is comprised of the following four segments:

- **Overhead Line Patrols & Pole Inspections**: this segment funds periodic line patrols to inspect and assess the condition of all overhead distribution equipment including pole-mounted transformers, switches, auxiliary equipment, and conductor wire. In addition, this segment also includes dedicated pole inspections of all wood, concrete and steel poles and wood poles treatment.
- **Overhead Switch Maintenance & Insulator Washing:** this segment funds two general sets of maintenance activities on the overhead distribution system (1) the periodic inspection and maintenance of overhead switches such as SCADA-Mate and Three Phase Gang-Operated Switches, and (2) the washing of porcelain insulators located at high-risk locations prone to contamination build-up.

- **Vegetation Management:** this segment funds the trimming of vegetation near overhead feeders to minimize the impact of tree-caused power interruptions on system reliability.
- **Metering Services:** this segment funds the inspections and maintenance of metering assets and associated communication technologies to ensure proper functionality and compliance with applicable legislative and regulatory requirements. Metering maintenance activities include: meter audits to verify meter accuracy; verifying, testing and troubleshooting wholesale meters installed at transmission grid supply points; investigating communication issues; and installing reused meters following accuracy testing.

4. PROGRAM COSTS

Toronto Hydro is requesting $6.0 million in 2020 to execute the functions in the Program. Without this level of funding, Toronto Hydro could be exposed to a number of risks:

- Reduced ability to comply with applicable legislative and regulatory requirements such as Measurement Canada's metering requirements or the OEB's Minimum Inspection Requirements.
- Increased frequency of equipment malfunctions or failures due to unidentified deficiencies or lack of maintenance leading to increased:
    - safety risks from incidents such as the collapse of a pole onto a roadway, sidewalk or residence or flashovers on electrical equipment;
    - environmental risk from oil leaks resulting from unidentified equipment deficiencies such as corrosion on the transformer tank; and
    - reliability risks from failure of overhead switches or other equipment which result in outages or interruptions caused by overgrown trees.

- Decreased ability to extend the life of wood poles through treatment.

The Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for each segment are summarized in Table 3 below.

Table 3: Overhead Maintenance Program Expenditures by Segment ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Overhead Line Patrols and Pole Inspections	0.5	0.9	0.9	0.8	0.6	0.6
Overhead Switch Maintenance and Insulator Washing	1.8	1.5	1.7	1.3	1.8	1.1
Vegetation Management	2.8	3.5	2.9	2.9	2.9	2.8
Metering Services	1.3	1.7	1.2	1.6	1.5	1.5
Total	**6.3**	**7.6**	**6.7**	**6.6**	**6.8**	**6.0**

4.1 Cost Drivers

The 2020 test year cost forecast represents a decrease of $0.3 million from Toronto Hydro's last rebasing year (2015), a decrease of $0.7 million from the most recent historical actual year (2017), and a decrease of $0.8 million from the bridge year (2019). The cost variances are primarily a result of:

- Expected reduction in the population of porcelain insulators requiring washing as Toronto Hydro's capital program starts to replace porcelain with polymer insulators beginning in 2020.
- One-off inspections of overhead distribution line insulators (required between 2016-2018 in response to a sharp rise in pole fires in 2015) which will no longer be required beyond 2018 once all insulators are inspected.
- Fluctuation in the number of overhead switches maintained over the 2015-2020 period.

4.2 Cost Control and Productivity Measures

4.2.1 Cost Management

Some maintenance activities require an outage to be taken to create a safe work zone in accordance with Toronto Hydro's Work Protection Code. Initiatives undertaken in 2016 included the development of an annual feeder scheduling program and enhanced work coordination to allow crews to carry out more maintenance work per outage. For maintenance activities that require an outage (e.g. overhead switch maintenance), this initiative entails cost control benefits given the need for fewer switching and isolation operations overall. In addition, the decision to replace porcelain insulators (which are prone to contamination build-up) will lead to immediate and long-term savings in terms of insulator washing maintenance costs.

4.2.2 Productivity

Toronto Hydro has placed significant emphasis on achieving greater output for the same or reduced input in each of the segments within the Preventative and Predictive Overhead Line Maintenance program. In an effort to achieve greater productivity, Toronto Hydro has recently undertaken an overhaul and recertification process for all Reliability Centered Maintenance ("RCM") studies and has adjusted maintenance tasks and frequencies based on RCM and Condition-based Maintenance principles. Examples of these adjustments include:

- Standardizing the maintenance cycles of overhead switches to align with station maintenance cycles (i.e. every four years) wherever possible to minimize the need for multiple equipment outages and significant switching resources, enable efficient execution of more maintenance work per outage, and minimize the need for multiple visits to work on particular sites;

- implementing "find and fix" protocols whereby crews that identify minor asset deficiencies address the deficiencies (e.g. replacing equipment nomenclature or addressing missing or defective guy guards and pole ground wires) onsite, as opposed to only logging the deficiencies for future action under the Corrective Maintenance program:[2]
- Issuing longer-term inspection maintenance contracts to third party service providers to keep unit costs stable and increase service quality levels over time (i.e. as result of accumulated service provider experience and familiarity with identifying deficiencies on Toronto Hydro's distribution system); and
- Introducing new tools or making greater use of existing technology such as Infrared Thermography, Electronic Maintenance Sheets, and Online Partial Discharge Testing.

For the Metering Services segment, Toronto Hydro has pursued the following initiatives with productivity benefits:

- Introduced new metering technologies for interval metered and suite metered services to improve the success of daily metering communication;
- Migrated from the failing legacy 2G meters to 4G LTE meters with more reliable communication network, reducing costs associated with on-site investigations and troubleshooting; and
- Replaced power-line with direct-line communication for added reliability and data collection for suite metered services.

The following sections describe each of the segments in the Preventative and Predictive Overhead Line Maintenance program.

[2] Exhibit 4A, Tab 2, Schedule 4.

5. OVERHEAD LINE PATROLS AND POLE INSPECTIONS SEGMENT

5.1 Segment Description

Toronto Hydro conducts line patrols to inspect approximately 4,100 circuit kilometres of primary and 11,500 circuit kilometres of secondary distribution lines every three years. Infrared thermography scans are also performed annually on all primary lines and nearby secondary lines. The inspection cycles for line patrols are as mandated by the OEB's Minimum Inspection Requirements (under Appendix C of the DSC).[3]

Line patrols cover all overhead distribution equipment including poles, conductor wires, pole-mounted transformers, switches, lightning arrestors, line insulators, and other peripheral attachments. Approximately 177,000 poles, 29,600 overhead transformers, and 7,600 overhead switches are inspected through line patrols.

In addition, Toronto Hydro also conducts dedicated pole inspections for wood, concrete, and steel poles on a ten-year cycle. Toronto Hydro has approximately 106,000 wood poles, 61,000 concrete poles and 10,000 steel poles. All wood poles are either butt or full length treated against rot.

Overhead line patrols are designed to identify visible deficiencies (such as signs of leaking transformers, loose or broken attachments (e.g. cross-arms, insulator brackets), and damaged poles), as well as deficiencies that can be identified through infrared thermography. This technology identifies thermal anomalies, such as a 63°C increase in temperature at the secondary connection point of the pole-mounted transformer shown in Figure 1. If undetected and not addressed, such a deficiency can lead to a failure of the connection over time and result in safety and environmental risks due to

[3] *Supra* note 1.

arcing, which can lead to a transformer fire and release of oil into the environment. The Institute of Electrical and Electronics Engineers ("IEEE"), American National Standards Institute ("ANSI") and the International Electrotechnical Commission ("IEC") all publish standard temperature ratings for assets, which are used to determine if an electrical component has a temperature above the recommended value. Thermography is an accepted and encouraged practice in the utility industry as evidenced by the National Fire Protection Association's standard 70B: Recommended Practice for Electrical Equipment Maintenance.[4]

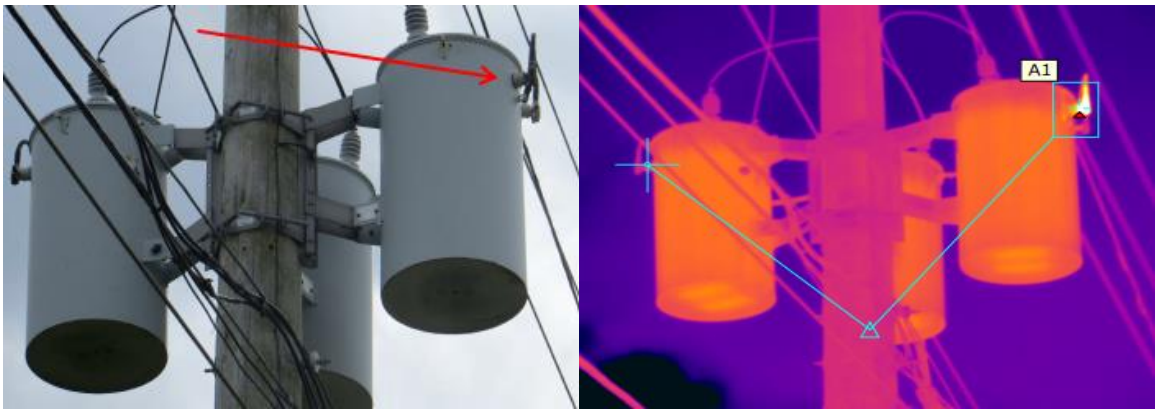


Figure 1: Secondary Connection on Pole-Mounted Transformer (Left) with an Infrared Thermography Image of the Same Asset Denoting a Hot Spot at A1 (Right)

Wood pole inspections involve a visual assessment of each pole and a sounding test using a hammer to check for internal cavities, which can indicate an infested or internally decayed pole. Based on the results of this assessment, one or more of the following steps may be taken:

[4] National Fire Protection Association, *NFPA 70B:* Recommended Practice for Electrical Equipment Maintenance (2013 Edition).

- A bore test (using a 12 millimetre diameter bit to drill into the pole) to assess the condition of the shavings from the interior;
- A resistograph test (using a 2 millimetre diameter needle drill bit and an electronic resistance measurement device to drill into the pole) to determine the presence of wood decay, stages of rot, and hollow areas;
- Treatment using a boron glass rod or copper-boron glass rod wood preservative;
- Treatment using an external copper napthenate wrap; and
- Treatment using an internal fumigant.

From 2020 onward, Toronto Hydro will inspect steel and concrete poles as part of its dedicated pole inspection program. Inspections of these poles will allow Toronto Hydro to improve decisions on planned renewal investments for these assets. Further, this is expected to reduce the burden on reactive capital by proactively identifying poles with substandard conditions and scheduling them for replacement before they require costly reactive intervention.

Overhead line patrols and pole inspections serve to assess asset conditions and identify overhead asset deficiencies resulting from aging assets or exposure to weather, animals, trees, or other environmental elements. Condition and deficiency information gathered during these activities is utilized to plan and prioritize capital and corrective maintenance work, so that public and employee safety, environmental, system reliability, and financial risks can be mitigated. Pole treatment activities are undertaken to extend the life of the pole and mitigate the risk of decay.

During 2015-2017, Toronto Hydro identified on average approximately 2,400 deficiencies annually during line patrols. Deficiencies identified include loose or

deteriorated connections, missing guy guards, tracking insulators, rusted equipment, oil leaks, vegetation interference, damaged conductors and conductor splices, which are all addressed in the Corrective Maintenance or Reactive and Corrective Capital programs.[5] Identifying and addressing these issues reduces the likelihood of a component failure and the associated risks. For example, an aging conductor splice that fails could result in a live conductor dropping to the ground, which would create a serious safety risk to the public and Toronto Hydro employees and cause a power interruption that may impact hundreds of customers. Thermography is used to mitigate this risk as it allows such deficiencies in splices to be identified.

Toronto Hydro has approximately 106,000 wood, 10,000 steel, and 61,000 concrete poles. Dedicated pole inspections identify poles that have lost their mechanical strength and are likely to fail, endangering the crews working on them and possibly resulting in collapse if they remain in service.

For wood poles, the primary indicator of health and remaining life is mechanical strength, given that the main function of poles is to act as support structures. As a natural material, a wood pole undergoes a different degradation process than most other distribution assets. The degradation processes are primarily biological and cumulative with age. They consist of insect infestation, moisture ingress, and bird or fungi attacks. Decay causes a wood pole to lose its strength and functionality, which increases the risk of a structural failure. Poles often support and withstand significant static loads such as transformer banks and conductors, and dynamic loads such as climbing workers or high winds. They typically fail with the onset of age and the loss of structural strength.

[5] See Exhibit 4A, Tab 2, Schedule 4 and Exhibit 2B, Section E6.7.

As further illustrated in Figures 2 and 3 below, deficiencies such as rot and excessive cracking are common causes of pole failures. Between 2015 and 2017, Toronto Hydro condemned on average over 290 wood poles annually.



Figure 2: Rot at Base of a Pole



Figure 3: (Left) Cracked Wood Pole, (Right) Surface Rot on Pole

For steel poles, the most common cause of degradation is corrosion. The corrosion protection system for steel poles can be compromised by mechanical degradation of the coating due to external impacts by foreign objects or abrasion, adverse weather conditions, and loss of coating due to age.

Concrete poles can begin to deteriorate from weather events or mechanical damage by external factors such as vehicle impacts. Cracks on concrete poles can either be circumferential (around the pole) or longitudinal (along the length of the pole), with the latter type typically being more serious in nature as shown in Figure 4 below. Longitudinal cracks can be caused by reinforcing steel being overly close to the surface of the concrete pole or degradation due to weather events such as freeze-thaw conditions.



Figure 4: (Left) Longitudinal Crack on Pole, (Right) Cracked Concrete Base

Poles are found predominantly along sidewalks, roadways, and other areas of high pedestrian and vehicular traffic. Without routine inspection, there is an unacceptable risk that poles and associated attachments could collapse onto sidewalks, roadways, and even residences. The collapse of a pole can also cause oil spills from ruptured transformer tanks, electrical arcs, flashovers, and fires, which pose serious environmental risks and safety risks to the public and Toronto Hydro employees. Minimizing the likelihood of a pole failure will mitigate these risks. Moreover, pole inspection activities, and in particular wood pole treatments (e.g. application of boron rods, copper napthenate wraps, and internal fumigant) extend the life of poles and allow for a more efficient and structured capital pole replacement program.

Between 2015 and 2017, there were on average approximately 190 incidents of overhead asset failures (excluding major event days) each year. These failures were primarily attributed to overhead transformers, switches, conductors, insulators, lightning arrestors and poles, and resulted in excess of 125,000 CIs and 89,000 CHIs annually. Line patrols and pole inspection activities are in place to identify deficiencies that, if left unaddressed, may lead to incidents that impact system reliability.

5.2 Overhead Line Patrols and Pole Inspections Segment Costs

Table 4 below provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for this segment.

Table 4: Overhead Line Patrols and Pole Inspections Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Overhead Line Patrols and Pole Inspections	0.5	0.9	0.9	0.8	0.6	0.6

The 2020 test year costs associated with this segment are projected to be $0.6 million, which represents an increase of $0.1 million from the utility's last rebasing year (2015), a $0.3 million reduction from the most recent actual year (2017), and no change from the bridge year (2019).

5.3 Overhead Line Patrols and Pole Inspections Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

Expenditures increased by approximately $0.4 million from 2015 to 2016, which was attributed to (i) inspecting for overhead line insulators as a response to the sharp rise in pole fires in 2015, as explained further in section 6.1; and (ii) testing an additional 4,700 wood poles due for inspections.

2016 – 2017 Variance Explanation

There is no material variance in this period.

2017 – 2018 Variance Explanation

The costs from 2017 to 2018 are forecast to decrease by $0.1 million as the number of insulator inspections decreases in 2018 as they are ramped down in their final year and the number of wood poles requiring testing return to 2015 levels.

2018 – 2019 Variance Explanation

The costs from 2018 to 2019 are forecast to decrease by $0.2 million as costs are expected to return to near 2015 spending levels after completion of the insulator inspections in 2018.

2019 – 2020 Variance Explanation

There is no material variance forecast for this period. From 2020 onwards, expenditures will be approximately $0.1 million higher than the 2015 spending levels to begin funding inspections of concrete and steel poles.

6. OVERHEAD SWITCH MAINTENANCE AND INSULATOR WASHING

6.1 Segment Description

This segment includes two general sets of maintenance activities on the overhead distribution system: (i) maintenance of overhead switches; and (ii) washing of porcelain overhead line insulators.

1) Overhead Switches: Toronto Hydro maintains overhead switches on a four-year cycle. There are two main types of switches on Toronto Hydro's distribution system:
   a) Supervisory Control and Data Acquisition ("SCADA") Switches (or SCADA-Mate Switches): These switches are motorized, and can be operated remotely from the Control Room via wireless communication, or operated locally by field crews. To enable communication and remote operation during a system failure, the switches and related equipment utilize a battery system that is capable of providing power for switch operation and communication. Maintenance of SCADA switches involves verifying the switch's remote and local operation along with lubrication of the pivot points on the visible air-gap isolation mechanism. It also includes battery replacements for the switch and repeater radio (in accordance with manufacturer's recommendations), and Remote Terminal Unit ("RTU") testing to verify proper communication with the Control Room. Figure 5 below shows a typical SCADA switch.



Figure 5: SCADA-Mate Switch

b) Three Phase Gang-Operated Switches: These switches are found throughout Toronto Hydro's overhead system and unlike the SCADA switches, are not capable of remote operation. While some have motorized controls, the vast majority are manually operable at the physical switch location. The scope of work to maintain these switches involves verifying correct blade alignment, blade penetration, travel stops, arc interrupter operation, and mechanical operation. The contacts are cleaned and greased and the switch is tested for correct operation. Figure 6 below shows a gang-operated switch.



Figure 6: Manual Gang-Operated Switch

In total, Toronto Hydro maintains approximately 2,100 overhead switches comprising of 1,100 SCADA switches and 990 Three Phase Gang-Operated Switches.

2) Insulator Washing: Conductors and switches used on the overhead distribution system have historically been attached to poles and structural infrastructure using porcelain insulators. Porcelain insulators have a high dielectric strength and good mechanical properties, including hardness and resistance to chemical erosion and thermal shock. However, porcelain has poor resistance to contamination build-up, which causes tracking (i.e. leakage of electricity across the insulator). The accumulation of dirt and salt, combined with moisture (during misty or foggy days), reduces the effective insulation levels, and can lead to insulator tracking, flashover, and potential pole fires. To mitigate the risk of contamination and insulator tracking, insulators at the highest risk locations are washed twice a year. Insulator washing is performed using a high-pressure intermittent water jet while lines are energized. Figure 7 shows an example of a porcelain insulator being washed.



Figure 7: Porcelain Insulator Washed Using a High Pressure Water Jet

Overhead switch maintenance and insulator washing serve to mitigate public and employee safety, system reliability, and financial risks. Manual overhead switching is a common and high-risk activity undertaken by Toronto Hydro crews. Switches that are not regularly maintained can be difficult to operate, which has led to strains and injuries for crew members. Regular maintenance enables the detection and prediction of common failure modes, including the failure of a switch's insulator as shown in Figure 8 below, which can result in an arc flash that can seriously injure crew members.



Figure 8: Broken Switch Insulator

A second common failure mode is corrosion of switch metal blades. This naturally occurs from contaminants such as road salt and water settling on the switch blades. It can result in excessive heating of the blade and, over time, can lead to the blade failing to conduct electricity. Contaminants and corrosion on a switch blade during a load break operation may also cause the electrical arc to elongate, which causes additional damage to the blade and can lead to blade failure. Associated safety risks include burns from an arc-flash and overexertion injuries to an employee (i.e. if a switch requires a significant amount of force to operate).

Other common failure modes include switch seizure due to the drying out of lubrication, excessive arcing due to the misalignment of blades, and in the case of SCADA switches, failure of batteries – all of which can lead to switch malfunction, and pose a risk of injury to Toronto Hydro employees.

Between 2015 and 2017, Toronto Hydro identified on average over 235 switch-related deficiencies annually. These deficiencies are addressed by overhead switch maintenance activities such as identifying and correcting deteriorated insulators and corroded switch blades, ensuring blades are properly aligned, lubricating switches, and replacing batteries proactively. Deficiencies requiring further follow-up action or replacement of the switch are addressed in the Corrective Maintenance or Reactive and Corrective Capital programs.[6]

From a system reliability perspective, reducing the likelihood of switch failures can reduce the number of CIs and CHIs. Between 2015 and 2017, Toronto Hydro's distribution system experienced on average approximately 38 power interruptions per year due to switch failures, which resulted in excess of 28,000 CIs and 15,000 CHIs annually. Switches are designed to isolate line sections from the distribution system when a fault occurs or for the purposes of undertaking planned work. Their function and impact on system reliability can be illustrated using the example in Figure 9 below.

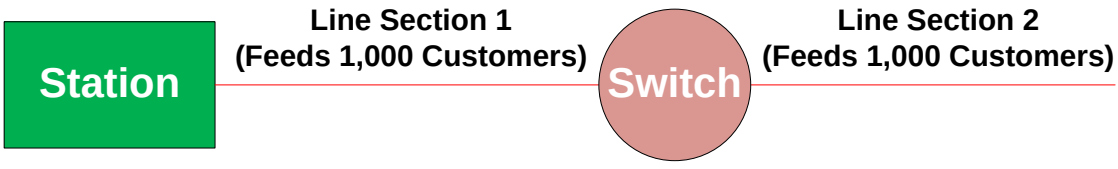


Figure 9: Example of Overhead Switch Impact on System Reliability

[6] *Supra* note 5.

Depicted above is a feeder that serves 2,000 customers, divided into two line sections using a switch, with each section serving 1,000 customers. When a fault occurs on Line Section 2, the switch can be operated to isolate that line section such that the station can continue to supply the customers on Line Section 1. Without an operable switch, 2,000 CIs would result, as the feeder would be isolated in its entirety from the station. Maintaining the switch in good working order has the potential to reduce that number to 1,000 CIs as only Line Section 2 would be isolated. Assuming in this theoretical example a fault is equally likely to occur on Line Section 1 or Line Section 2, an operable switch would improve system reliability by 33 percent.

Approximately one third of Toronto Hydro's overhead distribution system utilizes porcelain insulators. This equates to approximately 31,000 pole locations that are vulnerable to contamination building up on insulators. Thousands of these locations are at an increased risk as they are close to industrial areas and busy arterial roads and highways (such as the 401, 400, 427, and the Don Valley, Allen, and Gardiner Expressways), where salt used to melt snow or ice in the winter months becomes airborne through "salt spray" and deposits on the insulators.

Removing contamination through insulator washing reduces the risk of electrical tracking, pole fires, and insulator failures. From a safety perspective, pole fires and insulator failures in Toronto's dense urban areas can cause injury to individuals at ground level and crew members working near the insulators. The primary failure mode for porcelain equipment is cracking, which may start as a hairline crack, but has the potential to lead to a catastrophic failure with shards of debris falling to the ground and striking anyone in the vicinity and an arc flash risk to workers nearby. Figure 10 below shows a close-up view of a porcelain insulator damaged by electrical tracking over time.



Figure 10: Close-up of Damaged Porcelain Insulator Showing Tracking

From a system reliability perspective, insulator failures, depending on where they occur on a feeder, will cause a power interruption for tens to possibly thousands of customers. On March 3, 2015, Toronto Hydro experienced an all-time high of 121 pole fires, caused by a freezing rain storm event. These pole fires impacted approximately 107,000 customers and resulted in approximately 292,000 CHIs. The cause of the fires was a combination of the higher moisture levels caused by freezing rain and the build-up of salt used on roads, which became airborne and accumulated on the insulators. This combination of factors can significantly increase the risk of a pole fire (see example of a pole fire in Figure 11 below).



Figure 11: Pole fire on December 22nd, 2017

From a financial perspective, pole fires resulting from insulator tracking necessitate emergency response, equipment replacement, and in some instances, the payment of damage claims. Emergency response costs incurred by Toronto Hydro for the March 3, 2015 freezing rain event totalled $1.5 million.

In response to this event, Toronto Hydro developed a reactive insulator washing program, which involves additional system wide insulator washing of all high risk pole locations on a reactive basis, based on weather patterns and road salt usage trends. This work is funded through the Corrective Maintenance program.[7] Since this Program

[7] Exhibit 2B, Section D3

began, Toronto Hydro has not seen pole fires at 2015 levels. From 2016-2017, Toronto Hydro experienced a combined 66 pole fire events which were nearly half of what was experienced in 2015.

Given the risks associated with contaminated porcelain insulators (including public and employee safety, system reliability, and financial risks), routine Insulator washing is a necessary and prudent means of reducing the likelihood of contingencies resulting from debris build-up on insulators. Reductions in the amount of insulator washing could result in increased incidents of insulator tracking and poles fires.

As Toronto Hydro replaces porcelain insulators with polymer insulators through its Overhead System Renewal program,[8] the need for insulator washing is expected to diminish, as polymer insulators are hydrophobic and are not susceptible to the same failure mode due to contamination. However, based on the insulator inspections undertaken over the past few years (see section 4.1), Toronto Hydro has found that the number of additional locations requiring washing has outpaced capital replacements in recent years. The need for insulator washing will not diminish considerably in the short-term and continued insulator washing is expected to be required until 2020, after which it is projected the population of high risk locations will start to decline over the 2020-2024 period.

6.2 Overhead Switch Maintenance and Insulator Washing Segment Costs

Table 5 below provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for this segment.

[8] Exhibit 2B, Section E6.5

Table 5: Overhead Switch Maintenance and Insulator Washing Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Overhead Switch Maintenance and Insulator Washing	1.8	1.5	1.7	1.3	1.8	1.1

The 2020 test year costs associated with this segment are projected to be $1.1 million, which represents reductions of $0.7 million from the utility's last rebasing year (2015), $0.6 million from the most recent actual year (2017), and $0.7 million from the bridge year (2019).

6.3 Overhead Switch Maintenance and Insulator Washing Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

Expenditures decreased by approximately $0.2 million from 2015 to 2016. In 2015, Toronto Hydro washed an additional 1,900 poles with porcelain insulators to mitigate outage and pole fire risks in preparation for the 2015 Pan American Game venues. Because this work required a short turn around, it needed to be executed outside of the existing insulator wash contract, which resulted in higher costs. In addition, Toronto Hydro maintained more switches, from 641 units in 2015 to 352 units in 2016.

2016 – 2017 Variance Explanation

Expenditures increased by approximately $0.1 million from 2016 to 2017, which was primarily attributed to an increase in batteries replaced for SCADA-Mate Switches from 245 units in 2016 to 368 units in 2017.

2017 – 2018 Variance Explanation

The costs from 2017 to 2018 are forecast to decrease by approximately $0.3 million due to a decrease in the number of switches planned for maintenance from 344 units in 2017 to 294 units in 2018.

2018 – 2019 Variance Explanation

The costs from 2018 to 2019 are forecast to increase by $0.5 million, which is primarily due to an increase in the number of switches planned for maintenance from 294 units in 2018 to 526 units in 2019.

2019 – 2020 Variance Explanation

The costs from 2019 to 2020 are forecast to decrease by $0.7 million, which is attributed to: (i) the expected reduction in the population of porcelain insulators requiring washing from 4,750 poles washed bi-annually to 3,000 poles washed bi-annually, as Toronto Hydro's capital program starts to replace porcelain with polymer insulators beginning in 2020; and (ii) a reduction in the number of switches requiring maintenance from 526 units in 2019 to 401 units in 2020.

7. VEGETATION MANAGEMENT

7.1 Segment Description

Toronto Hydro performs vegetation management on over 800 overhead primary feeders extending almost 4,100 circuit kilometres along Toronto's arterial thoroughfares, rights-of-way, and residential streets. These feeders co-exist with the City of Toronto's mature and dense tree canopy, which includes about 600,000 City-owned "street trees" and thousands of trees located on customer properties. In total, there are over 10 million trees in the City of Toronto. Over 125,000 of these street trees

are adjacent to primary overhead feeders, and their overgrowth can potentially interfere with the safe and reliable distribution of electricity.

Planned vegetation management activities are executed by contractors with support from Toronto Hydro's internal resources. Trees and branches are pruned according to minimum clearance standards based on American National Standards Institute ("ANSI") A300 – Standard Practices for Trees, Shrubs and other Woody Plant Maintenance,[9] and the City of Toronto Forestry Pruning Guidelines. In addition to the minimum clearance standards, Toronto Hydro considers other factors such as:

- **Species and growth patterns of a tree**: fast-growing trees are trimmed more and slow-growing trees are trimmed less;
- **Natural trimming practices**: branches are pruned back to a natural point of growth in the crown of the tree and leaders are "trained" (shaped) to grow away from the lines;
- Distance of major limbs that exhibit minimal growth, versus minor branches that can exhibit aggressive growth;
- **Directional pruning practices**: maintenance of tree shape and branch patterning;
- Overall aesthetics and balance of the tree;
- Removal of dead limbs; and
- **Storm hardening**: select removal of branches within the canopy to minimize the possible effects of wind and severe weather, but maintain the overall tree appearance.

[9] American National Standards Institute, *American National Standard for Tree Care Operations — Tree, Shrub, and Other Woody Plant Maintenance — Standard Practices (Pruning)*, (A300 (Part 1) -2001).

Toronto Hydro avoids the practice of "tree topping", which is the indiscriminate removal of branches to reduce the size of the tree crown. As a result, and given the above-noted factors, Toronto Hydro mandates the use of certified utility arborists for vegetation management activities with training, knowledge, and certification in the practice of arboriculture.

Vegetation management mitigates the risk of vegetation interference by pruning trees near Toronto Hydro's overhead feeders. Each year, Toronto Hydro identifies the feeders in greatest need of tree pruning based on prioritization criteria such as feeder reliability history, number of customers supplied by each feeder, and the amount of time that has elapsed since the trees surrounding the feeder were last pruned. The prioritization process results in pruning trees surrounding feeders once every two to five years, with the system average being approximately three years. On average, Toronto Hydro pruned 1,628 circuit kilometres and approximately 53,000 trees annually between 2015 and 2017.



Figure 12: Tree Trimming of an Overhead Feeder

Vegetation interference is one of the most common causes of power interruptions, as overhead feeders are prone to tree branch contacts. Trees may make contact with

distribution feeders as a result of natural growth, or when severe weather causes branches to break and fall onto lines or to bend and make intermittent contact. Conductors on feeders can also naturally stretch and sag due to ice and snow build-up, heavy loading or warm weather, bringing the lines closer to tree limbs. Branch contacts with lines result in a new path for current to travel, causing the branch to become energized, and posing a safety risk.

Vegetation-related power interruptions have a significant impact on system reliability and are second only to defective equipment as the leading cause of system outages. Statistics from 2015 to 2017 show that tree contacts are responsible for over 60 power interruptions a year, and cause approximately 77,000 CIs and 105,000 CHIs annually. When all interruptions are considered, over the period of 2015-2017, trees accounted for approximately 7 percent of all CIs and 15 percent of all CHIs annually on average. These statistics exclude interruptions that occurred on major event days. During such days, the distribution system is particularly vulnerable to tree contacts and costly tree damage.

As more time passes since the last tree pruning for a particular feeder, it becomes more likely that tree contacts will occur and associated risks will increase (including system reliability, financial, and safety risks). These risks can be effectively mitigated through tree trimming.

From a reliability standpoint, Figure 13 illustrates the expected number of vegetation-related interruptions relative to time elapsed since the last pruning and trimming activities. An average feeder that is cleared after having experienced three to four years

of growth is expected to exhibit a reduction of approximately 20 percent to 40 percent in the number of tree-caused interruptions.

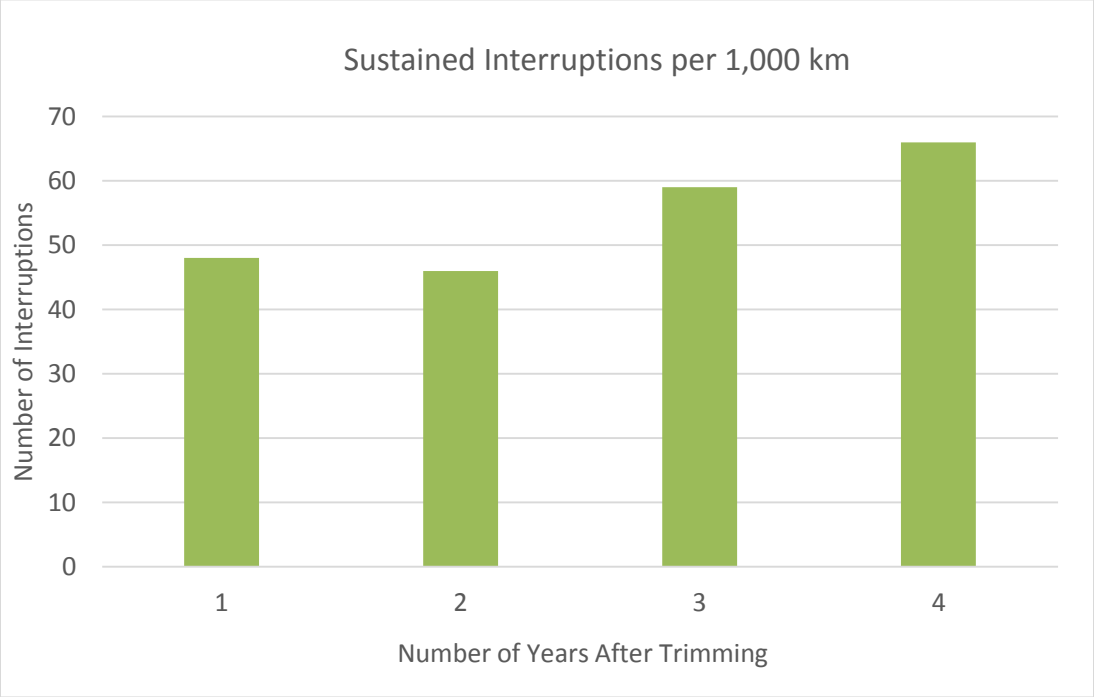


Figure 13: Expected Number of Tree-Related Interruptions

Vegetation management is also a widely accepted means of effectively "storm-hardening" a system (i.e. proactively mitigating against storm damage and associated system reliability risks). Storm hardening involves selectively removing portions of a tree canopy to reduce the "sail effect" of branches during high winds and to reduce the likelihood that broken branches will make contact with lines. As such, more frequent tree pruning further reduces risks posed by severe weather.

Toronto Hydro's system is susceptible to severe weather and storm damage, as evidenced by the 2013 ice storm and more recently the November 15, 2017 wind storm.

In many cases, the effects of these storms continue well after the storm has passed. Broken and weakened trees and tree limbs continue to pose a threat to overhead lines until the next tree pruning date. From a financial perspective, planned vegetation management is expected to reduce reactive expenditures from corrective and emergency responses.

In addition to system reliability and financial risks, vegetation management serves to mitigate safety risks, including as a result of trees and vegetation that grows or is blown into power lines. This vegetation can become energized, and in certain situations, can cause fires or step and touch potential risks to the general public. Another safety risk stems from branches or trees that bring energized conductors to the ground when they fall, which pose significant safety hazards to the public. Vegetation management is expected to mitigate these risks.

Within Toronto, vegetation risks have been increasing in recent years due to invasive species infestation such as the Emerald Ash Borer and the Asian Long-Horned Beetle. Both these species compromise a tree's structural integrity and greatly increase the risk of a branch or tree falling into overhead feeders. It is estimated that Toronto will lose approximately 860,000 of its ash trees to the Emerald Ash Borer,[10] while the Asian Long-Horned Beetle poses a risk to 42 percent of all street trees.[11] Vegetation management is expected to enable Toronto Hydro to mitigate the risks associated with invasive species by removing the dead and dying tree limbs that they cause.

[10] City of Toronto, *Emerald Ash Borer in Toronto: Managing Public and Private Trees* (2013).
[11] City of Toronto, *Trees Under Threat: The Asian Long-horned Beetle in Greater Toronto* (2014), online: <http://www1.toronto.ca/wps/portal/contentonly?vgnextoid=f26fdada600f0410VgnVCM10000071d60f89RCRD&vgnextchannel=17f4cacb759e0410VgnVCM10000071d60f89RCRD>.

7.2 Vegetation Management Segment Costs

Table 6 below provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for this segment.

Table 6: Vegetation Management Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Vegetation Management	2.8	3.5	2.9	2.9	2.9	2.8

The 2020 test year costs associated with this segment are projected to be $2.8 million, which is equal to the utility's last rebasing year (2015), and $0.1 million less than the most recent historical actual year (2017) and the bridge year (2019).

7.3 Vegetation Management Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

Expenditures increased by approximately $0.8 million from 2015 to 2016. In 2016, Toronto Hydro experienced a high volume of tree contact related interruptions, which resulted in excess of 87,000 CIs and 82,000 CHIs, and 30 percent of these interruptions occurred in the month of August. In response to this spike in tree-caused interruptions, Toronto Hydro increased tree trimming expenditures in late 2016 to trim additional feeders and mitigate further reliability impacts.

2016 – 2017 Variance Explanation

Expenditures decreased by approximately $0.6 million from 2016 to 2017 as spending returned to historical spending levels after the increase in late 2016 in response to the high volume of tree contact related interruptions.

2017 – 2018 Variance Explanation

There is no material variance forecast for this period.

2018 – 2019 Variance Explanation

There is no material variance forecast for this period.

2019 – 2020 Variance Explanation

The costs from 2019 to 2020 are forecast to decrease slightly by less than $0.1 million, which is consistent with historical spending levels.

8. METERING SERVICES SEGMENT

8.1 Segment Description

Toronto Hydro and its customers rely on metering equipment to track accurate and timely electricity consumption information for customer billing and market settlement purposes. The Metering Services segment is responsible for maintaining this equipment to ensure proper functionality and compliance with applicable legislative and regulatory requirements.

Toronto Hydro's metering assets include both meters and the communication systems that enable meter data collection and tracking. The maintenance of metering equipment is critical to ensuring the ongoing accuracy of meter reads and the associated billing and settlement data. Moreover, meter testing is a requirement under the *Electricity and Gas Inspection Act* administered by Measurement Canada. Metering Services maintains Toronto Hydro's 758,000 smart and suite meters and 153 wholesale meter installations as of December 31, 2017), examples of which are illustrated in Figures 14 and 15 below.



Figure 14: Smart MeterIinstallation at Customer Location.



Figure 15: Wholesale Meter Installation at Transformer Station.

Metering Services activities consist of three major functional categories: (i) Meter Sampling & Testing; (ii) Wholesale Meter Maintenance; and (iii) Field Response.

8.1.1 Meter Sampling and Testing

Toronto Hydro is required to comply with the metering requirements set out by Measurement Canada, which state that all meters must be resealed at specific intervals in order to ensure that customers' electricity use is metered accurately. The Toronto Hydro meter sampling and testing program verifies the accuracy of meters, ensuring compliance with applicable requirements under the *Electricity and Gas Inspection Act* and the *Weights and Measures Act*. These statutes permit the use of meters for a set period of time, also referred to as a "seal period", before they must be either tested (i.e. re-verified) or replaced. For smart meters, this time span is typically ten years. When meters are tested and re-verified for accuracy, the seal period is extended.

For meter testing purposes, Measurement Canada permits utilities to form isolation lots (i.e. groups of meters with homogeneous meter characteristics), and test only a small number (called the sample group) from the isolation lot. Typically, 2-5 percent of randomly selected meters from each isolation lot form the sample group. For smaller homogeneous lots, the sampling rate could be as high as 50 percent. These sampling rates are allowed given the large number of meters in-service. The number of meters to be tested is determined in accordance with Measurement Canada's specification S-S-06, *Sampling Plans for the Inspection of Isolated Lots of Meters in Service*.[12] The seal period of the isolation lot of meters can be extended if the accuracy statistics for the sample group meet tolerances stipulated in Measurement Canada's specification. Some unique meters do not belong to any isolation lot and must be removed from service and tested individually before their seal periods expire. Table 7 lists the number of meters with a seal period that will expire during the 2020-2024 period. It also lists the number of meters that will need to form the sample groups for meter testing purposes based on the sample size for each isolation lot, so as to comply with Measurement Canada's requirements.

Table 7: Number of Seal Expiring Meters in 2020-2024 and Sampling Units

Year	Seal-Expiring Meters	Sample Group Meters
2020	49,000	37,000
2021	21,600	15,000
2022	14,800	4,800
2023	25,000	10,400
2024	216,600	203,700
Total	**327,000**	**270,900**

[12] See Annex C, Table 2, Limiting Quality 3.15.

In conducting meter testing, Toronto Hydro relies on field crews to remove meters that are part of a sample group and return them to Toronto Hydro's accredited service provider for testing. Test results are forwarded to Toronto Hydro for documentation and further actions based on the test results. A pass will result in an update to the meter records and the extension of seal periods, based on the tested accuracy levels. For the utility's smart meters with a ten-year initial seal period, provided the meters pass testing, the seals will be extended for all of the meters within the group by an additional eight years.

8.1.2 Wholesale Meter Maintenance

Wholesale meters, including instrument transformers, are installed at transmission grid supply points to measure electricity supplied from Hydro One Networks Inc. ("Hydro One") to Toronto Hydro. Wholesale meter maintenance involves re-verifying (i.e. testing every six years) and troubleshooting wholesale meters, and ensuring compliance with all applicable regulations, such as the requirement to notify the Independent Electricity System Operator ("IESO") of Meter Trouble Reports within 48 hours pursuant to the IESO's *Market Rules* and *Market Manual*.

Meter Trouble Reports are issued if there is any failure in data communication or if the data is suspected to contain errors. Data communication failures can arise from issues with Toronto Hydro's wireless 4G private network, Bell phone lines, the meter itself or the modem. If such a failure occurs, Toronto Hydro attempts to resolve the issue remotely. If remote resolution is unsuccessful, Toronto Hydro deploys field crews to the site of the particular wholesale meter to address the issue directly.

Prior to market opening in 2002, Hydro One was the Meter Service Provider ("MSP") for all wholesale meters. As the MSP, Hydro One was the owner of the wholesale meter installations and was responsible for the meters, their communications, maintenance, troubleshooting, and replacement. Beginning in 2002, Local Distribution Companies ("LDCs") in Ontario, such as Toronto Hydro, were required to take ownership of the installations and assume the MSP responsibilities and costs.

8.1.3 Field Response

The third category of activities within Metering Services is Field Response, which includes activities such as:

- Testing the accuracy of large user meter installations;
- Converting legacy flat rate services (e.g. Water heaters) into metered activities; and
- Installing reused meters following accuracy testing.

Toronto Hydro's 684,000 smart meters have a failure rate of 0.9 percent (i.e. approximately 6,000 units annually). Toronto Hydro's 79,500 suite meters have a failure rate of 2 percent (i.e. approximately 1,600 annually). The majority of the failures are related to: (i) the use of radio frequency mesh technology for smart meters; and (ii) powerline carrier for the suite meters, to deliver the meter reading data back to Toronto Hydro's centralized meter reading software. As failures occur, staff and field crews must investigate failure causes and restore communications in a timely manner, as well as perform on-site interval energy data downloads to maintain time sensitive billing (time-of-use).

Overall, a significant portion of the work undertaken by Metering Services is not discretionary because it is either driven by statutory or regulatory obligations, or a need to resolve a meter issue in the field on a reactive basis.

8.2 Metering Services Segment Costs

Table 8 below provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for this segment.

Table 8: Metering Services Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Metering Services	1.3	1.7	1.2	1.6	1.5	1.5

The 2020 test year costs associated with this segment are projected to be $1.5 million, which represents an increase of $0.2 and $0.3 million from the utility's last rebasing year (2015) and the most recent historical actual year (2017) respectively, and is equal to the bridge year (2019).

8.3 Metering Services Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

Expenditures increased by approximately $0.4 million from 2015 to 2016 due to the migration of time-of-use rates for billing purposes, which required significantly more investigations of data and communication issues.

2016 – 2017 Variance Explanation

Expenditures decreased by approximately $0.5 million from 2016 to 2017 as, the responsibility of meter data collection and investigations was transferred from Meter

Services to Customer Care In 2017 as part of the Meter Service Investigation Orders ("MSIO") process.

2017 – 2018 Variance Explanation

The costs from 2017 to 2018 are forecast to increase by $0.4 million. This is largely due to a slightly higher than anticipated failure rate of suite meters. This higher than expected failure rate was an anomaly, and is not expected to reoccur, as Toronto Hydro has since moved from Bell telephone lines to a more robust 4G wireless network.

2018 – 2019 Variance Explanation

The costs from 2018 to 2019 are forecast to decrease slightly by approximately $0.1 million due to the higher than expected failure rate of suite meters in 2018, partially offset by growing number of suite metering units as number of condominium residents increases.

2019 – 2020 Variance Explanation

There is no material variance forecast for this period. Toronto Hydro's 2020 forecast expenditure of $1.5 million for this segment is generally consistent with historical spending levels, and takes into account the growing number of suite metering units, in conjunction with the growing population of condominium residents.

PREVENTATIVE AND PREDICTIVE UNDERGROUND LINE MAINTENANCE

1. OVERVIEW

Table 1: Preventative and Predictive Underground Line Maintenance Program Summary

2015-2017 Average Annual Cost ($M): 2.9	**2020 Cost ($M):** 5.5
Segments: • Below-Grade Equipment Maintenance • Padmounted Equipment Maintenance • Contact Voltage Scanning	
Outcomes: Reliability, Environment, and Safety	

The Preventative and Predictive Underground Line Maintenance program (the "Program") funds maintenance activities on Toronto Hydro's underground assets. This Program involves inspection and maintenance tasks typically conducted on a fixed cycle and inspection of equipment for predetermined conditions indicative of a potential failure. The activities comprising the individual segments in this Program are focused on preserving and maximizing an asset's performance over its expected useful life while mitigating a wide variety of system risks. This Program is also designed to minimize overall costs and account for other factors such as the safety of Toronto Hydro's work crew and the public, and statutory and regulatory requirements.[1] The Preventative and Predictive Underground Line Maintenance program is comprised of the following three segments:

- **Below-Grade Equipment Maintenance:** this segment includes the periodic inspection and maintenance of all underground vaults (such as network vaults

[1] Including the Minimum Inspection Requirements under Appendix C of the Ontario Energy Board's *Distribution System Code*.

primarily located in downtown core of Toronto), submersible vaults, cable chambers, and equipment housed within them.

- **Padmounted Equipment Maintenance:** this segment includes the periodic inspection of padmounted equipment (e.g. transformers, switches) and cable diagnostic testing.
- **Contact Voltage Scanning**: this segment addresses the periodic scanning of Toronto hydro's distribution system for contact voltage. Simply put, contact voltage results from an unintentional connection between structures or surfaces (e.g. bus shelters, surfaces above buried distribution equipment) and Toronto Hydro's distribution system. The main activity in this segment involves using vehicle mounted mobile scanning tools to scan for electrical connections and terminations that potentially energize poles, bus shelters etc., due to exposure to weather elements, thereby creating public safety hazards.

The proposed 2020 expenditure is based on historical levels and accounts for the OM&A treatment of the contact voltage segment; this is discussed in detail under the contact voltage segment below. By preserving and maximizing the performance of underground assets, this Program contributes to maintaining safety, environmental responsibility, and overall system reliability at reasonable costs to Toronto Hydro's customers.

2. OUTCOMES AND MEASURES

Table 2: Preventative and Predictive Underground Line Maintenance Program Outcomes and Measures Summary

Reliability	• Contribute to maintaining existing levels of system reliability – as measured by performance metrics like SAIDI, SAIFI, Customers Interrupted ("CI"), and Customer Hours Interrupted ("CHI") – through the effective inspection of underground assets for deficiencies in compliance with the Ontario Energy Board's ("OEB") Distribution Systems Code ("DSC").
Environment	• Contribute to reducing the environmental impact of Toronto Hydro's distribution system by proactively identifying transformers exhibiting signs of oil deficiencies for replacement, thereby reducing the likelihood of oil spill into the environment.[2]
Safety	• Contribute to Toronto Hydro's safety objectives (including compliance with Ontario Regulation 22/4, and safety performance as measured through the Serious Electrical Incidents Index) by: o minimizing public exposure to contact voltage by finding and eliminating energized (4.5 volts or greater) surfaces and structures on Toronto hydro's distribution system; and o minimizing exposure to cable chamber lid incidents through prompt identification and resolution of chamber lid deficiencies.

3. PROGRAM DESCRIPTION

The Preventative and Predictive Underground Line Maintenance program funds maintenance activities on Toronto Hydro's underground assets. This Program involves inspection and maintenance tasks typically conducted on a fixed cycle and inspection of equipment for predetermined conditions indicative of a potential failure. The activities comprising the individual segments in this Program are focused on preserving and maximizing an asset's performance over its expected useful life while mitigating a wide variety of system risks. Tasks in this Program are also designed to minimize overall costs

[2] 1,620 oil deficiencies (e.g. leaking underground transformers) were found and reported between 2015 and 2017.

and account for factors such as the safety of Toronto Hydro work crews and the public and statutory and regulatory requirements.

Maintenance activities include vault and cable chamber inspections to assess the condition of civil structures and the equipment housed inside (e.g. transformers, switches and cables), inspections of padmounted transformers and switches; cable diagnostic testing for underground cables; and contact voltage scanning for stray voltages across the distribution system.

- **Below-Grade Equipment Maintenance:** this segment funds the periodic inspection and maintenance of all underground vaults (such as network vaults primarily located in the downtown core of Toronto), CRD vaults, cable chambers, and equipment housed within them.
- **Padmounted Equipment Maintenance:** this segment funds the periodic inspections of padmounted equipment (e.g. transformers, switches) and cable diagnostic testing.
- **Contact Voltage Scanning:** this segment funds the periodic scanning of Toronto Hydro's distribution system for contact voltage. Simply put, contact voltage results from an unintentional connection between structures or surfaces (e.g. bus shelters, surfaces above buried distribution equipment etc.) and Toronto Hydro's distribution system. The main activity in this segment is the use of vehicle mounted mobile scanning tools to scan for electrical connections and terminations that potentially energize poles, bus shelters etc. due to exposure to weather elements, thereby creating public safety hazards.

4. PROGRAM COSTS

Toronto Hydro requires approximately $5.5 million per year during the 2020 to 2024 period to efficiently execute the functions in the Preventative and Predictive Underground Line Maintenance program. Without this level of funding, Toronto Hydro could be exposed to a number of risks. Those include:

- Inability to carry out the cyclical inspections necessary to maintain assets and prevent the below risks;
- Failure risks, such as increased number of failures and associated outages on the system due to a reduction in asset inspection and maintenance;
- Public and employee safety, such as:
    - The inability to prevent safety hazards such as electrical shocks caused by contact voltage which endanger the public, workers, and animals that may come into contact with energized surfaces; and
    - Inability to mitigate safety hazards associated with below-grade and padmounted equipment.
- Financial risks, such as the inability to mitigate costly failures, as the costs associated with emergency response and equipment replacement can result in ten to hundreds of thousands of dollars in repairs.

Table 3 provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for each of the Program's segments.

Table 3: Preventative and Predictive Underground Line Maintenance Program Expenditures by Segment ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Below-Grade Equipment Maintenance	2.2	2.5	2.6	2.5	2.6	2.8
Pad-mounted Equipment Maintenance	0.4	0.4	0.6	0.6	0.5	0.7
Contact Voltage	-	-	0.0	1.5	2.0	1.9
Total	**2.6**	**2.9**	**3.2**	**4.5**	**5.2**	**5.5**

4.1 Cost Drivers

The 2020 test year cost forecast represents an increase of $2.9 million from Toronto Hydro's last rebasing year (2015), an increase of $2.3 million from the most recent historical actual year (2017), and an increase of $0.3 million from the bridge year (2019).

4.1.1 Volume of Maintenance Work

The number of equipment units requiring maintenance from year to year is based on their inspection cycle. For example, in the Below–Grade Equipment Maintenance segment, Toronto Hydro increased the number of network protectors maintained from 270 units in 2015 to 382 units in 2016 (an increase of over 40 percent) by aligning the overhauls of network protectors with stations maintenance schedules. In the Padmounted Equipment Maintenance segment, Toronto Hydro inspected more padmounted transformers that were due for inspection, from 1,947 units in 2016 to 2,467 units in 2017.

4.1.2 Cost Amortization

The Contact Voltage segment of this Program is being fully amortized as of July 2018, therefore the costs are treated as OM&A rather than capital costs.

4.2 Cost Control and Productivity Measures

4.2.1 Cost Management

As explained in detail in Toronto Hydro's overall productivity discussions, certain maintenance activities require an outage to be taken to create a safe work zone in accordance with Toronto Hydro's Work Protection code.[3] Initiatives undertaken in 2016 include developing an annual feeder scheduling program and enhanced work coordination to allow crews to do more maintenance work per outage. This initiative improved maintenance accomplishments for activities requiring an outage (e.g. network protector maintenance).

4.2.2 Productivity

Toronto Hydro has placed significant emphasis on achieving greater output for the same or reduced input in each of the segments within the Preventative and Predictive Underground Line Maintenance program. In an effort to achieve greater productivity, Toronto Hydro has recently undertaken an overhaul and recertification process for all Reliability Centered Maintenance ("RCM") studies and adjusted maintenance tasks and frequencies that are based on RCM and Condition-based Maintenance ("CBM") principles. Examples of these adjustments include:

- Beginning in 2015, Toronto Hydro updated its processes for capturing greater details about substandard conditions or deficiencies found during inspections. This update enabled better prioritization and determination of the most appropriate corrective action for each deficiency to better mitigate public and employee safety, as well as environmental, system reliability, and financial risks.
- Standardizing the maintenance of network protector overhauls to align with station maintenance cycles at four years wherever possible to minimize the need

[3] See Exhibit 1B, Tab 2, Schedule 1

for multiple equipment outages (and significant switching resources), enable bundling of maintenance work, and minimize the need for multiple trips to particular sites.

- Implementing "find and fix" protocols whereby crews that identify minor asset deficiencies also address the deficiencies on site (through actions such as lubricating components, replacing faulted circuit indicators, replacing sump pumps, clearing drains, caulking ducts and roof slabs, and replacing defective locks, hinges or handles) as opposed to only logging the deficiencies for the Corrective Maintenance program.
- Introducing new tools or making greater use of technology such as 3D imaging and modelling of underground structures, Cable Diagnostic Testing, Contact Voltage Scanning, Infrared Thermography, Electronic Maintenance Sheets, and Online Partial Discharge Testing.

The following sections describe and discuss the drivers of each of the segments within the Preventative and Predictive Underground Line Maintenance program.

5. BELOW-GRADE EQUIPMENT MAINTENANCE SEGMENT

5.1 Segment Description

This segment covers the inspection and maintenance of underground vaults and cable chambers and the equipment housed within them. These below-grade structures are constructed out of reinforced or un-reinforced concrete and house transformers, switches, cables, and other electrical distribution equipment. Inspections and maintenance activities are conducted on various types of below-grade structures including network vaults, CRD vaults, underground residential distribution ("URD") vaults, submersible vaults, and cable chamber.

Constructed in the 1950s and 1960s, network vaults are primarily located in the downtown core of Toronto. These vaults are the largest of the below-grade structures, and house interconnected electrical equipment used for the secondary network system that provides reliable supply to large and critical customers in the city's dense downtown core. The four main electrical components within network vaults are: (i) primary switches, which isolate supply to transformers; (ii) transformers; (iii) network protectors, which open when reverse power flow is sensed, preventing the secondary grid from feeding a primary side fault; and (iv) fuse panels, which protect the cables feeding the secondary grid. The transformer and the network protector are referred to as a network unit, an example of which is illustrated in Figure 1. Toronto Hydro has over 1,000 network vaults and 1,800 network units that require inspection and maintenance. The civil structure of network vaults is inspected on a six-month cycle and the electrical assets are inspected annually. Network protectors are also inspected, cleaned, and functionally tested to ensure operability on a four-year cycle for high voltage protectors, and a five-year cycle for low voltage protectors.

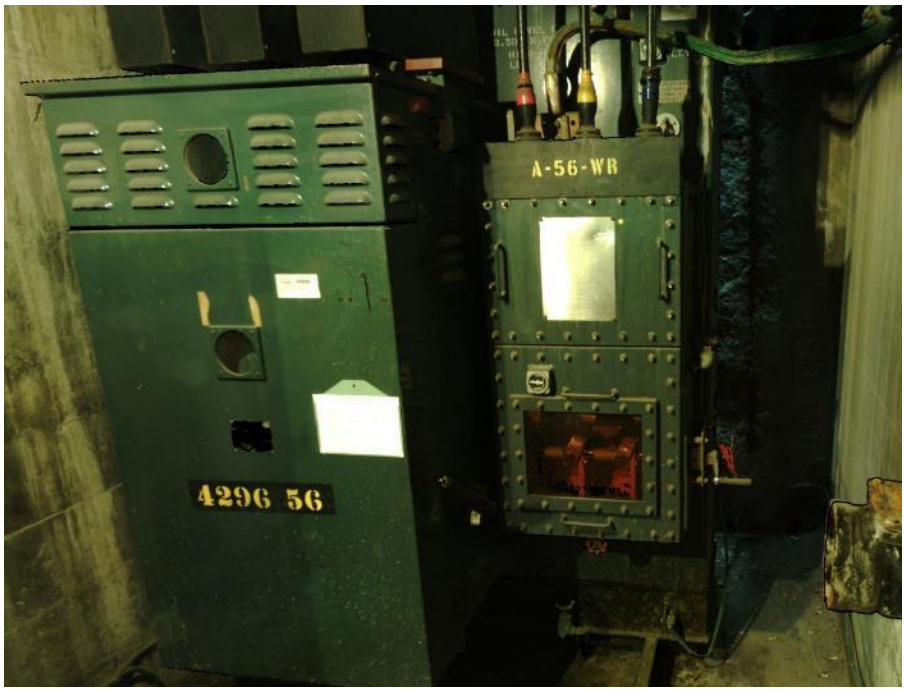


Figure 1: A Network Unit

Toronto Hydro's CRD and URD systems were constructed in the early 1990s and 2000s respectively. CRD vaults were designed to be a cheaper alternative to network vaults because of their simpler design. CRD vaults typically supply small retail, apartment, and commercial office buildings. URD vaults were used for 4 kV to 13.8 kV conversion projects and primarily power small residential or commercial buildings. Toronto Hydro has 690 CRD and URD vaults, which are inspected annually.

Submersible vaults are small civil structures installed on public road allowances, or private properties, and are used for residential distribution. These vaults contain transformers, switches, loop-through primary conductors, and secondary circuits. The vaults are sized to accommodate a transformer and secondary connections only. The over 8,600 submersible transformer vaults in Toronto Hydro's distribution system are inspected on a three-year cycle. Figure 2 illustrates a submersible vault.



Figure 2: Submersible Vault

Cable chambers are civil structures typically installed on public road allowances, and contain primary and secondary cables, cable splices, and in many cases, third party installations such as Toronto Transit Commission ("TTC") power cables, television cables, and phone lines. Located along the route of underground feeder, cable chambers facilitate cable installation in underground ducts. Toronto Hydro has over 11,000 cable chambers that are inspected on a ten-year maintenance cycle.

Below-Grade Equipment Maintenance, regardless of the type of vault or chamber, includes visual inspections of the civil infrastructure and electrical equipment, thermographic scans, partial discharge testing and drainage and sump pump tests.

The inspection cycles in this segment are designed to meet or exceed mandated cycles specified by the OEB's Minimum Inspection Requirements (Appendix C to the Distribution System Code).[4]

The average life of below-grade structures (including network vaults, CRD and URD vaults, and submersible vaults) is 60 years. The roofs of those structures however are expected to last for only 25 years, due to greater exposure to the environment and dynamic loads such as pedestrian and vehicular traffic. The equipment housed within below-grade structures is expected to have an average life between 30 and 45 years depending on the type of equipment.

The ages of Toronto Hydro's vaults vary from the relatively new URD and CRD vaults to the older network vaults in the downtown areas of the city. Approximately 60 percent of all network vaults will reach their expected life within the next five years, and approximately 80 percent of network vault roofs and 60 percent of all cable chamber roofs are already beyond their useful life.

As below-grade structures age, the greatest concern becomes structural strength. Structural deficiencies affecting vaults include degradation of concrete and corrosion of supports such as beams and rebar. Once degradation and corrosion set in, conditions can deteriorate rapidly and in many cases from one season to the next. Of particular concern is the winter season when moisture and water (often containing road salt) enter below-grade structures and, freeze and thaw. Figures 3 and 4 depict structural deficiencies that are common in older vaults.

[4] *Supra* note 1.



Figure 3: Crumbling Vault Roof with Exposed Rebar



Figure 4: Corroded I-Beams

Below-Grade Equipment Maintenance mitigates the risks that deterioration of civil and electrical assets pose, including public and employee safety, financial, environmental, and system reliability risks. Toronto Hydro mitigates these risks by identifying deficiencies in below-grade structures before they cause a failure. As illustrated in Figure 5 below, Toronto Hydro has identified on average over 12,000 deficiencies each year since 2015 and the number of deficiencies continues to rise year-over-year. Of the identified deficiencies, 46 percent on average are found in network vaults, and 28 percent in submersible vaults. These deficiencies are corrected under the Corrective Maintenance and Reactive and Corrective Capital programs.[5]

[5] See Exhibit 4A, Tab 2, Schedule 4 and Exhibit 2B, Section E6.7.

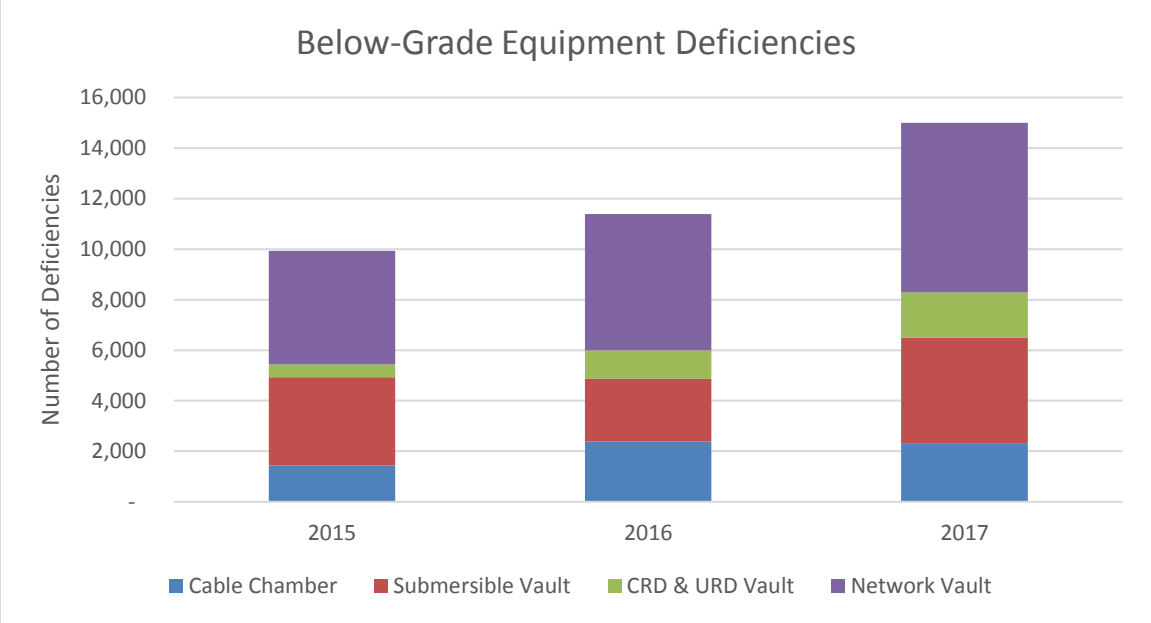


Figure 5: Below-Grade Equipment Deficiencies Identified Between 2015 and 2017

Below-grade structures are typically installed underneath roadways, pedestrian walkways and/or in residential neighbourhoods. Given their locations, it is important to identify and correct structural defects and potential failures proactively.

In addition to the importance of their structural integrity, vaults must be maintained in a relatively clean state, and contain appropriate nomenclature, functional lighting and drainage systems. Oil barrier devices installed in vault drains are also inspected and replaced as required. Vaults are naturally ventilated using grates to ensure uninterrupted ventilation. However, debris can enter over time, and if not addressed, create slip and fall hazards for employees.

From a financial risk perspective, inspections and maintenance mitigate the risk of costly failures. For example, identifying a vault with significant dirt and debris (such as the one

depicted in Figure 6) enables corrective action to be taken and reduces the risk that the debris will catalyse asset corrosion as shown in Figure 7, or potentially result in an arc flash or fire.



Figure 6: Vault Full of Dirt and Debris



Figure 7: Corrosion on Top of a Transformer

When equipment failures occur, emergency response and equipment replacement can result in tens of thousands or even hundreds of thousands of dollars in repair costs. An underground transformer replacement, for example, can approach $100,000, and a structural rebuild of a vault can exceed $100,000 and sometimes approach $1 million. These expenditures can be mitigated through proactive maintenance activities.

In addition to safety and financial risks, below-grade equipment maintenance mitigates environmental risks. For example, inspections enable the early identification of corroded equipment before an oil leak develops, potentially washing into the drainage system, which could result regulatory penalties and environmental restoration costs. Figure 8 below depicts an oil leak within a vault. This type of deficiency is addressed by cleaning activities, as shown in Figure 9.



Figure 8: Oil Leaking from a Transformer Base Inside a vault



Figure 9: Crews Cleaning a Vault that had a Transformer Oil Leak

In addition to the value provided by mitigating the aforementioned safety, financial, and environmental risks, below-grade equipment maintenance provides value to customers by mitigating system reliability risks associated with civil infrastructure or electrical equipment failures. Between 2015 and 2017, the distribution system experienced approximately 100 incidents of below-grade equipment failures annually, which resulted

in excess of 71,000 customer interruptions and 66,000 customer hours of interruption annually.

Between 2015 and 2017, Toronto Hydro experienced on average of three incidents of cable chamber lids blowing off annually. Failures also occur on CRD, URD, and submersible vaults, where Toronto Hydro experienced approximately 48 submersible transformer failures over the 2015-2017 period. These failures can increase public safety risks and system reliability risks (e.g. interruptions to tens and even hundreds of customers).

The risk of equipment failure and the related system reliability risks are not only mitigated through routine visual inspections, but also by thermographic scanning. Thermographic or infrared scanning identifies thermal anomalies in the target equipment, and is an effective predictor of equipment failure. Figure 10 below shows an example of a thermographic photograph of cable splices inside a cable chamber. The deficiency, as evidenced by an 80°C increase in temperature on one of the splices, is not visually evident (see picture on the left), but is easily identified using the infrared image (see picture on the right) so it can be corrected before failure.

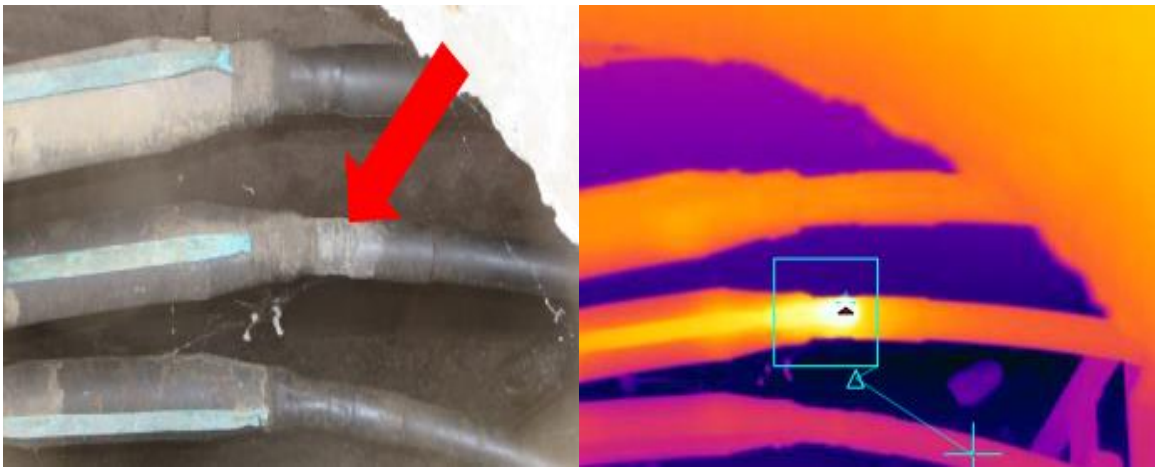


Figure 10: Cables Inside a Cable Chamber (Left) with an Infrared Thermography Image of the Same Cables Denoting a Hot Spot (Right)

5.2 Below-Grade Equipment Maintenance Segment Costs

Toronto Hydro requires approximately $2.8 million each year during the 2020 to 2024 period to execute the functions in this segment. Table 4 provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for this segment.

Table 4: Below-Grade Equipment Maintenance Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Below-Grade Equipment Maintenance	2.2	2.5	2.6	2.5	2.6	2.8

The 2020 proposed test year represents an increase of $0.6 million from the utility's last rebasing year (2015), and $0.2 million from the most recent historical actual year (2017) and bridge year (2019).

5.3 Below-Grade Equipment Maintenance Segment Year-over-Year Variance Analysis

2015-2016 Variance Explanation

Costs in 2016 increased by $0.3 million over 2015 actuals. This is attributed to the increased number of network protectors inspected and maintained (e.g. cleaning and testing of the equipment) after execution challenges experienced in 2015 were addressed. Toronto Hydro managed to increase the number of units maintained from 270 units in 2015 to 382 units in 2016 (an increase of over 40 percent).

2016-2017 Variance Explanation

From 2016 to 2017, expenditures increased by approximately $0.1 million due to an increase in network protectors inspected and maintained from 382 units in 2016 to 399 units in 2017.

2017-2018 Variance Explanation

Costs in 2018 are expected to decrease by $0.1 million, the net product of efficiency gains more than offsetting inflationary pressures.

2018-2019 Variance Explanation

Cost in 2019 are expected to increase by $0.1 million over 2018 as a result of inflationary pressures.

2019-2020 Variance Explanation

Costs in 2020 are expected to increase by $0.2 million over 2019. This is attributed to inflationary pressures and the planned inspection of approximately 300 more submersible transformers based on their three-year cycle. This represents an 11

percent increase over the total number of submersible transformers planned for inspection in 2019.

6. PADMOUNTED EQUIPMENT MAINTENANCE SEGMENT

6.1 Segment Description

Padmounted transformers and switches (collectively referred to as "padmounted equipment"), are metal-clad enclosures with lockable cabinet doors located on top of concrete pads within road allowances or on private properties. These assets are found on the underground distribution system where cables enter underground equipment through the pad. Padmounted transformers (see Figure 11) supply residential areas or commercial buildings, and padmounted switches (see Figure 12) enables the sectionalizing of underground feeders. Toronto Hydro owns approximately 6,600 padmounted transformers and 900 padmounted switches.



Figure 11: Padmounted Transformer



Figure 12: Padmounted SF6-Insulated Switch

Padmounted Equipment Maintenance includes: visual inspection of pads and protective bollards for damage or deterioration; visual inspection of the elevation of the pad in relation to the grade; removal of overgrown vegetation that may be encroaching on the pad; and a visual inspection and verification of equipment labels and safety signs. Visual inspections focus on both the mechanical components (e.g. doors, locks, hinges, handles, latches, and paint) and electrical components (e.g. terminations, bushings, elbow connectors, transformer tank, primary and secondary switches, fuses, disconnects, barriers, fault indicators, relays, oil levels). In addition, maintenance includes thermographic scans and partial discharge testing of electrical connections.

The following additional maintenance activities are carried out for padmounted switches:

- Batteries in SCADA switches are replaced once every three years;
- Gas levels are verified on units that are filled with SF_6 gas;
- Cable duct entries are inspected to ensure they are sealed, and ultrasonic testing is conducted to identify any partial discharge; and
- Air-insulated switches that have significant dirt build-up on their insulators, show evidence of tracking, or have exposed electrical terminations, are scheduled for CO_2 cleaning.

CO_2 cleaning is performed as part of the Corrective Maintenance program[6], to remove dirt and other contaminants from the switch to prevent tracking, which can lead to an arc flash and equipment failure.

[6] Exhibit 4A, Tab 2, Schedule 4

Toronto Hydro carries out the above noted activities on a three-year cycle for padmounted transformers and annually for padmounted switches. Regular maintenance cycles ensure Toronto Hydro is able to comply with applicable inspection requirements[7] and properly maintain padmounted equipment.

In addition to the above maintenance activities on padmounted equipment, since 2015, Toronto Hydro started performing diagnostic testing on all newly installed underground primary cables and cables at high risk locations (locations that exhibited underground faults based on reliability data). The two most common types of cables installed in Toronto Hydro's underground system are Paper Insulated Lead-Covered ("PILC") and Cross-Linked Polyethylene ("XLPE"), as shown in Figure 13.

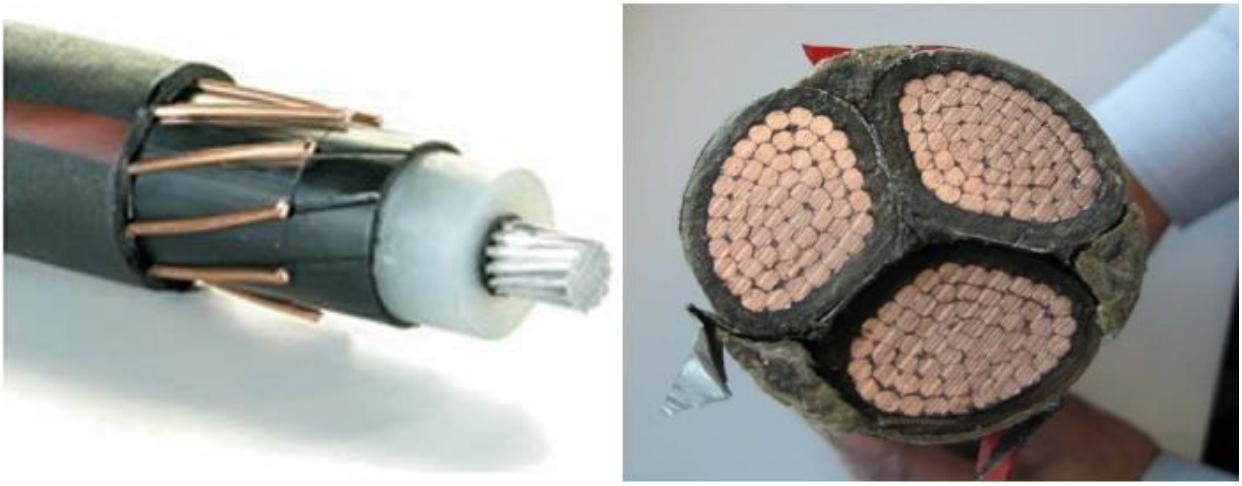


Figure 13: Example of XLPE Cable (Left) and PILC Cable (Right)

Toronto Hydro has approximately 1,200 circuit kilometres of PILC cables, and 4,000 circuit kilometres of XLPE cable.

[7] *Supra* note 1.

Currently, age is used to determine appropriate replacement strategies for these cables. Therefore, cable diagnostic testing provides a more accurate assessment of the condition of underground cables, splices, joints, and terminations. It enables predictive analysis and allows Toronto Hydro planners and engineers to effectively determine the cables that are, or will be, at a high risk of failure.

Cable diagnostic testing is an accepted practice industry-wide and used in numerous other electrical utilities in Canada and the United States. IEEE 400-2012, IEC 60060, IEC 60085, and IEC 60502 are some of the standards that support and provide guidelines for cable testing in the field. Diagnostic testing is expected to support the delivery of more reliable service to customers, and allow more effective use capital allocation by providing a stronger basis for informed underground project planning and prioritization. Toronto Hydro will be focusing its testing on direct buried XLPE cable, which has the highest rate of failure amongst underground cable installations.

The average useful life of padmounted transformers and switches are 35 and 30 years, respectively. The expected life of underground cable varies by type and construction, the expected life of XLPE cable is 25 years for direct buried installations, and 40 years for concrete duct installations. The expected life of PILC cable is 75 years. Approximately 18 percent of padmounted transformers have reached or surpassed their expected service life, while the padmounted switch population is significantly younger (none has exceeded 30 years). Approximately 95 percent of the PILC and XLPE cable populations (which were installed in the beginning in the early 1900s and 1950s, respectively) targeted for cable testing have reached their expected useful lives.

As padmounted transformers, switches, and cables age, the likelihood of failure increases as a result of:

- Current surges, ingress of moisture, dirt, and salt leading to excessive corrosion, mechanical damage, and the degradation of insulating barriers for equipment; and
- Water treeing, electrical treeing, and insulation breakdown for cables.

In addition, cables will experience aging differently depending on the following factors:

- Manufacturing quality;
- Damage during installation and workmanship issues;
- Installation environment (e.g. areas with high moisture levels result in water penetration of the insulation (or water treeing and cause insulation failure),
- Operating temperature and loading (e.g. higher loading and resulting temperatures accelerate the aging process); and
- Ambient temperature of the installation environment (e.g. higher temperatures accelerate the aging process).

As illustrated in Figure 14 below, Toronto Hydro's maintenance activities identified over 4,000 padmounted equipment deficiencies per year on average between 2015 and 2017, and the number of deficiencies rose year-over-year. Identifying and addressing these deficiencies (through the Corrective Maintenance and Reactive and Corrective Capital programs) serve to mitigate a wide variety of safety, environmental and system reliability risks.[8] Mitigating these risks is particularly important given this equipment is predominantly located in residential areas.

[8] *Supra* note 5.

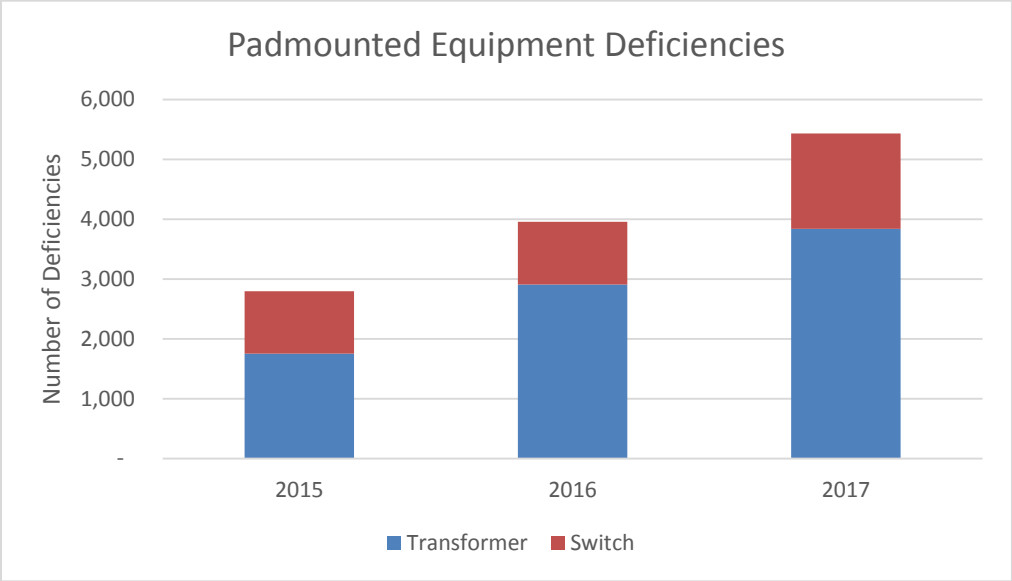


Figure 14: Padmounted Equipment Deficiencies Identified Between 2015 and 2017

An example of risk mitigation is promptly identifying a corroding enclosure as illustrated in Figure 15 below. If not identified and addressed, corrosion (which may also be present on internal components) can give rise to significant environmental, safety and reliability risks. Through maintenance activities, Toronto Hydro also rectifies switches with rusted coil springs (as shown in Figure 16 below), which may break during activation and prevent the switch from opening and closing. If undetected, this condition can result in an arc flash and endanger employees operating the switch.



Figure 15: Padmounted Transformer with Surface Corrosion

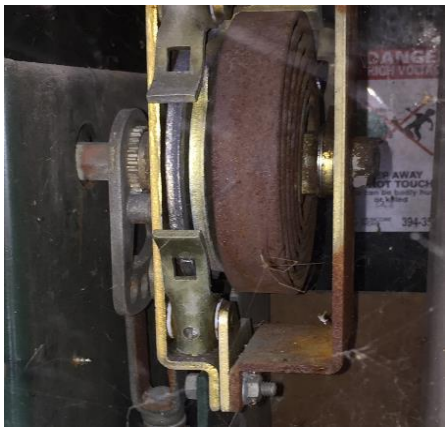


Figure 16: Padmounted Switch with Rusted Coil Spring

Another example of risk mitigation is identifying and addressing excessive vegetation growth near equipment. If unaddressed, overgrown vegetation not only hinders access to the transformer during an emergency, but can also pose a safety and fire risk. Electricity can arc or flashover to nearby vegetation, even without physical contact. Figure 17 below illustrates an example of excessive vegetation growth.



Figure 17: Padmounted Transformer Requiring Vegetation Removal

Transformers also require maintenance where locks, hinges, or warning signage have been vandalized, broken, or removed. If unaddressed, these conditions can lead to serious safety-related incidents if someone inadvertently comes into contact with padmounted equipment.

Padmounted unit failures also impact Toronto Hydro's system reliability, potentially affecting anywhere from several residential and commercial customers (when a transformer fails), to hundreds of customers in the case of a switch failure. When a switch unit fails, multiple feeders can experience a power interruption, as switches often act as a tie point for multiple feeders. Maintenance activities are designed to mitigate the risk of such failures and ensure SCADA switches do not contain failed batteries that render switches inoperable remotely. Between 2015 and 2017, the distribution system experienced over 5,400 customer interruptions and 5,400 customer hours of interruption annually due to failures of padmounted equipment.

Defective primary cables accounted for approximately 64 percent of all customer interruptions and 67 percent of all customer hours of interruption for underground equipment between 2015 and 2017. On average, over the same period, over 160 interruptions a year were related to defective underground primary cables, which resulted in over 138,000 customers interrupted and 144,000 customer hours of interruption annually.

Based on Toronto Hydro's experience, when a cable fails once, repeated failures are very likely. Cables prone to failure not only impact system reliability, but also entail safety and environmental risks. Figures 18 depicts a leaking cable splice.



Figure 18: Oil Leakage from Cable Lead Splice

6.2 Padmounted Equipment Maintenance Segment Costs

Toronto Hydro requires approximately $0.7 million each year during the 2020 to 2024 period to execute the functions in this segment. Table 5 below provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for this segment.

Table 5: Padmounted Equipment Maintenance Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Pad-mounted Equipment Maintenance	0.4	0.4	0.6	0.6	0.5	0.7

The 2020 proposed test year represents an increase of $0.3 million from the utility's last rebasing year (2015), $0.1 million from the most recent historical actual year (2017) and an increase of $0.2 million from the bridge year (2019).

6.3 Padmounted Equipment Maintenance Segment Year-over-Year Variance Analysis

2015-2016 Variance Explanation

Costs in 2016 did not change over 2015 costs, as variances were minor and offsetting.

2016-2017 Variance Explanation

Costs in 2017 increased by $0.2 million over 2016. Increases are attributed to an increase in padmounted transformers due for inspection (from 1,947 units in 2016 to 2,467 in 2017).

2017-2018 Variance Explanation

From 2017 to 2018, costs are not expected to change, with some variances being minor and offsetting.

2018-2019 Variance Explanation

From 2018 to 2019, costs are expected to decrease by $0.1 million. This is attributed to a decrease in the number of padmounted transformers inspected from 2,201 units in 2018 to 1,950 units in 2019.

2019-2020 Variance Explanation

From 2019 to 2020, costs are expected to increase by $0.2 million. This is attributed to the introduction of scheduled diagnostic testing for underground primary cables in 2020 and an increase in the number of padmounted transformers inspected form 1,950 units in 2019 to 2,102 units in 2020.

7. CONTACT VOLTAGE SCANNING SEGMENT

7.1 Segment Description

Most of Toronto Hydro's electrical distribution equipment is exposed to environmental elements, including wide seasonal temperature variations and accumulation of dirt or debris. This may result in the partial or total failures of electrical distribution equipment, and can lead to live wires making contact with nearby structures (poles, bus shelters, concrete housing etc.).

These issues create a public safety hazard known as contact voltage, which has the potential to cause electric shock. A typical example of a contact voltage hazard is an exposed secondary voltage wire in a sidewalk handwell or inside a street lighting pole that energizes the sidewalk or pole. Contact voltage endangers the public, workers, and pets that may come into contact with the energized surface.

The main activity in this segment is the use of a mobile scanning tool (i.e. a voltage detection system) mounted onto a vehicle to scan for contact voltage throughout Toronto Hydro's service area. Data is collected and analyzed to determine the location and nature of the fault. Based on the results, a repair crew is dispatched to further investigate and eliminate the fault.

Scanning is conducted on the entire distribution system on a one year cycle. The mobile scanning tool locates assets with contact voltages greater than 1 volt. Toronto Hydro uses the Third Harmonic ("3HD") as a guideline (as recommended by the IEEE Working Group on "Voltages at Publicly and Privately Accessible Locations") to prioritize corrective action for stray voltages found. If a contact voltage equal to or greater than 10 volts is found, the scanning crew will identify and barricade the relevant area and

remain on site until a follow-up emergency response crew arrives to make permanent repairs. With respect to a contact voltage between 4.5 volts and 10 volts, the voltage supply is disconnected and repairs are made immediately if the contact voltage was found on a distribution asset. Notices are issued to affected parties if the contact voltage was found on customer or third party owned equipment. Contact voltage incidents less than 4.5 volts are reported to Toronto Hydro for review, and notices are issued to affected parties (where the contact voltage was found on customer or third party owned equipment).

Figures 19 below shows the volume of contact voltage incidents (>4.5 volts) identified between 2015 and 2017.

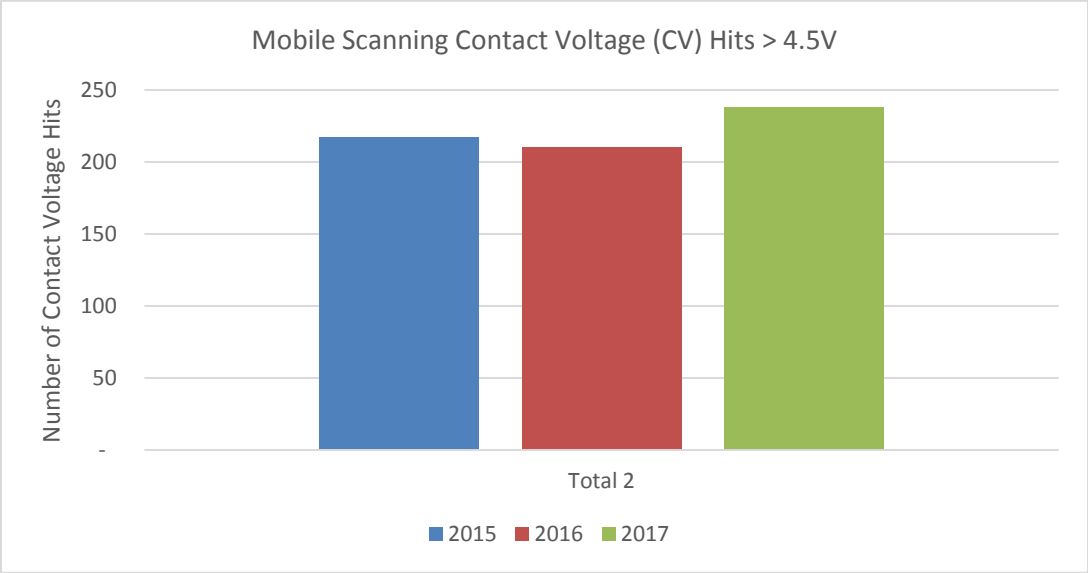


Figure 19: Contact Voltage Hits (>4.5 V) (2015-2017)

Traffic lights, bus shelters, street light poles, and handwells have been the primary sources of contact voltages throughout the City of Toronto in recent years as shown in Figure 20.

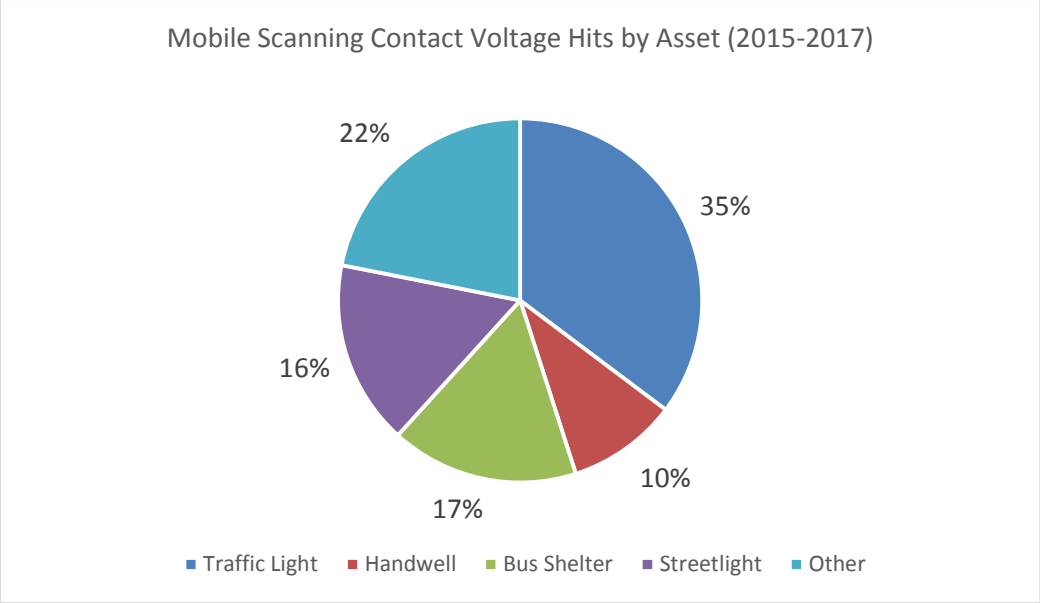


Figure 20: Contact Voltage Hits by Equipment (2015-2017)

In Toronto, most cases of contact voltage occur during the winter months. Underlying causes include aging infrastructure, freezing/thawing conditions, and vibrations at or below grade (which can cause wires to dislodge).

Due to their inherent design deficiencies, handwells also contribute significantly to contact voltage. They were the main driver in multiple stray voltage incidents in late 2009 that prompted Toronto Hydro to declare a Level III Emergency. Through the Reactive and Corrective Capital program, Toronto Hydro spent over $14.3 million in 2010 and over $2.6 million in 2011 on contact voltage remediation work.

Despite the handwell replacement work to date, contact voltage remains a risk for pedestrians and pets in the City of Toronto. By scanning for contact voltages across the city and addressing defective equipment through the Corrective Maintenance or Reactive and Corrective Capital program, the number of contact voltage related safety incidents can be reduced.

7.2 Contact Voltage Segment Costs

Toronto Hydro requires approximately $1.9 million each year during the 2020 to 2024 period to execute the functions in this segment. Table 6 provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for this segment.

Table 6: Contact Voltage Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Contact Voltage	-	-	0.0	1.5	2.0	1.9

The 2020 proposed test year represents an increase of $1.9 million from the utility's last rebasing year (2015), a $1.9 increase from the previous historical actual year (2017) and a decrease of $0.1 million from the bridge year (2019).

7.3 Contact Voltage Segment Year-over-Year Variance Analysis

Toronto Hydro has been carrying out contact voltage work since 2009 as part of a contractual agreement (treated as a capital lease since 2011). The costs associated with the lease will be fully amortized upon its expiration by the end of June 2018. Beginning in July 2018, Toronto Hydro will continue this work as part of this segment.

2018-2019 Variance Explanation

Costs in 2019 are expected to increase by $0.5 million over 2018. This is attributed to costs being fully amortized as of July 2018, therefore, costs in 2019 will be consistent with historical spending levels.

2019-2020 Variance Explanation

Costs in 2020 are expected to decrease by $0.1 million remaining consistent with historical spending levels. This is driven by the net result of inflationary pressures and a slight decrease in the volume of contact voltage work.

PREVENTATIVE AND PREDICTIVE STATION MAINTENANCE

1. OVERVIEW

Table 1: Preventative and Predictive Station Maintenance Program Summary

2015-2017 Average Annual Cost ($M): 5.5	**2020 Cost ($M):** 5.6
Segments: • Customer Location Maintenance • Station Inspections and Auxiliary Equipment Maintenance • Station Switchgear Maintenance • Station Equipment Maintenance	
Outcomes: Reliability, Environment, and Safety	

The Preventative and Predictive Station Maintenance program (the "Program") addresses maintenance activities on Toronto Hydro's: (i) station assets; and (ii) assets located at customer-owned buildings or dedicated areas on customer premises. This Program involves inspection and maintenance tasks typically conducted on a fixed cycle and inspection of equipment for predetermined conditions indicative of a potential failure. The activities comprising the individual segments in this Program are focused on preserving and maximizing an asset's performance over its expected useful life while mitigating a wide variety of system risks.

This Program is also designed to minimize overall costs and account for other factors such as the safety of Toronto Hydro's work crew and the public and ensures compliance with statutory and regulatory requirements.[1] The Station Maintenance program is comprised of the following four segments:

[1] Ontario Energy Board, *Distribution System Code*, (Toronto: Ontario Energy Board, 2017), at Appendix C ["DSC"].

- **Customer Location Maintenance:** A subset of Toronto Hydro's customers is supplied by electrical equipment such as transformers and switches located within customer-owned buildings (vaults) or dedicated areas on customer premises. The activities in this segment are aimed at inspecting and maintaining these equipment.
- **Station Inspections and Auxiliary Equipment Maintenance:** This segment focusses on two sets of work: (i) the periodic inspection of all Transformer Stations ("TS")[2] and Municipal Stations ("MS") and associated equipment; and (ii) maintenance of auxiliary equipment housed or used at stations, including station batteries, air compressors, and testing equipment.
- **Station Switchgear Maintenance:** This segment includes the testing and maintenance of Toronto Hydro owned switchgear units and circuit breakers located at TSs and MSs across the utility's service territory.
- **Station Equipment Maintenance:** This segment oversees and maintains equipment located at all of Toronto Hydro's 36 TS and 149 MS locations, including 235 station transformers.

The proposed 2020 expenditure for this Program is based on historical levels of approximately $5.6 million. By preserving and maximizing the performance of station assets and assets located in customer-owned buildings, this Program contributes to maintaining safety and the environment, and overall system reliability at reasonable costs to Toronto Hydro's customers.

[2] Transformer stations are points of power supply from Hydro One Networks Inc. ("Hydro One") transmission system which step down supply voltages.

2. OUTCOMES AND MEASURES

Table 2: Preventative and Predictive Station Maintenance Program Outcomes and Measures Summary

Reliability	• Contributes to maintaining existing levels of system reliability (SAIDI/SAIFI) by inspecting station assets for deficiencies in compliance with the Ontario Energy Board's ("OEB") Distribution Systems Code ("DSC").
Environment	• Operate in an environmentally responsible manner and reduce the environmental impact of Toronto Hydro's distribution system by proactively identifying station equipment (i.e. transformers) exhibiting signs of oil deficiencies for replacement and minimizing the likelihood of an oil spill into the environment.
Safety	• Contribute to Toronto Hydro's public safety performance (as measured by the OEB distributor scorecard safety metrics), employee safety performance, and compliance with applicable safety requirements (including Ontario Regulation 22/4, the *Ontario Fire Code*[3], and the *Occupational Health and Safety Act*) by proactively performing inspections to reduce the risk of asset failures that may otherwise endanger the general public and Toronto Hydro crews (e.g. failure of a vault transformer, station power transformer or switchgear which can result in a fire).

3. PROGRAM DESCRIPTION

The Preventative and Predictive Station Maintenance program funds maintenance activities in respect of: (i) Toronto Hydro's station assets; and (ii) Toronto Hydro's assets located at customer-owned buildings or dedicated areas on customer premises. This Program involves inspection and maintenance tasks typically conducted on a fixed cycle and inspection of equipment for indications of potential failure. The activities

[3] Ontario Regulation 213/07 made under the *Fire Protection and Prevention Act, 1997,* S.O. 1997, C. 4 ["*Ontario Fire Code*"].

comprising the individual segments in this Program are focused on preserving and maximizing an asset's performance over its expected useful life while mitigating a wide variety of system risks. This Program is also designed to minimize overall costs and account for other factors such as the safety of Toronto Hydro work crews and the public and ensure compliance with statutory and regulatory requirements.

Maintenance activities in this Program include inspections to assess the condition of customer location building vault structures and the equipment housed inside (including transformers, switches and cables), as well as inspections of station facilities and station assets (including power transformers, switchgear and auxiliary station equipment). The Station Maintenance program is comprised of the following four segments:

- **Customer Location Maintenance:** A subset of Toronto Hydro's customers is supplied by electrical equipment such as transformers and switches that are located within customer-owned buildings (vaults) or dedicated areas on customer premises. The activities in this segment are aimed at inspecting and maintaining these equipment.
- **Station Inspections and Auxiliary Equipment Maintenance:** This segment funds two types of work: (i) periodic inspection of all TSs and MSs and the associated equipment; and (ii) maintenance of auxiliary equipment housed or used at stations including station batteries, air compressors, and testing equipment.
- **Station Switchgear Maintenance**: This segment includes the testing and maintenance of Toronto Hydro owned switchgear units and circuit breakers located at TSs and MSs across the utility's service territory.
- **Station Equipment Maintenance** – This segment overseas and maintains equipment located at all of Toronto Hydro's 36 TS and 149 MS locations, including 235 station transformers.

Detailed descriptions of the segments are provided in sections 5-8 below.

4. PROGRAM COSTS

Toronto Hydro requires approximately $5.6 million each year to to support the efficient and effective execution of the segments in the Station Maintenance program. Without this level of funding, Toronto Hydro could be exposed to a number of risks.

- Reduced ability to comply with applicable legislative and regulatory requirements such as the OEB's *Distribution System Code*, *Ontario Fire Code* and *Occupational Health and Safety Act* requirements.
- Increased frequency of station equipment malfunctions or failures due to unidentified deficiencies or lack of maintenance leading to increased:
    - public safety risks from deficiencies at station access points and other security infrastructure
    - environmental risk from oil leaks resulting from unidentified equipment deficiencies such as transformers and cables, and
    - reliability risks from the failure of station backup battery systems operating as required during power interruption

Table 3 provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for each of the Program's segments.

Table 3: Stations Maintenance Program Expenditures by Segment ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Customer Location Maintenance	2.6	1.4	1.2	1.2	1.1	1.1
Station Inspections and Auxiliary Equipment Maintenance	1.0	0.9	1.0	0.9	0.9	1.0
Station Switchgear Maintenance	1.7	2.2	2.6	2.6	2.9	2.6
Station Equipment Maintenance	0.3	0.8	0.7	0.7	0.8	0.9
Total	**5.6**	**5.3**	**5.6**	**5.4**	**5.6**	**5.6**

4.1 Cost Drivers

The 2020 test year cost forecast represents an increase of under $0.1 million on the most recent historical actual year (2017), and a decrease of less than $0.1 million from the bridge year (2019).

Year-over-year expenditures in this Program has been relatively stable. Minor variations have been largely attributed to:

- Management decision in 2016 following the oil testing pilot program for the Customer Location Maintenance Segment (see Customer Location Segment section below for further details).
- Variation in the number of equipment maintained. For example, Toronto Hydro is currently able to maintain more station equipment than in past years due to improvements in managing work execution risks and by coordinating station outages on a four-year maintenance cycle. This has enabled Toronto Hydro work crews to maintain all equipment units at a station at once, without the need for multiple planned outages.

4.2 Cost Control and Productivity Measures

4.2.1 Cost Management

As explained in detail in the general productivity discussions, certain maintenance activities require an outage to create a safe work zone in accordance with Toronto Hydro's Work Protection Code.[4] Initiatives undertaken in 2016 included the development of an annual feeder scheduling program and enhanced work coordination to allow crews to carry out more maintenance work per outage. This initiative improved

[4] Exhibit 1B, Tab 2, Schedule 1

maintenance accomplishments for activities requiring an outage and reduced costs resulting from doing fewer switching and isolations for maintenance.

4.2.2 Productivity

Toronto Hydro has placed significant emphasis on achieving greater output for the same or reduced input in each of the segments within the Preventative and Predictive Station Maintenance program. In an effort to achieve greater productivity, Toronto Hydro has recently undertaken an overhaul and recertification process for all Reliability Centered Maintenance ("RCM") studies and have adjusted maintenance tasks and frequencies that are based on RCM, Condition-Based Maintenance and continuous improvement principles. Examples of these adjustments include:

- Beginning in 2015, Toronto Hydro updated all inspection forms for its distribution equipment to capture greater details about substandard conditions found during inspections (such as the location and extent of an oil leak or corrosion on a transformer). This update allowed Toronto Hydro to improve its processes in prioritizing and determining the appropriate corrective action for each deficiency, so as to more effectively mitigate public and employee safety, environmental, system reliability, and financial risks.
- Implementing "find and fix" protocols whereby crews that identify minor asset deficiencies address the deficiencies by replacing them onsite as opposed to only logging the deficiencies for the Corrective Maintenance program.[5]
- Issuing longer-term inspection maintenance contracts to third party service providers help keep unit costs stable and increases service quality levels over time as retaining the same service provider increases service provider

[5] See Exhibit 4A, Tab 2, Schedule 4.

experience and familiarity with identifying deficiencies on Toronto Hydro's distribution system.

- Introducing new tools or making greater use of technology such as Infrared Thermography, Electronic Maintenance Sheets, Furan Sampling, Double Testing, Dissolved Gas Testing, Online Partial Discharge Testing, and Enhanced Battery Testing.

The following sections discuss the drivers of each of the segments that make up the Preventative and Predictive Station Maintenance program.

5. CUSTOMER LOCATION MAINTENANCE SEGMENT

5.1 Segment Description

A subset of Toronto Hydro's customers are supplied by electrical equipment such as transformers and switches that are located within customer-owned buildings (vaults) or dedicated areas on customer premises. These sites are found in or adjacent to industrial or commercial buildings, hospitals, schools, apartments, and condominiums, and are secured to prevent unauthorized access to energized equipment.

The equipment contained in these sites is typically owned by Toronto Hydro and requires regular inspection and maintenance. Where the equipment is not owned by Toronto Hydro, it is nevertheless necessary to conduct switching operations at the location. As a result, on-site inspections are required to ensure ongoing operability and safety. There are approximately 5,380 customer-owned locations where Toronto Hydro must maintain or inspect equipment.

Of the 5,380 customer-owned locations, approximately 4,645 contain Toronto Hydro-owned equipment, including over 12,000 transformers. For maintenance purposes, these 5,380 locations are divided into two subsets based on customer load requirements: (i) Customer Building Vaults, which possess transformation capacity less than 2,000 kVA; and (ii) Customer Substations, which have transformation capacity of 2,000 kVA or above.

Toronto Hydro maintains Customer Building Vaults on a three-year cycle, in compliance with the OEB's Minimum Inspection Requirements (Appendix C of the DSC). Maintenance of Customer Building Vaults includes a visual inspection of the vault and equipment, thermographic scans and partial discharge testing of all electrical equipment and connections to detect thermal anomalies and corona, and general cleaning to reduce contamination build-up and electrical tracking. Deficiencies that are noted during inspections are either addressed immediately or subsequently addressed through corrective maintenance. The condition of the customer's civil structure is also assessed and any identified deficiencies are communicated to the customer for remediation.

Customer Substations are inspected annually and maintained every four years. Inspections ensure that ventilation, access, and drainage systems are operating as required and that equipment is not leaking, defective, or corroded. Maintenance includes visual inspections, thermographic scans, functional tests, oil testing, and general cleaning. Toronto Hydro maintains a total of 411 Customer Substations.

Through Customer Location Maintenance, Toronto Hydro identifies deficiencies in electrical equipment and verifies the integrity and security of the structures that house

the equipment at Customer Building Vaults and Customer Substations. Identifying and addressing deficiencies minimize the likelihood of equipment failure, mitigating risks relating to public and employee safety, the environmental, financial impact, and system reliability. As illustrated in Figure 1 below, since 2015, Toronto Hydro has identified on average over 7,000 deficiencies at Customer Locations each year. These deficiencies are addressed as part of the Corrective Maintenance and Reactive Capital programs.

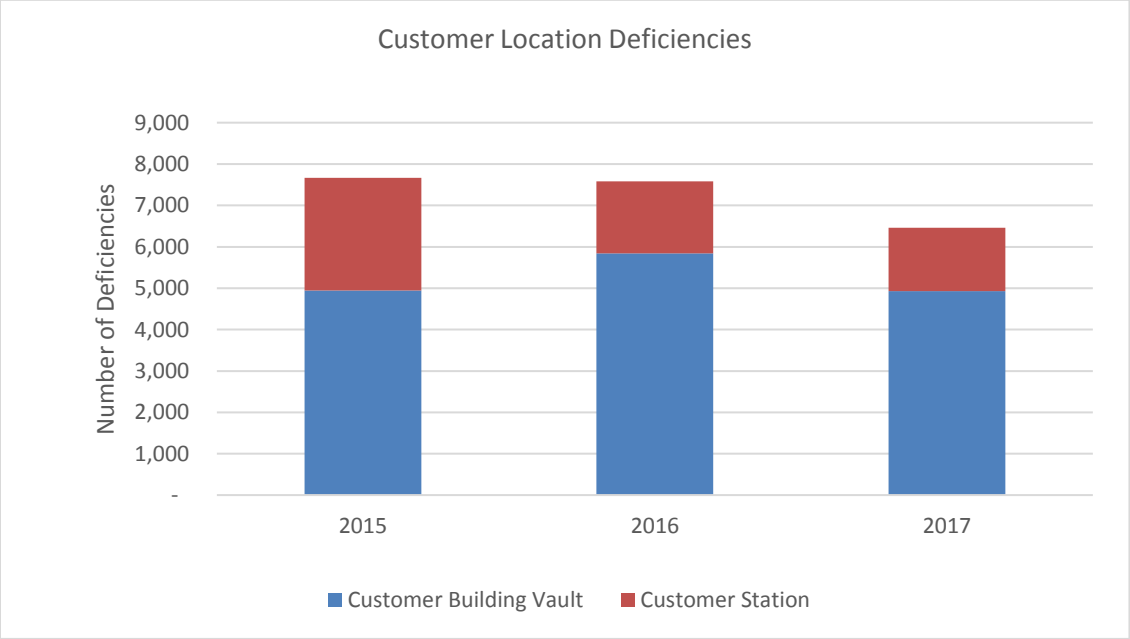


Figure 1: Customer Location Deficiencies Identified Between 2015 and 2017

Specific examples of deficiencies identified and their associated risks include:

- Dirty vaults that require cleaning to reduce the risks of flashover caused by contamination build-up and premature equipment failure, which can result in injury to employees, customers and members of the public that are near these vaults, as well as property damage;

- Corrosion of equipment, locks and doors (as illustrated in Figure 2 below), which can result in unauthorized entry and pose a safety risk if individuals make contact with energized equipment;
- Oil leaking from cables or transformers (as illustrated in Figure 3 below), which if not addressed in a timely manner, can result in oil entering the drainage system and potentially spilling into environmentally sensitive areas;
- "Hot spots" on equipment identified using a thermographic cameras before excessively high temperatures cause burnt insulation and electrical faults, which pose serious safety risks (e.g. vault fire); and
- Degradation of a transformer's insulating oil properties due to the concentrations of certain gases (e.g. hydrogen, carbon monoxide, methane, and acetylene), which can be identified via transformer oil testing as indications of an elevated risk of transformer failure.

Beyond inspections of the electrical equipment, Customer Location Maintenance activities include inspections of the civil infrastructure housing the equipment. Such civil infrastructure is owned by Toronto Hydro's customers, who are responsible for repairs. Nevertheless, it is prudent for Toronto Hydro to continue inspections and issue follow-up Customer Action Forms given the risk that customers may fail to carry out necessary repairs in a timely manner. It is not uncommon for structural elements to be in poor condition to the point that walls (as illustrated in Figure 4 below) and roofs are at risk of collapsing on Toronto Hydro's equipment.

In addition, improperly maintained landscaping and vegetation at or near outdoor customer locations can pose safety risks (e.g. vegetation becoming energized and possibly catching fire) and prevent Toronto Hydro crews from entering the sites to carry

out required work (as illustrated in Figure 5 below). Such serious deficiencies are communicated to customers so that they can be addressed.



Figure 2: Rusted Door



Figure 3: Transformer Leaking Oil



Figure 4: Cracked Walls



Figure 5: Vegetation Overgrowth

By preventing equipment failures and non-electrical deficiencies, Customer Location Maintenance activities also prevent power interruptions. A failure at a Customer Building Vault will typically impact one or more customers for a prolonged period of time depending on the type of failure. Failures at Customer Substations have a greater impact as more than 2,000 kVA of load may be interrupted for similar durations.

Through premises and equipment safety inspections, Toronto Hydro also manages the risk of equipment failure at Customer Locations involving all customer-owned civil and electrical equipment. Even though the assets are not owned by Toronto Hydro, an equipment failure at such location will still have an impact on system reliability, especially if the customer's protection equipment is not coordinated with the distribution system's protection devices or if the customer's equipment fails to operate.

Toronto Hydro crews may also be required to perform switching operations at these locations in contingency situations to protect the customer's equipment and provide an alternate source of power. Manual switching can pose significant risks to employees and as a result, it is important that Customer Locations remain safe and accessible for purposes of field response by utility crews during emergency situations. Toronto Hydro inspects over 770 of these locations annually.

5.2 Customer Location Maintenance Segment Costs

Toronto Hydro requires approximately $1.1 million each year during the 2020 to 2024 period to execute the functions in this segment. Table 4 provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for this segment.

Table 4: Customer Location Maintenance Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Customer Location Maintenance	2.6	1.4	1.2	1.2	1.1	1.1

The 2020 test year costs associated with this segment are projected to be $1.1 million which represents a decrease of $1.5 million from the utility's last rebasing year (2015), $0.1 million reduction from the most recent historical actual year (2017) and no change relative to the bridge year (2019).

5.3 Customer Location Maintenance Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

In 2015, Toronto Hydro conducted an oil testing pilot to obtain more data about the health of transformers and improve asset renewal plans for customer owned locations. The results of the pilot showed it is more efficient to target only customer locations without load break switches, and with loads greater than or equal to 2,000 kVA. This approach minimizes reliability impacts, as an outage is required to safely take an oil sample, and in many instances, it would be costly or not possible to isolate a location. This change accounts for most of the $1.2 million cost reduction in 2016.

2016 – 2017 Variance Explanation

The reduction of $0.2 million expenditures between 2016 and 2017 is primarily attributable to an approximately 13 percent reduction in the number of units requiring inspection in 2017.

2017 – 2018 Variance Explanation

There are no variances between 2017 and 2018 expenditures.

2018 – 2019 Variance Explanation

Variances in expenditures from 2018 to 2019 are primarily attributable to variations in the number of units inspected and maintained annually.

2019 – 2020 Variance Explanation

There is no material variance forecast for this period. Toronto Hydro's planned 2020 expenditures align in general with historical expenditures and equal those of 2019.

6. STATION INSPECTIONS AND AUXILIARY EQUIPMENT MAINTENANCE SEGMENT

6.1 Segment Description

Toronto Hydro owns equipment at 36 TSs and 149 MSs throughout the City of Toronto. Equipment is located either inside buildings or outside in fenced yards. The Station Inspections and Auxiliary Equipment Maintenance segment funds the following two categories of work:

- Periodic inspections of all TSs and MSs and the associated equipment; and
- Maintenance of auxiliary equipment housed or used at stations including station batteries, air compressors, and testing equipment.

Figures 6 and 7 show a typical MS found in a residential neighbourhood, and Figure 8 shows a TS yard.



Figure 6: Residential Area MS (front view)



Figure 7: Residential Area MS (rear view)



Figure 8: The Station Yard at Cavanagh TS

Periodic inspections of stations are conducted either monthly or semi-annually. During semi-annual inspections, crews look for any signs of transformer oil leaks, confirm transformer cooling fan operation, check battery electrolyte levels, verify the condition of equipment alarms, and look for any visual signs of equipment deterioration or imminent failure. In addition, adjustments to heating and ventilation systems are performed during the spring and fall to ensure assets are protected from damage due to temperature (e.g. turning on or turning off control cabinet heaters) and in the fall, oil samples are collected from power transformers for testing. During monthly inspections,

crews also look for deficiencies in station fences, gates, doors, building walls, roofs, danger signs, and lighting.

In addition to inspections, maintenance of station auxiliary equipment is performed. This equipment provides a support or service function and can be described as being peripheral to station power and protection and control equipment. Station auxiliary equipment includes: (i) Battery Banks; (ii) Station Protection Systems; (iii) Station Compressed Air Systems; and (iv) other miscellaneous station apparatus, including station buses, specialized environmental protection systems, and testing equipment. This equipment is described as follows:

- **Battery Banks:** The protection and control equipment in stations is powered by a DC supply from battery banks that are similar to those depicted in Figure 9 below, and are charged by station rectifiers (chargers). Stations typically have lead-acid or nickel cadmium batteries. Specialized inspections and tests on these battery banks are conducted every six months for MS and monthly for TS and include cleaning, measurements of specific gravity, voltage, electrolyte level, and temperature, inspection for corrosion on terminals, connections, battery racks and cabinets, and load cycle testing.
- **Station Protection Systems:** TS and MS stations are equipped with alarms to monitor and ensure proper functioning of various assets in stations including buildings, batteries, compressors, switchgear, and service transformers. Maintenance includes assessing the physical and mechanical conditions of the alarms and coordinating with the control room to perform functional tests. This work is carried out on a one year cycle.
- **Compressed Air Systems:** These systems are required to supply dry compressed air for the operation of air blast circuit breakers as depicted in Figure 10. Air

blast circuit breakers use compressed air to open their arcing contacts, and to extinguish the electrical arc that forms during breaker operation. There are approximately 20 air compressors used in Toronto Hydro's 4.16 kV and 13.8 kV stations. These assets are inspected and maintained twice a year.



Figure 9: Station Battery System at George and Duke MS



Figure 10: Air Compressor System

Station Inspections and Auxiliary Equipment Maintenance are undertaken to address two broad sets of needs: (i) the need to mitigate the risks posed by deficient or failed equipment and components, including public and employee safety, environmental, financial, and system reliability risks; and (ii) the need to ensure compliance with applicable regulatory requirements such as the *Ontario Fire Code* and the *Occupational Health and Safety Act*.

6.1.1 Station Inspections

During 2015-2017, Station Inspections identified over 1,400 deficiencies on average annually. Identified deficiencies were addressed through the Corrective Maintenance

program,[6] or equipment replacement programs as discussed in the Stations Renewal program.[7]

From a safety perspective, deficiencies at stations within urban and residential settings can pose significant risks. For example, deficiencies at access points such as gates, doors, fences, signs, and other security infrastructure can result in a station becoming accessible to the general public. Such deficiencies can arise due to structural degradation or other common causes including vandalism and wildlife, and can contribute to risk of injury to the general public. Frequent inspections are critical to maintaining secure station sites in a densely populated environment.

From an employee safety perspective, inspections identify deficiencies with station safety features such as alarms, emergency lightning, burn kits, eyewash stations, first aid kits, and fire extinguishers. This equipment is critical in protecting employees during emergency situations such as station fires. Inspections also enable Toronto Hydro to remain compliant with the Ontario *Fire Protection and Prevention Act* which requires, among others, fire extinguishers to be inspected monthly.[8]

From an environmental perspective, inspections allow for the identification of equipment that is leaking oil (an example of a leaking transformer is depicted in Figure 11). Leaking transformers or cables pose environmental risks, where oil can enter waterways, ground water and potentially sensitive ecological areas. Frequent inspections can identify signs of oil leaks, which can indicate assets that are at risk of

[6] *Supra* note 5.
[7] Exhibit 2B, Section E6.6
[8] Ontario *Fire Protection and Prevention Act, 1997*, S.O. 1997, c. 4

failing. Based on such findings, Toronto Hydro can address the leak and prevent equipment failures.



Figure 11: Oil Leak on a Station Transformer

Inspections also identify vegetation concerns and damage to grading and landscaping as depicted in Figure 12. Failure to address these deficiencies can result in customer complaints, damage to stations (i.e. due to poor drainage), and safety risks for employees including accessibility risks from vegetation overgrowth and slip-and-fall risks from poor landscaping.



Figure 12: Damaged Landscaping

In addition to identifying deficiencies to mitigate safety and environmental risks, Station Inspection work involves the oil sampling and testing of power transformers in order to mitigate financial and system reliability risks. Industry-standard oil tests are performed to identify poor conditions and abnormalities that cannot otherwise be detected without a complete disassembly of the transformer. Such tests include: (i) Dissolved Gas Analysis; (ii) Furan analysis; and (iii) tests for acid levels, moisture levels, and other oil quality attributes.

Oil testing is particularly valuable because it allows Toronto Hydro to identify transformers that may be at a high risk of failure and to schedule corrective action such as oil reclamation or replacement before a catastrophic event occurs. Consequences of such an event can include oil spills, fire, emergency response, substantial equipment replacement costs, and a prolonged power interruption.

6.1.2 Auxiliary Equipment Maintenance

As discussed above, Auxiliary Equipment Maintenance is performed to mitigate a variety of risks. Maintenance of station backup battery systems reduces the risk that a station's

protection and control system will not operate as required during a power interruption. During such an event, the system's DC power source allows all station protection and control equipment to function and communicate normally. Loss of the backup power supply can have consequences ranging from loss of communication and remote operation capability, to failure of a protecting device to function posing both safety and system reliability risks.

Maintenance of protection systems ensures the operability and dependability of alarms at station facilities so that Toronto Hydro can be notified and proactively respond to defective equipment before they lead to failure, which in turn can pose safety, environmental, and system reliability risks.

Maintenance of compressed air systems are designed to ensure that air blast circuit breakers are available to operate as designed when required. Without a certain pressure and volume of compressed air available, the circuit breakers will not close or trip. Failure to operate during fault conditions will expose employees to the risk of severe burns from arc flashes. When this occurs, protection devices upstream of the circuit breaker would need to operate resulting in outages to a far greater number of customers than would otherwise occur. For example, the failure of an air blast circuit breaker to clear a fault in July 2012 at George MS and Duke MS resulted in interruptions to 6,500 customers for nearly eight hours. Replacement costs for an air blast circuit breaker can range from $60,000 to $200,000 depending on factors including breaker type, voltage rating, and location. Maintenance tasks that mitigate the risks described above include inspections of all components for deficiencies, cleaning of filters, replacement of pressure relief valves and pump-up time testing which is used to determine their correct operation.

6.2 Station Inspections & Auxiliary Equipment Segment Costs

Toronto Hydro requires approximately $1.0 million each year during the 2020 to 2024 period to execute the functions in this segment. Table 5 below provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for this segment.

Table 5: Station Inspections & Auxiliary Equipment Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Station Inspections and Auxiliary Equipment Maintenance	1.0	0.9	1.0	0.9	0.9	1.0

The test year (2020) costs associated with this segment are projected to be $1.0 million which are equal to the utility's last rebasing year (2015), and the most recent historical actual year costs (2017), and are $0.1 million lower than the bridge year (2019).

6.3 Station Inspections & Auxiliary Equipment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

Expenditures under this segment have remained relatively stable during 2015 and 2016, with no material variances. Toronto Hydro anticipates this trend will continue into 2020.

2016 – 2017 Variance Explanation

Expenditures under this segment have remained relatively stable during 2016 and 2017, with no material variances. Toronto Hydro anticipates this trend will continue into 2020.

2017 – 2018 Variance Explanation

There is no material variance forecast for this period.

2018 – 2019 Variance Explanation

There is no material variance forecast for this period.

2019 – 2020 Variance Explanation

There is no material variance forecast for this period. Planned expenditure for 2020 is $1.0 million and is consistent with historical expenditures.

7. STATION SWITCHGEAR MAINTENANCE SEGMENT

7.1 Segment Description

Station Switchgear Maintenance includes testing and maintenance of Toronto Hydro's switchgear units and circuit breakers that are located at TSs and MSs across the utility's service territory. A switchgear unit is a combination of switching devices and their associated controls, measuring, protection, and regulating equipment. Assemblies of these devices and equipment, with associated interconnections, accessories, enclosures and supporting structures, are found at Toronto Hydro's distribution stations. There are approximately 250 switchgears installed within the distribution system and they collectively contain over 1,800 circuit breakers.

Switchgears and circuit breakers must operate quickly and reliably when an electrical interference or equipment failure causes a fault on the distribution system. Switchgear maintenance activities mitigate the risk that the equipment will malfunction during a contingency, failing to protect the downstream feeders and equipment and possibly leading to a safety incident involving the public or Toronto Hydro employees. Maintenance is particularly critical for the fleet of switchgear owned by Toronto Hydro, as many circuit breakers have surpassed their expected lives and rely on obsolete technology such as brick and mortar enclosures, non-arc resistant interrupting devices

(e.g. air blast or air magnetic circuit breakers), and electromechanical relays with no supervisory feedback or control.

Toronto Hydro owns and maintains two types of switchgears:

- The exposed bus type, used mainly for outdoor installations; and
- The enclosed type, further subdivided into metal clad, metal-enclosed, and brick structures, which are mainly used for indoor installations.

Examples of switchgear are illustrated in Figure 13 below.



Figure 13: (Left) Outdoor Enclosure Housing Metal clad Switchgear. (Right) Indoor Metal clad Switchgear

Station Switchgear Maintenance includes three sets of activities.

1) **Circuit Breaker Maintenance**: Circuit breakers (Figure 14) use various mediums to extinguish the electric arc that forms during an interruption operation. Toronto Hydro owns the following types of circuit breakers: air magnetic, air blast, Sulphur Hexafluoride (SF_6), oil, and vacuum units, which are maintained every four years. Circuit breaker maintenance work includes a visual inspection

and verification of the integrity of the mechanical and electrical components in circuit breakers, functional testing of the unit, and replacement of worn components.



Figure 14: (Left) KSO Oil Circuit Breaker, (Right) Vacuum Circuit Breaker

2) **Protection & Control ("P&C") Maintenance**: P&C equipment maintenance includes inspection and testing of sensing devices and relays that monitor the magnitude and flow of electrical power. In the event of a fault on the distribution system, the protective relays detect the fault and trigger interrupting devices, such as circuit breakers, to operate and isolate the circuit, protecting the system from further damage. A protective relay system has to be periodically tested and verified to ensure that the system remains protected, the settings are appropriate for the current state and loads, and a failure event does

not result in cascading outage events. More specifically, maintenance activities involve verifying the AC voltage and current to the fault detecting relay, testing the operating characteristics of the relay, validating relay settings, verifying the operation of auxiliary relays, and verifying output functions such as alarms and annunciations. This equipment is maintained every four years.

3) **Thermography and Ultrasonic Testing**: A thermographic scan of a switchgear unit provides Toronto Hydro with an advanced warning of developing electrical faults by identifying thermal anomalies on the equipment. Ultrasonic testing identifies high-frequency noise associated with surface tracking and corona, which are also indicators of impending failure. All load break switches, disconnect switches, and bolted electrical connections undergo thermographic scans and ultrasonic tests every four years.

Maintenance activities are designed to reduce the likelihood of switchgear or breaker failure and to mitigate the associated risks. One way that this is accomplished is by identifying deficiencies that can lead to common switchgear failure modes. These deficiencies include worn components, loose connections, degradation, corrosion, and contamination. Examples of these are shown in Figures 15 and 16, which illustrate a corroded switchgear enclosure and pest infestation inside an outdoor switchgear.



Figure 15: Rusted Switchgear Enclosure



Figure 16: Pests Inside Outdoor Switchgear

Figure 17 below shows an example of an internal arc fault, which can be destructive and pose a risk of injury because of the energy levels reached within the confined compartment.



Figure 17: Impact of Internal Arc Fault in a Switchgear

As illustrated in Figure 18 below, Toronto Hydro has identified on average 700 deficiencies on switchgear assets each year since 2015.

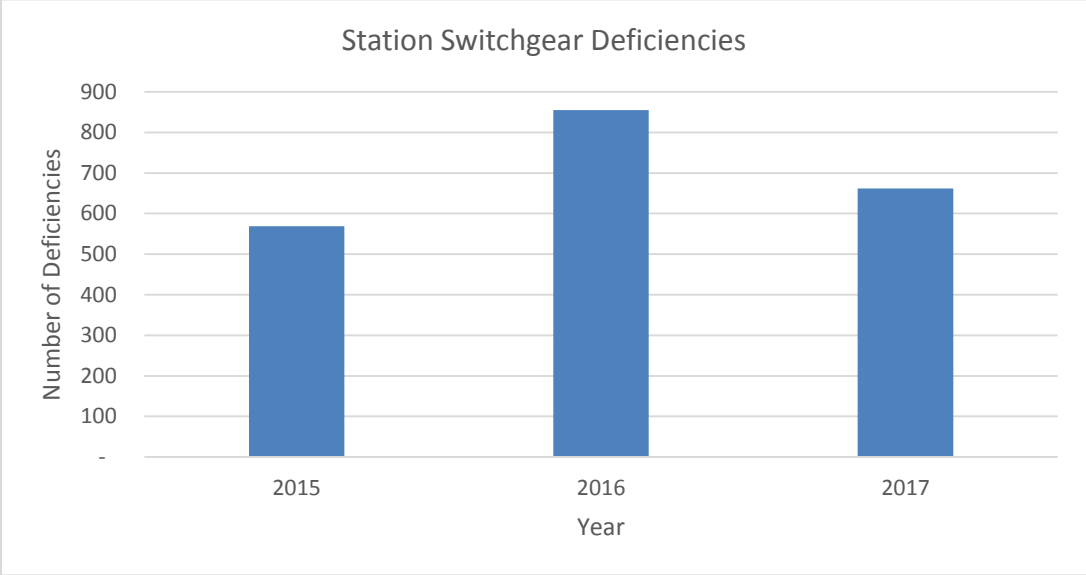


Figure 18: Switchgear Deficiencies Identified Between 2015 and 2017

The likelihood of deficiencies existing and leading to a failure increases as switchgear and breakers age and approach their end-of-life. The average expected lives of switchgear enclosures and circuit breakers are 50 and 45 years, respectively.

Approximately 28 percent of Toronto Hydro's switchgear and outdoor TS circuit breakers have surpassed their expected useful life. Of particular concern are the high numbers of air magnetic, air blast, and oil breakers that have exceeded their expected life. The likelihood of failure increases for these assets due to wear and tear caused by high occurrences of operations, contamination, loose connections, and corrosion.

Toronto Hydro's Asset Condition Assessment[9] indicates that over 40 percent of the population of switchgear have moderate to material deterioration and are at an increased likelihood of failure. A failure of one of these assets has the potential to lead to a catastrophic fire, release harmful contaminants into the environment (e.g. oil spills, combustion by-products), and safety risks in the form of debris or arc-flashes that can cause injury and property damage. The replacement of worn and corroded components, the alignment of switch blades, the lubrication of switches, and the removal of dirt and other contamination during maintenance mitigates the risk of failures and associated employee safety, financial, environmental, and system reliability risks that are associated with switchgear failure.

An example of a catastrophic station failure occurred at Station J in East York in 2009. The station was over 50 years old at the time, and a fire broke out following a switchgear failure and subsequent fault. The switchgear had surpassed its expected life and the fault resulted in the destruction of Station J. Maintenance, including thermographic scans and ultrasonic tests, serves to prevent similar occurrences by detecting defective components (e.g. closing coil, pallet switch, closing spring, and relay systems) and incipient faults in loose connections, contacts, and insulators that could develop into a catastrophic failure from the failure of a protection and control asset to operate and clear a fault.

The financial consequences of failures of switchgear and circuit breakers are also significant. The replacement of a circuit breaker can exceed $100,000 and approach $1 million depending on various factors including breaker type, voltage rating, and location.

[9] Exhibit 2B, Sections D1 & D3

The total replacement cost of a transformer station switchgear, including the costs of the enclosure and circuit breakers, is approximately $6 million. These costs significantly exceed the annual cost of switchgear maintenance activities. As such, the prevention of even one catastrophic failure over a multi-year period will offset the planned maintenance expenditures during the period.

In addition to mitigating safety, environmental, and financial risks, Switchgear Maintenance provides customer value by mitigating system reliability risks. A failure of station switchgear or a circuit breaker can result in a large number of customer interruptions and long interruption durations. During the 2015-2017 period, Toronto Hydro experienced seven incidents on average annually that were related to switchgear failures, which resulted in over 6,000 customers impacted and 7,000 customer hours of interruption annually on average.

Not all switchgear failures are catastrophic in nature and some are as small as the failure of a breaker to open and close. Nevertheless, these failures impact system reliability, as protection systems are designed to coordinate with each other, with the intent of isolating the fault or failure to the smallest possible area within the distribution system. If a protection device were to fail to function, a protection device located further upstream would operate. Such a scenario results in outages impacting greater numbers of customers and system assets as well as increasing the safety risks to employees and members of the public in proximity to the stations. Failure of protection devices on the distribution system could also result in the fault migrating to the transmission system, leading to even larger outages. Maintenance tasks are designed to ensure protection devices operate as designed. During maintenance, crews verify and correct improper settings onsite, including: (i) verifying that the voltage and current settings on the fault

detecting relays are correct for the system element being protected; (ii) verifying that the operating characteristics of the fault detecting relays are correct for the applied setting; and (3iii) verifying that the operation of auxiliary relays and output functions, such as circuit breaker tripping and annunciation, are correct.

7.2 Station Switchgear Maintenance Segment Costs

Toronto Hydro requires approximately $2.6 million each year during the 2020 to 2024 period to execute the functions in this segment. Table 6 below provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for this segment.

Table 6: Station Switchgear Maintenance Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Station Switchgear Maintenance	1.7	2.2	2.6	2.6	2.9	2.6

The test year (2020) costs associated with this segment are projected to be $2.6 million which represents an increase of $0.9 million from the utility's last rebasing year (2015), no change from the most recent historical actual year (2017), and a reduction of $0.3 million from the bridge year (2019).

7.3 Station Switchgear Maintenance Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

The 2015-2016 variance is attributed to the optimization of station maintenance cycles. Station outages are currently coordinated on a four-year cycle; whereas in the past, certain equipment at stations were maintained on varying cycles such as every three years and eight years. This optimization has allowed Toronto Hydro work crews to maintain all station equipment units at once, without the need for multiple planned

outages. This change resulted in a $0.5 million increase in expenditures from 2015 to 2016 to allow Toronto Hydro to maintain more breakers (an increase of 27 percent in 2017 from 2015 levels). Toronto Hydro maintained 304 circuit breakers in 2015, as compared to 378 in 2016.

2016 – 2017 Variance Explanation

Variances in expenditures from 2016 to 2017 are primarily attributable to variations in the number of units inspected and maintained annually. For example, Toronto Hydro maintained 378 circuit breakers in 2016, as compared to 385 in 2017.

2017 – 2018 Variance Explanation

There is no material variance forecast for this period.

2018 – 2019 Variance Explanation

From 2018-2019, expenditures are expected to increase slightly as Toronto Hydro continues to align breaker maintenance with prescribed maintenance cycles by increasing the number of circuit breakers maintained. The first maintenance cycle for breakers will be complete in 2019 and costs are expected to stabilize in 2020 at $2.6 million.

2019 – 2020 Variance Explanation

Planned expenditures for 2020 are consistent with historical (2017-2018) spending levels.

8. STATION EQUIPMENT MAINTENANCE SEGMENT

8.1 Segment Description

The Station Equipment Maintenance segment includes equipment that is located at all of Toronto Hydro's 36 TS and 149 MS locations, including 235 station power transformers. TSs are points of power supply from the Hydro One transmission system to Toronto Hydro's distribution system. These stations step down supply voltages from 230 kV or 115 kV to 27.6 kV or 13.8 kV, utilizing transformers that, with one exception, are owned by Hydro One. MSs are stations within Toronto Hydro's distribution system that are supplied by Toronto Hydro feeders, at 27.6 kV or 13.8 kV, and step down voltage to 13.8 kV or 4.16 kV. Toronto Hydro owns and maintains all equipment at MSs, including the transformers, and a large number of equipment at TSs. At TSs, Toronto Hydro does not own the power transformers.

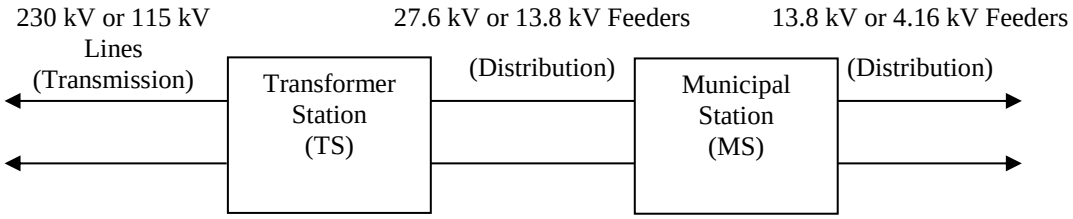


Figure 19: System Configuration

Figures 20 and 21 as follows depict examples of station power transformers at Toronto Hydro's stations.



Figure 20: Power Transformer at Cavanagh TS



Figure 21: Power Transformer at Neilson Dr. MS

Toronto Hydro's station equipment is aging, and a significant proportion has exceeded their expected useful life. The best indicator in this regard is the age demographics for power transformers, which are essential components of every station. Approximately two-thirds of Toronto Hydro's transformers were installed in the 1950s through the 1970s. The average useful life of these units is 45 years and over half of the entire population is beyond their useful life. In addition, Toronto Hydro's Asset Condition Assessment tool shows that currently over a third of all power transformers have moderate to material deterioration and are at an increased likelihood of failure.

As transformers age, maintenance becomes increasingly important to ensure that the core and windings continue to function within acceptable parameters, insulating properties do not deteriorate excessively, and that auxiliary equipment such as gauges and alarms are functioning properly to detect and provide early warnings of problems such as oil leakage, gases in the oil, and overheating.

Maintenance activities are focused on inspecting, testing, and cleaning assets, including power transformers and their auxiliary equipment, current transformers, potential transformers, station service transformers, DC batteries, chargers, disconnect switches, load break switches, fuses, interconnect cables, and remote terminal units. Failure of such equipment, and in particular, failure of power transformers, can result in station fires, oil leaks, significant emergency response and equipment replacement costs, and power interruptions impacting a large number of customers. Maintenance activities are vital for mitigating the risk of such failures and associated consequences. Maintenance activities also help to extend the useful life of equipment by promptly identifying failing insulation, deterioration of insulating oil, and transformer winding irregularities such as shorted turns, all of which can cause catastrophic equipment failure if not addressed in a timely manner.

The Station Equipment Maintenance segment does not include maintenance of station switchgear, which is captured in the dedicated Station Switchgear Maintenance segment. Examples of activities that are undertaken as part of Station Equipment Maintenance are:

- Comprehensive transformer testing including winding resistance and power factor testing to evaluate the insulation integrity of the core and windings;
- Cleaning of power transformer bushings to remove contamination that can lead to tracking and flashovers;
- Inspections and calibrations of transformer auxiliary equipment such as relays, temperature and oil gauges, and alarms;
- Verifying the integrity of all clamped and bolted connections on primary feeders, insulators, bushings, secondary feeders and buses;

- Cleaning and testing of on-load tap changers, which are devices used to regulate voltage; and
- Testing of transfer trip relays between a MS transformer (at 4 kV) and the upstream 13.8 kV or 27.6 kV supply feeder.

Station Equipment Maintenance, including the aforementioned activities, requires planned outages and is scheduled on a four-year cycle. In this regard, preventative and predictive tools and tests are employed during maintenance to prevent and identify deterioration on equipment that can lead to failures and associated consequences.

As illustrated in Figure 22 below, Toronto Hydro has identified on average 82 deficiencies on station equipment each year since 2015.

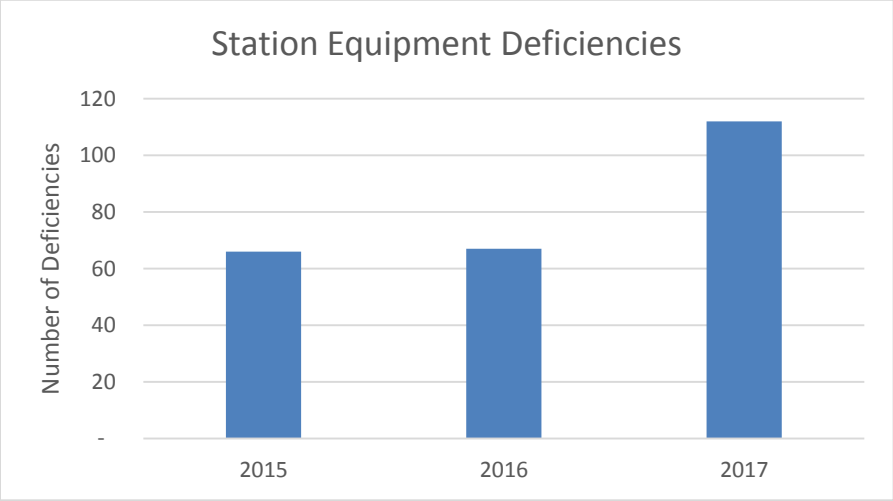


Figure 22: Station Equipment Deficiencies Identified Between 2015 and 2017

When equipment failures occur (e.g. on a power transformer), they pose significant safety, environmental, financial, and system reliability risks. An example of a

transformer failure is one that occurred at Dupont MS in 2003. The 49-year old transformer failed and resulted in a fire that caused damage to two other power transformers at the station and caused oil and fluids to spill into the station. This event interrupted 5,675 customers, resulting in over 23,341 customer hours interrupted. The entire outage lasted for 6.6 hours. Figures 23 to 25 show the damage caused by this incident.



Figure 23: Failed Power Transformer



Figure 24: Damages to the MS Wall



Figure 25: Leaking Fluids from Failed Transformer

The safety risks associated with a failure of this nature include station fires and flashovers which can cause injury to employees in a station. Further, associated environmental risks include the spillage of oil from ruptured transformer oil tanks which can contaminate ground water, soil and environmentally sensitive locations, as well as the release of hazardous combustion by-products.

During 2015-2017, Toronto Hydro experienced six outage incidents cause by failed station transformer equipment. Fortunately, none of these incidents were of the magnitude of the failure at Dupont MS in 2003; however, they did cause over 3,600 customer interruptions and 3,000 customer hours of interruption over the three-year period and thousands of dollars in emergency response. From a financial perspective, transformer failures can result in emergency response and equipment replacement expenditures that range between $0.2 million and $4 million. Given these figures, the mitigation of even one costly failure can result in savings that substantially offset the cost of the Station Equipment Maintenance program.

Although power transformer failures pose the greatest risk within stations, it is important to note that Station Equipment Maintenance mitigates failures on various other types of station equipment which can also cause significant safety, environmental, financial and system reliability risks. One example is load break switches, which are used to supply and isolate the primary voltage feed to a power transformer at MSs. These switches are installed in outdoor enclosures at 27.6 kV. A failure of such a switch can cause a station outage and significant safety risks as these switches are often operated manually. To ensure the successful operation of a switch during fault conditions, maintenance activities include cleaning insulators, lubricating contacts and gears, checking blade alignment, and conducting electrical tests such as contact

resistance, insulation resistance and fuse resistance tests. Another example is station service equipment, which supplies batteries, ventilating systems, lighting, and cranes. A failure of this equipment can result in the loss of power to station protection equipment, the loss of remote communication and control functions, overheating of switchgear, and various other risks. Maintenance mitigates the risk of these failures occurring.

8.2 Station Equipment Maintenance Segment Costs

Toronto Hydro requires approximately $0.9 million each year during the 2020 to 2024 period to execute the functions in this segment. Table 7 below provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for this segment.

Table 7: Station Equipment Maintenance Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Station Equipment Maintenance	0.3	0.8	0.7	0.7	0.8	0.9

The 2020 test year costs associated with this segment are projected to be $0.9 million, which represents an increase of $0.6 million from the utility's last rebasing year (2015), $0.2 from the most recent historical actual year (2017), and of $0.1 million, from the bridge year (2019).

8.3 Station Equipment Maintenance Segment Year-over-Year Variance Analysis

2015 -2016 Variance Explanation

The 2015-2016 variance is attributable to optimizations made to aligning and achieving a four-year maintenance cycle for all stations. Station outages are coordinated on a four-year cycle to allow work crews to maintain all station equipment units at once,

without the need for multiple planned outages. This optimization has allowed Toronto Hydro to maintain equipment at more stations in the downtown core than in the past, where 46 stations were maintained in 2016 when compared to the maintenance of 22 stations in 2015.

2016 -2017 Variance Explanation

Expenditures decreased by $0.1 million from 2016 to 2017 primarily due to a lower number of stations maintained in the downtown core (36 stations).

2017 -2018 Variance Explanation

Expenditures from 2017-2018 are forecast to be relatively stable, with potential variations in spending attributable to variations in the number of stations maintained.

2018 -2019 Variance Explanation

Expenditures from 2017-2018 are forecast to be relatively stable, with potential variations in spending attributable to variations in the number of stations maintained.

2019 -2020 Variance Explanation

The test year (2020) costs are generally consistent with historical spending levels.

CORRECTIVE MAINTENANCE

1. OVERVIEW

Table 1: Corrective Maintenance Program Summary

2015-2017 Average Annual Cost ($M): 17.7	**2020 Cost ($M):** 17.2
Segments: Corrective Maintenance	
Outcomes: Reliability, Environment, and Safety	

As part of the Corrective Maintenance program (the "Program"), the utility undertakes actions to address deficiencies or substandard conditions across the entire distribution system that are identified during the normal course of operations. This typically includes deficiencies or substandard conditions identified through activities undertaken as part of the Preventative and Predictive Maintenance programs[1] or the Emergency Response program.[2] Corrective Maintenance activities are non-discretionary, typically cover short planning horizons (given the risks that deficiencies and substandard conditions can pose if left unaddressed), and involve restoring assets to their normal operating conditions through maintenance, refurbishment, or minor component replacements.

Toronto Hydro's primary objective for this Program is to contribute to maintaining safety, environmental integrity, and overall system reliability by correcting or repairing deficiencies or substandard conditions on the distribution system. There has been a rise in the volume of corrective work requests executed under the Corrective Maintenance program attributed to the significant proportion of assets that are deteriorating from a

[1] Exhibit 4A, Tab 2, Schedule 1-3
[2] Exhibit 4A, Tab 2, Schedule 5

condition perspective or have exceeded their expected lives, thereby elevating the risk of failure across the distribution system.

The proposed 2020 expenditures for the Corrective Maintenance program are based on historical levels. Other than the 2017 costs which are notably higher than 2016 (as explained in the costs section below), the Program as a whole has seen an overall gradual increase in expenditures.

2. OUTCOMES AND MEASURES

Table 2: Corrective Maintenance Program Outcomes and Measures Summary

Reliability	• Contributes to Toronto Hydro's system reliability objectives (SAIFI, SAIDI, FESI-7) by repairing and restoring assets through corrective maintenance to acceptable operating conditions.
Environment	• Contributes to Toronto Hydro's environmental objectives by: ○ Repairing cables exhibiting signs of oil deficiency to prevent oil spills into the environment; and ○ Preventing excessive corrosion by cleaning oil-filled equipment and applying corrosion inhibiting coatings.
Safety	• Contributes to Toronto Hydro's public and employee safety objectives by: ○ Promptly repairing high-risk assets approaching imminent failure. ○ Washing insulators located in high contamination areas and preventing flashovers and pole fires; and ○ Detecting and eliminating energized contact voltage (4.5 volts or greater), surfaces and structures within Toronto Hydro's distribution system.

3. PROGRAM DESCRIPTION

By correcting or repairing deficiencies or substandard conditions on the distribution system, Toronto Hydro's primary objective for this Program is to contribute to

maintaining the safety of Toronto Hydro's work crew and general public, environmental integrity, and overall system reliability.

Deficiencies or substandard conditions across Toronto Hydro's distribution system are identified through the normal course of operations, the Preventative and Predictive Maintenance programs, or the Emergency Response program, as shown in Figure 1 below. Identified deficiencies or substandard conditions are subsequently addressed through a variety of programs; some are addressed immediately when found as part of the Preventative and Predictive Maintenance programs, some through the Reactive and Corrective Capital program,[3] and others through the Corrective Maintenance program.

Corrective Maintenance activities are non-discretionary, typically cover short planning horizons (given the risks that deficiencies and substandard conditions can pose if left unaddressed), and involve restoring assets to their normal operating conditions through maintenance, refurbishment or component replacements.

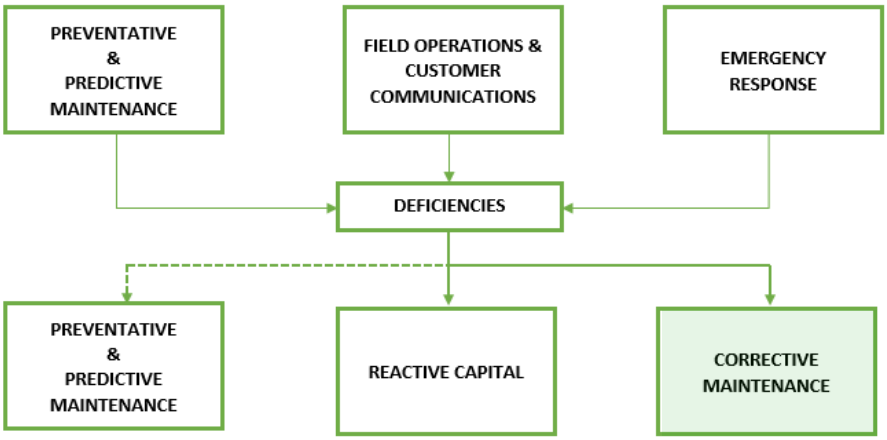


Figure 1: Deficiency Capturing Process[4]

[3] Exhibit 2B, Section E6.7
[4] The deficiency capturing process is described in detail in Exhibit 2B, Section D3.

- **Preventative & Predictive Maintenance Activities:** Field crews identify asset failures and deficiencies as part of scheduled maintenance inspection activities.
- **Field Operations & Customer Communications:** Corrective work can also be triggered by sources outside scheduled/planned maintenance activities. These include, but are not limited to: (i) phone calls from customers; (ii) external emails; (iii) observations by field crews during the normal course of operations; and (iv) customer inquiries requiring field assessment and follow up.
- **Emergency Response:** Corrective work can also be required as a result of emergencies or unplanned system events. For example, a faulted section of underground cable that has been isolated from the system during an emergency response may be unearthed and replaced as a corrective maintenance action.

All deficiencies from the above sources are reviewed to validate the need for reactive intervention, assess the nature of reactive intervention required (capital versus maintenance), and the level of urgency or priority to be assigned to each item. Toronto Hydro addresses the deficiencies identified through the above sources by issuing work requests.[5] The scope of the corrective maintenance work includes all overhead and underground assets and municipal and transformer stations. It also includes temporary repairs to assets during an emergency event, but excludes emergency repair work managed under the Emergency Response program. More specifically, the Corrective Maintenance program consists of the following activities:

- **Distribution Overhead Maintenance:** Corrective restoration of equipment and replacement of components that are part of the overhead distribution system, including conductor, conductor splices, insulators, brackets, lightning arresters, pole-mounted transformers, and overhead switches. Overhead maintenance

[5] Work requests are forms issued to assign and schedule corrective work to be performed by Toronto Hydro crew.

work includes vegetation management in response to off-cycle requests and spot trimming needs identified by Toronto Hydro crews or direct customer feedback, including dying or damaged tree limbs and branches, storm damage, or excessive tree growth that threatens overhead distribution lines or poses system reliability risks. Overhead work also includes the spot maintenance of worst performing feeders, which targets feeders that are at risk of experiencing seven or more power outages in a single year and may consist of tree trimming, switch maintenance, line patrols, and insulator washing depending on the needs of particular feeders.

- **Distribution Underground Maintenance:** Restoration of equipment that is part of the underground and network distribution system, including cables, cable splices, vaults, ducts, vents, hatchways, sump pumps, transformers, and switches. Activities may include patching spalling surfaces, leveling surfaces to eliminate tripping hazards, and replacing oil drain plugs, door locks, and hinges. This work also includes equipment CO_2 washing, which cleans excessive dirt, debris, and contamination from energized equipment in below-grade and padmounted installations to prevent arcing and flashover risks. This work also targets oil testing that is required to enable Toronto Hydro to comply with PCB regulations.
- **Stations Maintenance:** Corrective repairs to station equipment such as transformers, tap changers, cooling systems, switchgear, bus-bars, air compressors, circuit breakers, station auxiliary and DC power supplies, current transformers, potential transformers, relays, meters, fire alarms, remote terminal units, and SCADA systems. This work also includes oil reclamation, which involves filtering of transformer oil that has been found to contain

excessive moisture or contaminants and the restoration of the oil's properties to near new condition.

These activities are critical to maintaining distribution lines and stations assets, as assets are exposed to normal degradation processes (e.g. corrosion, water ingress, heavy loading) and external forces (e.g. adverse weather, tree contacts, foreign interference) that cause deficiencies and accelerate asset deterioration. Exhibit 4A, Tab 2, Schedules 1-3 (Preventative and Predictive Maintenance programs) set out the number of deficiencies that Toronto Hydro identifies annually for a variety of assets.

Figure 2 below shows a breakdown of the number and types of corrective work requests generated between 2015 and 2017.

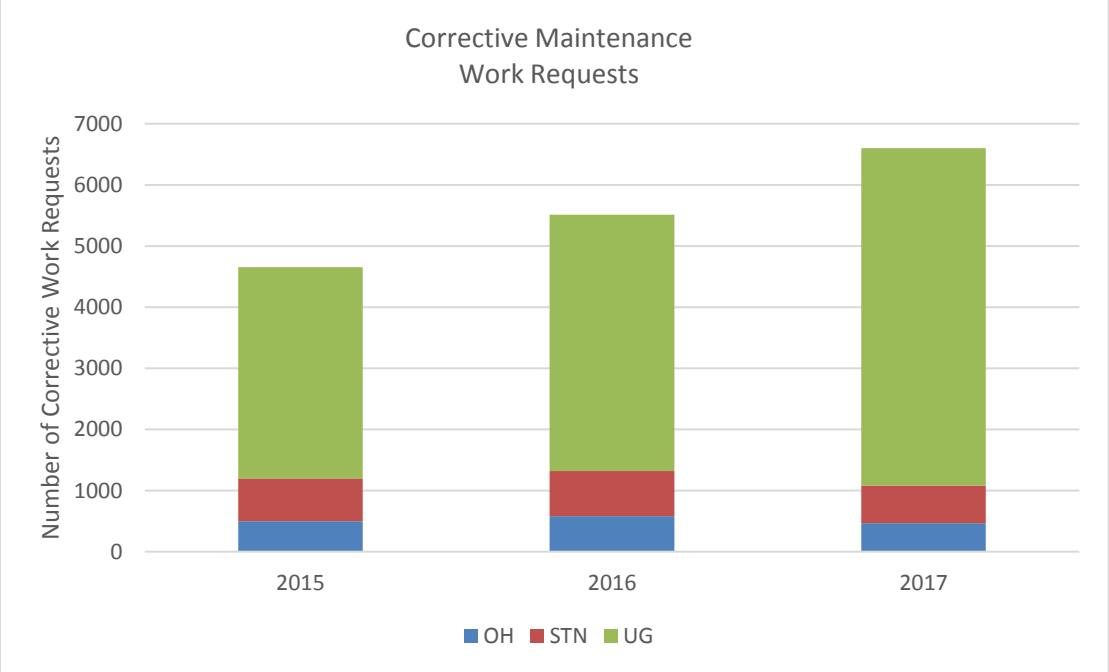


Figure 2: Historical Corrective Work Requests

There has been a rise in the volume of corrective work requests executed under the Corrective Maintenance program mainly due to the proportion of assets exhibiting deteriorating conditions and exceeding their expected lives, thereby elevating the risk of failure across the distribution system.

Beginning in 2015, Toronto Hydro updated its inspection forms for all asset types in order to capture greater details about substandard conditions found during inspections. As a result of this update, Toronto Hydro improved its process for capturing deficiencies and determining the appropriate corrective action. Consequently, the number of deficiencies reported from Preventative and Predictive maintenance activities increased starting in 2015, which contributed to the increase in the volume of corrective work requests.

On average, approximately 5,600 corrective work requests were issued each year between 2015 and 2017, with the majority targeting underground system assets such as vaults, cable chambers, padmounted equipment, and cables. In general, corrective maintenance needs tend to vary both in the volume and type of work required from year to year.

From a safety perspective, corrective maintenance addresses deficiencies that, if ignored, could endanger members of the public and Toronto Hydro employees. For example, a deficiency that is routinely found during overhead line patrols, using infrared thermography, is a thermal anomaly (or “hot spot”) on a conductor splice. Hot spots are evidence of over-heating within the splice and, if not addressed in a timely manner, could result in a live conductor failing, falling to the ground, and energizing the

surrounding area. Such a condition presents an unacceptable risk that must be mitigated through corrective maintenance in a timely manner.

The "hot spot" issue on a conductor splice also gives rise to system reliability risks. Splice failure, depending on the specific location of the conductor, may result in a power interruption to hundreds of customers for an hour or more. Other deficiencies that pose similar system reliability risks include deteriorated components such as insulators, mounting brackets and cross-arms, broken ground wire or guy wires, overgrown vegetation and dying branches, faulted circuit indicators with depleted batteries, failed surge arresters, conductor clearance issues (e.g. excessive conductor sag), transformer oil with high moisture or acid levels, and excessively dirty installations (e.g. vaults, padmounted transformers and switches). In aggregate, these individual deficiencies pose significant reliability risks.

From an environmental standpoint, corrective maintenance mitigates the risk of oil leaks and premature equipment failures. For example, cables leaking oil must be repaired promptly to prevent oil from entering the soil, drains, and waterways. Oil-filled equipment that is at risk of corroding should be maintained in a clean state, free of contaminants that can act as catalysts for corrosion. As part of the Corrective Maintenance program, Toronto Hydro crews clean dirty vaults and padmounted installations and apply corrosion inhibiting coatings to equipment to prevent excessive corrosion and the possibility of subsequent oil leaks. Corrective maintenance activities directed at corrosion prevention also serves to mitigate financial risks.

Maintenance work can extend the life of assets and defer the need for capital equipment replacement expenditures. An example is caulking that is applied to civil

infrastructure such as vaults and ducts. Caulking seals cracks in concrete and minimizes damage from moisture ingress. If caulking is not applied, cracks can grow to threaten the structural integrity of civil infrastructure and result in expensive vault rebuilds that may cost hundreds of thousands of dollars. Water ingress can also accelerate corrosion of equipment, leading to premature failure and associated costs.

4. PROGRAM COSTS

Toronto Hydro requires approximately $17.2 million each year during the 2020 to 2024 period to execute the functions in the Corrective Maintenance program, as described above. Without this level of funding, Toronto Hydro could be exposed to a number of risks:

- Reduced ability to address deficiencies that pose safety risks to the public and Toronto Hydro employees such as hot spots on conductor splices that could lead to failure of a live conductor and energization of a surrounding area if the conductor falls to the ground.
- Reduced ability to address deficiencies that pose risks to system reliability such as deteriorated or failed components, overgrown or dying vegetation, and excessively contaminated transformer oil or installations.
- Reduced ability to address failed or corroded equipment that could negatively impact the environment through oil leaks.
- Increased need for capital expenditures to replace equipment that otherwise could have been deferred through maintenance such as caulking of civil infrastructure.

Table 3 provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for this Program.

Table 3: Corrective Maintenance Program Expenditures ($ Millions)

Program	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Corrective Maintenance	16.1	16.8	20.3	17.0	17.0	17.2

4.1 Cost Drivers

The Test Year (2020) costs associated with this segment are projected to be $17.2 million which represents an increase of $1.1 million from 2015, a decrease of $3.1 million from the most recent historical actual year (2017), and an increase of $0.2 million from the bridge year (2019).

As discussed above, corrective maintenance needs tend to vary both in the volume and type of work required from year to year. Toronto Hydro continues to process increasing volumes of corrective work requests to address identified deficiencies. Overall, the observed variances are primarily attributable to:

- The type of work addressed each year. For example, on average, corrective work on underground assets tends to cost less than work performed on overhead and station assets.
- Increased corrective work volume in 2017 due to the completion of corrective work to address a backlog of issues across the system, and in particular for station assets. This included work on transformers/tap changers, circuit breakers, switches, primary fuses, switchgears, relays, SCADA/RTUs, tripping hazards, concrete patching, and poles and high voltage electrical work.

Toronto Hydro's 2020 forecast program expenditure of $17.2 million is based on historical spending levels and work request volumes, after accounting for the higher 2017 costs to address a backlog of work.

4.2 Cost Control and Productivity Measures

Corrective maintenance expenditures are driven largely by work request volumes and the types of repairs required. With work request volumes rising and the budget remaining relatively stable, Toronto Hydro is getting more work done for fewer dollars. Toronto Hydro has taken steps to manage costs and improve work processes in this Program.

- In 2016, Toronto Hydro introduced new inspection forms to capture more objectively quantifiable and measureable facts from field inspections. The revised inspection forms presented engineers with greater visibility into asset health and allowed for more effective condition assessment and risk mitigation.
- Toronto Hydro also continues to emphasize "find it and fix it" practices in the Preventative and Predictive Maintenance programs, which promote the on-site repair of minor deficiencies as they are identified. Examples of minor deficiencies and associated corrective actions include lubricating components, replacing nomenclature, replacing faulted circuit indicators, replacing sump pumps, clearing drains, caulking ducts and roof slabs, installing missing guy guards, and repairing or replacing locks, hinges, and handles. Addressing these deficiencies while on site during Preventative and Predictive Maintenance reduces the likelihood of having to dispatch another crew in the near future.
- The work request process has been improved in several ways in recent years. In particular, the time required for processing deficiencies into work request for execution has decreased. Updated records have helped to clarify asset

ownership and to more appropriately allocate spending (i.e. Toronto Hydro issues Customer Action Forms to non-Toronto Hydro owned assets).

- Lastly, through the "find it fix it" approach, Toronto Hydro strives to have cable chamber nomenclature deficiencies corrected on the spot as the contractor performing cable chamber infrared inspection identifies the need for such corrections. This eliminates the need to create a separate work request and additional travel time for repair, resulting in savings of approximately $400,000 per year. Furthermore, deficiency and work request reviews are now done digitally. This leads to a savings of approximately $50,000 per year.

4.3 Corrective Maintenance Program Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

The costs from 2015 to 2016 increased by $0.7 million due to an increase in the volume of corrective maintenance work requests.

2016 – 2017 Variance Explanation

The costs from 2016 to 2017 increased by $3.5 million as work volume increased to address backlog of issues across distribution system, especially for station assets.

2017 – 2018 Variance Explanation

The costs from 2017 to 2018 are forecast to decrease by $3.3 million as the backlog of work in 2017 has been addressed and work volumes are expected to return to steady increase consistent with 2015 and 2016 expenditures.

2018 – 2019 Variance Explanation

There is no material variance in this period.

2019 – 2020 Variance Explanation

The costs from 2019 to 2020 are forecast to increase slightly due to a higher budget for vegetation management, which is necessary to mitigate interruptions caused by worst performing feeders.

EMERGENCY RESPONSE

1. OVERVIEW

Table 1: Emergency Response Program Summary

2015-2017 Average Cost ($M): 15.9	**2020 Cost ($M):** 16.6
Segments: Emergency Response	
Outcomes: Customer Service, Public Policy, Reliability, Safety	

The Emergency Response program (the "Program") entails the provision of emergency response and restoration services related to unplanned and urgent events. The Program ensures that Toronto Hydro is compliant with applicable Distribution System Code ("DSC") requirements regarding emergency response to both types of events, and that customer service and system reliability are maintained.

The Program consists of three major functions: (i) dispatch logistics; (ii) grid response; and (iii) storm and major event restoration.

2. OUTCOMES AND MEASURES

Table 2: Emergency Response Program Outcomes and Measures Summary

Customer Service	• Contributes to Toronto Hydro's customer service objectives by: o Improving communications in relation to urgent events and emergency response, including urgent planned events which customers have identified as a priority for them; o Maintaining outage restoration time; and o Improving communication during urgent events, including urgent planned events which customers have communicated to Toronto Hydro as a priority for them.

Public Policy	• Contributes to Toronto Hydro's public policy objectives by responding to police, fire and ambulance calls, where necessary, with qualified staff within 60 minutes, 80 percent of the time as prescribed by section 7.9 of the DSC.
Reliability	• Contribute to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by reducing restoration times.
Safety	• Contributes to Toronto Hydro's public and employee safety objectives and performance (as measured via metrics like Total Recordable Injury Frequency) by: o Ensuring timely response to failing assets and cascading asset failures, to mitigate the risk of injury to the City of Toronto's emergency first responders, the general public and Toronto Hydro crews; and o Remaining compliant with Electrical Distribution Safety Regulation O. Reg. 22/04 (particularly, section 4 – safety standards) by ensuring that Toronto Hydro facilities present no undue hazard to the public).

3. PROGRAM DESCRIPTION

The primary purpose of the Emergency Response program is to provide emergency response and restoration services related to unplanned and urgent events. The program also ensures that Toronto Hydro remains compliant with sections 4.5 (Unplanned Outages and Emergency Conditions) and 7.9 (Emergency Response) of the DSC while responding to and restoring services during and following these events. The program includes three main functions:

- **Dispatch Logistics**: This function involves communications intake (e.g. telephone calls, email, and social media) from external stakeholders (e.g. customers, governmental authorities), information collection about incidents and events on the distribution system, and field resource assignment and dispatch for the purposes of investigating and resolving abnormal conditions.

- **Grid Response**: This function includes the senior trades staff and contract crews that are dispatched in response to emergency situations, including compromised or failing distribution assets, primary and secondary service interruptions, half-power calls, and other customer service related deficiencies.
- **Storm and Major Event Restoration**: This function involves efforts to restore power after major events, extended loss of transmission supply, and damage arising from severe weather related events.

The Program engages: (i) internal and contract crews on shift for immediate response and making temporary repairs, (ii) internal reactive crews and standby crews for emergency reconstruction, and (iii) dispatchers to communicate and collect information and to coordinate emergency responses.

Toronto Hydro operates within a dynamic and dense urban environment where emergency response may be required for a variety of reasons, including: (i) response to Toronto emergency management services ("EMS") (i.e. police, fire, and ambulance); (ii) equipment failure; (iii) events related to severe weather; (iv) motor vehicle accidents (as shown in Figure 1); (v) power quality issues; and (vi) equipment isolations.



Figure 1: Toronto Hydro Crews Responding to a Motor Vehicle Accident with a Distribution Pole

Over the 2015-2017 period, Toronto Hydro received approximately 24,000 calls per year related to events that required crew dispatch, representing over half of the calls received by Dispatchers.

Toronto Hydro classifies these events into the following four main categories:

- Emergency calls, including calls made by Toronto EMS (i.e. police, fire, and ambulance);
- "Power Off" calls attributed to power interruptions on primary facilities (i.e. on the primary side of the distribution transformer);
- "Power Off" calls attributed to interruptions on secondary facilities (i.e. the distribution transformer or equipment on the secondary side of transformer), and "Power On" events where power has not been interrupted but an issue has been identified on primary facilities; and

- Other situations such as sagging wires, objects on wires, feeder patrol findings,[1] and planned outages.

Figure 2 below shows the number of events by category during the 2015 to 2017 period.

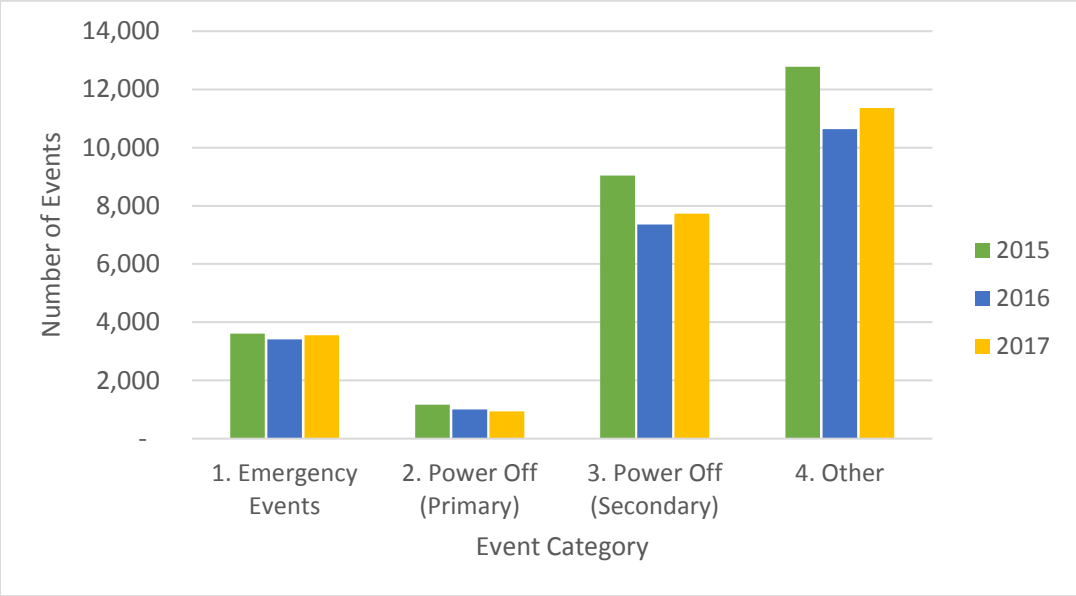


Figure 2: Number of Emergency Response Events (2015-2017)

Categories 1 and 2 (i.e. emergency and primary "power off" events) are the highest priority events for dispatchers.

Category 1 emergency calls (reported by Toronto EMS or members of the public) may involve significant public health and safety risks. Pursuant to the DSC (section 7.9), Toronto Hydro crew must arrive at the location of the event within one hour of being notified of the event, 80 percent of the time. Of the nearly 4,000 Category 1 emergency events annually, over 1,200 of those calls were from EMS and members of the public.

[1] Results of visual inspections of feeder assets

Category 2 primary "power off" events involve power disruptions to sizeable loads and large numbers of customers, typically requiring coordinated switching, load transfers, and often direct engagement with building superintendents and operations staff on location.

Category 3 and 4 events represent the largest number of calls and typically involve power interruptions to a small number of customers or lower risk situations. These events, which occur daily as part of the utility's routine operations, require timely response by crews that are properly equipped and trained to address potentially high risk situations. Due to the frequency of these events, Toronto Hydro assigns dedicated staff to the Grid Response function, which typically involves:

- An emergency crew restoring power to all customers and making all necessary permanent repairs (e.g. when current-limiting fuses have ruptured, primary or secondary conductors are down, or insulators or arrestors have failed);
- An emergency crew restoring power to all customers but only making temporary repairs or isolating the deficiency (necessitating follow-up repairs, usually commencing the next day); or
- An emergency crew arriving on site and, after assessing the situation and making the area safe for the public and employees, determining that the scope of the repair is beyond that crew's capabilities and that construction or civil crews are required to fully address the situation.

In addition to the events shown in Figure 2, Grid Response also attends to power interruptions on major or significant event days,[2] including significant storm damage. Severe weather systems and large scale events (e.g. loss of upstream supply from Hydro

[2] Major event days are considered are defined in accordance with the IEEE 1366 Standard.

One Networks Inc.) can necessitate significant crew efforts on a number of days each year. The effort is typically in response to widespread damage on the distribution system and power interruptions to customers. The largest of these events are referred to as "major events".

During the 2015-2017 period, Toronto Hydro experienced two major events. First, freezing rain on March 3, 2015 resulted in 38 fires on distribution poles. Second, a severe wind storm on October 15, 2017 (see Figure 3 below) knocked down trees and powerlines, affecting approximately 25,000 customers.



Figure 3: Fallen Tree on Power Lines from November 15, 2017 Wind Storm

Regardless of whether storm events are minor or major in nature, the damage that they inflict on the distribution system can require significant crew effort and resources to

repair. Figure 4 and Figure 5 illustrate examples of damage that had to be repaired following past storm events.



Figure 4: Fallen Tree on Oower Lines from High Wind Event on October 15th, 2017



Figure 5: Pole Fire on December 22nd, 2017

When major events and storm damage occur, Toronto Hydro directs requisite resources to repair the damage and restore power. For very large events such as the 2013 ice storm, which caused tremendous, widespread damage, all available resources are utilized and funded through the Emergency Response program, including internal resources (e.g. crews on planned projects) and external resources (e.g. contractors, mutual aid crews from other utilities).

Recently, the City of Toronto was experienced a severe wind storm that resulted in power outages across Toronto Hydro's service territory. Toronto Hydro's Grid Emergency Management team received a special weather statement from Environment Canada calling for strong winds throughout the day, including wind gusts between 90 and 100 Kilometres per hour in the Greater Toronto Area. The forecast conditions materialized, with the most severe conditions manifesting (during peak commuting hours in the city. During this time, winds ranged between 65-87km/hour, with gusts reaching up to 119 Kilometres per hour. As a result of these conditions, and at the event's peak, there were over 1,400 outage events that caused more than 68,000 customers to lose power across the city. In response, Toronto Hydro declared a Level 3 Emergency and activated its full emergency management organization (i.e. secondary or "storm" roles) to respond. Examples of the damages sustained from this incident can be seen in Figure 6 below.



Figure 6: Examples of Wind Damage Recent 2018 Storm

In the aftermath of the wind storm, restoration took place over a five day period. In day 1 of restoration, 90 percent of affected customers were restored; day 2 saw 96 percent of customers restored; day 3 saw 99 percent of customers restored; and, by day 4, 100 percent of customers were restored.[3] Certain challenges persisted into day 5 in terms of enabling customers to obtain repairs on their equipment so as to allow re-connection. Nevertheless, by the end of day 5, all customers impacted by the storm were reconnected and Toronto Hydro was able to focus its recovery efforts on general post-storm clean up.

Throughout the incident, Toronto Hydro had approximately 210 staff and contractors working during a given shift to restore impacted customers, with about 21 dedicated

[3] Referring to those customers whose customer-owned equipment was not damaged and could be reconnected safely to the Toronto Hydro distribution system.

emergency management team members during a given shift to coordinate response activities. All responders and emergency management personnel worked around the clock to ensure efficient and effective restoration. Despite working in hazardous and challenging conditions, all workers returned home safely with no major health or safety incidents reported.

Toronto Hydro's approach to this and other incidents is largely driven by the need to ensure that critical infrastructure and services (such as transit, hospitals and water pumping stations) remain functional, and to restore power to customers as quickly as possible. This approach is also reinforced by the need to mitigate public and employee safety (e.g. downed conductors, damaged poles), system reliability (e.g. long durations of customer interruptions), and environmental risks (e.g. failed transformers leaking oil) associated with storm damage and major events.

Grid Response teams also address deficiencies in equipment or components that are identified in the course of planned activities and that require immediate attention. For example, a subset of deficiencies found from Toronto Hydro's Preventative and Predictive Maintenance programs[4] are directed to Grid Response for immediate action on an emergency basis to address any unacceptable safety, environmental, or system reliability risks.

Given the nature of the events that Grid Response attends to, the vast majority of its work is non-discretionary. Restoration efforts after power interruptions, for example, are expected to be expedient to minimize customer outage time and maintain system reliability. Timely responses to EMS calls mandated by the DSC, which requires

[4] See Exhibit 4A, Tab 2, Schedules 1, 2, and 3.

emergency calls to be responded to within 60 minutes at least 80 percent of the time. Responses to serious equipment deficiencies are necessary to mitigate potential public safety, environmental, and system reliability risks. Such deficiencies include, for example, damaged poles (illustrated in Figures 7 and 8) that are likely to collapse and harm members of the public, and oil leak from a transformer (illustrated in Figure 9) which can contaminate residential and environmentally sensitive areas.



Figure 7: Distribution Poles Damaged by Vehicle Impacts



Figure 8: Distribution Poles Damaged by Vehicle Impacts



Figure 9: Distribution Transformer Leaking Oil After Vehicle Impact with Pole

4. PROGRAM COSTS

Toronto Hydro requires approximately $16.6 million each year during the 2020 to 2024 period to execute the functions in the Emergency Response program. Without this level of funding, Toronto Hydro will be exposed to a number of risks, including:

- Potential non-compliance with the DSC (Service Quality Requirements for emergency response),
- Delayed response to safety and environmental risks, thus increasing customer and crew exposure to unsafe conditions, plus increased potential for fines by federal, provincial and municipal regulatory agencies of failure to report and or mitigate spills in a timely manner,
- Extended customer outage durations,

- More frequent and longer duration resulting from second contingencies, placing added stress on assets and increasing the likelihood of more prolonged outages, and
- Delayed response to urgent customer and agency concerns.

Table 3 below provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for the Emergency Response program.

Table 3: Emergency Response Program Expenditures ($ Millions)

Program	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Emergency Response	16.4	15.2	15.9	16.4	16.5	16.6

4.1 Cost Drivers

The 2020 test year cost forecast represents an increase of $0.2 million from the utility's last rebasing year (2015), $0.7 million from the most recent historical actual year (2017), and $0.1 million from the bridge year (2019).

Due to the nature of events addressed by this program, costs can vary significantly from year to year. Major storms and the frequency of smaller storms are the drivers of the largest variances from year to year.

4.2 Cost Control and Productivity Measures

4.2.1 Cost Management

The frequency and severity of emergency and storm events are beyond Toronto Hydro's control. However, the impact of those events can be mitigated through effective planning and response. Continuous improvement in engineering and the work of the

standards committees, as well as preventative and predictive maintenance programs (including vegetation management and storm hardening) all contribute to the resilience of the distribution system. A more resilient system would incur lower emergency response costs. In addition, distribution asset renewal plays a significant role in maintaining, and in some cases, improving overall asset performance, and reducing reactive and emergency costs.

Toronto Hydro's complement of dispatch and emergency response staff is determined by the utility's obligation to meet emergency response requirements on a 24/7/365 basis, and to manage the key categories of work identified in Figure 2. Complement and shift arrangements are monitored and optimized to ensure requisite resources continue to support the level of response and volume of work.

4.2.2 Productivity

Call volumes vary over the course of each day, from week to week and month to month for weather-related and other reasons. When call volume is relatively low, this creates opportunities for the completion of additional work. In this regard, maintenance and small capital jobs (which can be dropped for higher priority calls) are assigned to crews to maximize labour utilization.

Increasing the time crews are available for work, by reducing downtime and assigning additional work during periods of lower call volumes, directly improves productivity. During the 2015 to 2017 period, dispatchers attended to, on average, over 41,500 telephone calls annually. For each call, dispatchers must interpret the nature of the event that has occurred, prioritize the event (if there are multiple overlapping events), and then dispatch the appropriate resources to the event. To accomplish this, dispatchers gather the required information and interact with various systems including

Toronto Hydro's Outage Management System ("OMS"), the Distribution Management System ("DMS"), the Geospatial Information System ("GIS"), and the Customer Information System ("CIS ").

Although the processing and proper dispatching of calls is a time consuming function, call volumes vary over time, presenting opportunities to assign additional duties to dispatchers Such duties may include entering information regarding planned work in the OMS, such as scheduling customer isolations, and inspections and maintenance tasks that can be issued to crews during times of low priority call volume.

Additionally, Toronto Hydro continues to assess and optimize the number of crews on shift throughout each day of the week, so as to maximize resources by, for example, staggering crew start and stop times and prioritizing events to increase the number of events responded to per crew shift. These productivity efficiencies have resulted in year over year improvements for response times during the 2015-2017 period, from 81 percent in 2015 to 89 percent in 2017.

4.3 Emergency Response Program Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

Relative to 2015, storm days were considerably reduced in 2016. The freezing rain event on March 3, 2015 resulted in approximately $2.1 million in response costs. There were no events of this magnitude in 2016.

2016 – 2017 Variance Explanation

Despite no major storm events during this period, 11 storm events resulted in an increase of $0.7 million in response costs in 2017 relative to 2016. The 2017 costs were in line with the 2015-2019 average cost of $16.1 million.

2017 – 2018 Variance Explanation

Costs in 2018 are expected to increase by $0.5 million, driven by slight increases for Storm and Major Event Damage, Emergency Field Response, and for Dispatch. It is also driven by inflation and costs expecting to be in line with a 5 year average cost of $16.1 million

2018 – 2019 Variance Explanation

Costs in 2019 are expected to increase by $0.1 million as a result of inflation.

2019 – 2020 Variance Explanation

Costs in 2020 are expected to increase by $0.1 million as a result of inflation.

DISASTER PREPAREDNESS MANAGEMENT

1. OVERVIEW

Table 1: Disaster Preparedness Management Program Summary

2015-2017 Average Cost ($M): 2.3	**2020 Cost ($M):** 2.7
Segments: Disaster Preparedness Management Program	
Outcomes: Customer Service, Reliability, and Safety	

The Disaster Preparedness Management program (the "Program") is responsible for the implementation of Toronto Hydro's robust and comprehensive disaster preparedness framework. The Program is comprised of activities to prepare for, respond to, and recover from disasters or large-scale emergencies (e.g. severe storms, major system/facility disruptions) at both a system and corporate level. It delivers the governance, planning, and training that enable Toronto Hydro to mobilize, and deploy its resources rapidly and effectively during and following disasters in order to mitigate the public safety, reliability, and financial-related risks that can materialize at those critical times.

Toronto is home to approximately 2.9 million residents and 106,000 businesses.[1] It is Canada's largest city and includes the Country's largest financial institutions, leading medical and research facilities, educational institutions, major transportation hubs, and federal, provincial, and municipal government offices. In addition, the City is a frequent host to events of regional, national, and international significance. Extended power disruptions can have significant impacts on these important organizations and events, causing far-reaching social and economic consequences. Accordingly, it is essential that

[1] City of Toronto, Toronto at a Glance, available at <https://www.toronto.ca/city-government/data-research-maps/toronto-at-a-glance/>.

Toronto Hydro respond quickly and effectively to minimize disaster-related power disruptions. The urgency of this need is further heightened given the growing likelihood and intensity of extreme weather events and deliberate threats (e.g. cyber-attacks).



Figure 1: Damage Caused by Toronto Ice Storm in April 2018

This Program is a continuation of the activities described in the Disaster Preparedness Management program from Toronto Hydro's 2015-2019 Rate Application.[2] The Program is necessary to ensure the continued implementation of a comprehensive and industry-leading disaster readiness program that satisfies customer expectations, maintains adequate service levels, and ensures public and employee safety during and following disasters.

[2] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015), Exhibit 4A, Tab 2, Schedule 4.

2. OUTCOMES AND MEASURES

Table 2: Disaster Preparedness Management Program Outcomes and Measures

Summary

Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by:
	  ○ Responding more efficiently (including through more effective utilization of available resources) to major disruptions;
	  ○ Reducing response times by conducting regular assessments to understand the utility's exposure to hazards and align preparatory activities based on expected event outcomes;
	  ○ Maximizing and expanding potential resources for disaster response and restoration by establishing mutual assistance relationships with external partners; and
	  ○ Using digital and physical damage assessment capabilities to enable more effective and informed prioritization of restoration efforts, in alignment with industry best practices.
	• Ensure compliance with Section 39 of the *Electricity Act, 1998* and Chapter 5, Section 11 of the IESO Market Rules that aim to alleviate the effects of an emergency on the electricity system by preparing and implementing emergency plans.

Safety	• Responding to disasters in a timely manner and lessening the public health and safety risks. • Increasing the number of staff available to maintain a perimeter for safety or risk hazards following a disaster event. • Providing clear role assignment and training with respect to disaster and emergency incident response.

Customer Service	• Contributes to Toronto Hydro's customer service objectives by:
	  ○ Coordinating more effectively with impacted customers, particularly those identified as key customers;
	  ○ Restoring customers more efficiently and effectively, using all available internal and external resources (e.g. through the utilization of mutual aid assistance); and
	  ○ Establishing and communicating accurate key outage restoration times for disaster incidents;

3. PROGRAM DESCRIPTION

The Program aims to increase the reliability of grid operations by implementing mechanisms to more effectively and efficiently restore operations in response to disaster events. This is consistent with both identified Toronto Hydro customer priorities and statutory and regulatory requirements regarding market participants' obligations to prepare and plan for disasters.[3]



Figure 2: Damage Caused by Toronto Wind Storm in April 2018

Toronto Hydro customers also expect the utility to deliver services safely and provide accurate and timely communications of restoration times during outages. However, providing electricity distribution services to a city of Toronto's size and complexity presents a host of operational challenges even under normal operating conditions. These challenges are drastically amplified during events such as severe storms and critical system disruptions. Table 3, below, outlines several recent examples of weather-related disaster incidents that exceeded the utility's standard response practices and

[3] Independent Electricity System Operator Market Rules for the Ontario Electricity Market, Chapter 5, Section 11.

triggered the deployment of additional planning and response resources under the Program.

Table 3: Examples of Recent Severe Weather Events in the City of Toronto

Event	Description
Freezing Rain (February 2017)	• Approximately 2-6 mm of freezing rain followed by additional heavy rain. • Estimated 9,200 customers out at peak; all customers restored within 24 hours of the start of the freezing rain event.
High-water/flooding (May - June 2017)	• Heavy rainfall in southern Ontario exceeded the yearly average for an entire summer. • Numerous incidents of high-water/flooding reported across Toronto. • No customers were directly impacted during this 55-day incident due to the utility's proactive damage assessment and DPM mitigation measures, including flood mitigation efforts.
Wind Storm (October 2017)	• Strong wind gusts approaching 100 km/h in some areas and lasting approximately 3 hours. • Estimated 43,000 customers out at peak. • 90 percent of customers restored within 11 hours of event; all customers restored within 48 hours of the end of the event.
Wind storm (April 2018)	• Sustained 65km/h winds, with gusts approaching 90km/h. • Estimated 24,000 customers out at peak; all customers restored within 48 hours of the end of the event.
Ice Storm (April 2018)	• Approximately 10-20 mm of freezing rain, 20-25 mm rain, sustained winds of 70 km/h with gusts up to 110 km/h. • Estimated 51,000 customers out at peak. • 99 percent of customers restored within first two days of response; all impacted customers restored within 5 days of the start of the event.
Wind Storm (May 2018)	• High winds reported throughout service territory with gusts reaching approximately 120 km/h. • Estimated 68,000 customers out at peak. • 96 percent of customers restored within 48 hours of the start of the event.
Flash Storm (June 2018)	• High winds reported throughout service territory with gusts reaching approximately 90-100/h. • Estimated 16,500 customers out at peak. • 86 percent of customers restored within the first 12 hours and 97 percent of customers restored within the first 24 hours of the event.

In light of the increasing frequency and severity of natural disasters (i.e. due to climate change) and deliberate hazards (including cyber-attacks and transnational threats to critical infrastructure), incidents can rapidly escalate in scope, cross jurisdictional lines, and result in significant losses. In this regard, the risk exposure of Canadian utilities– particularly those in its largest city – is a complex and urgent issue that could materialize in far-reaching social and economic consequences at the local, regional and national levels. In this context, it is imperative for Toronto Hydro to implement a comprehensive disaster preparedness framework that underpins its multi-faceted approach to planning, response, operations and recovery.

Overall, the Program enhances the utility's capacity for effective planning, communications, and response activity coordination in anticipation of, during, and following disasters that result in significant and widespread supply interruptions and/or threats to public safety. Program planning is calibrated to reflect Toronto Hydro's current risk profile and relevant standards and best practices.[4]

3.1 Disaster Preparedness Management Program Functions

The Program functions include hazard/risk profiling and planning and disaster preparedness framework implementation, evaluation, maintenance and improvement. Each function is summarized below. Hazard or risk profiling and disaster planning is the primary and largest function of the Program. This component encompasses business impact analysis, production of disaster/emergency management plans and procedures (including distribution system disaster preparedness planning), and external partnerships management.

[4] The Program aligns with the Canadian Standards Association's Z1600 Emergency and Continuity Management Program (CSAZ1600) standard. CSAZ1600 outlines requirements for emergency and continuity management programs that address disaster prevention, mitigation, preparedness, response, and recovery.

3.1.1 Hazard Identification Risk Assessment ("HIRA")

HIRA entails the identification of specific hazards and risks to Toronto Hydro's operations. Through HIRA, the utility determines how frequently such hazards can materialize, the severity of the potential impact, and which hazards pose the greatest threat to distribution system operations. HIRA findings enable the utility to prepare for worst-case scenarios and most likely risks, and efficiently allocate resources to hazards that may occur within its service territory.

In 2016-2017, the utility established a sustainable enterprise-wide HIRA framework consistent with industry best practices. Going forward, Toronto Hydro expects to fully operationalize the HIRA framework with a view to increasing its understanding of its up-to-date hazard exposure profile and to develop hazard risk models by correlating anticipated external events (e.g. weather forecast) to power system impacts in order to enhance operational decision-making in anticipation of an incident.

3.1.2 Business Impact Analysis ("BIA")

Through BIA, the utility predicts the consequences of an incident/disruption on key business functions and gathers information needed to develop disaster recovery strategies. BIA results show how hazards will impact the reliable distribution of electricity. In other words, which key services, facilities, and equipment are likely be impacted.

In 2016, Toronto Hydro retained an external consultant to conduct a BIA of the utility's Control Centre & Dispatch Operations. This BIA pilot project enabled documentation of key operational processes, recovery strategies, and down-time thresholds beyond which grid operations and oversight (including compliance with applicable regulatory

requirements) would be compromised. Toronto Hydro plans to conduct BIAs for all departments that carry out business critical functions, implementing a standardized approach to business continuity planning across the entire utility.

3.1.3 Response Planning

Toronto Hydro adopts an all-hazards approach to disaster preparedness, which involves the identification and integration of common disaster response elements across all hazard types (e.g. severe storms, cyber-attacks, large-scale system failures, etc.). This is accomplished through the use of the Ontario Incident Management System approach to emergency management, which includes recommendations on how personnel, facilities, equipment, procedures, and communications are to be coordinated during an incident. This increases planning efficiency, improves utilization of internal resources, and ensures standardized and efficient response if and when the utility must react rapidly. This approach also streamlines processes and improves the utility's ability to focus on unique response requirements for specific hazards and risks.

The Program produces and houses key disaster preparedness frameworks, including planning documents covering corporate disaster preparedness governance; emergency management; hazard-specific planning in respect of system damage and restoration strategies; Toronto Hydro's role in participating in a province-wide, black-start restoration of the provincial grid; planning for the management of supply chain, purchasing, and material distribution during emergencies; and the utility's approach to effectively engaging with customers and external stakeholders during emergencies.



Figure 3: Damage Caused by Toronto Wind Storm in June 2018

In addition, Toronto Hydro is frequently approached by public authorities and organizations hosting events in the City, to provide assurance in the form of contingency plans for specific events (e.g. G20 summit, PanAm Games) that bring together thousands of attendees. Each of these events is unique in nature, requiring custom response plans that are tailored in scope and approach relative to the existing grid emergency plans.

3.1.4 External Partnerships

The utility collaborates closely with electricity sector partners (e.g. Ontario Power Generation, Hydro One Networks Inc., Independent Electricity System Operator) to ensure consistent response and collaborative restoration. In addition, through Mutual Assistance ("MA") agreements with other utilities, Toronto Hydro has access to "at cost" crews, equipment, supplies or expertise following a disaster.

The Program includes planning for the deployment and onboarding of MA crews. This is because MA can give rise to operational challenges and requires significant planning and coordination to be leveraged safely and efficiently. To ensure the safety of external

crews assisting Toronto Hydro during disasters, the utility needs to undertake significant research, negotiation, and planning to implement the necessary MA arrangements and derive the maximum benefits of such arrangements. Jurisdiction-specific legislative and regulatory regimes, along with different operating standards and system configurations, can limit the host utility's ability to take full advantage of MA within a short timeframe. Operational complications associated with differences in safety practices, work protection code, construction standards, and restoration practices, and/or lack of familiarity with the requesting utility's system may result in MA crews being assigned simpler, non-critical tasks, which ultimately leads to longer restoration timelines and prevents the full utilization of highly qualified resources. Further, the difficulties encountered in the deployment of mutual aid resources can lead to an increase in overall restoration costs without the proper advance planning and coordination. For these reasons, during the 2020-2024 plan period, the utility will produce a plan for sourcing, onboarding, and utilizing non-Toronto Hydro crews following a disaster event.

3.2 Program Implementation and Evaluation

This Program function entails the delivery of required workforce training and execution of approved plans and processes during a disaster incident. The Program provides employees with training on updated disaster preparedness frameworks and processes, emergency roles, and incident management. It also integrates emergency response/preparedness requirements into new corporate IT systems.

The Program evaluates ongoing disaster planning and procedures through testing and exercises. Using simulation techniques (e.g. drills, system tests, etc.), the utility is able to identify gaps in its disaster planning including in respect to training, internal and

external coordination and communication and resource availability. For instance, in 2017, Toronto Hydro carried out the following disaster simulation activities:

- Administration of a utility-wide functional emergency exercise involving 80 participants from across Toronto Hydro;
- Two damage assessment drills; and
- Participation in IESO-led GridEx functional exercise that simulated a coordinated physical and cyberattack on the interconnected electricity system.

During the 2020-2024 plan period, Toronto Hydro expects to build and enhance a comprehensive exercise and testing program for disaster preparedness. It will continue to design and conduct disaster simulations and tests that identify program gaps with a view to inform adjustments and improvements in the overall disaster planning framework and supporting plans and procedures.

3.3 Program Maintenance & Improvement

This function consists of reviewing all elements of the Program including hazard/risk assessment, planning, business impact assessment, and exercises and testing, in order to ensure an updated framework that meets the utility's needs and risk profile. Given the unique characteristics of disaster events and the need to respond efficiently and effectively in each case, dedicated resources and processes are required in order to research, identify, evaluate, and implement adjustments and enhancements to existing practices.

Toronto Hydro aims to maintain and improve the effectiveness of the Program on an ongoing basis through the use of both internal and external reviews and assessments. For the 2020-2024 plan period, the utility intends to, through an "after-action" review

process, continue its systematic reviews of the Program by gathering feedback from internal personnel involved in disaster response as well as impacted stakeholders. In addition, the Program will establish a formal audit cycle to ensure continued program alignment with applicable regulatory requirements and industry standards. Finally, through the use of third party assessors, Toronto Hydro will ensure its disaster planning processes are robust and effective. Accordingly, in addition to training program development and facilitation, Toronto Hydro requires funding to source auditors and emergency management consultants to periodically evaluate and provide recommendations as the Program evolves.

4. PROGRAM COSTS

Toronto Hydro requires approximately $2.7 million per year over the 2020-2024 plan period to execute the functions describes above. Without this level of funding, Toronto Hydro could be exposed to a number of risks, including:

- Reduced disaster preparedness and response activities leading to possibly longer outage restoration times during such events;
- Adoption of an ad-hoc, reactive approach to disaster management (as compared to a proactive, systematic approach that includes ongoing risk/hazard assessments);
- Reduced ability to adequately perform drills and testing on current disaster framework;
- Reduced ability to retain internal expertise required to continuously improve the Program and bring it in line with industry best practices; and
- Reduced ability to provide essential disaster preparedness training to employees.

Table 4 below provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for the Disaster Preparedness Management program.

Table 4: Disaster Preparedness and Management Program Expenditures ($ Millions)

Program	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Disaster Preparedness Management	2.3	2.4	2.2	2.6	2.8	2.7

4.1 Cost Drivers

The requested forecast 2020 test year costs of $2.7 million represents an increase of $0.4 million from the utility's last rebasing year actual costs (2015), $0.5 million from the most recent historical actual year (2017), and $0.1 million less than the bridge year (2019). The variances are attributable to the following factors:

- **Reduction in external consulting costs**: Initial program development and implementation relied heavily on external expertise to compensate for the lack of internal experience and familiarity with industry best practices. As the Program has matured, the scope of major program development work has been reduced and a skilled and experienced internal resource base has been developed continue to update the disaster planning framework.
- **Increase in net payroll/labour costs and employee expenses**: These costs are associated with recruitment, training, and development of employees who are skilled, knowledgeable and qualified in the fields of emergency management, business continuity, and utility operations. Effective development and sustainment of the Program require dedicated employees with specialized skills and knowledge in utility operations and emergency management.
- **External testing and assessment costs**: Ongoing evaluation through testing and exercises provide insight into the effectiveness of the Program. The consulting

costs for the 2020-2024 plan period are associated with external auditing and benchmarking to maintain program efficacy and continued alignment with best practices. This budget will also be allocated for conducting large scale emergency response exercises across the utility.

4.2 Cost Control and Productivity Measures

The Program aims to ensure an up-to-date and robust utility-wide disaster planning framework while utilizing cost control and productivity initiatives to manage costs. For instance, as mentioned above, due to significant efforts to build and retain internal disaster planning expertise, the Program is able to reduce reliance on external consultants for program guidance and development, leading to cost savings.
In addition, the Program facilitates efficient use of internal resources with a view to controlling external labour costs. The Program aims to leverage existing emergency response capabilities within the utility by assigning Toronto Hydro employees to emergency functions. The Program trains employees on the utility's emergency structure and the emergency roles they will need to fulfill to assist with system operation and restoration. Lastly, in partnering with other utilities via the MA agreements, Toronto Hydro has access to "at cost" crews, equipment, supplies and expertise following a disaster event. These initiatives enables the utility to significantly increase the number of resources available for disaster response without an increased reliance on external resources and other labour costs.

Since 2016, Toronto Hydro has also adopted a number of tools, processes, and/or related improvements in support of program execution during actual events, including:

- Full implementation of the Ontario Incident Management System, which is the response system used by the vast majority of responders in the Province.

Adoption of this system means that Toronto Hydro is now positioned for collaborative response with other utilities (e.g. Enbridge), public safety organizations (e.g. Toronto Police, Fire, and Emergency Medical Services), and municipal/provincial governments. This provides the utility with access to all levels of emergency management and response organizations (e.g. municipal public works and forestry crews) during disaster response; and

- Implementation of statistical and comprehensive damage assessment tools aimed at enabling more rapid and effective estimation of restoration durations following a disaster event. This increases Toronto Hydro's understanding of which areas of the system have been most significantly impacted and require the most immediate attention. This allows the utility to plan its resource usage more effectively, focusing restoration efforts on areas requiring immediate response and those which will most positively impact the greatest number of customers and the impacted community.

4.3 Disaster Preparedness Management Program Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

Program costs increased by $0.1 million from 2015 to 2016 due to an increase in employee headcount related to improving and implementing the Program, which was offset by a reduction in external consulting costs for emergency management program development.

2016 – 2017 Variance Explanation

Program costs decreased by $0.2 million from 2016 to 2017 as a result of a decrease in external consulting costs which were partially offset by an increase in employee headcount related to improving and implementing the Program.

2017 – 2018 Variance Explanation

Program costs are forecast to increase by $0.4 million from 2017 to 2018 as a result of an increase in employee headcount related to improving and implementing the Program which will be partially offset by a further reduction in external consulting costs.

2018 – 2019 Variance Explanation

Program costs are budgeted to increase by $0.2 million from 2018 to 2019 as a result of an increase in employee headcount related to improving and implementing the Program, which will be partially offset by a further reduction in external consulting costs.

2019 – 2020 Variance Explanation

Program costs are forecasted to decrease by $0.1 million from 2019 to 2020 as a result of a retirement.

CONTROL CENTRE OPERATIONS

1. OVERVIEW

Table 1: Control Centre Program Summary

2015-2017 Average Annual Cost ($M): 5.7	**2020 Cost ($M):** 8.7
Segments: Control Centre Operations	
Outcomes: Reliability, Safety, Customer Service, Public Policy	

Toronto Hydro's Control Centre Operations program (the "Program") facilitates the safe and reliable operation of the utility's distribution grid through real-time system control and monitoring activities on a 24/7, 365-day basis. The Program coordinates system switching and restoration work through Toronto Hydro's Control Centre to mitigate the effect of outages on customers, and enables safe load transfers for capital and maintenance work. The Program further leverages the Control Centre to monitor the flow of electricity and asset performance across Toronto Hydro's distribution plant to provide real-time information and system condition data for future use in system planning activities. The Program includes the following functions:

- **Distribution System Operations:** Real-time, 24/7 operation of the distribution grid to monitor system conditions, respond to outages, enable field crews to safely work on the distribution system and coordinate operations with Hydro One and the Independent Electricity System Operator ("IESO");
- **Work and Outage Scheduling/Coordination**: Review and approval of work on the distribution system and scheduling outages or work to minimize system and customer impact;
- **Grid Analytics**: Reliability reporting and grid analysis to monitor risks, performance and approved construction project design; and

- **Supervisory Control and Data Acquisition ("SCADA") Maintenance and Support**: Maintenance, configuration and troubleshooting of the Toronto Hydro SCADA system, which enables Power System Controllers to monitor and operate distribution system equipment remotely and in real time.

The Program is a continuation of the activities described in the Control Centre Operations program in Toronto Hydro's 2015-2019 Rate Application.[1]

2. OUTCOMES AND MEASURES

Table 2: Control Centre Operations Program Outcomes and Measures Summary

Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: ○ Supporting and enabling successful execution of the annual distribution system capital and maintenance investment programs; ○ Maintaining the integrity of the registry database that pertains to system asset quantity and type. This information is used for planned and reactive distribution system work; and ○ Ensuring compliance with all statutory requirements related to grid emergency preparedness and business continuity, including emergency preparedness requirements outlined in Section 39 of the *Electricity Act, 1998* and IESO's Market Rules relating to emergency preparedness planning and system restoration planning.

[1] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015), Exhibit 4A, Tab 2, Schedule 5.

Safety	• Contributes to Toronto Hydro's safety objectives measured through metrics such as the Total Recordable Injury Frequency ("TRIF") by: ○ Providing seamless visibility over the distribution system, including load management and control over inadvertent energizing of equipment; and ○ Ensuring compliance with electrical distribution safety regulations through timely reporting of serious electrical incidents involving Toronto Hydro infrastructure.
Customer Service	• Contributes to Toronto Hydro's customer service objectives by: ○ Receiving and responding expeditiously to trouble calls from customers and/or external stakeholders; ○ Maintaining the capability to effectively manage, prioritize and resolve multiple concurrent system issues impacting customers; and ○ Providing relevant and timely outage information for customers, such as estimated outage restoration times and other situational information relating to system outages.
Public Policy	• Contributes to Toronto Hydro's public policy objectives by ensuring compliance with: ○ Emergency response-related provisions of the Distribution System Code by ensuring emergency calls are responded within a target of 60 minutes (in urban areas), 80% of the time; and ○ Ensuring compliance with requirements relating to the OEB Major Event Day reporting (Report of the Board EB-2015-0182), by efficiently communicating with external and internal parties, prioritizing system alarms, external and internal reports, and dispatching resources effectively.

3. PROGRAM DESCRIPTION

3.1 Control Centre Functions

As set out above, the Control Centre is responsible for the safe and efficient operation of the distribution system. This includes directly opening and closing remotely operable switches to redirect the flow of electricity, directing/instructing field crews with respect to the operation of locally operable switches and administering Toronto Hydro's Work Protection Code to ensure that work on or in proximity to Toronto Hydro's infrastructure can be conducted safely. Power System Controllers are responsible for establishing the existing system conditions, identifying the necessary steps to safely complete the work and minimize interruptions to customers, directing field crews in execution of these steps and maintaining records of which steps have been completed and which workers are actively working on the system.

Other processes administered by the Control Centre are switching steps and the issuance of "Hold Offs." Switching steps are documented as "Orders to Operate" safety documents. Each Order to Operate is comprised of a list of switching instructions that enable operations crews to safely transfer customer load and/or establish suitable work protection over a specified range of system devices. Hold Offs are special conditions that prevent certain automatic equipment operations for the duration of time that a field crew is working in proximity to Toronto Hydro's infrastructure. Power System Controllers record the location of workers within the direct proximity of electrical equipment (e.g. working on energized apparatus) to limit the possibility that other concurrent activities may increase the risk of equipment damage. Application of Hold Offs for certain activities are a requirement of Toronto Hydro's work procedures, and if not applied, can result in equipment damage and create extended outages should an incident occur in the physical or electrical proximity to the work site.

The Control Centre also plays a significant role with respect to outage restoration. When a feeder circuit breaker trips, the Control Centre is usually notified immediately through the SCADA system. Power System Controllers take immediate action to remotely isolate the issue, restore power where possible by switching to alternate supplies, coordinate with grid response crews to identify the specific location of the fault, make repairs and plan the final restoration. Where available, the Control Centre will relay situational information such as outage boundaries; number of customers effected and estimated restoration times to the Toronto Hydro communications team for dissemination to the public. Similarly, when issues on the transmission system impact supply to the Toronto Hydro's system, the Control Centre is the direct point of contact for the IESO and/or Hydro One. The Control Centre is also the point of contact for coordination of restoration efforts following a major disruption to the provincial electricity grid.

3.1.1 Distribution System Monitoring

The Control Centre is responsible for monitoring the status and operational state of the distribution system on a 24/7/365 basis. Power System Controllers maintain a real-time model and understanding of switch positions, device states, power flows, loading, work-in-progress, trouble alarms and abnormal system events across all 1,700+ circuits. This is accomplished through a combination of processes and tools.

3.1.2 Distribution Work and Outage Coordination

The Control Centre acts as a central authority for the operational assessment of designs, scheduling and coordination of work on the distribution system. All construction work involving modifications to the distribution system is submitted to the Control Centre for review. Control Centre engineers and technicians consider the operational impacts and

safety of the proposed designs and provide feedback and/or approval. Prior to work initiation, execution groups must also submit work requests to the Control Centre for planning and coordination purposes. This information is used to develop a plan that eliminates conflicts between jobs, identifies synergies (e.g. grouping of work requiring similar isolations to reduce the number of switching activities) and allows the work execution groups and the Control Centre to coordinate and optimize the use of shared field switching resources.

The Control Centre is also responsible for planning service isolations and restorations at the request of customers who require these services to safely work on their electrical systems.

3.1.3 Grid Analytics

The Control Centre analyzes system performance, calculates reliability statistics, reviews outage restoration performance, and plays a role in processing system record changes following the completion of work in the field. In addition, Control Centre engineers and technicians maintain the Interruption Tracking Information System, which stores data related to outages, including impacted devices/circuits, customer minutes out, customers impacted and the restoration sequence. From this database, the team compiles system performance statistics for reporting to internal and external stakeholders. The group also conducts in depth reviews of outages on a case by case basis to assess performance and identify improvement opportunities.

Toronto Hydro's distribution grid is in a state of perpetual change as new customers connect to the system and capital projects make modifications to the permanent physical design and configuration of the grid. The Control Centre requires access to the

most current information in order to effectively and safely carry out their work. The Control Centre, therefore, plays an important role in ensuring that system records are consistently and expediently updated. This work helps protect Toronto Hydro crews and customers from exposure to unsafe conditions and ensures that switching and other Control Centre activities achieve planned results without compromising system integrity and reliability**.**

3.1.4 SCADA System Maintenance and Support

As the SCADA system is integral to the efficient operation of the Control Centre, a team of specialized engineers oversee the activities related to maintaining, improving, and modifying Toronto Hydro's SCADA system to maintain cyber security and facilitate system operation efficiency. The SCADA team consists of trained engineers and technicians that possess specific skill sets in SCADA or industrial control systems. Their efforts facilitate remote system monitoring and control, and help ensure that decisions and orders from the Control Centre are quickly and efficiently executed. When Toronto Hydro installs new system monitoring and control equipment, it relies on SCADA engineers to configure and enable these devices to work seamlessly with the existing equipment and applications.

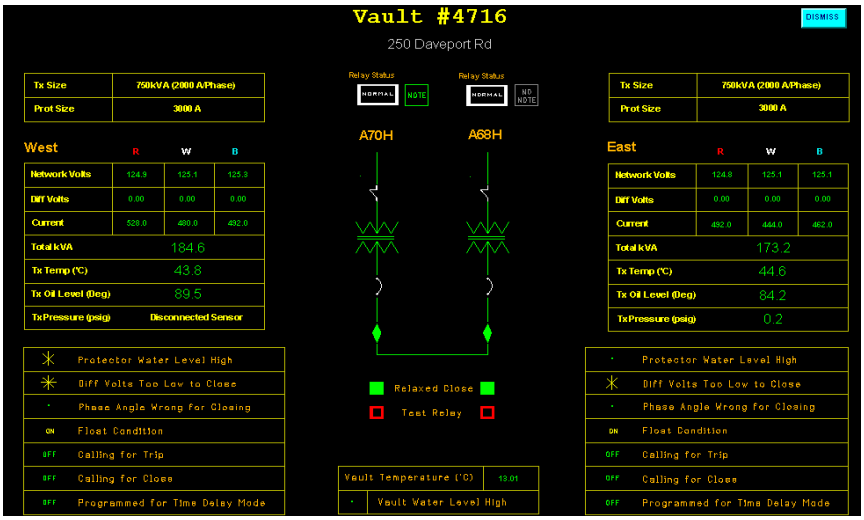


Figure 1: SCADA Display of a Typical Toronto Hydro Network Vault

3.2 Control Centre Operations

The Control Centre is comprised of two functions: (i) 24/7 Operations; and (ii) Grid Performance Analysis and Support. The 24/7 Operations is responsible for distribution system monitoring and operations, and work scheduling/coordination. This area is primarily staffed by Power System Controllers, Power System Controller Apprentices and Distribution Grid Operations Supervisors who work on a 24/7/365 shift schedule. The Grid Performance Analysis and Support function is primarily comprised of engineering technicians and engineers. The employees performing this function typically work a regular day schedule with after-hours support available through a rotating standby schedule.

Control Center functions require highly trained and experienced Power System Controllers.[2] The density and complexity of Toronto Hydro's urban setting adds additional complexities and challenges and therefore, Power System Controller

[2] Power System Controllers in training are referred to as apprentices, while fully trained Power System Controllers are referred to as journey persons.

qualifications can only be developed through a combination of in-class training and on the job experience. Power System Controller Apprentices, irrespective of educational backgrounds and prior experience, are required to complete a 4.5 year apprentice program, including 2-3 years of progressively more complex assignments, to substantially familiarize themselves with Toronto Hydro's system and become fully qualified Power System Controllers. Sustainment and development of this workforce is critical in ensuring that Toronto Hydro has the capability to realize the outcomes targeted by the utility.

Between 2018 and 2024, a substantial number of the current Power System Controllers are expected to retire. This trend is likely to continue for several more years. See Figure 2, below, for Toronto Hydro's forecast of expected Power System Controller retirements. Without a strategy to offset the expected loss of experience, it will be increasingly difficult for the Control Centre to sustain an appropriate level of service. This will negatively impact the utility's ability to meet strategic targets and outcomes related to safety, reliability and customer service.

Owing to the number of retirements forecasted to occur within a short period of time, the Program must continue to hire apprentices in order to sustain levels that are commensurate to the volume of work and the hours required to successfully run Control Centre operations. The Control Centre will need to continue to renew its workforce and incur expenses related to bridging the knowledge transfer (24/7 supervision), on-boarding new hires, and supporting competency evaluation, associated with mentoring new apprentices.

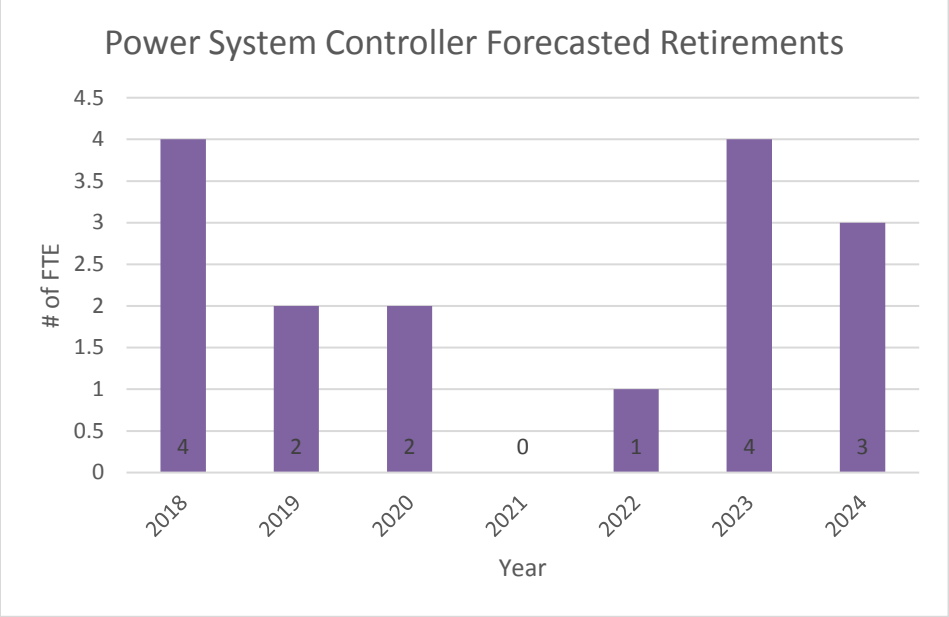


Figure 2: Forecast Power System Controller Retirements over 2018-2024 period

In order to ensure that there is sustainability within the workforce over the long term, the Power System Controller Apprentice Program will continue through to at least 2024. This will ensure Power System Controller Apprentice numbers are kept at a level that maintains qualified staff to handle work volumes and support a 24/7 schedule. In order to mitigate this retirement trend and account for voluntary exists of apprentices and Power System Controllers, Toronto Hydro plans to hire apprentices according to the plan shown in Figure 3, below.

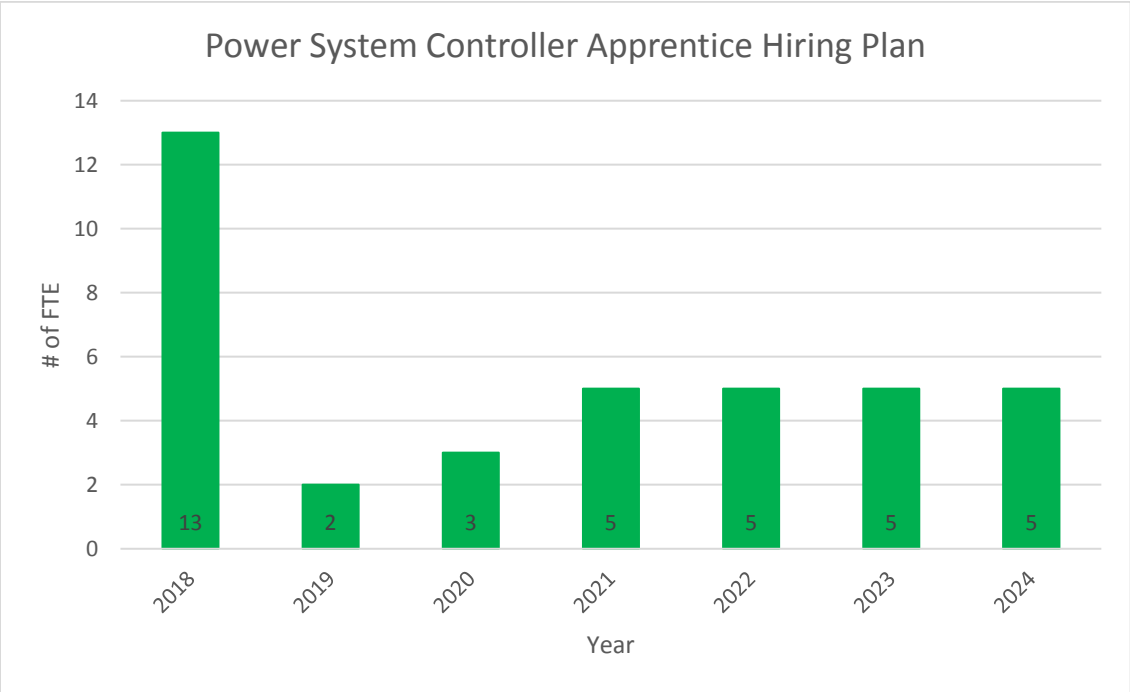


Figure 3: Power System Controller Apprentice Hiring Plan

In 2016, Control Centre operations transitioned to a 24/7 supervision model whereby Control Centre Supervisors work a rotating schedule of twelve hour shifts. The schedule ensures that at least one supervisor is present in the Centre at all times. As Power System Controllers coordinate with field crews to analyze, plan, execute and resolve public safety incidents or restore power outages, accurate customer centric information must be available in a timely manner. The new 24/7 supervision model allows for more consistent operational decision-making, more accurate and timely dissemination of information, and increased service for customer escalations. More importantly, as a result of retirements of experienced Power System Controllers, there is a significant reduction in the amount of experience present in the Control Centre at any given time. Having a Supervisor present at all times provides support for more junior apprentices as

they develop their skills and knowledge, and benefit from leadership guidance for public safety incidents and customer communication escalations.

Lastly, there are other externally driven factors that will likely increase the volume or complexity of Control Centre activities, further necessitating a supervisor presence in the Control Centre at all times, including:

- Increased market penetration of distributed generation, electric vehicles / vehicle charging stations and energy storage. This shift will introduce additional nodes that will need to be monitored and controlled to manage impact to the grid. The transition from a system where power flows primarily in one direction to multi-directional flows will also complicate switching operations in order to ensure that Toronto Hydro plant is safely isolated and grounded;
- Increases in extreme weather-related events due to climate change. Studies for the Toronto area predict that we will see an increased volume of adverse weather with the potential to disrupt the power grid, including extreme heat, ice storms, extreme wind and flooding. These events typically put a significant amount of stress on Control Centre operations as they frequently result in an extraordinary number of outages that must be managed and restored;[3] and
- Increasing customer expectations with respect to communication of outage status information. Along with grid response crews, Power System Controllers are typically directly responsible for coordinating restoration efforts and are often the source of this information. Toronto Hydro recognizes that it is important to be responsive to customer expectations around being kept informed about outages and restoration times.

[3] For a discussion of recent extreme weather related events experienced by the City, please refer to the Disaster Preparedness Management program at Exhibit 4A, Tab 2, Schedule 6.

4. PROGRAM COSTS

Toronto Hydro requires approximately $8.7 million each year over the 2020 to 2024 period to execute the functions described above. Without this level of funding, Toronto Hydro may encounter a number of risks, including:

- Inability to successfully execute the capital and maintenance investment programs due to Control Centre-related delays in administering field work;
- Significantly longer restoration times for outages;
- Less effective coordination with Hydro One and IESO counterparts with respect to bulk system issues, resulting in prolonged outages for customers;
- Reduced operating efficiency and higher safety risks as a result of the reduced ability to manage data on changing system configuration in a timely manner; and
- Persistence of abnormal system configurations, which can cause additional or prolonged outages.

Table 3 provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for the Program.

Table 3: Control Centre Operations Program Expenditures ($ Millions)

Program	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Control Centre Operations	5.4	5.4	6.3	7.8	8.7	8.7

4.1 Cost Drivers

The 2020 test year cost forecast represents an increase of $3.3 million from the utility's last rebasing year actual costs (2015) and $2.4 million from the most recent historical actual year (2017).

The cost drivers for this Program include the non-discretionary renewal of Toronto Hydro's Power System Controller workforce, a shift to 24/7 supervision, and additional support staff costs.

4.2 Cost Control and Productivity Measures

The Control Centre has led and/or supported several system modernization initiatives to control costs, improve productivity, and enable further optimization of operations. For instance, one such initiative resulted in a significant reduction in the average time crews spend waiting for Hold Offs (see Figure 4, below).

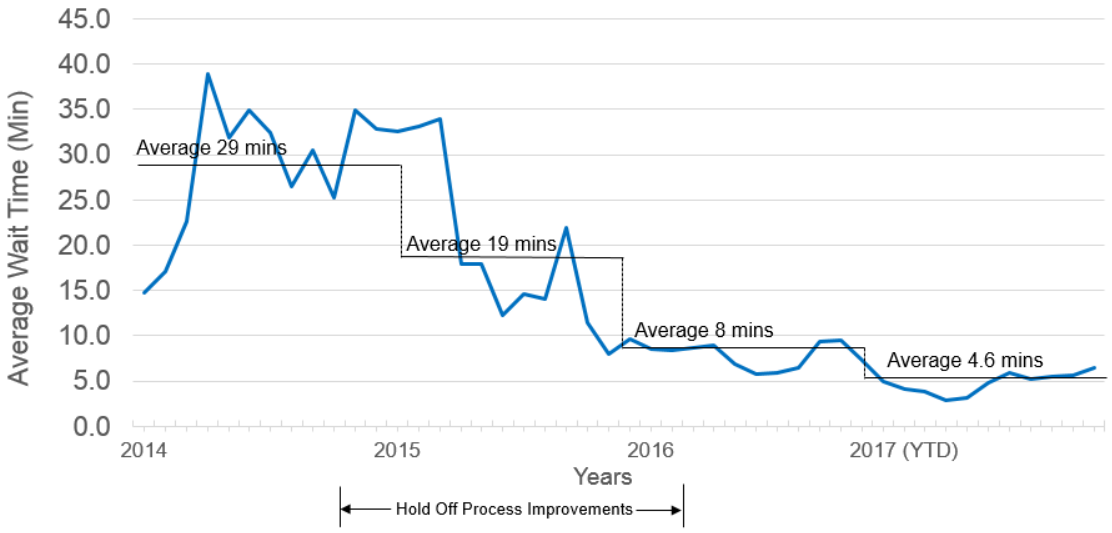


Figure 4: Average Wait Times for Planned Hold Offs

This reduction translates directly into increased productivity for field crews, as they spend less time waiting for a Hold Off before initiating work. The reduction was achieved by analyzing Hold Off volume data and spreading the peak demand across a longer time frame by staggering call-in times.

Another example of continued productivity improvements within the Control Centre is illustrated in Figure 5, below, which demonstrates a steady increase in the Control Centre's target for percentage of planned Orders To Operate which are to be written prior to work execution. By having Orders To Operate ready prior to execution, it reduces last minute work volume and increases the likelihood that field work can commence without delays caused by the Control Centre. While there is significant volatility in the planned Orders To Operate from month to month due to volatility in work volume, Toronto Hydro will continue to look for opportunities to improve in the future through improved scheduling and further process optimization.

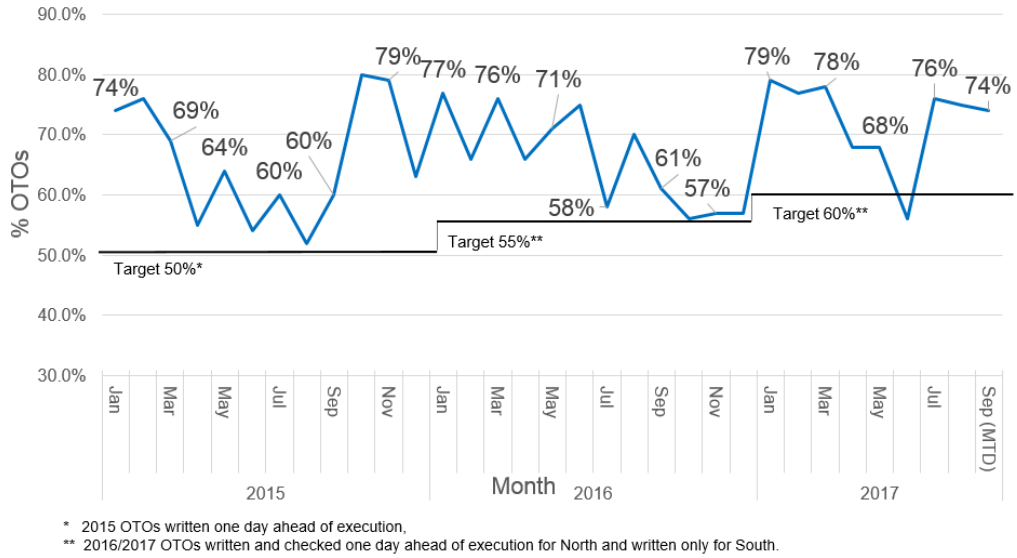


Figure 5: Percentage of Orders To Operate Prepared Ahead of Execution

The Control Centre has also increased the volume of work it processes. The work processed by the Control Centre is variable and dependant on several factors, including the size and complexity of Toronto Hydro's capital and maintenance programs, the number of equipment failures and external factors that influence system reliability such

as weather. Table 4, below, provides some measurable Control Centre output in recent years.

Table 4: Historical Control Centre Work Volumes

	2013	2014	2015	2016	2017
Total OTO Steps	63526	106734	237906	256098	278839
Executed OTOs	2936	3489	3574	3547	3696
Hold Offs	25741	27108	26468	24499	20544

Table 4 shows an increasing number of Orders To Operate steps which is a reflection of the complexity of the work being undertaken on Toronto Hydro's distribution system. The increase is generally attributable to a higher portion of electrical capital and maintenance work that requires extensive Control Centre support in recent years, as compared to civil work, which requires less Control Centre support. This volume will persist as Toronto Hydro continues to invest in its distribution system.

Table 5, below, provides examples of other productivity initiatives along with the results that will be enabled.

Table 5: Examples of Control Centre Productivity Initiatives

Initiative	Timing	Results
Development of Apprentice Programs	Ongoing	Enhancement of specialized skill sets in Power System Controllers, which will enable efficiencies in performance.
Network Management System Upgrade	2015-2018	Replacement of obsolete Distribution Management System and Outage Management System will lead to better system stability and performance due to vendor support, allow for increased capacity for Power System Controllers, dispatchers, and support staff during extra-ordinary circumstances, increase access to back-end operational data for reporting and productivity analysis, and enable implementation of various mobile solutions.
Mobile Orders To Operate	2018-2019	Eliminates the need for paper-based Orders To Operate to be sent between the Control Centre and field workers. The process enables Orders To Operate to be sent directly from the Power System Controller to the field crew's laptop or mobile device, reducing errors and increasing efficiency.
Operational Analytics	2018-2019	Enhances access to operational data that eliminates several manual reports and enables advanced reporting and analytics. The change modernizes reliability calculation processes.
Telephone Queuing	2016-2018	Enables allocation of customer and crew calls into Trouble Dispatchers to measure and prioritize timely response to crew work clearances, decreasing crew wait times. The process optimizes communications between Power System Controllers and field crews, allowing segregation of simple versus complex work and real-time work intake processes. Lastly, it also enables real-time performance reporting and analysis, which will inform further Control Centre process optimizations.

4.3 Control Centre Operations Program Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

There was virtually no variance between actual 2015 and actual 2016 costs. Retirements and other employee departures were offset by new hires.

2016 – 2017 Variance Explanation

Costs increased by $0.8 million between 2016 and 2017. This increase is attributable to an increase in net labour and payroll costs of approximately $0.2 million relating to continued implementation of the 24/7 supervision model and hiring of Power System Controller Apprentices and support staff, as well as costs associated with external consulting services and purchased services of approximately $0.6 million. External consulting services were utilized to conduct engineering studies and to develop and deliver training material for new hires. These costs are required to support continued development and delivery of highly specialized training modules and technical studies of operational work practices to identify/validate improvement opportunities and implement costs associated with system modernization initiatives.

2017 – 2018 Variance Explanation

Costs increased by $1.5 million between 2017 and 2018. This increase is attributable to an increase of approximately $0.9 million in payroll and labour costs related to continued implementation of the 24/7 supervision model and hiring of Power System Controller Apprentices and support staff, as well as continuation of costs associated with external consulting services and purchased services of approximately $0.6 million, for the reasons mentioned above.

2018 – 2019 Variance Explanation

Costs are forecast to increase by $0.9 million between 2018 and 2019. This increase is primarily attributable to an increase in staffing costs related to continued implementation of the 24/7 supervision model and hiring of Power System Controller Apprentices and support staff.

2019 – 2020 Variance Explanation

There is no forecasted variance between 2019 and 2020. A small increase in payroll and labour costs is offset by a decrease in external consulting and purchased services.

CUSTOMER-DRIVEN WORK

1. OVERVIEW

Table 1: Customer-Driven Work Program Summary

2015-2017 Average Cost ($M): 10.6	**2020 Cost ($M):** 9.6
Segments: • Customer Connections • Public Safety and Damage Prevention • Customer-Owned Equipment Services	
Outcomes: Customer Service, Safety	

The Customer-Driven Work program (the "Program") delivers services that respond to requests from existing and future customers. The specific activities this Program covers include planning, engineering, design, and field work to safely and efficiently enable customer connections and meet customer requests. This work is categorized into three segments as follows:

- Customer Connections;
- Public Safety and Damage Prevention; and
- Customer-Owned Equipment Services.

2. OUTCOMES AND MEASURES

Table 2: Customer-Driven Work Program Outcomes and Measures Summary

Customer Service	• Contributes to meeting Toronto Hydro's obligations for customer connections (including OEB mandated ESQR measures)[1] by: ○ Ensuring sufficient planning staff and required tools or resources are available to efficiently plan and design service connections and meet service request volumes; and ○ Providing the public with information concerning the location of Toronto Hydro's buried equipment (i.e. to facilitate construction) within five days 90 percent of the time, as required under the Ontario One Call regime. • Contributes to Toronto Hydro's customer service objectives by working with customers to ensure customer-owned civil structures containing distribution equipment on customer property are adequately maintained.
Safety	• Contributes to Toronto Hydro's public safety performance and objectives by providing cable locates in a timely manner; thereby improving general public safety.

3. PROGRAM DESCRIPTION

Most of the activities in the Program are driven by legislative and regulatory requirements, including the *Electricity Act, 1998*, the OEB's Distribution System Code ("DSC"), the *Ontario Underground Infrastructure Notification System Act, 2012* ("One

[1] More specifically, Toronto Hydro's customer connection-related obligations include:
(i) completing low and high voltage connections within five and ten business days respectively at least 90 percent of the time, as measured pursuant to the OEB's new connection metrics and section 7.2 of the Distribution System Code ("DSC");
(ii) completing customer appointments in accordance with the OEB's Appointment Scheduling and Appointments Met metrics 90 percent of the time, as per sections 7.3 and 7.4 of the DSC; and
(iii) responding to inquiries requiring a written response within ten business days at least 80 percent of the time, as measured pursuant to the OEB's Written Response metric and section 7.8 of the DSC.

Call Act"), the *Construction Projects Regulation O. Reg. 213/91*, and other legislative requirements governing fire prevention and detection activities.

The Program covers the interactions between Toronto Hydro's customers and its distribution system, addressing everything from customer requests for access to the grid to the safe completion of work in proximity of Toronto Hydro equipment. More specifically, the three Program segments are:

- **Customer Connections**, which includes the administrative and unrecovered costs associated with the investigative engineering, design, and field work to facilitate customer connection requests in accordance with applicable customer service and regulatory obligations.
- **Public Safety and Damage Prevention**, which aims to provide the general public and other utilities with timely information regarding the location of Toronto Hydro's buried equipment in accordance with applicable regulatory requirements.
- **Customer-Owned Equipment Services**, which aims to provide customers the means to access and service their equipment operating on the distribution system, including vault access, isolations and disconnections.

4. PROGRAM COSTS

Toronto Hydro requires approximately $9.6 million each year during the 2020 to 2024 period to execute the Customer-Driven Work program, as described above. Without this level of funding, Toronto Hydro could be exposed to a number of risks, including:

- Reduced ability to provide potential customers safe and reliable connection options in a timely manner. An in-depth analysis is required to determine the

impact of a new customer on the grid to ensure system integrity, and insufficient funding could compromise the ability to properly conduct this analysis;

- Customer dig-ins while performing work, which could potentially result in damaged distribution assets, service outages, or personnel injuries;
- Reduced ability to provide customers with isolations for the maintenance of their electrical equipment, resulting in potential reliability degradation on the distribution system; and
- Reduced ability to provide disconnection and asset removal services to customer wishing to upgrade or redevelop their land.

Table 3 provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for each of the Program's segments.

Table 3: Customer-Driven Work Program Expenditures by Segment ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Customer Connections	2.1	2.4	2.3	3.0	3.1	3.2
Public Safety and Damage	4.0	4.2	5.9	5.1	4.7	4.5
Customer-Owned Equipment	4.1	3.4	3.5	1.9	1.8	1.9
Total	**10.2**	**10.0**	**11.6**	**9.9**	**9.6**	**9.6**

4.1 Cost Drivers

The 2020 test year cost forecast represents a decrease of $0.6 million from the utility's last rebasing year (2015), a decrease of $2.0 million from the most recent historical actual year (2017), and is largely unchanged from the bridge year (2019).

The variances in the Customer Connections segment are attributable to the complexity of the initial investigation required prior to making an Offer to Connect. As both the number and complexity of expansion projects have been increasing over time, it is

expected that the overall time and administrative burden involved in these investigations will also increase. Projects that do not proceed are not capitalized. Any unfunded costs (including administrative resources) relating to such investigation are funded through this Program.

Variances in the Public Safety and Damage Prevention segment are attributable to a change in locate contractors in 2018 due to performance concerns. The work is now divided between two contractors. To onboard the new contractors, segment costs increased in 2017 and 2018, but are expected to decrease in 2019 and stabilize going forward. The discontinuation of the Line Cover-up Program Administration is also expected to decrease overall costs starting in 2019.

The decrease in Customer-Owned Equipment Services costs between 2015 and 2018 is primarily driven by customer-specific payment for isolations.

4.2 Cost Control and Productivity Measures

4.2.1 Cost Management

Toronto Hydro undertakes a number of measures to control costs in this Program. Under the Customer Connections segment, Toronto Hydro reviews pre-payment values on a project basis to ensure they cover a reasonable portion of the initial investigation work and mitigate financial risks should the project not proceed.

For the Public Safety and Damage Prevention segment, the utility is working with its cable locate services contractors to streamline the “clear” process, which indicates to customers that their work will be clear of any Toronto Hydro equipment. Toronto Hydro changed locate contractors in 2017. As part of the on-boarding process, the new

contractors have been primarily using “field clears”, where members of the team are sent into the field to address calls, even when there were no conflicts. Calls where there were no conflicts represent 57 percent of calls, and the potential to be addressed from the office (known as “office clears”). Toronto Hydro is working with the contractors to increase the use of “office clears.” This is expected to reduce costs.

Under the Customer-Owned Equipment Services segment, Toronto Hydro provides vault access at its expense, recognizing that the utility gains benefits, including the identification of potential hazards or deficiencies. However, Toronto Hydro does limit the free access to one time per year. Customers requiring access to vaults more than once per year are responsible for the full costs. This in turn incentivizes customers to find efficiencies during their access.

4.2.2 Productivity

Customer Connections

In 2017, Toronto Hydro combined its Low Voltage and High Voltage design teams. Prior to this, the Low Voltage team dealt with short turn-around seasonal work, while the High Voltage team dealt with larger developments that had long lead times. This merger has allowed the allocation and distribution of work across design team members in a more effective and efficient manner.

In addition, Toronto Hydro implemented an online (“C1”) form with standardized fields that customers complete in respect of their inquiries. A properly completed customer inquiry form would be promptly and accurately directed to the correct resource, thus minimizing the need for an inquiry to be passed from one department to another.

In 2016, Toronto Hydro piloted a Customer Relationship Management ("CRM") system to enable enhanced and more transparent project management and tracking. The pilot allowed Toronto Hydro to better manage customer requests by recording relevant information (e.g. when requests were received, milestone progress, response times, assigned designer, and project status). This ensures that existing customers or those who want to restart a project receive seamless and efficient service from the utility. This pilot system had led Toronto Hydro to consider expanding and implementing the CRM solution to capitalize on the potential benefits offered by the system.

Public Safety and Damage Prevention

As of 2017, Toronto Hydro divided its service territory (east and west of Yonge Street) between its two locate service providers. This boundary is flexible and allows Toronto Hydro to optimize the responsibilities of each contractor based on workload, costs, and performance as well as realize efficiencies by allowing contractors to focus on specific geographic areas. This enables the utility to minimize costs while meeting customer locate requirements. In December 2016, Toronto Hydro met the five day measure (i.e. to provide information within five days) 58 percent of the time. That number improved to 91 percent by December of 2017.

Customer-Owned Equipment Services

In 2017, Toronto Hydro initiated a pilot program with a new contractor to perform residential underground isolations. The new contractor performed the isolations successfully, meeting all safety and performance standards, at approximately half of the costs. Since isolations are fully billed to the customer, this saving is passed on fully to the customer.

5. CUSTOMER CONNECTIONS SEGMENT

5.1 Segment Description

The Customer Connections segment is driven by customer requests to connect to Toronto Hydro's distribution system or service upgrades for existing customers. Serving one of the fastest growing cities in North America, Toronto Hydro receives high volumes of request for connections and upgrades for residential and commercial developments each year. The requests vary in location, load requirements and the complexity of underlying planning or construction work. In accordance with its regulatory obligations, Toronto Hydro must connect a customer to its distribution system within prescribed timelines if that customer and the associated connection meet all technical requirements outlined in the DSC (Section 7.2) and the utility's Conditions of Service. Customer connections can be in the form of a basic connection, or a connection requiring expansion work. The types of connections Toronto Hydro performs can generally be divided into two categories as follows:

- **Low Voltage Requests:** These requests primarily relate to residential and small commercial customers that utilize existing Toronto Hydro transformation for their connection. As shown in Figure 1, the high volume of requests presents challenges as they require extensive project coordination and administrative oversight. The level of work is typically seasonal and has a relatively short turnaround time. To meet its service obligations, Toronto Hydro works with customers to provide options for a new connection or service upgrade.

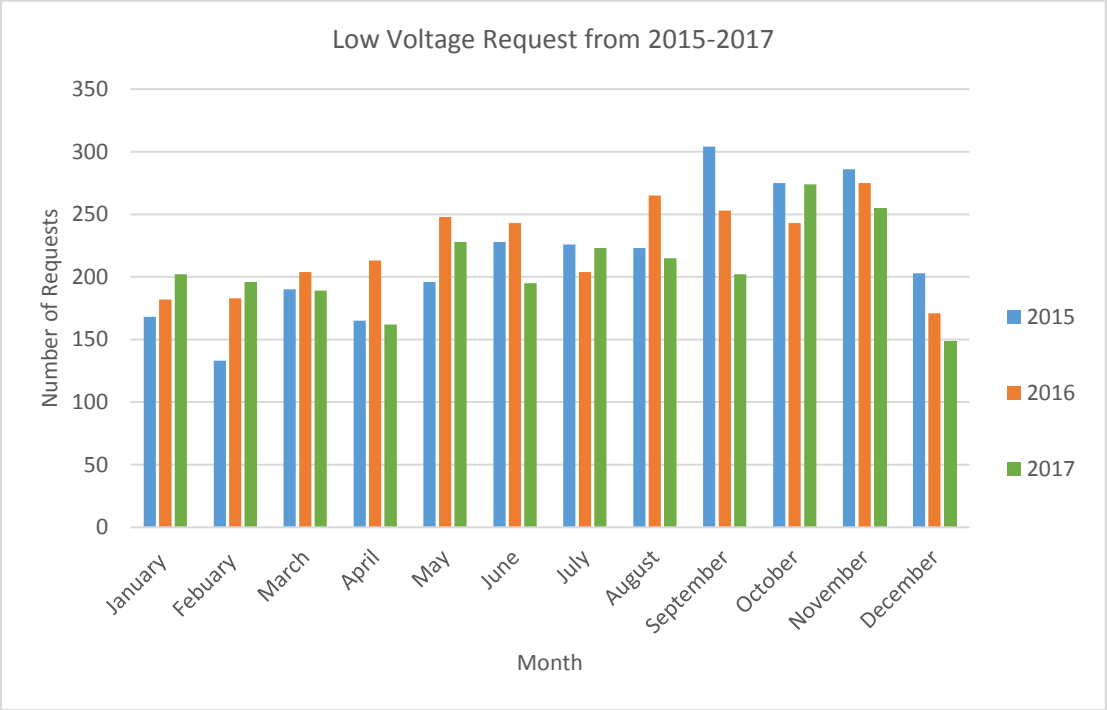


Figure 1: Low Voltage Connection Requests by Month (2015-2017)

- **High Voltage Requests**: These requests primarily relate to larger residential and commercial developments with dedicated transformation on customer property. These customers typically engage Toronto Hydro years before service is required. Figure 2 provides a year-over-year comparison of the volume of new formalized High Voltage requests that Toronto Hydro receives on an annual basis.

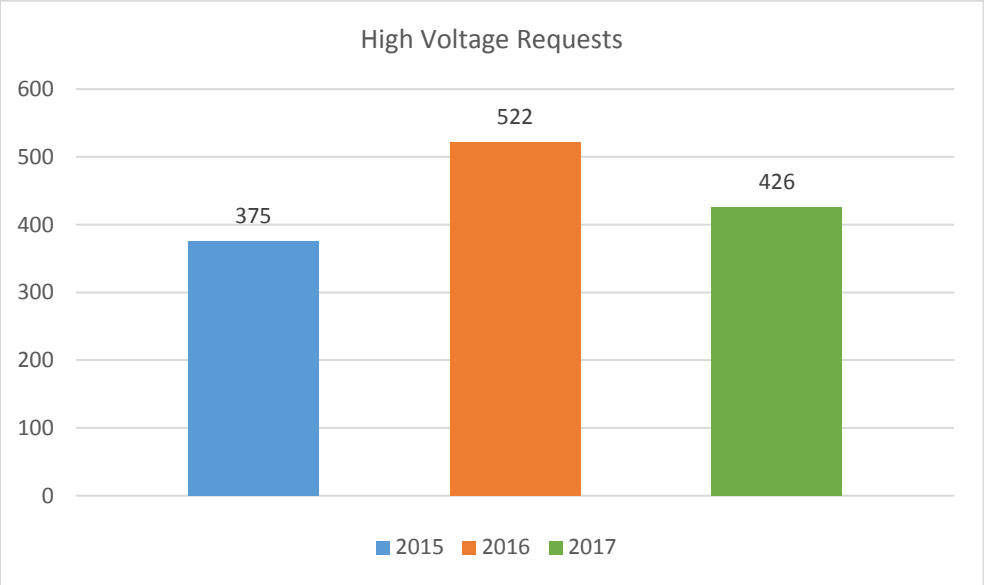


Figure 2: High Voltage Connection Requests (2015-2017)

Following the receipt of a connection request, Toronto Hydro works with prospective customers to develop an appropriate connection design, calculate the design pre-payment, and establish a mutually satisfactory construction schedule. Given the high density of Toronto's urban core, there are capacity limitations at many of the utility's Transformer Stations ("TS") and Municipal Stations ("MS") as well as spatial restrictions of existing underground or overhead easements. As such, Toronto Hydro may be required to undertake plant expansion and enhancement work to enable safe and reliable power. Projects with expansion work typically require connections that extend beyond the closest pole or cable chamber, resulting in work on various sections of the circuit or sometimes the entire circuit. Such work is complicated and requires a specialized team (including designers and distribution and stations engineers) to plan the system to accommodate the connection. As a result, customer jobs requiring expansion work require significantly more resources to prepare an Offer to Connect. Figure 3 illustrates the year-over-year volumes of Offers to Connect requiring expansion

projects. Over the past four years, both the volume and average complexity of expansion work have increased.

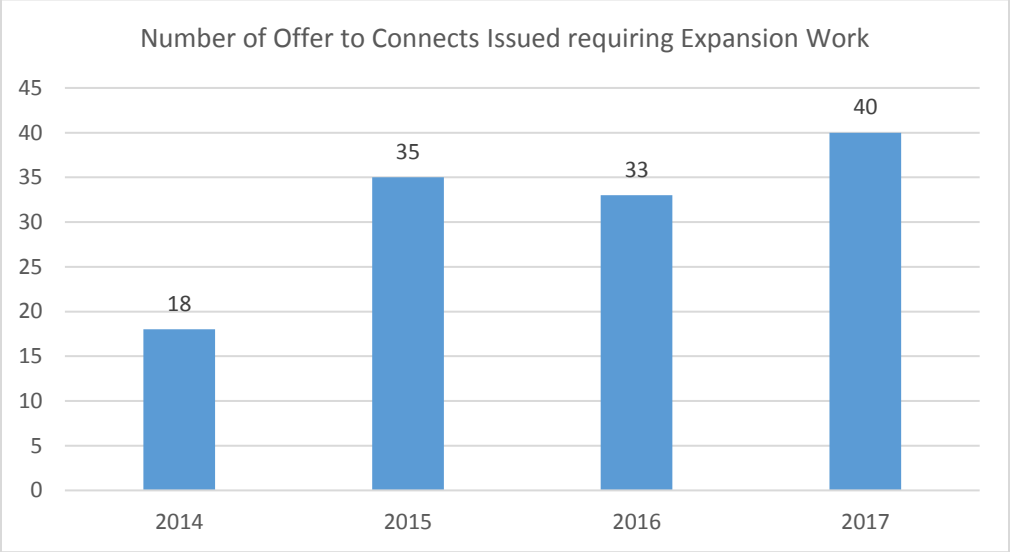


Figure 3: Number of Connections Requiring Expansion Work (2014-2017)

Given the current pace of Toronto's growth and the volume of large connection requests, Toronto Hydro identifies and addresses areas where insufficient connection capacity exists or is projected to materialize in the near or medium term. In this regard, the utility's customer connection work also entails an analysis of development plans prepared by provincial and municipal agencies and private development firms. Toronto Hydro incorporates the results of this analytical work into its load forecasts, system upgrade, and expansion plans.[2]

Throughout the duration of connection planning and design activities, Toronto Hydro maintains frequent communications with prospective customers to effectively manage

[2] See Load Demand at Exhibit 2B, Section E5.3 and Stations Expansion, Exhibit 2B, Section E7.4

their expectations and accommodate their evolving requirements or concerns where applicable. If planned or ongoing connection work may temporarily affect service quality, reliability or otherwise cause disruptions for existing Toronto Hydro customers, the utility endeavours to ensure that affected customers receive timely notifications and are able to provide input regarding the scheduling of planned activities.

The utility recovers eligible costs associated with the planning and execution of connection work from the requesting customers in accordance with the DSC and other relevant OEB and internal policies. The remainder of the costs is either capitalized or recovered through operating costs as described below.

Finally, operating costs related to customer connection work also include Program support costs such as tools and equipment, uniforms, information technology, vehicle and occupancy costs.

5.2 Customer Connections Segment Costs

Toronto Hydro requires approximately $3.2 million each year during the 2020 to 2024 period to execute the functions in this segment.

Table 4 provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for the Customer Connection segment.

Table 4: Customer Connections Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Customer Connections	2.1	2.4	2.3	3.0	3.1	3.2

The 2020 test year costs proposed in this segment represent an increase of $1.1 million from the utility's last rebasing year (2015), $0.9 million from the most recent historical actual year (2017), and $0.1 million from the bridge year (2019).

5.3 Customer Connections Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

The costs from 2015 to 2016 increased by $0.3 million due to a decrease in the recoveries from new service investigations.

2016 – 2017 Variance Explanation

There is no material variance in this period.

2017 – 2018 Variance Explanation

The costs from 2017 to 2018 are forecast to increase by $0.7 million due to the increasing complexity of projects and design work on customer connection jobs.

2018 – 2019 Variance Explanation

There is no material variance in this period.

2019 – 2020 Variance Explanation

There is no material variance in this period.

6. PUBLIC SAFETY AND DAMAGE PREVENTION SEGMENT

6.1 Segment Description

The Public Safety and Damage Prevention segment consists of the governance, oversight, and execution of work to ensure public safety and prevent potential damage

to Toronto Hydro's equipment when work is performed by customers (or their contractors) in proximity to the utility's assets. The primary activity in the segment is identifying the location of Toronto Hydro's underground assets (commonly referred to as "cable locates").

Prior to excavation, Ontario homeowners or contractors may use the Ontario One Call service to confirm that the work area does not contain any buried utility infrastructure. Toronto Hydro participates in the One Call program, and is responsible for the service costs associated with requests pertaining to its service territory.

Beyond leveraging the One Call contact centre capabilities, the utility outsources the cable locating function to third party providers who process incoming requests and identify the location of Toronto Hydro's underground infrastructure.

The public is not charged for using Ontario One Call. This encourages the widespread adoption of the service, which yields significant public safety benefits and prevents costly damage to utility infrastructure. Toronto Hydro is obligated to pay Ontario One Call for the call centre services it provides. The utility must also pay third party contractors to perform the actual locate work. The cost of an individual locate varies depending on the nature of work requested and the timeline for its execution.

The following tables outline the number of requests received by Ontario One Call relating to Toronto Hydro's territory and the associated costs of the service.

Table 5: Ontario One Call Customer Request Volumes and Costs

Year	Number of Requests	Cost ($ Millions)
2015	161,275	$ 0.2
2016	164,291	$ 0.2
2017	162,652	$ 0.2

Table 6: Third Party Locates Provider Volumes and Costs

Year	Number of Locates	Cost ($ Millions)
2015	134,989	$ 1.7
2016	131,222	$ 1.7
2017	116,479	$ 2.5

Segment activities also include the planning and execution of Alternate Locate Agreements ("ALAs") with large excavation companies. Through an ALA, an excavation company is assigned a blanket locate and an excavator identification number. Prior to excavating, the company can call Ontario One Call and obtain immediate approval to excavate. As a result, such companies are able to bypass the standard five-day turnaround time for the receipt of the service. In addition, Toronto Hydro is able to minimize the costs associated with completing the locate. ALAs result in higher customer satisfaction, require less coordination and oversight from Toronto Hydro, and lead to cost reductions for Toronto Hydro and its customers.

6.2 Public Safety and Damage Prevention Segment Costs

Toronto Hydro requires approximately $4.5 million each year during the 2020 to 2024 period to execute the functions in this segment.

Table 7 provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for this segment.

Table 7: Public Safety and Damage Prevention Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Public Safety and Damage	4.0	4.2	5.9	5.1	4.7	4.5

The 2020 test year cost forecast represents an increase of $0.5 million from the utility's last rebasing year (2015), a $1.4 million decrease from the most recent historical actual year (2017), and a decrease of $0.2 million from the bridge year (2019).

6.3 Public Safety and Damage Prevention Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

There is no material variance in this period.

2016 – 2017 Variance Explanation

Due to Toronto Hydro's inability to meet its obligated five day turnaround time with respect to One Call locates, it procured the services of two new locate providers in an effort to improve the overall service quality, which led to the $1.7 million increase during this period.

2017 – 2018 Variance Explanation

The costs between 2017 and 2018 increased by $0.8 million due to the increase in unit costs. This increase is primarily due to the onboarding process of new contractors that are not currently utilizing office clears.

2018 – 2019 Variance Explanation

From 2018 to 2019, costs are forecast to decrease by $0.4 million. Prior to 2019, Toronto Hydro provided the oversight for the installation of protective power line

covers, which were originally intended to allow competent individuals to be within the safe limits of approach during construction or maintenance work. In practice, a result of the use of line covers by the public was a false sense of safety when individuals without proper qualifications, such as window washers, worked near energized equipment. As such, Toronto Hydro is planning to discontinue the line cover program because of public safety risks. In addition, once locates contractors are fully on-boarded, costs are expected to decrease as a result of the lower unit costs.

2019 – 2020 Variance Explanation

There is no material variance in this period.

7. CUSTOMER-OWNED EQUIPMENT SERVICES SEGMENT

7.1 Segment Description

The work comprising this segment enables Toronto Hydro's commercial, industrial and residential condominium customers to safely perform periodic maintenance activities on their (customer-owned) civil infrastructure and other equipment, and facilitates the temporary or permanent disconnection of these assets from the grid.

7.1.1 Vault Access

Customers are responsible for supplying, maintaining, repairing and otherwise modifying all civil assets located on their property, and any civil infrastructure located on public road allowances that serve non-metered connections. The applicable infrastructure includes poles, cable chambers, transformer rooms, transformer vaults, handwells, junction boxes and other equipment housing or supporting Toronto Hydro's connection assets. Most commonly, however, customer equipment access activities involve transformer vaults located on customer property. In the interest of public

safety, Toronto Hydro places locks on transformer vault doors, helping to ensure that only qualified personnel have access to these rooms and the high-voltage electrical equipment they contain. From time to time, Toronto Hydro customers require access to vaults for periodic maintenance and inspections, or to perform repairs identified as necessary during prior site visits.

There are over 4,600 customer-owned vaults in the Toronto Hydro service territory that contain electrical plant owned by the utility. Each vault is required to contain fire detection equipment, which must be inspected annually in accordance with the applicable legislative requirements. During vault inspections, qualified Toronto Hydro staff must be on hand for safety purposes and to prevent damage to the utility's assets. When Toronto Hydro identifies structural deficiencies with the vault or a problem with the access door, it provides the customer with a completed Customer Action Form ("CAF"), which explains the nature of the deficiencies and recommends corrective steps.

7.1.2 Customer Action Forms

A CAF is a notice issued to a customer when any electrical or civil deficiencies are found in the field on customer-owned equipment or structures. Customers are responsible for replacing or repairing their defective electrical equipment, and those that own a transformer vault are responsible for inspecting, maintaining, repairing and replacing their vault when necessary.[3] This customer work is necessary to maintain the safety and reliability of their electrical equipment and civil assets as well as Toronto Hydro's electrical infrastructure, and help avoid potential disruptions to the electrical grid. Approximately 2,000 electrical and 1,500 civil defect CAFs are issued by Toronto Hydro field groups each year.

[3] Examples of such electrical equipment or civil assets include electrical meter base, stand pipe, transformer vault that houses Toronto Hydro high voltage equipment, etc.

Following a process review in 2016, Toronto Hydro implemented a more rigorous CAF process to ensure that customers are made aware of their deficiencies and corrective obligations and that the deficiencies are addressed promptly to maintain the continued safe and reliable operation of the distribution system

7.1.3 Customer Isolations

Customer isolation work (i.e. temporary disconnection of customer equipment from Toronto Hydro's distribution grid) allows customers to perform inspection, maintenance, repairs or replacement of their electrical equipment.

In June 2014, Toronto Hydro, alongside the Electrical Safety Authority, stopped allowing self-isolations by customers or their authorized electrical contractors to perform work (e.g. panel change outs), and required all isolations to be performed by Toronto Hydro, including service upgrades. This was done in order to ensure the safety of electrical contractors and the general public. In the subsequent two years, there has been a significant increase to the number of isolation service orders, from an immaterial number to over 10,000 per year. Figure 4 shows the total number of service orders related to customer isolation activities for 2015 to 2017.

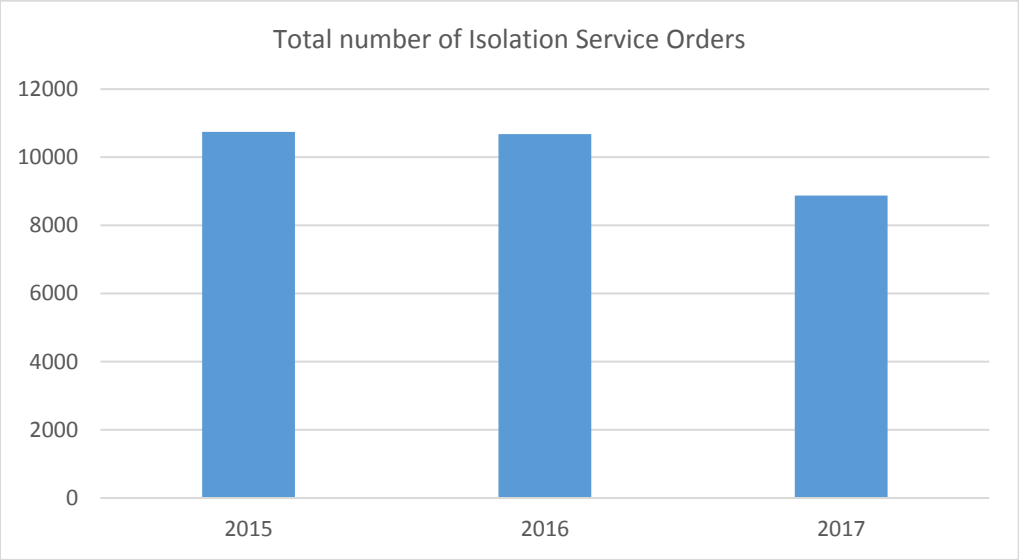


Figure 4: Total Number of Service Orders Related to Customer Isolation Activities

7.1.4 Deconstruction and Disconnections

Toronto Hydro typically carries out service disconnections and removals of the associated equipment in response to customer requests. In certain circumstances, such as where Toronto Hydro discovers unauthorized use of power, the utility carries out the disconnection work on its own initiative.

The utility recovers the costs of normal disconnection and removal work for Residential and Small General Service (Class 1 and Class 2) customers through rates, as these costs are assumed at the time of the economic evaluation of customer connection requests. For larger customers (Classes 3 and 4), Toronto Hydro recovers these costs directly from the requesting customers, based on procedures outlined in its Conditions of Service.

7.2 Customer-Owned Equipment Services Segment Costs

Toronto Hydro requires approximately $1.9 million each year during the 2020 to 2024 period to execute the functions in this segment.

Table 8 provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for the Customer-Owned Equipment Services segment.

Table 8: Customer-Owned Equipment Services Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Customer-Owned Equipment Services	4.1	3.4	3.5	1.9	1.8	1.9

The 2020 test year cost forecast represents a decrease of $2.2 million from the utility's last rebasing year (2015), $1.6 million from the most recent historical actual year (2017), and a $0.1 million increase from the bridge year (2019).

7.3 Customer-Owned Equipment Services Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

The costs between 2015 and 2016 decreased by $0.7 million, due to a lower volume of isolation requests.

2016 – 2017 Variance Explanation

There is no material variance in this period. In 2017, costs decreased as Toronto Hydro stopped offering free low voltage isolations, but this was offset by an increase in costs for isolating larger customer-owned structures (which are not recovered by the customer) due to the CAF process becoming more stringent.

2017 – 2018 Variance Explanation

The costs between 2017 and 2018 decrease by $1.6 million. This is primarily the result of Toronto Hydro recovering the costs of isolations from specific customers.

2018 – 2019 Variance Explanation

There are no material variances over this period.

2019 – 2020 Variance Explanation

There are no material variances over this period.

ASSET AND PROGRAM MANAGEMENT

1. OVERVIEW

Table 1: Asset and Program Management Program Summary

2015-2017 Average Cost ($M): 13.6	**2020 Cost ($M):** 13.1
Segments: • System Planning • Standards and Policies • Local Demand Response ("DR") • Program Management and Support	
Outcomes: Customer Service, Reliability, Safety, Public Policy, and Environment	

Toronto Hydro's Asset and Program Management program (the "Program") encompasses a broad range of asset management functions to support the reliable and safe operation of the utility's electricity distribution system.

The functions in this Program are performed under four segments: (i) System Planning; (ii) Standards and Policies; (iii) Local Demand Response; and (iv) Program Management and Support. The activities performed in these segments include:

- Equipment, materials and standards research;
- System planning and design;
- Forecasting customer and system needs;
- Outage investigations and reliability planning;
- Integration of new technologies into the utility's system;
- Incentive programs targeted at reducing peak load in areas where system expansion may be required in the medium-term; and
- Program planning, budgeting, scheduling, resourcing, and tracking/reporting of Toronto Hydro's distribution-related programs

The key outputs of the Program are plans and scopes of work, organized in annual work programs, for capital and maintenance investments, as well as incentive programs, all aimed at maintaining and improving Toronto Hydro's distribution system performance. While a portion of the associated costs are capitalized (i.e. for work directly related to capital planning and the execution of capital programs), this Program funds the remaining costs that are through operational expenditures.

2. OUTCOMES AND MEASURES

The most significant output of this Program is the Distribution System Plan ("DSP") and its maintenance and annual updates.[1] As such, the outcomes detailed in the plan are indirectly enabled by this Program. The following table summarizes specific outcomes directly attributable to this Program.

Table 2: Asset and Program Management Program Outcomes and Measures Summary

Customer Service	• Contributes to meeting Toronto Hydro's obligations for customer connections (including OEB mandated ESQR measures)[2] by:
	  ○ Processing and executing, in a timely manner, customer connection requests and offers to connect both load and generation customers as prescribed in section 7.2 of the Distribution System Code ("DSC"),
	  ○ Routinely meeting with, engaging, and responding to customer and stakeholder requests and concerns.
	• Consulting directly with customers through Local DR programs to develop cost-effective demand-side approaches that present mutually beneficial outcomes for both the utility and customers.

[1] For more details on the DSP, refer to Exhibit 2B.

[2] More specifically, Toronto Hydro's customer connection-related obligations include:
(i) completing low and high voltage connections within 5 and 10 business days respectively at least 90 percent of the time, as measured pursuant to the OEB's new connection metrics and section 7.2 of the DSC;
(ii) completing customer appointments in accordance with the OEB's Appointment Scheduling and Appointments Met metrics 90 percent of the time, as per sections 7.3 and 7.4 of the DSC; and
(iii) responding to inquiries requiring a written response within 10 business days at least 80 percent of the time, as measured pursuant to the OEB's Written Response metric and section 7.8 of the DSC.

Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by:
	  • Maintaining and actively managing Toronto Hydro's system and customer-specific reliability performance
	  • Ensuring ongoing stewardship of the distribution system and its ability to safely and reliably function in the long-term by maintaining asset records, scheduling maintenance activities, and developing capital investment scopes of work, and
	  • Maximizing the usage of existing assets by conducting asset condition assessments and utilizing DR resources to maximize existing system capacity.

Public Policy	• Contributes to Toronto Hydro's public policy objectives by;
	  ○ Ensuring regular inspection of assets to, at a minimum, comply with Appendix C of the DSC,
	  ○ Supporting Ontario's and the City of Toronto's greenhouse gas reduction targets by helping reduce peak demand within Toronto Hydro's service area, which supports curtailing high-emitting peaking gas-fired generation.

Environment	• Contributes to Toronto Hydro's environmental objectives by:
	  ○ Contributing to reducing the environmental impact and risks associated with Toronto Hydro's distribution system by removing underground assets at or beyond useful life that contain or are at risk of containing PCBs by 2024, pursuant to PCB regulations; and
	  ○ Reducing greenhouse gas emissions by reducing peak demand within Toronto Hydro's service area, which curtails high-emitting peaking gas-fired generation.

Safety	• Contributes to Toronto Hydro's public and employee safety objectives by: o By reviewing inspection findings, scheduling timely corrective work to address deficient equipment and infrastructure, and planning asset renewal investments over the medium to long-term; thereby mitigating safety risks o Monitoring system capacity conditions and minimize the risk of operating the system in violation of applicable design parameters through local DR, load transfer or capacity expansion projects. o Actively reviewing, researching, and updating material and standards documentation related to system assets and operating procedures
Financial	• Contributes to Toronto Hydro's financial objectives by: o Actively mitigating system risks that can result in costly failures and associated restoration work. o Enabling deferral of capital investment at selected stations, allowing the utility to allocate capital to priority projects.

3. PROGRAM DESCRIPTION

The Asset and Program Management program encompasses all functions supporting Toronto Hydro's asset management work and its coordination through the following segments:

- **System Planning:** This segment enables Toronto Hydro to analyze distribution system performance and needs, develop the utility's asset management strategy, develop the DSP as well as scopes of work for executing the DSP, and manage records keeping.
- **Standards and Policies**: This segment entails the development of all design and construction standards, management of the utility's quality programs, and facilitation of load connections through the offer to connect process.

- **Local Demand Response**: This segment utilizes demand-side approaches to support Toronto Hydro's station expansion activities, (including) identifying distribution system constraints that can be addressed using demand-side measures so as to enable the deferral of potentially high-cost asset upgrades.
- **Program Management and Support**: This segment funds activities that enable the planning, budgeting, scheduling, resourcing, and tracking and reporting of Toronto Hydro's distribution-related programs. It also manages changes throughout the lifecycle of capital and maintenance projects.

4. PROGRAM COSTS

Toronto Hydro requires approximately $13.1 million each year during the 2020 to 2024 period to execute the functions in the Asset and Program Management program. Without this level of funding, Toronto Hydro could be exposed to a number of risks, including:

- System planning risks, such as:
    - Inefficient and ineffective system planning;
    - Inability to support or plan capitalized work due to reduced ability to monitor and analyze distribution system performance measures, identify system needs, or develop the capital portions of the DSP;
    - Decreased short- and long-term reliability of the distribution system.
    - Inability to capitalize on synergies or maximize the use of existing distribution system assets;
    - Sub-optimal coordination with the IESO and regional planning groups, and with customers for purposes of enabling distributed generation ("DG") connections (resulting in potential non-compliance with OEB prescribed processes and timelines); and

- Significant safety and reliability risks if records and data updates are not synchronized with equipment or system configuration changes (given that such data is relied on by investment planners, system controllers, designers, and trades staff across the organization).

- Standards and policy-related risks, such as:
  - Reduced ability to facilitate load connections through the offer to connect process, thus resulting in potential non-compliance with OEB prescribed timelines;
  - Risk of not receiving the highest quality equipment from suppliers;
  - Less effective management of Toronto Hydro's quality programmes; and
  - Reduced access to highly specialized engineering expertise.
- Local DR-related risks, such as:
  - Inability to support Toronto Hydro's capital plans for Local DR.
- Program management and support-related risks, such as:
  - Decreased service levels in respect of customer service connections requests;
  - Less efficient use of design and construction labour resources, raising the risk for resource stranding;
  - Less effective project coordination, including sub-optimal alignment and integration with third party projects;
  - Reduced funding for governance and reporting functions that drive crucial elements of project management, such as cost controls, project performance and change management;
  - Potential for increased cost variances in execution, inconsistency in the application of design and construction standards, and adverse impact on

project development processes (including the assessment of projects for scope definition and executability); and

- Decreased risk management during operational phases.

Table provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for each of the Program's segments.

Table 3: Asset and Program Management Program Expenditures by Segment ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
System Planning	6.6	10.1	6.6	7.8	7.7	7.7
Local Demand Response	0.1	0.0	0.0	1.7	2.3	-
Standards & Policies	2.5	2.6	2.9	2.7	2.7	2.8
Program Managemnet & Support	2.0	5.3	2.0	2.6	2.6	2.6
Total	**11.2**	**18.1**	**11.5**	**14.8**	**15.3**	**13.1**

4.1 Cost Drivers

The 2020 test year cost forecast represents an increase of $1.9 million from Toronto Hydro's last rebasing year (2015), an increase of $1.6 million from the most recent historical actual year (2017), and a decrease of $2.2 million from the bridge year (2019). The high level cost drivers are described below. Specific variance explanations can be found under the detailed description of each Program segment in the sections below.

4.1.1 Planned Capital and Maintenance Work

The Program is driven by the amount of planned capital (system access, renewal, and service) and maintenance work, and associates scopes of work that must be developed. The costs of work that is required to support these programs is generally proportional to their magnitude.

4.1.2 Reactive Capital and Maintenance Work

Costs are also driven by the number of deficiencies identified through maintenance and inspections that must be processed.

4.1.3 Standards Change Requests

Costs in the Standards and Policies segment are driven by the number of standards change requests submitted and required.

4.1.4 Marketing and Legal

Costs in the Local DR segment are driven by incentive payments to customers, legal costs, software development (for the purpose of DR deployment), and program marketing materials. Toronto Hydro will benefit from the efforts made over the current rate period to develop program materials, customer contracts, and software platforms. It is therefore expected that there will be minimal risks of upward pressures over the next rate period.

4.1.5 Evolving Design Standards

The Standards and Policies segment costs are also driven by the need to comply with applicable compliance requirements, including Ontario Regulation 22/04 - Electrical Distribution Safety ("Electrical Distribution Safety Regulation").[3] For instance, all installation work must be based on standard design drawings and specifications, and all electrical equipment installed on the distribution system must be approved pursuant to that regulation. With revisions to industry standards (including CSA standards on Overhead and Underground Distribution Lines), standard design drawings and specifications are subject to change to ensure that safety standards as per the Electrical

[3] Ontario Regulation 22/04, made under the *Electricity Act, 1998*, S.O. 1998, c. 15, Sched. A.

Distribution Safety Regulation are met. Furthermore, as Toronto Hydro continues to explore the use of new technologies in its distribution system to achieve reliability improvement, gain operational efficiencies and reduce overall operating costs, standard designs evolve to reflect industry best practices.

4.2 Cost Control and Productivity Measures

Toronto Hydro expects cost control and productivity measures within the Asset and Program Management program to enable the program to maintain expenditures below 2016 and 2017 levels, thereby offsetting inflation. However, the results of these measures are not fully evident in the expenditure tables as efficiencies gained in some areas have been offset by new functions within the program. These measures include:

In the System Planning segment, despite an increased workload in terms of expanded scope of planning, Toronto Hydro expects to maintain segment expenditures below 2016 through continuous improvement measures, including:

- Implementation of new analytics tools and a data warehouse that have significantly reduced the amount of time it takes to prepare and analyze data for reliability, condition, and other risk analyses;
- Core IT system upgrades and replacements (e.g. GIS, ERP, NMS) that will enable staff to interact with the systems in a more efficient manner; and
- Strategic usage of records service providers to more cost effectively update and maintain asset records within core systems such as the GIS, ERP, and document management systems.

In the Standards and Policies segment, Toronto Hydro expects to maintain segment expenditures below 2017 levels through continuous improvement measures, including:

- Much of the work performed in this segment is initiated through formal change requests (e.g. change a construction standard to accommodate new equipment) or informal requests for support (e.g. technical clarification regarding a design policy). All instances of such services provided by this segment are tracked and categorized. The data is then used to identify trends and recurring issues, and opportunities for improvement and efficiency gains.
- Regular reviews of Key Performance Indicators and the data described above, focusing on continuous improvement, have enabled productivity gains. For example, in early 2017, the request process for changes and technical support was changed from paper-based to online. This not only made it easier to submit a request, but managing and tracking hundreds of requests became significantly more efficient. This change allowed staff to successfully handle the increase in requests discussed above.

In the Local Demand Response segment, productivity and efficiencies include:

- The development of generic templates (e.g. a generic DR contract, a residential DR program that is easily scalable) that are applicable to future Local DR programs. As a result, the costs required for marketing materials, legal documents, and software development are minimized. In the next phase, efforts to build in such efficiencies will continue, enabling increasingly more efficient programs in the future.
- Reductions in incentive payments, particularly for residential DR in the Cecil TS program, have driven significant cost savings. With a large base of residential DR participants (receiving a one-time incentive), the deployment cost associated with the DR capacity will significantly decrease.

- Additionally, based on an in-depth market segmentation analysis, selecting Basin TS will enable the next phase of Local DR to focus on Large DR projects (i.e. Toronto Hydro will contract for DR capacity directly with large electricity users).[4] This type of DR is cost-effective as it results in large capacity commitments with little overhead cost for the utility or the customer. The cost of this DR is projected to be about $110 per MW of capacity, whereas the value of that capacity to the grid is several orders of magnitude higher.

In the Program Management and Support segment, productivity and operational efficiencies are gained through the following:

- Broad productivity enhancements such as:
  - the introduction of new software to more efficiently track project information and associated change management;
  - new processes to improve the scheduling of feeder switching, which ultimately improves the effectiveness of field resource utilization as well as project execution; and
- The implementation of new time keeping software that has reduced the administration associated with labour cost processes (i.e. time sheets for field crews) by 35 percent.

5. SYSTEM PLANNING SEGMENT

5.1 Segment Description

The work done through the System Planning segment is divided into four functional areas:

- Distribution Lines & Stations Capital Planning;

[4] Local DR includes programs and technological solutions that encourage load curtailment and load-shifting, including targeted DR resource procurement at two stations: Cecil TS (continuation of current program) and Basin TS.

- Maintenance Planning;
- Generation & Capacity Planning; and
- Records Management.

Together, these functional areas enable Toronto Hydro to analyze the distribution system's performance and needs, develop the utility's asset management strategy, and produce the DSP as well as scopes of work for DSP execution.

5.1.1 Distribution Lines & Stations Planning

The Distribution Lines & Stations Planning function allows Toronto Hydro to monitor and analyze performance measures for its distribution system, identify system needs, and develop the capital portions of the DSP. The analytical work undertaken includes:

- **Reliability Analysis**: System power outage data is analyzed to: (i) identify performance patterns and trends related to specific types of equipment or geographical areas, and (ii) develop reliability forecasts based on investment scenarios. Outage data captured in specialized outage software is used to conduct detailed analyses of outage events, and identify worst performing areas as well as customers most affected by system outages. The analytical work performed under this function is critical to identifying system needs, informing investment decisions, and prioritization in various System Renewal and System Service capital programs. The results of reliability forecasting for the plan based on the DSP are provided in Exhibit 2B, Section E2. This analysis also forms the basis for managing reliability targets for measures such as SAIFI, SAIDI, and FESI-6 (further described in Exhibit 2B, Section C2), both from year to year and over the longer term.

- **Asset Condition Analysis**: This is done at both the discrete equipment and feeder (or station) levels to identify assets showing signs of significant deterioration and in need of replacement, refurbishment or other forms of intervention. This ensures the continued safe and reliable operation of the distribution system. As described in Exhibit 2B, Section D, Appendix C, Toronto Hydro devoted a significant amount of time to improve its ACA framework and algorithms and in 2017 and 2018 adopted the Common Network Asset Indices Methodology ("CNAIM"), which is a leading approach to assessing asset conditions.
- **Other Analyses**: The planning function supports the works of engineering groups by assessing risks relating to: environment and safety (e.g. oil leak deficiencies, PCB presence), customers (e.g. customer interruption costs, impact on large account customers), legal (e.g. claims relating to property damage), and corporate brand and reputation (e.g. with respect to various stakeholders, the media, specific communities).

As mentioned, the analytical work conducted as part of the Distributions Lines & Stations Planning function forms the basis of the development of Toronto Hydro's DSP and contributes to individual projects that together enable the utility to execute its capital and maintenance programs and address reliability, condition, or system risk needs at local levels (i.e. individual equipment, line sections, stations). Insights from the detailed analyses are used to explore feasible mitigation options to determine optimal solutions to specific issues. If the preferred solution for a particular issue is a capital investment, a scope of work is created. Figure 1 below illustrates Toronto Hydro's historic and forecasted capital expenditures initiated by a scope of work. Scoped work

represents planned work that requires design, whereas demand program represents work that is reactive in nature or requested or initiated by customers or a third party.

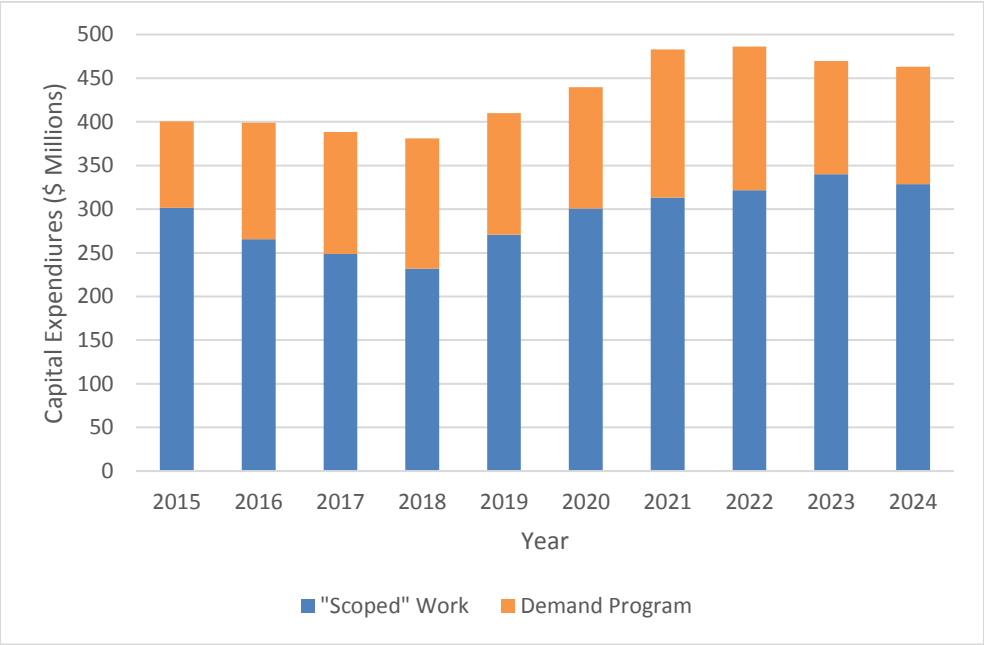


Figure 1: Value of Scopes of Work (Renewal, Service, Access)

5.1.2 Maintenance Planning

The Maintenance Planning function includes the analysis and preparation of Toronto Hydro's maintenance plans and schedules for all components of its distribution system. In 2003, Toronto Hydro adopted a Reliability-Centered Maintenance ("RCM") framework as the foundation for its maintenance planning, with subsequent review and updates in 2011 and 2016. RCM is an established engineering framework that determines failure management policies for any physical asset in its present operating context to maximize reliability and extend useful life based on the asset's function and the consequences of functional failure on the distribution system. RCM analyses are critical in scheduling asset maintenance programs and activities. From 2016 to 2018, Toronto Hydro updated the RCM results and analyses for each asset certified to align

with RCM best practices.[5] See Exhibit 4A, Tab 2, Schedules 1, 2, and 3 for details on Preventative and Predictive Maintenance.

Beginning in 2017, extensive work was also performed to update the ACA (based on the most recent inspection results) and adopt a new ACA framework. The ACA is crucial to guiding planners in deciding which assets to include in their investment plans. Details regarding the ACA model are provided in Appendix C of Exhibit 2B, Section D.

The Maintenance Planning function also entails the review of all asset deficiencies identified through maintenance and inspection activities. During the 2015-2017 period, approximately 29,000 deficiencies were reported annually, and reviewed and categorized for the purposes of formulating corrective and reactive responses (as detailed in Exhibit 4A, Tab 2, Schedule 4 Corrective Maintenance). Figure 2 below shows the number of past deficiencies processed and those forecasted to be processed. It also indicates the total volume of deficiency inquiries processed to determine those that can be cancelled (as they do not warrant action to be taken) and the volume of work that is executed (i.e. executable work) using Toronto Hydro's priority (i.e. P1, P2, P3) system.

[5] Applicable Standards: SAE JA-1011 (Evaluation Criteria for Reliability-Centered Maintenance (RCM) Processes). Applicable Guideline: SAE JA-1012 (A Guide to the Reliability-Centered Maintenance (RCM) Standard)

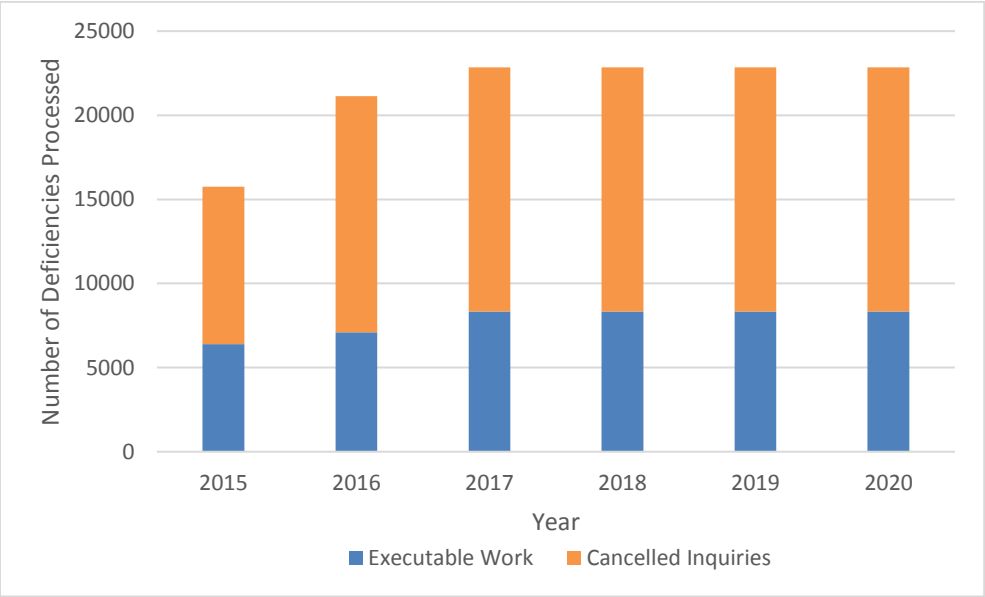


Figure 2: Number of Deficiencies Processed

The work undertaken in Maintenance Planning is critical to both the short-term viability (e.g. by addressing equipment deficiencies) and long-term viability (e.g. by prudently maintaining assets) of the distribution system.

5.1.3 Capacity and Generation Planning

This functional area is responsible for planning both the distribution system's future load requirements driven by customer growth, and requisite connection capacity to accommodate current and forecasted levels of DG in Toronto Hydro's service area. This group also identifies opportunities for adopting non-wires alternatives (including Local DR) to maximize the use of existing distribution system assets.

Capacity planning work requires the constant monitoring of changing system characteristics, such as feeder and transformer station loadings, short-circuit levels and system performance measures. Combining system performance data with past system

demand trends and known requests for load and generation connections, Toronto Hydro produces system demand forecasts.[6]

Given the nature of its mandate, the capacity and generation planning function is Toronto Hydro's technical liaison with the Independent Electricity System Operator ("IESO") on all matters related to DG programs (e.g. the former Feed-in-Tariff ("FIT") and MicroFIT) as well as regional planning. Toronto Hydro has a dedicated generation planning team that works closely with customers to ensure the DG connection process is followed and timelines are met. The Capacity & Generation Planning function is responsible for the capacity plan found in Exhibit 2B, Section E5.1 Customer Connections.

5.1.4 Records Management

The Records Management function involves the maintenance and upkeep of digital records of Toronto Hydro's distribution system. The utility must maintain up-to-date records to enable efficient and effective system planning and operations due to constantly evolving system capacity and configuration resulting from new customer connections, as well as equipment failures, retirements and additions. Toronto Hydro also maintains records of its distribution asset inspections pursuant to the Electrical Distribution Safety Regulation. When Toronto Hydro installs new assets on its distribution system on a planned or reactive basis, key data management systems must be updated based on relevant installation and inspection records.[7] Figure 3 below shows the historical and projected trend in the number of equipment change-outs processed and forecasted to be processed through the above systems.

[6] See Exhibit 2B, Section D2.
[7] e.g. Geographic Information System (GIS) – Referred to as GEAR (i.e. Geospatially Enabled Asset Registry), which also serves as the source of information for Toronto Hydro's DMS/NMS, and Enterprise Asset Management System (EAM) – Referred to as Ellipse, which at the time of filing was in the process of being replaced with SAP.

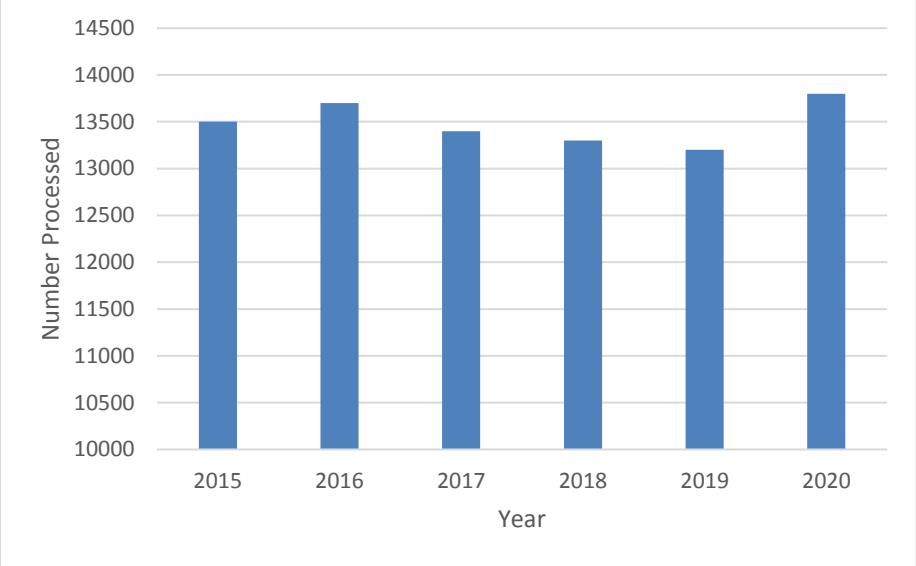


Figure 3: Number of Equipment Changeout Forms Processed

Failure to update systems and records when equipment is replaced or reconfigured in the system raises significant safety and reliability risks as this data is referenced and relied on daily by investment planners, system controllers, designers, and trades staff across the organization. The Records Management function plays a crucial role in ensuring the quality and accuracy of data maintained and used at Toronto Hydro.

5.2 System Planning Segment Costs

Toronto Hydro requires approximately $7.7 million each year during the 2020 to 2024 period to execute the functions in this segment. Table 4 provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for the segment.

Table 4: System Planning Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
System Planning	6.6	10.1	6.6	7.8	7.7	7.7

The 2020 test year costs represent an increase of $1.1 million from the utility's last rebasing year (2015), and an increase of $1.1 million from the most recent historical actual year (2017), and no change from the bridge year (2019).

5.3 System Planning Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

Costs in 2016 increased by $3.5 million over 2015 actuals. This is attributed to:

- An increase of $2.7 million associated with construction work in progress ("CWIP") write-offs in 2016 with respect to capacity, generation, records, investment, and maintenance and reliability work. These write-offs include any work that has had costs charged against it but is no longer required due to various factors including changes to system conditions, customer needs, or technology changes. $2.7 million represents approximately one percent of the scoped work that was executed in 2015. Beginning in 2016, Toronto Hydro undertook more rigorous reviews to identify work that qualifies as a CWIP write-off. Once this work is identified, the capital expenditure is expensed in accordance with applicable accounting policies.
- The remaining increase of $0.7 million is associated with increased payroll and contractor costs across the various functions for purposes that include updating RCM analyses, conducting preliminary work before implementing a new ACA framework, and addressing regulatory requirements.

2016 – 2017 Variance Explanation

The variance of $3.5 million from 2016 to 2017 is attributable to a reduction in CWIP write-offs.

2017 – 2018 Variance Explanation

Expenditures in 2018 are expected to increase by $1.2 million, as a result of inflation and a slight increase in the forecast for CWIP write-offs.

2018 – 2019 Variance Explanation

Costs in 2019 are expected to remain relatively consistent with 2018 costs.

2019 – 2020 Variance Explanation

Costs in 2020 are expected to be unchanged from costs in 2019, as a result of cost control measures offsetting inflationary pressures.

6. STANDARDS AND POLICIES SEGMENT

6.1 Segment Description

The Standards and Policies Segment is responsible for the development of the utility's design and construction standards, managing the utility's quality programs, and facilitating load connections through the offer to connect process.

More specifically, the segment's core function is the development and maintenance of design, construction and equipment standards and specifications for the electrical and civil construction work executed by Toronto Hydro. It is driven by the Electrical Distribution Safety Regulation, which requires distributors to create standard design drawings and specifications for all equipment comprising the distribution system. This function has a significant focus on safety with respect to utility workers as well as the public. "Safety by design" is a core principle routinely applied in the utility's decision making. Toronto Hydro has more than 1,000 construction standards managed by this function. Changes to these standards are driven by reliability improvements, new

technologies, regulatory changes, and industry standards (e.g. CSA standards) revisions. Figure 4 below shows the number of standard change requests processed in the past three years, as well as a forecast for 2018 to 2020. Recent increases are due to improvements to the standards change request process related to awareness, request submission, communication, and transparency.

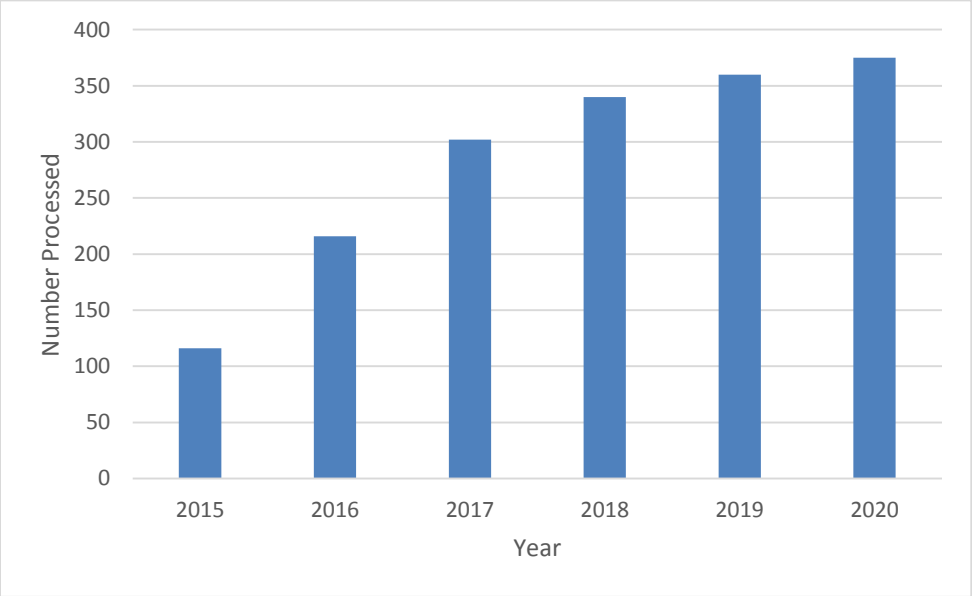


Figure 4: Number of Standards Change Requests Processed

The segment also provides services in the area of quality control throughout the equipment lifecycle. Quality audits, and reviews and investigations are conducted from when equipment and materials are procured from suppliers to when they fail in the field. Root cause analysis is the cornerstone of this segment's quality activities. Corrective and preventative actions, often issued through non-conformance reports to Toronto Hydro's equipment suppliers, drive improvements to standards and equipment. Where feasible, costs due to poor quality (e.g. equipment repairs and replacement) are recovered from equipment suppliers. This segment's quality programs play a critical

role in ensuring Toronto Hydro receives equipment of the highest quality from its suppliers. Figure 5 below shows the number of failed equipment returned from the field in the past three years, as well as a forecast for 2018 to 2020. Recent increases are due to improvements to the equipment return process related to employee training, awareness, and communication.

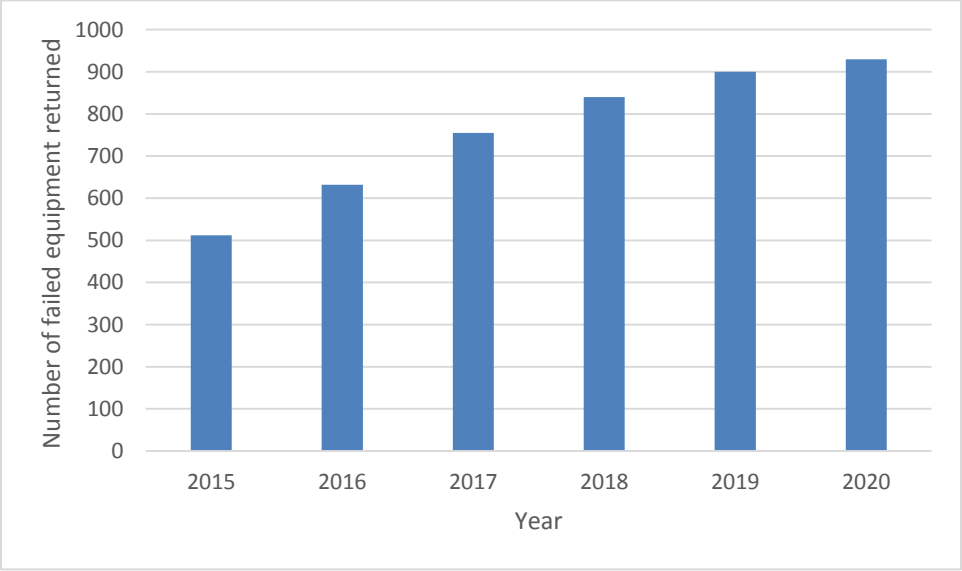


Figure 5: Number of Failed Equipment Returned from the Field

Finally, the Standards & Policies segment facilitates Toronto Hydro's offer to connect process, including economic evaluations to calculate capital contributions and expansion deposits for customer connections in accordance with the Distribution System Code. Additional details about Toronto Hydro's Customer Connections program may be found in Exhibit 2B, Section E5.1.

6.2 Standards and Policies Segment Costs

Toronto Hydro requires approximately $2.8 million each year during the 2020 to 2024 period to execute the functions in this segment. Table provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for the Standards and Policies segment.

Table 5: Standards and Policies Segment Expenditures ($ Million)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Standards & Policies	2.5	2.6	2.9	2.7	2.7	2.8

The 2020 test year costs represent an increase of $0.3 million from the utility's last rebasing year (2015), a $0.1 million decrease from the previous historical actual year (2017), and an increase of $0.1 million from the bridge year (2019).

6.3 Standards and Policies Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

There is no material variation in this period.

2016 – 2017 Variance Explanation

The variance of $0.3 million from 2016 to 2017 is attributable to an increase in spending on studies.

2017 – 2018 Variance Explanation

Costs in 2018 are expected to decrease by $0.2 million, as the net result of cost controls more than offsetting inflationary pressures.

2018 – 2019 Variance Explanation

Costs in 2019 are expected to remain stagnant over 2018, as the net result of cost controls offsetting inflationary pressures.

2019 – 2020 Variance Explanation

Costs in 2020 are expected to increase by $0.1 million over 2019, driven by a combination of the need to fund normal-course payroll cost escalations and inflationary pressures, slightly offset by cost control measures.

7. LOCAL DEMAND RESPONSE SEGMENT

7.1 Segment Description

The Local DR segment utilizes demand-side approaches to support Toronto Hydro's station expansion activities. The utility works to identify distribution system constraints that can be addressed using demand-side measures, enabling the deferral of potentially high-cost asset upgrades. Local DR supports the goals of the Conservation First Framework, the Toronto Integrated Regional Resource Plan ("IRRP") and the Ontario Long-Term Energy Plan ("LTEP") to meet local needs with distributed energy resources and conservation and demand response.

Local DR includes programs and technological solutions that encourage load curtailment and load-shifting, including targeted DR resource procurement at two stations: Cecil TS (continuation of current program) and Basin TS. These programs can help relieve capacity constraints using targeted deployment of DR, expanding the toolbox beyond wires options when determining the lowest cost capacity solution. Through DR, certain investment costs may be deferred, thus allowing the utility to reallocate and optimize capital as medium-term investment options are considered.

Local DR is needed to address capacity constraints that will begin developing in the 2020-2024 period. This program will mitigate the risks of operating the system in violation of applicable design parameters or having to undertake complex load transfer

projects to free up capacity for new customers. Failure to address the capacity constraint will lead to operational and reliability risks (see Exhibit 2B, Section E7.4, Stations Expansion program for more details).

7.2 Local Demand Response Segment Costs

Toronto Hydro requires approximately $0.8 million each year during the 2020 to 2024 period to execute the functions in this segment. Table 6 provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for the Local Demand Response segment.

Table 6: Local Demand Response Segment Expenditures ($ Millions)[8]

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Local Demand Response	0.1	0.0	-	1.7	2.3	0.8

The 2020 test year costs represent an increase of $0.7 million from the last rebasing year (2015), $0.8 million from the most recent actual year (2017), and a decrease of $1.5 million from the bridge year (2019).

7.3 Local Demand Response Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Analysis

Costs in 2016 decreased by $0.1 million over 2015 actuals. This is attributed to the lack of need for labour or operating costs during the development phase of the Local DR program.

[8] Capital costs for the Local DR segment are included in Exhibit 2B, Section E7.4, Stations Expansion, along with an analysis of cost-effectiveness.

2016 – 2017 Variance Explanation

Costs in 2017 were the same as those in 2016. Similarly, this is attributed to the lack of need for labour and operational costs for Local DR.

2017 – 2018 Variance Explanation

Costs in 2018 are expected to increase by $1.7 million over 2017 to develop program tools, contracts and marketing materials, to fund the operation of DR technologies (i.e. dispatch platforms), pay incentives to customers engaging in DR activities, and to support administrative functions.

2018 – 2019 Variance Explanation

Costs in 2019 are expected to increase by $0.6 million over 2018 to continue the functions carried out in 2018 with some minor variations in addition to expected increases in customer payments, and measurement and verification activities to assess the success of the 2015-2019 program.

2019 – 2020 Variance Explanation

Costs in 2020 are expected to decrease by $1.5 million over 2019. This is attributed to a decrease in customer payments (incentives) associated with the continuation of the Cecil TS DR related to a reduced capacity payment, and no costs required for marketing materials or contracts.

8. PROGRAM MANAGEMENT AND SUPPORT SEGMENT

8.1 Segment Description

The work in the Program Management and Support segment can be subdivided into four functional areas:

- Project Development
- Work Program Management
- Stations-Based Maintenance and Annual Feeder Scheduling
- Work Execution Support

Together, these activities enable the planning, budgeting, scheduling, resourcing, tracking and reporting of Toronto Hydro's distribution system-related programs. The segment also manages changes throughout the lifecycle of capital and maintenance projects.

Additionally, this function effectively allocates work, identifies and mitigates emerging risks, and coordinates and tracks capital projects and maintenance activities across the utility's service territory.

8.1.1 Project Development

The high level objectives for the Project Development function are to:

- Refine and finalize the scope of work of capital projects to support the generation of detailed designs for the construction of projects in the proposed project execution year.
- Ensure that the proposed work is executable before it is resourced and budgeted and prior to issuance to operations teams for detailed design and construction.
- Create budgetary estimates for capital construction projects to support budgeting and resource allocation by the work execution management team.
- Create work packages which allow construction and execution groups to prioritize, estimate and schedule work.

The Project Development process begins after receiving high-level capital project scopes of work from the System Planning function. Project Development staff then conduct field inspections, along with construction field subject matter experts, to determine project feasibility and execution risk. Project Development then produces refined scopes of work, preliminary designs, and estimates. It then aligns projects with execution work programs to allow for the most efficient use of resources. The project development team engages with internal and external stakeholders to ensure project timelines can be met and to avoid conflicts and delays when a project is undergoing construction.

Once a project is constructed, the Project Development group reviews actual scope and costs in comparison to planned estimates. Identified variance outcomes are reviewed for lessons learned to facilitate continuous improvement.

8.1.2 Work Program Management

The work program management function includes the following four activities: work allocation and resourcing for capital and maintenance projects; program and portfolio management and reporting; handling and processing customer inquiries for new connections, service repairs and service upgrades; and overseeing and supporting the customer vault access program. This coordinated approach allows Toronto Hydro to fulfill its program commitments to its customers and other stakeholders.

Part of the process of creating the execution work program is to check the resulting project labour requirements against the available labour schedules and make the appropriate resource allocations to discrete projects. Once the individual project-based analysis is complete, the combined program (i.e. a collection of individual projects) is

reviewed against available resources and other relevant reference information on an aggregate level, to identify any inconsistencies, deficiencies or sub-optimal resource utilization trends.

In addition to maintaining the program-wide resource balance, Program Management staff track the status of projects in the work program and the roll-up of the projects into programs and portfolios. While tracking project execution progress, Toronto Hydro seeks to proactively identify and monitor known or emerging risks that can impact the successful delivery of the work program, and develop the appropriate mitigation strategies.

Work Program Management responds to around 46,000 customer calls per year regarding requests related to new connections, service upgrades and repairs. Additionally, staff is responsible for updating customer records, scheduling appointments, issuing customer correspondence and field orders to ensure customers' needs are met within prescribed timelines.

The Work Program Management function also includes oversight and support of the customer vault access request program and customer deficiency resolution program. This includes customer work to correct civil and electrical deficiencies in a customer owned vault that contains Toronto Hydro equipment.

8.1.3 Stations-Based Maintenance and Annual Feeder Scheduling

Many projects require feeders to be taken out of service to create a safe work zone in accordance with safety requirements and practices. Each time a feeder is taken out of service in downtown Toronto, a combination of network and customer locations need

to be switched. Each of these switching steps requires a crew to visit the location and manually move switch handles. Once a feeder has been switched out, work on the system (such as maintenance or installation of new assets) can be performed.

Previously, maintenance work was executed with other work requiring a feeder outage. In some cases, this resulted in incomplete maintenance programs at year-end as certain feeders did not come out of service. Catch-up was then required in following years and maintenance of some assets was no longer within established cycles (e.g. every four years for SCADA switches, circuit breakers, overhead switches, and network protectors).

Given the resource requirements associated with switching downtown feeders, bundling work based on feeder synergies presents an opportunity for efficient work execution. A feeder "synergy" is defined as a group of jobs (e.g. planned capital, maintenance, customer, and reactive repair) executed at the same time when a feeder is taken out of service. This has increased the average number of completed jobs from 941 between 2010-2015 to 1,314 between 2016 and 2017.

Program Management and Support staff identify synergies on downtown feeders to create safety, reliability, customer, productivity and environmental benefits. From a safety perspective, some of the most significant hazards associated with switching include potential fire or explosion, electrical contact, musculoskeletal injuries, slips/falls and motor vehicle accidents driving to and from switch locations.

Other key benefits include:

- Higher attainment of capital and maintenance programs;
- Improved customer reliability due to fewer outages; and

- Enhanced system stability and flexibility with fewer feeders in an abnormal configuration.

8.1.4 Work Execution Support

During project execution, Toronto Hydro coordinates its work with the anticipated work of other utilities and City of Toronto planners. This is done iteratively, from the inception of a project to its completion. In the City of Toronto, it is especially critical to coordinate projects and obtain permits given the scale of new development, infrastructure renewal and major transit projects currently in development or construction. Work Execution staff maintain the databases and business processes necessary to coordinate the work and facilitate circulation of project data with other utilities. It seeks to maximize available synergies, prevent potential conflicts and reduce potential disruptions from construction projects to Toronto Hydro's customers.

Work Execution staff is responsible for securing timely and accurate approvals for the multiple roadway work permits Toronto Hydro requires throughout a given year. This involves coordination across Toronto Hydro engineers, designers, construction teams and City officials to ensure all relevant documentation is prepared in accordance with Municipal Consent Requirement for the installation of plant within City of Toronto streets.

Another critical function under the work execution support program is timekeeping. This entails monitoring, recording and supporting analytics of the labour efforts expended by field resources and engineering/design personnel. Such data collection allows Toronto Hydro to identify trends and adjust future planning and resource-allocation assumptions to better reflect the reality of the field conditions and increase efficiencies. Recently, operational efficiencies have been achieved through activities including the implementation of a web-based online timekeeping system for the entire organization.

Finally, the work execution support function provides oversight and governance over project and program management practices. This aims to ensure that business processes, including forecasting, risk identification, change management, progress tracking and analytics are being used for all applicable projects and programs. Given the number and variety of projects in Toronto Hydro's capital and maintenance work programs, the governance function is critical to ensure the integrity and accuracy of work plans and financial forecasts submitted to the OEB, its shareholders and other neighbouring utilities. In addition to providing oversight, it is also responsible for designing and maintaining procedural documents and project management tools in alignment with industry standards and best practices. This group also has ownership of the governance software systems that support these areas.

8.2 Program Management and Support Segment Costs

Toronto Hydro requires approximately $2.6 million each year during the 2020 to 2024 period to execute the functions in this segment. Table provides the Historical (2015-2017), Bridge (2018-2019), and Test tear (2020) expenditures for the Program Management and Support segment.

Table 7: Program Management and Support Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Program Managemnet & Support	2.0	5.3	2.0	2.6	2.6	2.6

The 2020 test year costs represent an increase of $0.6 million from the utility's last rebasing year (2015), a $0.6 million increase from the previous historical actual year (2017), and no net change from the bridge year (2019).

8.3 Program Management and Support Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

The variance of $3.3 million from 2015 to 2016 is attributable to:

- $2.8 million in write-offs for internal work execution, which were either: (i) design work for projects that may have been superseded by higher priority projects based on system or customer requirements; or (ii) urgent reactive work where replacement of major assets were expected but did not occur. After significant efforts to address these prior year projects and several related process improvements, the requirement for similar write-offs will be lower in future years covered by this rate application.
- An increase in $0.5 million as a result of the project development function being fully implemented in 2015 to enhance the sophistication of, and address certain risks associated with the delivery of the capital program.

2016 – 2017 Variance Explanation

Costs in 2017 decreased by $3.3 million over 2016 actuals, as a result of: (i) the lower requirement for write-offs due to the efforts made in 2016; and (ii) operational efficiencies achieved through software implementation as detailed in section 4.

2017 – 2018 Variance Explanation

Costs in 2018 are expected to increase by $0.6 million, driven by the transfer of employees from departments covered under other OM&A programs into the Work Program Execution program to support the formation of the Project Development function.[9]

[9] Exhibit 4A, Tab 2, Schedule 10

2018 – 2019 Variance Explanation

Costs in 2019 are expected to be the same as 2018, as the net result of operational efficiencies offsetting inflationary pressures.

2019 – 2020 Variance Explanation

Costs in 2020 are expected to be the same as 2019, as the net result of operational efficiencies offsetting inflationary pressures.

WORK PROGRAM EXECUTION

1. OVERVIEW

Table 1: Work Program Execution Program Summary

2015-2017 Average Annual Cost ($M): 19.8	**2020 Cost ($M):** 21.8
Segments: • External Work Execution • Internal Work Execution	
Outcomes: Reliability, Safety, and Financial	

The Work Program Execution program (the "Program") is responsible for oversight, administrative training, and other functions performed in the process of executing Toronto Hydro's capital and maintenance work programs, which are not eligible for capitalization in accordance with the utility's capitalization policy. The Program consists of the following two segments:

- **External Work Execution**: which covers the costs required to directly administer planning and execution of the portion of Toronto Hydro's capital and maintenance program that is completed by external contractors. This includes the issuance and oversight of capital and maintenance work to meet legislated and regulatory health and safety requirements; and
- **Internal Work Execution:** which covers the administrative and support costs for the portion of Toronto Hydro's capital and maintenance program that is completed by internal labour. This segment includes safety training costs for employees, including apprentices,[1] as well as costs for small tools issuances, Personal Protective Equipment ("PPE"), logistics, tracking, project-specific

[1] With the exception of Power System Controllers, see Exhibit 4A, Tab 2, Schedule 7.

planning, and supervisory time not directly attributable to a specific program or project.

The Program and its constituent segments are a continuation of the activities described in Operations Support – Work Program Execution in Toronto Hydro's 2015-2019 Rate Application.[2]

2. OUTCOMES AND MEASURES

Table 2: Work Program Execution Program Outcomes and Measures Summary

Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: o Undertaking oversight, administrative training and other functions performed in the process of executing Toronto Hydro's capital and maintenance work programs; and o Managing the administration associated with external contractors who respond to outages and reactive calls.
Safety	• Contributes to Toronto Hydro's safety objectives, measured through metrics such as the Total Recordable Injury Frequency ("TRIF"), by ensuring Toronto Hydro employees receive legislated safety training and possess the requisite tools and Personal Protective Equipment ("PPE") to perform their roles in a safe manner.
Financial	• Contributes to Toronto Hydro's financial objectives by ensuring that any work completed by external contractors is allocated based on a variety of factors including safety, costs, performance and qualifications. As a result, Toronto Hydro is able to determine the most qualified and cost efficient contractor for a specific project.

[2] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015), Exhibit 4A, Tab 2, Schedule 9. Note that in the utility's current Application, the "Contractor Administration" segment is now called "External Work Execution."

3. PROGRAM DESCRIPTION

The Program encompasses the labour costs for oversight and training activities relating to the execution of Toronto Hydro's capital and maintenance programs. This includes coordination and support of external contractors executing a portion of Toronto Hydro's capital and maintenance programs, the utility's internal design and construction crews, and apprentices. These activities are performed through two segments:

- **External Work Execution**, which covers the costs required to directly administer planning and execution of the portion of Toronto Hydro's capital and maintenance program that is completed by external contractors. This includes the issuance and oversight of capital and maintenance work to meet legislated and regulatory health and safety requirements; and
- **Internal Work Execution**, which covers the administrative and support costs for the portion of Toronto Hydro's capital and maintenance program that is completed by internal labour.

4. PROGRAM COSTS

Toronto Hydro requires approximately $21.8 million each year during the 2020 to 2024 period to execute the functions and activities described above. Without this level of funding, Toronto Hydro could be exposed to a number of risks, including**:**

- Decreased ability to meet legislated training targets, thereby exposing Toronto Hydro to unnecessary safety and legal risk;
- Reduced productivity due to inadequate tools and equipment;
- Increased risk of injury to employees and the public resulting from the lack of requisite PPE, clothing and equipment such as pylons, barriers, and hard hats; and
- Execution risk relating to a reduced ability to perform capital and maintenance plans due to lack of support and decrease in recruitment of skilled tradespeople.

Table 3, below, displays the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for the two segments comprising the Program.

Table 3: Work Program Execution Program Expenditures by Segment ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
External Work Execution	3.6	3.5	3.2	1.5	1.5	1.6
Internal Work Execution	15.9	16.0	17.4	17.6	18.7	20.2
Total	**19.5**	**19.5**	**20.5**	**19.1**	**20.3**	**21.8**

4.1 Cost Drivers

The 2020 test year cost forecast represents an increase of $2.3 million from the utility's last rebasing actual year costs (2015), $1.3 million from the most recent historical actual year (2017), and $1.5 million from the bridge year (2019). The primary cost drivers for this Program include an increase in training costs for new hires and the cost of safety equipment and clothing.

Due to retirements and attrition, recruitment within the Program is required to ensure staffing levels necessary to safely execute Toronto Hydro's capital and maintenance programs.[3] Toronto Hydro relies on a number of key certified and skilled positions, such as Certified Power Cable Person ("CPCP"), Certified Power Line Person ("CPLP"), Distribution System Technologist ("DST"), Certified Meter Mechanic/Tester, Engineering Technologist ("ETL"), and Engineers. All of these professions require a minimum number of hours training in order to fulfill their roles. The labour costs for such training is included in the Program.

[3] See Exhibit 4A, Tab 4, Schedule 3 for a discussion of Toronto Hydro's aging workforce and recruitment efforts.

The Program also funds safety equipment and PPE that is necessary for the health and safety of employees including reducing their exposure to hazards.

4.2 Cost Control & Productivity Measures

4.2.1 Cost Management

Toronto Hydro undertakes a number of measures to control costs within this Program, some of which are aimed at reducing training costs. Through the implementation of online training modules, employees now receive a substantial portion of their requisite training online. This eliminates added costs relating to travel time, and affords employees the flexibility to view the training at times that do not interfere with operations.

In addition, in 2018, Toronto Hydro began training its operational employees in groups in order to efficiently manage training a large number of similar tradespeople at the same time. Previously, if a course was required every three years, the course would be available every month for employees in need of a refresher. Currently, all Toronto Hydro tradespeople will undergo training together in 2018 and again in 2021. In doing so, the course will not need to be offered between those years and reduce the overall burden of managing the oversight of this training.

4.2.2 Productivity

Toronto Hydro continues to look for opportunities to improve the overall productivity of this Program. Since all of Toronto Hydro's external contractors have the requisite qualifications and experience to engage in all areas of Toronto Hydro's capital work, Toronto Hydro has implemented a process whereby work is allocated to specific contractors based on a variety of factors including safety, costs, performance, and

qualifications. As a result, Toronto Hydro is able to determine the most qualified and cost efficient contractor for a specific project.

5. EXTERNAL WORK EXECUTION SEGMENT

5.1 Segment Description

The External Work Execution segment consists of the administration of capital and maintenance work performed by external contractors. This function serves as the primary point of contact between Toronto Hydro and external contractors, including evaluating and administering competitive tenders for contractor services, providing oversight of the resulting contracts and administering support of the specific projects assigned to external contractor crews, such as:

- Job package development and issuance;
- Liaising with system planners to address specific design matters;
- Field issues management;
- Ordering of materials;
- Facilitating changing of project scopes;
- Monitoring contractor safety practices;
- Invoicing and receipting; and
- Inspection of newly constructed assets.

This segment ensures that Toronto Hydro provides the employees overseeing this function with training, safety equipment, and tools that ensure external contractors are adequately monitored and compliance with legislated and regulatory requirements is met.

Lastly, the External Work Execution segment also includes the administration costs associated with managing external contractors who respond to outages and reactive calls. Since this function is shared with Toronto Hydro employees, costs may also be included in the Internal Work Execution segment depending on the responding crew. Consequently, there are slight year-over-year cost variations depending on the identity of the response crews.

5.2 External Work Execution Segment Costs

Toronto Hydro requires approximately $1.5 million each year during the 2020 to 2024 period to to execute the functions in this segment. Table 4, below, provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for the External Work Execution segment.

Table 4: External Work Execution Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
External Work Execution	3.6	3.5	3.2	1.5	1.5	1.6

The 2020 test year costs proposed in this segment represents a decrease of $2.0 million from the utility's last rebasing actual year costs (2015), $1.6 million decrease from the most recent historical actual year (2017), and a $0.1 million increase from the bridge year (2019).

The costs for this segment can be separated into two categories:

- **Capital and Maintenance**: which includes the Program Support Office and Construction groups; and

- **Reactive Contractor Administration**: which covers the oversight of non-capital reactive work (for example, digging a splice pit to access a failed cable). In 2017 to 2020, this budget is currently under the Internal Work Execution segment and is transferred annually to account for the external assistance for reactive work.

5.3 External Work Execution Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

There is no material variance in this period.

2016 – 2017 Variance Explanation

There was a $0.3 million decrease resulting from lower oversight costs of external resources.

2017 – 2018 Variance Explanation

There is a $1.7 million decrease resulting from a budgeting practice that assumes that 100 percent of reactive work will be completed internally. Every year, reactive calls are mapped out depending on whether the work was completed internally, via the Internal Work Execution segment, or through external contractors, via the External Work Execution segment. This transfer is based on the amount of reactive work completed by either crew and the associated overhead costs. These transfers are completed yearly and reflect the relative breakdown between internal and external reactive costs. The transfer for this year has not happened yet and therefore, there is variance being reported.

2018 – 2019 Variance Explanation

There is no material variance in this period.

2019 – 2020 Variance Explanation

There is no material variance in this period.

6. INTERNAL WORK EXECUTION SEGMENT

6.1 Segment Description

The Internal Work Execution segment includes the administrative support and training costs associated with construction work performed by Toronto Hydro's internal construction and design employees. Among the costs included in this segment are small tools issuance, legislated training costs, office-related expenditures, as well as time not directly attributable to any specific capital program or project. This Program ensures that Toronto Hydro employees are receiving legislated safety training and possess the requisite tools and PPE to perform their roles in a safe and financially responsible manner.

6.1.1 Safety Training

As described in detail in the Human Resources and Safety program,[4] employee health and safety are top priorities at Toronto Hydro. Underlying this commitment is the extensive health and safety awareness and training work conducted throughout the year. Toronto Hydro certified tradespersons and apprentices participate in an average of five days of health and safety training per year. The training is aimed at providing employees with the tools and knowledge to perform their work safely and efficiently, thereby maximizing the value of their work for the utility and its customers.

In addition, due to the complexity of Toronto Hydro's distribution system and the number of legacy assets that are largely unique to the utility (e.g. Paper-Insulated Lead-

[4] Exhibit 4A, Tab 2, Schedule 15

Covered cable, Box Construction), apprentices are required to complete several years of theoretical and practical training to gain the skills and knowledge required to safely work on Toronto Hydro's distribution system.

6.1.2 Apprenticeships

The Internal Work Execution segment also includes a portion of (non-capitalized) expenditures associated with capital construction work performed by Toronto Hydro's skilled trades' apprentices. Certified and skilled trades are critical resources in the execution of Toronto Hydro's capital and maintenance programs. In light of the expected retirements over the 2020-2024 plan period, Toronto Hydro aims to maintain a sufficient complement of these key roles through recruitment into the apprenticeship training programs. As outlined in the Human Resources and Safety program, this Program includes apprentice labour costs for all classes of apprentices, with the exception of Power System Controllers.

6.2 Internal Work Execution Segment Costs

Toronto Hydro requires approximately $20.2 million in the 2020 test year to successfully execute the functions in this segment. Table 5, below, provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for the Internal Work Execution segment.

Table 5: Internal Work Execution Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Internal Work Execution	15.9	16.0	17.4	17.6	18.7	20.2

The 2020 test year cost forecast represents an increase of $4.3 million from the utility's last rebasing actual year costs (2015), $2.8 million increase from the most recent historical actual year (2017), and $1.5 increase million from the bridge year (2019). The variances are attributable to the following drivers:

- Implementation of a robust Apprentice Program in the 2020 to 2024 plan period. This strategy is to mitigate the large number of retirements expected from 2018 to 2020, specifically in the trades. See Exhibit 4A Tab 4 Schedule 3 for a discussion of Toronto Hydro's apprentice hiring efforts.
- As discussed in the External Work Execution segment, part of the costs from 2018 – 2020 from the Internal Work Execution segment will be transferred to the External Work Execution segment based on the oversight of external resources completing reactive non-capital reactive work. Based on 2015 and 2016 reconciliations, this can range from $2.0 million to $2.5 million.

6.3 Internal Work Execution Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

There is no material variance in this period.

2016 – 2017 Variance Explanation

The costs increased by $1.4 million due to a $5.3 million CWIP write-off offset by a reduction in overall head count costs and a slowdown in the apprentice hiring program for one year.

2017 – 2018 Variance Explanation

The costs increased by $0.2 million due to: (i) $5.3 million in CWIP write off in 2017; (ii) approximately $4.0 million in oversight and administration costs of reactive work

currently allocated in the Internal Execution segment, that will be transferred to the External Work Execution segment; and (iii) an increase in the Apprentice Program budget of approximately $1.5 million.

2018 – 2019 Variance Explanation

There is a $1.1 million increase due to an increase in the Apprentice Program.

2019 – 2020 Variance Explanation

There is a $1.5 million increase due to an increase in the Apprentice Program.

FLEET AND EQUIPMENT SERVICES

1. OVERVIEW

Table 1: Fleet and Equipment Services Program Summary

2015-2017 Average Cost ($M): 10.3	**2020 Cost ($M):** 11.0
Segments: Fleet and Equipment Services	
Outcomes: Reliability, Environment, Safety, and Financial	

The Fleet and Equipment Services program (the "Program") encompasses the administration of the procurement, maintenance, and disposal of Toronto Hydro vehicles, associated equipment and employee personal protective gear/equipment. Functions in this Program include ensuring certain safety equipment and implements are tested and repaired in accordance with occupational health and safety requirements and other applicable standards. Comprehensive and timely delivery of these services facilitates Toronto Hydro's ability to carry out its electricity distribution activities in a safe, reliable, and expedient manner.

The Program encompasses the services that oversee Toronto Hydro's 588 vehicle fleet, including a lab which provides testing services of safety equipment. The primary objective of the Program is to ensure the safe and reliable operation of all related vehicle assets and equipment, while managing these assets to the lowest overall lifecycle costs. The Program is a continuation of the activities described in the Fleet and Equipment Services program in Toronto Hydro's 2015-2019 Rate Application.[1] The majority of the core activities of the Program are governed by legislation administered by the Ministry of Transportation (the "MTO"), through the Electrical

[1] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015), Exhibit 4A, Tab 2, Schedule 10.

Utility Safety Rules ("EUSR"), and the *Occupational Health and Safety Act* (Ontario) ("OHSA"). In other words, the majority of the Program work is government mandated and non-discretionary and must be carried out by highly experienced and certified trade technicians.

2. OUTCOMES AND MEASURES

Table 2: Fleet and Equipment Services Program Outcomes and Measures Summary

Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: o Helping to ensure work crews have the ability to perform distribution work when required; and o Ensuring that the fleet is in good working order and assets are replaced before critical equipment failures arise that necessitate lengthy and costly offsite repairs.
Environment	• Contributes to Toronto Hydro's environmental objectives by aiming to reduce greenhouse gas ("GHG") emissions associated with fleet fuel consumption by: o Utilizing hybrid and electric vehicles and biofuels where possible; and o Implementing anti-idling technology, GPS reporting used to drive changes in driver behaviour, and the use of biofuels.[2]
Safety	• Contributes to Toronto Hydro's safety objectives as measured by metrics like Total Recordable Injury Frequency ("TRIF") by helping to ensure employees are working safely with minimal exposure to hazards by completing vehicle safety inspections.

[2] The use of technology to drive these results is limited by funding and classes of vehicles where the Return on Investment is justifiable.

Financial	• Contributes to Toronto Hydro's financial objectives as measured by the total cost and efficiency measures by: o Managing fleet and equipment assets to the lowest overall lifecycle costs; and o Mitigating fuel expenses by aiming to reduce fuel consumption through a combination of utilizing hybrid and electric vehicles; idle-reduction technologies; and adhering to recommended vehicle lifespans.

3. PROGRAM DESCRIPTION

The Program manages the lifecycle of vehicle and equipment assets, and the testing of related safety equipment for work on the distribution grid. This work involves the execution of competitive bids for equipment assets and related services (e.g. fueling, telematics, washing, lab testing, onboard technology), managing subsequent contracts and vendors, and the employment of skilled fleet mechanics. To ensure employee and public safety, the Program executes, in addition to ad-hoc corrective repairs, a preventative vehicle maintenance program in accordance with MTO requirements and original equipment manufacturers' ("OEM") guidelines. To ensure operator safety, Toronto Hydro equips its fleet with the necessary onboard equipment, specific to vehicle type, which can include ruggedized laptop mounts, truck grounds, air rescue kits, safety retrieval lines, and telematics systems. Toronto Hydro also employs technologies which reduce engine idle time and wear, in compliance with idle reduction targets by-laws.[3]

Toronto Hydro's fleet mechanics require a number of specialized licenses and certifications that enable them to perform repairs on utility equipment. In addition, the Program also includes the services of a North American Independent Laboratories

[3] Toronto Municipal Code, Chapter 517, Idling of Vehicles and Boats.

certified lab that provides the acquisition, certification and testing of safety tools, implements, and employee Personal Protective Equipment ("PPE") which are mandated by law for utility work. Current lab technicians are highly experienced (with more than 20 years of experience, on average) and are certified in the test and repair of gas monitors, system network protection relays, and rubber gloves. Improper functioning or lack of availability of these safety implements would expose workers to significant risks, such as potential exposure to harmful gases within vaults and cable chambers, and electrocution. Faults and failures of this equipment could also compromise grid integrity, thereby reducing system integrity.

4. PROGRAM COSTS

Toronto Hydro requires approximately $11 million each year during the 2020 to 2024 period to execute the functions in the Program, as described above. Table 3, below, provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for the Program. Program costs have remained fairly stable since the last rebasing period.

Table 3: Fleet and Equipment Services Program Expenditures ($ Millions)

Program	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Fleet and Equipment Services	10.1	9.8	11.0	10.9	11.0	11.0

The program costs cover the labour, parts, services and fuel attributable to the core program functions. The labour costs involve technicians who maintain, repair, and test all the capital assets within the Program (vehicles, equipment, and safety tools). The volume and pace of the preventative labour, as well as the testing requirements, are dictated by the legislated and policy recommendations of several oversight bodies.

Repairs to this equipment must be completed to ensure vehicles are safe for operators and the public, and the safety tools must be consistently tested to protect field employees on the job.

External service providers are used in cases where:

- The work entails greater physical risk, such as vehicle suspension work;
- The work does not require the technical expertise of a licensed mechanic, such as tire replacement;
- The work requires specific skills or credentials that Toronto Hydro employees do not possess, such as aerial lift dielectric testing; and
- The work uses equipment not owned by, or not readily accessible by the utility, such as vehicle emissions testing.

The Program also includes the costs for fueling, parts, tools, licences and insurance associated with the operation, maintenance and repair of the fleet equipment and safety programs. These costs are non-discretionary and are required for operations. Other operating costs include the employees associated with managing the Program's employees, who perform a variety of functions, including but not limited to advising on vehicle condition, administering the centralized vehicle pool and advising on standard vehicle selections for optimal safe and technical functioning, at the lowest available cost.

Without the requested funding for the Program, Toronto Hydro could be exposed to a number of risks, including:

- Reduced ability to procure all parts, services, and fuel required for proper vehicle functioning resulting in vehicle downtime, impaired ability to perform distribution work, and potentially prolonged outages;
- Reduction in the frequency, scope, and/or timeliness of vehicle maintenance work, resulting in undetected faults and potential public safety risks;
- Reduced ability to provide constant availability of certified and tested safety implements and PPE that are legislatively required for work;
- Inability to provide technologies and programs which yield sustained reduction in GHG emissions and adherence to idling by-laws;
- Reduced ability to perform management functions related to the continuous monitoring and compliance of legislated requirements; and
- Increase in costly and complex vehicle and equipment faults as a result of reduced labour capacity to perform routine maintenance.

To mitigate some of these risks, Toronto Hydro has invested in fuel-saving technologies and opts for electric and hybrid vehicles, where possible, to further save on fuel and engine-related maintenance costs. The overall fleet size has also been decreased from 660 in 2013 to 588 in 2017, which reduces maintenance, repair, and administrative costs. However, given that the average age profile of the fleet continues to escalate, these savings do not fully offset the operating costs required to sustain the current fleet.

4.1 Cost Drivers

The test year forecast represents an increase of $0.9 million from Toronto Hydro's last rebasing year (2015), remains flat when compared to the most recent historical actual year costs (2017), and remains flat from 2019 to 2020 at $11.0 million per annum.

Over 2015-2017, costs decreased due to the elimination of two administrative roles, however, these reductions were offset by an increase in vehicle-related parts and services over the same period due to maintenance costs.

4.2 Cost Control and Productivity Measures

4.2.1 Cost Management

- **Elimination of Under-Utilized Vehicles:** Toronto Hydro has reduced its fleet size in proportion to field crew attrition. Each vehicle reduction results in cost savings by eliminating the need for maintenance, repair, licensing, insurance, and associated fuel costs. On average, each vehicle removed from the fleet reduces operating costs by $2,000 to $7,000 per year. Since 2015, Toronto Hydro's fleet size has decreased by 30 vehicles (a net 5% reduction).
- **Fuel Cost Reduction**: Toronto Hydro has reduced its total fuel costs by investing in idling reduction technology and hybrid and electric vehicles.
- **Other Continuous Improvement Efforts:** The Program's employees improve processes, evaluate service agreements, and make ongoing adjustments where cost savings can be realized without increasing labour requirements. Specifically, since 2015, Toronto Hydro has generated approximately $100,000 of savings per year from the following initiatives: (i) utilizing GPS data for daily reporting on engine issues to proactively reduce breakdowns and towing; (ii) shifting externally sourced services to internal manpower where it is proven to be more cost effective; and (iii) streamlining of administration labour and processes. Between 2018 and 2020, following the completion of existing contracts, the Program plans to further explore measures to reduce parts and external services costs through the competitive bid process.

- **GPS Upgrade:** In 2016, GPS hardware was upgraded to prevent network service outages and to provide better reporting to further drive productivity gains. Engine data from the new devices is reported daily for any warning signs so that the vehicle can be brought in and serviced proactively, thus preventing more costly future failures that could arise, such as diesel particulate filter replacements. This reporting is also used to drive improvements in driver safety through management reporting on driving behaviour, which can help minimize incident frequency and related costs.

4.2.2 Productivity

Low utilization vehicles that are not required for dedicated use are allocated to a centralized vehicle pool for shared use. Specialized equipment, such as dump trucks and trailers, are allocated to the pool to eliminate the redundancy that would result from several crews with dedicated use of a particular piece of equipment.

4.3 Fleet and Equipment Services Program Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

From 2015 to 2016, costs decreased by $0.3 million (from $10.1 million to $9.8 million). This variance is comprised of:

- A $0.3 million reduction in fuel costs resulting from the timing of fuel allocations. The Program purchases all fuel upfront for the utility's use, and subsequently allocates those costs to other departments based on consumption. In 2016, these allocations exceeded total fuel costs due to an error in timing and system issue. These issues were later corrected in 2017.

2016 – 2017 Variance Explanation

From 2016 to 2017, costs increased by $1.2 million (from $9.8 million to $11.0 million). This variance is comprised of:

- An increase of $0.9 million resulting from fuel costs. The fuel allocation timing and system issues, referenced above, were resolved in 2017, resulting in a $0.9 million charge to the Fleet and Equipment Services Department. This charge was the result of a write-off of fuel allocations that should have been removed from inventory since mid-2014, but had not been removed due to an error in timing and system issues. The fuel consumption for the Fleet and Equipment Services Department (after normal allocations) is approximately $0.2 million per annum. In 2017, it was reflected as $1.0 million due to this fuel inventory correction ($1.0 million - $0.06 million typical use = $0.9 million, the value of the fuel reconciliation charge).
- An increase of $0.2 million for a mobile washing vendor. Toronto Hydro tendered a new mobile wash provider through a competitive bid process. The mobile wash vendor was the only technically qualified vendor, able to meet a City of Toronto By-Law requiring that all wash water must be prevented from entering storm sewers, and must be collected and removed from site.
- An increase of $0.1 million resulting from vehicle transfers. Toronto Hydro closed one of its three service garages towards the end of 2016, which created a need to transfer heavy duty vehicles from the west end location (71 Rexdale Blvd) to its central location (500 Commissioners) for some repair and maintenance jobs that rely upon having a fully equipped garage. The west location is equipped with a mobile service unit to handle less complicated repair and maintenance work. This cost increase to Fleet and Equipment Services was

offset by cost savings resulting from a reduced real estate footprint reflected in the Facilities Management program.[4]

2017 – 2018 Variance Explanation

From 2017 to 2018, costs are forecasted to decrease by $0.1 million (from $11.0 million to $10.9 million) as a result of a forecast decrease in fuel consumption.

2018 – 2019 Variance Explanation

From 2018 to 2019, costs increase by $0.1 million from $10.9 million to $11.0 million. This is attributable to:

- A $0.1 million reduction in payroll and labour costs due to retirements; and
- A $0.2 million increase in net vehicle costs due to forecasted increases in vehicle age.

2019 – 2020 Variance Explanation

There is no material variance in this period.

[4] Exhibit 4A, Tab 2, Schedule 12

FACILITIES MANAGEMENT

1. OVERVIEW

Table 1: Facilities Management Program Summary

2015-2017 Average Cost ($M): 26.8	**2020 Cost ($M):** 24.0
Segments: • Facilities Maintenance Services • Rentals & Leases • Utilities & Communications • Property Taxes	
Outcomes: Public Policy, Environment, Safety, and Financial	

Toronto Hydro's Facilities Management program (the "Program") delivers the workspace and property management services that enables the utility's employees to perform their work in optimally configured safe and structurally sound surroundings. The Program aims to maintain the utility's facilities in good working order and in compliance with applicable legislation and regulations. The Program is comprised of the following four segments:

- **Facilities Maintenance Services**: Work directed at maintaining and keeping the utility's facilities in good working order and in compliance with applicable legislation and regulations;
- **Rentals and Leases**: The costs associated with Toronto Hydro's leasehold agreements. Short-term equipment requirements are included in this segment;
- **Utilities and Communications**: Enabling technologies that allow Toronto Hydro to run and operate its facilities; and
- **Property Taxes**: Municipal taxes on the value of property held by Toronto Hydro.

The Program and its constituent segments are a continuation of the activities described in the Facilities Management program in Toronto Hydro's 2015-2019 Rate Application.[1]

2. OUTCOMES AND MEASURES

Table 2: Facilities Management Program Outcomes and Measures Summary

Reliability	• Contributes to Toronto Hydro's reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by executing a broad range of daily, monthly and annual maintenance activities for Toronto Hydro work centres and stations, many of which house assets critical to the proper functioning of the distribution system.
Environment	• Contributes to Toronto Hydro's environmental objectives by: o Conducting annual waste audits and monthly diversion reports which help Toronto Hydro comply with requirements of the *Waste Reduction and Waste Audit Work Plans* (O.Reg. 102/94) and maintain the *ISO 14001* certification for environmental management;[2] o Conducting Designated Substance Surveys, required under the *Occupational Health and Safety Act*, which help identify and dispose of designated substances in an environmentally compliant manner; and o Promoting Net Cumulative Energy Savings through efficient energy management, such as building automation and control and utilization of energy efficiency analytics and benchmarking reports.

[1] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015), Exhibit 4A, Tab 2, Schedule 11.
[2] International Organization for Standardization (2015). *Environmental Management Systems* (ISO/TC 14001). Retrieved from <https://www.iso.org/iso-14001-environmental-management.html>

Safety	• Contributes to Toronto Hydro's safety objectives, measured through metrics such as the Total Recordable Injury Frequency ("TRIF") by: o Ensuring compliance with Ontario's *Building Code*,[3] *Fire Code,*[4] and regulations under Ontario's *Environmental Protections Act,* in respect of emergency generator maintenance (O.Reg. 346/12), and the requirements contained in the *Fire Protection and Prevention Act, 1997* in respect of fire suppression certifications (O.Reg. 213/07); o Maintaining life safety systems (fire suppression & monitoring, first aid kits, etc.) housed within Toronto Hydro's buildings; o Completing prevention and routine maintenance and inspections on lighting and emergency exits; o Administering surveys (such as Asbestos Containing Material surveys required under OR 278/05) and sampling related to construction projects such as PCB containing caulking, lead paint, asbestos containing shingles, etc.; o Maintaining *OHSAS 18001* certification for Occupational Health and Safety Management using the Program's maintenance management system;[5] and o Managing security services such as guards, surveillance, access cards, etc., that secure and protect employees and distribution assets.

[3] S.O. 1992, c. 23 ["*Building Code Act*"].
[4] S.O. 1997, c. 4 ["*Fire Protection and Prevention Act*"].
[5] Occupational Safety and Health Administration (2018). *Occupational Health and Safety Management* (Standard No. 18001). Retrieved from <https://www.bsigroup.com/en-CA/BS-OHSAS-18001-Occupational-Health-and-Safety/>

Financial	• Contributes to Toronto Hydro's financial objectives by: o Utilizing a cost-effective maintenance approach involving a balance of preventative maintenance and run-to-fail strategies; o Avoiding monetary penalties for non-compliance with mandated legislative requirements; o Enhancing productivity of employees via the maintenance of optimally configured surroundings; o Utilizing the Facilities Asset Management Strategy to maximize the useful life of station and work centre supporting equipment; o Utilizing benchmarking data (e.g. *BOMA EER*) to optimize space utilization of existing footprint and control maintenance and utility costs;[6] and o Managing building operating costs by leveraging the added benefits (e.g. technology advancement and improved automation) of the capital modernization initiatives. The Program uses benchmarking data (e.g. *BOMA EER*) to optimize space utilization of existing footprint and control maintenance and utility costs.[6]

3. PROGRAM DESCRIPTION

Toronto Hydro's current building footprint consists of four work centres and 207 stations located throughout the City of Toronto. These buildings and stations are in various states of repair and range in age from historic sites to new buildings. Each property serves a unique function and must be maintained and serviced according to legislative and regulatory requirements, Toronto Hydro's environmental, health and safety policies, and the need to facilitate the distribution of electricity.

A subset of facilities maintenance work is driven by local and provincial government safety accessibility, emergency preparedness, and environmental regulations. Failure to

[6] BOMA Experience Exchange Report (2018).

comply with government regulations can result in temporary equipment lock out and/or fines, which may lead to costly interruptions to regular business activities that can ultimately affect Toronto Hydro's customers. In addition to this externally mandated work, the Program oversees the provision of services for Toronto Hydro buildings and stations which includes routine maintenance, preventative maintenance, office services, property maintenance, security and environmental services. These activities are undertaken through the following four segments: (i) Facilities & Maintenance Services; (ii) Rentals & Leases; (iii) Utilities & Communication; and (iv) Property Taxes.

4. PROGRAM COSTS

Toronto Hydro requires approximately $24.0 million each year during the 2020 to 2024 period to efficiently execute the activities in this Program, which are comprised of four segments: (i) Facilities Maintenance Services; (ii) Rentals and Leases; (iii) Utilities and Communications; and (iv) Property Taxes. Without adequate program funding, Toronto Hydro could be exposed to a number of risks, including, but not limited to**:**

- Fines, penalties, equipment lock out for non-compliance with the statutory and regulatory requirements;
- Service disruptions resulting from deferred maintenance at Toronto Hydro stations, which house critical distribution assets; and
- Employee and public safety risks resulting from the deferred maintenance.

Any reduction in funding levels would result in curtailment in the scope, frequency, and timeliness of maintenance activities. This could, in turn, create situations where safety issues or equipment malfunctions are not identified and rectified in a timely manner, thus imposing potential safety risks to the public and Toronto Hydro's employees or

compromising the utility's ability to perform its key functions due to equipment malfunctions.

The Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for each of the Program's segments are summarized in Table 3 below.

Table 3: Facilities Management Program Expenditures by Segment ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Facilities Maintenance Services	14.6	15.4	15.3	14.1	14.7	15.1
Rentals & Leases	5.2	5.3	1.7	0.3	0.4	0.4
Utilities & Communications	2.4	2.4	2.6	3.1	3.0	3.1
Property Taxes	5.2	4.6	5.6	5.6	5.4	5.5
Total	**27.4**	**27.8**	**25.3**	**23.2**	**23.4**	**24.0**

4.1 Cost Drivers

The 2020 test year forecast costs represent a decrease of $3.4 million from the utility's last rebasing year actual costs (2015), a decrease of $1.3 million from the most recent historical actual year (2017), and an increase of $0.6 million from the bridge year (2019).

These year-over-year variances are primarily attributable to building consolidation efforts that reduced the number of operating centres from seven to four. A breakdown of this effort is provided in the Facilities Program Cost Control Measures section that follows. As for the cost increase from the Bridge Year (2019) to the Test Year (2020), this timeframe marks the end of the consolidation efforts and the subsequent inflationary escalation thereafter.

4.1.1 Facilities Services Segment Cost Drivers

These variances are attributable to the following factors:

- The operating centre consolidation effort that reduced the overall building footprint, which in turn minimized the scope of the FMO;
- The addition of Copeland TS to the stations portfolio;
- Variable reactive maintenance due to the age of facilities' assets;
- Change order management; and
- Period inflationary escalations.

4.1.2 Rentals and Leases Cost Drivers

The Test Year (2020) costs associated with this segment are projected to be $0.4 million, which represents a decrease of $4.8 million from the utility's last rebasing year actual costs (2015), a decrease of $1.3 million from the most recent historical actual year costs (2017), and no increase from the bridge year (2019). These variances are attributable to the following drivers/factors:

- The expiry of two leases related to the OCCP;
- A change to the accounting treatment of leased facilities; and
- Inflationary pressures from 2019 and onward.

4.1.3 Utilities and Telecommunication Cost Drivers

The Test Year (2020) costs associated with this segment are projected to be $3.1 million, which represents an increase of $0.7 million from the utility's last rebasing year (2015), a $0.5 million increase from the most recent historical actual year (2017), and a $0.1 million increase from the bridge year (2019). The increase since the last rebasing year (2015) is a by-product of the end of the rental lease since property ownership leads to direct responsibility for utility costs.

4.1.4 Property Tax Segment Cost Drivers

The 2020 proposed test year costs associated with this segment are projected to be $5.5 million, which represents an increase of $0.3 million from the utility's last rebasing year (2015), a $0.1 million reduction from the most recent historical actual year (2017), and a $0.1 million increase from the bridge year (2019). These variances are attributable to the following drivers/factors:

- The use of a City of Toronto Property Tax Rebate program that provides savings for unoccupied commercial property; and
- The execution of the OCCP phases.

Absent the requested level of funding for this segment, Toronto Hydro could not pay its full property tax burden. This would lead to interest payments on the deferred amount, increasing overall costs.

4.2 Cost Control and Productivity Measures

Toronto Hydro uses the following tools and initiatives to control Program costs:

4.2.1 Real Estate Management

The primary driver of cost reductions in this Program are the realization of the net benefits resulting from Toronto Hydro's approach to the management of its real estate portfolio. The Operating Centres Consolidation Program ("OCCP")[7] was a real estate initiative from 2014 to 2018 driven by three primary outcomes:

a) Ensuring security of tenure at major crew-supporting operating centres;

[7] EB-2014-0116, Toronto Hydro-Electric System Limited, Exhibit 2B, Section E8.3 (Filed July 31, 2014, Corrected: September 23, 2014).

b) Ensuring the uninterrupted continuation of critical functions (i.e. Data, Control and Call Centres) by transferring these functions to a location where vital fibre-optic communication facilities and uninterruptable power supply are available or can be installed; and

c) Achieving cost savings for ratepayers through:

(i) Allocation of net after-tax gains and related tax savings on sale of properties;

(ii) Eliminating otherwise ongoing property-related costs associated with the properties; and

(iii) Increasing the utilization of remaining properties.

To deliver these outcomes, the OCCP was executed in four phases, see Table 4 blow.

Table 4: Consolidation of Toronto Hydro's Operating Centres

Phase No.	Phase Description	Execution Timing	Financial Impact
1	Sale of 5800 Yong Street	Mid-2018	Facilities services and costs no longer incurred. Proceeds to be returned to ratepayers.
2	Transfer of staff & operations from 601 Milner to 715 Milner	Mid-2017	The termination of the leases presented significant savings for the 'Rentals & Leases' segment. Cost in relation to the owned facilities partially offset these benefits.
3	Transfer of staff & operations from 6 Monogram to 71 Rexdale	Q4 2016	
4	Disposal of property at 28 Underwriters	Q2 2015	Facilities services and costs no longer incurred.

The resulting benefit of executing the phases of the OCCP translated to the year-over-year segment cost savings presented below:

Table 5: Year-Over-Year Cost Impact of the OCCP

Segment	14-15	15-16	16-17	17-18	18-19	19-20
Facilities Maintenance Services	-2.2	1.3	0.1	-1.8	0.2	0.0
Rentals & Leases	0.0	-0.1	-3.7	-1.2	0.0	0.0
Utilities & Communications	-0.6	-0.1	0.1	0.5	-0.2	0.0
Property Taxes	-0.1	0.0	0.5	-0.1	-0.3	0.0
Total Variance	**-2.9**	**1.1**	**-3.0**	**-2.6**	**-0.3**	**0.0**

In addition, in June 2017, the effectiveness of the Program's space utilization efforts allowed Toronto Hydro to dispose of an additional property at 60 Eglinton, the proceeds of which will be returned to ratepayers. The employees from 60 Eglinton were transferred to other Toronto Hydro owned-properties in June 2017, allowing for a reduction in maintenance costs, see Table 6 below.[8]

Table 6: Cost Implications of the Disposition of 60 Eglington

Segment	14-15	15-16	16-17	17-18	18-19	19-20
Facilities Maintenance Services	0.0	0.0	-0.1	-0.1	-0.1	0.0
Rentals & Leases	0.0	0.0	0.0	0.0	0.0	0.0
Utilities & Communications	0.0	0.0	0.0	-0.1	0.0	0.0
Property Taxes	0.0	0.0	0.0	0.0	0.0	0.0
Total Variance	**0.0**	**0.0**	**-0.1**	**-0.2**	**-0.1**	**0.0**

4.2.2 Hybrid Maintenance Approach

The use of a combination of internal resources and a third-party provider allows for the execution of a cost-effective maintenance approach involving a balance of preventative maintenance and run-to-fail strategies. This arrangement effectively creates a "one-window" approach for all facilities-related requests from employees and facilitates effective coordination of work.

[8] Toronto Hydro retains a lease for the property until June 2018 to provide the requisite time to decommission assets.

4.2.3 Performance Benchmarking

Leveraging parametric data received through membership in industry associations such as the Building Owners and Managers Association ("BOMA") to improve Toronto Hydro's operating efficiency. For instance, the regional BOMA Experience Exchange Reports ("EER") measures the cost per square-foot of key FMP functions against other peer utilities. In addition, performance is also tracked using benchmarking data retrieved from the Energy Star Portfolio Manager, an online tool to measure and track energy and water consumption against other commercial and institutional buildings. Toronto Hydro uses this data to analyze its performance and make recommendations for improvements to areas such as energy and utilities conservation.

4.2.4 Data Driven Decision Making

Toronto Hydro utilizes a comprehensive management system (CMMS) that tracks and schedules maintenance work and manages records. This database contains, among other things, historical data on the types of requests from each operating centre, and provides the ability to query the work order data related to sub-programs within this segment (e.g. repair and maintenance, cleaning, exterior grounds, etc.). The ability to differentiate the time spent on these different activity types allows for the related resource costs to be measured. This, in conjunction with departmental performance measures tracking the percentage of labour utilization, maximizes the time spent performing actual maintenance and repair work.

4.3 Segment-Specific Cost Control Measures

4.3.1 Rentals and Leases Segment Cost Control Measures

Toronto Hydro minimizes costs within this segment by working with commercial brokerage companies to secure appropriate office spaces, when needed, at fair market

value with favourable contractual arrangements. Currently, the utility has 12,000 square-feet of leased space and the rental costs are determined via existing agreements with owners of properties. However, Toronto Hydro's focus on utilizing owned rather than leased properties has led to some cost savings within this segment. Since the last rebasing year, Toronto Hydro eliminated 1.0 million square-feet of leased property.

4.3.2 Utilities and Telecommunication Segment Cost Control Measures

To mitigate the cost escalation, Toronto Hydro works to improve its energy efficiency performance (i.e. electricity, natural gas and water consumption) by progressively upgrading the equipment standards used across its facilities, where justifiable. These improvements allow Toronto Hydro to partially control/offset the pace and scale of externally driven escalations. Further, Toronto Hydro has begun enrolling its operating centres in the BOMA Best program, which provides visual reporting (e.g. dashboard, time plotted data, etc.) for electricity, gas and water consumption. This feature will aid performance tracking, allowing the FMP to control operating expenditures by stretching performance measures such as the Equivalent kilowatt hours per square-foot (ekWh/ft^2) on an annual basis (see Outcomes and Measures section above).

4.3.3 Property Tax Segment Cost Control Measures

Following the recent consolidation initiatives to reduce the number of Toronto Hydro's properties, the primary cost control measures are space management and tax rebate programs when available. An example of a tax rebate program that has been utilized to control costs is the "Vacant Commercial & Industrial Unit Tax Rebate Program", which provides savings of 30 percent for vacant properties.[9] Through this Program Toronto

[9] Vacant Commercial & Industrial Unit Tax Rebate Program (2017). Retrieved from <https://www.toronto.ca/services-payments/property-taxes-utilities/property-tax/property-tax-rebates-and-relief-programs/vacancy-rebate-program/.>

Hydro has reduced its property tax burden (See 2015-2016 variance explanation) by having its Stations properties reassessed by MPAC to reflect current occupancy.

5. FACILITIES MAINTENANCE SERVICES SEGMENT

5.1 Segment Description

Toronto Hydro's Facilities Maintenance Segment covers a broad range of daily, monthly, and annual maintenance activities that are driven by statutory and regulatory requirements, internal health and safety policies, building and asset condition reports, and industry best practices. The focus of this segment is to provide Toronto Hydro employees with a safe work environment that encourages effective and efficient execution of their duties, as well as to ensure that all owned and leased properties and buildings, including stations, are structurally sound and ensure employee and public safety.

Failure to comply with government regulations can result in temporary equipment lock out and/or fines, which may lead to costly interruptions to regular business activities that can ultimately affect Toronto Hydro's customers. In addition to the externally mandated work, the Program oversees the provision of services for Toronto Hydro buildings and stations.

Toronto Hydro relies on a combination of internal resources and a third-party service provider to execute the Program functions.[10] This arrangement allows Toronto Hydro to react to issues sooner, track data on reoccurring problems in a systematic manner, and formulate improved planning activities. These planning activities include all the

[10] Please refer to EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015), Exhibit 4A, Tab 2, Schedule 11 for a detailed discussion of this arrangement.

necessary tasks and services to maintain the properties, including offices, work centres and the buildings housing the utility's Transformer and Municipal stations ("TS" and "MS", respectively). Toronto Hydro's attention to regular preventative maintenance of its office buildings, work centres, and stations contributes to the utility's safety record. Toronto Hydro utilizes a cost-effective maintenance approach involving a balance of preventative maintenance and run-to-fail strategies. Run-to-fail strategies apply to low impact and low cost equipment that have readily available parts or replacements, and for which the cost of preventative work would be wasteful. Balancing the two methods keeps vital building systems operable while allowing technicians' capacity for proactive and reactive work. The CMMS schedules and tracks this approach through the following maintenance activities:

- **Preventative Maintenance**: Routine inspections and tasks to ensure that equipment, systems, and their respective components are fully operational. This includes activities such as periodic inspections of magnetic locks on all of Toronto Hydro's emergency exits, to prevent unauthorized entry and release when a fire alarm is activated.
- **Corrective Maintenance**: Through its routine preventative inspections, Toronto Hydro identifies the systems and equipment requiring corrective work, ensuring that any malfunctions are proactively rectified.
- **Reactive Maintenance**: Involves response to reports and requests to address any specific issues that arise from time to time. Examples of reactive work include repairs of run-to-fail assets, adjustments of building temperatures to meet the requirements of the *Occupational Health and Safety Act*,[11] lighting replacements, and repairs to parking gates.

[11] R.S.O. 1990, c. O.1 ["*Occupational Health and Safety Act*"].

5.2 Facilities Maintenance Services Segment Costs

The Test Year (2020) costs associated with this segment are projected to be $15.1 million. These costs include both internal and external work, vehicle costs for travel between sites and other related expenses. Table 7, below, provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for the Facilities Maintenance Services Segment.

Table 7: Facilities Maintenance Services Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Facilities Maintenance Services	14.6	15.4	15.3	14.1	14.7	15.1

The 2020 test year costs represent an increase of $0.5 million from the utility's last rebasing year (2015) actuals, a $0.2 million reduction from the most recent historical actual year (2017), and a $0.4 million increase from the bridge year (2019).

5.3 Facilities Maintenance Services Segment Year-over-Year Variance Analysis

This section provides a variance explanation for the year-over-year changes to the Facilities Maintenance Service Segment dating back to the last rebasing period (2015).

Table 8: Attribution of Year-over-Year Cost Variance ($ Millions)

Facilities & Maintenance Services	15-16	16-17	17-18	18-19	19-20
OCCP	1.3	0.1	-1.8	0.2	0.0
Other Consolidation	0.0	-0.1	-0.1	-0.1	0.0
Copeland TS			0.4		
Reporting Change	-1.1				
Reactive Work	0.3	-0.3	0.0	0.2	0.0
Escalation(s)	0.3	0.2	0.3	0.3	0.4
Total Variance	**0.8**	**-0.1**	**-1.2**	**0.6**	**0.4**

2015 – 2016 Variance Explanation

The $0.8 million increase from 2015 to 2016 is attributable to:

- A $1.3 million increase resulting from move-related costs related to the OCCP;
- A $1.1 million decrease, resulting from one-time environmental remediation costs being incurred 2015;
- A $0.3 million increase resulting from more reactive maintenance activities; and
- A $0.3 million increase resulting from inflationary pressures, such as material prices and compensation.

2016 – 2017 Variance Explanation

The $0.1 million reduction from 2016 to 2017 is attributable to:

- A $0.1 million increase resulting from the OCCP;
- A $0.1 million decrease resulting from maintenance scope reduction for the property at 60 Eglinton Avenue;
- $0.3 million decrease resulting from a decrease in reactive work; and
- A $0.2 million increase resulting from inflationary pressures, such as material prices and compensation.

2017 – 2018 Variance Explanation

The $1.2 million reduction from 2017 to 2018 is attributable to:

- A $1.8 million decrease resulting from the net impact of a property disposition, and incurring final consolidation-related costs in 2017;
- A $0.1 million forecasted decrease in costs resulting from the lease termination of 60 Eglinton in June 2018;
- A $0.4 million increase resulting from the expected increase in maintenance costs for a newly commissioned substation (i.e. Copeland TS); and
- A $0.3 million increase resulting from inflationary pressures, such as material prices and compensation.

2018 – 2019 Variance Explanation

The $0.6 million increase from 2018 to 2019 is attributable to:

- A $0.2 million increase resulting from lagging maintenance costs related to building systems and equipment coming off warranty at the newly constructed owned facilities;
- A $0.1 million decrease resulting from the disposal of 60 Eglinton in June 2018;
- A $0.2 million increase resulting from anticipated reactive maintenance work based on the existing condition assessments; and
- A $0.3 million increase resulting from inflationary pressures, such as material prices and compensation.

2019 – 2020 Variance Explanation

The $0.4 million increase from 2018 to 2019 is attributable to inflationary pressures.

6. RENTALS AND LEASES SEGMENT

6.1 Segment Description

The utility's rentals and leases expenditures are driven by the need for sufficient, properly configured, and cost-effective office and work centre spaces. Over the current rate period, Toronto Hydro eliminated 1.5 million square-feet of leased property. The residual lease costs are for office spaces located near Toronto Hydro's main owned facilities and are required for staff for whom there is insufficient space within those owned facilities.

6.2 Rentals and Leases Segment Costs

Table 9 below provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for the Rentals and Leases segment.

Table 9: Rentals and Leases Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Rentals & Leases	5.2	5.3	1.7	0.3	0.4	0.4

The 2020 test year costs represent an decrease of $4.8 million from the utility's last rebasing year (2015) actuals, a $1.3 million reduction from the most recent historical actual year (2017), and no change from the bridge year (2019).

6.3 Rentals and Leases Segment Year-over-Year Variance Analysis

This section provides a variance explanation for the year-over-year changes to the Rentals and Leases Segment going back to the last rebasing period (2015).

Table 10: Attribution of Year-over-Year Cost Variance ($ Millions)

Rentals & Leases	15-16	16-17	17-18	18-19	19-20
OCCP	-0.1	-3.7	-1.2	0.0	0.0
Accounting Treatment	0.0	0.0	-0.3	0.0	0.0
Escalation(s)	0.2	0.1	0.1	0.1	0.0
Total Variance	**0.1**	**-3.6**	**-1.4**	**0.1**	**0.0**

2015 – 2016 Variance Explanation

The increase of $0.1 million from 2015 to 2016 is attributable to:

- A $0.1 million decrease resulting from the OCCP i.e. termination of an operating centre lease in November 2016; and
- A $0.2 million increase resulting from contractual escalations.

2016 – 2017 Variance Explanation

The decrease of $3.6 million from 2016 to 2017 was attributable to:

- A decrease of $3.7 million relating to the OCCP. The residual benefit of the lease terminated November 2016 was realized since the expenditure was eliminated. Phase 2 of the OCCP was completed July 2017, which presented an additional five months of savings for 2017; and
- A $0.1 million increase resulting from contractual escalations.

2017 – 2018 Variance Explanation

The decrease of $1.4 million from 2017 to 2018 was attributable to:

- A $1.2 million decrease resulting from Phase 2 of the OCCP i.e. the 7 months of rent incurred during the 2017 period was removed from the 2018 budget;
- A $0.3 million decrease related to a new accounting treatment for leases (i.e. IFRS 16), which treats the base rent as capital expenditure; and

- A $0.1 million increase resulting from contractual escalations.

2018 – 2019 Variance Explanation

The increase of $0.1 million from 2018 to 2019 is attributable to contractual escalations.

2019 – 2020 Variance Explanation

Negligible contract escalations.

7. UTILITIES AND COMMUNICATIONS SEGMENT

7.1 Segment Description

The Utilities and Communications segment encompasses the costs of providing water, electricity, natural gas, and related services to Toronto Hydro's office buildings, work centres, and stations. The utility's costs for this segment are driven by the costs charged by various service providers. Beyond service rate increases, the year-over-year cost variances are affected by fluctuations in weather, such as extremely hot summers that increase electricity consumption or cooler-than-normal winters that result in higher heating expenditures.

Toronto Hydro works to manage its costs by promoting conservation and improving the energy efficiency of its facilities. To facilitate consistent implementation of energy efficiency standards, Toronto Hydro developed standards that outline the relevant energy, water, and gas efficiency criteria that the utility's new and renovated work spaces must adhere to. Consistent with its standards, Toronto Hydro has upgraded a large portion of its shared spaces with energy efficient lights, where it is economical to do so. The utility is also working to gradually convert its bathrooms to low-flow technologies.

Similar to other utilities, telecommunications are another key component of this Program's expenditures. Desk phones, cell phones, internet access and other wireless communication equipment and services are vital tools for the day-to-day operations. Beyond the typical business enablers, communications services and infrastructure enable the utility's security systems to communicate with command posts via fibre-optics or wireless networks, and allow service vehicles to have constant communication with dispatchers and the Control Centre.

7.2 Utilities and Communications Segment Costs

Table 11 below provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures relating to Utilities and Communications.

Table 11: Utilities and Communications Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Utilities & Communications	2.4	2.4	2.6	3.1	3.0	3.1

The 2020 test year costs represent an increase of $0.7 million from the utility's last rebasing year (2015) actuals, a $0.5 million increase from the most recent historical actual year (2017), and a $0.1 million increase from the bridge year (2019).

7.3 Utilities and Communications Segment Year-over-Year Variance Analysis

This section provides a variance explanation for the year-over-year changes to the Utilities and Communications Segment dating back to the last rebasing period (2015).

Table 12: Attribution of the Year-over-Year Cost Variance ($ Millions)

Utilities & Communications	15-16	16-17	17-18	18-19	19-20
OCCP	-0.1	0.1	0.5	-0.2	0.0
Other Consolidation	0.0	0.0	-0.1	0.0	0.0
Escalation(s)	0.1	0.1	0.1	0.1	0.1
Total Variance	**0.0**	**0.2**	**0.5**	**-0.1**	**0.1**

2015 – 2016 Variance Explanation

The negligible change from 2015 to 2016 was attributable to:

- A $0.1 million decrease resulting from the disposition of 28 Underwriters (as part of the OCCP); and
- A $0.1 million increase resulting from the annual increase of utility and communication rates.

2016 – 2017 Variance Explanation

The $0.2 million increase from 2016 to 2017 was attributable to:

- A $0.1 million increase resulting from the OCCP, which added incremental ownership costs to the segment. Previously, the leasehold arrangements included the utility costs in the rent payments; and
- A $0.1 million increase resulting from the annual increase of utility and communication rates.

2017 – 2018 Variance Explanation

The $0.5 million increase from 2017 to 2018 was attributable to:

- A $0.5 million increase resulting from the OCCP. The sale of 5800 Yonge, was completed in April 2018 reducing the annual expenditure. Offsetting this

reduction was the full annual expenditure related to the new property coming online July 2017; and

- A $0.1 million decrease related to the additional disposition of the property at 60 Eglinton due to the effectiveness of the OCCP.
- A $0.1 million increase resulting from the annual increase of utility and communication rates.

2018 – 2019 Variance Explanation

The $0.1 million decrease from 2018 to 2029 was attributable to:

- A $0.2 million decrease resulting from the reduction in annual expenditures for 2019 due to the sale of 5800 Yonge in Q2 2018.
- A $0.1 million increase resulting from the annual increase of utility and communication rates.

2019 – 2020 Variance Explanation

The $0.1 million increase from 2019 to 2020 was attributable to:

- Inflationary cost escalation resulting from the annual rate increases.

8. PROPERTY TAXES SEGMENT

8.1 Segment Description

Property taxes are based on the amount of the property owned by Toronto Hydro, the municipal tax rates and any applicable credits. With more than 5,000,000 square feet of property in the City of Toronto, property taxes are a significant expense for Toronto Hydro. Historically, Toronto Hydro's property taxes have increased at the rate of inflation. Toronto Hydro expects a similar trend to continue through the Test Year, which is reflected in the utility's forecasts.

8.2 Property Taxes Segment Costs

Table 13 below provides the Historical (2015-2017), Bridge (2018-2019) and Test Year (2020) expenditures relating to Property Taxes.

Table 13: Property Taxes Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Property Taxes	5.2	4.6	5.6	5.6	5.4	5.5

The 2020 test year costs represent an increase of $0.3 million from the utility's last rebasing year (2015) actuals, a $0.1 million reduction from the most recent historical actual year (2017), and a $0.1 million increase from the bridge year (2019).

8.3 Property Taxes Segment Year-over-Year Variance Analysis

This section provides a variance explanation for the year-over-year changes to the Property Tax Segment going back to the last rebasing period (2015).

Table 14: Attribution of the Year-over-Year Cost Variance ($ Millions)

Property Taxes	15-16	16-17	17-18	18-19	19-20
OCCP	0.0	0.5	-0.1	-0.3	0.0
Other Consolidation	0.0	0.0	0.0	0.0	0.0
Tax Rebate Initiative	-0.7	n/a	n/a	n/a	n/a
Escalations	0.1	0.5	0.1	0.1	0.1
Total Variance	**-0.6**	**1.0**	**0.0**	**-0.2**	**0.1**

2015 – 2016 Variance Explanation

The $0.6 million reduction from 2015 to 2016 is attributable to:

- A $0.7 million decrease resulting from the Vacant Commercial & Industrial Unit Tax Rebate Program described above as a cost control measure; and
- A $0.1 million increase resulting from inflationary pressure on the prescribed commercial rates.

2016 – 2017 Variance Explanation

The $1.0 million increase from 2016 to 2017 is attributable to:

- A $0.5 million increase resulting from the OCCP. The occupancy of the newly constructed owned properties introduced costs previously embedded in the rent payments; and
- A $0.5 million increase resulting from MPAC reassessments of Toronto Hydro-owned properties and rate increases.

2017 – 2018 Variance Explanation

The negligible change between these periods is attributable to:

- A $0.1 million decrease resulting from the completion of the OCCP. The transition from 601 Milner to 715 Milner was completed in July of 2017, offset by the sale of 5800 Yonge, which completed in April 2018; and
- A $0.1 million increase resulting from inflationary pressure on the prescribed commercial rates.

2018 – 2019 Variance Explanation

The $0.2 million reduction from 2018 to 2019 is attributable to:

- A $0.3 million reduction representing continued benefit realization from the OCCP. The property tax expenditure incurred for 5800 Yonge in 2017 was eliminated for 2018; and

- A $0.1 million increase resulting from inflationary pressure on the prescribed commercial rates.

2019 – 2020 Variance Explanation

The increase of $0.1 million from 2019 to 2020 is attributable to A $0.1 million increase resulting from inflationary pressure on the prescribed commercial rates.

SUPPLY CHAIN SERVICES

1. OVERVIEW

Table 1: Supply Chain Services Program Summary

2015-2017 Average Cost ($M): 11.7	**2020 Cost ($M):** 12.6
Segments: Supply Chain Services	
Outcomes: Reliability, Environment, and Financial	

The Supply Chain Services program (the "Program") supports the execution of Toronto Hydro's capital and operating programs that rely on procurement and warehousing activities. The objectives of the Program are to facilitate timely and cost-effective acquisition of services, materials and equipment, maintain sufficient inventory to support uninterrupted work execution, and manage material handling costs.

The Program consists of two interrelated functions: (i) Demand and Acquisition Services; and (ii) Warehouse and Logistics. The Demand and Acquisition Services function secures the requisite equipment, materials and services for Toronto Hydro within specified timelines and at an optimal cost. It also monitors vendor performance to ensure that the goods and services acquired are being delivered to Toronto Hydro in an efficient and effective manner. The Warehouse and Logistics function facilitates coordinated, cost-effective and timely receiving, stocking and distribution of materials and equipment required to execute Toronto Hydro's capital and maintenance work programs. The Program and its activities are a continuation of the Supply Chain Services program described in Toronto Hydro's 2015-2019 Rate Application.[1]

[1] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015), Exhibit 4A, Tab 2, Schedule 12.

2. OUTCOMES AND MEASURES

Table 2: Supply Chain Services Program Outcomes and Measures Summary

Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: ○ Supporting the effective execution of capital and maintenance programs by fulfilling warehouse orders and fulfilling supplier deliveries; and ○ Supporting Toronto Hydro's ability to respond to outages promptly and restore power through effective management of inventory.
Environment	• Contributes to Toronto Hydro's environmental objectives by ensuring Toronto Hydro meets all Municipal, Provincial and Federal regulations related to managing hazardous materials by safely collecting, storing, and removing hazardous waste from work sites.
Financial	• Contributes to Toronto Hydro's financial objectives as measured by the total cost and efficiency measures by: ○ Implementing processes such as automating the disbursement of certain inventory stock and purchasing certain equipment directly from the manufacturer; and ○ Maintaining an optimal level of inventory of materials and equipment to support uninterrupted work execution with minimal carrying cost.

3. PROGRAM DESCRIPTION

The Program is comprised of two interrelated functions: Demand and Acquisition Services and Warehouse and Logistics, each of which are described in the sections below.

3.1 Demand and Acquisition Services

The Demand and Acquisition Services function supports Toronto Hydro's capital and maintenance work programs, and enables the utility's day-to-day operations, by

providing the goods and services required to perform the work. The employees who deliver this function require an extensive set of supply chain and electricity industry-specific skills, including understanding of the competitive bid process, in-depth knowledge of quantitative analysis and inventory management tools, familiarity with changing electricity system equipment standards, as well as advanced negotiation and communication skills.

3.1.1 Procurement and Vendor Performance Management

Demand and Acquisition Services' activities involve sourcing of reputable and reliable suppliers, monitoring their performance to ensure that they meet their contractual obligations, and generating the purchase orders that underlie each agreement. Working with the various parts of the utility's operations, Demand and Acquisition Services lead the competitive bid generation and evaluation processes, and conduct market trend analysis to identify emerging industry trends and locate suitable suppliers.

Toronto Hydro's competitive bid selection process is based on pre-established selection criteria that balance the quantitative and qualitative aspects of each desired proposal. The proposals and the criteria are developed in collaboration with internal business units that require the goods or services in question.

After the supplier is chosen, Toronto Hydro negotiates the contract terms and conditions relevant to the goods or services provided. Demand and Acquisition Services monitor supplier performance through collaboration with other departments and regularly meeting with the supplier.

3.1.2 Material Requirements Planning

The Demand and Acquisition Services function manages inventory levels in Toronto Hydro's warehouses in support of the utility's capital and maintenance programs. This involves reviewing historic use trends and known work projects to develop planned work requirement forecasts and supplier orders.

In addition, Demand and Acquisition Services oversees materials and equipment inventory for reactive work driven by adverse weather, system contingencies and other unforeseen events. To facilitate efficient and expedient execution of reactive work, Toronto Hydro establishes minimum and maximum inventory settings for each warehouse location, and determines appropriate material re-order points and quantities that trigger purchase order generation as inventories are gradually depleted. Late shipments that can affect available inventory for either planned or reactive work are expedited with suppliers, and optimal delivery dates are ascertained and communicated to warehouses and requesting areas of the utility.

Unplanned extreme weather events present a significant challenge to the execution of the Program. The volumes of certain materials, such as overhead wire and associated hardware, required in the aftermath of major storms often exceed all normal inventory levels, contingency stocks held by vendors, and forecasted reactive work requirements. When major weather events occur, Toronto Hydro works with suppliers to immediately acquire all materials necessary to support power restoration activities.

For example, in the summer of 2017, the City of Toronto experienced record breaking levels of rainfall. Persistent downpour caused flooding, road closures, and power outages. As a result, the overall annual demand for sump pumps increased by 87

percent when compared to the previous three year average demand. May and September had the sharpest increase in demand for sump pumps from an average of 31 and 14 to 70 and 50, respectively. To support Toronto Hydro's efforts in restoring power, Demand and Acquisition Services began sourcing additional sump pumps from multiple vendors, but only one was able to meet required specifications. The surge in demand was rapidly depleting the vendor's inventory. To ensure uninterrupted supply of sump pumps, Toronto Hydro worked closely with the vendor to secure approximately 100 units originally destined for US markets and ramped up European factory production. As a result of these efforts, Toronto Hydro successfully reduced the risk of equipment damage caused by water intrusion.

Demand and Acquisition Services also works with other operational groups at Toronto Hydro to identify certain materials and equipment that are critical to the ongoing operation of the distribution network (e.g. various models and vintages of pad mounted switchgear and transformers). Once identified, these inventory items are flagged as critical spares and segregated from general stock for specific use in reactive situations. Where materials and equipment at the end of their useful lives are replaced with alternatives built to newer technical standards, Toronto Hydro ensures that the existing stock of the obsolete parts are used up first to minimize any residual inventory. In certain cases, Toronto Hydro may also return remaining quantities of the obsolete equipment to the supplier, or sell them for scrap.

3.1.3 Third-Party Procurement Provider

To support the long-term goal of improving customer service at a reduced cost, in 2015, Toronto Hydro sourced a Third-Party Procurement ("3PP") provider. The purpose was to decrease operating costs and improve productivity by outsourcing the function of

Demand and Acquisition Services employees as they retire. Using the 3PP provider is expected to:

- Reduce the overhead cost per purchase order;
- Provide better operational cost certainty; and
- Provide more operational flexibility to meet Toronto Hydro's varying operational requirements consisting of managing 10,340 active inventory codes linked to individual assets, issuing 14,700 purchase orders, and executing 133 solicitations annually.

To facilitate a smooth transition of responsibilities, the 3PP provider has been engaged to work alongside the Program's Demand and Acquisition Services employees to gain experience in dealing with Toronto Hydro's procurement and inventory needs. The 3PP provider's employees are fully integrated and act as an extension of the core Demand and Acquisition Services team by performing the full range of Procurement and Vendor Performance Management and Inventory Management activities. The goal is to gradually transition the majority of operational responsibilities to the 3PP provider as Demand and Acquisition Services employees retire.

3.2 Warehouse and Logistics

3.2.1 Inventory Management

The Warehousing and Logistics function receives, stocks, and supplies all inventory materials to Toronto Hydro's capital and other operating program requirements. Field crews receive the requisite equipment and materials from any of the four warehouse locations which are strategically situated across the City, including one managed by a third-party supplier, as described in more detail below.

The typical activities of the Warehousing and Logistics function includes:

- Unloading, visually inspecting, receiving, and storing materials and supplies from vendor vehicles to issue to crews;
- Picking, staging, and loading electric distribution material onto crew vehicles to facilitate a quick exit from the work centres at the beginning of each work day;
- Delivering and distributing requisite materials to and from job sites and between warehouses to facilitate faster and more efficient materials distribution;
- Issuing miscellaneous (over-the-counter) items such as tools, clothing and safety equipment to crews so they continue to have the mandatory safety equipment and necessary tools to perform work;
- Handling excess materials returned from the field upon work completion, such as partial cable reels which can be re-entered into inventory and issued to other jobs;
- Arranging for field equipment slated for repairs or replacement to be returned to vendors and suppliers;
- Establishing and maintaining appropriate minimum and maximum inventory levels at each warehouse to assure appropriate product mix is available to support the type of work being conducted by the crews serviced by each work centre; and
- Performing daily inventory cycle count activities to facilitate the accuracy of Toronto Hydro's financial reporting, and reconcile physical inventory on the shelf with records.

3.2.2 Third-Party Logistics Provider

In 2013, in an effort to support the scale of Toronto Hydro's capital program in a flexible and sustainable manner, the utility engaged a Third-Party Logistics ("3PL") warehousing

services provider. This was discussed in detail in the utility's 2015-2019 Rate Application.[2] The 3PL provider uses Toronto Hydro's Warehouse Management System ("WMS") software and provides services at competitive market rates.

The 3PL provider owns and operates a warehouse located just north of Toronto as an addition to the three existing Toronto Hydro warehouses. While the 3PL provider has assumed a significant portion of Toronto Hydro's warehousing duties, the internal work centres continue to play a key operational role by facilitating prompt materials issuance to the crews departing from the three work centres, and facilitating timely response to reactive requirements. Toronto Hydro crews are able to reach job sites faster, by being able to pick up materials from the warehouses across the City. This creates greater efficiency and execution of planned work and faster power restoration during reactive assignments.

3.3 On-Cost

The cost of Warehouse and Logistics function and a portion of the Acquisition and Demand Services function are recovered internally through the materials on-cost rate, which is applied to the value of the goods issued to crews for specific projects, and ultimately reflected in the projects' overall capital costs.[3]

On-cost rates shown in Table 3, below, reflect a temporary increase in short-term operating costs and a decrease starting in 2020. The 2017 decrease in the on-cost rate is attributable to the 15 percent increase of material usage during the year.

[2] EB-2014-0116, Toronto Hydro-Electric System Limited, Exhibit 4A, Tab 2, Schedule 12 (Filed July 31, 2014, corrected February 13, 2015), pages 9-10.
[3] Toronto Hydro calculates the annual rate by dividing the applicable Program costs over the anticipated cost of materials supplying that year's capital and maintenance work program. The resulting rate (%) is then added to the materials charged to the capital and maintenance projects.

Table 3: On-Cost Rate (2015-2020)

Year	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Test	2020 Test
On-Cost Rate	10.79%	11.30%	9.64%	13.01%	13.08%	12.2%

4. PROGRAM COSTS

Toronto Hydro requires approximately $12.6 million each year during the 2020 to 2024 period to execute the functions of the Program functions described above. Without this level of funding, Toronto Hydro could be exposed to a number of risks, including:

- Delayed or inefficient procurement of goods, which could affect quality of equipment installed in the field and lead to more frequent outages for customers;
- Delayed or inefficient procurement of services, which could affect the cost of third-party resources and increase overall operating costs;
- Unavailability of stock for both planned and reactive work, which could lead to prolonged outages for customers; and
- Absent a proper and adequately supported warehouse function, inventory could be misplaced, issued incorrectly, or damaged thus increasing the overall operating costs.

Table 4, below, provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for the Program.

Table 4: Supply Chain Services Program Expenditures ($ Millions)

Program	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Supply Chain Services	10.4	13.4	11.4	11.7	12.3	12.6

4.1 Cost Drivers

The 2020 test year cost forecast represents an increase of $2.2 million from the utility's last rebasing year actual costs (2015), $1.2 million increase from the most recent historical actual year (2017), and $0.3 million from the bridge year (2019). The variances are attributable to the following drivers:

- **Engagement of a 3PP provider**: As Acquisition and Demand Services' employees retire, their function will be performed by a 3PP provider, which is fully recovered through the materials on-cost rate (i.e. can be entirely allocated to capital projects). However, even though this function is to be outsourced, Toronto Hydro will still incur temporary costs associated with overlapping employees for knowledge transfer. In the future, the engagement of a 3PP provider is expected to provide cost savings.
- **Purchase of industrial vending machines:** The Program purchased vending machines to automate bin inventory and provide Toronto Hydro crew with self-service disbursement of warehouse material. The vending machines have been purchased by Toronto Hydro and replenished by its existing 3PL provider.
- **Increase in requests for materials:** increasing requests for materials contributes to the overall Program costs as the pricing model is based on the amount of materials issued through the 3PL service provider. For example, in 2017, there was an increase of 18.4 percent in materials issued through the 3PL service provider, which led to the corresponding increase in service fees by 5 percent.
- **Loss of transformer rebate:** In 2017, Toronto Hydro began to directly purchase transformers from a manufacturer instead of a distributor. This saved Toronto Hydro approximately $900,000 in the cost of transformers. However, the utility lost the rebate previously provided by the distributor in the amount of $300,000.

This rebate was reflected as an increase in the Program's costs, despite the fact that the utility saved approximately $600,000 in transformer costs.

4.2 Cost Control and Productivity Measures

Toronto Hydro will continue to manage costs in this Program by leveraging the 3PP provider to:

- Balance workload as internal headcounts within this Program decline;
- Support the utility's capital program; and
- Streamlining operations through 3PP, and reducing costs in the Vendor Managed Inventory Initiative. Suppliers are responsible for maintaining an appropriate level of inventory to ensure material is always ready for pick up. Once an order is placed, inventory is transferred from the vendor managed portion of the warehouse into the main warehouse. This reduces lead time and provides cost savings by engaging suppliers directly instead of distributers.

Toronto Hydro will also continue to manage costs in this Program by leveraging the 3PL provider to:

- To streamline field operations, transformers are packaged on skids along with auxiliary components needed for installation, known as transformer kits. Prior to 2016, these kits were assembled by the transformer manufacturer who purchased the auxiliary components from the same suppliers as Toronto Hydro. In order to reduce costs, Toronto Hydro began to purchase all components separately and assemble transformer kits via the 3PL service provider. This creates an average net savings of approximately $1.6 million over a five year period.

- To improve vendor performance, Demand and Acquisition Services has been continuously improving the vendor relationship function by introducing new metrics and adjusting existing measurement criteria. In 2018, the utility plans to expand this approach to non-inventory items.
- In 2016, Toronto Hydro installed two industrial vending machines, one at 500 Commissioners, and another at 71 Rexdale. In 2017, an additional vending machine was installed at 715 Milner. These machines stock inventory and provide self-service disbursement of warehouse material. Crews now have quick access to the most commonly used items at any time. The use of the vending machines has lowered labour costs and increased productivity via quicker access to materials.
- The WMS software and hardware solutions utilize barcode technology and provide real-time visibility over inventory, adding efficiency to the receiving and picking functions. Warehouse transactions are centrally prioritized and assigned to warehouse employees by queuing tasks to the employees' hand-held barcode guns. Tasks such as receiving, picking, and cycle counting are carried out by scanning the product bar code affixed to all incoming materials. This technological improvement significantly speeds up the previously manual tasks of keying in the entries for every incoming packing slip, outgoing picking slip, or cycle count entry. The use of this technology allows the warehouse to continue to provide and improve on expected service levels to Toronto Hydro crews. As shown in Figure 1, below, Warehouse and Logistics successfully fulfilled material requirements On Time and in Full ("OTIF") at an average rate of 96 percent.

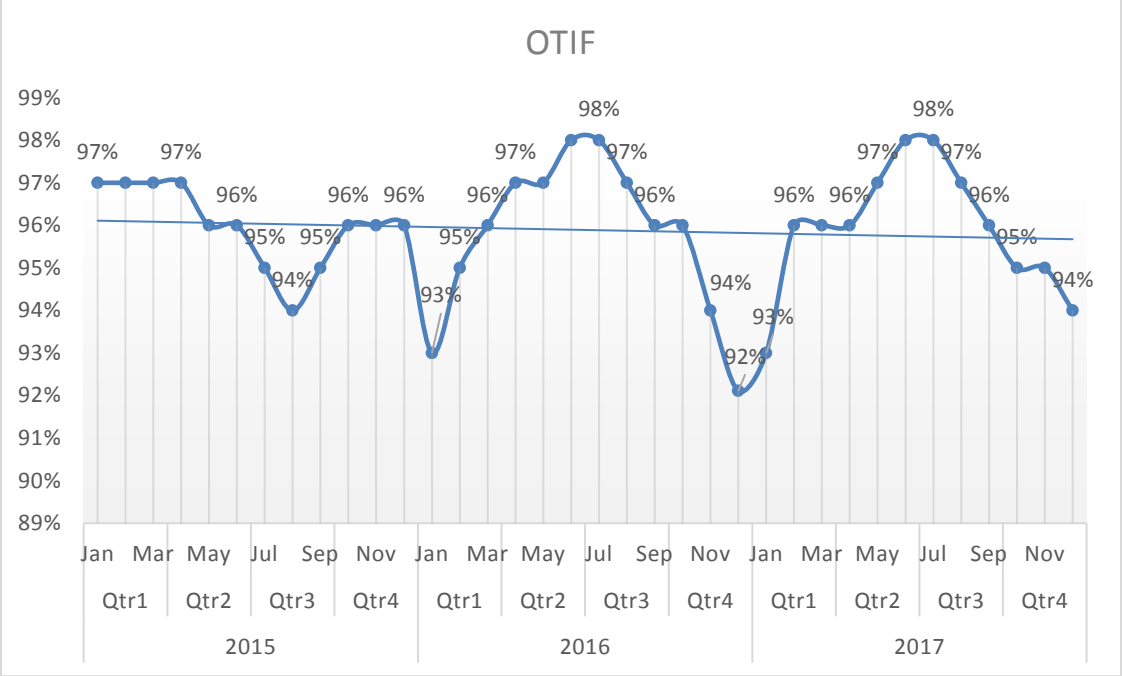


Figure 1: Warehouse OTIF Rate

4.3 Supply Chain Services Program Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

The Program experienced a $3.0 million increase from 2015 to 2016. This increase was due to the following factors: (i) a one-time inventory write off of $2.7 million in 2016, resulting from revised standards, obsolete materials, and the expiration of medications; (ii) an increase of $0.4 million driven by 3PP engagement; (iii) an increase of $0.3 million from 3PL due to the inventory management of two Vending Machines; (iv) an increase of $0.3 million from additional labour related expenditures due to compensation and salary inflationary increases; (v) an increase of $0.3 million resulting from loss of transformer rebates; (vi) a $0.5 million decrease from material returns to general inventory; (vii) a $0.2 million decrease associated with revisions to the clothing order process and buyback of inventory by the supplier; and (viii) a $0.3 million decrease resulting from changes to the transformer kit assembly process.

2016 – 2017 Variance Explanation

The Program experienced a $2.0 million decrease from 2016 to 2017. This decline was due to the following factors: (i) a $0.7 million increase driven by 3PP engagement; (ii) a $0.4 million increase in general inventory returns associated with a one-time return and revisions to process; (iii) a $0.3 million increase associated one-time reduction in spending resulting from changes in the transformer kit assembly process; (iv) a $0.2 million increase due to the installation of an additional industrial vending machine; (v) a $2.7 million reduction due to a one-time write off; (vi) a $0.7 million reduction in labour related expenses due to attrition and a one-time compensation expense; and (vii) a $0.2 million rebate associated with pole line hardware.

2017 – 2018 Variance Explanation

The Program experienced a $0.3 million increase from 2017 to 2018. This rise was primarily due to: (i) a $0.4 million increase driven by 3PL engagement; (ii) a $0.2 million increase driven by 3PP engagement; (iii) a $0.1 million increase associated with inflationary pressure on miscellaneous operating expenses; and (iv) a decrease of $0.4 million in labour related expenses.

2018– 2019 Variance Explanation

The Program is forecasted to experience an increase of $0.6 million from 2018 to 2019. This increase is due to: (i) a $0.4 million increase driven by 3PL engagement; and (ii) a $0.2 increase driven by additional labour related expenditures due to compensation and salary inflationary increases.

2019– 2020 Variance Explanation

The Program is forecasted to experience an increase of $0.3 million from 2019 to 2020. This increase is attributable to: (i) a $0.4 million increase driven by 3PL engagement; and (ii) a $0.1 million decrease in labour related expenses.

CUSTOMER CARE

1. OVERVIEW

Table 1: Customer Care Program Summary

2015-2017 Average Cost ($M): 39.5	**2020 Cost ($M):** 49.4
Segments: • Billing, Remittance, and Meter Data Management • Collections • Customer Relationship Management • Communications and Public Affairs	
Outcomes: Customer Service, Public Policy, and Financial	

The Customer Care program (the "Program") addresses the direct interactions between the utility and its approximately 768,000 customers, and the work required to support these interactions, including customer communications, relationship management, billing, metering and collections functions. Providing excellent customer service is at the core of Toronto Hydro's corporate priorities, and the utility is consistently seeking new ways to foster meaningful two-way communication, expand the range of service offerings to meet evolving customer needs, improve service convenience, and integrate new technological advancements to drive improvement and productivity.

The Program is comprised of the following four segments: (i) Billing, Remittance, and Meter Data Management, which handles the reading of customer meters, upkeep associated with infrastructure and metering data management, preparation of customer bills and payments; (ii) Collections, which handles all activities associated with unpaid accounts; (iii) Customer Relationship Management, which involves activities related to customer interactions; and (iv) Communications and Public Affairs, which involves community outreach, media relations, municipal government interactions and other

aspects of public communications. The Program and its constituent segments are a continuation of the activities described in the Customer Care program in Toronto Hydro's 2015-2019 Rate Application.[1]

2. OUTCOMES AND MEASURES

Table 2: Customer Care Program Outcomes and Measures Summary

Customer Service	• Contributes to Toronto Hydro's customer service objectives by: ○ Answering telephone calls within 30 seconds at least 65 percent of the time (on average) over the 2020-2024 plan period, as measured by the OEB's Telephone Calls Answered On Time metric; ○ Providing written responses to qualified inquiries within 10 business days at least 80 percent of the time (on average), as measured by the OEB Written Correspondence metric; ○ Aiming to address customers' needs in the first instance they contact the utility, as measured via the OEB's First Call Resolution measure; ○ Achieving a bill accuracy rate of at least 98 percent over the 2020-2024 plan period; ○ Increasing the usage of electronic billing to approximately 347,000 customers through the 2020-2024 plan period; ○ Meeting or exceeding the Reconnection Performance OEB standard of 85 percent; and ○ Ensuring no more than 10 percent of calls are abandoned, as measured by the OEB's Telephone Call Abandon Rate.
Public Policy	• Contributes to Toronto Hydro's public policy objectives by implementing legislative and regulatory initiatives within the mandated timelines over the 2020-2024 plan period.

[1] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015), Exhibit 4A, Tab 2, Schedule 13.

Financial	• Contributes to Toronto Hydro's financial objectives as measured by the total cost and efficiency metrics by: ○ Ensuring financial stability and revenue generation capabilities via issuance of customer bills on schedule; and ○ Investing in process improvements that eliminate manual efforts and promote customer self-service.

3. PROGRAM DESCRIPTION

The Program is composed of four segments covering most direct interactions between the utility and its customers and the work required to support these interactions:

- **Billing, Remittance, and Meter Data Management:** involves the reading of customer meters, upkeep of the associated infrastructure, management of meter data, preparation of customer bills, and processing of customer payments;
- **Collections**: involves activities to collect money associated with unpaid customer accounts;
- **Customer Relationship Management:** involves activities related to the utility's interactions with its customers; and
- **Communications and Public Affairs:** involves activities to perform community outreach, media relations, municipal government interactions and other aspects of public communications.

4. PROGRAM COSTS

Toronto Hydro requires approximately $49.4 million each year over the 2020-2024 plan period to execute the functions in the Customer Care program, as described above. Without this level of funding, Toronto Hydro could be exposed to a number of risks, including, but not limited to:

- Issuance of less timely and less accurate bills on a more frequent basis;

- Reduced ability to implement public policy changes in accordance with required timelines or in the most cost effective manner;
- Failure to attain full revenue collection and therefore experience higher levels of bad debt, affecting the financial stability of the utility;
- Decrease in timely responses to customer requests;
- Reduced ability to respond to market changes or changes in customer preferences; and
- Customer service challenges that may impact brand and result in reputational damage.

Table 3, below, provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for each of the four segments.

Table 3: Customer Care Program Expenditures by Segment ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Billing, Remittance & Meter Data Management	15.7	13.4	15.5	15.9	16.2	20.7
Collections	10.8	10.3	9.2	12.1	12.4	12.6
Customer Relationship Management	11.4	11.6	11.5	10.4	10.6	11.3
Communications & Public Affairs	3.1	2.9	3.3	4.6	4.7	4.9
Total	**41.0**	**38.1**	**39.6**	**43.0**	**44.0**	**49.4**

4.1 Cost Drivers

The 2020 test year cost forecast represents an increase of $8.4 million from the utility's last rebasing year actual costs (2015), $9.8 million from the most recent historical actual year (2017), and $5.4 million from the bridge year (2019). The cost drivers for this Program are primarily attributable to the following:

- Operational costs associated with the ongoing monthly billing transition. As discussed in Exhibit 9, Tab 1, Schedule 1, Toronto Hydro tracks, in a deferral

account, the net costs of its 2016 mandatory transition to monthly billing. However, beginning in 2020, the ongoing incremental costs associated with monthly billing must be funded through base distribution rates;

- Standard labour rate increases;
- Transferred payroll costs due to an organizational realignment which centralized the Customer Operations Communications Office from the Engineering and Construction group into the Communications and Public Affairs Segment in 2017;
- An increase in costs for external service providers, and a forecast increase in costs relating to clerical and field collection activities;
- An increase in external clerical and customer service resources due to the increase in minimum wage and extension of Contact Centre and Collections operating hours; and
- Ongoing implementation of public policy initiatives which necessitate additional customer service, collections, and field resources, including: (i) the Ontario Electricity Support Program ("OESP"); (ii) the expiry of the Ontario Clean Energy Benefit ("OCEB") and Debt Retirement Charges ("DRC"); (iii) the introduction of the Ontario Rebate for Electricity Consumers ("OREC") and the Fair Hydro Plan ("FHP"); (iv) new service level requirements for bill accuracy; (v) MDM/R integration; (vi) initiatives in support of the *Energy Consumer Protection Act, 2010*; (vii) the Large Building Energy and Water Reporting and Benchmarking Initiative ("EWRB"); and (viii) the mandatory winter reconnection/non-disconnection of residential customers.

4.2 Cost Control and Productivity Measures

Toronto Hydro continues to actively look for efficiencies and productivity opportunities throughout its Customer Care operations. The public policy initiatives described in the

Cost Drivers section, above, would normally have required an expansion of the workforce to execute. For example, the OESP program requires additional customer service and billing resources to ensure appropriate application of credits, and to address any issues with customer applications, renewals, and exception handling. However, Toronto Hydro was able to implement these policies internally by managing costs and offsetting the incremental resource requirements through implementation of the following initiatives:

- In 2017, Toronto Hydro invested in process optimization and technological solutions to reduce the number of estimated meter reads and the need for bill corrections, which corresponded to a reduction in meter reading labour costs. This resulted in a 99.2 percent billing accuracy average for the year;
- Installations of new meters facilitated the ability of meters to communicate wirelessly, reducing delays in billing and manual meter reading costs;
- Invested in automation of the meter exchange program to eliminate the manual work effort to update the Customer Information System ("CIS") with new meter information, and reduce the lag time that creates manual exception work;
- Reduced paper, printing and postage costs by driving electronic billing adoption to 224,420 enrolled customers, as at end of 2017, which saves $9.52 per electronically billed customer per year;
- Invested in and encouraged the use of customer self-service features on Toronto Hydro's website to provide easier customer access to information and to reduce the need for customer contact. For instance, Toronto Hydro's portal reduces the manual processing of customer move-ins and move-outs;
- Merging of standby roles for Key Accounts and Municipal Relations (within the Communication and Public Affairs segment) to reduce standby and overtime costs; and

- Optimized the use of lower cost outsourced labour. As an example, since business hours were expanded to 8:00 p.m., Toronto Hydro's third-party service provider has been used exclusively to provide call handling resources, optimizing costs and customer service.

The Program has also implemented a number of productivity and process improvements, including:

- Elimination of a number of processes that required manual work, including: (i) manual processing and recording field activities and updating the CIS via implementation of an automated mobile workforce management system for residential meter exchanges; (ii) manual billing adjustment work required to offset the creation of billing error conditions resulting from the overlap between the Ontario Rebate for Consumers Act (8 percent rebate) and the Ontario Electricity Support Program rules; and (iii) manual steps in the retail settlement process;
- During the 2016-2017 period, Toronto Hydro improved its analytics capability, providing more timely and relevant metrics on operational efficiency and effectiveness of collections steps, and better insight into the drivers of bad debt. This has resulted in more targeted collections strategies being put in place along with future plans for process improvements, such as revising the customer moves process to limit the number of times a customer move results in a premise with an unidentified account holder;
- By working with its vendor to streamline operations the utility improved the success rate of accessing meters at difficult to access premises. This reduced the amount of re-work and reduced outstanding account balances;

- In order to improve productivity in the Customer Relationship Management segment, the Program automated and streamlined call and email response processes through better workflow management, pre-defined tasks to respond to common customer requests and automation of process controls; and
- In order to improve productivity in the Communication and Public Affairs segment, the Program increased use of technology to track and manage escalated issues, reducing manual tracking and follow-up efforts and automating measurement and reporting of media relations effectiveness.

5. BILLING, REMITTANCE, AND METER DATA MANAGEMENT SEGMENT

5.1 Segment Description

The Billing, Remittance, and Meter Data Management segment involves the reading of electricity meters, validation and management of meter data, preparation of customer bills, processing of payments and refunding of credits balances.

Over the historical period, Toronto Hydro has enhanced its automated meter data collection and verification capabilities, increased billing accuracy to 99.2 percent in 2017, expanded its offerings of online and self-serve tools, and implemented numerous public policy initiatives (see Section 4, below).

The Billing, Remittance, and Meter Data Management segment is at the core of Toronto Hydro's "meter-to-cash" process that transforms customer consumption and other billable activities into customer bills, facilitates accuracy of bills, and processes customer payments and refunds. During the fourth quarter of 2016, Toronto Hydro converted all customers to monthly billing, and by the end of 2019 expects to issue over 9.4 million bills annually for a projected 780,000 customers. In performing this work, Toronto

Hydro provides its customers with a variety of billing and payment options that address their particular needs and preferences. Many of these options support higher levels of automation than traditional methods, lending themselves to faster receipt of payments and easier customer communication, helping to reduce costs and optimize cash flow while increasing customer satisfaction. As well, the automated nature of the majority of the utility's data collection and verification processes facilitates timely and accurate billing practices.

5.1.1 Billing and Remittance (Payment) Services

The utility prepares over nine million bills annually and offers its customers several delivery options, including standard paper-based bills, electronic bills ("eBills") and ePost billing services. For customers with specific accessibility needs, Toronto Hydro provides additional accommodation options, including bills with increased text size and audio playback. As of 2017, over 224,000 Toronto Hydro customers elected to receive their bills through an electronic method ("eBill"), which represents an increase of 250 percent in the last four years. This is the result of a targeted strategy to increase the eBill adoption, resulting in cost savings as well as convenience and accessibility for customers.

In addition to issuing electricity bills, Toronto Hydro prepares and issues 10,000 customer bills annually for non-electricity services, such as customer-driven electricity connection projects.

As part of this segment, the utility tracks and processes customer-move-ins and outs so that correct meter data is obtained, account holders are identified, and first bills and final bills are addressed correctly and issued without delay. In 2017, Toronto Hydro

processed over 100,000 customer moves, 24 percent of which were processed through an online self-serve channel. Total customer moves typically amount to over 13 percent of the utility's total customer base each year.

Toronto Hydro reviews each non-residential customer's account annually to validate the customer's rate classification. Where changes to a customer's annual consumption and/or monthly average peak demand justify a reclassification, Toronto Hydro assigns the customer to the appropriate rate class. As part of the rate classification review, Toronto Hydro also reviews any pricing plan elections and self-declarations that the customer has made to date in order to verify that the customer's account is billed on the appropriate pricing plan and correctly enrolled in programs for which the customer is eligible, such as the Ontario Rebate for Electricity Consumers. This process ensures the timely and accurate classification and billing of non-residential customers, and correct calculation of revenue.

To maximize cash flow and minimize bad debt, Toronto Hydro encourages customers to adopt a pre-authorized debit payment plan. However, the utility provides its customers with various other bill payment options. Customers may also choose to smooth out their payments through an equal monthly billing or payment plan with an annual reconciliation.

To ensure proper functionality and compliance with relevant legislative and regulatory requirements of the meter-to-cash process, Toronto Hydro maintains a system of internal controls for all systems and processes, and reviews these on an annual basis.

5.1.2 Meter Data Management

As of December 31, 2017, Toronto Hydro had over 773,000 installed meters, of which over 764,000 are read remotely on a daily basis. The automated meter data is retrieved by one of Toronto Hydro's three data collection systems. Each data collection system serves different meter types/customer classes and requires specialized skills to maintain acceptable data collection standards. These data collection systems further pass the data to two meter data management systems (Itron Enterprise Edition ("IEE") and Operational Data Store ("ODS")) for validation. Meter data management systems validate the data for consistency, accuracy, and readiness for billing. Where values are not successfully validated, the systems will automatically attempt to estimate the correct reading. If the systems cannot develop an estimate for the missing data the entry is directed to staff to be manually assessed and entered.

The expansion of automated meter data collection and verification has reduced the number of residential and small commercial bills issued with estimated readings to less than 0.5 percent. Automating the data collection of electricity meters also allows customers to view and extract their hourly electricity consumption via Toronto Hydro's web portals and use a customized energy management tool to help control their costs. In 2017, Toronto Hydro reduced the number of manual meter reads by 5,000, primarily through enhancements to data collection technology and processing capabilities.

Toronto Hydro is working to further maximize the efficiency of data collection by modernizing collection systems, enhancing the communication networks, and improving system processing capabilities to increase the amount of meter data that is retrieved automatically. Examples of this include replacement of older meters with newer meters

that have more powerful data transmitters, and upgrades to Toronto Hydro's meter data collection systems.

In addition to metered customers, Toronto Hydro has approximately 18,600 Unmetered Scattered Load ("USL") connections, which include service to bus shelters, cable television boosters, telephone booths, traffic and park lighting, and signs. These unmetered devices typically consume the same amount of electricity each month and bills are based on the technical consumption parameters of the device. The Billing, Remittance and Meter Data Management segment is responsible for keeping an up-to-date list of all service locations and updating usage calculations when customers make changes. To ensure USL billing accuracy, Toronto Hydro periodically conducts random field audits and reconciliation exercises with its customers.

5.2 Billing, Remittance, and Meter Data Management Segment Costs

Toronto Hydro requires approximately $20.7 million per year over the 2020-2024 plan period to execute the functions in the Billing, Remittance and Meter Data Management segment, as described above. Table 4, below, provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for the Billing, Remittance and Meter Data Management segment.

Table 4: Billing, Remittance, and Meter Data Management Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Billing, Remittance & Meter Data Management	15.7	13.4	15.5	15.9	16.2	20.7

The 2020 test year costs proposed in this segment represent an increase of $5.0 million from the utility's last rebasing year actual costs (2015), $5.2 million from the most recent historical actual year (2017), and $4.5 million from the bridge year (2019).

The mandatory implementation of monthly billing is the primary cost driver for the increase in costs between 2015 and 2020. The net incremental costs in this segment associated with this initiative are approximately $4.6 million per year. These costs are primarily attributable to postage and printing costs, along with additional resources required to support the increased volume of bills issued by Toronto Hydro. Please refer to Exhibit 9, Tab 1, Schedule 1 for a detailed breakdown of Toronto Hydro's incremental monthly billing costs.

Toronto Hydro's costs in this segment have been and are expected to continue to be relatively flat. When normalized for the monthly billing initiative, the increase from 2015 to 2020 is expected to be $0.6 million. Despite the various cost pressures faced in this segment (i.e. annual compensation increases, minimum wage increases impacting outsourced telephone and clerical work, incremental requirements related to customer growth, mandatory legal and regulatory obligations, etc.), Toronto Hydro has managed to keep the costs relatively flat and expects to continue to do so in the 2020 test year through a number of cost management and productivity initiatives (see section above).

Without this level of Program funding, Toronto Hydro could be exposed to the following segment-level risks, including**:**

- Cash flow could be negatively affected and working capital costs could increase;
- Electricity consumption may not be billed in an accurate and timely manner, resulting in uncollected revenue, revenue loss and customer dissatisfaction;

- Meters may not be read in a timely or effective manner increasing the frequency of billing delays, inaccurate bills, collection of account challenges and customer dissatisfaction;
- Non-residential customers' accounts may not be moved to the appropriate rate class in a timely manner, requiring subsequent billing adjustments;
- Payments, credits and refunds may not be processed in a timely and accurate manner, causing delays in cheques issued to customers;
- Changes in public policy may not be implemented in accordance with required timelines or in the most cost effective manner;
- The ability to maintain efficient operations could be jeopardized and continuous improvement efforts would be curtailed; and
- Toronto Hydro's ability to keep pace with evolving customer expectations could be limited.

5.3 Billing, Remittance, and Meter Data Management Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

Costs decreased by $2.3 million between 2015 and 2016 as a result of the following factors, which offset a $0.3 million increase in annual compensation for existing employees:

- $2.2 million decrease in the accounting provision for bad debt. $1.6 million of the decrease was due to a change in the accounting treatment and reporting of non-electricity claims invoices.
- $0.3 million decrease in contracted clerical resources as a result of realignment of work between segments; and
- $0.1 million decrease relating to manual meter reading services.

2016 – 2017 Variance Explanation

Costs increased by $2.1 million between 2016 and 2017 as a result of the following:

- $0.2 million decrease in labour costs due to higher recoveries from several capital projects;
- $2.3 million increase in the accounting provision for bad debt. $1.6 million of the increase reflects the change in the accounting treatment in 2016 for bad debt provisioning of non-electricity claims invoices.

2017 – 2018 Variance Explanation

From 2017 to 2018, the costs are forecast to increase by $0.4 million as a result of the following:

- $0.4 million increase in annual compensation for existing employees;
- $0.1 million increase in external clerical contract costs as a result of the minimum wage increase;
- $0.1 million increase in a cash processing fee due to a forecasted increase in payment processing fees and customer base driven volume increases;
- $0.1 million increase in postage costs as a result of a Canada Post rate increase; and
- $0.3 million decrease in the accounting provision for bad debt.

2018 – 2019 Variance Explanation

From 2018 to 2019, the costs in this segment are forecast to increase by $0.3 million, as a result of an increase in annual compensation for existing employees.

2019 – 2020 Variance Explanation

From 2018 to 2019, the costs in this segment are forecast to increase by $4.5 million. The increase is primarily attributable to the inclusion of approximately $4.6 million of incremental costs associated with converting from bi-monthly to monthly billing into the regular budget. These incremental monthly billing costs, as well as the annual compensation increases, are forecasted to be offset by a $0.1 million reduction in outsourced resources.

6. COLLECTIONS SEGMENT

6.1 Segment Description

The Collections segment involves work related to tracking and collecting amounts owing on customer accounts and administering low income programs. Toronto Hydro's collections procedures must meet all Ontario Energy Board ("OEB") and other applicable regulations and legislative requirements. These procedures work to minimize the bad debt expenses incurred by the utility, while providing customers various options to pay outstanding accounts.

For a utility with approximately 768,000 customers and over 100,000 customer moves annually, the collections function plays a key role in enabling Toronto Hydro to receive required revenue while minimizing bad debt expenditures, which would otherwise increase costs paid by all customers. In 2017, Toronto Hydro extended the availability of dedicated collections Customer Relations Representatives from 8:00 a.m. to 4:30 p.m. to 8:00 a.m. to 8:00 p.m. Customers also have 24/7 access to collections information through an Interactive Voice Response ("IVR") system and an online portal. The IVR and online technology assists customers with their account management inquiries by

providing updated account balances, payment option information, bill amount predictors and other related tools.

To facilitate stable and predictable cash flows and manage emerging arrears, Toronto Hydro proactively mails overdue payment reminder letters and places reminder phone calls to its customers, with over approximately 650,000 letters and 300,000 phone calls placed each year. To manage the costs of these high-volume activities while maintaining the efficiency and timeliness of reminders, Toronto Hydro deploys automated systems for both letter preparation and phone call placement.

In the event that regular reminders are unsuccessful, Toronto Hydro initiates a series of severance activities. Toronto Hydro's field collections contractors and internal field staff collect over $7 million in outstanding payments per year while delivering disconnection notices or when attending a premise to perform the disconnection.

As at the end of 2017, the utility had over 48,000 smart meters capable of remote disconnection, reconnection, and intermittent disconnection. This enables Toronto Hydro to reduce the potential impact on bad debt by resolving problems, such as an inability to gain access to meters at some premises, as well as providing power based on a pre-determined schedule to ensure that customers have enough power for essential household activities and cooling/heating their homes, while still motivating the customer to pay the arrears and limiting bad debt. Remotely disconnecting meters also improves the service Toronto Hydro can provide customers since power can be restored almost immediately upon receipt of payment on an overdue account, without needing to schedule a crew for reconnection. As Toronto Hydro upgrades its smart meters to

remotely controlled models, remote disconnections, reconnections, and timed load interruption will become more commonplace.

To comply with the OEB's winter disconnection moratorium that came into effect in 2017,[2] Toronto Hydro adapted its processes to rapidly contact customers previously disconnected for non-payment, process reconnections, provide information on financial assistance programs, and record and report on the status of affected customers.

To encourage timely payments, proactively identify at-risk accounts, and otherwise facilitate the collection of outstanding payments, Toronto Hydro undertakes a range of activities, including:

- Managing and monitoring about 19,000 commercial accounts with security deposits and overseeing the annual process of security deposit refunds;
- Preparing and sending over 14,000 inactive unpaid accounts per year to external collection agencies for follow up and collection;
- Implementing arrears payment arrangements and customized payment plans to assist customers with clearing their outstanding balances; and
- Educating customers on and overseeing the administration of financial assistance programs (e.g. Low-Income Energy Assistance Program, Ontario Electricity Support Program).

6.2 Collections Segment Costs

Toronto Hydro needs approximately $12.6 million per year over the 2020-2024 plan period to execute the functions in the Collections segment, as described above. Table 5,

[2] EB-2002-0497, Toronto Hydro-Electric System Limited Electricity Distribution License (Valid until October 16, 2023), s. 23.

below, provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures relating to the Collections segment.

Table 5: Collections Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Collections	10.8	10.3	9.2	12.1	12.4	12.6

The 2020 test year costs proposed in this segment represent an increase of $1.8 million from the utility's last rebasing year actual costs (2015), $3.4 million from the most recent historical actual year (2017), and $0.2 million from the bridge year (2019).

Toronto Hydro's costs in this segment have been and are expected to continue to be relatively flat. The $2.9 million increase in 2018 compared to 2017 is primarily due to an expected accounting provision adjustment for bad debt for electricity accounts as a result of the anticipated impact of the OEB's Winter Disconnection moratorium, as well as a forecasted increase in costs associated with collection related field and clerical activities.

Generally, the volume of collections-related work and the success of collecting delinquent accounts is heavily influenced by the number of customer visits made, the number of low income customers and the associated programs available to administer, collection tools available to address certain circumstances (such as the ability to disconnect certain premises), the number of customers who move out and receive a final bill in any given year, economic conditions, industry disruptions causing bankruptcies, and regulatory changes impacting customer behaviour and collections tools. Toronto Hydro monitors trends and implements strategies to minimize the cost of bad debt to the utility. For example, the OEB's 2017 winter disconnections

moratorium altered Toronto Hydro's strategy of using timed load interrupter devices during the winter months, necessitating that alternate strategies be created and deployed to control unpaid account balances.

Without this level of Program funding, Toronto Hydro could be exposed to the following segment-level risks, including:

- The volume and dollars associated with uncollectable accounts could increase, causing upwards pressure on rates for all customers;
- The ability to effectively communicate and deliver low income customer assistance programs could lead to customer hardship and disconnection risk; and
- Cash flow could be adversely impacted and working capital costs could increase.

6.3 Collections Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

From 2015 to 2016, the costs in this segment decreased by $0.5 million as a result of the following:

- $1.4 million decrease in an accounting provision adjustment for bad debt for electricity accounts;
- $0.1 million increase in temporary labour costs to backfill for vacant full-time positions;
- $0.6 million increase in collections related field and clerical activities; and
- $0.3 million increase in external clerical costs due to a realignment of costs between segments.

2016 – 2017 Variance Explanation

From 2016 to 2017, the costs in this segment decreased by $1.1 million as a result of the following:

- $0.1 million decrease in internal labour costs due to forecasted vacancies;
- $0.25 million decrease due to restricted collection activities as a result of the OEB's winter disconnection moratorium;
- $0.1 million decrease due to sufficiency of inventory of materials required for collection activities; and
- $0.5 million decrease in the accounting provision for bad debt to reflect a stronger than forecasted resolution of accounts in arrears and lower overall balances owing due to the Fair Hydro Plan.

2017 – 2018 Variance Explanation

From 2017 to 2018, the costs in this segment are forecast to increase by $2.9 million, primarily as a result of the OEB's winter disconnection moratorium:

- $1.0 million increase due to a forecasted increase in collection related field and clerical activities and cost; and
- $1.8 million increase in the accounting provision for electricity accounts bad debt.

2018 – 2019 Variance Explanation

From 2018 to 2019, the costs in this segment are forecast to increase by $0.3 million as a result of the following cost factors:

- $ 0.1 million increase in annual compensation for existing employees; and
- $ 0.1 million increase resulting from a forecasted accounting provision adjustment for bad debt for electricity accounts.

2019 – 2020 Variance Explanation

From 2019 to 2020, the costs in this segment are forecast to increase by $0.2 million as a result of the following cost factors:

- $ 0.1 million increase due to increases in annual compensation and external field collection contract costs; and
- $ 0.1 million increase resulting from a forecasted accounting provision adjustment for bad debt for electricity accounts.

7. CUSTOMER RELATIONSHIP MANAGEMENT SEGMENT

7.1 Segment Description

The Customer Relationship Management segment involves Toronto Hydro's communication interactions with its customers. Toronto Hydro aims to build trusted relationships by engaging customers at the right time, with the right information, and through the right channel to meet their needs. This approach delivers customer value by providing efficient and timely responses to all enquiries, building awareness of available low-income programs, and educating customers on how to better manage their electricity usage.

The segment includes the following functional areas: Contact Centre, Escalations, Key Accounts, Customer Experience, and Quality Assurance. These functions are designed to meet customer needs and improve operational efficiencies identified through the tracking and analysis of inbound customer inquiries, transactional surveys, focus groups, and other means of soliciting customer feedback.

In addition to the functional areas noted above, the segment also includes an area tasked with designing and overseeing critical technology projects for the Program, as

well as optimizing processes to increase efficiencies through ongoing process analysis and measurement activities.

7.1.1 Contact Centre

Toronto Hydro's Contact Centre is the primary functional area of the Customer Relationship Management segment. The Contact Centre receives and addresses an average of 96,000 written inquiries and 527,000 telephone calls per year. Customers engage with the Contact Centre to inquire about Toronto Hydro's business practices, including, but not limited to, payment options, electricity consumption, and collections.

Toronto Hydro closely monitors the quality and efficiency of its customer contact activities using a combination of OEB-mandated, common industry and internally developed measures. Toronto Hydro performs well against the OEB's performance targets in the areas of telephone and written response, consistently exceeding the required service standards. On average, over the 2015-2017 period, the contact centre answered 73 percent of calls within 30 seconds, and responded to 94 percent of written inquiries within ten days. To further support the utility's customer service objectives, the Contact Centre has extended its hours from 8:00 a.m. to 4:30 p.m. to 8:00 a.m. to 8:00 p.m.

7.1.2 Escalations and Special Investigations

The Escalations and Special Investigations area resolves specific concerns that require complex or lengthy analysis. The most frequently occurring concerns are related to energy and bill management, including high bill issues, energy management education, and payment challenges. The Escalations and Special Investigations function receives its requests through a variety of channels, including approximately 320 through the

Contact Centre, 190 through Toronto Hydro's Office of the President, and 115 through the OEB.

The Escalations and Special Investigations function is responsible for resolving these issues and deploys field resources to investigate power quality or billing issues when necessary. In 2017, the area resolved 98 percent of escalated customer inquiries within 10 business days or less.

7.1.3 Key Accounts

The Key Accounts function works proactively with large business customers in the Commercial and Industrial ("C&I") sector on matters such as planned outage notification and coordination, Global Adjustment settlement notification, load profile and rates analysis, and power quality and energy management.

The Key Accounts function also responds to issues raised by C&I customers and acts as a liaison to expedite workable solutions. Key Accounts' functions include:

- Meeting with customers to resolve billing issues, coordinate planned outages and connect customers with Toronto Hydro's Conservation and Demand Management ("CDM") program offerings to explore opportunities for energy efficiencies;
- Providing business-specific updates during unplanned outages;
- Providing account and sector specific information through various channels such as direct mail, newsletters, workshops, and association outreach;
- Acting as a single point of contact within Toronto Hydro to facilitate and coordinate work related to large C&I customers; and

- Building and maintaining positive relationships with Toronto's business community.

7.1.4 Customer Experience

The Customer Experience function manages research and works to achieve engagement and consistency across all customer interactions. Customer engagement activities allow Toronto Hydro to gain insights into how current services, processes, and communications align with customer views and experiences, while identifying ongoing opportunities for improvement of current programs and the development of new programs.

Customer engagement plays a significant role in Toronto Hydro's decision making and helps inform and guide overall business planning processes. In 2017, in support of this objective, Toronto Hydro established a Customer Advisory Panel ("CAP"). The CAP includes six sub-panels chosen through a multi-step process to ensure representation from a diverse cross-section of customers. The CAP is engaged to provide ongoing feedback on a variety of topics through a mix of focus groups, surveys, and workshop sessions for both residential and business customers.

One increasingly popular method of engagement continues to be Toronto Hydro's customized self-service portal (MyTorontoHydro). It offers automated move-in/move-out capability, eBill and pre-authorized payment enrolment, and the ability to view bill and payment histories. In addition, through the Independent Electricity System Operator's ("IESO") residential conservation program, Toronto Hydro expanded the functionality of its PowerLens portal to include a variety of electricity management tools and educational information such as usage breakdowns, kWh reduction goal setting,

consumption and cost alerts, disaggregation charts, home assessments, and customized tips and recommendations to reduce consumption. The portal is available online or via mobile devices, further enhancing the customer experience. The adoption of this service continues to be driven through marketing campaigns and the Contact Centre since it supports Toronto Hydro's customer service and financial stability outcomes.

Additional offerings will continue to be incorporated based on customer research and feedback to identify opportunities to bolster usage of the self-service portal. This includes offering MyTorontoHydro account management services to commercial customers, as well as expanding capabilities on PowerLens for electric vehicle usage.

Customer communication efforts continue to expand due to the ongoing changes in public policy affecting Ontario's electricity environment including the introduction of monthly billing and low income programs.

7.1.5 Quality Assurance

The Quality Assurance function manages the development and distribution of training materials for internal and external resources. It is also engaged in knowledge and service quality management, analyzing staff performance, escalation trends, and post-call customer surveys, to identify training gaps as well as process technology improvement opportunities. The function is responsible for maintaining tools that provide staff with information on current policies, procedures, and regulatory changes to better serve customers.

7.2 Customer Relationship Management Segment Costs

Toronto Hydro needs approximately $11.3 million per year over the 2020-2024 plan period to execute the functions in the Customer Relationship Management segment, as described above. Table 6, below, presents Toronto Hydro's Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) costs relating to the Customer Relationship Management Segment.

Table 6: Customer Relationship Management Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Customer Relationship Management	11.4	11.6	11.5	10.4	10.6	11.3

The 2020 test year costs represent a decrease of $0.1 million from the utility's last rebasing year actual costs (2015), a $0.2 million decrease from the most recent historical actual year (2017), and $0.7 million increase from the bridge year (2019).

Without this level of Program funding, Toronto Hydro could be exposed to the following segment-level risks, including:

- Changes to customer accounts may not be made in a timely fashion, resulting in billing errors and delays in issuing bills;
- Ongoing interactions and collaborative relationships with the utility's customer base could be limited; and
- Customers could experience longer wait times to resolve inquiries, potentially leading to erosion of service level standards and customer satisfaction.

Over the previous and current plan period, costs in this segment have been and are expected to remain relatively flat. The slight variances are attributable to inflation

adjustments to standard labour costs and contractual rate increases over the 2020-2024 plan period.

7.3 Customer Relationship Management Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

From 2015 to 2016, the costs in this segment have increased by $0.2 million as a result of the increase in marketing for executing a campaign related to the transition to monthly billing.

2016 – 2017 Variance Explanation

From 2016 to 2017, the costs in this segment decreased by $0.1 million as a result of the following:

- $0.3 million increase in annual compensation for existing employees, and deferred capitalization of projects to 2018; which was partially offset by reduction in temporary resources;
- $0.1 million increase in outsourcing due to increase in customer base; and
- $0.5 million decrease in marketing costs due to required customer satisfaction research and the non-reoccurring monthly billing project communication expenses in 2016.

2017 – 2018 Variance Explanation

From 2017 to 2018, the costs in this segment decreased by $1.1 million as a result of the following:

- $1.2 million decrease due to capitalization of business labour to projects, which also offset the inflationary increase in compensation;

- $0.3 million increase due to an anticipated increase in outsourcing cost resulting from the increase in the provincial minimum wage; and
- $0.3 million decrease in marketing and printing costs due to a change in marketing material vendor strategies.

2018 – 2019 Variance Explanation

From 2018 to 2019, the costs in this segment are forecast to increase by $0.2 million as a result of the following:

- $0.1 million decrease in labour cost due to capitalization of business labour to projects; and
- $0.3 million increase in call centre outsourcing due to an anticipated change in contracts resulting from the increase in the provincial minimum wage.

2019 – 2020 Variance Explanation

From 2019 to 2020, the costs in this segment are forecast to increase by $0.7 million as a result of the following:

- $0.5 million increase in annual compensation for existing employees, and the requirement for additional temporary staff to manage forecasted projects; and
- $0.2 million increase in contractual cost to manage marketing campaigns and customer satisfaction research;

8. COMMUNICATIONS AND PUBLIC AFFAIRS SEGMENT

8.1 Segment Description

The Communications and Public Affairs segment delivers high-quality, practical and timely information about Toronto Hydro's operations and programs to the general public and other interested parties. The work functions in the segment include:

Communications and Public Relations, Marketing, Municipal Relations/Office of the President, and Community Relations and Customer Operations Communications. To perform the activities in this segment, Toronto Hydro uses a number of communication channels, including

- Engagements with local media;
- Contact with local business improvement organizations, community groups and ratepayer associations;
- Toronto Hydro owned channels such as the utility's website;
- Social media, including Twitter and Facebook;
- Proactive outreach to City Councillors, the Mayor's office and City staff;
- Community events;
- Market analysis and customer analysis supporting business development and corporate strategy;
- Marketing campaigns;
- Direct-to-customer communications; and
- Capital program and planned outage communications through the Customer Operations and Communications Office.

Effective and timely communication within each work function is helpful to customers and other stakeholders as it increases their awareness about matters of interest such as the location and the anticipated restoration of outages, capital projects, and emergency preparedness. Particularly during outages, statistics (e.g. J.D. Power survey results and Third Party Audit following the 2013 Ice Storm) show that outage communication is a key driver of customer satisfaction. Increasingly, there is customer demand on digital channels to provide real-time or short interval information via social media, online outage maps, outage alerts to email and online report and outage. During major

instances it is not uncommon for 100+ social media inquiries and dozens of inquiries through the Office of the President — these demands increase the need for information and resources. By communicating key information proactively, stakeholders and customers may also have fewer reasons to contact Toronto Hydro, which reduces overall operating costs.

8.1.1 Communications and Public Relations

The Communications and Public Relations function includes all external communications from Toronto Hydro, whether direct-to-customer (e.g. bill inserts and newsletters), digital communications (e.g. website and social media), and corporate communications (e.g. news releases, project communications, annual reporting) not performed by the Municipal Relations or Customer Operations areas. Of particular importance to brand and reputation are media and social media communications and public relations events.

The media are an important conduit between Toronto Hydro and its customers and other stakeholders. The segment's media relations function proactively communicates accurate and timely information about power outages, electrical safety, consumer issues, and local investments in the distribution system and other corporate programs.

Media relations has a significant role to play during emergency outage situations. Throughout the duration of these outages, communications staff remain in contact with media outlets until services are restored. Media representatives receive up-to-date information on suspected outage causes, likely duration, and if necessary, appropriate measures to be taken for public safety and protection of Toronto Hydro's and customer-owned equipment. These efforts help disseminate key information to customers at a time when they are most likely to be looking for it.

Dedicated media relations personnel engage reporters directly on all matters, which allows the dispatched crews and other employees to proceed with their work without interruption. Media Relations officers and government relations staff provide timely information to local and provincial emergency management personnel, City councillors and social service agencies that may require such information in order to take appropriate action in the interests of public safety.

Increasingly, social media and the online outage map are becoming the preferred source of information for customers experiencing an outage. The digital team focuses on engaging the public through these channels and actively messages those who engage Toronto Hydro's Twitter feed during outages (Toronto Hydro has over 100,000 followers as of November 2017). Media are also gaining information from this channel, increasing its importance. In terms of public safety, the digital team also responds immediately to safety issues and reports them to the appropriate operational teams.

For both media relations and social media, Toronto Hydro has after-hours standby and 24/7 support during significant outages.

8.1.2 Marketing

The Marketing function focuses on supporting corporate strategy and business development through comprehensive market analysis and customer analysis, in order to inform strategy development and decision making regarding business cases and implementation plans. Marketing also focuses on promoting Toronto Hydro programs and services as well as the Toronto Hydro brand to improve its relationship with customers and build brand trust. This is accomplished through marketing campaigns (e.g. core brand campaigns, eBill campaigns to save costs and provide convenience),

marketing materials (e.g. spring and fall booklets, in-bill promotions), and community events to engage customers and promote programs and services. The marketing emphasis is on cultivating a better brand and promoting core Toronto Hydro corporate programs and services. Failure to do so may weaken Toronto Hydro's brand and reputation, position in the marketplace, and negatively affect adoption of programs and services designed to help customers and create efficiencies at Toronto Hydro (e.g. eBill campaigns).

8.1.3 Municipal Government Relations/Office of the President

Building, maintaining and enhancing relationships with the municipal government is critical to Toronto Hydro's ability to serve its customers and stakeholders. To facilitate this function, Toronto Hydro routinely meets with City councillors and City staff on a range of ongoing and emerging issues, and oversees a proactive councillor engagement process to disseminate project information on a ward-by-ward basis.

The Office of the President handles over 1,500 issues per year directed to it from councillors or as the second level in the customer complaint process. The most frequent concerns involve customers' inquiries regarding street lighting, capital projects, and power outage-related issues. The Municipal Relations team takes a strategic approach to shareholder management, building relationships, monitoring and responding to issues while actively participating in committees and working groups. The team also leverages councillors as key influencers in their community to provide communications and information to residents.

8.1.4 Community Relations and Customer Operations Communications

Toronto Hydro has comprehensive processes and protocols for communicating information to customers concerning planned capital work and planned outages, in order to provide a better understanding around the capital program and prepare the customer for work at or near their property. Toronto Hydro has a customer inquiry line and escalation process for customers and staff will be dispatched on-site, when needed, to liaise with customers. This process is important for customer relations, branding and reputation management.

Toronto Hydro maintains productive relationships with public interest groups and agencies involved in commerce, social services, environmental protection, and education. Stakeholder outreach commonly takes the form of one-on-one contact with customers, community town hall meetings, special information sessions, and a variety of online content. Using a variety of communication channels allows Toronto Hydro to engage customers with varying needs, concerns, and preferences, with the goal of giving appropriate attention to all customer segments.

The community relations function also supports the utility's most vulnerable customers through the management of the Low-Income Energy Assistance Program ("LEAP"), which helps eligible customers avoid disconnection and process the re-payment of arrears.[3] Toronto Hydro actively promotes LEAP using various communication channels such as posters, e-newsletters to United Way agencies, face-to-face meetings at community outreach events, and through news releases.

[3] Exhibit 4A, Tab 2, Schedule 19.

8.2 Communications and Public Affairs Segment Costs

Toronto Hydro needs $4.9 million per year over the 2020-2024 plan period to execute the functions in the Communications and Public Affairs segment as described above.

Table 7, below, presents Toronto Hydro's Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) costs relating to the Communications and Public Affairs segment.

Table 7: Communications and Public Affairs Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Communications & Public Affairs	3.1	2.9	3.3	4.6	4.7	4.9

The 2020 test year costs proposed in this segment represent an increase of $1.8 million from the utility's last rebasing year (2015), $1.6 million from the most recent historical actual year (2017), and $0.2 million from the bridge year (2019).

This increase is driven by an organizational realignment which moved the Customer Operations Communications Office from the Engineering and Construction division. This unit manages all communications relating to capital projects and has a role in reactive customer engagement. Additional increases to the budget were due to the Marketing and Communications team assuming full responsibility for Customer Care communications.

Without this level of Program funding, Toronto Hydro could be exposed to the following segment-level risks, including:

- Increased frequency of inaccurate or delayed outage information resulting in customer confusion and dissatisfaction;

- Reduced ability to announce the timing and scope of Toronto Hydro's capital projects, resulting in resident confusion;
- Increased number of customer escalations, with overall diminished customer satisfaction;
- Reduced uptake in key corporate and CDM programs due to lack of awareness/marketing; and
- Owing to the above, an increased potential for brand and reputation decline, resulting in loss of trust and faith in Toronto Hydro and diminished customer satisfaction.

8.3 Communications and Public Affairs Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

From 2015 to 2016, the costs in this segment have decreased by $0.2 million as a result of a decrease in marketing and event expenses, due to the delay of a planned marketing/public relations campaign into the following year to improve its effectiveness.

2016 – 2017 Variance Explanation

From 2016 to 2017, the costs in this segment have increased by $0.4 million as a result of the following cost factors:

- $ 0.1 million increase in annual compensation for existing employees, which was partially offset by labour recovery from CDM projects; and
- $ 0.3 million increase in advertising, marketing, and event expenses due to a delayed marketing/public relations campaign that was moved from 2016.

2017 – 2018 Variance Explanation

From 2017 to 2018, the costs in this segment are forecast to increase by $1.3 million as a result of the following:

- $1.0 million increase in annual compensation for existing employees and an organizational realignment, which moved the Customer Operations Communications Office into this segment; and
- $0.3 million increase to manage forecasted advertising, marketing campaigns, and events.

2018 – 2019 Variance Explanation

From 2018 to 2019, the costs in this segment are forecast to increase by $0.1 million as a result of the annual compensation increases for existing employees.

2019 – 2020 Variance Explanation

From 2019 to 2020, the costs in this segment are forecast to increase by $0.2 million as a result of annual compensation increases for existing employees.

HUMAN RESOURCES AND SAFETY

1. OVERVIEW

Table 1: Human Resources and Safety Program Summary

2015-2017 Average Cost ($M): 14.7	**2020 Cost ($M):** 15.9
Segments: • Environment, Health, and Safety • Human Resources Services and Employee Labour Relations • Talent Management and Organizational Effectiveness	
Outcomes: Environment, Safety, Public Policy, and Financial	

The Human Resources ("HR") and Safety program (the "Program") provides broad human resource management services to Toronto Hydro in various areas, including: environment, health and safety management; employee and labour relations; compensation and benefits management; performance and change management; employee communications; organization design and job design, recruitment, employee orientation; and training and development. These activities are delivered within the utility's complex operating environment characterized by unique operation conditions, organized labour dynamics, and aging workforce.

The work listed above is accomplished through the following three segments: (i) Environment, Health, and Safety; (ii) Human Resources Services and Employee Labour Relations; and (iii) Talent Management and Organizational Effectiveness. These segments operate in tandem to contribute to a safe and healthy work environment. The Environment, Health and Safety segment encompasses the standards and initiatives needed to ensure a safe work environment for Toronto Hydro employees, such as inspections, audits, training, as well as compliance with statutory health and safety requirements. The Human Resources Services and Employee Labour Relations segment

governs the effective management of employee and labour interactions, including the administration of collective agreements, employee claims, and compensation and benefits. Lastly, the Talent Management segment handles both internal and external staffing needs. This function allows Toronto Hydro to successfully recruit and develop a skilled and specialized workforce while maintaining its exceptional safety performance. The Program and its constituent segments are a continuation of the activities described in the Human Resources and Safety program in Toronto Hydro's 2015-2019 Rate Application.[1]

2. OUTCOMES AND MEASURES

Table 2: Human Resources and Safety Program Outcomes and Measures Summary

Public Policy	• Contributes to Toronto Hydro's public policy objectives by ensuring regulatory and legislative requirements are met in relation to employee training, collective bargaining and the development of utility-wide policies.
Environment	• Contributes to Toronto Hydro's environmental objectives by: o Integrating environmental, social and economic issues in planning; and o Measuring waste reduction, and promoting recycling and a culture of conservation.
Safety	• Contributes to Toronto Hydro's safety objectives, measured through metrics like the Total Recordable Injury Frequency ("TRIF") by: o Ensuring employees are working safely with minimal exposure to hazards; o Providing training to employees on safety in the work place; and o Remaining compliant with safety and audit findings.

[1] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015), Exhibit 4A, Tab 2, Schedule 14.

Financial	• Contributes to Toronto Hydro's financial objectives as measured by the total cost and efficiency measures by reducing reliance on external services via development and delivery of internal training and session facilitation, and promoting processes that decrease the Workplace Safety Insurance Board annual premium.

3. PROGRAM DESCRIPTION

The Program provides human resource management services to Toronto Hydro, including: environment, health and safety management; employee and labour relations; compensation and benefits management; corporate and individual performance management; change management; productivity and continuous improvement; employee engagement; organization and job design; recruitment; and training and development.

Toronto Hydro operates in a mature and dense urban environment of a scale and nature that is unique from other Ontario electricity distributors. This creates a number of distinct challenges for the Program, including:

- A complex and rapidly evolving distribution system that includes an asset-intensive downtown distribution network;
- A mature and diverse grid infrastructure featuring legacy assets requiring specialized skills (e.g. box construction and Paper Insulated Lead-Covered cable);
- Unique safety challenges associated with densely populated urban environment, and widespread presence of designated substances in buildings and infrastructure; and
- Large volumes of third party initiated work in an urban environment characterized by spatial limitations and municipal ordinances restricting available work hours.

These factors underscore the need to develop and maintain health and safety rules, provisions for comprehensive training and apprenticeship programs for new and existing employees. They also emphasize the need to actively identify talent, ensure succession planning, and undertake recruitment activities.

At the core of the Program is a commitment to maintaining and continuously improving a robust and effective environment, health, and safety management system ("EHSMS"). The Program supports prioritizing and promoting sustainability, employee safety, and wellness, fostering optimal working conditions to increase job satisfaction, facilitating productivity, and promoting innovation, while accommodating specific needs and responding to emerging trends.

The Program supports the achievement of key operational goals by reducing employee risks to injury through the development and implementation of programs and procedures, and enhancing productivity through the application of risk based management system standards, effective training, diligent inspections, and thorough investigations into incidents and near misses.

The Program includes three segments: (i) Environment, Health and Safety; (ii) Human Resources Services and Employee Labour Relations; and (iii) Talent Management and Organizational Effectiveness.

The Environment, Health, and Safety ("EHS") segment's objective is to ensure that Toronto Hydro works in an environmentally safe manner and provides a safe working environment for the employees through the implementation of safe work practices, engineering controls and adherence to legislative and regulatory requirements relating

to occupational health and safety, environmental protection, and sustainability while striving for continual improvement.

The Human Resources Services and Employee Labour Relations segment, is responsible for effective management of all employee and labour relations, including the interpretation and administration of the collective agreement provisions, non-occupational and occupational illness or injury employee claims, case management, design and administration of the compensation and benefits program, and associated technology systems and solutions. Employee Labour Relations supports both unionized and non-unionized work groups to ensure workplace issues are addressed promptly and appropriately, and in line with legislation, policies, and collective agreement procedures.

The Talent Management and Organizational Effectiveness segment develops and executes the workforce staffing plan, organization and job design, succession planning, employee engagement and communication, performance and productivity, and employee development strategies and programs. The Talent Management team is responsible for internal and external staffing selection. The Organizational Effectiveness stream creates and implements a variety of training, development, and change management initiatives to ensure Toronto Hydro employees are qualified and have the necessary skills, resources, and tools to successfully execute their role.

4. PROGRAM COSTS

Toronto Hydro requires $15.9 million per year over the 2020 to 2024 plan period to execute the segments in this Program. Without this level of funding, the Program could be exposed to a number of risks, including**:**

- Increased likelihood of safety-related incidents to the public and Toronto Hydro employees;
- Lower environmental performance;
- Inability to effectively acquire and retain talent;
- An erosion of technical and leadership skills through decreased investment in training; and,
- Legislative or regulatory non-compliance as a result of inadequate resources to provide advice, consultation, and research on matters relating to employment/labour relations, safety, and environmental legislation.

Table 3, below, provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for each of the Program's segments.

Table 3: Human Resource and Safety Program Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Environment Health and Safety	2.5	2.7	2.5	2.7	2.8	2.9
Human Resource Services and Employee Labour Relations	4.6	5.2	5.1	4.8	4.8	5.0
Talent Management & Organizational Effectiveness	7.0	7.3	7.0	7.8	7.9	8.1
Total	**14.1**	**15.2**	**14.7**	**15.2**	**15.5**	**15.9**

4.1 Cost Drivers

The 2020 test year cost represents an increase of $1.8 million from the last rebasing year actuals (2015), $1.2 million from the most recent historical actual year (2017), and $0.4 million from the bridge year (2019). These changes are attributable to the following cost drivers:

4.1.1 Compensation and Inflationary Increases

In 2019 and 2020, costs associated with the delivery of the functions within the Human Resources and Safety segment are expected to remain relatively stable. However, it is expected that overall program costs will increase slightly due to inflation and market compensation adjustments.

4.1.2 Projects that require increased support

In order to support projects and to fill vacancies, staffing changes have had an impact on year–over-year variances in actual and budgeted segment costs. These are outlined in the sections below. For instance, in 2017 and 2018, a number of employees from the Human Resources and Safety segment were seconded to support other corporate activities resulting in lower payroll costs until additional resources were hired as backfills.

4.1.3 Legal and arbitration related expenses

Legal expenses associated with grievance arbitrations, and other employment related legal matters can drive costs for this Program. These costs are often difficult to predict. Therefore, the costs of these expenses will fluctuate depending on the complexity of arbitration, the number internal and external witnesses, and the degree of preparation and legal research.

4.2 Cost Control and Productivity Measures

4.2.1 Cost Management

The Program has undertaken or plans to undertake the following initiatives to control and/or manage costs during the plan period:

1) Increase the use of specialized services including specialized software to collect and report on incidents, inspections, audits, etc., and use contractor prequalification services to eliminate the need for internal resources to manage systems and information. This function historically required three full time employees to perform similar services.
2) Assist in the development and delivery of internal training and session facilitation, leveraging internal resources and equipment to complete testing, audits, completion of applications, and authoring of reports.
3) Internally develop and distribute EHS related communications materials including posters, safety meeting materials, etc., thereby reducing reliance on external services with a corresponding savings to the utility.
4) Developed an online EHS training models throughout 2016 and 2017 that included a revised focus on Ergonomics and Workplace Hazardous Materials Information System. This investment in online training programs has saved external training vendor costs.
5) In 2017, Toronto Hydro conducted a benefits provider market review, which resulted in annual savings in premiums with no coverage impact for employees.
6) The Government of Ontario has recognized Toronto Hydro's curriculum for the Certified Power Line Person ("CPLP") as equivalent to the in-school requirements for Power Line Technician Trade. This accreditation and resulting ability to train its own apprentices has led to significant savings per apprentice.

4.2.2 Productivity

The Program has undertaken or plans to undertake the following productivity initiatives during the plan period:

Safety and Attendance

Toronto Hydro has achieved notable improvements with respect to the following safety indicators:

- A 57 percent decrease in the number of Workplace Safety and Insurance Board ("WSIB") claims;
- An 82 percent decrease in WSIB New Experimental Experience Rating ("NEER") costs, due to less incidents; and
- WSIB rebates of approximately $2.2 million from 2013 to 2017.

As a result of diligent case management efforts, Toronto Hydro has lower NEER costs. NEER is a mandatory program administered by the WSIB that provides financial incentives to employers to eliminate injuries and illnesses in the workplace.

In addition, from 2011 to 2016, Toronto Hydro achieved significant and sustained improvement relating to occupational safety, including:

- 68 percent decrease in total recordable injury frequency;
- 96 percent decrease in lost time injury severity;
- 63 percent decrease in lost time injury frequency; and
- 87 percent decrease in restricted workdays.

The performance improvements noted above are a testament to the effectiveness of the Program's related policies, programs, and procedures.

From 2013 to 2017, the corporate attendance number improved by 32 percent.

Improved Processes and Systems

New systems applied in recent years including a Learning Management System ("LMS") in 2016, which streamlines processes for training administration, documentation, tracking, reporting, and delivery. In 2017, the talent recruitment process was streamlined with the introduction of an Applicant Tracking System. This tool will improve productivity by streamlining the recruitment process, support the creation of qualified and diverse candidate pools thereby reducing costs associated with recruitment agencies, and enhance the candidate experience.

The Program has also implemented the Management Control and Reporting System ("MCRS") to manage divisional processes (e.g. performance management). MCRS helps to ensure continuous improvement through proper forecasting, planning, executing/controlling, and reporting on key processes. These approaches aim to improve productivity by streamlining work and eliminate waste in business processes.

5. ENVIRONMENT, HEALTH, AND SAFETY SEGMENT

5.1 Segment Description

The Environment, Health, and Safety ("EHS") segment ensures that Toronto Hydro works in an environmentally conscious manner and provides a safe working environment for the employees through the implementation of safe work practices, engineering controls and adherence to legislative and regulatory requirements.

The EHS segment includes the execution of operational activities, preparation of plans and delivery of targeted initiatives, while adhering to the applicable internal and external reporting requirements. The activities performed as part of this segment are instrumental to ensuring that the utility complies with its mandated obligations.

Consistent with Toronto Hydro's service obligations, the work performed within this segment is carried out 24 hours a day, 7 days a week.

EHS activities are integrated within the utility's strategic planning and execution of operational and capital work programs, and are comprised of the following activities:

- **Environment, Health, and Safety Management Systems ("EHSMS"):** The EHSMS system improves efficiency and efficacy of EHS activities through the joint delivery of common activities such as inspections, audits, reporting, investigations, annual planning, training, and management review meetings. The EHSMS also facilitates Toronto Hydro's compliance with the Distribution System Code, Electrical Utility Safety Rules, *Occupational Health & Safety Act* ("OHSA"),[2] and various other legislated requirements. In addition, the EHSMS also provides a mechanism for mitigating the risk in achieving corporate objectives relating to health, safety, and environmental performance. Lastly, the EHSMA exchanges safety information with other utilities and collaborates with its peers on public safety initiatives.
- **EHS Framework:** Toronto Hydro plans, organizes, and coordinates all EHS activities in accordance with internationally recognized standards.[3]
- **Occupational Health and Safety Activities:** Toronto Hydro develops, maintains, inspects, and audits occupational health practices as well as facilitates safety training programs. These programs ensure the long-term health and wellness of the utility's workforce. The Canadian Electricity Association has recognized the utility for its superior performance in occupational health and safety for 2015 and 2016 by being recognized as best in its peer group.

[2] R.S.O. 1990, c. O.1. ["*OHSA*"].
[3] Toronto Hydro is registered with ISO 14001:2015 and OHSAS 18001:2007, both internationally recognized standards in EHS. Together, they establish a framework that incorporates effective risk management, emphasizes continual improvement and achieves operational efficiencies.

- **Sustainable Development:** Toronto Hydro uses an internationally recognized standard, ISO 26000, as a structured approach to promoting sustainable development and integrating social responsibility into the utility's core values, processes, and operations.[4]
- EHS administers its **Environmental Policy** by delivering a number of environmental protection and compliance programs, such as: Management of non–hazardous and hazardous wastes, including:
    - Polychlorinated Bi-Phenyls ("PCBs") and PCB-containing equipment;
    - Environmental spill response, cleanup, investigation and reporting;
    - Delivery of prescribed environmental training (e.g. Transportation of Dangerous Goods);
    - Maintenance of environmental permits for equipment that discharge contaminants into the atmosphere;
    - Completion of annual and ad hoc reporting to federal, provincial, and municipal agencies; and
    - Hazardous waste streams registrations with the Ontario Ministry of the Environment, Conservation, and Parks.
- EHS is also responsible for responding to public concerns about the environmental effects of Toronto Hydro's activities (e.g. electromagnetic fields ("EMF"), presence of PCBs, contaminated soil).
- **Internal and External Reporting:** Toronto Hydro regularly reports on internal and external EHS performance. External reporting includes mandatory reports and notifications to the City of Toronto, the Ministry of Labour, the WSIB, the Ontario Ministry of the Environment, Conservation and Parks, and Environment and Climate Change Canada.

[4] Adherence to this ISO 26000 standard is required for the utility's continued maintenance of its Sustainable Electricity Company designation from the Canadian Electricity Association.

5.2 Environment, Health, and Safety Segment Costs

Toronto Hydro requires approximately $2.9 million per year over the 2020-2024 plan period to perform the EHS functions described above. If the utility does not receive the funding it requires to execute this segment as described, Toronto Hydro could be exposed to a number of risks, including:

- Injuries and illness to employees due to occupational health and safety hazards;
- Fines and penalties related to legislative and regulatory non-compliance; and,
- Stop work orders, which will halt execution of the utility's capital, work program.

Table 4, below, provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for the EHS segment.

Table 4: Environment, Health, and Safety Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Environment Health and Safety	2.5	2.7	2.5	2.7	2.8	2.9

The 2020 test year costs represent an increase of $0.4 million from the utility's last rebasing year actuals (2015), $0.4 million from the most recent historical actual year (2017), and $0.1 million from the bridge year (2019). Overall, the variances are mainly attributable to filling vacancies that existed in the previous test year, incremental external contractor costs required to support the safe execution of the utility's capital work program, and inflationary pressures.

5.3 Environment, Health, and Safety Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

From 2015 to 2016, costs increased by $0.2 million, the effect of filling prior vacancies.

2016 – 2017 Variance Explanation

From 2016 to 2017, costs decreased by $0.2 million. This was primarily due to a decrease in payroll costs related to resources being transferred to the Employee Labour Relations and Human Resources Services segment and in-year vacancies. There were a few employees who left the company during 2016-2017, these roles were either not filled immediately, or were not filled by the end of the year.

2017 – 2018 Variance Explanation

From 2017 actual to 2018 budgeted, costs are expected to increase by $0.2 million, the effect of filling prior vacancies.

2018 – 2019 Variance Explanation

From 2018 to 2019, costs are expected to increase by $0.1 million to account for inflationary pressures.

2019 – 2020 Variance Explanation

From 2019 to 2020, costs are expected to increase by $0.1 million to account for inflationary increases.

6. HUMAN RESOURCES SERVICES AND EMPLOYEE LABOUR RELATIONS SEGMENT

6.1 Segment Description

This segment is focused on management of all employee and labour relations, including the interpretation and administration of the collective agreement provisions, non-occupational and occupational illness or injury employee claims, case management, design and administration of the compensation and benefits program, and associated technology systems and solutions. Segment activities also include drafting, maintaining

and enforcing policies and legislative requirements, and providing corporate-wide human resource support in the execution of business deliverables. The key operational dimensions of the HR Services and Employee Labour Relations segment are:

- Employee and Labour Management;
- Employee Labour Relations; and
- Compensation and Benefits.

6.1.1 Employee and Labour Management

Employee and Labour Management ("ELM") focuses on the prevention, monitoring, mitigation, and resolution of specific issues relating to employee and labour relations, attendance, health, short and long-term disability, employee compliance with legislation, corporate policies, and practices and collective agreement provisions. Within the Employee and Labour Management area, health services processes and monitors occupational and non-occupational health and injury claims on behalf of Toronto Hydro. Health services assists injured employees through appropriate treatment and recovery measures to encourage their participation in the workplace within their prescribed restrictions until they can safely return to their pre-injury role.

6.1.2 Employee Labour Relations

Toronto Hydro has a diverse workforce in a variety of roles and functions including certified and skilled trades, and designated and technical professionals. Toronto Hydro also operates within a dynamic labour environment, as approximately 58 percent of its employees belong to a union. Unionized employees are organized into three bargaining units (inside workers, outside workers, and professional engineers) and are represented by sophisticated and established labour unions, the Power Workers' Union ("PWU") and the Society of Energy Professionals.

6.1.3 Employee and Labour Management

Employee Labour Relations ("ELR") supports Toronto Hydro's unionized and non-unionized work groups by ensuring workplace issues are addressed promptly and appropriately, and that the utility follows all applicable labour and employment related legislation, policies, and collective agreement requirements.

This work requires labour relations and legal professionals to provide advice, guidance, and support on how to address challenges, and where necessary, assist in preparing for litigation. Litigation can include grievance arbitration, civil employment claims, Ontario Labour Relations Board matters, and human rights claims. ELR also provides legal advice and assistance in regards to privacy matters and freedom of information requests that pertain to employees of the organization.

6.1.4 Compensation and Benefits

This function oversees and administers Toronto Hydro's workforce compensation strategy and practices.[5] The services provided through this function are critical to the utility's ability to secure and maintain a workforce that is skilled, adaptable, committed, and performance-driven. Toronto Hydro strives to achieve these key outcomes in a financially responsible manner by providing wages and benefits in the markets where Toronto Hydro competes for talent, and by recognizing employee contributions in achieving individual, divisional, and corporate performance goals.

6.2 Human Resources Services and Employee Labour Relations Segment Costs

Toronto Hydro requires approximately $5 million per year over the 2020-2024 plan period to perform the Human Resources Services and Employee Relations functions

[5] Exhibit 4A, Tab 4, Schedule 4.

described above. If the utility does not receive the funding it requires to execute this segment as described, Toronto Hydro's employees could be exposed to a number of risks, including:

- Legislative or regulatory non-compliance as a result of having insufficient resources to monitor, advise, and enforce compliance with the utility's statutory and regulatory obligations;
- Lower levels of productivity across the organization due to the inability to investigate and remedy employment issues such as attendance management; and
- Other miscellaneous risks, such as the inability to defend itself against employment related claims, or to pursue further efficiencies and cost-saving opportunities.

Table 5, below, provides the Historical (2015-2017), Bridge (2019), and Test Year (2020) expenditures for the Human Resource Services and Employee Relations segment.

Table 5: Human Resources Services and Employee Labour Relations Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Human Resource Services and Employee Labour Relations	4.6	5.2	5.1	4.8	4.8	5.0

The 2020 test year costs represent an increase of $0.4 million from the utility's last rebasing year actuals (2015), $1.0 million decrease from the utility's most recent historical actual year (2017), and $0.2 million increase from the bridge year (2019).

6.3 Human Resources Services and Employee Labour Relations Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

From 2015 to 2016, costs increased by $0.6 million. This was primarily due to an increase in legal fees and arbitration services related to employee relations cases and collective bargaining with the Society of Energy Professionals.

2016 – 2017 Variance Explanation

From 2016 to 2017, costs decreased by $0.1 million. A portion of the segment's resources was temporarily allocated to the ERP project, reducing the costs of this segment. Partially offsetting this temporary increase was an increase in resources added from the Organizational Effectiveness segment and the Environment, Health, and Safety segment.

2017 – 2018 Variance Explanation

From 2017 actual to 2018 budgeted, costs decreased by $0.3 million. This was a result of headcount and operating budget being transferred out of Human Resources Services and Employee Labour Relations segment to training initiatives during a reorganization of the division. The employees transferred to training initiatives are captured in the variance analysis in the next segment.

2018 – 2019 Variance Explanation

From 2018 to 2019, costs are expected to remain stable.

2019 – 2020 Variance Explanation

From 2019 to 2020, costs are expected to increase by $0.2 million to account for inflationary pressures.

7. TALENT MANAGEMENT AND ORGANIZATIONAL EFFECTIVENESS SEGMENT

7.1 Segment Description

The Talent Management and Organizational Effectiveness segment is focused on the development and execution of the workforce staffing plan, career succession, employee engagement and communication, performance and productivity, and employee development strategies and programs. The primary objective of this segment is to attract and maintain a skilled, productive, and adaptable workforce that Toronto Hydro requires to execute its programs and deliver safe and reliable services to its customer. Functions that allow Toronto Hydro to achieve these objectives include:

- Short and long term workforce staffing and planning;
- Career succession planning; job and organizational design;
- Attraction, recruitment and selection of new employees;
- Employee orientation, employee engagement and communication;
- Performance and change management systems; training and development; and
- Employee retention.

These functions are described in the sections below.

7.1.1 Talent Management

The Talent Management function plans and executes the utility's short and long-term staffing strategy, which includes:[6] (i) the resources that the utility needs to execute its

[6] Exhibit 4A, Tab 4, Schedule 3.

capital plans and operational programs; (ii) the availability of talent within the utility and in external market; and (iii) the actual and projected turnover rates. This segment is also responsible for establishing and administering industry specific collaborations with colleges and universities, attraction strategies, and the recruitment and selection processes.

Talent Management guides and executes both the internal and external recruiting and selection process, ensuring that it is fair, unbiased, and barrier free. Toronto Hydro relies on a number of approaches to attract highly skilled and diverse candidates from the external market. Toronto Hydro uses a competency-based selection process to fill vacancies, whereby candidates are evaluated on both behavioural corporate competencies and technical job specific requirements.

Collaborations with educational institutions allow Toronto Hydro to spread awareness about its human resource requirements, build recruitment relationships with future graduates and influence and shape the programs and curriculum offered to students with the utility's strategic goals and long-term needs. Through these partnerships, Toronto Hydro has hired a number of full time employees into the certified and skilled trades and designated and technical professional positions between 2014 and 2017.

7.1.2 Organization Design

Organization Design assesses the functionality of Toronto Hydro's business departments and operational divisions by reviewing each business units' functional responsibilities and associated processes for meeting those responsibilities. Organization Design also plans for long-term goals and objectives, considers succession opportunities, and devises the appropriate short-term and long-term workforce requirements for meeting

those goals and objectives. In addition, organizational structure is reviewed in order to identify strategies that enhance existing processes, achieve operational efficiencies and cost savings, and improve overall organization performance. This review ensures that job roles are clearly defined, that performance is adequately measured and that employees are compensated based on the appropriate job evaluation.

7.1.3 Change Management

Employees responsible for this function collaborate with other parts of the utility to support the successful implementation of large, cross-functional projects. Change Management helps to design and administer new systems and processes in relation to those projects, and to increase employee engagement and participation in order to maintain or increase productivity during and after the project's implementation.

7.1.4 Training and Development

In order to develop and sustain a qualified and competent workforce, Toronto Hydro provides a variety of training and development programs, including an onboarding program to support their transition to their new role, apprenticeship training, leadership, technical, legislative, and Toronto Hydro specific compliance programs. For instance, in 2017, the Training and Development team organized and successfully delivered 157 training programs. Designing and delivering these programs in-house provides for greater benefits to the utility's employees, along with cost-savings to the organization. External designers are now only used for complex legislative compliance matters.

Effective leadership and succession planning are essential to the utility's success and provide value to Toronto Hydro's customers by driving productivity and efficiency, and

protecting the continuity of the utility's operations. Training and Development facilitates these objectives, in conjunction with the performance management program, which allows employees to identify career development goals, specific interests, and any skill or knowledge gaps that they would like to fill. This information is critical to recognizing and developing potential leaders and successors from within the utility and to delivering Toronto Hydro's staffing strategy.[7] Leadership training is provided to employees at all levels of the organization.

Toronto Hydro's technical training and development programs are an essential resource for meeting all legislative, compliance and utility specific training requirements. Comprehensive training is not only a legislative requirement under the *Occupational Health Safety Act* and other key statutes and codes that govern Toronto Hydro, but it also contributes to higher employee productivity, efficiency and safer operations.

Toronto Hydro admnisters five certified apprenticeship training programs :

- Certified power line persons ("CPLP");
- Certified power cable persons ("CPCP");
- Distribution system technologists ("DST");
- Power system controllers ("PSC"); and
- Certified meter mechanics ("CMM").

Toronto Hydro also admnisters two technical training programs: (i) Engineering Technologists; and (ii) Engineers.

[7] Exhibit 4A, Tab 4, Schedule 3.

Together, these programs play a key role in facilitating the development and transfer of core knowledge about the complexities of Toronto Hydro's distribution system and in maintaining the specialized work skills which are critical at Toronto Hydro (e.g. network switching, positive identification of underground cable and lead cable splicing in the underground system), to allow experienced employees an opportunity to share the complexities of the utility's assets and mentor new employees.

As previously stated, Toronto Hydro is accredited with Training Delivery Agent status to provide training for Power Line Technicians. The other four apprenticeship programs are designed with the objective of developing and maintaining the specialized skills and knowledge that certified and skilled trades and designated and technical professionals require to work on Toronto Hydro's distribution system safely and efficiently.

7.1.5 Performance Management

Toronto Hydro employees are evaluated on specific competencies and results through the performance management program. The process establishes the ability for employees and supervisors to set goals throughout the year that are aligned with corporate objectives and outcomes, ensuring employees know what is expected of them and how their roles support the strategic objectives of the utility.[8] There is ongoing feedback to ensure project deadlines and goals are achieved. In addition to mobilizing Toronto Hydro's workforce to achieve the core objectives outlined in the corporate strategy, the performance management cycle facilitates career development and contributes to employee engagement and enrichment. All new employees are coached on aligning individual and organizational outcomes.

[8] Exhibit 1B, Tab 2, Schedule 1.

7.2 Talent Management and Organizational Effectiveness Segment Costs

Toronto Hydro requires approximately $8.1 million per year over the 2020-2024 plan period to perform the functions in the Talent Management and Organization Effectiveness segment, described above. If Toronto Hydro does not receive the requested level of funding to perform the functions and satisfy the responsibilities identified in this segment, the utility could be exposed to a number of risks, including but not limited to, a reduced ability to successfully recruit and develop the skilled and specialized resources that Toronto Hydro requires in the next five years. This, in turn, would impact Toronto Hydro's safety performance. It may also lead to an increase in WSIB premium rates and/or fines and penalties associated with non-compliance.

Table 6, below, provides the Historical (2015-2017), Bridge (2019), and Test Year (2020) expenditures associated with the Talent Management and Organizational Effectiveness segment.

Table 6: Talent Management and Organizational Effectiveness Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Talent Management & Organizational Development	7.0	7.3	7.0	7.8	7.9	8.1

The 2020 test year costs represent an increase of $1.1 million from the utility's last rebasing year actuals (2015), $1.1 million from the most recent historical actual year (2017), and $0.2 million from the bridge year (2019). The variances are primarily attributable to the addition of resources in 2018 to support the attraction and recruitment of employees to address planned retirements in all workforce segments.

7.3 Talent Management and Organizational Effectiveness Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

From 2015 to 2016, costs increased by $0.3 million as a result of new collaborations with colleges and universities to build recruitment relationships with future graduates, and an online leadership development program targeting organization's senior leadership.

2016 – 2017 Variance Explanation

From 2016 to 2017, costs decreased by $0.3 million. This was a result of transferring resources from the Talent Management and Organizational Effectiveness segment to the Human Resources Services and Employee Labour Relations Segment.

2017 – 2018 Variance Explanation

From 2017 actual to 2018 budgeted, costs are expected to increase by $0.8 million. This was a result of headcount and operating budget being reallocated from the Human Resources Services and Employee Labour Relations Segment to training initiatives.

2018 – 2019 Variance Explanation

From 2018 to 2019, costs are expected to increase by $0.1 million to account for inflationary pressures.

2019 – 2020 Variance Explanation

From 2019 to 2020, costs are expected to increase by $0.2 million to account for inflationary pressures.

FINANCE

1. OVERVIEW

Table 1: Finance Program Summary

2015-2017 Average Annual Cost ($M): 14.9	**2020 Cost ($M):** 16.2
Segments: • Controllership • Financial Services • External Reporting	
Outcomes: Public Policy, Financial	

The Finance program (the "Program") supports Toronto Hydro's operations through financial planning, management reporting, capital planning and reporting, payroll and disbursements, corporate tax, treasury, insurance and internal audit as well as external reporting and financial regulatory and revenue management.

The Program provides value to customers through the oversight of financial planning activities which support the utility's ability to execute long-term and short-term strategic plans and facilitates the appropriate governance of key performance measures such as operating expenses, regulated capital, in-service assets, net income and investor and stakeholder engagement as well as meeting its financial compliance requirements with the respective statutory and regulatory bodies.

The Program includes the following three segments:

- **Controllership**: encompasses oversight and governance of Toronto Hydro's financial activities. This includes financial planning, management reporting, capital planning, and payroll and disbursements.

- **Financial Services:** governs the activities permitting Toronto Hydro to meet its financial obligations. This includes Treasury activities, Insurance, Corporate Taxation, and Internal Audit. These functions are integral to contributing to financial compliance and solvency.
- **External Reporting:** oversees preparation and compilation of financial reporting materials for external parties, including, but not limited to, the Ontario Energy Board ("OEB"), Independent Electricity System Operator ("IESO"), and the Ontario Securities Commission ("OSC").

The Program and its constituent segments are a continuation of the activities described in the Finance program in Toronto Hydro's 2015-2019 Rate Application.[1]

Functionally, these segments work to support Toronto Hydro's operations through diligent financial planning, management reporting, capital activities, payroll and disbursements, corporate tax, treasury, insurance and abiding by internal and external auditing standards.

[1] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015), Exhibit 4A, Tab 2, Schedule 15.

2. OUTCOMES AND MEASURES

Table 2: Finance Program Outcomes and Measures Summary

Public Policy	• Contributes to Toronto Hydro's public policy objectives by: o Providing accurate and timely OEB's Electricity Record Keeping Requirements (the "RRR") reporting by maintaining the necessary processes and controls; o Preparing and issuing quarterly and audited annual financial statements, including the Management Discussion & Analysis ("MD&A") and Annual Information Form ("AIF") as required by the Ontario Securities Commission ("OSC") and the Canada Revenue Agency ("CRA"); and o Completing regulatory financial reporting required by the Ontario Energy Board ("OEB") including quarterly and annual reporting under the OEB's Electricity Reporting and Record Keeping Requirements (the "RRR") and compliance with the OEB's Accounting Procedures Handbook ("APH").
Financial	• Contributes to Toronto Hydro's financial objectives by: o Leading the governance of the DSP Implementation Progress Metric and Financial Ratios as annually reported via the OEB Distributor Scorecard; and o Meeting the financial obligations and maintenance of compliance requirements imposed by the relevant regulatory bodies and debt holder.

3. PROGRAM DESCRIPTION

The Program provides financial support to every aspect of Toronto Hydro's operations through business planning activities, management reporting, capital planning, payroll services, accounts payable, internal audits, and other issue-specific functions. It also enables the satisfaction of statutory and regulatory reporting obligations. These reporting requirements primarily relate to the preparation and issuance of securities law related continuous disclosure information completed on a consolidated basis.

Regulatory financial reporting required by the OEB includes quarterly and annual reporting under the OEB's RRR and compliance with the OEB's APH.

The Program also delivers traditional finance functions such as payroll and disbursement services, treasury, corporate tax, and internal audit that allow Toronto Hydro to meet its short and long-term financial, legal, and legislative obligations to its employees, external suppliers, service providers, debt holders, government agencies, board of directors, and its external auditors. In addition, the Program oversees a number of operational processes (i.e. management reporting and analysis and capital planning and reporting) that monitor the utility's financial performance and support management's ability to make informed, strategic decisions.

The Program also provides oversight and governance of the utility's business planning activities through the financial planning function which is responsible for the assessment and recommendation of short and long-term strategic plans and integration of operational, financial and regulatory plans. The Program also manages the co-ordination and consolidation of the annual budget.

The activities described above are accomplished via the following three segments:

- **Controllership**: Includes functions such as Financial Planning, Management Reporting and Analysis, Capital Planning and Reporting, and Payroll and Disbursements;
- **Financial Services**: Includes functions such as Corporate Tax, Treasury, Insurance, and Internal Audit; and
- **External Reporting**: Includes statutory and regulatory reporting functions such as External Reporting and Financial Regulatory and Revenue Management.

4. PROGRAM COSTS

Toronto Hydro requires approximately $16.2 million per year over the 2020-2024 plan period to execute the functions described above. Without this level of funding, the Program could be exposed to a number of risks, including:

- Reduced oversight and management functions that can negatively impact operational decisions and compromise the achievement of strategic objectives;
- Decreased ability to comply with statutory and regulatory reporting requirements;
- Inability to satisfy financial, legal and legislative obligations to its employees, external suppliers, service providers, debt holders, government agencies, Board of Directors and external auditors; and
- A compromised ability to secure funding to finance the Capital and OM&A programs and/or risk of violation of the covenants contained in the existing debt issuances.

Table 3, below, provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for each of the Program's segments.

Table 3: Finance Program Expenditures by Segment ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Controllership	8.4	7.3	6.4	7.2	7.2	7.0
External Reporting	2.5	2.7	2.7	3.0	3.1	3.2
Financial Services	5.2	5.0	4.6	5.7	5.9	6.1
Total	**16.1**	**15.0**	**13.6**	**15.9**	**16.2**	**16.2**

4.1 Cost Drivers

The Program's proposed 2020 test year costs represent an increase of $0.1 million from the utility's last rebasing year actual costs (2015), $2.6 million from the most recent historical actual year (2017), and no change from the bridge year (2019). These variances are attributable to the following drivers: compensation cost increases, higher insurance premiums, and System for Electronic Document Analysis and Retrieval ("SEDAR") fees, partially offset by expected cost savings resulting from departmental efficiencies and process improvements.

4.2 Cost Control and Productivity Measures

The Program has undertaken certain measures over the 2015-2019 plan period to control costs. In 2016, the Finance program engaged in an assessment of its functions, responsibilities and resources which resulted in a redesign of the Program, amalgamation of roles, and the streamlining of processes across the Controllership, Financial Services, and External Reporting Segments. Specifically:

- The amalgamation of Financial Planning and Management Reporting functions creating internal efficiencies within the Controllership segment;
- Re-allocation of the Financial Regulatory and Revenue management function to the External Reporting segment to streamline roles and responsibilities; and
- Re-allocation of resources to the Legal and Regulatory program.

Within the Controllership segment, additional cost savings of $0.9 million are forecasted for the 2019 Bridge and 2020 Test Year. These savings are related to departmental efficiencies through the streamlining of functions and process improvements resulting in the elimination of manual processes.

In 2017, within the Financial Services segment, Toronto Hydro took active measures to re-negotiate its insurance policies to drive down the property insurance premiums, resulting in annual savings of $0.4 million.

Lastly, over the 2015-2019 plan period, External Reporting is expected audit fees flat, and maintain current staffing levels.

5. CONTROLLERSHIP SEGMENT

5.1 Segment Description

The Controllership segment provides oversight and governance of Toronto Hydro's financial planning activities, timely and accurate financial information and support to Toronto Hydro's senior management and operational business units, and allows the utility's financial reports to meet both statutory and regulatory financial reporting requirements. The Controllership segment leverages knowledge of operational processes to produce accurate and relevant financial information, and provides appropriate financial context for decision making by the operational business units and senior management. This segment is crucial in assisting senior management make informed decisions, and for monitoring and analyzing the utility's financial performance against short-term goals, long-term plans and regulatory filings. The activities comprising this segment encompass the following functions: (i) Financial Planning; (ii) Management Reporting and Analysis; (iii) Capital Planning and Reporting; and (iv) Payroll and Disbursements. Further details of these activities are below.

5.1.1 Financial Planning

The Financial Planning function provides centralized oversight and governance of the utility's financial planning activities including the assessment and recommendation of

long-term strategic plans and integration of operational, financial, and regulatory plans. This function co-ordinates the development and execution of the utility's budget, financial projections, and support for electricity distribution rate applications. The group leverages the analysis provided through the Management Reporting and Analysis function described below to identify issues that may impact Toronto Hydro's ability to achieve its financial objectives. Financial planning allows the utility to make effective decisions that enable the achievement of the company's strategic goals and objectives while ensuring governance and oversight of all financial planning activities.

5.1.2 Management Reporting and Analysis

The Management Reporting function oversees internal management reporting and supports operational groups through month-end activities and financial analysis for decision making and achievement of strategic objectives. Responsibilities of this function include: (i) managing financial systems and processes to effectively deliver timely reports and outlooks; (ii) reviewing, consolidating and preparing analyses for management reports to enable timely decision making; (iii) providing support for external reporting and disclosure; and (iv) reviewing and consolidating monthly financial outlooks.

5.1.3 Capital Planning and Reporting

The Capital Planning function oversees the development of the utility's annual capital expenditure budget and long-term capital expenditure projections. The Capital Reporting function records capital projects in the fixed asset register, and maintains tangible, intangible, regulatory and statutory assets, and financial data under both Modified IFRS and IFRS. The team provides fixed assets, capital expenditure ("Capex"), depreciation expense, construction work in process ("CWIP") and in-service additions

("ISA") continuities, reconciliations, reports and analysis to ensure compliance with OSC, OEB and audit requirements. By providing regular reports and analysis of the capital work plan, this function enables Toronto Hydro to track and monitor its performance relating to execution of the plan. In addition, the team collaborates with operational groups to develop, implement and optimize internal controls and processes to maintain the integrity of financial data and improve efficiency. These services are essential to Toronto Hydro's ability to comply with regulatory standards, to produce accurate financial statements, and to successfully deliver the utility's capital work plans.

5.1.4 Payroll and Disbursements

The Payroll function ensures that Toronto Hydro employees are compensated for their services in a timely and accurate manner, consistent with relevant time-keeping and other records. The function also ensures that all relevant legislative requirements and statutory deductions are appropriately applied to employee payments and that payroll withholdings amounts are remitted on a timely basis. In addition, the function maintains accurate OMERS pension fund records for participating employees.

The Disbursements function facilitates timely and accurate payment of valid vendor invoices. It also processes payments for eligible customer refunds initiated by Toronto Hydro's Customer Care Department. In performing these tasks, the Disbursements function utilizes financial software to validate and/or correct the amounts and timing of payment of supplier invoices. In addition, it reviews software generated payment files and approves the resulting bank transfer files or cheque runs.

5.2 Controllership Segment Costs

Toronto Hydro requires approximately $7 million per year over the 2020-2024 plan period to execute the functions in the Controllership segment, as described above. Without this level funding, Toronto Hydro could be exposed to a number of risks:

- Compromised month-end and financial analyses for management reports to enable timely decision making;
- Reduced management of fixed assets and oversight of capital program spending and ISAs that can impact approved commitments in prior OEB decisions and compromise the achievement of strategic and financial objectives; and
- Reduced governance and oversight of financial planning activities that can limit the organization's ability to execute its long-term strategic vision and plans.

Table 4, below, provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for the Controllership segment.

Table 4: Controllership Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Controllership	8.4	7.3	6.4	7.2	7.2	7.0

The 2020 proposed test year costs represent a decrease of $1.4 million from the utility's last rebasing year actual costs (2015), an increase of $0.6 million from the most recent historical actual year (2017), and a decrease of $0.2 million from the bridge year (2019).

5.3 Controllership Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

A decrease of $1.1 million resulting from an organizational re-design of the Program due to the amalgamation of roles and streamlining of processes creating efficiencies within the segment as well as transfer of resources.

2016 – 2017 Variance Explanation

A decrease of $0.9 million due to headcount vacancies and additional capitalization of labour to the ERP project.

2017 – 2018 Variance Explanation

An increase of $0.8 million is due to headcount vacancies in 2017 which are expected to be filled in 2018.

2018 – 2019 Variance Explanation

There is no forecasted variance. Forecasted salary and other inflationary increases are expected to be offset by departmental efficiencies and streamlining of functions and process improvements resulting from the elimination of manual processes.

2019 – 2020 Variance Explanation

Forecasted decrease of $0.2 million due to capitalization of labour for internal projects

6. FINANCIAL SERVICES SEGMENT

6.1 Segment Description

The Financial Services segment encompasses the functions that enable Toronto Hydro to meet its regular and long-term financial obligations to its external suppliers and

service providers, Toronto Hydro's debt holders and the government. It also allows the utility to plan for, secure and provide timely payments for market-competitive debt instruments that it needs to finance its capital work program.

The Financial Services segment provides Toronto Hydro with a means to objectively evaluate the accuracy, consistency and efficiency of its core functions and processes to ensure compliance to internal and external policies and facilitate transparency in all corporate activities. The scope of activities comprising this segment includes the following functions: (i) Corporate Tax; (ii) Treasury; (iii) Insurance; and (iv) Internal Audit.

6.1.1 Corporate Tax

The Corporate Tax function facilitates the utility's compliance with all relevant tax laws and regulations. In addition, it ensures that taxes are appropriately recorded and reflected in accounting records and external financial statements. The function is responsible for preparing and submitting timely tax filings and applicable payments that include corporate income taxes, harmonized sales tax, the debt retirement charge, and non-resident withholding tax. The group executes tax-related financial planning activities, performs tax-related monitoring and reporting work, and supports both internal and external compliance tax audit activities as required by applicable legislation and internal policies. Corporate Tax is also responsible for regulatory tax reporting and compliance, such as the Payment in Lieu of Taxes ("PILs") calculations for the purposes of rate filings.[2]

[2] Exhibit 4B, Tab 2.

6.1.2 Treasury

The Treasury function oversees Toronto Hydro's cash management, debt management, and investor relations activities. Cash management activities include: (i) borrowing to provide the utility with adequate funds to meet its financial obligations, or investing any excess funds on hand; (ii) risk controls including segregation of duties and independent verification and approval of borrowing activities; and (iii) daily reporting and reconciliation of Toronto Hydro's cash position and general ledger and sub-ledger accounts. Debt management activities include the issuance of both long-term and short-term debt instruments to fund the capital programs and for general corporate purposes. Investor relations activities include developing and managing relationships with bank lenders, bond investors, independent financial and credit analysts, and the credit rating agencies in order to optimize the cost of funding. The activities performed by this function help facilitate access to the debt capital markets from which Toronto Hydro accesses funds to carry out its operations and fund its long term capital program.

6.1.3 Insurance

The Financial Services function also oversees the utility's comprehensive insurance requirements, the purpose of which are to provide Toronto Hydro protection for asset exposure, corporate liability and other activities which may expose the utility to a financial loss. Current insurance policies administered by this group provide coverage for a variety of losses and expenses, including comprehensive general liability, all risk property and boiler and machinery insurance, liabilities of directors and officers, automobile liability, professional liability, and crime and cyber insurance.

6.1.4 Internal Audit

Internal Audit provides independent and objective reporting to Toronto Hydro Corporation's Audit Committee and management through operational, compliance, and performance audits. Internal Audit focuses on assessing the adequacy and effectiveness of the utility's risk management, governance, and system of internal controls, and provides consultation and advisory services on the design, implementation, and maintenance of internal controls and reporting systems, governance activities, fraud detection procedures, and other matters requested by senior management or the Audit Committee.

6.2 Financial Services Segment Costs

Toronto Hydro requires approximately $6.1 million per year over the 2020-2024 plan period to execute the functions in the Financial Services segment, as described above. Without this level of funding, Toronto Hydro could be exposed to a number of risks, including**:**

- Compromised ability to secure funding to finance the capital programs and/or risk of violation of the covenants contained in the existing debt issuances;
- Increased difficulty maintaining compliance with relevant tax laws, rules, regulations and appropriate tax reporting and disclosure requirements, which could cause an increase in tax risks and related costs;
- Reduced ability to ensure operational compliance and performance due to lack of design, implementation and maintenance of internal controls and reporting systems, governance activities and fraud detection procedures; and
- Inability to protect the utility against a variety of financial risks and losses due to lack of oversight of insurance policies.

Table 5, below, provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for the Financial Services segment.

Table 5: Financial Services Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Financial Services	5.2	5.0	4.6	5.7	5.9	6.1

The 2020 proposed test year costs represent an increase of $0.9 million from the utility's last rebasing year actual costs (2015), $1.5 million from the most recent historical actual year (2017), and $0.2 million from the bridge year (2019).

6.3 Financial Services Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

A decrease of $0.2 million is primarily due to lower consulting costs in the Treasury and Internal Audit functions, partially offset by compensation cost increases.

2016 – 2017 Variance Explanation

A decrease of $0.4 million is primarily due to headcount vacancies resulting from the organizational re-design of the Program.

2017 – 2018 Variance Explanation

An increase of $1.1 million is primarily due to headcount vacancies expected to be filled in 2018, compensation cost increases and higher forecasted insurance premiums due to recent lost experience by the underwriters being pushed to policy holders.

2018 – 2019 Variance Explanation

A forecasted increase of $0.2 million is due to compensation cost increases.

2019 – 2020 Variance Explanation

A forecasted increase of $0.2 million is due to compensation cost increases and higher forecasted insurance premiums due to recent lost experience by the underwriters being pushed to policy holders.

7. EXTERNAL REPORTING SEGMENT

7.1 Segment Description

The External Reporting segment oversees the preparation and compilation of external financial reporting materials, such as those required by the OSC. Among other things, this function requires preparation of publically filed annual and interim financial statements and disclosures and reporting to the Board Audit Committee. The segment is also responsible for assessing, reviewing, documenting and communicating all changes in accounting standards to relevant stakeholders, and assessing the accounting treatment for new or complex transactions.

The specific activities and internal controls underlying Toronto Hydro's external reporting processes are subject to regular reviews by independent internal and external auditors.

To enable timely and accurate execution of its core functions, the segment undertakes two sets of primary activities. First, the segment performs central accounting functions such as consolidation entries, intercompany settlements and eliminations, accounting for post-employment benefits, and other account reconciliation and management

activities. Second, it uses information in the company's accounting systems to prepare all required financial filings. These filings include the audited annual financial statements and notes (consolidated and for each legal entity separately), the MD&A, the AIF and other reporting requirements from time to time. With the exception of the AIF, the above documents are filed quarterly.

In addition the External Reporting segment is responsible for the Financial Regulatory and Revenue Management function which oversees financial activities associated with the OEB and is responsible for the accounting in relation to Toronto Hydro's transactions with the IESO and other suppliers for cost of power expenses and other related regulatory settlements. Other responsibilities include budgeting, forecasting, financial analysis and related preparation of information for reporting under the OEB's RRR and for the purpose of rate applications. This function also supports OEB audits, enables compliance with the OEB financial and regulatory accounting procedures outlined in the APH, and supports the external reporting, management reporting and analysis and financial planning functions in relation to regulatory assets and liabilities.

7.2 External Reporting Segment Costs

Toronto Hydro requires approximately $3.2 million per year over the 2020-2024 plan period to execute the functions in the External Reporting segment, as described above. Without this level funding, Toronto Hydro could be exposed to a number of risks, including**:**

- Increased risk of reporting errors and material misstatements for financial reporting purposes;
- Compromised ability for the preparation and compilation of external financial reporting materials, such as those required by the OSC;

- Lack of appropriate governance to support Board of Directors responsibilities for financial and audit matters; and
- Lack of regulatory and revenue management leading to material misstatements and inability to comply with the OEB's financial and regulatory accounting procedures.

Table 6, below, provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for the External Reporting segment.

Table 6: External Reporting Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
External Reporting	2.5	2.7	2.7	3.0	3.1	3.2

The 2020 proposed test year costs represent an increase of $0.7 million from the utility's last rebasing year actual costs (2015), $0.5 million from the most recent historical actual year (2017), and $0.1 million from the bridge year (2019).

7.3 External Reporting Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

An increase of $0.2 million is due to compensation increases.

2016 – 2017 Variance Explanation

There is no variance.

2017 – 2018 Variance Explanation

An increase of $0.3 million is primarily due to mandated SEDAR fees related to financial reporting obligations made on a consolidated basis.

2018 – 2019 Variance Explanation

A forecasted increase of $0.1 million is due to compensation increases.

2019 – 2020 Variance Explanation

A forecasted increase of $0.1 million is due to compensation increases.

INFORMATION TECHNOLOGY

1. OVERVIEW

Table 1: Information Technology Program Summary

2015-2017 Average Cost ($M): 35.9	**2020 Cost ($M):** 44.0
Segments: • Security & Enterprise Architecture • IT Operations • Project Execution • IT Governance	
Outcomes: Customer Service, Reliability, Public Policy, Safety, and Financial	

The Information Technology ("IT") program (the "Program") supports all aspects of Toronto Hydro's business. The IT infrastructure and applications maintained by this Program and the IT services provided through it, enable and support the efficient operations of the utility and play a critical role in achieving Toronto Hydro's objective to provide safe, secure and reliable electricity.

The Program deploys, supports, and operates all information systems and associated components including hardware, software, network, telephony, communications, and information security. The types of technology managed by the Program include a mix of end point devices (laptops, tablets, and printers), communications hardware and software and storage infrastructure, user-facing applications and core infrastructure software. Toronto Hydro performs this work under clearly defined architectural standards and governance frameworks.

The Program consists of the following four segments:

- **Security and Enterprise Architecture*:*** Defines and implements utility-wide IT strategy, develops and oversees corporate IT policies and standards, security operations and manages enterprise IT risks including cyber security**.**
- **IT Operations**: Supports the day-to-day operation of Toronto Hydro's IT assets, including core back-end infrastructure and end-user applications.
- **Project Execution:** Facilitates the development and manages the implementation of new IT solutions (projects, programs and applications) required to achieve Toronto Hydro's strategic objectives.
- **IT Governance:** Provides program governance, budget control, contract and vendor management, records management, audit services and program planning. This segment is further responsible for prioritizing program execution, setting IT policies and goals, developing and analyzing program and project business cases.

The Program and its constituent segments are a continuation of the activities described in the Information Technology program (OM&A) in Toronto Hydro's 2015-2019 Rate Application.[1]

[1] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015), Exhibit 4A, Tab 2, Schedule 16.

2. OUTCOMES AND MEASURES

Table 2: Information Technology Program Outcomes and Measures Summary

Customer Service	• Contributes to Toronto Hydro's customer service objectives by: o Ensuring that IT assets which support Toronto Hydro's customer-interfacing systems (including timely communication with customers during prolonged power outages) are effective and available; and o Maintaining the integrity and availability of key customer facing applications such as the Customer Self-Serve Web Portal and the Outage Map, a map of Toronto Hydro's coverage area displaying outage zones.
Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) objectives by: o Maintaining the availability of modern, reliable and secure enterprise-wide IT/OT systems that monitor and control the performance of distribution assets (ex. SCADA), and by providing system operators timely and accurate information about these assets; and o Supporting outage restoration efforts by ensuring that system operators have the necessary IT/OT System tools to promptly identify incidents, develop effective resolution plans and communicate them to operational teams.

Public Policy	• Contributes to Toronto Hydro's public policy objectives by: o Enabling the efficient implementation of new policy initiatives and compliance with regulatory requirements passed by Regulatory authorities such as Measurement Canada, the OEB and the IESO; o Enabling the attainment of Ontario's Long Term Energy Plan objectives by providing the technological infrastructure framework required to achieve conservation and demand management targets, enable grid-modernization, and support the proliferation of energy storage and distributed energy resources; and o Increase protection against cyber security threats by maintaining compliance with the OEB's Cyber Security Framework.
Safety	• Contributes to Toronto Hydro's safety objectives, measured through metrics like the Total Recordable Injury Frequency ("TRIF") by: o Enabling more substation and field assets to be constantly monitored; o Ensuring underlying IT/OT Systems such as SCADA are functioning properly and are consistently available; and o Driving safety performance using software systems such as automated vehicle location (GPS), Intelex, LMS, SCADA, and NMS.
Financial	• Contributes to Toronto Hydro's financial objectives by ensuring that core systems are operational with high reliability and availability supporting all areas of Toronto Hydro's business, including operations, customer service, and regulatory, management, and internal and external financial reporting.

3. PROGRAM DESCRIPTION

The Program provides technology solutions to Toronto Hydro and its customers in a secure, timely, and cost-effective manner. It does this by implementing products that meet Toronto Hydro's evolving operational requirements (including security), customer need and preferences, and support continuous improvement across the utility. Timely

technical maintenance and support from vendor or internal resources ensure ongoing reliability and operability of key business applications and underlying IT infrastructure. The Program also continues to ensure preventative and detective system controls are aligned with industry best practices including the National Institute of Standards and Technology Cybersecurity Framework, and the OEB's Cybersecurity Framework. Toronto Hydro relies on IT to satisfy its obligations to customers, maintain system reliability and safety, and to comply with existing and emerging requirements of the various regulatory bodies that govern the utility's operations.

IT infrastructure and applications must be periodically refreshed or enhanced to maintain the availability of systems to support core operations and to minimize risk of failure. Accompanying these infrastructure and software capital expenditures is the associated support in the form of maintenance and licensing costs as well as the internal resources required to maintain these assets. IT infrastructure and software applications must be kept current to mitigate the risk of malicious cyber-attacks that can compromise sensitive customer data, operational and employee information, as well as the integrity of the distribution system.

IT supports the automation of core processes and functions, such as customer billing and outage management. It enables the utility to manage new business objectives and requirements, such as the need for additional data storage and processing capabilities to respond to customer growth demands or to respond to changing requirements of the industry or business units. These activities are provided through the Program's four constituent segments: (i) Security & Enterprise Architecture; (ii) IT Operations; (iii) Project Execution; and (iv) IT Governance.

4. PROGRAM COSTS

Toronto Hydro requires approximately $44.1 million per year over the 2020-2024 plan period to execute the Program functions, as described above. Without this level of funding, Toronto Hydro could be exposed to a number of risks, including**:**

- Increase the risk of cyber security attacks which would compromise customer and operational data;
- Increase the number of service outages and duration of outages if critical systems (SCADA, Outage Management, Metering, and Customer Care applications) are not adequately maintained;
- Lead to a delay or failure to provide required support for IT capital programs, including initiatives related to safety, regulatory compliance, and customer service;[2]
- Increased financial risk due to inadequate oversight of operational budgets, project budgets, and maintenance contract negotiations; and
- Reduced ability to meet the utility's regulatory and legal obligations with respect to records management and data governance.

Table 3, below, provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for each of the Program's segments.

[2] Please see the Information Technology and Operational Technology Systems program at Exhibit 2B, Section 8.4.

Table 3: Information Technology Program Expenditures by Segment ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
IT Governance	2.7	2.9	3.0	3.2	3.3	3.4
IT Operations	27.9	28.3	30.9	33.8	35.3	35.6
Project Execution	1.2	1.4	1.6	1.6	1.6	1.7
Security & Enterprise Architecture	2.7	2.4	2.9	3.0	3.3	3.4
Total	**34.4**	**35.0**	**38.4**	**41.7**	**43.5**	**44.0**

4.1 Cost Drivers

The 2020 test year forecast represents an increase of $9.6 million from the utility's last rebasing year actual costs (2015), $5.6 million from the most recent historical budget year (2017), and $0.5 million from the bridge year (2019).

Maintenance costs and subscription fees account for the majority of the expected increase. Software licenses and hardware require ongoing maintenance contracts ranging from simple patches and updates to targeted problem resolution. These contracts allow Toronto Hydro to maintain the integrity, reliability, availability, and security of Toronto Hydro's IT systems.

Factors driving the expected increase in maintenance costs and subscriptions fees include:

- New, recent applications such as SCADA upgrades, Engineering Analytics, and Power Monitoring Expert that were implemented to support reliability outcomes;
- A forecasted increase to infrastructure systems in support of systems such as Outage Management and Smart Metering or Suite Metering Advanced Metering Infrastructure;

- The implementation of upgrades to meter services such as Metering Data Collection contributed to the increased software license base, which is subject to support and maintenance costs;
- Enterprise-wide systems such as the Learning Management System and Applicant Tracking System were recently implemented. The most significant increase in the enterprise-wide systems is the upgrade of the Operating System resulting in additional maintenance licensing costs beginning in 2016;
- Investments in Operational Technology, such as the Radio Program which addresses safety and reliability concerns;
- Enterprise Resource Planning ("ERP") subscription services and related hardware upgrades; and
- On aggregate, all maintenance costs have increased as a result of inflationary contract escalation increases and changes in the USD to CAD exchange rate.

Segment specific cost drivers are summarized below:

- **Security and Enterprise Architecture:** To address risks of cyber-attacks, preventative and detective controls aligned with industry best practices, including the National Institute of Standards and Technology Cybersecurity Framework were implemented. This resulted in a requisite increase in employees.
- **IT Operations:** The expected variance is primarily attributable to expected increases in maintenance and licensing costs and subscription fees.
- **Project Execution**: The expected variance is primarily attributable to an increase in employees to assist with projects, such as the ERP, in relation to implementation and training.

- **IT Governance:** The expected variance is primarily attributable to an increase in program costs in the areas of data governance and incident, problem and change management, including the implementation and oversight of Toronto Hydro's evolving data management standards, practices, process, and technologies.

4.2 Cost Control and Productivity Measures

Toronto Hydro works to ensure that costs are contained. To this end, the Program employs several strategies, including: (i) working directly with internal clients to limit the number of licenses that are purchased and maintained; and (ii) in contracting external services, Toronto Hydro will go to market, where possible. For example, an additional $0.5 million in savings were realized in the telecom maintenance contract when Toronto Hydro changed vendors and was able to negotiate more favourable terms.

In addition, for the period 2016 through 2018, employee costs are expected to remain relatively stable and increase at a rate less than inflation. A number of employees who depart from the utility (whether through retirements or attrition) will not be replaced.

5. SECURITY AND ENTERPRISE ARCHITECTURE SEGMENT

5.1 Segment Description

The Security and Enterprise Architecture segment manages and oversees Toronto Hydro's corporate Information Technology portfolio, implements utility-wide IT architecture practices, and identifies and manages key enterprise IT risks, such as threats to cyber security. The segment performs several key functions:

- Establishes corporate IT standards, policies, and enterprise architecture principles;

- Manages compliance to the above policies and architecture principles;
- Manages the enterprise information security posture and risk profile; and
- Drives operational cost efficiencies and business process streamlining.

Security and Enterprise Architecture defines and integrates the elements of Toronto Hydro's IT infrastructure operations strategy, application support strategy, and project delivery strategy to enable compliance with technical standards, corporate policies, and practices**.** The work includes ongoing assessment of business requirements, future state forecasts, and IT industry trends and opportunities.

Lastly, the Security and Enterprise Architecture team also addresses cybersecurity at Toronto Hydro by implementing preventative and detective controls aligned with industry best practices including the National Institute of Standards and Technology Cybersecurity Framework. Distributors are vulnerable to cyber-attacks that could result in business or service disruption. The OEB's new Cyber Security Framework acknowledges the criticality of this emerging threat to utility operations, and prescribes regulatory requirements to address the risks.[3] The thwarted cyber-attack on Metrolinx in January 2018 highlights the need for ongoing vigilance to protect the privacy of Toronto Hydro's customers and maintain grid reliability.[4] The Security & Enterprise Architecture team's primary focus is to ensure the confidentiality, integrity, and availability of the utility's information assets, including the protection of customer information. This segment also addresses an increasing amount of targeted and emerging threats to the energy sector including but not limited to file-less malware, advanced persistent threats, and artificial intelligence.

[3] Ontario Cyber Security Framework (December 6, 2017), available at: <https://www.oeb.ca/sites/default/files/Ontario-Cyber-Security-Framework-20171206.pdf>.
[4] Toronto Star, Metrolinx Targeted by North Korean Cyberattack (January 23, 2018) <https://www.thestar.com/news/gta/2018/01/23/metrolinx-targeted-by-north-korean-cyberattack.html>.

5.2 Security and Enterprise Architecture Segment Costs

Toronto Hydro requires approximately $3.4 million each year during the 2020 and 2024 period to execute the functions in this segment. Table 4, below, provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for the IT Security & Enterprise Architecture segment.

Table 4: Security and Enterprise Architecture Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Security & Enterprise Architecture	2.7	2.4	2.9	3.0	3.3	3.4

The 2020 test year costs in this segment represent an increase of $0.7 million from the utility's last rebasing year actual costs (2015), $0.5 million from the most recent historical budget year (2017), and $0.1 million from the bridge year (2019).

A lower level of spending would place undue pressure on infrastructure reliability, create challenges to fulfilling business requirements, increase the risk of service outages due to a lack of IT architecture and governance, and ultimately result in end-customer impacts such as web services issues or potential billing system malfunctions. In addition, Toronto Hydro would be at greater risk of cyber-attacks that may compromise customer, employee, and operational data, and negatively impact the distribution system.

5.3 Security and Enterprise Architecture Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

Spending between 2015 and 2016 decreased by $0.3 million, due to a one-time cost reduction of $0.2 million for services related to closing gaps following a security audit

completed in 2014. The remaining cost reduction of $0.1 million was the result of temporary vacancies in internal positions that were not filled until late in 2016.

2016 – 2017 Variance Explanation

Costs between 2016 and 2017 increased by $0.5 million. A one-time cost for an IT security study accounts for $0.2 million of this variance. The security study enables Toronto Hydro to identify and guard against potential security threats by testing and evaluating any potential physical, system and network security vulnerabilities. The remaining $0.3 million represents the full-year effect of the filled vacancies from late in the previous year.

2017 – 2018 Variance Explanation

The increase of $0.1 million between 2017 and 2018 reflects standard inflationary pressures.

2018 – 2019 Variance Explanation

The forecast increase of $0.3 million between 2018 and 2019 is attributable to the addition of labour resources required to address cyber security risks.

2019 – 2020 Variance Explanation

The forecast cost increase of $0.1 million between 2019 and 2020 is attributable to standard inflationary pressures.

6. IT OPERATIONS SEGMENT

6.1 Segment Description

The IT Operations segment is responsible for the day-to-day operation, deployment, maintenance, and support of all IT systems at Toronto Hydro. This includes maintaining the integrity and availability of all corporate data, ensuring adequate end user devices and servers to support real-time data processing of applications and databases, proactive capacity and performance planning, routine systems maintenance, and continuous monitoring of all critical business systems.

Toronto Hydro's business processes rely on core back-end IT hardware assets, technology, and end user software to remain reliable, available, and secure. To facilitate continued operation of these and other systems, the segment includes a 24/7 monitoring and response structure to ensure timely resolution of incidents and problems to prevent or quickly address major system outages.

The IT Operations segment includes maintenance contracts, which provide technology and performance fixes (i.e. patches), and new features and functionality. The IT operations segment also administers upgrade patches to the utility's technology assets on an ongoing basis as they are released by vendors, thereby mitigating cyber and system performance risks.

The IT Operations segment consists of two core functions: (i) Hardware; and (ii) Software and Service Management.

The Hardware function is responsible for the deployment and management of the following asset components and services:

- Data and voice networks, fibre optic and radio infrastructure, telephony and communication infrastructure;
- Advanced Metering Infrastructure and grid management networks;
- Servers and operating system infrastructure;
- Data storage and backup environments; and
- Physical data centre infrastructure (cabling and racking).

The Software and Service Management function is responsible for the introduction and continuous operation of the following asset components and services:

- Client-facing software assets;
- Database and middleware software assets such as Oracle and Microsoft SQL;
- End user devices, including desktops, laptops, phones, printers, as well as services such as the upcoming deployment of Operating System software applications; and
- End user application development and reporting software assets and services.

6.2 IT Operations Segment Costs

Toronto Hydro requires approximately $35.5 million each year over the 2020 to 2024 period to execute the functions in this segment. Table 5, below, provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for the IT Operations Segment.

Table 5: IT Operations Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
IT Operations	27.9	28.3	30.9	33.8	35.3	35.6

The 2020 test year costs in this segment represent an increase of $7.7 million from the utility's last rebasing year actual costs (2015), $4.7 million from the most recent historical actual year (2017), and $0.3 million from the bridge year (2019).

Reductions to this budget would likely put at risk the utility's ability to adequately maintain and support critical systems, processes, and functions such as security systems, metering, stations and SCADA communications and business and customer applications services.

6.3 IT Operations Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

Between 2015 and 2016, the IT Operations segment experienced a net increase of $0.4 million due to the following factors:

- Increase of $0.8 million due to maintenance contracts increases greater than inflation, some of which were also subject to the US Dollar exchange rate fluctuations;
- Increase of $0.9 million related to Microsoft licensing costs;
- Increase of $0.4 million due to the addition of new maintenance and licensing requirements;
- Decrease of $0.6 million related to storage costs through efficiencies gained from Toronto Hydro's core backend infrastructure replacement program;
- Decrease of $0.6 million due to a reduction in the number of contract employees resulting from a change in infrastructure towards more capital intensive work, such as the radio upgrade project and fibre optic installation; and
- Decrease of $0.5 million in savings realized in the telecom maintenance contract when Toronto Hydro changed vendors and negotiated more favourable terms.

2016 – 2017 Variance Explanation

Between 2016 and 2017, costs increased by $2.6 million due to the following factors:

- Increase of $1.6 million due to incremental licenses and maintenance costs;
- increase of $0.6 million in volume-dependant licensing costs due to additional smart meters installations; and
- Increase of $0.4 million in labour costs, representing inflationary pressures on salaries.

2017 – 2018 Variance Explanation

Between 2017 and 2018, costs increased by $2.9 million due to the following:

- Increase of $2.1 million for net new maintenance corresponding to the implementation of capital investments in new and upgraded systems;
- Increase of $0.5 million for new managed services to support the operationalization of the ERP system in 2018; and
- Increase of $0.3 million resulting from inflationary pressures.

2018 – 2019 Variance Explanation

Between 2018 and 2019, costs are forecast to increase by $1.5 million, due to the following factors:

- Maintenance contract costs are expected to have a net increase of $0.6 million, with infrastructure maintenance increases of $1.0 million offset by savings of $0.4 million due to the decommissioning of legacy software made obsolete with the introduction of the ERP system; and
- Purchased services contracts are expected to increase by a net amount $0.8 million, with a contract increase of $1.0 million partially offset by an expected decrease in temporary staffing of $0.2 million. The decrease relates to staff

supporting legacy applications no longer required following the deployment of the ERP system.

2019 – 2020 Variance Explanation

Between 2019 and 2020, costs are forecast to increase by $0.3 million as a result of the following:

- Maintenance contracts are forecast to increase by $0.7 million to reflect expected increases in existing contracts of approximately $0.3 million, and $0.4 million for new contracts; and
- The increase in maintenance is expected to be offset by a reduction in temporary labour resources of $0.4 million, which currently support legacy applications that Toronto Hydro plans to decommission.

7. PROJECT EXECUTION SEGMENT

7.1 Segment Description

The Project Execution segment is responsible for the execution of Toronto Hydro's IT programs. In addition, the segment is responsible for continuous improvement of various project processes such as communication procedures and execution strategies.

Toronto Hydro's IT Project Execution practices are consistent with industry standards of project management frameworks, such as the Project Management Body of Knowledge ("PMBOK").[5] Since 2015, the Project Execution segment has managed anywhere from 10-20 complex projects per year, which represent approximately $12-15 million in annual capital expenditures.

[5] <https://www.pmi.org/pmbok-guide-standards>

7.2 Project Execution Segment Costs

Toronto Hydro requires approximately $1.7 million each year over the 2020 to 2024 period to execute the functions in this segment. Table 6, below, provides the Historical (2015-2017), Bridge (2018-2019) and Test Year (2020) expenditures for this segment.

Table 6: Project Execution Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Project Execution	1.2	1.4	1.6	1.6	1.6	1.7

The 2020 test year costs represent an increase of $0.5 million from the utility's last rebasing year actual costs (2015), a $0.1 million increase from the most recent historical actual year (2017), and a $0.1 million increase from the bridge year (2019).

A reduction of the proposed budget would reduce Toronto Hydro's ability to identify and execute IT projects to support the utility's operations. The Project Execution segment is essential to support new projects and program development, and to facilitate customer-facing products such as the Toronto Hydro customer internet portal. Reductions to the Program could place the successful execution of ongoing and planned IT capital programs at risk, including initiatives related to safety, regulatory compliance, or customer service.[6]

[6] *Supra* note 2.

7.3 Project Execution Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

The costs between 2015 and 2016 have increased by $0.2 million. This increase reflects additional labour requirements as a result of corresponding increases in capital spending.

2016 – 2017 Variance Explanation

The costs between 2015 and 2016 increased by $0.2 million due to additional labour resources required as a result of corresponding increases in capital spending and the needs of the ERP project in relation to implementation and training.

2017 – 2018 Variance Explanation

There is no variance over this time period.

2018 – 2019 Variance Explanation

There is no expected variance over this time period.

2019 – 2020 Variance Explanation

The costs between 2019 and 2020 are forecast to increase by $0.1 million as a result of standard inflationary pressures.

8. IT GOVERNANCE SEGMENT

8.1 Segment Description

The IT Governance segment provides oversight, capital planning, budget control, contract and vendor management, records management, compliance and audit services for Toronto Hydro's IT projects and services. The segment also facilitates the

implementation of the IT capital portfolio. This includes activities such as compliance review, project review and prioritization, project status monitoring/reporting, and benefit attainment monitoring/reporting. IT Governance also houses all project and portfolio documentation as the official enterprise custodian. By continuously monitoring the IT portfolio through the above-mentioned tools and processes, the IT Governance segment facilitates timely, cost effective, and successful delivery of IT projects.

The IT Governance segment performs a number of operational functions. It provides project governance by performing the necessary oversight, tracking, and reporting associated with the IT-based portfolio of programs and projects. The scope of this work also includes project reviews, status and change control reviews, project prioritization and benefit attainment monitoring. Administratively, it oversees the administration of external IT vendors, internal work order setup and purchase requisitions. This involves monitoring contract expiry dates and vendor negotiations, service level analysis and vendor consolidation work to drive savings.

From a records management perspective, it supports the enterprise-wide tracking and reporting requirements needed to comply with Toronto Hydro's Records Management Policy. This enables Toronto Hydro to meet its regulatory and legal obligations for the retention and destruction of records, and to educate employees on the utility's Records Retention Schedule, policy, and program guidelines.

Financially, the segment provides budget control and oversight to track and report on IT program expenditures and their alignment with the overall budget. This enables

Toronto Hydro to book IT expenditures to the correct expense accounts, and to post transactions in accordance with reporting requirements.

The segment also provides strategic solutions by developing and implementing the IT program strategy, defining and managing program- and segment-level performance expectations, and facilitating the development of business plans for new technological solutions.

On an ongoing basis, the work in this segment includes incident, problem and change management functions to ensure that normal service operation is restored as quickly as possible and business impact is minimized during an unplanned interruption to an IT service or system or a change (modification, addition or removal) of an IT service or system.

8.2 IT Governance Segment Costs

Toronto Hydro requires approximately $3.4 million each year over the 2020 to 20204 period to execute the functions in this segment. Table 7, below, provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for the IT Governance segment.

Table 7: IT Governance Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
IT Governance	2.7	2.9	3.0	3.2	3.3	3.4

The 2020 test year costs represent an increase of $0.7 million from the utility's last rebasing year actual costs (2015) and $0.4 million from the most recent budget year (2017), and a $0.1 million increase from the bridge year (2019).

The absence of a strong governance framework would expose Toronto Hydro to increased financial risk without intervention and oversight on operational budgets, project budgets, and maintenance contract negotiations. This segment is also responsible for prioritizing program execution, setting IT policies and goals, and developing and analyzing program and project business cases. Without these functions, Toronto Hydro could fail to meet its regulatory and legal obligations with respect to records management and data governance, and compromise its ability to ensure timely resolution of incidents and problems to prevent outages to critical systems.

8.3 IT Governance Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

The increase in costs of $0.2 million between 2015 and 2016 reflects additional employees hired in 2016 to backfill for prior year retirements and parental leaves.

2016 – 2017 Variance Explanation

The $0.1 million increase reflects standard inflationary cost pressures.

2017 – 2018 Variance Explanation

Between 2017 and 2018 costs increased by $0.2 million, which is driven by the requirements of data governance and change management.

2018 – 2019 Variance Explanation

The expected $0.1 million increase reflects standard inflationary cost pressures.

2019 – 2020 Variance Explanation

The expected $0.1 million increase reflects standard inflationary cost pressures.

LEGAL AND REGULATORY

1. OVERVIEW

Table 1: Legal and Regulatory Program Summary

2015-2017 Average Cost ($M): 13.2	**2020 Cost ($M):** 15.9
Segments: • Legal Services • Regulatory Affairs	
Outcomes: Customer Service, Public Policy, and Financial	

The Legal and Regulatory program ("Program") is a corporate services function providing specialized professional services to the utility. The Program responds to Toronto Hydro's legal and regulatory needs; being those of a large Ontario electricity distributor operating in the country's largest urban centre and seat of the Provincial Government. The Program covers many activities from detailed routine tasks, such as preparing customer connection agreements, processing legal claims, performing Independent Electricity System Operator ("IESO") wholesale market settlement, and filing regulatory reports with the Ontario Energy Board ("OEB"), to strategic advisory tasks, such as working with utility operations to improve decision-making by analysing legal and regulatory parameters and implications. The Program's objective is to sustain and improve utility performance through expert management of the ongoing and evolving external demands and expectations associated with the legal, regulatory, and other public policy drivers.

Through the Program, Toronto Hydro manages its corporate governance, securities and disclosure, commercial law matters, real property, litigation, claims, privacy, regulatory reporting and compliance, energy policy and stakeholder relations, regulatory

applications, regulatory law matters, load forecasting, wholesale settlement and rates calculations. This work is accomplished through two Program segments: (i) Legal Services; and (ii) Regulatory Affairs.

The Program costs include the fees remitted to the OEB and amortized costs of rate rebasing applications.

2. OUTCOMES AND MEASURES

Table 2: Legal and Regulatory Program Outcomes and Measures Summary

Public Policy	• Contributes to Toronto Hydro's public policy objectives by: o Measuring the percentage of OEB policy proceedings on which Toronto Hydro provides comments, either individually or through an industry organization; o Measuring the percentage of OEB policy working groups on which Toronto Hydro requests to participate; and, o Responding to Electricity Reporting & Recordkeeping Requirements ("RRR") and other required regulatory submissions in accordance with OEB requirements on time; and o Responding to freedom of information requests and appeals in accordance with the *Municipal Freedom of Information and Protection of Privacy Act*.
Financial	• Contributes to Toronto Hydro's financial objectives by: o Preparing and filing distribution rate rebasing applications in accordance with OEB requirements; and o Minimizing legal liability, recouping damages, and providing strong defenses against claims.

Customer Service	• Contributes to Toronto Hydro's customer service objectives by supporting operations in addressing easement inquiries, customer connection requests, claims and legal disputes and customer and stakeholder-facing issues governed by legislation, regulations and codes.

3. PROGRAM DESCRIPTION

The Legal and Regulatory program consists of two segments:

1) Legal Services
2) Regulatory Affairs

Legal Services provides Toronto Hydro with timely, accessible, and specialized legal advice and support. In alignment with the utility's corporate and operational strategy, Legal Services ensure Toronto Hydro is able to meet legal requirements and operate in an efficient and compliant manner. It also provides dispute resolution services, designs, effects commercial, and real property transactions with necessary legal protections and due diligence, and structures corporate governance processes to meet legal standards and best practices.

Regulatory Affairs supports the utility's ability to meet its obligations to the Government of Ontario, OEB, IESO, and other regulatory and public policy stakeholders. The main services provided by the segment include the development and execution of rate rebasing applications and other matters before the OEB, regulatory legal and advisory services, energy policy stakeholder relations, advocacy and implementation, regulatory compliance monitoring, regulatory reporting, load forecasting, wholesale market settlement, and rate design. Quarterly fees remitted to the OEB are also included in this segment. Costs pertaining to this rate rebasing application are also included, but

presented separately, with the full amount of these costs proposed to be recovered on an amortized basis from 2020-2024.

Personnel in the Program are highly-trained and experienced, with education, professional designations and skills in areas as such as law, public policy, engineering, economics, and accounting, reflective of both the breadth and depth of the issues that arise in the regulated utility industry. The Program processes a large workload year-round, every year. There are a variety of one-time and reoccurring projects and processes.

4. PROGRAM COSTS

Toronto Hydro needs $15.9 million in 2020 to perform the functions in the Legal and Regulatory program. Without this level of funding, Toronto Hydro could be exposed to a number of risks with financial consequences and/or reputational harm. Those include:

- Within the Legal Services Segment:
  - Failure to maintain compliance with all applicable laws;
  - Vendor non-compliance with Toronto Hydro policies and procedures;
  - An inability to effectively address privacy issues;
  - Ineffective or unfavourable contract terms, resulting in substandard performance by contracted parties or foregone recourse to appropriate remedies;
  - An inability to effectively recover amounts owing to the company from damages caused by third parties, or respond to third party claims or litigation;

- Dissatisfied customers and other stakeholders due to delays in completing planned and externally-driven capital work (e.g. not achieving customer connection timelines);
- Failure to obtain or protect adequate real property access rights for infrastructure, additional costs, and project delays; and
- An erosion in the utility's corporate governance performance and adherence to securities law and principles.

- Within the Regulatory Affairs Segment:
  - Incorrect wholesale settlement filings, which would adversely affect the cash flow of the utility or the IESO;
  - Errors in the Tariff of Rates and Charges that would result in under or over billing customers;
  - Non-compliance or incorrect implementation of energy policies and programs due to inadequate analysis of new or amended regulatory requirements;
  - More costly and less effective energy policies due to Toronto Hydro not being sufficiently engaged in public policy development processes;
  - Unmet OEB evidentiary requirements thereby hindering regulator's and stakeholders' reviews of Toronto Hydro's plans; and
  - Failure to meet important regulatory requirements, such as the OEB Scorecard or RRR filings.

Table 3 provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for each of the Program's segments.

Table 3: Legal Services and Regulatory Affairs Program Expenditures by Segment ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Legal Services	4.5	4.7	5.4	5.2	5.1	5.3
Regulatory Affairs	6.7	7.5	7.6	9.1	9.1	8.8
Amortized Costs of 2015-2019 CIR Application	0.9	1.1	1.0	1.0	1.0	-
Amortized Costs of 2020-2024 CIR Application	-	-	-	-	-	1.7
Total	12.1	13.4	14.0	15.3	15.1	15.9

4.1 Cost Drivers

The 2020 test year cost forecast represents an increase of $3.8 million from the utility's last rebasing year (2015), an increase of $1.9 million from the most recent historical actual year (2017), and an increase of $0.8 million from the final bridge year (2019).

4.1.1 Volume and Complexity of the Capital Program

Construction of new condominiums and other major developments in the City is projected to continue to increase in 2020-2024, which directly impacts the volume of offers to connect, other arrangements with developers, suite metering agreements, easements, relocation agreements, operating agreements and innovative services arrangements, as well as the number of third party damage incidents, which are expected.

4.1.2 Major External Transit Projects

A number of large transit projects are scheduled to commence or continue over the next five years (e.g. Metrolinx Light Rail Transit, Metrolinx Regional Express Rail, Toronto Transit Commission extensions, Ministry of Ontario bridge renovations, etc.). These third party initiated projects require large scale relocation of Toronto Hydro's assets, as

well as energization of new assets. This involves the negotiation of complex relocation agreements as well as the preparation of offers to connect and customer contribution agreements. Expanded development also entails a greater risk of third party damage incidents.

4.1.3 Nature of Claims

An increasing volume of complex claims, and larger claims payouts, is driving costs in the Legal Services Segment. Toronto Hydro's exposure to third party claims is generally correlated to factors such as the company's capital budget, economic conditions, third party infrastructure development, climate change, and adverse weather. While the size and volume of individual claims can be highly variable, the overall trend is an increase.

4.1.4 Legal, Regulatory and Policy Requirements

Changes in the energy sector reflected in technological, customer preference and public policy evolutions require new levels of support from the full range of services provided by the Legal and Regulatory program, such as, policy advocacy and implementation, commercial transaction support, legal and regulatory reporting and compliance. The Long Term Energy Plan, and the Implementation Plans of both the IESO and OEB, point to a continuation of intensive policy development for the foreseeable future with respect to a wide range of public policy priorities.

4.1.5 OEB Invoiced Costs

OEB costs invoiced to Toronto Hydro are a condition of its distribution licence. Pursuant to the 2018-2021 OEB Business Plan and the OEB's Annual Reports for prior years, the OEB's General Cost Recovery compound annual growth rate is forecast to be 5.8 percent between 2015 actuals and 2020 budget and 6.4 percent from 2017 actuals.

4.1.6 Distribution Rate Applications

The cost of preparing and prosecuting distribution rate rebasing applications has increased. The development of this application began in 2016, nearly 4 years in advance of the proposed effective date for rebased rates. Beginning to prepare these applications at an early date is necessary in order to ensure that the utility has adequate time to incorporate lessons from the OEB's prior rebasing decision, adapt to the emerging evolutions in the regulatory policy framework, and obtain and incorporate customer feedback in advance of business planning. For example, in addition to the ongoing growth in volume and detail of filing requirements, the OEB issued incremental guidance for rate applications through the 2016 Rate Handbook and 2017 Strategic Blueprint. Appendix 2-M provides the breakdown of the actual and anticipated 2020-2024 CIR application costs.

4.1.7 Compensation and Inflationary Increases

Over the historic period and through the bridge years and forecast period, Toronto Hydro expects that overall Program costs will increase slightly due to inflation and market compensation adjustments.

4.2 Cost Control and Productivity Measures

4.2.1 Cost Management

There have been significant past and ongoing efforts to minimize the cost of the Legal and Regulatory program and offset, in part, the external factors driving legal and regulatory cost increases. These efforts focus on building a strong model of internal resources (which are generally more cost-effective than external resources), reducing the cost of external resources, or finding alternative, lower-cost means of accomplishing the work.

Specific cost control measures employed include:

- Reducing and freezing external law firm hourly rates through a request for proposal ("RFP") process. The RFP also resulted in additional benefits at no incremental cost, such as temporary staff lawyer backfilling and articling student secondments, which further reduce the need to rely on external legal services;
- Negotiating alternative fee arrangement to cap costs on certain types of files;
- Negotiating additional contractual indemnities and insurance to reduce legal costs and payable claims in order to protect the utility and its ratepayers;
- Working within industry consortiums and associations to collaborate on common interest files, thus allowing Toronto Hydro to dedicate fewer resources to those files while maintaining high quality engagements in energy policy development; and
- Proactively working with stakeholders on energy policy design and implementation, reporting and compliance activities to build awareness of more efficient and effective solutions and mitigate risks and future costs, including those associated with potential non-compliance.

4.2.2 Productivity

Productivity enhancements in the Legal and Regulatory program are improving the output of the current complement of staffing resources. These include:

- Adopting new software that reduces the need for an administrative resource by approximately 50 percent;
- Developing and delivering internal training and education sessions that improve adherence to legal and regulatory requirements, thus reducing the costs of substandard performance and non-compliance;

- Developing legal and regulatory knowledge management databases, including document precedents, samples, clauses, research, and training materials, to prevent duplication of effort and improve work efficiency;
- In-housing the legal work for customer connections and making process improvements that allow the utility to meet its OEB-required timelines and reduce overall costs;
- Attending continuing professional development sessions offered by external law firms, consultant firms and legal organizations, to expand the scope of internal legal and regulatory expertise relating to issues that can be addressed without engaging external resources;
- Reducing processing time for procurement-related requests (e.g. RFP reviews, contract negotiations) by approximately one day; and
- Standardizing processes to minimize the personnel time required to process third party requests such as claims and freedom of information requests.

5. LEGAL SERVICES SEGMENT

5.1 Segment Description

Legal Services provides legal services to Toronto Hydro in support of a wide-range of utility activities.

Services in the segment cover day-to-day legal advice to internal clients, the review, negotiation, and drafting of commercial agreements, and completion of corporate, financial, and commercial transactions. It also includes the corporate secretariat function, which supports governance matters and compliance with corporate statutes and related rules and best practice guidelines. A key objective of these services is to

ensure the utility functions within existing laws and to work with the affected parts of the utility to ensure new policy and legal requirements are properly implemented.

Legal advice on real estate matters includes reviewing, negotiating and drafting legal documents relating to real property, such as customer connection agreements, easements, as well as real property dispositions and acquisitions and leasing arrangements. The legal staff supporting the real property function work closely with the construction, asset management, stations and facilities operational units in their activities to help ensure compliance with the requirements of the utility and its counterparties related to property access, maintenance and repair. New access rights are obtained where necessary, in particular for new infrastructure builds or connections. This allows capital projects to move forward efficiently. It also ensures penalties and damages relating to non-compliance with legislative restrictions or contractual obligations are avoided.

Claims professionals provide pre-litigation defense and response to claims made against the company, through the investigation of incidents, engagement with customers and insurers, and supervision of external adjustment service providers. This part of the segment's function manages and settles matters prior to them proceeding to litigation. In addition to resolving claims brought against the utility, claims professionals also support the recovery of invoiced claims when the utility's plant is damaged (e.g. poles hit by cars). By pursuing demands and legal actions, Legal Services recovers damages suffered by Toronto Hydro which otherwise would be unrecovered losses. Responding to claims and inquiries by customers, while still advocating the legal rights of the utility, is essential to positive customer service.

Litigation staff in Legal Services both respond to legal proceedings brought against Toronto Hydro and advance legal proceedings to assert the utility's legal rights. This involves the preparation and filing of statements of claim, statements of defence and related documentation. It also involves undertaking or working with external counsel in respect of, the defence and prosecution of personal injury and property damage matters and commercial disputes as they proceed to formal litigation. For most matters covered by the organization's insurance policies, Legal Services oversees external counsel approved by Toronto Hydro's insurers.

Legal Services also manages issues relating to privacy compliance and protection of personal information. This includes legal support in response to access to information requests, customer privacy complaints, or internal privacy inquiries. Toronto Hydro takes a pro-active approach to compliance with privacy best practices, with an emphasis on providing optimal, proactive customer service.

5.2 Legal Services Segment Costs

Toronto Hydro requires approximately $5.3 million per year over the 2020-2024 plan period to execute the functions in this segment. Table 4 provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for the Legal Services segment.

Table 4: Legal Services Segment Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Legal Services	4.5	4.7	5.4	5.2	5.1	5.3

The 2020 test year costs represent an increase of $0.8 million from the utility's last rebasing year (2015), a $0.1 million decrease from previous historical actual year (2017), and an increase of $0.2 million from the bridge year (2019)

5.3 Legal Services Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

Costs in 2016 increased by $0.2 million over 2015 actuals. This was largely due to claims costs increasing by $0.3 million as a result of higher volumes of complex claims received and handled. This amount was partially offset by the effect of cost control measures in the segment, as discussed above.

2016 – 2017 Variance Explanation

The variance of $0.7 million from 2016 to 2017 is attributable to:

- The legal services required to support the emergence of more complex, novel, multi-year, transit-related and station projects, a number of key governance-related projects related to external requirements, and an increasing number of major infrastructure projects such as those with transit authorities.
- An increase of $0.3 million in claims costs driven by higher volumes of complex claims.

2017 – 2018 Variance Explanation

Costs in 2018 are expected to decrease by $0.2 million, with the net result of cost controls more than offsetting inflationary pressures.

2018 – 2019 Variance Explanation

Costs in 2019 are expected to decrease by $0.1 million, with the net results of cost controls more than offsetting inflationary pressures.

2019 – 2020 Variance Explanation

Costs in 2020 are expected to increase by $0.2 million over 2019, driven by a combination of inflationary pressures and a projected small increase in the volume of complex claims.

6. REGULATORY AFFAIRS SEGMENT

6.1 Segment Description

Regulatory Affairs manages the regulatory affairs of the utility to help mitigate financial risks and improve public policy outcomes.

Regulatory Affairs works with external stakeholders and internal subject matter experts on energy policy files, including policy development by the Government, OEB, and IESO. Externally, the objective is to fully inform policy-makers with respect to the effects of prospective legislation, regulations, codes, and other rules and guidelines. Internally, the objective is to ready the utility for potential energy policy changes and work with the affected parts of the utility to ensure new requirements are properly implemented.

Regulatory Affairs professionals provide advice and support to the utility in decision-making processes and promoting compliance with regulatory requirements. Since Toronto Hydro's last rebasing, two additional staff were reallocated from the Finance program to the Regulatory Affairs segment to enhance this function. This is a reflection of both the need to meet incremental performance monitoring requirements and the

importance Toronto Hydro places on fulfilling its responsibilities and obligations in this regard.

Regulatory reporting staff in this segment gather and report information to the OEB through quarterly and annual RRR and other filings (e.g. winter disconnections, major outage events, cyber security), and facilitate the interpretation of and responses to new requirements. Continually evolving regulatory requirements (e.g. Ontario Clean Energy Benefit, Class A global adjustment, updated OEB codes, Distributor Scorecard, etc.) require significant effort in co-ordinating with affected parts of the utility and the OEB.

Regulatory Affairs also manages wholesale market settlement, retail settlement and related transactions and reporting in relation to the Government, IESO, and OEB. The nature of these activities and associated governing rules continue to evolve as a result of significant changes in government policy (e.g. feed-in-tariffs, net metering, bill rebate/reduction programs). These activities affect the accuracy of not only Toronto Hydro's financials, but also the financials of the IESO.

Regulatory Affairs prepares Toronto Hydro's applications to the OEB for rates and other regulatory approvals. The most significant of these are rebasing applications, which have most recently been large, complex CIR applications. Over the span of a 5-year rate cycle, approximately 3.5 years are spent preparing and prosecuting the CIR application. During the most intensive periods of CIR-related activities, Regulatory Affairs staff are temporarily reallocated from other functions within the segment to focus on these major projects. In the period between the issuance of a CIR Rate Order and the start of the next CIR, staff focus on assisting the utility with the implementation of the Decision and Rate Order, including helping to infuse utility decision-making with the parameters

and guidance of the OEB Decision. Regulatory Affairs also uses these "between CIR" periods to file annual rate updates, monitor other utility applications, prepare internal regulatory educational materials, and heighten attention to other regulatory functions that were temporarily understaffed during intensive periods of rate application activity.

In addition to the preparation of rate applications, Regulatory Affairs performs other rates-related functions, including: developing annual forecasts of the utility's load and customers; processing semi-annual commodity rate changes and other regulated rate updates (e.g. RRRP, WMSC, and RTSRs); and updating and testing in Toronto Hydro's billing system to ensure that the correct tariff rates are charged.

6.1.1 Distribution Rate Rebasing Applications

As discussed above, Regulatory Affairs is responsible for preparing and prosecuting Toronto Hydro's distribution rate rebasing applications. The costs of the 2015-2019 CIR and this Application are included in this segment. Unlike the costs in other OM&A programs, the OEB rate-making process requires special treatment for the costs of rebasing applications. Toronto Hydro sought recovery of the costs of the 2015-2019 CIR on an amortized basis over the 2015-2019 period. Toronto Hydro requests recovery of the costs of this Application on the same amortized basis over the 2020-2024 period.

In its Decision in EB-2014-0116, the OEB recognized that:

> "Toronto Hydro is larger and has more complex issues than most if not all distributors in Ontario, and the Application involves billions of dollars of spending. The RRFE requires distributors to prepare and support their applications, particularly Custom IRs, in a very thorough way."[1]

[1] EB-2014-0116 Decision and Order (December 29, 2015), pp. 12-13.

In preparing and prosecuting this Application, Toronto Hydro continues to engage in considerable background work and bears other costs, mindful of the critical issues that the OEB must carefully consider on an evidentiary basis. As with the 2015-2019 CIR, the regulatory costs of the 2020-2024 CIR are expected to be approximately 0.2 percent of the total applied for revenue requirement. Amortized over the duration of the rate period, the cost provides value to ratepayers, enabling Toronto Hydro to put forward a more thorough, thoughtful and customer-responsive application.

Toronto Hydro's costs of this Application are set out in Appendix 2-M. Toronto Hydro's own costs as well as the OEB's and intervenors' costs of this proceeding are included in the $8.7 million proposed for recovery.

6.2 Regulatory Affairs Segment Costs

Toronto Hydro requires approximately $10.6 million per year over the 2020-2024 plan period to execute the functions in this segment, which includes the amortized annual amount for this Application. Table 5 provides the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) expenditures for this segment.

Table 5: Regulatory Affairs Segment and CIR Program Expenditures ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Regulatory Affairs	6.7	7.5	7.6	9.1	9.1	8.8
Amortized Costs of 2015-2019 CIR Application	0.9	1.1	1.0	1.0	1.0	-
Amortized Costs of 2020-2024 CIR Application	-	-	-	-	-	1.7
Total	**7.6**	**8.7**	**8.6**	**10.1**	**10.1**	**10.6**

The Regulatory Affairs segment 2020 test year cost forecast represents an increase of $1.9 million from the utility's last rebasing year (2015), an increase of $1.2 million from

the most recent historical actual year (2017), and a decrease of $0.3 million from the bridge year (2019). The amortized cost of this Application represents a $0.8 million increase over the prior rebasing application.

6.3 Regulatory Affairs Segment Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

From 2015 to 2016, segment costs increased by $0.9 million, driven primarily by the effect of transferring resources from the Finance program to establish a new regulatory reporting and compliance team. The other main drivers of the variance relate to the filling of vacancies and an increase in OEB fees.

2016 – 2017 Variance Explanation

From 2016 to 2017, costs decreased by $0.1 million. Increases in the regulatory reporting and compliance function, including the full-year effect of the transferred resources, were more than offset by new vacancies and a decrease in OEB fees.

2017 – 2018 Variance Explanation

From 2017 to 2018, costs are expected to increase by $1.5 million. Approximately half of this amount is due to an expected increase in OEB fees as set out in the OEB's most recent Business Plan, with the remaining increase being attributed to filling vacant positions and a temporary increase in external services to support non-rate rebasing application activities while internal staff are reallocated to CIR-related activities.

2018 – 2019 Variance Explanation

From 2018 to 2019, costs are expected to stay the same, with an increase to OEB fees being offset through less use of external resources as internal staff who were

temporarily assigned to the CIR are reallocated back to their core regulatory functions part way through the year.

2019 – 2020 Variance Explanation

From 2019 to 2020, costs are expected to increase by $0.5 million, primarily due to the amortized costs of this Application being greater than those of the prior CIR. The OEB's filing requirements have increased and adjudicative process has expanded (e.g. community meetings), which are expected to increase Toronto Hydro, OEB, and intervenor costs. These higher costs will be partially offset by significant expected reductions in external services and staffing changes.

OEB Appendix 2-M
Regulatory Cost Schedule

TO BE UPDATED AT THE DRAFT RATE ORDER STAGE

	Regulatory Cost Category	USoA Account	USoA Account Balance	Last Rebasing Year (2015 Board Approved)	Last Rebasing Year (2015 Actual)	Most Current Actuals Year 2017	2018 Bridge Year	Annual % Change	2020 Test Year	Annual % Change	
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)=[(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)	
	Regulatory Costs (Ongoing)										
1	OEB Annual Assessment			$ 3,270,672	$ 3,169,065	$ 3,415,249	$ 4,007,971	17.36%	$ 4,297,340	7.22%	
2	OEB Section 30 Costs (OEB-initiated)			$ 200,658	$ 268,638	$ 54,909	$ 150,000	173.18%	$ 156,060	4.04%	
3	Expert Witness costs for regulatory matters										
4	Legal costs for regulatory matters										
5	Consultants' costs for regulatory matters										
6	Operating expenses associated with staff resources allocated to regulatory matters										
7	Operating expenses associated with other resources allocated to regulatory matters [1]										
8	Other regulatory agency fees or assessments			$ 800	$ 800	$ 800	$ 800	0.00%	$ 800	0.00%	
9	Any other costs for regulatory matters (please define)										
10	Intervenor costs										
11											
12											
	Regulatory Costs (One-Time)										
1	Expert Witness costs			note 4	note 4				note 4		
2	Legal costs			$ 2,738,150	$ 1,842,785				$ 3,055,015		/C
3	Consultants' costs			$ 2,583,178	$ 2,773,742				$ 3,522,100		/C
4	Incremental operating expenses associated with staff resources allocated to this application.										
5	Incremental operating expenses associated with other resources allocated to this application. [1]										
6	Intervenor costs			$ 650,000	$ 837,076				$ 1,200,000		
7	OEB Section 30 Costs (application-related)				$ 438,714				$ 700,000		
8	Operating Expenses - Printing				$ 167,845				$ 154,534		
9	Operating Expenses - Miscellaneous				$ 7,596				$ 14,416		
10											
1	Sub-total - Ongoing Costs [2]		$ -	$ 3,472,130	$ 3,438,503	$ 3,470,958	$ 4,158,771	19.82%	$ 4,454,200	7.10%	
2	Sub-total - One-time Costs [3]		$ -	$ 5,971,328	$ 6,067,757	$ -	$ -		$ 8,646,065		
3	Total		$ -	$ 9,443,458	$ 9,506,261	$ 3,470,958	$ 4,158,771	19.82%	$ 6,183,413	48.68%	

Application-Related One-Time Costs	Total
Total One-Time Costs Related to Application to be Amortized over IRM Period	$ 8,646,065
1/5 of Total One-Time Costs	$ 1,729,213

Notes:

[1] Please identify the resources involved.

[2] Sum of all ongoing costs.

[3] Sum of all one-time costs.

[4] Expert Witness and Consulting costs are aggregated.

CHARITABLE DONATIONS AND LOW-INCOME ENERGY ASSISTANCE PROGRAM ("LEAP")

1. CHARITABLE DONATIONS

Toronto Hydro is an important corporate contributor in the City of Toronto and supports outreach events that engage with the community, advances energy related issues of public importance (such as safety and sustainable energy), and promotes programs and services that help customers, particularly those that are most vulnerable.

Table 1, below, provides Toronto Hydro's Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) charitable contributions.

Table 1: Charitable Contributions Summary ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Rate Recoverable	0.7	0.9	0.8	0.8	0.8	0.9
Non-Rate Recoverable	0.2	0.2	0.3	0.3	0.3	0.3

Toronto Hydro's sole rate recoverable charitable contributions for the 2020-2024 plan period are its payments towards the OEB's Low-Income Energy Assistance Program ("LEAP"), which it continues to promote and operate for the benefit of its low-income customers and in full compliance with all governing OEB rules and guidelines.

Toronto Hydro's non-rate recoverable charitable contributions are comprised of multiple minor sponsorships of community not-for-profits, industry associations, and City entities or events of strategic alignment. The following are examples of causes the utility has made contributions to:

- Not-for-profit entities (e.g. Local Enhancement of Appreciation of Forests and Fatal Light Awareness Program, which support tree canopy and light pollution issues, respectively);
- Industry associations (e.g. Ontario Energy Association and Ontario Energy Network, which provide a voice to the energy industry, an opportunity to network and share best practices, and the furthering of industry issues publicly and at various levels of government); and
- City entities or events of strategic alignment (e.g. Live Green Toronto and Cavalcade of Lights, which provide opportunities to engage with communities regarding issues that align with Toronto Hydro's Corporate Social Responsibility Strategy and promote programs and services).

Sponsorships can be used to align with business development strategies to further Toronto Hydro's network and presence in areas of interest to the public (e.g. Electric Vehicles). Each sponsorship is reviewed according to an established process and matrix to gauge appropriateness and optimal level of support.

2. POLITICAL CONTRIBUTIONS

Toronto Hydro does not make political contributions of any kind.

3. LOW-INCOME ENERGY ASSISTANCE PROGRAM ("LEAP")

In accordance with the OEB's directives concerning LEAP funding, Toronto Hydro has allocated 0.12 percent of its total (service) distribution revenue requirement towards LEAP. This amounts to approximately $0.9 million disbursed annually over the 2020-2024 plan period.

Toronto Hydro continues to rely on the Neighbourhood Information Post ("NIP") as its designated LEAP agency. NIP has been responsible for operating Toronto Hydro's LEAP program since 2011, and is the United Way's designated agency for the Toronto area. The extended working relationship with NIP has allowed Toronto Hydro to establish operational efficiencies in qualifying low income customers, processing approved grants, and resolving any potential operational issues.

3.1 LEAP Expenditure Summary

Table 2, below, illustrates Toronto Hydro's annual LEAP contributions and grants:

Table 2: Toronto Hydro LEAP Program Disbursement Summary ($000s)

	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Annual Contribution	710	810	810	810	810	900
Carryover from Prior Years	0	0	0	49	N/A	N/A
One-Time Contribution	0	100[1]	0	10[2]	0	0
Total Available[3]	**710**	**910**	**810**	**869**	**N/A**	N/A
Total Dispersed (including admin fees)[4]	710	910	761	N/A	N/A	N/A
Total Unused	0	0	49	N/A	N/A	N/A

Demand for the LEAP program held steady over 2015 and 2016, with Toronto Hydro exhausting its allocated rate funding in the third quarter of each year, but grants to

[1] Given the timing of Toronto Hydro's EB-2014-0116 Decision, the utility was only able to provide an estimated donation amount in 2015. Since this turned out to be less than the required donation amount based on its approved service revenue requirement, Toronto Hydro provided the under-contribution as a one-time donation in 2016.
[2] As part of its EB-2014-0116 proceeding, Toronto Hydro proposed to transfer legacy late payment reversal credits owing to inactive customers to the LEAP program. The outstanding balance of these credits totaling $9,887 was transferred to the LEAP program as part of the 2018 funding year.
[3] Calculations exclude funding and grants from the Garland Settlement funds, which are administered by the United Way (see details below).
[4] Calculations exclude funding and grants from the Garland Settlement funds, which are administered by the United Way (see details below).

individual customers continued to be processed through the use of Garland Settlement funds during the remainder of each of those years.

The introduction of the Ontario Electricity Support Program and the Ontario Fair Hydro Plan has significantly reduced, on average, low-income customer bills, lowering demand for the program. The OEB's Winter Disconnection Moratorium has coincided with this period of falling demand. These factors have led to a reduced demand for LEAP in 2017, with unused funding of approximately $49,000 carrying forward into 2018.

While the overall impact on demand in future periods is difficult to assess at this time, Toronto Hydro expects that the Winter Disconnection Moratorium will continue to alter the timing of potential LEAP applications, with significantly lower demand during the moratorium period, followed by a higher volume of higher than average arrears applications being filed in the late spring and early summer months.

Toronto Hydro continues to monitor the demand for the program in order to provide assistance to its customers in the most efficient and effective manner, while respecting the current parameters governing LEAP eligibility. In the near term, in conjunction with NIP, Toronto Hydro intends to address the reduced program demand through more extensive and targeted customer communication and engagement.

Given the information above, Toronto Hydro expects that its new annual contribution level of $0.9 million per year, in combination with available Settlement Funds (discussed below), will be sufficient to meet the demand of its low income customers over the 2020-2024 plan period.

3.2 Settlement Funds

Toronto Hydro was subject to the 2010 Garland Settlement related to billing of late payment charges that were authorized, but in conflict with Federal legislation. Through this settlement, a total of $4.4 million was entrusted to the United Way in 2012 for the purposes of energy assistance to Toronto customers. As of the end of 2017, approximately $2 million of the original fund amount remains undisbursed, and the United Way continues to collaborate with Toronto Hydro on the most efficient way to make use of this funding.

In the event that Toronto Hydro's annual OEB-directed LEAP funds are insufficient to cover demand throughout the entire year (as was the case in 2015 and 2016), Toronto Hydro relies on the available United Way Settlement Funds to cover the shortfall in funding, which is made available to NIP once Toronto Hydro's annual LEAP fund allocation is expended.

COMMON COSTS AND ADJUSTMENTS

1. OVERVIEW

This schedule describes Toronto Hydro's costs that are not attributable to a specific program or would be administratively difficult or immaterial to allocate. The total expenditures associated with this schedule are comprised of ongoing or recurring costs and adjustments.

Table 1: Common Costs and Adjustments ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Ongoing or Recurring	1.1	(0.1)	1.6	(0.7)	(1.3)	0.8
Total	**1.1**	**(0.1)**	**1.6**	**(0.7)**	**(1.3)**	**0.8**

2. ONGOING OR RECURRING COSTS AND ADJUSTMENTS[1]

Ongoing or recurring costs and adjustments are comprised of the following expenditures described in further detail in the sections below.

2.1 Difference in Forecast and Actual Employee Benefits Costs

Toronto Hydro provides current employees with benefits that include medical, dental, and life insurance benefits and includes a provision for employee future benefits. Benefit costs are allocated through the payroll process using budgeted rates. The actual costs for benefits are based on consumption. The difference between the budgeted and the actual benefit costs incurred by the utility remains in this schedule.

[1] The utility has not included any one-time costs for recovery in its test year.

2.2 Other Post-Employment Benefits ("OPEBs")

Toronto Hydro also provides benefits to employees upon their retirement, including medical, dental, and life insurance benefits. The accrued benefit obligation and net periodic benefit cost are calculated by independent actuaries using the projected unit credit method and based on assumptions that reflect management's best estimate.[2] Differences in the budgeted employee future benefits cost and the final valuation are accounted for in this schedule.

In the 2015-2019 plan period, Toronto Hydro accounts for OPEBs on a cash rather than on an accrual basis for rate making purposes as directed by the OEB.[3] The difference between the actual cash payments and the forecasted OPEB costs related to its OM&A programs using the accounting accrual method is tracked in Account 1508 Other Regulatory Assets – Sub-account: OPEB Cash vs Accrual Variance Account[4] and this portion of OPEB costs is deferred and excluded from OM&A for the 2015-2019 plan period.

On September 14, 2017, the OEB issued its final report on the regulatory treatment of pension and OPEB costs and established the use of accrual accounting as the default method on which to set rates for pension and OPEB amounts in cost-based applications, unless that method does not result in just and reasonable rates.[5] Toronto Hydro's proposal for the 2020 test year is to account for OPEBs on an accrual basis for rate making purposes. Therefore, these costs are included in OM&A as explained in the 2019-2020 variance section below.

[2] See Exhibit 4A, Tab 4, Schedules 4 and 6 for more information.
[3] EB-2014-0116, Toronto Hydro-Electric System Limited Decision and Rate Order (March 1, 2016), Appendix E, p. 81.
[4] See Exhibit 9, Tab 1, Schedule 1
[5] EB-2015-0040, Ontario Energy Board Final Report on Consultation on the Regulatory Treatment of Pension and Other Post-Employment Benefit Costs and Notice of Hearing for Cost Awards (September 14, 2017).

2.3 Investment Tax Credits ("ITC")

The Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) costs reflect both refundable and non-refundable ITCs in compliance with International Financial Reporting Standards ("IFRS").[6]

2.4 Corporate Risk and Compliance

This category includes the costs that the utility incurs for the development, implementation and monitoring of the Enterprise Risk Management Program and the Corporate Compliance Policy Program.

2.5 Financing Costs

Financing costs are made up of standby fees, the amortization of the upfront and arrangement fees for Toronto Hydro's revolving credit facility and letters of credit fees.

2.6 Common Costs and Adjustments Year-over-Year Variance Analysis

2015 – 2016 Variance Explanation

Decrease of $1.2 million is primarily due to a difference in forecast and actual employee benefits costs, partially offset by OPEBs recognized on a cash rather than accrual basis.

2016 – 2017 Variance Explanation

Increase of $1.7 million is primarily due to difference in forecast and actual employee benefits costs, partially offset by OPEBs recognized on a cash rather than accrual basis, and municipal tax credits.

[6] Exhibit 4B, Tab 2.

2017 – 2018 Variance Explanation

Decrease of $2.3 million is primarily due to a difference in forecast and actual employee benefits costs and OPEBs recognized on a cash rather than accrual basis.

2018 – 2019 Variance Explanation

Forecasted decrease of $0.8 million is primarily due to investment tax credits and financing costs related to the credit facility.

2019 – 2020 Variance Explanation

Forecasted increase of $2.1 million is primarily due to Toronto Hydro's proposal to account for OPEBs on an accrual basis in the 2020 test year. These costs are included in OM&A in the 2020 test year, as compared to being deferred in a variance account for the 2015-2019 plan period.

ALLOCATIONS AND RECOVERIES

1. OVERVIEW

This schedule discusses the adjustments to Toronto Hydro's total Operations, Maintenance, and Administration ("OM&A") costs to reflect the recovery of certain expenditures such as Warehousing, Facilities, Fleet and Equipment, and Information Technology ("IT") from the internal user departments through other OM&A and/or capital programs and Shared Services.

2. DESCRIPTION

Table 1, below, provides a breakdown of the Historical (2015-2017), Bridge (2018-2019), and Test Year (2020) Allocations and Recoveries adjustments to Toronto Hydro's OM&A expenditures. The manner of allocating each individual component is discussed in detail below.

Table 1: Allocations and Recoveries Adjustments to OM&A ($ Millions)

Segment	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
On-cost Recovery	(10.6)	(11.5)	(11.3)	(11.9)	(11.8)	(11.8)
Fleet Recovery Offset	(12.5)	(12.4)	(11.5)	(11.4)	(11.4)	(11.6)
IT and Occupancy Charges	(0.7)	(1.1)	(1.0)	(1.0)	(1.0)	(1.0)
Shared Services	4.8	2.9	4.8	4.3	4.4	4.6
Other Allocated Costs	0.0	0.1	0.2	(0.1)	(0.1)	(0.1)
Total	**(19.0)**	**(21.9)**	**(18.9)**	**(20.1)**	**(20.0)**	**(19.9)**

3. ON-COST RECOVERY

On-cost Recovery is a material handling surcharge applied to all inventory issuances from warehouse to both capital and operating projects.[1] As a result, if the items issued

[1] Exhibit 4A, Tab 2, Schedule 13.

from the warehouse are associated with capital projects, the on-cost charge is capitalized, whereas if the items issued are associated with operating projects, the on-cost charge is expensed in the period in which it is incurred.

The costs included in the On-cost Recovery are mainly comprised of:

- Compensation costs;
- Directly attributable support costs; and
- Other warehouse costs (e.g. rental and leases, warehouse maintenance costs, etc.).

4. FLEET RECOVERY

The allocation of fleet costs to other programs provides for a transfer of operating costs to maintenance or capital projects. The allocation is based on the number and type of vehicles. This helps to maintain an optimal number of vehicles in the Fleet and Equipment Services Program.[2] In the case of maintenance projects, the allocation provides for a transfer of operating costs from the Fleet and Equipment Services Program to other programs using the service. In the case of capital projects, the allocation provides for a transfer of operating costs to capital projects. The allocation to capital is based on the nature of the work performed and follows Toronto Hydro's labour costing methodology.

The costs included in the fleet allocation are mainly comprised of:

- Fleet department compensation costs;
- Parts and material;
- Vehicle insurance, licensing, and registration; and

[2] Exhibit 4A, Tab 2, Schedule 11.

- Other Fleet costs.

The Fleet and Equipment Services Program employs a vehicle "lease-rate" cost recovery model, whereby vehicle expenses are recovered using a monthly user charge at the vehicle class level (e.g. "Compact Car", "Passenger Minivan up to 2,500 kilograms"). The lease-rate is calculated on an annual basis to ensure that operating cost changes at the vehicle class level are accurately reflected in user lease rates of the following year.

5. IT AND OCCUPANCY CHARGES

The allocation of IT charges to the non-rate regulated business is done to optimize the use of technology assets. The allocation is based on IT's support to the end users, including directly attributable labour and support costs. The allocation provides for a transfer of operating costs in the IT program to the non-rate regulated business.[3]

The costs included in the IT allocation are comprised mainly of:

- Compensation costs; and
- Directly attributable support costs.

The allocation of occupancy charges and facilities costs that are charged to business units is done to optimize the use of space within Toronto Hydro's facilities. The allocation is based on square-footage and type of space. The allocation provides for a transfer of operating costs from the Facilities Management program to the business units.[4]

[3] Exhibit 4A, Tab 2, Schedule 17.
[4] Exhibit 4A, Tab 2, Schedule 12.

The costs included in the Occupancy/Facilities allocation primarily consist of:

- Compensation costs;
- Maintenance costs;
- Facilities costs;
- Utilities costs;
- Property taxes; and
- Property lease.

6. SHARED SERVICES[5]

Shared services included in OM&A represent the cost of services received by Toronto Hydro from the non-rate regulated business. Toronto Hydro receives services primarily from Toronto Hydro Corporation ("THC") which provides strategic direction, corporate governance, and financial stewardship to the utility.[6]

7. OTHER ALLOCATED COSTS

Other allocated costs represent costs which are not specifically attributed to an OM&A program.

[5] Refer to Exhibit 4A, Tab 5 for more information about Toronto Hydro's shared services.
[6] Refer to Exhibit 1C, Tab 2, Schedule 1 for more information about Toronto Hydro's corporate structure and governance.

PURCHASES OF NON-AFFILIATE SERVICES

Toronto Hydro's Procurement Policy (the "Policy") establishes processes and protocols for obtaining services, equipment and materials that satisfy the operational needs of the utility in a manner that appropriately balances cost and value. Toronto Hydro relies on a comprehensive governance framework for its procurement activities. The Policy is set out at Appendix A.

Procurement contracts with a value exceeding $25,000 are sourced in accordance with Toronto Hydro's competitive procurement procedure, which outlines the general competitive bid process and sets out various rules with respect to communications, negotiations, bid reviews and conflicts of interest. This formalized competitive bidding process helps ensure that the procurement process remains fair, transparent, efficient and consistent.

1. SOLE SOURCING

Where procurement is related to, amongst other things, unforeseeable circumstances or where there is only one vendor uniquely qualified to deliver goods or services, Toronto Hydro may use sole source procedures as described in the Policy.[1] When exercising the option to perform sole source procurement, Toronto Hydro is often able to reduce the cost of goods or services or improve the value proposition in other ways.

Before executing sole source procurements, Toronto Hydro conducts due diligence reviews of the sole source purchase request. The reviews determine if the sole source

[1] See Appendix A for Procurement Policy (Exception 4).

purchase is warranted, and include a review of the proposed contract's specifications, scope, definition, commercial terms, liabilities, and insurance requirements.

Proposed sole source procurements that pass the review process are finalized through contract negotiations with the vendor. At that point a purchase order is issued.

2. PRE-QUALIFICATIONS FOR CONSTRUCTION CONTRACTS

When Toronto Hydro contemplates a civil or electrical construction project, potential contractors are pre-qualified in accordance with Toronto Hydro's pre-qualification procedure. A contractor's pre-qualification signifies that the contractor has met the minimum requirements established by Toronto Hydro for the purposes of a project. The factors used for evaluating contractors at this stage include, but are not limited to, technical skill and competence, experience, financial viability, health and safety record, reputation, work load, and any previous relationship with Toronto Hydro.

All contracts are authorized and executed in accordance with Toronto Hydro's Signing Policy. Toronto Hydro's signing authorization levels are approved by the Board of Directors and delegated to individual members of the executive and senior management of the utility to facilitate the day-to-day running of the business. Contracts must be signed by an authorized person who is directly responsible for the budget related to the subject area of the contract. Toronto Hydro's signing authorization levels for procurement contracts are shown in Table 1, below.

Table 1: Toronto Hydro's signing Authorization Levels for Procurement Contracts

Category	President and CEO	CFO	Responsible Officer	Controller	General Manager	Director	Person who is a Direct Report of an Officer
Procurement Signing Limit	Up to $30M	Up to $5M	Up to $5M	Up to $1M	Up to $500,000	Up to $250,000	Up to $250,000

3. COMPLIANCE CONFIRMATION

Toronto Hydro confirms that its non-affiliate purchases are in compliance with the utility's Policy. Appendix B identifies non-affiliate services that were procured in 2015, 2016 and 2017 under the exceptions to the general procurement rules contemplated within the Policy. These engagements did not originate from a competitive procurement process and surpass the utility's materiality threshold of $1 million.

POLICY

PROCUREMENT	**Policy Owner:** **Executive Vice President & Chief Electric Operations & Procurement Officer (THESL)**
	Policy Approver: **Policy Administration Steering Committee**
	Version Approval Date: **V5.0 2017-10-16**
	Last Reviewed by PASC: **V5.0 2017-10-16**
The most recent version of this policy can be obtained from the Toronto Hydro intranet Plugged In at: http://pluggedin.torontohydro.com/policy/Pages/DistributionGridManagementPolicies.aspx	
The distribution of this policy is not restricted.	

TABLE OF CONTENTS

1 DOCUMENT REVIEW & REVISION HISTORY 2
2 DISTRIBUTION HISTORY 2
3 POLICY OVERVIEW 2
4 DEFINITION AND ABBREVIATIONS 3
5 SCOPE 4
6 OBJECTIVES 4
7 GENERAL PROCUREMENT RULES APPLICABLE TO ALL BUSINESS UNITS 4
8 OWNERSHIP, APPROVAL AND RESPONSIBILITIES 5
9 POLICY COMMUNICATION 6
10 POLICY COMPLIANCE AND VIOLATIONS 6
11 RELATED LAWS, REGULATIONS AND DOCUMENTATION 6

1 DOCUMENT REVIEW & REVISION HISTORY

This policy is reviewed annually.

Version Number	Date of Review	Reviewed By	Brief Description of Change
V1.0	2007-07-01	PASC	V1.0 approved by PASC.
V2.0	2009-10-23	PASC	V2.0 Approved outside of regular scheduled PASC meeting
V3.0	2013-04-25	PASC	V3.0 approved by PASC members
V.3.1	2013-12-09	PASC	V3.1 approved by PASC
V4.0	2015-06-09	PASC	Administrative Changes V4.0 approved by PASC
V5.0	2017-10-16	PASC	Administrative Changes. Additional changes to align with new THESL Signing Policy. Added standards section regarding conflicts with other corporate policies and tracking policy compliance.

2 DISTRIBUTION HISTORY

Version Number	Date of Issue	Recipients
V1.0	2007-07-01	Toronto Hydro @ Home Employee Extranet
V2.0	2009-10-26	Toronto Hydro @ Home Employee Extranet
V3.0	2013-05-10	Toronto Hydro Intranet Plugged In at: http://pluggedin.torontohydro.com/policy/Pages/
V3.1	2013-12-09	Toronto Hydro Intranet Plugged In at: http://pluggedin.torontohydro.com/policy/Pages/
V4.0	2015-06-09	Toronto Hydro Intranet Plugged In at: http://pluggedin.torontohydro.com/policy/Pages/
V5.0	2017-10-16	Toronto Hydro Intranet Plugged In at http://pluggedin.torontohydro.com/policy/Pages/

3 POLICY OVERVIEW

This policy outlines the process that is to be followed for the procurement of any good or service by any of Toronto Hydro's corporate entities. The goals of this policy are to ensure Toronto Hydro business objectives are achieved and to facilitate compliance with applicable internal standards and requirements as well as regulatory, statutory and other legal requirements.

4 DEFINITIONS AND ABBREVIATIONS

TERM or ACRONYM	DESCRIPTION
Subsidiary	Toronto Hydro-Electric System Limited, Toronto Hydro Energy Services Inc. and any other direct or indirect subsidiary of Toronto Hydro Corporation, from time to time.
Authorization Level Document	The most recent version of the Authorization Level Document setting out expenditure levels for authorized persons.
Board	The Board of Directors of Toronto Hydro Corporation or of any Subsidiary as may be applicable.
Business Unit	The Toronto Hydro Corporation or Subsidiary department requesting a Procurement.
CEO	President and Chief Executive Officer of Toronto Hydro Corporation.
CIO	Chief Information Officer of THESL.

Contract Value	The total amount of expenditures required under any Procurement, which shall be determined by calculating:
	• The total amount of all possible expenditure over the term of the contract,
	  ○ Including all years of a multi-year term and all years of all possible contract renewals,
	  ○ Including the potential maximum of all conditional, contingent or variable payments,
	• Excluding all applicable taxes.
	Procurements shall not be artificially divided so as to constitute a Contract Value below applicable threshold values. For Contracts to be signed by the CEO, the Contract Amount shall exclude the value of any optional Contract renewal years where this option is exercised at the Corporation's discretion.

Senior Management	The Manager, Director, or General Manager of any Business Unit with responsibility for an approved budget for the Procurement in question.
Executives	The Vice President, Executive Vice President and/or CXO of Toronto Hydro Corporation or of any Subsidiary as may be applicable.
President	President of THESL.
Procurement	A purchase, agreement to purchase, licence, lease or rental of any good or service, including an agreement to purchase construction services. Includes any extension or renewal of any procurement or construction contract made prior to the date of this Procurement Policy.
Supply Chain Services Department	The department responsible for all the Procurements within THESL and its subsidiaries.
Senior Management, Supply Chain Services	The Senior Management responsible for the operation of the Supply Chain Services Department.

TERM or ACRONYM	DESCRIPTION
Procurement Policy	This Procurement Policy together with all forms and procedures referenced herein.
Signing Policies	The most recent versions of the signing policies of Toronto Hydro Corporation and its Subsidiaries, as approved by the Policy Administration Steering Committee.
THESL	Toronto Hydro-Electric System Limited.
Toronto Hydro / the Company	Toronto Hydro Corporation and all of its Subsidiaries

5 SCOPE

This policy applies to all Procurements made by Toronto Hydro except as otherwise authorized in writing by the Board, the President or the CEO.

5.1 This Policy is designed to augment other corporate policies and is not intended to replace or preclude them. Should an overlap arise between the application of this Policy and any other Policy, the Policy most specific to the situation will apply.

6 OBJECTIVES

6.1 The Procurement Policy is intended to assist in achieving Toronto Hydro business objectives such as:

- Ensuring efficient Procurements at most favourable acquisition cost
- Promoting the use of competition in selecting suppliers and contractors
- Providing for the fair and equitable treatment of all suppliers and contractors
- Providing safeguards for maintaining a procurement system of quality and integrity
- Ensuring suppliers meet or exceed Toronto Hydro Corporation's quality, safety and environmental requirements
- Ensuring that all Procurements are made in compliance with all regulatory requirements and applicable laws

7 GENERAL PROCUREMENT RULES APPLICABLE TO ALL BUSINESS UNITS

Unless otherwise authorized in writing by the Board, the President or the CEO:

7.1 All Procurements shall be administered by the Supply Chain Services Department and authorized by the Senior Management Supply Chain Services or his/her authorized delegate.

7.2 Other than the exceptions in *Appendix A - Exceptions to General Procurement Rules*, all Procurements with a Contract Value exceeding $25,000, shall be sourced via the *Procedure for Competitive Bids*.

7.3 All approved Procurements (regardless of value or whether they were approved via a competitive bid process) shall be processed and documented in accordance with the *Procedure to Document Approved Procurements*.

7.4 All Procurements of information technology related goods or services (including computer equipment, software or related services) must be made in accordance with the most recent version of Toronto Hydro's *Systems and Client Support Services – CSS660- Hardware and Software Purchasing Procedure* and any such Procurement with a Contract Value greater than $25,000 must also be approved by the CIO in writing**.**

7.5 The initial term for any Contract shall not exceed five (5) years, and any renewal term(s) shall not exceed a total of five (5) years.

7.6 The Senior Management Supply Chain Services may at any time request that a particular Procurement be made through the *Procedure for Competitive Bids*.

8 OWNERSHIP, APPROVAL AND RESPONSIBILITIES

Policy Owner

8.1 This policy is owned by the Executive Vice President, Chief Electric Operations & Procurement Officer (THESL)**.**

8.2 The Executive Vice President, Chief Electric Operations & Procurement Officer is responsible for*:*

- Ensuring that this policy is comprehensive, clear and current
- Ensuring that this policy is implemented and communicated to the departments and staff that are impacted
- Ensuring ongoing compliance with this policy
- Reviewing this policy bi-annually

Policy Approver

8.3 This policy is approved by the Policy Administration Steering Committee*.*

8.4 The Policy Administration Steering Committee is responsible for:

- Considering the impact of the proposed policy to the identified risk
- Reviewing and approving any proposed amendments or extensions to this policy
- Reviewing and approving this policy bi-annually

Designated Responsible Person (DRP)

8.5 This policy is managed by the Senior Management Supply Chain Services.

8.6 The Senior Management Supply Chain Services is responsible for:

- Immediately communicating any exceptions or violations of this policy to the Executive Vice President, Chief Electric Operations & Procurement Officer
- Reviewing this policy bi-annually and communicating any proposed amendments to the Executive Vice President, Chief Electric Operations & Procurement Officer
- Conducting quarterly reviews to ensure compliance with this Policy

Staff

8.7 All Toronto Hydro employees, officers and directors are required to comply with this policy.

9 POLICY COMMUNICATION

TYPE OF COMMUNICATION	COMMUNICATION TRIGGER	PARTY RESPONSIBLE FOR POLICY COMMUNICATION	AUDIENCE	ACKNOWLEDGEMENT?
E-mail	Policy Revision	Senior Management Supply Chain Services	All Business Unit employees involved in any Procurement	No
Presentation	Policy Revision	Senior Management Supply Chain Services	All Business Unit employees involved in any Procurement	Attendance Sheet and Quiz

10 POLICY COMPLIANCE AND VIOLATIONS

10.1 Any employee who fails to comply with this policy is subject to disciplinary action up to and including dismissal.

10.2 Failure to comply with this policy will pose significant financial, operational, legal and regulatory risks to Toronto Hydro.

Compliance Monitoring

10.3 Upon request of the Company's General Counsel, Senior Management of Supply Chain Services is responsible for tracking and collecting applicable data measuring compliance and reporting upon the same to the General Counsel in such format as he/she may require.

11 RELATED LAWS, REGULATIONS AND DOCUMENTATION

This Procurement Policy shall be read and applied in conjunction with the Signing Policies, the Authorization Level Document, as well as the following procedures and forms:

- *Procedure for Competitive Procurement*
- *Competitive Procurement Request Form*
- *Competitive Procurement Evaluation Recommendation Form*
- *Sole Source Justification Form*
- *Extending Existing Contract Justification Form*
- *Procedure to Document Approved Procurements*
- *Non-Discretionary Providers List*
- *Contractor Pre-Qualification Application*

PROCUREMENT POLICY
APPENDIX – EXCEPTIONS TO GENERAL PROCUREMENT RULES

Exception 1 – Petty Cash or Procurement Credit Card Purchases	This policy does not apply to Procurements that are processed via Toronto Hydro Corporation's Petty Cash or Corporate Card (Procard) procedures or policies, as implemented or amended from time to time.
Exception 2 – Purchases Below $25,000	Procurements with a value below $25,000 need not be sourced via the competitive procedures described in Rules 7.2 or 7.3 of the Procurement Policy unless the Procurement is environment or construction in nature, or requires a contract. Instead, a member of Senior Management may, in his/her discretion, approve Procurements not exceeding $25,000 in value in writing without receiving any competitive bids. The Business Unit shall retain all documentation substantiating the Procurement, approval and the award for annual review by Operation Support Services, or Toronto Hydro Corporation's Internal Audit Department, or otherwise as necessary. Such documentation should be retained for no less than six years in conjunction with Toronto Hydro's Document Retention Policy. Procurements shall not be artificially divided so as to constitute a value below $25,000.
Exception 3 – Contract Value Adjustments	1.1 Procurements which represent an amendment to the original Contract Value of an active, unexpired Contract need not be sourced via the competitive procedures described in Sections 7.2 or 7.3 of the Procurement Policy, nor need to meet the procedure for Sole Source procurements so long as the incremental increase in cost is less than or equal to 10% of the Contract Value, or $250,000 whichever is less. Instead, the responsible member of Senior Management, depending on required approval level, may approve such Procurements. 1.2 The Business Unit shall retain all documentation substantiating the change to the Contract Value for review by Operation Support Services, Toronto Hydro's Legal Division, or Internal Audit, as necessary. Such documentation should be retained for no less than seven years in conjunction with Toronto Hydro's Document Retention Policy. 1.3 Procurements shall not be artificially divided so as to constitute an adjustment below 10% or $250,000 whichever is less. 1.4 In the event of multiple adjustments, the cumulative value of the adjustments shall apply.
Exception 4 – Sole Source Procurements	The following procedure shall be followed when a Business Unit wishes to purchase any goods and/or services (including construction contracts) from a sole source vendor without going through the competitive procedures described in Rules 7.2 or 7.3 of the Procurement Policy: (i) In order to obtain approval for a sole source purchase, the Business Unit must complete, sign, and submit a *Sole Source Justification Report* to the Operation Support Services Department. The *Sole Source Justification Report* will require appropriate signing authority in accordance with the Authorization Level Document and must be signed by the divisional Executive. (ii) Upon receiving a completed *Sole Source Justification Report*, the Operation Support Services Department will conduct a due diligent review

	of the sole source purchase request to confirm that: (a) only one vendor is uniquely capable of providing the goods and/or services required and no other vendor can provide such goods and/or services; (b) an unforeseeable situation of urgency or emergency exists and the goods and/or services or construction cannot be obtained by means of a competitive process as required by the Procurement Policy: or (c) the Contract Value of an active, unexpired Contract for a good and/or service increases by greater than 10% or $250,000, whichever is less, versus its original approved value. The review will also determine if the sole source purchase is in the best interests of Toronto Hydro, and include a review of the proposed contract's specifications, scope, definition, commercial terms, liabilities, and insurance requirements. (iii) If approved, the Sole Source Procurement shall be processed by the Operation Support Services Department in accordance with the *Procedure to Document Approved Procurements*.
Exception 5 – Procurements From Non-Discretionary Providers	Procurements from specified government entities, utilities, and organizations providing certain corporate industry or professional memberships need not be sourced via the competitive procedures described in Rules 7.2 or 7.3 of the Procurement Policy, nor meet the procedure for Sole Source procurements. Instead, an authorized person under the Authorization Level Document may approve such Procurements, regardless of Contract Value, without receiving any competitive bids or submitting a Request For Sole Source Procurement so long as the vendor appears on the *Non-Discretionary Providers List.* *The Non-Discretionary Providers List* shall be updated on an bi-annual basis. Any proposed amendments to such list shall be reviewed by the Executive Vice President, Chief Electric Operations & Procurement Officer, and subject to the approval of the Policy Administration Steering Committee.
Exception 6 - Extension of Existing Contracts	When a Business Unit wishes to exercise its contractual right to extend an existing Procurement as set out in an existing contract : (i) In order to obtain approval to extend an existing contract, the Business Unit must complete, sign and submit an *Extending Existing Contract Justification Report* to the Operation Support Services Department. The *Extending Existing Contract Justification Report* will require appropriate signing authority in accordance with the Authorization Level Document. (ii) Upon receiving a completed *Extending Existing Contract Justification Report*, the Operation Support Services Department in consultation with Toronto Hydro's Legal Department will conduct a due diligent review of the extension request to determine if the current contract permits such an extension and whether such extension is in the best interests of Toronto Hydro, including a review of the proposed contract's specifications, scope, commercial terms, liabilities, and insurance requirements. (iii) If approved by the Operation Support Services Department, the Extension to the Existing Contract shall be processed by the Operation Support Services Department in accordance with the *Procedure to Document Approved Procurements*.
Exception 7 – Non-Order Invoice	Payments that are legally required to be made to specific entities and organizations that, cannot be sourced via the competitive procedures described in Rules 7.2 and 7.3 of the Procurement Policy, nor meet the procedure for Sole Source procurements. Instead, an authorized person under the Authorization Level Document may approve such payments, up to their authorized expenditure limit, without receiving any competitive bids or submitting a Request for Sole Source Procurement so long as the category/organization/entity appears on the Non-Order Invoice List. Such

	payments to Non-Order Invoice Providers shall be strictly limited to ensure the principles of the Procurement Policy are not violated. The *Non-Order Invoice List* shall be reviewed and updated on an annual basis. *Any proposed amendments to the Non-Order Invoice List shall be reviewed by the Executive Vice-President, Chief Electric Operations & Procurement Officer, and subject to the approval of the Policy Administration Steering Committee.*

Appendix B
Engagements Not Originating from a Competitive Procurement Process

Vendor	Summary of Nature of the Transaction	Year	Cost ($M)	Methodology used for Selection
Schneider Electric	Upgrade of SCADA equipment	2015	4,500,000.00	Sole Source
Itron	Upgrade of the legacy system components of the Advanced Metering Infrastructure	2016	4,300,000.00	Sole Source
Itron	Purchase of 4G LTE meters	2016	4,750,000.00	Sole Source
SAP Canada	Purchase of SAP software	2016	6,070,000.00	Sole Source
SAP Canada	Maintenance, licensing, and support services for SAP software applications	2016	3,560,000.00	Sole Source
Toronto Waterfront Revitalization Corporation	Completing infrastructure upgrades as part of the Waterfront Toronto Queens Quay project	2016	1,525,496.01	Sole Source
Honeywell Elster Solutions	Purchase of replacement meters	2016	6,750,000.00	Sole Source
S&C Electric	Purchase of electric power equipment directly from the manufacturer	2016	2,275,955.00	Sole Source
K-Line Insulators	Purchase of insulators directly from the manufacturer	2017	7,658,729.00	Sole Source
Albarrie Geocomposites	Purchase of oil containment system	2017	2,500,000.00	Sole Source
Hubbell Power Systems	Purchase of various types of small materials for overhead infrastructure (e.g. fuses, brackets, bolts) directly from the manufacturer	2017	13,653,874.00	Sole Source

WORKFORCE STAFFING AND COMPENSATION - EXECUTIVE SUMMARY

Exhibit 4A, Tab 4 discusses Toronto Hydro's workforce staffing plans and associated challenges, compensation strategies and costs, as detailed in Schedules 2 to 6.

The plans, strategies and costs set out in this evidence are aligned with, and necessary to fulfill, the following key objectives:

- execute planned programs in a safe and cost effective manner;
- provide customer value by maintaining and improving outcomes (e.g. reliability), and satisfying external obligations and legal requirement in a timely and cost-effective manner;
- mitigate the risks associated with the projected retirement of approximately 23 percent of Toronto Hydro's workforce over the 2020 to 2024 period by investing in training and development programs that facilitate knowledge transfer and enable new hires to acquire the specialized skills required perform utility operations safely and effectively;
- attract, develop and retain a highly skilled, responsive and adaptable workforce within a results-driven framework that is aligned with the utility's objectives;
- constrain compensation costs by maintaining relatively stable staffing levels and market-competitive wages; and
- continue to prudently manage the workforce complement and costs over the course of the 2020 to 2024 period.

1. EMPLOYEE COST BREAKDOWN (OEB APPENDIX 2-K)

A copy of OEB Appendix 2-K, which summarizes Toronto Hydro's historical and forecast staffing levels and compensation costs, is filed at Exhibit 4A, Tab 4, Schedule 2. That shows the following:

- the number of full-time equivalent employees ("FTEs") is expected to increase from approximately 1,483 in 2015 to 1,517 in 2020; and
- total compensation costs[1] are expected to increase from approximately $211.1 million in 2015, to $244.2 million in 2020. This is equivalent to compounded annual growth of 1.6 percent since the utility's corporate downsizing and restructuring in 2012.

2. STAFFING PLAN AND CHALLENGES

Toronto Hydro relies on a highly skilled and dedicated workforce to provide safe and reliable electricity service to its customers. The utility's response to the many weather-related major events since the 2013 ice storm highlight the dedication and commitment of its employees. During recent ice and wind storms that affected tens of thousands of customers, Toronto Hydro's crews worked around the clock to restore electricity service, communicate with customers about the restoration efforts, and ensure public safety. Despite extreme working conditions, not a single Toronto Hydro employee suffered a serious injury or fatality.

Toronto Hydro employees also play an essential role in the execution of planned work programs that are necessary to maintain the distribution system's integrity, mitigate unacceptable reliability and safety risks, and operate the system effectively. As detailed in the Distribution System Plan ("DSP") filed at Exhibit 2B, between 2020 and 2024, the

[1] Total compensation costs include: salary, wages, overtime, incentive pay, and benefits.

utility plans to continue executing the largest capital investment program in its history, renewing critical parts of its aging infrastructure and meeting the needs of the growing City of Toronto. To succeed in these endeavours the utility must maintain a workforce that is dependable, adaptable, highly skilled and knowledgeable.

2.1 Workforce Segmentation

In 2017, Toronto Hydro employed approximately 1,473 FTEs. As illustrated in Figure 1 below, Toronto Hydro's workforce can be broken down into the following segments:

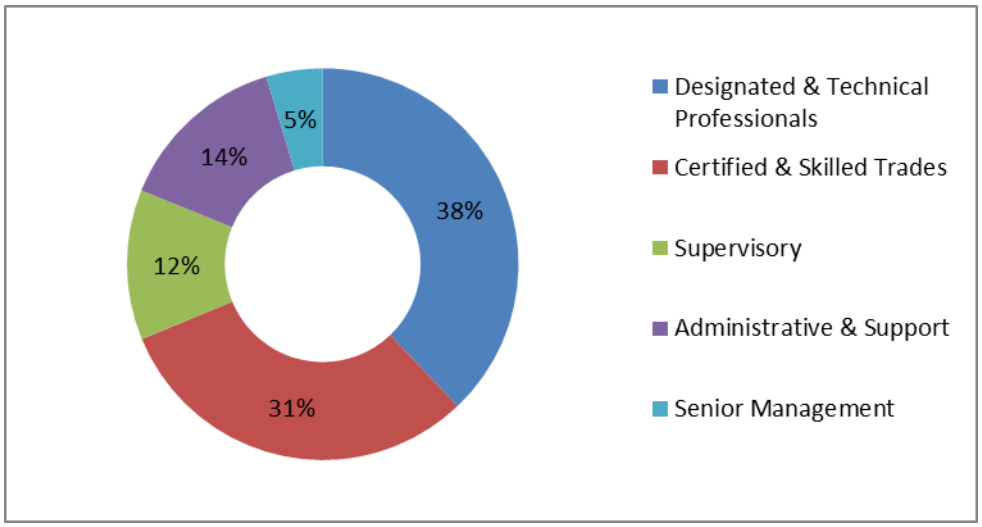


Figure 1: Toronto Hydro's Workforce Segments

- **Certified & Skilled Trades** are critical for executing the utility's capital and maintenance programs. Without funding to maintain the core staffing levels, Toronto Hydro will not be able to execute its work plan and its ability to respond to customer needs may be compromised.
- **Designated & Technical Professionals** include engineering technologists, engineers, and corporate professionals. These employees are required to ensure

Toronto Hydro is compliant with mandatory standards and best practices. They are essential to designing and planning a safe, secure, and reliable grid.

- **Supervisors** are trained and developed internally to oversee the safe and efficient design and execution of the work plan. They perform inspections, audits, investigations, training, role-modeling, performance and case management, and are instrumental to the safe and cost efficient delivery of service and operations.
- **Administrative and Support staff** perform important functions that enable operations, customer care, and corporate functions to operate efficiently.
- **Senior Management (including the executive team)** provides the strategic leadership and guidance required to effectively operate the utility. They have extensive accountabilities and oversee multiple subject portfolios, enhancing organizational productivity.

2.2 Aging Workforce Challenge and Mitigation Strategy

Toronto Hydro is in the midst of a significant renewal of its workforce, where approximately 23 percent of its workforce (or approximately 340 FTEs) are expected to retire between 2020 and 2024. Of that number, approximately 80 percent are from the staffing categories (certified and skilled trades, designated and technical professionals, and supervisory positions) that directly maintain and operate the distribution system.

Toronto Hydro plans to use an integrated, multi-faceted staffing model to fulfill its human resource requirements over the 2020 to 2024 period, consisting of the following approaches:

- **Hire new graduates and train them in a staged manner**: Toronto Hydro plans to admit 191 individuals to its in-house apprentice and technical programs over the

2020 to 2024 period. This approach provides cost-effective training that enables crews to learn the specialized skills which are required to work safely and efficiently on Toronto Hydro's distribution system.

- **Promote from within**: Between 2015 and 2017 approximately 40 percent of vacancies were filled internally, three quarters of which were internal promotions into more senior leadership roles. This cost-effective approach builds on existing knowledge, talent and skills, and rewards high performance. The utility plans to continue to develop its existing workforce to fill positions as they become available.
- **Hire skilled labour from the external market**: This approach is used when there is an insufficient pool of qualified internal candidates. However, for a number of reasons, it is not a viable option to fill positions for certified and skilled trades. External hires in these categories typically require an additional year of on-the-job training before they can safely work on Toronto Hydro's infrastructure. In addition, the external labour market for certified and skilled trades is constrained by aging workforce challenges.
- **Rely on third-party service providers**: This option provides Toronto Hydro flexibility to cost-effectively procure resources for peak demands, while maintaining a stable complement of employees.

3. COMPENSATION COSTS AND STRATEGIES

Toronto Hydro expects compensation costs to increase from $211.1 million in its last re-basing year (2015) to $244.2 million in the 2020 test year. In preparing this forecast, Toronto Hydro considered inflation rates contained in its collective agreements, relevant labour market-data and other factors such as the increasing size and complexity of the capital plan over the next five years.

3.1 Compensation Strategy

Toronto Hydro's strategy is to provide wages and benefits that are competitive in the markets where Toronto Hydro competes for talent. A Compensation and Benefits Benchmarking Report prepared by Mercer (Schedule 5) shows that Toronto Hydro's compensation levels are generally aligned with the market.

Toronto Hydro also offers a compensation program that aligns the behaviour and performance of the workforce with the core objectives and goals of the utility. The compensation strategy is an important tool for communicating performance expectations, fostering productivity, and rewarding employees for their contributions.

Between 2020 and 2024, Toronto Hydro intends to continue to rely on these principles to manage human resource requirements and costs appropriately and responsibly. The utility must do so with regard to the dynamic labour relations environment that it operates within, and the workforce challenges that it must contend with over the upcoming rate cycle.

3.2 Non-Bargaining Unit Employees

Less than one-third of Toronto Hydro's employees are not members of a bargaining unit. These employees receive a total cash compensation package comprised of base salary and variable performance pay. Salary grade/levels are set to correspond with salary ranges. Salaries are set and adjusted with regard to external market benchmarking.

3.3 Bargaining Unit Employees

Approximately two-thirds of Toronto Hydro's employees are represented by the following bargaining units pursuant to collective agreements:

- Power Workers' Union: collective agreement effective February 1, 2018 to January 31, 2022.
- The Society of United Professionals (formerly The Society of Energy Professionals): collective agreement effective January 1, 2016 to December 31, 2019.

3.4 Benefits and Pensions

Full-time employees are entitled to medical and dental benefits, short- and long-term disability income protection, life insurance, and accidental death and dismemberment insurance. Employees are also eligible to participate in the Ontario Municipal Employees Retirement System ("OMERS") pension plan and receive post-retirement benefits. The cost of employee benefits is expected to increase from $52.8 million in 2015 to $64.8 million in 2020.

OEB Appendix 2-K
EMPLOYEE COSTS /COMPENSATION TABLE

	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Number of Employees (FTEs including Part-Time)1						
Management (including executive)	61	69	69	68	68	67
Non-Management (union and non-union)	1,422	1,415	1,403	1,431	1,455	1,450
Total	**1,483**	**1,484**	**1,473**	**1,499**	**1,523**	**1,517**
Total Salary and Wages (including ovetime and incentive pay)						
Management (including executive)	$ 12,292,778	$ 14,152,809	$ 14,971,880	$ 15,015,969	$ 15,478,739	$ 15,719,811
Non-Management (union and non-union)	$ 145,975,363	$ 146,148,053	$ 148,139,852	$ 155,158,699	$ 160,518,242	$ 163,720,633
Total	**$ 158,268,141**	**$ 160,300,862**	**$ 163,111,731**	**$ 170,174,668**	**$ 175,996,982**	**$ 179,440,444**
Total Benefits (Current + Accrued)						
Management (including executive)	$ 3,573,323	$ 3,919,134	$ 4,202,856	$ 4,576,375	$ 4,844,923	$ 5,260,044
Non-Management (union and non-union)	$ 49,254,110	$ 48,138,488	$ 49,111,532	$ 51,162,437	$ 54,655,848	$ 59,509,241
Total	**$ 52,827,432**	**$ 52,057,622**	**$ 53,314,387**	**$ 55,738,811**	**$ 59,500,771**	**$ 64,769,286**
Total Compensation (Salary, Wages, & Benefits)						
Management (including executive)	$ 15,866,100	$ 18,071,943	$ 19,174,735	$ 19,592,344	$ 20,323,662	$ 20,979,856
Non-Management (union and non-union)	$ 195,229,473	$ 194,286,540	$ 197,251,383	$ 206,321,136	$ 215,174,090	$ 223,229,874
Total	**$ 211,095,573**	**$ 212,358,484**	**$ 216,426,119**	**$ 225,913,479**	**$ 235,497,752**	**$ 244,209,730**

WORKFORCE STAFFING PLAN AND STRATEGY

This schedule describes Toronto Hydro's workforce segments, and provides an overview of the utility's past, present and expected staffing levels, further to the data outlined in OEB Appendix 2-K – Employee Cost (Exhibit 4A, Tab 4, Schedule 2).

The schedule also discusses the challenges associated with Toronto Hydro's aging workforce and the staffing and development strategy that the utility has adopted to respond to such challenges over the 2020-2024 rate period. The evidence is organized as follows:

1) Introduction
2) Toronto Hydro's Workforce Segments
3) Workforce Complement: Past and Present
4) Aging Workforce Challenge
5) Staffing and Development Strategy

1. INTRODUCTION

To facilitate the safe and efficient execution of Toronto Hydro's planned capital and Operations, Maintenance, and Administration ("OM&A") programs, while meeting customer expectations and external obligations, Toronto Hydro needs to maintain a highly skilled workforce with a focus on certified and skilled trades, designated and technical professionals, and leadership staff. The current and forecast size of the utility's workforce continues to be commensurate with the magnitude and complexity of the work program, while maintaining efficiencies achieved in previous years.

Toronto Hydro is proposing to increase its workforce by approximately 2 percent in 2020 compared to 2015 levels. This modest increase in proposed staffing levels is necessary to secure the specific knowledge and talent that the utility requires to meet current and future operational and customer requirements. The utility's progress in filling and replenishing talent in key areas contributed to improvements in safety, customer response, reliability, and productivity, while achieving capital and operating needs. With the continuing trend of projected retirements over the next five to ten years, and the long training lead-times required for new entrants to the workforce, strategic staffing decisions are necessary in critical areas to balance work program execution and funding levels.

To deliver its programs, Toronto Hydro relies on a number of key Certified & Skilled Trades and Designated & Technical Professional positions, such as Certified Power Cable Person ("CPCP"), Certified Power Line Person ("CPLP"), Distribution System Technologist ("DST"), Certified Meter Mechanic/Tester, Power System Controller ("PSC"), Engineering Technologist ("ETL"), and Engineers. Detailed descriptions of Toronto Hydro's workforce segments are set out in section 2 of this schedule.

Toronto Hydro's task of maintaining the necessary complement of employees is made more difficult because of the significant number of actual and expected retirements. Toronto Hydro's plans are successfully responding to that challenge, particularly among the Designated & Technical Professionals, Certified & Skilled Trades, and Supervisory talent. In those segments, the number of 25-44-year-olds increased by approximately 10 percent, whereas 45-54-year-olds decreased by approximately 15 percent. Toronto Hydro plans to continue to invest in workforce renewal, and training and development of talent in these key areas of its operations.

Toronto Hydro takes a conservative approach to hiring to minimize the cost of its workforce. This is accomplished by planning for the minimum amount of training overlap to achieve a continuity of skills. A successful transfer of knowledge and skills is necessary to ensure the safe and efficient execution of the utility's work programs. Accordingly hiring is done in advance to provide the lead time necessary to train apprentices. Through longer-term workforce staffing planning within certified and skilled trades and designated and technical professional positions, this conservative approach maintains the required competencies and integrates talent at a pace that manages costs and prioritizes worker safety. As an example, between 2015 and 2017 the utility hired additional Power System Controller resources to reduce knowledge and skills gaps and have competent employees ready to take on the work as retiring employees leave. The work done by these employees is increasingly complex, due to the volume and nature of work undertaken by the utility, both in planned and emergency response situations.

Through resource optimization strategies, Toronto Hydro replenished talent in critical areas of its business, while managing overall staffing levels and compensation costs effectively. These strategies include supplementing the internal workforce with contracted resources; contracted resources selected using an optimization model to assess suitability to perform work aligned to factors such as previous experience, safety performance, and cost.

2. TORONTO HYDRO'S WORKFORCE SEGMENTS

Toronto Hydro employs a workforce of skilled employees who serve customers, allow the utility to satisfy its legal and regulatory obligations, safely maintain and operate the distribution system and execute the utility's plans. The major segments of the

workforce include certified and skilled trades, designated and technical professionals, supervisory staff, administrative and support staff, and senior management.

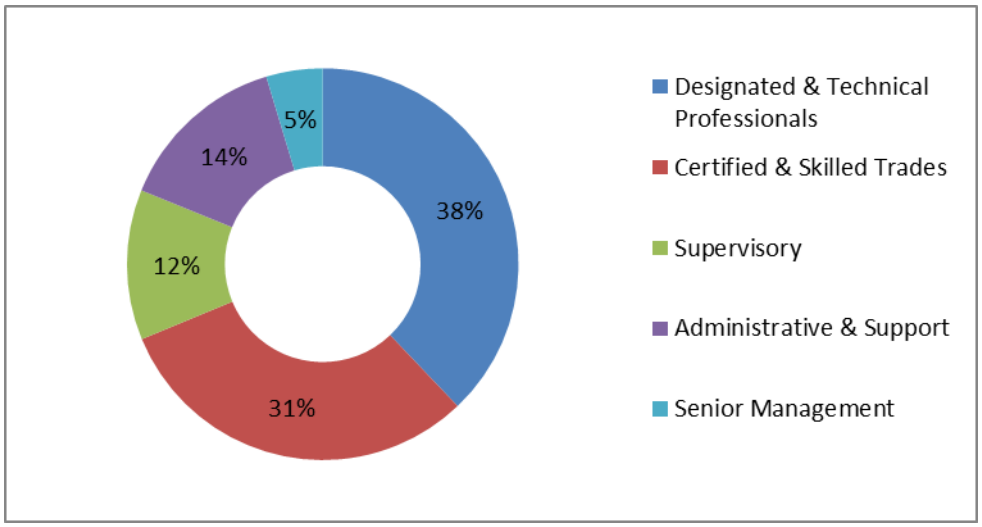


Figure 1: Toronto Hydro's Workforce Segments

2.1 Certified and Skilled Trades

As of the end of 2017, approximately 31 percent of Toronto Hydro's workforce was comprised of certified and skilled trades. These positions are critical for executing the primary activities and programs that enable the utility to construct and maintain the distribution system, deliver safe and reliable power to its customers, and respond to trouble calls and emergency situations.

Toronto Hydro operates in a uniquely complex and dense urban landscape, and its distribution system consists of a wide range of design standards, including legacy underground and overhead systems. This operating environment heightens the importance of Toronto Hydro's certified and skilled trades. Developing talent with these

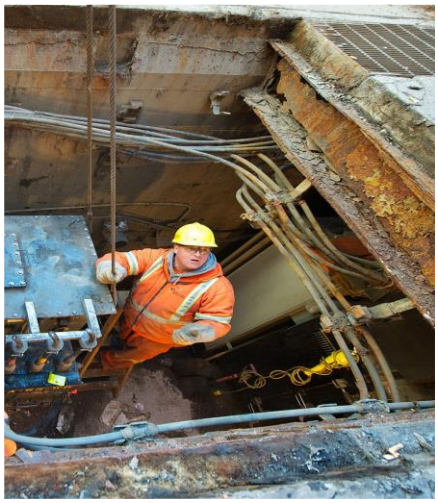
specialized knowledge and skills to build, operate, and maintain underground assets is a focus of the internal workforce renewal strategy.

Below is an overview of the roles and responsibilities of the key certified and skilled trades:

- **Power System Controller**: Operates the electrical distribution system to provide safe, reliable, and cost-effective delivery of electrical power on a 24-hour basis. In performing this function, PSCs monitor system conditions, develop, direct, and dispatch system switching, work protection, and trouble response for planned and emergency events.
- **Certified Meter Mechanic/Tester:** Installs, removes, repairs, inspects, tests, and calibrates all types of meters and metering equipment and troubleshoots faults in meters, metering equipment, and test boards.
- **Distribution System Technologist:** Operates, installs, commissions, constructs, repairs, maintains, and decommissions all types of substation equipment, protective relay and control systems, station metering, distribution automation equipment, and SCADA systems, including completion of all associated work orders, specifications, engineering drawings, reports, and work procedures.
- **Certified Power Line Person**: Responsible for the construction and maintenance of the overhead and underground distribution systems of all voltage levels in a safe and efficient manner; constructs, maintains, operates, and troubleshoots the overhead and underground distribution plant, including emergency repairs and switching operations; and performs line clearing duties as required.
- **Certified Power Cable Person**: Responsible for maintaining, operating, and troubleshooting the underground distribution systems of all voltage levels. Installs, removes, constructs, alters, operates, inspects, and maintains

equipment associated with the underground distribution system, including transformers, switchgear, protectors, primary switches, cables, and related equipment located in cable chambers, transformer vaults, etc., containing energized circuits.

For the above noted positions, it is crucial that talent be cultivated internally, which not only ensures that the skills developed by these employees are tailored to the unique challenges of Toronto Hydro's overhead and underground systems, but also helps to overcome the limitation that these skills generally are not readily available in the marketplace (meaning hiring externally is not a reliable strategy for this segment).



CPCP - Underground Plant



CPLP - Overhead Plant

Figure 2: CPCP and CPLP Employees at Work

Over the next five years, Toronto Hydro plans to continue making significant investments in the distribution system to achieve the outcomes proposed in this application that meet customers' needs and address known investment drivers. A stable complement of certified and skilled trades is critical to the execution of Toronto

Hydro's capital and OM&A programs. The table below provides examples of the capital and operational work programs executed by certified and skilled trades. For more information about these programs, please refer to the Distribution System Plan ("DSP") filed at Exhibit 2B, and the Maintenance Programs filed at Exhibit 4A, Tab 2.

Table 1: Examples of Work Programs Executed by Certified and Skilled Trades

Capital Program (Exhibit 2B)	**Type of Resources Required**
System Enhancements (Section E7.1)	CPLP and DST
Area Conversations (Section E6.1)	CPCP, CPLP, and DST
Underground System Renewal - Horseshoe (Section E6.2)	CPCP and CPLP
Overhead System Renewal (Section E6.5)	CPLP
Stations Renewal (Section E6.6)	DST, CPCP, and DST
Reactive and Corrective Capital (Section E6.7)	CPCP, CPLP, and DST
Maintenance Programs (Exhibit 4A, Tab 2)	**Type of Resources Required**
Preventative and Predictive Overhead Line Maintenance (Schedule 1)	CPCP
Preventative and Predictive Underground Line Maintenance (Schedule 2)	CPCP
Preventative and Predictive Station Maintenance (Schedule 3)	DST
Corrective Maintenance (Schedule 4)	CPCP, CPLP and DST
Emergency Response (Schedule 5)	CPCP, CPLP and DST

Without the funding required to maintain core staffing levels in the key areas described, Toronto Hydro's ability to execute the work plan and maintenance programs and deliver on the outcomes proposed in this application could be compromised. Potential negative impacts on customers include increased frequency and duration of power outages as a result of insufficient resources to respond to trouble calls or to renew aging infrastructure.

2.2 Designated and Technical Professionals

As of the end of 2017, approximately 38 percent of Toronto Hydro's workforce was employed in designated and technical professional positions (e.g. engineering technologists, engineers, and corporate professionals). This segment of the workforce is responsible for planning, designing, and executing the programs that enable the utility to construct and maintain the distribution system, and deliver safe and reliable power to its customers.

Below is an overview of the roles and responsibilities of the key Designated & Technical Professionals:

- **Engineer**: Participates in short- and long-range strategic asset planning to ensure technical soundness, reliability, cost effectiveness, and safety for the utility; prepares engineering reports and studies; performs engineering analysis and evaluations; provides timely technical support/consultation, project management, and testing; develops proposals and plans; and prepares and/or reviews methods, procedures (process re-engineering), and designs. Engineers are accountable, and legally responsible, for personal engineering work product (e.g. drawings, calculations, documents, and the work of others which the engineer has signed).
- **Engineering Technologist:** Supports the formulation of electric system plans and co-ordinates system operation services with the control centre; develops distribution plans by calculating load forecasts; prepares conceptual and detailed designs and cost estimates for projects related to system expansion, rehabilitation, and maintenance of the electrical and civil infrastructure; conducts studies, prepares reports, makes recommendations relating to station and system distribution load forecasts, engineering studies, technical standards,

utility materials, tools, and construction practices; and prepares, reviews, and maintains project schedules.

In addition to the above-noted technical professionals, corporate professionals in this segment enable the utility to satisfy a variety of external obligations and internal responsibilities in the areas of Finance (Exhibit 4A, Tab 2, Schedule 16), Information Technology (Exhibit 4A, Tab 2, Schedule 17), Legal and Regulatory (Exhibit 4A, Tab 2, Schedule 18), and Human Resources and Safety (Exhibit 4A, Tab 2, Schedule 15). For more detailed information about the activities that these employees perform, please refer to Toronto Hydro's capital investment plan filed at Exhibit 2B, Section E, and the operational programs filed at Exhibit 4A, Tab 2.

Without the required staffing levels of designated and technical professionals, Toronto Hydro will not have the necessary resources to design and plan for a safe, secure and reliable distribution system in compliance with legislative and regulatory requirements, applicable standards, and best practices.

2.3 Supervisory

As of the end of 2017, approximately 12 percent of Toronto Hydro's workforce supervises the design and execution of the work plan. The supervisory segment is primarily trained, developed, and promoted from within the organization, leveraging the wealth of specific internal knowledge developed within the utility. The responsibilities associated with these positions include inspections, audits, investigations, training, role modeling, performance management and coaching, and development.

The supervisory segment is critical to the work program delivery and ensures that employees work in a safe and productive manner. Toronto Hydro attributes much of its performance in safety and attendance improvements to the work performed by supervisors. The utility's achievements in this respect include:

- From 2011 to 2016, a 68 percent improvement in Total Recordable Injury Frequency ("TRIF"). Toronto Hydro employees worked over 5 million hours without a lost time injury.
- From 2013 to 2017, a 32 percent improvement in corporate attendance, from 5.23 days in 2013 to 3.54 days in 2017.
- From 2011 to 2016, an 87 percent reduction in restricted work days. In 2017, 130 employees returned to their positions faster than was otherwise possible through the Early and Safe Return to Work process.
- An 82 percent reduction in Workplace Safety and Insurance Board costs in relation to New Experimental Experience Rating ("NEER").

Without an appropriate complement of supervisory positions, Toronto Hydro would be at risk of experiencing reduced productivity and declining safety performance. For more details on Toronto Hydro's employee safety, see the Human Resources and Safety Program (Exhibit 4A, Tab 2, Schedule 15).

2.4 Administrative and Support

As of the end of 2017, approximately 14 percent of Toronto Hydro's workforce provides support to operations, customer care, and corporate functions in the delivery of the work plan. Administrative and support employees also play an important role in enabling the utility to satisfy a variety of external obligations and internal responsibilities, such as scheduling and timekeeping, invoicing, project coordination,

tracking and reporting, and research. Without appropriate staffing levels in these positions, Toronto Hydro would risk a reduction in productivity as a result of higher cost resources having to perform this type of work.

2.5 Senior Management

Senior management employees represented approximately 5 percent of the utility's workforce at the end of 2017. These individuals provide the leadership and strategic guidance necessary to achieve Toronto Hydro's core objectives in a complex and highly regulated environment. Their accountabilities are extensive, with many senior management positions providing oversight to multiple subject portfolios. Without a capable senior management team, Toronto Hydro would experience the risks noted in the previous sections, as well as the risk of not meeting its core objectives.

3. WORKFORCE COMPLEMENT: PAST AND PRESENT

In 1998, after Toronto Hydro was formed through the amalgamation of six former utilities, the utility's workforce was comprised of approximately 2,400 employees. Over a period of four years (i.e. 1998-2001), the workforce was reduced to approximately 1,550 employees. This reduction in headcount was achieved as a result of a voluntary retirement program and a voluntary separation program in 2001 that resulted in the loss of critical positions for the utility (such as those in the certified and skilled trades).

Over time, Toronto Hydro strengthened its workforce in these critical positions to prepare for continued retirements and unplanned exits that may occur over the following five to ten years, as necessary to support capital infrastructure renewal, and allow for the lead-time required to safely train new workforce entrants.

From 2011 to 2013, Toronto Hydro experienced another notable reduction in the size of its workforce, from approximately 1,737 full time equivalent ("FTE") employees in 2011 to 1,527 FTEs in 2013. This reduction was a result of: (i) rebalancing of critical positions (such as certified and skilled trades and designated and technical professional) through a voluntary exit program[1] and workforce downsizing; and (ii) organizational and job design.

Since 2013, Toronto Hydro's workforce further decreased in size. As discussed in more detail below, this is primarily a result of the age demographics of Toronto Hydro's workforce and significant levels of retirement-eligible employees leaving the organization. To manage costs during the upcoming rate period, Toronto Hydro is proposing a conservative staffing plan that would adequately support the proposed capital and operations plans. This calls for a slight increase to Toronto Hydro's current workforce by 2020, to a level consistent with 2013.

Toronto Hydro has a multi-faceted staffing strategy to maintain quality service and value to ratepayers, and to plan for continued retirements. Toronto Hydro's Workforce Renewal Strategy is discussed in more detail in section 5 below.

4. AGING WORKFORCE CHALLENGE

The Canadian utility industry continues to face a major workforce renewal challenge as the wave of baby-boomer retirements crests.[2] Compared to the Canadian workforce, Table 2 demonstrates that Toronto Hydro's employee complement is much more

[1] The program targeted administrative and clerical positions, and focused on the reduction of non-certified trades jobs in areas where automation increased and outsourcing opportunities at a lower operating cost presented itself.
[2] The term "baby boomers" refers to those individuals that were born between 1947 and 1965.

heavily weighted to workers in the 45-54 and 55-64 age cohorts, which constitute employees that are about to be, or are already, eligible for retirement.

Table 2: Population by Age Group (Canada and Toronto Hydro)

Demographic Cohorts	Statistics Canada % of Workforce[3]	Toronto Hydro % of Workforce[4]
Age <25	14.38%	3.70%
Age 25-34	21.79%	27.35%
Age 35-44	21.16%	20.15%
Age 45-54	22.15%	26.53%
Age 55-64	16.49%	21.25%
Age >65	4.03%	1.03%

Figure 3 below illustrates Toronto Hydro's demographic challenge. In 2013, the utility had a number of large age cohorts nearing retirement age.[5] At that time, the seven largest age groups, each constituting more than 4 percent of Toronto Hydro's workforce, were found in consecutive cohorts: 48 to 54 years of age. At the time, these were the next seven age groups to reach retirement eligibility.

[3] Statistics Canada data is current as of 2016.
[4] Based on December 31, 2017 year-end headcount.
[5] EB-2014-0116, UT J7.8, Filed 27 Feb 2015

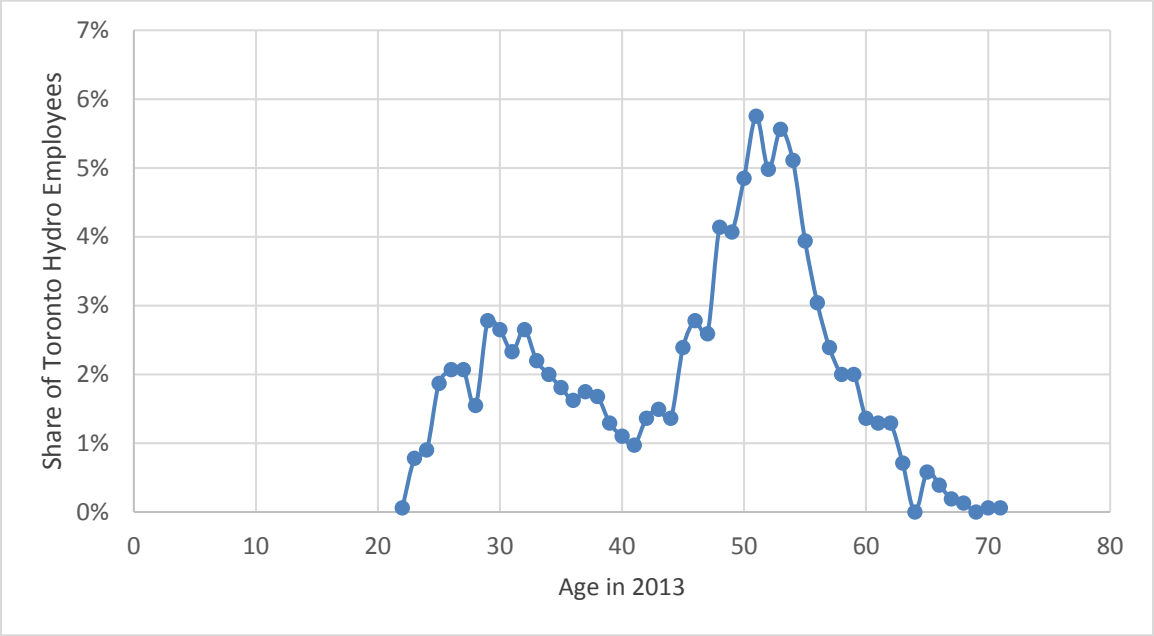


Figure 3: Toronto Hydro Workforce Demographics in 2013

Previous Toronto Hydro staffing strategies showed significant success in managing this demographic challenge. Figure 4 below overlays Toronto Hydro's age group demographics at the end of 2017, normalized to show employee age in 2013. New talent entering the organization is offsetting the wave of retirements to a significant extent. As a result, the median age of a Toronto Hydro employee was 43 at the end of 2017, down from 48 just four years prior.

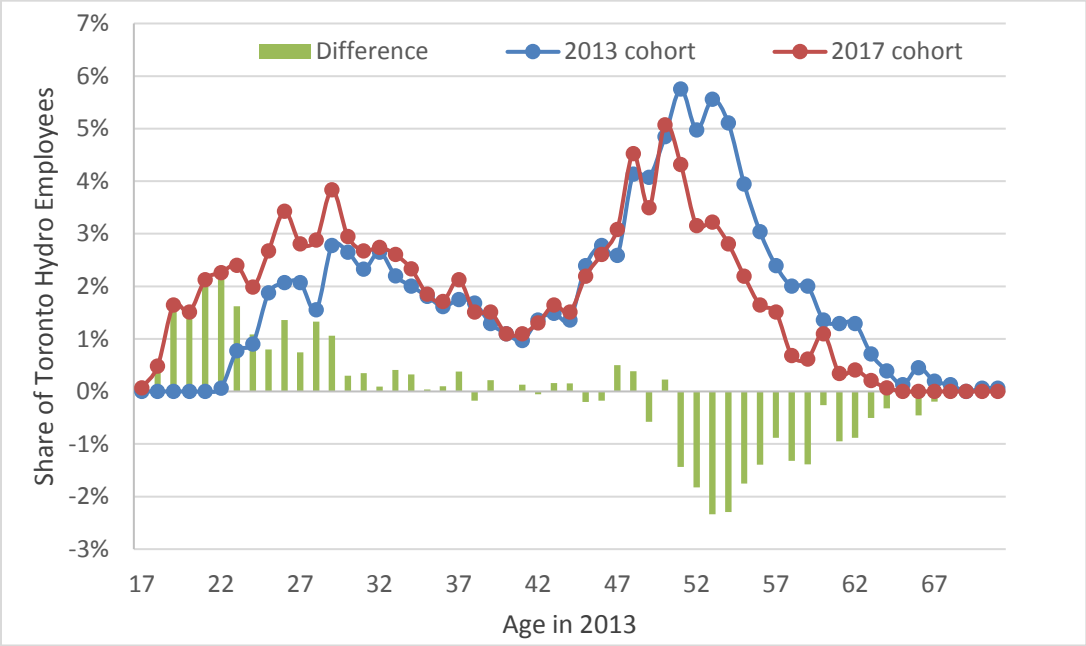


Figure 4: Toronto Hydro Workforce Demographics in 2013 and 2017, Normalized

Toronto Hydro expects a significant rate of employee retirements to continue over the next five to ten years, including the period of this 2020 to 2024 CIR Application. Employees reaching retirement age in 2020 and 2021 are currently the second and ninth largest age cohorts of Toronto Hydro's workforce. Approximately 27 percent of the utility's workforce are between 45 and 54 years old, and 21 percent are between 55 and 64. This means that over the next decade (i.e. by 2028), more than 37 percent of Toronto Hydro's workforce is expected to be eligible for retirement.

In addition to demographic-related challenges, Toronto Hydro employees are often sought after by other organizations that may offer similar roles in neighbouring geographic regions. While average voluntary turnover has remained below 5 percent, a competitive labour market challenges the utility to maintain market competitiveness of

its compensation and benefits programs to attract and retain employees to work in the City of Toronto.

To manage these challenges, Toronto Hydro requires funding to invest in hiring new entrants and facilitating apprenticeships, co-op programs, leadership development, and in-house training. Toronto Hydro must pursue these investments now to account for the lead time to train new employees and transfer corporate and technical knowledge to them from senior employees.

The potential consequences of delays in hiring and lack of funding to administer training programs include not having adequate resources to maintain and operate the systems or relying on an inexperienced or inadequately trained workforce to perform highly complex, safety-sensitive tasks. After each retirement, the organization must deal with not only a loss of knowledge and experience, but also a need to train and develop the individuals that have been promoted or newly hired to fill critical positions. As Figures 5 to 7 illustrate, the aging workforce challenge is even more acute for those segments of the workforce that are instrumental to executing the utility's capital programs, maintaining existing infrastructure, and sustaining safe and reliable operations into the future.

If the above-noted adverse consequences materialize, they could have significant effects on all critical aspects of the utility's business, including customer experience, reliability, safety, and financial performance.

4.1 Segment Demographics

The progress achieved so far in renewing Toronto Hydro's workforce is evident in the demographics of workforce segments. Focused hiring in certified and skilled trades and designated and technical professional segments was a contributor to this improvement. The promotion of internal talent also contributed considerably to renewal in the supervisory segment. The 45 to 54 age group, which includes the youngest baby boomers, is the focus of the utility's strategy to deal with the aging workforce, as these employees represent approximately 27 percent of Toronto Hydro's workforce.

As seen in the figures below, over the past three years, the utility made strides to rebalance its workforce in critical segments. For designated and technical professionals, certified and skilled trades and supervisors, the 25 to 34 age cohort experienced proportionate increases, while the 45 to 54 age cohort shrunk.

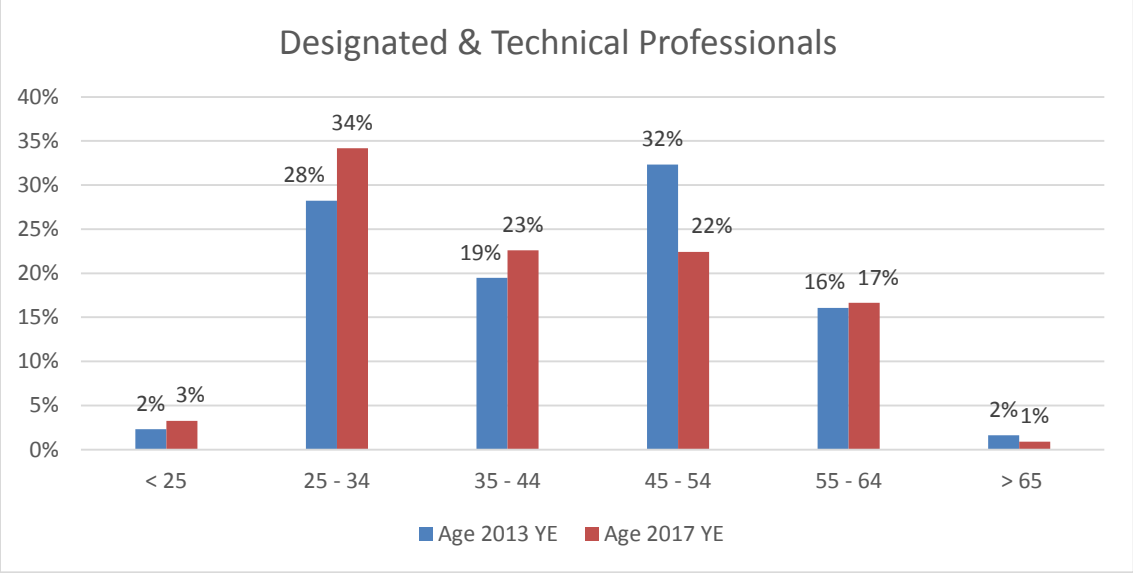


Figure 5: Toronto Hydro Workforce Demographic Profile – Designated & Technical Professionals

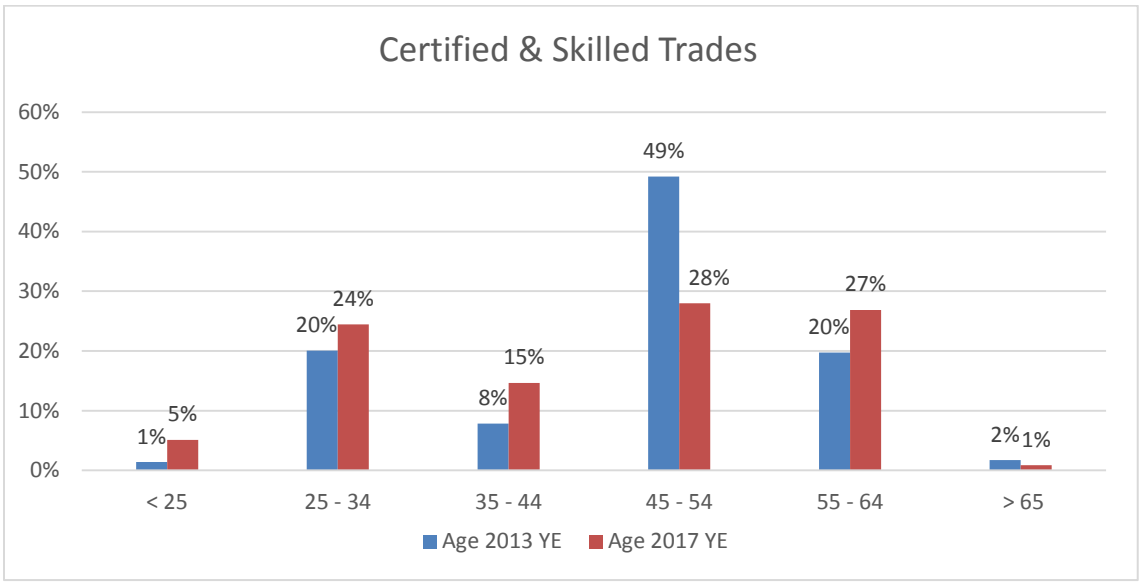


Figure 6: Toronto Hydro Workforce Demographic Profile – Certified & Skilled Trades

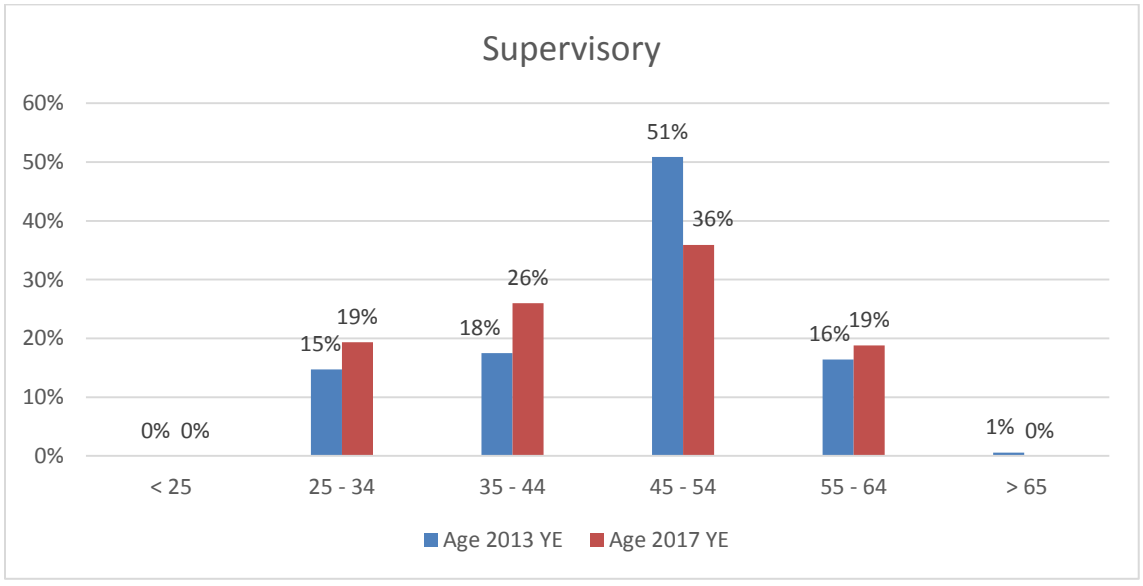


Figure 7: Toronto Hydro Workforce Demographic Profile - Supervisory

Given the physical demands associated with certain positions, particularly in the certified and skilled trades segment, retaining employees beyond their retirement date

can be challenging. Training new employees in targeted segments just in advance of retirement allows for an effective transition of knowledge and skills, while maintaining the organizational headcount. This allows the utility to invest in talent in the most critical areas while controlling costs.

On average, it takes approximately four to six years to train a new certified and skilled trades hire, and one to two years to develop a new supervisor. The development period for certified and skilled trades considers legislative training requirements. Toronto Hydro compliance training is based on operational requirements and best practices, and apprenticeship training (technical trades training) and testing requirements. Table 3 provides an example of training requirements for a CPCP apprentice.

Table 3: CPCP Apprentice Training Requirements

Course Type	Legislative	TH Compliance	Apprentice	Total Courses
Year 1	20	13	44	77
Year 2	1	1	20	22
Year 3	2	1	15	18
Year 4	14	7	13	34
Total Courses	**37**	**22**	**92**	**151**

Starting in 2010, Toronto Hydro adopted more stringent education requirements for certain apprenticeship positions. At a minimum, the utility now requires new hires to have a university or college diploma in an electrical background. As a result of this change, in-class training-time for apprentices decreased by 13 percent allowing them to start working on Toronto Hydro's distribution system four weeks sooner. Toronto Hydro attributes this improvement to a variety of qualities that are associated with higher education; namely, enhanced problem-solving skills, increased learning abilities,

communication and comprehension aptitudes, and heightened initiative and resourcefulness.

4.2 Retirements

In the 2020 to 2024 period, approximately 23 percent of Toronto Hydro's current workforce, or approximately 340 employees, will be eligible for retirement (as detailed in Table 4 below). Of the projected retirements, approximately 80 percent are expected to be from the certified and skilled trades, designated and technical professionals, and supervisory segments, which are critical to maintaining and operating the distribution system. At the end of 2017, 81 employees retired and 45 additional employees have notified the utility of their intention to retire or initiated retirement planning. Table 4 summarizes Toronto Hydro's retirement projections up to the end of 2024.

Table 4: Toronto Hydro Retirement Projections (2018-2024)

Year	2018	2019	2020	2021	2022	2023	2024
Annual	80	42	70	86	64	71	47
Cumulative	80	122	192	278	342	413	460

For the 2020 to 2024 rate period, Toronto Hydro forecasts long-term staffing needs using a combination of age and years of service (reaching the threshold of 92 when added) to estimate the timing of retirements.[6] Historical data indicate that years of service tends to drive retirement timing amongst longer tenured but relatively younger employees. This led to higher than projected retirements in both a given year and cumulatively over the 2015 to 2017 period (as demonstrated in Table 5), underscoring

[6] Based on 2015-2019 annual retirement projections, which used the Ontario Municipal Employees Retirement System ("OMERS") pension eligibility criteria for an unreduced pension, which stipulates a member must be:

- A minimum of 55 years of age with 30 years of OMERS service
- A minimum of 55 years of age, with total years of service and the age of retirement totalling 90, or
- OMERS normal retirement age 65.

the need to increase Toronto Hydro's internal staff complement over current levels by 2020.

Table 5: Toronto Hydro Retirement Projection Accuracy

Year	2015	2016	2017
Actual/Projected Retirees	103%	164%	137%

5. STAFFING AND DEVELOPMENT STRATEGY

Between 2020 and 2024, Toronto Hydro plans to execute a large capital work program (as outlined in the DSP, at Exhibit 2B), using approximately the same number of internal resources as it did in the 2015 to 2019 period. One of the greatest risks to the safe and responsible execution of this work program is maintaining an internal knowledge base to support the specialized knowledge and skills needed to address projected employee exits in the next five to ten years.

Workforce planning is a continuous process aimed at ensuring that the organization has sufficient talent to meet its human resource needs. The process is forward-looking and considers various sources of talent including permanent employment, contracted resources, and partnerships. The appropriate mix of talent is determined by examining various factors including changing utility operations requirements, actual resource availabilities and utilization, projected and actual loss of knowledge (e.g. retirements, attrition), and the results of recruitment, training, development, and other initiatives (e.g. job harmonization). Prudent workforce planning enables the utility to have a cost-effective and sustainable workforce, and facilitates continuous improvements over time. For example, through responsible workforce planning Toronto Hydro consolidated 41 job classifications into ten since 2007.

The overarching principles of Toronto Hydro's staffing strategy are to:

1) provide flexibility in the allocation of resources (both internal resources and external contractors) to complete the approved work program at the greatest long-term value to customers;
2) align future professional trades and technical hiring with capital and maintenance program volumes; and
3) continually review requirements to drive decision-making for effective resource cost management.

As discussed in the Aging Workforce Challenges section above, Toronto Hydro is proposing a staffing plan that addresses the utility's projected retirements and the resources it requires to deliver its programs and satisfy its mandatory obligations over the next five years. Failing to do so could expose the utility to a multitude of operational and financial risks, such as not having the resources required to provide safe and reliable electricity service to its customers, and not being able to fulfill legal and regulatory requirements.

Toronto Hydro uses a number of staffing approaches, including: (i) promoting from within the utility; (ii) hiring skilled labour from the external market; (iii) acquiring and training new graduates; and (iv) using third-party service providers. As explained in more detail below, Toronto Hydro relies on all four approaches to meet human resource requirements, leveraging the relative strengths of each of these options as appropriate in a given set of circumstances.

Toronto Hydro uses a multi-faceted staffing strategy because it provides the flexibility to staff up or down as required to effectively plan and manage its staffing needs over the

next five years and beyond. Given the breadth and complexity of the utility's operations, and the rate at which the City of Toronto is growing and expanding, flexibility is particularly important for Toronto Hydro. Toronto Hydro also considers a multi-faceted approach to be a more effective and cost-efficient solution than a single or double-pronged strategy to address the aging workforce challenge that the utility faces, and replenish talent at a pace that is cost-effective and aligned to critical resource areas (as discussed in section 1).

5.1 Hire from Within

Hiring from within the utility allows Toronto Hydro to recognize and advance those employees that demonstrate exceptional skills, knowledge and leadership qualities. These individuals are critical to training the new generation of employees and overseeing the key functions of the utility. Toronto Hydro relies on this strategy to fill supervisory positions, and for senior certified and skilled trades and designated and technical professionals positions. Despite the advantages of hiring from within (particularly to support succession planning), Toronto Hydro cannot rely on this strategy for entry level positions, and cannot rely on this option alone to fulfill retirement vacancies because the utility does not have a sufficient pool of employees. Between 2015 and 2017, approximately 40 percent of vacancies were filled internally, 75 percent of which were internal promotions to more senior leadership roles.

5.2 Hire from the External Market

This approach entails going to market to hire the skilled and experienced resources that the utility requires over the next five to ten years. To the extent that the external market has an available pool of qualified candidates, this option would allow the utility to meet its human resource needs. However, because of the complexity of its

distribution plant and dynamic operating conditions, it is challenging for Toronto Hydro to hire skilled labour without investing in training and development. For example, an experienced CPLP from the external market would require one year of additional on-the-job training to become fully competent to work on Toronto Hydro's plant. Due to the lack of qualified candidates in the job market, hiring skilled labour is not an optimal strategy in and of itself, especially for Certified and Skilled Trades positions.

5.3 Hire New Graduates

The third option is to hire new graduates and rely on the utility's training and apprenticeship programs to instill the specialized skills and knowledge that they require to safely work on the distribution system. This is a reliable source for skilled entry level positions. Further, it allows Toronto Hydro to develop and maintain a dependable workforce that is capable of servicing the operational needs well into the future. However, the utility cannot rely on this option alone, as the utility is limited by the ability to safely absorb and integrate apprentices in practice.

Toronto Hydro collaborates with colleges and universities (e.g. Ryerson University and Georgian College) that offer academic programs aligned to entry level qualifications for Certified and Skilled Trades and Designated and Technical professionals. Investments continue in these areas with a focus on institutions within Toronto to develop a pipeline of talent situated within the utility's geographic service territory and to mitigate risks of talent loss to neighbouring comparators. Such collaborations are valuable because they allow Toronto Hydro to:

- influence and shape the programs and curricula to better match the utility's strategic goals and long-term needs;

- spread awareness about the utility's career prospect and human resource requirements; and
- build recruitment relationships with future graduates.

As an example, Toronto Hydro's partnership with Georgian College yielded 53 recruits since its inception in 2011 (including 32 certified and skilled trades, 18 designated and technical professionals and three administrative and support). Toronto Hydro expects to continue to leverage it alliances with universities and colleges to recruit new graduates in the coming years.

Toronto Hydro's commitment to hiring apprentices requires careful planning to enable efficient and effective execution. This includes hiring proactively to ensure that apprenticeships, which can be as long as six years, are completed in time to replace expected retirements or other exits. To minimize the total cost of the apprenticeship process, recruits are typically hired in cohorts. From a talent attraction perspective, aligning recruitment activities with post-secondary graduation cycles ensures the utility access to the broadest range of qualified applicants to fill available opportunities.

5.4 Use Third-Party Service Providers

Outsourcing Toronto Hydro's workforce requirements to third-party service providers is another approach employed by the utility. In many cases, third-party service providers enable the utility to cost-effectively ensure resource availability to meet peak demands, maintain flexibility in operations, and gain access to specialized expertise. The utility endeavours to optimize the selection of third-party services providers by assessing overall value and performance, looking to cost, safety, skills, and experience as some of the factors in selecting the provider for a given program or project.

5.5 Development Strategy

Toronto Hydro's workforce development strategy focuses on in-house training to cultivate skilled apprentices, technical staff, and leaders. Due to the complexity of the utility's distribution system, the aging workforce challenges over the next five to ten years, and the need for sustained capital investment to renew its infrastructure, Toronto Hydro must resource these positions from within. To do so, the utility relies on a robust talent pool for entry-level certified and skilled trades and designated and technical professional positions, and requires funding to accelerate its training and development programs. In the long-term, this strategy helps to ensure that Toronto Hydro has the resources it requires to perform core activities, fulfill future leadership requirements and satisfy key obligations.

As summarized in Table 6 below, from 2015 to 2017, Toronto Hydro administered more than 400 training and development programs. While many of these programs were targeted at developing the specialized skills sets required to work on Toronto Hydro's distribution system, the utility also leveraged its training facilities to deliver a variety of legislative and compliance programs. For more information about these initiatives, refer to the Human Resources and Safety Program at Exhibit 4A, Tab 2, Schedule 15.

Table 6: Training and Development Programs (2015-2017)

Area	2015 Courses	2016 Courses	2017 Courses
Compliance (e.g. Environmental and Safety legislative training, EUSA and ESA Rules, Confined Space, Work Protection Code, Network Switching)	63	41	49
Legislative (e.g. WHMIS, Defensive Driving, Forklift Training)	44	33	48
Apprentice	30	42	22

Area	2015 Courses	2016 Courses	2017 Courses
(e.g. Distribution Systems Technologist, Power Systems Controllers, Certified Power Cable Persons, Certified Power Line Persons, Meter Mechanics)			
Leadership (e.g. Safety Leadership, Performance Management, Management Control & Reporting System, Project Management, Policy Administration)	9	4	6
Technical & Customer Service Training (e.g. Engineering Technicians, Electrical Awareness, Project Execution, Customer Education Training)	28	30	32
Total	**174**	**150**	**157**

The apprenticeship program is a key aspect of the Toronto Hydro's workforce development strategy because it enables the utility to train and develop employees with required specialized skills including Certified Power Cable Persons, who work on the underground system (see Figure 8 below), and Distribution Station Technologists, who operate and maintain equipment in the stations.



Figure 8: Underground Cable Chamber in Toronto Hydro's System.

Toronto Hydro initiated the apprenticeship program in 2003, when the utility recognized that basic training acquired externally by crews was insufficient to enable them to work safely and efficiently in Toronto Hydro's system. For example, Figure 8 shows a complex underground cable chamber that is common in Toronto Hydro's distribution system.

Between 2003 and 2017, Toronto Hydro admitted over 300 apprentices to the program and retained approximately 80 percent of these individuals as full-time employees. Table 7 summarizes the number of certified and skilled trades, as well as Engineering Technologists and Engineers that the utility developed through its apprenticeship programs, and retained as full-time employees, as of year-end 2017.

Table 7: Apprenticeship Program Summary (as of December 31, 2017)

	CPLP	DST	Meter Mechanic	PSC	CPCP	ETL	Engineer	Total
Apprentices	122	49	14	50	77	115	80	**507**
# Retained	91	45	11	35	63	97	63	**405**
% Retained	74.6	91.8	78.6	70.0	81.8	84.3	78.8	**79.9**

To prepare for expected retirements over the next five to ten years, Toronto Hydro plans to admit over 100 individuals to the apprenticeship program during the 2018-2020 timeframe. It plans to hire apprentices in a staged approach (as outlined in Table 8 below), to facilitate workforce renewal in a safe and effective way, while ensuring knowledge transfer and maintaining productivity.

The staged approach allows for new entrants to be safely absorbed and integrated into Toronto Hydro's workforce with the appropriate training, supervision and mentoring on Toronto Hydro with respect to the utility's practices, procedures, and standards. It also allows for supervision and mentoring practices to be undertaken without jeopardizing

the utility's objectives or ability to safely and effectively deliver its capital and maintenance work programs.

Table 8: Apprenticeship and Technical Hiring Plan (2020-2024)

Apprentice Group	2020	2021	2022	2023	2024	Total
CPCP/CPLP	32	20	18	20	18	**108**
DST	2	5	5	5	5	**22**
PSC	3	5	5	5	5	**23**
Certified Meter Mechanic	4	2	2	2	2	**12**
Engineering Technologist	2	5	5	5	5	**22**
Engineer	0	1	2	0	1	**4**
Total	**43**	**38**	**37**	**37**	**36**	**191**

COMPENSATION STRATEGY AND WORKFORCE GOVERNANCE

This schedule discusses Toronto Hydro's compensation strategy and workforce governance practices. Further to the information outlined in OEB Appendix 2-K (Employee Costs/Compensation Table) at Exhibit 4A, Tab 4, Schedule 2, this schedule provides an overview of Toronto Hydro's compensation costs and practices, and pension and benefit programs and costs. The evidence is organized as follows:

1) Compensation Costs Overview;
2) Compensation Strategy and Workforce Governance;
3) Compensation Practices for Non-Union Employees;
4) Compensation Practices for Bargaining Unit Employees; and
5) Benefits and Pensions.

1. COMPENSATION COSTS OVERVIEW

Table 1 below summarizes Toronto Hydro's total compensation costs, which include base salary wages, overtime and incentive payments, and actual and accrued benefits.

Table 1: Total Compensation ($ Millions)

Year	2015 Actual	2016 Actual	2017 Actual	2018 Test	2019 Test	2020 Test
Management (including executive)	15.9	18.1	19.2	19.6	20.3	21.0
Non-Management (union and non-union)	195.2	194.3	197.3	206.3	215.2	223.2
Total	**211.1**	**212.4**	**216.4**	**225.9**	**235.5**	**244.2**

Over the 2015 to 2020 period, Toronto Hydro is making measured investments to continue its workforce renewal in the face of demographic challenges and in the context

of its proposed capital and operational plans. The utility is facing a significant wave of retirements into the 2020 to 2024 period (see Exhibit 4A, Tab 4, Schedule 3). It is also proposing to continue with significant capital program investments from 2020 to 2024. For more information on Toronto Hydro's workforce challenges and capital work program, refer to Exhibit 4A, Tab 4, Schedule 3 and Exhibit 2B, respectively.

Underpinning the utility's compensation costs is a compensation strategy that balances cost-effectiveness and the need to attain and retain the talent required to operate the utility in an increasingly complex and dynamic industry. According to Mercer, Toronto Hydro's total compensation is, on aggregate, below the general industry market and aligned with its energy sector peers.

Toronto Hydro's forecast compensation costs for 2020 are consistent with recent historical actuals prior to 2015, demonstrating its ability to manage costs in a financially responsible manner over the longer term. Compared to 2011, when total compensation costs were $234.6 million, the forecast for 2020 represents a compounded annual growth rate of 0.4 percent.[1] Relative to 2012 costs (i.e. following Toronto Hydro's corporate downsizing and restructuring), that rate is 1.6 percent.

As part of its workforce renewal efforts, Toronto Hydro continues to manage compensation costs to support Operations, Maintenance, and Administration ("OM&A") and capital programs. From 2015 to 2020, the utility's total cash compensation costs are increasing by a compounded annual growth rate of 2.5 percent, in line with findings

[1] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015), Exhibit 4A, Tab 4, Schedule 5.

from the recent Mercer Canadian Compensation Planning Survey.[2] Inclusive of benefits, which are discussed later in this schedule, the annual growth rate is 3.0 percent.

Both of the aforementioned annual growth rates are lower once normalized for changes in full time equivalent ("FTE") count. Over the same period, Toronto Hydro's workforce is expected to grow on average by 0.5 percent annually. As a result, the compounded annual growth rate in total cash compensation per FTE is 2.1 percent, and total compensation (inclusive of benefits) per FTE is 2.5 percent.

In preparing its 2018 to 2020 forecasts, Toronto Hydro considered the inflation rates set out in its collective agreements, as well as relevant labour market data. Toronto Hydro also considered other factors, such as the increasing scope and complexity of the utility's work plan over the next five years.

2. COMPENSATION STRATEGY AND WORKFORCE GOVERNACE

Toronto Hydro's workforce is the means by which the utility delivers service and value to its customers, carries out its objectives, and complies with mandatory obligations. The utility strives to secure and maintain a workforce that is skilled, adaptable, committed, and performance-driven. To achieve these key outcomes in a cost-effective manner, Toronto Hydro's strategy is to provide wages and benefits that are competitive in the markets where Toronto Hydro competes for talent. Toronto Hydro's strategy also includes offering a compensation program that aligns the behaviour and performance of the workforce with the core objectives and goals of the utility. The utility's compensation program is therefore an important tool for communicating performance expectations, fostering productivity, and rewarding employees for their contributions.

[2] Mercer, 2017/18 CA Compensation Planning Survey Report (August, 2017).

2.1 Market-Competitive

Toronto Hydro's compensation strategy aims to strike a balance between controlling costs and providing market-competitive compensation. In doing so, the utility examines the reasonableness and effectiveness of its compensation program in alignment with industry peers and relevant labour markets. Mercer defines "market-competitive" in its Non-Executive Compensation and Benefits Review as "within 10 percent of the target market positioning on a position-by-position basis."[3] Providing value to customers requires the utility to maintain the ability to attract, motivate, and retain employees who have the knowledge, skills, and ability that are critical to the utility's success.

Maintaining a market-competitive compensation program is essential to the utility's ability to complete its proposed work plan, achieve its performance objectives, and otherwise meet its obligations. The uniqueness and complexity of Toronto Hydro's distribution plant makes it challenging to hire skilled labour. The utility competes with other industries and organizations such as Alectra Utilities, Ontario Power Generation, and Hydro One, which also have a high demand for certified and skilled trades, designated and technical professionals, and supervisory and leadership positions.

Over the 2020 to 2024 period, Toronto Hydro expects to encounter additional constraints on the eligible and qualified talent pool and its retention capabilities as a result of a number of factors, including demographic trends and ongoing construction activity in the City of Toronto that could draw upon the same pool of qualified candidates (see Exhibit 4A, Tab 4, Schedule 3).

[3] *Supra* note 1, page 1.

The utility periodically reviews the external competitiveness of its compensation programs to help ensure that the level, form, and mix of compensation offered by Toronto Hydro is competitive with those provided for comparable jobs in the markets where the utility competes for talent. For example, in 2017, Toronto Hydro engaged an independent human resources consulting firm, Mercer, to undertake a detailed compensation and benefits benchmarking study**.** The results of the study indicate that the utility's cash compensation (base salary and performance pay) is generally aligned with the relevant markets (see Exhibit 4A, Tab 4, Schedule 5).

Toronto Hydro reviews the market-competitiveness of its compensation packages for non-union employees as part of its annual business planning and budgeting process. This can include participating in compensation salary surveys offered through independent consulting firms that specialize in the compilation of aggregate compensation data.

2.2 Performance-Based Compensation

Part of Toronto Hydro's strategy is to compensate employees based on their actual performance outcomes. In particular, Toronto Hydro's performance management program aligns the capabilities and competencies of its workforce with the core objectives and goals of the utility, which are embodied in the four pillars outlined in Figure 1 below. Based on its corporate competencies (see Table 2 below), Toronto Hydro's philosophy is to direct its workforce in an integrated fashion, and encourage employees to demonstrate certain behaviours and achieve defined performance expectations. Over the past ten years, this philosophy has underpinned Toronto Hydro's achievements in areas such as customer energy savings and safety.

The utility's performance pay model includes individual, divisional, and corporate components. Performance measures are developed annually and reviewed regularly to ensure alignment and achievement of objectives. Table 2 below lists the competencies and descriptors that the utility relies upon to attain these core objectives.



Figure 1: Toronto Hydro's Corporate Areas of Focus

Table 2: Toronto Hydro's Workforce Competencies and Descriptors

Workforce Competencies	Workforce Descriptors
Drives Results & Accountability	• Has a clear sense of corporate direction and expectations, and holds self and others accountable to achieve objectives.
Demonstrates Customer-Focus	• Models customer-focussed approach in all decisions and actions.
Builds Strong Relationships	• Builds valuable relationships across the organization and externally to support the future of Toronto Hydro.
Develops Culture & People	• Recognizes personal development and a strong organizational culture as integral components of an effective organization.

Workforce Competencies	Workforce Descriptors
Champions Change, Productivity & Innovation	• Prioritizes in innovation, continuous improvement, and productivity as essential drivers of long-term sustainability.
Demonstrates Commitment to Environment, Health & Safety	• Manages risks to protect the health and safety of employees and the public, and shows commitment to sustainability.

Toronto Hydro's corporate competencies guide all areas of human resource management:

- **Recruitment and Selection**: Toronto Hydro uses the corporate competencies in developing the recruitment process for a particular position and takes the competencies into consideration as part of the selection criteria.
- **Training and Development**: The corporate competencies underpin the utility's training initiatives. As an example, if Toronto Hydro determines through the performance management process that an individual or team lacks in the customer focus competencies, an assessment of training needs would be performed. Based on the results, an appropriate customer awareness training program would be implemented to assist in closing this gap.
- **Performance Management and Compensation**: The corporate competencies are integrated with Toronto Hydro's compensation practices. For non-union employees, this occurs through the assignment of performance ratings, which evaluate employees' performance in relation to the corporate competencies. The performance rating is one of the components that determine the base salary increase. For unionized employees, Toronto Hydro uses performance assessments to determine base step increases for employees with a solid performance rating that are not at the top of the defined salary range.

- **Succession Planning and Promotion**: Decisions on succession planning and promotion focus on developing employees who consistently meet the corporate competencies, as indicated by their annual performance ratings.

3. COMPENSATION PRACTICES FOR NON-UNION EMPLOYEES

Toronto Hydro provides non-unionized employees with a total cash compensation package comprised of two elements: base salary and variable performance pay. Base salary compensates an employee for meeting the expectations related to their responsibilities, accountabilities, and technical skills, while variable performance pay rewards employees for their contribution to the achievement of goals and objectives tied to the utility's strategic pillars in combination with their successful demonstration of corporate competencies.

Each non-union position at Toronto Hydro has a salary grade/level with a corresponding salary range. To maintain alignment with the competitive labour market, the utility adjusts salary ranges based on annual market reviews.

Non-union employees receive a portion of their annual compensation through the variable performance pay program. This program is an incentive performance-based compensation tool designed to retain, motivate, and reward employees for reaching performance objectives, which are established at the beginning of each calendar year. Each employee's variable performance pay is based on a weighting of performance objectives, which are measured by Key Performance Indicators, and by individual goals set out in the employee's annual performance contract.

4. COMPENSATION PRACTICES FOR BARGAINING UNIT EMPLOYEES

Approximately two-thirds of Toronto Hydro's employees belong to collective bargaining units represented by the Power Workers' Union ("PWU") or the Society of Professional Engineers ("Society"). Toronto Hydro's compensation costs with respect to these employees are negotiated through periodic collective bargaining. The utility is obligated to bargain in good faith with the unions, pursuant to section 17 of the *Ontario Labour Relations Act, 1995*,[4] and has a contractual and statutory obligation[5] to honour the terms of its collective bargaining agreements.

Toronto Hydro's bargaining interests are focused on changes that support the organization's ability to safely execute capital and operational programs in an efficient and cost effective manner while preserving management's rights to manage and direct the workforce. The most recent round of bargaining that the utility engaged in with PWU resulted in a 2.3 percent average wage increase over four years. Toronto Hydro focused on achieving a negotiated settlement that was fair and reasonable for its employees, while continuing to provide safe, efficient service to its customers.

The utility regularly reviews external compensation data to understand the compensation landscape both at the time of negotiation and in the years preceding and following bargaining. In doing so, the utility monitors bargaining trends and reviews past settlements. In preparation for the most recent round of bargaining with PWU, the utility also commissioned a compensation study by an independent third party, Mercer. For the results of this study, refer to the report filed at Exhibit 4A, Tab 4, Schedule 5.

[4] S.O. 1995, C. 1, Sched. A, section 17. ["*Ontario Labour Relations Act*"]
[5] *Ontario Labour Relations Act,* section 56.

4.1 PWU Collective Agreement

The current collective agreement with PWU was effective as of February 1, 2018 and is valid until January 31, 2022. Table 3 below summarizes the year-over-year percentage increases in base salary under the previous (i.e. CUPE) and current collective agreement.

Table 3: CUPE/PWU Base Salary Increases (2015-2020)

2015	2016	2017	2018*	2019	2020
1.75%	1.75%	2.0%	2.3%	2.3%	2.3%

*New collective agreement effective February 1, 2018 until January 31, 2022.

Toronto Hydro achieved stability through a long-term agreement, maintaining management's right to manage and direct the workforce. In negotiating the wage rate increases outlined above, Toronto Hydro considered: (i) the OEB's fourth Generation IRM inflation parameters, which were released in November 2013 and are updated annually; [6] and (ii) the Mercer Non-Executive Compensation and Benefits Review (Exhibit 4A, Tab 4, Schedule 5). Based on these key considerations, Toronto Hydro's bargaining position was to maintain market positioning.

4.2 Society Collective Agreement

The utility's current collective agreement with the Society came into effect January 1, 2016 and is valid until December 31, 2019. Table 4 below summarizes the year-over-year base salary percentage increases for Society employees.

Table 4: Society Base Salary Increases (2016-2020)

2016	2017	2018	2019	2020
1.25%	1.25%	1.50%	2.0%	N/A

[6] EB-2010-0379 Report of the Board Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors (Issued November 21, 2013 and corrected on December 4, 2013).

Toronto Hydro was able to achieve the following objectives during its 2016 negotiations with the Society:

- Ensure workforce stability and productivity through a long term agreement;
- Contain current and future costs through modest wage rate increases;
- Continue the development of employees;
- Maintain management's right to manage and direct the workforce; and
- Clarify the contractual process that applied to wage scale progression.

For the purpose of these negotiations, Toronto Hydro considered comparable market data, which was collected through a review of external surveys and external compensation data. Toronto Hydro compared base salary and variable performance pay against information from companies within the utility sector. As a result of these analyses, Toronto Hydro's position was that year-over-year increases had to stay close to inflation in order to maintain alignment with the market.

Employees who are part of the Society are also eligible for variable performance pay based on their achievement of the deliverables outlined in their annual performance contract, as well as the achievement of the utility's performance objectives.

5. BENEFITS AND PENSIONS

Toronto Hydro's employee benefits include the following:

- Medical insurance, including vision care, prescription drugs, and paramedical services;
- Dental insurance, including major dental and orthodontic services;
- Short-term disability ("STD") and long-term disability ("LTD") income protection;

- Life insurance and accidental death and dismemberment ("AD&D") insurance; and
- Refundable expenses, such as the fitness reimbursement program;

Related benefits costs paid by Toronto Hydro include employer contributions for the following:

- Workplace Safety and Insurance Board ("WSIB") premiums;
- Pension contributions;
- Canadian Pension Plan contributions;
- Employment Insurance contributions; and
- Employer Health Tax contributions.

All contributions aside from pensions are required under Canadian law.

The historical and forecasted cost of employee benefits are summarized in Table 5.

Table 5: Employee Benefit Costs (2015-2020) ($ Millions)

	2015	2016	2017	2018	2019	2020
Employee Benefit Total Cost	52.8	52.1	53.3	55.7	59.5	64.8

Toronto Hydro periodically reviews the trends and costs associated with its benefit programs to help ensure that the utility receives value for its money, and that the program is aligned with the relevant labour markets.

In 2017, Toronto Hydro retained Mercer to conduct a review of its compensation and benefits programs (see Exhibit 4A, Tab 4, Schedule 5). In this study, Toronto Hydro's market position for employer paid benefits was reviewed in two parts: active benefits

(e.g. life insurance, AD&D, STD, LTD, Health and Dental, Health Care Spending Account) and employer pension contributions. Mercer found that both of these components are generally aligned to the energy peer group. When looking at Toronto Hydro's positioning for employer pension contributions, the overall market (which includes Defined Benefit and Defined Contribution plans) should be considered since many of the comparators have Defined Contribution plans. Relative to the overall market, Toronto Hydro is positioned more competitively than against the subset of peers with Defined Contribution plans.

Toronto Hydro strives to minimize the cost of its benefit offerings. For example, in 2017, Toronto Hydro conducted a benefits provider market review, which resulted in an estimated annual savings of over $250,000 in premiums with no coverage impact for employees. The team continues to negotiate with benefit providers to effectively manage costs while continuing to provide a market-competitive program and ensuring awareness by plan members regarding their benefits plan.

In addition to the benefits program, Toronto Hydro has a number of Health and Wellness initiatives, including an Employee Assistance Program that provides employees and their dependents with access to work-life/wellness resources (e.g. support for mental health, financial planning, and relationship counselling). Through these initiatives, Toronto Hydro aims to promote employee health and well-being, increase productivity in the workplace, and minimize healthcare costs. These initiatives contribute to Toronto Hydro's corporate attendance (which improved by 32 percent from 2013 to 2017) and safety performance (which improved by 68 percent from 2011 to 2016 as measured by total recordable injury frequency).

Toronto Hydro also provides a pension for fulltime employees through its membership in the Ontario Municipal Employees Retirement System ("OMERS"), a multi-employer defined benefit pension plan. Both participating employers and their employees are required to make contributions to the plan. The required contribution rates are based on the employee's earnings, and are periodically reviewed by the OMERS Sponsors Corporation relative to the assets and obligations of the plan.

Decisions on contribution rates are guided by the Funding Management Strategy developed by OMERS Sponsors Corporation. Table 6 below summarizes the contribution rates (historical and forecasted) over the 2015 to 2020 period. OMERS has confirmed that the contribution rates for 2019 will remain unchanged, but has not yet determined the 2020 contribution rates. Toronto Hydro expects that there will be no changes to the contribution rates for 2020, which will be confirmed.

Table 6: OMERS Contribution Rates (2015-2020)

	2015	2016	2017	2018	2019	2020
Employer Rate	9.0% up to YMPE 14.6% over YMPE	9.0% up to YMPE 14.6% over YMPE	9.0% up to YMPE 14.6% over YMPE	9.0% up to YMPE 14.6% over YMPE	9.0% up to YMPE 14.6% over YMPE	9.0% up to YMPE 14.6% over YMPE
Employee Rate	9.0% up to YMPE 14.6% over YMPE	9.0% up to YMPE 14.6% over YMPE	9.0% up to YMPE 14.6% over YMPE	9.0% up to YMPE 14.6% over YMPE	9.0% up to YMPE 14.6% over YMPE	9.0% up to YMPE 14.6% over YMPE

Participating employees and employers contribute to OMERS at a lower tier rate on earnings up to the Yearly Maximum Pensionable Earnings ("YMPE"), and a higher tier rate on earnings above the YMPE. The YMPE is the Canada Pension Plan ("CPP") earnings limit (i.e. contributions to the CPP are made on earnings up to this limit). The

OMERS contribution rate is lower up to the YMPE because OMERS is designed to work together with CPP to provide combined pension benefits.

Table 7 below summarizes Toronto Hydro's historical (2015-2017) and forecasted (2018-2020) pension costs, including capitalized and expensed amounts each year.

Table 7: Pension Costs (2015-2020) ($ Millions)

	2015	2016	2017	2018	2019	2020
Pension Contributions	16.9	16.8	16.9	18.4	19.2	19.6
Less: Amount Capitalized	7.3	7.1	7.7	8.1	8.5	8.7
Amount Expensed in Each Year	9.5	9.8	9.2	10.3	10.7	10.9

In addition to pension benefits, Toronto Hydro pays certain medical, dental, and life insurance benefits on behalf of its retired employees. An actuarial analysis using the projected unit credit method determines the cost of these benefits. This method incorporates Toronto Hydro's best estimate of future salary levels, retirement ages of employees, health care costs, and other actuarial factors. The latest actuarial valuation was performed by Willis Towers Watson based on information current as if January 1, 2016, and forecasts of post-employment benefit costs are based on extrapolations of those results (see Exhibit 4A, Tab 4, Schedule 6).

Table 8 below presents Toronto Hydro's historical (2015-2017) and forecasted (2018-2020) post-employment benefit costs, including capitalized and expensed amounts.

1 **Table 8: Post-employment Benefit Costs (2015-2020) ($ Millions)**

	2015	2016	2017	2018	2019	2020
Benefit Costs	17.7	15.3	18.0	15.3	15.7	16.0
Capitalized Amounts	7.7	6.4	8.1	6.9	7.0	7.2
Expensed Amounts	10.0	8.9	9.9	8.4	8.7	8.8

HEALTH WEALTH CAREER

NON-EXECUTIVE COMPENSATION AND BENEFITS REVIEW

JANUARY 2018

Toronto Hydro-Electric Systems Limited

CONFIDENTIAL – NOT FOR DISTRIBUTION

INTRODUCTION AND EXECUTIVE SUMMARY

Mercer Canada Limited ("Mercer") has been engaged by Toronto Hydro-Electric Systems Limited ("Toronto Hydro") to complete a market review of compensation and benefits program competitiveness for non-executive management, non-union professional and union positions within Toronto Hydro.

The purpose of this review is to provide an independent, market-based assessment of the market positioning of Toronto Hydro's non-executive total remuneration that includes base salary, short-term incentives, total cash compensation, active employee benefits, and pensions relative to the markets Toronto Hydro competes with for talent. Toronto Hydro employee groups considered include non-executive management and non-union professionals, as well as those positions represented by the Power Workers Union ("PWU") and the Society of Professional Engineers ("Society").

EXECUTIVE SUMMARY

This review approach is consistent with Mercer's standard market benchmarking methodologies, and relies on compensation and benefits practices information provided by Toronto Hydro, in addition to Mercer's proprietary compensation databases. Market comparisons are made to a group of peer organizations, selected by Mercer and confirmed by Toronto Hydro, that are representative of the energy and general industry sectors Toronto Hydro competes with for talent.

In conducting the compensation analysis, Mercer worked together with Toronto Hydro to identify benchmark positions to compare to market that represent a valid cross sample of the organization's functions and levels. The breadth of benchmark positions selected is within the range of 50% to 75% of employees considered best practice when benchmarking on an organization basis. The benchmarking includes positions that represent approximately 56% of employees at Toronto Hydro.

On an overall organization basis, Toronto Hydro's total remuneration, including the value of all cash compensation, benefit and pension plans are positioned within a market competitive range relative to the 50th percentile of the energy market, and are below the general industry market. The general industry market is generally representative of publicly traded, for-profit organizations. Competitive positioning varies by job and by level within Toronto Hydro. Management and professional positions are generally positioned competitively against the 50th percentile of the energy sector and at or below the market 50th percentile against the general industry due to the availability of long-term incentives and higher short-term incentives in the general industry. Society and PWU represented roles are generally positioned competitively against the energy sector, and are reflective of energy sector specific positions.

Mercer considers compensation levels to be within a "competitive range" if they fall within 10% of the target market positioning on a position-by-position basis (where you have a smaller sample size and higher variability in observations) and 5% on an overall organization basis (where you have a larger

sample size and smaller variability in observations) when compared to target positioning (e.g., the 50th percentile).

METHODOLOGY

Mercer worked with Toronto Hydro to determine the appropriate markets and organizations for comparison given the organizations they compete with for talent (i.e., organizations that Toronto Hydro might reasonably recruit employees from or lose employees to) and that are comparable in scope or type of operations. Two specific peer groups were identified for the purposes of the compensation and benefits review:

- **Energy Peer Group**
  - Reflects select Canadian organizations from Mercer's Total Compensation Survey ("MTCS") and proprietary custom surveys with energy industry-specific roles
  - Organizations were selected considering the comparability of their operations, relative size of revenues and full-time employee equivalents when compared to Toronto Hydro, resulting in a peer group primarily consisting of other energy utilities
- **General Industry Peer Group**
  - Reflects select for-profit Canadian Organizations from Mercer's Benchmark Database ("MBD") that includes general industry roles and organizations located in the Greater Toronto Area ("GTA")
  - Aligned with Mercer's standard benchmarking methodology, organizations are generally within ½ to 2x the size of Toronto Hydro on the basis of annual revenue
  - Where required to provide statistically significant market information for a specific position, the peer group is expanded to include Canadian general industry.

A listing of organizations that belong to each of these peer groups for the purposes of either cash compensation, benefits or pension benchmarking is presented in ***Appendix A****.*

A sample of Toronto Hydro's jobs across all grades was benchmarked against equivalent roles within organizations from the defined peer groups. Equivalences were determined on the basis of overlaps in responsibilities between Toronto Hydro and survey position descriptions.

- 49 management jobs at Toronto Hydro were matched to equivalent survey jobs and levels in the two peer groups.
- 10 collective bargaining jobs were matched to equivalent survey jobs and levels in the energy peer group, as positions are generally energy industry specific in their responsibilities

Mercer's benchmarking objective with this review is to map a reasonable sample of Toronto Hydro's positions that best represent the total employee population across the different job levels in the organization. With this approach, our analysis includes 265 of the 582 management and professional employees and 531 of the 850 bargaining unit positions to make up 56% of the total population considered in-scope for this review. Mercer believes this to be a statistically reliable and

representative sample for assessing the competitive levels of total remuneration for Toronto Hydro's employees.

A listing of the specific Toronto Hydro benchmark positions matched to market as part of this review is presented in ***Appendix B****.*

Cash compensation levels tend to be aligned with the scope and complexity of the individual position and as such, to the extent possible, Mercer analyzed market data specific to the individual position. Benefit and pension programs tend to be common to all participants within a defined group and, as such comparisons to market are made on a plan or aggregate basis for each employee group (e.g., management, Society, PWU, etc.).

For the retirement and benefits program review, Mercer similarly benchmarked Toronto Hydro against the energy peer group and general industry peer groups for organizations available in the Mercer Plan Design databases considering their relative **employer provided value** ("EPV"). Relative value analysis focuses only on the plan design as it sets all other cost drivers at a common level and is more consistent when comparing the value of the benefit programs of several organizations.

We note how benchmarking Total Value (TV) compares to Employer Provided Value (EPV) for the benefits analysis:



The relative value benchmarking results are presented as a percentage of base salary using a base salary of $100,000 and bonus of 10% of base salary. Plans for all comparator organizations have been valued using the same earnings information and composite workforce profile. Using different earnings levels would change the dollar value of the benefit, but any change in relative value of the plan amongst the participants would not, in Mercer's opinion, be material.

As each element of the total remuneration package serves a different role, and companies may choose to offer a different pay mix in order to accomplish different objectives, Mercer recommends Toronto Hydro consider the competitiveness of its total remuneration package as a whole (considering total remuneration) rather than the competitiveness of each individual compensation element. In order to provide a complete picture, report findings and observations are presented for separate compensation elements as well as aggregate total remuneration.

All compensation data is reflective of the most recently available data as of the completion of the analysis, and is presented effective for 2017.

SUMMARY OF FINDINGS

Our commentary describes the competitiveness of Toronto Hydro's base salary, short-term incentive, total cash compensation and total remuneration at an aggregate level for each grade in the organization, relative to the 50th percentile of the respective market. Based on Mercer's compensation practices and policy research, the majority of organizations target compensation at the 50th percentile of their competitive market, which balances fiduciary and cost considerations with the need to attract and retain talent.

- As discussed above, Mercer considers Toronto Hydro to be within the competitive range if they fall within 10% of the target market positioning on a position-by-position basis and 5% on the overall organization basis.
- Market figures are presented where there is sufficient data to show the 50th percentile (Conversely, insufficient data is denoted by a "-").

The table below presents Toronto Hydro's **base salaries, target STI, target total cash compensation (TTC)** and **total remuneration (TRem)** at an aggregate level, compared to the market 50th percentile across the two peer groups:

All dollar figures presented in $000's

	Toronto Hydro				Energy Peer Group				General Industry Peer Group			
Grade	Base Salary ($)[1]	Target STI (%)	TTC ($)[2]	TRem ($)[3]	Base Salary ($)[1]	Target STI (%)	TTC ($)[2]	TRem ($)[3]	Base Salary ($)[1]	Target STI (%)	TTC ($)[2]	TRem ($)[3]
Z	$197	25%	$246	$291	$183	20%	$198	$232	$232	30%	$307	$411
					8%	*5%*	*25%*	*26%*	*-15%*	*-5%*	*-20%*	*-29%*
Y3	$162	25%	$203	$240	$199	23%	$247	$301	$211	20%	$249	$316
					-19%	*3%*	*-18%*	*-20%*	*-23%*	*5%*	*-18%*	*-24%*
Y2	$147	20%	$177	$210	$148	15%	$165	$194	$167	22%	$207	$256
					-1%	*6%*	*7%*	*8%*	*-12%*	*-2%*	*-14%*	*-18%*
Y1	$133	13%	$150	$178	$147	14%	$169	$184	$156	20%	$180	$202
					-10%	*0%*	*-11%*	*-3%*	*-15%*	*-6%*	*-17%*	*-12%*
W4	$121	10%	$133	$159	$131	13%	$150	$171	$153	19%	$187	$223
					-7%	*-3%*	*-11%*	*-7%*	*-21%*	*-9%*	*-29%*	*-29%*
W3	$114	10%	$125	$150	$131	15%	$146	$170	$124	16%	$139	$154
					-13%	*-5%*	*-14%*	*-12%*	*-8%*	*-6%*	*-10%*	*-2%*
W2	$104	8%	$112	$136	$86	-	$96	$116	$87	8%	$94	$109
					22%	*-*	*17%*	*18%*	*20%*	*0%*	*19%*	*25%*
V4	$117	8%	$126	$150	$123	-	$136	$156	$114	15%	$128	$142
					-5%	*-*	*-7%*	*-4%*	*2%*	*-7%*	*-1%*	*5%*
V3	$110	8%	$119	$141	$105	9%	$117	$140	$107	14%	$117	$132
					5%	*-1%*	*2%*	*1%*	*3%*	*-6%*	*1%*	*7%*
V2	$101	8%	$109	$131	$94	10%	$102	$121	$103	13%	$112	$126
					8%	*-2%*	*7%*	*8%*	*-2%*	*-5%*	*-2%*	*4%*
V1	$91	8%	$98	$118	$91	8%	$98	$115	$93	11%	$101	$113
					0%	*0%*	*0%*	*3%*	*-2%*	*-3%*	*-3%*	*4%*
U3	$81	6%	$85	$103	$86	-	$86	$101	$77	10%	$79	$91
					-7%	*-*	*-1%*	*2%*	*4%*	*-4%*	*8%*	*13%*
U2	$73	6%	$78	$94	$78	7%	$82	$97	$71	7%	$79	$91
					-5%	*-1%*	*-5%*	*-4%*	*3%*	*-1%*	*-1%*	*3%*
U1	$66	6%	$70	$85	$74	7%	$79	$93	$74	9%	$78	$88
					-11%	*-1%*	*-12%*	*-9%*	*-11%*	*-3%*	*-10%*	*-3%*
T1	$52	6%	$55	$67	$64	7%	$69	$80	$57	8%	$60	$70
					-18%	*-1%*	*-20%*	*-16%*	*-8%*	*-2%*	*-8%*	*-3%*
SOCIETY	$114	8%	$123	$146	$99	-	$106	$129	-	-	-	-
					15%	*-*	*16%*	*13%*	*-*	*-*	*-*	*-*
PWU	$97	-	$97	$116	$89	-	$90	$105	-	-	-	-
					9%	*-*	*8%*	*10%*	*-*	*-*	*-*	*-*
Overall					**98%**		**99%**	**100%**	**91%**		**89%**	**89%**

(1) Toronto Hydro base salary reflects salary structure job rates
(2) Toronto Hydro target total cash ("TCC") reflects salary structure job rates plus target short-term incentives
(3) Total remuneration ("TRem") reflects target total cash compensation plus the value of long-term incentives, pensions and benefits
Note: Figures are rounded to the nearest thousand (dollars) or percent

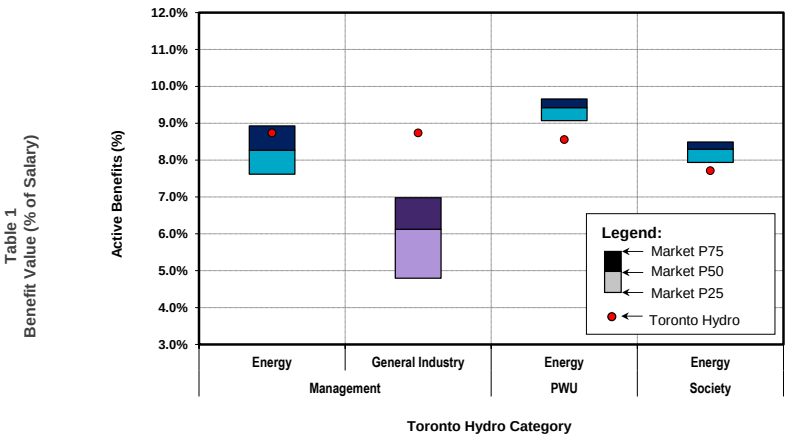
Overall, Toronto Hydro's compensation program, on a **total remuneration** basis, is closely aligned with the 50th percentile market pay levels of the energy peer group, the most comparable peer group given relative roles and responsibilities, and is at or below a market competitive level relative to the general industry peer group. Few grades, including Y3 and W2, are consistently outside of the competitive range relative to both the energy peer group and general industry peer group.

On **base salaries** for union and non-unionized positions, Toronto Hydro is generally competitive, except for the Y3, Y1, W2 and U1 salary grades that are outside of the competitive range relative to both the energy peer group and general industry peer group. The W2 salary grade with the supervisory positions exceeds the market median due to upward pay pressures between management and directly supervised unionized positions. Society represented positions roles are paid above the competitive range relative to the energy peer group.

Market eligibility for **short-term incentives** ("**STI")** is generally more prevalent for positions on the team lead level and above (i.e., close to 100% eligibility for jobs benchmarked to the W4 grade level and above). In comparison, Toronto Hydro offers incentive pay for all positions, except for the PWU represented positions. On STI, Toronto Hydro is slightly below market competitiveness.

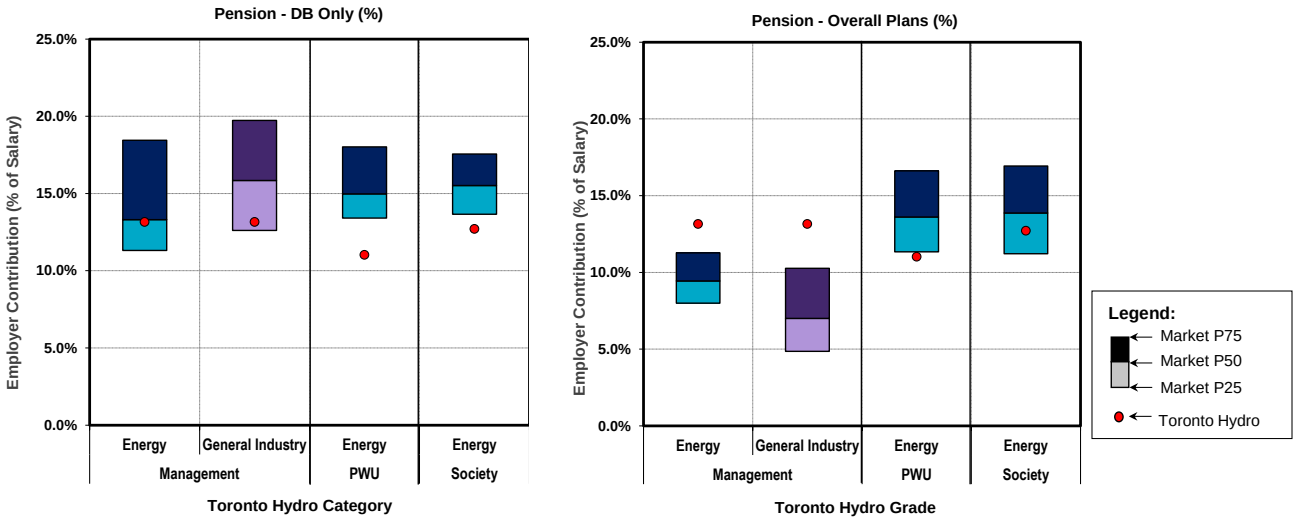
Overall, on **total cash compensation**, Toronto Hydro remains within the range of market competitiveness for the energy peer group but shifts lower in the general industry peer group due to below-market STI. Grades Y3, Y1, W4, W3, W2 and U1 are outside of a competitive range relative to both the energy peer group and general industry peer group. W2 grade total cash compensation continues to exceed the market median due to upward pay pressures between management and directly supervised unionized positions. Society represented positions roles are paid above the competitive range relative to the energy peer group.

To illustrate the impact of the benefits element on total remuneration, the tables below present Toronto Hydro's **active benefits (Table 1)** and **pension (Table 2)** value for each employee group considering employer-provided value, compared to the market 50th percentile across the two peer groups. We note that for pension value we focus on an employer-provided basis given a 50% cost share in the OMERS pension plan that impacts the actual value paid by the company.



When compared to the energy peer group, Toronto Hydro is generally within 2% of the market 50th percentile considering the overall value of active benefits (including life insurance, accidental death and dismemberment, short-term disability, long-term disability, health, dental and health-care spending accounts) across all employee groups. When compared to the general industry peer group, Toronto Hydro provides a top quartile active benefits plan.

Table 2



Toronto Hydro pension arrangements for management employees through OMERS are aligned with the 50th percentile of the employer provided value of other defined benefits (DB) plans among energy peer group companies. Many comparators have a fixed employee contribution, with the employer contributing the balance, positioning PWU and Society employer provided benefits in the first market quartile (up to the 25th percentile) relative to other organizations that provide a defined benefit plan among the energy peer group.

Many of the comparators provide a defined contribution plan. When defined contribution plans are taken into account to determine the overall market, Toronto Hydro pension arrangements for management, PWU and Society employee groups are positioned more competitively.

APPENDIX A

The following companies comprise the **energy peer group** used for the purposes of the review:

ENERGY INDUSTRY COMPARATOR COMPANIES	
AltaGas, Ltd. *	Hydro One Inc. *
AltaLink L.P. *	Manitoba Hydro *
ATCO Electric *	NB Power *
BC Hydro Power & Authority *	Newfoundland & Labrador Hydro Electric Corporation *
Bruce Power L.P. *	Nova Scotia Power (Emera, Inc.)
City of Medicine Hat (Hydro Division) *	Ontario Power Generation *
Enbridge Gas Distribution *	SaskEnergy Incorporated *
ENMAX Corporation *	SaskPower *
EPCOR Utilities *	Spectra Energy Transmission *
Fortis Inc.	TransAlta Corporation *
FortisAlberta Inc. *	TransCanada Corporation - Energy Group *
FortisBC Energy Inc. *	TransCanada Corporation - Pipelines Group *
FortisBC Inc. *	

(*) Energy companies from the Mercer Plan Design databases used in the benefits analysis

The following companies comprise the **general industry peer group** used in the review:

GENERAL INDUSTRY COMPARATOR COMPANIES	
3M Canada Company	General Dynamics Land Systems - Canada
Agrium, Inc. - Wholesale Group	La Coop fédérée
AltaGas, Ltd.	NOVA Chemicals Corporation
Bombardier Recreational Products, Inc.	Pacific Exploration & Production Corporation
CAE, Inc.	Parkland Fuel Corporation
Canadian Natural Resources, Ltd. - Horizon Oil Sands	Pembina Pipeline Corporation
ConocoPhillips Canada	Procter & Gamble, Inc.
Crescent Point Energy Corp.	Repsol Oil & Gas Canada Inc.
Dow Chemical Canada, Inc.	TransAlta Corporation
Encana Corporation	TransCanada Corporation - Pipelines Group
Encana Corporation - Encana Services Company, Ltd.	Volvo Group Canada, Inc.
ENMAX Corporation	Workers' Compensation Board - Alberta
GE Energy - GE Oil & Gas Drilling & Production Services	

APPENDIX B

Mercer worked closely with Toronto Hydro to select jobs that best represent the total employee population across the different job levels in the organization. The following 49 non-bargaining positions were included within the scope of the review:

#	TORONTO HYDRO POSITION	GRADE	#	TORONTO HYDRO POSITION	GRADE
1	General Manager, Design & Construction	Z	26	IT Architect, Database & Reporting	V4
2	Controller	Z	27	Strategic Planning Consultant	V3
3	Director, Regulatory Affairs	Y3	28	Senior Internal Auditor	V3
4	Director, Power System Services	Y3	29	Senior Financial Analyst	V3
5	Director, Legal Services & Corporate Secretary	Y3	30	Regulatory Counsel	V3
6	Director, IT Security & Ent Architecture	Y3	31	IT Technical Consultant	V3
7	Director, Environmental Health & Safety	Y3	32	Strategy & Enterprise Risk Management Consultant	V3
8	Manager, Rates	Y2	33	Employee/Labour Relations Consultant	V3
9	Manager, Project Management	Y2	34	EHS Consultant	V3
10	Manager, Program Support Office	Y2	35	Program Management Consultant	V2
11	Manager, Internal Audit	Y2	36	Communications Specialist	V2
12	Manager, Finance Services & Systems	Y2	37	Recruitment Consultant	V1
13	Manager, Commercial & Real Property Legal Services	Y2	38	Financial Analyst	V1
14	Manager, Call Centre	Y2	39	Quality Assurance Associate	U3
15	Manager, Regulatory Law	Y1	40	EHS Associate	U3
16	Manager, Facility & Building Security Operations	Y1	41	Payroll & Disbursements Analyst	U2
17	Supervisor, Control Centre	W4	42	Executive Assistant	U2
18	Supervisor, Project Execution	W4	43	ERM & Policy Administrative Analyst	U2
19	Lead, Project Management	W4	44	Law Clerk, Real Property	U1
20	Lead, Legal Services, Commercial	W4	45	IT Technical Support Analyst	U1
21	Supervisor, Supply Chain Services	W3	46	Communications Coordinator	U1
22	Supervisor, Facilities	W3	47	OD Administrator	T1
23	Supervisor, Design	W3	48	Claims Administrator	T1
24	Supervisor, Construction & Maintenance	W3	49	Administrative Assistant	T1
25	Supervisor, Call Centre	W2			

The following 10 bargaining positions were included within the scope of the review:

#	TORONTO HYDRO POSITION	UNION
50	Engineering Technologist Level 1	PWU
51	Engineering Technologist Level 2	PWU
52	Customer Relations Representative	PWU
53	Distribution System Technologist	PWU
54	Cert Meter Mechanic / Tester	PWU
55	Cert Power Line Person	PWU
56	Cert Power Cable Person	PWU
57	Power System Controller	PWU
58	Cert Crew Leader, Power Cable Person	PWU
59	Engineer	SOCIETY

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MARSH & McLENNAN COMPANIES

Willis Towers Watson

Private and Confidential

January 15, 2018

Ms. Janandre Lamprecht
Toronto Hydro Corporation
14 Carlton Street
Toronto, ON
M5B 1K5

Dear Janandre:

POST-EMPLOYMENT BENEFITS FOR EMPLOYEES OF TORONTO HYDRO
2017 YEAR-END DISCLOSURES AND ESTIMATED 2018 AND 2019 BENEFIT EXPENSE
UNDER INTERNATIONAL ACCOUNTING STANDARDS

As requested, this letter and appendices have been prepared for Toronto Hydro Corporation ("the Company", or "Toronto Hydro") and present the Company's liabilities and costs in respect of the following post-retirement and post-employment benefits plans ("the Plans"):

- Extended health benefits for retirees and members on disability;
- Dental benefits for retirees and members on disability;
- Life insurance benefits for retirees;
- Vested and non-vested sick leave benefits;
- OMERS top up pension; and
- Executive retirement allowances.

This letter and appendices have been prepared for the Company and its external reporting, for the following purposes:

- Determining the final calculation of the 2017 benefit expense under International Financial Reporting Standards (IFRS) in accordance with International Accounting Standards Section 19 revised in 2011,

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Towers Watson Canada Inc.

- Providing the required information for year-end disclosure purposes as of December 31, 2017 under IAS 19 rev. 2011,

- Determining an estimate of 2018 and 2019 benefit expense under IAS 19 rev. 2011.

The information contained in this letter and appendices are presented in thousands of Canadian dollars, and are in respect of the benefits mentioned above only.

The 2017 year-end disclosure results and extrapolations for 2018 and 2019 are based on the results of the January 1, 2016 actuarial valuation.

The balance of this letter sets out comments and notes to our calculations. Appendix A provides details of the relevant accounting results. Please refer to the January 1, 2016 actuarial valuation reports presented by Willis Towers Watson on November 18, 2016, for the summaries of the plan provisions, the membership data and the actuarial basis used in the valuation.

Actuarial Assumptions and Methods

- The measurement date used for Fiscal 2017 year-end financial reporting is December 31, 2017.

- The 2017 benefit expense is based on a discount rate of 4.00% per annum and the defined benefit obligation ("DBO") at December 31, 2017 is based on a discount rate of 3.50% per annum, as instructed by the Company. The discount rates are based on long-term high-quality Canadian corporate bond yields at December 31, 2016 and December 31, 2017 respectively.

- In September 2017, the Canadian Institute of Actuaries published the MI-2017 mortality improvement scale that reflects mortality improvement experience data from the Human Mortality Database to 2011, supplemented by OAS data to 2015. The new scale uses a long-term improvement rate factor of 1.0% (compared to a long-term improvement rate factor of 0.8% under the CPM-B scale). The Canadian Institute of Actuaries is currently working on guidance for actuaries relating to the MI-2017 scale. It is still uncertain whether the new MI-2017 scale will be prevalent and used across Canadian plan sponsors at year-end 2017, but we expect materiality to be a key consideration when deciding whether to move to MI-2017. Based on our discussion with the Toronto Hydro, the Company decided not to adopt the MI-2017 projection scale for year-end 2017.

- Other than those noted in this letter, the actuarial methods and assumptions used for the determination of the 2017 net periodic benefit cost are consistent with those used for the 2016 year-end disclosures and the actuarial methods and assumptions used for the December 31, 2017 obligation are consistent with those used for the January 1, 2016 actuarial valuation.

- The obligation as of December 31, 2017 and the 2018 and 2019 expense estimates are based on extrapolations from the January 1, 2016 valuation results for the medical, dental, life insurance, sick leave, OMERS and retirement allowance benefit plans, assuming that there are no experience gains or losses other than from actual benefit payments being different from expected, and reflecting changes in the assumptions during the extrapolation period such as changes in the discount rate.

Accounting Methods

- As directed by the Company, Appendix A includes an exhibit that assumes the transition date to IAS 19 rev. 2011 of January 1, 2014.
- Under IAS 19 rev. 2011, we understand that Toronto Hydro has determined that both the non-vested sick leave benefit program and the vested sick leave benefit program should be included for post-employment benefits reporting. As such, these benefits are included in the financial information under IAS 19 rev. 2011 presented in this letter.
- On an ongoing basis, actuarial gains and losses for all benefit plans other than the sick leave benefits plan and the incentive plan retirement allowance will be immediately recognized in other comprehensive income. Actuarial gains and losses for the sick leave benefit plan and the incentive plan retirement allowance will be recognized immediately in expense.
- On an ongoing basis, the impact of plan changes will be immediately recognized in benefit expense.

Summary of Financial Results

The summary of Fiscal 2017 benefit expense, the defined benefit liability and the DBO as at December 31, 2017, under IAS 19 rev. 2011 is as follows (in $ 000s):

	Fiscal 2017 Net Periodic Benefit Costs	Defined Benefit Asset/(Liability) at December 31, 2017	DBO at December 31, 2017
Electric System Limited	$ 17,978	$ (307,147)	$ 307,147
Toronto Hydro Corporation	283	(2,296)	2,296
Energy Service Incorporated	74	(2,117)	2,117
LDC Unregulated	97	(1,410)	1,410
Consolidated	$ 18,432	$ (312,970)	$ 312,970

- Actual benefit payments for 2017 of $11,040,000 are based on information provided by the Company on January 5, 2018. We have projected 2018 and 2019 benefit payments based on the valuation assumptions.

Other Comments

- The Company informed us that effective January 1, 2017 they transferred 22 active employees from Energy Services Incorporated (ESI) division to Electric System Limited (ESL) division. Of the 22 affected members, we found 17 in our January 1, 2016 actuarial valuation census data. As directed by the Company, we transferred $1.3 million of obligation as of January 1, 2017 and $0.1 million of the 2017 service cost from ESI to ESL. As a result, the 2017 benefit expense and December 31, 2017 obligations for ESI and ESL were revised to reflect these changes. However, there was no impact at the Consolidated level.

- We understand that the post-employment benefits plans are not pre-funded, and therefore our accounting results do not consider any expected investment income on plan assets.

- As directed by the Company, the full defined benefit liability has been classified as a non-current liability.

- Other than those described in this letter and appendices, the Company's management has confirmed that there have been no significant events, changes to the plan provisions or changes to plan membership since January 1, 2016 for all benefit plans, that would materially affect the results of our valuations.

* * * * *

Actuarial Certification

The Company may make a copy of this report available to its auditors, but we make no representation as to the suitability of this report for any purpose other than that for which it was originally provided and accept no responsibility or liability to the Company's auditors in this regard. We are aware that the information contained in this report will be used to support the audit of the Company's financial statements. Except where we expressly agree in writing, this report should not be disclosed or provided to any third party, other than as provided above. Willis Towers Watson accepts no responsibility for any consequences arising from any other party relying on this report or any advice relating to its contents.

In preparing these results, we have relied upon information and data provided to us orally, electronically and/or in writing by the Company and other persons or organizations designated by the Company. We have relied on all the data and information provided, including plan provisions and membership data as being complete and accurate. Based on discussions with and concurrence by the plan sponsor, assumptions or estimates may have been made if data were not available. We have not independently verified the accuracy or completeness of the data or information provided, but we have performed limited checks for consistency.

We are not aware of any errors or omissions in the data that would have a significant effect on the results of our calculations.

The results presented in this report are directly dependent upon the accuracy and completeness of the underlying data and information. Any material inaccuracy in the data, plan provisions or other information provided to us may have produced results that are not suitable for the purposes of this report and such inaccuracies may produce materially different results that could require that a revised report be issued.

The results summarized in this report involve actuarial calculations that require assumptions about future events. The Company is responsible for the selection of the assumptions, as required by IAS 19. Other assumptions may also be reasonable and appropriate and their use would produce different results.

The expense and obligation levels will change in the future as a result of future changes in the actuarial methods and assumptions, the membership data, the plan provisions, accounting rules, legislature, and the government health care programs, or as a result of

future experience gains or losses. None of these changes has been anticipated at this time, but will be revealed in future accounting valuations.

The figures provided in this letter reflect, to the best of our knowledge, all of the Company's substantive commitments and obligations, as described herein. Furthermore, to the best of our knowledge, there are no other subsequent events, the occurrence of which is probable and the effects of which are reasonably estimable, which have not been reflected in the figures provided as of the date of our letter.

In our opinion:

- the membership data on which the valuation is based are sufficient and reliable for purposes of the valuation;
- the assumptions are appropriate for the purposes of the valuation(s);
- the methods employed in the valuation are appropriate for the purposes of the valuation(s);
- the calculations have been made in accordance with our understanding of the requirements of IAS 19 and the Company's accounting policies.

This report has been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada.

We are pleased to provide you with this year-end disclosure report. Please contact us if you need any additional information.

Willis Towers Watson

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Enclosures

cc: Claudia Oancea — Toronto Hydro Corporation
Cindy Dieng — Toronto Hydro Corporation
Winnie Cheng – Toronto Hydro Corporation

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2017 Year-End Disclosure Information ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Statement of Financial Position at Beginning of Period			**January 01, 2017**		
Defined Benefit Asset/(Liability) at Beginning of Period	(274,171)	(1,909)	(3,210)	(1,195)	(280,485)
Reconciliation of Defined Benefit Obligation			**2017**		
Defined Benefit Obligation at Beginning of Period	274,171	1,909	3,210	1,195	280,485
Employer Service Cost at Beginning of Period	3,839	182	12	48	4,081
Interest Cost	10,994	82	74	49	11,199
Net Actuarial (Gain) or Loss					
Sick Leave Plan	*3,145*	-	*(12)*	-	*3,133*
Retirement Allowance Benefit #1	-	*19*	-	-	*19*
Other Plans	*25,881*	*113*	*(1,046)*	*145*	*25,093*
Total Net Actuarial (Gain) or Loss	29,026	132	(1,058)	145	28,245
Benefits Paid Directly by the Employer	(10,883)	(9)	(121)	(27)	(11,040)
Defined Benefit Obligation at Current Period End	307,147	2,296	2,117	1,410	312,970
Change in Plan Assets			**2017**		
Fair Value of Plan Assets at Prior Period End	-	-	-	-	-
Employer Contributions	10,883	9	121	27	11,040
Benefits Paid	(10,883)	(9)	(121)	(27)	(11,040)
Fair Value of Plan Assets at Current Period End	-	-	-	-	-
Total Benefit (Expense)/Income for Period			**2017**		
Employer Service Cost at Beginning of Period	3,839	182	12	48	4,081
Interest Cost	10,994	82	74	49	11,199
Actuarial (Gain)/Loss Recognized in Expense	3,145	19	(12)	-	3,152
Total Benefit Expense/(Income)	17,978	283	74	97	18,432
Reconciliation of Balance Sheet			**2017**		
Defined Benefit Asset/(Liability) at Prior Period End	(274,171)	(1,909)	(3,210)	(1,195)	(280,485)
Total Benefit (Expense)/Income for Period	(17,978)	(283)	(74)	(97)	(18,432)
Benefits Paid Directly by the Employer	10,883	9	121	27	11,040
Gain/(Loss) Recognized via OCI	(25,881)	(113)	1,046	(145)	(25,093)
Defined Benefit Asset/(Liability) at Current Period End	(307,147)	(2,296)	(2,117)	(1,410)	(312,970)
Change in Accumulated Other Comprehensive Income			**2017**		
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Prior Period End	26,533	(1,212)	(180)	(33)	25,108
Actuarial (Gain)/Loss Recognized via OCI for Period	25,881	113	(1,046)	145	25,093
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Current Period End	52,414	(1,099)	(1,226)	112	50,201
Statement of Financial Position at End of Period			**December 31, 2017**		
Defined Benefit Asset/(Liability) at Current Period End	(307,147)	(2,296)	(2,117)	(1,410)	(312,970)
Breakdown of Defined Benefit Obligation: Current and Non-Current			**December 31, 2017**		
Current Liabilities	-	-	-	-	-
Non-Current Asset/(Liability)	(307,147)	(2,296)	(2,117)	(1,410)	(312,970)
Defined Benefit Asset/(Liability) at Current Period End	(307,147)	(2,296)	(2,117)	(1,410)	(312,970)

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2017 Year-End Disclosure Information ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Sensitivity to Changes in Medical and Dental Trend Rate Assumption					
Effect on total of service and interest cost for 2017					
1% point increase	2,135	8	14	18	2,175
1% point decrease	(1,906)	(6)	(13)	(14)	(1,939)
Effect on accrued benefit obligation at December 31, 2017					
1% point increase	39,463	178	340	220	40,201
1% point decrease	(35,376)	(159)	(305)	(191)	(36,031)
Sensitivity to Changes in Discount Rate Assumption					
Effect on total of service and interest cost for 2017					
1% point increase	(223)	(9)	(1)	(9)	(242)
1% point decrease	79	9	(1)	13	100
Effect on accrued benefit obligation at December 31, 2017					
1% point increase	(45,889)	(324)	(372)	(246)	(46,831)
1% point decrease	58,970	410	489	322	60,191
Sensitivity to Changes in Mortality Rates Assumption					
Effect on accrued benefit obligation at December 31, 2017					
Set back 1 year	11,071	45	80	54	11,250
Set forward 1 year	(10,828)	(44)	(79)	(53)	(11,004)
Key Assumptions					
Discount rate at Dec 31/17 (used for Dec 31/17 obligation)	3.50%	3.50%	3.50%	3.50%	3.50%
Discount rate at Dec 31/16 (used for 2017 Benefit Costs)	4.00%	4.00%	4.00%	4.00%	4.00%
Assumed medical and dental cost trend rate at December 31, 2017					
Dental care cost trend rate assumed for next year	4.00%	4.00%	4.00%	4.00%	4.00%
For pre July 2000 retirements:					
Health care cost trend rate assumed for next year	5.00%	5.00%	5.00%	5.00%	5.00%
Rate that the cost trend gradually declines to	5.00%	5.00%	5.00%	5.00%	5.00%
Year that the rate reaches the ultimate rate	2015	2015	2015	2015	2015
For other retirements:					
Health care cost trend rate assumed for next year	5.00%	5.00%	5.00%	5.00%	5.50%
Rate that the cost trend gradually declines to	5.00%	5.00%	5.00%	5.00%	5.00%
Year that the rate reaches the ultimate rate	2018	2018	2018	2018	2018
Expected Benefit Payments					
Following Year	9,293	224	50	21	9,588
Following Year +1	9,868	152	55	22	10,097
Following Year +2	9,982	124	64	23	10,193
Following Year +3	10,535	135	64	27	10,761
Following Year +4	11,171	139	81	33	11,424
Modified Duration at the end of the year	16.8	11.5	19.7	19.5	16.7
Breakdown of actuarial (gain)/loss at December 31, 2017					
Demographic assumptions:	0	0	0	0	0
Economic assumptions:					
Updated discount rate assumption	25,821	181	209	138	26,349
Plan Experience:					
Transfers 1.1.2017	1,344	-	(1,344)	-	-
Actual versus expected benefit payments	1,861	(49)	77	7	1,896
Total net actuarial (gain)/loss	**29,026**	**132**	**(1,058)**	**145**	**28,245**

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2018 Expense Estimate ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Statement of Financial Position at Beginning of Period			**January 01, 2018**		
Defined Benefit Asset/(Liability) at Beginning of Period	(307,147)	(2,296)	(2,117)	(1,410)	(312,970)
Reconciliation of Defined Benefit Obligation			**2018**		
Defined Benefit Obligation at Beginning of Period	307,147	2,296	2,117	1,410	312,970
Employer Service Cost at Beginning of Period	4,554	197	14	57	4,822
Interest Cost	10,747	83	74	51	10,955
Net Actuarial (Gain) or Loss	-	-	-	-	-
Benefits Paid Directly by the Employer	(9,293)	(224)	(50)	(21)	(9,588)
Defined Benefit Obligation at Current Period End	313,155	2,352	2,155	1,497	319,159
Change in Plan Assets			**2018**		
Fair Value of Plan Assets at Prior Period End	-	-	-	-	-
Employer Contributions	9,293	224	50	21	9,588
Benefits Paid	(9,293)	(224)	(50)	(21)	(9,588)
Fair Value of Plan Assets at Current Period End	-	-	-	-	-
Total Benefit (Expense)/Income for Period			**2018**		
Employer Service Cost at Beginning of Period	4,554	197	14	57	4,822
Interest Cost	10,747	83	74	51	10,955
Total Benefit Expense/(Income)	15,301	280	88	108	15,777
Reconciliation of Balance Sheet			**2018**		
Defined Benefit Asset/(Liability) at Prior Period End	(307,147)	(2,296)	(2,117)	(1,410)	(312,970)
Total Benefit (Expense)/Income for Period	(15,301)	(280)	(88)	(108)	(15,777)
Benefits Paid Directly by the Employer	9,293	224	50	21	9,588
Gain/(Loss) Recognized via OCI	-	-	-	-	-
Defined Benefit Asset/(Liability) at Current Period End	(313,155)	(2,352)	(2,155)	(1,497)	(319,159)
Change in Accumulated Other Comprehensive Income			**2018**		
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Prior Period End	26,533	(1,212)	(180)	(33)	25,108
Actuarial (Gain)/Loss Recognized via OCI for Period	-	-	-	-	-
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Current Period End	26,533	(1,212)	(180)	(33)	25,108
Statement of Financial Position at End of Period			**December 31, 2018**		
Defined Benefit Asset/(Liability) at Current Period End	(313,155)	(2,352)	(2,155)	(1,497)	(319,159)
Breakdown of Defined Benefit Obligation: Current and Non-Current			**December 31, 2018**		
Current Liabilities	-	-	-	-	-
Non-Current Asset/(Liability)	(313,155)	(2,352)	(2,155)	(1,497)	(319,159)
Defined Benefit Asset/(Liability) at Current Period End	(313,155)	(2,352)	(2,155)	(1,497)	(319,159)
Key Assumptions					
Discount rate at Dec 31/17 (used for Dec 31/18 obligation)	3.50%	3.50%	3.50%	3.50%	3.50%
Discount rate at Dec 31/17 (used for 2018 Benefit Costs)	3.50%	3.50%	3.50%	3.50%	3.50%
Assumed medical and dental cost trend rate at December 31, 2018					
Dental care cost trend rate assumed for next year	4.00%	4.00%	4.00%	4.00%	4.00%
For pre July 2000 retirements:					
Health care cost trend rate assumed for next year	5.00%	5.00%	5.00%	5.00%	5.00%
Rate that the cost trend gradually declines to	5.00%	5.00%	5.00%	5.00%	5.00%
Year that the rate reaches the ultimate rate	2015	2015	2015	2015	2015
For other retirements:					
Health care cost trend rate assumed for next year	5.00%	5.00%	5.00%	5.00%	5.00%
Rate that the cost trend gradually declines to	5.00%	5.00%	5.00%	5.00%	5.00%
Year that the rate reaches the ultimate rate	2018	2018	2018	2018	2018
Expected Benefit Payments for Following Year	9,868	152	55	22	10,097

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2019 Expense Estimate ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Statement of Financial Position at Beginning of Period			**January 01, 2019**		
Defined Benefit Asset/(Liability) at Beginning of Period	(313,155)	(2,352)	(2,155)	(1,497)	(319,159)
Reconciliation of Defined Benefit Obligation			**2019**		
Defined Benefit Obligation at Beginning of Period	313,155	2,352	2,155	1,497	319,159
Employer Service Cost at Beginning of Period	4,713	204	14	59	4,990
Interest Cost	10,953	87	75	54	11,169
Net Actuarial (Gain) or Loss	-	-	-	-	-
Benefits Paid Directly by the Employer	(9,868)	(152)	(55)	(22)	(10,097)
Defined Benefit Obligation at Current Period End	318,953	2,491	2,189	1,588	325,221
Change in Plan Assets			**2019**		
Fair Value of Plan Assets at Prior Period End	-	-	-	-	-
Employer Contributions	9,868	152	55	22	10,097
Benefits Paid	(9,868)	(152)	(55)	(22)	(10,097)
Fair Value of Plan Assets at Current Period End	-	-	-	-	-
Total Benefit (Expense)/Income for Period			**2019**		
Employer Service Cost at Beginning of Period	4,713	204	14	59	4,990
Interest Cost	10,953	87	75	54	11,169
Total Benefit Expense/(Income)	15,666	291	89	113	16,159
Reconciliation of Balance Sheet			**2019**		
Defined Benefit Asset/(Liability) at Prior Period End	(313,155)	(2,352)	(2,155)	(1,497)	(319,159)
Total Benefit (Expense)/Income for Period	(15,666)	(291)	(89)	(113)	(16,159)
Benefits Paid Directly by the Employer	9,868	152	55	22	10,097
Gain/(Loss) Recognized via OCI	-	-	-	-	-
Defined Benefit Asset/(Liability) at Current Period End	(318,953)	(2,491)	(2,189)	(1,588)	(325,221)
Change in Accumulated Other Comprehensive Income			**2019**		
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Prior Period End	26,533	(1,212)	(180)	(33)	25,108
Actuarial (Gain)/Loss Recognized via OCI for Period	-	-	-	-	-
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Current Period End	26,533	(1,212)	(180)	(33)	25,108
Statement of Financial Position at End of Period			**December 31, 2019**		
Defined Benefit Asset/(Liability) at Current Period End	(318,953)	(2,491)	(2,189)	(1,588)	(325,221)
Breakdown of Defined Benefit Obligation: Current and Non-Current			**December 31, 2019**		
Current Liabilities	-	-	-	-	-
Non-Current Asset/(Liability)	(318,953)	(2,491)	(2,189)	(1,588)	(325,221)
Defined Benefit Asset/(Liability) at Current Period End	(318,953)	(2,491)	(2,189)	(1,588)	(325,221)
Key Assumptions					
Discount rate at Dec 31/17 (used for Dec 31/19 obligation)	3.50%	3.50%	3.50%	3.50%	3.50%
Discount rate at Dec 31/17 (used for 2019 Benefit Costs)	3.50%	3.50%	3.50%	3.50%	3.50%
Assumed medical and dental cost trend rate at December 31, 2019					
Dental care cost trend rate assumed for next year	4.00%	4.00%	4.00%	4.00%	4.00%
For pre July 2000 retirements:					
Health care cost trend rate assumed for next year	5.00%	5.00%	5.00%	5.00%	5.00%
Rate that the cost trend gradually declines to	5.00%	5.00%	5.00%	5.00%	5.00%
Year that the rate reaches the ultimate rate	2015	2015	2015	2015	2015
For other retirements:					
Health care cost trend rate assumed for next year	5.00%	5.00%	5.00%	5.00%	5.00%
Rate that the cost trend gradually declines to	5.00%	5.00%	5.00%	5.00%	5.00%
Year that the rate reaches the ultimate rate	2018	2018	2018	2018	2018
Expected Benefit Payments for Following Year	9,982	124	64	23	10,193

SHARED SERVICES AND CORPORATE COST ALLOCATIONS

1. OVERVIEW

This schedule provides information about shared services and corporate costs allocations between Toronto Hydro and the affiliated corporate entities described below:

- **Toronto Hydro Corporation ("THC"):** THC provides strategic direction, corporate governance, and financial stewardship to Toronto Hydro and Toronto Hydro Energy Services Inc. ("TH Energy"). Toronto Hydro is wholly-owned by Toronto Hydro Corporation. THC receives shared corporate services from Toronto Hydro, and provides such services to Toronto Hydro as described below.
- **TH Energy:** TH Energy's primary line of business is the provision of street lighting and expressway lighting services to the City of Toronto. TH Energy receives shared corporate services from Toronto Hydro, and provides Toronto Hydro with emergency services for storm damage response.

For more information about these entities and their relationship to Toronto Hydro, please refer to Corporate Structure and Governance evidence at Exhibit 1C, Tab 2, Schedule 1.

This schedule provides information about corporate cost allocations to the non-rate regulated aspects of Toronto Hydro's business (referred to as "THESU"), including Conservation and Demand Management ("CDM") and generation activities.

2. OEB APPENDIX 2-N

A completed copy of OEB Appendix 2-N is filed at Exhibit 4A, Tab 5, Schedule 2. This appendix provides cost information and allocation details relating to each shared service provided or received by Toronto Hydro in the historical years (2015 to 2017), the bridge years (2018 and 2019) and the test year (2020). The Board of Directors related costs included in THC's cost allocation to Toronto Hydro is also provided in this appendix.

3. SHARED SERVICE MODEL

Toronto Hydro's shared services methodology has not changed since the utility's last rebasing application.[1]

Each service transaction is reviewed to determine the costing formula and method of allocation. In establishing the price of a service transaction, Toronto Hydro follows the Affiliate Relationships Code ("ARC"). The ARC provides for the use of fully allocated cost based pricing ("CBP") for shared corporate services, and the use of fair market value ("FMV"), where a reasonably competitive market exists.

If a competitive market does not exist, Toronto Hydro uses fully-allocated cost-based pricing. With regard to these fundamental principles and historical information about the quantity of services provided, Toronto Hydro assesses the approximate annual cost of each service. At the end of the fiscal year, the estimated cost of providing or receiving each service is reconciled with the actual cost and any differences are settled.

Table 1, below, provides a description of Toronto Hydro's corporate cost allocators by each functional service.

[1] EB-2014-0116, Toronto Hydro-Electric System Limited Application, Exhibit 4A, Tab 5, Schedule 1.

Table 1: Shared Corporate Services Primary Allocation Drivers

Functional service	Allocator	Reason
Finance (other than payroll, accounts payable, insurance)	Time allocation	Financial support, analysis, planning, calculations, and reports provided for certain affiliates are more labour intensive than others.
Finance – Payroll	Headcount	Amount of payroll services required such as processing is dependent on the number of employees.
Finance – Accounts Payable	Invoices	Amount of accounts payable services required such as processing is dependent on the number of invoices.
Finance – Insurance	Usage proportion	Amount of insurance required is dependent on the coverage required.
Health and Safety	Union headcount	Services are mainly required for unionized positions as these positions typically are required to perform field work.
Information Technology & Services	By employee	Required equipment and IT services are dependent on the number of employees who need equipment/services.
Legal	Billable hours	Legal services and support for some affiliates are more labour intensive than others.
Human Resources ("HR") (other than Talent Management and Administration)	Headcount	Amount of OE services required such as compensation/benefits related services is dependent on the number of employees.
HR – Talent Management and Administration	Time allocation	Services provided to certain affiliates are more labour intensive than others.
Procurement	Number of purchase orders	Amount procured for each affiliate is dependent on the number of purchase orders.
Facilities	Square footage	Amount of building space required is measured in square foot.
Office of the President	Time allocation	Services provided related to Councillor administration and requests
THC – CEO, CFO, Board of Directors	Time allocation	Services provided to certain affiliates are more labour intensive than others.

For other services, Toronto Hydro uses market price, if a reasonably competitive market exists for the service, and if it is practicable and cost efficient to undertake a market value assessment for the service.

If market price can be determined, Toronto Hydro charges the higher of fully-allocated cost or market price for any non-shared corporate services that it provides to the affiliated entities, and pays the lower of fully-allocated cost or market price for any such services that its receives from the affiliated entities.

If a market price cannot be determined, Toronto Hydro applies fully allocated cost-based pricing, which includes direct costs, indirect cost, and cost of capital, to determine the cost of providing or receiving the non-shared corporate service.

4. VARIANCE ANALYSIS

4.1 TH Energy

Further to Appendix 2-N, Table 2, below, provides a summary of the cost of shared service provided by and received by Toronto Hydro to or from TH Energy. A variance analysis between 2015 actuals and 2020 test year amounts, as well as 2017 actuals and 2020 test year amounts is included after the table.

Table 2: Summary of the Cost of Shared Services Provided by and Received by Toronto Hydro to/from TH Energy ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Services Provided by Toronto Hydro	2.0	2.1	1.1	1.6	1.6	1.6
Services Received by Toronto Hydro	1.9	2.6	0.3	0.0	0.0	0.0

2015 Actual versus 2020 Test Year

- **Services Provided by Toronto Hydro:** The $0.4 million variance between 2015 actual and the 2020 test year is primarily attributable to lower allocated fleet services costs as a result of the transfer of all employees from TH Energy to Toronto Hydro. This transfer came into effect in 2017 and was budgeted accordingly in the 2018-19 Bridge years and 2020 Test year.
- **Services Received by Toronto Hydro:** The $1.9 million variance between 2015 actual and the 2020 test year is primarily attributable to the transfer of all employees from TH Energy to Toronto Hydro.

2017 Actual versus 2020 Test Year

- **Services Provided by Toronto Hydro:** The $0.5 million variance from the 2017 actual amounts and the 2020 test year forecasted amounts is primarily attributable to higher estimated spend to support street lighting projects.
- **Services Received by Toronto Hydro:** The $0.3 million variance from the 2017 actual and the 2020 test year is primarily attributable to contractor costs in TH Energy.

4.2 Non-Rate Regulated Toronto Hydro Activities

Further to Appendix 2-N, Table 3, below, provides a summary of the cost of shared service relating to Toronto Hydro's non-rate regulated activities (i.e. CDM, generation from 2015 to 2020). A variance analysis between 2015 actuals and 2020 test year amounts, as well as 2017 actuals and 2020 test year amounts is included after the table.

Table 3: Summary of the Cost of Services relating to Non-Rate Regulated Toronto Hydro activities ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Services Provided by Toronto Hydro	1.3	1.7	1.9	1.6	1.6	1.7

2015 Actual versus 2020 Test Year

For non-rate regulated Toronto Hydro activities, the variance in the shared corporate services allocation between 2015 actual and 2020 test year is primarily due to increased IT requirements resulting from incremental activities in 2020.

2017 Actual versus 2020 Test Year

The $0.2 million variance between the 2017 actual and 2020 test year is attributable to a transfer of employees from the regulated entity to the unregulated business.

4.3 THC

Further to Appendix 2-N, Table 4, below, provides a summary of the cost of shared service provided by and received by Toronto Hydro to or from THC. A variance analysis between 2015 actuals and 2020 test year amounts, as well as 2017 actuals and 2020 test year amounts is included after the table.

Table 4: Summary of the Cost of Shared Services Provided by and Received by Toronto Hydro to/from THC ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test
Services Provided by Toronto Hydro	1.2	1.3	3.2	3.9	3.9	3.9
Services Received by Toronto Hydro	4.8	2.9	4.8	4.3	4.4	4.6

2015 Actual versus 2020 Test Year

- **Services Provided by Toronto Hydro:** The $2.7 million variance between 2015 actual and the 2020 test year is due to increased services related to councillor administration and requests, and redesign of corporate risk, disaster planning and compliance function in 2020.
- **Services Received by Toronto Hydro:** The $0.2 million variance from the 2015 actual and the 2020 test year is due to lower expected stewardship costs allocated to the regulated business.

2017 Actual versus 2020 Test Year

- **Services Provided by Toronto Hydro:** The $0.7 million variance from the 2017 actual and the 2020 test year is due to the redesign of corporate risk, disaster planning and compliance function in 2020.
- **Services Received by Toronto Hydro:** The $0.2 million variance from the 2017 actual and the 2020 test year is due to lower expected stewardship costs allocated to the regulated business.

OEB Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2015

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
THESL	THESI	Fleet*	Fully allocated-cost	0.38	0.38
THESL	THESI	Emergency Calls / Streetlighting Relamping	Market**	0.52	0.48
THESI	THESL	Emergency/Field Work	Market**	0.04	0.04
THESI	THESL	Design	Market**	1.82	1.59

* A portion of the fleet charge is allocated from THESI to THESU.

** Because of cost-benefit impacts and impracticability, there was no study done to verify market amounts.

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
THESL	THESI	Finance/Treasury	Fully allocated-cost	2.9%	0.49
THESL	THESI	EHS	Fully allocated-cost	0.4%	0.01
THESL	THESI	Legal/Insurance	Fully allocated-cost	3.6%	0.18
THESL	THESI	HR&OE	Fully allocated-cost	1.3%	0.17
THESL	THESI	Procurement	Fully allocated-cost	1.7%	0.04
THESL	THESI	Consolidated Billing	Fully allocated-cost	0.0%	-
THESL	THESI	IT&S	Fully allocated-cost	0.8%	0.06
THESL	THESI	Facilities	Fully allocated-cost	0.5%	0.11
THESL	THESU	Finance/Treasury	Fully allocated-cost	2.3%	0.39
THESL	THESU	Legal/Insurance	Fully allocated-cost	0.6%	0.03
THESL	THESU	HR&OE	Fully allocated-cost	2.5%	0.37
THESL	THESU	Procurement	Fully allocated-cost	5.4%	0.12
THESL	THESU	IT&S	Fully allocated-cost	0.9%	0.07
THESL	THESU	Facilities	Fully allocated-cost	1.6%	0.37
THESL	THC	Finance/Treasury	Fully allocated-cost	2.8%	0.47
THESL	THC	Legal/Insurance	Fully allocated-cost	13.9%	0.71
THESL	THC	HR&OE	Fully allocated-cost	0.1%	0.01
THESL	THC	Procurement	Fully allocated-cost	0.2%	0.01
THESL	THC	IT&S	Fully allocated-cost	0.1%	0.01
THESL	THC	Facilities	Fully allocated-cost	0.2%	0.04
THC	THESL	Corporate Stewardship - CEO	Fully allocated-cost	95.0%	2.71
THC	THESL	Corporate Governance - Board of Directors	Fully allocated-cost	90.0%	0.22
THC	THESL	Finance Stewardship - CFO	Fully allocated-cost	95.0%	1.89
THC	THESI	Corporate Governance - Board of Directors	Fully allocated-cost	5.0%	0.01

Year: **2016**

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
THESL	THESI	Fleet*	Fully allocated-cost	0.43	0.43
THESL	THESI	Emergency Calls / Streetlighting Relamping	Market**	0.46	0.38
THESI	THESL	Emergency/Field Work	Market**	2.39	2.07
THESI	THESL	Design	Market**	0.19	0.16

* A portion of the fleet charge is allocated from THESI to THESU.

** Because of cost-benefit impacts and impracticability, there was no study done to verify market amounts.

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
THESL	THESI	Finance/Treasury/Insurance	Fully allocated-cost	3.0%	0.480
THESL	THESI	EHS	Fully allocated-cost	0.3%	0.006
THESL	THESI	Legal	Fully allocated-cost	4.6%	0.244
THESL	THESI	HR&OE	Fully allocated-cost	1.2%	0.163
THESL	THESI	Procurement	Fully allocated-cost	1.3%	0.075
THESL	THESI	Billing and Settlement Services	Fully allocated-cost	11.1%	0.049
THESL	THESI	IT&S	Fully allocated-cost	0.3%	0.11
THESL	THESI	Facilities	Fully allocated-cost	0.4%	0.11
THESL	THESU	Finance/Treasury/Insurance	Fully allocated-cost	2.3%	0.369
THESL	THESU	Legal	Fully allocated-cost	1.0%	0.056
THESL	THESU	HR&OE	Fully allocated-cost	2.4%	0.320
THESL	THESU	Procurement	Fully allocated-cost	3.7%	0.212
THESL	THESU	IT&S	Fully allocated-cost	0.7%	0.26
THESL	THESU	Facilities	Fully allocated-cost	2.0%	0.50
THESL	THC	Finance/Treasury/Insurance	Fully allocated-cost	2.5%	0.393
THESL	THC	Legal	Fully allocated-cost	15.4%	0.824
THESL	THC	HR&OE	Fully allocated-cost	0.0%	0.006
THESL	THC	Procurement	Fully allocated-cost	0.3%	0.014
THESL	THC	IT&S	Fully allocated-cost	0.0%	0.01
THESL	THC	Facilities	Fully allocated-cost	0.3%	0.07
THC	THESL	Corporate Stewardship - CEO	Fully allocated-cost	95.0%	1.88
THC	THESL	Corporate Governance - Board of Directors	Fully allocated-cost	90.0%	0.29
THC	THESL	Finance Stewardship - CFO	Fully allocated-cost	95.0%	0.69
THC	THESI	Corporate Governance - Board of Directors	Fully allocated-cost	5.0%	0.02

Year: **2017**

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
THESL	THESI	Fleet*	Fully allocated-cost	-	-
THESL	THESI	Emergency Calls / Streetlighting Relamping	Market**	0.33	0.30
THESI	THESL	Emergency/Field Work	Market**	0.21	0.21
THESI	THESL	Design	Market**	0.07	0.07

* A portion of the fleet charge is allocated from THESI to THESU.

** Because of cost-benefit impacts and impracticability, there was no study done to verify market amounts.

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
THESL	THESI	Finance/Treasury/Insurance	Fully allocated-cost	2.3%	0.32
THESL	THESI	EHS	Fully allocated-cost	0.3%	0.01
THESL	THESI	Legal	Fully allocated-cost	5.7%	0.33
THESL	THESI	HR&OE	Fully allocated-cost	0.0%	-
THESL	THESI	Procurement	Fully allocated-cost	1.1%	0.04
THESL	THESI	Billing and Settlement Services	Fully allocated-cost	5.0%	0.05
THESL	THESI	IT&S	Fully allocated-cost		-
THESL	THESI	Facilities	Fully allocated-cost		-
THESL	THESU	Finance/Treasury/Insurance	Fully allocated-cost	4.3%	0.61
THESL	THESU	Legal	Fully allocated-cost	1.9%	0.11
THESL	THESU	HR&OE	Fully allocated-cost	1.5%	0.21
THESL	THESU	Procurement	Fully allocated-cost	5.6%	0.21
THESL	THESU	IT&S	Fully allocated-cost	0.6%	0.25
THESL	THESU	Facilities	Fully allocated-cost	2.3%	0.54
THESL	THC	Finance/Treasury/Insurance	Fully allocated-cost	2.6%	0.37
THESL	THC	Legal	Fully allocated-cost	14.0%	0.82
THESL	THC	HR&OE	Fully allocated-cost	0.2%	0.03
THESL	THC	Office of the President	Fully allocated-cost	***	1.70
THESL	THC	Procurement	Fully allocated-cost	0.2%	0.01
THESL	THC	IT&S	Fully allocated-cost	0.03%	0.01
THESL	THC	Facilities	Fully allocated-cost	1.0%	0.22
THC	THESL	Corporate Stewardship - CEO	Fully allocated-cost	95.0%	3.02
THC	THESL	Corporate Governance - Board of Directors	Fully allocated-cost	90.0%	0.27
THC	THESL	Finance Stewardship - CFO	Fully allocated-cost	90.0%	1.47
THC	THESI	Corporate Governance - Board of Directors	Fully allocated-cost	5.0%	0.02

***Based on time allocation of multiple functions across the organization.

Year: **2018**

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
THESL	THESI	Fleet*	Fully allocated-cost	-	-
THESL	THESI	Emergency Calls / Streetlighting Relamping	Market**	0.67	0.57
THESI	THESL	Emergency/Field Work	Market**	-	-
THESI	THESL	Design	Market**	-	-

* A portion of the fleet charge is allocated from THESI to THESU.

** Because of cost-benefit impacts and impracticability, there was no study done to verify market amounts.

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
THESL	THESI	Finance/Treasury/Insurance	Fully allocated-cost	2.3%	0.40
THESL	THESI	EHS	Fully allocated-cost	0.3%	0.01
THESL	THESI	Legal	Fully allocated-cost	5.7%	0.32
THESL	THESI	HR&OE	Fully allocated-cost	0.0%	0.14
THESL	THESI	Procurement	Fully allocated-cost	1.1%	0.04
THESL	THESI	Billing and Settlement Services	Fully allocated-cost	5.0%	0.05
THESL	THESI	IT&S	Fully allocated-cost		
THESL	THESI	Facilities	Fully allocated-cost		
THESL	THESU	Finance/Treasury/Insurance	Fully allocated-cost	4.3%	0.35
THESL	THESU	Legal	Fully allocated-cost	1.9%	0.06
THESL	THESU	HR&OE	Fully allocated-cost	1.5%	0.36
THESL	THESU	Procurement	Fully allocated-cost	5.6%	0.13
THESL	THESU	IT&S	Fully allocated-cost	0.6%	0.35
THESL	THESU	Facilities	Fully allocated-cost	2.3%	0.36
THESL	THC	Finance/Treasury/Insurance	Fully allocated-cost	2.6%	1.04
THESL	THC	Legal	Fully allocated-cost	14.0%	0.83
THESL	THC	HR&OE	Fully allocated-cost	0.2%	0.01
THESL	THC	Office of the President	Fully allocated-cost	***	1.70
THESL	THC	Procurement	Fully allocated-cost	0.2%	0.01
THESL	THC	IT&S	Fully allocated-cost	0.03%	0.04
THESL	THC	Facilities	Fully allocated-cost	1.0%	0.23
THC	THESL	Corporate Stewardship - CEO	Fully allocated-cost	95.0%	2.68
THC	THESL	Corporate Governance - Board of Directors	Fully allocated-cost	90.0%	0.36
THC	THESL	Finance Stewardship - CFO	Fully allocated-cost	95.0%	1.29
THC	THESI	Corporate Governance - Board of Directors	Fully allocated-cost	5.0%	0.02

***Based on time allocation of multiple functions across the organization.

Year: **2019**

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
THESL	THESI	Fleet*	Fully allocated-cost	-	-
THESL	THESI	Emergency Calls / Streetlighting Relamping	Market**	0.67	0.57
THESI	THESL	Emergency/Field Work	Market**	-	-
THESI	THESL	Design	Market**	-	-

* A portion of the fleet charge is allocated from THESI to THESU.

** Because of cost-benefit impacts and impracticability, there was no study done to verify market amounts.

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
THESL	THESI	Finance/Treasury/Insurance	Fully allocated-cost	2.2%	0.40
THESL	THESI	EHS	Fully allocated-cost	0.3%	0.01
THESL	THESI	Legal	Fully allocated-cost	5.8%	0.32
THESL	THESI	HR&OE	Fully allocated-cost	1.0%	0.13
THESL	THESI	Billing and Settlement Services	Fully allocated-cost	5.3%	0.05
THESL	THESI	Procurement	Fully allocated-cost	1.3%	0.05
THESL	THESI	IT&S	Fully allocated-cost		
THESL	THESI	Facilities	Fully allocated-cost		
THESL	THESU	Finance/Treasury/Insurance	Fully allocated-cost	1.9%	0.35
THESL	THESU	Legal	Fully allocated-cost	1.1%	0.06
THESL	THESU	HR&OE	Fully allocated-cost	2.7%	0.37
THESL	THESU	Procurement	Fully allocated-cost	3.7%	0.13
THESL	THESU	IT&S	Fully allocated-cost	0.8%	0.36
THESL	THESU	Facilities	Fully allocated-cost	1.3%	0.37
THESL	THC	Finance/Treasury/Insurance	Fully allocated-cost	5.9%	1.07
THESL	THC	Legal	Fully allocated-cost	15.4%	0.85
THESL	THC	HR&OE	Fully allocated-cost	0.1%	0.01
THESL	THC	Office of the President	Fully allocated-cost	***	1.70
THESL	THC	Procurement	Fully allocated-cost	0.3%	0.01
THESL	THC	IT&S	Fully allocated-cost	0.03%	0.04
THESL	THC	Facilities	Fully allocated-cost	1.4%	0.24
THC	THESL	Corporate Stewardship - CEO	Fully allocated-cost	95.0%	2.76
THC	THESL	Corporate Governance - Board of Directors	Fully allocated-cost	90.0%	0.36
THC	THESL	Finance Stewardship - CFO	Fully allocated-cost	95.0%	1.32
THC	THESI	Corporate Governance - Board of Directors	Fully allocated-cost	5.0%	0.02

***Based on time allocation of multiple functions across the organization.

Year: **2020**

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
THESL	THESI	Fleet*	Fully allocated-cost	-	-
THESL	THESI	Emergency Calls / Streetlighting Relamping	Market**	0.67	0.57
THESI	THESL	Emergency/Field Work	Market**	-	-
THESI	THESL	Design	Market**	-	-

* A portion of the fleet charge is allocated from THESI to THESU.

** Because of cost-benefit impacts and impracticability, there was no study done to verify market amounts.

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
THESL	THESI	Finance/Treasury/Insurance	Fully allocated-cost	2.2%	0.40
THESL	THESI	EHS	Fully allocated-cost	0.3%	0.01
THESL	THESI	Legal	Fully allocated-cost	5.8%	0.33
THESL	THESI	HR&OE	Fully allocated-cost	0.9%	0.13
THESL	THESI	Billing and Settlement Services	Fully allocated-cost	5.4%	0.05
THESL	THESI	Procurement	Fully allocated-cost	1.3%	0.05
THESL	THESI	IT&S	Fully allocated-cost		
THESL	THESI	Facilities	Fully allocated-cost		
THESL	THESU	Finance/Treasury/Insurance	Fully allocated-cost	1.9%	0.35
THESL	THESU	Legal	Fully allocated-cost	1.1%	0.06
THESL	THESU	HR&OE	Fully allocated-cost	2.7%	0.38
THESL	THESU	Procurement	Fully allocated-cost	3.7%	0.13
THESL	THESU	IT&S	Fully allocated-cost	0.8%	0.37
THESL	THESU	Facilities	Fully allocated-cost	3.7%	0.38
THESL	THC	Finance/Treasury/Insurance	Fully allocated-cost	5.6%	1.01
THESL	THC	Legal	Fully allocated-cost	15.4%	0.89
THESL	THC	HR&OE	Fully allocated-cost	0.1%	0.01
THESL	THC	Office of the President	Fully allocated-cost	***	1.70
THESL	THC	Procurement	Fully allocated-cost	0.3%	0.01
THESL	THC	IT&S	Fully allocated-cost	0.03%	0.04
THESL	THC	Facilities	Fully allocated-cost	1.4%	0.24
THC	THESL	Corporate Stewardship - CEO	Fully allocated-cost	95.0%	2.86
THC	THESL	Corporate Governance - Board of Directors	Fully allocated-cost	90.0%	0.36
THC	THESL	Finance Stewardship - CFO	Fully allocated-cost	95.0%	1.35
THC	THESI	Corporate Governance - Board of Directors	Fully allocated-cost	5.0%	0.02

***Based on time allocation of multiple functions across the organization.

Note:

1 This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years. The required information includes:

- ***Type of Service:***

Services such as billing, accounting, payroll, etc. The applicant must identify any costs related to the Board of Directors of the parent company that are allocated to the applicant.

- ***Pricing Methodology:***

Pricing Methodology includes approaches such as cost-base, market-base, tendering, etc. The applicant must provide evidence demonstrating the pricing methodology used. The applicant must also provide a description of why that pricing methodology was chosen, whether or not it is in conformity with ARC, and why it is appropriate.

- ***% Allocation:***

The applicant must provide the percentage of the costs allocated to the entity for the service being offered. The Applicant must also provide a description of the allocator and why it is an appropriate allocator.

2 The above tables include the costs included in Toronto Hydro's OM&A expenses, as per the Filing Requirement reference 2.4.3.2, Shared Services and Corporate Cost Allocation

DEPRECIATION AND AMORTIZATION

This schedule provides information about Toronto Hydro's depreciation and amortization rates and expenses.

1. BACKGROUND

Toronto Hydro converted to International Financial Reporting Standards ("IFRS") effective January 1, 2015. This application represents Toronto Hydro's second rebasing application under Modified IFRS ("MIFRS").

2. FILING REQUIREMENTS

In accordance with s. 2.4.4 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (July 12, 2018), this schedule provides the following information:

- Details regarding depreciation, amortization and depletion by asset group for the 2015 to 2017 historical years, 2018 to 2019 bridge years and 2020 forecast year;
- A description of Toronto Hydro's depreciation and amortization practices and a summary of the changes implemented since the utility's last rebasing application;
- An explanation of Toronto Hydro's variance from the "half-year rule" regarding the calculation of depreciation expense; and
- Information about the utility's decommissioning provision and any associated depreciation or accretion expenses in relation to the decommissioning provision.

2.1 Depreciation Expense Details

Appendix A to this schedule provides the depreciation expense by Uniform System of Accounts for the historical (2015 to 2017), bridge (2018 to 2019) and forecast (2020) years. These amounts are based on MIFRS and include derecognition as described in Exhibit 4B, Tab 1, Schedule 2.

3. DEPRECIATION AND AMORTIZATION

In accordance with the OEB's Accounting Procedures Handbook for Electricity Distributors (the "APH"), Toronto Hydro depreciates and amortizes its assets on a straight-line basis over the estimated useful lives of the assets. Tables 1 and 2 below provide Toronto Hydro's annual depreciation and amortization rates by asset category for 2015 to 2017 (actual), 2018 and 2019 (bridge) and 2020 (forecast). Toronto Hydro does not expect any changes to the annual depreciation rates for 2021 to 2024.

In accordance with the OEB's filing requirements, Toronto Hydro is not required to file Appendix 2-BB as the utility has not made any changes to its depreciation and amortization practices or to estimated asset useful lives since its last rebasing application (EB-2014-0116). Regardless, a completed Appendix 2-BB is enclosed as Appendix C to this schedule.

/ C

As part of its normal course of business, Toronto Hydro has added new asset classes and made minor presentation changes to the grouping of asset categories related to depreciation. These presentation changes are discussed below.

Table 1: Property, Plant, and Equipment Depreciation Rates (%)

Asset Category	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Forecast
Distribution Lines	1.7 - 5.0	1.7 - 5.0	1.7 - 5.0	1.7 - 5.0	1.7 - 5.0	1.7 - 5.0
Transformers	3.3 - 5.0	3.3 - 5.0	3.3 - 5.0	3.3 - 5.0	3.3 - 5.0	3.3 - 5.0
Meters	2.5 - 6.7	2.5 - 6.7	2.5 - 6.7	2.5 - 6.7	2.5 - 6.7	2.5 - 6.7
Stations	2.5 - 10.0	2.5 - 10.0	2.0 - 10.0	2.0 - 10.0	2.0 - 10.0	2.0 - 10.0
Buildings	1.3 - 5.0	1.3 - 5.0	1.3 - 5.0	1.3 - 5.0	1.3 - 5.0	1.3 - 5.0
Other Capital Assets	4.0 - 25.0	4.0 - 25.0	4.0 - 25.0	4.0 - 25.0	4.0 - 25.0	4.0 - 25.0
Assets Under Capital Lease	1.0 - 14.3	1.0 - 14.3	1.0 - 14.3	1.0 - 14.3	1.0 - 14.3	1.0 - 14.3

Table 2: Intangible Assets Amortization Rates (%)

Asset Category	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Forecast
Computer Software	10.0 - 25.0	10.0 - 25.0	10.0 - 25.0	10.0 - 25.0	10.0 - 25.0	10.0 - 25.0
Contributions	4.0	4.0	4.0	4.0	4.0	4.0

3.1 Asset Categorization

Toronto Hydro did not make any changes to its depreciation and amortization practices since the last rebasing application, outside of the presentation of categories. The rolling stock, equipment and tools, computer hardware and communications depreciation categories which were discussed in the last rebasing application have been rolled into the other capital asset category, with no change to the depreciation rate applied.

3.2 Variance from Half-Year Rule

Toronto Hydro calculates depreciation based on the month that an asset comes into service, rather than on the basis of the half-year rule, which assumes that all asset additions are put into service in the middle of the fiscal year. Similarly, Toronto Hydro

calculates depreciation associated with assets that are retired, transferred or become fully depreciated within a given year based on the month of transaction.

Depreciation reflects the pattern in which the utility expects to receive the asset's future economic benefits over the useful life of the asset. IFRS (IAS 16.55) provides that "depreciation of an asset begins when it is available for use, i.e. when it is in the location and condition necessary for it to be capable of operating in the manner intended by management".

In accordance with these accounting principles, Toronto Hydro adopted a monthly depreciation methodology for the historical and forecasted years for reasons including that it:

1) Provides a more accurate reflection of the asset's future economic benefits over its useful life; and
2) Aligns the calculation of depreciation expense for rate making purposes with Toronto Hydro's external financial reporting policies and historical practices.

4. DECOMMISSIONING PROVISION

Toronto Hydro recognizes liabilities for the future removal and handling costs for contamination in distribution equipment and for the future environmental remediation of certain properties (collectively known as "decommissioning provisions") in accordance with Article 410 of the APH. A decommissioning provision is recognized at the time that the obligation arises. Initially, Toronto Hydro measures the liability at present value and the amount of the liability is added to the carrying amount of the related asset. In subsequent periods, the utility depreciates the capitalized amount over the useful life of the related asset and the liability is adjusted quarterly for the discount

applied upon initial recognition of the liability ("accretion expense") and for changes in the underlying assumptions.

Table 3 below sets out Toronto Hydro's historical and forecasted decommissioning costs and the related depreciation expense for 2015-2020. Table 4 below shows the corresponding decommissioning liability and related accretion expense.

Table 3: Historical and Forecasted Decommissioning Costs and Related Depreciation Expense ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Forecast
Decommissioning Costs	1.0	0.8	0.8	0.7	0.7	0.6
Related Depreciation Expense	0.1	0.1	0.1	0.1	0.1	0.1

Table 4: Historical and Forecasted Decommissioning Liability and Related Accretion Expense ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Forecast
Decommissioning Liability	1.9	1.5	1.5	1.3	1.3	1.2
Related Accretion Expense	-	-	-	-	-	-

5. DEPRECIATION AND AMORTIZATION EXPENSE

Table 5: Depreciation and Amortization Expense[1] 2015 to 2019 ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Forecast
Depreciation and Amortization Expense[2]	166.0	179.1	192.5	210.7	228.2	242.9

The year-over-year increases in depreciation and amortization expense are primarily due to Toronto Hydro's in-service asset additions. Depreciation and amortization expense reflected in revenue requirement (Exhibit 6, Tab 1, Schedule 1, Table 1) and Schedule 2-BA result from detailed calculations by asset class as determined through the utility's enterprise financial system for historical amounts, and financial models for forecast. This method incorporates the depreciation and amortization rates presented in Tables 1 and 2 and considers the actual timing of asset additions and removals from service.

As required, Toronto Hydro provides the OEB's Appendix 2-C in Appendix B to this exhibit but notes that the depreciation and amortization values in Appendix 2-C are based on broad assumptions. As a result, differences in depreciation and amortization values calculated by the financial system and using the formulas in Appendix 2-C are expected. For example, Appendix 2-C assumes depreciation in the first year, for all assets placed into service, begins at mid-year while Toronto Hydro depreciates assets from the month they are capitalized. In addition, applying broad depreciation assumptions to assets with shorter service lives (e.g. IT assets) and significant balances amplifies the magnitude of the differences in depreciation and amortization.

[1] Includes depreciation of the decommissioning costs and excludes derecognition. See Exhibit 4B, Tab 1, Schedule 2 for information about asset derecognition.
[2] See Exhibit 4B, Tab 1, Schedule 1, Appendix A for additional information.

Appendix A: Summary of Depreciation Expense

		2015 MIFRS			2016 MIFRS			2017 MIFRS			2018 MIFRS			2019 MIFRS			2020 MIFRS		
OEB	Description	Depreciation Expense	Derecognition	Total Depreciation Expense	Depreciation Expense	Derecognition	Total Depreciation Expense	Depreciation Expense	Derecognition	Total Depreciation Expense	Depreciation Expense	Derecognition	Total Depreciation Expense	Depreciation Expense	Derecognition	Total Depreciation Expense	Depreciation Expense	Derecognition	Total Depreciation Expense
1611	Computer Software (Formally known as Account 1925)	$ 19,290,957	$ -	$ 19,290,957	$ 19,291,705	$ -	$ 19,291,705	$ 19,982,844	$ -	$ 19,982,844	$ 20,892,805	$ 1,385,063	$ 22,277,868	$ 31,832,793	$ -	$ 31,832,793	$ 36,099,942	$ -	$ 36,099,942
1612	Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ 2,636,758	$ -	$ 2,636,758	$ 2,404,722	$ 8,590	$ 2,413,312	$ 2,796,835	$ -	$ 2,796,835	$ 3,308,486	$ 9,993	$ 3,318,479	$ 3,671,135	$ -	$ 3,671,135	$ 3,720,102	$ -	$ 3,720,102
1815	Transformer Station Equipment >50 kV	$ 404,102	$ -	$ 404,102	$ 404,897	$ -	$ 404,897	$ 651,800	$ 11,479	$ 663,278	$ 1,298,265	$ -	$ 1,298,265	$ 1,321,906	$ -	$ 1,321,906	$ 1,325,172	$ -	$ 1,325,172
1820	Distribution Station Equipment <50 kV	$ 7,285,185	$ 21,905	$ 7,307,090	$ 7,479,328	$ 374,856	$ 7,854,185	$ 7,811,055	$ 717,437	$ 8,528,492	$ 8,622,713	$ 751,097	$ 9,373,810	$ 10,158,330	$ 187,293	$ 10,345,623	$ 11,273,000	$ 230,873	$ 11,503,874
1830	Poles, Towers & Fixtures	$ 9,290,599	$ 6,288,437	$ 15,579,036	$ 10,031,935	$ 5,542,995	$ 15,574,929	$ 10,443,048	$ 2,735,544	$ 13,178,593	$ 10,921,669	$ 2,529,950	$ 13,451,618	$ 11,274,091	$ 4,507,458	$ 15,781,548	$ 11,739,346	$ 5,970,306	$ 17,709,652
1835	Overhead Conductors & Devices	$ 7,893,309	$ 2,637,264	$ 10,530,573	$ 9,360,888	$ 1,974,920	$ 11,335,808	$ 10,246,549	$ 2,290,636	$ 12,537,185	$ 10,827,432	$ 2,919,194	$ 13,746,626	$ 11,559,544	$ 1,766,477	$ 13,326,022	$ 12,364,683	$ 2,345,789	$ 14,710,472
1840	Underground Conduit	$ 37,556,567	$ 437,626	$ 37,994,193	$ 40,921,100	$ 595,780	$ 41,516,880	$ 42,854,989	$ 404,729	$ 43,259,718	$ 44,888,220	$ 426,821	$ 45,315,041	$ 47,539,941	$ 448,686	$ 47,988,627	$ 50,257,599	$ 570,460	$ 50,828,059
1845	Underground Conductors & Devices	$ 18,848,584	$ 4,327,216	$ 23,175,800	$ 21,057,038	$ 5,147,566	$ 26,204,603	$ 23,402,291	$ 5,946,699	$ 29,348,991	$ 25,369,256	$ 6,216,247	$ 31,585,502	$ 26,397,900	$ 3,917,577	$ 30,315,478	$ 29,225,810	$ 5,343,042	$ 34,568,852
1850	Line Transformers	$ 19,940,274	$ 8,109,405	$ 28,049,679	$ 21,221,738	$ 8,549,023	$ 29,770,760	$ 22,739,608	$ 8,366,045	$ 31,105,653	$ 23,997,546	$ 7,327,460	$ 31,325,006	$ 25,933,134	$ 7,491,686	$ 33,424,820	$ 28,236,015	$ 9,503,228	$ 37,739,243
1855	Services (Overhead & Underground)	$ 2,012,677	$ 292,242	$ 2,304,920	$ 2,418,759	$ 516,109	$ 2,934,869	$ 2,723,949	$ 1,113,020	$ 3,836,969	$ 2,947,558	$ 480,467	$ 3,428,026	$ 3,429,537	$ 268,161	$ 3,697,698	$ 3,818,256	$ 375,123	$ 4,193,379
1860	Meters	$ 13,384,647	$ 1,458,318	$ 14,842,965	$ 14,216,811	$ 4,332,646	$ 18,549,457	$ 14,956,008	$ 3,581,022	$ 18,537,030	$ 16,018,913	$ 2,559,854	$ 18,578,767	$ 17,185,912	$ 1,526,243	$ 18,712,155	$ 18,611,346	$ 1,431,703	$ 20,043,049
1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 6,451,486	$ 230,096	$ 6,681,582	$ 7,898,271	$ 7,299	$ 7,905,570	$ 10,714,877	$ 23,837	$ 10,738,714	$ 11,319,161	$ 113,573	$ 11,432,734	$ 11,349,805	$ -	$ 11,349,805	$ 11,382,932	$ -	$ 11,382,932
1910	Leasehold Improvements	$ 234,715	$ -	$ 234,715	$ 184,054	$ -	$ 184,054	$ 30,736	$ -	$ 30,736	$ 10,481	$ -	$ 10,481	$ 8,734	$ -	$ 8,734	$ -	$ -	$ -
1915	Office Furniture & Equipment	$ 1,762,299	$ -	$ 1,762,299	$ 1,688,533	$ 1,606	$ 1,690,139	$ 1,898,974	$ 66,913	$ 1,965,887	$ 2,051,264	$ 3,544	$ 2,054,807	$ 2,097,661	$ -	$ 2,097,661	$ 1,905,523	$ -	$ 1,905,523
1920	Computer Equipment - Hardware	$ 5,612,079	$ -	$ 5,612,079	$ 8,721,873	$ -	$ 8,721,873	$ 9,195,801	$ -	$ 9,195,801	$ 10,714,855	$ -	$ 10,714,855	$ 11,744,632	$ -	$ 11,744,632	$ 11,692,222	$ -	$ 11,692,222
1930	Transportation Equipment	$ 5,852,780	$ -	$ 5,852,780	$ 5,294,930	$ -	$ 5,294,930	$ 4,455,106	$ -	$ 4,455,106	$ 3,636,383	$ -	$ 3,636,383	$ 3,254,411	$ -	$ 3,254,411	$ 3,045,967	$ -	$ 3,045,967
1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 2,401,040	$ -	$ 2,401,040	$ 2,248,169	$ -	$ 2,248,169	$ 2,100,269	$ -	$ 2,100,269	$ 2,257,857	$ -	$ 2,257,857	$ 2,480,670	$ -	$ 2,480,670	$ 3,095,774	$ -	$ 3,095,774
1945	Measurement & Testing Equipment	$ 67,711	$ -	$ 67,711	$ 67,711	$ -	$ 67,711	$ 67,053	$ -	$ 67,053	$ 59,822	$ -	$ 59,822	$ 59,861	$ -	$ 59,861	$ 44,522	$ -	$ 44,522
1950	Power Operated Equipment	$ 122,523	$ -	$ 122,523	$ 102,041	$ -	$ 102,041	$ 95,035	$ -	$ 95,035	$ 158,280	$ -	$ 158,280	$ 95,793	$ -	$ 95,793	$ 84,739	$ -	$ 84,739
1955	Communications Equipment	$ 2,202,404	$ -	$ 2,202,404	$ 2,100,612	$ -	$ 2,100,612	$ 4,010,158	$ -	$ 4,010,158	$ 4,690,337	$ -	$ 4,690,337	$ 4,122,018	$ -	$ 4,122,018	$ 3,827,071	$ -	$ 3,827,071
1960	Miscellaneous Equipment	$ 36,919	$ -	$ 36,919	$ 37,245	$ -	$ 37,245	$ 37,310	$ -	$ 37,310	$ 37,310	$ -	$ 37,310	$ 37,712	$ -	$ 37,712	$ 34,673	$ -	$ 34,673
1970	Load Management Controls Customer Premises	$ 1,067,310	$ -	$ 1,067,310	$ 836,068	$ -	$ 836,068	$ 37,379	$ -	$ 37,379	($ 62,634)	$ -	($ 62,634)	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 2,253,207	$ 711,842	$ 2,965,049	$ 2,273,836	$ 441,014	$ 2,714,850	$ 2,364,096	$ 393,416	$ 2,757,512	$ 2,668,961	$ 308,612	$ 2,977,573	$ 3,581,825	$ 409,567	$ 3,991,391	$ 4,128,590	$ 560,039	$ 4,688,628
2440	Contributions & Grants	($ 2,210,580)	($ 375,192)	($ 2,585,773)	($ 3,765,318)	($ 501,631)	($ 4,266,949)	($ 4,710,955)	($ 1,113,168)	($ 5,824,124)	$ -	$ -	$ -	($ 6,334,692)	($ 400,524)	($ 6,735,216)	($ 8,995,336)	($ 537,050)	($ 9,532,386)
1609	Capital Contributions Paid	$ 1,127,378	$ -	$ 1,127,378	$ 2,056,028	$ -	$ 2,056,028	$ 3,140,006	$ -	$ 3,140,006	$ 3,538,390	$ -	$ 3,538,390	$ 7,676,972	$ -	$ 7,676,972	$ 8,780,891	$ -	$ 8,780,891
2005	Property Under Capital Leases	$ 2,254,564	$ -	$ 2,254,564	$ 2,254,564	$ -	$ 2,254,564	$ 2,064,349	$ -	$ 2,064,349	$ 1,320,504	$ -	$ 1,320,504	$ 89,423	$ -	$ 89,423	$ 89,423	$ -	$ 89,423
	Sub-Total	$ 167,779,494	$ 24,139,160	$ 191,918,654	$ 180,807,538	$ 26,990,771	$ 207,798,309	$ 194,109,167	$ 24,537,611	$ 218,646,778	$ 211,493,835	$ 25,031,872	$ 236,525,708	$ 230,569,049	$ 20,122,625	$ 250,691,674	$ 245,788,261	$ 25,793,513	$ 271,581,774
	Less Socialized Renewable Energy Generation Investments (input as negative)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	($ 113,812)	$ -	($ 113,812)	($ 570,353)	$ -	($ 570,353)
	Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -	$ -	$ -	$ -	$ -	$ -	($ 33,367)	$ -	($ 33,367)	$ 133,468	$ -	$ 133,468	($ 453,429)	$ -	($ 453,429)	($ 587,711)	$ -	($ 587,711)
	Total	$ 167,779,494	$ 24,139,160	$ 191,918,654	$ 180,807,538	$ 26,990,771	$ 207,798,309	$ 194,075,800	$ 24,537,611	$ 218,613,411	$ 211,627,304	$ 25,031,872	$ 236,659,176	$ 230,001,808	$ 20,122,625	$ 250,124,434	$ 244,630,196	$ 25,793,513	$ 270,423,709
	Less: *Fully Allocated Depreciation*																		
	Transportation	($ 1,799,817)		($ 1,799,817)	($ 1,721,911)		($ 1,721,911)	($ 1,622,598)		($ 1,622,598)	($ 961,328)		($ 961,328)	($ 1,759,521)		($ 1,759,521)	($ 1,759,521)		($ 1,759,521)
	Net Depreciation	**$ 165,979,678**	**$ 24,139,160**	**$ 190,118,837**	**$ 179,085,627**	**$ 26,990,771**	**$ 206,076,398**	**$ 192,453,202**	**$ 24,537,611**	**$ 216,990,813**	**$ 210,665,976**	**$ 25,031,872**	**$ 235,697,848**	**$ 228,242,288**	**$ 20,122,625**	**$ 248,364,913**	**$ 242,870,675**	**$ 25,793,513**	**$ 268,664,188**

Appendix 2-C
Depreciation and Amortization Expense

This appendix is to be completed in conjunction with the accounting instructions in Appendix 2-B

Scenario that applies	Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012. ☐	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Rebasing for the first time with depreciation policy changes made in 2013. ☐	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Already rebased with depreciation policy changes in a prior rate application ☑	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).	2015	MIFRS

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 69,572,669	$ 6,806,320	$ 62,766,349	$ 17,158,081		$ 17,158,081	$ 14,918,812	4.91	20.36%	4.76	21.02%	**$ 12,776,458**	**$ 3,606,252**	**$ 1,567,803**	**$ 17,950,512**	$ 19,290,957	**$ 1,340,445**
1612	Land Rights	$ -	$ -	$ -	$ -		$ -	$ -	-	0.00%	-	0.00%	**$ -**	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1805	Land	$ 7,588,531	$ -	$ 7,588,531	-$ 8,030		-$ 8,030	$ -	-	0.00%	-	0.00%	**$ -**	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1808	Buildings	$ 29,677,626	$ 2,912,639	$ 26,764,988	-$ 402,428		-$ 402,428	$ 22,289,048	18.08	5.53%	62.45	1.60%	**$ 1,480,511**	**-$ 6,444**	**$ 178,456**	**$ 1,652,523**	$ 2,636,758	**$ 984,235**
1815	Transformer Station Equipment >50 kV	$ 5,839,955	$ -	$ 5,839,955	$ 24		$ 24	$ -	14.45	6.92%	-	0.00%	**$ 404,100**	**$ -**	**$ -**	**$ 404,100**	$ 404,102	**$ 2**
1820	Distribution Station Equipment <50 kV	$ 112,667,455	$ 174,306	$ 112,493,149	$ 30,399,194		$ 30,399,194	$ 6,822,070	19.20	5.21%	28.31	3.53%	**$ 5,858,973**	**$ 1,073,873**	**$ 120,497**	**$ 7,053,342**	$ 7,285,185	**$ 231,843**
1830	Poles, Towers & Fixtures	$ 208,620,348	$ 135,709	$ 208,484,640	$ 70,674,946		$ 70,674,946	$ 38,385,574	31.60	3.16%	37.87	2.64%	**$ 6,596,772**	**$ 1,866,230**	**$ 506,801**	**$ 8,969,803**	$ 9,290,599	**$ 320,796**
1835	Overhead Conductors & Devices	$ 197,786,423	$ 242,709	$ 197,543,713	$ 55,811,276		$ 55,811,276	$ 48,487,450	34.02	2.94%	44.63	2.24%	**$ 5,806,909**	**$ 1,250,531**	**$ 543,215**	**$ 7,600,656**	$ 7,893,309	**$ 292,653**
1840	Underground Conduit	$ 639,376,710	$ 854,436	$ 638,522,274	$ 216,195,167		$ 216,195,167	$ 96,834,638	22.27	4.49%	33.26	3.01%	**$ 28,676,375**	**$ 6,500,135**	**$ 1,455,718**	**$ 36,632,227**	$ 37,556,567	**$ 924,340**
1845	Underground Conductors & Devices	$ 397,494,067	$ 1,719,873	$ 395,774,194	$ 131,334,521		$ 131,334,521	$ 85,845,120	31.09	3.22%	36.82	2.72%	**$ 12,729,848**	**$ 3,566,515**	**$ 1,165,603**	**$ 17,461,967**	$ 18,848,584	**$ 1,386,618**
1850	Line Transformers	$ 305,215,157	$ 6,989,425	$ 298,225,732	$ 63,607,838		$ 63,607,838	$ 52,697,845	18.14	5.51%	27.59	3.62%	**$ 16,439,232**	**$ 2,305,741**	**$ 955,131**	**$ 19,700,104**	$ 19,940,274	**$ 240,169**
1855	Services (Overhead & Underground)	$ 61,419,385	$ 14,306	$ 61,405,079	$ 13,832,001		$ 13,832,001	$ 18,367,060	40.50	2.47%	44.35	2.25%	**$ 1,516,306**	**$ 311,883**	**$ 207,069**	**$ 2,035,258**	$ 2,012,677	**-$ 22,581**
1860	Meters	$ 44,538,583	$ 4,686	$ 44,533,896	$ 6,513,784		$ 6,513,784	$ 10,745,470	19.72	5.07%	19.07	5.24%	**$ 2,258,856**	**$ 341,630**	**$ 281,785**	**$ 2,882,272**	$ 3,131,803	**$ 249,531**
1860	Meters (Smart Meters)	$ 94,589,513	$ 6,353	$ 94,583,160	$ 7,273,587		$ 7,273,587	$ 6,712,905	9.75	10.25%	15.00	6.67%	**$ 9,696,869**	**$ 484,906**	**$ 223,764**	**$ 10,405,538**	$ 10,252,844	**-$ 152,694**
1905	Land	$ 9,150,994	$ -	$ 9,150,994	$ 9,250,031		$ 9,250,031	$ -	-	0.00%	-	0.00%	**$ -**	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 65,356,634	$ 3,796,564	$ 61,560,071	$ 16,995,733		$ 16,995,733	$ 45,213,438	12.89	7.76%	26.13	3.83%	**$ 4,774,727**	**$ 650,316**	**$ 865,012**	**$ 6,290,055**	$ 6,451,486	**$ 161,431**
1910	Leasehold Improvements	$ 701,434	$ 132,441	$ 568,992	$ 52,406		$ 52,406	-$ 0	3.03	32.97%	5.00	20.00%	**$ 187,583**	**$ 10,481**	**-$ 0**	**$ 198,064**	$ 234,715	**$ 36,651**
1915	Office Furniture & Equipment	$ 9,802,431	$ 656,684	$ 9,145,747	$ 33,319		$ 33,319	$ 921,298	5.87	17.02%	10.00	10.00%	**$ 1,556,948**	**$ 3,332**	**$ 46,065**	**$ 1,606,345**	$ 1,762,299	**$ 155,954**
1920	Computer Equipment - Hardware	$ 11,192,631	$ 2,265,073	$ 8,927,558	$ 8,779,388		$ 8,779,388	$ 7,346,747	3.34	29.93%	4.53	22.05%	**$ 2,672,050**	**$ 1,936,107**	**$ 810,084**	**$ 5,418,241**	$ 5,612,079	**$ 193,839**
1930	Transportation Equipment	$ 21,967,081	$ 1,594,665	$ 20,372,416	$ 2,131,310		$ 2,131,310	$ 2,522,325	4.03	24.80%	7.73	12.94%	**$ 5,052,584**	**$ 275,794**	**$ 163,196**	**$ 5,491,573**	$ 5,852,780	**$ 361,206**
1935	Stores Equipment	$ 7,066	$ 7,066	$ -	$ -		$ -	$ -	-	0.00%	-	0.00%	**$ -**	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 11,036,987	$ 580,501	$ 10,456,486	$ 1,825,237		$ 1,825,237	$ 1,879,478	5.61	17.81%	10.00	10.00%	**$ 1,862,802**	**$ 182,524**	**$ 93,974**	**$ 2,139,299**	$ 2,401,040	**$ 261,741**
1945	Measurement & Testing Equipment	$ 9,367,510	$ 4,392	$ 9,363,118	-$ 8,887,507		-$ 8,887,507	$ 239	4.39	22.77%	4.39	22.77%	**$ 2,131,812**	**-$ 2,023,524**	**$ 27**	**$ 108,315**	$ 67,711	**-$ 40,605**
1950	Service Equipment	$ 615,688	$ 64,211	$ 551,476	$ 20,747		$ 20,747	$ -	5.09	19.66%	8.00	12.50%	**$ 108,436**	**-$ 2,593**	**$ -**	**$ 111,029**	$ 122,523	**$ 11,494**
1955	Communications Equipment	$ 4,593,288	$ 911,619	$ 3,681,669	$ 2,920,677		$ 2,920,677	$ 511,863	2.94	34.04%	5.52	18.10%	**$ 1,253,215**	**$ 528,700**	**$ 46,329**	**$ 1,828,244**	$ 2,202,404	**$ 374,161**
1960	Miscellaneous Equipment	$ 267,071	$ -	$ 267,071	$ -		$ -	$ -	7.23	13.82%	-	0.00%	**$ 36,919**	**$ -**	**$ -**	**$ 36,919**	$ 36,919	**-$ 0**
1970	Load Management Controls Customer Premises	$ 3,022,834	$ 87,491	$ 2,935,342	$ -		$ -	$ -	2.85	35.12%	-	0.00%	**$ 1,030,948**	**$ -**	**$ -**	**$ 1,030,948**	$ 1,067,310	**$ 36,362**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -		$ -	$ -	-	0.00%	-	0.00%	**$ -**	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 19,174,795	$ 409,094	$ 18,765,702	$ 3,888,039		$ 3,888,039	$ 3,137,694	11.09	9.02%	14.86	6.73%	**$ 1,692,192**	**$ 261,713**	**$ 105,603**	**$ 2,059,509**	$ 2,253,207	**$ 193,699**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -		$ -	$ -	-	0.00%	-	0.00%	**$ -**	**$ -**	**$ -**	**$ -**	$ -	**$ -**
2440	Contributions & Grants (Formally known as Account 1995)	$ -	$ -	$ -	-$ 28,510,489		-$ 28,510,489	-$ 30,083,801	-	0.00%	35.93	2.78%	**$ -**	**-$ 793,517**	**-$ 418,653**	**-$ 1,212,170**	-$ 2,210,580	**-$ 998,410**
1609	Capital Contributions Paid	$ 19,104,312	$ -	$ 19,104,312	$ 862,476		$ 862,476	$ 1,763,500	21.68	4.61%	23.07	4.33%	**$ 881,195**	**$ 37,387**	**$ 38,222**	**$ 956,804**	$ 1,127,378	**$ 170,575**
2005	Property Under Capital Leases	$ 7,191,090	$ -	$ 7,191,090	$ 10,979,744	$ 1,648,742	$ 9,331,002	$ -	80.42	1.24%	4.31	23.20%	**$ 89,423**	**$ 2,165,141**	**$ -**	**$ 2,254,564**	$ 2,254,564	**-$ 0**
	Sub-Total	**$ 2,366,938,267**	**$ 30,370,566**	**$ 2,336,567,702**	**$ 632,731,071**	**$ 1,648,742**	**$ 631,082,329**	**$ 435,318,773**					**$ 127,572,042**	**$ 24,538,298**	**$ 8,955,701**	**$ 161,066,041**	**$ 167,779,494**	**$ 6,713,453**
	Less Socialized Renewable Energy Generation Investments ***(input as negative)***			$ -			$ -	$ -		0.00%		0.00%	**$ -**	**$ -**	**$ -**	**$ -**	$ -	**$ -**
	Less Other Non Rate-Regulated Utility Assets ***(input as negative)***			$ -			$ -	$ -		0.00%		0.00%	**$ -**	**$ -**	**$ -**	**$ -**	$ -	**$ -**
	Total	**$ 2,366,938,267**	**$ 30,370,566**	**$ 2,336,567,702**	**$ 632,731,071**	**$ 1,648,742**	**$ 631,082,329**	**$ 435,318,773**					**$ 127,572,042**	**$ 24,538,298**	**$ 8,955,701**	**$ 161,066,041**	**$ 167,779,494**	**$ 6,713,453**

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1 This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.

2 This is the opening gross book value of assets that have been acquired after the date of the utilities change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the gross book value of the prior year plus the prior year's additions.
A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as at January 1 of the year of policy changes. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the revised CGAAP as at January 1 of the year of policy changes.

3

4 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.

5 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

6 The applicant must provide an explanation of material variances in evidence.

7 This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change

8 This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

Appendix 2-C
Depreciation and Amortization Expense

This appendix is to be completed in conjunction with the accounting instructions in Appendix 2-B

Scenario that applies	Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule
Rebasing for the first time with depreciation policy changes made in 2012. ☐	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Rebasing for the first time with depreciation policy changes made in 2013. ☐	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Already rebased with depreciation policy changes in a prior rate application ☑	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).	2016	MIFRS

		Book Values							Service Lives				Depreciation Expense						
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1)[1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 69,572,669	$ 12,999,956	$ 56,572,713	$ 32,076,893	$ -	$ 32,076,893	$ 11,914,202	4.91	20.36%	4.82	20.74%	$ 11,515,707	$ 6,652,949	$ 1,235,540	$ 19,404,195	$ 19,291,705	-$ 112,490
1612	Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land	$ 7,588,531	$ -	$ 7,588,531	-$ 8,030	$ -	-$ 8,030	$ -	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ 29,677,626	$ 4,319,418	$ 25,358,208	$ 21,886,621	$ 5,350	$ 21,881,271	$ 53,726,576	18.08	5.53%	68.65	1.46%	$ 1,402,694	$ 318,756	$ 391,332	$ 2,112,782	$ 2,404,722	$ 291,940
1815	Transformer Station Equipment >50 kV	$ 5,839,955	$ -	$ 5,839,955	$ 24	$ -	$ 24	$ 152,667	14.45	6.92%	32.00	3.13%	$ 404,100	$ 1	$ 2,385	$ 406,486	$ 404,897	-$ 1,589
1820	Distribution Station Equipment <50 kV	$ 112,667,455	$ 593,507	$ 112,073,949	$ 37,221,263	$ -	$ 37,221,263	$ 7,439,750	19.20	5.21%	28.68	3.49%	$ 5,837,139	$ 1,297,664	$ 129,688	$ 7,264,491	$ 7,479,328	$ 214,838
1830	Poles, Towers & Fixtures	$ 208,620,348	$ 523,138	$ 208,097,210	$ 109,060,521	$ 274,745	$ 108,785,776	$ 34,585,346	31.60	3.16%	37.46	2.67%	$ 6,584,513	$ 2,904,401	$ 461,686	$ 9,950,599	$ 10,031,935	$ 81,335
1835	Overhead Conductors & Devices	$ 197,786,423	$ 556,091	$ 197,230,332	$ 104,298,726	$ 67,113	$ 104,231,613	$ 52,320,421	34.02	2.94%	44.24	2.26%	$ 5,797,697	$ 2,356,062	$ 591,328	$ 8,745,087	$ 9,360,888	$ 615,801
1840	Underground Conduit	$ 639,376,710	$ 1,807,136	$ 637,569,573	$ 313,029,805	$ 72,195	$ 312,957,610	$ 99,687,834	22.27	4.49%	33.34	3.00%	$ 28,633,588	$ 9,387,375	$ 1,495,102	$ 39,516,065	$ 40,921,100	$ 1,405,035
1845	Underground Conductors & Devices	$ 397,494,067	$ 3,692,376	$ 393,801,691	$ 217,179,641	$ 1,064,923	$ 216,114,718	$ 86,622,401	31.09	3.22%	36.93	2.71%	$ 12,666,403	$ 5,851,601	$ 1,172,710	$ 19,690,714	$ 21,057,038	$ 1,366,323
1850	Line Transformers	$ 305,215,157	$ 4,278,969	$ 300,936,188	$ 116,305,683	$ 42,532	$ 116,263,151	$ 63,107,081	18.14	5.51%	27.52	3.63%	$ 16,588,642	$ 4,225,270	$ 1,146,728	$ 21,960,640	$ 21,221,738	-$ 738,902
1855	Services (Overhead & Underground)	$ 61,419,385	$ 204,199	$ 61,215,186	$ 32,199,061	$ 3,158	$ 32,195,903	$ 16,333,002	40.50	2.47%	44.37	2.25%	$ 1,511,617	$ 725,659	$ 184,064	$ 2,421,340	$ 2,418,759	-$ 2,581
1860	Meters	$ 44,538,583	$ 676,092	$ 43,862,491	$ 17,259,253	$ 20,696	$ 17,238,557	$ 13,064,420	19.72	5.07%	20.45	4.89%	$ 2,224,801	$ 843,045	$ 319,455	$ 3,387,301	$ 3,742,156	$ 354,855
1860	Meters (Smart Meters)	$ 94,589,513	$ 1,273,230	$ 93,316,284	$ 13,986,492	$ -	$ 13,986,492	$ 4,596,069	9.75	10.25%	15.00	6.67%	$ 9,566,986	$ 932,433	$ 153,202	$ 10,652,621	$ 10,474,655	-$ 177,966
1905	Land	$ 9,150,994	$ -	$ 9,150,994	$ 9,250,031	$ -	$ 9,250,031	$ 301	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 65,356,634	$ 7,174,806	$ 58,181,828	$ 62,209,171	$ 281,185	$ 61,927,986	$ 57,613,894	12.89	7.76%	32.10	3.12%	$ 4,512,703	$ 1,929,248	$ 897,425	$ 7,339,376	$ 7,898,271	$ 558,895
1910	Leasehold Improvements	$ 701,434	$ 570,148	$ 131,286	$ 52,406	$ -	$ 52,406	$ -	3.03	32.97%	5.00	20.00%	$ 43,282	$ 10,481	$ -	$ 53,763	$ 184,054	$ 130,291
1915	Office Furniture & Equipment	$ 9,802,431	$ 1,653,568	$ 8,148,863	$ 954,617	$ -	$ 954,617	$ 4,541,011	5.87	17.02%	10.00	10.00%	$ 1,387,241	$ 95,462	$ 227,051	$ 1,709,753	$ 1,688,533	-$ 21,221
1920	Computer Equipment - Hardware	$ 11,192,631	$ 4,793,678	$ 6,398,953	$ 16,126,136	$ 389,901	$ 15,736,235	$ 19,919,107	3.34	29.93%	5.00	20.00%	$ 1,915,230	$ 3,147,789	$ 1,992,254	$ 7,055,272	$ 8,721,873	$ 1,666,601
1930	Transportation Equipment	$ 21,967,081	$ 5,461,297	$ 16,505,784	$ 4,653,635	$ -	$ 4,653,635	$ 3,390,059	4.03	24.80%	7.37	13.58%	$ 4,093,617	$ 631,823	$ 230,134	$ 4,955,573	$ 5,294,930	$ 339,357
1935	Stores Equipment	$ 7,066	$ 7,066	$ -	$ -	$ -	$ -	$ -	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 11,036,987	$ 2,153,197	$ 8,883,790	$ 3,704,715	$ -	$ 3,704,715	$ 3,129,240	5.61	17.81%	9.91	10.09%	$ 1,582,629	$ 373,966	$ 157,938	$ 2,114,533	$ 2,248,169	$ 133,636
1945	Measurement & Testing Equipment	$ 9,367,510	$ 4,392	$ 9,363,118	-$ 8,887,268	$ -	-$ 8,887,268	$ -	4.39	22.77%	4.39	22.77%	$ 2,131,812	-$ 2,023,470	$ -	$ 108,343	$ 67,711	-$ 40,632
1950	Service Equipment	$ 615,688	$ 115,477	$ 500,210	$ 20,747	$ -	$ 20,747	$ 22,000	5.09	19.66%	8.00	12.50%	$ 98,356	$ 2,593	$ 1,375	$ 102,324	$ 102,041	-$ 283
1955	Communications Equipment	$ 4,593,288	$ 3,183,808	$ 1,409,480	$ 3,432,541	$ -	$ 3,432,541	$ 27,860,758	2.94	34.04%	11.38	8.79%	$ 479,777	$ 301,587	$ 1,223,940	$ 2,005,305	$ 2,100,612	$ 95,307
1960	Miscellaneous Equipment	$ 267,071	$ -	$ 267,071	$ -	$ -	$ -	$ 3,907	7.23	13.82%	10.00	10.00%	$ 36,919	$ -	$ 195	$ 37,114	$ 37,245	$ 130
1970	Load Management Controls Customer Premises	$ 3,022,834	$ 2,013,119	$ 1,009,715	$ -	$ -	$ -	$ -	2.85	35.12%	-	0.00%	$ 354,631	$ -	$ -	$ 354,631	$ 836,068	$ 481,437
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 19,174,795	$ 1,353,959	$ 17,820,837	$ 7,025,733	$ -	$ 7,025,733	$ 3,264,626	11.09	9.02%	14.90	6.71%	$ 1,606,989	$ 471,457	$ 109,535	$ 2,187,982	$ 2,273,836	$ 85,854
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
2440	Contributions & Grants (Formally known as Account 1995)	$ -	$ -	$ -	-$ 58,594,290	-$ 829,259	-$ 57,765,032	-$ 32,842,749	-	0.00%	35.42	2.82%	$ -	-$ 1,630,963	-$ 463,648	-$ 2,094,612	-$ 3,765,318	-$ 1,670,707
1609	Capital Contributions Paid	$ 19,104,312	$ -	$ 19,104,312	$ 2,625,976	$ -	$ 2,625,976	$ 53,844,210	21.68	4.61%	24.92	4.01%	$ 881,195	$ 105,389	$ 1,080,474	$ 2,067,058	$ 2,056,028	-$ 11,030
2005	Property Under Capital Leases	$ 7,191,090	$ -	$ 7,191,090	$ 10,979,744	$ 1,648,742	$ 9,331,002	$ -	80.42	1.24%	4.31	23.20%	$ 89,423	$ 2,165,141	$ -	$ 2,254,564	$ 2,254,564	-$ 0
	Sub-Total	**$ 2,366,938,267**	**$ 59,408,628**	**$ 2,307,529,639**	**$ 1,068,049,844**	**$ 3,041,282**	**$ 1,065,008,562**	**$ 584,296,135**					**$ 121,947,693**	**$ 41,075,717**	**$ 12,739,892**	**$ 175,763,302**	**$ 180,807,538**	**$ 5,044,236**
	Less Socialized Renewable Energy Generation Investments ***(input as negative)***	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
	Less Other Non Rate-Regulated Utility Assets ***(input as negative)***	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
	Total	**$ 2,366,938,267**	**$ 59,408,628**	**$ 2,307,529,639**	**$ 1,068,049,844**	**$ 3,041,282**	**$ 1,065,008,562**	**$ 584,296,135**					**$ 121,947,693**	**$ 41,075,717**	**$ 12,739,892**	**$ 175,763,302**	**$ 180,807,538**	**$ 5,044,236**

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1 This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.

2 This is the opening gross book value of assets that have been acquired after the date of the utilities change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the gross book value of the prior year plus the prior year's additions.
A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as at January 1 of the year of policy changes. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the revised CGAAP as at January 1 of the year of policy changes.

3

4 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.

5 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

6 The applicant must provide an explanation of material variances in evidence.

7 This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change

8 This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

Appendix 2-C
Depreciation and Amortization Expense

This appendix is to be completed in conjunction with the accounting instructions in Appendix 2-B

Scenario that applies	Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012. ☐	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Rebasing for the first time with depreciation policy changes made in 2013. ☐	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Already rebased with depreciation policy changes in a prior rate application ☑	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).	2017	MIFRS

		Book Values							Service Lives				Depreciation Expense						
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1)[1]	Less Fully Depreciated[7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change[2]	Less Fully Depreciated[8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change[3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change[4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions[5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance[6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 69,572,669	$ 28,723,849	$ 40,848,820	$ 43,991,094	$ -	$ 43,991,094	$ 23,396,902	4.91	20.36%	4.88	20.48%	**$ 8,315,016**	**$ 9,009,298**	**$ 2,395,822**	**$ 19,720,137**	$ 19,982,844	**$ 262,707**
1612	Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	-	0.00%	**$ -**	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1805	Land	$ 7,588,531	$ -	$ 7,588,531	-$ 8,030	$ -	-$ 8,030	$ -	-	0.00%	-	0.00%	**$ -**	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1808	Buildings	$ 29,677,626	$ 3,130,730	$ 26,546,897	$ 75,613,197	$ 5,350	$ 75,607,847	$ 11,714,238	18.08	5.53%	66.17	1.51%	**$ 1,468,447**	**$ 1,142,686**	**$ 88,521**	**$ 2,699,654**	$ 2,796,835	**$ 97,181**
1815	Transformer Station Equipment >50 kV	$ 5,839,955	$ 13,224	$ 5,826,730	$ 152,691	$ -	$ 152,691	$ 30,938,545	14.45	6.92%	37.08	2.70%	**$ 403,185**	**$ 4,118**	**$ 417,174**	**$ 824,477**	$ 651,800	**-$ 172,677**
1820	Distribution Station Equipment <50 kV	$ 112,667,455	$ 1,224,334	$ 111,443,121	$ 44,661,013	$ -	$ 44,661,013	$ 28,828,722	19.20	5.21%	31.08	3.22%	**$ 5,804,284**	**$ 1,437,016**	**$ 463,798**	**$ 7,705,098**	$ 7,811,055	**$ 105,957**
1830	Poles, Towers & Fixtures	$ 208,620,348	$ 714,621	$ 207,905,727	$ 143,645,867	$ 936,696	$ 142,709,171	$ 26,137,523	31.60	3.16%	37.82	2.64%	**$ 6,578,454**	**$ 3,772,898**	**$ 345,508**	**$ 10,696,859**	$ 10,443,048	**-$ 253,811**
1835	Overhead Conductors & Devices	$ 197,786,423	$ 665,967	$ 197,120,456	$ 156,619,147	$ 852,220	$ 155,766,927	$ 43,677,626	34.02	2.94%	44.48	2.25%	**$ 5,794,467**	**$ 3,502,044**	**$ 490,993**	**$ 9,787,505**	$ 10,246,549	**$ 459,044**
1840	Underground Conduit	$ 639,376,710	$ 3,010,042	$ 636,366,667	$ 412,717,640	$ 81,779	$ 412,635,860	$ 77,448,153	22.27	4.49%	33.11	3.02%	**$ 28,579,565**	**$ 12,460,854**	**$ 1,169,397**	**$ 42,209,816**	$ 42,854,989	**$ 645,173**
1845	Underground Conductors & Devices	$ 397,494,067	$ 5,796,942	$ 391,697,125	$ 303,802,042	$ 2,977,281	$ 300,824,761	$ 98,821,342	31.09	3.22%	37.13	2.69%	**$ 12,598,711**	**$ 8,102,996**	**$ 1,330,923**	**$ 22,032,630**	$ 23,402,291	**$ 1,369,661**
1850	Line Transformers	$ 305,215,157	$ 6,197,455	$ 299,017,702	$ 179,412,764	$ 1,297,338	$ 178,115,426	$ 66,492,438	18.14	5.51%	27.53	3.63%	**$ 16,482,889**	**$ 6,470,359**	**$ 1,207,728**	**$ 24,160,975**	$ 22,739,608	**-$ 1,421,367**
1855	Services (Overhead & Underground)	$ 61,419,385	$ 719,489	$ 60,699,896	$ 48,532,063	$ 52,517	$ 48,479,546	$ 14,283,272	40.50	2.47%	43.99	2.27%	**$ 1,498,893**	**$ 1,102,156**	**$ 162,361**	**$ 2,763,410**	$ 2,723,949	**-$ 39,461**
1860	Meters	$ 44,538,583	$ 1,198,476	$ 43,340,106	$ 30,323,673	$ 125,058	$ 30,198,616	$ 8,019,209	19.72	5.07%	20.83	4.80%	**$ 2,198,305**	**$ 1,449,684**	**$ 192,481**	**$ 3,840,470**	$ 4,133,564	**$ 293,094**
1860	Meters (Smart Meters)	$ 94,589,513	$ 2,176,233	$ 92,413,280	$ 18,582,561	$ 106,085	$ 18,476,475	$ 15,926,835	9.75	10.25%	15.00	6.67%	**$ 9,474,408**	**$ 1,231,765**	**$ 530,894**	**$ 11,237,067**	$ 10,822,444	**-$ 414,623**
1905	Land	$ 9,150,994	$ -	$ 9,150,994	$ 9,250,332	$ -	$ 9,250,332	$ -	-	0.00%	-	0.00%	**$ -**	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 65,356,634	$ 4,656,826	$ 60,699,808	$ 119,823,065	$ 2,372,563	$ 117,450,501	$ 65,192,176	12.89	7.76%	31.10	3.22%	**$ 4,708,003**	**$ 3,776,548**	**$ 1,048,107**	**$ 9,532,657**	$ 10,714,877	**$ 1,182,219**
1910	Leasehold Improvements	$ 701,434	$ 701,434	$ -	$ 52,406	$ -	$ 52,406	$ -	3.03	32.97%	5.00	20.00%	**$ -**	**$ 10,481**	**$ -**	**$ 10,481**	$ 30,736	**$ 20,254**
1915	Office Furniture & Equipment	$ 9,802,431	$ 2,135,113	$ 7,667,318	$ 5,495,628	$ -	$ 5,495,628	$ 3,731,695	5.87	17.02%	10.00	10.00%	**$ 1,305,264**	**$ 549,563**	**$ 186,585**	**$ 2,041,412**	$ 1,898,974	**-$ 142,438**
1920	Computer Equipment - Hardware	$ 11,192,631	$ 9,482,098	$ 1,710,533	$ 36,045,243	$ 389,901	$ 35,655,342	$ 11,445,468	3.34	29.93%	4.92	20.31%	**$ 511,969**	**$ 7,241,084**	**$ 1,162,204**	**$ 8,915,257**	$ 9,195,801	**$ 280,544**
1930	Transportation Equipment	$ 21,967,081	$ 10,076,979	$ 11,890,102	$ 8,043,694	$ -	$ 8,043,694	$ 4,044,806	4.03	24.80%	7.44	13.44%	**$ 2,948,877**	**$ 1,080,696**	**$ 271,716**	**$ 4,301,288**	$ 4,455,106	**$ 153,818**
1935	Stores Equipment	$ 7,066	$ 7,066	$ -	$ -	$ -	$ -	$ -	-	0.00%	-	0.00%	**$ -**	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 11,036,987	$ 2,633,504	$ 8,403,483	$ 6,833,955	$ -	$ 6,833,955	$ 3,325,955	5.61	17.81%	9.94	10.06%	**$ 1,497,064**	**$ 687,653**	**$ 167,334**	**$ 2,352,050**	$ 2,100,269	**-$ 251,781**
1945	Measurement & Testing Equipment	$ 9,367,510	$ 35,289	$ 9,332,221	-$ 8,887,268	$ -	-$ 8,887,268	$ -	4.39	22.77%	4.39	22.77%	**$ 2,124,778**	**-$ 2,023,470**	**$ -**	**$ 101,308**	$ 67,053	**-$ 34,254**
1950	Service Equipment	$ 615,688	$ 115,477	$ 500,210	$ 42,747	$ -	$ 42,747	$ 187,338	5.09	19.66%	8.00	12.50%	**$ 98,356**	**$ 5,343**	**$ 11,709**	**$ 115,408**	$ 95,035	**-$ 20,373**
1955	Communications Equipment	$ 4,593,288	$ 3,682,500	$ 910,787	$ 31,293,298	$ -	$ 31,293,298	$ 9,471,460	2.94	34.04%	13.43	7.45%	**$ 310,026**	**$ 2,330,528**	**$ 352,687**	**$ 2,993,241**	$ 4,010,158	**$ 1,016,917**
1960	Miscellaneous Equipment	$ 267,071	$ -	$ 267,071	$ 3,907	$ -	$ 3,907	$ -	7.23	13.82%	10.00	10.00%	**$ 36,919**	**$ 391**	**$ -**	**$ 37,310**	$ 37,310	**-$ 0**
1970	Load Management Controls Customer Premises	$ 3,022,834	$ 3,022,834	$ -	$ -	$ -	$ -	$ -	2.85	35.12%	-	0.00%	**$ -**	**$ -**	**$ -**	**$ -**	$ 37,379	**$ 37,379**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	-	0.00%	**$ -**	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 19,174,795	$ 1,357,609	$ 17,817,186	$ 10,290,359	$ 70,327	$ 10,220,032	$ 7,882,436	11.09	9.02%	14.95	6.69%	**$ 1,606,660**	**$ 683,773**	**$ 263,688**	**$ 2,554,121**	$ 2,364,096	**-$ 190,026**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	-	0.00%	**$ -**	**$ -**	**$ -**	**$ -**	$ -	**$ -**
2440	Contributions & Grants (Formally known as Account 1995)	$ -	$ -	$ -	-$ 91,437,039	-$ 4,021,007	-$ 87,416,032	-$ 28,704,350	-	0.00%	35.12	2.85%	**$ -**	**-$ 2,489,313**	**-$ 408,701**	**-$ 2,898,015**	-$ 4,710,955	**-$ 1,812,941**
1609	Capital Contributions Paid	$ 19,104,312	$ -	$ 19,104,312	$ 56,470,186	$ -	$ 56,470,186	$ -	21.68	4.61%	24.92	4.01%	**$ 881,195**	**$ 2,266,337**	**$ -**	**$ 3,147,532**	$ 3,140,006	**-$ 7,526**
2005	Property Under Capital Leases	$ 7,191,090	$ -	$ 7,191,090	$ 10,979,744	$ 2,092,578	$ 8,887,166	$ -	80.42	1.24%	4.31	23.20%	**$ 89,423**	**$ 2,062,155**	**$ -**	**$ 2,151,577**	$ 2,064,349	**-$ 87,229**
	Sub-Total	**$ 2,366,938,267**	**$ 91,478,094**	**$ 2,275,460,173**	**$ 1,652,345,978**	**$ 7,338,686**	**$ 1,645,007,292**	**$ 522,261,787**					**$ 115,315,156**	**$ 65,867,642**	**$ 11,850,927**	**$ 193,033,726**	**$ 194,109,167**	**$ 1,075,441**
	Less Socialized Renewable Energy Generation Investments ***(input as negative)***	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	**$ -**	**$ -**	**$ -**	**$ -**	$ -	**$ -**
	Less Other Non Rate-Regulated Utility Assets ***(input as negative)***	$ -		$ -	$ -		$ -	-$ 2,002,023		0.00%	15.00	6.67%	**$ -**	**$ -**	**-$ 66,734**	**-$ 66,734**	-$ 33,367	**$ 33,367**
	Total	**$ 2,366,938,267**	**$ 91,478,094**	**$ 2,275,460,173**	**$ 1,652,345,978**	**$ 7,338,686**	**$ 1,645,007,292**	**$ 520,259,765**					**$ 115,315,156**	**$ 65,867,642**	**$ 11,784,193**	**$ 192,966,992**	**$ 194,075,800**	**$ 1,108,808**

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1 This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.

2 This is the opening gross book value of assets that have been acquired after the date of the utilities change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the gross book value of the prior year plus the prior year's additions.

3 A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as at January 1 of the year of policy changes. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the revised CGAAP as at January 1 of the year of policy changes.

4 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.

5 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

6 The applicant must provide an explanation of material variances in evidence.

7 This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change

8 This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

Appendix 2-C
Depreciation and Amortization Expense

This appendix is to be completed in conjunction with the accounting instructions in Appendix 2-B

Scenario that applies	Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012. ☐	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Rebasing for the first time with depreciation policy changes made in 2013. ☐	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Already rebased with depreciation policy changes in a prior rate application ☑	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).	2018	MIFRS

		Book Values							Service Lives				Depreciation Expense						
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1)[1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 69,572,669	$ 36,877,357	$ 32,695,312	$ 67,387,997	$ 5,290,961	$ 62,097,036	$ 96,165,279	4.91	20.36%	6.84	14.63%	**$ 6,655,322**	**$ 9,082,563**	**$ 7,032,761**	**$ 22,770,646**	$ 24,791,002	**$ 2,020,356**
1612	Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	-	0.00%	**$ -**	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1805	Land	$ 7,588,531	$ -	$ 7,588,531	-$ 8,030	$ -	-$ 8,030	$ -	-	0.00%	-	0.00%	**$ -**	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1808	Buildings	$ 29,677,626	$ 3,203,894	$ 26,473,732	$ 87,327,434	$ 5,350	$ 87,322,084	$ 16,455,257	18.08	5.53%	62.90	1.59%	**$ 1,464,400**	**$ 1,388,355**	**$ 130,813**	**$ 2,983,568**	$ 3,351,463	**$ 367,895**
1815	Transformer Station Equipment >50 kV	$ 5,839,955	$ 13,224	$ 5,826,730	$ 31,091,235	$ -	$ 31,091,235	$ 1,310,327	14.45	6.92%	36.88	2.71%	**$ 403,185**	**$ 843,138**	**$ 17,767**	**$ 1,264,090**	$ 1,291,156	**$ 27,066**
1820	Distribution Station Equipment <50 kV	$ 112,667,455	$ 1,707,056	$ 110,960,399	$ 73,489,735	$ -	$ 73,489,735	$ 44,518,078	19.20	5.21%	31.75	3.15%	**$ 5,779,142**	**$ 2,314,304**	**$ 700,971**	**$ 8,794,418**	$ 8,890,469	**$ 96,052**
1830	Poles, Towers & Fixtures	$ 208,620,348	$ 763,354	$ 207,856,994	$ 169,783,390	$ 1,311,076	$ 168,472,314	$ 29,326,949	31.60	3.16%	38.16	2.62%	**$ 6,576,912**	**$ 4,414,728**	**$ 384,249**	**$ 11,375,888**	$ 10,881,638	**-$ 494,250**
1835	Overhead Conductors & Devices	$ 197,786,423	$ 735,569	$ 197,050,854	$ 200,296,773	$ 1,434,382	$ 198,862,391	$ 43,657,910	34.02	2.94%	44.44	2.25%	**$ 5,792,421**	**$ 4,474,977**	**$ 491,214**	**$ 10,758,613**	$ 10,809,893	**$ 51,280**
1840	Underground Conduit	$ 639,376,710	$ 5,008,668	$ 634,368,042	$ 490,165,792	$ 205,791	$ 489,960,001	$ 98,322,508	22.27	4.49%	33.22	3.01%	**$ 28,489,806**	**$ 14,750,716**	**$ 1,480,047**	**$ 44,720,569**	$ 44,902,816	**$ 182,247**
1845	Underground Conductors & Devices	$ 397,494,067	$ 6,633,322	$ 390,860,745	$ 402,623,384	$ 5,111,479	$ 397,511,905	$ 88,499,944	31.09	3.22%	37.46	2.67%	**$ 12,571,810**	**$ 10,610,301**	**$ 1,181,111**	**$ 24,363,221**	$ 24,982,566	**$ 619,345**
1850	Line Transformers	$ 305,215,157	$ 8,045,785	$ 297,169,373	$ 245,905,202	$ 1,520,860	$ 244,384,342	$ 67,842,711	18.14	5.51%	27.49	3.64%	**$ 16,381,002**	**$ 8,889,683**	**$ 1,233,917**	**$ 26,504,602**	$ 24,107,411	**-$ 2,397,191**
1855	Services (Overhead & Underground)	$ 61,419,385	$ 720,464	$ 60,698,921	$ 62,815,335	$ 76,476	$ 62,738,858	$ 17,736,555	40.50	2.47%	44.28	2.26%	**$ 1,498,869**	**$ 1,416,874**	**$ 200,278**	**$ 3,116,021**	$ 3,057,508	**-$ 58,513**
1860	Meters	$ 44,538,583	$ 1,198,476	$ 43,340,106	$ 38,342,883	$ 235,731	$ 38,107,151	$ 17,692,914	19.72	5.07%	21.06	4.75%	**$ 2,198,305**	**$ 1,809,336**	**$ 420,032**	**$ 4,427,673**	$ 4,618,567	**$ 190,894**
1860	Meters (Smart Meters)	$ 94,589,513	$ 2,176,233	$ 92,413,280	$ 34,509,395	$ 106,085	$ 34,403,310	$ 8,399,704	9.75	10.25%	15.00	6.67%	**$ 9,474,408**	**$ 2,293,554**	**$ 279,990**	**$ 12,047,952**	$ 11,305,147	**-$ 742,805**
1905	Land	$ 9,150,994	$ -	$ 9,150,994	$ 9,250,332	$ -	$ 9,250,332	$ -	-	0.00%	-	0.00%	**$ -**	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 65,356,634	$ 16,446,753	$ 48,909,881	$ 185,015,240	$ 2,372,563	$ 182,642,677	$ 3,834,718	12.89	7.76%	30.98	3.23%	**$ 3,793,552**	**$ 5,895,372**	**$ 61,889**	**$ 9,750,813**	$ 11,331,950	**$ 1,581,138**
1910	Leasehold Improvements	$ 701,434	$ 701,434	$ -	$ 52,406	$ -	$ 52,406	$ -	3.03	32.97%	5.00	20.00%	**$ -**	**$ 10,481**	**$ -**	**$ 10,481**	$ 10,481	**$ 0**
1915	Office Furniture & Equipment	$ 9,802,431	$ 2,404,395	$ 7,398,035	$ 9,227,322	$ -	$ 9,227,322	$ 567,003	5.87	17.02%	10.00	10.00%	**$ 1,259,422**	**$ 922,732**	**$ 28,350**	**$ 2,210,505**	$ 2,112,380	**-$ 98,125**
1920	Computer Equipment - Hardware	$ 11,192,631	$ 11,254,107	-$ 61,476	$ 47,490,710	$ 4,698,090	$ 42,792,621	$ 11,534,282	3.34	29.93%	4.75	21.05%	**-$ 18,400**	**$ 9,008,314**	**$ 1,214,046**	**$ 10,203,960**	$ 11,352,594	**$ 1,148,635**
1930	Transportation Equipment	$ 21,967,081	$ 15,357,998	$ 6,609,083	$ 12,088,500	$ -	$ 12,088,500	$ 4,652,877	4.03	24.80%	7.41	13.49%	**$ 1,639,126**	**$ 1,630,510**	**$ 313,792**	**$ 3,583,428**	$ 3,733,970	**$ 150,542**
1935	Stores Equipment	$ 7,066	$ 7,066	$ -	$ -	$ -	$ -	$ -	-	0.00%	-	0.00%	**$ -**	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 11,036,987	$ 3,173,694	$ 7,863,293	$ 10,159,910	$ -	$ 10,159,910	$ 3,306,026	5.61	17.81%	9.95	10.05%	**$ 1,400,830**	**$ 1,020,702**	**$ 166,068**	**$ 2,587,600**	$ 2,282,386	**-$ 305,214**
1945	Measurement & Testing Equipment	$ 9,367,510	$ 35,289	$ 9,332,221	-$ 8,887,268	$ -	-$ 8,887,268	$ 182	4.39	22.77%	4.39	22.77%	**$ 2,124,778**	**-$ 2,023,470**	**$ 21**	**$ 101,329**	$ 59,829	**-$ 41,499**
1950	Service Equipment	$ 615,688	$ 266,460	$ 349,228	$ 230,085	$ -	$ 230,085	$ 192,667	5.09	19.66%	8.00	12.50%	**$ 68,668**	**$ 28,761**	**$ 12,042**	**$ 109,471**	$ 113,681	**$ 4,210**
1955	Communications Equipment	$ 4,593,288	$ 4,444,612	$ 148,676	$ 40,764,758	$ -	$ 40,764,758	$ 616,253	2.94	34.04%	13.35	7.49%	**$ 50,608**	**$ 3,053,852**	**$ 23,083**	**$ 3,127,543**	$ 4,287,086	**$ 1,159,543**
1960	Miscellaneous Equipment	$ 267,071	$ -	$ 267,071	$ 3,907	$ -	$ 3,907	$ 4,792	7.23	13.82%	10.00	10.00%	**$ 36,919**	**$ 391**	**$ 240**	**$ 37,549**	$ 37,343	**-$ 206**
1970	Load Management Controls Customer Premises	$ 3,022,834	$ 3,022,834	$ -	$ -	$ -	$ -	$ -	2.85	35.12%	-	0.00%	**$ -**	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	-	0.00%	**$ -**	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 19,174,795	$ 1,725,140	$ 17,449,656	$ 18,172,795	$ 70,327	$ 18,102,468	$ 15,440,125	11.09	9.02%	14.97	6.68%	**$ 1,573,518**	**$ 1,209,110**	**$ 515,643**	**$ 3,298,271**	$ 2,887,747	**-$ 410,524**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	-	0.00%	**$ -**	**$ -**	**$ -**	**$ -**	$ -	**$ -**
2440	Contributions & Grants (Formally known as Account 1995)	$ -	$ -	$ -	-$ 120,141,389	-$ 6,053,553	-$ 114,087,836	-$ 64,488,417	-	0.00%	35.31	2.83%	**$ -**	**-$ 3,230,645**	**-$ 913,065**	**-$ 4,143,710**	-$ 5,203,131	**-$ 1,059,421**
1609	Capital Contributions Paid	$ 19,104,312	$ -	$ 19,104,312	$ 56,470,186	$ -	$ 56,470,186	$ 110,620,512	21.68	4.61%	24.97	4.00%	**$ 881,195**	**$ 2,261,340**	**$ 2,214,891**	**$ 5,357,427**	$ 5,592,493	**$ 235,066**
2005	Property Under Capital Leases	$ 7,191,090	$ -	$ 7,191,090	$ 10,979,744	$ 10,979,744	$ -	$ -	80.42	1.24%	4.31	23.20%	**$ 89,423**	**$ -**	**$ -**	**$ 89,423**	$ 1,076,886	**$ 987,463**
	Sub-Total	**$ 2,366,938,267**	**$ 125,923,184**	**$ 2,241,015,083**	**$ 2,174,607,766**	**$ 27,365,363**	**$ 2,147,242,402**	**$ 616,209,155**					**$ 110,185,220**	**$ 82,075,979**	**$ 17,190,149**	**$ 209,451,348**	**$ 212,665,331**	**$ 3,213,983**
	Less Socialized Renewable Energy Generation Investments ***(input as negative)***	$ -		$ -	$ -		$ -	-$ 806,300		0.00%	10.00	10.00%	**$ -**	**$ -**	**-$ 40,315**	**-$ 40,315**	-$ 5,944	**$ 34,371**
	Less Other Non Rate-Regulated Utility Assets ***(input as negative)***	$ -		$ -	-$ 2,002,023		-$ 2,002,023	-$ 6,480,512		0.00%	15.00	6.67%	**$ -**	**-$ 133,468**	**-$ 216,017**	**-$ 349,485**	-$ 187,386	**$ 162,099**
	Total	**$ 2,366,938,267**	**$ 125,923,184**	**$ 2,241,015,083**	**$ 2,172,605,743**	**$ 27,365,363**	**$ 2,145,240,380**	**$ 608,922,343**					**$ 110,185,220**	**$ 81,942,510**	**$ 16,933,817**	**$ 209,061,547**	**$ 212,472,001**	**$ 3,410,453**

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1 This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.

2 This is the opening gross book value of assets that have been acquired after the date of the utilities change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the gross book value of the prior year plus the prior year's additions.

3 A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as at January 1 of the year of policy changes. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the revised CGAAP as at January 1 of the year of policy changes.

4 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.

5 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

6 The applicant must provide an explanation of material variances in evidence.

7 This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change

8 This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

Appendix 2-C
Depreciation and Amortization Expense

This appendix is to be completed in conjunction with the accounting instructions in Appendix 2-B

Scenario that applies	Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012. ☐	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Rebasing for the first time with depreciation policy changes made in 2013. ☐	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Already rebased with depreciation policy changes in a prior rate application ☑	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).	2019	MIFRS

		Book Values							Service Lives				Depreciation Expense						
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 69,572,669	$ 36,877,357	$ 32,695,312	$ 163,553,275	$ 19,277,944	$ 144,275,331	$ 34,899,862	4.91	20.36%	6.51	15.36%	$ 6,655,322	$ 22,154,745	$ 2,679,590	$ 31,489,657	$ 31,832,793	$ 343,136
1612	Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land	$ 7,588,531	$ -	$ 7,588,531	-$ 8,030	$ -	-$ 8,030	$ -	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ 29,677,626	$ 3,292,155	$ 26,385,471	$ 103,782,692	$ 5,350	$ 103,777,342	$ 1,390,768	18.08	5.53%	62.41	1.60%	$ 1,459,518	$ 1,662,787	$ 11,142	$ 3,133,446	$ 3,671,135	$ 537,689
1815	Transformer Station Equipment >50 kV	$ 5,839,955	$ 13,224	$ 5,826,730	$ 32,401,562	$ -	$ 32,401,562	$ 98,421	14.45	6.92%	36.86	2.71%	$ 403,185	$ 879,024	$ 1,335	$ 1,283,544	$ 1,321,906	$ 38,362
1820	Distribution Station Equipment <50 kV	$ 112,667,455	$ 2,585,570	$ 110,081,886	$ 118,007,813	$ -	$ 118,007,813	$ 22,534,698	19.20	5.21%	31.65	3.16%	$ 5,733,387	$ 3,728,302	$ 355,977	$ 9,817,666	$ 10,158,330	$ 340,664
1830	Poles, Towers & Fixtures	$ 208,620,348	$ 763,354	$ 207,856,994	$ 199,110,339	$ 1,397,281	$ 197,713,059	$ 27,186,494	31.60	3.16%	38.40	2.60%	$ 6,576,912	$ 5,148,472	$ 353,970	$ 12,079,354	$ 11,274,091	-$ 805,263
1835	Overhead Conductors & Devices	$ 197,786,423	$ 934,614	$ 196,851,809	$ 243,954,683	$ 1,713,413	$ 242,241,270	$ 40,428,298	34.02	2.94%	44.41	2.25%	$ 5,786,570	$ 5,454,979	$ 455,198	$ 11,696,747	$ 11,559,544	-$ 137,203
1840	Underground Conduit	$ 639,376,710	$ 7,697,861	$ 631,678,849	$ 588,488,300	$ 205,791	$ 588,282,509	$ 96,757,977	22.27	4.49%	33.30	3.00%	$ 28,369,033	$ 17,666,342	$ 1,452,839	$ 47,488,214	$ 47,539,941	$ 51,727
1845	Underground Conductors & Devices	$ 397,494,067	$ 6,914,611	$ 390,579,456	$ 491,123,328	$ 5,858,818	$ 485,264,510	$ 96,185,169	31.09	3.22%	37.21	2.69%	$ 12,562,762	$ 13,040,325	$ 1,292,373	$ 26,895,460	$ 26,397,900	-$ 497,560
1850	Line Transformers	$ 305,215,157	$ 10,840,283	$ 294,374,874	$ 313,747,913	$ 1,520,860	$ 312,227,053	$ 79,882,272	18.14	5.51%	27.49	3.64%	$ 16,226,960	$ 11,359,645	$ 1,453,164	$ 29,039,769	$ 25,933,134	-$ 3,106,636
1855	Services (Overhead & Underground)	$ 61,419,385	$ 720,464	$ 60,698,921	$ 80,551,889	$ 77,979	$ 80,473,910	$ 16,527,952	40.50	2.47%	44.44	2.25%	$ 1,498,869	$ 1,810,939	$ 185,968	$ 3,495,775	$ 3,429,537	-$ 66,238
1860	Meters	$ 44,538,583	$ 1,198,476	$ 43,340,106	$ 56,035,796	$ 273,348	$ 55,762,448	$ 18,432,082	19.72	5.07%	21.05	4.75%	$ 2,198,305	$ 2,648,537	$ 437,732	$ 5,284,573	$ 5,447,752	$ 163,179
1860	Meters (Smart Meters)	$ 94,589,513	$ 2,176,233	$ 92,413,280	$ 42,909,100	$ 106,085	$ 42,803,014	$ 8,482,042	9.75	10.25%	15.00	6.67%	$ 9,474,408	$ 2,853,534	$ 282,735	$ 12,610,677	$ 11,738,159	-$ 872,517
1905	Land	$ 9,150,994	$ -	$ 9,150,994	$ 9,250,332	$ -	$ 9,250,332	$ -	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 65,356,634	$ 5,140,983	$ 60,215,651	$ 188,849,958	$ 2,372,563	$ 186,477,395	$ 992,208	12.89	7.76%	30.94	3.23%	$ 4,670,451	$ 6,026,815	$ 16,034	$ 10,713,300	$ 11,349,805	$ 636,505
1910	Leasehold Improvements	$ 701,434	$ 701,434	$ -	$ 52,406	$ 52,406	-$ 0	$ -	3.03	32.97%	5.00	20.00%	$ -	-$ 0	-$ 0	$ 0	$ 8,734	$ 8,734
1915	Office Furniture & Equipment	$ 9,802,431	$ 2,499,302	$ 7,303,129	$ 9,794,325	$ -	$ 9,794,325	$ 355,697	5.87	17.02%	10.00	10.00%	$ 1,243,266	$ 979,432	$ 17,785	$ 2,240,483	$ 2,097,661	-$ 142,822
1920	Computer Equipment - Hardware	$ 11,192,631	$ 11,254,520	-$ 61,889	$ 59,024,992	$ 13,726,866	$ 45,298,126	$ 7,685,101	3.34	29.93%	4.66	21.44%	-$ 18,524	$ 9,710,722	$ 823,741	$ 10,515,940	$ 11,744,632	$ 1,228,692
1930	Transportation Equipment	$ 21,967,081	$ 21,164,466	$ 802,615	$ 16,741,377	$ -	$ 16,741,377	$ 3,123,485	4.03	24.80%	7.43	13.46%	$ 199,057	$ 2,253,375	$ 210,209	$ 2,662,642	$ 3,254,411	$ 591,769
1935	Stores Equipment	$ 7,066	$ 7,066	$ -	$ -	$ -	$ -	$ -	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 11,036,987	$ 3,804,933	$ 7,232,054	$ 13,465,936	$ -	$ 13,465,936	$ 9,125,806	5.61	17.81%	9.97	10.03%	$ 1,288,376	$ 1,350,255	$ 457,531	$ 3,096,162	$ 2,480,670	-$ 615,491
1945	Measurement & Testing Equipment	$ 9,367,510	$ 35,289	$ 9,332,221	-$ 8,887,085	$ -	-$ 8,887,085	$ 610	4.39	22.77%	4.39	22.77%	$ 2,124,778	-$ 2,023,428	$ 69	$ 101,419	$ 59,861	-$ 41,557
1950	Service Equipment	$ 615,688	$ 390,650	$ 225,037	$ 422,752	$ -	$ 422,752	$ 76,515	5.09	19.66%	8.00	12.50%	$ 44,249	$ 52,844	$ 4,782	$ 101,875	$ 95,793	-$ 6,082
1955	Communications Equipment	$ 4,593,288	$ 4,444,612	$ 148,676	$ 41,381,011	$ 2,487,921	$ 38,893,090	$ 659,651	2.94	34.04%	13.28	7.53%	$ 50,608	$ 2,929,041	$ 24,839	$ 3,004,488	$ 4,122,018	$ 1,117,530
1960	Miscellaneous Equipment	$ 267,071	$ -	$ 267,071	$ 8,699	$ -	$ 8,699	$ -	7.23	13.82%	10.00	10.00%	$ 36,919	$ 870	$ -	$ 37,789	$ 37,712	-$ 78
1970	Load Management Controls Customer Premises	$ 3,022,834	$ 3,022,834	$ -	$ -	$ -	$ -	$ -	2.85	35.12%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 19,174,795	$ 1,993,489	$ 17,181,306	$ 33,612,920	$ 70,327	$ 33,542,593	$ 11,782,424	11.09	9.02%	14.98	6.68%	$ 1,549,320	$ 2,239,277	$ 393,293	$ 4,181,889	$ 3,581,825	-$ 600,064
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
2440	Contributions & Grants (Formally known as Account 1995)	$ -	$ -	$ -	-$ 184,629,806	-$ 6,958,091	-$ 177,671,714	-$ 72,738,047	-	0.00%	34.28	2.92%	$ -	-$ 5,182,205	-$ 1,060,786	-$ 6,242,991	-$ 6,334,692	$ 91,700
1609	Capital Contributions Paid	$ 19,104,312	$ -	$ 19,104,312	$ 167,090,698	$ -	$ 167,090,698	$ 5,579,006	21.68	4.61%	24.97	4.00%	$ 881,195	$ 6,690,880	$ 111,701	$ 7,683,776	$ 7,676,972	-$ 6,804
2005	Property Under Capital Leases	$ 7,191,090	$ -	$ 7,191,090	$ 10,979,744	$ 10,979,744	$ -	$ -	80.42	1.24%	4.31	23.20%	$ 89,423	$ -	$ -	$ 89,423	$ 89,423	-$ 0
	Sub-Total	**$ 2,366,938,267**	**$ 128,473,782**	**$ 2,238,464,486**	**$ 2,790,816,920**	**$ 53,168,607**	**$ 2,737,648,314**	**$ 409,448,493**					**$ 109,104,347**	**$ 113,435,509**	**$ 9,961,222**	**$ 232,501,078**	**$ 230,569,049**	**-$ 1,932,030**
	Less Socialized Renewable Energy Generation Investments ***(input as negative)***	$ -		$ -	-$ 806,300		-$ 806,300	-$ 7,332,469		0.00%	10.00	10.00%	$ -	-$ 80,630	-$ 366,623	-$ 447,253	-$ 113,812	$ 333,442
	Less Other Non Rate-Regulated Utility Assets ***(input as negative)***	$ -		$ -	-$ 8,482,535		-$ 8,482,535	-$ 4,280,125		0.00%	15.00	6.67%	$ -	-$ 565,502	-$ 142,671	-$ 708,173	-$ 453,429	$ 254,745
	Total	**$ 2,366,938,267**	**$ 128,473,782**	**$ 2,238,464,486**	**$ 2,781,528,086**	**$ 53,168,607**	**$ 2,728,359,479**	**$ 397,835,898**					**$ 109,104,347**	**$ 112,789,377**	**$ 9,451,927**	**$ 231,345,651**	**$ 230,001,808**	**-$ 1,343,843**

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1 This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.

2 This is the opening gross book value of assets that have been acquired after the date of the utilities change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the gross book value of the prior year plus the prior year's additions.
A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as at January 1 of the year of policy changes. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the revised CGAAP as at January 1 of the year of policy changes.

3

4 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.

5 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

6 The applicant must provide an explanation of material variances in evidence.

7 This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change

8 This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

Appendix 2-C
Depreciation and Amortization Expense

This appendix is to be completed in conjunction with the accounting instructions in Appendix 2-B

Scenario that applies	Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012. ☐	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Rebasing for the first time with depreciation policy changes made in 2013. ☐	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Already rebased with depreciation policy changes in a prior rate application ☑	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).	2020	MIFRS

		Book Values							Service Lives				Depreciation Expense						
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 69,572,669	$ 36,877,357	$ 32,695,312	$ 198,453,137	$ 31,870,339	$ 166,582,798	$ 30,655,579	4.91	20.36%	6.31	15.85%	**$ 6,655,322**	**$ 26,404,467**	**$ 2,429,555**	**$ 35,489,344**	$ 36,099,942	**$ 610,598**
1612	Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	-	0.00%	**$ -**	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1805	Land	$ 7,588,531	$ -	$ 7,588,531	-$ 8,030	$ -	-$ 8,030	$ -	-	0.00%	-	0.00%	**$ -**	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1808	Buildings	$ 29,677,626	$ 3,502,025	$ 26,175,601	$ 105,173,460	$ 5,350	$ 105,168,110	$ 2,986,710	18.08	5.53%	61.39	1.63%	**$ 1,447,909**	**$ 1,713,087**	**$ 24,325**	**$ 3,185,321**	$ 3,720,102	**$ 534,781**
1815	Transformer Station Equipment >50 kV	$ 5,839,955	$ 13,224	$ 5,826,730	$ 32,499,983	$ -	$ 32,499,983	$ 112,337	14.45	6.92%	36.84	2.71%	**$ 403,185**	**$ 882,095**	**$ 1,524**	**$ 1,286,804**	$ 1,325,172	**$ 38,368**
1820	Distribution Station Equipment <50 kV	$ 112,667,455	$ 3,473,401	$ 109,194,054	$ 140,542,512	$ -	$ 140,542,512	$ 27,166,846	19.20	5.21%	31.13	3.21%	**$ 5,687,146**	**$ 4,514,288**	**$ 436,306**	**$ 10,637,739**	$ 11,273,000	**$ 635,261**
1830	Poles, Towers & Fixtures	$ 208,620,348	$ 763,354	$ 207,856,994	$ 226,296,834	$ 1,397,281	$ 224,899,553	$ 34,478,688	31.60	3.16%	38.64	2.59%	**$ 6,576,912**	**$ 5,820,424**	**$ 446,156**	**$ 12,843,492**	$ 11,739,346	**-$ 1,104,146**
1835	Overhead Conductors & Devices	$ 197,786,423	$ 1,150,248	$ 196,636,175	$ 284,382,981	$ 1,713,413	$ 282,669,569	$ 47,031,817	34.02	2.94%	44.50	2.25%	**$ 5,780,232**	**$ 6,352,131**	**$ 528,448**	**$ 12,660,810**	$ 12,364,683	**-$ 296,128**
1840	Underground Conduit	$ 639,376,710	$ 10,972,359	$ 628,404,350	$ 685,246,277	$ 205,791	$ 685,040,485	$ 111,087,570	22.27	4.49%	33.29	3.00%	**$ 28,221,973**	**$ 20,575,265**	**$ 1,668,264**	**$ 50,465,502**	$ 50,257,599	**-$ 207,903**
1845	Underground Conductors & Devices	$ 397,494,067	$ 7,329,048	$ 390,165,019	$ 587,308,497	$ 5,858,818	$ 581,449,679	$ 99,413,968	31.09	3.22%	37.53	2.66%	**$ 12,549,432**	**$ 15,494,355**	**$ 1,324,582**	**$ 29,368,369**	$ 29,225,810	**-$ 142,559**
1850	Line Transformers	$ 305,215,157	$ 13,904,114	$ 291,311,043	$ 393,630,185	$ 1,520,860	$ 392,109,325	$ 79,659,607	18.14	5.51%	27.38	3.65%	**$ 16,058,071**	**$ 14,322,912**	**$ 1,454,897**	**$ 31,835,880**	$ 28,236,015	**-$ 3,599,865**
1855	Services (Overhead & Underground)	$ 61,419,385	$ 720,464	$ 60,698,921	$ 97,079,842	$ 77,979	$ 97,001,862	$ 19,867,315	40.50	2.47%	44.49	2.25%	**$ 1,498,869**	**$ 2,180,446**	**$ 223,293**	**$ 3,902,607**	$ 3,818,256	**-$ 84,351**
1860	Meters	$ 44,538,583	$ 1,198,476	$ 43,340,106	$ 74,467,878	$ 273,348	$ 74,194,530	$ 20,046,264	19.72	5.07%	21.06	4.75%	**$ 2,198,305**	**$ 3,522,410**	**$ 475,852**	**$ 6,196,566**	$ 6,389,230	**$ 192,663**
1860	Meters (Smart Meters)	$ 94,589,513	$ 2,176,233	$ 92,413,280	$ 51,391,142	$ 106,085	$ 51,285,056	$ 9,339,433	9.75	10.25%	15.00	6.67%	**$ 9,474,408**	**$ 3,419,004**	**$ 311,314**	**$ 13,204,726**	$ 12,222,117	**-$ 982,609**
1905	Land	$ 9,150,994	$ -	$ 9,150,994	$ 9,250,332	$ -	$ 9,250,332	$ -	-	0.00%	-	0.00%	**$ -**	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 65,356,634	$ 5,869,810	$ 59,486,824	$ 189,842,166	$ 2,372,563	$ 187,469,603	$ 2,499,408	12.89	7.76%	30.84	3.24%	**$ 4,613,922**	**$ 6,078,026**	**$ 40,517**	**$ 10,732,465**	$ 11,382,932	**$ 650,467**
1910	Leasehold Improvements	$ 701,434	$ 701,434	$ -	$ 52,406	$ 52,406	-$ 0	$ -	3.03	32.97%	5.00	20.00%	**$ -**	**-$ 0**	**$ -**	**-$ 0**	$ -	**$ 0**
1915	Office Furniture & Equipment	$ 9,802,431	$ 5,698,460	$ 4,103,971	$ 10,150,022	$ -	$ 10,150,022	$ 896,014	5.87	17.02%	10.00	10.00%	**$ 698,649**	**$ 1,015,002**	**$ 44,801**	**$ 1,758,452**	$ 1,905,523	**$ 147,071**
1920	Computer Equipment - Hardware	$ 11,192,631	$ 11,254,520	-$ 61,889	$ 66,710,093	$ 23,468,331	$ 43,241,762	$ 11,081,696	3.34	29.93%	4.57	21.88%	**-$ 18,524**	**$ 9,462,728**	**$ 1,212,521**	**$ 10,656,725**	$ 11,692,222	**$ 1,035,496**
1930	Transportation Equipment	$ 21,967,081	$ 21,784,692	$ 182,389	$ 19,864,862	$ 419,948	$ 19,444,914	$ 4,654,924	4.03	24.80%	7.40	13.51%	**$ 45,234**	**$ 2,626,123**	**$ 314,334**	**$ 2,985,692**	$ 3,045,967	**$ 60,275**
1935	Stores Equipment	$ 7,066	$ 7,066	$ -	$ -	$ -	$ -	$ -	-	0.00%	-	0.00%	**$ -**	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 11,036,987	$ 6,458,923	$ 4,578,064	$ 22,591,742	$ -	$ 22,591,742	$ 9,772,286	5.61	17.81%	9.98	10.02%	**$ 815,573**	**$ 2,263,431**	**$ 489,535**	**$ 3,568,539**	$ 3,095,774	**-$ 472,765**
1945	Measurement & Testing Equipment	$ 9,367,510	$ 149,700	$ 9,217,811	-$ 8,886,476	$ -	-$ 8,886,476	$ 2,661	4.39	22.77%	4.39	22.77%	**$ 2,098,729**	**-$ 2,023,290**	**$ 303**	**$ 75,742**	$ 44,522	**-$ 31,220**
1950	Service Equipment	$ 615,688	$ 478,132	$ 137,556	$ 499,267	$ -	$ 499,267	$ 59,523	5.09	19.66%	8.00	12.50%	**$ 27,047**	**$ 62,408**	**$ 3,720**	**$ 93,176**	$ 84,739	**-$ 8,437**
1955	Communications Equipment	$ 4,593,288	$ 4,444,612	$ 148,676	$ 42,040,663	$ 4,143,448	$ 37,897,215	$ 1,711,630	2.94	34.04%	13.09	7.64%	**$ 50,608**	**$ 2,895,700**	**$ 65,392**	**$ 3,011,701**	$ 3,827,071	**$ 815,371**
1960	Miscellaneous Equipment	$ 267,071	$ 127,233	$ 139,837	$ 8,699	$ -	$ 8,699	$ -	7.23	13.82%	10.00	10.00%	**$ 19,331**	**$ 870**	**$ -**	**$ 20,201**	$ 34,673	**$ 14,472**
1970	Load Management Controls Customer Premises	$ 3,022,834	$ 3,022,834	$ -	$ -	$ -	$ -	$ -	2.85	35.12%	-	0.00%	**$ -**	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	-	0.00%	**$ -**	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 19,174,795	$ 2,694,612	$ 16,480,184	$ 45,395,344	$ 70,327	$ 45,325,017	$ 9,907,190	11.09	9.02%	14.98	6.67%	**$ 1,486,096**	**$ 3,025,098**	**$ 330,615**	**$ 4,841,809**	$ 4,128,590	**-$ 713,220**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	-	0.00%	**$ -**	**$ -**	**$ -**	**$ -**	$ -	**$ -**
2440	Contributions & Grants (Formally known as Account 1995)	$ -	$ -	$ -	-$ 257,367,852	-$ 6,958,091	-$ 250,409,761	-$ 75,354,275	-	0.00%	34.81	2.87%	**$ -**	**-$ 7,193,835**	**-$ 1,082,398**	**-$ 8,276,233**	-$ 8,995,336	**-$ 719,103**
1609	Capital Contributions Paid	$ 19,104,312	$ -	$ 19,104,312	$ 172,669,703	$ -	$ 172,669,703	$ 46,229,405	21.68	4.61%	24.98	4.00%	**$ 881,195**	**$ 6,912,697**	**$ 925,379**	**$ 8,719,271**	$ 8,780,891	**$ 61,620**
2005	Property Under Capital Leases	$ 7,191,090	$ -	$ 7,191,090	$ 10,979,744	$ 10,979,744	$ -	$ -	80.42	1.24%	4.31	23.20%	**$ 89,423**	**$ -**	**$ -**	**$ 89,423**	$ 89,423	**-$ 0**
	Sub-Total	**$ 2,366,938,267**	**$ 144,772,334**	**$ 2,222,165,934**	**$ 3,200,265,413**	**$ 77,577,941**	**$ 3,122,687,472**	**$ 493,306,595**					**$ 107,359,046**	**$ 130,325,843**	**$ 11,669,234**	**$ 249,354,123**	**$ 245,788,261**	**-$ 3,565,862**
	Less Socialized Renewable Energy Generation Investments ***(input as negative)***	$ -		$ -	-$ 8,138,769		-$ 8,138,769	-$ 263,784		0.00%	10.00	10.00%	**$ -**	**-$ 813,877**	**-$ 13,189**	**-$ 827,066**	-$ 570,353	**$ 256,713**
	Less Other Non Rate-Regulated Utility Assets ***(input as negative)***	$ -		$ -	-$ 12,762,660		-$ 12,762,660	-$ 3,195,791		0.00%	15.00	6.67%	**$ -**	**-$ 850,844**	**-$ 106,526**	**-$ 957,370**	-$ 587,711	**$ 369,659**
	Total	**$ 2,366,938,267**	**$ 144,772,334**	**$ 2,222,165,934**	**$ 3,179,363,984**	**$ 77,577,941**	**$ 3,101,786,043**	**$ 489,847,020**					**$ 107,359,046**	**$ 128,661,122**	**$ 11,549,519**	**$ 247,569,686**	**$ 244,630,196**	**-$ 2,939,490**

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1 This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.

2 This is the opening gross book value of assets that have been acquired after the date of the utilities change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the gross book value of the prior year plus the prior year's additions.
A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as at January 1 of the year of policy changes. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the revised CGAAP as at January 1 of the year of policy changes.

3

4 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.

5 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

6 The applicant must provide an explanation of material variances in evidence.

7 This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change

8 This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

OEB Appendix 2-BB
Service Life Comparison
Table F-1 from Kinetrics Report[1]

		Asset Details			Useful Life			USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
Parent*	#	Category| Component | Type			MIN UL	TUL	MAX UL			Years	Rate	Years	Rate	Below Min TUL	Above Max TUL
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	1830	Poles, Towers and Fixtures	40	3%	40	3%	No	No
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	2	Fully Dressed Concrete Poles	Overall		50	60	80	1830	Poles, Towers and Fixtures (Streetlighting Assembly)	40	3%	40	3%	Yes	No
								1830	Poles, Towers and Fixtures	50	2%	50	2%	No	No
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95	1830	Poles, Towers and Fixtures	50	2%	50	2%	No	No
	3	Fully Dressed Steel Poles	Overall		60	60	80								
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	4	OH Line Switch			30	45	55	1835	Overhead Conductors and Devices	30	3%	30	3%	No	No
	5	OH Line Switch Motor			15	25	25								
	6	OH Line Switch RTU			15	20	20								
	7	OH Integral Switches			35	45	60	1835	Overhead Conductors and Devices	45	2%	45	2%	No	No
	8	OH Conductors			50	60	75	1835	Overhead Conductors and Devices (Streetlighting Assembly)	40	3%	40	3%	Yes	No
								1835	Overhead Conductors and Devices	50	2%	50	2%	No	No
								1855	Services (Overhead & Underground)	50	2%	50	2%	No	No
	9	OH Transformers & Voltage Regulators			30	40	60	1850	Line Transformers	30	3%	30	3%	No	No
	10	OH Shunt Capacitor Banks			25	30	40								
	11	Reclosers			25	40	55								
TS & MS	12	Power Transformers	Overall		30	45	60	1815	Transformer Station Equipment - Normally Primary Above 50 kV	32	3%	32	3%	No	No
								1820	Distribution Station Equipment - Normally Primary Below 50 kV	32	3%	32	3%	No	No
			Bushing		10	20	30								
			Tap Changer		20	30	60								
	13	Station Service Transformer			30	45	55	1815	Transformer Station Equipment - Normally Primary Above 50 kV	32	3%	32	3%	No	No
								1820	Distribution Station Equipment - Normally Primary Below 50 kV	32	3%	32	3%	No	No
	14	Station Grounding Transformer			30	40	40	1820	Distribution Station Equipment - Normally Primary Below 50 kV	25	4%	25	4%	Yes	No
								1820	Distribution Station Equipment - Normally Primary Below 50 kV	30	3%	30	3%	No	No
	15	Station DC System	Overall		10	20	30								
			Battery Bank		10	15	15	1820	Distribution Station Equipment - Normally Primary Below 50 kV	10	10%	10	10%	No	No
			Charger		20	20	30	1820	Distribution Station Equipment - Normally Primary Below 50 kV	20	5%	20	5%	No	No
	16	Station Metal Clad Switchgear	Overall		30	40	60	1815	Transformer Station Equipment - Normally Primary Above 50 kV	50	2%	50	2%	No	No
								1820	Distribution Station Equipment - Normally Primary Below 50 kV	40	3%	40	3%	No	No
			Removable Breaker		25	40	60								
	17	Station Independent Breakers			35	45	65	1820	Distribution Station Equipment - Normally Primary Below 50 kV	30	3%	30	3%	Yes	No
	18	Station Switch			30	50	60	1815	Transformer Station Equipment - Normally Primary Above 50 kV	30	3%	30	3%	No	No
								1820	Distribution Station Equipment - Normally Primary Below 50 kV	30	3%	30	3%	No	No
	19	Electromechanical Relays			25	35	50								
	20	Solid State Relays			10	30	45	1820	Distribution Station Equipment - Normally Primary Below 50 kV	10	10%	10	10%	No	No
	21	Digital & Numeric Relays			15	20	20								
	22	Rigid Busbars			30	55	60	1815	Transformer Station Equipment - Normally Primary Above 50 kV	35	3%	35	3%	No	No
	23	Steel Structure			35	50	90	1815	Transformer Station Equipment - Normally Primary Above 50 kV	35	3%	35	3%	No	No
								1820	Distribution Station Equipment - Normally Primary Below 50 kV	35	3%	35	3%	No	No
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables			60	65	75	1845	Underground Conductors and Devices	60	2%	60	2%	No	No
	25	Primary Ethylene-Propylene Rubber (EPR) Cables			20	25	25								
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried			20	25	30								
	27	Primary Non-TR XLPE Cables in Duct			20	25	30								
	28	Primary TR XLPE Cables Direct Buried			25	30	35	1845	Underground Conductors and Devices	20	5%	20	5%	Yes	No
	29	Primary TR XLPE Cables in Duct			35	40	55	1845	Underground Conductors and Devices	40	3%	40	3%	No	No
	30	Secondary PILC Cables			70	75	80								
	31	Secondary Cables Direct Buried			25	35	40	1845	Underground Conductors and Devices	20	5%	20	5%	Yes	No
								1855	Services (Overhead & Underground)	20	5%	20	5%	Yes	No
	32	Secondary Cables in Duct			35	40	60	1845	Underground Conductors and Devices	40	3%	40	3%	No	No
								1855	Services (Overhead & Underground)	40	3%	40	3%	No	No
	33	Network Tranformers	Overall		20	35	50	1850	Line Transformers	20	5%	20	5%	No	No
			Protector		20	35	40	1850	Line Transformers	20	5%	20	5%	No	No
	34	Pad-Mounted Transformers			25	40	45	1850	Line Transformers	30	3%	30	3%	No	No
	35	Submersible/Vault Transformers			25	35	45	1850	Line Transformers	30	3%	30	3%	No	No
	36	UG Foundation			35	55	70	1840	Underground Conduit	50	2%	50	2%	No	No
	37	UG Vaults	Overall		40	60	80	1840	Underground Conduit	40	3%	40	3%	No	No
			Roof		20	30	45	1840	Underground Conduit	20	5%	20	5%	No	No
	38	UG Vault Switches			20	35	50	1845	Underground Conductors and Devices	30	3%	30	3%	No	No
	39	Pad-Mounted Switchgear			20	30	45	1845	Underground Conductors and Devices	20	5%	20	5%	No	No
	40	Ducts			30	50	85	1840	Underground Conduit	30	3%	30	3%	No	No
	41	Concrete Encased Duct Banks			35	55	80								
	42	Cable Chambers			50	60	80	1840	Underground Conduit	50	2%	50	2%	No	No
								1840	Underground Conduit (Cable Chamber Roof)	20	5%	20	5%	Yes	No
S	43	Remote SCADA			15	20	30	1835	Overhead Conductors & Devices	30	3%	30	3%	No	No
								1980	System Supervisory Equipment	15	7%	15	7%	No	No
								1980	System Supervisory Equipment	30	3%	30	3%	No	No

OEB Appendix 2-BB
Service Life Comparison

Table F-2 from Kinetrics Report[1]

#	Asset Details: Category	Asset Details: Component | Type	Useful Life Range		USoA Account Number	USoA Account Description	Current: Years	Current: Rate	Proposed: Years	Proposed: Rate	Outside Range of Min, Max TUL? Below Min Range	Outside Range of Min, Max TUL? Above Max Range
1	Office Equipment		5	15	1915	Office Furniture and Equipment	10	10%	10	10%	No	No
2	Vehicles	Trucks & Buckets	5	15	1930	Transportation Equipment	8	13%	8	13%	No	No
		Trailers	5	20	1930	Transportation Equipment	5	20%	5	20%	No	No
		Vans	5	10								
3	Administrative Buildings		50	75	1908	Buildings and Fixtures	20	5%	20	5%	Yes	No
					1908	Buildings and Fixtures	30	3%	30	3%	Yes	No
					1908	Buildings and Fixtures	50	2%	50	2%	No	No
					1908	Buildings and Fixtures	75	1%	75	1%	No	No
4	Leasehold Improvements		Lease dependent		1910	Leasehold Improvements	5	20%	5	20%	Yes	Yes
5	Station Buildings	Station Buildings	50	75	1808	Buildings and Fixtures	20	5%	20	5%	Yes	No
					1808	Buildings and Fixtures	30	3%	30	3%	Yes	No
					1808	Buildings and Fixtures	36	3%	36	3%	Yes	No
					1808	Buildings and Fixtures	75	1%	75	1%	No	No
		Parking	25	30	1808	Buildings and Fixtures	30	3%	30	3%	No	No
		Fence	25	60	1808	Buildings and Fixtures	30	3%	30	3%	No	No
		Roof	20	30	1808	Buildings and Fixtures	20	5%	20	5%	No	No
6	Computer Equipment	Hardware	3	5	1920	Computer Equipment - Hardware	4	25%	4	25%	No	No
					1920	Computer Equipment - Hardware	5	20%	5	20%	No	No
					1920	Computer Equipment - Hardware	6	17%	6	17%	No	Yes
		Software	2	5	1611	Computer Software	4	25%	4	25%	No	No
					1611	Computer Software	5	20%	5	20%	No	No
					1611	Computer Software	10	10%	10	10%	No	Yes
7	Equipment	Power Operated	5	10								
		Stores	5	10	1935	Stores Equipment	10	10%	10	10%	No	No
		Tools, Shop, Garage Equipment	5	10	1940	Tools, Shop and Garage Equipment	6	17%	6	17%	No	No
					1940	Tools, Shop and Garage Equipment	10	10%	10	10%	No	No
					1950	Service Equipment	8	13%	8	13%	No	No
					1960	Miscellaneous Equipment	10	10%	10	10%	No	No
					1930	Transportation Equipment	8	13%	8	13%	No	No
		Measurement & Testing Equipment	5	10	1945	Measurement and Testing Equipment	10	10%	10	10%	No	No
					1970	Load Management Controls - Customer Premises	10	10%	10	10%	No	No
					1975	Load Management Controls - Utility Premises	10	10%	10	10%	No	No
8	Communication	Towers	60	70								
		Wireless	2	10	1955	Communication Equipment	5	20%	5	20%	No	No
					1955	Communication Equipment	10	10%	10	10%	No	No
9	Residential Energy Meters		25	35	1860	Meters	25	4%	25	4%	No	No
10	Industrial/Commercial Energy Meters		25	35	1860	Meters	25	4%	25	4%	No	No
11	Wholesale Energy Meters		15	30	1860	Meters	25	4%	25	4%	No	No
12	Current & Potential Transformer (CT & PT)		35	50	1860	Meters	40	3%	40	3%	No	No
13	Smart Meters		5	15	1860	Meters (Smart Meters)	15	7%	15	7%	No	No
14	Repeaters - Smart Metering		10	15								
15	Data Collectors - Smart Metering		15	20								

Additional Notes

The useful life of Toronto Hydro handwells is twenty years. The streetlighting handwells is fourty years
The useful life of the IT related data centre is ten years.

*** TS & MS = Transformer and Municipal Stations UG = Underground Systems S = Monitoring and Control Systems**

Note 1: Tables F-1 and F-2 above are to be used as a reference in order to complete columns J, K, L and N.
See pages 17-19 of Kinetrics Report

DERECOGNITION OF ASSETS

1. BACKGROUND

Upon implementation of Modified International Financial Reporting Standards ("MIFRS"), Article 410 of the Ontario Energy Board's ("OEB") Accounting Procedures Handbook for Electricity Distributors requires property, plant and equipment ("PP&E") and intangible assets to be derecognized upon disposal or when their use is no longer expected to offer future economic benefits. The gain or loss arising from the derecognition of PP&E and intangible assets is calculated as the difference between the net disposal proceeds (if any) and the carrying amount of the item. The gain or loss arising from derecognition of an item is included in the utility's profit or loss during the period in which the item is derecognized.

2. DERECOGNTION

Table 1 below summarizes Toronto Hydro's 2015 to 2017 historical and 2018 to 2020 forecasted derecognition. The forecast is informed by the utility's capital expenditure proposals as outlined in its Distribution System Plan (Exhibit 2B, Section E), and calculated on the basis of the net book values associated with assets that the utility expects to remove from service as part of its planned capital program.

Table 1: Derecognition 2015 to 2020 ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Forecast
Derecognition	24.1	27.0	24.5	20.8	20.1	25.8

As discussed in its last rebasing application (EB-2014-0116) and as experienced in the historical periods, Toronto Hydro expects significant and ongoing volatility in

derecognition over the 2020-2024 period – year-over-year and plan-to-actual – due to the dynamic nature of its capital program and operating environment (see Table 2). Toronto Hydro's distribution system is comprised of assets which have a broad range of asset ages. Volatility in forecasted derecognition results from variations in the actual assets removed from service as compared to plan which may be caused by operational constraints and other factors as field work is planned and executed.

As a result of this volatility, Toronto Hydro is requesting a continuation of the derecognition variance account which tracks the annual differences between actual and forecasted derecognition (see Exhibit 9, Tab 1, Schedule 1).

3. DERECOGNITION VOLATILITY

Table 2: Derecognition Variance 2015 to 2019 ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge
OEB-Approved	33.9	26.6	28.0	29.4	32.6
Actual/Forecast[1]	24.1	27.0	24.5	20.8	20.1
Variance	(9.8)	0.4	(3.5)	(8.6)	(12.5)

The variances from OEB-approved derecognition amounts result from differences in planned versus actual assets removed from service, as described above.

Furthermore, the OEB-approved amounts in Table 2 are the same as forecasted in the 2015-2019 CIR application. Following the OEB's decision to Toronto Hydro's last rebasing application, changes to derecognition forecasts were not made as a derecognition variance account was approved (see Exhibit 9, Tab 1, Schedule 1).

[1] See Exhibit 4B, Tab 1, Schedule 1, Appendix A for additional information.

CORPORATE TAXES (PILS)

1. INTRODUCTION

The Revenue Requirement filed at Exhibit 6, Tab 1, Schedule 1 of this application reflects amounts for Payments in Lieu of Taxes ("PILs") of $34.7 million (excluding investment tax credits of $1.9 million reallocated to OM&A), for the 2020 Test Year. The 2020 PILs tax models are filed at Exhibit 4B, Tab 2, Schedule 2.

Toronto Hydro used the OEB's PILs model for 2019 filers to prepare the 2020 PILs tax models. Other than the changes described below, no other changes to the OEB's PILs tax models have been made:

- All Tabs: The date in the header changed from "…2019 Filers" to "…2020 Filers".
- Tab "S. Summary":
    - Lines listed below have been added and linked to Tab "T0 PILs, Tax Provision" accordingly:
        - "Test Year – Grossed-up PILs before tax credits reclass to OM&A", and
        - "Test Year – Tax credits reclass to OM&A".
    - Description for "Test Year – Grossed-up PILs" changed to "Test Year – Grossed-up PILS after tax credits reclass to OM&A".
- Tab "B. Tax Rates & Exemptions": tax rates are updated for Toronto Hydro effective January 1, 2015 to January 1, 2020.
- Tabs "B0 PILs, Tax Provision Bridge" and "T0 PILs, Tax Provision" for bridge and test years: added adjustment for tax credits included in OM&A. The following lines have been added:

- "Corporate PILs/Income Tax Provision Gross Up" (only for Tab "B0 PILs, Tax Provision Bridge")
- "Income Tax (grossed up) before tax credits reclass to OM&A"
- "Tax credits reclass to OM&A", and
- "Income Tax (grossed-up) after tax credits reclass to OM&A" (only for Tab "B0 PILs, Tax Provision Bridge").
- Description for "Income Tax (grossed-up)" changed to "Income Tax (grossed-up) after tax credits reclass to OM&A (only for Tab "T0 PILs, Tax Provision")
- Formula referencing is updated accordingly.

2. PRUDENT MANAGEMENT OF PILS/TAXES

The amount of PILs paid by Toronto Hydro in any given year is correlated with net income calculated for tax purposes. Toronto Hydro manages its tax costs diligently in an effort to keep the effective rate of tax as low as possible. Where appropriate, Toronto Hydro takes advantage of available tax deductions and tax credits, such as research and development tax credits to minimize its tax burden.

3. METHODOLOGY

The methodology for calculating PILs is consistent with the principles set out in Chapter 2 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (July 12, 2018), and reflects applicable legislative and regulatory changes, such as changes to corporate tax rates and capital cost allowance rates. Toronto Hydro confirms that non-recoverable expenses and expenses disallowed for regulatory purposes have been excluded from the regulatory tax calculation.

4. DISCLOSURE OF PILS TAX ADMINISTRATION AND TAX RULINGS

Toronto Hydro has not received any specific tax rulings that are inconsistent with Toronto Hydro's previously filed and approved tax model.

5. TAX STATUS

Toronto Hydro has not changed its tax status.

6. TAX REASSESSMENTS

The Ministry of Finance has recently completed its review of Toronto Hydro's 2013 PILs return. The PILs amount computed reflects methodologies approved by the Ministry of Finance through its audits.

7. TAX TREATMENT OF DIVIDENDS PAID IN PRIOR YEARS

Dividends paid in the historical years were treated as payments out of tax paid retained earnings and therefore were not treated as deductible for tax purposes.

8. LOSS CARRY-FORWARDS

Toronto Hydro does not have any non-capital or capital loss carry-forwards as of the end of December 2017, and does not expect to have such loss carry-forwards as of the end of December 2024.

9. CAPITAL COST ALLOWANCE ("CCA")

Toronto Hydro is filing this application on a forward test year basis and therefore, CCA is computed for 2020 based on projections of the change in capital assets from the 2016 historical year. A separate schedule is prepared to compute the projected CCA for 2019 to derive the projected undepreciated capital cost balances at January 1, 2020 (Exhibit

4B, Tab 2, Schedule 2). Maximum CCA is therefore claimed in the 2020 test year. Any projected additions are subject to the half-year rule in the year of acquisition.

10. INTEREST DEDUCTION

Actual interest expense is lower than the deemed interest expense calculated based on the 2020 model, as filed at Exhibit 4B, Tab 2, Schedule 2. Therefore, the difference between actual and deemed interest expense has not been deducted in calculating taxable income in the tax models for that year.

11. CAPITALIZED INTEREST

Interest is not capitalized to construction work in progress ("CWIP") for tax purposes. However, interest is capitalized for accounting purposes in the 2020 projection.

12. NON-DISTRIBUTION ELIMINATION

Toronto Hydro has included only income from the rate-regulated business in this application.

13. TAX CREDITS

Toronto Hydro expects that the level of expenditures qualifying for Scientific Research and Experimental Development ("SRED") in 2020 will be similar to expenditures in 2016. Federal investment tax credits arising from expenditures on qualifying SRED projects carried on by Toronto Hydro in 2011 decreased from $2.6 million to $1.5 million in 2016. This is a result of the 2012 Federal Budget (Bill C-45) which reduced the SRED investment tax credit rate from 20 percent to 15 percent for taxation years ending after 2013. Reductions in the overhead proxy rate and eligible expenditures to contractors

were also implemented as part of this Bill. Toronto Hydro has used the latest filed historical SRED credit in 2016 as the basis for deriving the 2020 credit ($1.5 million). Toronto Hydro has also included the Federal Apprenticeship Job Creation Tax Credit, the Ontario Apprenticeship Training Tax Credit and the Ontario Co-Operative Education Tax Credit in its PILs-related revenue requirement. A projected tax credit of $1.3 million, based on the average benefit of 2014 through 2016 claims, has been included in the 2020 tax models.

14. CAPITAL LEASES

Appropriate adjustments have been made in determining taxable income in the 2020 tax model with respect to leases capitalized for accounting purposes.

15. INTEGRITY CHECKS

The following integrity checks have been completed in respect of the PILs model:

- Depreciation and amortization added back agrees with the numbers disclosed in the rate base section of the application;
- Capital additions and deductions agree with the rate base section for historical, bridge and test years;
- Schedule 8 of the most recent tax return filed with the application has a closing December 31 historic year undepreciated capital cost ("UCC") that agrees with the opening bridge year UCC at January 1. A reconciliation has been provided to remove the non-distribution amounts in Exhibit 4B, Tab 2, Schedule 2;
- The CCA deductions in the application's PILs tax model for historical, bridge and test years agree with the numbers in Schedule 8;
- Accounting other post-employment benefits and pension amounts added back on Schedule 1;

- Reconciliation of accounting income to net income for tax purposes agrees with the OM&A analysis for compensation and is reasonable when compared with the notes to the audited financial statements and the actuarial valuations; and
- The income tax rate used to calculate the tax expense is consistent with the current legislated rate.

16. TAX PAYABLE FILINGS

Details of actual taxes paid by Toronto Hydro from 2014 to 2016, as well as the forecasted taxes to be paid for 2017 and 2018, are outlined in the table below. Explanations of the variances for the forecast years are also provided. The tax return copy for the historical year 2016 is provided in Exhibit 4B, Tab 2, Schedule 3.[1]

Table 1: Summary of PILs by Year ($ Millions)

	2014 Actual	2015 Actual	2016 Actual	2017 Forecast	2018 Forecast	2019 Bridge	2020 Test
Income Taxes	10.5	3.2	18.8	29.4	30.8	20.4	34.7

The decrease/increase in PILs from year to year is mainly due to the change in net income before tax and the differences between tax and accounting treatments of various costs. These differences primarily stem from the variance between capital cost allowance and accounting depreciation, other post-employment benefit adjustments, investment tax credits and other costs.

[1] Toronto Hydro has provided its tax return for 2016, the latest completed tax return available at the time the application was being prepared.

17. PROPERTY TAX

Property taxes are discussed in the Facilities Management program (Exhibit 4A, Tab 2, Schedule 12).

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Version 1.10

Utility Name	Toronto Hydro-Electric System Limited
Assigned EB Number	
Name and Title	
Phone Number	
Email Address	
Date	
Last COS Re-based Year	**2015**

Note: Drop-down lists are shaded blue; Input cells are shaded green.

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While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

1. Info
S. Summary
A. Data Input Sheet
B. Tax Rates & Exemptions

Historical Year

H0 - PILs, Tax Provision Historical Year
H1 - Adj. Taxable Income Historical Year
H4 - Schedule 4 Loss Carry Forward Historical Year
H8 - Schedule 8 Historical
H13 - Schedule 13 Tax Reserves Historical

Bridge Year

B0 - PILs,Tax Provision Bridge Year
B1 - Adj. Taxable Income Bridge Year
B4 - Schedule 4 Loss Carry Forward Bridge Year
B8 - Schedule 8 CCA Bridge Year
B13 - Schedule 13 Tax Reserves Bridge Year

Test Year

T0 PILs, Tax Provision Test Year
T1 Taxable Income Test Year
T4 Schedule 4 Loss Carry Forward Test Year
T8 Schedule 8 CCA Test Year
T13 Schedule 13 Reserve Test Year

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

No inputs required on this worksheet.

Inputs on Service Revenue Requirement Worksheet

The Service Revenue Requirement is in the 'Revenue Requirement Workform' - Tab 3.

Item	Working Paper Reference		
Adjustments required to arrive at taxable income	as below	**-61,393,745**	
Test Year - Payments in Lieu of Taxes (PILs)	T0	**24,143,968**	
Test Year - Grossed-up PILs before tax credits reclass to OM&A	T0	**32,848,936**	
Test Year - Tax credits reclass to OM&A	T0	**1,875,113**	
Test Year - Grossed-up PILs after tax credits reclass to OM&A	T0	**34,724,049**	
Effective Federal Tax Rate	T0	**15.0%**	
Effective Ontario Tax Rate	T0	**11.5%**	
Calculation of Adjustments required to arrive at Taxable Income			
Regulatory Income (before income taxes)	T1	162,827,585	
Taxable Income	T1	101,433,840	
Difference	calculated	-61,393,745	as above

Income Tax/PILs Workform for 2020 Filers

Integrity Checks

The applicant must ensure the following integrity checks have been completed and confirm this is the case in the table below, or provide an explanation if this is not the case:

	Item	Utility Confirmation (Y/N)	Notes
1	The depreciation and amortization added back in the application's PILs model agree with the numbers disclosed in the rate base section of the application	Y	
2	The capital additions and deductions in the UCC/ CCA Schedule 8 agree with the rate base section for historical, bridge and test years	Y	
3	Schedule 8 of the most recent federal T2 tax return filed with the application has a closing December 31 historical year UCC that agrees with the opening (January 1) bridge year UCC. If the amounts do not agree, then the applicant must provide a reconciliation with explanations. Distributors must segregate non- distribution tax amounts on Schedule 8.	Y	
4	The CCA deductions in the application's PILs tax model for historical, bridge and test years (as applicable) agree with the numbers in the UCC schedules for the same years filed in the application	Y	
5	Loss carry-forwards, if any, from the tax returns (Schedule 4) agree with those disclosed in the application	N	Toronto Hydro does not have any non-capital or capital loss carry-forwards as of the end of December 2017, and does not expect to have such loss carry-forwards as of the end of December 2024 (Exhibit 4B, Tab 2, Schedule 1).
6	A discussion is included in the application as to when the loss carry-forwards, if any, will be fully utilized	N	Toronto Hydro does not have any non-capital or capital loss carry-forwards as of the end of December 2017, and does not expect to have such loss carry-forwards as of the end of December 2024 (Exhibit 4B, Tab 2, Schedule 1).
7	CCA is maximized even if there are tax loss carry-forwards	N	Toronto Hydro does not have any non-capital or capital loss carry-forwards as of the end of December 2017, and does not expect to have such loss carry-forwards as of the end of December 2024 (Exhibit 4B, Tab 2, Schedule 1).
8	Accounting OPEB and pension amounts added back on Schedule 1 to reconcile accounting income to net income for tax purposes, must agree with the OM&A analysis for compensation. The amounts deducted must be reasonable when compared with the notes in the audited financial statements, FSCO reports, and the actuarial valuations.	Y	
9	The income tax rate used to calculate the tax expense must be consistent with the utility's actual tax facts and evidence filed in the application.	Y	

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Income Tax/PILs Workform for 2020 Filers

			Test Year	Bridge Year	
Rate Base		S	**$ 4,615,294,360**	**$ 4,481,989,147**	
Return on Ratebase					
Deemed ShortTerm Debt %	4.00%	T	$ 184,611,774	*W = S * T*	
Deemed Long Term Debt %	56.00%	U	$ 2,584,564,841	*X = S * U*	
Deemed Equity %	40.00%	V	$ 1,846,117,744	*Y = S * V*	
Short Term Interest Rate	2.61%	Z	$ 4,818,367	*AC = W * Z*	
Long Term Interest	3.71%	AA	$ 95,979,661	*AD = X * AA*	
Return on Equity (Regulatory Income)	8.82%	AB	**$ 162,827,585**	*AE = Y * AB*	T1
Return on Rate Base			**$ 263,625,614**	*AF = AC + AD + AE*	

Questions that must be answered

	Historical Year	Bridge Year	Test Year
1. Does the applicant have any Investment Tax Credits (ITC)?	Yes	Yes	Yes
2. Does the applicant have any SRED Expenditures?	Yes	Yes	Yes
3. Does the applicant have any Capital Gains or Losses for tax purposes?	Yes	No	No
4. Does the applicant have any Capital Leases?	Yes	Yes	Yes
5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	No	No	No
6. Since 1999, has the applicant acquired another regulated applicant's assets?	No	No	No
7. Did the applicant pay dividends? *If Yes, please describe what was the tax treatment in the manager's summary.*	Yes	No	No
8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes?	No	No	No

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Tax Rates Federal & Provincial As of June 29, 2018	Effective January 1, 2015	Effective January 1, 2016	Effective January 1, 2017	Effective January 1, 2018	Effective January 1, 2019	Effective January 1, 2020
Federal income tax						
General corporate rate	38.00%	38.00%	38.00%	38.00%	38.00%	38.00%
Federal tax abatement	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%
Adjusted federal rate	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%
Rate reduction	-13.00%	-13.00%	-13.00%	-13.00%	-13.00%	-13.00%
Federal Income Tax	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Ontario income tax	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%
Combined federal and Ontario	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Federal & Ontario Small Business						
Federal small business threshold	500,000	500,000	500,000	500,000	500,000	500,000
Ontario Small Business Threshold	500,000	500,000	500,000	500,000	500,000	500,000
Federal small business rate	11.00%	11.00%	10.50%	10.00%	9.00%	9.00%
Ontario small business rate	4.50%	4.50%	4.50%	3.50%	3.50%	3.50%

Notes

1. The Ontario Energy Board's proxy for taxable capital is rate base.
2. Regarding the small business deduction, if applicable,
   a. If taxable capital exceeds $15 million, the small business rate will not be applicable.
   b. If taxable capital is below $10 million, the small business rate would be applicable.
   c. If taxable capital is between $10 million and $15 million, the appropriate small business rate will be calculated.

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

PILs Tax Provision - Historical Year

INFORMATION NOT AVAILABLE. THIS SCHEDULE WILL BE UPDATED ONCE 2018 TAX RETURN IS FILED IN JUNE 2019.

Note: Input the actual information from the tax returns for the historical year.

				Wires Only	
Regulatory Taxable Income			H1	$ -	**A**
Combined Tax Rate and PILs	Ontario Tax Rate (Maximum 11.5%)				**B**
	Federal tax rate (Maximum 15%)				**C**
	Combined tax rate (Maximum 26.5%)			0.00%	**D = B+C**
Total Income Taxes				$ -	**E = A * D**
	Investment Tax Credits				**F**
	Miscellaneous Tax Credits				**G**
Total Tax Credits				$ -	**H = F + G**
Corporate PILs/Income Tax Provision for Historical Year				$ -	**I = E - H**

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Income Tax/PILs Workform for 2020 Filers

Adjusted Taxable Income - Historical Year

INFORMATION NOT AVAILABLE. THIS SCHEDULE WILL BE UPDATED ONCE 2018 TAX RETURN IS FILED IN JUNE 2019.

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Income before PILs/Taxes	**(A + 101 + 102)**			0
Additions:				
Interest and penalties on taxes	103			0
Amortization of tangible assets	104			0
Amortization of intangible assets	106			0
Recapture of capital cost allowance from Schedule 8	107			0
Gain on sale of eligible capital property from Schedule 10	108			0
Income or loss for tax purposes- joint ventures or partnerships	109			0
Loss in equity of subsidiaries and affiliates	110			0
Loss on disposal of assets	111			0
Charitable donations	112			0
Taxable Capital Gains	113			0
Political Donations	114			0
Deferred and prepaid expenses	116			0
Scientific research expenditures deducted on financial statements	118			0
Capitalized interest	119			0
Non-deductible club dues and fees	120			0
Non-deductible meals and entertainment expense	121			0
Non-deductible automobile expenses	122			0
Non-deductible life insurance premiums	123			0
Non-deductible company pension plans	124			0
Tax reserves deducted in prior year	125			0
Reserves from financial statements- balance at end of year	126			0
Soft costs on construction and renovation of buildings	127			0
Book loss on joint ventures or partnerships	205			0
Capital items expensed	206			0
Debt issue expense	208			0
Development expenses claimed in current year	212			0
Financing fees deducted in books	216			0
Gain on settlement of debt	220			0
Non-deductible advertising	226			0
Non-deductible interest	227			0
Non-deductible legal and accounting fees	228			0
Recapture of SR&ED expenditures	231			0
Share issue expense	235			0
Write down of capital property	236			0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237			0
Other Additions				
Interest Expensed on Capital Leases	290			0
Realized Income from Deferred Credit Accounts	291			0
Pensions	292			0
Non-deductible penalties	293			0
	294			0
	295			0
ARO Accretion expense				0
Capital Contributions Received (ITA 12(1)(x))				0
Lease Inducements Received (ITA 12(1)(x))				0
Deferred Revenue (ITA 12(1)(a))				0
Prior Year Investment Tax Credits received				0
				0
				0
				0
				0
				0
				0
				0
				0
				0
				0
Total Additions		**0**	**0**	**0**

Adjusted Taxable Income - Historical Year

INFORMATION NOT AVAILABLE. THIS SCHEDULE WILL BE UPDATED ONCE 2018 TAX RETURN IS FILED IN JUNE 2019.

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Deductions:				
Gain on disposal of assets per financial statements	401			0
Dividends not taxable under section 83	402			0
Capital cost allowance from Schedule 8	403			0
Terminal loss from Schedule 8	404			0
Allowable business investment loss	406			0
Deferred and prepaid expenses	409			0
Scientific research expenses claimed in year	411			0
Tax reserves claimed in current year	413			0
Reserves from financial statements - balance at beginning of year	414			0
Contributions to deferred income plans	416			0
Book income of joint venture or partnership	305			0
Equity in income from subsidiary or affiliates	306			0
Other deductions: (Please explain in detail the nature of the item)				
Interest capitalized for accounting deducted for tax	390			0
Capital Lease Payments	391			0
Non-taxable imputed interest income on deferral and variance accounts	392			0
	393			0
	394			0
ARO Payments - Deductible for Tax when Paid				0
ITA 13(7.4) Election - Capital Contributions Received				0
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds				0
Deferred Revenue - ITA 20(1)(m) reserve				0
Principal portion of lease payments				0
Lease Inducement Book Amortization credit to income				0
Financing fees for tax ITA 20(1)(e) and (e.1)				0
				0
				0
				0
				0
				0
				0
				0
				0
Total Deductions		**0**	**0**	**0**
Net Income for Tax Purposes		**0**	**0**	**0**
Charitable donations from Schedule 2	311			0
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320			0
Non-capital losses of preceding taxation years from Schedule 4	331			0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332			0
Limited partnership losses of preceding taxation years from Schedule 4	335			0
TAXABLE INCOME		**0**	**0**	**0**

H0

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Schedule 7-1 Loss Carry Forward - Historical

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance	
Actual Historical			0	B4

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance	
Actual Historical			0	B4

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Schedule 8 - Historical Year

BELOW ARE FORECASTED AMOUNTS . THIS SCHEDULE WILL BE UPDATED ONCE 2018 TAX RETURN IS FILED IN JUNE 2019.

Class	Class Description	UCC End of Year Historical per tax returns	Less: Non-Distribution Portion	UCC Regulated Historical Year	Working Paper Reference
1	Distribution System - post 1987	$ 1,007,780,742		$ 1,007,780,742	B8
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election			$ -	B8
2	Distribution System - pre 1988	$ 227,301,557		$ 227,301,557	B8
8	General Office/Stores Equip	$ 24,890,022	$ 725,670	$ 24,164,352	B8
10	Computer Hardware/ Vehicles	$ 11,431,301	$ 57,891	$ 11,373,410	B8
10.1	Certain Automobiles			$ -	B8
12	Computer Software	$ 44,366,441	$ 186,199	$ 44,180,242	B8
13 1	Lease # 1	$ 5,242		$ 5,242	B8
13 2	Lease #2			$ -	B8
13 3	Lease # 3			$ -	B8
13 4	Lease # 4			$ -	B8
14	Franchise			$ -	B8
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 28,154,236		$ 28,154,236	B8
42	Fibre Optic Cable	$ 8,918,768		$ 8,918,768	B8
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -		$ -	B8
43.2	Certain Clean Energy Generation Equipment	$ 679,111	$ 679,111	$ -	B8
45	Computers & Systems Software acq'd post Mar 22/04	$ 4,110		$ 4,110	B8
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ 9,668,041		$ 9,668,041	B8
47	Distribution System - post February 2005	$ 2,378,863,638	$ 7,989,478	$ 2,370,874,160	B8
50	Data Network Infrastructure Equipment - post Mar 2007	$ 21,560,631	$ 52	$ 21,560,579	B8
52	Computer Hardware and system software	$ -		$ -	B8
95	CWIP	$ 475,576,173	$ 1,558,854	$ 474,017,319	B8
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)[1]	$ 44,751,921		$ 44,751,921	B8
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)[1]	$ 103,062,740		$ 103,062,740	B8
6	Fence	$ 2,004,778		$ 2,004,778	B8
				$ -	
				$ -	
				$ -	
				$ -	
				$ -	
				$ -	
				$ -	
	SUB-TOTAL - UCC	**$ 4,389,019,452**	**$ 11,197,255**	**$ 4,377,822,197**	

[1] New CCA class 14.1 effective January 1, 2017. The class includes property that was eligible capital property immediately before January 1, 2017. For tax years that end prior to 2027, transitional rules apply to class 14.1 that were acquired before January 1, 2017.

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Schedule 13 Tax Reserves - Historical

Continuity of Reserves

BELOW ARE FORECASTED AMOUNTS . THIS SCHEDULE WILL BE UPDATED ONCE 2018 TAX RETURN IS FILED IN JUNE 2019.

Description	Historical Balance as per tax returns	Non-Distribution Eliminations	Utility Only	
Capital Gains Reserves ss.40(1)			0	B13
Tax Reserves Not Deducted for accounting purposes				
Reserve for doubtful accounts ss. 20(1)(l)			0	B13
Reserve for goods and services not delivered ss. 20(1)(m)			0	B13
Reserve for unpaid amounts ss. 20(1)(n)			0	B13
Debt & Share Issue Expenses ss. 20(1)(e)			0	B13
Other tax reserves			0	B13
			0	
			0	
			0	
			0	
			0	
Total	**0**	**0**	**0**	
Financial Statement Reserves (not deductible for Tax Purposes)				
General Reserve for Inventory Obsolescence (non-specific)			0	B13
General reserve for bad debts			0	B13
Accrued Employee Future Benefits:			0	B13
- Medical and Life Insurance			0	B13
-Short & Long-term Disability			0	B13
-Accmulated Sick Leave			0	B13
- Termination Cost			0	B13
- Other Post-Employment Benefits	319,159,000	1,497,000	317,662,000	B13
Provision for Environmental Costs			0	B13
Restructuring Costs			0	B13
Accrued Contingent Litigation Costs			0	B13
Accrued Self-Insurance Costs			0	B13
Other Contingent Liabilities			0	B13
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0	B13
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0	B13
Other			0	B13
			0	
			0	
Total	**319,159,000**	**1,497,000**	**317,662,000**	

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

PILS Tax Provision - Bridge Year

Wires Only

Regulatory Taxable Income					Reference B1	$ 61,664,933	**A**
	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate			
Ontario (Max 11.5%)	11.5%	11.5%	$ 7,091,467	11.5%	**B**		
Federal (Max 15%)	15.0%	15.0%	$ 9,249,740	15.0%	**C**		
Combined effective tax rate (Max 26.5%)						26.50%	**D = B + C**
Total Income Taxes						**$ 16,341,207**	**E = A * D**
Investment Tax Credits						$ 1,478,000	**F**
Miscellaneous Tax Credits						$ 1,258,000	**G**
Total Tax Credits						**$ 2,736,000**	**H = F + G**
Corporate PILs/Income Tax Provision for Bridge Year						**$ 13,605,207**	**I = E - H**
Corporate PILs/Income Tax Provision Gross Up [1]					73.50% **J = 1-D**	**$ 4,905,279**	**K = I/J-I**
Income Tax (grossed-up) before tax credits reclass to OM&A						$ 18,510,486	**L = K + I**
Tax credits reclass to OM&A						$ 1,875,113	**M**
Income Tax (grossed-up) after tax credits reclass to OM&A						**$ 20,385,599**	**N = L + M**

Note:

1. This is for the derivation of Bridge year PILs income tax expense and should not be used for Test year revenue requirement calculations.

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Working Paper Reference	Total for Regulated Utility
Income before PILs/Taxes	**(A + 101 + 102)**		166,801,708
Additions:			
Interest and penalties on taxes	103		
Amortization of tangible assets	104		247,713,157
Amortization of intangible assets	106		
Recapture of capital cost allowance from Schedule 8	107		
Gain on sale of eligible capital property from Schedule 10	108		
Income or loss for tax purposes- joint ventures or partnerships	109		
Loss in equity of subsidiaries and affiliates	110		
Loss on disposal of assets	111		
Charitable donations	112		
Taxable Capital Gains	113		
Political Donations	114		
Deferred and prepaid expenses	116		
Scientific research expenditures deducted on financial statements	118		
Capitalized interest	119		
Non-deductible club dues and fees	120		334,453
Non-deductible meals and entertainment expense	121		227,915
Non-deductible automobile expenses	122		
Non-deductible life insurance premiums	123		
Non-deductible company pension plans	124		
Tax reserves deducted in prior year	125	B13	0
Reserves from financial statements- balance at end of year	126	B13	323,633,000
Soft costs on construction and renovation of buildings	127		
Book loss on joint ventures or partnerships	205		
Capital items expensed	206		
Debt issue expense	208		
Development expenses claimed in current year	212		
Financing fees deducted in books	216		1,173,682
Gain on settlement of debt	220		
Non-deductible advertising	226		
Non-deductible interest	227		
Non-deductible legal and accounting fees	228		
Recapture of SR&ED expenditures	231		
Share issue expense	235		
Write down of capital property	236		
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237		
Other Additions			
Interest Expensed on Capital Leases	290		26,379
Realized Income from Deferred Credit Accounts	291		
Pensions	292		
Non-deductible penalties	293		
	294		
	295		
ARO Accretion expense			
Capital Contributions Received (ITA 12(1)(x))			72,742,087
Lease Inducements Received (ITA 12(1)(x))			
Deferred Revenue (ITA 12(1)(a))			1,100,000
Prior Year Investment Tax Credits received			2,736,000
Total Additions			**649,686,673**

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Working Paper Reference	Total for Regulated Utility
Deductions:			
Gain on disposal of assets per financial statements	401		
Dividends not taxable under section 83	402		
Capital cost allowance from Schedule 8	403	B8	353,929,269
Terminal loss from Schedule 8	404		
Allowable business investment loss	406		
Deferred and prepaid expenses	409		
Scientific research expenses claimed in year	411		
Tax reserves claimed in current year	413	B13	0
Reserves from financial statements - balance at beginning of year	414	B13	317,662,000
Contributions to deferred income plans	416		
Book income of joint venture or partnership	305		
Equity in income from subsidiary or affiliates	306		
Other deductions: (Please explain in detail the nature of the item)			
Interest capitalized for accounting deducted for tax	390		
Capital Lease Payments	391		299,000
Non-taxable imputed interest income on deferral and variance accounts	392		
	393		
	394		
ARO Payments - Deductible for Tax when Paid			74,232
ITA 13(7.4) Election - Capital Contributions Received			72,742,087
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds			
Deferred Revenue - ITA 20(1)(m) reserve			1,100,000
Principal portion of lease payments			
Lease Inducement Book Amortization credit to income			54,792
Financing fees for tax ITA 20(1)(e) and (e.1)			1,681,277
Land Lease payment capitalized for accounting			89,423
Other Post-Employment Benefits adjustment - change in balance with no Income Statement Impact			173,000
Other Post-Employment Benefits adjustment - current year capitalized portion with no Income Statement Impact			7,018,368
Total Deductions		calculated	**754,823,448**
Net Income for Tax Purposes		calculated	**61,664,933**
Charitable donations from Schedule 2	311		
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320		
Non-capital losses of preceding taxation years from Schedule 4	331	B4	0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332	B4	0
Limited partnership losses of preceding taxation years from Schedule 4	335		
TAXABLE INCOME		calculated	**61,664,933**

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Corporation Loss Continuity and Application

Schedule 4 Loss Carry Forward - Bridge Year

Non-Capital Loss Carry Forward Deduction		Total	
Actual Historical	H4	0	
Amount to be used in Bridge Year	B1	0	
Loss Carry Forward Generated in Bridge Year (if any)	B1	0	
Other Adjustments			
Balance available for use post Bridge Year	calculated	0	T4

Net Capital Loss Carry Forward Deduction		Total	
Actual Historical	H4	0	
Amount to be used in Bridge Year			
Loss Carry Forward Generated in Bridge Year (if any)	B1		
Other Adjustments			
Balance available for use post Bridge Year	calculated	0	T4

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Schedule 8 CCA - Bridge Year

Class	Class Description	Working Paper Reference	UCC Regulated Historical Year	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Bridge Year CCA		UCC End of Bridge Year	Working Paper Reference
1	Distribution System - post 1987	H8	$ 1,007,780,742	$ 1,868,245		$ 1,009,648,987	$ 934,123	$ 1,008,714,865	4%	$ 40,348,595		$ 969,300,392	T8
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	H8				$ -	$ -	$ -	6%	$ -		$ -	T8
2	Distribution System - pre 1988	H8	$ 227,301,557			$ 227,301,557	$ -	$ 227,301,557	6%	$ 13,638,093		$ 213,663,464	T8
8	General Office/Stores Equip	H8	$ 24,164,352	$ 2,289,594		$ 26,453,946	$ 1,144,797	$ 25,309,149	20%	$ 5,061,830		$ 21,392,116	T8
10	Computer Hardware/ Vehicles	H8	$ 11,373,410	$ 3,200,000		$ 14,573,410	$ 1,600,000	$ 12,973,410	30%	$ 3,892,023		$ 10,681,387	T8
10.1	Certain Automobiles	H8				$ -	$ -	$ -	30%	$ -		$ -	T8
12	Computer Software	H8	$ 44,180,242	$ 24,444,222		$ 68,624,464	$ 12,222,111	$ 56,402,353	100%	$ 56,402,353		$ 12,222,111	T8
13 1	Lease # 1	H8	$ 5,242			$ 5,242	$ -	$ 5,242	SL	$ 5,242		$ -	T8
13 2	Lease #2	H8				$ -	$ -	$ -		$ -		$ -	T8
13 3	Lease # 3	H8				$ -	$ -	$ -		$ -		$ -	T8
13 4	Lease # 4	H8				$ -	$ -	$ -		$ -		$ -	T8
14	Franchise	H8				$ -	$ -	$ -		$ -		$ -	T8
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	H8	$ 28,154,236	$ 300,000		$ 28,454,236	$ 150,000	$ 28,304,236	8%	$ 2,264,339		$ 26,189,897	T8
42	Fibre Optic Cable	H8	$ 8,918,768			$ 8,918,768	$ -	$ 8,918,768	12%	$ 1,070,252		$ 7,848,516	T8
43.1	Certain Energy-Efficient Electrical Generating Equipment	H8	$ -			$ -	$ -	$ -	30%	$ -		$ -	T8
43.2	Certain Clean Energy Generation Equipment	H8	$ -			$ -	$ -	$ -	50%	$ -		$ -	T8
45	Computers & Systems Software acq'd post Mar 22/04	H8	$ 4,110			$ 4,110	$ -	$ 4,110	45%	$ 1,850		$ 2,261	T8
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	H8	$ 9,668,041			$ 9,668,041	$ -	$ 9,668,041	30%	$ 2,900,412		$ 6,767,629	T8
47	Distribution System - post February 2005	H8	$ 2,370,874,160	$ 331,429,816		$ 2,702,303,976	$ 165,714,908	$ 2,536,589,068	8%	$ 202,927,125		$ 2,499,376,851	T8
50	Data Network Infrastructure Equipment - post Mar 2007	H8	$ 21,560,579	$ 17,918,410		$ 39,478,989	$ 8,959,205	$ 30,519,784	55%	$ 16,785,881		$ 22,693,108	T8
52	Computer Hardware and system software	H8	$ -			$ -	$ -	$ -	100%	$ -		$ -	T8
95	CWIP	H8	$ 474,017,319			$ 474,017,319	$ -	$ 474,017,319	0%	$ -		$ 474,017,319	T8
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)[1]	H8	$ 44,751,921			$ 44,751,921	$ -	$ 44,751,921	7%	$ 3,132,634		$ 41,619,287	T8
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)[1]	H8	$ 103,062,740	$ 5,400,989		$ 108,463,729	$ 2,700,495	$ 105,763,235	5%	$ 5,288,162		$ 103,175,567	T8
6	Fence	H8	$ 2,004,778	$ 200,000		$ 2,204,778	$ 100,000	$ 2,104,778	10%	$ 210,478		$ 1,994,300	T8
						$ -	$ -	$ -		$ -		$ -	
						$ -	$ -	$ -		$ -		$ -	
						$ -	$ -	$ -		$ -		$ -	
						$ -	$ -	$ -		$ -		$ -	
						$ -	$ -	$ -		$ -		$ -	
						$ -	$ -	$ -		$ -		$ -	
						$ -	$ -	$ -		$ -		$ -	
	TOTAL		$ 4,377,822,197	$ 387,051,276	$ -	$ 4,764,873,473	$ 193,525,638	$ 4,571,347,835		$ 353,929,269	B1	$ 4,410,944,204	

1. New CCA class 14.1 effective January 1, 2017. The class includes property that was eligible capital property immediately before January 1, 2017. For tax years that end prior to 2027, transitional rules apply to class 14.1 that were acquired before January 1, 2017

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Schedule 13 Tax Reserves - Bridge Year

Continuity of Reserves

Description	Reference	Historical Utility Only	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance		Bridge Year Adjustments: Additions	Bridge Year Adjustments: Disposals	Balance for Bridge Year		Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	H13	0		0				0	T13	0	
Tax Reserves Not Deducted for accounting purposes											
Reserve for doubtful accounts ss. 20(1)(l)	H13	0		0				0	T13	0	
Reserve for goods and services not delivered ss. 20(1)(m)	H13	0		0				0	T13	0	
Reserve for unpaid amounts ss. 20(1)(n)	H13	0		0				0	T13	0	
Debt & Share Issue Expenses ss. 20(1)(e)	H13	0		0				0	T13	0	
Other tax reserves	H13	0		0				0	T13	0	
		0		0				0		0	
		0		0				0		0	
Total		**0**	**0**	**0**	B1	**0**	**0**	**0**	B1	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)											
General Reserve for Inventory Obsolescence (non-specific)	H13	0		0				0	T13	0	
General reserve for bad debts	H13	0		0				0	T13	0	
Accrued Employee Future Benefits:	H13	0		0				0	T13	0	
- Medical and Life Insurance	H13	0		0				0	T13	0	
-Short & Long-term Disability	H13	0		0				0	T13	0	
-Accmulated Sick Leave	H13	0		0				0	T13	0	
- Termination Cost	H13	0		0				0	T13	0	
- Other Post-Employment Benefits	H13	317,662,000		317,662,000		5,971,000		323,633,000	T13	5,971,000	
Provision for Environmental Costs	H13	0		0				0	T13	0	
Restructuring Costs	H13	0		0				0	T13	0	
Accrued Contingent Litigation Costs	H13	0		0				0	T13	0	
Accrued Self-Insurance Costs	H13	0		0				0	T13	0	
Other Contingent Liabilities	H13	0		0				0	T13	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	H13	0		0				0	T13	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	H13	0		0				0	T13	0	
Other	H13	0		0				0	T13	0	
		0		0				0		0	
		0		0				0		0	
Total		**317,662,000**	**0**	**317,662,000**	B1	**5,971,000**	**0**	**323,633,000**	B1	**5,971,000**	**0**

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

PILs Tax Provision - Test Year

							Wires Only	
Regulatory Taxable Income						T1	$ 101,433,840	**A**
	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate				
Ontario (Max 11.5%)	11.5%	11.5%	$ 11,664,892	11.5%	**B**			
Federal (Max 15%)	15.0%	15.0%	$ 15,215,076	15.0%	**C**			
Combined effective tax rate (Max 26.5%)							26.50%	**D = B + C**
Total Income Taxes							**$ 26,879,968**	**E = A * D**
Investment Tax Credits							$ 1,478,000	**F**
Miscellaneous Tax Credits							$ 1,258,000	**G**
Total Tax Credits							**$ 2,736,000**	**H = F + G**
Corporate PILs/Income Tax Provision for Test Year							**$ 24,143,968**	**I = E - H** S. Summary
Corporate PILs/Income Tax Provision Gross Up [1]						73.50% **J = 1-D**	**$ 8,704,968**	**K = I/J-I**
Income Tax (grossed-up) before tax credits reclass to OM&A							$ 32,848,936	**L = K + I** S. Summary
Tax credits reclass to OM&A							$ 1,875,113	**M** S. Summary
Income Tax (grossed-up) after tax credits reclass to OM&A							**$ 34,724,049**	**N = L + M** S. Summary

Note:

1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Taxable Income - Test Year

		Working Paper Reference	Test Year Taxable Income
Net Income Before Taxes		A.	162,827,585
	T2 S1 line #		
Additions:			
Interest and penalties on taxes	103		
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104		268,664,188
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106		
Recapture of capital cost allowance from Schedule 8	107		
Gain on sale of eligible capital property from Schedule 10	108		
Income or loss for tax purposes- joint ventures or partnerships	109		
Loss in equity of subsidiaries and affiliates	110		
Loss on disposal of assets	111		
Charitable donations	112		
Taxable Capital Gains	113		
Political Donations	114		
Deferred and prepaid expenses	116		
Scientific research expenditures deducted on financial statements	118		
Capitalized interest	119		
Non-deductible club dues and fees	120		334,453
Non-deductible meals and entertainment expense	121		227,915
Non-deductible automobile expenses	122		
Non-deductible life insurance premiums	123		
Non-deductible company pension plans	124		
Tax reserves beginning of year	125	T13	0
Reserves from financial statements- balance at end of year	126	T13	329,895,150
Soft costs on construction and renovation of buildings	127		
Book loss on joint ventures or partnerships	205		
Capital items expensed	206		
Debt issue expense	208		
Development expenses claimed in current year	212		
Financing fees deducted in books	216		1,125,064
Gain on settlement of debt	220		
Non-deductible advertising	226		
Non-deductible interest	227		
Non-deductible legal and accounting fees	228		
Recapture of SR&ED expenditures	231		
Share issue expense	235		
Write down of capital property	236		
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237		
Other Additions: (please explain in detail the nature of the item)			
Interest Expensed on Capital Leases	290		20,214
Realized Income from Deferred Credit Accounts	291		
Pensions	292		
Non-deductible penalties	293		
	294		
	295		
	296		
	297		
ARO Accretion expense			
Capital Contributions Received (ITA 12(1)(x))			68,786,707
Lease Inducements Received (ITA 12(1)(x))			
Deferred Revenue (ITA 12(1)(a))			1,100,000
Prior Year Investment Tax Credits received			2,736,000
Total Additions			**672,889,691**

Taxable Income - Test Year

		Working Paper Reference	Test Year Taxable Income
Net Income Before Taxes		A.	162,827,585
	T2 S1 line #		
Deductions:			
Gain on disposal of assets per financial statements	401		
Dividends not taxable under section 83	402		
Capital cost allowance from Schedule 8	403	T8	331,389,972
Terminal loss from Schedule 8	404		
Allowable business investment loss	406		
Deferred and prepaid expenses	409		
Scientific research expenses claimed in year	411		
Tax reserves end of year	413	T13	0
Reserves from financial statements - balance at beginning of year	414	T13	323,633,000
Contributions to deferred income plans	416		
Book income of joint venture or partnership	305		
Equity in income from subsidiary or affiliates	306		
Other deductions: (Please explain in detail the nature of the item)			
Interest capitalized for accounting deducted for tax	390		
Capital Lease Payments	391		310,176
Non-taxable imputed interest income on deferral and variance accounts	392		
	393		
	394		
	395		
	396		
	397		
ARO Payments - Deductible for Tax when Paid			75,717
ITA 13(7.4) Election - Capital Contributions Received			68,786,707
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds			
Deferred Revenue - ITA 20(1)(m) reserve			1,100,000
Principal portion of lease payments			
Lease Inducement Book Amortization credit to income			54,792
Financing fees for tax ITA 20(1)(e) and (e.1)			1,453,417
Other Post-Employment Benefits adjustment - change in balance with no Income Statement Impact			204,443
Other Post-Employment Benefits adjustment - current year capitalized portion with no Income Statement Impact			7,185,789
Land Lease payment capitalized for accounting			89,423
Total Deductions		calculated	**734,283,436**
NET INCOME FOR TAX PURPOSES		calculated	**101,433,840**
Charitable donations	311		
Taxable dividends received under section 112 or 113	320		
Non-capital losses of preceding taxation years from Schedule 7-1	331	T4	0
Net-capital losses of preceding taxation years (Please show calculation)	332	T4	0
Limited partnership losses of preceding taxation years from Schedule 4	335		
REGULATORY TAXABLE INCOME		calculated	**101,433,840**

T0

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Schedule 7-1 Loss Carry Forward - Test Year

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Working Paper Reference	Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year Carried Forward	B4	0		0
Amount to be used in Test Year and Price Cap Years	T1	0		0
Number of years loss until next cost of service (i.e. years the loss is to be spread over)				
Amount to be used in Test Year	calculated	0		0
Loss Carry Forward Generated in Test Year (if any)	T1	0		0
Other Adjustments				0
Balance available for use in Future Years	calculated	0		0

Net Capital Loss Carry Forward Deduction		Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year Carried Forward	B4	0		0
Amount to be used in Test Year and Price Cap Years				0
Number of years loss until next cost of service (i.e. years the loss is to be spread over)				
Amount to be used in Test Year	T1	0		0
Loss Carry Forward Generated in Test Year (if any)				0
Other Adjustments				0
Balance available for use in Future Years		0		0

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Schedule 8 CCA - Test Year

Class	Class Description	Working Paper Reference	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA		UCC End of Test Year
1	Distribution System - post 1987	B8	$ 969,300,392	4,280,813		$ 973,581,205	$ 2,140,407	$ 971,440,799	4%	$ 38,857,632		$ 934,723,573
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	B8	$ -			$ -	$ -	$ -	6%	$ -		$ -
2	Distribution System - pre 1988	B8	$ 213,663,464			$ 213,663,464	$ -	$ 213,663,464	6%	$ 12,819,808		$ 200,843,656
8	General Office/Stores Equip	B8	$ 21,392,116	4,365,021		$ 25,757,137	$ 2,182,511	$ 23,574,627	20%	$ 4,714,925		$ 21,042,212
10	Computer Hardware/ Vehicles	B8	$ 10,681,387	4,714,447		$ 15,395,834	$ 2,357,224	$ 13,038,611	30%	$ 3,911,583		$ 11,484,251
10.1	Certain Automobiles	B8	$ -			$ -	$ -	$ -	30%	$ -		$ -
12	Computer Software	B8	$ 12,222,111	24,573,046		$ 36,795,157	$ 12,286,523	$ 24,508,634	100%	$ 24,508,634		$ 12,286,523
13 1	Lease # 1	B8	$ -			$ -	$ -	$ -		$ -		$ -
13 2	Lease #2	B8	$ -			$ -	$ -	$ -		$ -		$ -
13 3	Lease # 3	B8	$ -			$ -	$ -	$ -		$ -		$ -
13 4	Lease # 4	B8	$ -			$ -	$ -	$ -		$ -		$ -
14	Franchise	B8	$ -			$ -	$ -	$ -		$ -		$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	B8	$ 26,189,897	700,000		$ 26,889,897	$ 350,000	$ 26,539,897	8%	$ 2,123,192		$ 24,766,705
42	Fibre Optic Cable	B8	$ 7,848,516			$ 7,848,516	$ -	$ 7,848,516	12%	$ 941,822		$ 6,906,694
43.1	Certain Energy-Efficient Electrical Generating Equipment	B8	$ -			$ -	$ -	$ -	30%	$ -		$ -
43.2	Certain Clean Energy Generation Equipment	B8	$ -			$ -	$ -	$ -	50%	$ -		$ -
45	Computers & Systems Software acq'd post Mar 22/04	B8	$ 2,261			$ 2,261	$ -	$ 2,261	45%	$ 1,017		$ 1,243
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	B8	$ 6,767,629			$ 6,767,629	$ -	$ 6,767,629	30%	$ 2,030,289		$ 4,737,340
47	Distribution System - post February 2005	B8	$ 2,499,376,851	376,618,091		$ 2,875,994,942	$ 188,309,046	$ 2,687,685,896	8%	$ 215,014,872		$ 2,660,980,070
50	Data Network Infrastructure Equipment - post Mar 2007	B8	$ 22,693,108	16,929,237		$ 39,622,345	$ 8,464,619	$ 31,157,726	55%	$ 17,136,749		$ 22,485,595
52	Computer Hardware and system software	B8	$ -			$ -	$ -	$ -	100%	$ -		$ -
95	CWIP	B8	$ 474,017,319			$ 474,017,319	$ -	$ 474,017,319	0%	$ -		$ 474,017,319
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)1	B8	$ 41,619,287			$ 41,619,287	$ -	$ 41,619,287	7%	$ 2,913,350		$ 38,705,936
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)1	B8	$ 103,175,567	41,315,611		$ 144,491,178	$ 20,657,806	$ 123,833,373	5%	$ 6,191,669		$ 138,299,510
6	Fence	B8	$ 1,994,300	500,000		$ 2,494,300	$ 250,000	$ 2,244,300	10%	$ 224,430		$ 2,269,870
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
	TOTAL		$ 4,410,944,204	$ 473,996,266	$ -	$ 4,884,940,470	$ 236,998,133	$ 4,647,942,337		$ 331,389,972	T1	$ 4,553,550,498

1. New CCA class 14.1 effective January 1, 2017. The class includes property that was eligible capital property immediately before January 1, 2017. For tax years that end prior to 2027, transitional rules apply to class 14.1 that were acquired before January 1, 2017

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Schedule 13 Tax Reserves - Test Year

Continuity of Reserves

Description	Working Paper Reference	Bridge Year	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance		Test Year Adjustments: Additions	Test Year Adjustments: Disposals	Balance for Test Year		Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	B13	0		0				0		0	
Tax Reserves Not Deducted for accounting purposes											
Reserve for doubtful accounts ss. 20(1)(l)	B13	0		0		0	0	0		0	
Reserve for goods and services not delivered ss. 20(1)(m)	B13	0		0				0		0	
Reserve for unpaid amounts ss. 20(1)(n)	B13	0		0				0		0	
Debt & Share Issue Expenses ss. 20(1)(e)	B13	0		0				0		0	
Other tax reserves	B13	0		0				0		0	
		0		0				0		0	
		0		0				0		0	
Total		**0**	**0**	**0**	T1	**0**	**0**	**0**	T1	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)											
General Reserve for Inventory Obsolescence (non-specific)	B13	0		0				0		0	
General reserve for bad debts	B13	0		0				0		0	
Accrued Employee Future Benefits:	B13	0		0				0		0	
- Medical and Life Insurance	B13	0		0				0		0	
-Short & Long-term Disability	B13	0		0				0		0	
-Accmulated Sick Leave	B13	0		0				0		0	
- Termination Cost	B13	0		0				0		0	
- Other Post-Employment Benefits	B13	323,633,000		323,633,000		6,262,150		329,895,150		6,262,150	
Provision for Environmental Costs	B13	0		0				0		0	
Restructuring Costs	B13	0		0				0		0	
Accrued Contingent Litigation Costs	B13	0		0				0		0	
Accrued Self-Insurance Costs	B13	0		0				0		0	
Other Contingent Liabilities	B13	0		0				0		0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	B13	0		0				0		0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	B13	0		0				0		0	
Other	B13	0		0				0		0	
		0		0				0		0	
		0		0				0		0	
Total		**323,633,000**	**0**	**323,633,000**	T1	**6,262,150**	**0**	**329,895,150**	T1	**6,262,150**	**0**

Canada Revenue Agency / Agence du revenu du Canada

Code 1501

Scientific Research and Experimental Development (SR&ED) Expenditures Claim

Toronto Hydro-Electric System Limited
EB-2018-0165
Exhibit 4B
Tab 2
Schedule 3
UPDATED: November 13, 2018
(185 pages)

Use this form:

- to provide technical information on your SR&ED projects;
- to calculate your SR&ED expenditures; and
- to calculate your qualified SR&ED expenditures for investment tax credits (ITC).

To claim an ITC, use either:

- Schedule T2SCH31, *Investment Tax Credit – Corporations*, or
- Form T2038(IND), *Investment Tax Credit (Individuals)*.

The information requested in this form and documents supporting your expenditures and project information (Part 2) are prescribed information.

Your SR&ED claim must be filed within 12 months of the filing due date of your income tax return.

To help you fill out this form, use the T4088, *Guide to Form T661*, which is available on our Web site: **www.cra.gc.ca/sred**.

Part 1 – General information

010 Name of claimant

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

Enter one of the following:

[redacted]
Business number (BN)

Tax year
From: 2016-01-01 (Year Month Day)
To: 2016-12-31 (Year Month Day)

Social insurance number (SIN)

050 Total number of projects you are claiming this tax year: 10

100 Contact person for the financial information [redacted]	**105** Telephone number/extension [redacted]	**110** Fax number [redacted]
115 Contact person for the technical information [redacted]	**120** Telephone number/extension [redacted]	**125** Fax number

151 If this claim is filed for a partnership, was Form T5013 filed? . . . . . 1 ☐ Yes 2 ☐ No

If you answered **no** to line 151, complete lines 153, 156 and 157.

153 Names of the partners	**156** %	**157** BN or SIN
1		
2		
3		
4		
5		

Part 2 - Project information

CRA internal form identifier 060
Code 1501

Complete a separate Part 2 for each project claimed this year.

Section A - Project identification

200 Project title (and identification code if applicable)

See schedule

Part 3 – Calculation of SR&ED expenditures

What did you spend on your SR&ED projects?

Section A – Select the method to calculate the SR&ED expenditures

I elect (choose) to use the following method to calculate my SR&ED expenditures and related investment tax credits (ITC) for this tax year.
I understand that my election is irrevocable (cannot be changed) for this tax year.

160 1 [X] I elect to use the proxy method
(Enter "0" on line 360 and complete Part 5.)

162 1 [ ] I choose to use the traditional method
(Enter "0" on lines 355 and 502. Complete line 360.)

Section B – Calculation of allowable SR&ED expenditures (to the nearest dollar)

• SR&ED portion of salary or wages of employees directly engaged in the SR&ED:			
a) Employees other than specified employees for work performed in Canada	300	+	3,203,537
b) Specified employees for work performed in Canada	305	+	
Subtotal (add lines 300 and 305)	306	=	3,203,537
c) Employees other than specified employees for work performed outside Canada (subject to limitations – see guide)	307	+	
d) Specified employees for work performed outside Canada (subject to limitations – see guide)	309	+	
• Salary or wages identified on line 315 in prior years that were paid in this tax year	310	+	
• Salary or wages incurred in the year but not paid within 180 days of the tax year end	315		
• Cost of materials consumed in performing SR&ED	320	+	
• Cost of materials transformed in performing SR&ED	325	+	
• Contract expenditures for SR&ED performed on your behalf:			
a) Arm's length contracts (see note 1)	340	+	3,989,881
b) Non-arm's length contracts (see note 1)	345	+	
• Lease costs of equipment used **before 2014**:			
a) All or substantially all (90% of the time or more) for SR&ED	350	+	
b) Primarily (more than 50% of the time but less than 90%) for SR&ED. (Enter 50% of lease costs if you use the proxy method or enter "0" if you use the traditional method)	355	+	
• Overhead and other expenditures (enter "0" if you use the proxy method)	360	+	
• Third-party payments (see note 2) (complete Form T1263*)	370	+	196,000
Total current SR&ED expenditures (add lines 306 to 370; do not add line 315) (Corporations may need to adjust line 118 of schedule T2SCH1)	380	=	7,389,418
• Capital expenditures for depreciable property available for use **before 2014** (Do not include these capital expenditures on schedule T2SCH8)	390	+	
Total allowable SR&ED expenditures (add lines 380 and 390)	400	=	7,389,418

Section C – Calculation of pool of deductible SR&ED expenditures (to the nearest dollar)

Amount from line 400	420		7,389,418
Deduct			
• provincial government assistance for expenditures included on line 400	429	–	286,672
• other government assistance for expenditures included on line 400	431	–	
• non-government assistance for expenditures included on line 400	432	–	
• SR&ED ITCs applied and/or refunded in the prior year (see guide)	435	–	993,624
• sale of SR&ED capital assets and other deductions	440	–	
Subtotal (line 420 minus lines 429 to 440)	442	=	6,109,122
Add			
• repayments of government and non-government assistance that previously reduced the SR&ED expenditure pool	445	+	
• prior year's pool balance of deductible SR&ED expenditures (from line 470 of prior year T661)	450	+	
• SR&ED expenditure pool transfer from amalgamation or wind-up	452	+	
• amount of SR&ED ITC recaptured in the prior year	453	+	
Amount available for deduction (add lines 442 to 453) (enter positive amount only, include negative amount in income)	455	=	6,109,122
• Deduction claimed in the year (Corporations should enter this amount on line 411 of schedule T2SCH1)	460	–	6,109,122
Pool balance of deductible SR&ED expenditures to be carried forward to future years (line 455 minus 460)	470	=	

* Form T1263, *Third-Party Payments for Scientific Research and Experimental Development (SR&ED)*

Note 1 – For contract expenditures made after 2013, no amounts for purchasing or leasing capital property can be included.

Note 2 – For third-party payments made after 2013, no amounts for purchasing or leasing capital property can be included.

Part 4 – Calculation of qualified SR&ED expenditures for investment tax credit (ITC) purposes

The resulting amount is used to calculate your refundable and/or non refundable ITC.

Enter the breakdown between current and capital expenditures (to the nearest dollar)

		Current Expenditures		Capital Expenditures
Total expenditures for SR&ED (from lines 380 and 390)	**492**	7,389,418	**496**	
Add				
• payment of prior years' unpaid amounts (other than salary or wages) (see note 5)	**500** +			
• prescribed proxy amount (complete Part 5) (Enter "0" if you use the traditional method)	**502** +	1,528,617		
• expenditures on shared-use equipment for property acquired **before 2014**			**504** +	
• qualified expenditures transferred to you (see note 3) (complete Form T1146**)	**508** +		**510** +	
Subtotal (add lines 492 to 508, and add lines 496 to 510)	**511** =	8,918,035	**512** =	
Deduct (see note 4)				
• provincial government assistance	**513** –	346,522	**514** –	
• other government assistance	**515** –		**516** –	
• non-government assistance and contract payments	**517** –		**518** –	
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end (see note 5)	**520** –			
• amounts paid in respect of an SR&ED contract to a person or partnership that is not a taxable supplier	**528** –			
• 20% of expenditures included on lines 340 and 370	**529** –	837,176		
• prescribed expenditures not allowed by regulations (see guide)	**530** –		**532** –	
• other deductions (see guide)	**533** –		**535** –	
• non-arm's length transactions				
– assistance allocated to you (complete Form T1145*)	**538** –		**540** –	
– expenditures for non-arm's length SR&ED contracts (from line 345)	**541** –			
– adjustments to purchases (limited to costs) of goods and services from non-arm's length suppliers (see guide)	**542** –		**543** –	
– qualified expenditures you transferred (complete Form T1146**)	**544** –		**546** –	
Subtotal (line 511 minus lines 513 to 544 and line 512 minus lines 514 to 546)	**557** =	7,734,337	**558** =	
Qualified SR&ED expenditures (add lines 557 and 558)			**559** =	7,734,337
Add				
• repayments of assistance and contract payments made in the year			**560** +	
Total qualified SR&ED expenditures for ITC purposes (add lines 559 and 560)			**570** =	7,734,337

* Form T1145, *Agreement to Allocate Assistance for SR&ED Between Persons Not Dealing at Arm's Length*

** Form T1146, *Agreement to Transfer Qualified Expenditures Incurred in Respect of SR&ED Contracts Between Persons Not Dealing at Arm's Length*

Note 3 – On line 510 (capital) – Only include expenditures made before 2014 by the transferor (performer). Complete the latest version of Form T1146.

Note 4 – On lines 514, 516, 518, 532, 535, 540, 543 and 546 – Only include amounts related to expenditures of a capital nature made before 2014.

Note 5 – For arm's length contracts, only include 80% of the contract amount.

Part 5 – Calculation of prescribed proxy amount (PPA)

A notional amount representing your overhead and other expenditures.

This part calculates the PPA to enter on line 502 in Part 4. Do not complete this part if you have chosen to use the traditional method in Part 3 (line 162).
You can only claim a PPA if you elected to use the proxy method for the year in Part 3 (line 160).

Special rules apply for specified employees. Calculate your salary base in Section A and the PPA in Section B.

Section A – Salary base

Salary or wages of employees other than specified employees (from lines 300 and 307)	**810**	+	3,203,537
Deduct			
Bonuses, remuneration based on profits, and taxable benefits that were included on line 810	**812**	–	424,233
Subtotal (line 810 minus 812)	**814**	=	2,779,304

Salary or wages of specified employees

850	852	854	856	858	860
Column 1	**Column 2**	**Column 3**	**Column 4**	**Column 5**	**Column 6**
Name of specified employee	Total salary or wages for the year (SR&ED and non-SR&ED) excluding bonuses, remuneration based on profits, and taxable benefits (to the nearest dollar)	% of time spent on SR&ED (maximum 75%)	Amount in column 2 multiplied by percentage in column 3	2,5 x A x B/365 A = Year's maximum pensionable earnings B = Number of days employed in tax year	Amount in column 4 or 5, whichever amount is less

(Enter total of column 6 on line 816) **816** +

Salary base (total of lines 814 and 816) **818** = 2,779,304

Section B – Prescribed proxy amount (PPA)

Enter 65% of the salary base (line 818) less 5% of the salary base for the number of 2013 calendar days in the tax year, and less 10% of the salary base for number of days after 2013 in the tax year (use the formula in the guide-line 820) **820** = 1,528,617

Enter the amount from line 820 on line 502 in Part 4 unless the overall cap on PPA applies to you.

(See the guide for explanation and example of the overall cap on PPA)

Part 6 – Project costs

Information requested in this part must be provided for **all** SR&ED projects claimed in the year.
Expenditures should be recorded and allocated on a project basis.

750	752	754	756
Project title or identification code	Salary or wages in the tax year (Total of lines 306 to 309)	Cost of materials in the tax year (Total of lines 320 and 325)	Contract expenditures for SR&ED performed on your behalf in the tax year (Total of lines 340 and 345)
1. P1: Electric Vehicle Program	19,558		
2. P10: Sustainable power generation systems development	288,160		114,441
3. P2:Electric Power System Reliability Improvement	275,236		711,031
4. P3: Electric Power System Capacity Planning & Improvemen	128,461		40,000
5. P3A: Underground Gas Transformer Station Design	546,152		2,617,571
6. P4: Improved Grid Solutions	221,613		
7. P5: Downtown network reliability improvements	151,605		
8. P6: Distribution system design standards development	389,257		159,903

750	752	754	756
Project title or identification code	Salary or wages in the tax year (Total of lines 306 to 309)	Cost of materials in the tax year (Total of lines 320 and 325)	Contract expenditures for SR&ED performed on your behalf in the tax year (Total of lines 340 and 345)
9. P7: Developing & applying smart metering systems	812,338		346,935
10. P8: Distributed generation (DG) and Protection facilitation	371,157		
Total	3,203,537		3,989,881

Part 7 – Additional information

Expenditures for SR&ED performed by you in Canada (line 400 minus lines 307, 309, 340, 345, and 370) **605** 3,203,537

From the total you entered on line 605, estimate the percentage of distribution of the sources of funds for SR&ED performed within your organization.

		Canadian (%)		Foreign (%)
Internal	**600**	100.000		
Parent companies, subsidiaries, and affiliated companies	**602**		**604**	
Federal grants (do not include funds or tax credits from SR&ED tax incentives)	**606**			
Federal contracts	**608**			
Provincial funding	**610**			
SR&ED contract work performed for other companies on their behalf	**612**		**614**	
Other funding (e.g., universities, foreign governments)	**616**		**618**	

For statistical purposes indicate whether the work you performed falls within the realm of Basic or Applied research (to advance scientific knowledge) or Experimental development (to achieve a technological advancement):

620 1 ☐ Basic or Applied research **622** 1 ☒ Experimental development

Enter the number of SR&ED personnel in full-time equivalents (FTE):

Scientists and engineers	**632**	22
Technologists and technicians	**634**	
Managers and administrators	**636**	
Other technical supporting staff	**638**	

Part 8 – Claim checklist

To ensure your claim is complete, make sure you have:

1. used the current version of this form . . . . . ☒
2. entered the method you have chosen for reporting your SR&ED expenditures in Section A of Part 3 . . . . . ☒
3. completed Part 2 for each project . . . . . ☒
4. filed a completed Schedule T2SCH31 or Form T2038(IND) to claim ITCs on your qualified SR&ED expenditures . . . . . ☒
5. filed a completed Form T1145*, T1146**, T1174*** and/or T1263**** including any required attachments, if applicable . . . . . ☒

To expedite the processing of your claim, make sure you have:

1. completed Form T2, *Corporation Income Tax Return* or Form T1, *Income Tax and Benefit Return* . . . . . ☒
2. filed the appropriate provincial and/or territorial tax credit forms, if applicable . . . . . ☒
3. retained documents to support the SR&ED work performed and SR&ED expenditures you claimed . . . . . ☒
4. checked boxes 231 and 232 on page 2 of your T2 return to indicate attachment of Form T661 and Schedule T2SCH31 . . . . . ☒

* Form T1145, *Agreement to Allocate Assistance for SR&ED Between Persons Not Dealing at Arm's Length*

** Form T1146, *Agreement to Transfer Qualified Expenditures Incurred in Respect of SR&ED Contracts Between Persons Not Dealing at Arm's Length*

*** Form T1174, *Agreement Between Associated Corporations to Allocate Salary or Wages of Specified Employees for Scientific Research and Experimental Development (SR&ED)*

**** Form T1263, *Third-Party Payments for Scientific Research and Experimental Development (SR&ED)*

Part 9 – Claim preparer information

Information requested in this part must be provided for each claim preparer that has accepted consideration to prepare or assist in the preparation of this SR&ED claim. Certification is required on lines 935, 970, and 975.

A $1000 penalty may be assessed if the information requested below about the claim preparer(s) and billing arrangement(s), is missing, incomplete, or inaccurate. Where a claim preparer has prepared or assisted in the preparation of this SR&ED form, the claimant and the claim preparer will be jointly and severally, or solidarily, liable for the penalty.

935 Was a claim preparer engaged in any aspect of the preparation of this SR&ED claim?

1 [X] Yes (complete the claim preparer information table and lines 970 and 975 below)

2 [ ] No (complete lines 970 and 975)

Claim preparer information table

940 Name of claim preparer (company or individual)	945 Business number	950 Billing arrangement code (see codes*)	955 Billing rate (percentage, hourly/daily rate or flat fee)	960 Other billing arrangement(s) (Maximum 10 words)	965 Total fee paid, payable, or expected to pay
1. Under separate cover by Deloitte LLP	[redacted]	5		Under separate cover by	1
				Total	1

*** Billing arrangement codes**

Code	Type of billing arrangement
1	Contingency fee arrangement – where the fee is based on a percentage of the investment tax credit earned
2	Hourly rate
3	Daily rate
4	Flat fee arrangement (lump sum)
5	Other arrangements – describe the arrangement in box 960 in 10 words or less

970 I, Sean Bovingdon, certify that the information provided in this part is complete and accurate.

Name of authorized signing officer of the corporation, or individual (print)

Signature

975 2017-06-28 (Year Month Day)

Part 10 – Certification

I certify that I have examined the information provided on this form and on the attachments and it is true, correct, and complete.

165 Sean Bovingdon

Name of authorized signing officer of the corporation, or individual

Signature

170 2017-06-28

Date

175 Deloitte & Touche LLP

Name of person/firm who completed this form

Privacy Notice

Personal information is collected pursuant to subsections 37(1), 37(11), and 162(5.1) of the *Income Tax Act* (the Act) and is used for verification of compliance, administration and enforcement of the Scientific Research and Experimental Development (SR&ED) program requirements.

Information may also be used for the administration and enforcement of other provisions of the Act, including assessment, audit, enforcement, collections, and appeals, and may be disclosed under information-sharing agreements in accordance with the Act. Incomplete or inaccurate information may result in assessment of monetary penalties and delays in processing SR&ED claims.

The social insurance number is collected pursuant to section 237 of the Act and is used for identification purposes.

Information is described in personal information bank CRA PPU 441 "Scientific Research and Experimental Development" in the Canada Revenue Agency (CRA) chapter of *Info Source*. Personal information is protected under the *Privacy Act*, and individuals have a right of access to, correction, and protection of their personal information. Further details regarding requests for personal information at the CRA and our *Info Source* chapter can be found at www.cra.gc.ca/atip.

Canada Revenue Agency / Agence du revenu du Canada

THIRD-PARTY PAYMENTS FOR SCIENTIFIC RESEARCH AND EXPERIMENTAL DEVELOPMENT (SR&ED)

Complete this form for each third-party payment and attach it to Form T661.

For more information on third-party payments:

- See line 370 of Guide to Form T661, S*cientific Research and Experimental Development (SR&ED) Expenditures Claim*;
- Third-Party Payments Policy;
- Consult our Web site: **www.cra.gc.ca/sred**.

Required Information

1. Identification

701 Name of the third party
Ryerson University

702 Address (Street number and name)
350 Victoria Street

City	Province / Territory	Postal Code
Toronto	ON CA	M5B 2K3

704 Total amount paid in the year
$ 150,000

Identify the research project(s) performed by the third-party entity for the payment

706 Project title (and identification code if applicable)
1 P10 Applied research at the CUE of Ryerson University

Check the appropriate box to indicate the type of entity:

711	Approved association	1 Yes		
712	Non-profit SR&ED corporation resident in Canada	1 Yes		
714	An approved university, college, research institute, or other similar institution	1 Yes	X	
716	Granting council	1 Yes		
718	Other corporation resident in Canada	1 Yes		
721	Are you dealing at arm's length with the recipient?	1 Yes	X	2 No

2. Nature of payment

Check the appropriate box to indicate the type of entity:

The payment is for:

731	Experimental development	1 Yes	
732	Applied research	1 Yes	X
734	Basic research	1 Yes	

736 Briefly explain what the payment is for:
Research into urban energy issues, creation of new knowledge in various areas including distribution power engineering and utiity applications, energy storage, etc.

738 Briefly explain how the SR&ED is related to a business that you carry on:

The research related directly to the business of the company which distributes electricity and is responsible for leading the way in conservation and demand management.

740 Briefly explain how you are entitled to exploit the results of the SR&ED:

Toronto Hydro has the right to exploit any of the intellectual property arising out of the research funded by Toronto Hydro.

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Information may also be used for the administration and enforcement of other provisions of the Act, including audit, enforcement action, collections, and appeals, and may be disclosed under information-sharing agreements in accordance with the Act. Incomplete or inaccurate information may result in assessment of monetary penalties and/or delays in processing SR&ED claims.

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T1263 E (15)

Canada

Canada Revenue Agency / Agence du revenu du Canada

THIRD-PARTY PAYMENTS FOR SCIENTIFIC RESEARCH AND EXPERIMENTAL DEVELOPMENT (SR&ED)

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- Third-Party Payments Policy;
- Consult our Web site: **www.cra.gc.ca/sred**.

Required Information

1. Identification

701 Name of the third party
Georgian College

702 Address (Street number and name)
1 Georgian Drive

City	Province / Territory	Postal Code
Barrie	ON CA	L4M 3X9

704 Total amount paid in the year
$ 20,000

Identify the research project(s) performed by the third-party entity for the payment

706 Project title (and identification code if applicable)
1 P2 - EPS Reliability

Check the appropriate box to indicate the type of entity:

711	Approved association	1 Yes		
712	Non-profit SR&ED corporation resident in Canada	1 Yes		
714	An approved university, college, research institute, or other similar institution	1 Yes	X	
716	Granting council	1 Yes		
718	Other corporation resident in Canada	1 Yes		
721	Are you dealing at arm's length with the recipient?	1 Yes	X	2 No

2. Nature of payment

Check the appropriate box to indicate the type of entity:

The payment is for:

731	Experimental development	1 Yes	
732	Applied research	1 Yes	X
734	Basic research	1 Yes	

736 Briefly explain what the payment is for:
The consortium is uniquely positioned to provide the aforementioned opportunities.

738 Briefly explain how the SR&ED is related to a business that you carry on:

The research related directly to the business of the company which distributes electricity and is responsible for leading the way in conservation and demand management.

740 Briefly explain how you are entitled to exploit the results of the SR&ED:

Toronto Hydro has the right to exploit any of the intellectual property arising out of the research funded by Toronto Hydro.

Personal information is collected pursuant to subsections 37(1), 37(11), and 162(5.1) of the *Income Tax Act* (the Act) and is used for verification of compliance, administration and enforcement of the Scientific Research and Experimental Development (SR&ED) program requirements.

Information may also be used for the administration and enforcement of other provisions of the Act, including audit, enforcement action, collections, and appeals, and may be disclosed under information-sharing agreements in accordance with the Act. Incomplete or inaccurate information may result in assessment of monetary penalties and/or delays in processing SR&ED claims.

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T1263 E (15)

Canada

Canada Revenue Agency / Agence du revenu du Canada

THIRD-PARTY PAYMENTS FOR SCIENTIFIC RESEARCH AND EXPERIMENTAL DEVELOPMENT (SR&ED)

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For more information on third-party payments:

- See line 370 of Guide to Form T661, S*cientific Research and Experimental Development (SR&ED) Expenditures Claim*;
- Third-Party Payments Policy;
- Consult our Web site: **www.cra.gc.ca/sred**.

Required Information

1. Identification

701 Name of the third party
University of Toronto

702 Address (Street number and name)
5 King's College Road

City	Province / Territory	Postal Code
Toronto	ON CA	M5S 3G8

704 Total amount paid in the year
$ 26,000

Identify the research project(s) performed by the third-party entity for the payment

706 Project title (and identification code if applicable)
1 P2 - EPS Reliability

Check the appropriate box to indicate the type of entity:

711	Approved association	1 Yes		
712	Non-profit SR&ED corporation resident in Canada	1 Yes		
714	An approved university, college, research institute, or other similar institution	1 Yes	X	
716	Granting council	1 Yes		
718	Other corporation resident in Canada	1 Yes		
721	Are you dealing at arm's length with the recipient?	1 Yes	X	2 No

2. Nature of payment

Check the appropriate box to indicate the type of entity:

The payment is for:

731	Experimental development	1 Yes	
732	Applied research	1 Yes	X
734	Basic research	1 Yes	

736 Briefly explain what the payment is for:
The consortium is uniquely positioned to provide the aforementioned opportunities.

738 Briefly explain how the SR&ED is related to a business that you carry on:

The research related directly to the business of the company which distributes electricity and is responsible for leading the way in conservation and demand management.

740 Briefly explain how you are entitled to exploit the results of the SR&ED:

Toronto Hydro has the right to exploit any of the intellectual property arising out of the research funded by Toronto Hydro.

Personal information is collected pursuant to subsections 37(1), 37(11), and 162(5.1) of the *Income Tax Act* (the Act) and is used for verification of compliance, administration and enforcement of the Scientific Research and Experimental Development (SR&ED) program requirements.

Information may also be used for the administration and enforcement of other provisions of the Act, including audit, enforcement action, collections, and appeals, and may be disclosed under information-sharing agreements in accordance with the Act. Incomplete or inaccurate information may result in assessment of monetary penalties and/or delays in processing SR&ED claims.

The social insurance number is collected pursuant to section 237 of the Act and is used for identification purposes.

Information is described in personal information bank CRA PPU 441 “Scientific Research and Experimental Development”, in the Canada Revenue Agency (CRA) chapter of *Info Source*. Personal information is protected under the *Privacy Act* and individuals have a right of access to, correction, and protection of their personal information. Further details regarding requests for personal information at the CRA and our Info Source chapter can be found at **http://www.cra.gc.ca/atip/**.

T1263 E (15)

Canada

Part 2 – Project information (continued)

Project number **1**

CRA internal form identifier 060

Complete a separate Part 2 for each project claimed this year. Code 1501

Section A – Project identification

200 Project title (and identification code if applicable)

P1: Electric Vehicle Program

202 Project start date	**204** Completion or expected completion date	**206** Field of science or technology code (See guide for list of codes)
2010-02 (Year Month)	2017-12 (Year Month)	2.02.01 Electrical and electronic engineering

Project claim history

208 1 [X] Continuation of a previously claimed project **210** 1 [ ] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
1	

Section B – Project descriptions

242 What scientific or technological uncertainties did you attempt to overcome? (*Maximum 50 lines*)

1. The obstacles that TH had to overcome at the start of the claim project were:
2. (1) Understanding what steps did TH have to take now and in future to be ready
3. to accommodate the Provincial Government's target of 1 in 20 new vehicles in
4. Ontario by 2020 being electric ones; how would we need to develop and prepare
5. the assets and infrastructure;
6. (2) Determining the electric vehicle makes, and technologies used, that would
7. be selected for use in internal field trials;
8. (3) Understanding and developing the design, operation, monitoring and
9. reporting parameters that would need to be specified to ensure the data
10. captured and analyzed from internal pilots, and from external participants
11. through the EV Connections Program (CP), would lead to meaningful insights
12. about all aspects of electric vehicle charging on its grid operations.
13.
14. TH had made initial efforts in prior years to establish from modeling what the
15. aggregate impacts on its grid might be. The EV pilot field trial continued in
16. FY2016 from the previous fiscal year. The hope was that the trial results
17. would be scalable and applicable to different degrees of EV penetration across
18. its service area, and inform how EV charging could be integrated within its
19. grid operations and control. Whether results from its internal trials and
20. from the EV CP participants would be scalable and facilitate the integration
21. of EV charging with grid operations remained to be explored.
22.
23.

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

1. Data collected from the EV connections program was used to develop a model to
2. understand what number and type of EVs could be connected to a distribution
3. transformer before causing local infrastructure impacts. This model provided
4. realistic representation of factors such as state of charge before charging,
5. charging time and flow during various points in the charging time in addition
6. to actual demand related to vehicle type. Few vehicles are needed to trigger
7. a local infrastructure constraint. Together with the data on the location of
8. actual EVs, local areas can be targeted for intervention.
9. Project for curb-side charging with the City of Toronto after being stalled
10. for regulatory/legal issues. The focus is to understand the pattern of usage
11. and the impact on downtown infrastructure. Focus will be to find solutions

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

that permit increased deployment while minimizing infrastructure impact and therefore cost.

Project was initiated to provide charging capability into neighbourhoods that have no private means of charging a vehicle. During 2016, customers were found to use extension cords over sidewalks which presents a safety issue. To prevent a safety concern, we worked to find/develop pole mounted solutions with manufacturers (such models do not currently exist in North America).
We worked with Cross Chasm Technologies in the deployment of on-board and off-board vehicle charging controls to control over-night charging in a way that is beneficial to the grid and not user experience impactive to the driver. ("SmartCharging"). We worked with Cross Chasm to design the demand impact control, the data collection aspects to enable further technical insight as well as on the rewards program to encourage participation. Project was successful and objectives were achieved. Toronto Hydro will be participating in a larger Canada wide project using the same technology in 2017.
We also used the results of our work with Cross Chasm and retained ICF Consulting to develop models for use in Regulatory proceedings that would determine the cost benefit of SmartCharging program with rewards deployment given a variety of vehicle charging characteristics (captured through EV Connections program).
In late 2016 we initiated work on a workplace charging project at 500 Commissioners St. The aim of the project is to integrate electric vehicle charging with existing solar generation, battery storage and building demand management system to manage overall building electrical demand. This in turn would be a showcase for our customers.
The impact of the Ontario Climate Change Action Plan, particularly related to the electrification of transportation was assessed on a system wide basis to determine the infrastructure impact on a wide area basis
We also did work to modify our Conditions of Service technical requirements for metering in Multi-Unit Residential Buildings to achieve lower costs, less resource demand and increased deployment of electric vehicles.
Work would continue into FY2017 with: outreach programs, forecasting and projects (curbside EV charging stations, utilization of streetlight poles for charging capability, design of workplace charging systems, increasing the utilization of EV fleet, and condominium solutions to reduce cost of EV adoption.

246 What scientific or technological advancements did you achieve or attempt to achieve as a result of the work described in line 244? (*Maximum 50 lines*)

Scientific and technological advancements include:
Better models of the impact of the electric vehicle charging behaviour on a local area basis using data from the EV Connections program.
Understanding of the capabilities and implementability of "Smart Charging" (utility control of electric vehicle charging) to minimize local grid impacts as well as customer inconvenience.

Understanding of the impacts of Ontario's Climate Change Action Plan, specifically the electrification of transportation, on Toronto Hydro's peak demand at a system wide basis.
Understanding of the technical barriers that further need to be worked on to proceed with curb-side and workplace charging in 2017 in the context of minimizing infrastructure impacts.

Section C – Additional project information

Who prepared the responses for Section B?

253 1 [X] Employee directly involved in the project	**254** Name [redacted]		
255 1 [ ] Other employee of the company	**256** Name		
257 1 [X] External consultant	**258** Name Deloitte LLP	**259** Firm Deloitte LLP	

List the key individuals directly involved in the project and indicate their qualifications/experience.

260 Names	**261** Qualifications/experience and position title
1 [redacted]	[redacted]
2 [redacted]	[redacted]
3 [redacted]	[redacted]

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . . 1 [ ] Yes 2 [X] No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . . 1 [ ] Yes 2 [X] No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 267, complete lines 268 and 269.

268 Names of individuals or companies	**269** BN
1	

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270 1 [X] Project planning documents

271 1 [X] Records of resources allocated to the project, time sheets

272 1 [ ] Design of experiments

273 1 [X] Project records, laboratory notebooks

274 1 [ ] Design, system architecture and source code

275 1 [ ] Records of trial runs

276 1 [X] Progress reports, minutes of project meetings

277 1 [X] Test protocols, test data, analysis of test results, conclusions

278 1 [X] Photographs and videos

279 1 [ ] Samples, prototypes, scrap or other artefacts

280 1 [X] Contracts

281 1 [X] Others, specify **282** Invoices & emails.

Part 2 – Project information (continued)

Project number **2**

CRA internal form identifier 060

Complete a separate Part 2 for each project claimed this year. Code 1501

Section A – Project identification

200 Project title (and identification code if applicable)

P10: Sustainable power generation systems development

202 Project start date	**204** Completion or expected completion date	**206** Field of science or technology code (See guide for list of codes)
2007-04 (Year Month)	2018-12 (Year Month)	2.02.01 Electrical and electronic engineering

Project claim history

208 1 [X] Continuation of a previously claimed project **210** 1 [ ] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
1	

Section B – Project descriptions

242 What scientific or technological uncertainties did you attempt to overcome? (*Maximum 50 lines*)

THESL wanted to further develop its capability to design & develop commercially viable sustainable systems to generate electricity, and which capture all of a specific site's potential; given the actual resources available.

The obstacles and uncertainties related to wind resources:

(1) Keeping the off-shore wind research platform in Lake Ontario in service and operate continuously over the year even under extreme weather conditions, such as high winds (>100 km/h), high waves (>5m waves) and cold temperatures (<-15C) causing icing and additional loading of equipment;

(2) Removal of the platform from Lake Ontario after 2 years of data collection, if no other use for it can be found; and

(3) Monitoring of the performance of the control/converter system of the demonstration WTG in operation at Exhibition Place to determine if a replacement more reliable control/converter system was warranted.

For PV systems, uncertainties related to:

(1) establishing the potential capacity of a proposed rooftop host site given an assessment of its current condition/possible rehabilitation/upgrading;

(2) preparing FIT and micro-FIT applications for acceptance with sufficient system concept definition to assure a high probability of acceptance;

(3) determining detailed system & design features including circuit design, metering, and grid connection arrangements, given application acceptance by the OPA, that will pass ESA inspection; and

(4) meeting system design performance targets in-service.

For Biogas systems, uncertainties related to:

(1) establishing the potential capacity of a depleting fuel resource;

(2) determining the scaling factors involved of various power generation methods;

(3) understanding the technological obstacles of utilizing a 'dirty' fuel resource which must be filter for water and CO2 and scrubbed of impurities prior to combustion in a power generating unit; and

(4) Monitoring performance and meeting system design performance targets in-service.

For Wind Resource and PV systems, and renewable generation activities uncertainties related to a "HydroStor" 660kW, 330kWh underwater-compressed air energy storage system would also need to be resolved. Attempting to use compressed air as an energy storage mechanism would require an understanding of the feasibility of this type of system in Toronto, and whether or not it

242 What scientific or technological uncertainties did you attempt to overcome? (*Maximum 50 lines*)

38. had a role to monitor/forecast/control generator resources within its service
39. area in "real-time".

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

1.
2. PV Solar:
3. PV Solar activities continued in FY2016 with monitoring and analysis of
4. systems and data in attempts to improve the understanding of the effects on
5. the distribution network and maintenance cycles. TH encountered failures on PV
6. panels and had initiated investigations on wiring and inverter concerns. Snow
7. monitoring methods continued and studies conducted to determine the effects of
8. snow loading on the PV cells. Development in PV solar also entailed devising
9. weight distribution techniques. Ballested solar projects investigations began
10. in FY2016. Specialized modified structures were conceptualized, designed and
11. tested in applications where the site roof structures could not support the
12. load of convention TH installations (elevated truss systems will be further
13. explored in FY2017). PV solar applications will continue to be evaluated for
14. operational impact and reliability.
15.
16. Off-shore wind development activities was on-hold through FY2016.
17.
18. Bio-Gas Development:
19. Bio-gas system development continued on three main initiatives: Ashbridges
20. Treatment Plant (ABTP), Greenlane, and Keele Valley - in each case TH would
21. attempt to resolve technical constraints from low EROEI (Energy Return on
22. Energy Invested) resources.
23. - ABTP 10MW biogas resource. The design concept was completed although
24. challenges with other infrastructure assets were encountered. A possible
25. mitigation strategy may involve developing a tunneling concept involving
26. horizontal drilling through bedrock to avoid any possible interferences - this
27. approach is unique for a district system application. Site challenges remain
28. concerning interface with other infrastructure projects and development will
29. extend into FY2017.
30. - The Green Lane 8MW landfill gas resource - the present challenge for all
31. alternative generation and distribution systems stem from the taper of FIT
32. (feed in tariff) funding and the present extremely low cost of conventional
33. fossil fuel generation systems. The Green Lane application is a landfill
34. source of mixed CO2 and 'dirty' natural gas which must be separated for use in
35. power generation - the extra step and increased maintenance requirement adds
36. costs to the system despite the green-house gas reduction potential.
37. Technology was explored through FY2016 to address gas treatment for co-gen or
38. pipeline injection. Use of resource yet to be determined and will be further
39. explored in FY2017.
40. - Keele Valley 6MW landfill gas resource is an inactive site with a depleting
41. natural gas resource. The original power station was comprised of large
42. generating turbines that now have insufficient fuel supply to efficiently
43. generate power. A concept with multiple smaller modular power generating sets
44. (Gen. Sets) to exploit the remaining natural gas was explored with further
45. work to be undertaken next year. Given the lack of renewable power contracts
46. with IESO and low market price of electricity the economics remain a challenge
47. and various refurbished equipment options have been reviewed.
48.
49. Hydrostor:
50. In this fiscal period, THESL continued working with Hydrostor to develop a
51. demonstration system. This project is considered to be a temporary,
52. scientific research project with the goal of testing and validating this
53. underwater compressed air energy storage technology for future use. This

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

system will also be used to analyze, understand and document the potential benefits that bulk energy storage can provide for THESL and the Toronto Electrical grid.

At the end of the fiscal period, preliminary trials were conducted and observations made. The system appeared to be capable of producing 650kW but only had 330kWh of storage. The operating trip efficiency was noted to be under 60%. The pilot demonstrated that the system is feasible, however, scaling efficiencies would be necessary. It was also observed that with a 5 minute start up and shut down process lag the storage technique was less flexible than battery storage. Overcoming and mitigating these observations would be the focus of ongoing development. In FY2016 - a small expansion and greater heat recovery was tested - The pilot will be upgraded in capacity from 330kWh to 1000kWh and heat recovery improved to attempt to improve overall plant efficiency. Construction in Q3 of FY2017 planned. The target is to triple capacity by FY2018 - currently 50% efficient and target is to get to over 60%. In FY2017 an investigation of phase-changing materials for the heat recovery medium will be explored.

Energy Storage:
Smaller pilot projects commenced. 500kWh lithium-ion battery storage unit explored. Pole mount energy storage system explored (with Ryerson). Operating characteristics and integration and resilience with the distributed generation systems are yet to be determined. Larger energy storage solutions were explored in FY2016 with increased focus in FY2017. Attempting to re-purpose an un-used municipal station and utilize storage solutions to balance grid loads and reduce generation investment. Limitations in the legacy structure pose technical challenges.

FY2016 - studies: Irving 30MW 7.5MWh storage study undertaken (to optimize energy storage system to address energy quality at the Irving plant) and Sunnybrook 12MW 3MWh (to optimize energy storage for reliability and supporting generator ride-through) (15 min of ride-though requirement). Contracted to Ryerson Q to perform technical review. Determined that tuned reactors and capacitors would improve battery storage systems and power quality could address 95% of the reliability with storage solutions at the on-site end point. Eglington LRT - investigation of large-scale storage for emergency power and conditioning demand response and ancillary services. Power Advisory group subcontracted to perform initial review activity with TH personnel. Concept 20MW - 80MWh system devised. Global Adjustment (GA)studies - attempting to mitigate via off-peak demand and cut-off in on-peak demand periods - Investigated energy storage solutions to attempt to reduce GA but costs are presently prohibitive. Further investigation is required.

Contracted resources, listed below, worked as an integral part of the development teams.

246 What scientific or technological advancements did you achieve or attempt to achieve as a result of the work described in line 244? (*Maximum 50 lines*)

With wind resources, THESL was advancing its knowledge from operating an autonomously designed R&D anemometer platform located in Lake Ontario placed in service in mid-2010. It was still operating entering 2012. Last fiscal year, the initial analysis of the data was started. The performance of the control/converter system of THESL's first wind turbine generator at Exhibition Place was a concern - in FY2017 the generator winding of the unit will be refurbished - but methodology to repair has yet to be determined.
For PV Solar, experimental development continued with monitoring and analysis activity. Work pertaining to unique structures and applications have been

conducted and new knowledge gained (for example - elevated truss structure for low capacity roofs, use of string inverters to improve part load efficiency and reliability). For bio-gas fuelled systems, THESL wanted to have the capabilities to design and develop such systems, irrespective of the bio-gas source. Various issues had been addressed, but methods to overcome EROEI uncertainties remain. In conjunction with the Utility Host Toronto Hydro, Hydrostor has constructed a pilot of a 660kW, 330 kWh UW-CAES system to demonstrate the use and value of compressed air as an energy storage mechanism. The system operates by storing electrical energy in the form of compressed air in concrete accumulators located below the surface of water, taking advantage of the pressure found at depth. The project has two components, an onshore portion of the system located on the Toronto Islands (which will house the mechanical aspects), and an offshore portion located ~5km away in Lake Ontario (which is an underwater cavity capable of storing compressed air). Preliminary construction began in 2013, and was completed at the end of 2015 with data acquisition and engineering analysis in 2016. In FY2015 preliminary failures with water slugs and low scale efficiencies had been encountered and new methodologies and systematic approaches devised. In FY2016 expansion and improvement options were explored and would be pursued. Energy storage storage techniques and methodologies will be further investigated in FY2017.

Section C – Additional project information

Who prepared the responses for Section B?

253 1 [X] Employee directly involved in the project	**254** Name [redacted]			
255 1 [ ] Other employee of the company	**256** Name			
257 1 [X] External consultant	**258** Name Deloitte LLP	**259** Firm Deloitte LLP		

List the key individuals directly involved in the project and indicate their qualifications/experience.

260 Names	**261** Qualifications/experience and position title
1 [redacted]	[redacted]
2 [redacted]	[redacted]
3	

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . . 1 [ ] Yes 2 [X] No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . . 1 [ ] Yes 2 [X] No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . . 1 [X] Yes 2 [ ] No

If you answered **yes** to line 267, complete lines 268 and 269.

268 Names of individuals or companies	**269** BN
1 CEM ENGINEERING	[redacted]
2 LES SOLUTIONS QUATRIC INC.	[redacted]
3 SNC-LAVALIN INC.	[redacted]
4 THE BIGLIERI GROUP LTD.	[redacted]

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270	1	[X]	Project planning documents		
271	1	[X]	Records of resources allocated to the project, time sheets		
272	1	[ ]	Design of experiments		
273	1	[X]	Project records, laboratory notebooks		
274	1	[ ]	Design, system architecture and source code		
275	1	[X]	Records of trial runs		
276	1	[X]	Progress reports, minutes of project meetings		
277	1	[X]	Test protocols, test data, analysis of test results, conclusions		
278	1	[X]	Photographs and videos		
279	1	[ ]	Samples, prototypes, scrap or other artefacts		
280	1	[ ]	Contracts		
281	1	[X]	Others, specify	282	Presentations, e-mails and W.O. detail

Part 2 – Project information (continued)

Project number **3**

CRA internal form identifier 060

Complete a separate Part 2 for each project claimed this year. Code 1501

Section A – Project identification

200 Project title (and identification code if applicable)

P2:Electric Power System Reliability Improvement

202 Project start date	**204** Completion or expected completion date	**206** Field of science or technology code (See guide for list of codes)
2007-01 (Year Month)	2017-12 (Year Month)	2.02.01 Electrical and electronic engineering

Project claim history

208 1 [X] Continuation of a previously claimed project **210** 1 [ ] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
1	

Section B – Project descriptions

242 What scientific or technological uncertainties did you attempt to overcome? (*Maximum 50 lines*)

THESL is trying to achieve sustained, measureable improvements in the performance of its distribution system. In electricity distribution, standard metrics are used for service performance and reliability tracking, SAIDI and SAIFI. These metrics reflect factors within THESL's control, e.g. the extent and targeting of its annual spend on capital and O&M, and factors and events beyond THESL's control such as numbers of storm days experienced annually. Historical data shows that the number of storm days on average has increased since 2005, but physical damage to the grid from such weather was not as extensive as in prior years. Past efforts to storm harden the grid and to use covered cables where warranted seem to have had a beneficial impact on reliability performance. To sustain existing levels and strive to make further improvements in the values of those standard metrics, THESL needed to work to improve the distribution system.

The obstacles faced and whose resolution the THESL project worked on with some subcontractor assistance were as follows:

1. (Event Management/AMI Data Analytics) - Understanding how to improve the quality of historical asset reliability data; for use in improved OMS/ITIS reporting. Challenges included geospatial cross-referencing of existing OMS/ITIS data, and developing an enhanced outage reporting process. ITIS itself required a minor overhaul and data tables had to be realigned to support new Event management requirements. This work transitioned into a broader AMI data analytics approach in 2016.
2. (Risk Analyzer) - Development of a model/tool that can quantify the "installed risk" value of the distribution system based on data (historical and current).
3. (Feeder Automation Radio Study) - As we expanded our capabilities in Feeder Automation, the network becomes larger and more complicated - which can lead to radio saturation. For this project, we investigated new potential designs that could overcome issues with noise, location, communication interferences, terrain, and prevent oversaturation while providing communication between switches.
4. (Power Quality Monitoring) - Understanding how availability technologies could be developed for use in the TH infrastructure. Installation of a Power Quality Monitoring network for real time event analysis and alerts.

242 What scientific or technological uncertainties did you attempt to overcome? (*Maximum 50 lines*)

5. (Underground Cable Testing) - Involved test method development in an effort to be able to prioritize replacement of underground cable assets. Challenges included understanding what methods work best for the many different types and conditions of cables and environment.

6. Analytics [operating] - Analytics Road map for visual and deductive reasoning analysis, as well as use cases development to assess the various inputs which drive the decisions and execution times within the control room.

7. Analytics [planning] - Understanding how new analytical tools could be integrated within to THESL's planning processes to maximize productivity benefits.

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

Experimental development in this fiscal period included the following:

1. (AMI Data Analytics) - Utilization of Smart Metering data to enhance and evolve existing planning practices. Work included analytics of individual residential meters to develop system wide outage metrics such as CEMI and CELID; integration of data into NMS environment for real time system outage reporting; outage and customer focused interruption validation; integration with traditional outage data sources such as SCADA and customer calls; and loading data for asset utilization and contingency analysis. Includes beginning road mapping exercise of metering data needs and applications to drive the direction of the overall metering program to support analytical needs.

2. (Risk Analyzer) - In 2016, a broader initiative to establish a metric that measures the risk of the system from a customer interruption cost perspective was started. As a result, the Risk Analyzer will be integrated into that initiative.

3. (Feeder Automation Radio Study) - Investigate integration of a FLISR system into existing NMS product. Ongoing testing and benefit realization to be applied in the following year to enhance SAIFI and SAIDI. Sandbox environment to be utilized as Engineering Planning tool to optimize SCADA integration across the system.

4. (Power Quality Monitoring) - Work continued from prior fiscal year. Applications investigated included: network automation; underground structure inspection methods development for PQM; and fault localization for PQM (software/algorithm development).

5. (Underground Cable Testing) - Continued development, investigated various test methods to be able to quantify the condition of existing underground assets. Experimented/analyzed/developed different methods work for the many different types and conditions of cables and environments, and performed actual physical testing.

6. (Analytics - operating) - Developed a roadmap with Quatric Solutions Inc. to outline the various departments which interact with the Control Room and the number of tools involved in tracking the various metrics which are used to track and improve performance across the organization. In development with Quatric Solutions Inc., 25 use cases were developed to support frame work of a Power System analysis tool for the control room.

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

43.
44. 7. (Analytics - planning) - Continued the development of an
45. engineering data warehouse to streamline the access to data as well as perform
46. 'big data' calculations required by THESL's planning department. In parallel
47. to this activity, continued the deployment of new data blending & analytics
48. software to THESL's planning department and integrated software into business
49. processes to improve productivity & drive new insights into THESL data based
50. on new capabilities.
51.
52. Long term strategies in EPS reliability are being devised to define capital
53. requirements over the coming decades. These strategies will continue to
54. challenge known techniques and methodologies and will result in continued
55. development-oriented activities in future fiscal periods.
56. [CEATI - PQ, DLAM,Stations; C-MORE (UofT); Smart Grid Canada]
57.
58. SR&ED activities were sub-contracted during the course of this fiscal period.
59. Sub-contractors performed investigations and analysis required to continue
60. development in EPS initiatives.
61.

246 What scientific or technological advancements did you achieve or attempt to achieve as a result of the work described in line 244? (*Maximum 50 lines*)

1. Through experimental development, the following advancements were sought or
2. achieved:
3.
4. 1. (Event Management) - Improved quality of historical asset reliability data;
5. and developed correlations to specific impacted asset location(s).
6.
7. 2. (Risk Analyzer) - Developed a model/tool that can quantify the "installed
8. risk" value of the distribution system based on data (historical and current)
9. which is to drive a customer interruption cost driven risk outcome.
10.
11. 3. (Feeder Automation Radio Study) - Study progressed; improved knowledge of
12. influencing factors - work continued in next fiscal period.
13.
14. 4. (Power Quality Monitoring) - Improvement knowledge of how various new
15. technologies could be developed for use in the TH infrastructure;
16. analysis/research would continue in next fiscal period.
17.
18. 5. (Underground Cable Testing) - Test method development improved our
19. knowledge of the different types and conditions of cables; including that age
20. was not the only primary factor for asset condition.
21.
22. 6. (Analytics - Operations) - Model development was approved for progressing
23. to next steps for hiring the necessary staff and ensuring that the right IT
24. infrastructure is in place.
25.
26. 7. (Analytics - Planning) - Improved productivity of select business processes
27. and enhanced the quality of existing data analysis capability. The
28. implementation enabled increased analytical and data visualization
29. capabilities in planning. It further increased efficient access to data for
30. engineers within the Engineering Planning area.

Section C – Additional project information

Who prepared the responses for Section B?

253 1 [X] Employee directly involved in the project	**254** Name [redacted]			
255 1 [ ] Other employee of the company	**256** Name			
257 1 [X] External consultant	**258** Name Deloitte LLP	**259** Firm Deloitte LLP		

List the key individuals directly involved in the project and indicate their qualifications/experience.

260 Names	**261** Qualifications/experience and position title
1 [redacted]	[redacted]
2 [redacted]	[redacted]
3 [redacted]	[redacted]

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . . 1 [ ] Yes 2 [X] No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . . 1 [ ] Yes 2 [X] No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . . 1 [X] Yes 2 [ ] No

If you answered **yes** to line 267, complete lines 268 and 269.

268 Names of individuals or companies	**269** BN
1 CEATI INTERNATIONAL INC.	[redacted]
2 COMPASS POINT SYSTEMS INC	[redacted]
3 METSCO ENERGY SOLUTIONS INC.	[redacted]

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270 1 [X] Project planning documents	**276** 1 [X] Progress reports, minutes of project meetings
271 1 [X] Records of resources allocated to the project, time sheets	**277** 1 [X] Test protocols, test data, analysis of test results, conclusions
272 1 [ ] Design of experiments	**278** 1 [ ] Photographs and videos
273 1 [X] Project records, laboratory notebooks	**279** 1 [ ] Samples, prototypes, scrap or other artefacts
274 1 [ ] Design, system architecture and source code	**280** 1 [X] Contracts
275 1 [X] Records of trial runs	**281** 1 [X] Others, specify **282** Invoices & emails.

Part 2 – Project information (continued)

Project number **4**

CRA internal form identifier 060

Complete a separate Part 2 for each project claimed this year. Code 1501

Section A – Project identification

200 Project title (and identification code if applicable)

P3: Electric Power System Capacity Planning & Improvement

202 Project start date	**204** Completion or expected completion date	**206** Field of science or technology code (See guide for list of codes)
2007-03 (Year Month)	2017-12 (Year Month)	2.02.01 Electrical and electronic engineering

Project claim history

208 1 [X] Continuation of a previously claimed project **210** 1 [ ] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
1	

Section B – Project descriptions

242 What scientific or technological uncertainties did you attempt to overcome? (*Maximum 50 lines*)

1.
2. The technological objective of the project is to develop more accurate and
3. flexible tools for peak demand forecasting and option development. The
4. primary tool for input into subsequent tools is the load forecasting tool.
5.
6. Challenges with current methods are: 1) they deal poorly with abrupt changes
7. in underlying drivers of peak demand, 2) they are not flexible to include new
8. factors (without previous history) that will increase electricity demand such
9. as the electrification of transportation as proposed in the Ontario Climate
10. Change Action Plan and 3 they do not provide understanding in the seasonality
11. of peaks (as compared with a yearly peak) and further they are not designed
12. to provide an hourly profile for peak conditions (which would be necessary in
13. order to understand the feasibility of non-wires solution to deal with peak
14. constraints).
15.

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

1.
2. Investigation into two key studies continued from the previous tax year.
3.
4. In the first, new methods/techniques, beyond current practices, were
5. developed. A subcontractor completed a long-term/25 year spatial peak demand
6. forecast, including sensitivity analysis and a peak demand forecast process
7. design, based on City forecasts of population & employment and IESO weather
8. correction and extremes calculation, with the flexibility to handle multiple
9. CDM and DG scenarios. Different CDM and DG scenarios were analyzed using the
10. newly developed method. The Spatial Peak Demand Forecast from this study was
11. contributed to the Central Toronto IRRP. THESL also continued to work with
12. the OPA on developing contingencies for reliability and security analysis to
13. identify mid- to long-term needs of the transmission system supplying downtown
14. Toronto. Needs were examined on a probabilistic in addition to a
15. deterministic approach traditionally used. A broader Metro Toronto Regional
16. Infrastructure Report Plan (MTRI) extrapolating from the central IRRP was made
17. and incorporated GO Line electrification and other potential future system
18. additions. Through FY2016, a method to reduce work load in forecasting was
19. pursued, and a new load forecasting approach conceived as a result of the

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

World Climate Change Action Plan (with extensive investigation planned for FY2017).

The second study took a broader approach to identify the root problems of supply unreliability covering the areas of asset condition, system design/operation/ maintenance, and contingency planning of supplies with a focus on bulk supply points to THESL and the distribution of power from these points of supply in an integrated manner. In addition, the study examined the reliability of supply and the investment planning process in other major cities and make improvement recommendations for both THESL and HONI. The study was completed in the tax year. A 2nd subcontractor contributed to this study's activities. A final report covered 3 major components, i.e. reliability of supply, the investment planning process, and key implementation considerations. Business plan and engineering feasibility would be subsequently pursued

After the release of the Ontario Climate Change Action Plan, an in-house study was performed of the impact of such a plan on Toronto's overall peak demand. The study included the adoption of electric vehicles, further electrification of mass transit, increased solar generation, conversion of natural gas heating to electric heat pumps, and conversion of natural gas water heaters to electricity.

Further internal study was undertaken to assess the impacts of the above factors on a seasonal basis rather than on a yearly basis as well as the impacts on an hourly load profile basis.

Contracted resources, listed below, worked as an integral part of the development teams.

246 What scientific or technological advancements did you achieve or attempt to achieve as a result of the work described in line 244? (*Maximum 50 lines*)

THESL sought in general terms, to gain more knowledge about how to plan for increasing its distribution system capacity and sources of power supplies in a cost effective manner in the face of severe physical constraints and changing circumstances. Electricity system planning in Ontario is conducted at 3 levels: bulk transmission system planning, regional system planning and distribution system planning. The OPA is responsible for the first level, and leads the effort in the second with the active participation of transmitters and distributors. The third level is led by distributors. More specifically the advances were to increase the knowledge and know-how behind the main options and key variables in the quest to increase bulk electricity supply to downtown Toronto, in a more reliable cost effective manner, and which examines the use of non-traditional contributions from distributed generation and demand management options and to improve long term planning techniques for supplies of different kinds and determining infrastructure needs. Furthermore, the impact of the Ontario Climate Change Action Plan are now known to increase winter peak demand in a way that would closely resemble summer peak demand and that on a system wide basis, it is now understood that peak demand will be shifted in time on a peak day to the interaction of decreased solar generation at the time of increased electric vehicle charging. These learnings on a system wide basis are guiding the development of a study for a small area forecast to be performed in 2017, closely aligned to the physical power system, the impact of the factors seen on a system wide basis due to the Ontario Climate Change Action Plan.

Section C – Additional project information

Who prepared the responses for Section B?

253 1 [X] Employee directly involved in the project	**254** Name [redacted]			
255 1 [ ] Other employee of the company	**256** Name			
257 1 [X] External consultant	**258** Name Deloitte LLP	**259** Firm Deloitte LLP		

List the key individuals directly involved in the project and indicate their qualifications/experience.

260 Names	**261** Qualifications/experience and position title
1 [redacted]	[redacted]
2 [redacted]	[redacted]
3 [redacted]	[redacted]

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . . 1 [ ] Yes 2 [X] No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . . 1 [ ] Yes 2 [X] No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . . 1 [X] Yes 2 [ ] No

If you answered **yes** to line 267, complete lines 268 and 269.

268 Names of individuals or companies	**269** BN
1 NAVIGANT CONSULTING LTD.	[redacted]

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270 1 [X] Project planning documents	**276** 1 [X] Progress reports, minutes of project meetings
271 1 [X] Records of resources allocated to the project, time sheets	**277** 1 [ ] Test protocols, test data, analysis of test results, conclusions
272 1 [ ] Design of experiments	**278** 1 [ ] Photographs and videos
273 1 [X] Project records, laboratory notebooks	**279** 1 [ ] Samples, prototypes, scrap or other artefacts
274 1 [ ] Design, system architecture and source code	**280** 1 [X] Contracts
275 1 [ ] Records of trial runs	**281** 1 [X] Others, specify **282** Invoices, emails, reports

Part 2 – Project information (continued)

Project number **5**

CRA internal form identifier 060

Complete a separate Part 2 for each project claimed this year. Code 1501

Section A – Project identification

200 Project title (and identification code if applicable)

P3A: Underground Gas Transformer Station Design

202 Project start date	**204** Completion or expected completion date	**206** Field of science or technology code (See guide for list of codes)
2010-02 (Year Month)	2017-03 (Year Month)	2.01.01 Civil engineering

Project claim history

208 1 [X] Continuation of a previously claimed project **210** 1 [ ] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
1	

Section B – Project descriptions

242 What scientific or technological uncertainties did you attempt to overcome? (*Maximum 50 lines*)

This project encompasses the design activity for an Underground Gas Transformer Station Design in a small constrained construction site location adjacent to a heritage building (the Toronto Roundhouse). More details on the back ground for this project can be found at: http://www.torontohydro.com/sites/electricsystem/powerup/copelandstation/pages /copelandstation.aspx.

The objectives that the detailed design had to meet were: (1) Flexibility and space to accommodate equipment voltage upgrading from an initial 115kV to 230kV, (2) Facilitation of TS development and operation in an environmentally sustainable manner, (3) Incorporation of green energy to power station auxiliaries and other strategies to reduce carbon footprint, and of safety-by-design features, and (4) Complete avoidance of any impact on the foundations and above grade structures of all facilities adjacent to the site, and also being architecturally compatible with these facilities.

The obstacles THESL had to address during the project duration, and attempt to resolve during the year included: The underground station configuration to include all the equipment necessary and accommodate Hydro One owned HV switch gear (S/G) on the same restricted site.

Determining with HONI the preferred supply arrangements for the new TS and what cross-sectional detailed design could be used to carry 4 circuits in a supply tunnel.

Whether or not the cables supplying the new TS would have to be cooled and how this capability could be provided within a tunnel of a nominal 3m in internal diameter, 600m long, 30m below street level

How to develop a design and construction approach for a fixed shoring wall with no tie-backs that would support both the 600m tunnel as well as the transformer station.

(How to design and build 100 ft mine shafts under the station floor to connect the tunnel to the station while achieving mining construction requirements.

The original design incorporated pre-cast shaft-liners, however during construction we recognized that this approach couldn't be used because of safety reasons (mining regulations). We needed to work with our consultants to determine how to achieve this, as it has never been done before.

How to improve the constructability of the station floor using a modified pour

242 What scientific or technological uncertainties did you attempt to overcome? (*Maximum 50 lines*)

-strip design in an effort to reduce the time required to pour.
How to develop a venting approach or method to deal with the challenges if the transformer gas (SF6) leaks (in an underground station).
We encountered a large obstacle in the side of the shoring wall part-way through construction. Needed to develop a design approach to overcome this challenge.
Have the historical machine shop on the site - which was going to be dismantled and re-built during construction - could be upgraded by design to serve as a post disaster building and retain all existing heritage features of the existing building.
Systematic uncertainties were encountered in the course of development as methods to resolve individual obstacles would form competing demands with other obstacles.

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

The project team continued to meet on a daily basis to review progress, discuss emerging issues, examine failure modes and technical direction. Civil and Electrical Engineering systematic development required regular review meetings for teams including: technical coordination, cable installation, protection teams, asset management planning, telecommunications and other co-development technical teams. Frequency of weekly technical meetings increased as the project progressed from design review meetings of civil engineering to electrical design coordination meetings focused on discussion of electrical design issues. Technical meetings-'equipment coordination meetings'-generally dealt with the installation, testing and commissioning phase for major electrical equipment such as Toshiba Gas-Insulated Transformers, ABB MV Air-Insulated Switchgear, Siemens MV Gas-Insulated Switchgear, and Siemens HV Gas-Insulated Switchgear.

Previously, requirements for supply tunnel cooling were confirmed by a 3rd party study funded by HONI. The HONI room (for HV GIS) was completed in 2016 and the switchgear is expected to be installed, tested and commissioned in 2017.

OEB approved the project and contracts were awarded to TS - tunnel construction and large equipment orders were made. The project was delayed with a new service date initially set for FY2016 but further delays were incurred and the latest forecast is for full testing/commissioning completion in FY2018. Some of the major electrical equipment was placed in storage in FY2014, FY2015 and portion of FY2016, with most of them were delivered to site by end of FY2016. Installation, testing and commissioning of the delivered major electrical equipment commenced in FY2016 and is expected to continue into FY2017. A third party contractor was selected for integrated testing and commissioning in FY2015 and installation and testing work was carried out in FY2016 and will continue until FY2018. Overall, construction is expected to be completed by end of FY2017, with energization expected in FY2018.

Station excavation was completed and steel and concrete work began for the station (building) portion in FY2014. In FY2015 specialized the Tunnel was completed as were the underground transformer station structure (vertical walls, mezzanine and roof). Commencement of above-roof two-floor Machine Shop structure began in 2015. Most of the Machine Shop walls and floor slabs were completed in 2016, with steel, roof, and heritage bricks work forecasted for 2017.

In an effort to improve constructability of our original design approach,

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

studies and new approaches would be modified as construction is underway to accommodate challenges encountered onsite. Structural building design revisions to incorporate updated specifications of major equipment (gas-insulated transformer, high voltage gas-insulated switchgear, medium voltage gas-insulated switchgear, medium voltage tie-switch, protection & control). In particular, building design had to be modified to accommodate base plates for major equipment. Structural design revisions to overcome on-site challenges with waterproofing, steel rebar congestion, and concrete forming were also considered. Destructive sample testing was performed to address ongoing concerns and remediation techniques were explored.

Detailed electrical designs were reviewed and modifications considered. Changes to Tie Breaker capacity and cable capacity to allow for additional flexibility for the medium voltage switchgear was undertaken and Rely protection considered. Identified the need to recognize pilot wire customers. A modified cable racking design concept was devised to attempt to compensate for a large amount of medium voltage cable in the station (ongoing through 2016) In additions, in order for the cable to connect to the gear adapter/termination concepts had to be developed. Redundancy measures for a hardened RTU (Remote Terminal Unit) were also considered.

Three main subcontractors assisted us with the detailed design and development activities for this project: One was responsible for the new Transformer Station design and designing renovations and upgrades to the historic machine shop (IBI Group), the second for the tunnel through which power supplies would flow to the new TS (MMM Group); and both of these subcontractors were supported by Isherwood who was the shoring consultant that worked with us to design develop the shoring/caisson walls. Other subcontracted activity involved Kinectrics, who was hired to carry out full thermal performance testing for tunnel cable conduits. The third-party testing and commissioning contractor, K-tek, oversaw testing and commissioning of the major ABB, Siemens, and Toshiba electrical equipment. Metsco also assisted us in development activity.

In FY2016, due to their immense weight, the delivery of the Toshiba GIT transformers required comprehensive technical analysis to ensure they could be transported safely over a TTC tunnel beneath an existing road in downtown Toronto. Deflection monitors were deployed to monitor the tunnel during the delivery of the transformers. The final delivery to site required a tandem (dual) crane lift and the concrete floors required significant reshoring. Later when the transformers were being assembled, prior to filling the tanks with SF6 gas, detection and monitoring systems for gas insulation was deployed, along with leak control, spill and mitigation plans.

Ahead of major electrical equipment installation, seismic design analysis of the room structure was performed to ensure seismic requirements were met. Furthermore, HV and MV cable pulling work commenced in late FY2016.

246 What scientific or technological advancements did you achieve or attempt to achieve as a result of the work described in line 244? (*Maximum 50 lines*)

THESL needed to increase its knowledge and know-how of TS detailed design - to the most stringent applicable standards - and of construction practices that would be required to build and commission a one-of-a-kind, below grade indoor TS (with gas-insulated transformers) on a unique constrained site to facilitate additional bulk electricity supply and transformer capacity for downtown Toronto. This project involved the development of the first

underground TS that used gas-insulated transformers, and the industry will now be able to use our advancements as a starting point for future designs.

Some of the key technological advancements achieved in 2016 were as follows:

1. Development of all the design approaches to overcome the obstacles listed above and achieve the project objectives to include all the equipment necessary and accommodate Hydro One owned HV switch gear (S/G) on the same restricted site in an underground TS.

2. Development of a unique design and construction approach for a fixed shoring wall with no tie-backs that could support both the 600m tunnel as well as the transformer station 100 ft underground, and divide the two projects into separate construction projects for regulatory (Safety) purposes.

3. New methods to improve the constructability of the station floor using a modified pour-strip design in an effort to reduce the time required to pour.

4. Development of a unique venting approach to deal with the challenges if the transformer gas (SF6) leaks (in an underground station) - this continued into 2015 and extended into 2016.

5. Understanding how to modify the shoring wall design to overcome a large obstacle (cement) in the side of the shoring wall part-way through construction.

Other engineering concept and method advancements would be devised as a result of systematic obstacles encountered in the course of the development process.

Section C – Additional project information

Who prepared the responses for Section B?

253 1 [X] Employee directly involved in the project	**254** Name [redacted]		
255 1 [ ] Other employee of the company	**256** Name		
257 1 [X] External consultant	**258** Name Deloitte LLP	**259** Firm Deloitte LLP	

List the key individuals directly involved in the project and indicate their qualifications/experience.

260 Names	**261** Qualifications/experience and position title
1 [redacted]	[redacted]
2 [redacted]	[redacted]
3 [redacted]	[redacted]

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . . 1 [ ] Yes 2 [X] No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . . 1 [ ] Yes 2 [X] No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . . 1 [X] Yes 2 [ ] No

If you answered **yes** to line 267, complete lines 268 and 269.

	268 Names of individuals or companies	**269** BN
1	IBI GROUP	[redacted]
2	KINECTRICS NORTH AMERICA INC.	[redacted]
3	METSCO ENERGY SOLUTIONS INC.	[redacted]
4	MMM GROUP LIMITED	[redacted]

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270	1	[X]	Project planning documents		
271	1	[X]	Records of resources allocated to the project, time sheets		
272	1	[ ]	Design of experiments		
273	1	[X]	Project records, laboratory notebooks		
274	1	[X]	Design, system architecture and source code		
275	1	[ ]	Records of trial runs		
276	1	[X]	Progress reports, minutes of project meetings		
277	1	[X]	Test protocols, test data, analysis of test results, conclusions		
278	1	[X]	Photographs and videos		
279	1	[ ]	Samples, prototypes, scrap or other artefacts		
280	1	[X]	Contracts		
281	1	[X]	Others, specify	282	Invoices, emails, reports

Part 2 – Project information (continued)

Project number **6**

CRA internal form identifier 060

Complete a separate Part 2 for each project claimed this year. Code 1501

Section A – Project identification

200 Project title (and identification code if applicable)

P4: Improved Grid Solutions

202 Project start date	**204** Completion or expected completion date	**206** Field of science or technology code (See guide for list of codes)
2010-03 (Year Month)	2017-12 (Year Month)	2.02.01 Electrical and electronic engineering

Project claim history

208 1 [X] Continuation of a previously claimed project **210** 1 [ ] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
1	

Section B – Project descriptions

242 What scientific or technological uncertainties did you attempt to overcome? (*Maximum 50 lines*)

The capability to deploy/implement a range of Smart Grid (SG) concepts/technologies across THESL's grid to transition it to one that has a fully intelligent infrastructure with: Compatible, durable and reliable equipment with built-in sensing and intelligent electronic devices for monitoring, fault diagnosis, and self-restoration; Fail-safe, robust, fast, high band-width, 2-way advanced communications from customers to the grid control centre; Centralized monitoring & control utilizing integrated databases for customer information, for asset records including their geographic locations, for the management of outages, for grid operations and for making physical changes to the grid infrastructure; Informed & intelligent operators & customers regarding electricity use and the assets for local generation, distribution & storage and initiatives to facilitate wise consumption for system-wide benefits; and unrestricted capability to accommodate, plug-in hybrid (PH) electric vehicles (EV), battery only EVs, distributed generation (DG), and energy storage devices. The obstacles faced in 2016 were:

-Meter-ready transformers failed tests leading to design changes. (In previous fiscal periods, outages from failures of pole top mounted units with ongoing TM were reviewed. However, in only one case had the unit been overloaded for a relatively long time prior to failure. TM data analytics work continued in FY16 to gain greater insight into transformer failures.

- Uncertainty of data analytics tools to extract and analyze information.

-The extent to which the benefits expected from the pilot field trial of PLMs were being realized. THESL wanted pilot implementation to lead to: (A) Better management of O/H assets and improved reliability, (B) Significant customer-minutes-out improvements by reporting outages to the control room (C) Reduction of momentary outages.

-Intelligent node implementation at Exhibition Place generation sites did not have telecommunications to meet utility grade cyber-security requirements or permit access and integration into utility SCADA system. In addition, significant technical challenges were encountered in implementing an intelligent node in the Strachan TS station. Using new secure routers and adapting THESL cellular private network for the purpose, secure communications were achieved. In addition, creative use of approved THESL intelligent electronic devices provided a means of installing the intelligent node at Strachan TS without having to modify the 13.8 kV buswork. Other uncertainties emerged in the course of development as a result of systematic challenges.

242 What scientific or technological uncertainties did you attempt to overcome? (*Maximum 50 lines*)

38.
39.
40.
41.
42.
43.

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

1.
2. In this fiscal period, progress continued to be made with design of a unit
3. with integral plug-in connection. Failures were encountered and a design
4. change process continued. 1st-phase prototypes built in the previous period
5. were tested. The new design passed all the tests as documented in the test
6. plan.
7.
8. Monitoring of pole top mounted 1-phase transformers continued. When the
9. existing tool stopped working, Toronto Hydro investigated options and decided
10. to develop in-house scripts to replace the tool leading to faster data
11. extraction and analysis. Customized Project Reports summarizing the options,
12. implementation strategy and results continue to be prepared. (Transformer
13. monitoring: 5800 units installed - with roughly 4000 working presently).
14.
15. 102 PLM purchases and greater insight into the causes of outages were
16. observed. Detailed real-time profiles could be generated - an ability to
17. observe 'profile signatures' was possible. A signature profile study was
18. conducted. TH will explore the harmonization of legacy communication systems
19. in the next fiscal period (to attempt to improve the fidelity of the PLM
20. monitors and data generation). Development remains ongoing.
21.
22. Intelligent Nodes were installed at Exhibition Place Wind Turbine Building,
23. Horse Palace, and Agricultural Center. The central intelligent node has been
24. moved to the Point of Presence room at 500 Commissioners. All data was
25. processed at an alternate server at Prolucid's office. TH approved routers
26. were installed and data sent via TH Rogers APN to the central intelligent node
27. - network configurations and security clearances are complete for data
28. transfer over TH network. Development continued with TH approved routers and
29. locks to ensure robust pathways to central communications - concepts involved
30. re-purposing Closed-Circuit systems to attempt to achieve cyber-compliant
31. connections. Communication faults were encountered since simultaneous
32. replacement of the routers was not possible - a bridging solution was devised.
33. Hard drive modifications were also required to improve functionality. TH and
34. Prolucid developed algorithms to gather generation output data to attempt to
35. refine energy distribution and output. Detailed reports were subsequently
36. generated.
37.
38.
39. In previous fiscal periods solutions for monitoring padmount and submersible
40. transformers from various vendors were evaluated and a selection was made to
41. proceed with a pilot. Instead of moving to a field trial directly, it was
42. decided that end-to-end integration be performed in the Solutions Development
43. Centre to identify technical challenges. The vendor was engaged and a test
44. kit was designed to demonstrate the technology in the Solutions Development
45. Centre.
46.
47.
48. Power Line monitoring through older generation Wi-Fi CDMA data collectors are
49. becoming obsolete. TH is now investigating migrating data and assessing in new

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

generation Wi-Fi. TH may internalize the process to attempt to bring
intelligence to a more comprehensive integrated system. All CDMA were re-
located -Transformers were on a broader smart grid, while the Powerline
monitors were targeted for lines with reliability or repeatable concerns to
attempt to ensure rapid restoration. Development will continue with the
exploration of diagnostic methodologies in the next fiscal period.

246 What scientific or technological advancements did you achieve or attempt to achieve as a result of the work described in line 244? (*Maximum 50 lines*)

In previous fiscal periods and during FY 16, transformer monitoring (TM)
continued for 1-phase pole top mounted units on an extended basis. TM data
extraction and analytics were improved by creation of in-house developed
scripts.
The Power Line Monitors (PLM) pilot was expanded and additional PLMs were
chosen to be installed in the field at 34 locations for installation early
2015. Data from the Power Line Monitors was analyzed to identify new
signatures and develop use cases for Planning, Control Room and Power Quality
teams.
The Intelligent Node project with Prolucid Technologies tapered. Security
issues that had previously disallowed coordination and control by locally
positioned intelligent devices without a centralized controller was overcome
by CC technologies and pathway strategies. 6 Intelligent Nodes (four at
Exhibition Place, one at 500 Commissioners, and one at Strachan TS) were
installed. Data from the Intelligent Nodes was validated and improvements were
made to the data viewer. Cyber-compliance and further algorithm refinements
were devised.
Additional advancements were sought in the course of development as obstacles
were encountered in power line and transformer communication methodologies.

Section C – Additional project information

Who prepared the responses for Section B?

253 1 [X] Employee directly involved in the project

254 Name [redacted]

255 1 [ ] Other employee of the company

256 Name

257 1 [X] External consultant

258 Name: Deloitte LLP

259 Firm: Deloitte LLP

List the key individuals directly involved in the project and indicate their qualifications/experience.

260 Names	**261** Qualifications/experience and position title
1 [redacted]	[redacted]
2 [redacted]	[redacted]
3	

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . . 1 [ ] Yes 2 [X] No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . . 1 [ ] Yes 2 [X] No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 267, complete lines 268 and 269.

268 Names of individuals or companies	269 BN
1	

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270	1	X	Project planning documents		
271	1	X	Records of resources allocated to the project, time sheets		
272	1		Design of experiments		
273	1	X	Project records, laboratory notebooks		
274	1	X	Design, system architecture and source code		
275	1	X	Records of trial runs		
276	1	X	Progress reports, minutes of project meetings		
277	1	X	Test protocols, test data, analysis of test results, conclusions		
278	1	X	Photographs and videos		
279	1		Samples, prototypes, scrap or other artefacts		
280	1		Contracts		
281	1	X	Others, specify	282	Emails & Invoices

Part 2 – Project information (continued)

Project number **7**

CRA internal form identifier 060

Complete a separate Part 2 for each project claimed this year. Code 1501

Section A – Project identification

200 Project title (and identification code if applicable)

P5: Downtown network reliability improvements

202 Project start date	**204** Completion or expected completion date	**206** Field of science or technology code (See guide for list of codes)
2010-01 (Year Month)	2017-12 (Year Month)	2.02.01 Electrical and electronic engineering

Project claim history

208 1 [X] Continuation of a previously claimed project **210** 1 [ ] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
1	

Section B – Project descriptions

242 What scientific or technological uncertainties did you attempt to overcome? (*Maximum 50 lines*)

1. THESL's network distribution system, used in the downtown core, is the most
2. reliable distribution system in use in the city of Toronto. Most feeder and
3. equipment failures do not result in any interruption to customers. In certain
4. circumstances, some failure modes may result in widespread, long duration
5. service interruptions. The most important of these failure modes involves
6. catastrophic equipment failures that result not only in the destruction of the
7. equipment in the vault, but often damage the civil structure of the vault as
8. well. In the previous years THESL has been refining its network protector
9. design. Recently, in order to consolidate several items a single dual voltage
10. submersible protector was developed.
11.
12. The obstacles THESL faced and overcame during the year include the following:
13. (1) Develop a submersible case for the network protector that is no taller,
14. wider or deeper than the existing ventilated case designs;
15. (2) Investigate alternative silver-sand current limiting fuses and alloy type
16. fuses. Fuses had to be compatible with submersible case designs and coordinate
17. with the variety of transformers that could be paired with the protectors;
18. (3) If alloy type fuses were selected, any arc products discharged during
19. operation must not result in fault currents transferring to protector case
20. ground. The much greater arc energy available for protectors connected to
21. large size 433Y/250V transformers were of particular concern;
22. (4) Develop the necessary step-down transformation to allow the protector to
23. operate at both 216Y/125V and 433Y/250V. The previous design developed for the
24. stand alone network protector interfered with the protector mechanism lifting
25. facilities, requiring partial teardown prior to lifting the mechanism. The new
26. design must eliminate this problem;
27. (5) The position of the network protector operating handle must be compatible
28. with sizes, manufacturers and vintages of network transformers. THESL has
29. historically had interference problems with some combinations of network
30. protectors and transformers;
31. (6) Continued development and improvement of the SCADA remote monitoring and
32. operating system for the network protector was required. In particular the
33. junction box connecting the remote sensors to the network protector is very
34. difficult for crews to work on.
35.
36. Other systematic uncertainties would be encountered through the development
37. process and techniques and concepts to overcome potential failure modes would

242 What scientific or technological uncertainties did you attempt to overcome? (*Maximum 50 lines*)

38. be explored.

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

1. Development in attempts to overcome the obstacles THESL faced in FY2015
2. included:
3.
4. (1) Submersible case development: Modifications to the lifting brackets were
5. made due to clearance issues - roll-out arm bolts were redesigned without
6. compromising function. We also standardized the height of the mechanism so
7. that it was interchangeable with existing network protectors (many variations
8. of protector internal mechanism (CM-22) were devised - this concept was to be
9. universal but a limited number of adapters were required - the activity
10. carries over into FY2015). New gasket configurations were explored and a load
11. brake primary switch concept for the network transformers was devised and
12. tested in FY2015. (now considered complete).
13.
14. (2) Alternative silver-sand current limiting fuses and alloy type fuse
15. development: Ground leakage current tests failed with original design. A
16. concept with a barrier was conceived and was tested with mixed, yet
17. satisfactory, results. (now considered complete).
18.
19. (3) Alloy type fuses development: THESL attempted to identify fuse types and
20. determined a narrow range to protect transformers yet still allow for
21. transformer operation at near overload conditions. Final testing was completed
22. and the development portion of this activity has ended. However, in FY2016 -
23. we developed fuse and cable limiter for 600V applications.
24.
25. (4) Step-down transformation to allow the protector to operate at both
26. 216Y/125V and 433Y/250V: The original concept electrically worked but was not
27. mechanically adequate. Work on the mechanisms to attempt to achieve the
28. desired performance remained ongoing. (now considered complete).
29.
30. (5) The position of the network protector: Experimented with a small chassis
31. size that would hypothetically fit in all protectors. An engineered adapter
32. bus was designed to attempt to work with all vintages identified. A universal
33. mechanism to attempt to enable incremental re-installation was also devised.
34. Retro-fit concepts were devised as the universal mechanism was not entirely
35. effective for all applications - development remains ongoing. Small chassis
36. testing will commence in the future fiscal period. This was ongoing in through
37. FY2016 and may extend into FY2017.
38.
39. (6) Continued development and improvement of the SCADA remote monitoring and
40. operating system for the network protector was required. Obstacles were
41. encountered when attempting to deploy a fibre system that was intended to be
42. compatible with existing technologies. A revised concept involving developing
43. a hybrid fibre / radio link data transfer method was considered. The concept
44. is believed to be an economical method to provide communications throughout
45. the city service zone without deploying a singular expensive fibre link. Proof
46. of concept of the radio equipment and new fibre topology would be explored.
47. Work performed on fibre technology in FY2016 - radio trials planned for
48. FY2017/2018.
49.
50. Other inter-related development activities included: Development of a portable
51. transformer phase testing device for use with 600V circuits [completed in
52. FY2016]; fully electronic relays have been found to hesitate when de-energized
53. as a result of emulated performance of mechanical devices - preliminary
54. exploration of electronic relays with improved performance in extreme

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

operations has begun - development involved real time monitoring and control of dual radial switch gear automation (DRA) and a remote operation terminal (Beta-testing in FY2016) [ongoing in FY2016 and extends into FY2017]; and development of feed systems at 347Y/600V will allow for services to larger / taller downtown buildings - mag-brake primary switch development was undertaken to attempt to improve power interruption events and enable remote network control [Eaton visovac vacuum switch investigated in place of the mag- brake - investigated in FY2016 and will be piloted in FY2017].

Other items FY2016:
- 600V network - development items: antler design for the protectors, upper link box design, revised communication support (primary and secondary monitoring operations) - experimentation, testing and validation ongoing into FY2017.
- Communication system - revisions to box, radial line to loop design - applicable to 600V and existing network enhancements.
- 600V network test box to be developed in FY2017.

246 What scientific or technological advancements did you achieve or attempt to achieve as a result of the work described in line 244? (*Maximum 50 lines*)

THESL undertook to develop equipment to address the continuing problems with the less common, but higher risk, "high voltage" 433Y/250 Volt network protectors. THESL's existing designs of 433Y/250 Volt network protectors are compact, ventilated, and use silver-sand current-limiting fuses. Existing network vault designs are the smallest that can fit existing equipment and provide minimally adequate working space. The new network protectors developed had to be of submersible design, no larger than the existing ventilated protectors, and requiring no more working space than the existing protectors. THESL presently has three standard sizes of network protector, 1875A, 3000A and 3500A in each of two voltage classes, 216Y/125V and 433Y/250V. This requires THESL to maintain an inventory of six different network protector types. A final desired advancement was to develop two standard network protectors that could replace all six existing stocked varieties. This added an additional requirement for the protectors to be of dual-voltage design, with ratings of 1875A and a new "large frame" protector rated for use at both 3000A and 3500A. These two new network protector developments had to be able to replace all existing transformer mounted network protectors, with improved durability, tolerance to adverse environmental conditions, safety, utility, maintainability, protection coordination, combined with remote monitoring and control capabilities. Other advancements would be derived from testing new concepts and methodologies encountered in the course of the development process.

Section C – Additional project information

Who prepared the responses for Section B?

253 1 [X] Employee directly involved in the project	**254** Name [redacted]		
255 1 [ ] Other employee of the company	**256** Name		
257 1 [X] External consultant	**258** Name Deloitte LLP	**259** Firm Deloitte LLP	

List the key individuals directly involved in the project and indicate their qualifications/experience.

260 Names	**261** Qualifications/experience and position title
1 [redacted]	[redacted]
2 [redacted]	[redacted]
3 [redacted]	[redacted]

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . . 1 [ ] Yes 2 [X] No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . . 1 [ ] Yes 2 [X] No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 267, complete lines 268 and 269.

268 Names of individuals or companies	**269** BN
1	

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270 1 [X] Project planning documents

271 1 [X] Records of resources allocated to the project, time sheets

272 1 [ ] Design of experiments

273 1 [X] Project records, laboratory notebooks

274 1 [ ] Design, system architecture and source code

275 1 [X] Records of trial runs

276 1 [X] Progress reports, minutes of project meetings

277 1 [X] Test protocols, test data, analysis of test results, conclusions

278 1 [ ] Photographs and videos

279 1 [ ] Samples, prototypes, scrap or other artefacts

280 1 [ ] Contracts

281 1 [X] Others, specify **282** Invoices and Emails

Part 2 – Project information (continued)

Project number **8**

CRA internal form identifier 060

Complete a separate Part 2 for each project claimed this year. Code 1501

Section A – Project identification

200 Project title (and identification code if applicable)

P6: Distribution system design standards development

202 Project start date	**204** Completion or expected completion date	**206** Field of science or technology code (See guide for list of codes)
2011-01 (Year Month)	2016-12 (Year Month)	2.02.01 Electrical and electronic engineering

Project claim history

208 1 [X] Continuation of a previously claimed project **210** 1 [ ] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
1	

Section B – Project descriptions

242 What scientific or technological uncertainties did you attempt to overcome? (*Maximum 50 lines*)

THESL has sets of existing technical specifications and standards for the equipment, materials and construction methods for both the underground and the overhead portions of its overall power distribution network/grid. For the past few years THESL has been subjected to increasing regulatory scrutiny by the OEB and interveners participating in OEB proceedings. Such scrutiny extends to design standards, equipment & materials specifications, and construction practices. THESL therefore needed to know the degree to which THESL's distribution standards differed from those of similar LDCs and where differences existed whether or not they were justified given the unique characteristics of Toronto and THESL. Experimental development involved a number of studies performed with specific uncertainties listed below. The uncertainties THESL faced were as follows:

(1) How could it show the regulatory authorities that its technical design standards, equipment & materials specifications, and construction practices were comparable to those of other peer LDCs serving a mix of suburban & high density urban load, and where differences existed, why they were justifiable;

(2) An evaluation of currently available new equipment that can potentially be incorporated within underground residential distribution (URD) system within the downtown core;

(3) The identification of asset classes predominantly involved with forced outages, and whether or not these assets in the field are in full compliance with current existing construction standards, standard practices & equipment specifications;

(4) The upgrades and improvements needed for 2 existing key standard practices for (a) Major Equipment Re-use, and (b) Equipment Failure Analysis Program;

(5) Understanding how the grid was prepared for future expansion and development;

(6) Pole loading is generally non-linear, and no software/modelling tools existing that incorporate all potential scenarios. We sought to develop such a tool;

(7) The impact of wrapping 1 & 3 phase transformers had an unknown impact on heat dissipation and transformer life. A study was required to determine the effects; and

(8) Failures take place in the field, that have unknown causes. We would fully investigate and understand the potential causes of these failures.

Other uncertainties and challenges would emerge from potential failure modes

242 What scientific or technological uncertainties did you attempt to overcome? (*Maximum 50 lines*)

(reliability and repeatability) of evolving complex systematic distribution system concepts and methodologies.

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

In the previous FY trials were performed on a 600A switch which was intended to fit within the confines of the legacy structure - the application was energized and will be tested for reliability and repeatability. The activity extended into FY2016 for adjacent 200A cascading systems. New infrastructure was considered and evaluated to replace obsolete 80E fusing suitable for the confined environment. Ongoing corrosion issues are being mitigated through selection of marine grade steels and recommendations in maintenance practices to minimize system impact.

RTU / SCADA box -system harmonization [Quatric]. Wide ranging applications of RTU and SCADA infrastructure sees conflicting requirements on RTUs across the system. The specification ensures consistency across interface, communications, mounting, power supply, ports etc. that will see improved support and compatibility across the network.

Reclosers - In 2016, several scenarios of how reclosers could be best utilized on the Toronto Hydro grid to increase system reliability were explored. The utilization of reclosers were further analysed through a research project at the Centre for Urban Energy (CUE) at Ryerson.

Analysis of the assessment data showed just 6 asset categories contributed to 80% of forced outages caused by defective equipment. THESL developed the requirements to conduct field operational audits of these assets, which would also involve visual and thermal inspections. Field inspections of the various assets continued into FY2016.

LED technology was tested and new lighting standards developed. A remote control and monitoring system for street lighting was tested and installed as part of a pilot project. Issue with Correlated Colour Temperature (CCT) of the LED luminaires were encountered.

The development of a web-based tool that can analyze all pole loading analysis components continued. A revision to the tool was developed in 2016 to add additional features.

Development of chamber lid concepts with energy mitigating mechanism to resolve displacement of lids during cable chamber explosions. The lid has gone through numerous design revisions to eliminate all identified risks, issues and concerns.

Dynamic cable management philosophies were devised to attempt to use factors other than merely age to determine the health of the cable system - new tools and concepts would be developed based on the data collected and information gained. In 2016 we completed the mechanism complete with testing using data from the last 15 years to predict results of the 16 years and then cross reference those results with actuals to determine accuracy of the mechanism.

Climate Adaptation - execution of roadmap in FY2016. Initiatives completed include climate data validation, load forecasting sensitivity, major equipment specifications review, risk map development and lightning mapping. Two studies

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

were completed. New assets that are water resistant (Solid Insulation Transformers) were purchased. Grid emergency management - a study was completed to determine alternate methods to re-route power in an emergency situation.

Grounding study performed to attempt to improve conditions - In 2016, several installations of pad-mount equipment that could not meet construction grounding standards were brought to the attention of the Standards group. Primarily, this included installations above parking foundations or in boulevards where clearance to other utilities could not be maintained. Standards group initiated a study to develop alternative grounding standards. This work is continuing in 2017.

Drainage systems for transformers - Report 98% done. Final revision in progress.

Equipment wrapping - investigation to wrap the equipment in foliage / canvas to improve asset masking - report [METSCO - 'Investigation of Easthetic Appearance of Pad Mounted Transformers' (16-167-001-RV).

Underground infrastructure - Reinforce aging vaults - Civil Structure Additives. Trial test performed and a one year freeze thaw cycle to be performed.

City Place - investigation of equipment failures. In depth evaluation was performed to complete a needs analysis for an engineering lab.

Work continued on the development of a modelling tool (City planning project) to understand how feeders and transformer stations could be affected by future city expansion. Development and testing of the tool in GIS software was conducted with many filtering layers.

Many different subcontractors were used to assist with various studies. Details are listed below in box 268.

246 What scientific or technological advancements did you achieve or attempt to achieve as a result of the work described in line 244? (*Maximum 50 lines*)

Advancements included:
- understanding the degree to which THESL's distribution standards differed from those of similar LDCs and where differences existed whether or not they were justified given the unique characteristics of Toronto and THESL.
- Determine what new equipment could potentially be incorporated into the design standards for this application after appropriate field trials had been held with satisfactory results.
- increased understanding of (1) the asset classes that were the predominant contributors to forced outages, (2) compliance of these assets with current standards/specifications, and (3) how 2 key standard practices could be improved.
- Through development of a modelling tool, we obtained knowledge of how the existing grid might respond to a wide range of future potential development scenarios.
- Developed a web-based tool that can analyze all pole loading analysis components, and developed modified design and construction standards to incorporate the new tool.
- Developed a web-based tool that can voltage drop for both overhead and

19.	underground systems and developed modified design and construction standards
20.	to incorporate the new tool.
21.	- Developed a temperature profile for pad-mounted transformers wrapped with a
22.	graffiti-proof layer under a range of operating conditions.
23.	- Through engineering studies on failed components, we gained knowledge of
24.	potential failure causes for a wide range of equipment (splices, switches &
25.	switchgear).
26.	- Various investigation led to new methodologies and strategies in improving
27.	reliability and repeatability of distribution system assets.
28.	
29.	
30.	

Section C – Additional project information

Who prepared the responses for Section B?

253	1 [X] Employee directly involved in the project	**254** Name [redacted]		
255	1 [ ] Other employee of the company	**256** Name		
257	1 [X] External consultant	**258** Name Deloitte LLP	**259** Firm Deloitte LLP	

List the key individuals directly involved in the project and indicate their qualifications/experience.

260 Names	**261** Qualifications/experience and position title
1 [redacted]	[redacted]
2 [redacted]	[redacted]
3	

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . . 1 [ ] Yes 2 [X] No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . . 1 [ ] Yes 2 [X] No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . . 1 [X] Yes 2 [ ] No

If you answered **yes** to line 267, complete lines 268 and 269.

268 Names of individuals or companies	**269** BN
1 LVM, A DIVISION OF ENGLOBE CORP.	[redacted]
2 METSCO ENERGY SOLUTIONS INC.	[redacted]
3 SNC-LAVALIN INC.	[redacted]

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270 1 [X] Project planning documents		**276** 1 [X] Progress reports, minutes of project meetings	
271 1 [X] Records of resources allocated to the project, time sheets		**277** 1 [X] Test protocols, test data, analysis of test results, conclusions	
272 1 [ ] Design of experiments		**278** 1 [X] Photographs and videos	
273 1 [X] Project records, laboratory notebooks		**279** 1 [ ] Samples, prototypes, scrap or other artefacts	
274 1 [ ] Design, system architecture and source code		**280** 1 [X] Contracts	
275 1 [ ] Records of trial runs		**281** 1 [X] Others, specify	**282** Emails, invoices

Part 2 – Project information (continued)

Project number **9**

CRA internal form identifier 060

Complete a separate Part 2 for each project claimed this year. Code 1501

Section A – Project identification

200 Project title (and identification code if applicable)

P7: Developing & applying smart metering systems

202 Project start date	**204** Completion or expected completion date	**206** Field of science or technology code (See guide for list of codes)
2004-07 (Year Month)	2017-12 (Year Month)	2.02.01 Electrical and electronic engineering

Project claim history

208 1 [X] Continuation of a previously claimed project **210** 1 [ ] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
1	

Section B – Project descriptions

242 What scientific or technological uncertainties did you attempt to overcome? (*Maximum 50 lines*)

The overall project objective/advancement sought was the knowledge and capability to be able to deploy smart meters (SM) and Advanced Metering Infrastructure (AMI), Ontario Energy Board (OEB) and Ministry of Energy and Infrastructure specifications compliant, across the THESL distribution network serving about 700,000 customers for automated meter reading of all residential, commercial & industrial customers, with seamless & reliable end-to-end data communications for settlement and billing purposes through a set of IT application tools that performs consistently, and in a stable manner.

Key uncertainties were as follows:
(1) The performance of the application configuration and preferred arrangements to implement smart metering for medium and large C & I customers to bring the SM read data handling in-house instead of relying on external subcontractors;
(2) The performance of the approach chosen in 2010 to implement the Measurement Canada requirement for cumulative readings on all TOU bills;
(3) Integration of other emerging requirements, e. g. for Smart Grid applications, for EV metering, and accommodating the implementation of DG FIT and micro-FIT systems with bi-directional metering;
(4) Whether or not other improvements would be needed for the existing set of S/W tools as an integral part of the technology development, implementation and completion of smart metering for all types of C & I customers;
(5) Stability of suite meter AMI and meter read data for billing; and
(6) Smart Meter AMI system EA_MS will form a legacy system.

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

The new add-on function, Power Status Check (PSC) was developed, tested and added to EA_MS. It allowed operators to ping a group of smart meters to verify power supplies had been restored after an outage has been resolved without logging into EA_MS. Upgrading to attempt to improve the communication methodology was undertaken - a multichannel EA_MS 9 Upgraded with GIS tool (AxisDetect), and Batch Request Tools (Power Status Check, On Request Read, Remote Connect/Disconnect) was pursued. Testing of the fault detection and resolution with geographical data was conducted and utilized Elster Handheld

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

devices for mesh network communication. In FY2016 work would extent to include remote connect/disconnect and batch reader capabilities.

SmartSync meters reached their serviceable life due to of the retirement of Roger's 2G network. These meters will be replaced with Itron Centron LTE meters in 2016 extending through to 2018. In this fiscal period Toronto Hydro completed the requirement specification phase of the MV-STAR (upgrading - live September 2017), MV-90 and MV-WEB (upgrading - live September 2017) upgrade to Itron's new Itron Enterprise Edition (IEE). These new MV-90 version 5 meters will be initially tested in May 2016 - complete - live in November 2016.

Activities to improve small C & I customer billing practices continued from the prior fiscal year. Testing continued throughout with the re-configured ODS, ESB and CC&B to allow the billing of small C & I customers to be made from the SM reads with KWh and KVARh register reads and peak demands - with fully converted meters from manual reads to automated reads in FY2016. By the end of the fiscal period we had implemented small C&I billing with the data collected through smart meters for small C&I customers.

For suite meter rate class implementation as per an OEB directive, THESL had to bill its Quadlogic Site Meter customers using a different rate. A new suite meter rate (RES120) was created and added into CC&B in 2012. A set of complicated rate structures was designed, developed and tested in 2012, and implementation took place in 2013 with further modifications extending through to 2016. In FY2015 THESL upgraded Primeread to attempt to support wireless transponders (converted to 4G in FY2016 with ongoing implementation in FY2017). THESL completed test of the enhancements to communicate with multiple transponders connected in a daisy-chain, to perform ad-hoc export data to ODS, to export register data with mid-night timestamps - modifications completed in early 2016 - complete.

In FY2015 Toronto Hydro implemented new Rogers private apn for metering systems - EA_MS, Primeread and MV90 are all able to communicated to meters with wireless communication capabilities. THESL replaced 1700 smart meter phoneline gatekeepers with 810 pole mount wireless gatekeepers with battery backup - complete. The wireless gatekeepers enables Rex 2 meters to report outages and restorations in real time to the back office system. The outage / restoration event data can be fed to Outage Management System. Event reports were activated to function in 20 wireless gatekeepers for testing - complete. In FY2016, to improve the accuracy and EA_MS system capability to process high volumes of outage information during a significant storm. We are coordinating the installation of an additional 8,000 meters with last gasp capability (3,000 installations completed in 2016 5,000 scheduled for 2017) with our engineering planning department, to ensure that every transformer has a "last gasp" capable meter connected to it. These meters will be identified as bell weather meters used to identify transformer outages.

PrimeStone's AMI Primeread went live in Q2 2013 and more defects were found through testing and analysis. By the end of 2013, there were 32 thousand suite meters read and billed with the data collected through the Primeread. In FY2014 primeread was upgraded with reading capabilities for condominiums and apartment suite meters. The number of commissioned suite meters reached 70 thousand in Primereads at the end of 2016. Upgrading software to v10 in FY2017.

In FY2015 and extending into FY2016 high fidelity Schneider Electric ION meters with wireless communication to MV-90 were examined and tested for integration into the TH system. The power quality data from ION meters are

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

captured through Schneider's Power Monitoring Export (PME) software. Initial development involved testing a dashboard concept to view near real time meter reads for 2 meters installed on 2 Toronto Hydro buildings - complete and ongoing.

ION - 1MW+ customers - additional power quality tools and grid management team...in the event of outage or frequency it can detect faults and potential failure modes - implemented in FY2016 - ongoing through to FY2019. MDMR (meter data management / repository) - integration SME smart meter entity via IESO - expected to go live September 2017 - subsequent Phase II for billing data. MWM - Mobile Workforce Management for metering replacement/installation - tracking system for near-real time work activity developed and initiated in late FY2016. In the future an upgrade of Smart Meter mesh system will be undertaken (Synergy net conversion) a 2020 completion timeframe was proposed.

Contractors: ITRON, PRIMESTONE, OLAMETER, TRILIANT - SUITE METERS, OPTIMA (data reading, set-up of suite meters in condo units) - capitalized equipment contractors.

Labour Sub-contract - Bagg Group: Bob Russel, Troy Martins, Sabrina Wang, Matt Martin contract started January 2017, Elisa Arutiunian , Jason Serano Contract ended January 2017, Joseph Akkarapattiakal Contract started April 2017.

246 What scientific or technological advancements did you achieve or attempt to achieve as a result of the work described in line 244? (*Maximum 50 lines*)

Virtually all residential customers are now on time-of-use (TOU) rates. The related SM systems and practices have stabilized and their development can be considered substantially complete. Residential customer AMI included a suite of IT tools: (1) EnergyAxis Management System (EA_MS), version 7.0, for aggregating/managing readings, fed from collectors (with uploaded meter data) using dedicated wireless communication network, (2) Operations Data Store (ODS), version 6.4, that takes/holds EA_MS and Primeread data in an Oracle database which interfaces with (a) a Customer Care & Billing System, and (b) a customer accessible TOU Website, with IVR through and Enterprise Service Bus (ESB) on a JBoss platform, (3) Cleo VL Trader, interfacing with the IESO's MDM/R system, work in combination with ESB and ODS, (4) MapInfo, a GIS using EA_MS data to track all field SM hardware, and (5) an interface with the Kubra i-docs software tool for ensuring cumulative readings of customers' bills.

Full implementation of PrimeStone's AMI for Quadlogic suite meters - using power line carrier communications within the buildings was somewhat completed, as was the improvement of PrimeStone's AMI functionality, suite metering practices and procedures for medium/large C & I customers. Some work in this area would continue, as would upgrading EA_MS version 7 to 9, and preparing to upgrade large C&I AMI MV systems to IEE. Knowledge would be gained from Primeread enhancements, EA_MS version upgrades, MV systems upgrades, and a Mobile Meter workforce management (MWM) system to automate the process of large volume of meter changes in the coming years.

Section C – Additional project information

Who prepared the responses for Section B?

253 1 [X] Employee directly involved in the project	**254** Name [redacted]			
255 1 [ ] Other employee of the company	**256** Name			
257 1 [X] External consultant	**258** Name Deloitte LLP	**259** Firm Deloitte LLP		

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2 [redacted]	[redacted]
3 [redacted]	[redacted]

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268 Names of individuals or companies	**269** BN
1 The Bagg Group	[redacted]

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273 1 [X] Project records, laboratory notebooks	**279** 1 [ ] Samples, prototypes, scrap or other artefacts
274 1 [X] Design, system architecture and source code	**280** 1 [ ] Contracts
275 1 [X] Records of trial runs	**281** 1 [X] Others, specify **282** Invoices & emails.

Part 2 – Project information (continued)

Project number **10**

CRA internal form identifier 060

Complete a separate Part 2 for each project claimed this year. Code 1501

Section A – Project identification

200 Project title (and identification code if applicable)

P8: Distributed generation (DG) and Protection facilitation

202 Project start date	**204** Completion or expected completion date	**206** Field of science or technology code (See guide for list of codes)
2007-01 (Year Month)	2019-12 (Year Month)	2.02.01 Electrical and electronic engineering

Project claim history

208 1 [X] Continuation of a previously claimed project **210** 1 [ ] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
1	

Section B – Project descriptions

242 What scientific or technological uncertainties did you attempt to overcome? (*Maximum 50 lines*)

For 2016, the uncertainties the project team had to address during the year were as follows:

(1) Developing and finalizing the standard for communication equipment that would maintain distribution system integrity and reliability and allow THESL to monitor/take appropriate corrective action during system contingencies;

(2) Continuing connection impact assessments (CIA) for all proposed DG projects to determine the suitability of connecting to the distribution system;

(3) Developing a forecast of near, medium and long term DG sites that will be connected to the THESL distribution system based on system technology, size and area of connection (station bus and feeder level);

(4) Identifying jurisdictions that operate a distribution system similar to THESL, which have implemented a centralized monitoring and control system for DG sites, and understanding how the similarities and differences could relate to the THESL distribution system;

(5) Identifying solutions that will allow for the integration of additional DG sites to the THESL distribution system (e.g. upgrading station protection systems and installing bus-tie reactors at transformer substations, installing remote communication equipment at DG sites for monitoring and control); and

(6) Developing and specifying a system tool that will enable power system simulation and which interfaces with Toronto Hydro's mapping system and enterprise systems to extract and build a network models for analyzing key parameters needed to assess system conditions.

Additional uncertainties that evolved over the course of development:

-Integrating a growing number and capacity of renewable energy and energy storage projects with the distribution grid

-Interconnecting large customer substations with rotating type generators and designs to improve interface and reliability with distributed generation

-Investigating and analyzing system disturbances impacting utility station protection systems and take corrective action to improve system reliability

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

1.

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

2. Ongoing in this fiscal period DG forecasting methods continued to be
3. developed. To uphold the reliability/integrity of its distribution supply
4. grid, analysis/simulation studies continued to be performed. Power system
5. simulation and modeling studies had shown that distributed generation causes
6. several challenges to the protection of distribution networks - development of
7. a Gateway assessment tool continued with CYME.
8.
9. The evolving practices and methodologies developed for DG would be tested on
10. specific applications and would be subsequently modified and augmented to
11. improve performance. New Conservation and Demand Management initiatives to
12. reduce peak demand and energy were completed including projects such as the
13. Campbell's Soup 3.8 MW combined heat and power generator, the Enwave 4MW steam
14. generation and Humber Waste-Water Treatment Plant with 4.7MW biogas facility.
15.
16. Large data centers and critical loads would be connected to the distribution
17. grid with embedded generation. All data center activities considered complete
18. toward the end of the fiscal period.
19.
20. Protection and Control of Distribution Grid ongoing development continued -
21. Investigated protection miscoordination and developed module with added
22. flexibility to integrate large new customer capacity and load at Humber
23. College.
24.
25. Energy storage - Energy storage projects were developed to provide Toronto
26. Hydro with strategic ancillary capabilities to address system efficiency,
27. reliability and power quality, as well as Distributed Generation (DG) and
28. Electric Vehicle (EV) enablement in targeted areas of the Toronto Hydro
29. distribution system. By placing ancillary ESS strategically throughout the
30. distribution system, localized issues can be addressed. This approach allows
31. for a minor augmentation of the distribution system, rather than an expensive
32. rebuild or major asset replacement. In this way, ESS deployments can be a
33. creative and prudent approach to system risk mitigation. The Bulwer Battery
34. Energy Storage System (BESS) project is a 2MW/8MWh and is located in the
35. Downtown area of Toronto with ever increasing demands for electricity. The
36. Community Energy Storage (CES) project includes a consortium partners eCAMION,
37. Dow-Kokam, Toronto Hydro-Electric Systems Limited (THESL) and the University
38. of Toronto with the first project installed at Roding Community Centre and the
39. second installation at Toronto Hydro's Commissioners office is in progress and
40. is slated for completion in 2017. Toronto Hydro is presently working with
41. Green Power Labs Inc. on the deployment of Supervisory Predictive Control
42. technology - The installation of a supervisory grid controller will provide
43. real time analysis and control enabling the Battery Storage and Solar PV.
44. Toronto Hydro, in collaboration with Ryerson University and eCAMION,
45. successfully installed and commissioned the world's first grid-scale
46. integrated pole mounted energy storage system (PMESS). Mounted on a Toronto
47. Hydro pole in Toronto, Ontario, the unit employs lithium-ion batteries that
48. charge during off-peak hours and discharge during peak hours. Toronto Hydro
49. also initiated energy storage initiative with Metrolinx on the Eglinton
50. Crosstown Transit for a 20MW/80MWh supply to power the traction power system.
51. Technical specifications were developed to integrate the storage system with
52. the Toronto Hydro feeder supplies from Runnymede TS and Bermondsey TS.
53.
54. Ongoing:
55. Protection and coordination - models developed that enables analytic studies
56. of the network to ensure adequacy of protection and loading capability.
57. Distribution Generation and Protection Methodologies - Developed the
58. Generation Protection, Monitoring and Control program for the 2015-2019
59. forecast period -Future activities would include installing an advanced

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

protection systems at three stations with short-circuit capacity constraints; a bus-tie reactor at station bus tie to alleviate short-circuit capacity constraints; and a required monitoring and control systems at all DG facilities.

Network protectors: A revised criteria was developed to specifically address connecting DG onto network distribution system in order to avoid potential failure modes.

Arc Flash Studies: Labelling procedures developed to properly identify the arc flash level with the warning signs at the equipment.

We initiated the development of a power analysis tool for power systems simulation. CYME Gateway is an application that will be interfaced with Toronto Hydro's mapping system and enterprise systems in order to extract and build the network model as required to analyze loading, fault levels and assess Distributed Energy Resources connectivity with the distribution system.

246 What scientific or technological advancements did you achieve or attempt to achieve as a result of the work described in line 244? (*Maximum 50 lines*)

THESL system. DG sites 50kW and above were connected to THESL's Control Room using the utility wireless communication system and DG sites 500kW and above were connected using a private wired communication system. In both instances, THESL needed to know: (A) the nearest THESL network node in the area of the DG site, (B) For wireless: The signal strength in the area of the DG site, and (C) For wired: The shortest path to the network trunk line.

In addition to ensuring that THESL could enable DG sites in the near term (2016 - 2017), THESL began developing a technical plan to ensure it could connect the forecasted increase of DG sites for the medium and long term (2018 - 2025). The project teams focus was on (1) determining the technical roadblocks that would prevent THESL from connecting additional DG sites to the distribution system, (2) identifying solutions that can be implemented in the near term to meet the forecasted demand of generation connections, (3) identifying and quantifying the impact of the additional data coming into THESL existing Control Room systems from the additional DG sites, (4) identifying the necessary backend systems required to enable next-generation monitoring, forecasting, and control of DG sites, and (5) implementing the plan that will address DG connection issues as part of the 2015- 2019 Rate Application to the Ontario Energy Board (OEB).

Additional advancements realized over the course of development included:

Developing energy storage connection methodology:

- Developing technical requirement for the interconnection of Energy Storage Unit to help resolve localized system issues.
- Utilize CYME to create system study models for the connection impact on THESL's distribution system.

Developing Arc Flash hazard criteria and deployment approach:

- Existing arc flash hazard programs are suitable for Arc Flash Hazard (AFH) calculation in local or small distribution system.
- TH worked with CYME closely in developing the existing CYME AFH module to handle AFH calculation in large distribution system such as TH.

Developing System Protection methodology, analysis tools and criteria for modernizing station protection at TS and MS:

- Developed Protection Philosophy document to assist in the determination of feeder protection relay settings for Transformer and Municipal Stations.
- Numerous protection relay enhancements and supply station transformer replacements under way with feeder protection implications and settings required to be addressed.
- Protection Philosophy document prepared also serves as a technical guide

39. relating to the grid with key parameters including station sequence data,
40. generator interconnections and max/min protection scenarios.
41. - Protection review process in progress to improve feeder settings given
42. modifications, enhancements and generator interconnection.

Section C – Additional project information

Who prepared the responses for Section B?

253 1 [X] Employee directly involved in the project	**254** Name [redacted]		
255 1 [ ] Other employee of the company	**256** Name		
257 1 [X] External consultant	**258** Name Deloitte LLP	**259** Firm Deloitte LLP	

List the key individuals directly involved in the project and indicate their qualifications/experience.

260 Names	**261** Qualifications/experience and position title
1 [redacted]	[redacted]
2 [redacted]	[redacted]
3 [redacted]	[redacted]

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . . 1 [ ] Yes 2 [X] No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . . 1 [ ] Yes 2 [X] No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 267, complete lines 268 and 269.

268 Names of individuals or companies	**269** BN
1	

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270 1 [X] Project planning documents

271 1 [X] Records of resources allocated to the project, time sheets

272 1 [ ] Design of experiments

273 1 [X] Project records, laboratory notebooks

274 1 [ ] Design, system architecture and source code

275 1 [ ] Records of trial runs

276 1 [X] Progress reports, minutes of project meetings

277 1 [X] Test protocols, test data, analysis of test results, conclusions

278 1 [X] Photographs and videos

279 1 [ ] Samples, prototypes, scrap or other artefacts

280 1 [X] Contracts

281 1 [X] Others, specify **282** Invoices & emails.

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

200

055 **Do not use this area**

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act* and *Income Tax Regulations*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see cra.gc.ca or Guide T4012, *T2 Corporation - Income Tax Guide*.

Identification

Business number (BN) . . . . . 001 [redacted]

Corporation's name

002 TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

Address of head office

Has this address changed since the last time we were notified? . . . . . 010 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 011 to 018.)

011 14 CARLTON STREET

012

City	Province, territory, or state
015 TORONTO	016 ON
Country (other than Canada)	**Postal code/Zip code**
017	018 M5B 1K5

Mailing address (if different from head office address)

Has this address changed since the last time we were notified? . . . . . 020 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 021 to 028.)

021 c/o [redacted]

022 14 CARLTON STREET

023 5TH FLOOR -CORPORATE TAX DEPT

City	Province, territory, or state
025 TORONTO	026 ON
Country (other than Canada)	**Postal code/Zip code**
027	028 M5B 1K5

Location of books and records (if different from head office address)

Has this address changed since the last time we were notified? . . . . . 030 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 031 to 038.)

031 14 CARLTON STREET

032

City	Province, territory, or state
035 TORONTO	036 ON
Country (other than Canada)	**Postal code/Zip code**
037	038 M5B 1K5

040 **Type of corporation at the end of the tax year**

1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change . . . . . 043 Year Month Day

To which tax year does this return apply?

Tax year start	Tax year-end
Year Month Day	Year Month Day
060 2016-01-01	061 2016-12-31

Has there been an acquisition of control resulting in the application of subsection 249(4) since the tax year start on line 060? . . . . . 063 1 Yes [ ] 2 No [X]

If **yes**, provide the date control was acquired . . . . . 065 Year Month Day

Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)? . . . . . 066 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? . . . . . 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:

Incorporation? . . . . . 070 1 Yes [ ] 2 No [X]
Amalgamation? . . . . . 071 1 Yes [ ] 2 No [X]

If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . . 072 1 Yes [ ] 2 No [X]

If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . . 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? . . . . . 078 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used 079

Is the corporation a resident of Canada? 080 1 Yes [X] 2 No [ ]

If **no**, give the country of residence on line 081 and complete and attach Schedule 97.

081

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . . 082 1 Yes [ ] 2 No [X]

If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [X] Exempt under other paragraphs of section 149

Do not use this area

095 096 898

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders who own voting shares?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter?	166		T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation own any shares in one or more foreign affiliates in the tax year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the *Income Tax Regulations*?	170		29
Did the corporation have a total amount over $1 million of reportable transactions with non-arm's length non-residents?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		———
Does the corporation earn income from one or more Internet webpages or websites?	180		88
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts of cultural or ecological property; or gifts of medicine?	202	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203		3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206	X	6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	207	X	7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal, provincial, or territorial foreign tax credits, or any federal logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231	X	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232	X	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	33/34/35
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	———
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates in the tax year?	271		T1134
Did the corporation own or hold specified foreign property where the total cost amount of all such property, at any time in the year, was more than CAN$100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265		55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270	1 Yes	X	2 No	
Is the corporation inactive?	280	1 Yes		2 No	X

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution

Specify the principal products mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	ELECTRICITY DISTRIBUTION	285	100.000 %
286		287	%
288		289	%

Did the corporation immigrate to Canada during the tax year?	291	1 Yes		2 No	X
Did the corporation emigrate from Canada during the tax year?	292	1 Yes		2 No	X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293	1 Yes		2 No	X

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 (Year Month Day)

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 1 Yes 2 No

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.	300		90,427,842	A
Deduct: Charitable donations from Schedule 2	311	193,476		
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal		193,476 ▶	193,476	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			90,234,366	C
Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		90,234,366	
Income exempt under paragraph 149(1)(t)	370			
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)			90,234,366	Z
Taxable income for the year from a personal services business**				Z.1

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 9.

** For a taxation year that ends after 2015.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . . . **400** 89,612,631 A

Taxable income from line 360 on page 3, **minus** 100/28 3.57143 of the amount on line 632* on page 8, **minus** 4 times the amount on line 636** on page 8, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . . **405** 90,234,366 B

Business limit (see notes 1 and 2 below) . . . . . **410** 500,000 C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 500,000 x **415** *** 4,934,211 / 11,250 D = ... 219,298,267 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . . **425** F

Business limit the CCPC assigns under subsection 125(3.2) (amount O below) . . . . . G

Amount F **minus** amount G . . . . . H

Small business deduction

Amount A, B, C, or H, whichever is the least x (Number of days in the tax year before January 1, 2016 / Number of days in the tax year) x 17 % = 1

Amount A, B, C, or H, whichever is the least x (Number of days in the tax year after December 31, 2015 / Number of days in the tax year) x 17.5 % = 2

Total of amounts 1 and 2 (enter amount I on line J on page 8) **430** I

***** Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

****** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

***** Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

Specified corporate income and assignment under subsection 125(3.2)

	J Name of corporation receiving the income and assigned amount	K Business number of the corporation	L Income for the small business deduction given to the corporation identified in column J [under clause 125(1)(a)(i)(B)] [3]	M Business limit assigned to corporation identified in column J [4]
1.				
			Total N	Total O

Notes:

3. This amount is [as defined in subsection 125(7) **specified corporate income** (a)(i)] the total of all amounts each of which is income from an active business of the corporation for the year from the provision of services or property to a private corporation (directly or indirectly, in any manner whatever) if

   (A) at any time in the year, the corporation (or one of its shareholders) or a person who does not deal at arm's length with the corporation (or one of its shareholders) holds a direct or indirect interest in the private corporation, and

   (B) it is not the case that all or substantially all of the corporation's income for the year from an active business is from the provision of services or property to

   (I) persons (other than the private corporation) with which the corporation deals at arm's length, or

   (II) partnerships with which the corporation deals at arm's length, other than a partnership in which a person that does not deal at arm's length with the corporation holds a direct or indirect interest.

4. The amount of the business limit you assign cannot be greater than the amount in column L.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from page 3 (line 360 or amount Z, whichever applies)			90,234,366	A
Lesser of amounts B9 and H9 from Part 9 of Schedule 27				B
Amount K13 from Part 13 of Schedule 27				C
Personal services business income	432			D
Amount used to calculate the credit union deduction (amount F from Schedule 17)				E
Amount from line 400, 405, 410, or amount H on page 4, whichever is the least				F
Aggregate investment income from line 440 on page 6*		815,211		G
Subtotal (**add** amounts B to G)		815,211 ▶	815,211	H
Amount A **minus** amount H (if negative, enter "0")			89,419,155	I
General tax reduction for Canadian-controlled private corporations – Amount I **multiplied** by 13 %			11,624,490	J

Enter amount J on line 638 on page 8.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)				K
Lesser of amounts B9 and H9 from Part 9 of Schedule 27				L
Amount K13 from Part 13 of Schedule 27				M
Personal services business income	434			N
Amount used to calculate the credit union deduction (amount F from Schedule 17)				O
Subtotal (**add** amounts L to O)		▶		P
Amount K **minus** amount P (if negative, enter "0")				Q
General tax reduction – Amount Q **multiplied** by 13 %				R

Enter amount R on line 639 on page 8.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . . **440** 815,211 A

Amount A 815,211 x (Number of days in the tax year before January 1, 2016 / Number of days in the tax year) ____ / 366 x 26 2/3 % = ____ 1

Amount A 815,211 x (Number of days in the tax year after December 31, 2015 / Number of days in the tax year) 366 / 366 x 30 2/3 % = 249,998 2

Subtotal (amount 1 **plus** amount 2) 249,998 ▶ 249,998 B

Foreign investment income from Schedule 7 . . . . . **445** ____ C

Amount C ____ x (Number of days in the tax year before January 1, 2016 / Number of days in the tax year) ____ / 366 x 9 1/3 % = ____ 3

Amount C ____ x (Number of days in the tax year after December 31, 2015 / Number of days in the tax year) 366 / 366 x 8 % = ____ 4

Subtotal (amount 3 **plus** amount 4) ____ D

Foreign non-business income tax credit from line 632 on page 8 **minus** amount D (if negative, enter "0") . . . . . ____ E

Amount B **minus** amount E (if negative, enter "0") . . . . . 249,998 F

Foreign non-business income tax credit from line 632 on page 8 . . . . . ____ G

Number of days in the tax year before January 1, 2016 / Number of days in the tax year ____ / 366 x 35 = ... ____ 5

Number of days in the tax year after December 31, 2015 / Number of days in the tax year 366 / 366 x 38 2/3 = ... 38.66667 6

Subtotal (amount 5 **plus** amount 6) 38.6667 H

Amount G ____ x 100/H 100/38.6667 = ... ____ I

Taxable income from line 360 on page 3 . . . . . 90,234,366 J

Deduct:

Amount from line 400, 405, 410, or amount H on page 4, whichever is the least . . . . . ____ K

Amount I . . . . . ____ L

Foreign business income tax credit from line 636 on page 8 . . . . . ____ x 4 = ____ M

Subtotal (total of amounts K to M) ____ ▶ ____ N

Subtotal (amount J **minus** amount N) 90,234,366 O

Amount O 90,234,366 x (Number of days in the tax year before January 1, 2016 / Number of days in the tax year) ____ / 366 x 26 2/3 % = ____ 7

Amount O 90,234,366 x (Number of days in the tax year after December 31, 2015 / Number of days in the tax year) 366 / 366 x 30 2/3 % = 27,671,872 8

Subtotal (amount 7 **plus** amount 8) 27,671,872 ▶ 27,671,872 P

Part I tax payable **minus** investment tax credit refund (line 700 **minus** line 780 from page 9) . . . . . 12,543,937 Q

Refundable portion of Part I tax – Amount F, P, or Q, whichever is the least . . . . . **450** 249,998 R

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year	460	547,210		
Deduct:				
Dividend refund for the previous tax year	465			
		547,210	▶	547,210 A
Add the total of:				
Refundable portion of Part I tax from line 450 on page 6		249,998	B	
Total Part IV tax payable from Schedule 3			C	
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation	480			
		249,998	▶	249,998 D
Refundable dividend tax on hand at the end of the tax year – Amount A **plus** amount D	485			797,208

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 3 of Schedule 3 ____ E

Amount E ____ x (Number of days in the tax year before January 1, 2016 / Number of days in the tax year) ____ / 366 x 33 1/3 % = ____ 1

Amount E ____ x (Number of days in the tax year after December 31, 2015 / Number of days in the tax year) 366 / 366 x 38 1/3 % = ____ 2

Subtotal (amount 1 **plus** amount 2) ____ ▶ ____ F

Refundable dividend tax on hand at the end of the tax year from line 485 above 797,208 G

Dividend refund – Amount F or G, whichever is less ____ H

Enter amount H on line 784 on page 9.

Part I tax

Base amount Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 %* . . **550** 34,289,059 A

Personal services business income tax (section 123.5)

Taxable income from a personal services business **555** _____ x (Number of days in the tax year after December 31, 2015 / Number of days in the taxation year) 366/366 x 5 % = **560** _____ B

Recapture of investment tax credit from Schedule 31 . . . . . **602** _____ C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6 . . . . . 815,211 D

Taxable income from line 360 on page 3 . . . . . 90,234,366 E

Deduct:

Amount from line 400, 405, 410, or amount H on page 4, whichever is the least . . . . . F

Net amount (amount E **minus** amount F) 90,234,366 ▶ 90,234,366 G

Amount D or G, whichever is less 815,211 x (Number of days in the tax year before January 1, 2016 / Number of days in the tax year) 366/366 x 6 2/3 % = _____ 1

Amount D or G, whichever is less 815,211 x (Number of days in the tax year after December 31, 2015 / Number of days in the tax year) 366/366 x 10 2/3 % = 86,956 2

Refundable tax on CCPC's investment income (amount 1 **plus** amount 2) . . . . . **604** 86,956 ▶ 86,956 H

Subtotal (**add** amounts A, B, C, and H) 34,376,015 I

Deduct:

Small business deduction from line 430 on page 4 . . . . . J

Federal tax abatement	**608**	9,023,437
Manufacturing and processing profits deduction from Schedule 27	**616**	
Investment corporation deduction	**620**	
Taxed capital gains **624**		
Additional deduction – credit unions from Schedule 17	**628**	
Federal foreign non-business income tax credit from Schedule 21	**632**	
Federal foreign business income tax credit from Schedule 21	**636**	
General tax reduction for CCPCs from amount J on page 5	**638**	11,624,490
General tax reduction from amount R on page 5	**639**	
Federal logging tax credit from Schedule 21	**640**	
Eligible Canadian bank deduction under section 125.21	**641**	
Federal qualifying environmental trust tax credit	**648**	
Investment tax credit from Schedule 31	**652**	1,184,151
Subtotal		21,832,078 ▶ 21,832,078 K

Part I tax payable – Amount I **minus** amount K . . . . . 12,543,937 L

Enter amount L on line 700 on page 9.

Privacy statement

Personal information is collected under the *Income Tax Act* to administer tax, benefits, and related programs. It may also be used for any purpose related to the administration or enforcement of the Act such as audit, compliance and the payment of debts owed to the Crown. It may be shared or verified with other federal, provincial/territorial government institutions to the extent authorized by law. Failure to provide this information may result in interest payable, penalties or other actions. Under the *Privacy Act*, individuals have the right to access their personal information and request correction if there are errors or omissions. Refer to Info Source cra.gc.ca/gncy/tp/nfsrc/nfsrc-eng.html, personal information bank CRA PPU 047.

Summary of tax and credits

Federal tax

Part I tax payable from amount L on page 8	700	12,543,937
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		12,543,937

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	6,260,874
Total tax payable	770	18,804,811 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund from amount H on page 7	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	20,535,568
Total credits	890	20,535,568 ▶ 20,535,568 B

Refund code 894 2 Overpayment 1,730,757

Balance (amount A **minus** amount B) -1,730,757

If the result is positive, you have a **balance unpaid**.
If the result is negative, you have an **overpayment**.
Enter the amount on whichever line applies.
Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid

For information on how to make your payment, go to cra.gc.ca/payments.

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 Branch number

914 Institution number 918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No ☒

If this return was prepared by a tax preparer for a fee, provide their EFILE number 920

Certification

I, 950 Bovingdon (Last name) 951 Sean (First name) 954 EVP & Chief Financial Officer (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2017-06-28 (Date yyyy/mm/dd) Signature of the authorized signing officer of the corporation 956 (416) 542-3100 Telephone number

Is the contact person the same as the authorized signing officer? If no, complete the information below 957 1 Yes ☐ 2 No ☒

958 [redacted] Name of other authorized person 959 [redacted] Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

Canada Revenue Agency / Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

Schedule 1

Corporation's name	Business Number	Tax year end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2016-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125				150,331,448 A
Add:				
Provision for income taxes – current	101	23,135,447		
Amortization of tangible assets	104	210,601,025		
Charitable donations and gifts from Schedule 2	112	193,476		
Taxable capital gains from Schedule 6	113	815,211		
Scientific research expenditures deducted per financial statements	118	2,547,371		
Non-deductible club dues and fees	120	281,450		
Non-deductible meals and entertainment expenses	121	344,210		
Reserves from financial statements – balance at the end of the year	126	280,712,692		
Subtotal of additions		518,630,882 ▶		518,630,882
Other additions:				
Debt issue expense	208	1,134,436		

Miscellaneous other additions:

	1 Description 605	2 Amount 295				
1	OITC/ORDTC/BCRDTC/ABRDTC from prior year under 12(1)(x) ITA	58,647				
2	See attached	114,987,678				
3	Ontario Co-op Credit	1,062,207				
4	Ontario apprenticeship credit	50,160				
	Total of column 2	116,158,692 ▶	296	116,158,692		
	Subtotal of other additions		199	117,293,128 ▶		117,293,128
	Total additions		500	635,924,010 ▶		635,924,010 B
Amount A **plus** amount B						786,255,458 C
Deduct:						
Gain on disposal of assets per financial statements			401	2,132,160		
Capital cost allowance from Schedule 8			403	255,578,362		
Cumulative eligible capital deduction from Schedule 10			405	3,894,582		
SR&ED expenditures claimed in the year on line 460 from Form T661			411	6,109,122		
Reserves from financial statements – balance at the beginning of the year			414	296,657,273		
Subtotal of deductions				564,371,499 ▶		564,371,499
Other deductions:						

Miscellaneous other deductions:

	1 Description 705	2 Amount 395				
1	Deduction under 20(1)(e) ITA	2,053,258				
2	See attached	129,402,859				
	Total of column 2	131,456,117 ▶	396	131,456,117		

Subtotal of other deductions	499	131,456,117 ▶	131,456,117	
Total deductions	510	695,827,616 ▶	695,827,616	D
Net income (loss) for income tax purposes (amount C **minus** amount D)			90,427,842	E

Enter amount E on line 300 of the T2 return.

Attached Schedule with Total

Line 295 – Amount

Title Line 295 – Amount

Explanatory note

Other additions to Schedule 1

Description		Amount	
ARO accretion expense not deductible for tax		24,235	00
Deferred revenue - 12(1)(a) addback	+	6,529,077	00
Para 12(1)(x) - 777 Bay Street Lease Inducement	+	81,156	00
Para 12(1)(x) -Fixed asset capital contributions & 777 Bay Lease Inducement	+	34,099,823	00
Smart meters revenue, per 2014 rate rider	+	7,745,837	00
Reversal of IS impact re. tax savings materialized on gain on sale of OCCP	+	5,223,055	00
Reversal of IS impact re. CC on deferred gain on sale of OCCP	+	28,669	00
Stranded meters revenue	+	3,102,224	00
RDA - capitalized POEB tax liability, CC [not yet approved]	+	37,569	00
HONI contributions - per drawdown as a result of FRO for 2015 rate app	+	382,315	00
HST Variance CC recorded as reg liab for acctg in 2016 [not yet approved]	+	2,016	00
2008 Named properties - per drawdown as a result of FRO for 2015 rate app	+	1,155,079	00
LRAM - per drawdown as a result of FRO for 2015 rate application	+	3,257,159	00
Reversal of PILS regulatory variance 1592 CC deducted for acctg	+	4,244	00
1575 - 2014 Derecognition-per drawdown as a result of FRO for 2015 rate app	+	6,128,044	00
De-recognition variance (not yet approved)	+	2,902,692	00
Deferred monthly billing (revenue requirement not yet approved)	+	375,500	00
Capital-related revenue requirement variance (not yet approved)	+	6,048,416	00
Reg investment variance (not yet approved)	+	1,026,599	00
Foregone revenue per drawdown as a result of FRO for 2015 rate app	+	16,016,555	00
Externally driven capital variance (not yet approved)	+	153,013	00
Wireless attachment - CC, OPEX and deferred income in 2016	+	102,877	00
POEB transferred from THESI and THC, IS impact is in THESI and THC	+	414,000	00
Interest income included in acctg gain on sale, taxable for tax	+	524	00
Change in AOCI with no IS impact	+	20,147,000	00
	+		
	Total	114,987,678	00

Attached Schedule with Total

Line 395 – Amount

Title Line 395 – Amount

Explanatory note

Other deductions to Schedule 1

Description		Amount	
Amortization of contributed capital received recorded in other revenue		3,766,493	00
Deductible land lease recorded in depreciation for accounting	+	89,423	00
13(7.4) election re:Contributed capital received & 777 Bay Lease inducement	+	34,099,823	00
Capitalized POEB for accounting, not for tax	+	6,423,865	00
ARO payments - deductible for tax	+	226,033	00
Deferred revenue - 20(1)(m) deduction	+	6,529,077	00
777 Bay Street lease inducement - reverse accounting amortization	+	54,792	00
Gain on sale of OCCP deduction - per drawdown as a result of FRO	+	19,709,644	00
Capitalized POEB regulatory liab deduction -per drawdown as a result of FRO	+	6,388,159	00
HST variance deduction - per drawdown as a result of FRO for 2015 rate app	+	1,109,744	00
1592 deduction - per drawdown as a result of FRO for 2015 rate app	+	2,346,386	00
Deferred monthly billing - actual OPEX incurred – deductible for tax	+	2,016,269	00
Deferred monthly billing - CC not yet approved	+	7,868	00
LRAM reversal of CC before OEB approval	+	171,776	00
LRAM reversal of distribution revenue before OEB approval	+	4,481,352	00
Foregone revenue reverse IS impact not yet entitled	+	19,172,248	00
OPEB cash vs accrual variance (not yet approved)	+	1,123,410	00
PSC lease payment capitalized for acctg, deducted for tax	+	3,143,256	00
HONI Capital lease payment capitalized for acctg, deducted for tax	+	234,894	00
Cogeco payment for lease cancellation, s 20(1)(z) deduction	+	1,220,759	00
Environmental remediation costs in CWIP, s 9(1) deduction	+	124,801	00
Property disposal costs in other assets, s 9(1) deduction	+	703,293	00
Reversal of 2015 Ont R&D credit recorded for acctg in 2016; taxed in 2015/6	+	312,133	00
Reversal of 2015 Fed R&D credit recorded for acctg in 2016; taxed thru T661	+	993,624	00
2015 Ont apprentice &coop credits;taxed in 2015; recorded for acctg in 2016	+	1,352,109	00
AFUDC income that is not taxable	+	12,531,040	00
Deductible property tax (re: 715 Miller) capitalized for accounting	+	500,022	00
Deductible property tax (re: 71 Rexdale) capitalized for accounting	+	317,754	00
Deductible OPEX (re: innovation projects) recorded in CWIP	+	239,992	00
Deferred monthly billing – revenue requirement not yet approved	+	12,820	00
	+		
	Total	129,402,859	00

Toronto Hydro Electric System Limited

Taxation year ended: December 31, 2016
C.R.A. Bus#: [redacted]
MOF A/C# (Hydro PILs #): [redacted]

Election under subsection 13(7.4)

The company hereby elects under subsection 13(7.4) of the Income Tax Act to reduce the capital cost of depreciable property acquired in the taxation year by a total amount of $34,099,823 received in the taxation year in respect of that property that would otherwise be included in income under paragraph 12(1)(x).

Authorized Signing Officer

Canada Revenue Agency / Agence du revenu du Canada

Schedule 2

Charitable Donations and Gifts

Corporation's name	Business number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2016-12-31

- For use by corporations to claim any of the following:
  - the eligible amount of charitable donations to qualified donees;
  - the Ontario community food program donation tax credit for farmers;
  - the eligible amount of gifts of certified cultural property;
  - the eligible amount of gifts of certified ecologically sensitive land; or
  - the additional deduction for gifts of medicine.
- All legislative references are to the federal *Income Tax Act*, unless otherwise specified.
- The eligible amount of a gift is the amount by which the fair market value of the gifted property exceeds the amount of an advantage, if any, for the gift.
- The donations and gifts are eligible for a 5-year carryforward except for gifts of certified ecologically sensitive land made after February 10, 2014, which are eligible for a 10-year carryforward.
- Use this schedule to show a transfer of unused amounts from previous years following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1) of the federal *Act*.
- Subsection 110.1(1.2) of the federal Act provides as follows:
  - Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control.
  - If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- An eligible medical gift to a qualifying organization for activities outside of Canada may be eligible for an additional deduction. Calculate the additional deduction in Part 5.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation - Income Tax Guide*.

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
The Princess Margaret Cancer Foundation	125
Sunnybrook Foundation	50,000
Michael Garron Hospital (formerly Toronto East G	393
Michael Garron Hospital (formerly Toronto East G	828
Canadian Museum of Immigration at Pier 21	2,600
Fatal Light Awareness Program	8,000
Starlight Children's Foundation of Canada	200
Georgian College	130,000
Subtotal	192,146
Add: Total donations of less than $100 each	1,330
Total donations in current tax year	193,476

Part 1 – Charitable donations

			Federal		Québec	Alberta
Charitable donations at the end of the previous tax year				A		
Deduct: Charitable donations expired after five tax years*	239					
Charitable donations at the beginning of the current tax year	240			B		
Add:						
Charitable donations transferred on an amalgamation or the wind-up of a subsidiary	250					
Total charitable donations made in the current year (include this amount on line 112 of Schedule 1)	210		193,476		193,476	193,476
Subtotal (line 250 **plus** line 210)			193,476	C	193,476	193,476
Subtotal (amount B **plus** amount C)			193,476	D	193,476	193,476
Deduct: Adjustment for an acquisition of control	255					
Total charitable donations available (amount D **minus** amount on line 255)			193,476	E	193,476	193,476
Deduct: Amount applied in the current year against taxable income (cannot be more than amount O in Part 2) (enter this amount on line 311 of the T2 return)	260		193,476		193,476	193,476
Charitable donations closing balance (amount E **minus** amount on line 260)	280					
Ontario community food program donation for farmers included in the amount on line 260 (for donations made after December 31, 2013)	262					
Ontario community food program donation tax credit for farmers (amount on line 262 **multiplied** by 25 %)				1		

Enter the amount from line 1 on line 420 of Schedule 5, *Tax Calculation Supplementary – Corporations*. The maximum amount you can claim in the current year is whichever is less; the Ontario income tax otherwise payable or the amount on line 1. For more information, see section 103.1.2 of the *Taxation Act, 2007* (Ontario).

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amounts carried forward – Charitable donations

Year of origin:		Federal	Québec	Alberta
1st prior year	2015-12-31			
2nd prior year	2014-12-31			
3rd prior year	2013-12-31			
4th prior year	2012-12-31			
5th prior year	2011-12-31			
6th prior year*	2010-12-31			
7th prior year	2009-12-31			
8th prior year	2008-12-31			
9th prior year	2007-12-31			
10th prior year	2006-12-31			
11th prior year	2005-12-31			
12th prior year	2004-12-31			
13th prior year	2003-12-31			
14th prior year	2002-12-31			
15th prior year	2001-12-31			
16th prior year	2001-09-30			
17th prior year	2000-09-30			
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total (to line A)				

***** For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 2 – Maximum allowable deduction for charitable donations

Net income for tax purposes* **multiplied** by 75 % . . . . . 67,820,882 F

Taxable capital gains arising in respect of gifts of capital property included in Part 1 ** . . . . . 225 _____ G

Taxable capital gain in respect of a disposition of a non-qualifying security under subsection 40(1.01) . . . . . 227 _____ H

The amount of the recapture of capital cost allowance in respect of charitable donations . . . . . 230 _____

Proceeds of disposition, **less** outlays and expenses** . . . . . _____ I

Capital cost** . . . . . _____ J

Amount I or J, whichever is less . . . . . 235 _____

Amount on line 230 or 235, whichever is less . . . . . _____ K

Subtotal (**add** amounts G, H, and K) _____ L

Amount L **multiplied** by 25 % _____ M

Subtotal (amount F **plus** amount M) 67,820,882 N

Maximum allowable deduction for charitable donations (enter amount E from Part 1, amount N, or net income for tax purposes, whichever is less) . . . . . 193,476 O

* For credit unions, subsection 137(2) states that this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

** This amount must be prorated by the following calculation: eligible amount of the gift **divided by** the proceeds of disposition of the gift.

Part 3 – Gifts of certified cultural property

		Federal		Québec	Alberta
Gifts of certified cultural property at the end of the previous tax year			A		
Deduct: Gifts of certified cultural property expired after five tax years*	439				
Gifts of certified cultural property at the beginning of the current tax year	440		B		
Add:					
Gifts of certified cultural property transferred on an amalgamation or the wind-up of a subsidiary	450				
Total gifts of certified cultural property in the current year (include this amount on line 112 of Schedule 1)	410				
Subtotal (line 450 **plus** line 410)			C		
Subtotal (amount B **plus** amount C)			D		
Deduct:					
Adjustment for an acquisition of control	455				
Amount applied in the current year against taxable income (enter this amount on line 313 of the T2 return)	460				
Subtotal (line 455 **plus** line 460)			E		
Gifts of certified cultural property closing balance (amount D **minus** amount E)	480				

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Québec	Alberta
1st prior year	2015-12-31			
2nd prior year	2014-12-31			
3rd prior year	2013-12-31			
4th prior year	2012-12-31			
5th prior year	2011-12-31			
6th prior year*	2010-12-31			
7th prior year	2009-12-31			
8th prior year	2008-12-31			
9th prior year	2007-12-31			
10th prior year	2006-12-31			
11th prior year	2005-12-31			
12th prior year	2004-12-31			
13th prior year	2003-12-31			
14th prior year	2002-12-31			
15th prior year	2001-12-31			
16th prior year	2001-09-30			
17th prior year	2000-09-30			
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total				

***** For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 4 – Gifts of certified ecologically sensitive land

		Federal	Québec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year			F	
Deduct: Gifts of certified ecologically sensitive land expired after 5 tax years, or after 10 tax years for gifts made after February 10, 2014*	539			
Gifts of certified ecologically sensitive land at the beginning of the current tax year	540		G	
Add:				
Gifts of certified ecologically sensitive land transferred on an amalgamation or the wind-up of a subsidiary	550			
Total current-year gifts of certified ecologically sensitive land made before February 11, 2014 (include this amount on line 112 of Schedule 1)	510			
Total current-year gifts of certified ecologically sensitive land made after February 10, 2014 (include this amount on line 112 of Schedule 1)	520			
Subtotal (**add** lines 550, 510, and 520)			H	
Subtotal (amount G **plus** amount H)			I	
Deduct:				
Adjustment for an acquisition of control	555			
Amount applied in the current year against taxable income (enter this amount on line 314 of the T2 return)	560			
Subtotal (line 555 **plus** line 560)			J	
Gifts of certified ecologically sensitive land closing balance (amount I **minus** amount J)	580			

***** For the federal and Alberta, gifts made before February 11, 2014 , expire after five tax years and gifts made after February 10, 2014, expire after ten tax years. For Québec, gifts made during a tax year that ended before March 24, 2006, expire after five tax years and gifts made during a tax year that ended after March 23, 2006 expire after twenty tax years.

Amounts carried forward – Gifts of certified ecologically sensitive land

Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date . . . . . .

Year of origin:		Federal	Québec	Alberta
1st prior year	2015-12-31			
2nd prior year	2014-12-31			
3rd prior year	2013-12-31			
4th prior year	2012-12-31			
5th prior year	2011-12-31			
6th prior year*	2010-12-31			
7th prior year	2009-12-31			
8th prior year	2008-12-31			
9th prior year	2007-12-31			
10th prior year	2006-12-31			
11th prior year*	2005-12-31			
12th prior year	2004-12-31			
13th prior year	2003-12-31			
14th prior year	2002-12-31			
15th prior year	2001-12-31			
16th prior year	2001-09-30			
17th prior year	2000-09-30			
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total				

***** For the federal and Alberta, gifts made before February 11, 2014, expire after five tax years and gifts made after February 10, 2014, expire after ten tax years. The field "Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date" is used to determine the portion of the gifts made in the tax year straddling February 11, 2014, that expires after ten tax years.
For Québec, gifts made during a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Part 5 – Additional deduction for gifts of medicine

		Federal		Québec		Alberta	
Additional deduction for gifts of medicine at the end of the previous tax year			K				
Deduct: Additional deduction for gifts of medicine expired after five tax years*	639						
Additional deduction for gifts of medicine at the beginning of the current tax year	640		L				
Add:							
Additional deduction for gifts of medicine transferred on an amalgamation or the wind-up of a subsidiary	650						
Additional deduction for gifts of medicine for the current year:							
Proceeds of disposition	602		1		1		1
Cost of gifts of medicine	601		2		2		2
Subtotal (line 1 **minus** line 2)			3		3		3
Line 3 **multiplied** by 50 %			4		4		4
Eligible amount of gifts	600		5		5		5

Federal

a _____ x (b _____ / c) = Additional deduction for gifts of medicine for the current year 610 _____

Québec

a _____ x (b _____ / c) = Additional deduction for gifts of medicine for the current year _____

Alberta

a _____ x (b _____ / c) = Additional deduction for gifts of medicine for the current year _____

where:

a is the **lesser** of line 2 and line 4

b is the eligible amount of gifts (line 600)

c is the proceeds of disposition (line 602)

Subtotal (line 650 **plus** line 610)			M		
Subtotal (amount L **plus** amount M)			N		
Deduct:					
Adjustment for an acquisition of control	655				
Amount applied in the current year against taxable income (enter this amount on line 315 of the T2 return)	660				
Subtotal (line 655 **plus** line 660)			O		
Additional deduction for gifts of medicine closing balance (amount N **minus** amount O)	680				

***** For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made before March 19, 2007, expire after five tax years and gifts made after March 18, 2007, expire after twenty tax years.

Amounts carried forward – Additional deduction for gifts of medicine

Year of origin:		Federal	Québec	Alberta
1st prior year	2015-12-31			
2nd prior year	2014-12-31			
3rd prior year	2013-12-31			
4th prior year	2012-12-31			
5th prior year	2011-12-31			
6th prior year*	2010-12-31			
7th prior year	2009-12-31			
8th prior year	2008-12-31			
9th prior year	2007-12-31			
10th prior year	2006-12-31			
11th prior year	2005-12-31			
12th prior year	2004-12-31			
13th prior year	2003-12-31			
14th prior year	2002-12-31			
15th prior year	2001-12-31			
16th prior year	2001-09-30			
17th prior year	2000-09-30			
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total				

***** For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, gifts made before March 19, 2007, expire after five tax years and gifts made after March 18, 2007, expire after twenty tax years.

Québec – Gifts of musical instruments

Gifts of musical instruments at the end of the previous tax year		A
Deduct: Gifts of musical instruments expired after twenty tax years		B
Gifts of musical instruments at the beginning of the tax year		C
Add:		
Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary		D
Total current-year gifts of musical instruments		E
Subtotal (line D **plus** line E)		F
Deduct: Adjustment for an acquisition of control		G
Total gifts of musical instruments available		H
Deduct: Amount applied against taxable income		I
Gifts of musical instruments closing balance		J

Amounts carried forward – Gifts of musical instruments

Year of origin:		Québec
1st prior year	2015-12-31	
2nd prior year	2014-12-31	
3rd prior year	2013-12-31	
4th prior year	2012-12-31	
5th prior year	2011-12-31	
6th prior year*	2010-12-31	
7th prior year	2009-12-31	
8th prior year	2008-12-31	
9th prior year	2007-12-31	
10th prior year	2006-12-31	
11th prior year	2005-12-31	
12th prior year	2004-12-31	
13th prior year	2003-12-31	
14th prior year	2002-12-31	
15th prior year	2001-12-31	
16th prior year	2001-09-30	
17th prior year	2000-09-30	
18th prior year		
19th prior year		
20th prior year		
21st prior year*		
Total		

***** These gifts expired in the current year.

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Schedule 5

Tax Calculation Supplementary – Corporations

Corporation's name	Business Number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2016-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- All legislative references mentioned in this schedule are from the *Income Tax Regulations*.
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 _____ Enter the Regulation that applies (402 to 413).

A Jurisdiction (Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *)		B Total salaries and wages paid in jurisdiction	C (B x taxable income) / G	D Gross revenue	E (D x taxable income) / H	F Allocation of taxable income (C + E) x 1/2** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes ☐	103		143		
Newfoundland and Labrador Offshore	004 1 Yes ☐	104		144		
Prince Edward Island	005 1 Yes ☐	105		145		
Nova Scotia	007 1 Yes ☐	107		147		
Nova Scotia Offshore	008 1 Yes ☐	108		148		
New Brunswick	009 1 Yes ☐	109		149		
Quebec	011 1 Yes ☐	111		151		
Ontario	013 1 Yes ☐	113		153		
Manitoba	015 1 Yes ☐	115		155		
Saskatchewan	017 1 Yes ☐	117		157		
Alberta	019 1 Yes ☐	119		159		
British Columbia	021 1 Yes ☐	121		161		
Yukon	023 1 Yes ☐	123		163		
Northwest Territories	025 1 Yes ☐	125		165		
Nunavut	026 1 Yes ☐	126		166		
Outside Canada	027 1 Yes ☐	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in subsection 400(2).

** For corporations other than those described under section 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.
3. If the corporation is a member of a partnership and the partnership had a permanent establishment in a jurisdiction, select the jurisdiction in Column A and include your proportionate share of the partnership's salaries and wages and gross revenue in columns B and D, respectively.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
90,234,366		90,234,366	10,376,952

Ontario basic income tax (from Schedule 500) **270** 10,376,952

Deduct: Ontario small business deduction (from Schedule 500) **402**

Subtotal 10,376,952 ▶ 10,376,952 A6

Add:

Ontario additional tax re Crown royalties (from Schedule 504) **274**

Ontario transitional tax debits (from Schedule 506) **276**

Recapture of Ontario research and development tax credit (from Schedule 508) **277**

Subtotal ▶ B6

Subtotal (amount A6 **plus** amount B6) 10,376,952 C6

Deduct:

Ontario resource tax credit (from Schedule 504) **404**

Ontario tax credit for manufacturing and processing (from Schedule 502) **406**

Ontario foreign tax credit (from Schedule 21) **408**

Ontario credit union tax reduction (from Schedule 500) **410**

Ontario political contributions tax credit (from Schedule 525) **415**

Subtotal ▶ D6

Subtotal (amount C6 **minus** amount D6) (if negative, enter "0") 10,376,952 E6

Deduct: Ontario research and development tax credit (from Schedule 508) **416** 315,162

Ontario corporate income tax payable before Ontario corporate minimum tax credit and Ontario community food program donation tax credit for farmers (amount E6 **minus** amount on line 416) (if negative, enter "0") 10,061,790 F6

Deduct:

Ontario corporate minimum tax credit (from Schedule 510) **418** 2,657,189

Ontario community food program donation tax credit for farmers (from Schedule 2) **420**

Ontario corporate income tax payable (amount F6 **minus** amounts on line 418 and line 420) (if negative, enter "0") 7,404,601 G6

Add:

Ontario corporate minimum tax (from Schedule 510) **278**

Ontario special additional tax on life insurance corporations (from Schedule 512) **280**

Subtotal ▶ H6

Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6) 7,404,601 I6

Deduct:

Ontario qualifying environmental trust tax credit **450**

Ontario co-operative education tax credit (from Schedule 550) **452** 1,062,207

Ontario apprenticeship training tax credit (from Schedule 552) **454** 50,160

Ontario computer animation and special effects tax credit (from Schedule 554) **456**

Ontario film and television tax credit (from Schedule 556) **458**

Ontario production services tax credit (from Schedule 558) **460**

Ontario interactive digital media tax credit (from Schedule 560) **462**

Ontario sound recording tax credit (from Schedule 562) **464**

Ontario book publishing tax credit (from Schedule 564) **466**

Ontario innovation tax credit (from Schedule 566) **468**

Ontario business-research institute tax credit (from Schedule 568) **470** 31,360

Subtotal 1,143,727 ▶ 1,143,727 J6

Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) **290** 6,260,874 K6
(if a credit, enter a negative amount) Include this amount on line 255.

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits **255** 6,260,874

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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Schedule 6

Summary of Dispositions of Capital Property

Corporation's name	Business number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2016-12-31

- Use this schedule if your corporation disposed of (actual or deemed) capital property or claimed an allowable business investment loss (ABIL), or both, in the tax year.
- Also use this schedule to make a designation under paragraph 111(4)(e) of the *Income Tax Act* if control of the corporation has been acquired by a person or a group of persons.
- For more information, see the section called "Schedule 6, Summary of Dispositions of Capital Property" in Guide T4012, *T2 Corporation – Income Tax Guide*.

Designation under paragraph 111(4)(e) of the Income Tax Act

Are any dispositions shown on this schedule related to deemed dispositions designated under paragraph 111(4)(e)? . . . . . 050 1 Yes ☐ 2 No ☒

If **yes**, attach a statement specifying which properties such a designation applies to.

Part 1 – Shares

1 Number of shares 100	2 Name of corporation in which the shares are held 105	3 Class of shares 106	4 Date of Acquisition YYYY/MM/DD 110	5 Proceeds of disposition 120	6 Adjusted cost base 130	7 Outlays and expenses from disposition 140	8 Gain (or loss) (column 5 **minus** columns 6 and 7) 150	Foreign source
			Totals					

Total adjustment under subsection 112(3) of the Act to all losses identified in Part 1 160

Actual gain or loss from the disposition of shares (total of column 8 **plus** line 160) . . . . . **A**

Part 2 – Real estate (Do not include losses on depreciable property)

	1 Municipal address of real estate (1 = Address 1, 2 = Address 2, 3 = City, 4 = Province, Country, Postal Code and Zip Code or Foreign Postal Code) 200	2 Date of Acquisition YYYY/MM/DD 210	3 Proceeds of disposition 220	4 Adjusted cost base 230	5 Outlays and expenses from disposition 240	6 Gain (or loss) (column 3 **minus** columns 4 and 5) 250	Foreign source
1	750 Huntingwood Drive		422,000	173,502	27,491	221,007	
2	169 Goulding Avenue		2,000,000	172,578	418,008	1,409,414	
	Totals		2,422,000	346,080	445,499	1,630,421	**B**

Part 3 – Bonds

1 Face value of bonds 300	2 Maturity date YYYY/MM/DD 305	3 Name of bond issuer 307	4 Date of Acquisition YYYY/MM/DD 310	5 Proceeds of disposition 320	6 Adjusted cost base 330	7 Outlays and expenses from disposition 340	8 Gain (or loss) (column 5 **minus** columns 6 and 7) 350	Foreign source
			Totals					**C**

Part 4 – Other properties (Do not include losses on depreciable property)

1 Description of other property 400	2 Date of Acquisition YYYY/MM/DD 410	3 Proceeds of disposition 420	4 Adjusted cost base 430	5 Outlays and expenses from disposition 440	6 Gain (or loss) (column 3 **minus** columns 4 and 5) 450	Foreign source
Totals						**D**

Note
Other property includes capital debts established as bad debts, as well as amounts that arise from foreign currency transactions.

Part 5 – Personal-use property (Do not include listed personal property)

1 Description of personal-use property 500	2 Date of Acquisition YYYY/MM/DD 510	3 Proceeds of disposition 520	4 Adjusted cost base 530	5 Outlays and expenses from disposition 540	6 Gain only (column 3 **minus** columns 4 and 5; if negative, enter "0") 550	Foreign source
Totals						**E**

Note
You cannot deduct losses on dispositions of personal-use property (other than listed personal property) from your income.

Part 6 – Listed personal property

1 Description of listed personal property 600	2 Date of Acquisition YYYY/MM/DD 610	3 Proceeds of disposition 620	4 Adjusted cost base 630	5 Outlays and expenses from disposition 640	6 Gain (or loss) (column 3 **minus** columns 4 and 5) 650	Foreign source
Totals						

Deduct: Unapplied listed personal property losses from other years (amount from line 530 of Schedule 4, *Corporation Loss Continuity and Application*) . . . . . 655 _____

Net gains (or losses) from the disposition of listed personal property (total of column 6 **minus** line 655) . . . . . _____ **F**

Note
Net listed personal property losses can only be applied against listed personal property gains.

Part 7 – Property qualifying for and resulting in an allowable business investment loss

1 Name of small business corporation 900	2 Shares, enter 1; debt, enter 2 905	3 Date of Acquisition YYYY/MM/DD 910	4 Proceeds of disposition 920	5 Adjusted cost base 930	6 Outlays and expenses from disposition 940	7 Loss only (column 4 **minus** columns 5 and 6) 950	Foreign source
Totals							

Allowable business investment losses (ABILs) . . . . . Total of Column 7 _____ x 50.0000 % = _____ **G**

Enter amount G on line 406 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*.

Note
Properties listed in Part 7 should not be included in any other parts of this schedule.

Part 8 – Capital gains or losses

Total of amounts A to F (do not include amount F if it is a loss) . . . . . 1,630,421 H

Add:

Foreign source

Capital gains dividend received in the year . . . . . **875** I ☐

Capital gains reserve opening balance (from Part 1 of Schedule 13, *Continuity of Reserves,* enter the amount from line 8, *Balance at the beginning of the year* **plus** the amount from line 9, *Transfer on an amalgamation or the wind–up of a subsidiary*) . . . . . **880** J

Subtotal (total of amounts H to J) 1,630,421 K

Deduct: Capital gains reserve closing balance (from Schedule 13) . . . . . **885** L

Capital gains or losses, excluding ABILs (amount K **minus** amount L) . . . . . **890** 1,630,421 M

Part 9 – Taxable capital gains and total capital losses

Capital gains or losses, excluding ABILs (amount from line 890 in Part 8) . . . . . 1,630,421 N

Deduct the following amounts included in amount N, that are subject to the zero inclusion rate:

Note

When a taxpayer is entitled to an advantage in respect of a donation, the zero inclusion rate is restricted to only part of the taxpayer's capital gain on disposition of the property. See section 38.2 of the Act for more information.

Foreign source

Gain on the donation to a qualified donee of a share, debt obligation, or right listed on a designated stock exchange and other securities under subparagraphs 38(a.1)(i) and (iii) of the Act . . . . . **895** a ☐

Foreign source

Gain on the donation to a qualified donee of ecologically sensitive land under paragraph 38(a.2) of the Act* . . . . . **896** b ☐

Foreign source

Exempt portion of the gain on the donation of securities arising from the exchange of a partnership interest under paragraph 38(*a.3*) . . . . . b-2 ☐

Subtotal (amount a **plus** amount b **plus** b-2) ▶ O

Subtotal (amount N **minus** amount O) 1,630,421 P

Add:

Deemed capital gain from the donation of property included in a flow-through share class of property to a qualified donee under subsection 40(12) of the Act:

Exemption threshold at time of disposition . . . . . **897** c

The total of all capital gains from the disposition of the actual property . . . . . **898** d

Foreign source

Amount c or amount d, whichever is less Q ☐

Taxable capital gains under section 34.2 of the Act (line 275 of Schedule 73, *Income Inclusion Summary for Corporations that are Members of Partnerships*) . . . . . x 2 = **899** R

Subtotal (total of amounts P to R) 1,630,421 S

Deduct:

Allowable capital losses under section 34.2 of the Act (line 285 of Schedule 73, *Income Inclusion Summary for Corporations that are Members of Partnerships*) . . . . . x 2 = **901** T

Total capital gains or losses (amount S **minus** amount T) 1,630,421 U

Taxable capital gains or total capital losses

Total capital losses (amount U, if amount U is negative; if amount U is positive, enter "0") V

Enter amount V on line 210 of Schedule 4.

Taxable capital gains (if amount U is positive, enter amount U 1,630,421 multiplied by 50.0000 %; if amount U is negative, enter "0") . . . . . 815,211 W

Enter amount W on line 113 of Schedule 1.

***** Do not include gains on donations of ecologically sensitive land to a private foundation.

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Schedule 7

Aggregate Investment Income and Active Business Income

Corporation's name	Business number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2016-12-31

- This schedule is for the use of Canadian-controlled private corporations (CCPCs) to calculate:
  - for the purpose of determining the refundable portion of Part I tax, aggregate investment income and foreign investment income, as defined in subsection 129(4) of the *Income Tax Act;*
  - specified partnership income, when the CCPC is a member of one or more partnership(s); and
  - income from an active business carried on in Canada for the small business deduction.
- For more information, see the sections called "Small Business Deduction" and "Refundable Portion of Part I Tax" in Guide T4012, *T2 Corporation – Income Tax Guide.*

Part 1 – Aggregate investment income

The aggregate investment income is the aggregate **world** source income.

Eligible portion of taxable capital gains for the year . . . . . **002** 815,211 A

Deduct:

Eligible portion of allowable capital losses for the year (including allowable business investment losses) . . . . . **012** a

Net capital losses of previous years claimed on line 332 on the T2 return . . . . . **022** b

Subtotal (amount a **plus** amount b) ▶ B

Amount A **minus** amount B (if negative, enter "0") 815,211 C

Total income from property (include income from a specified investment business carried on in Canada other than income from a source outside Canada) . . . . . **032** c

Deduct:

Exempt income **042** 1

Amounts received from AgriInvest Fund No. 2 that were included in computing the corporation's income for the year **052** 2

Taxable dividends deductible (total of column F on Schedule 3 **minus** related expenses) **062** 3

Business income from an interest in a trust that is considered property income under paragraph 108(5)(a) . **072** 4

Subtotal (**add** amounts 1 to 4) ▶ d

Subtotal (amount c **minus** amount d) ▶ D

Amount C **plus** amount D 815,211 E

Total losses from property (include losses from a specified investment business carried on in Canada other than a loss from a source outside Canada) . . . . . **082** F

Amount E **minus** amount F (if negative, enter "0") . . . . . **092** 815,211 G

Enter amount G on line 440 of the T2 return.

Part 2A – Canadian investment income calculation

Eligible portion of taxable capital gains for the year before taking into account the capital gains reserve (federal) of Schedule 13	815,211	1.1	
Reserve's eligible portion (addition/deduction)		1.2	
Taxable capital gains under section 34.2 of the ITA		1.3	
The eligible portion of taxable capital gains for the year after taking into account the capital gains reserve (federal) of Schedule 13 (total of amounts 1.1, 1.2 and 1.3) ▶	815,211		815,211 1a
Deduct:			
Eligible portion of allowable capital losses for the year (including allowable business investment losses)		2a	
Net capital losses of previous years of other years claimed on line 332 on the T2 return		3a	
Allowable capital losses under section 34.2 of the ITA		3.1	
Total of amounts 2a, 3a and 3.1 ▶			4a
Amount 1a **minus** amount 4a (if negative, enter "0")			815,211 5a
Taxable dividends		6.1	
Rental property income (under regulation 1100(11))		6.2	
Other property income		6.3	
Property income under section 34.2 of the ITA (line 280 of Schedule 73, *Income Inclusion Summary for Corporations that are Members of Partnerships*)		6.4	
Total property income from **Canadian** sources ▶			6a
Deduct:			
Exempt income		7a	
Amounts received from AgriInvest Fund No. 2 that were included in computing the corporation's income for the year		8a	
Taxable dividends deductible (total of column F on Schedule 3 **minus** related expenses)		9a	
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a)		10a	
Total of amounts 7a to 10a ▶			11a
Amount 6a **minus** amount 11a			12a
Amount 5a **plus** amount 12a			815,211 13a
Rental property losses (under regulation 1100(11))		14.1	
Dividend losses		14.2	
Other property losses		14.3	
Property losses under section 34.2 of the ITA (line 280 of Schedule 73, *Income Inclusion Summary for Corporations that are Members of Partnerships*)		14.4	
Total property losses from **Canadian** sources ▶			14a
Amount 13a **minus** amount 14a (if negative, enter "0")			815,211 15a

Part 2 – Foreign investment income

The foreign investment income is all income from sources **outside Canada**.

Eligible portion of taxable capital gains for the year before taking into account the capital gains reserve (federal) of Schedule 13 . . . . . H1

Reserve's eligible portion (addition/deduction) H2

Taxable capital gains under section 34.2 of the ITA* H3

Eligible portion of taxable capital gains for the year after taking into account the capital gains reserve (federal) of Schedule 13 (total of amounts H1, H2 and H3) . . . . . ▶ 001 H

Allowable capital losses for the year I1

Allowable capital losses under section 34.2 of the ITA* I2

Eligible portion of allowable capital losses for the year (including allowable business investment losses) (total of amounts I1 and I2) . . . . . ▶ 009 I

Subtotal (amount H **minus** amount I) (if negative, enter "0") J

Taxable dividends e1

Rental property income (under regulation 1100(11)) e2

Other property income e3

Property income under section 34.2 of the ITA (line 280 of Schedule 73, *Income Inclusion Summary for Corporations that are Members of Partnerships*)* e4

Total income from property from a source **outside Canada** (net of related expenses) . . . . . ▶ 019 e

Deduct:

Exempt income 029 5

Taxable dividends deductible (total of column F on Schedule 3 **minus** related expenses) 049 6

Business income from an interest in a trust that is considered property income under paragraph 108(5)(a) . 059 7

Subtotal (**add** amounts 5 to 7) ▶ f

Subtotal (amount e **minus** amount f) ▶ K

Amount J **plus** amount K L

Rental property losses (under regulation 1100(11)) M1

Dividend losses M2

Other property losses M3

Property losses under section 34.2 of the ITA (line 280 of Schedule 73, *Income Inclusion Summary for Corporations that are Members of Partnerships*)* M4

Total losses from property from a source **outside Canada** . . . . . ▶ 069 M

Amount L **minus** amount M (if negative, enter "0") . . . . . 079 N

(enter amount N on line 445 of the T2 return)

* When an amount is entered on these lines, the amounts calculated for the taxable capital gains or allowable capital losses on lines 1.3 and 3.1 as well as property income or losses on lines 6.4 and 14.3 in Part 2A, "Canadian investment income calculation" are automatically updated. For more details, press F1 to consult the Help.

Net taxable dividends	Canadian	Foreign	Total
Taxable dividends deducted per schedule 3			
Less: Expenses related to such dividends			
Total expenses			
Net taxable dividends			

Part 3 – Specified partnership income

	A		B
Is the corporation a designated member of the partnership?*	Partnership name **200**	Partnership's account number	Total income (loss) of partnership from an active business **300**
Yes / No			

C	D1	D2	D3	D	E
Corporation's share of amount column B **310**	Adjustment under section 34.2**	Expenses incurred to earn partnership income	Income amount earned by the corporation for the year from the provision of services or property to the partnership*	Adjustments (column D1 **minus** column D2 **plus** column D3) **315**	Corporation's income (loss) of the partnership (column C **plus** column D) **320**
				Total	**350**

E1	E2	F	G	H	I
Amount assigned by a member of the partnership to the corporation that is a designated member of the partnership*	Specified partnership's business limit amount assigned by the corporation to a designated member of the partnership*	Number of days in the partnership's fiscal period **325**	Prorated business limit or assigned amount*** **330**	Column E **minus** column G (if negative, enter "0")	Lesser of columns E and G (if column E is negative, enter "0") **340**
				Total **385**	**360**

Corporation's losses for the year from an active business carried on in Canada (other than as a member of a partnership) – enter as a positive amount . . . . . **370** _____ g

Specified partnership loss of the corporation for the year – enter as a positive amount (total of all negative amounts in column E) . . . . . **380** _____ h

Subtotal (amount g **plus** amount h) _____ i

Amount at line 385 or amount i, whichever is less . . . . . **390** _____ O

Specified partnership income (line 360 **plus** amount O) . . . . . **400** _____ P

Enter amount P at line T in Part 4.

Part 3 – Specified partnership income (continued)

* As a result of the tabling of Bill C-29, *A second Act to implement certain provisions of the budget tabled in Parliament on March 22, 2016 and other measures*, on October 25, 2016, modifications have been made to the calculations of the specified partnership's income. For more information, consult the Help (F1).

** In general, amounts included under subsections 34.2(2), (3), and (12) or claimed under subsections 34.2(4) and (11) are deemed to have the **same character** and be in the **same proportions** as the partnership income they relate to. For example, if a corporation receives $100,000 of partnership income for the partnership's fiscal period ending in its tax year, and that income is made up of $40,000 of active business income, $30,000 of income from property, and $30,000 as a taxable capital gain, the corporation's adjusted stub period accrual (ASPA) in respect of the partnership would be 40% active business income, 30% property income, and 30% taxable capital gains. Add or deduct **only the portion** of the following amounts that is deemed under subsection 34.2(5) to be **active business income**:

Add:

– the ASPA under subsection 34.2(2) (column 4 of Schedule 73)

– the income inclusion for a new corporate member of a partnership under subsection 34.2(3) (column 6 of Schedule 73)

– the previous-year transitional reserve under subsection 34.2(12) (column 12 of Schedule 73)

Deduct:

– the previous-year ASPA under subsection 34.2(4) (column 5 of Schedule 73)

– the previous-year income inclusion for a new corporate member of a partnership under subsection 34.2(4) (column 7 of Schedule 73)

– the current-year transitional reserve under subsection 34.2(11) (column 11 of Schedule 73)

*** When the corporation is a member of the partnership, Column G is equal to the result of the following equation: (column C ÷ column B) x ($500,000 x (column F ÷ 365)) - column E2. If the total in column C is negative, enter “0.”

When a partnership carries on more than one business, one of which generates income and another of which realizes a loss, the loss is not netted against the partnership's income for the purpose of calculating the prorated business limit in column G. Enter on line h the total of all loss from column E.

When the corporation is a designated member of the partnership, Column G is equal to the amount in column E1.

Part 4 – Partnership income not eligible for the small business deduction

Corporation's share of partnership income from active businesses carried on in Canada after deducting related expenses – from line 350 in Part 3 (if the net amount is negative, enter "0" on line U)		Q
Specified partnership loss (from amount h in Part 3)		R
Subtotal (amount Q **plus** amount R)		S
Deduct:		
Specified partnership income (from amount P in Part 3)		T
Partnership income not eligible for the small business deduction (amount S **minus** amount T) (enter on line p in Part 5)	450	U

Part 5 – Income from active business carried on in Canada

Net income for income tax purposes from line 300 of the T2 return		90,427,842	j	
Plus:				
Allowable business investment loss from line 406 of Schedule 1			k	
Subtotal (amount j **plus** amount k)		90,427,842 ▶		90,427,842 V
Deduct:				
Foreign business income after deducting related expenses*	500		l	
Taxable capital gains from line 113 of Schedule 1		815,211	m	
Net property income (amount c** **minus** amounts 1, 2, and F* in Part 1)			n	
Personal services business income and other income after deducting related expenses*	520		o	
Corporate income not eligible for the small business deduction (amount A minus B from part 6)***			o.1	
Income deemed to be active business income under subsection 129(6) ITA from an associated corporation that is not a CCPC or that is a CCPC that elects to be a third corporation under subsection 256(2)ITA***			o.2	
Subtotal (**add** amounts l to o.2)		815,211 ▶		815,211 W
Net amount (amount V **minus** amount W)				89,612,631 X
Deduct:				
Partnership income not eligible for the small business deduction (amount U in Part 4)			p	
Income allocated to the corporation under subsection 96(1.1)	530		q	
Subtotal (amount p **plus** amount q)		▶		Y
Income from active business carried on in Canada (amount X **minus** amount Y)				89,612,631 Z

(enter amount Z on line 400 of the T2 return - if negative, enter "0")

* If negative, enter amount in brackets, and **add** instead of **subtracting**.

** Net of related expenses.

*** As a result of the tabling of Bill C-29, *A second Act to implement certain provisions of the budget tabled in Parliament on March 22, 2016 and other measures*, on October 25, 2016, modifications have been made to the calculations of the income from active business. For more information, consult the Help (F1).

Part 6 – Specified corporate income and assignment under subsection 125(3.2)

A CCPC with a tax year starting before March 22, 2016 can assign part or all of its business limit to your corporation for the 2016 tax year if the tax year of your corporation started after March 21, 2016.

	1 Name of corporation assigning business limit	2 Business number of the corporation assigning business limit	3 Income not eligible for the small business deduction **received from** the corporation identified in column 1 [under clause 125(1)(a)(i)(B)]*	4 Business limit assigned **from** Corporation identified in column 1**
1				

Total A _____ Total B _____

* This amount is [as defined in subsection 125(7) **specified corporate income** (a)(i)] the total of all amounts each of which is income from an active business of the corporation for the year from the provision of services or property to a private corporation (directly or indirectly, in any manner whatever) if

(A) at any time in the year, the corporation (or one of its shareholders) or a person who does not deal at arm's length with the corporation (or one of its shareholders) holds a direct or indirect interest in the private corporation, and

(B) it is not the case that all or substantially all of the corporation's income for the year from an active business is from the provision of services or property to

(I) persons (other than the private corporation) with which the corporation deals at arm's length, or

(II) partnerships with which the corporation deals at arm's length, other than a partnership in which a person that does not deal at arm's length with the corporation holds a direct or indirect interest.

** The amount of business limit assigned in column 4 **cannot** be more than column 3.

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Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business Number	Tax year end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2016-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under *Regulation* 1101(5q)? **101** 1 Yes ☐ 2 No ☒

	1 Class number (See Note) **200**	Description	2 Undepreciated capital cost at the beginning of the year (amount from column 12 of last year's schedule 8) **201**	3 Cost of acquisitions during the year (new property must be available for use)* **203**	4 Adjustments and transfers** **205**	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) **207**	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** **211**	7 Reduced undepreciated capital cost	8 CCA rate % **** **212**	9 Recapture of capital cost allowance***** (line 107 of Schedule 1) **213**	10 Terminal loss (line 404 of Schedule 1) **215**	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ****** **217**	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) **220**
1.	1		1,037,708,320	55,682,124		221,419	27,730,353	1,065,438,672	4	0	0	42,617,547	1,050,551,478
2.	8		23,336,568	7,878,985		0	3,939,493	27,276,060	20	0	0	5,455,212	25,760,341
3.	10		10,313,061	3,412,059		71,045	1,670,507	11,983,568	30	0	0	3,595,070	10,059,005
4.	12		6,803,517	10,088,375		0	5,044,188	11,847,704	100	0	0	11,847,704	5,044,188
5.	17		20,988,930	2,916,879		39,710	1,438,585	22,427,514	8	0	0	1,794,201	22,071,898
6.	2		273,664,743			0		273,664,743	6	0	0	16,419,885	257,244,858
7.		CWIP	566,645,539		-70,555,724	0		496,089,815	0	0	0		496,089,815
8.	45	computer hardware	24,702			0		24,702	45	0	0	11,116	13,586
9.	47	ELECTRICITY DISTRIBUTION EQ	1,770,735,464	379,714,138		0	189,857,069	1,960,592,533	8	0	0	156,847,403	1,993,602,199
10.	13	2006 Additions				0			NA	0	0		
11.	13	2007 Additions				0			NA	0	0		
12.	42	Fibre	28,970	4,902,732		0	2,451,366	2,480,336	12	0	0	297,640	4,634,062
13.	50	Computers acquired after March	11,663,603	20,308,499		0	10,154,250	21,817,852	55	0	0	11,999,819	19,972,283
14.	13	2008 Additions				0			NA	0	0		
15.	13	2009 Additions				0			NA	0	0		
16.	13	2010 Additions				0			NA	0	0		
17.	43.2		949,467	2,463,651		0	1,231,826	2,181,292	50	0	0	1,090,646	2,322,472
18.	13	2011 Additions	19,181			0		19,181	NA	0	0	19,181	
19.	13	2012 additions	176,240			0		176,240	NA	0	0	117,492	58,748
20.	46		143,700	21,481,106		0	10,740,553	10,884,253	30	0	0	3,265,276	18,359,530
21.	13	2014 addition	36,684			0		36,684	NA	0	0	10,481	26,203
22.	6		1,720,988	351,806		0	175,903	1,896,891	10	0	0	189,689	1,883,105
		Totals	3,724,959,677	509,200,354	-70,555,724	332,174	254,434,093	3,908,838,040				255,578,362	3,907,693,771

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see *Regulation* 1100(2) and (2.2).

** Enter in column 4, "Adjustments and transfers", amounts that increase or reduce the undepreciated capital cost. Items that **increase** the undepreciated capital cost include amounts transferred under section 85, or transferred on amalgamation or winding-up of a subsidiary. Items that **reduce** the undepreciated capital cost include government assistance received or entitled to be received in the year, or a reduction of capital cost after the application of section 80. See the *T2 Corporation Income Tax Guide* for other examples of adjustments and transfers to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments and transfers from column 4. For information on the exceptions to the 50% rule, as well as how to calculate the amounts to enter in column 6 in those cases, see Interpretation Bulletin IT-285, *Capital Cost Allowance - General Comments*.

**** Enter a rate only if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** For every entry in column 9, the "Recapture of capital cost allowance" there must be a corresponding entry in column 5, "Proceeds of dispositions during the year". The recapture and terminal loss rules do not apply to passenger vehicles in Class 10.1.

****** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

T2 SCH 8 (14)

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2016-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	TORONTO HYDRO CORPORATION		[redacted]	1					
2.	TORONTO HYDRO ENERGY SERVIC			3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11)

Canada

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2016-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0") . . . . . **200** 20,633,148 A

Add: Cost of eligible capital property acquired during the taxation year **222** 46,671,653

Other adjustments **226**

Subtotal (line 222 plus line 226) 46,671,653 x 3 / 4 = 35,003,740 B

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 . . . . . **228** x 1 / 2 = C

amount B minus amount C (if negative, enter "0") 35,003,740 ▶ 35,003,740 D

Amount transferred on amalgamation or wind-up of subsidiary . . . . . **224** E

Subtotal (add amounts A, D, and E) **230** 55,636,888 F

Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year . . . . **242** G

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) . . . . . **244** H

Other adjustments . . . . . **246** I

(add amounts G,H, and I) x 3 / 4 = **248** J

Cumulative eligible capital balance (amount F minus amount J) . . . . . 55,636,888 K

(if amount K is negative, enter "0" at line M and proceed to Part 2)

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business **249**

amount K 55,636,888

less amount from line 249

Current year deduction . . . . . 55,636,888 x 7.00 % = **250** 3,894,582 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 3,894,582 ▶ 3,894,582 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") . . . . . **300** 51,742,306 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)				N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988	400		1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)	401		2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402		3	
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408		4	
Line 3 minus line 4 (if negative, enter "0")		▶	5	
Total of lines 1, 2 and 5			6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400			7	
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000			8	
Subtotal (line 7 plus line 8)	409	▶	9	
Line 6 minus line 9 (if negative, enter "0")		▶		O
Line N minus line O (if negative, enter "0")				P
Line 5 _____ x 1 / 2 =				Q
Line P minus line Q (if negative, enter "0")				R
Amount R _____ x 2 / 3 =				S
Amount N or amount O, whichever is less				T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)	410			

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1	POEB	296,520,000			16,035,000	280,485,000
2	Termination Accrual	137,273		90,419		227,692
	Reserves from Part 2 of Schedule 13					
	Totals	296,657,273		90,419	16,035,000	280,712,692

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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Schedule 23

Agreement Among Associated Canadian-Controlled Private Corporations to Allocate the Business Limit

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* not to be associated for purposes of the small business deduction.

Column 2: Provide the business number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code from the list below that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)
2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 – Associated non-CCPC
5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A.

Ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . . 025 — Year Month Day

Enter the calendar year to which the agreement applies . . . . . 050 — Year: 2016

Is this an amended agreement for the above calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . 075 — 1 Yes ☐ 2 No ☒

	1 Names of associated corporations 100	2 Business number of associated corporations 200	3 Asso-ciation code 300	4 Business limit for the year before the allocation $	5 Percentage of the business limit % 350	6 Business limit allocated* $ 400
1	TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	1	500,000	100.0000	500,000
2	TORONTO HYDRO CORPORATION		1	500,000		
3	TORONTO HYDRO ENERGY SERVICES INC.		1	500,000		
				Total	100.0000	500,000 A

Business limit reduction under subsection 125(5.1) of the Act

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "large corporation amount" at line 415 of the T2 return. The amount at line 415 is determined using the formula 0.225% x (D - $10,000,000). Details of this formula and variable D are in subsection 125(5.1) of the Act.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules for business limit

Special rules apply under subsection 125(5) if a CCPC has more than one tax year ending in the same calendar year and it is associated in more than one of those tax years with another CCPC that has a tax year ending in that calendar year. The business limit for the second or later tax year will be equal to the business limit determined for the first tax year ending in the calendar year or the business limit determined for the second or later tax year ending in the same calendar year, whichever is less.

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Schedule 31

Investment Tax Credit – Corporations

General information

- Use this schedule:
  - to calculate an investment tax credit (ITC) earned during the tax year;
  - to claim a deduction against Part I tax payable;
  - to claim a refund of credit earned during the current tax year;
  - to claim a carryforward of credit from previous tax years;
  - to transfer a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1);
  - to request a credit carryback to one or more previous years; or
  - if you are subject to a recapture of ITC.
- Unless otherwise noted, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward.
- Investments or expenditures, described in subsection 127(9) and Regulation Part XLVI, that earn an ITC are:
  - qualified property and qualified resource property (Parts 4 to 7 of this schedule);
  - expenditures that are part of the scientific research and experimental development (SR&ED) qualified expenditure pool (Parts 8 to 17). File Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*;
  - pre-production mining expenditures (Parts 18 to 20);
  - apprenticeship job creation expenditures (Parts 21 to 23); and
  - child care spaces expenditures (Parts 24 to 28).
- Include a completed copy of this schedule with the *T2 Corporation Income Tax Return*. If you need more space, attach additional schedules.
- For more information on ITCs, see "Investment Tax Credit" in Guide T4012, *T2 Corporation – Income Tax Guide*, Information Circular IC78-4, *Investment Tax Credit Rates*, and its related Special Release.
- For more information on SR&ED, see T4088, *Guide to Form T661 – Scientific Research and Experimental Development (SR&ED) Expenditures Claim*. Also see the *Eligibility of Work for SR&ED Investment Tax Credits Policy* at **cra.gc.ca/txcrdt/sred-rsde/clmng/lgbltywrkfrsrdnvstmnttxcrdts-eng.html**.

Detailed information

- For the purpose of this schedule, **investment** means the capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
- An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces both the capital cost of that property and the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
- Property acquired has to be **available for use** before a claim for an ITC can be made. See subsections 127(11.2) and 248(19) for more information.
- Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures or capital costs.
- Expenditures for pre-production mining, apprenticeship, or child care space for an ITC must be identified by the claimant on Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures or capital costs.
- Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 is not applicable for the agreement to share any income or loss. Special rules apply to specified and limited partners. For more information, see Guide T4068, *Guide for the Partnership Information Return*.
- For SR&ED expenditures, the expression **in Canada** includes the "exclusive economic zone" (as defined in the *Oceans Act* to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone.
- For the purpose of this schedule, the expression **Atlantic Canada** includes the Gaspé Peninsula and the provinces of Newfoundland and Labrador, Prince Edward Island, Nova Scotia, and New Brunswick, as well as their respective offshore regions (prescribed in Regulation 4609).
- For the purpose of this schedule, **qualified property** means property in Atlantic Canada that is used primarily for manufacturing and processing, farming or fishing, logging, storing grain, or harvesting peat. Property in Atlantic Canada that is used primarily for oil and gas, and mining activities is considered qualified property only if acquired by the taxpayer **before** March 29, 2012. Qualified property includes new buildings and new machinery and equipment (prescribed in Regulation 4600), and if acquired by the taxpayer **after** March 28, 2012, new energy generation and conservation property (prescribed in Regulation 4600). Qualified property can also be used primarily to produce or process electrical energy or steam in a prescribed area (as described in Regulation 4610). See the definition of **qualified property** in subsection 127(9) for more information.

Detailed information (continued)

- For the purpose of this schedule, **qualified resource property** means property in Atlantic Canada that is used primarily for oil and gas, and mining activities, if acquired by the taxpayer **after** March 28, 2012, and **before** January 1, 2016. Qualified resource property includes new buildings and new machinery and equipment (prescribed in Regulation 4600). See the definition of **qualified resource property** in subsection 127(9) for more information.
- For the purpose of this schedule, **pre-production mining exploration expenditures** are pre-production mining expenditures incurred **after** March 28, 2012, by the taxpayer to determine the existence, location, extent, or quality of certain mineral resources in Canada, excluding expenses incurred in the exploration of an oil or gas well. See subparagraph (a)(i) of the definition of **pre-production mining expenditure** in subsection 127(9) for more information.
- For the purpose of this schedule, **pre-production mining development expenditures** are pre-production mining expenditures incurred **after** March 28, 2012, by the taxpayer to bring a new mineral resource mine in Canada into production, excluding expenses in the development of a bituminous sands deposit or an oil shale deposit. See subparagraph (a)(ii) of the definition of **pre-production mining expenditure** in subsection 127(9) for more information.

Part 1 – Investments, expenditures, and percentages

Investments	**Specified percentage**
Qualified property acquired primarily for use in Atlantic Canada	10 %
Qualified resource property acquired primarily for use in Atlantic Canada and acquired:	
– after March 28, 2012, and before 2014	10 %
– after 2013 and before 2016	5 %
– after 2015*	0 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than your expenditure limit (see Part 10 on page 5), the excess is eligible for an ITC calculated at the 20 % rate**.	
If you are a corporation that is not a CCPC and have incurred qualified expenditures for SR&ED in any area in Canada:	
– before 2014**	20 %
– after 2013**	15 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures before March 29, 2012	10 %
If you are a taxable Canadian corporation that incurred pre-production mining exploration expenditures:	
– after March 28, 2012, and before 2013	10 %
– in 2013	5 %
– after 2013	0 %
If you are a taxable Canadian corporation that incurred pre-production mining development expenditures***:	
– after March 28, 2012, and before 2014	10 %
– in 2014	7 %
– in 2015	4 %
– after 2015	0 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment	10 %
If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

* A transitional relief rate of 10% may apply to property acquired after 2013 and before 2017, if the property is acquired under a written agreement entered into before March 29, 2012, or the property is acquired as part of a **phase** of a project where the construction or the engineering and design work for the construction started before March 29, 2012. See paragraph (a.1) of the definition of **specified percentage** in subsection 127(9) for more information.

** The reduction of the rate from 20% to 15% applies to 2014 and later tax years, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013.

*** A transitional relief rate may apply to expenditures incurred after 2013 and before 2016, if the expenditure is incurred under a written agreement entered into before March 29, 2012, or the expenditure is incurred as part of the development of a new mine where the construction or the engineering and design work for the construction of the new mine started before March 29, 2012. See subparagraphs (k)(ii) and (iii) of the definition of **specified percentage** in subsection 127(9) for more information.

Corporation's name	Business number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2016-12-31

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? . . . . . **101** 1 Yes ☐ 2 No ☒

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and its taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC considered associated with another corporation under subsection 256(1) will be considered **not** associated for the calculation of a refundable ITC if:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;

b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or

c) any combination of persons referred to in a) or b) above.

* Capital expenditures incurred after December 31, 2013, including lease payments for property that would have been a capital expenditure if purchased directly, are **not** qualified SR&ED expenditures and are **not** eligible for an ITC on SR&ED expenditures.

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions.

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . . . **102** 1 Yes ☐ 2 No ☒

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in.

Contributions to agricultural organizations for SR&ED* . . . . . **103** _____
(Enter this amount on line 350 of Part 8)

* Enter only contributions not already included on Form T661.
Include 80% of the contributions made **after** 2012. For contributions made **before** 2013, include all of the contributions.

Qualified Property and Qualified Resource Property

Part 4 – Eligible investments for qualified property and qualified resource property from the current tax year

Capital cost allowance class number **105**	Description of investment **110**	Date available for use **115**	Location used in Atlantic Canada (province) **120**	Amount of investment **125**

Total of investments for qualified property and qualified resource property A1

Part 5 – Current-year credit and account balances – ITC from investments in qualified property and qualified resource property

ITC at the end of the previous tax year B1

Deduct:

Credit deemed as a remittance of co-op corporations 210

Credit expired 215

Subtotal (line 210 **plus** line 215) ▶ C1

ITC at the beginning of the tax year (amount B1 **minus** amount C1) 220

Add:

Credit transferred on amalgamation or wind-up of subsidiary 230

ITC from repayment of assistance 235

Qualified property; and qualified resource property acquired after March 28, 2012, and before January 1, 2014* (applicable part from amount A1 in Part 4) . . . . . x 10 % = 240

Qualified resource property acquired after December 31, 2013, and before January 1, 2016 (applicable part from amount A1 in Part 4) . . . . . x 5 % = 242

Credit allocated from a partnership 250

Subtotal (total of lines 230 to 250) ▶ D1

Total credit available (line 220 **plus** amount D1) E1

Deduct:

Credit deducted from Part I tax (enter this amount at line D8 in Part 30) 260

Credit carried back to the previous year(s) (from amount H1 in Part 6) . . . . . a

Credit transferred to offset Part VII tax liability 280

Subtotal (total of line 260, amount a, and line 280) ▶ F1

Credit balance before refund (amount E1 **minus** amount F1) G1

Deduct:

Refund of credit claimed on investments from qualified property and qualified resource property (from Part 7) 310

ITC closing balance of investments from qualified property and qualified resource property (amount G1 **minus** line 310) 320

* Include investments acquired after 2013 and before 2017 that are eligible for transitional relief.

Part 6 – Request for carryback of credit from investments in qualified property and qualified resource property

	Year	Month	Day
1st previous tax year			
2nd previous tax year			
3rd previous tax year			

Credit to be applied 901

Credit to be applied 902

Credit to be applied 903

Total of lines 901 to 903 (enter amount H1 on line a in Part 5) H1

Part 7 – Refund of ITC for qualifying corporations on investments from qualified property and qualified resource property

Current-year ITCs (total of lines 240, 242, and 250 in Part 5) I1

Credit balance before refund (from amount G1 in Part 5) J1

Refund (40 % of amount I1 or J1, whichever is less) K1

Enter amount K1 or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if you don't claim an SR&ED ITC refund).

SR&ED

Part 8 – Qualified SR&ED expenditures

Current expenditures (from line 557 on Form T661) 7,734,337

Contributions to agricultural organizations for SR&ED . . . . . _____

Deduct:

Government assistance, non-government assistance, or contract payment . . . . . _____

Contributions to agricultural organizations for SR&ED for the federal ITC (this amount is updated to line 103 of Part 3. For more details, consult the Help.)* . . . . . _____ ▶ + _____

Current expenditures (line 557 on Form T661 **plus** line 103 in Part 3)*	7,734,337 ▶	350	7,734,337
Capital expenditures incurred **before** 2014 (from line 558 on Form T661)**		360	
Repayments made in the year (from line 560 on Form T661)		370	
Qualified SR&ED expenditures (total of lines 350 to 370)		380	7,734,337

* If you are claiming only contributions made to agricultural organizations for SR&ED, line 350 should equal line 103 in Part 3. Do not file Form T661.

** Capital expenditures incurred after December 31, 2013, are not qualified SR&ED expenditures. Capital cost allowance can be claimed for depreciable property acquired for use in SR&ED after 2013.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if you are a CCPC.

Note: A CCPC considered associated with another corporation under subsection 256(1) will be considered not associated for the calculation of an SR&ED expenditure limit if:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? . . . . . 385 1 Yes [X] 2 No [ ]

If you answered **no** to the question on line 385 above or if you are not associated with any other corporations, complete lines 390 and 398.
If you answered **yes**, the amounts for associated corporations will be determined on Schedule 49.

Enter your taxable income for the previous tax year* (prior to any loss carrybacks applied) . . . . . 390 _____

Enter your taxable capital employed in Canada for the previous tax year minus $10 million. If this amount is nil or negative, enter "0".
If this amount is over $40 million, enter $40 million . . . . . 398 _____

* If the tax years referred to on line 390 is less than 51 weeks, **multiply** the taxable income by the following result: 365 **divided** by the number of days in that tax year.

Part 10 – SR&ED expenditure limit for a CCPC

For a stand-alone (not associated) corporation: $ 8,000,000

Deduct:

Taxable income for the previous tax year (from line 390 in Part 9) or $500,000, whichever is more _____ x 10 = _____ A2

Excess ($8,000,000 **minus** amount A2; if negative, enter "0") . . . . . _____ B2

$ 40,000,000 **minus** line 398 in Part 9 . . . . . _____ a

Amount a **divided** by $ 40,000,000 . . . . . _____ C2

Expenditure limit for the stand-alone corporation (amount B2 **multiplied** by amount C2)* . . . . . _____ D2

For an associated corporation:

If associated, the allocation of the SR&ED expenditure limit, as provided on Schedule 49* . . . . . 400 _____ E2

If your tax year is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Amount D2 or E2 _____ x Number of days in the tax year / 365 366 = ... _____ F2

Your SR&ED expenditure limit for the year (enter the amount from amount D2, E2, or F2, whichever applies) . . . . . 410 _____

* Amount D2 or E2 cannot be more than $3,000,000.

Part 11 – Investment tax credits on SR&ED expenditures

Current expenditures (from line 350 in Part 8) or the expenditure limit (from line 410 in Part 10), whichever is less* . . . . . **420** _____ x 35 % = _____ G2

Line 350 **minus** line 410 (if negative, enter "0") **430** 7,734,337

Amount from line 430 _____ x (Number of days in the tax year before 2014 / Number of days in the tax year) _____ x 20% = _____ b

Amount from line 430** 7,734,337 x (Number of days in the tax year after 2013 / Number of days in the tax year) 366 / 366 x 15 % = 1,160,151 c

Subtotal (amount b **plus** amount c) . . . . . 1,160,151 ▶ 1,160,151 H2

Line 410 **minus** line 350 (if negative, enter "0") . . . . . _____ d

Capital expenditures (from line 360 in Part 8) or amount d above, whichever is less* . . . . . **440** _____ x 35 % = _____ I2

Line 360 **minus** amount d above (if negative, enter "0") . . . . . **450** _____

Amount from line 450 _____ x (Number of days in the tax year before 2014 / Number of days in the tax year) _____ x 20% = _____ e

Amount from line 450** _____ x (Number of days in the tax year after 2013 / Number of days in the tax year) 366 / 366 x 15 % = _____ f

Subtotal (amount e **plus** amount f) . . . . . _____ ▶ _____ J2

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit.

Repayments (amount from line 370 in Part 8) . . . . . _____

The ITC on the repayment (the credit) is calculated using the ITC rate that you used to determine your ITC when your qualified expenditures for ITC purposes were reduced because of the government or non-government assistance, or contract payments. Enter the amount of the repayment on the line that corresponds to the appropriate rate. ***

460 _____ x 35 % = _____ g

480 _____ x 20 % = _____ h

490 _____ x 15 % = _____ i

Subtotal (**add** amounts g to i) _____ ▶ _____ K2

Current-year SR&ED ITC (total of amounts G2 to K2; enter on line 540 in Part 12) 1,160,151 L2

* For corporations that are not CCPCs, enter "0" for amounts G2 and I2.

** For tax years that end after 2013, the general SR&ED ITC rate is reduced from 20% to 15%, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013. For tax years that have a start date **after** 2013, you can simply multiply the amount by 15%.

*** If you are reporting a repayment for a tax year which included two calendar years with different rates (such as a 2014 tax year that started in 2013), the amount of repayment is allocated between the two ITC rates as follows:

- For the first part of the tax year, enter on the line next to the applicable ITC rate, the result of the following calculation: The full repayment amount **multiplied** by the number of days in the tax year which were in the first calendar year, **divided** by the total number of days in the tax year.
- For the last part of the tax year which is in the second calendar year, enter on the line next to the applicable ITC rate, the difference between the first part calculated above and the full repayment amount.

Part 12 – Current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year				M2
Deduct:				
Credit deemed as a remittance of co-op corporations	510			
Credit expired	515			
Subtotal (line 510 **plus** line 515)			▶	N2
ITC at the beginning of the tax year (amount M2 **minus** amount N2)	520			
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	530			
Total current-year credit (from amount L2 in Part 11)	540	1,160,151		
Credit allocated from a partnership	550			
Subtotal (total of lines 530 to 550)		1,160,151	▶	1,160,151 O2
Total credit available (line 520 **plus** amount O2)				1,160,151 P2
Deduct:				
Credit deducted from Part I tax (enter this amount at line E8 in Part 30)	560	1,160,151		
Credit carried back to the previous year(s) (from amount S2 in Part 13)			j	
Credit transferred to offset Part VII tax liability	580			
Subtotal (total of line 560, amount j, and line 580)		1,160,151	▶	1,160,151 Q2
Credit balance before refund (amount P2 **minus** amount Q2)				R2
Deduct:				
Refund of credit claimed on SR&ED expenditures (from Part 14 or 15, whichever applies)	610			
ITC closing balance on SR&ED (amount R2 **minus** line 610)	620			

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	911	
2nd previous tax year				Credit to be applied	912	
3rd previous tax year				Credit to be applied	913	
				Total of lines 911 to 913 (enter amount S2 at line j in Part 12)		S2

Part 14 – Refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined on line 101 in Part 2.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? . . . . . **650** 1 Yes ☐ 2 No ☒

Current-year ITC (lines 540 **plus** 550 in Part 12 **minus** amount K2 in Part 11) . . . . . k

Refundable credits (amount k or amount R2 in Part 12, whichever is less)* T2

Deduct:

Amount T2 or amount G2 in Part 11, whichever is less U2

Net amount (amount T2 **minus** amount U2; if negative, enter "0") V2

Amount V2 **multiplied** by 40 % W2

Add:

Amount U2 . . . . . X2

Refund of ITC (amount W2 **plus** amount X2 – enter this, or a lesser amount, on line 610 in Part 12) Y2

Enter the total of line 310 in Part 5 and line 610 in Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation, as defined in subsection 127.1(2), this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC for amount Y2.

Part 15 – Refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined on line 101 in Part 2.

Credit balance before refund (from amount R2 in Part 12) Z2

Deduct:

Amount Z2 or amount G2 in Part 11, whichever is less AA2

Net amount (amount Z2 **minus** amount AA2; if negative, enter "0") BB2

Amount BB2 or amount I2 in Part 11, whichever is less CC2

Amount CC2 **multiplied** by 40 % DD2

Add :

Amount AA2 . . . . . EE2

Refund of ITC (amount DD2 **plus** amount EE2) FF2

Enter FF2, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

Recapture – SR&ED

Part 16 – Recapture of ITC for corporations and partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, and the credit was earned in a tax year ending after 1997 and did not expire before 2008;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

Note:

The recapture **does not apply** if you disposed of the property to a non-arm's-length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's-length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the **note** above **700**	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710**	Amount from column 700 or 710, whichever is less

Subtotal (enter amount A3 on line C3 in Part 17) A3

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil on line B3.

A Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement **720**	B Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition **730**	C Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) **740**	D Amount determined by the formula (A x B) – C	E ITC earned by the transferee for the qualified expenditures that were transferred **750**	F Amount from column D or E, whichever is less

Subtotal (total of column F) (enter amount B3 on line D3 in Part 17) B3

Part 16 – Recapture of ITC for corporations and partnerships – SR&ED (continued)

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 760.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported on line E3 in Part 17) **760** _____

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC from calculation 1, amount A3 in Part 16 . . . . . _____ C3

Recaptured ITC from calculation 2, amount B3 in Part 16 . . . . . _____ D3

Recaptured ITC from calculation 3, line 760 in Part 16 . . . . . _____ E3

Total recapture of SR&ED investment tax credit (total of amounts C3 to E3) . . . . . _____ F3

Enter amount F3 on line A8 in Part 29.

Pre-Production Mining

Part 18 – Pre-production mining expenditures

Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

For each of the minerals reported in column 800, identify each project (in column 805), mineral title (in column 806), and mining division (in column 807) where title is registered. If there is no mineral title, identify only the project and mining division.

List of minerals 800	Project name 805

Mineral title 806	Mining division 807

Pre-production mining expenditures*

Exploration:

Pre-production mining expenditures that you incurred in the tax year (**before** January 1, 2014) for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting 810

Geological, geophysical, or geochemical surveys 811

Drilling by rotary, diamond, percussion, or other methods 812

Trenching, digging test pits, and preliminary sampling 813

Development:

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping 820

Sinking a mine shaft, constructing an adit, or other underground entry 821

Other pre-production mining expenditures incurred in the tax year:

Description 825	Amount 826
Total of column 826	▶ A4

Total pre-production mining expenditures (total of lines 810 to 821 and amount A4) 830

Deduct:

Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to on line 830 above 832

Excess (line 830 **minus** line 832) (if negative, enter "0") B4

Add:

Repayments of government and non-government assistance 835

Pre-production mining expenditures (amount B4 **plus** line 835) C4

* A pre-production mining expenditure is defined under subsection 127(9).

Part 19 – Current-year credit and account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year D4

Deduct:

Credit deemed as a remittance of co-op corporations 841

Credit expired 845

Subtotal (line 841 **plus** line 845) ▶ E4

ITC at the beginning of the tax year (amount D4 **minus** amount E4) 850

Add:

Credit transferred on amalgamation or wind-up of subsidiary 860

Pre-production mining expenditures* incurred before January 1, 2013 (applicable part from amount C4 in Part 18)	870	x	10 %	=	a	
Pre-production mining exploration expenditures** incurred in 2013 (applicable part from amount C4 in Part 18)	872	x	5 %	=	b	
Pre-production mining development expenditures incurred in 2014 (applicable part from amount C4 in Part 18)	874	x	7 %	=	c	
Pre-production mining development expenditures incurred in 2015 (applicable part from amount C4 in Part 18)	876	x	4 %	=	d	

Current year credit (total of amounts a to d) 880 ▶ F4

Total credit available (total of lines 850, 860, and amount F4) G4

Deduct:

Credit deducted from Part I tax (enter this amount at line F8 in Part 30) 885

Credit carried back to the previous year(s) (from amount I4 in Part 20) . . . . . e

Subtotal (line 885 **plus** amount e) ▶ H4

ITC closing balance from pre-production mining expenditures (amount G4 **minus** amount H4) 890

* Also include pre-production mining development expenditures incurred before 2014 and pre-production mining development expenditures incurred after 2013 and before 2016 that are eligible for transitional relief.

** Also include pre-production mining development expenditures incurred in 2015 if the expense is described in paragraph (a)(ii) of the definition **pre-production mining expenditure** in subsection 127(9) of the Act because of paragraph (g.4) of the definition **Canadian exploration expense** in subsection 66.1(6) of the Act.

Part 20 – Request for carryback of credit from pre-production mining expenditures

	Year	Month	Day
1st previous tax year			
2nd previous tax year			
3rd previous tax year			

Credit to be applied 921

Credit to be applied 922

Credit to be applied 923

Total of lines 921 to 923 I4
(enter amount I4 on line e in Part 19)

Apprenticeship Job Creation

Part 21 – Total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number (SIN) or name) appears below? (If not, you cannot claim the tax credit.) . . . . . 611 1 Yes ☐ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the SIN or the name of the eligible apprentice.

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
1.	1[redacted]	Lineworker	69,418	6,942	2,000
2.	[redacted]	Lineworker	64,843	6,484	2,000
3.	[redacted]	Lineworker	70,140	7,014	2,000
4.	[redacted]	Lineworker	68,736	6,874	2,000
5.	[redacted]	Lineworker	83,791	8,379	2,000
6.	[redacted]	Lineworker	95,606	9,561	2,000
7.	[redacted]	Lineworker	96,056	9,606	2,000
8.	[redacted]	Lineworker	85,886	8,589	2,000
9.	[redacted]	Lineworker	83,753	8,375	2,000
10.	[redacted]	Lineworker	89,771	8,977	2,000
11.	[redacted]	Lineworker	83,296	8,330	2,000
12.	[redacted]	Lineworker	83,941	8,394	2,000

Total current-year credit (total of column E) (enter amount A5 on line 640 in Part 22) 24,000 A5

* Other than qualified expenditure incurred, and net of any other government or non-government assistance received or to be received. **Eligible salary and wages**, and **qualified expenditures** are defined under subsection 127(9).

Part 22 – Current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year B5

Deduct:

Credit deemed as a remittance of co-op corporations 612

Credit expired after 20 tax years 615

Subtotal (line 612 **plus** line 615) ▶ C5

ITC at the beginning of the tax year (amount B5 **minus** amount C5) 625

Add:

Credit transferred on amalgamation or wind-up of subsidiary 630

ITC from repayment of assistance 635

Total current-year credit (from amount A5 in Part 21) 640 24,000

Credit allocated from a partnership 655

Subtotal (total of lines 630 to 655) 24,000 ▶ 24,000 D5

Total credit available (line 625 **plus** amount D5) 24,000 E5

Deduct:

Credit deducted from Part I tax (enter this amount at line G8 in Part 30) 660 24,000

Credit carried back to the previous year(s) (from amount G5 in Part 23) . . . . . a

Subtotal (line 660 **plus** amount a) 24,000 ▶ 24,000 F5

ITC closing balance from apprenticeship job creation expenditures (amount E5 **minus** amount F5) 690

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Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

	Year	Month	Day
1st previous tax year			
2nd previous tax year			
3rd previous tax year			

. . . . . Credit to be applied **931**

. . . . . Credit to be applied **932**

. . . . . Credit to be applied **933**

Total of lines 931 to 933 (enter amount G5 on line a in Part 22) G5

Child Care Spaces

Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that you incurred to create licensed child care spaces for the children of the employees and, potentially, for other children. You cannot be carrying on a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures.

Properties should be acquired and expenditures should be incurred only to create new child care spaces at a licensed child care facility.

Cost of depreciable property from the current tax year

	Capital cost allowance class number **665**	Description of investment **675**	Date available for use **685**	Amount of investment **695**
1.				

Total cost of depreciable property from the current tax year (total of column 695) **715**

Add:

Specified child care start-up expenditures from the current tax year **705**

Total gross eligible expenditures for child care spaces (line 715 **plus** line 705) A6

Deduct:

Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to in amount A6 . . . . . **725**

Excess (amount A6 **minus** line 725) (if negative, enter "0") B6

Add:

Repayments by the corporation of government and non-government assistance **735**

Total eligible expenditures for child care spaces (amount B6 **plus** line 735) **745**

Part 25 – Current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (from line 745 in Part 24) . . . . . x 25 % = C6

Number of child care spaces . . . . . **755** x $ 10,000 = D6

ITC from child care spaces expenditures (amount C6 or D6, whichever is less) E6

Part 26 – Current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year F6

Deduct:

Credit deemed as a remittance of co-op corporations 765

Credit expired after 20 tax years 770

Subtotal (line 765 **plus** line 770) ▶ G6

ITC at the beginning of the tax year (amount F6 **minus** amount G6) 775

Add:

Credit transferred on amalgamation or wind-up of subsidiary 777

Total current-year credit (from amount E6 in Part 25) 780

Credit allocated from a partnership 782

Subtotal (total of lines 777 to 782) ▶ H6

Total credit available (line 775 **plus** amount H6) I6

Deduct:

Credit deducted from Part I tax (enter this amount at line H8 in Part 30) 785

Credit carried back to the previous year(s) (from amount K6 in Part 27) . . . . . a

Subtotal (line 785 **plus** amount a) ▶ J6

ITC closing balance from child care spaces expenditures (amount I6 **minus** amount J6) 790

Part 27 – Request for carryback of credit from child care space expenditures

	Year	Month	Day
1st previous tax year	2015	12	31
2nd previous tax year	2014	12	31
3rd previous tax year	2013	12	31

1st previous tax year . . . . . Credit to be applied 941

2nd previous tax year . . . . . Credit to be applied 942

3rd previous tax year . . . . . Credit to be applied 943

Total of lines 941 to 943 (enter amount K6 on line a in Part 26) K6

Recapture – Child Care Spaces

Part 28 – Recapture of ITC for corporations and partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

- the new child care space is no longer available; or
- property that was an eligible expenditure for the child care space is:
  - disposed of or leased to a lessee; or
  - converted to another use.

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) **792**

In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:

The amount that can reasonably be considered to have been included in the original ITC **795**

25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property **797**

Amount from line 795 or line 797, whichever is less A7

Partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 799 below.

Corporate partner's share of the excess of ITC **799**

Total recapture of child care spaces investment tax credit (total of line 792, amount A7, and line 799) B7

Enter amount B7 on line B8 in Part 29.

Summary of Investment Tax Credits

Part 29 – Total recapture of investment tax credit

Recaptured SR&ED ITC (from amount F3 in Part 17) A8

Recaptured child care spaces ITC (from amount B7 in Part 28) B8

Total recapture of investment tax credit (amount A8 **plus** amount B8) C8

Enter amount C8 on line 602 of the T2 return.

Part 30 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5) D8

ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12) 1,160,151 E8

ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19) F8

ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22) 24,000 G8

ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26) H8

Total ITC deducted from Part I tax (total of amounts D8 to H8) 1,184,151 I8

Enter amount I8 on line 652 of the T2 return.

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 97 Apprenticeship job creation ITC

Current year

	Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
	24,000	24,000			

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)	
2015-12-31					
2014-12-31					
2013-12-31					
2012-12-31					
2011-12-31					
2010-12-31					
2009-12-31					
2008-12-31					
2007-12-31					
2006-12-31					*
2005-12-31					
2004-12-31					
2003-12-31					
2002-12-31					
2001-12-31					
2001-09-30					
2000-09-30					
					*
Total					

B+C+D+G **Total ITC utilized** 24,000

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit expires at the end of the tax year and any expired credit will be posted to line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 the following year.

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 99 Cur. or cap. R&D for ITC

Current year

	Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
	1,160,151	1,160,151			

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)	
2015-12-31					
2014-12-31					
2013-12-31					
2012-12-31					
2011-12-31					
2010-12-31					
2009-12-31					
2008-12-31					
2007-12-31					
2006-12-31					*
2005-12-31					
2004-12-31					
2003-12-31					
2002-12-31					
2001-12-31					
2001-09-30					
2000-09-30					
					*
Total					

B+C+D+G **Total ITC utilized** 1,160,151

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit expires at the end of the tax year and any expired credit will be posted to line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 the following year.

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Schedule 33

Taxable Capital Employed in Canada – Large Corporations

Corporation's name	Business number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2016-12-31

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- If the total taxable capital employed in Canada of the corporation and its related corporations is greater than $10,000,000, file a completed Schedule 33 with your T2 *Corporation Income Tax Return* no later than six months from the end of the tax year.
- Unless otherwise noted, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms **financial institution**, **long-term debt**, and **reserves**.
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, **Taxable capital employed in Canada**.

Part 1 – Capital

Add the following year-end amounts:

Reserves that have not been deducted in calculating income for the year under Part I	101	280,712,692	
Capital stock (or members' contributions if incorporated without share capital)	103	556,300,000	
Retained earnings	104	995,900,000	
Contributed surplus	105	12,800,000	
Any other surpluses	106		
Deferred unrealized foreign exchange gains	107		
All loans and advances to the corporation	108		
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109	2,333,800,000	
Any dividends declared but not paid by the corporation before the end of the year	110		
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111		
The total of all amounts, each of which is the amount, if any, in respect of a partnership in which the corporation held a membership interest at the end of the year, either directly or indirectly through another partnership (see note below)	112		
Subtotal (**add** lines 101 to 112)		4,179,512,692 ▶	4,179,512,692 A

Note:

Line 112 is determined by the formula (A – B) x C/D (as per paragraph 181.2(3)(g)) where:

A is the total of all amounts that would be determined for lines 101, 107, 108, 109, and 111 in respect of the partnership for its last fiscal period that ends at or before the end of the year if

a) those lines applied to partnerships in the same manner that they apply to corporations, and

b) those amounts were computed without reference to amounts owing by the partnership

(i) to any corporation that held a membership interest in the partnership either directly or indirectly through another partnership, or

(ii) to any partnership in which a corporation described in subparagraph (i) held a membership interest either directly or indirectly through another partnership.

B is the partnership's deferred unrealized foreign exchange losses at the end of the period,

C is the share of the partnership's income or loss for the period to which the corporation is entitled either directly or indirectly through another partnership, and

D is the partnership's income or loss for the period.

Part 1 – Capital (continued)

Subtotal A (from page 1) 4,179,512,692 A

Deduct the following amounts:

Deferred tax debit balance at the end of the year	121		
Any deficit deducted in calculating its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122		
To the extent that the amount may reasonably be regarded as being included in any of lines 101 to 112 above for the year, any amount deducted under subsection 135(1) in calculating income under Part I for the year.	123		
Deferred unrealized foreign exchange losses at the end of the year	124		
Subtotal (**add** lines 121 to 124)		▶	B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")	190	4,179,512,692	

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend payable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim or similar obligation of, a partnership each member of which was, throughout the year, another corporation (other than a financial institution) that was not exempt from tax under this Part (otherwise than because of paragraph 181.1(3)(d)), or another partnership described in paragraph 181.2(4)(d.1)	406	
An interest in a partnership (see note 2 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	

Notes:

1. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 (other than a non-resident corporation that at no time in the year carried on business in Canada through a permanent establishment).
2. Where the corporation has an interest in a partnership held either directly or indirectly through another partnership, refer to subsection 181.2(5) for additional rules regarding the carrying value of an interest in a partnership.
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation. Refer to subsection 181.2(6) for special rules that may apply.

Part 3 – Taxable capital

Capital for the year (line 190)		4,179,512,692	C
Deduct: Investment allowance for the year (line 490)			D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	4,179,512,692	

Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500) 4,179,512,692 x (Taxable income earned in Canada / Taxable income) **610** 90,234,366 / 90,234,366 = **Taxable capital employed in Canada** **690** 4,179,512,692

Notes:
1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada **701**

Deduct the following amounts:

Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada **711**

Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada **712**

Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below) **713**

Total deductions (**add** lines 711, 712, and 713) ▶ E

Taxable capital employed in Canada (line 701 **minus** amount E) (if negative, enter "0") **790**

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (amount from line 690) . . . . . F

Deduct: . . . . . 10,000,000 G

Excess (amount F **minus** amount G) (if negative, enter "0") H

Calculation for purposes of the small business deduction (amount H x 0.225%) I

Enter this amount at line 415 of the T2 return.

Attached Schedule with Total

Part 1 – Reserves that have not been deducted in calculating income for the year under Part I

Title Part 1 – Reserves that have not been deducted in computing income for th

Description		Amount
Termination accrual		227,692 00
	+	
POEB liability	+	280,485,000 00
	+	
	+	
	Total	280,712,692 00

Attached Schedule with Total

Part 1 – All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations

Title Part 1 – All indebtedness of the corporation represented by bonds, debentu

Description		Amount
Notes payable		2,135,500,000 00
Customer deposits	+	54,100,000 00
Deferred revenue	+	144,200,000 00
	+	
	Total	2,333,800,000 00

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2016-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

		Provide only one number per shareholder				
	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Business Number (If a corporation is not registered, enter "NR") 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	TORONTO HYDRO CORPORATION	[redacted]			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

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Schedule 53

General Rate Income Pool (GRIP) Calculation

Corporation's name	Business number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2016-12-31

On: 2016-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- All legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? . . . . . ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? . . . . . ☒ Yes ☐ No
   If the answer to question 3 is yes, complete Part "GRIP addition for 2006".

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? . . . . . ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC . . . . . ☐ Yes ☒ No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation . . . . . ☐ Yes ☒ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? . . . . . ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? . . . . . ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Has the corporation wound-up a subsidiary in the preceding taxation year? . . . . . ☐ Yes ☒ No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    If the answer to question 11 is yes, complete Part 3.

Part 1 – General rate income pool (GRIP)

GRIP at the end of the previous tax year			100	303,801,210 A
Taxable income for the year (DICs enter "0") *		110 90,234,366 B		
Income for the credit union deduction * (amount E in Part 3 of Schedule 17)	120			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less *	130			
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income *	140	815,211		
Subtotal (**add** lines 120, 130, and 140)		815,211 ▶	815,211 C	
Income taxable at the general corporate rate (amount B **minus** amount C) (if negative enter "0")		150 89,419,155		
After-tax income (line 150 **multiplied** by 0.72 (the general rate factor for the tax year))			190	64,381,792 D
Eligible dividends received in the tax year	200			
Dividends deductible under section 113 received in the tax year	210			
Subtotal (line 200 **plus** line 210)		▶		E
GRIP addition:				
Becoming a CCPC (amount PP in Part 4)	220			
Post-amalgamation (total of amounts EE in Part 3 and amounts PP in Part 4)	230			
Post-wind-up (total of amounts EE in Part 3 and amounts PP in Part 4)	240			
Subtotal (**add** lines 220, 230, and 240)	290	▶		F
Subtotal (**add** amounts A, D, E, and F)				368,183,002 G
Eligible dividends paid in the previous tax year	300			
Excessive eligible dividend designations made in the previous tax year	310			
(If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.)				
Subtotal (line 300 **minus** line 310)		▶		H
GRIP before adjustment for specified future tax consequences (amount G **minus** amount H) (amount can be negative)			490	368,183,002
Total GRIP adjustment for specified future tax consequences to previous tax years (amount W in Part 2)			560	
GRIP at the end of the tax year (line 490 **minus** line 560)			590	368,183,002

Enter this amount on line 160 of Schedule 55.

***** For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

First previous tax year 2015-12-31

Taxable income before specified future tax consequences from the current tax year		10,918,774 J1		
Enter the following amounts before specified future tax consequences from the current tax year:				
Income for the credit union deduction (amount E in Part 3 of Schedule 17)		K1		
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less		L1		
Aggregate investment income (line 440 of the T2 return)		1,564,378 M1		
Subtotal (**add** amounts K1, L1, and M1)		1,564,378 ▶	1,564,378 N1	
Subtotal (amount J1 **minus** amount N1) (if negative, enter "0")		9,354,396 ▶		9,354,396 O1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less R1

Aggregate investment income (line 440 of the T2 return) S1

Subtotal (**add** amounts Q1, R1, and S1) ▶ T1

Subtotal (amount P1 **minus** amount T1) (if negative, enter "0") ▶ U1

Subtotal (amount O1 **minus** amount U1) (if negative, enter "0") V1

GRIP adjustment for specified future tax consequences to the first previous tax year

(amount V1 **multiplied** by 0.72) **500**

Second previous tax year 2014-12-31

Taxable income before specified future tax consequences from the current tax year 50,381,643 J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less L2

Aggregate investment income (line 440 of the T2 return) 487,660 M2

Subtotal (**add** amounts K2, L2, and M2) 487,660 ▶ 487,660 N2

Subtotal (amount J2 **minus** amount N2) (if negative, enter "0") 49,893,983 ▶ 49,893,983 O2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less R2

Aggregate investment income (line 440 of the T2 return) S2

Subtotal (**add** amounts Q2, R2, and S2) ▶ T2

Subtotal (amount P2 **minus** amount T2) (if negative, enter "0") ▶ U2

Subtotal (amount O2 **minus** amount U2) (if negative, enter "0") V2

GRIP adjustment for specified future tax consequences to the second previous tax year

(amount V2 **multiplied** by 0.72) **520**

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2013-12-31

Taxable income before specified future tax consequences from the current tax year 44,139,984 J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . _____ K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . _____ L3

Aggregate investment income (line 440 of the T2 return) 573,891 M3

Subtotal (**add** amounts K3, L3, and M3) 573,891 ▶ 573,891 N3

Subtotal (amount J3 **minus** amount N3) (if negative, enter "0") 43,566,093 ▶ 43,566,093 O3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . . _____ P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . _____ Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . _____ R3

Aggregate investment income (line 440 of the T2 return) . . . . . _____ S3

Subtotal (**add** amounts Q3, R3, and S3) _____ ▶ _____ T3

Subtotal (amount P3 **minus** amount T3) (if negative, enter "0") _____ ▶ _____ U3

Subtotal (amount O3 **minus** amount U3) (if negative, enter "0") _____ V3

GRIP adjustment for specified future tax consequences to the third previous tax year

(amount V3 **multiplied by** 0.72) . . . . . **540** _____

Total GRIP adjustment for specified future tax consequences to previous tax years:

(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . . _____ W

Enter amount W on line 560 in part 1.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

nb. 1 Post amalgamation . . . ☐ Post wind-up . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . . . _____ AA

Eligible dividends paid by the corporation in its last tax year . . . . . _____ BB

Excessive eligible dividend designations made by the corporation in its last tax year . . . . . _____ CC

Subtotal (amount BB **minus** amount CC) _____ ▶ _____ DD

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

(amount AA **minus** amount DD) . . . . . _____ EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE amounts. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC . . . . . ☐ Post amalgamation . . . . . ☐ Post wind-up . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year . . . . . FF

The corporation's money on hand immediately before the end of its previous/last tax year . . . . . GG

Total of subsection 111(1) losses that would have been deductible in calculating the corporation's taxable income for the previous/last tax year if the corporation had had unlimited income from each business carried on and each property held and had realized an unlimited amount of capital gains for the previous/last tax year:

Non-capital losses	a	
Net capital losses	b	
Farm losses	c	
Restricted farm losses	d	
Limited partnership losses	e	
Subtotal (**add** amounts a to e) ▶		1

Total of all amounts deducted under subsection 111(1) in calculating the corporation's taxable income for the previous/last tax year:

Non-capital losses	f	
Net capital losses	g	
Farm losses	h	
Restricted farm losses	i	
Limited partnership losses	j	
Subtotal (**add** amounts f to j) ▶		2
Unused and unexpired losses at the end of the corporation's previous/last tax year (amount 1 **minus** amount 2) ▶		HH
Subtotal (**add** amounts FF, GG, and HH)		II

All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year . . . . . JJ

Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year . . . . . KK

All the corporation's reserves deducted in its previous/last tax year LL

The corporation's capital dividend account immediately before the end of its previous/last tax year . . . . . MM

The corporation's low rate income pool immediately before the end of its previous/last tax year . . . . . NN

Subtotal (**add** amounts JJ to NN) ▶ OO

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC (amount II **minus** amount OO) (if negative, enter "0") . . . . . PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP amounts. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

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Schedule 500

Ontario Corporation Tax Calculation

Corporation's name	Business number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2016-12-31

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- This schedule is a worksheet only. You do not have to file it with your *T2 Corporation Income Tax Return*.

Part 1 – Ontario basic rate of tax for the year

Ontario basic rate of tax for the year . . . . . 11.5 % A

Part 2 – Calculation of Ontario basic income tax

Ontario taxable income * . . . . . 90,234,366 B

Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A from Part 1) . . . . . 10,376,952 C

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit in addition to Ontario basic income tax, or has Ontario corporate minimum tax or Ontario special additional tax on life insurance corporations payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

Income from active business carried on in Canada (amount from line 400 of the T2 return) 89,612,631 1

Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return) 90,234,366 2

Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return) 500,000 3

Ontario business limit reduction:

Amount from line 3 . . . . . 500,000 a

Deduct:

Amount from line E of the T2 return: 219,298,267 x (Number of days in the tax year after May 1, 2014 / Number of days in the tax year) 366 / 366 = 219,298,267 b

Reduced Ontario business limit (amount a **minus** amount b) (if negative, enter "0") c

Business limit the CCPC assigns under subsection 125(3.2) ITA d

Amount c **minus** amount d ▶ 4

Enter the least of amounts 1, 2, 3, and 4 . . . . . D

Ontario domestic factor (ODF): Ontario taxable income * / Taxable income earned in all provinces and territories ** 90,234,366.00 / 90,234,366 = ... 1.00000 E

Amount D × ODF (line E) e

Ontario taxable income (amount B from Part 2) 90,234,366 f

Reduced Ontario business limit (amount e **minus** amount f) (if negative, enter "0") . . . . . F

OSBD rate for the year . . . . . 7 % G

Ontario small business deduction: amount F **multiplied** by rate G . . . . . H

Enter amount H on line 402 of Schedule 5.

* Enter amount B from Part 2.

** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Part 4 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Ontario adjusted small business income (lesser of amount D and amount d from Part 3) I

Enter amount I on line K in Part 5 of this schedule or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 5 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount D from Part 3 of Schedule 17 . . . . . J

Deduct:

Ontario adjusted small business income (amount I from Part 4) . . . . . K

Subtotal (amount J **minus** amount K) (if negative, enter "0") L

Amount L **multiplied** by rate G from Part 3 . . . . . M

Ontario domestic factor (line E from Part 3) . . . . . 1.00000 N

Ontario credit union tax reduction (amount M **multiplied** by ODF from line N) . . . . . O

Enter amount O on line 410 of Schedule 5.

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SCHEDULE 508

ONTARIO RESEARCH AND DEVELOPMENT TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2016-12-31

- Use this schedule to:
  - calculate an Ontario research and development tax credit (ORDTC);
  - claim an ORDTC earned in the tax year or carried forward from any of the 20 previous tax years that are a tax year ending after December 31, 2008, to reduce Ontario corporate income tax payable in the current tax year;
  - carry back an ORDTC to reduce Ontario corporate income tax payable in any of the three previous tax years, but not to a tax year that ends before January 1, 2009;
  - add an ORDTC that was allocated to the corporation by a partnership of which it was a member;
  - transfer an ORDTC after an amalgamation or windup; or
  - calculate a recapture of the ORDTC.
- The ORDTC is a 4.5% non-refundable tax credit on eligible expenditures incurred by a corporation in a tax year that ends after December 31, 2008.
- An eligible expenditure is an expenditure for a permanent establishment in Ontario of a corporation, that is a qualified expenditure for the purposes of section 127 of the federal *Income Tax Act* for scientific research and experimental development (SR&ED) carried on in Ontario.
- Only corporations that are not exempt from Ontario corporate income tax and none of whose income is exempt income can claim the ORDTC.
- Attach a completed copy of this schedule to the *T2 Corporation Income Tax Return.*

Part 1 – Ontario SR&ED expenditure pool

Total eligible expenditures incurred by the corporation in Ontario in the tax year	100	8,080,859	A	
Deduct: Government assistance, non-government assistance, or a contract payment for eligible expenditures	105	31,360	B	
Net eligible expenditures for the tax year (amount A **minus** amount B) (if negative, enter "0")		8,049,499	C	
Add: Eligible expenditures transferred to the corporation by another corporation	110		D	
Subtotal (amount C **plus** amount D)		8,049,499 ▶		8,049,499 E
Deduct: Eligible expenditures the corporation transferred to another corporation	115			F
Ontario SR&ED expenditure pool (amount E **minus** amount F) (if negative, enter "0")	120			8,049,499 G

Part 2 – Calculation of the current part of the ORDTC

Ontario SR&ED expenditure pool (amount G in Part 1) . . . . . 8,049,499 x 3.9153 % = **200** 315,162 H

Note: Pursuant to subsection 38(2) of the *Taxation Act, 2007* (Ontario), the research and development tax credit rate is decreased from 4.5% to 3.5% on June 1, 2016. The rate must be prorated for taxation years straddling June 1, 2016.

ORDTC allocated to a corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year * . . . . . **205** I

* If there is a disposal or change of use of eligible property, see Part 6

Repayment made in the tax year of government or non-government assistance or a contract payment that reduced an eligible expenditure, other than for first term or second term shared-use equipment, incurred in a tax year ending before June 1, 2016 . . . . . x 4.50 % =

Repayment made in the tax year of government or non-government assistance or a contract payment that reduced an eligible expenditure, other than for first term or second term shared-use equipment, incurred in a tax year that straddles June 1, 2016 . . . . . x 3.9153 % =

Repayment made in the tax year of government or non-government assistance or a contract payment that reduced an eligible expenditure, other than for first term or second term shared-use equipment, incurred in a tax year that starts after May 31, 2016 . . . . . x 3.50 % =

Total **210** ▶ **215** J

Repayment made in the tax year of government or non-government assistance or a contract payment that reduced an eligible expenditure for first term or second term shared-use equipment . . . . **220** x 1 / 4 = x 4.50 % = **225** K

Current part of the ORDTC (total of amounts H to K) . . . . . **230** 315,162 L

Part 3 – Calculation of ORDTC available for deduction and ORDTC balance

ORDTC balance at the end of the previous tax year . . . . . M

Deduct: ORDTC expired after 20 tax years . . . . . **300** N

ORDTC at the beginning of the tax year (amount M **minus** amount N) . . . . . **305** O

Add:

ORDTC transferred on amalgamation or windup . . . . . **310** P

Current part of ORDTC (amount L in Part 2) . . . . . 315,162 Q

Are you waiving all or part of the current part of the ORDTC? . . . . . **315** Yes 1 ☐ No 2 ☒

If you answered **yes** at line 315, enter the amount of the tax credit waived on line 320.

If you answered **no** at line 315, enter "0" on line 320.

Deduct: Waiver of the current part of the ORDTC . . . . . **320** R

Subtotal (amount Q **minus** amount R) 315,162 ▶ 315,162 S

ORDTC available for deduction (total of amounts O, P and S) . . . . . 315,162 ▶ 315,162 T

Deduct:

ORDTC claimed * (Enter amount U on line 416 of Schedule 5, *Tax Calculation Supplementary – Corporations*) . . . . . 315,162 U

ORDTC carried back to a previous tax year (from Part 4) V

Subtotal (amount U **plus** amount V) 315,162 ▶ 315,162 W

ORDTC balance at the end of the tax year (amount T **minus** amount W) . . . . . **325** X

* This amount cannot be more than the lesser of the following amounts:
- ORDTC available for deduction (amount T); or
- Ontario corporate income tax payable before the ORDTC and the Ontario corporate minimum tax credit (amount from line E6 of Schedule 5).

Part 4 – Request for carryback of tax credit

	Year	Month	Day		
1st previous tax year	2015-12-31			Credit to be applied	**901**
2nd previous tax year	2014-12-31			Credit to be applied	**902**
3rd previous tax year	2013-12-31			Credit to be applied	**903**

Total (enter amount on line V in Part 3)

Part 5 – Analysis of tax credit available for carryforward by tax year of origin

You can complete this part to show all the credits from preceding tax years available for carryforward, by year of origin. This will help you determine the amount of credit that could expire in following years.

Tax year of origin (earliest tax year first) Year Month Day	Credit available
2000-09-30	
2001-09-30	
2001-12-31	
2002-12-31	
2003-12-31	
2004-12-31	
2005-12-31	

Tax year of origin (earliest tax year first) Year Month Day	Credit available
2006-12-31	
2007-12-31	
2008-12-31	
2009-12-31	
2010-12-31	
2011-12-31	
2012-12-31	
2013-12-31	
2014-12-31	
2015-12-31	
Current tax year 2016-12-31	

Total (equals line 325 in Part 3) _____

The amount available from the 20th preceding tax year will expire after this year. When you file your return for the next year, you will enter the expired amount on line 300 of Schedule 508 for that year.

Part 6 – Calculation of a recapture of ORDTC

You will have a recapture of ORDTC in a tax year when you meet **all** of the following conditions:

- you acquired a particular property in the current year or in any of the 20 previous tax years if the ORDTC was earned in a tax year ending after 2008;
- you claimed the cost of the property as an eligible expenditure for the ORDTC;
- the cost of the property was included in computing your ORDTC or was subject to an agreement made under subsection 127(13) of the federal Act to transfer qualified expenditures and section 42 of the *Taxation Act, 2007* (Ontario) applied; and
- you disposed of the property or converted it to commercial use in a tax year ending after December 31, 2008. You also meet this condition if you disposed of or converted to commercial use a property which incorporates the particular property previously referred to.

Note: The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED in Ontario. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical federal investment tax credit (ITC) rate * of the original user in Calculation 1 below.

You have to report the recapture on Schedule 5 for the year in which you disposed of the property or converted it to commercial use. If the corporation is a member of a partnership, report its share of the recapture.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

* Federal ITC in calculations 1 and 2 should be determined without reference to paragraph (e) of the definition **investment tax credit** in subsection 127(9) of the federal Act.

Calculation 1 – If you meet all of the above conditions

	Y Amount of federal ITC you originally calculated for the property you acquired, or the original user's federal ITC where you acquired the property from a non-arm's length party, as described in the note above **700**	Z Amount calculated using the federal ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710**	AA Amount from column 700 or 710, whichever is less
1.			

Subtotal (enter amount BB, on line KK in Part 7) _____ BB

Calculation 2 – If the corporation is deemed by subsection 42(1) of the *Taxation Act, 2007* (Ontario) to have transferred all or part of the eligible expenditure to another corporation as a consequence of an agreement described in subsection 127(13) of the federal Act complete Calculation 2. Otherwise, enter nil on line II.

	CC The rate percentage that the transferee used to determine its federal ITC for a qualified expenditure that was transferred under an agreement under subsection 127(13) of the federal Act **720**	DD The proceeds of disposition of the property if you dispose of it to a person at arm's length; or, in any other case, the fair market value of the property at conversion or disposition **730**	EE The amount, if any, already provided for in Calculation 1 (this allows for the situation where only part of the cost of a property is transferred for an agreement under subsection 127(13) of the federal Act) **740**
1.			

	FF Amount determined by the formula (CC x DD) – EE (using the columns above)	GG The federal ITC earned by the transferee for the qualified expenditure that was transferred **750**	HH Amount from column FF or GG, whichever is less
1.			

Subtotal (enter amount II on line LL below) _____ II

Calculation 3

As a member of a partnership, you will report your share of the ORDTC of the partnership after the ORDTC has been reduced by the amount of the recapture. If this is a positive amount, you will report it on line 205 in Part 2. However, if the partnership does not have enough ORDTC otherwise available to offset the recapture, then the amount by which reductions to the ORDTC exceeds additions (the excess) will be determined and reported on line JJ.

Corporate partner's share of the excess of ORDTC (enter amount JJ at line NN below) . . . . . **760** _____ JJ

Part 7 – Total recapture of ORDTC

Recaptured federal ITC for Calculation 1 (amount from line BB) . . . . . _____ KK

Recaptured federal ITC for Calculation 2 (amount from line II above) . . . . . _____ LL

Amount KK **plus** amount LL . . . . . _____ x 23.56 % = _____ MM

Add: Corporate partner's share of the excess of ORDTC for Calculation 3 (amount from line JJ above) . . . . . _____ NN

Recapture of ORDTC (amount MM **plus** amount NN) (enter amount OO on line 277 of Schedule 5) . . . . . _____ OO

Schedule A - Worksheet for eligible expenditures incurred by the corporation in Ontario for the current taxation year

This worksheet allows you to report the amount of eligible expenditures entered on Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim* which represents eligible expenditures as defined in section 127 of the *Income Tax Act* (ITA) with regard to scientific research and experimental development (SR&ED) **carried on in Ontario and attributable to a permanent establishment in Ontario of a corporation**.

Data on the worksheet is calculated based on the amounts on Form T661, but will have to be adjusted according to the rules of Ontario, if applicable, in particular when the corporation has had a permanent establishment in more than one jurisdiction. This data will be used when calculating Schedule 508 and Schedule 566.

Enter the breakdown between current and capital expenditures

		Current Expenditures		Capital Expenditures	
Total expenditures for SR&ED		7,389,418			
Add					
• payment of prior years' unpaid expenses (other than salary or wages)	+				
• prescribed proxy amount (Enter "0" if you use the traditional method)	+	1,528,617			
• expenditures on shared-use equipment			+		
• other additions	+		+		
Subtotal	=	8,918,035	=		
Less					
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end	–				
• amounts paid in respect of an SR&ED contract to a person or partnership that is not taxable supplier	–				
• 20% of contract expenditures for SR&ED performed on your behalf	–	837,176			
• prescribed expenditures not allowed by regulations	–		–		
• other deductions	–		–		
• non-arm's length transactions					
– expenditures for non-arm's length SR&ED contracts	–				
– purchases (limited to costs) of goods and services from non-arm's length suppliers	–		–		
Subtotal	=	8,080,859 I	=		II
Total eligible expenditures incurred by the corporation in Ontario in the tax year (add amount I and II)			=	8,080,859	III

Enter amount III on line 100 of Schedule 508.

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Schedule 510

Ontario Corporate Minimum Tax

Corporation's name	Business number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2016-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	4,919,100,000
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	3,821,223,000
Total assets (total of lines 112 to 116)		8,740,323,000
Total revenue of the corporation for the tax year **	142	4,020,400,000
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	258,412,000
Total revenue (total of lines 142 to 146)		4,278,812,000

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Adjusted net income/loss for CMT purposes

Net income/loss per financial statements *		210	150,331,448
Add (to the extent reflected in income/loss):			
Provision for current income taxes/cost of current income taxes	220 23,135,447		
Provision for deferred income taxes (debits)/cost of future income taxes	222		
Equity losses from corporations	224		
Financial statement loss from partnerships and joint ventures	226		
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230		
Other additions (see note below):			
Share of adjusted net income of partnerships and joint ventures **	228		
Total patronage dividends received, not already included in net income/loss	232		
281	282		
283	284		
Subtotal	23,135,447 ▶		23,135,447 A
Deduct (to the extent reflected in income/loss):			
Provision for recovery of current income taxes/benefit of current income taxes	320		
Provision for deferred income taxes (credits)/benefit of future income taxes	322		
Equity income from corporations	324		
Financial statement income from partnerships and joint ventures	326		
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330		
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332		
Gain on donation of listed security or ecological gift	340		
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342		
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344		
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346		
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348		
Other deductions (see note below):			
Share of adjusted net loss of partnerships and joint ventures **	328		
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334		
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336		
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338		
381	382		
383	384		
385	386		
387	388		
389	390		
Subtotal	▶		B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)		490	173,466,895

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

- exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
- include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

- Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive) **515** 173,466,895

Deduct:

CMT loss available (amount R from Part 7) . . . . . _____

Minus: Adjustment for an acquisition of control * . . . . . **518** _____

Adjusted CMT loss available . . . . . _____ ▶ _____ C

Net income subject to CMT calculation (if negative, enter "0") **520** 173,466,895

Amount from line 520 173,466,895 x (Number of days in the tax year before July 1, 2010 / Number of days in the tax year 366) x 4 % = _____ 1

Amount from line 520 173,466,895 x (Number of days in the tax year after June 30, 2010 366 / Number of days in the tax year 366) x 2.7 % = 4,683,606 2

Subtotal (amount 1 **plus** amount 2) 4,683,606 3

Gross CMT: amount on line 3 above x OAF ** **540** 4,683,606

Deduct:

Foreign tax credit for CMT purposes *** . . . . . **550** _____

CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0") . . . . . 4,683,606 D

Deduct:

Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) 10,061,790

Net CMT payable (if negative, enter "0") . . . . . _____ E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** _____ = _____

Ontario allocation factor . . . . . 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *		2,657,189	G	
Deduct:				
CMT credit expired *	600			
CMT credit carryforward at the beginning of the current tax year * (see note below)		2,657,189 ▶	620	2,657,189
Add:				
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)	650			
CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)				2,657,189 H
Deduct:				
CMT credit deducted in the current tax year (amount P from Part 5)				2,657,189 I
Subtotal (amount H **minus** amount I)				J
Add:				
Net CMT payable (amount E from Part 3)				
SAT payable (amount O from Part 6 of Schedule 512)				
Subtotal		▶		K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)	670			L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)				2,657,189 M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		10,061,790	1	
For a corporation that is not a life insurance corporation:				
CMT after foreign tax credit deduction (amount D from Part 3)		4,683,606	2	
For a life insurance corporation:				
Gross CMT (line 540 from Part 3)			3	
Gross SAT (line 460 from Part 6 of Schedule 512)			4	
The **greater** of amounts 3 and 4			5	
Deduct: line 2 or line 5, whichever applies:		4,683,606	6	
Subtotal (if negative, enter "0")		5,378,184 ▶		5,378,184 N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		10,061,790		
Deduct:				
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)		1,143,727		
Subtotal (if negative, enter "0")		8,918,063 ▶		8,918,063 O
CMT credit deducted in the current tax year (least of amounts M, N, and O)				2,657,189 P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin		CMT credit balance *
10th previous tax year	680	
9th previous tax year	681	
8th previous tax year	682	
7th previous tax year	683	
6th previous tax year	684	
5th previous tax year	685	
4th previous tax year	686	
3rd previous tax year	687	
2nd previous tax year	688	
1st previous tax year	689	
Total **		

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . . Q

Deduct:

CMT loss expired * 700

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . . ▶ 720

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) 750

CMT loss available (line 720 **plus** line 750) . . . . . R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . . . .

Subtotal (if negative, enter "0") S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) 760

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . . 770 T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:

- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year	[redacted]	829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2016-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
1	TORONTO HYDRO CORPORATION	[redacted]	3,784,800,000	237,500,000
2	TORONTO HYDRO ENERGY SERVICES INC.		36,423,000	20,912,000
		Total	450 3,821,223,000	550 258,412,000

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

*** Rules for total assets**

- Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
- Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

**** Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
- Include the associated corporation's share of the total revenue of partnerships and joint ventures.
- If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2016-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	**110** Date of incorporation or amalgamation, whichever is the most recent (Year Month Day)	**120** Ontario Corporation No.
Ontario	2012-01-01	[redacted]

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable)

210 Street number	**220** Street name/Rural route/Lot and Concession number	**230** Suite number
14	Carlton Street	

240 Additional address information if applicable (line 220 must be completed first)

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
Toronto	ON	CA	M5B 1K5

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 [1] If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 Bovingdon (Last name) **451** Sean (First name)

454 _____ (Middle name(s))

460 [2] Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 ☐ Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)

520 Street number | **530** Street name/Rural route/Lot and Concession number | **540** Suite number

550 Additional address information if applicable (line 530 must be completed first)

560 Municipality (e.g., city, town) | **570** Province/state | **580** Country | **590** Postal/zip code

Part 6 – Language of preference

600 ☐ Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 550

ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2016-12-31

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information	120 Telephone number including area code
[redacted]	[redacted]

Is the claim filed for a CETC earned through a partnership?* . . . . . 150 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 150, what is the name of the partnership? . . . . . 160 _____

Enter the percentage of the partnership's CETC allocated to the corporation . . . . . 170 _____ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . 200 1 Yes ☒ 2 No ☐
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . . . 210 1 Yes ☐ 2 No ☒

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * **300** 224,900,000

For eligible expenditures incurred before March 27, 2009:

- If line 300 is $400,000 or less, enter 15% on line 310.
- If line 300 is $600,000 or more, enter 10% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\% - \left[5\% \times \left(\frac{\text{amount on line 300 } \textbf{minus } \$\ 400{,}000}{\$\ 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . . **310** 10.000 %

For eligible expenditures incurred after March 26, 2009:

- If line 300 is $400,000 or less, enter 30% on line 312.
- If line 300 is $600,000 or more, enter 25% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\% - \left[5\% \times \left(\frac{\text{amount on line 300 } \textbf{minus } \$\ 400{,}000}{\$\ 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . . **312** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

	A Name of university, college, or other eligible educational institution **400**	B Name of qualifying co-operative education program **405**
1.	McMaster University	Electrical Engineering
2.	McMaster University	Electrical Engineering
3.	Mohawk College	Electrical Engineering
4.	Mohawk College	Electrical Engineering
5.	Mohawk College	Electrical Engineering
6.	UTSC	Management
7.	UTSC	Management
8.	McMaster University	Electrical Engineering
9.	McMaster University	Electrical Engineering
10.	University of Toronto	Engineering
11.	University of Toronto	Engineering
12.	University of Toronto	Engineering
13.	University of Toronto	Engineering
14.	University of Toronto	Engineering
15.	University of Toronto	Engineering
16.	University of Toronto	Engineering
17.	University of Toronto	Engineering
18.	University of Toronto	Engineering
19.	University of Toronto	Engineering
20.	McMaster University	Mechanical Engineering & Management
21.	McMaster University	Mechanical Engineering & Management
22.	McMaster University	Electical Engineering
23.	McMaster University	Electical Engineering

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
24.	McMaster University	Software Engineering
25.	McMaster University	Software Engineering
26.	McMaster University	Energy Engineering Technology
27.	McMaster University	Energy Engineering Technology
28.	University of Toronto	Engineering
29.	University of Toronto	Engineering
30.	University of Toronto	Engineering
31.	University of Toronto	Engineering
32.	Georgian College	Electricial Engineering
33.	Georgian College	Electricial Engineering
34.	University of Toronto	Engineering
35.	University of Toronto	Engineering
36.	University of Toronto	Engineering
37.	University of Toronto	Engineering
38.	University of Toronto	Engineering
39.	University of Toronto	Engineering
40.	Ryerson University	Elecrical & Computer Engineering
41.	Ryerson University	Elecrical & Computer Engineering
42.	University of Toronto	Engineering
43.	University of Toronto	Engineering
44.	UOIT	Engineering
45.	UOIT	Engineering
46.	Ryerson University	Elecrical & Computer Engineering
47.	Ryerson University	Elecrical & Computer Engineering
48.	McMaster University	Mechanical Engineering & Management
49.	McMaster University	Mechanical Engineering & Management
50.	Ryerson University	Elecrical & Computer Engineering
51.	Ryerson University	Elecrical & Computer Engineering
52.	University of Toronto	Engineering
53.	University of Toronto	Engineering
54.	University of Toronto	Engineering
55.	University of Toronto	Engineering
56.	McMaster University	Computer Science
57.	McMaster University	Computer Science
58.	University of Toronto	Engineering
59.	University of Toronto	Engineering
60.	UTSC	Statistics
61.	UTSC	Statistics
62.	McMaster University	Software Engineering
63.	McMaster University	Software Engineering
64.	McMaster University	Computer Science
65.	McMaster University	Computer Science
66.	University of Toronto	Engineering
67.	University of Toronto	Engineering
68.	Queen's University	Chemical Engineering
69.	Queen's University	Chemical Engineering
70.	Mohawk College	Electrical Engineering
71.	Mohawk College	Electrical Engineering
72.	McMaster University	Electrical Engineering
73.	McMaster University	Electrical Engineering
74.	Mohawk College	Electrical Engineering
75.	Mohawk College	Electrical Engineering
76.	Mohawk College	Electrical Engineering
77.	Queen's University	Electricial & Computer Engineering
78.	Queen's University	Electricial & Computer Engineering

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
79.	Ryerson University	Elecrical & Computer Engineering
80.	Ryerson University	Elecrical & Computer Engineering
81.	University of Toronto	Engineering
82.	University of Toronto	Engineering
83.	University of Toronto	Engineering
84.	University of Toronto	Engineering
85.	McMaster University	Mechanical Engineering
86.	McMaster University	Mechanical Engineering
87.	Queen's University	Mechanical and Materials Engineering
88.	Queen's University	Mechanical and Materials Engineering
89.	McMaster University	Computer Engineering
90.	McMaster University	Computer Engineering
91.	Ryerson University	Elecrical & Computer Engineering
92.	Ryerson University	Elecrical & Computer Engineering
93.	University of Toronto	Engineering
94.	University of Toronto	Engineering
95.	Ryerson University	Elecrical & Computer Engineering
96.	Ryerson University	Elecrical & Computer Engineering
97.	Brock University	Business Administration
98.	Brock University	Business Administration
99.	Wilfred Laurier University	Business Technology Management
100.	Wilfred Laurier University	Business Technology Management
101.	Centennial College	Computer Systems Technology
102.	Centennial College	Computer Systems Technology
103.	Ryerson University	Electrical & Computing Engineering
104.	Ryerson University	Electrical & Computing Engineering
105.	Seneca College	Interdisciplinary Studies
106.	Seneca College	Interdisciplinary Studies
107.	University of Toronto	Engineering
108.	University of Toronto	Engineering
109.	University of Toronto	Engineering
110.	University of Toronto	Engineering
111.	McMaster University	Electrical & Biomedical Engineering
112.	McMaster University	Electrical & Biomedical Engineering
113.	Ryerson University	Elecrical & Computer Engineering
114.	Ryerson University	Elecrical & Computer Engineering
115.	University of Toronto	Engineering
116.	University of Toronto	Engineering
117.	Ryerson University	Chemical Engineering
118.	Ryerson University	Chemical Engineering
119.	Seneca College	Business Management
120.	Seneca College	Business Management
121.	Ryerson University	Occupational Health and Safety
122.	Ryerson University	Occupational Health and Safety
123.	University of Toronto	Engineering
124.	University of Toronto	Engineering
125.	Ryerson University	Occupational Health and Safety
126.	Ryerson University	Occupational Health and Safety
127.	McMaster University	Electrical Engineering
128.	McMaster University	Electrical Engineering
129.	University of Toronto	Engineering
130.	University of Toronto	Engineering
131.	Brock University	Business Administration
132.	Brock University	Business Administration
133.	University of Toronto	Engineering

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
134.	University of Toronto	Engineering
135.	York University	HR Management
136.	York University	HR Management
137.	York University	Finance
138.	York University	Finance
139.	UOIT	Engineering
140.	UOIT	Engineering
141.	Georgian College	Electricial Engineering
142.	Georgian College	Electricial Engineering
143.	Georgian College	Electricial Engineering
144.	Georgian College	Electricial Engineering
145.	Georgian College	Electricial Engineering
146.	Georgian College	Electricial Engineering
147.	Brock University	Master of Business Administration
148.	Brock University	Master of Business Administration
149.	Seneca College	Government Relations
150.	UTSC	Management
151.	Mohawk College	Electrical Engineering
152.	Mohawk College	Electrical Engineering
153.	Mohawk College	Electrical Engineering
154.	Georgian College	Electricial Engineering
155.	Georgian College	Electricial Engineering
156.	University of Waterloo	Environmenal & Business
157.	University of Waterloo	Environment & Business
158.	UTSC	Management
159.	UTSC	Management
160.	University of Waterloo	Elecrical Engineering
161.	University of Waterloo	Electrical Engineering
162.	Ryerson University	Elecrical & Computer Engineering
163.	Ryerson University	Elecrical & Computer Engineering
164.	Queen's University	Bachelor of Applied Science
165.	Queen's University	Bachelor of Applied Science
166.	Ryerson University	Elecrical & Computer Engineering
167.	Ryerson University	Elecrical & Computer Engineering
168.	University of Toronto	Engineering
169.	University of Toronto	Engineering
170.	McMaster University	Electrical Engineering
171.	McMaster University	Electrical Engineering
172.	University of Toronto	Engineering
173.	University of Toronto	Engineering
174.	University of Western Ontario	Electrical Engineering
175.	University of Western Ontario	Electrical Engineering
176.	Seneca College	Public Relations
177.	Sheridan College	HR Management
178.	Seneca College	HR Management
179.	University of Western Ontario	Electrical Engineering
180.	University of Western Ontario	Electrical Engineering
181.	University of Toronto	Engineering
182.	University of Toronto	Engineering
183.	University of Toronto	Engineering
184.	University of Toronto	Engineering
185.	Ryerson University	Elecrical & Computer Engineering
186.	Ryerson University	Elecrical & Computer Engineering
187.	Ryerson University	Elecrical & Computer Engineering
188.	Ryerson University	Elecrical & Computer Engineering

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
189.	McMaster University	Computer Engineering
190.	McMaster University	Computer Engineering
191.	UTSC	Management
192.	UTSC	Management
193.	University of Toronto	Engineering
194.	University of Toronto	Engineering
195.	Ryerson University	Elecrical & Computer Engineering
196.	Ryerson University	Elecrical & Computer Engineering
197.	UTSC	Management
198.	UTSC	Management
199.	University of Toronto	Engineering
200.	University of Toronto	Engineering
201.	University of Toronto	Engineering
202.	University of Toronto	Engineering
203.	UTSC	Management
204.	UTSC	Management
205.	University of Western Ontario	Electrical Engineering
206.	University of Western Ontario	Electrical Engineering
207.	University of Toronto	Engineering
208.	University of Toronto	Engineering
209.	University of Toronto	Engineering
210.	University of Toronto	Engineering
211.	UTSC	Management
212.	UTSC	Management
213.	Ryerson University	Elecrical & Computer Engineering
214.	Ryerson University	Elecrical & Computer Engineering
215.	Ryerson University	Elecrical & Computer Engineering
216.	Ryerson University	Elecrical & Computer Engineering
217.	University of Toronto	Engineering
218.	University of Toronto	Engineering
219.	Ryerson University	Elecrical & Computer Engineering
220.	Ryerson University	Elecrical & Computer Engineering
221.	Queen's University	Bachelor of Applied Science
222.	Queen's University	Bachelor of Applied Science
223.	Georgian College	Electricial Engineering
224.	University of Waterloo	Electrical Engineering
225.	UTSC	Management
226.	Georgian College	Electricial Engineering
227.	Georgian College	Electricial Engineering
228.	University of Waterloo	Environmental Sciences/Ecology
229.	Georgian College	Electrical Engineering
230.	Ryerson University	Electrical & Computer Engineering
231.	University of Toronto	Engineering
232.	UOIT	Engineering
233.	McMaster University	Electical Engineering
234.	University of Toronto	Engineering
235.	University of Toronto	Engineering
236.	Niagara College	Electrical Engineering Technology
237.	University of Toronto	Engineering
238.	University of Toronto	Engineering
239.	University of Toronto	Engineering
240.	University of Toronto	Engineering
241.	University of Toronto	Engineering
242.	University of Toronto	Engineering
243.	Wilfred Laurier University	Business Technology Management

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
244.	Ryerson University	Elecrical & Computer Engineering
245.	Georgian College	Electricial Engineering
246.	Georgian College	Electricial Engineering
247.	UTSC	Management
248.	UTSC	Management
249.	University of Windsor	Business Administration
250.	UTSC	Management
251.	University of Windsor	Business Administration
252.	UTSC	Management
253.	Georgian College	Electricial Engineering
254.	University of Toronto	Engineering
255.	Seneca College	Computer Systems Technology
256.	York University	HR Management
257.	University of Waterloo	Mathematics
258.	Brock University	International Master of Accountancy
259.	University of Toronto	Engineering
260.	Georgian College	Electricial Engineering
261.	Ryerson University	Chemical Engineering
262.	Centennial College	Computer Systems Technology
263.	UTSC	Management
264.	Georgian College	Electricial Engineering
265.	UTSC	Management
266.	Mohawk College	Electrical Engineering
267.	Georgian College	Electricial Engineering
268.	Georgian College	Electricial Engineering
269.	Seneca College	International Business Management
270.	University of Waterloo	Accounting & Financial Management
271.	Georgian College	Electricial Engineering
272.	University of Waterloo	Environmental Engineering
273.	University of Waterloo	Systems Design Engineering
274.	Georgian College	Electricial Engineering
275.	Conestoga College	Public Relations
276.	University of Waterloo	Mechanical Engineering
277.	University of Waterloo	Civil Engineering
278.	University of Waterloo	Civil Engineering
279.	Sheridan College	HR Management
280.	University of Western Ontario	Management & Organizational Studies
281.	University of Waterloo	Civil Engineering
282.	Georgian College	Electricial Engineering
283.	Georgian College	Electricial Engineering
284.	Georgian College	Electricial Engineering
285.	Sheridan College	HR Management
286.	Georgian College	Electricial Engineering
287.	Georgian College	Electricial Engineering
288.	University of Waterloo	Electrical Engineering
289.	Mohawk College	Electrical Engineering
290.	Georgian College	Electricial Engineering
291.	Georgian College	Electricial Engineering
292.	Georgian College	Electricial Engineering
293.	McMaster University	Mechanical Enginering
294.	UTSC	Management
295.	Ryerson University	Elecrical & Computer Engineering
296.	UTSC	Management
297.	UTSC	Management
298.	UTSC	Public Policy

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
299.	Georgian College	Electricial Engineering
300.	Georgian College	Electricial Engineering
301.	Georgian College	Electricial Engineering
302.	University of Waterloo	Civil Engineering
303.	Queen's University	Bachelor of Applied Science
304.	McMaster University	Chemical Engineering
305.	UTSC	Management
306.	University of Waterloo	Actuarial Science
307.	Georgian College	Electricial Engineering
308.	Mohawk College	Electical Engineering
309.	Georgian College	Electricial Engineering
310.	University of Toronto	Engineering
311.	Georgian College	Electricial Engineering
312.	Georgian College	Electricial Engineering
313.	Mohawk College	Electrical Engineering
314.	UTSC	Management
315.	University of Western Ontario	Management & Organizational Studies
316.	Georgian College	Electricial Engineering
317.	McMaster University	Chemical Engineering
318.	Georgian College	HR Management
319.	Brock University	Business Administration
320.	University of Toronto	Engineering
321.	Brock University	Business Administration
322.	University of Toronto	Engineering
323.	Georgian College	Electricial Engineering
324.	Mohawk College	Electrical Engineering
325.	George Brown College	System Business Analysis
326.	McMaster University	Energy Engineering Technology
327.	McMaster University	Enginering Physics & Management
328.	York University	Electrical Engineering
329.	University of Toronto	Engineering
330.	Mohawk College	Energy Systems Enginering Technology
331.	University of Western Ontario	Mechanical Engineering
332.	University of Toronto	Engineering
333.	UTSC	Management
334.	McMaster University	Electrical Engineering
335.	UTSC	Management
336.	Ryerson University	Elecrical & Computer Engineering
337.	UOIT	Engineering
338.	McMaster University	Mechatronics
339.	Georgian College	Electricial Engineering
340.	Seneca College	International Business Management
341.	UTSC	Management
342.	Ryerson University	Chemical Engineering
343.	Mohawk College	Electrical Engineering
344.	Brock University	Business Administration
345.	Centennial College	Computer Systems Technology
346.	McMaster University	Electrical Engineering
347.	Centennial College	Computer Systems Technology
348.	University of Waterloo	Planning
349.	University of Toronto	Engineering
350.	Centennial College	Computer Systems Technology
351.	Brock University	Business Administration
352.	University of Toronto	Engineering
353.	McMaster University	Degroote Commerce

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
354.	University of Toronto	Engineering
355.	Queen's University	Bachelor of Applied Science
356.	University of Waterloo	Nanotechnology Engineering
357.	Georgian College	Electricial Engineering
358.	Georgian College	Electricial Engineering
359.	York University	Economics
360.	Ryerson University	Chemical Engineering
361.	George Brown College	Information Systems Business Analysis
362.	Georgian College	Electricial Engineering
363.	Ryerson University	Public Health and Safety
364.	McMaster University	Electrical Engineering
365.	University of Waterloo	Electrical Engineering
366.	University of Waterloo	Environment & Business
367.	University of Waterloo	Electrical Engineering
368.	University of Toronto	Engineering
369.	University of Waterloo	Mathematics/Business Admin
370.	University of Waterloo	Math/Fin. Analysis & Risk Management

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
1.	[redacted]	2016-01-04	2016-04-29
2.		2016-05-02	2016-08-26
3.		2016-01-04	2016-04-29
4.		2016-05-02	2016-09-02
5.		2016-09-06	2016-12-23
6.		2016-05-02	2016-09-02
7.		2016-09-06	2016-12-23
8.		2016-01-04	2016-04-29
9.		2016-05-02	2016-08-26
10.		2016-01-04	2016-04-29
11.		2016-05-02	2016-08-26
12.	[redacted]	2016-01-04	2016-04-29
13.		2016-05-02	2016-08-26
14.	[redacted]	2016-01-04	2016-04-29
15.		2016-05-02	2016-08-26
16.		2016-01-04	2016-04-29
17.		2016-05-02	2016-08-26
18.		2016-01-04	2016-04-29
19.		2016-05-02	2016-08-26
20.		2016-01-04	2016-04-29
21.		2016-05-02	2016-08-26
22.		2016-01-04	2016-04-29
23.		2016-05-02	2016-08-26
24.		2016-01-04	2016-04-29
25.		2016-05-02	2016-08-26
26.		2016-01-04	2016-04-29
27.		2016-05-02	2016-08-26
28.		2016-01-04	2016-04-29
29.		2016-05-02	2016-08-26
30.		2016-01-04	2016-04-29
31.		2016-05-02	2016-08-26

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
32.	[redacted]	2016-01-04	2016-04-29
33.		2016-09-06	2016-12-23
34.		2016-01-04	2016-04-29
35.		2016-05-02	2016-08-26
36.		2016-01-04	2016-04-29
37.		2016-05-02	2016-08-26
38.		2016-01-04	2016-04-29
39.		2016-05-02	2016-08-26
40.		2016-01-04	2016-04-29
41.		2016-05-02	2016-08-26
42.		2016-01-04	2016-04-29
43.		2016-05-02	2016-08-26
44.		2016-01-04	2016-04-29
45.		2016-05-02	2016-08-26
46.		2016-01-04	2016-04-29
47.		2016-05-02	2016-08-26
48.		2016-01-04	2016-04-29
49.		2016-05-02	2016-08-26
50.		2016-01-04	2016-04-29
51.		2016-05-02	2016-08-26
52.		2016-01-04	2016-04-29
53.		2016-05-02	2016-08-26
54.		2016-01-04	2016-04-29
55.		2016-05-02	2016-08-26
56.		2016-01-04	2016-04-29
57.		2016-05-02	2016-08-26
58.		2016-01-04	2016-04-29
59.		2016-05-02	2016-08-26
60.		2016-01-04	2016-04-29
61.		2016-05-02	2016-08-26
62.		2016-01-04	2016-04-29
63.		2016-05-02	2016-08-26
64.		2016-01-04	2016-04-29
65.		2016-05-02	2016-08-26
66.		2016-01-04	2016-04-29
67.		2016-05-02	2016-08-26
68.		2016-01-04	2016-04-29
69.		2016-05-02	2016-08-26
70.		2016-01-04	2016-04-29
71.		2016-09-06	2016-12-23
72.		2016-01-04	2016-04-29
73.		2016-05-02	2016-08-26
74.		2016-01-04	2016-04-29
75.		2016-05-02	2016-09-02
76.		2016-09-06	2016-12-23
77.		2016-01-04	2016-04-29
78.		2016-05-02	2016-08-26
79.		2016-01-04	2016-04-29
80.		2016-05-02	2016-08-26
81.		2016-01-04	2016-04-29
82.		2016-05-02	2016-08-26
83.		2016-01-04	2016-04-29
84.		2016-05-02	2016-08-26
85.		2016-01-04	2016-04-29

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
86.	[redacted]	2016-05-02	2016-08-26
87.		2016-01-04	2016-04-29
88.		2016-05-02	2016-08-26
89.		2016-01-04	2016-04-29
90.		2016-05-02	2016-08-26
91.		2016-01-04	2016-04-29
92.		2016-05-02	2016-08-26
93.		2016-01-04	2016-04-29
94.		2016-05-02	2016-08-26
95.		2016-01-04	2016-04-29
96.		2016-05-02	2016-08-26
97.		2016-01-04	2016-04-29
98.		2016-05-02	2016-08-26
99.		2016-01-04	2016-04-29
100.		2016-09-06	2016-12-23
101.		2016-01-04	2016-04-29
102.		2016-05-02	2016-09-02
103.		2016-01-04	2016-04-29
104.		2016-05-02	2016-09-02
105.		2016-01-04	2016-04-29
106.		2016-05-02	2016-09-02
107.		2016-01-04	2016-04-29
108.		2016-05-02	2016-08-26
109.		2016-01-04	2016-04-29
110.		2016-05-02	2016-08-26
111.		2016-01-04	2016-04-29
112.		2016-05-02	2016-08-26
113.		2016-01-04	2016-04-29
114.		2016-05-02	2016-08-26
115.		2016-01-04	2016-04-29
116.		2016-05-02	2016-09-02
117.		2016-01-04	2016-04-29
118.		2016-05-02	2016-09-02
119.		2016-01-04	2016-04-29
120.		2016-05-02	2016-09-02
121.		2016-01-04	2016-04-29
122.		2016-05-02	2016-09-02
123.		2016-01-04	2016-04-29
124.		2016-05-02	2016-08-26
125.		2016-01-04	2016-04-29
126.		2016-05-02	2016-09-02
127.		2016-01-04	2016-04-29
128.		2016-05-02	2016-08-26
129.		2016-01-04	2016-04-29
130.		2016-05-02	2016-08-26
131.		2016-01-04	2016-04-29
132.		2016-05-02	2016-09-02
133.		2016-01-04	2016-04-29
134.		2016-05-02	2016-08-26
135.		2016-01-04	2016-04-29
136.		2016-05-02	2016-07-29
137.		2016-01-04	2016-04-29
138.		2016-05-02	2016-09-02
139.		2016-01-04	2016-04-29

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
140.	[redacted]	2016-05-02	2016-08-26
141.		2016-01-04	2016-04-29
142.		2016-09-06	2016-12-23
143.		2016-01-04	2016-04-29
144.		2016-09-06	2016-12-23
145.		2016-01-04	2016-04-29
146.		2016-09-06	2016-12-23
147.		2016-01-04	2016-04-29
148.		2016-05-02	2016-09-02
149.		2016-01-04	2016-04-29
150.		2016-01-04	2016-04-29
151.		2016-01-04	2016-04-29
152.		2016-05-02	2016-09-02
153.		2016-09-06	2016-12-23
154.		2016-01-04	2016-04-29
155.		2016-05-02	2016-09-02
156.		2016-01-04	2016-04-29
157.		2016-05-02	2016-09-02
158.		2016-01-04	2016-04-29
159.		2016-05-02	2016-09-02
160.		2016-01-04	2016-04-29
161.		2016-09-06	2016-12-23
162.		2016-05-02	2016-09-02
163.		2016-09-06	2016-12-23
164.		2016-05-02	2016-09-02
165.		2016-09-06	2016-12-23
166.		2016-05-02	2016-09-02
167.		2016-09-06	2016-12-23
168.		2016-05-02	2016-09-02
169.		2016-09-06	2016-12-23
170.		2016-05-02	2016-09-02
171.		2016-09-06	2016-12-23
172.		2016-05-02	2016-09-02
173.		2016-09-06	2016-12-23
174.		2016-05-02	2016-09-02
175.		2016-09-06	2016-12-23
176.		2016-05-02	2016-09-02
177.		2016-05-02	2016-09-02
178.		2016-05-02	2016-09-02
179.		2016-05-02	2016-09-02
180.		2016-09-06	2016-12-23
181.		2016-05-02	2016-09-02
182.		2016-09-06	2016-12-23
183.		2016-05-02	2016-09-02
184.		2016-09-06	2016-12-23
185.		2016-05-02	2016-09-02
186.		2016-09-06	2016-12-23
187.		2016-05-02	2016-09-02
188.		2016-09-06	2016-12-23
189.		2016-05-02	2016-09-02
190.		2016-09-06	2016-12-23
191.		2016-05-02	2016-09-02
192.		2016-09-06	2016-12-23
193.		2016-05-02	2016-09-02

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
194.	[redacted]	2016-09-06	2016-12-23
195.		2016-05-02	2016-09-02
196.		2016-09-06	2016-12-23
197.		2016-05-02	2016-09-02
198.		2016-09-06	2016-12-23
199.		2016-05-02	2016-09-02
200.		2016-09-06	2016-12-23
201.		2016-05-02	2016-09-02
202.		2016-09-06	2016-12-23
203.		2016-05-02	2016-09-02
204.		2016-09-06	2016-12-23
205.		2016-05-02	2016-09-02
206.		2016-09-06	2016-12-23
207.		2016-05-02	2016-09-02
208.		2016-09-06	2016-12-23
209.		2016-05-02	2016-09-02
210.		2016-09-06	2016-12-23
211.		2016-05-02	2016-09-02
212.		2016-09-06	2016-12-23
213.		2016-05-02	2016-09-02
214.		2016-09-06	2016-12-23
215.		2016-05-02	2016-09-02
216.		2016-09-06	2016-12-23
217.		2016-05-02	2016-09-02
218.		2016-09-06	2016-12-23
219.		2016-05-02	2016-09-02
220.		2016-09-06	2016-12-23
221.		2016-05-02	2016-09-02
222.		2016-09-06	2016-12-23
223.		2016-05-02	2016-09-02
224.		2016-01-04	2016-04-29
225.		2016-01-04	2016-04-29
226.		2016-01-04	2016-04-29
227.		2016-01-04	2016-04-29
228.		2016-05-02	2016-09-02
229.		2016-01-04	2016-04-29
230.		2016-01-04	2016-04-29
231.		2016-01-04	2016-04-29
232.		2016-05-02	2016-09-02
233.		2016-09-06	2016-12-23
234.		2016-01-04	2016-04-29
235.		2016-01-04	2016-04-29
236.		2016-05-02	2016-09-02
237.		2016-01-04	2016-04-29
238.		2016-01-04	2016-04-29
239.		2016-01-04	2016-04-29
240.		2016-01-04	2016-04-15
241.		2016-01-04	2016-04-29
242.		2016-01-04	2016-04-29
243.		2016-01-04	2016-04-29
244.		2016-01-04	2016-04-29
245.		2016-05-02	2016-09-02
246.		2016-01-04	2016-04-29
247.		2016-01-04	2016-04-29

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
248.	[redacted]	2016-01-04	2016-04-29
249.		2016-01-04	2016-04-29
250.		2016-01-04	2016-04-29
251.		2016-01-04	2016-04-29
252.		2016-01-04	2016-04-29
253.		2016-01-04	2016-04-29
254.		2016-01-04	2016-04-29
255.		2016-01-04	2016-04-29
256.		2016-01-04	2016-04-29
257.		2016-01-04	2016-04-29
258.		2016-01-04	2016-04-29
259.		2016-01-04	2016-04-29
260.		2016-01-04	2016-04-29
261.		2016-01-04	2016-04-29
262.		2016-01-04	2016-04-29
263.		2016-01-04	2016-04-29
264.		2016-05-02	2016-09-02
265.		2016-05-02	2016-09-02
266.		2016-01-04	2016-04-29
267.		2016-01-04	2016-04-29
268.	[redacted]	2016-01-04	2016-04-29
269.	[redacted]	2016-01-04	2016-04-29
270.		2016-01-04	2016-04-29
271.		2016-01-04	2016-04-29
272.		2016-01-04	2016-04-29
273.		2016-01-04	2016-04-29
274.		2016-01-04	2016-04-29
275.		2016-01-04	2016-04-29
276.		2016-01-04	2016-04-29
277.		2016-01-04	2016-04-29
278.		2016-01-04	2016-04-29
279.		2016-05-02	2016-09-02
280.		2016-05-02	2016-09-02
281.		2016-05-02	2016-09-02
282.		2016-05-02	2016-09-02
283.		2016-05-02	2016-09-02
284.		2016-05-02	2016-09-02
285.		2016-05-02	2016-09-02
286.		2016-05-02	2016-09-02
287.		2016-05-02	2016-09-02
288.		2016-05-02	2016-09-02
289.		2016-05-02	2016-09-02
290.		2016-05-02	2016-09-02
291.		2016-05-02	2016-09-02
292.		2016-05-02	2016-09-02
293.		2016-05-02	2016-09-02
294.		2016-09-06	2016-12-23
295.		2016-09-06	2016-12-23
296.		2016-09-06	2016-12-23
297.		2016-09-06	2016-12-23
298.		2016-09-06	2016-12-23
299.		2016-09-06	2016-12-23
300.		2016-09-06	2016-12-23
301.		2016-09-06	2016-12-23

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
302.	[redacted]	2016-09-06	2016-12-23
303.		2016-09-06	2016-12-23
304.		2016-09-06	2016-12-23
305.		2016-09-06	2016-12-23
306.		2016-09-06	2016-12-23
307.		2016-09-06	2016-12-23
308.		2016-09-06	2016-12-23
309.		2016-09-06	2016-12-23
310.		2016-09-06	2016-12-23
311.		2016-09-06	2016-12-23
312.		2016-09-06	2016-12-23
313.		2016-09-06	2016-12-23
314.		2016-09-06	2016-12-23
315.		2016-09-06	2016-12-23
316.		2016-09-06	2016-12-23
317.		2016-09-06	2016-12-23
318.		2016-09-06	2016-12-23
319.		2016-09-06	2016-12-23
320.		2016-09-06	2016-12-23
321.		2016-09-06	2016-12-23
322.		2016-09-06	2016-12-23
323.		2016-09-06	2016-12-23
324.		2016-09-06	2016-12-23
325.		2016-09-06	2016-12-23
326.		2016-09-06	2016-12-23
327.		2016-09-06	2016-12-23
328.		2016-09-06	2016-12-23
329.		2016-09-06	2016-12-23
330.		2016-09-06	2016-12-23
331.		2016-09-06	2016-12-23
332.		2016-09-06	2016-12-23
333.		2016-09-06	2016-12-23
334.		2016-09-06	2016-12-23
335.		2016-09-06	2016-12-23
336.		2016-09-06	2016-12-23
337.		2016-09-06	2016-12-23
338.		2016-09-06	2016-12-23
339.		2016-09-06	2016-12-23
340.		2016-09-06	2016-12-23
341.		2016-09-06	2016-12-23
342.		2016-09-06	2016-12-23
343.		2016-09-06	2016-12-23
344.		2016-09-06	2016-12-23
345.		2016-09-06	2016-12-23
346.		2016-09-06	2016-12-23
347.		2016-09-06	2016-12-23
348.		2016-09-06	2016-12-23
349.		2016-09-06	2016-12-23
350.		2016-09-06	2016-12-23
351.		2016-09-06	2016-12-23
352.		2016-09-06	2016-12-23
353.		2016-09-06	2016-12-23
354.		2016-09-06	2016-12-23
355.		2016-09-06	2016-12-23

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
356.	[redacted]	2016-09-06	2016-12-23
357.		2016-09-06	2016-12-23
358.		2016-09-06	2016-12-23
359.		2016-09-06	2016-12-23
360.		2016-09-06	2016-12-23
361.		2016-09-06	2016-12-23
362.		2016-09-06	2016-12-23
363.		2016-09-06	2016-12-23
364.		2016-09-06	2016-12-23
365.		2016-09-06	2016-12-23
366.		2016-09-06	2016-12-23
367.		2016-09-06	2016-12-23
368.		2016-09-06	2016-12-23
369.		2016-09-06	2016-12-23
370.		2016-09-06	2016-12-23

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
1.		10.000 %	15,443	25.000 %		17
2.		10.000 %	15,443	25.000 %		17
3.		10.000 %	15,255	25.000 %		17
4.		10.000 %	16,152	25.000 %		18
5.		10.000 %	13,460	25.000 %		15
6.		10.000 %	12,272	25.000 %		18
7.		10.000 %	10,226	25.000 %		15
8.		10.000 %	12,517	25.000 %		17
9.		10.000 %	12,517	25.000 %		17
10.		10.000 %	11,577	25.000 %		17
11.		10.000 %	11,577	25.000 %		17
12.		10.000 %	15,532	25.000 %		17
13.		10.000 %	15,532	25.000 %		17
14.		10.000 %	8,930	25.000 %		17
15.		10.000 %	8,930	25.000 %		17
16.		10.000 %	11,374	25.000 %		17
17.		10.000 %	11,374	25.000 %		17
18.		10.000 %	15,621	25.000 %		17
19.		10.000 %	15,621	25.000 %		17
20.		10.000 %	12,517	25.000 %		17
21.		10.000 %	12,517	25.000 %		17
22.		10.000 %	11,036	25.000 %		17
23.		10.000 %	11,036	25.000 %		17
24.		10.000 %	11,847	25.000 %		17
25.		10.000 %	11,847	25.000 %		17
26.		10.000 %	15,621	25.000 %		17
27.		10.000 %	15,621	25.000 %		17
28.		10.000 %	11,023	25.000 %		17
29.		10.000 %	11,023	25.000 %		17
30.		10.000 %	15,370	25.000 %		17
31.		10.000 %	15,370	25.000 %		17
32.		10.000 %	14,502	25.000 %		17
33.		10.000 %	12,796	25.000 %		15
34.		10.000 %	11,480	25.000 %		17
35.		10.000 %	11,480	25.000 %		17
36.		10.000 %	13,773	25.000 %		17
37.		10.000 %	13,773	25.000 %		17
38.		10.000 %	15,944	25.000 %		17
39.		10.000 %	15,944	25.000 %		17
40.		10.000 %	15,175	25.000 %		17
41.		10.000 %	15,175	25.000 %		17
42.		10.000 %	11,847	25.000 %		17
43.		10.000 %	11,847	25.000 %		17
44.		10.000 %	15,409	25.000 %		17
45.		10.000 %	15,409	25.000 %		17
46.		10.000 %	15,621	25.000 %		17
47.		10.000 %	15,621	25.000 %		17
48.		10.000 %	15,621	25.000 %		17
49.		10.000 %	15,621	25.000 %		17
50.		10.000 %	12,517	25.000 %		17
51.		10.000 %	12,517	25.000 %		17

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
52.		10.000 %	10,891	25.000 %		17
53.		10.000 %	10,891	25.000 %		17
54.		10.000 %	10,811	25.000 %		17
55.		10.000 %	10,811	25.000 %		17
56.		10.000 %	11,101	25.000 %		17
57.		10.000 %	11,101	25.000 %		17
58.		10.000 %	11,044	25.000 %		17
59.		10.000 %	11,044	25.000 %		17
60.		10.000 %	11,673	25.000 %		17
61.		10.000 %	11,673	25.000 %		17
62.		10.000 %	10,090	25.000 %		17
63.		10.000 %	10,090	25.000 %		17
64.		10.000 %	12,035	25.000 %		17
65.		10.000 %	12,035	25.000 %		17
66.		10.000 %	15,265	25.000 %		17
67.		10.000 %	15,265	25.000 %		17
68.		10.000 %	12,184	25.000 %		17
69.		10.000 %	12,184	25.000 %		17
70.		10.000 %	15,665	25.000 %		17
71.		10.000 %	13,822	25.000 %		15
72.		10.000 %	15,452	25.000 %		17
73.		10.000 %	15,452	25.000 %		17
74.		10.000 %	14,716	25.000 %		17
75.		10.000 %	15,582	25.000 %		18
76.		10.000 %	12,985	25.000 %		15
77.		10.000 %	15,086	25.000 %		17
78.		10.000 %	15,086	25.000 %		17
79.		10.000 %	11,847	25.000 %		17
80.		10.000 %	11,847	25.000 %		17
81.		10.000 %	14,018	25.000 %		17
82.		10.000 %	14,018	25.000 %		17
83.		10.000 %	14,370	25.000 %		17
84.		10.000 %	14,370	25.000 %		17
85.		10.000 %	15,621	25.000 %		17
86.		10.000 %	15,621	25.000 %		17
87.		10.000 %	8,225	25.000 %		17
88.		10.000 %	8,225	25.000 %		17
89.		10.000 %	11,798	25.000 %		17
90.		10.000 %	11,798	25.000 %		17
91.		10.000 %	14,196	25.000 %		17
92.		10.000 %	14,196	25.000 %		17
93.		10.000 %	11,104	25.000 %		17
94.		10.000 %	11,104	25.000 %		17
95.		10.000 %	15,175	25.000 %		17
96.		10.000 %	15,175	25.000 %		17
97.		10.000 %	10,672	25.000 %		17
98.		10.000 %	10,672	25.000 %		17
99.		10.000 %	12,918	25.000 %		17
100.		10.000 %	11,398	25.000 %		15
101.		10.000 %	10,642	25.000 %		17
102.		10.000 %	11,268	25.000 %		18
103.		10.000 %	13,718	25.000 %		17
104.		10.000 %	14,525	25.000 %		18

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
105.		10.000 %	18,659	25.000 %		17
106.		10.000 %	19,756	25.000 %		18
107.		10.000 %	14,552	25.000 %		17
108.		10.000 %	14,552	25.000 %		17
109.		10.000 %	15,621	25.000 %		17
110.		10.000 %	15,621	25.000 %		17
111.		10.000 %	11,075	25.000 %		17
112.		10.000 %	11,075	25.000 %		17
113.		10.000 %	15,175	25.000 %		17
114.		10.000 %	15,175	25.000 %		17
115.		10.000 %	11,002	25.000 %		17
116.		10.000 %	11,649	25.000 %		18
117.		10.000 %	10,829	25.000 %		17
118.		10.000 %	11,466	25.000 %		18
119.		10.000 %	18,235	25.000 %		17
120.		10.000 %	19,308	25.000 %		18
121.		10.000 %	11,503	25.000 %		17
122.		10.000 %	12,180	25.000 %		18
123.		10.000 %	11,171	25.000 %		17
124.		10.000 %	11,171	25.000 %		17
125.		10.000 %	11,771	25.000 %		17
126.		10.000 %	12,463	25.000 %		18
127.		10.000 %	15,621	25.000 %		17
128.		10.000 %	15,621	25.000 %		17
129.		10.000 %	15,766	25.000 %		17
130.		10.000 %	15,766	25.000 %		17
131.		10.000 %	9,749	25.000 %		17
132.		10.000 %	10,323	25.000 %		18
133.		10.000 %	15,354	25.000 %		17
134.		10.000 %	15,354	25.000 %		17
135.		10.000 %	11,119	25.000 %		17
136.		10.000 %	8,502	25.000 %		13
137.		10.000 %	10,433	25.000 %		17
138.		10.000 %	11,047	25.000 %		18
139.		10.000 %	12,184	25.000 %		17
140.		10.000 %	12,184	25.000 %		17
141.		10.000 %	12,861	25.000 %		17
142.		10.000 %	11,347	25.000 %		15
143.		10.000 %	14,220	25.000 %		17
144.		10.000 %	12,547	25.000 %		15
145.		10.000 %	14,678	25.000 %		17
146.		10.000 %	12,951	25.000 %		15
147.		10.000 %	11,483	25.000 %		17
148.		10.000 %	12,159	25.000 %		18
149.		10.000 %	23,642	25.000 %		17
150.		10.000 %	11,483	25.000 %		17
151.		10.000 %	15,141	25.000 %		17
152.		10.000 %	16,032	25.000 %		18
153.		10.000 %	13,360	25.000 %		15
154.		10.000 %	13,060	25.000 %		17
155.		10.000 %	13,828	25.000 %		18
156.		10.000 %	10,730	25.000 %		17
157.		10.000 %	11,361	25.000 %		18

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
158.		10.000 %	9,933	25.000 %		17
159.		10.000 %	10,517	25.000 %		18
160.		10.000 %	13,180	25.000 %		17
161.		10.000 %	11,629	25.000 %		15
162.		10.000 %	12,837	25.000 %		18
163.		10.000 %	10,697	25.000 %		15
164.		10.000 %	16,480	25.000 %		18
165.		10.000 %	13,734	25.000 %		15
166.		10.000 %	11,643	25.000 %		18
167.		10.000 %	9,702	25.000 %		15
168.		10.000 %	12,499	25.000 %		18
169.		10.000 %	10,415	25.000 %		15
170.		10.000 %	12,499	25.000 %		18
171.		10.000 %	10,415	25.000 %		15
172.		10.000 %	12,351	25.000 %		18
173.		10.000 %	10,293	25.000 %		15
174.		10.000 %	16,480	25.000 %		18
175.		10.000 %	13,734	25.000 %		15
176.		10.000 %	22,291	25.000 %		18
177.		10.000 %	22,178	25.000 %		18
178.		10.000 %	22,854	25.000 %		18
179.		10.000 %	16,189	25.000 %		18
180.		10.000 %	13,491	25.000 %		15
181.		10.000 %	12,320	25.000 %		18
182.		10.000 %	10,266	25.000 %		15
183.		10.000 %	16,480	25.000 %		18
184.		10.000 %	13,734	25.000 %		15
185.		10.000 %	16,429	25.000 %		18
186.		10.000 %	13,691	25.000 %		15
187.		10.000 %	15,558	25.000 %		18
188.		10.000 %	12,965	25.000 %		15
189.		10.000 %	12,467	25.000 %		18
190.		10.000 %	10,389	25.000 %		15
191.		10.000 %	12,011	25.000 %		18
192.		10.000 %	10,009	25.000 %		15
193.		10.000 %	12,499	25.000 %		18
194.		10.000 %	10,415	25.000 %		15
195.		10.000 %	16,480	25.000 %		18
196.		10.000 %	13,734	25.000 %		15
197.		10.000 %	10,615	25.000 %		18
198.		10.000 %	8,846	25.000 %		15
199.		10.000 %	16,122	25.000 %		18
200.		10.000 %	13,435	25.000 %		15
201.		10.000 %	16,480	25.000 %		18
202.		10.000 %	13,734	25.000 %		15
203.		10.000 %	11,320	25.000 %		18
204.		10.000 %	9,434	25.000 %		15
205.		10.000 %	11,909	25.000 %		18
206.		10.000 %	9,924	25.000 %		15
207.		10.000 %	15,318	25.000 %		18
208.		10.000 %	12,765	25.000 %		15
209.		10.000 %	12,499	25.000 %		18
210.		10.000 %	10,415	25.000 %		15

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
211.		10.000 %	11,913	25.000 %		18
212.		10.000 %	9,927	25.000 %		15
213.		10.000 %	16,480	25.000 %		18
214.		10.000 %	13,734	25.000 %		15
215.		10.000 %	15,120	25.000 %		18
216.		10.000 %	12,600	25.000 %		15
217.		10.000 %	16,200	25.000 %		18
218.		10.000 %	13,500	25.000 %		15
219.		10.000 %	16,480	25.000 %		18
220.		10.000 %	13,734	25.000 %		15
221.		10.000 %	16,568	25.000 %		18
222.		10.000 %	13,806	25.000 %		15
223.		10.000 %	13,914	25.000 %		18
224.		10.000 %	15,448	25.000 %		17
225.		10.000 %	12,210	25.000 %		17
226.		10.000 %	15,444	25.000 %		17
227.		10.000 %	13,894	25.000 %		17
228.		10.000 %	14,223	25.000 %		18
229.		10.000 %	15,440	25.000 %		17
230.		10.000 %	16,274	25.000 %		17
231.		10.000 %	12,210	25.000 %		17
232.		10.000 %	16,032	25.000 %		18
233.		10.000 %	14,346	25.000 %		15
234.		10.000 %	11,574	25.000 %		17
235.		10.000 %	16,100	25.000 %		17
236.		10.000 %	16,032	25.000 %		18
237.		10.000 %	11,631	25.000 %		17
238.		10.000 %	11,930	25.000 %		17
239.		10.000 %	11,800	25.000 %		17
240.		10.000 %	14,363	25.000 %		15
241.		10.000 %	16,433	25.000 %		17
242.		10.000 %	15,388	25.000 %		17
243.		10.000 %	12,210	25.000 %		17
244.		10.000 %	12,075	25.000 %		17
245.		10.000 %	14,186	25.000 %		18
246.		10.000 %	13,080	25.000 %		17
247.		10.000 %	10,562	25.000 %		17
248.		10.000 %	12,210	25.000 %		17
249.		10.000 %	11,400	25.000 %		17
250.		10.000 %	10,310	25.000 %		17
251.		10.000 %	12,210	25.000 %		17
252.		10.000 %	11,395	25.000 %		17
253.		10.000 %	13,966	25.000 %		17
254.		10.000 %	11,684	25.000 %		17
255.		10.000 %	10,562	25.000 %		17
256.		10.000 %	10,329	25.000 %		17
257.		10.000 %	10,562	25.000 %		17
258.		10.000 %	11,940	25.000 %		17
259.		10.000 %	16,008	25.000 %		17
260.		10.000 %	14,148	25.000 %		17
261.		10.000 %	11,108	25.000 %		17
262.		10.000 %	12,210	25.000 %		17
263.		10.000 %	12,045	25.000 %		17

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
264.		10.000 %	10,100	25.000 %		18
265.		10.000 %	12,159	25.000 %		18
266.		10.000 %	17,101	25.000 %		17
267.		10.000 %	12,857	25.000 %		17
268.		10.000 %	13,098	25.000 %		17
269.		10.000 %	12,581	25.000 %		17
270.		10.000 %	9,933	25.000 %		17
271.		10.000 %	13,098	25.000 %		17
272.		10.000 %	15,177	25.000 %		17
273.		10.000 %	12,944	25.000 %		17
274.		10.000 %	15,448	25.000 %		17
275.		10.000 %	11,483	25.000 %		17
276.		10.000 %	26,967	25.000 %		17
277.		10.000 %	15,400	25.000 %		17
278.		10.000 %	13,098	25.000 %		17
279.		10.000 %	20,187	25.000 %		18
280.		10.000 %	10,517	25.000 %		18
281.		10.000 %	16,032	25.000 %		18
282.		10.000 %	13,830	25.000 %		18
283.		10.000 %	14,193	25.000 %		18
284.		10.000 %	14,197	25.000 %		18
285.		10.000 %	22,156	25.000 %		18
286.		10.000 %	13,885	25.000 %		18
287.		10.000 %	13,883	25.000 %		18
288.		10.000 %	13,868	25.000 %		18
289.		10.000 %	14,193	25.000 %		18
290.		10.000 %	13,868	25.000 %		18
291.		10.000 %	13,868	25.000 %		18
292.		10.000 %	13,868	25.000 %		18
293.		10.000 %	13,868	25.000 %		18
294.		10.000 %	10,620	25.000 %		15
295.		10.000 %	14,008	25.000 %		15
296.		10.000 %	10,620	25.000 %		15
297.		10.000 %	10,620	25.000 %		15
298.		10.000 %	10,620	25.000 %		15
299.		10.000 %	11,960	25.000 %		15
300.		10.000 %	11,344	25.000 %		15
301.		10.000 %	12,173	25.000 %		15
302.		10.000 %	12,019	25.000 %		15
303.		10.000 %	10,620	25.000 %		15
304.		10.000 %	10,620	25.000 %		15
305.		10.000 %	10,620	25.000 %		15
306.		10.000 %	8,877	25.000 %		15
307.		10.000 %	9,115	25.000 %		15
308.		10.000 %	14,364	25.000 %		15
309.		10.000 %	12,173	25.000 %		15
310.		10.000 %	10,620	25.000 %		15
311.		10.000 %	14,364	25.000 %		15
312.		10.000 %	11,694	25.000 %		15
313.		10.000 %	14,186	25.000 %		15
314.		10.000 %	10,672	25.000 %		15
315.		10.000 %	10,546	25.000 %		15
316.		10.000 %	14,072	25.000 %		15

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
317.		10.000 %	10,620	25.000 %		15
318.		10.000 %	10,620	25.000 %		15
319.		10.000 %	11,870	25.000 %		15
320.		10.000 %	10,485	25.000 %		15
321.		10.000 %	8,758	25.000 %		15
322.		10.000 %	10,620	25.000 %		15
323.		10.000 %	13,894	25.000 %		15
324.		10.000 %	14,072	25.000 %		15
325.		10.000 %	10,485	25.000 %		15
326.		10.000 %	13,833	25.000 %		15
327.		10.000 %	10,702	25.000 %		15
328.		10.000 %	14,004	25.000 %		15
329.		10.000 %	10,620	25.000 %		15
330.		10.000 %	13,295	25.000 %		15
331.		10.000 %	14,004	25.000 %		15
332.		10.000 %	14,004	25.000 %		15
333.		10.000 %	10,090	25.000 %		15
334.		10.000 %	14,117	25.000 %		15
335.		10.000 %	9,187	25.000 %		15
336.		10.000 %	14,004	25.000 %		15
337.		10.000 %	14,004	25.000 %		15
338.		10.000 %	14,004	25.000 %		15
339.		10.000 %	10,942	25.000 %		15
340.		10.000 %	10,773	25.000 %		15
341.		10.000 %	10,620	25.000 %		15
342.		10.000 %	10,908	25.000 %		15
343.		10.000 %	14,008	25.000 %		15
344.		10.000 %	10,350	25.000 %		15
345.		10.000 %	10,317	25.000 %		15
346.		10.000 %	13,892	25.000 %		15
347.		10.000 %	10,537	25.000 %		15
348.		10.000 %	12,173	25.000 %		15
349.		10.000 %	13,881	25.000 %		15
350.		10.000 %	10,085	25.000 %		15
351.		10.000 %	11,865	25.000 %		15
352.		10.000 %	9,675	25.000 %		15
353.		10.000 %	10,620	25.000 %		15
354.		10.000 %	14,004	25.000 %		15
355.		10.000 %	10,350	25.000 %		15
356.		10.000 %	14,004	25.000 %		15
357.		10.000 %	13,607	25.000 %		15
358.		10.000 %	12,173	25.000 %		15
359.		10.000 %	10,620	25.000 %		15
360.		10.000 %	10,620	25.000 %		15
361.		10.000 %	10,672	25.000 %		15
362.		10.000 %	11,548	25.000 %		15
363.		10.000 %	10,418	25.000 %		15
364.		10.000 %	13,654	25.000 %		15
365.		10.000 %	12,173	25.000 %		15
366.		10.000 %	9,479	25.000 %		15
367.		10.000 %	12,173	25.000 %		15
368.		10.000 %	10,620	25.000 %		15
369.		10.000 %	9,349	25.000 %		15

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
370.		10.000 %	5,151	25.000 %		15

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
1.	3,861	3,000	3,000		3,000
2.	3,861	3,000	3,000		3,000
3.	3,814	3,000	3,000		3,000
4.	4,038	3,000	3,000		3,000
5.	3,365	3,000	3,000		3,000
6.	3,068	3,000	3,000		3,000
7.	2,557	3,000	2,557		2,557
8.	3,129	3,000	3,000		3,000
9.	3,129	3,000	3,000		3,000
10.	2,894	3,000	2,894		2,894
11.	2,894	3,000	2,894		2,894
12.	3,883	3,000	3,000		3,000
13.	3,883	3,000	3,000		3,000
14.	2,233	3,000	2,233		2,233
15.	2,233	3,000	2,233		2,233
16.	2,844	3,000	2,844		2,844
17.	2,844	3,000	2,844		2,844
18.	3,905	3,000	3,000		3,000
19.	3,905	3,000	3,000		3,000
20.	3,129	3,000	3,000		3,000
21.	3,129	3,000	3,000		3,000
22.	2,759	3,000	2,759		2,759
23.	2,759	3,000	2,759		2,759
24.	2,962	3,000	2,962		2,962
25.	2,962	3,000	2,962		2,962
26.	3,905	3,000	3,000		3,000
27.	3,905	3,000	3,000		3,000
28.	2,756	3,000	2,756		2,756
29.	2,756	3,000	2,756		2,756
30.	3,843	3,000	3,000		3,000
31.	3,843	3,000	3,000		3,000
32.	3,626	3,000	3,000		3,000
33.	3,199	3,000	3,000		3,000
34.	2,870	3,000	2,870		2,870
35.	2,870	3,000	2,870		2,870
36.	3,443	3,000	3,000		3,000
37.	3,443	3,000	3,000		3,000
38.	3,986	3,000	3,000		3,000
39.	3,986	3,000	3,000		3,000
40.	3,794	3,000	3,000		3,000
41.	3,794	3,000	3,000		3,000
42.	2,962	3,000	2,962		2,962
43.	2,962	3,000	2,962		2,962
44.	3,852	3,000	3,000		3,000
45.	3,852	3,000	3,000		3,000

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
46.	3,905	3,000	3,000		3,000
47.	3,905	3,000	3,000		3,000
48.	3,905	3,000	3,000		3,000
49.	3,905	3,000	3,000		3,000
50.	3,129	3,000	3,000		3,000
51.	3,129	3,000	3,000		3,000
52.	2,723	3,000	2,723		2,723
53.	2,723	3,000	2,723		2,723
54.	2,703	3,000	2,703		2,703
55.	2,703	3,000	2,703		2,703
56.	2,775	3,000	2,775		2,775
57.	2,775	3,000	2,775		2,775
58.	2,761	3,000	2,761		2,761
59.	2,761	3,000	2,761		2,761
60.	2,918	3,000	2,918		2,918
61.	2,918	3,000	2,918		2,918
62.	2,523	3,000	2,523		2,523
63.	2,523	3,000	2,523		2,523
64.	3,009	3,000	3,000		3,000
65.	3,009	3,000	3,000		3,000
66.	3,816	3,000	3,000		3,000
67.	3,816	3,000	3,000		3,000
68.	3,046	3,000	3,000		3,000
69.	3,046	3,000	3,000		3,000
70.	3,916	3,000	3,000		3,000
71.	3,456	3,000	3,000		3,000
72.	3,863	3,000	3,000		3,000
73.	3,863	3,000	3,000		3,000
74.	3,679	3,000	3,000		3,000
75.	3,896	3,000	3,000		3,000
76.	3,246	3,000	3,000		3,000
77.	3,772	3,000	3,000		3,000
78.	3,772	3,000	3,000		3,000
79.	2,962	3,000	2,962		2,962
80.	2,962	3,000	2,962		2,962
81.	3,505	3,000	3,000		3,000
82.	3,505	3,000	3,000		3,000
83.	3,593	3,000	3,000		3,000
84.	3,593	3,000	3,000		3,000
85.	3,905	3,000	3,000		3,000
86.	3,905	3,000	3,000		3,000
87.	2,056	3,000	2,056		2,056
88.	2,056	3,000	2,056		2,056
89.	2,950	3,000	2,950		2,950
90.	2,950	3,000	2,950		2,950
91.	3,549	3,000	3,000		3,000
92.	3,549	3,000	3,000		3,000
93.	2,776	3,000	2,776		2,776
94.	2,776	3,000	2,776		2,776
95.	3,794	3,000	3,000		3,000
96.	3,794	3,000	3,000		3,000
97.	2,668	3,000	2,668		2,668
98.	2,668	3,000	2,668		2,668

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
99.	3,230	3,000	3,000		3,000
100.	2,850	3,000	2,850		2,850
101.	2,661	3,000	2,661		2,661
102.	2,817	3,000	2,817		2,817
103.	3,430	3,000	3,000		3,000
104.	3,631	3,000	3,000		3,000
105.	4,665	3,000	3,000		3,000
106.	4,939	3,000	3,000		3,000
107.	3,638	3,000	3,000		3,000
108.	3,638	3,000	3,000		3,000
109.	3,905	3,000	3,000		3,000
110.	3,905	3,000	3,000		3,000
111.	2,769	3,000	2,769		2,769
112.	2,769	3,000	2,769		2,769
113.	3,794	3,000	3,000		3,000
114.	3,794	3,000	3,000		3,000
115.	2,751	3,000	2,751		2,751
116.	2,912	3,000	2,912		2,912
117.	2,707	3,000	2,707		2,707
118.	2,867	3,000	2,867		2,867
119.	4,559	3,000	3,000		3,000
120.	4,827	3,000	3,000		3,000
121.	2,876	3,000	2,876		2,876
122.	3,045	3,000	3,000		3,000
123.	2,793	3,000	2,793		2,793
124.	2,793	3,000	2,793		2,793
125.	2,943	3,000	2,943		2,943
126.	3,116	3,000	3,000		3,000
127.	3,905	3,000	3,000		3,000
128.	3,905	3,000	3,000		3,000
129.	3,942	3,000	3,000		3,000
130.	3,942	3,000	3,000		3,000
131.	2,437	3,000	2,437		2,437
132.	2,581	3,000	2,581		2,581
133.	3,839	3,000	3,000		3,000
134.	3,839	3,000	3,000		3,000
135.	2,780	3,000	2,780		2,780
136.	2,126	3,000	2,126		2,126
137.	2,608	3,000	2,608		2,608
138.	2,762	3,000	2,762		2,762
139.	3,046	3,000	3,000		3,000
140.	3,046	3,000	3,000		3,000
141.	3,215	3,000	3,000		3,000
142.	2,837	3,000	2,837		2,837
143.	3,555	3,000	3,000		3,000
144.	3,137	3,000	3,000		3,000
145.	3,670	3,000	3,000		3,000
146.	3,238	3,000	3,000		3,000
147.	2,871	3,000	2,871		2,871
148.	3,040	3,000	3,000		3,000
149.	5,911	3,000	3,000		3,000
150.	2,871	3,000	2,871		2,871
151.	3,785	3,000	3,000		3,000

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
152.	4,008	3,000	3,000		3,000
153.	3,340	3,000	3,000		3,000
154.	3,265	3,000	3,000		3,000
155.	3,457	3,000	3,000		3,000
156.	2,683	3,000	2,683		2,683
157.	2,840	3,000	2,840		2,840
158.	2,483	3,000	2,483		2,483
159.	2,629	3,000	2,629		2,629
160.	3,295	3,000	3,000		3,000
161.	2,907	3,000	2,907		2,907
162.	3,209	3,000	3,000		3,000
163.	2,674	3,000	2,674		2,674
164.	4,120	3,000	3,000		3,000
165.	3,434	3,000	3,000		3,000
166.	2,911	3,000	2,911		2,911
167.	2,426	3,000	2,426		2,426
168.	3,125	3,000	3,000		3,000
169.	2,604	3,000	2,604		2,604
170.	3,125	3,000	3,000		3,000
171.	2,604	3,000	2,604		2,604
172.	3,088	3,000	3,000		3,000
173.	2,573	3,000	2,573		2,573
174.	4,120	3,000	3,000		3,000
175.	3,434	3,000	3,000		3,000
176.	5,573	3,000	3,000		3,000
177.	5,545	3,000	3,000		3,000
178.	5,714	3,000	3,000		3,000
179.	4,047	3,000	3,000		3,000
180.	3,373	3,000	3,000		3,000
181.	3,080	3,000	3,000		3,000
182.	2,567	3,000	2,567		2,567
183.	4,120	3,000	3,000		3,000
184.	3,434	3,000	3,000		3,000
185.	4,107	3,000	3,000		3,000
186.	3,423	3,000	3,000		3,000
187.	3,890	3,000	3,000		3,000
188.	3,241	3,000	3,000		3,000
189.	3,117	3,000	3,000		3,000
190.	2,597	3,000	2,597		2,597
191.	3,003	3,000	3,000		3,000
192.	2,502	3,000	2,502		2,502
193.	3,125	3,000	3,000		3,000
194.	2,604	3,000	2,604		2,604
195.	4,120	3,000	3,000		3,000
196.	3,434	3,000	3,000		3,000
197.	2,654	3,000	2,654		2,654
198.	2,212	3,000	2,212		2,212
199.	4,031	3,000	3,000		3,000
200.	3,359	3,000	3,000		3,000
201.	4,120	3,000	3,000		3,000
202.	3,434	3,000	3,000		3,000
203.	2,830	3,000	2,830		2,830
204.	2,359	3,000	2,359		2,359

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
205.	2,977	3,000	2,977		2,977
206.	2,481	3,000	2,481		2,481
207.	3,830	3,000	3,000		3,000
208.	3,191	3,000	3,000		3,000
209.	3,125	3,000	3,000		3,000
210.	2,604	3,000	2,604		2,604
211.	2,978	3,000	2,978		2,978
212.	2,482	3,000	2,482		2,482
213.	4,120	3,000	3,000		3,000
214.	3,434	3,000	3,000		3,000
215.	3,780	3,000	3,000		3,000
216.	3,150	3,000	3,000		3,000
217.	4,050	3,000	3,000		3,000
218.	3,375	3,000	3,000		3,000
219.	4,120	3,000	3,000		3,000
220.	3,434	3,000	3,000		3,000
221.	4,142	3,000	3,000		3,000
222.	3,452	3,000	3,000		3,000
223.	3,479	3,000	3,000		3,000
224.	3,862	3,000	3,000		3,000
225.	3,053	3,000	3,000		3,000
226.	3,861	3,000	3,000		3,000
227.	3,474	3,000	3,000		3,000
228.	3,556	3,000	3,000		3,000
229.	3,860	3,000	3,000		3,000
230.	4,069	3,000	3,000		3,000
231.	3,053	3,000	3,000		3,000
232.	4,008	3,000	3,000		3,000
233.	3,587	3,000	3,000		3,000
234.	2,894	3,000	2,894		2,894
235.	4,025	3,000	3,000		3,000
236.	4,008	3,000	3,000		3,000
237.	2,908	3,000	2,908		2,908
238.	2,983	3,000	2,983		2,983
239.	2,950	3,000	2,950		2,950
240.	3,591	3,000	3,000		3,000
241.	4,108	3,000	3,000		3,000
242.	3,847	3,000	3,000		3,000
243.	3,053	3,000	3,000		3,000
244.	3,019	3,000	3,000		3,000
245.	3,547	3,000	3,000		3,000
246.	3,270	3,000	3,000		3,000
247.	2,641	3,000	2,641		2,641
248.	3,053	3,000	3,000		3,000
249.	2,850	3,000	2,850		2,850
250.	2,578	3,000	2,578		2,578
251.	3,053	3,000	3,000		3,000
252.	2,849	3,000	2,849		2,849
253.	3,492	3,000	3,000		3,000
254.	2,921	3,000	2,921		2,921
255.	2,641	3,000	2,641		2,641
256.	2,582	3,000	2,582		2,582
257.	2,641	3,000	2,641		2,641

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
258.	2,985	3,000	2,985		2,985
259.	4,002	3,000	3,000		3,000
260.	3,537	3,000	3,000		3,000
261.	2,777	3,000	2,777		2,777
262.	3,053	3,000	3,000		3,000
263.	3,011	3,000	3,000		3,000
264.	2,525	3,000	2,525		2,525
265.	3,040	3,000	3,000		3,000
266.	4,275	3,000	3,000		3,000
267.	3,214	3,000	3,000		3,000
268.	3,275	3,000	3,000		3,000
269.	3,145	3,000	3,000		3,000
270.	2,483	3,000	2,483		2,483
271.	3,275	3,000	3,000		3,000
272.	3,794	3,000	3,000		3,000
273.	3,236	3,000	3,000		3,000
274.	3,862	3,000	3,000		3,000
275.	2,871	3,000	2,871		2,871
276.	6,742	3,000	3,000		3,000
277.	3,850	3,000	3,000		3,000
278.	3,275	3,000	3,000		3,000
279.	5,047	3,000	3,000		3,000
280.	2,629	3,000	2,629		2,629
281.	4,008	3,000	3,000		3,000
282.	3,458	3,000	3,000		3,000
283.	3,548	3,000	3,000		3,000
284.	3,549	3,000	3,000		3,000
285.	5,539	3,000	3,000		3,000
286.	3,471	3,000	3,000		3,000
287.	3,471	3,000	3,000		3,000
288.	3,467	3,000	3,000		3,000
289.	3,548	3,000	3,000		3,000
290.	3,467	3,000	3,000		3,000
291.	3,467	3,000	3,000		3,000
292.	3,467	3,000	3,000		3,000
293.	3,467	3,000	3,000		3,000
294.	2,655	3,000	2,655		2,655
295.	3,502	3,000	3,000		3,000
296.	2,655	3,000	2,655		2,655
297.	2,655	3,000	2,655		2,655
298.	2,655	3,000	2,655		2,655
299.	2,990	3,000	2,990		2,990
300.	2,836	3,000	2,836		2,836
301.	3,043	3,000	3,000		3,000
302.	3,005	3,000	3,000		3,000
303.	2,655	3,000	2,655		2,655
304.	2,655	3,000	2,655		2,655
305.	2,655	3,000	2,655		2,655
306.	2,219	3,000	2,219		2,219
307.	2,279	3,000	2,279		2,279
308.	3,591	3,000	3,000		3,000
309.	3,043	3,000	3,000		3,000
310.	2,655	3,000	2,655		2,655

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
311.	3,591	3,000	3,000		3,000
312.	2,924	3,000	2,924		2,924
313.	3,547	3,000	3,000		3,000
314.	2,668	3,000	2,668		2,668
315.	2,637	3,000	2,637		2,637
316.	3,518	3,000	3,000		3,000
317.	2,655	3,000	2,655		2,655
318.	2,655	3,000	2,655		2,655
319.	2,968	3,000	2,968		2,968
320.	2,621	3,000	2,621		2,621
321.	2,190	3,000	2,190		2,190
322.	2,655	3,000	2,655		2,655
323.	3,474	3,000	3,000		3,000
324.	3,518	3,000	3,000		3,000
325.	2,621	3,000	2,621		2,621
326.	3,458	3,000	3,000		3,000
327.	2,676	3,000	2,676		2,676
328.	3,501	3,000	3,000		3,000
329.	2,655	3,000	2,655		2,655
330.	3,324	3,000	3,000		3,000
331.	3,501	3,000	3,000		3,000
332.	3,501	3,000	3,000		3,000
333.	2,523	3,000	2,523		2,523
334.	3,529	3,000	3,000		3,000
335.	2,297	3,000	2,297		2,297
336.	3,501	3,000	3,000		3,000
337.	3,501	3,000	3,000		3,000
338.	3,501	3,000	3,000		3,000
339.	2,736	3,000	2,736		2,736
340.	2,693	3,000	2,693		2,693
341.	2,655	3,000	2,655		2,655
342.	2,727	3,000	2,727		2,727
343.	3,502	3,000	3,000		3,000
344.	2,588	3,000	2,588		2,588
345.	2,579	3,000	2,579		2,579
346.	3,473	3,000	3,000		3,000
347.	2,634	3,000	2,634		2,634
348.	3,043	3,000	3,000		3,000
349.	3,470	3,000	3,000		3,000
350.	2,521	3,000	2,521		2,521
351.	2,966	3,000	2,966		2,966
352.	2,419	3,000	2,419		2,419
353.	2,655	3,000	2,655		2,655
354.	3,501	3,000	3,000		3,000
355.	2,588	3,000	2,588		2,588
356.	3,501	3,000	3,000		3,000
357.	3,402	3,000	3,000		3,000
358.	3,043	3,000	3,000		3,000
359.	2,655	3,000	2,655		2,655
360.	2,655	3,000	2,655		2,655
361.	2,668	3,000	2,668		2,668
362.	2,887	3,000	2,887		2,887
363.	2,605	3,000	2,605		2,605

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
364.	3,414	3,000	3,000		3,000
365.	3,043	3,000	3,000		3,000
366.	2,370	3,000	2,370		2,370
367.	3,043	3,000	3,000		3,000
368.	2,655	3,000	2,655		2,655
369.	2,337	3,000	2,337		2,337
370.	1,288	3,000	1,288		1,288

Ontario co-operative education tax credit (total of amounts in column K) **500** 1,062,207 **L**

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L _____ x percentage on line 170 in Part 1 _____ % = ... **M**

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009, and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received. Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 552

Ontario Apprenticeship Training Tax Credit

Corporation's name	Business number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2016-12-31

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. For eligible expenditures incurred after March 26, 2009 for an apprenticeship program that began before April 24, 2015, the maximum credit for each qualifying apprenticeship is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. For an apprenticeship program that began after April 23, 2015, the maximum credit for each qualifying apprenticeship is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  - paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  - for services provided by the apprentice during the first 48 months of the apprenticeship program, if an apprenticeship program began before April 24, 2015; and
  - for services provided by the apprentice during the first 36 months of the apprenticeship program, if an apprenticeship program began after April 23, 2015.
- An expenditure is not eligible for an ATTC if:
  - the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  - it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  - the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario) or a person designated by him or her; and
  - the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009, or* the *Apprenticeship and Certification Act, 1998,* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act*.
- Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return*. Keep a copy of the training agreement or contract of apprenticeship to support your claim.
- File this schedule with your *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information [redacted]

120 Telephone number [redacted]

Is the claim filed for an ATTC earned through a partnership? * . . . . . **150** 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 150, what is the name of the partnership? **160** _____

Enter the percentage of the partnership's ATTC allocated to the corporation . . . . . **170** _____ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes ☒ 2 No ☐
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . . . **210** 1 Yes ☐ 2 No ☒

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

Part 3 – Specified percentage

Corporation's salaries and wages paid in the previous tax year * **300** 224,900,000

For eligible expenditures incurred after March 26, 2009 for an apprenticeship program that began before April 24, 2015:

- If line 300 is $400,000 or less, enter 45% on line 312.
- If line 300 is $600,000 or more, enter 35% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Specified percentage} = 45\% - \left[10\% \times \left(\frac{\text{amount on line 300 } \textbf{minus } 400{,}000}{200{,}000} \right) \right]$$

Specified percentage . . . . . **312** 35.000 %

For eligible expenditures incurred for an apprenticeship program that began after April 23, 2015:

- If line 300 is $400,000 or less, enter 30% on line 314.
- If line 300 is $600,000 or more, enter 25% on line 314.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 314 using the following formula:

$$\text{Specified percentage} = 30\% - \left[5\% \times \left(\frac{\text{amount on line 300 } \textbf{minus } 400{,}000}{200{,}000} \right) \right]$$

Specified percentage . . . . . **314** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Ontario apprenticeship training tax credit

Complete a **separate entry** for each apprentice for each qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a **separate entry** for each repayment, and complete columns A to G and M and N with the details for the employment period in the previous tax year in which the government assistance was received.

	A Trade code **400**	B Apprenticeship program/trade name **405**	C Name of apprentice **410**
1.	434a	Powerline Technician	[redacted]
2.	434a	Powerline Technician	
3.	434a	Powerline Technician	
4.	434a	Powerline Technician	
5.	434a	Powerline Technician	
6.	434a	Powerline Technician	
7.	434a	Powerline Technician	
8.	434a	Powerline Technician	
9.	434a	Powerline Technician	
10.	434a	Powerline Technician	
11.	434a	Powerline Technician	
12.	434a	Powerline Technician	

	D Original contract or training agreement number **420**	E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1) **425**	F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2) **430**	G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3) **435**
1.	[redacted]	2016-02-29	2016-02-29	2016-12-31
2.	[redacted]	2016-02-29	2016-02-29	2016-12-31
3.	[redacted]	2016-02-29	2016-02-29	2016-12-31
4.	[redacted]	2016-02-29	2016-02-29	2016-12-31
5.	[redacted]	2016-02-29	2016-02-29	2016-12-31
6.	[redacted]	2016-02-29	2016-02-29	2016-12-31
7.	[redacted]	2016-02-29	2016-02-29	2016-12-31
8.	[redacted]	2016-02-29	2016-02-29	2016-12-31
9.	[redacted]	2016-02-29	2016-02-29	2016-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1) 425	F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2) 430	G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3) 435
10.	[redacted]	2016-02-29	2016-02-29	2016-12-31
11.	[redacted]	2016-02-29	2016-02-29	2016-12-31
12.	[redacted]	2016-02-29	2016-02-29	2016-12-31

Note 1: Enter the original registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the last day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

Part 4 – Ontario apprenticeship training tax credit (continued)

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
1.		306	4,180
2.		306	4,180
3.		306	4,180
4.		306	4,180
5.		306	4,180
6.		306	4,180
7.		306	4,180
8.		306	4,180
9.		306	4,180
10.		306	4,180
11.		306	4,180
12.		306	4,180

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.
For H1: The days employed as an apprentice must be within 48 months of the registration date provided in column E.
For H2: The days employed as an apprentice must be within 36 months of the registration date provided in column E.

Note 2: Maximum credit = ($10,000 × H1/365*****) or ($5,000 × H2/365*****), whichever applies.
***** 366 days, if the tax year includes February 29

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
1.		58,039	14,510
2.		54,213	13,553
3.		58,642	14,661
4.		57,468	14,367
5.		70,055	17,514
6.		79,933	19,983
7.		80,309	20,077
8.		71,806	17,952
9.		70,023	17,506
10.		75,055	18,764
11.		69,642	17,411
12.		70,181	17,545

Note 3: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.
For J1: Eligible expenditures must be for services provided by the apprentice to the taxpayer during the first 48 months of the apprenticeship program, and not relating to services performed before the apprenticeship program began or after it ended.
For J2: Eligible expenditures must be for services provided by the apprentice to the taxpayer during the first 36 months of the apprenticeship program, and not relating to services performed before the apprenticeship began or after it ended.

Note 4: Calculate the amount in column K as follows:
Column K = (J1 × line 312) or (J2 × line 314), whichever applies.

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
1.	4,180		4,180
2.	4,180		4,180

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
3.	4,180		4,180
4.	4,180		4,180
5.	4,180		4,180
6.	4,180		4,180
7.	4,180		4,180
8.	4,180		4,180
9.	4,180		4,180
10.	4,180		4,180
11.	4,180		4,180
12.	4,180		4,180

Ontario apprenticeship training tax credit (total of amounts in column N) **500** 50,160 **O**

Or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O _____ x percentage on line 170 in Part 1 _____ % = ... _____ **P**

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, **add** the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year. Complete a **separate entry** for each repayment of government assistance.

See the privacy notice on your return.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 568

ONTARIO BUSINESS-RESEARCH INSTITUTE TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2016-12-31

- Use this schedule to claim the Ontario business-research institute tax credit (OBRITC) under section 97 of the *Taxation Act, 2007* (Ontario).
- The OBRITC is a 20% refundable tax credit based on qualified expenditures incurred in Ontario under an eligible contract with an eligible research institute (ERI).
- A list of eligible research institutes and the applicable ERI codes for eligible contracts can be found on our website. Go to **www.cra.gc.ca/ctao** and select "business-research institute tax credit".
- The criteria for a corporation to be eligible for the OBRITC include the eligibility requirements in Part 1 of this schedule.
- The annual qualified expenditure limit is $20 million. If a corporation is associated with other corporations at any time in the calendar year, the $20 million limit must be allocated among the associated corporations.
- Qualifying corporations are defined in subsection 97(3) of the *Taxation Act, 2007* (Ontario).
- For each eligible contract, you must complete a separate Schedule 569, *Ontario Business-Research Institute Tax Credit Contract Information*.
- Keep the eligible contract to support your claim. Do not submit the contract with the *T2 Corporation Income Tax Return*.
- To claim the OBRITC, include the following with the *T2 Corporation Income Tax Return*:
  – a completed copy of this schedule; and
  – a completed copy of Schedule 569 for each eligible contract.

Part 1 – Eligibility

1. Did the corporation, for the tax year, carry on business in Ontario through a permanent establishment in Ontario? . . . . . **100** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax for the tax year under Part III of the *Taxation Act, 2007* (Ontario)? . . . . . **105** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, the corporation is **not eligible** for the OBRITC.

Part 2 – Qualified expenditure limit for the tax year

Was the corporation associated at any time in the tax year with another corporation? . . . . . **200** 1 Yes [X] 2 No [ ]

If the corporation answered **no** at line 200, enter $20,000,000 on line 205. If the corporation answered **yes** at line 200, complete Part 3 and enter on line 205 the expenditure limit allocated to the corporation in column 310 in Part 3.

Qualified expenditure limit . . . . . **205** 20,000,000 A

If the tax year is 51 weeks or more, enter amount A on line 210.

If the tax year of the filing corporation is less than 51 weeks, complete the following proration calculation:

Amount A 20,000,000 x (days in the tax year 366 / 365) = ... B

Qualified expenditure limit for the tax year (amount A or amount B, whichever applies) . . . . . **210** 20,000,000 C

Part 3 – Allocation of the $20 million expenditure limit between associated corporations

Use this part to allocate the $20 million expenditure limit to the filing corporation and all its associated corporations for each of their tax years ending in the calendar year. See subsection 38(4) of Ontario Regulation 37/09 for expenditure limit allocation rules for associated corporations. Attach additional schedules if you need more space.

	Name of all associated corporations, including the filing corporation (include the associated corporations that have a tax year that ends in the calendar year) **300**	Business Number (enter "NR" if corporation is not registered) **305**	Expenditure limit allocated **310**
1.	TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	20,000,000
2.	TORONTO HYDRO CORPORATION		
3.	TORONTO HYDRO ENERGY SERVICES INC.		

Total expenditure limit (cannot exceed $20 million) **315** 20,000,000 D

Enter the expenditure limit allocated to the corporation on line 205 in Part 2.

Part 4 – Calculation of the Ontario business-research institute tax credit

Total number of eligible contracts used to determine the OBRITC for this tax year **400** 3

Total qualified expenditures for all eligible contracts identified on line 400 for this tax year (total of amounts on line 310 in Part 3 of each **Schedule 569**) . . . . . **405** 156,800 E

Qualified expenditure limit for the tax year (amount C in Part 2) . . . . . 20,000,000 F

Qualified expenditures for the OBRITC for the tax year (amount E or F, whichever is less) **410** 156,800

Ontario business-research Institute tax credit (line 410 x 20 %) . . . . . 31,360 G

Enter amount G on line 470 of Schedule 5, *Tax Calculation Supplementary – Corporations*.

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SCHEDULE 569

ONTARIO BUSINESS-RESEARCH INSTITUTE TAX CREDIT CONTRACT INFORMATION

Name of corporation	Business Number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2016-12-31

- Use this schedule to support your claim for the Ontario business-research institute tax credit (OBRITC), which is made on Schedule 568, *Ontario Business-Research Institute Tax Credit*. Complete a separate Schedule 569 for each eligible contract.
- The OBRITC is a 20% refundable tax credit based on qualified expenditures incurred in Ontario under an eligible contract with an eligible research institute (ERI). An ERI, for purposes of the OBRITC, is defined in subsection 97(27) of the *Taxation Act, 2007* (Ontario).
- A list of eligible research institutes and the applicable ERI codes for eligible contracts can be found on our web site. Go to **www.cra.gc.ca/ctao** and select "business-research institute tax credit".
- The eligibility requirements in Part 2 of this schedule must be met for the qualifying corporation to claim an OBRITC for this contract.
- Eligible contracts entered into before August 10, 2007 were subject to advanced ruling legislation. OBRITC claims relating to one of these contracts must have the corresponding Ontario Ministry of Revenue ruling reference number entered at line 130 in Part 1 of this schedule.
- Corporations can only claim the OBRITC for the number of days in the tax year that the corporation **was not** connected to the ERI. Connected corporations, for the purposes of the OBRITC, are defined in subsection 97(4) of the *Taxation Act*, 2007 (Ontario).
- Eligible contracts and qualified expenditures are defined in subsections 97(6) and 97(8), respectively, of the *Taxation Act, 2007* (Ontario).
- According to subsections 97(16) and (19) of the *Taxation Act, 2007* (Ontario), qualified expenditures must be reduced by contributions the corporation received, is entitled to receive or may reasonably expect to receive. Qualified expenditures include repayment of government assistance made by the corporation during the year. Contribution and government assistance are defined in subsection 97(27) of the *Taxation Act, 2007* (Ontario).

Part 1 – Contract details

100 Name of person to contact for more information: [redacted]

105 Telephone number including area code: [redacted]

110 Name of the ERI on the contract: Ryerson University

115 ERI code: 111

120 Date of contract: Year Month Day 2016-01-01

If the date on line 120 is before August 10, 2007, was the contract subject to an advanced ruling? . . . **125** 1 Yes ☐ 2 No ☒

For all contracts entered into before August 10, 2007, enter the Ontario Ministry of Revenue ruling reference number . . . . . **130** ☐ – ☐

Is the claim filed for an OBRITC earned through a partnership?* . . . . . **135** 1 Yes ☐ 2 No ☒

If the answer on line 135 is **yes**, are you a specified member? . . . . . **140** 1 Yes ☐ 2 No ☒

If the answer on line 135 is **yes**, what is the name of the partnership? **145**

Enter the corporation's percentage share of the income or loss of the partnership's fiscal period ending in the corporation's tax year . . . . . **150** ____ %

* When a corporate member of a partnership is claiming an amount for qualified expenditures incurred during the tax year under the eligible contract by the partnership, complete Schedule 569 as if the partnership were a corporation. Each corporate member, other than a specified member, should file a Schedule 569 as if it, instead of the partnership, had entered into the contract with the ERI and can claim the corporation's share of the partnership's qualified expenditures. Specified members of a partnership cannot claim an OBRITC. A definition of "specified member" can be found in subsection 248(1) of the federal *Income Tax Act*.

Part 2 – Eligibility

Contract:

1.	Did the corporation enter into a contract with an ERI?	200	1 Yes	X	2 No
2.	Do the terms of the contract state that the ERI agrees to perform, in Ontario, scientific research and experimental development (SR&ED) related to the business carried on in Canada by the corporation?	205	1 Yes	X	2 No
3.	Was the corporation entitled to exploit the results of the SR&ED carried out under the contract?	210	1 Yes	X	2 No

If you answered **no** to question 1, 2, or 3, the contract is **not** an **eligible** contract for the purposes of an OBRITC.

Expenditures:

4.	Were the expenditures made by a payment of money by the corporation to the ERI or by a prescribed payment?	215	1 Yes	X	2 No
5.	Were the expenditures incurred in respect of SR&ED carried on in Ontario by the ERI?	220	1 Yes	X	2 No
6.	Are the expenditures identified in subparagraph 37(1)(a)(i), (i.1) or (ii) of the federal *Income Tax Act* and would they also qualify as qualified expenditures, as defined in subsection 127(9) of the federal Act, other than prescribed types of expenditures and certain salaries or wages?	225	1 Yes	X	2 No
7.	Were the expenditures incurred by the corporation for purposes of SR&ED related to the business carried on in Canada by the corporation?	230	1 Yes	X	2 No

If you answered **no** to question 4, 5, 6, or 7, the expenditures are **not eligible** expenditures for the purposes of an OBRITC.

Part 3 – Qualified expenditures for this contract for the tax year

Qualified expenditures incurred in the tax year 300 120,000

If the corporation answered **yes** at line 135 in Part 1, and **no** at line 140 in Part 1, determine the partnerships' share of qualified expenditures available to claim in the tax year:

Line 300 120,000 x percentage on line 150 in Part 1 % = A

Number of days in this tax year that the corporation was **not** connected to the ERI identified on line 110 in Part 1 . . . . . 305 366

Qualified expenditures for this contract for the tax year:

$$\frac{\text{(Line 300 or amount A, whichever applies) x line 305}}{\text{number of days in the tax year}} \quad \frac{43{,}920{,}000}{366} =$$

. . . . . 310 120,000 B

Enter amount B on line 405 of **Schedule 568**, *Ontario Business-Research Institute Tax Credit*.

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SCHEDULE 569

ONTARIO BUSINESS-RESEARCH INSTITUTE TAX CREDIT CONTRACT INFORMATION

Name of corporation	Business Number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2016-12-31

- Use this schedule to support your claim for the Ontario business-research institute tax credit (OBRITC), which is made on Schedule 568, *Ontario Business-Research Institute Tax Credit*. Complete a separate Schedule 569 for each eligible contract.
- The OBRITC is a 20% refundable tax credit based on qualified expenditures incurred in Ontario under an eligible contract with an eligible research institute (ERI). An ERI, for purposes of the OBRITC, is defined in subsection 97(27) of the *Taxation Act, 2007* (Ontario).
- A list of eligible research institutes and the applicable ERI codes for eligible contracts can be found on our web site. Go to **www.cra.gc.ca/ctao** and select "business-research institute tax credit".
- The eligibility requirements in Part 2 of this schedule must be met for the qualifying corporation to claim an OBRITC for this contract.
- Eligible contracts entered into before August 10, 2007 were subject to advanced ruling legislation. OBRITC claims relating to one of these contracts must have the corresponding Ontario Ministry of Revenue ruling reference number entered at line 130 in Part 1 of this schedule.
- Corporations can only claim the OBRITC for the number of days in the tax year that the corporation **was not** connected to the ERI. Connected corporations, for the purposes of the OBRITC, are defined in subsection 97(4) of the *Taxation Act*, 2007 (Ontario).
- Eligible contracts and qualified expenditures are defined in subsections 97(6) and 97(8), respectively, of the *Taxation Act, 2007* (Ontario).
- According to subsections 97(16) and (19) of the *Taxation Act, 2007* (Ontario), qualified expenditures must be reduced by contributions the corporation received, is entitled to receive or may reasonably expect to receive. Qualified expenditures include repayment of government assistance made by the corporation during the year. Contribution and government assistance are defined in subsection 97(27) of the *Taxation Act, 2007* (Ontario).

Part 1 – Contract details

100 Name of person to contact for more information: [redacted]

105 Telephone number including area code: [redacted]

110 Name of the ERI on the contract: University of Toronto

115 ERI code: 116

120 Date of contract (Year Month Day): 2016-01-01

If the date on line 120 is before August 10, 2007, was the contract subject to an advanced ruling? . . . **125** 1 Yes ☐ 2 No ☒

For all contracts entered into before August 10, 2007, enter the Ontario Ministry of Revenue ruling reference number . . . . . **130** ☐ – ☐

Is the claim filed for an OBRITC earned through a partnership?* . . . . . **135** 1 Yes ☐ 2 No ☒

If the answer on line 135 is **yes**, are you a specified member? . . . . . **140** 1 Yes ☐ 2 No ☒

If the answer on line 135 is **yes**, what is the name of the partnership? **145**

Enter the corporation's percentage share of the income or loss of the partnership's fiscal period ending in the corporation's tax year . . . . . **150** ____ %

* When a corporate member of a partnership is claiming an amount for qualified expenditures incurred during the tax year under the eligible contract by the partnership, complete Schedule 569 as if the partnership were a corporation. Each corporate member, other than a specified member, should file a Schedule 569 as if it, instead of the partnership, had entered into the contract with the ERI and can claim the corporation's share of the partnership's qualified expenditures. Specified members of a partnership cannot claim an OBRITC. A definition of "specified member" can be found in subsection 248(1) of the federal *Income Tax Act*.

Part 2 – Eligibility

Contract:

1.	Did the corporation enter into a contract with an ERI?	200	1 Yes	X	2 No
2.	Do the terms of the contract state that the ERI agrees to perform, in Ontario, scientific research and experimental development (SR&ED) related to the business carried on in Canada by the corporation?	205	1 Yes	X	2 No
3.	Was the corporation entitled to exploit the results of the SR&ED carried out under the contract?	210	1 Yes	X	2 No

If you answered **no** to question 1, 2, or 3, the contract is **not** an **eligible** contract for the purposes of an OBRITC.

Expenditures:

4.	Were the expenditures made by a payment of money by the corporation to the ERI or by a prescribed payment?	215	1 Yes	X	2 No
5.	Were the expenditures incurred in respect of SR&ED carried on in Ontario by the ERI?	220	1 Yes	X	2 No
6.	Are the expenditures identified in subparagraph 37(1)(a)(i), (i.1) or (ii) of the federal *Income Tax Act* and would they also qualify as qualified expenditures, as defined in subsection 127(9) of the federal Act, other than prescribed types of expenditures and certain salaries or wages?	225	1 Yes	X	2 No
7.	Were the expenditures incurred by the corporation for purposes of SR&ED related to the business carried on in Canada by the corporation?	230	1 Yes	X	2 No

If you answered **no** to question 4, 5, 6, or 7, the expenditures are **not eligible** expenditures for the purposes of an OBRITC.

Part 3 – Qualified expenditures for this contract for the tax year

Qualified expenditures incurred in the tax year 300 20,800

If the corporation answered **yes** at line 135 in Part 1, and **no** at line 140 in Part 1, determine the partnerships' share of qualified expenditures available to claim in the tax year:

Line 300 20,800 x percentage on line 150 in Part 1 % = A

Number of days in this tax year that the corporation was **not** connected to the ERI identified on line 110 in Part 1 . . . . . 305 366

Qualified expenditures for this contract for the tax year:

$$\frac{\text{(Line 300 or amount A, whichever applies) x line 305}}{\text{number of days in the tax year}} \quad \frac{7{,}612{,}800}{366} =$$

. . . . . 310 20,800 B

Enter amount B on line 405 of **Schedule 568**, *Ontario Business-Research Institute Tax Credit*.

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SCHEDULE 569

ONTARIO BUSINESS-RESEARCH INSTITUTE TAX CREDIT CONTRACT INFORMATION

Name of corporation	Business Number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2016-12-31

- Use this schedule to support your claim for the Ontario business-research institute tax credit (OBRITC), which is made on Schedule 568, *Ontario Business-Research Institute Tax Credit*. Complete a separate Schedule 569 for each eligible contract.
- The OBRITC is a 20% refundable tax credit based on qualified expenditures incurred in Ontario under an eligible contract with an eligible research institute (ERI). An ERI, for purposes of the OBRITC, is defined in subsection 97(27) of the *Taxation Act, 2007* (Ontario).
- A list of eligible research institutes and the applicable ERI codes for eligible contracts can be found on our web site. Go to **www.cra.gc.ca/ctao** and select "business-research institute tax credit".
- The eligibility requirements in Part 2 of this schedule must be met for the qualifying corporation to claim an OBRITC for this contract.
- Eligible contracts entered into before August 10, 2007 were subject to advanced ruling legislation. OBRITC claims relating to one of these contracts must have the corresponding Ontario Ministry of Revenue ruling reference number entered at line 130 in Part 1 of this schedule.
- Corporations can only claim the OBRITC for the number of days in the tax year that the corporation **was not** connected to the ERI. Connected corporations, for the purposes of the OBRITC, are defined in subsection 97(4) of the *Taxation Act*, 2007 (Ontario).
- Eligible contracts and qualified expenditures are defined in subsections 97(6) and 97(8), respectively, of the *Taxation Act, 2007* (Ontario).
- According to subsections 97(16) and (19) of the *Taxation Act, 2007* (Ontario), qualified expenditures must be reduced by contributions the corporation received, is entitled to receive or may reasonably expect to receive. Qualified expenditures include repayment of government assistance made by the corporation during the year. Contribution and government assistance are defined in subsection 97(27) of the *Taxation Act, 2007* (Ontario).

Part 1 – Contract details

100 Name of person to contact for more information: [redacted]

105 Telephone number including area code: [redacted]

110 Name of the ERI on the contract: Georgian College

115 ERI code: 212

120 Date of contract (Year Month Day): 2016-01-01

If the date on line 120 is before August 10, 2007, was the contract subject to an advanced ruling? . . . **125** 1 Yes [ ] 2 No [X]

For all contracts entered into before August 10, 2007, enter the Ontario Ministry of Revenue ruling reference number . . . . . **130** [ ] – [ ]

Is the claim filed for an OBRITC earned through a partnership?* . . . . . **135** 1 Yes [ ] 2 No [X]

If the answer on line 135 is **yes**, are you a specified member? . . . . . **140** 1 Yes [ ] 2 No [X]

If the answer on line 135 is **yes**, what is the name of the partnership? . . . . . **145** _____

Enter the corporation's percentage share of the income or loss of the partnership's fiscal period ending in the corporation's tax year . . . . . **150** _____ %

* When a corporate member of a partnership is claiming an amount for qualified expenditures incurred during the tax year under the eligible contract by the partnership, complete Schedule 569 as if the partnership were a corporation. Each corporate member, other than a specified member, should file a Schedule 569 as if it, instead of the partnership, had entered into the contract with the ERI and can claim the corporation's share of the partnership's qualified expenditures. Specified members of a partnership cannot claim an OBRITC. A definition of "specified member" can be found in subsection 248(1) of the federal *Income Tax Act*.

Part 2 – Eligibility

Contract:

1.	Did the corporation enter into a contract with an ERI?	**200**	1 Yes	X	2 No
2.	Do the terms of the contract state that the ERI agrees to perform, in Ontario, scientific research and experimental development (SR&ED) related to the business carried on in Canada by the corporation?	**205**	1 Yes	X	2 No
3.	Was the corporation entitled to exploit the results of the SR&ED carried out under the contract?	**210**	1 Yes	X	2 No

If you answered **no** to question 1, 2, or 3, the contract is **not** an **eligible** contract for the purposes of an OBRITC.

Expenditures:

4.	Were the expenditures made by a payment of money by the corporation to the ERI or by a prescribed payment?	**215**	1 Yes	X	2 No
5.	Were the expenditures incurred in respect of SR&ED carried on in Ontario by the ERI?	**220**	1 Yes	X	2 No
6.	Are the expenditures identified in subparagraph 37(1)(a)(i), (i.1) or (ii) of the federal *Income Tax Act* and would they also qualify as qualified expenditures, as defined in subsection 127(9) of the federal Act, other than prescribed types of expenditures and certain salaries or wages?	**225**	1 Yes	X	2 No
7.	Were the expenditures incurred by the corporation for purposes of SR&ED related to the business carried on in Canada by the corporation?	**230**	1 Yes	X	2 No

If you answered **no** to question 4, 5, 6, or 7, the expenditures are **not eligible** expenditures for the purposes of an OBRITC.

Part 3 – Qualified expenditures for this contract for the tax year

Qualified expenditures incurred in the tax year **300** 16,000

If the corporation answered **yes** at line 135 in Part 1, and **no** at line 140 in Part 1, determine the partnerships' share of qualified expenditures available to claim in the tax year:

Line 300 16,000 x percentage on line 150 in Part 1 % = A

Number of days in this tax year that the corporation was **not** connected to the ERI identified on line 110 in Part 1 **305** 366

Qualified expenditures for this contract for the tax year:

$$\frac{\text{(Line 300 or amount A, whichever applies) x line 305}}{\text{number of days in the tax year}} \quad \frac{5{,}856{,}000}{366} =$$

310 16,000 B

Enter amount B on line 405 of **Schedule 568**, *Ontario Business-Research Institute Tax Credit*.

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COST OF CAPITAL

In accordance with Section 2.5 of the OEB Filing Requirements for Electricity Distribution Rate Applications (July 12, 2018), this Schedule provides an overview of Toronto Hydro's capital structure and financing plans for 2018, 2019 and 2020.

1. CAPITAL STRUCTURE

Toronto Hydro's sets its capital structure for ratemaking purposes in accordance with the OEB's Cost of Capital guidelines issued December 11, 2009 in the Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084) ("Report of the Board"). For Toronto Hydro, the debt to equity split for the test years is set at 60:40. The debt component in each year includes a deemed four percent short-term debt component.

2. FINANCING PLANS

2.1 Equity

Toronto Hydro Corporation ("THC") is the sole shareholder of Toronto Hydro.

Toronto Hydro's forecasted Return on Equity ("ROE") for the 2020 Test Year is based on the OEB's formulaic approach as outlined in the Report of the Board. For 2020, the ROE calculation uses the March 2018 bond yield spread[1] and the Ten-Year Government of Canada Bond Yield Forecast.[2]

[1] Difference between the average 30-Year A-Rated Canadian Utility bond yield from Bloomberg L.P. and the average 30-Year Government of Canada bond as published by the Bank of Canada

[2] The average of the forecast Ten-Year Government of Canada bond yield as at December 31, 2019 and September 30, 2020 from Bloomberg L.P.

Table 1, below, shows the projected ROE for 2020, and details of the derivation based on OEB's formulaic approach.

Table 1: Return on Equity

Year	Return on Equity
2020	8.82%

Return on Equity (ROE) forecast		
Initial ROE		9.75
Change in LCBF from September 2009		
LCBF	2.490	
Base LCBF	4.250	
Difference	-1.760	
0.5 X Difference		-0.880
Change in A-rated Utility Bond Yield Spread from September 2009		
A-rated Utility Bond Spread (March 2018)	1.314	
Base A-rated Utility Bond Yield Spread	1.415	
Difference	-0.101	
0.5 X Difference		-0.050
2020 Projected ROE based on March 2018 data		**8.82**

Toronto Hydro uses the 2020 ROE forecast for the purpose of calculating revenue requirement for the 2020 Test Year (Exhibit 6, Tab 1) and the derivation of the C-factor in the Custom Price Cap Index (Exhibit 1B, Tab 4, Schedule 1). To determine the final revenue requirement for 2020 and the updated C-factor, Toronto Hydro will rely on the ROE approved by the OEB in late 2019. Toronto Hydro proposes that the deemed ROE

throughout the 2020-2024 rate cycle be the rate that the OEB sets in late 2019 for 2020 rebasing applications.

2.2 Financial Market Overview and Forecast

2017 marked the second most active year on record (after 2013) in the Canadian bond market with total corporate issuance of C$120 billion (compared to C$121 billion in 2013). Elevated issuance in 2017 was driven by positive investor sentiment combined with low Government of Canada yields which provided attractive funding opportunities for corporate issuers. In 2017, global markets experienced less volatility and uncertainty, and the Canadian markets benefitted from strong demand from investors, notable oversubscription of issuances and minimal new issue pricing concessions. This trend was also seen in the utility sector.

In the third quarter of 2017, the Bank of Canada increased interest rates twice by 25 bps. A further 25 bps rate increase occurred in January 2018 following the release of strong economic data in December 2017. In conjunction with the rate moves the Government of Canada yields had risen with the 10 year yield by approximately 50 bps relative to the lows in 2017. The expectation of further unwinding of monetary easing policies by central banks and a return to rate normalization is an expected global trend after years of low absolute interest rates. This expectation is being supported by stronger economic growth conditions globally, and in the US by more recent tax reform. Concerns that this trend may create tighter labour markets, higher wages and inflation may continue to drive interest rates higher in 2018. Canadian rates are forecasted to continue to rise, although at a slower pace than in the U.S.

Corporate credit spreads started to tighten in 2017, partially offsetting the rising Government of Canada yields and allowing the absolute all-in yields of issuances to remain relatively stable during the 2015-2017 period. This is evidenced by the all-in coupon rate of 3.485 percent on the most recent THC's 30-year issuance on November 14, 2017, compared to an all-in coupon rate of 3.55 percent on THC's 30-year issuance on March 16, 2015. From now until 2020, the assumption is for THC's 10-year bond spread to be 111 basis points and 30-year bond spread to be 150 basis points. These spreads are determined from the weekly indicative quotes provided by designated banks in THC's revolving credit facility. These 10-year and 30-year spreads represent the average of the quotes received over a historical period from January 2014 to March 2018.

2.3 Medium and Long-Term Debt

Toronto Hydro's issues debt at the THC level via medium term notes in the Canadian public debt market. This requires THC to obtain and maintain credit ratings. As of July 1, 2018, THC's debentures were rated by DBRS and S&P as follows:

Table 2: Rating of THC Debentures

Rating Agency	Commercial Paper	Long-Term Debt
DBRS	R-1 (Low)	A Stable
Standard & Poor's ("S&P")	Not rated	A

The most recent ratings reports from DBRS and S&P are provided in (Exhibit 1C, Tab 3, Schedule 8).

Toronto Hydro is assigned debt through promissory notes between the Toronto Hydro and its parent, THC. The promissory notes are written on the same terms as the parent

debt as the borrowing is done on behalf of the corporation's affiliates. A fee of five basis points is charged for administration.

As of July 1st, 2018 Toronto Hydro had outstanding long-term debt in the amount of $2.10 billion, as detailed in Table 3 below.

Table 3: Long-Term Debt

Description	Maturity	Outstanding Principal ($)	Rate (%)
$245M Prom Note	Nov. 12, 2019	245,057,739	4.54
$300M Prom Note	Nov. 18, 2021	300,000,000	3.59
$15M Prom Note	Jan. 1, 2022	15,000,000	3.32
$250M Prom Note	Apr. 10, 2023	250,000,000	2.96
$200M Prom Note	Aug. 25, 2026	200,000,000	2.572
$200M Prom Note	May 21, 2040	200,000,000	5.59
$200M Prom Note	Sept. 16, 2044	200,000,000	4.13
$200M Prom Note	July 28, 2045	200,000,000	3.60
$200M Prom Note	Feb. 28, 2048	200,000,000	3.535
$200M Prom Note	Apr. 9, 2063	200,000,000	4.01
$45M Prom Note	Apr. 9, 2063	45,000,000	3.988
$45M Prom Note	Due on demand	45,000,000	4.16% (using deemed LTD rate)
Total		**2,100,057,739**	**3.83**

Forecasted new debt issuance for 2018-2020 is driven primarily by Toronto Hydro's capital plans and the repayment requirements of the maturing debt. Details of the forecasted debt issues for 2018-2020 are shown in Table 4.

Table 4: Forecasted Long-Term Debt Issues

Description	Issue Date	Term	Principal ($)	Underlying Govt Bond Rate (%)	Corporate Spread Forecast (%)	Forecast Coupon Rate (%)
$200M Prom Note (Series 14)	Feb 15, 2019	10 Years	200,000,000	2.20	1.16	**3.36**
$250M Prom Note (Series 15)	Oct 15, 2019	30 Years	250,000,000	2.34	1.55	**3.89**
$200M Prom Note (Series 16)	July 2, 2020	10 Years	200,000,000	2.33	1.16	**3.49**

Forecasted debt rates are based on the 10-Year and 30-Year Government of Canada Bond Yield Forecast (Bloomberg L.P.), when applicable, plus Toronto Hydro's estimate of corporate spreads at the time of issuance (inclusive of the five basis point administration fee).

Toronto Hydro applies the weighted average forecasted debt rates in its Cost of Capital, rather than applying the OEB's deemed debt rate, since this debt is based on market rates. Toronto Hydro proposes that the embedded debt rates set for 2020 apply throughout the 2020-2024 rate cycle.

2.4 Preferred Shares

Toronto Hydro has no plans to issue any preferred shares over the 2018-2020 period.

2.5 Short-Term Debt

Over the 2018-2020 period, Toronto Hydro plans to issue short-term debt in order to better match its liquidity needs in an effort to minimize net financing charges. THC

maintains a revolving credit facility and also has the ability to issue commercial paper available for Toronto Hydro when short-term funds are required.

One-Month Banker's Acceptance rates (Bloomberg L.P.) are used as a proxy for Toronto Hydro's forecast of its short-term debt rate, plus a five basis point administration fee. The rates are outlined in Table 5 below. The deemed short-term debt weighting of 4 percent applies to Toronto Hydro's capital structure.

Table 5: Short-Term Rates

Year	Short Term Rates
2018	1.83%
2019	2.44%
2020	2.61%

OEB Appendix 2-OA
Capital Structure and Cost of Capital

This table must be completed for the last Board approved year and the test year.

Year: 2015 OEB Approved

Line No.	Particulars	Capitalization Ratio			Cost Rate		Return
		(%)		($)	(%)		($)
	Debt						
1	Long-term Debt	56.00%		$1,809,917,329	4.28%		$77,464,462
2	Short-term Debt	4.00%	(1)	$129,279,809	1.38%		$1,784,061
3	**Total Debt**	60.0%		$1,939,197,139	4.09%		$79,248,523
	Equity						
4	Common Equity	40.00%		$1,292,798,092	9.30%		$120,230,223
5	Preferred Shares	0.00%		$ -			$ -
6	**Total Equity**	40.0%		$1,292,798,092	9.30%		$120,230,223
7	**Total**	100.0%		$3,231,995,231	6.17%		$199,478,746

Notes

(1) 4.0% unless an applicant has proposed or been approved for a different amount.

OEB Appendix 2-OA
Capital Structure and Cost of Capital

This table must be completed for the last Board approved year and the test year.

Year: 2020 Test Year

Line No.	Particulars	Capitalization Ratio			Cost Rate		Return
		(%)		($)	(%)		($)
	Debt						
1	Long-term Debt	56.00%		$2,584,564,841	3.71%		$95,887,356
2	Short-term Debt	4.00%	(1)	$184,611,774	2.61%		$4,818,367
3	**Total Debt**	60.0%		$2,769,176,616	3.64%		$100,705,723
	Equity						
4	Common Equity	40.00%		$1,846,117,744	8.82%		$162,827,585
5	Preferred Shares	0.00%		$ -			$ -
6	**Total Equity**	40.0%		$1,846,117,744	8.82%		$162,827,585
7	**Total**	100.0%		$4,615,294,360	5.71%		$263,533,308

Notes

(1) 4.0% unless an applicant has proposed or been approved for a different amount.

OEB Appendix 2-OB
Debt Instruments

This table must be completed for all required historical years, the bridge year and the test year.

Year 2016

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	2007 Series 2	THC	Affiliated	Fixed Rate	14-Nov-07	10	$ 245,057,739	5.20%	$ 12,743,002	
2	2009 Series 3	THC	Affiliated	Fixed Rate	12-Nov-09	10	$ 245,057,739	4.54%	$ 11,125,621	
3	2010 Series 6	THC	Affiliated	Fixed Rate	20-May-10	30	$ 200,000,000	5.59%	$ 11,180,000	
4	2011 Series 7	THC	Affiliated	Fixed Rate	18-Nov-11	10	$ 300,000,000	3.59%	$ 10,770,000	
5	2012 Prom Note #1	THC	Affiliated	Fixed Rate	1-Jan-12	10	$ 15,000,000	3.32%	$ 498,000	
6	2012 Prom Note #2	THC	Affiliated	Fixed Rate	1-Jan-12	N/A	$ 45,000,000	4.54%	$ 2,043,000	Payable on demand - deemed LTD rate for 2016
7	2013 Series 8	THC	Affiliated	Fixed Rate	9-Apr-13	10	$ 250,000,000	2.96%	$ 7,400,000	
8	2013 Series 9	THC	Affiliated	Fixed Rate	9-Apr-13	50	$ 200,000,000	4.01%	$ 8,020,000	
9	2014 Series 10	THC	Affiliated	Fixed Rate	16-Sep-14	30	$ 200,000,000	4.13%	$ 8,260,000	
10	2015 Series 11	THC	Affiliated	Fixed Rate	16-Mar-15	30	$ 200,000,000	3.60%	$ 7,200,000	
11	2013 Series 9 re-open	THC	Affiliated	Fixed Rate	2-Sep-15	50	$ 45,000,000	3.988%	$ 1,794,600	
12	2016 Series 12	THC	Affiliated	Fixed Rate	14-Jun-16	10	$ 200,000,000	2.572%	$ 2,832,723	
Total							$ 2,055,252,464	4.08%	$ 83,866,947	

Notes

1 If financing is in place only part of the year, calculate the pro-rated interest and input in the cell.
2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* ,
3 Add more lines above row 12 if necessary.

OEB Appendix 2-OB
Debt Instruments

This table must be completed for all required historical years, the bridge year and the test year.

Year 2017

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	2007 Serie	THC	Affiliated	Fixed Rate	14-Nov-07	10	$ 245,057,739	5.20%	$ 11,102,123	
2	2009 Serie	THC	Affiliated	Fixed Rate	12-Nov-09	10	$ 245,057,739	4.54%	$ 11,125,621	
3	2010 Serie	THC	Affiliated	Fixed Rate	20-May-10	30	$ 200,000,000	5.59%	$ 11,180,000	
4	2011 Serie	THC	Affiliated	Fixed Rate	18-Nov-11	10	$ 300,000,000	3.59%	$ 10,770,000	
5	2012 Prom	THC	Affiliated	Fixed Rate	1-Jan-12	10	$ 15,000,000	3.32%	$ 498,000	
6	2012 Prom	THC	Affiliated	Fixed Rate	1-Jan-12	N/A	$ 45,000,000	3.72%	$ 1,674,000	Payable on demand - deemed LTD rate for 2017
7	2013 Serie	THC	Affiliated	Fixed Rate	9-Apr-13	10	$ 250,000,000	2.96%	$ 7,400,000	
8	2013 Serie	THC	Affiliated	Fixed Rate	9-Apr-13	50	$ 200,000,000	4.01%	$ 8,020,000	
9	2014 Serie	THC	Affiliated	Fixed Rate	16-Sep-14	30	$ 200,000,000	4.13%	$ 8,260,000	
10	2015 Serie	THC	Affiliated	Fixed Rate	16-Mar-15	30	$ 200,000,000	3.60%	$ 7,200,000	
11	2013 Serie	THC	Affiliated	Fixed Rate	2-Sep-15	50	$ 45,000,000	3.988%	$ 1,794,600	
12	2016 Serie	THC	Affiliated	Fixed Rate	14-Jun-16	10	$ 200,000,000	2.572%	$ 5,144,000	
13	2017 Serie	THC	Affiliated	Fixed Rate	14-Nov-17	30	$ 200,000,000	3.535%	$ 929,753	
Total							$ 2,139,861,467	3.98%	$ 85,098,097	

Notes

1 If financing is in place only part of the year, calculate the pro-rated interest and input in the cell.
2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated*
3 Add more lines above row 12 if necessary.

OEB Appendix 2-OB
Debt Instruments

This table must be completed for all required historical years, the bridge year and the test year.

Year 2018

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	2009 Serie	THC	Affiliated	Fixed Rate	12-Nov-09	10	$ 245,057,739	4.54%	$ 11,125,621	
2	2010 Serie	THC	Affiliated	Fixed Rate	20-May-10	30	$ 200,000,000	5.59%	$ 11,180,000	
3	2011 Serie	THC	Affiliated	Fixed Rate	18-Nov-11	10	$ 300,000,000	3.59%	$ 10,770,000	
4	2012 Prom	THC	Affiliated	Fixed Rate	1-Jan-12	10	$ 15,000,000	3.32%	$ 498,000	
5	2012 Prom	THC	Affiliated	Fixed Rate	1-Jan-12	N/A	$ 45,000,000	4.16%	$ 1,872,000	Payable on demand - deemed LTD rate for 2018
6	2013 Serie	THC	Affiliated	Fixed Rate	9-Apr-13	10	$ 250,000,000	2.96%	$ 7,400,000	
7	2013 Serie	THC	Affiliated	Fixed Rate	9-Apr-13	50	$ 200,000,000	4.01%	$ 8,020,000	
8	2014 Serie	THC	Affiliated	Fixed Rate	16-Sep-14	30	$ 200,000,000	4.13%	$ 8,260,000	
9	2015 Serie	THC	Affiliated	Fixed Rate	16-Mar-15	30	$ 200,000,000	3.60%	$ 7,200,000	
10	2013 Serie	THC	Affiliated	Fixed Rate	2-Sep-15	50	$ 45,000,000	3.988%	$ 1,794,600	
11	2016 Serie	THC	Affiliated	Fixed Rate	14-Jun-16	10	$ 200,000,000	2.572%	$ 5,144,000	
12	2017 Serie	THC	Affiliated	Fixed Rate	14-Nov-17	30	$ 200,000,000	3.535%	$ 7,070,000	
Total							$ 2,100,057,739	3.83%	$ 80,334,221	

Notes

1 If financing is in place only part of the year, calculate the pro-rated interest and input in the cell.
2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's*
3 Add more lines above row 12 if necessary.

OEB Appendix 2-OB
Debt Instruments

This table must be completed for all required historical years, the bridge year and the test year.

Year 2019

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	2009 Serie	THC	Affiliated	Fixed Rate	12-Nov-09	10	$ 245,057,739	4.54%	$ 9,632,045	
2	2010 Serie	THC	Affiliated	Fixed Rate	20-May-10	30	$ 200,000,000	5.59%	$ 11,180,000	
3	2011 Serie	THC	Affiliated	Fixed Rate	18-Nov-11	10	$ 300,000,000	3.59%	$ 10,770,000	
4	2012 Prom	THC	Affiliated	Fixed Rate	1-Jan-12	10	$ 15,000,000	3.32%	$ 498,000	
5	2012 Prom	THC	Affiliated	Fixed Rate	1-Jan-12	N/A	$ 45,000,000	4.16%	$ 1,872,000	Payable on demand - deemed LTD rate for 2018
6	2013 Serie	THC	Affiliated	Fixed Rate	9-Apr-13	10	$ 250,000,000	2.96%	$ 7,400,000	
7	2013 Serie	THC	Affiliated	Fixed Rate	9-Apr-13	50	$ 200,000,000	4.01%	$ 8,020,000	
8	2014 Serie	THC	Affiliated	Fixed Rate	16-Sep-14	30	$ 200,000,000	4.13%	$ 8,260,000	
9	2015 Serie	THC	Affiliated	Fixed Rate	16-Mar-15	30	$ 200,000,000	3.60%	$ 7,200,000	
10	2013 Serie	THC	Affiliated	Fixed Rate	2-Sep-15	50	$ 45,000,000	3.988%	$ 1,794,600	
11	2016 Serie	THC	Affiliated	Fixed Rate	14-Jun-16	10	$ 200,000,000	2.572%	$ 5,144,000	
12	2017 Serie	THC	Affiliated	Fixed Rate	14-Nov-17	30	$ 200,000,000	3.535%	$ 7,070,000	
13	2019 Serie	THC	Affiliated	Fixed Rate	15-Feb-19	10	$ 200,000,000	3.36%	$ 5,891,507	Expected issu
14	2019 Serie	THC	Affiliated	Fixed Rate	15-Oct-19	30	$ 250,000,000	3.89%	$ 2,078,219	Expected issu
Total							$ 2,295,926,700	3.78%	$ 86,810,371	

Notes

1 If financing is in place only part of the year, calculate the pro-rated interest and input in the cell.
2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario*'s
3 Add more lines above row 12 if necessary.

OEB Appendix 2-OB
Debt Instruments

This table must be completed for all required historical years, the bridge year and the test year.

Year 2020

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	2010 Serie	THC	Affiliated	Fixed Rate	20-May-10	30	$ 200,000,000	5.59%	$ 11,180,000	
2	2011 Serie	THC	Affiliated	Fixed Rate	18-Nov-11	10	$ 300,000,000	3.59%	$ 10,770,000	
3	2012 Prom	THC	Affiliated	Fixed Rate	1-Jan-12	10	$ 15,000,000	3.32%	$ 498,000	
4	2012 Prom	THC	Affiliated	Fixed Rate	1-Jan-12	N/A	$ 45,000,000	4.16%	$ 1,872,000	Payable on demand - deemed LTD rate for 2018
5	2013 Serie	THC	Affiliated	Fixed Rate	9-Apr-13	10	$ 250,000,000	2.96%	$ 7,400,000	
6	2013 Serie	THC	Affiliated	Fixed Rate	9-Apr-13	50	$ 200,000,000	4.01%	$ 8,020,000	
7	2014 Serie	THC	Affiliated	Fixed Rate	16-Sep-14	30	$ 200,000,000	4.13%	$ 8,260,000	
8	2015 Serie	THC	Affiliated	Fixed Rate	16-Mar-15	30	$ 200,000,000	3.60%	$ 7,200,000	
9	2013 Serie	THC	Affiliated	Fixed Rate	2-Sep-15	50	$ 45,000,000	3.988%	$ 1,794,600	
10	2016 Serie	THC	Affiliated	Fixed Rate	14-Jun-16	10	$ 200,000,000	2.572%	$ 5,144,000	
11	2017 Serie	THC	Affiliated	Fixed Rate	14-Nov-17	30	$ 200,000,000	3.535%	$ 7,070,000	
12	2019 Serie	THC	Affiliated	Fixed Rate	15-Feb-19	10	$ 200,000,000	3.36%	$ 6,720,000	Expected issuar
13	2019 Serie	THC	Affiliated	Fixed Rate	15-Oct-19	30	$ 250,000,000	3.89%	$ 9,725,000	Expected issuar
14	2020 Serie	THC	Affiliated	Fixed Rate	2-Jul-20	10	$ 200,000,000	3.49%	$ 3,499,562	Expected issuar
Total							$ 2,405,273,973	3.71%	$ 89,153,162	

Notes

1 If financing is in place only part of the year, calculate the pro-rated interest and input in the cell.
2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's*
3 Add more lines above row 12 if necessary.

REVENUE REQUIREMENT AND SUFFICIENCY / DEFICIENCY

Toronto Hydro earns the majority of its revenue through distribution rates and also earns other revenues through the provision of non-distribution related activities. These other revenues offset the revenue requirement Toronto Hydro collects from its distribution service customers.

The recovery of Deferral and Variance Accounts ("DVAs") is not included in the revenue requirement. DVAs are recovered through separate rate riders as described in Exhibit 9, Tab 1, Schedule 1. Table 1, below, summarizes Toronto Hydro's 2020 revenue requirement.

Table 1: 2020 Forecast Revenue Requirement ($ Millions)

	2020 Test Year
OM&A Expenses (incl. property taxes)	277.5
Amortization/Depreciation	268.7
Income Taxes (Grossed up)	34.7
Deemed Interest Expense	100.8
Return on Deemed Equity	162.8
Service Revenue Requirement	844.5
Revenue Offsets	47.7
Base Revenue Requirement	796.8

Full details on the calculation of revenue requirement, including the Determination of Net Utility Income, Statement of Rate Base, Actual Utility Return on Rate Base, Indicated Rate of Return, Requested Rate of Return and the Deficiency in Revenue, are found in the Revenue Requirement Workforms ("RRWF"), filed as Exhibit 6, Tab 1, Schedule 2-6.

While Toronto Hydro files the RRWF for all years, including 2021-2024 during which rates are proposed to be set based on the Custom Price Cap Index and not on a revenue requirement basis, Toronto Hydro submits that the calculations shown in the RRWF, particularly the tabs related to Cost Allocation and Rate Design, are not directly relevant for the OEB to determine final distribution rates.

In order to meet the specific requirements of Toronto Hydro, some minor adjustments to the Rates-related tabs of the OEB's RRWF were required. Appendix A fully documents these adjustments.

1. SERVICE REVENUE REQUIREMENT

Service revenue requirement is comprised of operating expenses, cost of capital and PILs.

Operating Expenses, including administrative and general, depreciation and amortization, and property taxes, are explained in further detail in Exhibits 4A and 4B. Exhibit 4A, Tab 1, Schedule 1 contains a summary of distribution expenses.

Cost of capital is calculated based on a weighted average of interest expense and return on equity. Toronto Hydro's capital structure for ratemaking purposes is determined in accordance with the OEB's Cost of Capital guidelines. The cost of capital based on the OEB's deemed capital structure is discussed in Exhibit 5, Tab 1.

Income taxes and PILs are explained in detail in Exhibit 4B, Tab 2, Schedule 1.

2. REVENUE OFFSETS

Toronto Hydro earns revenue from its distribution tariff as well as other revenues from non-distribution related services, rentals and short term investment income. These other revenues offset the revenue requirement to be collected through the distribution tariff.

Revenue offsets are detailed in Exhibit 3, Tab 2, Schedule 1.

3. BASE REVENUE REQUIREMENT

Base revenue requirement is derived as service revenue requirement less revenue offsets. The base revenue requirement is allocated to and collected from the various customer classes through distribution rates.

4. OVERALL REVENUE DEFICIENCY

For 2020, revenue deficiency is the difference between the 2020 forecast year revenue requirement and the 2020 forecast year revenues calculated at current rates.

The 2020 test year revenue is determined using the 2020 forecast of billing units at expected 2019 base distribution rates.[1] The deficiency is net of electricity price differentials captured in RSVA accounts and any costs associated with LV charges or DVA balances.

Toronto Hydro's revenue deficiency for the 2020 test year is summarized in Table 2.

[1] Toronto Hydro will file for 2019 Distribution Rates as part of the final year of the EB-2014-0116 OEB approved 2015-2019 rate application in the summer of 2018, based on the OEB issued Inflation value.

Table 2: Revenue Deficiency ($ Millions)

	2020 Forecast
Service Revenue at expected 2019 Rates	819.1
Service Revenue Requirement	844.5
Gross Revenue Deficiency	(25.4)

Full details of the calculation of revenue deficiency are shown in Tab 8 of the RRWF, filed in Exhibit 6, Tab 1, Schedule 2.

5. CAUSES OF REVENUE DEFICIENCY

The drivers of Toronto Hydro's revenue deficiency are summarized in Table 3.

Table 3: Revenue Deficiency Drivers ($ Millions)

	2015 OEB Approved	2020 Forecast	Difference	
Rate Base	3,232.0	4,615.3		Higher net fixed assets offset by lower working capital allowance
ROE	9.30%	8.82%		Lower forecast ROE rate
Debt Rate	4.09%	3.64%		Lower forecast embedded debt rates
DRIVERS OF DEFICIENCY				
OM&A	243.9	277.5	33.6	Higher OM&A expenses
Depreciation	206.0	268.7	62.7	Higher rate base plus de-recognition expense
Deemed Interest Expense	79.3	100.8	21.5	Higher rate base offset by lower forecast debt rates
Return on Equity	120.2	162.8	42.6	Higher rate base offset by lower forecast ROE rate
PILS	25.0	34.7	9.8	Higher net income
TOTAL SERVICE REVENUE REQUIREMENT	674.5	844.5	170.0	
Distribution Revenue at 2015/19 Rates	633.1	771.4	138.3	Increase in OEB approved rates 2015-19 and customer growth
Revenue Offsets	41.3	47.7	6.4	Higher Other Revenues
TOTAL OPERATING REVENUE	674.5	819.1	144.7	
TOTAL DEFICIENCY		25.4	25.4	

Rate base increases are primarily due to fixed asset additions over the 2015-2020 period, as described in Exhibit 2B. Partially offsetting the increase in net fixed assets is a decrease in Working Capital Allowance based on the updated Lead-Lag Study (Exhibit 2A, Tab 3, Schedule 2).

Debt and ROE rates are expected to be lower in 2020 (Exhibit 5, Tab 1, Schedule 1), reducing the cost of capital, and partially offsetting the increase in revenue requirement from higher rate base.

The revenue deficiency arising from the 2020 OM&A costs is due to the forecast level of OM&A, as detailed in Exhibit 4A.

Higher depreciation amounts are primarily due to the additional capital included in rate base (Exhibit 2A, Tab 1, Schedule 1), as well as the requirements related to de-recognition of assets (Exhibit 4B, Tab 1, Schedule 2).

The revenue deficiency is partially offset by higher revenue due to OEB approved rate increases and customer growth over the 2015-2019 period (Exhibit 3, Tab 1, Schedule 1), as well as higher forecasted revenue offsets (Exhibit 3, Tab 2, Schedule 1).

APPENDIX A - MODIFICATIONS TO THE OEB's 2018 REVENUE REQUIREMENT WORK FORM

The following information details the changes that have been incorporated into the Ontario Energy Board's Revenue Requirement Workform for 2018 Filers V7.02.

1. WORKSHEET 12.1 CSMUR RATE DESIGN

This additional worksheet is needed to demonstrate the impact of the New Rate Design Policy on the Competitive Sector Multi-Unit Customers rate class. The logic of this worksheet mirrors the same test for the Residential rate class in worksheet 12. Res_Rate_Design.

2. WORKSHEET 13. RATE DESIGN

In all rate classes, the sum of revenue from the Fixed and Variable components adds to 100% of revenue for the class. Toronto Hydro's Unmetered Scattered Load rate class has an approved three parts rate. Therefore the total class revenue in Cell O35 has been reallocated for a three part rate (cells Q35, Q36 and S35). These changes are captured as follows:

- Fixed/Variable spilt inputs (cells U35, U36 and W35)
- Monthly Service Charge Calculations (cells AA35 and AA36)

Toronto Hydro's approved Monthly Service Charge and kVA Volumetric Rates are based on 30 days of service. Both the Monthly Service Charge and kVA Volumetric Rates calculation in columns AA and AE have been changed to reflect this requirement.

In addition, Toronto Hydro's Volumetric Rate is based on either kWh or kVA with the respective 5 and 4 number of decimals. Changes in column AI capture the applicable number of decimals.

In the **Revenue Reconciliation** section, Total Distribution Revenue needs to be converted back to 365 days of revenue, and therefore reflects the "days of service" adjustment factor of 365/360, or 1.013888889 (shown in cell AK25).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2020 Filers

Version 8.00

Utility Name	Toronto Hydro-Electric System Limited
Service Territory	
Assigned EB Number	EB-2018-0165
Name and Title	
Phone Number	
Email Address	
Test Year	
Bridge Year	
Last Rebasing Year	2015

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

This Workbook Model is protected by copyright and is being made available to you solely for the purpose of filing your application. You may use and copy this model for that purpose, and provide a copy of this model to any person that is advising or assisting you in that regard. Except as indicated above, any copying, reproduction, publication, sale, adaptation, translation, modification, reverse engineering or other use or dissemination of this model without the express written consent of the Ontario Energy Board is prohibited. If you provide a copy of this model to a person that is advising or assisting you in preparing the application or reviewing your draft rate order, you must ensure that the person understands and agrees to the restrictions noted above.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2020 Filers

1. Info
2. Table of Contents
3. Data_Input_Sheet
4. Rate_Base
5. Utility Income
6. Taxes_PILs
7. Cost_of_Capital
8. Rev_Def_Suff
9. Rev_Reqt
10. Load Forecast
11. Cost Allocation
12. Residential Rate Design
13. Rate Design and Revenue Reconciliation
14. Tracking Sheet

Notes:

(1)	Pale green cells represent inputs
(2)	Pale green boxes at the bottom of each page are for additional notes
(3)	Pale yellow cells represent drop-down lists
(4)	***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5)	***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2020 Filers

Data Input (1)

		Initial Application	(2)		(6)		Per Board Decision	
1	**Rate Base**							
	Gross Fixed Assets (average)	$5,616,709,673		############			$5,616,709,673	
	Accumulated Depreciation (average)	($1,236,603,102)	(5)	############			($1,236,603,102)	
	Allowance for Working Capital:							
	Controllable Expenses	$277,497,844		$ 277,497,844			$277,497,844	
	Cost of Power	$3,384,043,227		############			$3,384,043,227	
	Working Capital Rate (%)	6.42%	(9)		(9)			(9)
2	**Utility Income**							
	Operating Revenues:							
	Distribution Revenue at Current Rates	$771,399,203						
	Distribution Revenue at Proposed Rates	$796,824,614						
	Other Revenue:							
	Specific Service Charges	$6,581,270						
	Late Payment Charges	$3,751,641						
	Other Distribution Revenue	$35,898,269						
	Other Income and Deductions	$1,455,901						
	Total Revenue Offsets	$47,687,081	(7)					
	Operating Expenses:							
	OM+A Expenses	$271,962,868		$ 271,962,868			$271,962,868	
	Depreciation/Amortization	$268,664,188		$ 268,664,188			$268,664,188	
	Property taxes	$5,534,976		$ 5,534,976			$5,534,976	
	Other expenses							
3	**Taxes/PILs**							
	Taxable Income:							
	Adjustments required to arrive at taxable income	($61,393,745)	(3)					
	Utility Income Taxes and Rates:							
	Income taxes (not grossed up)	$25,522,176	(10)					
	Income taxes (grossed up)	$34,724,049						
	Federal tax (%)	15.00%						
	Provincial tax (%)	11.50%						
	Income Tax Credits	($2,736,000)						
4	**Capitalization/Cost of Capital**							
	Capital Structure:							
	Long-term debt Capitalization Ratio (%)	56.0%						
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		(8)			(8)
	Common Equity Capitalization Ratio (%)	40.0%						
	Prefered Shares Capitalization Ratio (%)							
		100.0%						
	Cost of Capital							
	Long-term debt Cost Rate (%)	3.71%						
	Short-term debt Cost Rate (%)	2.61%						
	Common Equity Cost Rate (%)	8.82%						
	Prefered Shares Cost Rate (%)							

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is **7.5%** (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

(10) This value is adjusted from PILS model to reflect inclusion of tax credits in OM&A. See Exhibit 4B, Tab 2, Schedule 1

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2020 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application						Per Board Decision
1	Gross Fixed Assets (average)	(2)	$5,616,709,673		$ -		$5,616,709,673	$ -	$5,616,709,673
2	Accumulated Depreciation (average)	(2)	($1,236,603,102)		$ -		($1,236,603,102)	$ -	($1,236,603,102)
3	Net Fixed Assets (average)	(2)	$4,380,106,571		$ -		$4,380,106,571	$ -	$4,380,106,571
4	Allowance for Working Capital	(1)	$235,187,789		###########		$ -	$ -	$ -
5	**Total Rate Base**		$4,615,294,360		###########		$4,380,106,571	$ -	$4,380,106,571

(1) Allowance for Working Capital - Derivation

6	Controllable Expenses		$277,497,844		$ -		$277,497,844	$ -	$277,497,844
7	Cost of Power		$3,384,043,227		$ -		$3,384,043,227	$ -	$3,384,043,227
8	Working Capital Base		$3,661,541,071		$ -		$3,661,541,071	$ -	$3,661,541,071
9	Working Capital Rate %	(1)	6.42%		-6.42%		0.00%	0.00%	0.00%
10	Working Capital Allowance		$235,187,789		###########		$ -	$ -	$ -

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2018 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2020 Filers

Utility Income

Line No.	Particulars	Initial Application				Per Board Decision
	Operating Revenues:					
1	Distribution Revenue (at Proposed Rates)	$796,824,614	($796,824,614)	$ -	$ -	$ -
2	Other Revenue (1)	$47,687,081	($47,687,081)	$ -	$ -	$ -
3	Total Operating Revenues	$844,511,695	($844,511,695)	$ -	$ -	$ -
	Operating Expenses:					
4	OM+A Expenses	$271,962,868	$ -	$271,962,868	$ -	$271,962,868
5	Depreciation/Amortization	$268,664,188	$ -	$268,664,188	$ -	$268,664,188
6	Property taxes	$5,534,976	$ -	$5,534,976	$ -	$5,534,976
7	Capital taxes	$ -	$ -	$ -	$ -	$ -
8	Other expense	$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)	$546,162,032	$ -	$546,162,032	$ -	$546,162,032
10	Deemed Interest Expense	$100,798,029	($100,798,029)	$ -	$ -	$ -
11	Total Expenses (lines 9 to 10)	$646,960,061	($100,798,029)	$546,162,032	$ -	$546,162,032
12	**Utility income before income taxes**	$197,551,634	($743,713,666)	($546,162,032)	$ -	($546,162,032)
13	Income taxes (grossed-up)	$34,724,049	$ -	$34,724,049	$ -	$34,724,049
14	**Utility net income**	$162,827,585	($743,713,666)	($580,886,081)	$ -	($580,886,081)

Notes

(1) **Other Revenues / Revenue Offsets**

Specific Service Charges	$6,581,270		$ -		$ -
Late Payment Charges	$3,751,641		$ -		$ -
Other Distribution Revenue	$35,898,269		$ -		$ -
Other Income and Deductions	$1,455,901		$ -		$ -
Total Revenue Offsets	$47,687,081	$ -	$ -	$ -	$ -

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2020 Filers

Taxes/PILs

Line No.	Particulars	Application		Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$162,827,585	$ -	$ -
2	Adjustments required to arrive at taxable utility income	($61,393,745)	$ -	$ -
3	Taxable income	$101,433,840	$ -	$ -
	Calculation of Utility income Taxes			
4	Income taxes	$25,522,176	$25,522,176	$25,522,176
6	Total taxes	$25,522,176	$25,522,176	$25,522,176
7	Gross-up of Income Taxes	$9,201,873	$9,201,873	$9,201,873
8	Grossed-up Income Taxes	$34,724,049	$34,724,049	$34,724,049
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$34,724,049	$34,724,049	$34,724,049
10	Other tax Credits	($2,736,000)	($2,736,000)	($2,736,000)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2020 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate		Return
		Initial Application				
		(%)	($)	(%)		($)
	Debt					
1	Long-term Debt	56.00%	$2,584,564,841	3.71%		$95,979,661
2	Short-term Debt	4.00%	$184,611,774	2.61%		$4,818,367
3	**Total Debt**	60.00%	$2,769,176,616	3.64%		$100,798,029
	Equity					
4	Common Equity	40.00%	$1,846,117,744	8.82%		$162,827,585
5	Preferred Shares	0.00%	$ -	0.00%		$ -
6	**Total Equity**	40.00%	$1,846,117,744	8.82%		$162,827,585
7	**Total**	100.00%	$4,615,294,360	5.71%		$263,625,614
		(%)	($)	(%)		($)
	Debt					
1	Long-term Debt	0.00%	$ -	0.00%		$ -
2	Short-term Debt	0.00%	$ -	0.00%		$ -
3	**Total Debt**	0.00%	$ -	0.00%		$ -
	Equity					
4	Common Equity	0.00%	$ -	0.00%		$ -
5	Preferred Shares	0.00%	$ -	0.00%		$ -
6	**Total Equity**	0.00%	$ -	0.00%		$ -
7	**Total**	0.00%	$4,380,106,571	0.00%		$ -
		Per Board Decision				
		(%)	($)	(%)		($)
	Debt					
8	Long-term Debt	0.00%	$ -	3.71%		$ -
9	Short-term Debt	0.00%	$ -	2.61%		$ -
10	**Total Debt**	0.00%	$ -	0.00%		$ -
	Equity					
11	Common Equity	0.00%	$ -	8.82%		$ -
12	Preferred Shares	0.00%	$ -	0.00%		$ -
13	**Total Equity**	0.00%	$ -	0.00%		$ -
14	**Total**	0.00%	$4,380,106,571	0.00%		$ -

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2020 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application				Per Board Decision	
		At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$23,550,297		($251,094,780)		$743,077,595
2	Distribution Revenue	$771,399,203	$773,274,317	$771,399,203	$1,047,919,394	$ -	($743,077,595)
3	Other Operating Revenue Offsets - net	$47,687,081	$47,687,081	$ -	$ -	$ -	$ -
4	**Total Revenue**	$819,086,284	$844,511,695	$771,399,203	$796,824,614	$ -	$ -
5	Operating Expenses	$546,162,032	$546,162,032	$546,162,032	$546,162,032	$546,162,032	$546,162,032
6	Deemed Interest Expense	$100,798,029	$100,798,029	$ -	$ -	$ -	$ -
8	**Total Cost and Expenses**	$646,960,061	$646,960,061	$546,162,032	$546,162,032	$546,162,032	$546,162,032
9	**Utility Income Before Income Taxes**	$172,126,224	$197,551,634	$225,237,171	$250,662,582	($546,162,032)	($546,162,032)
10	Tax Adjustments to Accounting Income per 2013 PILs model	($61,393,745)	($61,393,745)	($61,393,745)	($61,393,745)	$ -	$ -
11	**Taxable Income**	$110,732,479	$136,157,889	$163,843,426	$189,268,837	($546,162,032)	($546,162,032)
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$29,344,107	$36,081,841	$43,418,508	$50,156,242	$ -	$ -
14	**Income Tax Credits**	($2,736,000)	($2,736,000)	($2,736,000)	($2,736,000)	$ -	$ -
15	**Utility Net Income**	$145,518,117	$162,827,585	$184,554,663	($580,886,081)	($546,162,032)	($580,886,081)
16	**Utility Rate Base**	$4,615,294,360	$4,615,294,360	$4,380,106,571	$4,380,106,571	$4,380,106,571	$4,380,106,571
17	Deemed Equity Portion of Rate Base	$1,846,117,744	$1,846,117,744	$ -	$ -	$ -	$ -
18	Income/(Equity Portion of Rate Base)	7.88%	8.82%	0.00%	0.00%	0.00%	0.00%
19	Target Return - Equity on Rate Base	8.82%	8.82%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Return on Equity	-0.94%	0.00%	0.00%	0.00%	0.00%	0.00%
21	Indicated Rate of Return	5.34%	5.71%	4.21%	0.00%	-12.47%	0.00%
22	Requested Rate of Return on Rate Base	5.71%	5.71%	0.00%	0.00%	0.00%	0.00%
23	Deficiency/Sufficiency in Rate of Return	-0.38%	0.00%	4.21%	0.00%	-12.47%	0.00%
24	Target Return on Equity	$162,827,585	$162,827,585	$ -	$ -	$ -	$ -
25	Revenue Deficiency/(Sufficiency)	$17,309,468	$0	($184,554,663)	$ -	$546,162,032	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$23,550,297 (1)		($251,094,780) (1)		$743,077,595 (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2020 Filers

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$271,962,868		$271,962,868		$271,962,868	
2	Amortization/Depreciation	$268,664,188		$268,664,188		$268,664,188	
3	Property Taxes	$5,534,976		$5,534,976		$5,534,976	
5	Income Taxes (Grossed up)	$34,724,049		$34,724,049		$34,724,049	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$100,798,029		$ -		$ -	
	Return on Deemed Equity	$162,827,585		$ -		$ -	
8	**Service Revenue Requirement (before Revenues)**	$844,511,695		$580,886,081		$580,886,081	
9	Revenue Offsets	$47,687,081		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$796,824,614		$580,886,081		$580,886,081	
11	Distribution revenue	$796,824,614		$ -		$ -	
12	Other revenue	$47,687,081		$ -		$ -	
13	**Total revenue**	$844,511,695		$ -		$ -	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$0	(1)	($580,886,081)	(1)	($580,886,081)	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application		Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$844,511,695	$580,886,081	**($0)**	$580,886,081	**($1)**
Grossed-Up Revenue Deficiency/(Sufficiency)	$23,550,297	($251,094,780)	**($12)**	$743,077,595	**($1)**
Base Revenue Requirement (to be recovered from Distribution Rates)	$796,824,614	$580,886,081	**($0)**	$580,886,081	**($1)**
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$25,425,411	$ -	**($1)**	$ -	**($1)**

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2020 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Initial Application

	Customer Class	Initial Application						Per Board Decision		
	Input the name of each customer class.	Customer / Connections Test Year average or mid-year	kWh Annual	kW/kVA [1] Annual	Customer / Connections Test Year average or mid-year	kWh Annual	kW/kVA [1] Annual	Customer / Connections Test Year average or mid-	kWh Annual	kW/kVA [1] Annual
1	Residential	615,965	4,510,636,914							
2	Competitive Sector Multi-Unit Residential	85,161	277,127,203							
3	GS <50	71,499	2,267,638,936							
4	GS - 50 to 999	10,374	9,587,728,582	24,899,249						
5	GS - 1000 to 4999	430	4,561,528,177	10,392,864						
6	Large Use >5MW	44	2,009,923,443	4,789,334						
7	Street Light	165,348	115,390,403	326,622						
8	Unmetered Scattered Load	857	41,313,479							
9	Unmetered Scattered Load (Connections)	12,196								
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		###########	**40,408,069**		-	-		-	-

Notes:

[1] Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2020 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class [3]	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1]	%
	From Sheet 10. Load Forecast			(7A)	
1	Residential	$ 287,079,871	42.26%	$ 324,653,418	38.4%
2	Competitive Sector Multi-Unit Residentia	$ 19,267,312	2.84%	$ 36,290,421	4.3%
3	GS <50	$ 99,019,246	14.58%	$ 131,607,020	15.6%
4	GS - 50 to 999	$ 157,700,127	23.21%	$ 210,166,261	24.9%
5	GS - 1000 to 4999	$ 55,701,964	8.20%	$ 74,249,773	8.8%
6	Large Use >5MW	$ 31,087,389	4.58%	$ 40,433,897	4.8%
7	Street Light	$ 25,331,820	3.73%	$ 22,560,059	2.7%
8	Unmetered Scattered Load	$ 4,173,832	0.61%	$ 4,550,846	0.5%
9	Unmetered Scattered Load (Connections)				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 679,361,561	100.00%	**$ 844,511,695**	100.0%
			Service Revenue Requirement (from Sheet 9)	**$ 844,511,695**	

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.
(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.
(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential	$ 305,630,924	$ 315,784,637	$ 315,784,637	$ 19,230,275
2	Competitive Sector Multi-Unit Residentia	$ 34,001,178	$ 35,130,770	$ 34,611,162	$ 1,679,259
3	GS <50	$ 106,186,653	$ 109,714,401	$ 110,012,229	$ 8,162,022
4	GS - 50 to 999	$ 210,952,231	$ 213,888,036	$ 213,888,036	$ 7,333,311
5	GS - 1000 to 4999	$ 72,282,491	$ 69,063,008	$ 69,145,224	$ 1,396,409
6	Large Use >5MW	$ 35,514,268	$ 33,653,821	$ 33,788,485	$ 571,724
7	Street Light	$ 15,072,589	$ 15,573,332	$ 15,573,332	$ 9,005,777
8	Unmetered Scattered Load	$ 3,887,458	$ 4,016,607	$ 4,021,508	$ 308,303
9	Unmetered Scattered Load (Connections)				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 783,527,792	$ 796,824,614	$ 796,824,614	$ 47,687,081

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.
(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.
(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.
(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

Cost Allocation and Rate Design

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year: 2015 %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
1	Residential	94.3%	103.2%	103.2%	85 - 115
2	Competitive Sector Multi-Unit Residentia	100.0%	101.4%	100.0%	
3	GS <50	91.5%	89.6%	89.8%	80 - 120
4	GS - 50 to 999	119.0%	105.3%	105.3%	80 - 120
5	GS - 1000 to 4999	101.9%	94.9%	95.0%	80 - 120
6	Large Use >5MW	95.3%	84.6%	85.0%	85 - 115
7	Street Light	82.7%	108.9%	108.9%	80 - 120
8	Unmetered Scattered Load	90.5%	95.0%	95.1%	80 - 120
9	Unmetered Scattered Load (Connections)				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) Proposed Revenue-to-Cost Ratios [11]

	Name of Customer Class	Proposed Revenue-to-Cost Ratio Test Year 2020	Price Cap IR Period 2021	2022	Policy Range
1	Residential	103.2%			85 - 115
2	Competitive Sector Multi-Unit Residentia	100.0%			
3	GS <50	89.8%			80 - 120
4	GS - 50 to 999	105.3%			80 - 120
5	GS - 1000 to 4999	95.0%			80 - 120
6	Large Use >5MW	85.0%			85 - 115
7	Street Light	108.9%			80 - 120
8	Unmetered Scattered Load	95.1%			80 - 120
9	Unmetered Scattered Load (Connection				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2019 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2020 and 2021 Price Cap IR models, as necessary. For 2020 and 2021, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2018 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2020 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential Class	
Customers	615,965
kWh	4,510,636,914

Proposed Residential Class Specific Revenue Requirement[1]	$	315,784,637.29

Residential Base Rates on Current Tariff		
Monthly Fixed Charge ($)	$	37.98
Distribution Volumetric Rate ($/kWh)	$	0.00552

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed	37.98	615,965	$ 280,732,208.40	91.85%
Variable	0.00552	4,510,636,914	$ 24,898,715.77	8.15%
TOTAL	-	-	$ 305,630,924.17	-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	1

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed	$ 290,058,732.92	39.24	$ 290,045,599.20
Variable	$ 25,725,904.37	0.0057	$ 25,710,630.41
TOTAL	$ 315,784,637.29	-	$ 315,756,229.61

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed	100.00%	$ 315,784,637.29	$ 42.72	$ 315,768,297.60
Variable	0.00%	$ -	$ -	$ -
TOTAL	-	$ 315,784,637.29	-	$ 315,768,297.60

Checks[3]		
Change in Fixed Rate	$	3.48
Difference Between Revenues @ Proposed Rates and Class Specific Revenue Requirement		($16,339.69)
		-0.01%

Notes:

[1] The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

[2] The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

[3] Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2020 Filers

New Rate Design Policy For Competitive Sector Multi-Unit Customers (CSMUR)

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for CSMUR	
Customers	85,161
kWh	277,127,203

Proposed CSMUR Class Specific Revenue Requirement[1]	$	34,812,874.82

CSMUR Base Rates on Current Tariff		
Monthly Fixed Charge ($)	$	30.98
Distribution Volumetric Rate ($/kWh)	$	0.00845

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed	30.98	85,161	$ 31,659,453.36	93.11%
Variable	0.00845	277,127,203	$ 2,341,724.87	6.89%
TOTAL	-	-	$ 34,001,178.23	-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	1

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed	$ 32,415,246.89	31.72	$ 32,415,683.04
Variable	$ 2,397,627.93	0.0087	$ 2,411,006.67
TOTAL	$ 34,812,874.82	-	$ 34,826,689.71

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed	100.00%	$ 34,812,874.82	$ 34.07	$ 34,817,223.24
Variable	0.00%	$ -	$ -	$ -
TOTAL	-	$ 34,812,874.82	-	$ 34,817,223.24

Checks[3]		
Change in Fixed Rate	$	2.35
Difference Between Revenues @ Proposed Rates and Class Specific Revenue Requirement		$4,348.42
		0.01%

Notes:

[1] The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

[2] The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

[3] Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2020 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process: *Initial Application*

	Customer Class (From sheet 10. Load Forecast)	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Class Allocated Revenues: Total Class Revenue Requirement (From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design)	Class Allocated Revenues: Monthly Service Charge	Class Allocated Revenues: Volumetric	Fixed / Variable Splits [2] (Percentage to be entered as a fraction between 0 and 1): Fixed	Fixed / Variable Splits [2]: Variable	Transformer Ownership Allowance [1] ($)	Distribution Rates: Monthly Service Charge Rate	Monthly Service Charge No. of decimals	Volumetric Rate	Volumetric Rate No. of decimals	Revenue Reconciliation: MSC Revenues (1.013888889)	Volumetric revenues	Distribution Revenues less Transformer Ownership Allowance
1	Residential	kWh	615,965	4,510,636,914	-	$ 315,784,637	$ 315,784,637	$ -	100.00%	0.00%	$ -	$42.14	2	$0.00000 /kWh	5	315,807,309	-	$ 315,807,308.72
2	Competitive Sector Multi-Unit Residential	kWh	85,161	277,127,203	-	$ 34,611,162	$ 34,611,162	$ -	100.00%	0.00%	$ -	$33.40		$0.00000 /kWh	5	34,606,592	-	$ 34,606,591.70
3	GS <50	kWh	71,499	2,267,638,936	-	$ 110,012,229	$ 32,249,243	$ 77,762,986	29.31%	70.69%	$ -	$37.07		$0.03429 /kWh	5	32,247,360	77,757,339	$ 110,004,698.93
4	GS - 50 to 999	kVA	10,374	9,587,728,582	24,899,249	$ 213,888,036	$ 6,584,923	$ 207,303,113	3.08%	96.92%	$ 3,941,533	$52.17		$8.3678 /kVA	4	6,584,741	211,245,713	$ 213,888,920.78
5	GS - 1000 to 4999	kVA	430	4,561,528,177	10,392,864	$ 69,145,224	$ 4,919,308	$ 64,225,916	7.11%	92.89%	$ 5,440,129	$940.29		$6.6114 /kVA	4	4,919,284	69,665,706	$ 69,144,860.61
6	Large Use >5MW	kVA	44	2,009,923,443	4,789,334	$ 33,788,485	$ 2,209,874	$ 31,578,611	6.54%	93.46%	$ 2,942,549	$4,128.03		$7.1092 /kVA	4	2,209,872	34,521,227	$ 33,788,549.74
7	Street Light	kVA	165,348	115,390,403	326,622	$ 15,573,332	$ 3,341,654	$ 12,231,678	21.46%	78.54%	$ -	$1.66		$36.9360 /kVA	4	3,339,478	12,231,667	$ 15,571,145.72
8	Unmetered Scattered Load	kWh	857	41,313,479	-	$ 4,021,508	$ 76,917	$ 3,831,042	1.91%	95.26%	$ -	$7.38		$0.09273 /kWh	5	76,950	3,830,999	$ 3,907,948.94
9	Unmetered Scattered Load (Connections)		12,196	-	-		$ 113,549	$ -	2.82%		$ -	$0.77		$0.00000		114,256	-	$ 114,256.19
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
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#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -

Total Transformer Ownership Allowance $ 12,324,211

Rates recover revenue requirement

Total Distribution Revenues	$ 796,834,281.33
Base Revenue Requirement	$ 796,824,613.75
Difference	$ 9,667.58
% Difference	0.001%

Notes:

[1] Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

[2] The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calcutated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2019 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

(2) Short description of change, issue, etc.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference (1)	Item / Description (2)	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 263,625,614	5.71%	$ 4,615,294,360	$ 3,661,541,071	$ 235,187,789	$ 268,664,188	$ 34,724,049	$ 271,962,868	$ 844,511,695	$ 47,687,081	$ 796,824,614	$ 23,550,297
1														
		Change												
2														

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021

Version 8.00

Filers

Utility Name	Toronto Hydro-Electric System Limited
Service Territory	
Assigned EB Number	EB-2018-0165
Name and Title	
Phone Number	
Email Address	
Test Year	
Bridge Year	
Last Rebasing Year	2015

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

This Workbook Model is protected by copyright and is being made available to you solely for the purpose of filing your application. You may use and copy this model for that purpose, and provide a copy of this model to any person that is advising or assisting you in that regard. Except as indicated above, any copying, reproduction, publication, sale, adaptation, translation, modification, reverse engineering or other use or dissemination of this model without the express written consent of the Ontario Energy Board is prohibited. If you provide a copy of this model to a person that is advising or assisting you in preparing the application or reviewing your draft rate order, you must ensure that the person understands and agrees to the restrictions noted above.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021Filers

1. Info
2. Table of Contents
3. Data_Input_Sheet
4. Rate_Base
5. Utility Income
6. Taxes_PILs
7. Cost_of_Capital
8. Rev_Def_Suff
9. Rev_Reqt
10. Load Forecast
11. Cost Allocation
12. Residential Rate Design
13. Rate Design and Revenue Reconciliation
14. Tracking Sheet

Notes:

(1)	Pale green cells represent inputs
(2)	Pale green boxes at the bottom of each page are for additional notes
(3)	Pale yellow cells represent drop-down lists
(4)	***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5)	***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Data Input (1)

		Initial Application	(2)		(6)		Per Board Decision	
1	**Rate Base**							
	Gross Fixed Assets (average)	$6,073,208,605			$6,073,208,605		$6,073,208,605	
	Accumulated Depreciation (average)	($1,483,326,686)	(5)		($1,483,326,686)		($1,483,326,686)	
	Allowance for Working Capital:							
	Controllable Expenses	$279,995,324			$ 279,995,324		$279,995,324	
	Cost of Power	$3,442,278,635			$3,442,278,635		$3,442,278,635	
	Working Capital Rate (%)	6.42%	(9)			(9)		(9)
2	**Utility Income**							
	Operating Revenues:							
	Distribution Revenue at Current Rates	$797,841,742						
	Distribution Revenue at Proposed Rates	$824,227,732						
	Other Revenue:							
	Specific Service Charges	$6,640,353						
	Late Payment Charges	$3,785,321						
	Other Distribution Revenue	$37,689,511						
	Other Income and Deductions							
	Total Revenue Offsets	$48,115,184	(7)					
	Operating Expenses:							
	OM+A Expenses	$274,410,533			$ 274,410,533		$274,410,533	
	Depreciation/Amortization	$281,929,611			$ 281,929,611		$281,929,611	
	Property taxes	$5,584,791			$ 5,584,791		$5,584,791	
	Other expenses							
3	**Taxes/PILs**							
	Taxable Income:							
	Adjustments required to arrive at taxable income	($63,873,242)	(3)					
	Utility Income Taxes and Rates:							
	Income taxes (not grossed up)	$26,862,812						
	Income taxes (grossed up)	$36,548,043						
	Federal tax (%)	15.00%						
	Provincial tax (%)	11.50%						
	Income Tax Credits	($2,736,000)						
4	**Capitalization/Cost of Capital**							
	Capital Structure:							
	Long-term debt Capitalization Ratio (%)	56.0%						
	Short-term debt Capitalization Ratio (%)	4.0%	(8)			(8)		(8)
	Common Equity Capitalization Ratio (%)	40.0%						
	Prefered Shares Capitalization Ratio (%)							
		100.0%						
	Cost of Capital							
	Long-term debt Cost Rate (%)	3.71%						
	Short-term debt Cost Rate (%)	2.61%						
	Common Equity Cost Rate (%)	8.82%						
	Prefered Shares Cost Rate (%)							

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is **7.5%** (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application						Per Board Decision
1	Gross Fixed Assets (average)	(2)	$6,073,208,605		$ -		$6,073,208,605	$ -	$6,073,208,605
2	Accumulated Depreciation (average)	(2)	##############		$ -		($1,483,326,686)	$ -	($1,483,326,686)
3	Net Fixed Assets (average)	(2)	$4,589,881,919		$ -		$4,589,881,919	$ -	$4,589,881,919
4	Allowance for Working Capital	(1)	$239,088,778		###########		$ -	$ -	$ -
5	**Total Rate Base**		$4,828,970,698		###########		$4,589,881,919	$ -	$4,589,881,919

(1) Allowance for Working Capital - Derivation

6	Controllable Expenses		$279,995,324		$ -		$279,995,324	$ -	$279,995,324
7	Cost of Power		$3,442,278,635		$ -		$3,442,278,635	$ -	$3,442,278,635
8	Working Capital Base		$3,722,273,959		$ -		$3,722,273,959	$ -	$3,722,273,959
9	Working Capital Rate %	(1)	6.42%		-6.42%		0.00%	0.00%	0.00%
10	Working Capital Allowance		$239,088,778		###########		$ -	$ -	$ -

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2018 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Utility Income

Line No.	Particulars		Initial Application							Per Board Decision
	Operating Revenues:									
1	Distribution Revenue (at Proposed Rates)		$824,227,732		($824,227,732)		$ -		$ -	$ -
2	Other Revenue	(1)	$48,115,184		($48,115,184)		$ -		$ -	$ -
3	Total Operating Revenues		$872,342,916		($872,342,916)		$ -		$ -	$ -
	Operating Expenses:									
4	OM+A Expenses		$274,410,533		$ -		$274,410,533		$ -	$274,410,533
5	Depreciation/Amortization		$281,929,611		$ -		$281,929,611		$ -	$281,929,611
6	Property taxes		$5,584,791		$ -		$5,584,791		$ -	$5,584,791
7	Capital taxes		$ -		$ -		$ -		$ -	$ -
8	Other expense		$ -		$ -				$ -	
9	Subtotal (lines 4 to 8)		$561,924,935		$ -		$561,924,935		$ -	$561,924,935
10	Deemed Interest Expense		$105,464,720		($105,464,720)		$ -		$ -	$ -
11	Total Expenses (lines 9 to 10)		$667,389,654		($105,464,720)		$561,924,935		$ -	$561,924,935
12	**Utility income before income taxes**		$204,953,261		($766,878,196)		($561,924,935)		$ -	($561,924,935)
13	Income taxes (grossed-up)		$36,548,043		$ -		$36,548,043		$ -	$36,548,043
14	**Utility net income**		$168,405,218		($766,878,196)		($598,472,978)		$ -	($598,472,978)

Notes

Other Revenues / Revenue Offsets

(1)

Specific Service Charges	$6,640,353		$ -		$ -
Late Payment Charges	$3,785,321		$ -		$ -
Other Distribution Revenue	$37,689,511		$ -		$ -
Other Income and Deductions	$ -		$ -		$ -
Total Revenue Offsets	$48,115,184	$ -	$ -	$ -	$ -

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Taxes/PILs

Line No.	Particulars	Application		Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$170,366,086	$ -	$ -
2	Adjustments required to arrive at taxable utility income	($63,873,242)	$ -	$ -
3	Taxable income	$106,492,844	$ -	$ -
	Calculation of Utility income Taxes			
4	Income taxes	$26,862,812	$26,862,812	$26,862,812
6	Total taxes	$26,862,812	$26,862,812	$26,862,812
7	Gross-up of Income Taxes	$9,685,231	$9,685,231	$9,685,231
8	Grossed-up Income Taxes	$36,548,043	$36,548,043	$36,548,043
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$36,548,043	$36,548,043	$36,548,043
10	Other tax Credits	($2,736,000)	($2,736,000)	($2,736,000)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate		Return
		Initial Application				
		(%)	($)	(%)		($)
	Debt					
1	Long-term Debt	56.00%	$2,704,223,591	3.71%		$100,423,274
2	Short-term Debt	4.00%	$193,158,828	2.61%		$5,041,445
3	**Total Debt**	60.00%	$2,897,382,419	3.64%		$105,464,720
	Equity					
4	Common Equity	40.00%	$1,931,588,279	8.82%		$170,366,086
5	Preferred Shares	0.00%	$ -	0.00%		$ -
6	**Total Equity**	40.00%	$1,931,588,279	8.82%		$170,366,086
7	**Total**	100.00%	$4,828,970,698	5.71%		$275,830,806
		(%)	($)	(%)		($)
	Debt					
1	Long-term Debt	0.00%	$ -	0.00%		$ -
2	Short-term Debt	0.00%	$ -	0.00%		$ -
3	**Total Debt**	0.00%	$ -	0.00%		$ -
	Equity					
4	Common Equity	0.00%	$ -	0.00%		$ -
5	Preferred Shares	0.00%	$ -	0.00%		$ -
6	**Total Equity**	0.00%	$ -	0.00%		$ -
7	**Total**	0.00%	$4,589,881,919	0.00%		$ -
		Per Board Decision				
		(%)	($)	(%)		($)
	Debt					
8	Long-term Debt	0.00%	$ -	3.71%		$ -
9	Short-term Debt	0.00%	$ -	2.61%		$ -
10	**Total Debt**	0.00%	$ -	0.00%		$ -
	Equity					
11	Common Equity	0.00%	$ -	8.82%		$ -
12	Preferred Shares	0.00%	$ -	0.00%		$ -
13	**Total Equity**	0.00%	$ -	0.00%		$ -
14	**Total**	0.00%	$4,589,881,919	0.00%		$ -

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application				Per Board Decision	
		At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$26,471,745		($262,668,384)		$764,523,721
2	Distribution Revenue	$797,841,742	$797,755,986	$797,841,742	$1,086,896,116	$ -	($764,523,721)
3	Other Operating Revenue Offsets - net	$48,115,184	$48,115,184	$ -	$ -	$ -	$ -
4	**Total Revenue**	$845,956,926	$872,342,916	$797,841,742	$824,227,732	$ -	$ -
5	Operating Expenses	$561,924,935	$561,924,935	$561,924,935	$561,924,935	$561,924,935	$561,924,935
6	Deemed Interest Expense	$105,464,720	$105,464,720	$ -	$ -	$ -	$ -
8	**Total Cost and Expenses**	$667,389,654	$667,389,654	$561,924,935	$561,924,935	$561,924,935	$561,924,935
9	**Utility Income Before Income Taxes**	$178,567,271	$204,953,261	$235,916,807	$262,302,797	($561,924,935)	($561,924,935)
10	Tax Adjustments to Accounting Income per 2013 PILs model	($63,873,242)	($63,873,242)	($63,873,242)	($63,873,242)	$ -	$ -
11	**Taxable Income**	$114,694,029	$141,080,019	$172,043,565	$198,429,555	($561,924,935)	($561,924,935)
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$30,393,918	$37,386,205	$45,591,545	$52,583,832	$ -	$ -
14	**Income Tax Credits**	($2,736,000)	($2,736,000)	($2,736,000)	($2,736,000)	$ -	$ -
15	**Utility Net Income**	$150,909,353	$168,405,218	$193,061,262	($598,472,978)	($561,924,935)	($598,472,978)
16	**Utility Rate Base**	$4,828,970,698	$4,828,970,698	$4,589,881,919	$4,589,881,919	$4,589,881,919	$4,589,881,919
17	Deemed Equity Portion of Rate Base	$1,931,588,279	$1,931,588,279	$ -	$ -	$ -	$ -
18	Income/(Equity Portion of Rate Base)	7.81%	8.72%	0.00%	0.00%	0.00%	0.00%
19	Target Return - Equity on Rate Base	8.82%	8.82%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Return on Equity	-1.01%	-0.10%	0.00%	0.00%	0.00%	0.00%
21	Indicated Rate of Return	5.31%	5.67%	4.21%	0.00%	-12.24%	0.00%
22	Requested Rate of Return on Rate Base	5.71%	5.71%	0.00%	0.00%	0.00%	0.00%
23	Deficiency/Sufficiency in Rate of Return	-0.40%	-0.04%	4.21%	0.00%	-12.24%	0.00%
24	Target Return on Equity	$170,366,086	$170,366,086	$ -	$ -	$ -	$ -
25	Revenue Deficiency/(Sufficiency)	$19,456,733	($1,960,868)	($193,061,262)	$ -	$561,924,935	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$26,471,745 (1)		($262,668,384) (1)		$764,523,721 (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$274,410,533		$274,410,533		$274,410,533	
2	Amortization/Depreciation	$281,929,611		$281,929,611		$281,929,611	
3	Property Taxes	$5,584,791		$5,584,791		$5,584,791	
5	Income Taxes (Grossed up)	$36,548,043		$36,548,043		$36,548,043	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$105,464,720		$ -		$ -	
	Return on Deemed Equity	$170,366,086		$ -		$ -	
8	**Service Revenue Requirement (before Revenues)**	$874,303,784		$598,472,978		$598,472,978	
9	Revenue Offsets	$48,115,184		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$826,188,600		$598,472,978		$598,472,978	
11	Distribution revenue	$824,227,732		$ -		$ -	
12	Other revenue	$48,115,184		$ -		$ -	
13	**Total revenue**	$872,342,916		$ -		$ -	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($1,960,868)	(1)	($598,472,978)	(1)	($598,472,978)	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application		Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$874,303,784	$598,472,978	**($0)**	$598,472,978	**($1)**
Grossed-Up Revenue Deficiency/(Sufficiency)	$26,471,745	($262,668,384)	**($11)**	$764,523,721	**($1)**
Base Revenue Requirement (to be recovered from Distribution Rates)	$826,188,600	$598,472,978	**($0)**	$598,472,978	**($1)**
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$26,385,990	$ -	**($1)**	$ -	**($1)**

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Initial Application

	Customer Class	Initial Application					Per Board Decision		
	Input the name of each customer class.	Customer / Connections Test Year average or mid-year	kWh Annual	kW/kVA [1] Annual	Customer / Connections Test Year average or mid-year	kWh Annual	kW/kVA [1] Annual	Customer / Connections Test Year average or mid-year	kWh Annual	kW/kVA [1] Annual
1	Residential	617,609	4,458,695,848	-						
2	Competitive Sector Multi-Unit Residential	90,045	286,903,886	-						
3	GS <50	71,596	2,238,780,453	-						
4	GS - 50 to 999	10,363	9,526,101,781	24,849,478						
5	GS - 1000 to 4999	430	4,500,819,338	10,334,297						
6	Large Use >5MW	44	1,991,635,383	4,764,614						
7	Street Light	165,571	115,193,891	327,106						
8	Unmetered Scattered Load	857	41,200,600	-						
9	Unmetered Scattered Load (Connections)	12,272		-						
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		**23,159,331,182**	**40,275,495**		**-**	**-**		**-**	**-**

Notes:

(1) Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
1	Residential	$ 287,079,871	42.26%	$ 336,106,313	38.4%
2	Competitive Sector Multi-Unit Resident	$ 19,267,312	2.84%	$ 37,570,649	4.3%
3	GS <50	$ 99,019,246	14.58%	$ 136,249,759	15.6%
4	GS - 50 to 999	$ 157,700,127	23.21%	$ 217,580,358	24.9%
5	GS - 1000 to 4999	$ 55,701,964	8.20%	$ 76,869,104	8.8%
6	Large Use >5MW	$ 31,087,389	4.58%	$ 41,860,296	4.8%
7	Street Light	$ 25,331,820	3.73%	$ 23,355,917	2.7%
8	Unmetered Scattered Load	$ 4,173,832	0.61%	$ 4,711,388	0.5%
9	Unmetered Scattered Load (Connections)				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 679,361,561	100.00%	**$ 874,303,784**	100.0%
			Service Revenue Requirement (from Sheet 9)	**$ 874,303,784**	

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.
(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.
(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential	$ 316,685,191	$ 327,160,072	$ 326,944,706	$ 19,402,912
2	Competitive Sector Multi-Unit Resident	$ 36,587,084	$ 37,797,262	$ 37,785,433	$ 1,694,334
3	GS <50	$ 109,054,714	$ 112,661,877	$ 112,620,337	$ 8,235,295
4	GS - 50 to 999	$ 213,465,985	$ 220,526,721	$ 220,563,142	$ 7,399,145
5	GS - 1000 to 4999	$ 68,782,349	$ 71,057,437	$ 71,212,854	$ 1,408,946
6	Large Use >5MW	$ 33,625,363	$ 34,737,577	$ 34,823,821	$ 576,857
7	Street Light	$ 15,587,707	$ 16,103,296	$ 16,093,607	$ 9,086,625
8	Unmetered Scattered Load	$ 4,010,849	$ 4,143,515	$ 4,143,857	$ 311,071
9	Unmetered Scattered Load (Connections)				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 797,799,242	$ 824,187,757	$ 824,187,757	$ 48,115,185

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.
(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.
(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.
(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year: 2015 %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
1	Residential	94.3%	103.1%	103.0%	85 - 115
2	Competitive Sector Multi-Unit Resident	100.0%	105.1%	105.1%	
3	GS <50	91.5%	88.7%	88.7%	80 - 120
4	GS - 50 to 999	119.0%	104.8%	104.8%	80 - 120
5	GS - 1000 to 4999	101.9%	94.3%	94.5%	80 - 120
6	Large Use >5MW	95.3%	84.4%	84.6%	85 - 115
7	Street Light	82.7%	107.9%	107.8%	80 - 120
8	Unmetered Scattered Load	90.5%	94.5%	94.6%	80 - 120
9	Unmetered Scattered Load (Connections)				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.
(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".
(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) Proposed Revenue-to-Cost Ratios [11]

	Name of Customer Class	Proposed Revenue-to-Cost Ratio Test Year 2020	Price Cap IR Period 2021	Price Cap IR Period 2022	Policy Range
1	Residential	103.0%			85 - 115
2	Competitive Sector Multi-Unit Resident	105.1%			
3	GS <50	88.7%			80 - 120
4	GS - 50 to 999	104.8%			80 - 120
5	GS - 1000 to 4999	94.5%			80 - 120
6	Large Use >5MW	84.6%			85 - 115
7	Street Light	107.8%			80 - 120
8	Unmetered Scattered Load	94.6%			80 - 120
9	Unmetered Scattered Load (Connectio				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2019 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2020 and 2021 Price Cap IR models, as necessary. For 2020 and 2021, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2018 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential Class	
Customers	617,609
kWh	4,458,695,848

Proposed Residential Class Specific Revenue Requirement[1]	$ 326,944,705.68

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	
Distribution Volumetric Rate ($/kWh)	

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed		617,609		
Variable		4,458,695,848		
TOTAL	-	-		-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	0

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed			
Variable			
TOTAL		-	

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed				
Variable				
TOTAL	-	$ -	-	

Checks[3]	
Change in Fixed Rate	
Difference Between Revenues @ Proposed Rates and Class Specific Revenue Requirement	

Notes:

[1] The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

[2] The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

[3] Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process: *Initial Application*

	Customer and Load Forecast					Class Allocated Revenues (From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design)			Fixed / Variable Splits [2] (Percentage to be entered as a fraction between 0 and 1)		Transformer Ownership Allowance [1] ($)	Distribution Rates					Revenue Reconciliation		
	Customer Class (From sheet 10. Load Forecast)	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable		Monthly Service Charge Rate	Monthly Service Charge No. of decimals	Volumetric Rate		Volumetric Rate No. of decimals	1.013888889 MSC Revenues	Volumetric revenues	Distribution Revenues less Transformer Ownership Allowance
1	Residential	kWh	617,609	4,458,695,848	-	$ 326,944,706	$ 326,944,706	$ -	100.00%	0.00%	$ -	$43.51	2	$0.00000	/kWh	5	326,944,706	-	$ 326,944,705.68
2	Competitive Sector Multi-Unit Residential	kWh	90,045	286,903,886	-	$ 37,785,433	$ 37,785,433	$ -	100.00%	0.00%	$ -	$34.49		$0.00000	/kWh	5	37,785,433	-	$ 37,785,433.28
3	GS <50	kWh	71,596	2,238,780,453	-	$ 112,620,337	$ 33,344,376	$ 79,275,961	29.61%	70.39%	$ -	$38.28		$0.03541	/kWh	5	33,345,121	79,275,216	$ 112,620,336.90
4	GS - 50 to 999	kVA	10,363	9,526,101,781	24,849,478	$ 220,563,142	$ 6,672,881	$ 213,890,261	3.03%	96.97%	$ 3,934,179	$52.92		$8.6457	/kVA	4	6,672,321	217,825,040	$ 220,563,182.28
5	GS - 1000 to 4999	kVA	430	4,500,819,338	10,334,297	$ 71,212,854	$ 4,721,559	$ 66,491,295	6.63%	93.37%	$ 5,409,797	$902.50		$6.8622	/kVA	4	4,721,579	71,900,958	$ 71,212,739.61
6	Large Use >5MW	kVA	44	1,991,635,383	4,764,614	$ 34,823,821	$ 2,105,035	$ 32,718,786	6.04%	93.96%	$ 2,927,366	$3,932.19		$7.3790	/kVA	4	2,105,032	35,646,392	$ 34,824,057.44
7	Street Light	kVA	165,571	115,193,891	327,106	$ 16,093,607	$ 3,446,247	$ 12,647,360	21.41%	78.59%	$ -	$1.71		$38.1348	/kVA	4	3,444,708	12,647,374	$ 16,092,081.70
8	Unmetered Scattered Load	kWh	857	41,200,600	-	$ 4,143,857	$ 79,425	$ 3,948,719	1.92%	95.29%	$ -	$7.62		$0.09584	/kWh	5	79,452	3,948,666	$ 4,028,118.00
9	Unmetered Scattered Load (Connections)		12,272	-	-		$ 115,713	$ -	2.79%		$ -	$0.77		$0.00000			114,968	-	$ 114,968.19
10			-	-	-												$ -	$ -	$ -
11			-	-	-												$ -	$ -	$ -
12			-	-	-												$ -	$ -	$ -
13			-	-	-												$ -	$ -	$ -
14			-	-	-												$ -	$ -	$ -
15			-	-	-												$ -	$ -	$ -
16			-	-	-												$ -	$ -	$ -
17			-	-	-												$ -	$ -	$ -
18			-	-	-												$ -	$ -	$ -
19			-	-	-												$ -	$ -	$ -
20			-	-	-												$ -	$ -	$ -

Total Transformer Ownership Allowance $ 12,271,342

Rates recover revenue requirement

Total Distribution Revenues	$ 824,185,623.08
Base Revenue Requirement	$ 826,188,599.67
Difference	-$ 2,002,976.59
% Difference	-0.242%

Notes:

[1] Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

[2] The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calcutated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2019 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

(2) Short description of change, issue, etc.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference [1]	Item / Description [2]	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 275,830,806	5.71%	$4,828,970,698	$3,722,273,959	$ 239,088,778	$ 281,929,611	$ 36,548,043	$ 274,410,533	$ 874,303,784	$ 48,115,184	$ 826,188,600	$ 26,471,745
1		Change												

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2022 Filers

Version 8.00

Utility Name	Toronto Hydro-Electric System Limited
Service Territory	
Assigned EB Number	EB-2018-0165
Name and Title	
Phone Number	
Email Address	
Test Year	
Bridge Year	
Last Rebasing Year	2015

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

This Workbook Model is protected by copyright and is being made available to you solely for the purpose of filing your application. You may use and copy this model for that purpose, and provide a copy of this model to any person that is advising or assisting you in that regard. Except as indicated above, any copying, reproduction, publication, sale, adaptation, translation, modification, reverse engineering or other use or dissemination of this model without the express written consent of the Ontario Energy Board is prohibited. If you provide a copy of this model to a person that is advising or assisting you in preparing the application or reviewing your draft rate order, you must ensure that the person understands and agrees to the restrictions noted above.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2022 Filers

1. Info
2. Table of Contents
3. Data_Input_Sheet
4. Rate_Base
5. Utility Income
6. Taxes_PILs
7. Cost_of_Capital
8. Rev_Def_Suff
9. Rev_Reqt
10. Load Forecast
11. Cost Allocation
12. Residential Rate Design
13. Rate Design and Revenue Reconciliation
14. Tracking Sheet

Notes:

(1)	Pale green cells represent inputs
(2)	Pale green boxes at the bottom of each page are for additional notes
(3)	Pale yellow cells represent drop-down lists
(4)	***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5)	***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2022 Filers

Data Input (1)

		Initial Application	(2)		(6)		Per Board Decision	
1	**Rate Base**							
	Gross Fixed Assets (average)	$6,579,674,706			$ 6,579,674,706		$6,579,674,706	
	Accumulated Depreciation (average)	($1,741,668,171)	(5)		($1,741,668,171)		($1,741,668,171)	
	Allowance for Working Capital:							
	Controllable Expenses	$282,515,282			$ 282,515,282		$282,515,282	
	Cost of Power	$3,510,397,351			$ 3,510,397,351		$3,510,397,351	
	Working Capital Rate (%)	6.42%	(9)		(9)			(9)
2	**Utility Income**							
	Operating Revenues:							
	Distribution Revenue at Current Rates	$826,212,025						
	Distribution Revenue at Proposed Rates	$846,898,973						
	Other Revenue:							
	Specific Service Charges	$6,699,967						
	Late Payment Charges	$3,819,304						
	Other Distribution Revenue	$38,027,870						
	Other Income and Deductions							
	Total Revenue Offsets	$48,547,141	(7)					
	Operating Expenses:							
	OM+A Expenses	$276,880,228			$ 276,880,228		$276,880,228	
	Depreciation/Amortization	$293,076,608			$ 293,076,608		$293,076,608	
	Property taxes	$5,635,054			$ 5,635,054		$5,635,054	
	Other expenses							
3	**Taxes/PILs**							
	Taxable Income:							
	Adjustments required to arrive at taxable income	($83,502,066)	(3)					
	Utility Income Taxes and Rates:							
	Income taxes (not grossed up)	$24,023,360						
	Income taxes (grossed up)	$32,684,843						
	Federal tax (%)	15.00%						
	Provincial tax (%)	11.50%						
	Income Tax Credits	($2,736,000)						
4	**Capitalization/Cost of Capital**							
	Capital Structure:							
	Long-term debt Capitalization Ratio (%)	56.0%						
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		(8)			(8)
	Common Equity Capitalization Ratio (%)	40.0%						
	Prefered Shares Capitalization Ratio (%)							
		100.0%						
	Cost of Capital							
	Long-term debt Cost Rate (%)	3.71%						
	Short-term debt Cost Rate (%)	2.61%						
	Common Equity Cost Rate (%)	8.82%						
	Prefered Shares Cost Rate (%)							

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is **7.5%** (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2022 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application						Per Board Decision
1	Gross Fixed Assets (average)	(2)	$6,579,674,706		$ -		$6,579,674,706	$ -	$6,579,674,706
2	Accumulated Depreciation (average)	(2)	##############		$ -		($1,741,668,171)	$ -	($1,741,668,171)
3	Net Fixed Assets (average)	(2)	$4,838,006,535		$ -		$4,838,006,535	$ -	$4,838,006,535
4	Allowance for Working Capital	(1)	$243,626,036		##########		$ -	$ -	$ -
5	**Total Rate Base**		$5,081,632,571		##########		$4,838,006,535	$ -	$4,838,006,535

(1) Allowance for Working Capital - Derivation

6	Controllable Expenses		$282,515,282		$ -		$282,515,282	$ -	$282,515,282
7	Cost of Power		$3,510,397,351		$ -		$3,510,397,351	$ -	$3,510,397,351
8	Working Capital Base		$3,792,912,633		$ -		$3,792,912,633	$ -	$3,792,912,633
9	Working Capital Rate %	(1)	6.42%		-6.42%		0.00%	0.00%	0.00%
10	Working Capital Allowance		$243,626,036		##########		$ -	$ -	$ -

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2018 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2022 Filers

Utility Income

Line No.	Particulars	Initial Application				Per Board Decision
	Operating Revenues:					
1	Distribution Revenue (at Proposed Rates)	$846,898,973	($846,898,973)	$ -	$ -	$ -
2	Other Revenue (1)	$48,547,141	($48,547,141)	$ -	$ -	$ -
3	Total Operating Revenues	$895,446,114	($895,446,114)	$ -	$ -	$ -
	Operating Expenses:					
4	OM+A Expenses	$276,880,228	$ -	$276,880,228	$ -	$276,880,228
5	Depreciation/Amortization	$293,076,608	$ -	$293,076,608	$ -	$293,076,608
6	Property taxes	$5,635,054	$ -	$5,635,054	$ -	$5,635,054
7	Capital taxes	$ -	$ -	$ -	$ -	$ -
8	Other expense	$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)	$575,591,890	$ -	$575,591,890	$ -	$575,591,890
10	Deemed Interest Expense	$110,982,855	($110,982,855)	$ -	$ -	$ -
11	Total Expenses (lines 9 to 10)	$686,574,745	($110,982,855)	$575,591,890	$ -	$575,591,890
12	**Utility income before income taxes**	$208,871,369	($784,463,259)	($575,591,890)	$ -	($575,591,890)
13	Income taxes (grossed-up)	$32,684,843	$ -	$32,684,843	$ -	$32,684,843
14	**Utility net income**	$176,186,526	($784,463,259)	($608,276,733)	$ -	($608,276,733)

Notes

(1) **Other Revenues / Revenue Offsets**

Specific Service Charges	$6,699,967		$ -		$ -
Late Payment Charges	$3,819,304		$ -		$ -
Other Distribution Revenue	$38,027,870		$ -		$ -
Other Income and Deductions	$ -		$ -		$ -
Total Revenue Offsets	$48,547,141	$ -	$ -	$ -	$ -

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2022 Filers

Taxes/PILs

Line No.	Particulars	Application		Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$179,279,997	$ -	$ -
2	Adjustments required to arrive at taxable utility income	($83,502,066)	$ -	$ -
3	Taxable income	$95,777,931	$ -	$ -
	Calculation of Utility income Taxes			
4	Income taxes	$24,023,360	$24,023,360	$24,023,360
6	Total taxes	$24,023,360	$24,023,360	$24,023,360
7	Gross-up of Income Taxes	$8,661,483	$8,661,483	$8,661,483
8	Grossed-up Income Taxes	$32,684,843	$32,684,843	$32,684,843
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$32,684,843	$32,684,843	$32,684,843
10	Other tax Credits	($2,736,000)	($2,736,000)	($2,736,000)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2022 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate		Return
		Initial Application				
		(%)	($)	(%)		($)
	Debt					
1	Long-term Debt	56.00%	$2,845,714,240	3.71%		$105,677,631
2	Short-term Debt	4.00%	$203,265,303	2.61%		$5,305,224
3	**Total Debt**	60.00%	$3,048,979,542	3.64%		$110,982,855
	Equity					
4	Common Equity	40.00%	$2,032,653,028	8.82%		$179,279,997
5	Preferred Shares	0.00%	$ -	0.00%		$ -
6	**Total Equity**	40.00%	$2,032,653,028	8.82%		$179,279,997
7	**Total**	100.00%	$5,081,632,571	5.71%		$290,262,852
		(%)	($)	(%)		($)
	Debt					
1	Long-term Debt	0.00%	$ -	0.00%		$ -
2	Short-term Debt	0.00%	$ -	0.00%		$ -
3	**Total Debt**	0.00%	$ -	0.00%		$ -
	Equity					
4	Common Equity	0.00%	$ -	0.00%		$ -
5	Preferred Shares	0.00%	$ -	0.00%		$ -
6	**Total Equity**	0.00%	$ -	0.00%		$ -
7	**Total**	0.00%	$4,838,006,535	0.00%		$ -
		Per Board Decision				
		(%)	($)	(%)		($)
	Debt					
8	Long-term Debt	0.00%	$ -	3.71%		$ -
9	Short-term Debt	0.00%	$ -	2.61%		$ -
10	**Total Debt**	0.00%	$ -	0.00%		$ -
	Equity					
11	Common Equity	0.00%	$ -	8.82%		$ -
12	Preferred Shares	0.00%	$ -	0.00%		$ -
13	**Total Equity**	0.00%	$ -	0.00%		$ -
14	**Total**	0.00%	$4,838,006,535	0.00%		$ -

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2022 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application				Per Board Decision	
		At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$21,905,307		($284,448,771)		$783,118,217
2	Distribution Revenue	$826,212,025	$824,993,666	$826,212,025	$1,131,347,744	$ -	($783,118,217)
3	Other Operating Revenue Offsets - net	$48,547,141	$48,547,141	$ -	$ -	$ -	$ -
4	**Total Revenue**	$874,759,165	$895,446,114	$826,212,025	$846,898,973	$ -	$ -
5	Operating Expenses	$575,591,890	$575,591,890	$575,591,890	$575,591,890	$575,591,890	$575,591,890
6	Deemed Interest Expense	$110,982,855	$110,982,855	$ -	$ -	$ -	$ -
8	**Total Cost and Expenses**	$686,574,745	$686,574,745	$575,591,890	$575,591,890	$575,591,890	$575,591,890
9	**Utility Income Before Income Taxes**	$188,184,420	$208,871,369	$250,620,135	$271,307,083	($575,591,890)	($575,591,890)
10	Tax Adjustments to Accounting Income per 2013 PILs model	($83,502,066)	($83,502,066)	($83,502,066)	($83,502,066)	$ -	$ -
11	**Taxable Income**	$104,682,354	$125,369,303	$167,118,069	$187,805,017	($575,591,890)	($575,591,890)
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$27,740,824	$33,222,865	$44,286,288	$49,768,330	$ -	$ -
14	**Income Tax Credits**	($2,736,000)	($2,736,000)	($2,736,000)	($2,736,000)	$ -	$ -
15	**Utility Net Income**	$163,179,597	$176,186,526	$209,069,847	($608,276,733)	($575,591,890)	($608,276,733)
16	**Utility Rate Base**	$5,081,632,571	$5,081,632,571	$4,838,006,535	$4,838,006,535	$4,838,006,535	$4,838,006,535
17	Deemed Equity Portion of Rate Base	$2,032,653,028	$2,032,653,028	$ -	$ -	$ -	$ -
18	Income/(Equity Portion of Rate Base)	8.03%	8.67%	0.00%	0.00%	0.00%	0.00%
19	Target Return - Equity on Rate Base	8.82%	8.82%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Return on Equity	-0.79%	-0.15%	0.00%	0.00%	0.00%	0.00%
21	Indicated Rate of Return	5.40%	5.65%	4.32%	0.00%	-11.90%	0.00%
22	Requested Rate of Return on Rate Base	5.71%	5.71%	0.00%	0.00%	0.00%	0.00%
23	Deficiency/Sufficiency in Rate of Return	-0.32%	-0.06%	4.32%	0.00%	-11.90%	0.00%
24	Target Return on Equity	$179,279,997	$179,279,997	$ -	$ -	$ -	$ -
25	Revenue Deficiency/(Sufficiency)	$16,100,401	($3,093,471)	($209,069,847)	$ -	$575,591,890	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$21,905,307 (1)		($284,448,771) (1)		$783,118,217 (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2022 Filers

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$276,880,228		$276,880,228		$276,880,228	
2	Amortization/Depreciation	$293,076,608		$293,076,608		$293,076,608	
3	Property Taxes	$5,635,054		$5,635,054		$5,635,054	
5	Income Taxes (Grossed up)	$32,684,843		$32,684,843		$32,684,843	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$110,982,855		$ -		$ -	
	Return on Deemed Equity	$179,279,997		$ -		$ -	
8	**Service Revenue Requirement (before Revenues)**	$898,539,585		$608,276,733		$608,276,733	
9	Revenue Offsets	$48,547,141		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$849,992,444		$608,276,733		$608,276,733	
11	Distribution revenue	$846,898,973		$ -		$ -	
12	Other revenue	$48,547,141		$ -		$ -	
13	**Total revenue**	$895,446,114		$ -		$ -	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($3,093,471)	(1)	($608,276,733)	(1)	($608,276,733)	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application		Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$898,539,585	$608,276,733	**($0)**	$608,276,733	**($1)**
Grossed-Up Revenue Deficiency/(Sufficiency)	$21,905,307	($284,448,771)	**($14)**	$783,118,217	**($1)**
Base Revenue Requirement (to be recovered from Distribution Rates)	$849,992,444	$608,276,733	**($0)**	$608,276,733	**($1)**
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$20,686,948	$ -	**($1)**	$ -	**($1)**

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2022 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Initial Application

	Customer Class	Initial Application					Per Board Decision			
	Input the name of each customer class.	Customer / Connections Test Year average or mid-year	kWh Annual	kW/kVA [1] Annual	Customer / Connections Test Year average or mid-year	kWh Annual	kW/kVA [1] Annual	Customer / Connections Test Year average or mid-year	kWh Annual	kW/kVA [1] Annual
1	Residential	619,254	4,422,717,979							
2	Competitive Sector Multi-Unit Residential	95,962	300,278,055							
3	GS <50	71,692	2,214,262,866							
4	GS - 50 to 999	10,352	9,482,679,716	24,840,867						
5	GS - 1000 to 4999	430	4,444,016,815	10,283,783						
6	Large Use >5MW	44	1,977,187,697	4,748,366						
7	Street Light	165,839	115,380,364	327,591						
8	Unmetered Scattered Load	857	41,200,600							
9	Unmetered Scattered Load (Connections)	12,272								
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		**22,997,724,093**	**40,200,607**		**-**	**-**		**-**	**-**

Notes:

[1] Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2022 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class [3]	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1]	%
	From Sheet 10. Load Forecast			(7A)	
1	Residential	$ 287,079,871	42.26%	$ 345,423,219	38.4%
2	Competitive Sector Multi-Unit Residentia	$ 19,267,312	2.84%	$ 38,612,112	4.3%
3	GS <50	$ 99,019,246	14.58%	$ 140,026,618	15.6%
4	GS - 50 to 999	$ 157,700,127	23.21%	$ 223,611,711	24.9%
5	GS - 1000 to 4999	$ 55,701,964	8.20%	$ 78,999,924	8.8%
6	Large Use >5MW	$ 31,087,389	4.58%	$ 43,020,668	4.8%
7	Street Light	$ 25,331,820	3.73%	$ 24,003,346	2.7%
8	Unmetered Scattered Load	$ 4,173,832	0.61%	$ 4,841,988	0.5%
9	Unmetered Scattered Load (Connections)				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 679,361,561	100.00%	**$ 898,539,585**	100.0%
			Service Revenue Requirement (from Sheet 9)	**$ 898,539,585**	

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.
(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.
(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential	$ 327,783,527	$ 336,012,380	$ 335,877,177	$ 19,577,103
2	Competitive Sector Multi-Unit Residentia	$ 40,269,494	$ 41,280,441	$ 41,505,964	$ 1,709,545
3	GS <50	$ 111,795,446	$ 114,602,019	$ 114,450,611	$ 8,309,228
4	GS - 50 to 999	$ 220,473,129	$ 226,008,004	$ 226,003,812	$ 7,465,571
5	GS - 1000 to 4999	$ 70,877,474	$ 72,656,820	$ 72,734,767	$ 1,421,594
6	Large Use >5MW	$ 34,706,612	$ 35,577,905	$ 35,575,066	$ 582,036
7	Street Light	$ 16,110,700	$ 16,515,151	$ 16,510,255	$ 9,168,200
8	Unmetered Scattered Load	$ 4,142,264	$ 4,246,254	$ 4,241,320	$ 313,864
9	Unmetered Scattered Load (Connections)				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 826,158,645	$ 846,898,973	$ 846,898,973	$ 48,547,141

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.
(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.
(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.
(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year: 2015 %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
1	Residential	94.3%	102.9%	102.9%	85 - 115
2	Competitive Sector Multi-Unit Residentia	100.0%	111.3%	111.9%	
3	GS <50	91.5%	87.8%	87.7%	80 - 120
4	GS - 50 to 999	119.0%	104.4%	104.4%	80 - 120
5	GS - 1000 to 4999	101.9%	93.8%	93.9%	80 - 120
6	Large Use >5MW	95.3%	84.1%	84.0%	85 - 115
7	Street Light	82.7%	107.0%	107.0%	80 - 120
8	Unmetered Scattered Load	90.5%	94.2%	94.1%	80 - 120
9	Unmetered Scattered Load (Connections)				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) Proposed Revenue-to-Cost Ratios *(11)*

	Name of Customer Class	Proposed Revenue-to-Cost Ratio Test Year 2020	Price Cap IR Period 2021	Price Cap IR Period 2022	Policy Range
1	Residential	102.9%			85 - 115
2	Competitive Sector Multi-Unit Residentia	111.9%			
3	GS <50	87.7%			80 - 120
4	GS - 50 to 999	104.4%			80 - 120
5	GS - 1000 to 4999	93.9%			80 - 120
6	Large Use >5MW	84.0%			85 - 115
7	Street Light	107.0%			80 - 120
8	Unmetered Scattered Load	94.1%			80 - 120
9	Unmetered Scattered Load (Connection				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2019 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2020 and 2021 Price Cap IR models, as necessary. For 2020 and 2021, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2018 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2022 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential Class	
Customers	619,254
kWh	4,422,717,979

Proposed Residential Class Specific Revenue Requirement[1]	$ 335,877,177.06

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	$ -
Distribution Volumetric Rate ($/kWh)	$ -

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed	0	619,254	$ -	
Variable	0	4,422,717,979	$ -	
TOTAL	-	-	$ -	-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	1

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed			
Variable			
TOTAL		-	

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed				
Variable				
TOTAL	-	$ -	-	

Checks[3]	
Change in Fixed Rate	
Difference Between Revenues @ Proposed Rates and Class Specific Revenue Requirement	

Notes:

[1] The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

[2] The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

[3] Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2022 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process: *Initial Application*

	Customer and Load Forecast					Class Allocated Revenues (From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design)			Fixed / Variable Splits [2] (Percentage to be entered as a fraction between 0 and 1)		Transformer Ownership Allowance [1] ($)	Distribution Rates				Revenue Reconciliation		
	Customer Class (From sheet 10. Load Forecast)	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable		Monthly Service Charge Rate	Monthly Service Charge No. of decimals	Volumetric Rate		Volumetric Rate No. of decimals	1.013888889 MSC Revenues	Volumetric revenues	Distribution Revenues less Transformer Ownership Allowance
1	Residential	kWh	619,254	4,422,717,979	-	$ 335,877,177	$ 335,877,177	$ -	100.00%	0.00%	$ -	$44.58	2	$0.00000	/kWh	5	335,877,177	-	$ 335,877,177.06
2	Competitive Sector Multi-Unit Residential	kWh	95,962	300,278,055	-	$ 41,505,964	$ 41,505,964	$ -	100.00%	0.00%	$ -	$35.55		$0.00000	/kWh	5	41,505,964	-	$ 41,505,964.05
3	GS <50	kWh	71,692	2,214,262,866	-	$ 114,450,611	$ 34,183,160	$ 80,267,451	29.87%	70.13%	$ -	$39.19		$0.03625	/kWh	5	34,183,582	80,267,029	$ 114,450,610.90
4	GS - 50 to 999	kVA	10,352	9,482,679,716	24,840,867	$ 226,003,812	$ 6,833,426	$ 219,170,387	3.02%	96.98%	$ 3,932,887	$54.26		$8.8583	/kVA	4	6,834,011	223,104,073	$ 226,005,197.47
5	GS - 1000 to 4999	kVA	430	4,444,016,815	10,283,783	$ 72,734,767	$ 4,844,620	$ 67,890,147	6.66%	93.34%	$ 5,383,442	$926.02		$7.0276	/kVA	4	4,844,628	73,274,064	$ 72,735,250.26
6	Large Use >5MW	kVA	44	1,977,187,697	4,748,366	$ 35,575,066	$ 2,157,357	$ 33,417,709	6.06%	93.94%	$ 2,917,387	$4,029.93		$7.5473	/kVA	4	2,157,356	36,335,083	$ 35,575,052.58
7	Street Light	kVA	165,839	115,380,364	327,591	$ 16,510,255	$ 3,528,205	$ 12,982,050	21.37%	78.63%	$ -	$1.75		$39.0860	/kVA	4	3,530,992	12,982,058	$ 16,513,050.50
8	Unmetered Scattered Load	kWh	857	41,200,600	-	$ 4,241,320	$ 81,375	$ 4,042,210	1.92%	95.31%	$ -	$7.80		$0.09811	/kWh	5	81,329	4,042,191	$ 4,123,520.20
9	Unmetered Scattered Load (Connections)		12,272	-	-		$ 117,735	$ -	2.78%		$ -	$0.79		$0.00000			117,954	-	$ 117,954.37
10			-	-	-												$ -	$ -	$ -
11			-	-	-												$ -	$ -	$ -
12			-	-	-												$ -	$ -	$ -
13			-	-	-												$ -	$ -	$ -
14			-	-	-												$ -	$ -	$ -
15			-	-	-												$ -	$ -	$ -
16			-	-	-												$ -	$ -	$ -
17			-	-	-												$ -	$ -	$ -
18			-	-	-												$ -	$ -	$ -
19			-	-	-												$ -	$ -	$ -
20			-	-	-												$ -	$ -	$ -

Total Transformer Ownership Allowance $ 12,233,716

Rates recover revenue requirement

Total Distribution Revenues	$ 846,903,777.39
Base Revenue Requirement	$ 849,992,444.33
Difference	-$ 3,088,666.94
% Difference	-0.363%

Notes:

[1] Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

[2] The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calcutated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2019 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

(2) Short description of change, issue, etc.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference (1)	Item / Description (2)	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 290,262,852	5.71%	$5,081,632,571	$3,792,912,633	$ 243,626,036	$ 293,076,608	$ 32,684,843	$ 276,880,228	$ 898,539,585	$ 48,547,141	$ 849,992,444	$ 21,905,307
1		Change												

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Version 8.00

Utility Name	Toronto Hydro-Electric System Limited
Service Territory	
Assigned EB Number	EB-2018-0165
Name and Title	
Phone Number	
Email Address	
Test Year	
Bridge Year	
Last Rebasing Year	2015

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

This Workbook Model is protected by copyright and is being made available to you solely for the purpose of filing your application. You may use and copy this model for that purpose, and provide a copy of this model to any person that is advising or assisting you in that regard. Except as indicated above, any copying, reproduction, publication, sale, adaptation, translation, modification, reverse engineering or other use or dissemination of this model without the express written consent of the Ontario Energy Board is prohibited. If you provide a copy of this model to a person that is advising or assisting you in preparing the application or reviewing your draft rate order, you must ensure that the person understands and agrees to the restrictions noted above.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

1. Info
2. Table of Contents
3. Data_Input_Sheet
4. Rate_Base
5. Utility Income
6. Taxes_PILs
7. Cost_of_Capital
8. Rev_Def_Suff
9. Rev_Reqt
10. Load Forecast
11. Cost Allocation
12. Residential Rate Design
13. Rate Design and Revenue Reconciliation
14. Tracking Sheet

Notes:

(1)	Pale green cells represent inputs
(2)	Pale green boxes at the bottom of each page are for additional notes
(3)	Pale yellow cells represent drop-down lists
(4)	***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5)	***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Data Input [1]

		Initial Application	[2]		[6]	Per Board Decision	
1	**Rate Base**						
	Gross Fixed Assets (average)	$7,140,052,883		###########		$7,140,052,883	
	Accumulated Depreciation (average)	($2,013,781,505)	[5]	###########		($2,013,781,505)	
	Allowance for Working Capital:						
	Controllable Expenses	$285,057,919		$ 285,057,919		$285,057,919	
	Cost of Power	$3,579,801,165		###########		$3,579,801,165	
	Working Capital Rate (%)	6.42%	[9]		[9]		[9]
2	**Utility Income**						
	Operating Revenues:						
	Distribution Revenue at Current Rates	$848,702,180					
	Distribution Revenue at Proposed Rates	$885,241,080					
	Other Revenue:						
	Specific Service Charges	$6,760,117					
	Late Payment Charges	$3,853,592					
	Other Distribution Revenue	$38,369,275					
	Other Income and Deductions						
	Total Revenue Offsets	$48,982,985	[7]				
	Operating Expenses:						
	OM+A Expenses	$279,372,150		$ 279,372,150		$279,372,150	
	Depreciation/Amortization	$310,853,964		$ 310,853,964		$310,853,964	
	Property taxes	$5,685,769		$ 5,685,769		$5,685,769	
	Other expenses						
3	**Taxes/PILs**						
	Taxable Income:						
	Adjustments required to arrive at taxable income	($85,418,999)	[3]				
	Utility Income Taxes and Rates:						
	Income taxes (not grossed up)	$26,253,623					
	Income taxes (grossed up)	$35,719,215					
	Federal tax (%)	15.00%					
	Provincial tax (%)	11.50%					
	Income Tax Credits	($2,736,000)					
4	**Capitalization/Cost of Capital**						
	Capital Structure:						
	Long-term debt Capitalization Ratio (%)	56.0%					
	Short-term debt Capitalization Ratio (%)	4.0%	[8]		[8]		[8]
	Common Equity Capitalization Ratio (%)	40.0%					
	Prefered Shares Capitalization Ratio (%)						
		100.0%					
	Cost of Capital						
	Long-term debt Cost Rate (%)	3.71%					
	Short-term debt Cost Rate (%)	2.61%					
	Common Equity Cost Rate (%)	8.82%					
	Prefered Shares Cost Rate (%)						

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

[1] All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

[2] Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

[3] Net of addbacks and deductions to arrive at taxable income.

[4] Average of Gross Fixed Assets at beginning and end of the Test Year

[5] Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

[6] Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

[7] Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

[8] 4.0% unless an Applicant has proposed or been approved for another amount.

[9] The default Working Capital Allowance factor is **7.5%** (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application						Per Board Decision
1	Gross Fixed Assets (average)	(2)	$7,140,052,883		$ -		$7,140,052,883	$ -	$7,140,052,883
2	Accumulated Depreciation (average)	(2)	($2,013,781,505)		$ -		($2,013,781,505)	$ -	($2,013,781,505)
3	Net Fixed Assets (average)	(2)	$5,126,271,378		$ -		$5,126,271,378	$ -	$5,126,271,378
4	Allowance for Working Capital	(1)	$248,247,294		###########		$ -	$ -	$ -
5	**Total Rate Base**		$5,374,518,672		###########		$5,126,271,378	$ -	$5,126,271,378

(1) Allowance for Working Capital - Derivation

6	Controllable Expenses		$285,057,919		$ -		$285,057,919	$ -	$285,057,919
7	Cost of Power		$3,579,801,165		$ -		$3,579,801,165	$ -	$3,579,801,165
8	Working Capital Base		$3,864,859,084		$ -		$3,864,859,084	$ -	$3,864,859,084
9	Working Capital Rate %	(1)	6.42%		-6.42%		0.00%	0.00%	0.00%
10	Working Capital Allowance		$248,247,294		###########		$ -	$ -	$ -

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2018 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Utility Income

Line No.	Particulars	Initial Application				Per Board Decision
	Operating Revenues:					
1	Distribution Revenue (at Proposed Rates)	$885,241,080	($885,241,080)	$ -	$ -	$ -
2	Other Revenue (1)	$48,982,985	($48,982,985)	$ -	$ -	$ -
3	Total Operating Revenues	$934,224,064	($934,224,064)	$ -	$ -	$ -
	Operating Expenses:					
4	OM+A Expenses	$279,372,150	$ -	$279,372,150	$ -	$279,372,150
5	Depreciation/Amortization	$310,853,964	$ -	$310,853,964	$ -	$310,853,964
6	Property taxes	$5,685,769	$ -	$5,685,769	$ -	$5,685,769
7	Capital taxes	$ -	$ -	$ -	$ -	$ -
8	Other expense	$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)	$595,911,884	$ -	$595,911,884	$ -	$595,911,884
10	Deemed Interest Expense	$117,379,488	($117,379,488)	$ -	$ -	$ -
11	Total Expenses (lines 9 to 10)	$713,291,371	($117,379,488)	$595,911,884	$ -	$595,911,884
12	**Utility income before income taxes**	$220,932,693	($816,844,577)	($595,911,884)	$ -	($595,911,884)
13	Income taxes (grossed-up)	$35,719,215	$ -	$35,719,215	$ -	$35,719,215
14	**Utility net income**	$185,213,478	($816,844,577)	($631,631,099)	$ -	($631,631,099)

Notes

(1) **Other Revenues / Revenue Offsets**

Specific Service Charges	$6,760,117		$ -		$ -
Late Payment Charges	$3,853,592		$ -		$ -
Other Distribution Revenue	$38,369,275		$ -		$ -
Other Income and Deductions	$ -		$ -		$ -
Total Revenue Offsets	$48,982,985	$ -	$ -	$ -	$ -

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Taxes/PILs

Line No.	Particulars	Application		Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$189,613,019	$ -	$ -
2	Adjustments required to arrive at taxable utility income	($85,418,999)	$ -	$ -
3	Taxable income	$104,194,020	$ -	$ -
	Calculation of Utility income Taxes			
4	Income taxes	$26,253,623	$26,253,623	$26,253,623
6	Total taxes	$26,253,623	$26,253,623	$26,253,623
7	Gross-up of Income Taxes	$9,465,592	$9,465,592	$9,465,592
8	Grossed-up Income Taxes	$35,719,215	$35,719,215	$35,719,215
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$35,719,215	$35,719,215	$35,719,215
10	Other tax Credits	($2,736,000)	($2,736,000)	($2,736,000)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate		Return
		Initial Application				
		(%)	($)	(%)		($)
	Debt					
1	Long-term Debt	56.00%	$3,009,730,456	3.71%		$111,768,490
2	Short-term Debt	4.00%	$214,980,747	2.61%		$5,610,997
3	**Total Debt**	60.00%	$3,224,711,203	3.64%		$117,379,488
	Equity					
4	Common Equity	40.00%	$2,149,807,469	8.82%		$189,613,019
5	Preferred Shares	0.00%	$ -	0.00%		$ -
6	**Total Equity**	40.00%	$2,149,807,469	8.82%		$189,613,019
7	**Total**	100.00%	$5,374,518,672	5.71%		$306,992,506
		(%)	($)	(%)		($)
	Debt					
1	Long-term Debt	0.00%	$ -	0.00%		$ -
2	Short-term Debt	0.00%	$ -	0.00%		$ -
3	**Total Debt**	0.00%	$ -	0.00%		$ -
	Equity					
4	Common Equity	0.00%	$ -	0.00%		$ -
5	Preferred Shares	0.00%	$ -	0.00%		$ -
6	**Total Equity**	0.00%	$ -	0.00%		$ -
7	**Total**	0.00%	$5,126,271,378	0.00%		$ -
		Per Board Decision				
		(%)	($)	(%)		($)
	Debt					
8	Long-term Debt	0.00%	$ -	3.71%		$ -
9	Short-term Debt	0.00%	$ -	2.61%		$ -
10	**Total Debt**	0.00%	$ -	0.00%		$ -
	Equity					
11	Common Equity	0.00%	$ -	8.82%		$ -
12	Preferred Shares	0.00%	$ -	0.00%		$ -
13	**Total Equity**	0.00%	$ -	0.00%		$ -
14	**Total**	0.00%	$5,126,271,378	0.00%		$ -

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application				Per Board Decision	
		At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$39,063,327		($287,310,071)		$810,764,468
2	Distribution Revenue	$848,702,180	$846,177,752	$848,702,180	$1,172,551,151	$ -	($810,764,468)
3	Other Operating Revenue Offsets - net	$48,982,985	$48,982,985	$ -	$ -	$ -	$ -
4	**Total Revenue**	$897,685,165	$934,224,064	$848,702,180	$885,241,080	$ -	$ -
5	Operating Expenses	$595,911,884	$595,911,884	$595,911,884	$595,911,884	$595,911,884	$595,911,884
6	Deemed Interest Expense	$117,379,488	$117,379,488	$ -	$ -	$ -	$ -
8	**Total Cost and Expenses**	$713,291,371	$713,291,371	$595,911,884	$595,911,884	$595,911,884	$595,911,884
9	**Utility Income Before Income Taxes**	$184,393,794	$220,932,693	$252,790,296	$289,329,196	($595,911,884)	($595,911,884)
10	Tax Adjustments to Accounting Income per 2013 PILs model	($85,418,999)	($85,418,999)	($85,418,999)	($85,418,999)	$ -	$ -
11	**Taxable Income**	$98,974,795	$135,513,694	$167,371,297	$203,910,197	($595,911,884)	($595,911,884)
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$26,228,321	$35,911,129	$44,353,394	$54,036,202	$ -	$ -
14	**Income Tax Credits**	($2,736,000)	($2,736,000)	($2,736,000)	($2,736,000)	$ -	$ -
15	**Utility Net Income**	$160,901,473	$185,213,478	$211,172,903	($631,631,099)	($595,911,884)	($631,631,099)
16	**Utility Rate Base**	$5,374,518,672	$5,374,518,672	$5,126,271,378	$5,126,271,378	$5,126,271,378	$5,126,271,378
17	Deemed Equity Portion of Rate Base	$2,149,807,469	$2,149,807,469	$ -	$ -	$ -	$ -
18	Income/(Equity Portion of Rate Base)	7.48%	8.62%	0.00%	0.00%	0.00%	0.00%
19	Target Return - Equity on Rate Base	8.82%	8.82%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Return on Equity	-1.34%	-0.20%	0.00%	0.00%	0.00%	0.00%
21	Indicated Rate of Return	5.18%	5.63%	4.12%	0.00%	-11.62%	0.00%
22	Requested Rate of Return on Rate Base	5.71%	5.71%	0.00%	0.00%	0.00%	0.00%
23	Deficiency/Sufficiency in Rate of Return	-0.53%	-0.08%	4.12%	0.00%	-11.62%	0.00%
24	Target Return on Equity	$189,613,019	$189,613,019	$ -	$ -	$ -	$ -
25	Revenue Deficiency/(Sufficiency)	$28,711,546	($4,399,540)	($211,172,903)	$ -	$595,911,884	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$39,063,327 (1)		($287,310,071) (1)		$810,764,468 (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$279,372,150		$279,372,150		$279,372,150	
2	Amortization/Depreciation	$310,853,964		$310,853,964		$310,853,964	
3	Property Taxes	$5,685,769		$5,685,769		$5,685,769	
5	Income Taxes (Grossed up)	$35,719,215		$35,719,215		$35,719,215	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$117,379,488		$ -		$ -	
	Return on Deemed Equity	$189,613,019		$ -		$ -	
8	**Service Revenue Requirement (before Revenues)**	$938,623,605		$631,631,099		$631,631,099	
9	Revenue Offsets	$48,982,985		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$889,640,620		$631,631,099		$631,631,099	
11	Distribution revenue	$885,241,080		$ -		$ -	
12	Other revenue	$48,982,985		$ -		$ -	
13	**Total revenue**	$934,224,064		$ -		$ -	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($4,399,540)	(1)	($631,631,099)	(1)	($631,631,099)	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application		Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$938,623,605	$631,631,099	**($0)**	$631,631,099	**($1)**
Grossed-Up Revenue Deficiency/(Sufficiency)	$39,063,327	($287,310,071)	**($8)**	$810,764,468	**($1)**
Base Revenue Requirement (to be recovered from Distribution Rates)	$889,640,620	$631,631,099	**($0)**	$631,631,099	**($1)**
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$36,538,900	$ -	**($1)**	$ -	**($1)**

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Initial Application

	Customer Class	Initial Application					Per Board Decision		
	Input the name of each customer class.	Customer / Connections Test Year average or mid-year	kWh Annual	kW/kVA [1] Annual	Customer / Connections Test Year average or mid-year	kWh Annual	kW/kVA [1] Annual	Customer / Connections Test Year average or mid-	kWh Annual	kW/kVA [1] Annual
1	Residential	620,899	4,386,740,109							
2	Competitive Sector Multi-Unit Residential	101,879	313,817,857							
3	GS <50	71,788	2,187,481,667							
4	GS - 50 to 999	10,341	9,432,138,729	24,813,648						
5	GS - 1000 to 4999	430	4,387,143,302	10,232,645						
6	Large Use >5MW	44	1,962,015,257	4,730,195						
7	Street Light	166,107	115,566,836	328,076						
8	Unmetered Scattered Load	857	41,200,600							
9	Unmetered Scattered Load (Connections)	12,272								
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		###########	**40,104,565**		-	-		-	-

Notes:

[1] Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class [3]	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1]	%
	From Sheet 10. Load Forecast			(7A)	
1	Residential	$ 287,079,871	42.26%	$ 360,832,613	38.4%
2	Competitive Sector Multi-Unit Residentia	$ 19,267,312	2.84%	$ 40,334,605	4.3%
3	GS <50	$ 99,019,246	14.58%	$ 146,273,232	15.6%
4	GS - 50 to 999	$ 157,700,127	23.21%	$ 233,587,071	24.9%
5	GS - 1000 to 4999	$ 55,701,964	8.20%	$ 82,524,126	8.8%
6	Large Use >5MW	$ 31,087,389	4.58%	$ 44,939,828	4.8%
7	Street Light	$ 25,331,820	3.73%	$ 25,074,140	2.7%
8	Unmetered Scattered Load	$ 4,173,832	0.61%	$ 5,057,990	0.5%
9	Unmetered Scattered Load (Connections)				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 679,361,561	100.00%	**$ 938,623,605**	100.0%
			Service Revenue Requirement (from Sheet 9)	**$ 938,623,605**	

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.
(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.
(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential	$ 336,775,618	$ 351,270,826	$ 351,046,981	$ 19,752,861
2	Competitive Sector Multi-Unit Residentia	$ 43,803,895	$ 45,689,265	$ 45,664,205	$ 1,724,893
3	GS <50	$ 113,613,325	$ 118,503,373	$ 118,435,994	$ 8,383,826
4	GS - 50 to 999	$ 225,749,054	$ 235,465,552	$ 235,495,164	$ 7,532,595
5	GS - 1000 to 4999	$ 72,417,879	$ 75,534,827	$ 75,726,989	$ 1,434,357
6	Large Use >5MW	$ 35,504,757	$ 37,032,922	$ 37,139,549	$ 587,261
7	Street Light	$ 16,526,848	$ 17,238,183	$ 17,227,775	$ 9,250,510
8	Unmetered Scattered Load	$ 4,244,397	$ 4,427,080	$ 4,425,373	$ 316,681
9	Unmetered Scattered Load (Connections)				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 848,635,773	$ 885,162,029	$ 885,162,029	$ 48,982,986

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.
(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.
(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.
(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year: 2015 %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
1	Residential	94.3%	102.8%	102.8%	85 - 115
2	Competitive Sector Multi-Unit Residentia	100.0%	117.6%	117.5%	
3	GS <50	91.5%	86.7%	86.7%	80 - 120
4	GS - 50 to 999	119.0%	104.0%	104.0%	80 - 120
5	GS - 1000 to 4999	101.9%	93.3%	93.5%	80 - 120
6	Large Use >5MW	95.3%	83.7%	83.9%	85 - 115
7	Street Light	82.7%	105.6%	105.6%	80 - 120
8	Unmetered Scattered Load	90.5%	93.8%	93.8%	80 - 120
9	Unmetered Scattered Load (Connections)				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) Proposed Revenue-to-Cost Ratios *(11)*

	Name of Customer Class	Proposed Revenue-to-Cost Ratio Test Year 2020	Price Cap IR Period 2021	Price Cap IR Period 2022	Policy Range
1	Residential	102.8%			85 - 115
2	Competitive Sector Multi-Unit Residentia	117.5%			
3	GS <50	86.7%			80 - 120
4	GS - 50 to 999	104.0%			80 - 120
5	GS - 1000 to 4999	93.5%			80 - 120
6	Large Use >5MW	83.9%			85 - 115
7	Street Light	105.6%			80 - 120
8	Unmetered Scattered Load	93.8%			80 - 120
9	Unmetered Scattered Load (Connection				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2019 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2020 and 2021 Price Cap IR models, as necessary. For 2020 and 2021, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2018 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential Class	
Customers	620,899
kWh	4,386,740,109

Proposed Residential Class Specific Revenue Requirement[1]	$ 351,046,981.12

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	$ -
Distribution Volumetric Rate ($/kWh)	$ -

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed	0	620,899	$ -	
Variable	0	4,386,740,109	$ -	
TOTAL	-	-	$ -	-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	1

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed			
Variable			
TOTAL		-	

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed				
Variable				
TOTAL	-	$ -	-	

Checks[3]	
Change in Fixed Rate	
Difference Between Revenues @ Proposed Rates and Class Specific Revenue Requirement	

Notes:

[1] The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

[2] The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

[3] Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process: *Initial Application*

	Customer Class (From sheet 10. Load Forecast)	Customer and Load Forecast: Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Class Allocated Revenues: Total Class Revenue Requirement (From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design)	Monthly Service Charge	Volumetric	Fixed / Variable Splits [2] (Percentage to be entered as a fraction between 0 and 1): Fixed	Variable	Transformer Ownership Allowance [1] ($)	Distribution Rates: Monthly Service Charge Rate	No. of decimals	Volumetric Rate		No. of decimals	Revenue Reconciliation: 1.013888889 MSC Revenues	Volumetric revenues	Distribution Revenues less Transformer Ownership Allowance
1	Residential	kWh	620,899	4,386,740,109	-	$ 351,046,981	$ 351,046,981	$ -	100.00%	0.00%	$ -	$46.47	2	$0.00000	/kWh	5	351,046,981	-	$ 351,046,981.12
2	Competitive Sector Multi-Unit Residential	kWh	101,879	313,817,857	-	$ 45,664,205	$ 45,664,205	$ -	100.00%	0.00%	$ -	$36.84		$0.00000	/kWh	5	45,664,205	-	$ 45,664,205.38
3	GS <50	kWh	71,788	2,187,481,667	-	$ 118,435,994	$ 35,707,207	$ 82,728,786	30.15%	69.85%	$ -	$40.88		$0.03782	/kWh	5	35,705,437	82,730,557	$ 118,435,993.52
4	GS - 50 to 999	kVA	10,341	9,432,138,729	24,813,648	$ 235,495,164	$ 7,121,349	$ 228,373,816	3.02%	96.98%	$ 3,928,646	$56.60		$9.2336	/kVA	4	7,121,157	232,301,517	$ 235,494,028.10
5	GS - 1000 to 4999	kVA	430	4,387,143,302	10,232,645	$ 75,726,989	$ 5,067,463	$ 70,659,526	6.69%	93.31%	$ 5,356,674	$968.61		$7.3270	/kVA	4	5,067,445	76,015,904	$ 75,726,674.92
6	Large Use >5MW	kVA	44	1,962,015,257	4,730,195	$ 37,139,549	$ 2,260,352	$ 34,879,196	6.09%	93.91%	$ 2,906,232	$4,222.33		$7.8787	/kVA	4	2,260,354	37,785,396	$ 37,139,518.74
7	Street Light	kVA	166,107	115,566,836	328,076	$ 17,227,775	$ 3,677,749	$ 13,550,026	21.35%	78.65%	$ -	$1.82		$40.7357	/kVA	4	3,678,166	13,550,022	$ 17,228,188.62
8	Unmetered Scattered Load	kWh	857	41,200,600	-	$ 4,425,373	$ 84,909	$ 4,217,493	1.92%	95.30%	$ -	$8.14		$0.10236	/kWh	5	84,874	4,217,293	$ 4,302,167.87
9	Unmetered Scattered Load (Connections)		12,272	-	-		$ 122,971	$ -	2.78%		$ -	$0.82		$0.00000			122,434	-	$ 122,433.65
10			-	-	-												$ -	$ -	$ -
11			-	-	-												$ -	$ -	$ -
12			-	-	-												$ -	$ -	$ -
13			-	-	-												$ -	$ -	$ -
14			-	-	-												$ -	$ -	$ -
15			-	-	-												$ -	$ -	$ -
16			-	-	-												$ -	$ -	$ -
17			-	-	-												$ -	$ -	$ -
18			-	-	-												$ -	$ -	$ -
19			-	-	-												$ -	$ -	$ -
20			-	-	-												$ -	$ -	$ -

Total Transformer Ownership Allowance $ 12,191,552

Revenues recovered from rates deviate materially from revenue requirement - check data inputs and calculations

Total Distribution Revenues	$	885,160,191.92
Base Revenue Requirement	$	889,640,619.91
Difference	-$	4,480,427.99
% Difference		-0.504%

Notes:

[1] Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

[2] The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calcutated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2019 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

(2) Short description of change, issue, etc.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference [1]	Item / Description [2]	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 306,992,506	5.71%	$5,374,518,672	$3,864,859,084	$ 248,247,294	$ 310,853,964	$ 35,719,215	$ 279,372,150	$ 938,623,605	$ 48,982,985	$ 987,606,590	$ 39,063,327
1														
		Change												

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Version 8.00

Utility Name	Toronto Hydro-Electric System Limited
Service Territory	
Assigned EB Number	EB-2018-0165
Name and Title	
Phone Number	
Email Address	
Test Year	
Bridge Year	
Last Rebasing Year	2015

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

This Workbook Model is protected by copyright and is being made available to you solely for the purpose of filing your application. You may use and copy this model for that purpose, and provide a copy of this model to any person that is advising or assisting you in that regard. Except as indicated above, any copying, reproduction, publication, sale, adaptation, translation, modification, reverse engineering or other use or dissemination of this model without the express written consent of the Ontario Energy Board is prohibited. If you provide a copy of this model to a person that is advising or assisting you in preparing the application or reviewing your draft rate order, you must ensure that the person understands and agrees to the restrictions noted above.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

1. Info
2. Table of Contents
3. Data_Input_Sheet
4. Rate_Base
5. Utility Income
6. Taxes_PILs
7. Cost_of_Capital
8. Rev_Def_Suff
9. Rev_Reqt
10. Load Forecast
11. Cost Allocation
12. Residential Rate Design
13. Rate Design and Revenue Reconciliation
14. Tracking Sheet

Notes:

(1)	Pale green cells represent inputs
(2)	Pale green boxes at the bottom of each page are for additional notes
(3)	Pale yellow cells represent drop-down lists
(4)	***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5)	***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Data Input (1)

		Initial Application	(2)		(6)		Per Board Decision	
1	**Rate Base**							
	Gross Fixed Assets (average)	$7,697,160,940		###########			$7,697,160,940	
	Accumulated Depreciation (average)	($2,301,158,835)	(5)	###########			($2,301,158,835)	
	Allowance for Working Capital:							
	Controllable Expenses	$287,623,441		$ 287,623,441			$287,623,441	
	Cost of Power	$3,666,550,979		###########			$3,666,550,979	
	Working Capital Rate (%)	6.42%	(9)		(9)			(9)
2	**Utility Income**							
	Operating Revenues:							
	Distribution Revenue at Current Rates	$888,835,029						
	Distribution Revenue at Proposed Rates	$924,276,142						
	Other Revenue:							
	Specific Service Charges	$6,820,809						
	Late Payment Charges	$3,888,190						
	Other Distribution Revenue	$38,713,753						
	Other Income and Deductions							
	Total Revenue Offsets	$49,422,752	(7)					
	Operating Expenses:							
	OM+A Expenses	$281,886,499		$ 281,886,499			$281,886,499	
	Depreciation/Amortization	$325,365,901		$ 325,365,901			$325,365,901	
	Property taxes	$5,736,941		$ 5,736,941			$5,736,941	
	Other expenses							
3	**Taxes/PILs**							
	Taxable Income:							
	Adjustments required to arrive at taxable income	($77,248,067)	(3)					
	Utility Income Taxes and Rates:							
	Income taxes (not grossed up)	$30,994,322						
	Income taxes (grossed up)	$42,169,146						
	Federal tax (%)	15.00%						
	Provincial tax (%)	11.50%						
	Income Tax Credits	($2,736,000)						
4	**Capitalization/Cost of Capital**							
	Capital Structure:							
	Long-term debt Capitalization Ratio (%)	56.0%						
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		(8)			(8)
	Common Equity Capitalization Ratio (%)	40.0%						
	Prefered Shares Capitalization Ratio (%)							
		100.0%						
	Cost of Capital							
	Long-term debt Cost Rate (%)	3.71%						
	Short-term debt Cost Rate (%)	2.61%						
	Common Equity Cost Rate (%)	8.82%						
	Prefered Shares Cost Rate (%)							

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is **7.5%** (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application						Per Board Decision
1	Gross Fixed Assets (average)	(2)	$7,697,160,940		$ -		$7,697,160,940	$ -	$7,697,160,940
2	Accumulated Depreciation (average)	(2)	($2,301,158,835)		$ -		($2,301,158,835)	$ -	($2,301,158,835)
3	Net Fixed Assets (average)	(2)	$5,396,002,105		$ -		$5,396,002,105	$ -	$5,396,002,105
4	Allowance for Working Capital	(1)	$253,984,189		###########		$ -	$ -	$ -
5	**Total Rate Base**		$5,649,986,294		###########		$5,396,002,105	$ -	$5,396,002,105

(1) Allowance for Working Capital - Derivation

6	Controllable Expenses		$287,623,441		$ -		$287,623,441	$ -	$287,623,441
7	Cost of Power		$3,666,550,979		$ -		$3,666,550,979	$ -	$3,666,550,979
8	Working Capital Base		$3,954,174,420		$ -		$3,954,174,420	$ -	$3,954,174,420
9	Working Capital Rate %	(1)	6.42%		-6.42%		0.00%	0.00%	0.00%
10	Working Capital Allowance		$253,984,189		###########		$ -	$ -	$ -

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2018 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Utility Income

Line No.	Particulars	Initial Application				Per Board Decision
	Operating Revenues:					
1	Distribution Revenue (at Proposed Rates)	$924,276,142	($924,276,142)	$ -	$ -	$ -
2	Other Revenue (1)	$49,422,752	($49,422,752)	$ -	$ -	$ -
3	Total Operating Revenues	$973,698,894	($973,698,894)	$ -	$ -	$ -
	Operating Expenses:					
4	OM+A Expenses	$281,886,499	$ -	$281,886,499	$ -	$281,886,499
5	Depreciation/Amortization	$325,365,901	$ -	$325,365,901	$ -	$325,365,901
6	Property taxes	$5,736,941	$ -	$5,736,941	$ -	$5,736,941
7	Capital taxes	$ -	$ -	$ -	$ -	$ -
8	Other expense	$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)	$612,989,342	$ -	$612,989,342	$ -	$612,989,342
10	Deemed Interest Expense	$123,395,700	($123,395,700)	$ -	$ -	$ -
11	Total Expenses (lines 9 to 10)	$736,385,042	($123,395,700)	$612,989,342	$ -	$612,989,342
12	**Utility income before income taxes**	$237,313,852	($850,303,194)	($612,989,342)	$ -	($612,989,342)
13	Income taxes (grossed-up)	$42,169,146	$ -	$42,169,146	$ -	$42,169,146
14	**Utility net income**	$195,144,706	($850,303,194)	($655,158,488)	$ -	($655,158,488)

Notes

(1) **Other Revenues / Revenue Offsets**

Specific Service Charges	$6,820,809		$ -		$ -
Late Payment Charges	$3,888,190		$ -		$ -
Other Distribution Revenue	$38,713,753		$ -		$ -
Other Income and Deductions	$ -		$ -		$ -
Total Revenue Offsets	$49,422,752	$ -	$ -	$ -	$ -

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Taxes/PILs

Line No.	Particulars	Application		Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$199,331,516	$ -	$ -
2	Adjustments required to arrive at taxable utility income	($77,248,067)	$ -	$ -
3	Taxable income	$122,083,449	$ -	$ -
	Calculation of Utility income Taxes			
4	Income taxes	$30,994,322	$30,994,322	$30,994,322
6	Total taxes	$30,994,322	$30,994,322	$30,994,322
7	Gross-up of Income Taxes	$11,174,824	$11,174,824	$11,174,824
8	Grossed-up Income Taxes	$42,169,146	$42,169,146	$42,169,146
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$42,169,146	$42,169,146	$42,169,146
10	Other tax Credits	($2,736,000)	($2,736,000)	($2,736,000)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate		Return
		Initial Application				
		(%)	($)	(%)		($)
	Debt					
1	Long-term Debt	56.00%	$3,163,992,324	3.71%		$117,497,115
2	Short-term Debt	4.00%	$225,999,452	2.61%		$5,898,586
3	**Total Debt**	60.00%	$3,389,991,776	3.64%		$123,395,700
	Equity					
4	Common Equity	40.00%	$2,259,994,517	8.82%		$199,331,516
5	Preferred Shares	0.00%	$ -	0.00%		$ -
6	**Total Equity**	40.00%	$2,259,994,517	8.82%		$199,331,516
7	**Total**	100.00%	$5,649,986,294	5.71%		$322,727,217
		(%)	($)	(%)		($)
	Debt					
1	Long-term Debt	0.00%	$ -	0.00%		$ -
2	Short-term Debt	0.00%	$ -	0.00%		$ -
3	**Total Debt**	0.00%	$ -	0.00%		$ -
	Equity					
4	Common Equity	0.00%	$ -	0.00%		$ -
5	Preferred Shares	0.00%	$ -	0.00%		$ -
6	**Total Equity**	0.00%	$ -	0.00%		$ -
7	**Total**	0.00%	$5,396,002,105	0.00%		$ -
		Per Board Decision				
		(%)	($)	(%)		($)
	Debt					
8	Long-term Debt	0.00%	$ -	3.71%		$ -
9	Short-term Debt	0.00%	$ -	2.61%		$ -
10	**Total Debt**	0.00%	$ -	0.00%		$ -
	Equity					
11	Common Equity	0.00%	$ -	8.82%		$ -
12	Preferred Shares	0.00%	$ -	0.00%		$ -
13	**Total Equity**	0.00%	$ -	0.00%		$ -
14	**Total**	0.00%	$5,396,002,105	0.00%		$ -

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application				Per Board Decision	
		At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$37,752,811		($307,419,480)		$833,999,105
2	Distribution Revenue	$888,835,029	$886,523,332	$888,835,029	$1,231,695,622	$ -	($833,999,105)
3	Other Operating Revenue Offsets - net	$49,422,752	$49,422,752	$ -	$ -	$ -	$ -
4	**Total Revenue**	$938,257,781	$973,698,894	$888,835,029	$924,276,142	$ -	$ -
5	Operating Expenses	$612,989,342	$612,989,342	$612,989,342	$612,989,342	$612,989,342	$612,989,342
6	Deemed Interest Expense	$123,395,700	$123,395,700	$ -	$ -	$ -	$ -
8	**Total Cost and Expenses**	$736,385,042	$736,385,042	$612,989,342	$612,989,342	$612,989,342	$612,989,342
9	**Utility Income Before Income Taxes**	$201,872,739	$237,313,852	$275,845,687	$311,286,800	($612,989,342)	($612,989,342)
10	Tax Adjustments to Accounting Income per 2013 PILs model	($77,248,067)	($77,248,067)	($77,248,067)	($77,248,067)	$ -	$ -
11	**Taxable Income**	$124,624,672	$160,065,785	$198,597,620	$234,038,733	($612,989,342)	($612,989,342)
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$33,025,538	$42,417,433	$52,628,369	$62,020,264	$ -	$ -
14	**Income Tax Credits**	($2,736,000)	($2,736,000)	($2,736,000)	($2,736,000)	$ -	$ -
15	**Utility Net Income**	$171,583,201	$195,144,706	$225,953,318	($655,158,488)	($612,989,342)	($655,158,488)
16	**Utility Rate Base**	$5,649,986,294	$5,649,986,294	$5,396,002,105	$5,396,002,105	$5,396,002,105	$5,396,002,105
17	Deemed Equity Portion of Rate Base	$2,259,994,517	$2,259,994,517	$ -	$ -	$ -	$ -
18	Income/(Equity Portion of Rate Base)	7.59%	8.63%	0.00%	0.00%	0.00%	0.00%
19	Target Return - Equity on Rate Base	8.82%	8.82%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Return on Equity	-1.23%	-0.19%	0.00%	0.00%	0.00%	0.00%
21	Indicated Rate of Return	5.22%	5.64%	4.19%	0.00%	-11.36%	0.00%
22	Requested Rate of Return on Rate Base	5.71%	5.71%	0.00%	0.00%	0.00%	0.00%
23	Deficiency/Sufficiency in Rate of Return	-0.49%	-0.07%	4.19%	0.00%	-11.36%	0.00%
24	Target Return on Equity	$199,331,516	$199,331,516	$ -	$ -	$ -	$ -
25	Revenue Deficiency/(Sufficiency)	$27,748,316	($4,186,810)	($225,953,318)	$ -	$612,989,342	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$37,752,811 (1)		($307,419,480) (1)		$833,999,105 (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$281,886,499		$281,886,499		$281,886,499	
2	Amortization/Depreciation	$325,365,901		$325,365,901		$325,365,901	
3	Property Taxes	$5,736,941		$5,736,941		$5,736,941	
5	Income Taxes (Grossed up)	$42,169,146		$42,169,146		$42,169,146	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$123,395,700		$ -		$ -	
	Return on Deemed Equity	$199,331,516		$ -		$ -	
8	**Service Revenue Requirement (before Revenues)**	$977,885,705		$655,158,488		$655,158,488	
9	Revenue Offsets	$49,422,752		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$928,462,953		$655,158,488		$655,158,488	
11	Distribution revenue	$924,276,142		$ -		$ -	
12	Other revenue	$49,422,752		$ -		$ -	
13	**Total revenue**	$973,698,894		$ -		$ -	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($4,186,810)	(1)	($655,158,488)	(1)	($655,158,488)	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application		Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$977,885,705	$655,158,488	**($0)**	$655,158,488	**($1)**
Grossed-Up Revenue Deficiency/(Sufficiency)	$37,752,811	($307,419,480)	**($9)**	$833,999,105	**($1)**
Base Revenue Requirement (to be recovered from Distribution Rates)	$928,462,953	$655,158,488	**($0)**	$655,158,488	**($1)**
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$35,441,113	$ -	**($1)**	$ -	**($1)**

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Initial Application

	Customer Class	Initial Application					Per Board Decision		
	Input the name of each customer class.	Customer / Connections Test Year average or mid-year	kWh Annual	kW/kVA [1] Annual	Customer / Connections Test Year average or mid-year	kWh Annual	kW/kVA [1] Annual	Customer / Connections Test Year average or mid-year	kWh Annual	kW/kVA [1] Annual
1	Residential	622,544	4,366,437,563							
2	Competitive Sector Multi-Unit Residential	107,796	328,419,229							
3	GS <50	71,885	2,169,915,395							
4	GS - 50 to 999	10,330	9,419,379,152	24,875,671						
5	GS - 1000 to 4999	430	4,351,721,474	10,228,471						
6	Large Use >5MW	44	1,956,322,242	4,733,922						
7	Street Light	166,375	116,138,779	328,561						
8	Unmetered Scattered Load	857	41,313,479							
9	Unmetered Scattered Load (Connections)	12,272								
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		**22,749,647,312**	**40,166,624**		**-**	**-**		**-**	**-**

Notes:

[1] Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class [3]	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1]	%
	From Sheet 10. Load Forecast			(7A)	
1	Residential	$ 287,079,871	42.26%	$ 375,926,040	38.4%
2	Competitive Sector Multi-Unit Residentia	$ 19,267,312	2.84%	$ 42,021,779	4.3%
3	GS <50	$ 99,019,246	14.58%	$ 152,391,759	15.6%
4	GS - 50 to 999	$ 157,700,127	23.21%	$ 243,357,888	24.9%
5	GS - 1000 to 4999	$ 55,701,964	8.20%	$ 85,976,064	8.8%
6	Large Use >5MW	$ 31,087,389	4.58%	$ 46,819,636	4.8%
7	Street Light	$ 25,331,820	3.73%	$ 26,122,977	2.7%
8	Unmetered Scattered Load	$ 4,173,832	0.61%	$ 5,269,563	0.5%
9	Unmetered Scattered Load (Connections)				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 679,361,561	100.00%	**$ 977,885,705**	100.0%
			Service Revenue Requirement (from Sheet 9)	**$ 977,885,705**	

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.
(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.
(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential	$ 352,011,279	$ 366,043,682	$ 365,837,982	$ 19,930,202
2	Competitive Sector Multi-Unit Residentia	$ 48,314,167	$ 50,240,139	$ 50,218,024	$ 1,740,379
3	GS <50	$ 117,821,799	$ 122,518,589	$ 122,461,164	$ 8,459,096
4	GS - 50 to 999	$ 236,050,526	$ 245,460,327	$ 245,490,240	$ 7,600,223
5	GS - 1000 to 4999	$ 75,687,090	$ 78,704,243	$ 78,883,982	$ 1,447,235
6	Large Use >5MW	$ 37,160,502	$ 38,641,850	$ 38,741,455	$ 592,534
7	Street Light	$ 17,263,427	$ 17,951,607	$ 17,928,726	$ 9,333,561
8	Unmetered Scattered Load	$ 4,435,147	$ 4,611,947	$ 4,610,813	$ 319,524
9	Unmetered Scattered Load (Connections)				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 888,743,938	$ 924,172,386	$ 924,172,386	$ 49,422,753

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.
(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.
(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.
(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year: 2015 %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
1	Residential	94.3%	102.7%	102.6%	85 - 115
2	Competitive Sector Multi-Unit Residentia	100.0%	123.7%	123.6%	
3	GS <50	91.5%	85.9%	85.9%	80 - 120
4	GS - 50 to 999	119.0%	104.0%	104.0%	80 - 120
5	GS - 1000 to 4999	101.9%	93.2%	93.4%	80 - 120
6	Large Use >5MW	95.3%	83.8%	84.0%	85 - 115
7	Street Light	82.7%	104.4%	104.4%	80 - 120
8	Unmetered Scattered Load	90.5%	93.6%	93.6%	80 - 120
9	Unmetered Scattered Load (Connections)				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) Proposed Revenue-to-Cost Ratios [11]

	Name of Customer Class	Proposed Revenue-to-Cost Ratio Test Year 2020	Price Cap IR Period 2021	Price Cap IR Period 2022	Policy Range
1	Residential	102.6%			85 - 115
2	Competitive Sector Multi-Unit Residentia	123.6%			
3	GS <50	85.9%			80 - 120
4	GS - 50 to 999	104.0%			80 - 120
5	GS - 1000 to 4999	93.4%			80 - 120
6	Large Use >5MW	84.0%			85 - 115
7	Street Light	104.4%			80 - 120
8	Unmetered Scattered Load	93.6%			80 - 120
9	Unmetered Scattered Load (Connection				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2019 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2020 and 2021 Price Cap IR models, as necessary. For 2020 and 2021, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2018 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential Class	
Customers	622,544
kWh	4,366,437,563

Proposed Residential Class Specific Revenue Requirement[1]	$ 365,837,981.60

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	$ 37.98
Distribution Volumetric Rate ($/kWh)	$ 0.00552

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed	37.98	622,544	$ 283,730,653.44	92.17%
Variable	0.00552	4,366,437,563	$ 24,102,735.35	7.83%
TOTAL	-	-	$ 307,833,388.79	-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	1

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed	$ 337,193,603.27	45.14	$ 337,219,633.92
Variable	$ 28,644,378.33	0.0066	$ 28,818,487.91
TOTAL	$ 365,837,981.60	-	$ 366,038,121.83

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed	100.00%	$ 365,837,981.60	$ 48.97	$ 365,831,756.16
Variable	0.00%	$ -	$ -	$ -
TOTAL	-	$ 365,837,981.60	-	$ 365,831,756.16

Checks[3]	
Change in Fixed Rate	$ 3.83
Difference Between Revenues @ Proposed Rates and Class Specific Revenue Requirement	($6,225.44)
	0.00%

Notes:

[1] The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

[2] The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

[3] Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

New Rate Design Policy For Competitive Sector Multi-Unit Customers (CSMUR)

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for CSMUR	
Customers	85,161
kWh	277,127,203

Proposed CSMUR Class Specific Revenue Requirement[1]	$ 34,812,874.82

CSMUR Base Rates on Current Tariff	
Monthly Fixed Charge ($)	$ 30.98
Distribution Volumetric Rate ($/kWh)	$ 0.00845

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed	30.98	85,161	$ 31,659,453.36	93.11%
Variable	0.00845	277,127,203	$ 2,341,724.87	6.89%
TOTAL	-	-	$ 34,001,178.23	-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	1

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed	$ 32,415,246.89	31.72	$ 32,415,683.04
Variable	$ 2,397,627.93	0.0087	$ 2,411,006.67
TOTAL	$ 34,812,874.82	-	$ 34,826,689.71

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed	100.00%	$ 34,812,874.82	$ 34.07	$ 34,817,223.24
Variable	0.00%	$ -	$ -	$ -
TOTAL	-	$ 34,812,874.82	-	$ 34,817,223.24

Checks[3]	
Change in Fixed Rate	$ 2.35
Difference Between Revenues @ Proposed Rates and Class Specific Revenue Requirement	$4,348.42
	0.01%

Notes:

[1] The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

[2] The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

[3] Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process: *Initial Application*

	Customer Class (From sheet 10. Load Forecast)	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Class Allocated Revenues: Total Class Revenue Requirement (From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design)	Class Allocated Revenues: Monthly Service Charge	Class Allocated Revenues: Volumetric	Fixed / Variable Splits [2] (Percentage to be entered as a fraction between 0 and 1): Fixed	Fixed / Variable Splits [2]: Variable	Transformer Ownership Allowance [1] ($)	Distribution Rates: Monthly Service Charge Rate	Monthly Service Charge No. of decimals	Volumetric Rate	Volumetric Rate	Volumetric Rate No. of decimals	Revenue Reconciliation: 1.013888889 MSC Revenues	Volumetric revenues	Distribution Revenues less Transformer Ownership Allowance
1	Residential	kWh	622,544	4,366,437,563	-	$ 365,837,982	$ 365,837,982	$ -	100.00%	0.00%	$ -	$48.30	2	$0.00000	/kWh	5	365,837,982	-	$ 365,837,981.60
2	Competitive Sector Multi-Unit Residential	kWh	107,796	328,419,229	-	$ 50,218,024	$ 50,218,024	$ -	100.00%	0.00%	$ -	$38.29		$0.00000	/kWh	5	50,218,024	-	$ 50,218,024.22
3	GS <50	kWh	71,885	2,169,915,395	-	$ 122,461,164	$ 35,898,553	$ 86,562,611	29.31%	70.69%	$ -	$41.05		$0.03989	/kWh	5	35,902,364	86,557,925	$ 122,460,289.33
4	GS - 50 to 999	kVA	10,330	9,419,379,152	24,875,671	$ 245,490,240	$ 7,557,853	$ 237,932,387	3.08%	96.92%	$ 3,941,533	$60.13		$9.5901	/kVA	4	7,557,239	241,873,508	$ 245,489,213.88
5	GS - 1000 to 4999	kVA	430	4,351,721,474	10,228,471	$ 78,883,982	$ 5,612,168	$ 73,271,814	7.11%	92.89%	$ 5,440,129	$1,072.73		$7.5900	/kVA	4	5,612,166	78,712,343	$ 78,884,380.03
6	Large Use >5MW	kVA	44	1,956,322,242	4,733,922	$ 38,741,455	$ 2,533,814	$ 36,207,641	6.54%	93.46%	$ 2,942,549	$4,733.15		$8.1568	/kVA	4	2,533,813	39,149,953	$ 38,741,217.19
7	Street Light	kVA	166,375	116,138,779	328,561	$ 17,928,726	$ 3,847,064	$ 14,081,662	21.46%	78.54%	$ -	$1.90		$42.2715	/kVA	4	3,846,039	14,081,666	$ 17,927,705.11
8	Unmetered Scattered Load	kWh	857	41,313,479	-	$ 4,610,813	$ 88,189	$ 4,392,436	1.91%	95.26%	$ -	$8.46		$0.10632	/kWh	5	88,211	4,392,449	$ 4,480,660.06
9	Unmetered Scattered Load (Connections)		12,272	-	-		$ 130,188	$ -	2.82%		$ -	$0.87		$0.00000			129,899	-	$ 129,899.12
10			-	-	-												$ -	$ -	$ -
11			-	-	-												$ -	$ -	$ -
12			-	-	-												$ -	$ -	$ -
13			-	-	-												$ -	$ -	$ -
14			-	-	-												$ -	$ -	$ -
15			-	-	-												$ -	$ -	$ -
16			-	-	-												$ -	$ -	$ -
17			-	-	-												$ -	$ -	$ -
18			-	-	-												$ -	$ -	$ -
19			-	-	-												$ -	$ -	$ -
20			-	-	-												$ -	$ -	$ -

Total Transformer Ownership Allowance $ 12,324,211

Rates recover revenue requirement

Total Distribution Revenues	$ 924,169,370.54
Base Revenue Requirement	$ 928,462,952.64
Difference	-$ 4,293,582.10
% Difference	-0.462%

Notes:

[1] Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

[2] The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calcutated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2019 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

(2) Short description of change, issue, etc.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference [1]	Item / Description [2]	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 322,727,217	5.71%	$5,649,986,294	$3,954,174,420	$ 253,984,189	$ 325,365,901	$ 42,169,146	$ 281,886,499	$ 977,885,705	$ 49,422,752	$ 928,462,953	$ 37,752,811
1		Change												

COST ALLOCATION

Toronto Hydro's total revenue requirement, as detailed in Exhibit 6, is allocated to rate classes as the basis for determining distribution rates for the 2020 rebasing year. The allocation methodology employed for the 2020 Test Year is the OEB's latest Cost Allocation Model, which includes the updated policy related cost allocation for the Street Lighting class.[1]

The results of the cost allocation, which shows the revenue/cost ratios prior to applying the proposed rates, are summarized in Table 1 below.

Table 1: Revenue/Cost Ratios from Cost Allocation Model (%)

Rate Class	2020 Revenue / Cost Ratio from Model	OEB's Guideline Ranges
Residential	103.2	85-115
Competitive Sector Multi-Unit Residential	101.4	n/a
General Service <50kW	89.6	80-120
General Service 50-999kW	105.3	80-120
General Service 1000-4999kW	94.9	80-120
Large Use	84.7	85-115
Street Lighting	108.9	80-120
Unmetered Scattered Load	95.0	80-120

Exhibit 7, Tab 1, Schedule 3 provides sheets I-6, I-8, O-1 and O-2 from the Cost Allocation model for the Test Year, as required by the OEB's Filing Requirements. The full live MS Excel model is also filed electronically.

[1] Ontario Energy Board, Issuance of New Cost Allocation Policy for Street Lighting Rate Class (June 12, 2015), available at: <https://www.oeb.ca/oeb/_Documents/EB-2012-0383/LTR_CostAllocation_Streetlighting_20150612.pdf>.

1. COST ALLOCATION MODEL

In completing the Cost Allocation model, Toronto Hydro reviewed and updated all of the inputs to the model.

1.1 Load Profiles

The load profiles for each class used in the model for the demand allocators were updated using hourly-metered 2016 load data for each rate class. Sample data sets were used for the Residential, Competitive Sector Multi-Unit Residential ("CSMUR") and GS<50 rate classes, while metering data for all customers in the other classes were used. The hourly load profiles were then reconciled to the 2016 purchased energy and wholesale market participant data, weather normalized to 2020 heating and cooling degree days, and scaled to the 2020 load forecast based on the ratio of 2020 kWh to 2016 kWh by class. An example of the data and calculations is filed as Exhibit 7, Tab 1, Schedule 2.

1.2 Allocators

Toronto Hydro reviewed all of the "default" allocators, and where available, uses data specific to Toronto Hydro to determine the allocator values. For example:

- **Weighting factor for services:** all rate classes, with the exception of the CSMUR, Unmetered Scattered Load ("USL") and Street Lighting classes, receive a weighting factor of one. This reflects the fact that service costs greater than a basic allowance are recovered through a direct contribution from the customers. The weighting factor for the CSMUR rate class is derived by dividing the number of units by the number of buildings housing these units, as originally directed by the OEB in EB-2010-0142. For the USL and Street Lighting classes, the cost of

services is directly collected from those customers, and hence they receive a weighting factor of zero.

- **Weighting factor for billing and collections:** based on estimates provided by the Utility's billing specialists, the weighting factors reflect estimates of billing effort and costs related to each class.

For those costs, which are allocated on a joint customer/demand, a density factor is used to determine the proportion of customer related and demand related costs. Toronto Hydro adjusted the value of the density factor from the default values provided in the model. The OEB's model groups this information into three different density ranges: (i) less than 30 customers per kilometre; (ii) between 30 and 60 customers per kilometre; and (iii) greater than 60 customers per kilometre. For each of these ranges, the customer-related proportion is provided, which is based on information from a number of different historical studies.

At 135 customers per kilometre, Toronto Hydro's density factor is well above the 60 customers per kilometre ratio. The OEB's model acknowledges that the customer related proportion of jointly determined costs is lower for denser systems. Given that Toronto Hydro's density factor is much higher than the top grouping; the utility believes it is appropriate to use a custom-related proportion, which is aligned with the realities of Toronto Hydro's system. For the current application, Toronto Hydro uses a density factor of 23 percent, as approved by the OEB in the EB-2014-0116 decision.

1.3 Street Lighting

As approved by the OEB in EB-2014-0116, Toronto Hydro has included approved Street Lighting assets and operating expenses in its 2020 revenue requirement. For the

purposes of cost allocation all assets and expenses are directly allocated 95 percent to the Street Lighting class, and 5 percent to the USL class. This allocation reflects the fact that these assets currently serve these two classes only, and ensures that no other rate classes are allocated a share of these costs. In addition, 100 percent of the additional revenue requirement is offset through a direct allocation of the revenues received through the existing Street Lighting contract to revenue offsets for the Street Lighting class. The effect is a revenue-to-cost ratio of 1.0 for these assets and costs.

1.4 Adjustments to Cost Allocation Model

The following adjustments were made to the Cost Allocation Model to meet Toronto Hydro's requirements.

In Worksheet I6.1 Revenue, cell M34 was locked and empty. Toronto Hydro added the variable rate to complete the distribution revenue calculation.

In Worksheet I6.2 Customer Data, cells M28 and M29 were adjusted to reflect the direct assignment of meter capital and meter reading costs for the CSMUR rate class.

In Worksheet O1 Revenue to Cost, cell J19 was modified to include the direct assignment of revenue offsets related to the Street Lighting class, as noted above.

2. IMPLEMENTATION OF COST ALLOCATION RESULTS

The Report of the Board: Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219) dated March 31, 2011 established updated "target ranges" for the revenue to cost ratios for each customer class. The OEB's review of the Street Lighting cost

allocation methodology resulted in an updated target range for that rate class.[2] Table 2 below shows the revenue to cost ratios calculated prior to and after the proposed Test Year rate design in comparison with the "target ranges" (all ratios exclude revenues and costs related to transformer ownership allowance).

Table 2: Revenue/Cost Ratios (%)

Rate Class	2015 OEB Approved	2020		OEB's Guideline Ranges
		Model	Proposed	
Residential	94.3	103.2	103.2	85-115
Competitive Sector Multi-Unit Residential	100.0	101.4	100.0	
General Service <50kW	91.5	89.6	89.8	80-120
General Service 50-999kW	119.0	105.3	105.3	80-120
General Service 1000-4999kW	101.9	94.9	95.0	80-120
Large Use	95.3	84.6	85.0	85-115
Street Lighting	82.7	108.9	108.9	80-120
Unmetered Scattered Load	90.5	94.6	94.7	80-120

The proposed revenue to cost ratios for all Toronto Hydro rate classes are within the OEB's "target ranges".

In accordance with the EB-2010-1042 decision, rates in the CSMUR class are set to maintain the revenue to cost ratio equal at unity, so as to ensure that this class is recovering its fully allocated costs.

With respect to the Street Lighting class, the proposed revenue to cost ratio reflects the application of the new OEB Cost Allocation model, and includes the allocation of

[2] *Ibid.*

revenue offsets related to the Street Lighting assets in rate base to fully offset the costs that have been directly allocated to this class.

Toronto Hydro engages its customers with significant unmetered load (e.g. City, telecommunications companies) as part of ongoing customer engagement. Through those interactions and direct participation by these customers in OEB rate application and policy proceedings, they have developed familiarity with the regulatory context, including the basis on which costs are allocated to them through rates. Toronto Hydro's proposed cost allocation for unmetered customers (including street lighting) follows the OEB's current methodology, which was developed in consultation with unmetered customers. With the filing of this Application, Toronto Hydro is sending a communication to major customers within these classes regarding changes to rates and charges, and inviting them to participate in the proceeding.

Sample Methodology - Demand Data for Cost Allocation Model

ALL DATA are for ILLUSTRATIVE USE ONLY

	Hour	Cust 1	Cust 2	Cust 3	Cust 4	Cust 5	Cust 6	Cust 7	Cust 8	Cust 9	Cust 10	Total	Avg	Sample Rate Class Hourly Profile for Jan	Total of All rate Classes (Includes Sample Rate Class)	Sample Rate Class % of Sum of all Rate Classes	IESO Purchased and Whoesale Market Participants Metered Load	Sample Rate Class portion of the Total System Load.	Weather Correction Factor for Sample Rate Class is 1.024935		Demand scaled to the 2020 load forecast based on the ratio of 2020 sample rate class kWh to sample rate Class Test year kWh.
		Hourly kW demands from customer load data											Sample size = 10	Total Number of Customers in Sample Rate Class in test year = 20							
													(b) = (a) / 10	(c) = (b) * 20		(e) = (d) / (c)		(g) = (e) * (f)	(h) = (g) * 1.024935		(i) = (h) * (1 - .054)
												(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)		(i)
01-Jan-16	1	0.55	0.03	0.06	0.83	0.24	3.06	0.55	0.17	0.8	0.55	6.84	0.684	13.68	300.96	5%	331.06	15.05	15.42		14.59
01-Jan-16	2	0.53	0.15	0.1	0.61	0.12	2.36	0.51	0.13	1.33	0.53	6.37	0.637	12.74	280.28	5%	336.34	15.29	15.67		14.82
01-Jan-16	3	0.47	0.03	0.05	1.17	0.19	2	0.61	0.15	0.7	0.47	5.84	0.584	11.68	256.96	5%	308.35	14.02	14.37		13.59
01-Jan-16	4	0.31	0.15	0.11	0.46	0.18	1.18	0.53	0.25	0.89	0.31	4.37	0.437	8.74	131.10	7%	157.32	10.49	10.75		10.17
01-Jan-16	5	0.13	0.06	0.08	0.29	0.19	1.15	0.57	0.21	1.25	0.13	4.06	0.406	8.12	105.56	8%	126.67	9.74	9.99		9.45
01-Jan-16	6	0.13	0.12	0.11	0.26	0.16	1.14	0.55	0.17	0.86	0.13	3.63	0.363	7.26	71.15	10%	85.38	8.71	8.93		8.45
01-Jan-16	7	0.17	0.09	0.06	0.21	0.19	1.14	0.59	0.19	1.01	0.17	3.82	0.382	7.64	71.05	11%	85.26	9.17	9.40		8.89
01-Jan-16	8	0.14	0.09	0.08	0.26	0.21	1.13	0.53	0.19	0.97	0.14	3.74	0.374	7.48	67.32	11%	80.78	8.98	9.20		8.70
01-Jan-16	9	0.16	0.14	0.19	0.27	0.32	1.12	0.56	0.14	0.98	0.16	4.04	0.404	8.08	68.68	12%	109.89	12.93	13.25		12.53
01-Jan-16	10	0.24	0.04	0.09	0.24	0.32	1.08	0.71	0.14	1.09	0.24	4.19	0.419	8.38	67.04	13%	80.45	10.06	10.31		9.75
01-Jan-16	11	0.46	0.15	0.1	0.54	0.27	1.27	0.64	0.15	1.11	0.46	5.15	0.515	10.30	61.80	17%	74.16	12.36	12.67		11.98
01-Jan-16	12	0.51	0.05	0.06	1.92	0.6	1.44	0.56	0.09	0.91	0.51	6.65	0.665	13.30	106.40	13%	191.52	23.94	24.54		23.21
01-Jan-16	13	0.9	0.14	0.09	1.15	2.84	1.76	0.57	0.09	1.21	0.9	9.65	0.965	19.30	164.05	12%	180.46	21.23	21.76		20.58
01-Jan-16	14	0.97	0.07	0.06	0.83	1.95	2.88	0.61	0.15	0.74	0.97	9.23	0.923	18.46	166.14	11%	**342.58**	38.06	**39.01**	**Sample Rate Class Jan CP**	**36.91**
01-Jan-16	15	1.3	0.11	0.09	0.39	0.39	4.13	0.75	0.18	1.31	1.3	9.95	0.995	19.90	199.00	10%	258.70	25.87	26.52		25.08
01-Jan-16	16	0.71	0.13	0.07	0.32	0.31	3.99	0.53	0.18	0.74	0.71	7.69	0.769	15.38	169.18	9%	203.02	18.46	18.92		17.89
01-Jan-16	17	0.59	0.05	0.11	4.9	0.27	2	0.6	1.13	1.25	0.59	11.49	1.149	22.98	137.88	17%	261.97	43.66	**44.75**	**Sample Rate Class Jan NCP**	**42.33**
01-Jan-16	18	0.92	0.17	0.05	0.91	0.29	1.34	0.74	0.28	0.63	0.92	6.25	0.625	12.50	137.50	9%	165.00	15.00	15.37		14.54
01-Jan-16	19	1.29	0.02	0.09	0.26	0.24	1.59	0.58	0.18	1.42	1.29	6.96	0.696	13.92	153.12	9%	183.74	16.70	17.12		16.20
01-Jan-16	20	1.19	0.17	0.07	0.77	0.15	1.8	0.56	0.38	0.91	1.19	7.19	0.719	14.38	172.56	8%	207.07	17.26	17.69		16.73
01-Jan-16	21	1.9	0.06	0.08	1.57	0.34	2.36	0.66	0.28	1.83	1.9	10.98	1.098	21.96	285.48	8%	314.03	26.35	27.01		25.55
01-Jan-16	22	1.42	0.13	0.09	2.21	0.25	1.94	0.76	0.27	0.66	1.42	9.15	0.915	18.30	256.20	7%	307.44	21.96	22.51		21.29
01-Jan-16	23	1.09	0.12	0.07	0.74	0.35	1.68	0.62	0.23	1.81	1.09	7.80	0.78	15.60	234.00	7%	280.80	18.72	19.19		18.15
01-Jan-16	24	0.9	0.08	0.09	0.56	0.33	1.77	0.78	0.26	1.25	1.32	7.34	0.734	14.68	234.88	6%	281.86	17.62	18.06		17.08
02-Jan-16	25	0.8	0.17	0.06	1.33	0.21	1.47	0.59	0.2	1.22	0.8	6.85	0.685	13.70	219.20	6%	81.10	5.07	5.20		4.91
02-Jan-16	26	0.17	0.03	0.1	0.52	0.22	1.23	0.66	0.14	1.4	0.17	4.64	0.464	9.28	157.76	6%	54.00	3.18	3.26		3.08
02-Jan-16	27	0.26	0.17	0.06	0.36	0.14	1.46	0.79	0.09	0.84	0.26	4.43	0.443	8.86	159.48	6%	86.60	4.81	4.93		4.66
02-Jan-16	28	0.31	0.07	0.1	0.34	0.23	1.39	0.66	0.05	1.71	0.31	5.17	0.517	10.34	155.10	7%	117.20	7.81	8.01		7.58
02-Jan-16	29	0.28	0.14	0.07	0.3	0.17	1.06	0.58	0.08	0.97	0.28	3.93	0.393	7.86	102.18	8%	83.00	6.38	6.54		6.19

Ontario Energy Board

2019 Cost Allocation Model

EB-2018-0165

Sheet I6.1 Revenue Worksheet -

Total kWhs from Load Forecast	23,371,287,137
Total kWs from Load Forecast	40,408,069
Deficiency/sufficiency (RRWF 8. cell F51)	- 25,621,033
Miscellaneous Revenue (RRWF 5. cell F48)	47,687,081

			1	2	4	5	6	7	9	10
	ID	**Total**	**Residential**	**GS <50**	**GS - 50 to 999**	**GS - 1000 to 4999**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Competitive Sector Multi-Unit Residential**
Billing Data										
Forecast kWh	**CEN**	23,371,287,137	4,510,636,914	2,267,638,936	9,587,728,582	4,561,528,177	2,009,923,443	115,390,403	41,313,479	277,127,203
Forecast kW	**CDEM**	40,408,069			24,899,249	10,392,864	4,789,334	326,622		
Forecast kW, included in CDEM, of customers receiving line transformer allowance		19,562,240			6,256,401	8,635,125	4,670,713			
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-								
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	23,770,548,368	4,909,898,145	2,267,638,936	9,587,728,582	4,561,528,177	2,009,923,443	115,390,403	41,313,479	277,127,203
Existing Monthly Charge			$37.98	$36.28	$52.17	$996.61	$4,399.14	$1.63	$7.23	$30.98
Existing Distribution kWh Rate			$0.0055	$0.0331					$0.0896	$0.0085
Existing Distribution kW Rate					$8.2114	$6.4602	$6.9303	$36.2449	$0.7500	
Existing TOA Rate			$0.63	$0.63	$0.63	$0.63	$0.63	$0.63	$0.63	$0.63
Additional Charges										
Distribution Revenue from Rates		$783,527,792	$305,630,924	$106,186,653	$210,952,231	$72,282,491	$35,514,268	$15,072,589	$3,887,458	$34,001,178
Transformer Ownership Allowance		$12,324,211	$0	$0	$3,941,533	$5,440,129	$2,942,549	$0	$0	$0
Net Class Revenue	**CREV**	$771,203,581	$305,630,924	$106,186,653	$207,010,698	$66,842,362	$32,571,719	$15,072,589	$3,887,458	$34,001,178

Ontario Energy Board

2019 Cost Allocation Model

EB-2018-0165

Sheet I6.2 Customer Data Worksheet -

Billing Data

	ID	Total	1 Residential	2 GS <50	4 GS - 50 to 999	5 GS - 1000 to 4999	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load	10 Competitive Sector Multi-Unit Residential
Bad Debt 3 Year Historical Average	BDHA	$7,377,253	$3,890,292	$2,111,101	$828,264	$261,154	$0	$0	$0	$286,442
Late Payment 3 Year Historical Average	LPHA	$4,287,180	$2,487,420	$919,878	$596,564	$77,959	$16,058		$5,649	$183,652
Number of Bills	CNB	9,532,208	7,391,580	857,988.00	124,488.00	5,160	528.00	139.00	130,393.00	1,021,932
Number of Devices	CDEV							165,348		
Number of Connections (Unmetered)	CCON	104,056						91,860	12,196	
Total Number of Customers	CCA	784,331	615,965	71,499	10,374	430	44	1	857	85,161
Bulk Customer Base	CCB	-								
Primary Customer Base	CCP	802,861	615,965	71,499	10,374	430	44	18,531	857	85,161
Line Transformer Customer Base	CCLT	800,443	615,965	71,499	8,333	94	2	18,531	857	85,161
Secondary Customer Base	CCS	775,531	615,965	71,499	2,041	5	2	1	857	85,161
Weighted - Services	CWCS	689,834	615,965	71,499	2,041	5	2	-	-	322
Weighted Meter -Capital	CWMC	137,125,872	87,467,030	36,607,488	11,120,928	1,675,710	254,716	-	-	-
Weighted Meter Reading	CWMR	9,721,465	7,391,580	986,686	1,206,289	124,201	12,709	-	-	-
Weighted Bills	CWNB	11,436,262	7,391,580	1,715,976	871,416	36,120	7,920	139	391,179	1,021,932

Bad Debt Data

Historic Year:	2015	5,920,268	3,264,885	1,679,206	910,835	-				65,342
Historic Year:	2016	9,841,560	4,872,078	2,746,113	1,039,975	783,461				399,934
Historic Year:	2017	6,369,929	3,533,912	1,907,985	533,980	-				394,051
Three-year average		**7,377,253**	**3,890,292**	**2,111,101**	**828,264**	**261,154**	**-**	**-**	**-**	**286,442**

Street Lighting Adjustment Factors

NCP Test Results	4 NCP

	Primary Asset Data		Line Transformer Asset Data	
Class	**Customers/ Devices**	**4 NCP**	**Customers/ Devices**	**4 NCP**
Residential	615,965	4,129,569	615,965	4,129,569
Street Light	165,348	124,238	165,348	124,238

Street Lighting Adjustment Factors	
Primary	8.9227
Line Transformer	8.9227

Ontario Energy Board

2019 Cost Allocation Model

EB-2018-0165

Sheet I8 Demand Data Worksheet -

This is an input sheet for demand allocators.

CP TEST RESULTS	12 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

Customer Classes		Total	1 Residential	2 GS <50	4 GS - 50 to 999	5 GS - 1000 to 4999	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load	10 Competitive Sector Multi-Unit Residential
		CP Sanity Check	Pass	Pass	Pass	Check 4CP	Check 4CP and 12CP	Check 12CP	Check 4CP and 12CP	Pass
CO-INCIDENT PEAK										
1 CP										
Transformation CP	TCP1	4,253,037	972,614	578,946	1,662,853	734,765	260,218	-	3,548	40,093
Bulk Delivery CP	BCP1	4,253,037	972,614	578,946	1,662,853	734,765	260,218	-	3,548	40,093
Total Sytem CP	DCP1	4,253,037	972,614	578,946	1,662,853	734,765	260,218	-	3,548	40,093
4 CP										
Transformation CP	TCP4	16,410,330	3,718,466	1,992,718	6,532,784	2,948,683	1,048,449	-	16,832	152,399
Bulk Delivery CP	BCP4	16,410,330	3,718,466	1,992,718	6,532,784	2,948,683	1,048,449	-	16,832	152,399
Total Sytem CP	DCP4	16,410,330	3,718,466	1,992,718	6,532,784	2,948,683	1,048,449	-	16,832	152,399
12 CP										
Transformation CP	TCP12	45,215,926	8,853,188	5,623,085	18,460,316	7,995,202	3,604,817	171,288	58,103	449,926
Bulk Delivery CP	BCP12	45,215,926	8,853,188	5,623,085	18,460,316	7,995,202	3,604,817	171,288	58,103	449,926
Total Sytem CP	DCP12	45,215,926	8,853,188	5,623,085	18,460,316	7,995,202	3,604,817	171,288	58,103	449,926
NON CO_INCIDENT PEAK										
		NCP Sanity Check	Pass	Pass	Pass	Pass	Pass	Pass	Pass	Pass
1 NCP										
Classification NCP from Load Data Provider	DNCP1	4,603,543	1,085,007	601,583	1,674,421	752,021	394,832	31,399	5,833	58,447
Primary NCP	PNCP1	4,489,529	1,085,007	601,583	1,560,710	752,021	394,832	31,399	5,530	58,447
Line Transformer NCP	LTNCP1	3,383,973	1,085,007	601,583	1,399,700	165,038	37,269	31,399	5,530	58,447
Secondary NCP	SNCP1	2,218,380	1,085,007	601,583	419,910	16,504	-	31,399	5,530	58,447
4 NCP										
Classification NCP from Load Data Provider	DNCP4	17,669,073	4,129,569	2,275,913	6,481,669	2,974,900	1,437,604	124,238	22,521	222,660
Primary NCP	PNCP4	17,227,732	4,129,569	2,275,913	6,041,495	2,974,900	1,437,604	124,238	21,354	222,660
Line Transformer NCP	LTNCP4	12,980,524	4,129,569	2,275,913	5,418,227	652,868	135,697	124,238	21,354	222,660
Secondary NCP	SNCP4	8,464,488	4,129,569	2,275,913	1,625,468	65,287	-	124,238	21,354	222,660
12 NCP										
Classification NCP from Load Data Provider	DNCP12	48,366,920	10,395,631	6,389,304	18,220,979	8,227,998	4,127,668	320,510	63,331	621,500
Primary NCP	PNCP12	47,126,239	10,395,631	6,389,304	16,983,582	8,227,998	4,127,668	320,510	60,047	621,500
Line Transformer NCP	LTNCP12	35,213,790	10,395,631	6,389,304	15,231,478	1,805,705	389,615	320,510	60,047	621,500
Secondary NCP	SNCP12	22,537,005	10,395,631	6,389,304	4,569,443	180,571	-	320,510	60,047	621,500

Ontario Energy Board

2019 Cost Allocation Model

EB-2018-0165

Sheet O1 Revenue to Cost Summary Worksheet -

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	4 GS - 50 to 999	5 GS - 1000 to 4999	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load	10 Competitive Sector Multi-Unit Residential
crev	Distribution Revenue at Existing Rates	$771,203,581	$305,630,924	$106,186,653	$207,010,698	$66,842,362	$32,571,719	$15,072,589	$3,887,458	$34,001,178
mi	Miscellaneous Revenue (mi)	$47,687,081	$19,230,275	$8,162,022	$7,333,311	$1,396,409	$571,724	$9,005,777	$308,303	$1,679,259
		Miscellaneous Revenue Input equals Output								
	Total Revenue at Existing Rates	**$818,890,662**	**$324,861,200**	**$114,348,675**	**$214,344,010**	**$68,238,771**	**$33,143,444**	**$24,078,365**	**$4,195,761**	**$35,680,437**
	Factor required to recover deficiency (1 + D)	1.0332								
	Distribution Revenue at Status Quo Rates	$796,824,614	$315,784,637	$109,714,401	$213,888,036	$69,063,008	$33,653,821	$15,573,332	$4,016,607	$35,130,770
	Miscellaneous Revenue (mi)	$47,687,081	$19,230,275	$8,162,022	$7,333,311	$1,396,409	$571,724	$9,005,777	$308,303	$1,679,259
	Total Revenue at Status Quo Rates	**$844,511,695**	**$335,014,913**	**$117,876,423**	**$221,221,348**	**$70,459,417**	**$34,225,546**	**$24,579,109**	**$4,324,910**	**$36,810,029**
	Expenses									
di	Distribution Costs (di)	$126,815,041	$43,220,429	$19,863,200	$37,815,836	$14,586,274	$6,728,377	$1,417,305	$329,621	$2,853,999
cu	Customer Related Costs (cu)	$44,779,654	$28,555,322	$7,416,244	$3,661,458	$387,365	$27,255	$218,829	$1,141,029	$3,372,152
ad	General and Administration (ad)	$101,234,363	$40,916,530	$15,681,349	$24,089,189	$8,701,308	$4,109,340	$2,565,499	$874,536	$4,296,612
dep	Depreciation and Amortization (dep)	$260,980,412	$103,208,543	$43,515,994	$68,700,925	$22,837,618	$10,799,037	$3,866,816	$788,234	$7,263,246
INPUT	PILs (INPUT)	$33,548,804	$12,657,398	$5,252,576	$8,780,570	$3,117,500	$1,661,181	$751,558	$115,756	$1,212,265
INT	Interest	$97,386,492	$36,742,281	$15,247,339	$25,488,507	$9,049,574	$4,822,126	$2,181,646	$336,019	$3,518,999
	Total Expenses	**$664,744,766**	**$265,300,503**	**$106,976,702**	**$168,536,486**	**$58,679,639**	**$28,147,316**	**$11,001,653**	**$3,585,194**	**$22,517,273**
	Direct Allocation	**$22,450,288**	**$0**	**$0**	**$456,032**	**$951,591**	**$4,496,993**	**$8,034,208**	**$422,853**	**$8,088,610**
NI	Allocated Net Income (NI)	$157,316,641	$59,352,915	$24,630,317	$41,173,743	$14,618,543	$7,789,589	$3,524,197	$542,799	$5,684,537
	Revenue Requirement (includes NI)	$844,511,695	$324,653,418	$131,607,020	$210,166,261	$74,249,773	$40,433,897	$22,560,059	$4,550,846	$36,290,421
		Revenue Requirement Input equals Output								

EB-2018-0165

Sheet O1 Revenue to Cost Summary Worksheet -

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	4 GS - 50 to 999	5 GS - 1000 to 4999	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load	10 Competitive Sector Multi-Unit Residential
	Rate Base Calculation									
	Net Assets									
dp	Distribution Plant - Gross	$4,691,198,377	$1,843,759,884	$768,291,753	$1,258,786,037	$436,489,552	$197,385,994	$55,554,715	$13,832,858	$117,097,584
gp	General Plant - Gross	$839,667,754	$315,100,152	$130,663,121	$218,361,671	$77,653,942	$42,516,340	$20,391,565	$2,969,654	$32,011,310
accum dep	Accumulated Depreciation	($1,209,717,480)	($476,587,015)	($201,371,398)	($315,859,779)	($108,129,319)	($51,813,652)	($18,371,450)	($3,644,954)	($33,939,913)
co	Capital Contribution	($73,594,426)	($30,668,135)	($12,253,020)	($18,919,155)	($5,965,680)	($2,656,653)	($924,537)	($233,305)	($1,973,941)
	Total Net Plant	$4,247,554,225	$1,651,604,886	$685,330,456	$1,142,368,774	$400,048,495	$185,432,029	$56,650,293	$12,924,252	$113,195,040
	Directly Allocated Net Fixed Assets	$132,552,346	$0	$0	$3,241,784	$6,764,514	$31,969,398	$42,348,089	$2,228,847	$45,999,714
COP	Cost of Power (COP)	$3,384,043,227	$698,987,138	$322,827,562	$1,364,936,453	$649,392,193	$286,138,448	$16,427,308	$5,881,505	$39,452,621
	OM&A Expenses	$272,829,058	$112,692,281	$42,960,793	$65,566,484	$23,674,947	$10,864,972	$4,201,633	$2,345,186	$10,522,763
	Directly Allocated Expenses	$4,668,786	$0	$0	$22,111	$46,138	$218,029	$2,872,171	$151,167	$1,359,170
	Subtotal	***$3,661,541,071***	***$811,679,419***	***$365,788,355***	***$1,430,525,048***	***$673,113,278***	***$297,221,449***	***$23,501,112***	***$8,377,858***	***$51,334,554***
	Working Capital	$235,187,789	$52,135,722	$23,495,286	$91,885,361	$43,235,354	$19,091,102	$1,509,521	$538,126	$3,297,317
	Total Rate Base	$4,615,294,360	$1,703,740,608	$708,825,742	$1,237,495,919	$450,048,362	$236,492,529	$100,507,903	$15,691,225	$162,492,070
		Rate Base Input equals Output								
	Equity Component of Rate Base	$1,846,117,744	$681,496,243	$283,530,297	$494,998,368	$180,019,345	$94,597,012	$40,203,161	$6,276,490	$64,996,828
	Net Income on Allocated Assets	$157,316,641	$69,714,410	$10,899,721	$52,228,830	$10,828,187	$1,581,237	$5,543,247	$316,863	$6,204,145
	Net Income on Direct Allocation Assets	$5,510,944	$0	$0	$134,779	$281,239	$1,329,147	$1,760,648	$92,666	$1,912,466
	Net Income	$162,827,585	$69,714,410	$10,899,721	$52,363,609	$11,109,426	$2,910,385	$7,303,895	$409,529	$8,116,611
	RATIOS ANALYSIS									
	REVENUE TO EXPENSES STATUS QUO%	100.00%	103.19%	89.57%	105.26%	94.90%	84.65%	108.95%	95.04%	101.43%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($25,621,033)	$207,781	($17,258,344)	$4,177,749	($6,011,002)	($7,290,453)	$1,518,306	($355,086)	($609,984)
		Deficiency Input equals Output								
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	$0	$10,361,494	($13,730,596)	$11,055,087	($3,790,355)	($6,208,351)	$2,019,050	($225,936)	$519,608
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.82%	10.23%	3.84%	10.58%	6.17%	3.08%	18.17%	6.52%	12.49%

Ontario Energy Board

2019 Cost Allocation Model

EB-2018-0165

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1 Residential	2 GS <50	4 GS - 50 to 999	5 GS - 1000 to 4999	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load	10 Competitive Sector Multi-Unit Residential
Customer Unit Cost per month - Avoided Cost	$5.11	$12.91	$28.99	$17.18	-$153.65	$0.15	$7.37	$2.68
Customer Unit Cost per month - Directly Related	$7.24	$17.39	$44.09	$40.14	-$113.42	$0.26	$11.47	$4.36
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$18.85	$32.14	$62.08	$136.78	-$27.77	$5.06	$13.40	$12.31
Existing Approved Fixed Charge	$37.98	$36.28	$52.17	$996.61	$4,399.14	$1.63	$7.23	$30.98

Information to be Used to Allocate PILs, ROD, ROE and A&G

	Total	1 Residential	2 GS <50	4 GS - 50 to 999	5 GS - 1000 to 4999	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load	10 Competitive Sector Multi-Unit Residential
General Plant - Gross Assets	$839,667,754	$315,100,152	$130,663,121	$218,361,671	$77,653,942	$42,516,340	$20,391,565	$2,969,654	$32,011,310
General Plant - Accumulated Depreciation	($375,982,230)	($141,093,971)	($58,507,679)	($97,776,898)	($34,771,494)	($19,037,754)	($9,130,833)	($1,329,737)	($14,333,864)
General Plant - Net Fixed Assets	$463,685,525	$174,006,181	$72,155,442	$120,584,774	$42,882,448	$23,478,586	$11,260,732	$1,639,917	$17,677,445
General Plant - Depreciation	$71,867,332	$26,969,486	$11,183,483	$18,689,619	$6,646,417	$3,638,982	$1,745,318	$254,173	$2,739,854
Total Net Fixed Assets Excluding General Plant	$3,916,418,640	$1,477,598,705	$613,175,015	$1,025,025,784	$363,930,561	$193,922,841	$87,735,364	$13,513,062	$141,517,308
Total Administration and General Expense	$101,234,363	$40,916,530	$15,681,349	$24,089,189	$8,701,308	$4,109,340	$2,565,499	$874,536	$4,296,612
Total O&M	$176,262,465	$71,775,751	$27,279,443	$41,499,406	$15,019,776	$6,973,662	$4,507,340	$1,621,766	$7,585,321

EB-2018-0165

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

			1	2	4	5	6	7	9	10	
USoA Account #	**Accounts**	**Total**	**Residential**	**GS <50**	**GS - 50 to 999**	**GS - 1000 to 4999**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Competitive Sector Multi-Unit Residential**	
	Distribution Plant										
1860	Meters	$206,493,389	$131,713,755	$55,126,025	$16,746,644	$2,523,397	$383,569	$0	$0	$0	CWMC
	Accumulated Amortization										
	Accum. Amortization of Electric Utility Plant - Meters only	($95,621,684)	($60,993,192)	($25,527,419)	($7,754,932)	($1,168,519)	($177,621)	$0	$0	$0	
	Meter Net Fixed Assets	**$110,871,705**	**$70,720,562**	**$29,598,606**	**$8,991,711**	**$1,354,878**	**$205,948**	**$0**	**$0**	**$0**	
	Misc Revenue										
4082	Retail Services Revenues	($274,804)	($113,508)	($43,272)	($66,041)	($23,846)	($10,944)	($4,232)	($2,362)	($10,599)	CWNB
4084	Service Transaction Requests (STR) Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
4090	Electric Services Incidental to Energy Sales	($2,407,409)	($994,382)	($379,081)	($578,550)	($208,905)	($95,871)	($37,075)	($20,694)	($92,852)	CWNB
4220	Other Electric Revenues	($912,869)	($377,061)	($143,744)	($219,381)	($79,215)	($36,354)	($14,058)	($7,847)	($35,209)	NFA
4225	Late Payment Charges	($3,751,641)	($2,176,700)	($804,970)	($522,043)	($68,221)	($14,052)	$0	($4,943)	($160,711)	LPHA
	Sub-total	*($7,346,723)*	*($3,661,652)*	*($1,371,067)*	*($1,386,016)*	*($380,187)*	*($157,220)*	*($55,365)*	*($35,846)*	*($299,370)*	
	Operation										
5065	Meter Expense	$476,757	$304,104	$127,276	$38,665	$5,826	$886	$0	$0	$0	CWMC
5070	Customer Premises - Operation Labour	$1,470,099	$1,020,282	$118,431	$17,183	$712	$73	$152,156	$20,201	$141,060	CCA
5075	Customer Premises - Materials and Expenses	$640,352	$444,418	$51,586	$7,485	$310	$32	$66,277	$8,799	$61,444	CCA
	Sub-total	*$2,587,207*	*$1,768,804*	*$297,293*	*$63,333*	*$6,849*	*$990*	*$218,433*	*$29,001*	*$202,504*	
	Maintenance										
5175	Maintenance of Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	1860
	Billing and Collection										
5310	Meter Reading Expense	$2,868,729	$2,181,198	$291,163	$355,966	$36,651	$3,750	$0	$0	$0	CWMR
5315	Customer Billing	$9,470,331	$6,120,943	$1,420,994	$721,617	$29,911	$6,559	$115	$323,934	$846,259	CWNB
5320	Collecting	$22,254,548	$14,383,745	$3,339,227	$1,695,744	$70,288	$15,412	$270	$761,220	$1,988,642	CWNB
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
	Sub-total	$34,593,608	$22,685,886	$5,051,384	$2,773,327	$136,850	$25,721	$386	$1,085,154	$2,834,901	
	Total Operation, Maintenance and Billing	$37,180,815	$24,454,689	$5,348,677	$2,836,660	$143,698	$26,711	$218,819	$1,114,155	$3,037,405	
	Amortization Expense - Meters	$19,305,119	$12,313,952	$5,153,746	$1,565,648	$235,913	$35,860	$0	$0	$0	
	Allocated PILs	$849,707	$541,981	$226,853	$68,917	$10,383	$1,574	$0	$0	$0	
	Allocated Debt Return	$2,466,556	$1,573,279	$658,514	$200,055	$30,139	$4,568	$0	$0	$0	
	Allocated Equity Return	$3,984,436	$2,541,450	$1,063,754	$323,166	$48,687	$7,379	$0	$0	$0	
	Total	**$56,439,910**	**$37,763,699**	**$11,080,478**	**$3,608,430**	**$88,634**	**($81,128)**	**$163,454**	**$1,078,309**	**$2,738,035**	

EB-2018-0165

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

			1	2	4	5	6	7	9	10	
USoA Account #	**Accounts**	**Total**	**Residential**	**GS <50**	**GS - 50 to 999**	**GS - 1000 to 4999**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Competitive Sector Multi-Unit Residential**	
	Distribution Plant										
1860	Meters	$206,493,389	$131,713,755	$55,126,025	$16,746,644	$2,523,397	$383,569	$0	$0	$0	CWMC
	Accumulated Amortization										
	Accum. Amortization of Electric Utility Plant - Meters only	($95,621,684)	($60,993,192)	($25,527,419)	($7,754,932)	($1,168,519)	($177,621)	$0	$0	$0	
	Meter Net Fixed Assets	$110,871,705	$70,720,562	$29,598,606	$8,991,711	$1,354,878	$205,948	$0	$0	$0	
	Allocated General Plant Net Fixed Assets	$13,053,645	$8,328,252	$3,483,019	$1,057,791	$159,647	$24,934	$0	$0	$0	
	Meter Net Fixed Assets Including General Plant	$123,925,350	$79,048,815	$33,081,625	$10,049,503	$1,514,525	$230,882	$0	$0	$0	
	Misc Revenue										
4082	Retail Services Revenues	($274,804)	($113,508)	($43,272)	($66,041)	($23,846)	($10,944)	($4,232)	($2,362)	($10,599)	CWNB
4084	Service Transaction Requests (STR) Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
4090	Electric Services Incidental to Energy Sales	($2,407,409)	($994,382)	($379,081)	($578,550)	($208,905)	($95,871)	($37,075)	($20,694)	($92,852)	CWNB
4220	Other Electric Revenues	($912,869)	($377,061)	($143,744)	($219,381)	($79,215)	($36,354)	($14,058)	($7,847)	($35,209)	NFA
4225	Late Payment Charges	($3,751,641)	($2,176,700)	($804,970)	($522,043)	($68,221)	($14,052)	$0	($4,943)	($160,711)	LPHA
	Sub-total	*($7,346,723)*	*($3,661,652)*	*($1,371,067)*	*($1,386,016)*	*($380,187)*	*($157,220)*	*($55,365)*	*($35,846)*	*($299,370)*	
	Operation										
5065	Meter Expense	$476,757	$304,104	$127,276	$38,665	$5,826	$886	$0	$0	$0	CWMC
5070	Customer Premises - Operation Labour	$1,470,099	$1,020,282	$118,431	$17,183	$712	$73	$152,156	$20,201	$141,060	CCA
5075	Customer Premises - Materials and Expenses	$640,352	$444,418	$51,586	$7,485	$310	$32	$66,277	$8,799	$61,444	CCA
	Sub-total	*$2,587,207*	*$1,768,804*	*$297,293*	*$63,333*	*$6,849*	*$990*	*$218,433*	*$29,001*	*$202,504*	
	Maintenance										
5175	Maintenance of Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	1860
	Billing and Collection										
5310	Meter Reading Expense	$2,868,729	$2,181,198	$291,163	$355,966	$36,651	$3,750	$0	$0	$0	CWMR
5315	Customer Billing	$9,470,331	$6,120,943	$1,420,994	$721,617	$29,911	$6,559	$115	$323,934	$846,259	CWNB
5320	Collecting	$22,254,548	$14,383,745	$3,339,227	$1,695,744	$70,288	$15,412	$270	$761,220	$1,988,642	CWNB
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
	Sub-total	*$34,593,608*	*$22,685,886*	*$5,051,384*	*$2,773,327*	*$136,850*	*$25,721*	*$386*	*$1,085,154*	*$2,834,901*	
	Total Operation, Maintenance and Billing	$37,180,815	$24,454,689	$5,348,677	$2,836,660	$143,698	$26,711	$218,819	$1,114,155	$3,037,405	
	Amortization Expense - Meters	$19,305,119	$12,313,952	$5,153,746	$1,565,648	$235,913	$35,860	$0	$0	$0	
	Amortization Expense - General Plant assigned to Meters	*$2,023,204*	*$1,290,809*	*$539,839*	*$163,949*	*$24,744*	*$3,865*	*$0*	*$0*	*$0*	
	Admin and General	$21,206,738	$13,940,656	$3,074,640	$1,646,598	$83,248	$15,740	$124,548	$600,807	$1,720,501	
	Allocated PILs	$949,749	$605,806	$253,547	$77,025	$11,606	$1,764	$0	$0	$0	
	Allocated Debt Return	$2,756,959	$1,758,552	$736,005	$223,590	$33,691	$5,121	$0	$0	$0	
	Allocated Equity Return	$4,453,549	$2,840,739	$1,188,931	$361,184	$54,423	$8,273	$0	$0	$0	
	Total	**$80,529,410**	**$53,543,550**	**$14,924,320**	**$5,488,637**	**$207,137**	**($59,887)**	**$288,002**	**$1,679,116**	**$4,458,536**	

EB-2018-0165

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	1 Residential	2 GS <50	4 GS - 50 to 999	5 GS - 1000 to 4999	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load	10 Competitive Sector Multi-Unit Residential	
	Distribution Plant										
1565	Conservation and Demand Management Expenditures and Recoveries	$0	$0	$0	$0	$0	$0	$0	$0	$0	CDMPP
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	#N/A
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	BCP
1830-4	Poles, Towers and Fixtures - Primary	$53,669,039	$40,602,112	$4,712,947	$683,815	$28,344	$2,900	$1,221,511	$803,915	$5,613,495	PNCP
1830-5	Poles, Towers and Fixtures - Secondary	$34,312,992	$24,052,479	$2,791,925	$79,684	$195	$78	$3,586,991	$476,235	$3,325,405	SNCP
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	#N/A
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	BCP
1835-4	Overhead Conductors and Devices - Primary	$68,757,879	$52,017,237	$6,037,974	$876,067	$36,313	$3,716	$1,564,934	$1,029,932	$7,191,707	PNCP
1835-5	Overhead Conductors and Devices - Secondary	$43,959,956	$30,814,739	$3,576,864	$102,087	$250	$100	$4,595,459	$610,126	$4,260,330	SNCP
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	#N/A
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	BCP
1840-4	Underground Conduit - Primary	$220,743,819	$166,998,803	$19,384,620	$2,812,571	$116,580	$11,929	$5,024,143	$3,306,547	$23,088,625	PNCP
1840-5	Underground Conduit - Secondary	$87,988,795	$61,677,764	$7,159,333	$204,334	$501	$200	$9,198,119	$1,221,209	$8,527,335	SNCP
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	#N/A
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	BCP
1845-4	Underground Conductors and Devices - Primary	$159,500,636	$120,666,641	$14,006,549	$2,032,251	$84,236	$8,620	$3,630,244	$2,389,179	$16,682,915	PNCP
1845-5	Underground Conductors and Devices - Secondary	$63,577,177	$44,565,880	$5,173,047	$147,643	$362	$145	$6,646,192	$882,397	$6,161,511	SNCP
1850	Line Transformers	$156,379,002	$118,657,428	$13,773,327	$1,605,310	$18,177	$438	$3,569,797	$2,349,396	$16,405,129	LTNCP
1855	Services	$165,577,509	$147,847,167	$17,161,567	$489,806	$1,200	$480	$0	$0	$77,288	CWCS
1860	Meters	$206,570,677	$131,713,755	$55,126,025	$16,746,644	$2,523,397	$383,569	$0	$0	$77,288	CWMC
											0
	Sub-total	*$1,261,037,481*	*$939,614,005*	*$148,904,178*	*$25,780,213*	*$2,809,556*	*$412,175*	*$39,037,390*	*$13,068,936*	*$91,411,028*	
	Accumulated Amortization										
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	($279,813,864)	($200,854,740)	($41,762,044)	($9,405,070)	($1,220,485)	($182,740)	($7,046,572)	($2,421,868)	($16,920,346)	
	Customer Related Net Fixed Assets	$981,223,617	$738,759,265	$107,142,134	$16,375,143	$1,589,071	$229,435	$31,990,818	$10,647,068	$74,490,682	
	Allocated General Plant Net Fixed Assets	$116,450,731	$86,998,370	$12,607,963	$1,926,384	$187,242	$27,778	$4,105,984	$1,292,106	$9,304,904	
	Customer Related NFA Including General Plant	$1,097,674,348	$825,757,635	$119,750,097	$18,301,527	$1,776,314	$257,213	$36,096,802	$11,939,175	$83,795,586	
	Misc Revenue										
4082	Retail Services Revenues	($274,804)	($113,508)	($43,272)	($66,041)	($23,846)	($10,944)	($4,232)	($2,362)	($10,599)	CWNB
4084	Service Transaction Requests (STR) Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
4090	Electric Services Incidental to Energy Sales	($2,407,409)	($994,382)	($379,081)	($578,550)	($208,905)	($95,871)	($37,075)	($20,694)	($92,852)	CWNB
4220	Other Electric Revenues	($912,869)	($377,061)	($143,744)	($219,381)	($79,215)	($36,354)	($14,058)	($7,847)	($35,209)	NFA
4225	Late Payment Charges	($3,751,641)	($2,176,700)	($804,970)	($522,043)	($68,221)	($14,052)	$0	($4,943)	($160,711)	LPHA
4235	Miscellaneous Service Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
	Sub-total	*($7,346,723)*	*($3,661,652)*	*($1,371,067)*	*($1,386,016)*	*($380,187)*	*($157,220)*	*($55,365)*	*($35,846)*	*($299,370)*	

EB-2018-0165

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

	Operating and Maintenance										
5005	Operation Supervision and Engineering	$7,790,742	$5,937,780	$693,305	$88,641	$12,740	$4,898	$286,672	$95,978	$670,727	1815-1855
5010	Load Dispatching	$2,007,476	$1,530,015	$178,647	$22,841	$3,283	$1,262	$73,868	$24,731	$172,829	1815-1855
5020	Overhead Distribution Lines and Feeders - Operation Labour	$133,829	$98,345	$11,416	$1,161	$43	$5	$7,314	$1,947	$13,597	1830 & 1835
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$188,759	$138,712	$16,101	$1,638	$61	$6	$10,316	$2,746	$19,178	1830 & 1835
5035	Overhead Distribution Transformers- Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	1850
5040	Underground Distribution Lines and Feeders - Operation Labour	$127,555	$94,479	$10,967	$1,246	$48	$5	$5,876	$1,871	$13,062	1840 & 1845
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$616,551	$456,676	$53,009	$6,025	$234	$24	$28,402	$9,042	$63,138	1840 & 1845
5055	Underground Distribution Transformers - Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	1850
5065	Meter Expense	$476,757	$304,104	$127,276	$38,665	$5,826	$886	$0	$0	$0	CWMC
5070	Customer Premises - Operation Labour	$1,470,099	$1,020,282	$118,431	$17,183	$712	$73	$152,156	$20,201	$141,060	CCA
5075	Customer Premises - Materials and Expenses	$640,352	$444,418	$51,586	$7,485	$310	$32	$66,277	$8,799	$61,444	CCA
5085	Miscellaneous Distribution Expense	$1,397,837	$1,065,374	$124,395	$15,904	$2,286	$879	$51,435	$17,221	$120,344	1815-1855
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	1840 & 1845
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	1830 & 1835
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	O&M
5105	Maintenance Supervision and Engineering	$3,871,554	$2,950,738	$344,533	$44,050	$6,331	$2,434	$142,459	$47,696	$333,313	1815-1855
5120	Maintenance of Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	1830
5125	Maintenance of Overhead Conductors and Devices	$4,292,769	$3,154,590	$366,173	$37,252	$1,392	$145	$234,614	$62,460	$436,142	1835
5130	Maintenance of Overhead Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	1855
5135	Overhead Distribution Lines and Feeders - Right of Way	$771,935	$567,265	$65,846	$6,699	$250	$26	$42,189	$11,232	$78,428	1830 & 1835
5145	Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	1840
5150	Maintenance of Underground Conductors and Devices	$1,272,324	$942,403	$109,391	$12,433	$483	$50	$58,612	$18,659	$130,293	1845
5155	Maintenance of Underground Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	1855
5160	Maintenance of Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	1850
5175	Maintenance of Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	1860
	Sub-total	*$25,058,539*	*$18,705,181*	*$2,271,076*	*$301,224*	*$34,001*	*$10,726*	*$1,160,191*	*$322,585*	*$2,253,556*	

EB-2018-0165

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

	Billing and Collection										
5305	Supervision	$785,685	$507,810	$117,890	$59,867	$2,481	$544	$10	$26,874	$70,208	CWNB
5310	Meter Reading Expense	$2,868,729	$2,181,198	$291,163	$355,966	$36,651	$3,750	$0	$0	$0	CWMR
5315	Customer Billing	$9,470,331	$6,120,943	$1,420,994	$721,617	$29,911	$6,559	$115	$323,934	$846,259	CWNB
5320	Collecting	$22,254,548	$14,383,745	$3,339,227	$1,695,744	$70,288	$15,412	$270	$761,220	$1,988,642	CWNB
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
5335	Bad Debt Expense	$6,813,154	$3,592,822	$1,949,677	$764,931	$241,185	$0	$0	$0	$264,540	BDHA
5340	Miscellaneous Customer Accounts Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
	Sub-total	*$42,192,447*	*$26,786,518*	*$7,118,950*	*$3,598,125*	*$380,516*	*$26,265*	*$395*	*$1,112,029*	*$3,169,649*	
	Sub Total Operating, Maintenance and Biling	*$67,250,986*	*$45,491,699*	*$9,390,026*	*$3,899,349*	*$414,517*	*$36,991*	*$1,160,586*	*$1,434,613*	*$5,423,205*	
	Amortization Expense - Customer Related	$58,116,163	$41,614,698	$8,578,106	$2,038,342	$307,188	$63,658	$1,456,408	$508,102	$3,549,661	
	Amortization Expense - General Plant assigned to Meters	$18,048,878	$13,484,011	$1,954,128	$298,573	$29,021	$4,305	$636,393	$200,266	$1,442,181	
	Admin and General	$38,362,303	$25,933,027	$5,397,774	$2,263,458	$240,139	$21,797	$660,585	$773,614	$3,071,908	
	Allocated PILs	$8,405,352	$6,328,356	$917,800	$140,273	$13,612	$1,965	$274,040	$91,205	$638,102	
	Allocated Debt Return	$24,399,313	$18,370,144	$2,664,219	$407,188	$39,514	$5,705	$795,490	$264,752	$1,852,301	
	Allocated Equity Return	$39,414,275	$29,674,847	$4,303,738	$657,765	$63,831	$9,216	$1,285,023	$427,677	$2,992,179	
	PLCC Adjustment for Line Transformer	$8,201,434	$6,217,538	$721,655	$84,108	$953	$23	$188,760	$123,488	$864,910	
	PLCC Adjustment for Primary Costs	$19,690,280	$14,888,563	$1,728,685	$249,118	$10,277	$1,055	$446,537	$295,064	$2,070,981	
	PLCC Adjustment for Secondary Costs	$23,331,063	$16,814,366	$1,810,996	$257,008	$10,596	$0	$0	$1,284,566	$3,153,531	
	Total	$195,427,770	**$139,314,663**	**$27,573,389**	**$7,728,698**	**$705,810**	**($14,660)**	**$5,577,863**	**$1,961,265**	**$12,580,743**	

EB-2018-0165

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Below: Grouping to avoid disclosure

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS - 50 to 999	GS - 1000 to 4999	Large Use >5MW	Street Light	Unmetered Scattered Load	Competitive Sector Multi-Unit Residential
Distribution Plant									
CWMC	$ 206,493,389	$ 131,713,755	$ 55,126,025	$ 16,746,644	$ 2,523,397	$ 383,569	$ -	$ -	$ -
Accumulated Amortization									
Accum. Amortization of Electric Utility Plant - Meters only	$ (95,621,684)	$ (60,993,192)	$ (25,527,419)	$ (7,754,932)	$ (1,168,519)	$ (177,621)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 110,871,705	$ 70,720,562	$ 29,598,606	$ 8,991,711	$ 1,354,878	$ 205,948	$ -	$ -	$ -
Misc Revenue									
CWNB	$ (2,682,213)	$ (1,107,890)	$ (422,352)	$ (644,591)	$ (232,751)	$ (106,815)	$ (41,307)	$ (23,056)	$ (103,450)
NFA	$ (912,869)	$ (377,061)	$ (143,744)	$ (219,381)	$ (79,215)	$ (36,354)	$ (14,058)	$ (7,847)	$ (35,209)
LPHA	$ (3,751,641)	$ (2,176,700)	$ (804,970)	$ (522,043)	$ (68,221)	$ (14,052)	$ -	$ (4,943)	$ (160,711)
Sub-total	$ (7,346,723)	$ (3,661,652)	$ (1,371,067)	$ (1,386,016)	$ (380,187)	$ (157,220)	$ (55,365)	$ (35,846)	$ (299,370)
Operation									
CWMC	$ 476,757	$ 304,104	$ 127,276	$ 38,665	$ 5,826	$ 886	$ -	$ -	$ -
CCA	$ 2,110,451	$ 1,464,700	$ 170,017	$ 24,668	$ 1,022	$ 105	$ 218,433	$ 29,001	$ 202,504
Sub-total	$ 2,587,207	$ 1,768,804	$ 297,293	$ 63,333	$ 6,849	$ 990	$ 218,433	$ 29,001	$ 202,504
Maintenance									
1860	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Billing and Collection									
CWMR	$ 2,868,729	$ 2,181,198	$ 291,163	$ 355,966	$ 36,651	$ 3,750	$ -	$ -	$ -
CWNB	$ 31,724,879	$ 20,504,688	$ 4,760,221	$ 2,417,360	$ 100,199	$ 21,971	$ 386	$ 1,085,154	$ 2,834,901
Sub-total	$ 34,593,608	$ 22,685,886	$ 5,051,384	$ 2,773,327	$ 136,850	$ 25,721	$ 386	$ 1,085,154	$ 2,834,901
Total Operation, Maintenance and Billing	$ 37,180,815	$ 24,454,689	$ 5,348,677	$ 2,836,660	$ 143,698	$ 26,711	$ 218,819	$ 1,114,155	$ 3,037,405
Amortization Expense - Meters	$ 19,305,119	$ 12,313,952	$ 5,153,746	$ 1,565,648	$ 235,913	$ 35,860	$ -	$ -	$ -
Allocated PILs	$ 849,707	$ 541,981	$ 226,853	$ 68,917	$ 10,383	$ 1,574	$ -	$ -	$ -
Allocated Debt Return	$ 2,466,556	$ 1,573,279	$ 658,514	$ 200,055	$ 30,139	$ 4,568	$ -	$ -	$ -
Allocated Equity Return	$ 3,984,436	$ 2,541,450	$ 1,063,754	$ 323,166	$ 48,687	$ 7,379	$ -	$ -	$ -
Total	**$ 56,439,910**	**$ 37,763,699**	**$ 11,080,478**	**$ 3,608,430**	**$ 88,634**	**$ (81,128)**	**$ 163,454**	**$ 1,078,309**	**$ 2,738,035**

EB-2018-0165

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS - 50 to 999	GS - 1000 to 4999	Large Use >5MW	Street Light	Unmetered Scattered Load	Competitive Sector Multi-Unit Residential
Distribution Plant									
CWMC	$ 206,493,389	$ 131,713,755	$ 55,126,025	$ 16,746,644	$ 2,523,397	$ 383,569	$ -	$ -	$ -
Accumulated Amortization									
Accum. Amortization of Electric Utility Plant - Meters only	$ (95,621,684)	$ (60,993,192)	$ (25,527,419)	$ (7,754,932)	$ (1,168,519)	$ (177,621)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 110,871,705	$ 70,720,562	$ 29,598,606	$ 8,991,711	$ 1,354,878	$ 205,948	$ -	$ -	$ -
Allocated General Plant Net Fixed Assets	$ 13,053,645	$ 8,328,252	$ 3,483,019	$ 1,057,791	$ 159,647	$ 24,934	$ -	$ -	$ -
Meter Net Fixed Assets Including General Plant	$ 123,925,350	$ 79,048,815	$ 33,081,625	$ 10,049,503	$ 1,514,525	$ 230,882	$ -	$ -	$ -
Misc Revenue									
CWNB	$ (2,682,213)	$ (1,107,890)	$ (422,352)	$ (644,591)	$ (232,751)	$ (106,815)	$ (41,307)	$ (23,056)	$ (103,450)
NFA	$ (912,869)	$ (377,061)	$ (143,744)	$ (219,381)	$ (79,215)	$ (36,354)	$ (14,058)	$ (7,847)	$ (35,209)
LPHA	$ (3,751,641)	$ (2,176,700)	$ (804,970)	$ (522,043)	$ (68,221)	$ (14,052)	$ -	$ (4,943)	$ (160,711)
Sub-total	*$ (7,346,723)*	*$ (3,661,652)*	*$ (1,371,067)*	*$ (1,386,016)*	*$ (380,187)*	*$ (157,220)*	*$ (55,365)*	*$ (35,846)*	*$ (299,370)*
Operation									
CWMC	$ 476,757	$ 304,104	$ 127,276	$ 38,665	$ 5,826	$ 886	$ -	$ -	$ -
CCA	$ 2,110,451	$ 1,464,700	$ 170,017	$ 24,668	$ 1,022	$ 105	$ 218,433	$ 29,001	$ 202,504
Sub-total	*$ 2,587,207*	*$ 1,768,804*	*$ 297,293*	*$ 63,333*	*$ 6,849*	*$ 990*	*$ 218,433*	*$ 29,001*	*$ 202,504*
Maintenance									
1860	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Billing and Collection									
CWMR	$ 2,868,729	$ 2,181,198	$ 291,163	$ 355,966	$ 36,651	$ 3,750	$ -	$ -	$ -
CWNB	$ 31,724,879	$ 20,504,688	$ 4,760,221	$ 2,417,360	$ 100,199	$ 21,971	$ 386	$ 1,085,154	$ 2,834,901
Sub-total	*$ 34,593,608*	*$ 22,685,886*	*$ 5,051,384*	*$ 2,773,327*	*$ 136,850*	*$ 25,721*	*$ 386*	*$ 1,085,154*	*$ 2,834,901*
Total Operation, Maintenance and Billing	$ 37,180,815	$ 24,454,689	$ 5,348,677	$ 2,836,660	$ 143,698	$ 26,711	$ 218,819	$ 1,114,155	$ 3,037,405
Amortization Expense - Meters	$ 19,305,119	$ 12,313,952	$ 5,153,746	$ 1,565,648	$ 235,913	$ 35,860	$ -	$ -	$ -
Amortization Expense - General Plant assigned to Meters	$ 2,023,204	$ 1,290,809	$ 539,839	$ 163,949	$ 24,744	$ 3,865	$ -	$ -	$ -
Admin and General	$ 21,206,738	$ 13,940,656	$ 3,074,640	$ 1,646,598	$ 83,248	$ 15,740	$ 124,548	$ 600,807	$ 1,720,501
Allocated PILs	$ 949,749	$ 605,806	$ 253,547	$ 77,025	$ 11,606	$ 1,764	$ -	$ -	$ -
Allocated Debt Return	$ 2,756,959	$ 1,758,552	$ 736,005	$ 223,590	$ 33,691	$ 5,121	$ -	$ -	$ -
Allocated Equity Return	$ 4,453,549	$ 2,840,739	$ 1,188,931	$ 361,184	$ 54,423	$ 8,273	$ -	$ -	$ -
Total	**$ 80,529,410**	**$ 53,543,550**	**$ 14,924,320**	**$ 5,488,637**	**$ 207,137**	**$ (59,887)**	**$ 288,002**	**$ 1,679,116**	**$ 4,458,536**

EB-2018-0165

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	Residential	GS <50	GS - 50 to 999	GS - 1000 to 4999	Large Use >5MW	Street Light	Unmetered Scattered Load	Competitive Sector Multi-Unit Residential
	Distribution Plant									
	CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Poles, Towers and Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	PNCP	$ 502,671,373	$ 380,284,792	$ 44,142,090	$ 6,404,706	$ 265,474	$ 27,165	$ 11,440,831	$ 7,529,573	$ 52,576,743
	SNCP	$ 229,838,919	$ 161,110,863	$ 18,701,169	$ 533,748	$ 1,308	$ 523	$ 24,026,761	$ 3,189,967	$ 22,274,581
	Overhead Conductors and Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LTNCP	$ 156,379,002	$ 118,657,428	$ 13,773,327	$ 1,605,310	$ 18,177	$ 438	$ 3,569,797	$ 2,349,396	$ 16,405,129
	CWCS	$ 165,577,509	$ 147,847,167	$ 17,161,567	$ 489,806	$ 1,200	$ 480	$ -	$ -	$ 77,288
	CWMC	$ 206,570,677	$ 131,713,755	$ 55,126,025	$ 16,746,644	$ 2,523,397	$ 383,569	$ -	$ -	$ 77,288
	Sub-total	*$ 1,261,037,481*	*$ 939,614,005*	*$ 148,904,178*	*$ 25,780,213*	*$ 2,809,556*	*$ 412,175*	*$ 39,037,390*	*$ 13,068,936*	*$ 91,411,028*
	Accumulated Amortization									
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	$ (279,813,864)	$ (200,854,740)	$ (41,762,044)	$ (9,405,070)	$ (1,220,485)	$ (182,740)	$ (7,046,572)	$ (2,421,868)	$ (16,920,346)
	Customer Related Net Fixed Assets	$ 981,223,617	$ 738,759,265	$ 107,142,134	$ 16,375,143	$ 1,589,071	$ 229,435	$ 31,990,818	$ 10,647,068	$ 74,490,682
	Allocated General Plant Net Fixed Assets	$ 116,450,731	$ 86,998,370	$ 12,607,963	$ 1,926,384	$ 187,242	$ 27,778	$ 4,105,984	$ 1,292,106	$ 9,304,904
	Customer Related NFA Including General Plant	$ 1,097,674,348	$ 825,757,635	$ 119,750,097	$ 18,301,527	$ 1,776,314	$ 257,213	$ 36,096,802	$ 11,939,175	$ 83,795,586
	Misc Revenue									
	CWNB	$ (2,682,213)	$ (1,107,890)	$ (422,352)	$ (644,591)	$ (232,751)	$ (106,815)	$ (41,307)	$ (23,056)	$ (103,450)
	NFA	$ (912,869)	$ (377,061)	$ (143,744)	$ (219,381)	$ (79,215)	$ (36,354)	$ (14,058)	$ (7,847)	$ (35,209)
	LPHA	$ (3,751,641)	$ (2,176,700)	$ (804,970)	$ (522,043)	$ (68,221)	$ (14,052)	$ -	$ (4,943)	$ (160,711)
	Sub-total	*$ (7,346,723)*	*$ (3,661,652)*	*$ (1,371,067)*	*$ (1,386,016)*	*$ (380,187)*	*$ (157,220)*	*$ (55,365)*	*$ (35,846)*	*$ (299,370)*
	Operating and Maintenance									
	1815-1855	$ 15,067,610	$ 11,483,906	$ 1,340,879	$ 171,436	$ 24,640	$ 9,474	$ 554,435	$ 185,626	$ 1,297,214
	1830 & 1835	$ 1,094,523	$ 804,323	$ 93,363	$ 9,498	$ 355	$ 37	$ 59,819	$ 15,925	$ 111,203
	1850	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1840 & 1845	$ 744,106	$ 551,155	$ 63,976	$ 7,271	$ 282	$ 29	$ 34,278	$ 10,913	$ 76,201
	CWMC	$ 476,757	$ 304,104	$ 127,276	$ 38,665	$ 5,826	$ 886	$ -	$ -	$ -
	CCA	$ 2,110,451	$ 1,464,700	$ 170,017	$ 24,668	$ 1,022	$ 105	$ 218,433	$ 29,001	$ 202,504
	O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1835	$ 4,292,769	$ 3,154,590	$ 366,173	$ 37,252	$ 1,392	$ 145	$ 234,614	$ 62,460	$ 436,142
	1855	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1845	$ 1,272,324	$ 942,403	$ 109,391	$ 12,433	$ 483	$ 50	$ 58,612	$ 18,659	$ 130,293
	1860	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Sub-total	*$ 25,058,539*	*$ 18,705,181*	*$ 2,271,076*	*$ 301,224*	*$ 34,001*	*$ 10,726*	*$ 1,160,191*	*$ 322,585*	*$ 2,253,556*

EB-2018-0165

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Billing and Collection										
CWNB	$ 32,510,564	$ 21,012,498	$ 4,878,110	$ 2,477,228	$ 102,681	$ 22,515	$ 395	$ 1,112,029	$ 2,905,109
CWMR	$ 2,868,729	$ 2,181,198	$ 291,163	$ 355,966	$ 36,651	$ 3,750	$ -	$ -	$ -
BDHA	$ 6,813,154	$ 3,592,822	$ 1,949,677	$ 764,931	$ 241,185	$ -	$ -	$ -	$ 264,540
Sub-total	*$ 42,192,447*	*$ 26,786,518*	*$ 7,118,950*	*$ 3,598,125*	*$ 380,516*	*$ 26,265*	*$ 395*	*$ 1,112,029*	*$ 3,169,649*
Sub Total Operating, Maintenance and Biling	*$ 67,250,986*	*$ 45,491,699*	*$ 9,390,026*	*$ 3,899,349*	*$ 414,517*	*$ 36,991*	*$ 1,160,586*	*$ 1,434,613*	*$ 5,423,205*
Amortization Expense - Customer Related	$ 58,116,163	$ 41,614,698	$ 8,578,106	$ 2,038,342	$ 307,188	$ 63,658	$ 1,456,408	$ 508,102	$ 3,549,661
Amortization Expense - General Plant assigned to Meters	$ 18,048,878	$ 13,484,011	$ 1,954,128	$ 298,573	$ 29,021	$ 4,305	$ 636,393	$ 200,266	$ 1,442,181
Admin and General	$ 38,362,303	$ 25,933,027	$ 5,397,774	$ 2,263,458	$ 240,139	$ 21,797	$ 660,585	$ 773,614	$ 3,071,908
Allocated PILs	$ 8,405,352	$ 6,328,356	$ 917,800	$ 140,273	$ 13,612	$ 1,965	$ 274,040	$ 91,205	$ 638,102
Allocated Debt Return	$ 24,399,313	$ 18,370,144	$ 2,664,219	$ 407,188	$ 39,514	$ 5,705	$ 795,490	$ 264,752	$ 1,852,301
Allocated Equity Return	$ 39,414,275	$ 29,674,847	$ 4,303,738	$ 657,765	$ 63,831	$ 9,216	$ 1,285,023	$ 427,677	$ 2,992,179
PLCC Adjustment for Line Transformer	$ 8,201,434	$ 6,217,538	$ 721,655	$ 84,108	$ 953	$ 23	$ 188,760	$ 123,488	$ 864,910
PLCC Adjustment for Primary Costs	$ 19,690,280	$ 14,888,563	$ 1,728,685	$ 249,118	$ 10,277	$ 1,055	$ 446,537	$ 295,064	$ 2,070,981
PLCC Adjustment for Secondary Costs	$ 23,331,063	$ 16,814,366	$ 1,810,996	$ 257,008	$ 10,596	$ -	$ -	$ 1,284,566	$ 3,153,531
Total	**$ 195,427,770**	**$ 139,314,663**	**$ 27,573,389**	**$ 7,728,698**	**$ 705,810**	**$ (14,660)**	**$ 5,577,863**	**$ 1,961,265**	**$ 12,580,743**

RATE DESIGN

1. INTRODUCTION AND SUMMARY

In this application, Toronto Hydro is asking for new base distribution rates and new rate riders effective January 1, 2020, for the 2020 rebasing year. For the 2021 to 2024 period, Toronto Hydro is proposing to apply a Custom Price Cap Index ("CPCI") to the base distribution rates derived for 2020. This CPCI, which has been developed on the same basis as the CPCI approved by the OEB in EB-2014-0116, will adjust rates for all rate classes based on a mechanism which incorporates an inflation index, productivity, and a component to address Toronto Hydro's significant capital needs over the next five years.

Other than the Residential and Competitive Sector Multi-Unit Residential ("CSMUR") classes, Toronto Hydro is proposing fixed and variable rates for all rate classes based on the current split of revenue generated through each of these components. For the Residential and CSMUR classes, 2020 is the final year of the implementation of the OEB's policy to set distribution rates for these classes on a fully fixed basis.

Toronto Hydro is proposing new rate riders to effect the clearance of a number of Deferral and Variance Accounts ("DVAs"), as well as to clear to customers a number of other amounts owed or owing.

Toronto Hydro is proposing an updated rate for Wireline attachment rate, as well as the elimination of one Specific Service Charge. The updated Wireline attachment rate reflects the findings of the OEB's EB-2015-0304 Report dated March 22, 2018.

Tariff Schedules for the Forecast Years are shown in Exhibit 8, Tab 3, Schedule 2. Exhibit 8, Tab 6, Schedule 1 shows the bill impacts for customers in each rate class for various levels of billing units.

The proposed rate changes for 2020 reflect Toronto Hydro's revenue requirement, the results of applying the OEB's Cost Allocation model, and the conclusion of the transition to fully fixed distribution rates for the Residential and CSMUR classes. For the 2021-2024 period, the proposed rate changes reflect the operation of the CPCI and clearance of proposed DVA accounts.

A summary of the bill impacts (including all rate riders) resulting from the utility's proposals is shown in Table 1 below.

Table 1: Bill Impacts – Change In Monthly Bill

	Change in bill	2020 Proposed	2021 Proposed	2022 Proposed	2023 Proposed	2024 Proposed
Residential	$/30 days	-3.10	1.44	1.12	1.40	1.92
	%	*-2.4*	*1.1*	*0.9*	*1.1*	*1.5*
Competitive Sector Multi-Unit Residential	$/30 days	-1.19	1.14	0.89	0.99	1.52
	%	*-1.7*	*1.7*	*1.3*	*1.4*	*2.1*
General Service <50 kW	$/30 days	-6.60	3.62	2.81	4.39	4.82
	%	*-2.0*	*1.1*	*0.9*	*1.3*	*1.4*
General Service 50-999 kW	$/30 days	-156.17	63.57	49.55	87.48	84.52
	%	*-1.1*	*0.5*	*0.4*	*0.6*	*0.6*
General Service 1,000-4,999 kW	$/30 days	-1,452.01	521.66	406.45	717.98	693.76
	%	*-0.9*	*0.3*	*0.3*	*0.5*	*0.5*
Large Use	$/30 days	-3,187.65	2,692.82	2,098.05	3,704.72	3,579.26
	%	*-0.5*	*0.4*	*0.3*	*0.5*	*0.5*
Street Lighting	$/30 days	-2,514.52	4,577.71	3,585.65	6,320.80	6,149.95
	%	*-0.9*	*1.6*	*1.2*	*2.1*	*2.0*
Unmetered Scattered Load	$/30 days	-1.23	1.19	0.93	1.62	1.57
	%	*-1.9*	*1.9*	*1.4*	*2.5*	*2.3*

2. 2020 BASE DISTRIBUTION RATES

As 2020 is Toronto Hydro's rebasing year, distribution rates for this year have been developed on a Cost of Service basis. The Revenue Requirement for 2020 (see Exhibit 6) is allocated to rate classes using the OEB's latest Cost Allocation model and rates are designed to collect the allocated costs from each customer class.

2.1 Revenue/Cost Ratios

The cost allocation results are provided in Exhibit 7. As described in that exhibit, Toronto Hydro proposes rates so that all rate classes are within the ranges as provided in the Report of the Board: *Review of Electricity Distribution Cost Allocation Policy* (EB-2010-0219) and the updated policy for the Street Lighting class as provided in the Report of the Board: *New Cost Allocation Policy for Street Lighting Rate Class* (EB-2012-0383).

In its EB-2010-0142 decision, the OEB directed Toronto Hydro to set rates for the CSMUR class so that the revenue-to-cost ratio for this class is 1.0. In the 2020 cost allocation exercise, based on current rates (adjusted for the 2020 revenue requirement) the CSMUR class would have a revenue-to-cost ratio of 1.014. In order to maintain the revenue-to-cost ratio at exactly 1.0, rates are adjusted downwards for this class. The extra revenue requirement is allocated to those classes with revenue-to-cost ratios below 1.0 proportionally to the amounts those classes were below their allocated costs.

2.2 Fixed versus Variable Charge

Toronto Hydro is proposing to maintain the fixed/variable split at 2015 approved ratios for the purposes of designing the fixed and variable components of rates for all years in

this application, with the exception of the Residential and CSMUR classes. For these two classes, 2020 is the final year of the transition to fully fixed rates.

Exhibit 8, Tab 1, Schedule 2 provides details on the fixed/variable split for each rate class.

2.3 Transition to Fully Fixed Distribution rates for Residential and CSMUR classes

Pursuant to OEB policy EB-2012-0410, 2020 will be the final year of the transition to fully fixed distribution rates for the Residential and CSMUR classes.

As shown in Tabs 12 and 12.1 of the Revenue Requirement Workform (Exhibit 6, Tab 1, Schedule 2), the change in the monthly fixed charge for this last step is below the OEB's threshold of $4. Also, the total bill impacts for a Residential or CSMUR customer consuming energy at the 10th percentile level, as demonstrated in the Bill Impact tables in Exhibit 8, Tab 6, Schedule 1, are below the 10 percent threshold. Therefore, mitigation for the final step is not required.[1]

2.4 Monthly Fixed Charge

As required by the OEB's filing requirements, Table 2 below summarizes the 2019 expected[2] and the 2020 proposed monthly fixed charge with the floor and ceiling values, as calculated via the Cost Allocation Model, for each customer class.

[1] The 10th percentile consumption levels were determined based on a sample of customers from both the Residential (5,684 customers in sample) and CSMUR classes (3,031 customers in sample). Based on weather normalized 2016 billing data, theses samples were also used to determine the updated load profiles for the Cost Allocation study.
[2] Expected to be filed in Toronto Hydro's 2019 rate application, which is the fifth year of the current CIR period.

Table 2: Monthly Fixed Charge ($)[3]

	Residential	CSMUR	GS<50 kW	GS 50-999 kW	GS 1000-4999 kW	Large Use	Street Lighting	USL
CA Model Floor	5.11	2.68	12.91	28.99	17.18	-153.65	0.15	7.37
CA Model Ceiling	18.85	12.31	32.14	62.08	136.78	-27.77	5.06	13.40
Expected (2019)	37.98	30.98	36.28	52.17	996.61	4,399.14	1.63	7.23
Proposed (2020)	42.14	33.40	37.07	52.17	940.29	4,128.03	1.66	7.38

Note 1: Proposed 2020 rates are shown on a 30 day basis. Floor, ceiling, and 2019 expected rates are not adjusted for 30 day basis, and come directly from Cost Allocation model in Exhibit 7, Tab 1, Schedule 3.

For the Residential and CSMUR classes, the proposed fixed rate is the result of the OEB EB-2012-0410 policy for fully fixed distribution rates for these classes.

2.5 Transformer Allowance

Toronto Hydro is not proposing to change its current transformer allowance credit in this application. The rate provided to customers that own their own transformation facilities will remain at $0.62/kVA per 30 days.

2.6 Billing Determinants

Toronto Hydro is not proposing any changes to the currently approved billing determinants for any customer class. Customers will continue to be billed on a 30-day fixed portion and on a kVA or kWh variable portion. For the Unmetered Scattered Load

[3] *Supra* note 1.

class, customers will continue to be charged a monthly service charge, a per-connection charge and a variable charge based on kWh. As noted previously, 2020 is the final year of the transition to fully fixed distribution rates for the Residential and CSMUR classes.

2.7 Standby Rates

Toronto Hydro is proposing to continue the historical treatment of standby rates.

In RP-2005-0020, Toronto Hydro received approval from the OEB, on an interim basis, for Standby rates to be applied to generation customers. The approved rates consist of a monthly administration charge, a fixed monthly charge and a variable standby facility rate that matches both the fixed and variable rates for the applicable rate class for each customer (i.e. a customer with a nameplate generation rating of 2000 kW would be assessed the same fixed and variable rates as any other customer in that same class). For those months that a generator takes standby power from the utility in excess of the contract amount, the variable standby facility rate is applied to the contracted standby demand.

3. 2021-2024 PRICE CAP INDEX

Continuing from the OEB's EB-2014-0116 decision, Toronto Hydro is proposing a rate framework for the 2021-2024 period which adjusts rates based on a CPCI. The CPCI incorporates components to reflect inflation, productivity and the significant capital needs of the utility. A detailed explanation of this mechanism is provided in Exhibit 1B, Tab 4, and Schedule 1.

In this evidence, Toronto Hydro presents proposed base distribution rates for 2021-2024 based on projections for the various components of the CPCI. As noted in Exhibit 1B,

Tab 4, Schedule 1, Toronto Hydro plans to update the inflation factor of the mechanism annually, prior to the beginning of each rate year. For the final determination of base distribution rates the utility will submit an annual rate update application to the OEB that incorporates the latest inflation value. For the purposes of this application and the indicative bill impacts, Toronto Hydro applied a 1.2 percent inflation variable, which is the OEB's current inflation value

4. OTHER RATES AND CHARGES

4.1 Retail Transmission Service Rates ("RTSRs")

Toronto Hydro's proposed RTSRs for 2020 are calculated using the OEB's RTSR model, and filed as Exhibit 8, Tab 5, Schedule 1 (and as a live MS Excel model). The proposed 2020 rates in the model reflect the projected 2020 billing units, applied to the current Uniform Transmission Rates ("UTRs"). Toronto Hydro will update the calculated rates prior to 2020 rate implementation based on OEB approved UTR's at that time.

In order to meet Toronto Hydro's requirements for the calculation of RTSR rates, Toronto Hydro made the following changes to the OEB's RTSR model:

- Headers have been updated to display "2020 RTSR Workform for Electricity Distributors"
- The "Year" columns in Sheet 5 UTRs and Sub-Transmission were changed to reflect 2018, 2019, and 2020 years.
- On Sheet 5 RTSR Rates to Forecast, the Proposed RTSR rates are calculated to 5 decimal places for kWh based rates, and 4 decimal places for kW based rates. The kW based rates are also adjusted for 30-days of service.

Since the UTRs are updated annually, Toronto Hydro proposes to file updated RTSR models and calculated rates over the 2021-24 period, as part of the annual rate update application under the CPCI proposal.

4.2 Retail Service Charges

Toronto Hydro is not proposing any changes to the current Retail Service Charges.

4.3 Wholesale Market Service Rate ("WMS"), Capacity Based Recovery ("CBR"), and Rural and Remote Rate Protection ("RRRP")

This application reflects a WMS rate of $0.0032/kWh, a CBR rate of $0.0004/kWh and a RRRP rate of $0.0003/kWh which are the latest rates approved by the OEB. If these rates are changed by the OEB during the 2020-24 period, Toronto Hydro will update these rates accordingly.

4.4 Smart Metering Charge

On March 1, 2018, the OEB issued a letter to LDC's establishing a Smart Metering Charge of $0.57 per month for Residential and GS< 50 kW customers effective January 1, 2018 until Dec 31, 2022.

Toronto Hydro implemented this charge (adjusted to $0.56 to reflect the utility's fixed charges on a 30-day basis), and has included this charge in its proposed rates for the effective period.

4.5 Specific Service Charges

Toronto Hydro has proposed an update to the Specific Service charge for Wireline attachments for 2020, in accordance with the OEB's EB-2015-0304 Report dated March 22, 2018. Details of the updated charge are provided in Exhibit 8, Tab 2, Schedule 1.

4.6 Loss Adjustment Factors

In its EB-2014-0116 decision, the Board indicated its expectation that loss factors for Toronto Hydro would be updated at its next full Cost of Service or Custom IR filing.[4]

Toronto Hydro engaged Navigant to undertake an engineering study to estimate losses for its Large User (> 5000 kW) class. The existing Large User class loss factors were based on estimates made in 1999 using data from 24 Large User customers at the time. For the updated study, Navigant used a recent full year of load data for all 44 Large User customers. Navigant took into account Large User customers served by feeders that were dedicated, as well as feeders that were serving other customers and customer groups. Navigant's modelling determined primary losses (i.e. excluding transformation). Most Large User customers of Toronto Hydro are primary metered.

Based on Navigant's analysis, line losses for the Large User class at the primary level is estimated as 0.0025 percent, or a loss factor of 1.0025. The Distribution Loss Factor, including transformation, is 1.0126, which is the loss factor at the primary level (1.0025) divided by the Primary Metering Adjustment (0.99). The full Navigant study is filed at Exhibit 8, Tab 4, Schedule 2. Toronto Hydro proposes to use these estimated Large User loss factors for billing Large User customers beginning in 2020.

[4] EB-2014-0116 Decision, page 46

Loss factors for the remaining rate classes are estimated using the applicable format set out in OEB filing schedules, Appendix 2-R, filed as Exhibit 8, Tab 4, Schedule 1. The loss factor for the non-Large User classes is estimated based on five years of purchases (including embedded generation) and consumption, and results in a reduction from the current OEB approved total loss factor of 1.0376 to 1.0295. Toronto Hydro proposes to use this five-year average of the non-Large User loss factor for billing customers beginning in 2020.

A summary of the current and proposed loss factors is shown in the following table.

Table 3: Loss Factors

	Current Approved	2020 Proposed
(A) Primary Metering Adjustment	0.9900	0.9900
(B) Supply Facilities Loss Factor	1.0045	1.0045
Distribution Loss Factors		
(C) Customer Less than 5,000kW	1.0330	1.0249
(D) Customer Greater than 5,000kW	1.0141	1.0126
Total Loss Factors		
Secondary Metered Customers		
(E) Customer Less than 5,000kW (B*C)	1.0376	1.0295
(F) Customer Greater than 5,000kW (B*D)	1.0187	1.0172
Primary Metered Customers		
(G) Customer Less than 5,000kW (A*E)	1.0272	1.0192
(H) Customer Greater than 5,000kW (A*F)	1.0085	1.0070

Toronto Hydro is not an embedded distributor, and proposes to maintain the Supply Facilities Loss Factor and Primary Metering Adjustment at the current approved levels of 1.0045 and 0.99 respectively.

4.7 Rate Riders

Rate riders for the proposed clearance of a number of DVAs are described in detail in Exhibit 9, Tab 1, Schedule 1. In this application, Toronto Hydro also seeks approval to clear to customers amounts related to sale of property, Accounts Receivable ("AR") Credits, and funds collected related to excess expansion deposits.

Details related to excess expansion deposits can be found in Exhibit 9, Tab 1, Schedule 1.

Toronto Hydro seeks approval to clear amounts related to the sale of property at 50/60 Eglinton Avenue. During 2017, Toronto Hydro realized a net after-tax gain of $8.0M in connection with the sale of this surplus property. In the OEB's Decision EB-2014-0116, the OEB approved a rate rider to clear the forecasted net gains on the sale of properties related to the Operating Centers Consolidation Program ("OCCP") to ratepayers. The sale of 50/60 Eglinton Avenue was similar in nature. Toronto Hydro does not dispose of properties on a frequent basis, and thus proposes this treatment of the gains, rather than through inclusion in Revenue Offsets.

With respect to AR Credits, Toronto Hydro has identified a number of historical credits in its AR balance. These credits would have arisen when customer accounts with a remaining final credit balance did not receive a final refund cheque. The balance consists of a large number of small credits stemming from 1997-2011, totaling $3.2 million. Toronto Hydro is seeking approval to clear these amounts, plus carrying charges, to all customers in the classes these credits are derived from, as it is not cost-efficient to locate these historical customers. Toronto Hydro has since implemented a number of changes to ensure that all reasonable efforts are made to return a final refund cheque to customers directly.

5. TARIFF OF RATES AND CHARGES

Exhibit 8, Tab 3, Schedules 1 and 2, show the 2018 existing, and 2020-2024 proposed tariff of rates and charges.

5.1 Revenue Reconciliation

Tab 13 of the Revenue Requirement Workform, filed at Exhibit 6, Tab 1, Schedule 2, shows the difference between revenue at the proposed rates and allocated revenue requirements by customer class.

5.2 Bill Impacts

Details of the impacts of the proposed rates are provided in Exhibit 8, Tab 6, Schedule 1. The schedules show the individual and combined impacts of the distribution component, rate riders, other components (e.g. transmission and network charges), and total bill, calculated for representative levels of consumption for each rate class.

5.3 Rate Mitigation

As shown in the Bill Impacts, the impacts on the total bill for all classes of the proposed distribution and transmission rates for 2020-24 are less than 10 percent. As discussed in detail elsewhere in this application (e.g. Exhibit 2B; Exhibit 1B, Tab 2, Schedule 1; and Exhibit 4A, Tab 1, Schedule 1), Toronto Hydro has incorporated consideration of rate impacts as part of its proposed capital and OM&A funding requests.

				2019 Rates (For Revenue Requirement Aloocation by Rate Class)			Calculated Revenue for Allocation between Fixed and Variable: 2020 Consumption determinants x Rates for 2019				Allocation between Fixed and Variable %		
	2020 Forecast Customer count	2020 Forecast kWh	2020 Forecast kVA	Distribution Rate kWh	Distribution Rate kVA without Days of Service	Mthly Service Chrg - without Days of Service (Per Cust./ Connection/ Device)	Volumetric kWh ($)	Volumetric kVA ($)	Monthly Fixed Charges ($)	Total ($)	Volumetric as percent of Total for customer class	Fixed charges as percent of total for customer class	
				$	$	$							
Residential	615,965	4,510,636,914		0.00552		37.98	24,898,716		280,732,208	**305,630,924**	8.15%	91.85%	**100.00%**
Competitive Sector Multi-Unit Residential	85,161	277,127,203		0.00845		30.98	2,341,725		31,659,453	**34,001,178**	6.89%	93.11%	**100.00%**
GS < 50 kW	71,499	2,267,638,936		0.0331		36.28	75,058,849		31,127,805	**106,186,653**	70.69%	29.31%	**100.00%**
GS - 50 to 999 kW	10,374	9,587,728,582	24,899,249		8.2114	52.17		204,457,692	6,494,539	**210,952,231**	96.92%	3.08%	**100.00%**
GS - 1000 to 4999 kW	430	4,561,528,177	10,392,864		6.4602	996.61		67,139,983	5,142,508	**72,282,491**	92.89%	7.11%	**100.00%**
Large Use (> 5000 kW)	44	2,009,923,443	4,789,334		6.9303	4399.14		33,191,522	2,322,746	**35,514,268**	93.46%	6.54%	**100.00%**
Street Lighting	165,348	115,390,403	326,622		36.2449	1.63		11,838,382	3,234,207	**15,072,589**	78.54%	21.46%	**100.00%**
Unmetered Scattered Load - Admin per Customer	857	41,313,479		0.08964		7.23	3,703,340		74,353	**3,777,694**	95.26%	1.91%	**97.18%**
Unmetered Scattered Load - Connections	12,196	0				0.75			109,764	**109,764**	0.00%	2.82%	**2.82%**
TOTALS	961,874	23,371,287,137	40,408,069				106,002,630	316,627,579	360,897,583	**783,527,792**	53.94%	46.06%	**100.00%**
				1.013888889									

SPECIFIC SERVICE CHARGES

Toronto Hydro charges user fees for certain non-distribution services.[1] Some of these services, such as duplicate invoices, are provided at customers' request. Others result from Toronto Hydro's business operations, such as collection fees resulting from customers' non-payment of bills.

Toronto Hydro last updated its Specific Service Charges in EB-2014-0116. For this application, Toronto Hydro proposes to leave these rates unchanged, with the exception of the Wireline Pole attachment rate. A summary of the proposed Specific Service Charges is shown in Table 1. Historic and forecast revenues from these service charges, and their inclusion as Other Revenue, are further described in Exhibit 3, Tab 2.

Table 1: Updated Specific Service Charges 2020-2024

Specific Service Charge	Existing Rates ($)	Proposed Rates ($)	Existing Versus Proposed Variance ($)
Duplicate invoices for previous billing	25.00	25.00	$0
Request for other billing or system information	25.00	25.00	$0
Easement letter	25.00	25.00	$0
Income tax letter	25.00	25.00	$0
Account history	25.00	25.00	$0
Returned cheque charge (plus bank charges)	25.00	25.00	$0
Account set up charge/change of occupancy charge	35.00	35.00	$0
Special meter reads	55.00	55.00	$0
Collection of account charge - no disconnection	55.00	55.00	$0
Disconnect/Reconnect at meter -during regular hours	120.00	120.00	$0
Install/Remove load control device - during regular hours	120.00	120.00	$0
Disconnect/Reconnect at meter -after regular hours	400.00	400.00	$0

[1] In accordance with the Distribution Rate Handbook ("DRH"), all other services provided to customers are billed on an actual-cost basis.

Specific Service Charge	Existing Rates ($)	Proposed Rates ($)	Existing Versus Proposed Variance ($)
Install/Remove load control device - after regular hours	400.00	400.00	$0
Disconnect/Reconnect at pole - during regular hours	300.00	300.00	$0
Disconnect/Reconnect at pole - after regular hours	820.00	820.00	$0
Meter dispute charge plus Measurement Canada fees	55.00	55.00	$0
Service call - customer owned equipment	55.00	Remove	Not Applicable
Temporary service install & remove – overhead - no transformer	2,040.00	2,040.00	$0
Specific Charge for Access to Power Poles (Wireline Attachments) ($/pole/year)	42.00	44.15	$2.15

1. REMOVAL OF SELECT APPROVED SPECIFIC SERVICE CHARGES

1.1 Service Call - Customer-Owned Equipment

Toronto Hydro requests to remove the "Service Call – Customer-Owned Equipment" charge from its Schedule of Rates and Charges. The charge, "Service Call – Customer Owned Equipment or Missed Appointments", was initially requested as part of Toronto Hydro's 2015 CIR application to recover the costs of missed appointments as well as basic level service calls related to customer owned equipment. In its Decision, however, the OEB did not approve the "Missed Appointments" component of the charge, leaving only the "Service Call – Customer Owned Equipment" charge component in effect. Toronto Hydro believes the scope of work that could be perceived to fall under this charge description is too broad with a high degree of cost variation. As such, it proposes to recover the costs associated with these services through a demand billable charge structure.

2. SPECIFIC SERVICE CHARGES – RATE UPDATES

2.1 Specific Charge for Access to Power Poles (Wireline Attachments) ($/Pole/Year)

Toronto Hydro currently charges telecommunication companies for any wireline attachments placed on its poles at a rate of $42[2] per pole per year, a rate that was set specific to Toronto Hydro as part its 2015 CIR application. In its EB-2015-0304 report on Wireline Pole Attachment Charges ("Wireline Report") issued March 22, 2018, the OEB outlined an updated policy for the wireline pole attachment rates to be charged by all Local Distribution Companies ("LDCs") for attachments by telecommunication and cable companies (carriers) to distribution poles, setting a standard province-wide rate of $43.63 per attacher per pole per year for 2019.

In accordance with the Wireline Report, Toronto Hydro proposes to update its wireline pole attachment charge to $44.15 per pole per year effective January 1, 2020. This rate is calculated based on the standard rate of $43.63 for 2019 and the application of 1.2 percent escalation (the OEB's current inflation rate) for 2020. Toronto Hydro proposes that this rate be updated once the final OEB inflation factor for 2020 is determined. In adopting the standard province-wide rate, Toronto Hydro has not filed the OEB's Pole Attachment Workform. /C /C /C

3. OTHER RATES AND CHARGES

In accordance with section 2.8.6 of the OEB Filing Requirements (July 12, 2018), Toronto Hydro has identified certain charges that appear in its Conditions of Service but are excluded from the current OEB-approved tariff sheet. These include the following Basic

[2] Per July 23, 2015 OEB Decision on Toronto Hydro's Settlement Proposal (EB-2014-0116).

Connection Charges for unmetered customers that are not included in distribution rates[3]:

1) Unmetered Connections – Overhead Supply (excludes Street Lighting):
    a) $446 standard allowance plus variable costs - source connection made at the Distributor's supply pole and service mast located on same supply pole; and
    b) $1,011 standard allowance plus variable costs - source connection made at the Distributor's supply pole and service mast is not located on same supply pole.
2) New or Upgraded Street Lighting Services:
    a) $533.36 standard allowance plus variable costs - Municipal Lights attached to Distributor's poles and connected to Distributor's overhead 120/240 V secondary bus;
    b) $573.97 standard allowance plus variable costs - Municipal Lights attached to Distributor's poles in mixed used urban setting and connected to Distributors underground 120/240 V secondary bus; and
    c) $573.97 standard allowance plus variable costs - Municipal Lights attached to Municipality's poles in residential setting and connected to Distributor's underground 120/240 V secondary bus.

These charges were developed to recover the actual cost of labour, materials, equipment and contracts Toronto Hydro incurs to provide the basic connection service for these specific customer groups on an as requested basis.[4] They are comprised of a

[3] Please refer to Toronto Hydro's Conditions of Service effective January 1, 2018, Tables 2 and 3, pages 101 and 102, respectively for the Basic Connection Charges. These charges are billed directly to the customer.
[4] Basic Connection Charges for unmetered connections are defined in Toronto Hydro's Conditions of Service, Sections 3.8. Cost includes installation and commissioning of single transformer and the associated service drop up to 30 metres in length.

base amount and variable portion (for any costs beyond the base amount), both of which are billed directly. These charges are recovered as capital contributions. Consistent with other similar charges that are recovered through capital contributions, they are not recorded as a Specific Service Charge in Toronto Hydro's OEB-approved tariff sheet. Amounts collected over the 2015-2017 period are shown in the table below. Forecast amounts are not available, as the work is done on a customer request basis.

Table 2: Service Connection Capital Contributions ($)

	2015	2016	2017
Service Connection Contributions	56,880	72,044	35,264

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2018

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2017-0077

RESIDENTIAL SERVICE CLASSIFICATION

This classification is applicable to an account where electricity is used exclusively for residential purposes in a separately metered living accommodation, where the Competitive Sector Multi-Unit Residential classification is not applicable. Eligibility is restricted to a dwelling unit that consists of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex building, with a residential zoning; a separately metered dwelling within a town house complex or apartment building; and bulk metered residential buildings with six or fewer units. Class B consumers are defined in accordance with O. Reg. 429/04. Further details concerning the terms of service are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	32.63	(per 30 days)
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.78	(per 30 days)
Rate Rider for Recovery of Stranded Meter Assets - effective until December 31, 2019	$	0.28	(per 30 days)
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until December 31, 2018	$	(0.48)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until December 31, 2018	$	(1.48)	(per 30 days)
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until December 31, 2019	$	0.10	(per 30 days)
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until December 31, 2019	$	0.03	(per 30 days)
Rate Rider for Application of IFRS - 2014 Derecognition - effective until December 31, 2019	$	0.46	(per 30 days)
Rate Rider for Recovery of 2015 Foregone Revenue - effective until December 31, 2019	$	0.88	(per 30 days)
Rate Rider for Recovery of 2016 Foregone Revenue - effective until December 31, 2019	$	0.28	(per 30 days)
Distribution Volumetric Rate	$/kWh	0.01063	
Rate Rider for Disposition of Global Adjustment Account (2018) - effective until December 31, 2018 (Applicable only for Non-RPP Customers)	$/kWh	(0.00112)	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until December 31, 2018	$/kWh	0.00041	
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until December 31, 2018	$/kWh	(0.00320)	
Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until December 31, 2018 Applicable only for Class B Customers	$/kWh	0.00007	

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2018

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2017-0077

Retail Transmission Rate - Network Service Rate	$/kWh	0.00759	
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.00617	

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2018

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2017-0077

COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICATION

This classification is applicable to an account where electricity is used exclusively for residential purposes in a multi- unit residential building, where unit metering is provided using technology that is substantially similar to that employed by competitive sector sub-metering providers. Use of electricity in non-residential units of multi-unit buildings does not qualify for this classification and will instead be subject to the applicable commercial classification. Class B consumers are defined in accordance with O. Reg. 429/04. Further details concerning the terms of service are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	26.80	(per 30 days)
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.78	(per 30 days)
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until December 31, 2018	$	(0.19)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until December 31, 2018	$	(0.59)	(per 30 days)
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until December 31, 2019	$	0.04	(per 30 days)
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until December 31, 2019	$	0.01	(per 30 days)
Rate Rider for Application of IFRS - 2014 Derecognition - effective until December 31, 2019	$	0.18	(per 30 days)
Rate Rider for Recovery of 2015 Foregone Revenue - effective until December 31, 2019	$	0.19	(per 30 days)
Rate Rider for Recovery of 2016 Foregone Revenue - effective until December 31, 2019	$	0.09	(per 30 days)
Distribution Volumetric Rate	$/kWh	0.01627	
Rate Rider for Disposition of Global Adjustment Account (2018) - effective until December 31, 2018 (Applicable only for Non-RPP Customers)	$/kWh	(0.00112)	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until December 31, 2018	$/kWh	0.00068	
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until December 31, 2018	$/kWh	(0.00392)	
Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until December 31, 2018 (Applicable only for Class B Customers)	$/kWh	0.00007	
Retail Transmission Rate - Network Service Rate	$/kWh	0.00759	

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2018

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2017-0077

Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.00617	

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2018

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2017-0077

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is less than, or is forecast to be less than 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	34.45	(per 30 days)
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.78	(per 30 days)
Rate Rider for Recovery of Stranded Meter Assets - effective until December 31, 2019	$	1.55	(per 30 days)
Rate Rider for Recovery of 2015 Foregone Revenue - effective until December 31, 2019	$	0.79	(per 30 days)
Rate Rider for Recovery of 2016 Foregone Revenue - effective until December 31, 2019	$	0.25	(per 30 days)
Distribution Volumetric Rate	$/kWh	0.03187	
Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until December 31, 2018 (Applicable only for Class B Customers)	$/kWh	0.00007	
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until December 31, 2018	$/kWh	(0.00051)	
Rate Rider for Disposition of Global Adjustment Account (2018) - effective until December 31, 2018 (Applicable only for Non-RPP Customers)	$/kWh	(0.00112)	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until December 31, 2018	$/kWh	(0.00019)	
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until December 31, 2018	$/kWh	(0.00317)	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until December 31, 2018	$/kWh	(0.00156)	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until December 31, 2019	$/kWh	0.00013	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until December 31, 2019	$/kWh	0.00003	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until December 31, 2019	$/kWh	0.00049	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until December 31, 2019	$/kWh	0.00076	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until December 31, 2019	$/kWh	0.00024	
Retail Transmission Rate - Network Service Rate	$/kWh	0.00739	
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.00552	

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2018

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2017-0077

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2018

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2017-0077

GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than 50 kW but less than 1,000 kW, or is forecast to be equal to or greater than 50 kW but less than 1,000 kW. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

The rate rider for the disposition of Post 2011 Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	49.55	(per 30 days)
Rate Rider for Recovery of Stranded Meter Assets - effective until December 31, 2019	$	4.64	(per 30 days)
Rate Rider for Recovery of 2015 Foregone Revenue - effective until December 31, 2019	$	1.01	(per 30 days)
Rate Rider for Recovery of 2016 Foregone Revenue - effective until December 31, 2019	$	0.30	(per 30 days)
Distribution Volumetric Rate	$/kVA	7.7987	(per 30 days)
Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until December 31, 2018 (Applicable only for Class B Customers)	$/kVA	0.0277	(per 30 days)
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until December 31, 2018	$/kVA	(0.0814)	(per 30 days)
Rate Rider for Disposition of Global Adjustment Account (2018) - effective until December 31, 2018 (Applicable only for Non-RPP Customers)	$/kWh	(0.00112)	

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2018

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2017-0077

Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until December 31, 2018	$/kVA	0.0912	(per 30 days)
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until December 31, 2018 (Applicable only for Non-Wholesale Market Participants)	$/kVA	(0.5191)	(per 30 days)
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until December 31, 2018	$/kVA	(0.7597)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until December 31, 2018	$/kVA	(0.2512)	(per 30 days)
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until December 31, 2019	$/kVA	0.0114	(per 30 days)
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until December 31, 2019	$/kVA	0.0047	(per 30 days)
Rate Rider for Application of IFRS - 2014 Derecognition - effective until December 31, 2019	$/kVA	0.0781	(per 30 days)
Rate Rider for Recovery of 2015 Foregone Revenue - effective until December 31, 2019	$/kVA	0.1659	(per 30 days)
Rate Rider for Recovery of 2016 Foregone Revenue - effective until December 31, 2019	$/kVA	0.0498	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kW	2.5690	(per 30 days)
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.0515	(per 30 days)

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2018

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2017-0077

GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than 1,000 kW but less than 5,000 kW, or is forecast to be equal to or greater than 1,000 kW but less than 5,000 kW. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

The rate rider for the disposition of Post 2011 Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	946.52	(per 30 days)
Rate Rider for Recovery of 2015 Foregone Revenue - effective until December 31, 2019	$	18.89	(per 30 days)
Rate Rider for Recovery of 2016 Foregone Revenue - effective until December 31, 2019	$	5.48	(per 30 days)
Distribution Volumetric Rate	$/kVA	6.1355	(per 30 days)
Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until December 31, 2018 (Applicable only for Class B Customers)	$/kVA	0.0295	(per 30 days)
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until December 31, 2018	$/kVA	(0.0653)	(per 30 days)
Rate Rider for Disposition of Global Adjustment Account (2018) - effective until December 31, 2018 (Applicable only for Non-RPP Customers)	$/kWh	(0.00112)	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until December 31, 2018	$/kVA	0.1051	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2018

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2017-0077

Rate Rider for Disposition of Deferral/Variance Accounts (2018)			
- effective until December 31, 2018 (pplicable only for Non-Wholesale Market Participants)	$/kVA	(0.5704)	(per 30 days)
Rate Rider for Disposition of Deferral/Variance Accounts (2018)			
- effective until December 31, 2018	$/kVA	(0.8339)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing			
- effective until December 31, 2018	$/kVA	(0.2017)	(per 30 days)
Rate Rider for Recovery of the Gain on the Sale of Named Properties			
- effective until December 31, 2019	$/kVA	0.0056	(per 30 days)
Rate Rider for Recovery of Hydro One Capital Contributions Variance			
- effective until December 31, 2019	$/kVA	0.0038	(per 30 days)
Rate Rider for Application of IFRS - 2014 Derecognition - effective until December 31, 2019	$/kVA	0.0627	(per 30 days)
Rate Rider for Recovery of 2015 Foregone Revenue - effective until December 31, 2019	$/kVA	0.1226	(per 30 days)
Rate Rider for Recovery of 2016 Foregone Revenue - effective until December 31, 2019	$/kVA	0.0356	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kW	2.4821	(per 30 days)
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.0494	(per 30 days)

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2018

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2017-0077

LARGE USE SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

The rate rider for the disposition of Post 2011 Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	4,178.03	(per 30 days)
Rate Rider for Recovery of 2015 Foregone Revenue - effective until December 31, 2019	$	85.84	(per 30 days)
Rate Rider for Recovery of 2016 Foregone Revenue - effective until December 31, 2019	$	25.18	(per 30 days)
Distribution Volumetric Rate	$/kVA	6.5820	(per 30 days)
Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until December 31, 2018 (Applicable only for Class B Customers)	$/kVA	0.0032	(per 30 days)
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until December 31, 2018	$/kVA	(0.0675)	(per 30 days)
Rate Rider for Disposition of Global Adjustment Account (2018) - effective until December 31, 2018 (Applicable only for Non-RPP Customers)	$/kWh	(0.00112)	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until December 31, 2018	$/kVA	0.2763	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2018

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2017-0077

Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until December 31, 2018 (Applicable only for Non-Wholesale Market Participants)	$/kVA	(0.5945)	(per 30 days)
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until December 31, 2018	$/kVA	(0.8782)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until December 31, 2018	$/kVA	(0.2084)	(per 30 days)
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until December 31, 2019	$/kVA	0.0044	(per 30 days)
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until December 31, 2019	$/kVA	0.0039	(per 30 days)
Rate Rider for Application of IFRS - 2014 Derecognition - effective until December 31, 2019	$/kVA	0.0648	(per 30 days)
Rate Rider for Recovery of 2015 Foregone Revenue - effective until December 31, 2019	$/kVA	0.1382	(per 30 days)
Rate Rider for Recovery of 2016 Foregone Revenue - effective until December 31, 2019	$/kVA	0.0406	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kW	2.8295	(per 30 days)
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.2769	(per 30 days)

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2018

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2017-0077

STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation and requires THESL to provide back- up service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component - APPROVED ON AN INTERIM BASIS

Standby Charge - for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of generation facility).

Service Charge	$	237.17	(per 30 days)
Distribution Volumetric Rate			
For General Service 50 - 999 kW Service Classification	$/kVA	7.7987	(per 30 days)
For General Service 1,000 - 4,999 kW Service Classification	$/kVA	6.1355	(per 30 days)
For Large Use Service Classification	$/kVA	6.5820	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2018

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2017-0077

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand at each location is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by THESL and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	6.87	(per 30 days)
Connection Charge (per connection)	$	0.71	(per 30 days)
Rate Rider for Recovery of 2015 Foregone Revenue - effective until December 31, 2019	$	0.16	(per 30 days)
Rate Rider for Recovery of 2015 Foregone Revenue (per connection) - effective until December 31, 2019	$	0.02	(per 30 days)
Rate Rider for Recovery of 2016 Foregone Revenue - effective until December 31, 2019	$	0.05	(per 30 days)
Rate Rider for Recovery of 2016 Foregone Revenue (per connection) - effective until December 31, 2019	$	0.01	(per 30 days)
Distribution Volumetric Rate	$/kWh	0.08632	
Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until December 31, 2018 (Applicable only for Class B Customers)	$/kWh	0.00007	
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until December 31, 2018	$/kWh	(0.00096)	
Rate Rider for Disposition of Global Adjustment Account (2018) - effective until December 31, 2018 (Applicable only for Non-RPP Customers)	$/kWh	(0.00112)	
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until December 31, 2018	$/kWh	(0.00316)	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until December 31, 2018	$/kWh	(0.00296)	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until December 31, 2019	$/kWh	0.00029	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until December 31, 2019	$/kWh	0.00006	

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2018

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2017-0077

Rate Rider for Application of IFRS - 2014 Derecognition - effective until December 31, 2019	$/kWh	0.00092	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until December 31, 2019	$/kWh	0.00203	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until December 31, 2019	$/kWh	0.00062	
Retail Transmission Rate - Network Service Rate	$/kWh	0.00460	
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.00390	

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2018

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2017-0077

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per device)	$	1.55	(per 30 days)
Distribution Volumetric Rate	$/kVA	34.4231	(per 30 days)
Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until December 31, 2018 (Applicable only for Class B Customers)	$/kVA	0.0236	(per 30 days)
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until December 31, 2018	$/kVA	(0.5347)	(per 30 days)
Rate Rider for Disposition of Global Adjustment Account (2018) - effective until December 31, 2018 (Applicable only for Non-RPP Customers)	$/kWh	(0.00112)	
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until December 31, 2018	$/kVA	(1.0860)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until December 31, 2018	$/kVA	(1.6506)	(per 30 days)
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until December 31, 2019	$/kVA	0.0741	(per 30 days)
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until December 31, 2019	$/kVA	0.0312	(per 30 days)
Rate Rider for Application of IFRS - 2014 Derecognition - effective until December 31, 2019	$/kVA	0.5133	(per 30 days)
Rate Rider for Recovery of 2016 Foregone Revenue - effective until December 31, 2019	$/kVA	0.0478	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kW	2.2849	(per 30 days)
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.4461	(per 30 days)

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2018

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2017-0077

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.33	(per 30 days)

ALLOWANCES

Transformer Allowance for Ownership	$/kVA	(0.62)	(per 30 days)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)	

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2018

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EB-2017-0077

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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Customer Administration		
Account history	$	25.00
Duplicate invoices for previous billing	$	25.00
Request for other billing or system information	$	25.00
Easement letter	$	25.00
Income tax letter	$	25.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	35.00
Returned cheque (plus bank charges)	$	25.00
Special meter reads	$	55.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	55.00
Non-Payment of Account		
Late payment - per month	%	1.50
Late payment - per annum	%	19.56
Collection of account charge - no disconnection	$	55.00
Disconnect/reconnect at meter - during regular hours	$	120.00
Disconnect/reconnect at meter - after regular hours	$	400.00
Disconnect/reconnect at pole - during regular hours	$	300.00
Disconnect/reconnect at pole - after regular hours	$	820.00
Install/remove load control device - during regular hours	$	120.00
Install/remove load control device - after regular hours	$	400.00
Other		
Service call - customer owned equipment	$	55.00
Disconnect/reconnect at meter - during regular hours	$	120.00
Disconnect/reconnect at meter - after regular hours	$	400.00
Disconnect/reconnect at pole - during regular hours	$	300.00
Disconnect/reconnect at pole - after regular hours	$	820.00
Temporary service install & remove - overhead - no transformer	$	2,040.00
Specific charge for access to the power poles (wireline attachments) - per pole/year	$	42.00

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2018

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2017-0077

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

Retail Service Charges refer to services provided by THESL to retailers or customers related to the supply of competitive electricity and are defined in the 2006 Electricity Distribution Rate Handbook.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0376
Total Loss Factor - Secondary Metered Customer > 5,000 kW	1.0187
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0272
Total Loss Factor - Primary Metered Customer > 5,000 kW	1.0085

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2020

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

RESIDENTIAL SERVICE CLASSIFICATION

This classification is applicable to an account where electricity is used exclusively for residential purposes in a separately metered living accommodation, where the Competitive Sector Multi-Unit Residential classification is not applicable. Eligibility is restricted to a dwelling unit that consists of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex building, with a residential zoning; a separately metered dwelling within a town house complex or apartment building; and bulk metered residential buildings with six or fewer units. Class B consumers are defined in accordance with O. Reg. 429/04. Further details concerning the terms of service are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	42.14	(per 30 days)
Rate Rider for Smart Metering Entity Charge - effective until December 31, 2022	$	0.56	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$	0.09	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$	0.90	(per 30 days)
Rate Rider for Recovery of Monthly Billing - effective until December 31, 2024	$	0.28	(per 30 days)
Rate Rider for Recovery of Stranded Meter Assets - effective until December 31, 2024	$	(0.02)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$	(0.75)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until December 31, 2024	$	(0.12)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$	(0.01)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$	(0.02)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$	(0.63)	(per 30 days)
Rate Rider for Disposition of External Driven Capital - effective until December 31, 2024	$	(0.02)	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$	(0.45)	(per 30 days)
Rate Rider for Disposition of AR Credits - effective until December 31, 2024	$	(0.08)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kWh	0.00825	
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.00679	

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2020

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICATION

This classification is applicable to an account where electricity is used exclusively for residential purposes in a multi- unit residential building, where unit metering is provided using technology that is substantially similar to that employed by competitive sector sub-metering providers. Use of electricity in non-residential units of multi-unit buildings does not qualify for this classification and will instead be subject to the applicable commercial classification. Class B consumers are defined in accordance with O. Reg. 429/04. Further details concerning the terms of service are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	33.40	(per 30 days)
Rate Rider for Smart Metering Entity Charge - effective until December 31, 2022	$	0.56	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$	0.06	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$	0.61	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$	(0.51)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until December 31, 2024	$	(0.08)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$	(0.01)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$	(0.43)	(per 30 days)
Rate Rider for Disposition of External Driven Capital - effective until December 31, 2024	$	(0.02)	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$	(0.30)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kWh	0.00825	
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.00679	

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2020

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is less than, or is forecast to be less than 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	37.07	(per 30 days)
Rate Rider for Smart Metering Entity Charge - effective until December 31, 2022	$	0.56	(per 30 days)
Distribution Volumetric Rate	$/kWh	0.03429	
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kWh	0.00011	
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kWh	0.00106	
Rate Rider for Recovery of Monthly Billing - effective until December 31, 2024	$/kWh	0.00010	
Rate Rider for Recovery of Stranded Meter Assets - effective until December 31, 2024	$	(0.10)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kWh	(0.00089)	
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until December 31, 2024	$/kWh	(0.00015)	
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kWh	(0.00001)	
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$/kWh	(0.00002)	
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kWh	(0.00074)	
Rate Rider for Disposition of External Driven Capital - effective until December 31, 2024	$/kWh	(0.00003)	
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kWh	(0.00053)	
Rate Rider for Disposition of AR Credits - effective until December 31, 2024	$/kWh	(0.00005)	
Retail Transmission Rate - Network Service Rate	$/kWh	0.00803	
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.00607	

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2020

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than 50 kW but less than 1,000 kW, or is forecast to be equal to or greater than 50 kW but less than 1,000 kW. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B

The rate rider for the disposition of Post 2011 Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	52.17	(per 30 days)
Distribution Volumetric Rate	$/kVA	8.3678	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kVA	0.0191	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kVA	0.1825	(per 30 days)
Rate Rider for Recovery of Stranded Meter Assets - effective until December 31, 2024	$	(0.37)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kVA	(0.1523)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Named Property - effective until December 31, 2024	$/kVA	(0.0251)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kVA	(0.0009)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$/kVA	(0.0033)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kVA	(0.1272)	(per 30 days)
Rate Rider for Disposition of External Driven Capital - effective until December 31, 2024	$/kVA	(0.0050)	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kVA	(0.0901)	(per 30 days)
Rate Rider for Disposition Excess Expansion Deposits - effective until December, 2024	$/kVA	(0.0276)	(per 30 days)
Rate Rider for Disposition of AR Credits - effective until December 31, 2024	$/kVA	(0.0004)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kW	2.7525	(per 30 days)
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.2236	(per 30 days)

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2020

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than 1,000 kW but less than 5,000 kW, or is forecast to be equal to or greater than 1,000 kW but less than 5,000 kW. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B

The rate rider for the disposition of Post 2011 Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	940.29	(per 30 days)
Distribution Volumetric Rate	$/kVA	6.6114	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kVA	0.0144	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kVA	0.1377	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31,	$/kVA	(0.1149)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Named Property - effective until December 31, 2024	$/kVA	(0.0190)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kVA	(0.0004)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$/kVA	(0.0025)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December	$/kVA	(0.0960)	(per 30 days)
Rate Rider for Disposition of External Driven Capital - effective until December 31, 2024	$/kVA	(0.0038)	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kVA	(0.0680)	(per 30 days)
Rate Rider for Disposition of Excess Expansion Deposits - effective until December, 2024	$/kVA	(0.0208)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kW	2.6594	(per 30 days)
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.2236	(per 30 days)

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2020

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

LARGE USE SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B

The rate rider for the disposition of Post 2011 Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	4,128.03	(per 30 days)
Distribution Volumetric Rate	$/kVA	7.1092	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kVA	0.0164	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kVA	0.1559	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kVA	(0.1301)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until December 31, 2024	$/kVA	(0.0215)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kVA	(0.0004)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$/kVA	(0.0028)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kVA	(0.1086)	(per 30 days)
Rate Rider for Disposition of External Driven Capital - effective until December 31, 2024	$/kVA	(0.0043)	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kVA	(0.0769)	(per 30 days)
Rate Rider for Disposition of Excess Expansion Deposits - effective until December, 2024	$/kVA	(0.0236)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kW	3.0316	(per 30 days)
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.4705	(per 30 days)

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2020

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation and requires THESL to provide back- up service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component - APPROVED ON AN INTERIM BASIS

Standby Charge - for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of generation facility).

Service Charge	$	245.00	(per 30 days)
Distribution Volumetric Rate			
For General Service 50 - 999 kW Service Classification	$/kVA	8.3678	(per 30 days)
For General Service 1,000 - 4,999 kW Service Classification	$/kVA	6.6114	(per 30 days)
For Large Use Service Classification	$/kVA	7.1092	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2020

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand at each location is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by THESL and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	7.38	(per 30 days)
Connection Charge (per connection)	$	0.77	(per 30 days)
Distribution Volumetric Rate	$/kWh	0.09273	
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kWh	0.00022	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kWh	0.00211	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kWh	(0.00176)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Named Property - effective until December 31, 2024	$/kWh	(0.00029)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kWh	(0.00002)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$/kWh	(0.00004)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kWh	(0.00147)	(per 30 days)
Rate Rider for Disposition of External Driven Capital - effective until December 31, 2024	$/kWh	(0.00006)	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kWh	(0.00104)	(per 30 days)
Rate Rider for Disposition of Excess Expansion Deposits - effective until December, 2024	$/kWh	(0.00032)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kWh	0.00500	
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.00429	

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2020

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per device)	$	1.66	(per 30 days)
Distribution Volumetric Rate	$/kVA	36.9360	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kVA	0.1071	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kVA	1.0207	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kVA	(0.8516)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Named Property - effective until December 31, 2024	$/kVA	(0.1407)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kVA	(0.0088)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$/kVA	(0.0187)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kVA	(0.7114)	(per 30 days)
Rate Rider for Disposition of External Driven Capital - effective until December 31, 2024	$/kVA	(0.0279)	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kVA	(0.5037)	(per 30 days)
Rate Rider for Disposition of Excess Expansion Deposits - effective until December, 2024	$/kVA	(0.1543)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kW	2.4481	(per 30 days)
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.6541	(per 30 days)

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2020

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.33	(per 30 days)

ALLOWANCES

Transformer Allowance for Ownership	$/kVA	(0.62)	(per 30 days)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)	

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

Customer Administration		
Account history	$	25.00
Duplicate invoices for previous billing	$	25.00
Request for other billing or system information	$	25.00
Easement letter	$	25.00
Income tax letter	$	25.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	35.00
Returned cheque (plus bank charges)	$	25.00
Special meter reads	$	55.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	55.00
Non-Payment of Account		
Late payment - per month	%	1.50
Late payment - per annum	%	19.56
Collection of account charge - no disconnection	$	55.00
Disconnect/reconnect at meter - during regular hours	$	120.00
Disconnect/reconnect at meter - after regular hours	$	400.00
Disconnect/reconnect at pole - during regular hours	$	300.00
Disconnect/reconnect at pole - after regular hours	$	820.00
Install/remove load control device - during regular hours	$	120.00
Install/remove load control device - after regular hours	$	400.00
Other		
Disconnect/reconnect at meter - during regular hours	$	120.00
Disconnect/reconnect at meter - after regular hours	$	400.00
Disconnect/reconnect at pole - during regular hours	$	300.00
Disconnect/reconnect at pole - after regular hours	$	820.00
Temporary service install & remove - overhead - no transformer	$	2,040.00
Specific charge for access to the power poles (wireline attachments) - per pole/year	$	44.15

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2020

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

Retail Service Charges refer to services provided by THESL to retailers or customers related to the supply of competitive electricity and are defined in the 2006 Electricity Distribution Rate Handbook.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0295
Total Loss Factor - Secondary Metered Customer > 5,000 kW	1.0172
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0192
Total Loss Factor - Primary Metered Customer > 5,000 kW	1.0070

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2021

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

RESIDENTIAL SERVICE CLASSIFICATION

This classification is applicable to an account where electricity is used exclusively for residential purposes in a separately metered living accommodation, where the Competitive Sector Multi-Unit Residential classification is not applicable. Eligibility is restricted to a dwelling unit that consists of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex building, with a residential zoning; a separately metered dwelling within a town house complex or apartment building; and bulk metered residential buildings with six or fewer units. Class B consumers are defined in accordance with O. Reg. 429/04. Further details concerning the terms of service are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	43.51	(per 30 days)
Rate Rider for Smart Metering Entity Charge - effective until December 31, 2022	$	0.56	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$	0.09	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$	0.90	(per 30 days)
Rate Rider for Recovery of Monthly Billing - effective until December 31, 2024	$	0.28	(per 30 days)
Rate Rider for Recovery of Stranded Meter Assets - effective until December 31, 2024	$	(0.02)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$	(0.75)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until December 31, 2024	$	(0.12)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$	(0.01)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$	(0.02)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$	(0.63)	(per 30 days)
Rate Rider for Disposition of External Driven Capital - effective until December 31, 2024	$	(0.02)	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$	(0.45)	(per 30 days)
Rate Rider for Disposition of AR Credits - effective until December 31, 2024	$	(0.08)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kWh	0.00825	
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.00679	

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2021

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICATION

This classification is applicable to an account where electricity is used exclusively for residential purposes in a multi- unit residential building, where unit metering is provided using technology that is substantially similar to that employed by competitive sector sub-metering providers. Use of electricity in non-residential units of multi-unit buildings does not qualify for this classification and will instead be subject to the applicable commercial classification. Class B consumers are defined in accordance with O. Reg. 429/04. Further details concerning the terms of service are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	34.49	(per 30 days)
Rate Rider for Smart Metering Entity Charge - effective until December 31, 2022	$	0.56	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$	0.06	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$	0.61	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$	(0.51)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until December 31, 2024	$	(0.08)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$	(0.01)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$	(0.43)	(per 30 days)
Rate Rider for Disposition of External Driven Capital - effective until December 31, 2024	$	(0.02)	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$	(0.30)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kWh	0.00825	
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.00679	

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2021

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is less than, or is forecast to be less than 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	38.28	(per 30 days)
Rate Rider for Smart Metering Entity Charge - effective until December 31, 2022	$	0.56	(per 30 days)
Distribution Volumetric Rate	$/kWh	0.03541	
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kWh	0.00011	
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kWh	0.00106	
Rate Rider for Recovery of Monthly Billing - effective until December 31, 2024	$/kWh	0.00010	
Rate Rider for Recovery of Stranded Meter Assets - effective until December 31, 2024	$	(0.10)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31,	$/kWh	(0.00089)	
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until December 31, 2024	$/kWh	(0.00015)	
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kWh	(0.00001)	
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$/kWh	(0.00002)	
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31,	$/kWh	(0.00074)	
Rate Rider for Disposition of External Driven Capital - effective until December 31, 2024	$/kWh	(0.00003)	
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kWh	(0.00053)	
Rate Rider for Disposition of AR Credits - effective until December 31, 2024	$/kWh	(0.00005)	
Retail Transmission Rate - Network Service Rate	$/kWh	0.00803	
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.00607	

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2021

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than 50 kW but less than 1,000 kW, or is forecast to be equal to or greater than 50 kW but less than 1,000 kW. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

The rate rider for the disposition of Post 2011 Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	53.87	(per 30 days)
Distribution Volumetric Rate	$/kVA	8.6406	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kVA	0.0191	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kVA	0.1825	(per 30 days)
Rate Rider for Recovery of Stranded Meter Assets - effective until December 31, 2024	$	(0.37)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kVA	(0.1523)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Named Property - effective until December 31, 2024	$/kVA	(0.0251)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kVA	(0.0009)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$/kVA	(0.0033)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kVA	(0.1272)	(per 30 days)
Rate Rider for Disposition of External Driven Capital - effective until December 31, 2024	$/kVA	(0.0050)	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kVA	(0.0901)	(per 30 days)
Rate Rider for Disposition Excess Expansion Deposits - effective until December, 2024	$/kVA	(0.0276)	(per 30 days)
Rate Rider for Disposition of AR Credits - effective until December 31, 2024	$/kVA	(0.0004)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kW	2.7525	(per 30 days)
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.2236	(per 30 days)

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2021

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than 1,000 kW but less than 5,000 kW, or is forecast to be equal to or greater than 1,000 kW but less than 5,000 kW. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.
The rate rider for the disposition of Post 2011 Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	970.94	(per 30 days)
Distribution Volumetric Rate	$/kVA	6.8269	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kVA	0.0144	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kVA	0.1377	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kVA	(0.1149)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Named Property - effective until December 31, 2024	$/kVA	(0.0190)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kVA	(0.0004)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$/kVA	(0.0025)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kVA	(0.0960)	(per 30 days)
Rate Rider for Disposition of External Driven Capital - effective until December 31, 2024	$/kVA	(0.0038)	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kVA	(0.0680)	(per 30 days)
Rate Rider for Disposition of Excess Expansion Deposits - effective until December, 2024	$/kVA	(0.0208)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kW	2.6594	(per 30 days)
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.2236	(per 30 days)

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2021

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

LARGE USE SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B

The rate rider for the disposition of Post 2011 Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	4,262.60	(per 30 days)
Distribution Volumetric Rate	$/kVA	7.3410	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kVA	0.0164	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kVA	0.1559	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kVA	(0.1301)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until December 31, 2024	$/kVA	(0.0215)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kVA	(0.0004)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$/kVA	(0.0028)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kVA	(0.1086)	(per 30 days)
Rate Rider for Disposition of External Driven Capital - effective until December 31, 2024	$/kVA	(0.0043)	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kVA	(0.0769)	(per 30 days)
Rate Rider for Disposition of Excess Expansion Deposits - effective until December, 2024	$/kVA	(0.0236)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kW	3.0316	(per 30 days)
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.4705	(per 30 days)

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2021

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation and requires THESL to provide back- up service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component - APPROVED ON AN INTERIM BASIS

Standby Charge - for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of generation facility).

Service Charge	$	253.09	(per 30 days)
Distribution Volumetric Rate			
For General Service 50 - 999 kW Service Classification	$/kVA	8.6406	(per 30 days)
For General Service 1,000 - 4,999 kW Service Classification	$/kVA	6.8269	(per 30 days)
For Large Use Service Classification	$/kVA	7.3410	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2021

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand at each location is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by THESL and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	7.62	(per 30 days)
Connection Charge (per connection)	$	0.80	(per 30 days)
Distribution Volumetric Rate	$/kWh	0.09575	
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kWh	0.00022	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kWh	0.00211	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kWh	(0.00176)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Named Property - effective until December 31, 2024	$/kWh	(0.00029)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kWh	(0.00002)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$/kWh	(0.00004)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kWh	(0.00147)	(per 30 days)
Rate Rider for Disposition of External Driven Capital - effective until December 31, 2024	$/kWh	(0.00006)	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kWh	(0.00104)	(per 30 days)
Rate Rider for Disposition of Excess Expansion Deposits - effective until December, 2024	$/kWh	(0.00032)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kWh	0.00500	
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.00429	

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2021

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per device)	$	1.71	(per 30 days)
Distribution Volumetric Rate	$/kVA	38.1401	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kVA	0.1071	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kVA	1.0207	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kVA	(0.8516)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Named Property - effective until December 31, 2024	$/kVA	(0.1407)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kVA	(0.0088)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$/kVA	(0.0187)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kVA	(0.7114)	(per 30 days)
Rate Rider for Disposition of External Driven Capital - effective until December 31, 2024	$/kVA	(0.0279)	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kVA	(0.5037)	(per 30 days)
Rate Rider for Disposition of Excess Expansion Deposits - effective until December, 2024	$/kVA	(0.1543)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kW	2.4481	(per 30 days)
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.6541	(per 30 days)

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2021

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.33	(per 30 days)

ALLOWANCES

Transformer Allowance for Ownership	$/kVA	(0.62)	(per 30 days)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)	

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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Customer Administration		
Account history	$	25.00
Duplicate invoices for previous billing	$	25.00
Request for other billing or system information	$	25.00
Easement letter	$	25.00
Income tax letter	$	25.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	35.00
Returned cheque (plus bank charges)	$	25.00
Special meter reads	$	55.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	55.00
Non-Payment of Account		
Late payment - per month	%	1.50
Late payment - per annum	%	19.56
Collection of account charge - no disconnection	$	55.00
Disconnect/reconnect at meter - during regular hours	$	120.00
Disconnect/reconnect at meter - after regular hours (change extended hours ending time from 8:00 p.m. to 8:00 a.m.	$	400.00
Disconnect/reconnect at pole - during regular hours	$	300.00
Disconnect/reconnect at pole - after regular hours	$	820.00
Install/remove load control device - during regular hours (8 a.m. to 8 p.m.) - blended rate	$	120.00
Install/remove load control device - after regular hours (change extended hours ending time from 8:00 p.m. to 8:00 a.m.)	$	400.00
Other		
Disconnect/reconnect at meter - during regular hours (8 a.m. to 8 p.m.) - blended rate	$	120.00
Disconnect/reconnect at meter - after regular hours	$	400.00
Disconnect/reconnect at pole - during regular hours	$	300.00
Disconnect/reconnect at pole - after regular hours	$	820.00
Temporary service install & remove - overhead - no transformer	$	2,040.00
Specific charge for access to the power poles (wireline attachments) - per pole/year	$	44.15

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2021

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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Retail Service Charges refer to services provided by THESL to retailers or customers related to the supply of competitive electricity and are defined in the 2006 Electricity Distribution Rate Handbook.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0295
Total Loss Factor - Secondary Metered Customer > 5,000 kW	1.0172
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0192
Total Loss Factor - Primary Metered Customer > 5,000 kW	1.0070

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

RESIDENTIAL SERVICE CLASSIFICATION

This classification is applicable to an account where electricity is used exclusively for residential purposes in a separately metered living accommodation, where the Competitive Sector Multi-Unit Residential classification is not applicable. Eligibility is restricted to a dwelling unit that consists of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex building, with a residential zoning; a separately metered dwelling within a town house complex or apartment building; and bulk metered residential buildings with six or fewer units. Class B consumers are defined in accordance with O. Reg. 429/04. Further details concerning the terms of service are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	44.58	(per 30 days)
Rate Rider for Smart Metering Entity Charge - effective until December 31, 2022	$	0.56	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$	0.09	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$	0.90	(per 30 days)
Rate Rider for Recovery of Monthly Billing - effective until December 31, 2024	$	0.28	(per 30 days)
Rate Rider for Recovery of Stranded Meter Assets - effective until December 31, 2024	$	(0.02)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$	(0.75)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until December 31, 2024	$	(0.12)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$	(0.01)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$	(0.02)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$	(0.63)	(per 30 days)
Rate Rider for Disposition of External Driven Capital - effective until December 31, 2024	$	(0.02)	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$	(0.45)	(per 30 days)
Rate Rider for Disposition of AR Credits - effective until December 31, 2024	$	(0.08)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kWh	0.00825	
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.00679	

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICATION

This classification is applicable to an account where electricity is used exclusively for residential purposes in a multi- unit residential building, where unit metering is provided using technology that is substantially similar to that employed by competitive sector sub-metering providers. Use of electricity in non-residential units of multi-unit buildings does not qualify for this classification and will instead be subject to the applicable commercial classification. Class B consumers are defined in accordance with O. Reg. 429/04. Further details concerning the terms of service are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	35.34	(per 30 days)
Rate Rider for Smart Metering Entity Charge - effective until December 31, 2022	$	0.56	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$	0.06	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$	0.61	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$	(0.51)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until December 31, 2024	$	(0.08)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$	(0.01)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$	(0.43)	(per 30 days)
Rate Rider for Disposition of External Driven Capital - effective until December 31, 2024	$	(0.02)	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$	(0.30)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kWh	0.00825	
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.00679	

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is less than, or is forecast to be less than 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	39.22	(per 30 days)
Rate Rider for Smart Metering Entity Charge - effective until December 31, 2022	$	0.56	(per 30 days)
Distribution Volumetric Rate	$/kWh	0.03628	
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kWh	0.00011	
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kWh	0.00106	
Rate Rider for Recovery of Monthly Billing - effective until December 31, 2024	$/kWh	0.00010	
Rate Rider for Recovery of Stranded Meter Assets - effective until December 31, 2024	$	(0.10)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kWh	(0.00089)	
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until December 31, 2024	$/kWh	(0.00015)	
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kWh	(0.00001)	
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$/kWh	(0.00002)	
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kWh	(0.00074)	
Rate Rider for Disposition of External Driven Capital - effective until December 31, 2024	$/kWh	(0.00003)	
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kWh	(0.00053)	
Rate Rider for Disposition of AR Credits - effective until December 31, 2024	$/kWh	(0.00005)	
Retail Transmission Rate - Network Service Rate	$/kWh	0.00803	
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.00607	

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than 50 kW but less than 1,000 kW, or is forecast to be equal to or greater than 50 kW but less than 1,000 kW. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

The rate rider for the disposition of Post 2011 Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	55.20	(per 30 days)
Distribution Volumetric Rate	$/kVA	8.8532	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kVA	0.0191	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kVA	0.1825	(per 30 days)
Rate Rider for Recovery of Stranded Meter Assets - effective until December 31, 2024	$	(0.37)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kVA	(0.1523)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Named Property - effective until December 31, 2024	$/kVA	(0.0251)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kVA	(0.0009)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$/kVA	(0.0033)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kVA	(0.1272)	(per 30 days)
Rate Rider for Disposition of External Driven Capital - effective until December 31, 2024	$/kVA	(0.0050)	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kVA	(0.0901)	(per 30 days)
Rate Rider for Disposition Excess Expansion Deposits - effective until December, 2024	$/kVA	(0.0276)	(per 30 days)
Rate Rider for Disposition of AR Credits - effective until December 31, 2024	$/kVA	(0.0004)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kW	2.7525	(per 30 days)
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.2236	(per 30 days)

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than 1,000 kW but less than 5,000 kW, or is forecast to be equal to or greater than 1,000 kW but less than 5,000 kW. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

The rate rider for the disposition of Post 2011 Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	994.83	(per 30 days)
Distribution Volumetric Rate	$/kVA	6.9948	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kVA	0.0144	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kVA	0.1377	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kVA	(0.1149)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Named Property - effective until December 31, 2024	$/kVA	(0.0190)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kVA	(0.0004)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$/kVA	(0.0025)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kVA	(0.0960)	(per 30 days)
Rate Rider for Disposition of External Driven Capital - effective until December 31, 2024	$/kVA	(0.0038)	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kVA	(0.0680)	(per 30 days)
Rate Rider for Disposition of Excess Expansion Deposits - effective until December, 2024	$/kVA	(0.0208)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kW	2.6594	(per 30 days)
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.2236	(per 30 days)

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

LARGE USE SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

The rate rider for the disposition of Post 2011 Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	4,367.46	(per 30 days)
Distribution Volumetric Rate	$/kVA	7.5216	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kVA	0.0164	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kVA	0.1559	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kVA	(0.1301)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until December 31, 2024	$/kVA	(0.0215)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kVA	(0.0004)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$/kVA	(0.0028)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kVA	(0.1086)	(per 30 days)
Rate Rider for Disposition of External Driven Capital - effective until December 31, 2024	$/kVA	(0.0043)	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kVA	(0.0769)	(per 30 days)
Rate Rider for Disposition of Excess Expansion Deposits - effective until December, 2024	$/kVA	(0.0236)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kW	3.0316	(per 30 days)
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.4705	(per 30 days)

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation and requires THESL to provide back- up service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component - APPROVED ON AN INTERIM BASIS

Standby Charge - for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of generation facility).

Service Charge	$	261.44	(per 30 days)
Distribution Volumetric Rate			
For General Service 50 - 999 kW Service Classification	$/kVA	8.8532	(per 30 days)
For General Service 1,000 - 4,999 kW Service Classification	$/kVA	6.9948	(per 30 days)
For Large Use Service Classification	$/kVA	7.5216	(per 30 days)

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand at each location is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by THESL and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	7.81	(per 30 days)
Connection Charge (per connection)	$	0.82	(per 30 days)
Distribution Volumetric Rate	$/kWh	0.09811	
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kWh	0.00022	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kWh	0.00211	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kWh	(0.00176)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Named Property - effective until December 31, 2024	$/kWh	(0.00029)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kWh	(0.00002)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$/kWh	(0.00004)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kWh	(0.00147)	(per 30 days)
Rate Rider for Disposition of External Driven Capital - effective until December 31, 2024	$/kWh	(0.00006)	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kWh	(0.00104)	(per 30 days)
Rate Rider for Disposition of Excess Expansion Deposits - effective until December, 2024	$/kWh	(0.00032)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kWh	0.00500	
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.00429	

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per device)	$	1.75	(per 30 days)
Distribution Volumetric Rate	$/kVA	39.0783	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kVA	0.1071	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kVA	1.0207	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kVA	(0.8516)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Named Property - effective until December 31, 2024	$/kVA	(0.1407)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kVA	(0.0088)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$/kVA	(0.0187)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kVA	(0.7114)	(per 30 days)
Rate Rider for Disposition of External Driven Capital - effective until December 31, 2024	$/kVA	(0.0279)	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kVA	(0.5037)	(per 30 days)
Rate Rider for Disposition of Excess Expansion Deposits - effective until December, 2024	$/kVA	(0.1543)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kW	2.4481	(per 30 days)
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.6541	(per 30 days)

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.33	(per 30 days)

ALLOWANCES

Transformer Allowance for Ownership	$/kVA	(0.62)	(per 30 days)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)	

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

Customer Administration		
Account history	$	25.00
Duplicate invoices for previous billing	$	25.00
Request for other billing or system information	$	25.00
Easement letter	$	25.00
Income tax letter	$	25.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	35.00
Returned cheque (plus bank charges)	$	25.00
Special meter reads	$	55.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	55.00
Non-Payment of Account		
Late payment - per month	%	1.50
Late payment - per annum	%	19.56
Collection of account charge - no disconnection	$	55.00
Disconnect/reconnect at meter - during regular hours	$	120.00
Disconnect/reconnect at meter - after regular hours (change extended hours ending time from 8:00 p.m. to 8:00 a.m.	$	400.00
Disconnect/reconnect at pole - during regular hours	$	300.00
Disconnect/reconnect at pole - after regular hours	$	820.00
Install/remove load control device - during regular hours (8 a.m. to 8 p.m.) - blended rate	$	120.00
Install/remove load control device - after regular hours (change extended hours ending time from 8:00 p.m. to 8:00 a.m.)	$	400.00
Other		
Disconnect/reconnect at meter - during regular hours (8 a.m. to 8 p.m.) - blended rate	$	120.00
Disconnect/reconnect at meter - after regular hours	$	400.00
Disconnect/reconnect at pole - during regular hours	$	300.00
Disconnect/reconnect at pole - after regular hours	$	820.00
Temporary service install & remove - overhead - no transformer	$	2,040.00
Specific charge for access to the power poles (wireline attachments) - per pole/year	$	44.15

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

Retail Service Charges refer to services provided by THESL to retailers or customers related to the supply of competitive electricity and are defined in the 2006 Electricity Distribution Rate Handbook.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0295
Total Loss Factor - Secondary Metered Customer > 5,000 kW	1.0172
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0192
Total Loss Factor - Primary Metered Customer > 5,000 kW	1.0070

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

RESIDENTIAL SERVICE CLASSIFICATION

This classification is applicable to an account where electricity is used exclusively for residential purposes in a separately metered living accommodation, where the Competitive Sector Multi-Unit Residential classification is not applicable. Eligibility is restricted to a dwelling unit that consists of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex building, with a residential zoning; a separately metered dwelling within a town house complex or apartment building; and bulk metered residential buildings with six or fewer units. Class B consumers are defined in accordance with O. Reg. 429/04. Further details concerning the terms of service are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	46.47	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$	0.09	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$	0.90	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$	0.28	(per 30 days)
Rate Rider for Recovery of Stranded Meter Assets - effective until December 31, 2024	$	(0.02)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$	(0.75)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$	(0.12)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until December 31, 2024	$	(0.01)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$	(0.02)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$	(0.63)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$	(0.02)	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$	(0.45)	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$	(0.08)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kWh	0.00825	
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.00679	

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICATION

This classification is applicable to an account where electricity is used exclusively for residential purposes in a multi- unit residential building, where unit metering is provided using technology that is substantially similar to that employed by competitive sector sub-metering providers. Use of electricity in non-residential units of multi-unit buildings does not qualify for this classification and will instead be subject to the applicable commercial classification. Class B consumers are defined in accordance with O. Reg. 429/04. Further details concerning the terms of service are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	36.84	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$	0.06	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$	0.61	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$	(0.51)	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$	(0.08)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$	(0.01)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until December 31, 2024	$	(0.43)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$	(0.02)	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$	(0.30)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kWh	0.00825	
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kWh	0.00679	

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is less than, or is forecast to be less than 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	40.88	(per 30 days)
Distribution Volumetric Rate	$/kWh	0.03782	
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kWh	0.00011	
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kWh	0.00106	
Rate Rider for Recovery of Monthly Billing - effective until December 31, 2024	$/kWh	0.00010	
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$	(0.10)	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kWh	(0.00089)	
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until December 31, 2024	$/kWh	(0.00015)	
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kWh	(0.00001)	
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kWh	(0.00002)	
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until December 31, 2024	$/kWh	(0.00074)	
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kWh	(0.00003)	
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$/kWh	(0.00053)	
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kWh	(0.00005)	
Retail Transmission Rate - Network Service Rate	$/kWh	0.00803	
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kWh	0.00607	

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than 50 kW but less than 1,000 kW, or is forecast to be equal to or greater than 50 kW but less than 1,000 kW. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

The rate rider for the disposition of Post 2011 Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	57.54	(per 30 days)
Distribution Volumetric Rate	$/kVA	9.2286	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kVA	0.0191	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kVA	0.1825	(per 30 days)
Rate Rider for Recovery of Stranded Meter Assets - effective until December 31, 2024	$	(0.37)	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kVA	(0.1523)	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kVA	(0.0251)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kVA	(0.0009)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kVA	(0.0033)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Named Property - effective until December 31, 2024	$/kVA	(0.1272)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kVA	(0.0050)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$/kVA	(0.0901)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kVA	(0.0276)	(per 30 days)
Rate Rider for Disposition of AR Credits - effective until December 31, 2024	$/kVA	(0.0004)	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kW	2.7525	(per 30 days)
Rate Rider for Disposition Excess Expansion Deposits - effective until December, 2024	$/kW	2.2236	(per 30 days)

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than 1,000 kW but less than 5,000 kW, or is forecast to be equal to or greater than 1,000 kW but less than 5,000 kW. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

The rate rider for the disposition of Post 2011 Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	1,037.01	(per 30 days)
Distribution Volumetric Rate	$/kVA	7.2914	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kVA	0.0144	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kVA	0.1377	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kVA	(0.1149)	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kVA	(0.0190)	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kVA	(0.0004)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kVA	(0.0025)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Named Property - effective until December 31, 2024	$/kVA	(0.0960)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kVA	(0.0038)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$/kVA	(0.0680)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kVA	(0.0208)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kW	2.6594	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kW	2.2236	(per 30 days)
Rate Rider for Disposition of Excess Expansion Deposits - effective until December, 2024			

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

LARGE USE SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

The rate rider for the disposition of Post 2011 Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	4,552.64	(per 30 days)
Distribution Volumetric Rate	$/kVA	7.8405	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kVA	0.0164	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kVA	0.1559	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kVA	(0.1301)	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kVA	(0.0215)	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kVA	(0.0004)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kVA	(0.0028)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until December 31, 2024	$/kVA	(0.1086)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kVA	(0.0043)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$/kVA	(0.0769)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kVA	(0.0236)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kW	3.0316	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kW	2.4705	(per 30 days)
Rate Rider for Disposition of Excess Expansion Deposits - effective until December, 2024			

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation and requires THESL to provide back- up service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component - APPROVED ON AN INTERIM BASIS

Standby Charge - for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of generation facility).

Service Charge	$	270.07	(per 30 days)
Distribution Volumetric Rate			
For General Service 50 - 999 kW Service Classification	$/kVA	9.2286	(per 30 days)
For General Service 1,000 - 4,999 kW Service Classification	$/kVA	7.2914	(per 30 days)
For Large Use Service Classification	$/kVA	7.8405	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand at each location is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by THESL and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	8.14	(per 30 days)
Connection Charge (per connection)	$	0.85	(per 30 days)
Distribution Volumetric Rate	$/kWh	0.10227	
- effective until December 31, 2024	$/kWh	0.00022	(per 30 days)
- effective until December 31, 2024	$/kWh	0.00211	(per 30 days)
- effective until December 31, 2024	$/kWh	(0.00176)	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kWh	(0.00029)	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kWh	(0.00002)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kWh	(0.00004)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Named Property - effective until December 31, 2024	$/kWh	(0.00147)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kWh	(0.00006)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$/kWh	(0.00104)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kWh	(0.00032)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kWh	0.00500	
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kWh	0.00429	
Rate Rider for Disposition of Excess Expansion Deposits - effective until December, 2024			

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per device)	$	1.82	(per 30 days)
Distribution Volumetric Rate	$/kVA	40.7352	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kVA	0.1071	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kVA	1.0207	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kVA	(0.8516)	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kVA	(0.1407)	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kVA	(0.0088)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kVA	(0.0187)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Named Property - effective until December 31, 2024	$/kVA	(0.7114)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kVA	(0.0279)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$/kVA	(0.5037)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kVA	(0.1543)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kW	2.4481	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kW	2.6541	(per 30 days)
Rate Rider for Disposition of Excess Expansion Deposits - effective until December, 2024			

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.33	(per 30 days)

ALLOWANCES

Transformer Allowance for Ownership	$/kVA	(0.62)	(per 30 days)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)	

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

Customer Administration		
Account history	$	25.00
Duplicate invoices for previous billing	$	25.00
Request for other billing or system information	$	25.00
Easement letter	$	25.00
Income tax letter	$	25.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	35.00
Returned cheque (plus bank charges)	$	25.00
Special meter reads	$	55.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	55.00
Non-Payment of Account		
Late payment - per month	%	1.50
Late payment - per annum	%	19.56
Collection of account charge - no disconnection	$	55.00
Disconnect/reconnect at meter - during regular hours	$	120.00
Disconnect/reconnect at meter - after regular hours (change extended hours ending time from 8:00 p.m. to 8:00 a.m.	$	400.00
Disconnect/reconnect at pole - during regular hours	$	300.00
Disconnect/reconnect at pole - after regular hours	$	820.00
Install/remove load control device - during regular hours (8 a.m. to 8 p.m.) - blended rate	$	120.00
Install/remove load control device - after regular hours (change extended hours ending time from 8:00 p.m. to 8:00 a.m.)	$	400.00
Other		
Disconnect/reconnect at meter - during regular hours (8 a.m. to 8 p.m.) - blended rate	$	120.00
Disconnect/reconnect at meter - after regular hours	$	400.00
Disconnect/reconnect at pole - during regular hours	$	300.00
Disconnect/reconnect at pole - after regular hours	$	820.00
Temporary service install & remove - overhead - no transformer	$	2,040.00
Specific charge for access to the power poles (wireline attachments) - per pole/year	$	44.15

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

Retail Service Charges refer to services provided by THESL to retailers or customers related to the supply of competitive electricity and are defined in the 2006 Electricity Distribution Rate Handbook.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0295
Total Loss Factor - Secondary Metered Customer > 5,000 kW	1.0172
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0192
Total Loss Factor - Primary Metered Customer > 5,000 kW	1.0070

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2024

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EB-2018-0165

RESIDENTIAL SERVICE CLASSIFICATION

This classification is applicable to an account where electricity is used exclusively for residential purposes in a separately metered living accommodation, where the Competitive Sector Multi-Unit Residential classification is not applicable. Eligibility is restricted to a dwelling unit that consists of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex building, with a residential zoning; a separately metered dwelling within a town house complex or apartment building; and bulk metered residential buildings with six or fewer units. Class B consumers are defined in accordance with O. Reg. 429/04. Further details concerning the terms of service are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	48.30	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$	0.09	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$	0.90	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$	0.28	(per 30 days)
Rate Rider for Recovery of Stranded Meter Assets - effective until December 31, 2024	$	(0.02)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$	(0.75)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$	(0.12)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until December 31, 2024	$	(0.01)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$	(0.02)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$	(0.63)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$	(0.02)	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$	(0.45)	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$	(0.08)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kWh	0.00825	
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.00679	

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2024

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICATION

This classification is applicable to an account where electricity is used exclusively for residential purposes in a multi- unit residential building, where unit metering is provided using technology that is substantially similar to that employed by competitive sector sub-metering providers. Use of electricity in non-residential units of multi-unit buildings does not qualify for this classification and will instead be subject to the applicable commercial classification. Class B consumers are defined in accordance with O. Reg. 429/04. Further details concerning the terms of service are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	38.29	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$	0.06	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$	0.61	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$	(0.51)	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$	(0.08)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$	(0.01)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until December 31, 2024	$	(0.43)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$	(0.02)	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$	(0.30)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kWh	0.00825	
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kWh	0.00679	

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2024

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is less than, or is forecast to be less than 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	42.49	(per 30 days)
Distribution Volumetric Rate	$/kWh	0.03931	
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kWh	0.00011	
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kWh	0.00106	
Rate Rider for Recovery of Monthly Billing - effective until December 31, 2024	$/kWh	0.00010	
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$	(0.10)	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kWh	(0.00089)	
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until December 31, 2024	$/kWh	(0.00015)	
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kWh	(0.00001)	
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kWh	(0.00002)	
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until December 31, 2024	$/kWh	(0.00074)	
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kWh	(0.00003)	
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$/kWh	(0.00053)	
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kWh	(0.00005)	
Retail Transmission Rate - Network Service Rate	$/kWh	0.00803	
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kWh	0.00607	

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2024

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than 50 kW but less than 1,000 kW, or is forecast to be equal to or greater than 50 kW but less than 1,000 kW. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

The rate rider for the disposition of Post 2011 Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	59.80	(per 30 days)
Distribution Volumetric Rate	$/kVA	9.5913	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kVA	0.0191	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kVA	0.1825	(per 30 days)
Rate Rider for Recovery of Stranded Meter Assets - effective until December 31, 2024	$	(0.37)	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kVA	(0.1523)	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kVA	(0.0251)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kVA	(0.0009)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kVA	(0.0033)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Named Property - effective until December 31, 2024	$/kVA	(0.1272)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kVA	(0.0050)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$/kVA	(0.0901)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kVA	(0.0276)	(per 30 days)
Rate Rider for Disposition of AR Credits - effective until December 31, 2024	$/kVA	(0.0004)	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kW	2.7525	(per 30 days)
Rate Rider for Disposition Excess Expansion Deposits - effective until December, 2024	$/kW	2.2236	(per 30 days)

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2024

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than 1,000 kW but less than 5,000 kW, or is forecast to be equal to or greater than 1,000 kW but less than 5,000 kW. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

The rate rider for the disposition of Post 2011 Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	1,077.76	(per 30 days)
Distribution Volumetric Rate	$/kVA	7.5780	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kVA	0.0144	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kVA	0.1377	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kVA	(0.1149)	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kVA	(0.0190)	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kVA	(0.0004)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kVA	(0.0025)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Named Property - effective until December 31, 2024	$/kVA	(0.0960)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kVA	(0.0038)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$/kVA	(0.0680)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kVA	(0.0208)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kW	2.6594	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kW	2.2236	(per 30 days)
Rate Rider for Disposition of Excess Expansion Deposits - effective until December, 2024			

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2024

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

LARGE USE SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

The rate rider for the disposition of Post 2011 Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	4,731.56	(per 30 days)
Distribution Volumetric Rate	$/kVA	8.1486	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kVA	0.0164	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kVA	0.1559	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kVA	(0.1301)	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kVA	(0.0215)	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kVA	(0.0004)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kVA	(0.0028)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until December 31, 2024	$/kVA	(0.1086)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kVA	(0.0043)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$/kVA	(0.0769)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kVA	(0.0236)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kW	3.0316	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kW	2.4705	(per 30 days)
Rate Rider for Disposition of Excess Expansion Deposits - effective until December, 2024			

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2024

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation and requires THESL to provide back- up service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component - APPROVED ON AN INTERIM BASIS

Standby Charge - for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of generation facility).

Service Charge	$	278.98	(per 30 days)
Distribution Volumetric Rate			
For General Service 50 - 999 kW Service Classification	$/kVA	9.5913	(per 30 days)
For General Service 1,000 - 4,999 kW Service Classification	$/kVA	7.5780	(per 30 days)
For Large Use Service Classification	$/kVA	8.1486	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2024

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand at each location is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by THESL and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	8.46	(per 30 days)
Connection Charge (per connection)	$	0.88	(per 30 days)
Distribution Volumetric Rate	$/kWh	0.10629	
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kWh	0.00022	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kWh	0.00211	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kWh	(0.00176)	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kWh	(0.00029)	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kWh	(0.00002)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kWh	(0.00004)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Named Property - effective until December 31, 2024	$/kWh	(0.00147)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kWh	(0.00006)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$/kWh	(0.00104)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kWh	(0.00032)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kWh	0.00500	
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kWh	0.00429	
Rate Rider for Disposition of Excess Expansion Deposits - effective until December, 2024			

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2024

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EB-2018-0165

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per device)	$	1.89	(per 30 days)
Distribution Volumetric Rate	$/kVA	42.3361	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kVA	0.1071	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kVA	1.0207	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kVA	(0.8516)	(per 30 days)
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until December 31, 2024	$/kVA	(0.1407)	(per 30 days)
Rate Rider for Disposition of the Impact for USGAAP (Actuarial loss on OPEB) - effective until December 31, 2024	$/kVA	(0.0088)	(per 30 days)
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until December 31, 2024	$/kVA	(0.0187)	(per 30 days)
Rate Rider for Recovery of the Deferred Gain on Disposal of Named Property - effective until December 31, 2024	$/kVA	(0.7114)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kVA	(0.0279)	(per 30 days)
Rate Rider for Disposition of IFRS - CGAPP Property Plant and Equipment - effective until December 31, 2024	$/kVA	(0.5037)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kVA	(0.1543)	(per 30 days)
Retail Transmission Rate - Network Service Rate	$/kW	2.4481	(per 30 days)
Rate Rider for Application of Derecognition Variance Account - effective until December 31, 2024	$/kW	2.6541	(per 30 days)
Rate Rider for Disposition of Excess Expansion Deposits - effective until December, 2024			

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2024

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.33	(per 30 days)

ALLOWANCES

Transformer Allowance for Ownership	$/kVA	(0.62)	(per 30 days)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)	

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

Customer Administration		
Account history	$	25.00
Duplicate invoices for previous billing	$	25.00
Request for other billing or system information	$	25.00
Easement letter	$	25.00
Income tax letter	$	25.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	35.00
Returned cheque (plus bank charges)	$	25.00
Special meter reads	$	55.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	55.00
Non-Payment of Account		
Late payment - per month	%	1.50
Late payment - per annum	%	19.56
Collection of account charge - no disconnection	$	55.00
Disconnect/reconnect at meter - during regular hours	$	120.00
Disconnect/reconnect at meter - after regular hours (change extended hours ending time from 8:00 p.m. to 8:00 a.m.	$	400.00
Disconnect/reconnect at pole - during regular hours	$	300.00
Disconnect/reconnect at pole - after regular hours	$	820.00
Install/remove load control device - during regular hours (8 a.m. to 8 p.m.) - blended rate	$	120.00
Install/remove load control device - after regular hours (change extended hours ending time from 8:00 p.m. to 8:00 a.m.)	$	400.00
Other		
Disconnect/reconnect at meter - during regular hours (8 a.m. to 8 p.m.) - blended rate	$	120.00
Disconnect/reconnect at meter - after regular hours	$	400.00
Disconnect/reconnect at pole - during regular hours	$	300.00
Disconnect/reconnect at pole - after regular hours	$	820.00
Temporary service install & remove - overhead - no transformer	$	2,040.00
Specific charge for access to the power poles (wireline attachments) - per pole/year	$	44.15

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2024

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0165

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

Retail Service Charges refer to services provided by THESL to retailers or customers related to the supply of competitive electricity and are defined in the 2006 Electricity Distribution Rate Handbook.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0295
Total Loss Factor - Secondary Metered Customer > 5,000 kW	1.0172
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0192
Total Loss Factor - Primary Metered Customer > 5,000 kW	1.0070

OEB Appendix 2-R
Loss Factors

		Historical Years					5-Year Average
		2013	2014	2015	2016	2017	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	25,298,829,279	25,255,918,253	25,122,151,061	25,265,003,588	24,268,564,347	25,042,093,306
A(2)	"Wholesale" kWh delivered to distributor (lower value)	25,185,617,039	25,142,911,602	25,009,865,761	25,152,263,759	24,160,294,017	24,930,190,436
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	2,326,834,039	2,250,042,478	2,200,621,818	2,216,840,555	2,163,272,443	2,231,522,267
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	22,858,783,000	22,892,869,124	22,809,243,943	22,935,423,204	21,997,021,574	22,698,668,169
D	"Retail" kWh delivered by distributor	24,679,119,127	24,595,275,075	24,414,826,442	24,524,435,043	23,593,363,669	24,361,403,871
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)	2,308,966,335	2,232,965,485	2,183,967,508	2,199,972,985	2,146,688,360	2,214,512,134
F	Net "Retail" kWh delivered by distributor = **D - E**	22,370,152,792	22,362,309,590	22,230,858,934	22,324,462,058	21,446,675,309	22,146,891,737
G	Loss Factor in Distributor's system = **C / F**	1.0218	1.0237	1.0260	1.0274	1.0257	1.0249
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0045	1.0045	1.0045	1.0045	1.0045	1.0045
	Total Losses						
I	Total Loss Factor = **G x H**	1.0264	1.0283	1.0306	1.0320	1.0303	1.0295

Notes:

A(1) If directly connected to the IESO-controlled grid, kWh pertains to the virtual meter on the primary or high voltage side of the transformer at the interface with the transmission grid. This corresponds to the "With Losses" kWh value provided by the IESO's MV-WEB. It is the higher of the two values provided by MV-WEB.

If fully embedded within a host distributor, kWh pertains to the virtual meter on the primary or high voltage side of the transformer, at the interface between the host distributor and the transmission grid. For example, if the host distributor is Hydro One Networks Inc., kWh from the Hydro One Networks' invoice corresponding to "Total kWh w Losses" should be reported. This corresponds to the higher of the two kWh values provided in Hydro One Networks' invoice.

If partially embedded, kWh pertains to the sum of the above.

A(2) If directly connected to the IESO-controlled grid, kWh pertains to a metering installation on the secondary or low voltage side of the transformer at the interface with the transmission grid. This corresponds to the "Without Losses" kWh value provided by the IESO's MV-WEB. It is the lower of the two kWh values provided by MV-WEB.

If fully embedded with the host distributor, kWh pertains to a metering installation on the secondary or low voltage side of the transformer at the interface between the embedded distributor and the host distributor. For example, if the host distributor is Hydro One Networks Inc., kWh from the Hydro One Networks' invoice corresponding to "Total kWh" should be reported. This corresponds to the lower of the two kWh values provided in Hydro One Networks' invoice.

If partially embedded, kWh pertains to the sum of the above.

Additionally, kWh pertaining to distributed generation directly connected to the distributor's own distribution network should be included in **A(2)**.

B If a Large Use Customer is metered on the secondary or low voltage side of the transformer, the default loss is 1% (i.e., **B** = 1.01 X **E**).

D kWh corresponding to D should equal metered or estimated kWh at the customer's delivery point.

G and **I** These loss factors pertain to secondary-metered customers with demand less than 5,000 kW.

H If directly connected to the IESO-controlled grid, SFLF = 1.0045.

If fully embedded within a host distributor, SFLF = loss factor re losses in transformer at grid interface X loss factor re losses in host distributor's system. If the host distributor is Hydro One Networks Inc., SFLF = 1.0060 X 1.0278 = 1.0340. If partially embedded, SFLF should be calculated as the weighted average of

Distributors that wish to propose a different SFLF should provide appropriate justification for any such proposal including supporting calculations and any other relevant material.

Distribution System Loss Factors

For the Large User (>5000kW) Class

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TABLE OF CONTENTS

Disclaimer ii

Executive Summary 1

Background 1
System-Wide Losses and Variances 1
Methodology 1
Dedicated versus non-Dedicated Feeders 2
Findings and Results 2

1. Introduction 4

1.1 Background and Objectives 4
1.2 Structure of Report 4

2. Process and methodology 5

2.1 Prior THESL Methodology 5
2.2 Navigant Approach 6
2.2.1 Loading Data 6
2.2.2 CYME 7
2.2.3 Dedicated versus Mixed Use Feeders 7
2.2.4 Primary and Secondary Losses 12
2.3 Process workflow 12

3. Results 14

3.1 Findings and Results 14
3.1.1 Results 14
3.1.2 Evaluation of updated primary loss factor and comparison to previous calculation 15
3.1.3 Further Methodology Considerations 16

4. conclusions 17

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EXECUTIVE SUMMARY

Background

Navigant Consulting was engaged by Toronto Hydro-Electric Systems Ltd. (THESL) to update distribution system loss factors for its Large Users (demand greater than 5000kW) class. This class represents 44 customers in the THESL network. Navigant's methodology is based on detailed distribution feeder simulation modeling for each circuit where Large User class customers are located. Of these 44 customers, 21, are located on dedicated feeders (i.e. the only customer located on the feeder). Many of these dedicated feeders are located in downtown Toronto, whereas other Large User class customers are located on mixed use feeders in the "horseshoe' area surrounding downtown Toronto. Previously, energy losses for THESL's system was estimated via empirical methods, which considered the total length of conductor servicing a particular class of customers, the conductor impedance, metered peak losses for a subset of customers, and the calculation of a "loss factor" to convert peak losses into average energy losses.[1]

System-Wide Losses and Variances

Methodology

System losses represent the difference between the electricity injected and withdrawn from the distribution network (i.e. the difference between purchases and sales). Losses are characterized as technical and non-technical. Technical losses are primarily due to heat dissipation resulting from current passing through conductors (wires and cables) and distribution line transformers (windings and magnetic core losses). Non-technical losses occur because of energy diversion, metering inaccuracies and unmetered energy. In Navigant's experience, non-technical losses for a large user class tend to be relatively insignificant compared to technical losses. The risk of energy diversion is low as energy is sold to large corporations rather than individual customers and unmetered energy is not a risk as the customer class contains very few customers (meter points and proper functionality can be easily accounted for). Furthermore, THESL has recently installed high accuracy Schneider "Ion" meters for its large user class, which would functionally eliminate non-technical losses due to metering inaccuracy.

Navigant reviewed and compared THESL's previous loss methodology to industry best practices. Our review indicated a new methodology should be applied to update the factor which indicates losses that occur on the primary (high voltage) conductor that services large user customers. This is the factor that was defined in previous THESL rate filings. The new approach is based on rigorous load flow simulations for each circuit where Large User class customers are located. Navigant applied the CYME distribution simulation software (a commercially available power systems analysis software package and THESL's distribution system modeling tool of choice) to perform the loss calculations.[2] CYME is a widely recognized distribution system modeling tool, and is used by several electric utilities in Ontario (including Hydro One Networks Inc., Alectra, Hydro Ottawa, London Hydro, and Ontario Power Generation).[3]

[1] The prior THESL methodology is described in greater detail in Case No. EB-2005-0421.

[2] THESL provided the feeder model databases used to perform distribution simulation analyses.

[3] From CYME's 'Partial List of CYME International Software Users': http://www.cyme.com/company/clients/#Canada

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Navigant simulated existing CYME models of THESL feeders that service Large User customers to calculate technical losses attributable to these customers.

Navigant calculated large user consumption using a "meter data method." THESL provided 2016[4] energy consumption over fifteen-minute meter intervals for each distribution feeder serving large user customers as well as meter data for the large user customers themselves. Navigant then determined feeder and customer loading at the time of THESL's system peak during the test year in order to estimate peak demand losses on a per-customer basis via CYME simulation. Finally, the interval metered data was used to convert peak demand losses to average annual energy losses, which are used to define a primary loss factor for the customer class.

Dedicated versus non-Dedicated Feeders

Customers in THESL's Large User class are served by two feeder topologies: dedicated and non-dedicated or "mixed-use" feeders. Dedicated feeders are those that only serve Large User customers while mixed-use feeders also serve customers in other load classes (e.g. Residential customers). Due to the very high load for some Large Users class customers, multiple distribution feeders supply some customers (operating in parallel) to ensure there is sufficient capacity to reliably serve these customers.

The approach Navigant used to assess losses for each feeder varied based on feeder topology. For dedicated feeders, we assigned 100% of the peak losses derived from the CYME load flow simulation analysis to the Large User class. However, for mixed-use feeder simulations an alternative method was required. For mixed use circuits, Navigant derived losses attributable solely to Large Users by modifying load flow model parameters. THESL metered load data for a mixed-use feeder was allocated to each customer using a combination of metered data for the entire feeder model and class allocation factors. Load flow simulation output was collected (including feeder loading and losses) for this modeled state. Next, we removed Large User load(s) from the feeder model and performed simulation analyses with all other load allocations unchanged. We then compared simulation model results for the new modeled state to those obtained for the original state with all loads in service. The difference in losses between each state is the amount of technical losses assigned to the Large User class.

Findings and Results

Navigant first determined loading conditions for distribution feeders serving THESL's large user customers at the time of THESL's 2016 system peak, the latest full-calendar year in which meter data was available. We then performed load flow simulations for each distribution feeder to determine losses directly attributable to THESL's large user class at the time of the 2016 system peak. The THESL CYME model database includes distribution transformers for all loads connected to the THESL system, including the Large User class. Navigant's methodology, which uses simulation modeling to calculate losses, thus captures losses that occur on the transformer; however, it excludes lower voltage secondary lines serving Large User customers.[5] In order to isolate primary conductor losses to arrive at a loss factor that accounts for the same distribution system components as THESL's prior findings, Navigant separated primary losses and transformer losses. Then, we applied a load loss factor (LLF) to convert peak losses to calculate average energy losses.

[4] Most recent year with full year of data available at the time of the study

[5] For most large user customers, secondary line losses between the transformer and meter are very small, as the length of the secondary lines and size of the secondary conductor is large.

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Table 1 summarizes the results of the analysis.

Table 1.
Summary of Annual Energy losses calculated for each customer in the Large User (>5000 kW) class

Total Losses at time of System Peak (kW)	Average Loss Load Factor	Total Average Customer Losses (kW)	Total Annual Energy Loss (kWh)	Total Annual Consumption (kWh)	Primary loss factor
2329 kW	0.22	575 kW	5,034,940 kWh	2,034,836,023 kWh	0.25%

The resulting loss factor is 0.0025 or 0.25%. This value is about 40 percent lower than the "energy loss percentage" of 0.41% that THESL presented as evidence in its 2006 THESL EDR Application. The 2006 value was calculated in a 1999 THESL study, which in turn was based on loading data collected in a 1998 survey of 24 of the 41 Large Users connected to THESL's distribution system. In addition to sampling a subset of the customers, a uniform power factor of 0.875 was assumed for the large user class in this analysis. Metered data provided actual power factor reading for the modeled customers in Navigant's analysis, and the average power factor for the modeled customers was approximately 94% for the simulated conditions. This partially accounts for the decrease in class losses that was observed in this study.

Furthermore, Navigant's study results are based on a more rigorous calculation of loss factors associated with each feeder serving Large User customers. Navigant was able to conduct these more detailed analyses due to access to granular customer meter data and detailed feeder models. Since detailed CYME distribution feeder models are now available, primary conductor losses are easily distinguishable from secondary losses, thereby enabling a direct comparison of Navigant's study results to prior THESL estimates.

The difference in the primary loss factor calculated in Navigant's study (0.25%) versus THESL's prior value (0.41%) is primarily due to: (1) a more rigorous and therefore more accurate methodology (i.e. detailed simulation modeling versus customer survey) and (2) a previously assumed versus actual metered customer power factor data. Other factors that may contribute to the reduction in the updated loss factor include upgrades to THESL's distribution network and the configuration of lines serving large users, as well as changes in demand-side operations. Operational changes could include shifting peak demand in response to current government policies surrounding how large users are billed for global adjustment costs, implementing conservation and demand management initiatives, and generating energy behind-the-meter via cogeneration facilities. These strategies would serve to reduce customer demand which would in turn decrease expected energy losses as a percentage of total consumption.

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1. INTRODUCTION

1.1 Background and Objectives

Navigant Consulting was engaged by Toronto Hydro-Electric Systems Ltd. (THESL) to update distribution system loss factors for its Large Users (demand greater than 5000kW) class. This class represents 44 customers in the THESL network. Navigant's methodology is based on detailed distribution feeder simulation modeling for each circuit where Large User class customers are located. Of these 44 customers, 21, are located on dedicated feeders (i.e. the only customer located on the feeder). Many of these dedicated feeders are in downtown Toronto, whereas other Large User class customers are located on mixed use feeders in the "horseshoe' area surrounding downtown Toronto. Previously, energy losses for THESL's system was estimated via empirical methods, which took into account the total length of conductor servicing a particular class of customers, the conductor impedance, metered peak losses for a subset of customers, and the calculation of a "loss factor" to convert peak losses into average energy losses.

1.2 Structure of Report

This report details Navigant' methodology and the processes it followed to update THESL's primary loss factor for its Large User class. It provides a description of the loading conditions, feeders, customers and calculations performed based on distribution feeder simulation model results. results. We also compare the calculated primary loss factor derived from the distribution model simulation analysis to the primary loss factor developed and applied by THESL in prior rate filings. We also list the assumptions and methods applied to account for differences in THESL's current loss factor versus the factor presented in this report.

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2. PROCESS AND METHODOLOGY

The Large User loss factor is a factor used to estimate technical losses for energy deliveries to this load class. Technical losses refer to power that is consumed (i.e. "lost") as heat in the process of delivering power to customers. Technical losses occur on distribution feeder lines and equipment due to current flows through resistive components (primarily the feeder overhead conductor and underground cable) and transformer winding and magnetic core losses in the windings. Equation 1 provides the real power conductor or "line" loss in kilowatts that occurs in a balanced three-phase power system.

Equation 1

$$P_{loss} = 3 \times \frac{I^2 \times R}{1000}\ kW$$

The Large User loss factor accounts for losses in the distribution network that are directly attributable to large users, and that are applied to total metered consumption to ensure correct billing is adjusted for losses the meter point. In addition to the technical losses described above, losses also include a non-technical component due to energy diversion, metering inaccuracies and unmetered energy. In Navigant's experience, non-technical losses for a large user class tend to be relatively insignificant compared to technical losses. The risk of energy diversion is low as energy is sold to large corporations rather than individual customers. Furthermore, THESL has recently rolled out high accuracy Schneider "Ion" meters to its large user class, which would functionally eliminate non-technical losses due to metering inaccuracy and unmetered energy. Therefore, our methodology focuses on an update to the technical loss component of the distribution loss factor.

2.1 Prior THESL Methodology

In its 2006 THESL Electric Rate Distribution (EDR) filing, THESL submitted evidence of how its current Large User loss factor was calculated. The original calculation methodology was developed in 1999 based on a 1998 survey of 24 of the 41 large user customers. The methodology applied the load factor of the surveyed customers to convert peak losses to average energy losses. This conversion was performed using a loss factor approach, calculated empirically from a formula referenced in "Distribution System Performance Improvement Guide"[6]. The formulas are shown in the equations below. Table 1 lists the data from the survey that was used in the equations to calculate a loss factor for the large user class.

Equation 2

$$Load\ Factor = (Average\ Load)/(Peak\ Load)$$

Equation 3

$$Loss\ Factor = 0.2 \times Load\ Factor + 0.8 \times Load\ Factor^2$$

Equation 4

$$Energy\ Loss = Loss\ Factor\ \times Peak\ Loss\ \times 8{,}760\ hours$$

[6] Distribution System Performance Improvement Guide: A Technical Guide Developed for the American Public Power Association. David Robert Brown. APPA, 1997

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Equation 5

$$Energy\ Loss\ \% = \frac{Energy\ Loss}{(Energy\ Loss + Energy\ Consumed)} \times 100\%$$

Table 1. Data from the 1998 survey of 21 Large Users

Given	Measurement
Load Factor	0.7012
Loss Load Factor (calculated)	0.5334
Assumed Power Factor	0.85
Peak Loss Percentage	0.54%
Peak Load	398,769kW

Evidence from the 2006 filing indicates that THESL's Energy Loss percentage of 0.41% only considered conductor losses on the primary (i.e. medium voltage) section of the feeders serving large user customers. As a result, an adjustment is required to account for losses that occur on customer secondary (i.e. Low Voltage) lines and transformers for customers that are secondary metered.

2.2 Navigant Approach

The improvement of distribution network modeling tools and deployment of more accurate metering technologies since the prior loss factor calculation enabled Navigant to apply a more rigorous methodology to derive THESL's primary loss factor for its Large User class.

2.2.1 Loading Data

Navigant collected and analyzed 15-minute interval loading data (power and reactive power at the customer level, amperage at the feeder level) provided by THESL. This meter data was used to calculate the Loss Load Factor for each customer via Equation 6.

Equation 6

$$Loss\ Load\ Factor = \sum_{15-minutes}^{1\ year} \frac{15\ minute\ consumption^2}{Peak\ load^2 \times Number\ of\ intervals}$$

In addition, due to the granularity of the metered data, Navigant was able to "fine-tune" the simulation model on feeders serving individual large users. For example, the feeder loading in amps and customer power and reactive power consumed during peak system load for the last calendar year (2016) are entered as model parameters to accurately define peak losses for each of the large users.

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2.2.2 CYME

THESL uses the CYME (i.e. CYMDIST Distribution System Analysis module) platform[7] to simulate the operation of its distribution network.[8] The CYMDIST platform is used by distribution engineers and planners to perform load flow, short-circuit, and network optimization analysis and related studies. An important output of the load flow analysis is the amount current based losses for each system configuration and associated loading. THESL provided Navigant with the CYME models for each of the feeders that supply each of the large user customers.[9] Navigant initialized these models with the provided meter data while maintaining THESL's original modeling assumptions for allocating feeder load to non-large user customers. The models capture distribution load flows from the Transformer Station (TS) to customers located downstream of the TS. Devices that are included in these models that produce losses (and appear in the simulation model output) include interface transformers and the feeder conductor (overhead wire and underground cable).

Since power factor data is not metered at the feeder level, Navigant assumed a uniform power factor of 0.925 at the feeder head. This assumption aligns with inspected data from THESL's TS-level metered power factor data.

2.2.3 Dedicated versus Mixed Use Feeders

Feeder topology must be accounted for when calculating losses attributable to a specific subset of customers. There are two common topologies which service the large user class in THESL's network: dedicated feeders, and non-dedicated or "mixed-use" feeders. A dedicated feeder consists of a length of conductor, a service transformer and the large user customer load. An example of this topology is shown in Figure 1.

[7] Software package produced by Cooper Power Systems (a subsidiary of Eaton)

[8] THESL's distribution network include all primary or medium voltage lines originating at the substation feeder breaker, and distribution line transformers. THESL's current CYME data base excludes secondary lines and services

[9] Under normal conditions. Under emergency conditions or for short-term maintenance, feeders segments may be temporarily transferred to adjacent feeders.

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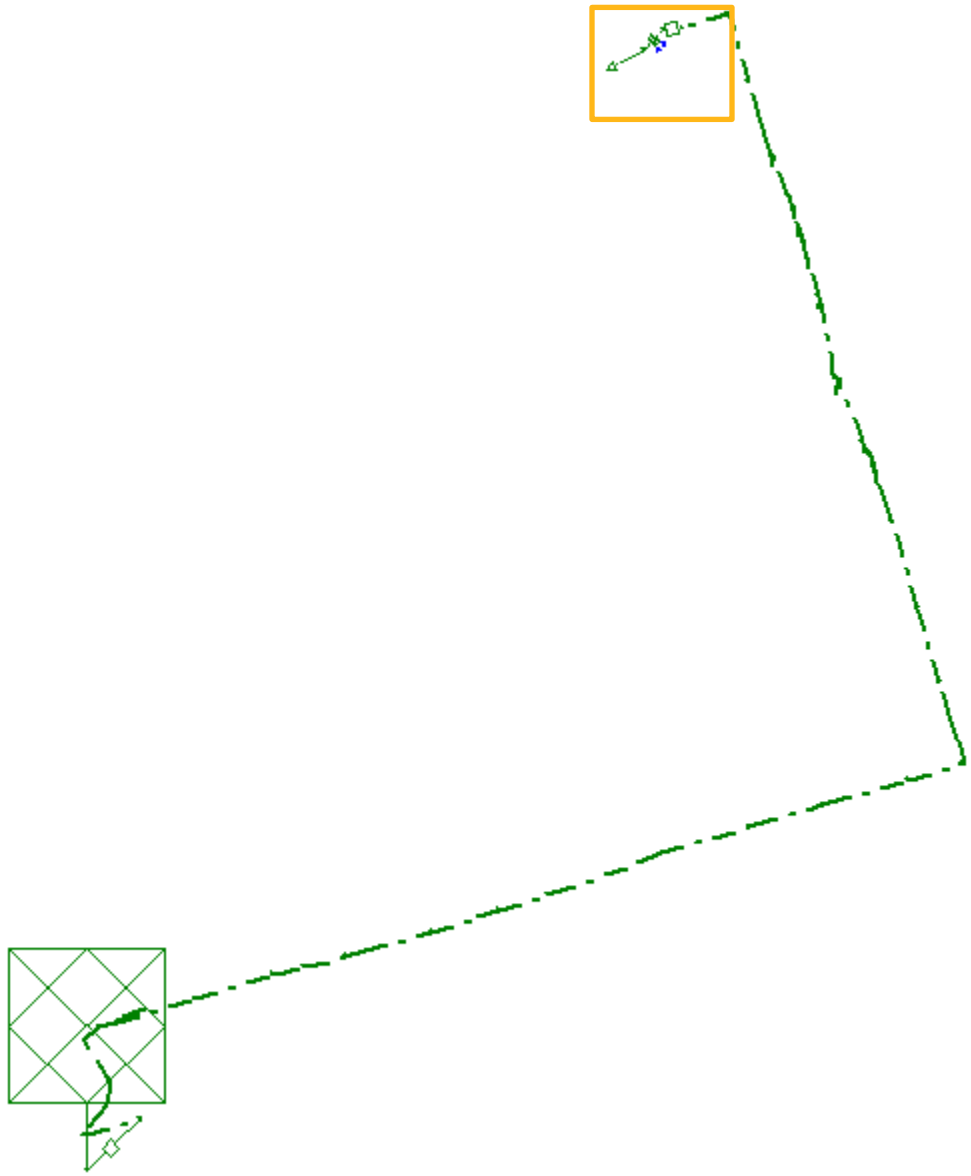

Figure 1. Dedicated feeder topology example for a feeder in the modeled set. Large User customer is indicated in orange.

Table 2 shows the large users that are supplied by dedicated feeders by address.

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Table 2. List of large users with dedicated feeds

Address	Feeder 1	Feeder 2	Feeder 3	Feeder 4	Feeder 5
Customer 1	R26-M33				
Customer 2	A-30-X	A-31-X	A-32-X		
Customer 3	A33X	A34X	A35X	A36X	
Customer 4	A-26-WR-CCW	A-28-WR-CCW	A-27-WR-CCW		
Customer 5	A13WR	A15WR	A-17-WR		
Customer 6	A-16-WR	A-12-WR	A-18-WR	A-10-WR	A-4-WR
Customer 7	A-1-WR	A-48-WR			
Customer 8	A-74-WR	A-2-WR			
Customer 9	A-95-WR	A-96-WR	A-97-WR		
Customer 10	A45A	A46A	A47A		
Customer 11	A-23-A	A-25-A	A-27-A		
Customer 12	A-24-A	A-26-A	A-29-A		
Customer 13	A-31-MN	A-20-MN			
Customer 14	A21CE/A26CE	A24CE/A22CE	A23CE	A25CE	
Customer 15	A-80-E	A-82-E	A-81-E		
Customer 16	A-17-BN	A-19-BN	A-23-BN	A-25-BN	A-27-BN
Customer 17	A-81-T	A-82-T	A-83-T		
Customer 18	A-20-DX	A-21-DX			
Customer 19	502-M30	63-M7			
Customer 21	R29-M32				
Customer 42	A-38-WR	A-36-WR			
Customer 44	A-28-GD	A-29-GD			

A mixed-use feeder will service other loads that are not part of the large user class (i.e. Residential loads) and may be more complex in terms of downstream connections, often interconnecting distributed generation. An example of this topology is shown in Figure 2.

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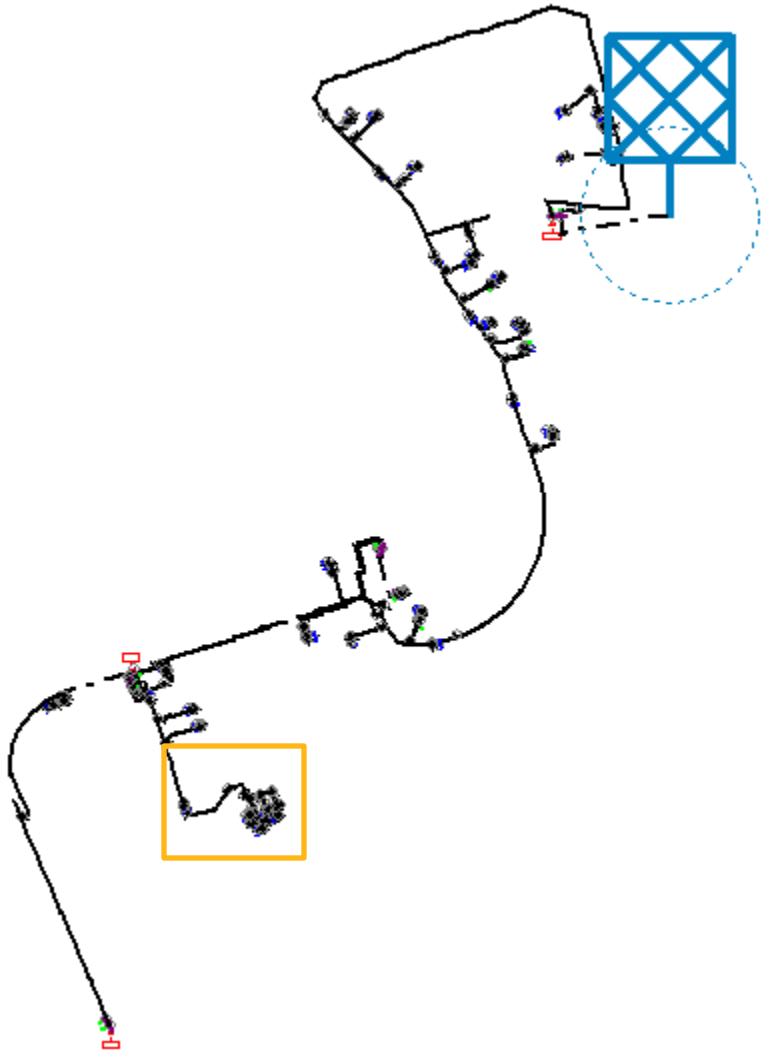

Figure 2. Mixed-use feeder topology example for a feeder in the modeled set. Large User customer is indicated in orange.

Table 3 shows the large users that are serviced by mixed-use feeders.

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Table 3. Large users with mixed-use feeds

Address	Feeder 1	Feeder 2	Feeder 3	Feeder 4
Customer 13	A-21-MN			
Customer 20	38M13	R30-M2		
Customer 21	D6-M4			
Customer 22	R30-M7	R30-M10		
Customer 23	55-M26	55-M23		
Customer 24	55-M2	55M30	85M30	85M32
Customer 25	E5-M28	E5-M26		
Customer 26	E5-M25	E5-M22		
Customer 27	85-M25	85-M34		
Customer 28	85-M1	85-M33		
Customer 29	85-M26	85-M3	85-M34	
Customer 30	85-M6	85-M7		
Customer 31	R30-M2			
Customer 32	R30-M5	R30-M10		
Customer 33	11-M3	88-M18		
Customer 34	A-38-A	A-40-A	A-64-A	A-67-A
Customer 35	38-M8			
Customer 36	A-3-CS	A-1-CS		
Customer 37	H9-M29	47-M16	47-M7	
Customer 38	34-M6	34-M7		
Customer 39	H9-M22	47-M8		
Customer 40	80-M3	80-M5		
Customer 41	88-M44			
Customer 43	A-80-CS	A-81-CS	A-82-CS	

The calculated peak demand losses from CYME load flow analysis of the dedicated feeder topology are 100% attributable to the large user customer. However, mixed-use feeders supply other load classes and losses must be allocated to determine losses attributable to large users. In order to allocate losses, individual customer loading along with distance between the substation and the individual customers must be accounted for simultaneously.

In the past, loss factor studies requiring this means of allocation would involve tracing out of conductor length and effective impedances for each customer on each modelled feeder. This type of allocation is extremely complex and would be analytically challenging given the modelling approach developed, wherein every large user is simulated in CYME. We determined that to produce a repeatable and standardized methodology, this process may be simplified while still providing an accurate estimate of the large user's "impact" on total peak feeder loss. Therefore, losses attributable solely to Large Users were instead determined by modifying load flow model parameters. The metered loading data for a mixed-use

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feeder was allocated to each of its supplied customers. Large users were allocated a portion of the feeder load based on customer meter data, and non-large users (i.e. commercial/residential class customers) were allocated the remainder of the feeder load using the nameplate ratings of transformers that interfaced these customers. Load flow simulations were performed, and output was collected (including feeder loading and losses) for this modeled state. Then, we removed the large user from the feeder model and simulated the feeder state with all other load allocations unchanged. We compared simulation model results for the new modeled state to those obtained for the original state with all loads in service. The difference in losses between each state is the amount of technical losses assigned to the large user.

2.2.4 Primary and Secondary Losses

In the process followed, the modeled feeders that supply large users in THESL's network consist of a source node, primary (distribution voltage) conductor, and step-down interface transformers that are located directly upstream of the customer load. THESL provided CYME models configured such that all customer load connected is interfaced through a step-down transformer, including the Large User class. The majority (39/44) of large user customers are primary metered; THESL customer load is metered on the primary side of the step-down transformer, and therefore meter readings do not include the step-down transformer losses or the losses that would occur on any additional secondary conductor downstream of the step-down transformer. Figure 3 illustrates this concept.

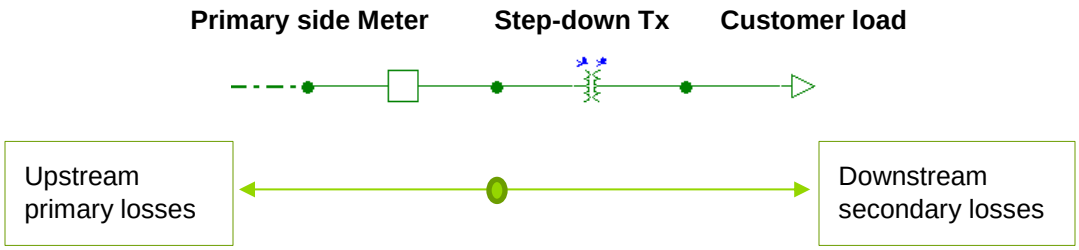

Figure 3. Primary vs. secondary losses illustration

CYME simulation output provides demand losses in kilowatts for transformer and conductor elements. In order to develop a loss factor that was based on the system components evaluated in THESL's 2006 submission (i.e. primary conductor only), Navigant utilized this feature of the simulation output to effectively isolate primary conductor losses.

2.3 Process workflow

Figure 4 shows the methodology and workflow that Navigant followed to calculate the updated primary loss factor.

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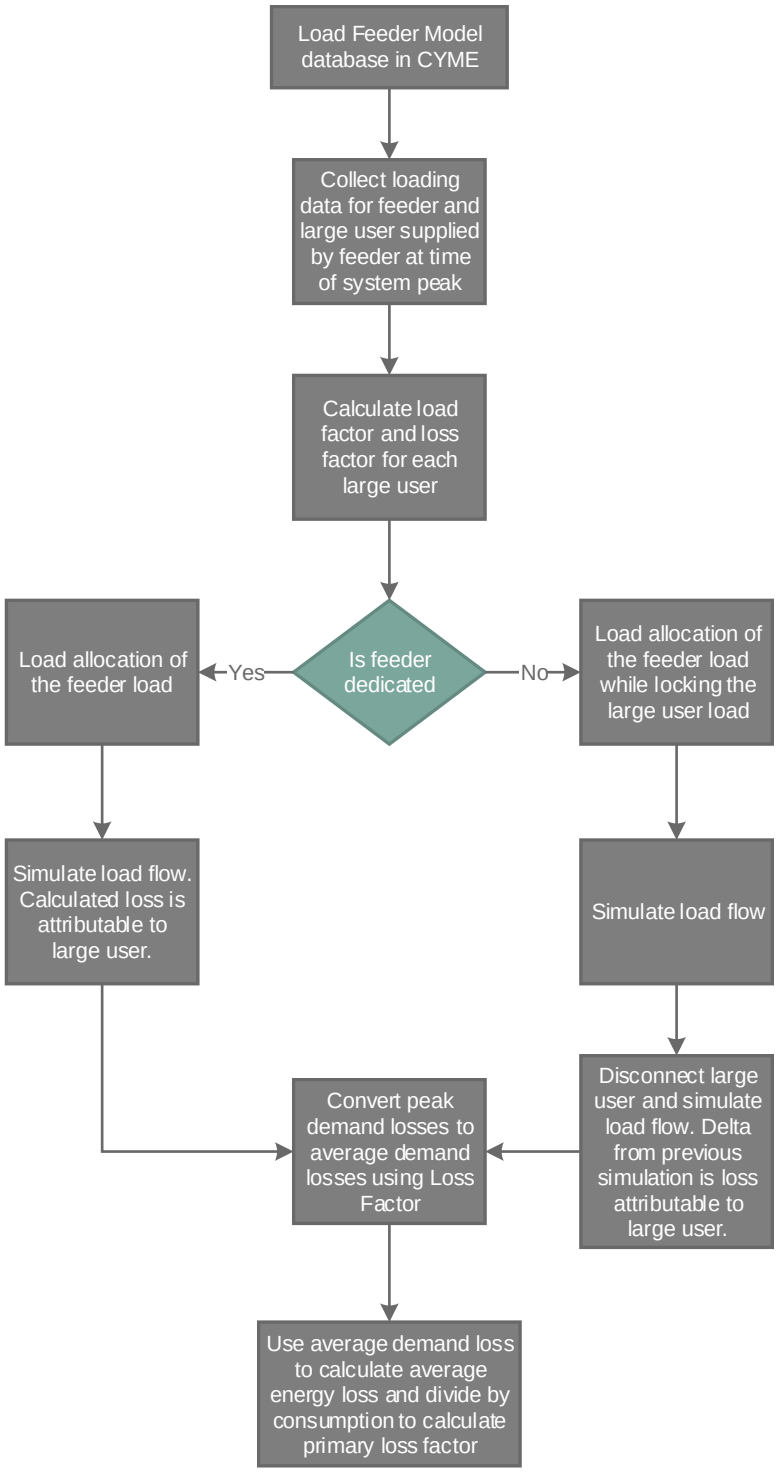

Figure 4. Process flowchart for calculating updated primary loss factor

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3. RESULTS

3.1 Findings and Results

Navigant followed the methodology outlined in Section 2 to determine 2016 peak losses in kW occurring on primary conductor for each large user. These peak losses were then converted to average losses via the loss load factors that were calculated from interval meter data. Then, average demand losses were converted to 2016 average energy losses in kWh and aggregated for the entire large user class. Finally, the aggregated average energy loss was divided by the 2016 total energy consumption for the large user class to determine the overall primary loss factor for the load class.

3.1.1 Results

The results from the load flow simulation and converted annual average losses are shown in Table 4.

Table 4. Load flow modeling results and primary loss factor calculation

Customer	Losses at time of System Peak (kW)	Loss Load Factor	Average Customer Losses (kW)	Annual Energy Loss (kWh)	Annual kWh
Customer 1	36.6	0.49	17.8	155869	86405309
Customer 2	8.3	0.24	2.0	17545	19129037
Customer 3	10.6	0.01	0.1	1309	3773251
Customer 4	4.8	0.12	0.6	5138	38208128
Customer 5	28.5	0.31	8.9	78205	68425014
Customer 6	17.7	0.28	5.0	43470	96044596
Customer 7	2.5	0.28	0.7	5985	19678435
Customer 8	18.3	0.14	2.6	22994	47298166
Customer 9	0.4	0.11	0.0	377	32488898
Customer 10	5.9	0.40	2.4	20988	54939792
Customer 11	13.7	0.15	2.0	17597	23024767
Customer 12	8.5	0.22	1.9	16613	46149425
Customer 13	5.7	0.12	0.7	6105	32624759
Customer 14	48.5	0.07	3.4	29461	31915025
Customer 15	0.6	0.13	0.1	714	23224548
Customer 16	49.7	0.23	11.2	98468	125662288
Customer 17	11.2	0.12	1.3	11780	43351725
Customer 18	7.0	0.38	2.7	23235	41005063
Customer 19	393.5	0.38	157.2	1376798	135551450
Customer 20	105.5	0.04	4.4	38448	10688287
Customer 21	11.3	0.38	4.3	37981	39756431
Customer 22	43.7	0.33	14.4	126306	32364532
Customer 23	53.6	0.37	20.1	175862	34312397

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Customer 24	222.0	0.07	15.4	135271	43076834
Customer 25	47.0	0.41	19.3	168901	106283525
Customer 26	52.6	0.36	18.8	164286	74268610
Customer 27	69.9	0.26	17.9	156575	35581487
Customer 28	84.1	0.41	34.7	304091	112826355
Customer 29	79.5	0.05	4.1	36188	37259168
Customer 30	80.0	0.02	1.3	10960	5744768
Customer 31	11.0	0.03	0.3	2670	7691571
Customer 32	32.5	0.13	4.4	38124	45999589
Customer 33	83.0	0.45	37.1	324957	163213806
Customer 34	11.9	0.28	3.4	29389	84557334
Customer 35	44.0	0.09	4.0	35240	8840312
Customer 36	29.8	0.41	12.3	107871	1643077
Customer 37	3.7	0.12	0.4	3918	40705391
Customer 38	276.5	0.39	109.1	955397	71523368
Customer 39	44.4	0.09	4.2	36587	22675151
Customer 40	78.8	0.18	14.0	122683	14617150
Customer 41	76.4	0.02	1.8	15596	1971145
Customer 42	2.0	0.27	0.6	4840	41655337
Customer 43	20.9	0.22	4.5	39751	32292053
Customer 44	93.5	0.04	3.5	30399	10138889
Total	2329 kW	0.22 (average)	575 kW	5,034,940 kWh	2,034,836,023 kWh

$$\textbf{Primary loss factor} = \frac{\textbf{Annual average energy loss}}{\textbf{Annual energy consumption}} \times 100\%$$

$$\textbf{Primary loss factor} = \frac{5,034,940\ \textbf{kWh}}{2,034,836,023\ \textbf{kWh}} \times 100\% = 0.25\%$$

3.1.2 Evaluation of updated primary loss factor and comparison to previous calculation

The large user primary energy loss factor calculated via Navigant's methodology described herein is 0.25%. This compares to THESL's previous primary energy loss factor of 0.41% (Section 2.1). Again, both numbers account only for primary conductor losses.

The methodology that Navigant employed to arrive at the updated primary loss factor was based on methods and tools that are more rigorous than those used as evidence to support the factor submitted in the 2006 EDR filing. Whereas the loss load factor (LLF) for each of the feeders was previously estimated empirically, Navigant calculated LLFs for each customer based on actual 15-minute interval data (the average LLF was 0.21 for the large user class, shown in Table 4). The prior LLF of 0.53 that was used in the 1999 calculation (Table 1) was approximately 2.5 times as high, which would result in greater average energy losses.

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Furthermore, THESL used an assumed average power factor of 0.85 in the 1999 calculation in lieu of actual power factor data for the customers in its large user class. The current study used 15-minute meter data to model the actual power factor for each of the large users and the class power factor was on average 0.936. If real power demand remains constant and power factor decreases, apparent power and total line current increase. The much lower power factor assumed in the prior calculation would increase overall line current and thus increase the total losses in distribution (as in Equation 1). This would account for a significant decrease in the updated primary loss factor.

In addition to the difference in LLF and customer power factor, THESL has made significant upgrades to its network in the 20 years since its last loss factor study. Investments made to upgrade distribution system devices such as transformer change-outs, voltage conversion, reconductoring, rephasing, and the construction of newer or shorter feeders to service large users would result in lower overall losses in distribution to the large user class. Finally, a shift in customer-side operations for the large user class may also drive this change in technical losses. For example, shifting demand to off-peak times to avoid global adjustment costs, operating on-site cogeneration in parallel with load, and engaging in CDM and energy efficiency programs would effectively reduce peak demand losses caused by a large user.

3.1.3 Further Methodology Considerations

The methodology presented in this report is rigorous, standardized and repeatable and is comparable to current best practices for calculating loss factors in distribution networks. Navigant acknowledges gaps in data and modeling that would provide more accurate results, but are would not be expected to materially change the outcome of this study.

The first is that a uniform feeder power factor of 0.925 was assumed in absence of metered feeder level power factor data. Although customer power factors were known, a 15-minute metered feeder power factor would allow for a more direct alignment of feeder loading conditions at the simulated peak load state. As is, the assumed power factor may overstate or understate the ratio of real and reactive power that may be flowing on the feeder at any given time. Real and reactive power data is metered for large users, so this gap is bypassed when modeling dedicated feeders.

The second is that THESL has limited visibility into the full secondary network that a large user maintains to service its load. It is Navigant's engineering opinion that most of secondary losses would be attributable to step-down interface transformers that connect the customer load to the primary as it is often the case that secondary conductor is not long enough to cause significant loss. However, the inability to model the full customer secondary network means that modeled secondary losses may differ from actual conditions.

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4. CONCLUSIONS

Navigant conducted a load flow modeling based approach to updating the primary loss factor for THESL's Large User class of customers. Based on 15-minute interval meter data available at the feeder and customer level, we were able to achieve a high degree of accuracy in the loss estimation approach compared to previous methods for calculating system losses. In addition, the relatively small number of large users in THESL's network allowed us to conduct load flow simulations for all feeders and for all the customers in this load class, which increases the accuracy of our calculations and associated variances introduced by sampling a subset of these customers.

The primary loss factor for the large user class is 0.25% (compared to 0.41% submitted in the 2006 filing evidence). This factor includes only primary conductor losses which is aligned with the factor calculated in the previous filing. Calculated losses for secondary metered customers would need to be adjusted based on an accepted methodology to account for additional losses on sections of low voltage network. Although the updated primary loss factor is lower than the prior factor for the large user class, Navigant attributes the reduction due to: (1) the current modeling methodology being more accurate than prior studies because of accessibility of additional interval and CYME modeling data; and (2) more granular meter data allowing for modeling of actual customer power factors which are much higher than previously approximated values. In addition, upgrades made to THESL's network over the last 20 years and changes in customer-side operations to shift demand from peak periods and operating on-site generation to offset load would contribute to lower system losses. In conjunction, these factors support our findings that average annual losses are lower over the entire large user class compared to prior results.

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2020 RTSR Workform for Electricity Distributors

Drop-down lists are shaded blue; Input cells are shaded green.

Utility Name	Toronto Hydro-Electric System Limited
Service Territory	
Assigned EB Number	EB-2018-0165
Name and Title	
Phone Number	
Email Address	
Date	
Last COS Re-based Year	**2015**

This Workbook Model is protected by copyright and is being made available to you solely for the purpose of filing your COS application. You may use and copy this model for that purpose, and provide a copy of this model to any person that is advising or assisting you in that regard. Except as indicated above, any copying, reproduction, publication, sale, adaptation, translation, modification, reverse engineering or other use or dissemination of this model without the express written consent of the Ontario Energy Board is prohibited. If you provide a copy of this model to a person that is advising or assisting you in preparing the application or reviewing your draft rate order, you must ensure that the person understands and agrees to the restrictions noted above.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

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2020 RTSR Workform for Electricity Distributors

1. Info
2. Table of Contents
3. Rate Classes
4. RRR Data
5. UTRs and Sub-Transmission
6. Historical Wholesale
7. Current Wholesale
8. Forecast Wholesale
9. RTSR Rates to Forecast

Ontario Energy Board **v 1.2**

2020 RTSR Workform for Electricity Distributors

1. **Select the appropriate rate classes that appear on your most recent Board-Approved Tariff of Rates and Charges.**
2. **Enter the RTS Network and Connection Rate as it appears on the Tariff of Rates and Charges**

Rate Class	Unit	RTSR-Network	RTSR-Connection
Residential	kWh	0.0076	0.0062
Residential Regular	kWh	0.0076	0.0062
General Service Less Than 50 kW	kWh	0.0074	0.0055
General Service 50 to 999 kW	kW	2.5690	2.0515
General Service 1,000 to 4,999 kW	kW	2.4821	2.0494
Large Use > 5000 kW	kW	2.8295	2.2769
Unmetered Scattered Load	kWh	0.0046	0.0039
Street Lighting	kW	2.2849	2.4461
Choose Rate Class			
Choose Rate Class			
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Choose Rate Class			
Choose Rate Class			

Ontario Energy Board

v 1.2

2020 RTSR Workform for Electricity Distributors

Rate Class	Rate Description	Unit	Rate	Non-Loss Adjusted Metered kWh	Non-Loss Adjusted Metered kW	Applicable Loss Factor *eg: (1.0325)*	Loss Adjusted Billed kWh
Residential	RTSR - Network	kWh	0.0076	4,510,636,914		1.0295	4,643,700,703
Residential	RTSR - Connection	kWh	0.0062	4,510,636,914		1.0295	4,643,700,703
Residential Regular	RTSR - Network	kWh	0.0076	277,127,203		1.0295	285,302,456
Residential Regular	RTSR - Connection	kWh	0.0062	277,127,203		1.0295	285,302,456
General Service Less Than 50 kW	RTSR - Network	kWh	0.0074	2,267,638,936		1.0295	2,334,534,285
General Service Less Than 50 kW	RTSR - Connection	kWh	0.0055	2,267,638,936		1.0295	2,334,534,285
General Service 50 to 999 kW	RTSR - Network	kW	2.5690	9,587,728,582	22,878,951		
General Service 50 to 999 kW	RTSR - Connection	kW	2.0515	9,587,728,582	22,878,951		
General Service 1,000 to 4,999 kW	RTSR - Network	kW	2.4821	4,561,528,177	9,624,782		
General Service 1,000 to 4,999 kW	RTSR - Connection	kW	2.0494	4,561,528,177	9,624,782		
Large Use > 5000 kW	RTSR - Network	kW	2.8295	2,009,923,443	4,443,293		
Large Use > 5000 kW	RTSR - Connection	kW	2.2769	2,009,923,443	4,443,293		
Unmetered Scattered Load	RTSR - Network	kWh	0.0046	41,313,479		1.0295	42,532,226
Unmetered Scattered Load	RTSR - Connection	kWh	0.0039	41,313,479		1.0295	42,532,226
Street Lighting	RTSR - Network	kW	2.2849	115,390,403	326,622		
Street Lighting	RTSR - Connection	kW	2.4461	115,390,403	326,622		

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Uniform Transmission Rates	Unit	2018	2019	2020
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 3.66	$ 3.61	$ 3.61
Line Connection Service Rate	kW	$ 0.87	$ 0.95	$ 0.95
Transformation Connection Service Rate	kW	$ 2.02	$ 2.34	$ 2.34

Hydro One Sub-Transmission Rates	Unit	2018	2019	2020
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 3.1942	$ 3.1942	
Line Connection Service Rate	kW	$ 0.7710	$ 0.7710	
Transformation Connection Service Rate	kW	$ 1.7493	$ 1.7493	
Both Line and Transformation Connection Service Rate	kW	$ 2.5203	$ 2.5203	$ -

If needed, add extra host here. (I)	Unit	2018	2019	2020
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW			
Line Connection Service Rate	kW			
Transformation Connection Service Rate	kW			
Both Line and Transformation Connection Service Rate	kW	$ -	$ -	$ -

If needed, add extra host here. (II)	Unit	Effective January 1, 2018	Effective January 1, 2019	Effective January 1, 2020
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW			
Line Connection Service Rate	kW			
Transformation Connection Service Rate	kW			
Both Line and Transformation Connection Service Rate	kW	$ -	$ -	$ -

		Historical 2018	Current 2019	Forecast 2020
Low Voltage Switchgear Credit (if applicable, enter as a negative value)	$	-$ 10,042,014	-$ 10,042,014	-$ 10,042,014

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2020 RTSR Workform for Electricity Distributors

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants on Sheet "4. RRR Data". For Hydro One Sub-transmission Rates, if you are charged a *combined* Line and Transformer connection rate, please ensure that both the line connection and transformer connection columns are completed.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	3,839,383	$3.52	13,514,627	3,607,436	$0.88	3,174,544	3,551,116	$2.13	7,563,878	$ 10,738,422
February	3,708,020	$3.52	13,052,230	3,541,237	$0.88	3,116,289	3,484,007	$2.13	7,420,935	$ 10,537,223
March	3,674,590	$3.52	12,934,557	3,545,780	$0.88	3,120,286	3,487,030	$2.13	7,427,374	$ 10,547,661
April	3,306,272	$3.52	11,638,079	3,507,369	$0.88	3,086,484	3,447,347	$2.13	7,342,850	$ 10,429,334
May	3,559,825	$3.52	12,530,585	3,388,728	$0.88	2,982,081	3,313,919	$2.13	7,058,648	$ 10,040,728
June	4,229,363	$3.52	14,887,357	3,945,478	$0.88	3,472,020	3,887,829	$2.13	8,281,075	$ 11,753,095
July	4,205,569	$3.52	14,803,602	3,972,684	$0.88	3,495,962	3,900,902	$2.13	8,308,921	$ 11,804,882
August	4,084,611	$3.52	14,377,831	3,885,448	$0.88	3,419,194	3,827,102	$2.13	8,151,728	$ 11,570,922
September	4,407,905	$3.52	15,515,827	4,190,349	$0.88	3,687,507	4,126,671	$2.13	8,789,810	$ 12,477,317
October	3,381,493	$3.52	11,902,854	3,278,393	$0.88	2,884,986	3,238,599	$2.13	6,898,215	$ 9,783,201
November	3,349,423	$3.52	11,789,969	3,312,347	$0.88	2,914,865	3,414,801	$2.13	7,273,526	$ 10,188,391
December	3,644,538	$3.52	12,828,774	3,641,081	$0.88	3,204,151	3,727,966	$2.13	7,940,568	$ 11,144,719
Total	45,390,992	$ 3.52	$ 159,776,291	43,816,330	$ 0.88	$ 38,558,370	43,407,289	$ 2.13	$ 92,457,526	$ 131,015,896

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		$ -
August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

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In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants on Sheet "4. RRR Data". For Hydro One Sub-transmission Rates, if you are charged a *combined* Line and Transformer connection rate, please ensure that both the line connection and transformer connection columns are completed.

Add Extra Host Here (I) (if needed)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		$ -
August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (II) (if needed)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		$ -
August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	3,839,383	$3.52	$ 13,514,627	3,607,436	$0.88	$ 3,174,544	3,551,116	$2.13	$ 7,563,878	$ 10,738,422
February	3,708,020	$3.52	$ 13,052,230	3,541,237	$0.88	$ 3,116,289	3,484,007	$2.13	$ 7,420,935	$ 10,537,223
March	3,674,590	$3.52	$ 12,934,557	3,545,780	$0.88	$ 3,120,286	3,487,030	$2.13	$ 7,427,374	$ 10,547,661
April	3,306,272	$3.52	$ 11,638,079	3,507,369	$0.88	$ 3,086,484	3,447,347	$2.13	$ 7,342,850	$ 10,429,334
May	3,559,825	$3.52	$ 12,530,585	3,388,728	$0.88	$ 2,982,081	3,313,919	$2.13	$ 7,058,648	$ 10,040,728
June	4,229,363	$3.52	$ 14,887,357	3,945,478	$0.88	$ 3,472,020	3,887,829	$2.13	$ 8,281,075	$ 11,753,095
July	4,205,569	$3.52	$ 14,803,602	3,972,684	$0.88	$ 3,495,962	3,900,902	$2.13	$ 8,308,921	$ 11,804,882
August	4,084,611	$3.52	$ 14,377,831	3,885,448	$0.88	$ 3,419,194	3,827,102	$2.13	$ 8,151,728	$ 11,570,922
September	4,407,905	$3.52	$ 15,515,827	4,190,349	$0.88	$ 3,687,507	4,126,671	$2.13	$ 8,789,810	$ 12,477,317
October	3,381,493	$3.52	$ 11,902,854	3,278,393	$0.88	$ 2,884,986	3,238,599	$2.13	$ 6,898,215	$ 9,783,201
November	3,349,423	$3.52	$ 11,789,969	3,312,347	$0.88	$ 2,914,865	3,414,801	$2.13	$ 7,273,526	$ 10,188,391
December	3,644,538	$3.52	$ 12,828,774	3,641,081	$0.88	$ 3,204,151	3,727,966	$2.13	$ 7,940,568	$ 11,144,719
Total	45,390,992	$ 3.52	$ 159,776,291	43,816,330	$ 0.88	$ 38,558,370	43,407,289	$ 2.13	$ 92,457,526	$ 131,015,896

Low Voltage Switchgear Credit (if applicable)	-$ 10,042,014
Total including deduction for Low Voltage Switchgear Credit	$ 120,973,882

Ontario Energy Board v 1.2

2020 RTSR Workform for Electricity Distributors

The purpose of this sheet is to calculate the expected billing when current 2018 Uniform Transmission Rates are applied against historical 2017 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	3,839,383	$ 3.6100	$ 13,860,171	3,607,436	$ 0.9500	$ 3,427,064	3,551,116	$ 2.3400	$ 8,309,612	$ 11,736,677
February	3,708,020	$ 3.6100	$ 13,385,952	3,541,237	$ 0.9500	$ 3,364,175	3,484,007	$ 2.3400	$ 8,152,576	$ 11,516,751
March	3,674,590	$ 3.6100	$ 13,265,270	3,545,780	$ 0.9500	$ 3,368,491	3,487,030	$ 2.3400	$ 8,159,651	$ 11,528,142
April	3,306,272	$ 3.6100	$ 11,935,643	3,507,369	$ 0.9500	$ 3,332,000	3,447,347	$ 2.3400	$ 8,066,793	$ 11,398,793
May	3,559,825	$ 3.6100	$ 12,850,969	3,388,728	$ 0.9500	$ 3,219,292	3,313,919	$ 2.3400	$ 7,754,571	$ 10,973,862
June	4,229,363	$ 3.6100	$ 15,268,000	3,945,478	$ 0.9500	$ 3,748,204	3,887,829	$ 2.3400	$ 9,097,519	$ 12,845,723
July	4,205,569	$ 3.6100	$ 15,182,103	3,972,684	$ 0.9500	$ 3,774,050	3,900,902	$ 2.3400	$ 9,128,110	$ 12,902,160
August	4,084,611	$ 3.6100	$ 14,745,446	3,885,448	$ 0.9500	$ 3,691,175	3,827,102	$ 2.3400	$ 8,955,420	$ 12,646,595
September	4,407,905	$ 3.6100	$ 15,912,539	4,190,349	$ 0.9500	$ 3,980,832	4,126,671	$ 2.3400	$ 9,656,411	$ 13,637,242
October	3,381,493	$ 3.6100	$ 12,207,189	3,278,393	$ 0.9500	$ 3,114,474	3,238,599	$ 2.3400	$ 7,578,321	$ 10,692,795
November	3,349,423	$ 3.6100	$ 12,091,417	3,312,347	$ 0.9500	$ 3,146,730	3,414,801	$ 2.3400	$ 7,990,634	$ 11,137,364
December	3,644,538	$ 3.6100	$ 13,156,782	3,641,081	$ 0.9500	$ 3,459,027	3,727,966	$ 2.3400	$ 8,723,440	$ 12,182,467
Total	45,390,992	$ 3.61	$ 163,861,481	43,816,330	$ 0.95	$ 41,625,513	43,407,289	$ 2.34	$ 101,573,057	$ 143,198,570

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ 3.1942	$ -	-	$ 0.7710	$ -	-	$ 1.7493	$ -	$ -
February	-	$ 3.1942	$ -	-	$ 0.7710	$ -	-	$ 1.7493	$ -	$ -
March	-	$ 3.1942	$ -	-	$ 0.7710	$ -	-	$ 1.7493	$ -	$ -
April	-	$ 3.1942	$ -	-	$ 0.7710	$ -	-	$ 1.7493	$ -	$ -
May	-	$ 3.1942	$ -	-	$ 0.7710	$ -	-	$ 1.7493	$ -	$ -
June	-	$ 3.1942	$ -	-	$ 0.7710	$ -	-	$ 1.7493	$ -	$ -
July	-	$ 3.1942	$ -	-	$ 0.7710	$ -	-	$ 1.7493	$ -	$ -
August	-	$ 3.1942	$ -	-	$ 0.7710	$ -	-	$ 1.7493	$ -	$ -
September	-	$ 3.1942	$ -	-	$ 0.7710	$ -	-	$ 1.7493	$ -	$ -
October	-	$ 3.1942	$ -	-	$ 0.7710	$ -	-	$ 1.7493	$ -	$ -
November	-	$ 3.1942	$ -	-	$ 0.7710	$ -	-	$ 1.7493	$ -	$ -
December	-	$ 3.1942	$ -	-	$ 0.7710	$ -	-	$ 1.7493	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (I)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Ontario Energy Board v 1.2

2020 RTSR Workform for Electricity Distributors

The purpose of this sheet is to calculate the expected billing when current 2018 Uniform Transmission Rates are applied against historical 2017 transmission units.

Add Extra Host Here (II)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	3,839,383	$3.61	$ 13,860,171	3,607,436	$0.95	$ 3,427,064	3,551,116	$2.34	$ 8,309,612	$ 11,736,677
February	3,708,020	$3.61	$ 13,385,952	3,541,237	$0.95	$ 3,364,175	3,484,007	$2.34	$ 8,152,576	$ 11,516,751
March	3,674,590	$3.61	$ 13,265,270	3,545,780	$0.95	$ 3,368,491	3,487,030	$2.34	$ 8,159,651	$ 11,528,142
April	3,306,272	$3.61	$ 11,935,643	3,507,369	$0.95	$ 3,332,000	3,447,347	$2.34	$ 8,066,793	$ 11,398,793
May	3,559,825	$3.61	$ 12,850,969	3,388,728	$0.95	$ 3,219,292	3,313,919	$2.34	$ 7,754,571	$ 10,973,862
June	4,229,363	$3.61	$ 15,268,000	3,945,478	$0.95	$ 3,748,204	3,887,829	$2.34	$ 9,097,519	$ 12,845,723
July	4,205,569	$3.61	$ 15,182,103	3,972,684	$0.95	$ 3,774,050	3,900,902	$2.34	$ 9,128,110	$ 12,902,160
August	4,084,611	$3.61	$ 14,745,446	3,885,448	$0.95	$ 3,691,175	3,827,102	$2.34	$ 8,955,420	$ 12,646,595
September	4,407,905	$3.61	$ 15,912,539	4,190,349	$0.95	$ 3,980,832	4,126,671	$2.34	$ 9,656,411	$ 13,637,242
October	3,381,493	$3.61	$ 12,207,189	3,278,393	$0.95	$ 3,114,474	3,238,599	$2.34	$ 7,578,321	$ 10,692,795
November	3,349,423	$3.61	$ 12,091,417	3,312,347	$0.95	$ 3,146,730	3,414,801	$2.34	$ 7,990,634	$ 11,137,364
December	3,644,538	$3.61	$ 13,156,782	3,641,081	$0.95	$ 3,459,027	3,727,966	$2.34	$ 8,723,440	$ 12,182,467
Total	45,390,992	$ 3.61	$ 163,861,481	43,816,330	$ 0.95	$ 41,625,513	43,407,289	$ 2.34	$ 101,573,057	$ 143,198,570

Low Voltage Switchgear Credit (if applicable)	-$ 10,042,014
Total including deduction for Low Voltage Switchgear Credit	$ 133,156,556

Ontario Energy Board v 1.2

2020 RTSR Workform for Electricity Distributors

The purpose of this sheet is to calculate the expected billing when forecasted 2019 Uniform Transmission Rates are applied against historical 2017 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	3,839,383	$ 3.6100	$ 13,860,171	3,607,436	$ 0.9500	$ 3,427,064	3,551,116	$ 2.3400	$ 8,309,612	$ 11,736,677
February	3,708,020	$ 3.6100	$ 13,385,952	3,541,237	$ 0.9500	$ 3,364,175	3,484,007	$ 2.3400	$ 8,152,576	$ 11,516,751
March	3,674,590	$ 3.6100	$ 13,265,270	3,545,780	$ 0.9500	$ 3,368,491	3,487,030	$ 2.3400	$ 8,159,651	$ 11,528,142
April	3,306,272	$ 3.6100	$ 11,935,643	3,507,369	$ 0.9500	$ 3,332,000	3,447,347	$ 2.3400	$ 8,066,793	$ 11,398,793
May	3,559,825	$ 3.6100	$ 12,850,969	3,388,728	$ 0.9500	$ 3,219,292	3,313,919	$ 2.3400	$ 7,754,571	$ 10,973,862
June	4,229,363	$ 3.6100	$ 15,268,000	3,945,478	$ 0.9500	$ 3,748,204	3,887,829	$ 2.3400	$ 9,097,519	$ 12,845,723
July	4,205,569	$ 3.6100	$ 15,182,103	3,972,684	$ 0.9500	$ 3,774,050	3,900,902	$ 2.3400	$ 9,128,110	$ 12,902,160
August	4,084,611	$ 3.6100	$ 14,745,446	3,885,448	$ 0.9500	$ 3,691,175	3,827,102	$ 2.3400	$ 8,955,420	$ 12,646,595
September	4,407,905	$ 3.6100	$ 15,912,539	4,190,349	$ 0.9500	$ 3,980,832	4,126,671	$ 2.3400	$ 9,656,411	$ 13,637,242
October	3,381,493	$ 3.6100	$ 12,207,189	3,278,393	$ 0.9500	$ 3,114,474	3,238,599	$ 2.3400	$ 7,578,321	$ 10,692,795
November	3,349,423	$ 3.6100	$ 12,091,417	3,312,347	$ 0.9500	$ 3,146,730	3,414,801	$ 2.3400	$ 7,990,634	$ 11,137,364
December	3,644,538	$ 3.6100	$ 13,156,782	3,641,081	$ 0.9500	$ 3,459,027	3,727,966	$ 2.3400	$ 8,723,440	$ 12,182,467
Total	45,390,992	$ 3.61	$ 163,861,481	43,816,330	$ 0.95	$ 41,625,513	43,407,289	$ 2.34	$ 101,573,057	$ 143,198,570

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (I)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Ontario Energy Board v 1.2

2020 RTSR Workform for Electricity Distributors

The purpose of this sheet is to calculate the expected billing when forecasted 2019 Uniform Transmission Rates are applied against historical 2017 transmission units.

Add Extra Host Here (II)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	3,839,383	$ 3.61	13,860,171	3,607,436	$ 0.95	3,427,064	3,551,116	$ 2.34	8,309,612	$ 11,736,677
February	3,708,020	$ 3.61	13,385,952	3,541,237	$ 0.95	3,364,175	3,484,007	$ 2.34	8,152,576	$ 11,516,751
March	3,674,590	$ 3.61	13,265,270	3,545,780	$ 0.95	3,368,491	3,487,030	$ 2.34	8,159,651	$ 11,528,142
April	3,306,272	$ 3.61	11,935,643	3,507,369	$ 0.95	3,332,000	3,447,347	$ 2.34	8,066,793	$ 11,398,793
May	3,559,825	$ 3.61	12,850,969	3,388,728	$ 0.95	3,219,292	3,313,919	$ 2.34	7,754,571	$ 10,973,862
June	4,229,363	$ 3.61	15,268,000	3,945,478	$ 0.95	3,748,204	3,887,829	$ 2.34	9,097,519	$ 12,845,723
July	4,205,569	$ 3.61	15,182,103	3,972,684	$ 0.95	3,774,050	3,900,902	$ 2.34	9,128,110	$ 12,902,160
August	4,084,611	$ 3.61	14,745,446	3,885,448	$ 0.95	3,691,175	3,827,102	$ 2.34	8,955,420	$ 12,646,595
September	4,407,905	$ 3.61	15,912,539	4,190,349	$ 0.95	3,980,832	4,126,671	$ 2.34	9,656,411	$ 13,637,242
October	3,381,493	$ 3.61	12,207,189	3,278,393	$ 0.95	3,114,474	3,238,599	$ 2.34	7,578,321	$ 10,692,795
November	3,349,423	$ 3.61	12,091,417	3,312,347	$ 0.95	3,146,730	3,414,801	$ 2.34	7,990,634	$ 11,137,364
December	3,644,538	$ 3.61	13,156,782	3,641,081	$ 0.95	3,459,027	3,727,966	$ 2.34	8,723,440	$ 12,182,467
Total	45,390,992	$ 3.61	$ 163,861,481	43,816,330	$ 0.95	$ 41,625,513	43,407,289	$ 2.34	$ 101,573,057	$ 143,198,570
							Low Voltage Switchgear Credit (if applicable)			-$ 10,042,014
							Total including deduction for Low Voltage Switchgear Credit			$ 133,156,556

Ontario Energy Board

v 1.2

2020 RTSR Workform for Electricity Distributors

The purpose of this sheet is to re-align the current RTS Network Rates to recover current wholesale network costs.

Rate Class	Rate Description	Unit	Current RTSR-Network	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Adjusted RTSR Network
Residential	RTSR - Network	kWh	0.0076	4,643,700,703		35,245,688	23.4%	38,287,490	0.0082
Residential Regular	RTSR - Network	kWh	0.0076	285,302,456		2,165,446	1.4%	2,352,330	0.0082
General Service Less Than 50 kW	RTSR - Network	kWh	0.0074	2,334,534,285		17,252,208	11.4%	18,741,122	0.0080
General Service 50 to 999 kW	RTSR - Network	kW	2.5690		22,878,951	58,776,025	39.0%	63,848,561	2.7907
General Service 1,000 to 4,999 kW	RTSR - Network	kW	2.4821		9,624,782	23,889,671	15.8%	25,951,417	2.6963
Large Use > 5000 kW	RTSR - Network	kW	2.8295		4,443,293	12,572,298	8.3%	13,657,322	3.0737
Unmetered Scattered Load	RTSR - Network	kWh	0.0046	42,532,226		195,648	0.1%	212,533	0.0050
Street Lighting	RTSR - Network	kW	2.2849		326,622	746,299	0.5%	810,706	2.4821

The purpose of this table is to re-align the current RTS Connection Rates to recover current wholesale connection costs.

Rate Class	Rate Description	Unit	Current RTSR-Connection	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Adjusted RTSR-Connection
Residential	RTSR - Connection	kWh	0.0062	4,643,700,703		28,651,633	23.7%	31,519,369	0.0068
Residential Regular	RTSR - Connection	kWh	0.0062	285,302,456		1,760,316	1.5%	1,936,506	0.0068
General Service Less Than 50 kW	RTSR - Connection	kWh	0.0055	2,334,534,285		12,886,629	10.6%	14,176,449	0.0061
General Service 50 to 999 kW	RTSR - Connection	kW	2.0515		22,878,951	46,936,168	38.8%	51,633,999	2.2568
General Service 1,000 to 4,999 kW	RTSR - Connection	kW	2.0494		9,624,782	19,725,028	16.3%	21,699,302	2.2545
Large Use > 5000 kW	RTSR - Connection	kW	2.2769		4,443,293	10,116,934	8.4%	11,129,536	2.5048
Unmetered Scattered Load	RTSR - Connection	kWh	0.0039	42,532,226		165,876	0.1%	182,478	0.0043
Street Lighting	RTSR - Connection	kW	2.4461		326,622	798,950	0.7%	878,917	2.6909

The purpose of this table is to update the re-aligned RTS Network Rates to recover future wholesale network costs.

Rate Class	Rate Description	Unit	Adjusted RTSR-Network	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR-Network
Residential	RTSR - Network	kWh	0.0082	4,643,700,703		38,287,490	23.4%	38,287,490	**0.00825**
Residential Regular	RTSR - Network	kWh	0.0082	285,302,456		2,352,330	1.4%	2,352,330	**0.00825**
General Service Less Than 50 kW	RTSR - Network	kWh	0.0080	2,334,534,285		18,741,122	11.4%	18,741,122	**0.00803**
General Service 50 to 999 kW	RTSR - Network	kW	2.7907		22,878,951	63,848,561	39.0%	63,848,561	**2.75250**
General Service 1,000 to 4,999 kW	RTSR - Network	kW	2.6963		9,624,782	25,951,417	15.8%	25,951,417	**2.65940**
Large Use > 5000 kW	RTSR - Network	kW	3.0737		4,443,293	13,657,322	8.3%	13,657,322	**3.03160**
Unmetered Scattered Load	RTSR - Network	kWh	0.0050	42,532,226		212,533	0.1%	212,533	**0.00500**
Street Lighting	RTSR - Network	kW	2.4821		326,622	810,706	0.5%	810,706	**2.44810**

The purpose of this table is to update the re-aligned RTS Connection Rates to recover future wholesale connection costs.

Rate Class	Rate Description	Unit	Adjusted RTSR-Connection	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR-Connection
Residential	RTSR - Connection	kWh	0.0068	4,643,700,703		31,519,369	23.7%	31,519,369	**0.00679**
Residential Regular	RTSR - Connection	kWh	0.0068	285,302,456		1,936,506	1.5%	1,936,506	**0.00679**
General Service Less Than 50 kW	RTSR - Connection	kWh	0.0061	2,334,534,285		14,176,449	10.6%	14,176,449	**0.00607**
General Service 50 to 999 kW	RTSR - Connection	kW	2.2568		22,878,951	51,633,999	38.8%	51,633,999	**2.22590**
General Service 1,000 to 4,999 kW	RTSR - Connection	kW	2.2545		9,624,782	21,699,302	16.3%	21,699,302	**2.22360**
Large Use > 5000 kW	RTSR - Connection	kW	2.5048		4,443,293	11,129,536	8.4%	11,129,536	**2.47050**
Unmetered Scattered Load	RTSR - Connection	kWh	0.0043	42,532,226		182,478	0.1%	182,478	**0.00429**
Street Lighting	RTSR - Connection	kW	2.6909		326,622	878,917	0.7%	878,917	**2.65410**

OEB Appendix 2-W
Bill Impacts

Customer Class: RESIDENTIAL SERVICE

TOU / non-TOU: TOU

Consumption 750 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	2018 Current Board-Approved Rate ($)	Volume	Charge ($)	2019 Expected Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change	2020 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change	2021 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change	2022 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change	2023 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change	2024 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change
Service Charge	per 30 days	$ 32.63	1	$ 32.63	$ 37.46	1	$ 37.46	$ 4.83	14.80%	$ 42.14	1	$ 42.14	$ 4.68	12.49%	$ 43.51	1	$ 43.51	$ 1.37	3.25%	$ 44.58	1	$ 44.58	$ 1.07	2.46%	$ 46.47	1	$ 46.47	$ 1.89	4.24%	$ 48.30	1	$ 48.30	$ 1.83	3.94%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per 30 days									$ 0.09	1	$ 0.09	$ 0.09		$ 0.09	1	$ 0.09	$ -	0.00%	$ 0.09	1	$ 0.09	$ -	0.00%	$ 0.09	1	$ 0.09	$ -	0.00%	$ 0.09	1	$ 0.09	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per 30 days									$ 0.90	1	$ 0.90	$ 0.90		$ 0.90	1	$ 0.90	$ -	0.00%	$ 0.90	1	$ 0.90	$ -	0.00%	$ 0.90	1	$ 0.90	$ -	0.00%	$ 0.90	1	$ 0.90	$ -	0.00%
Rate Rider for Recovery of Monthly Billing - effective until Dec. 31, 2024	per 30 days									$ 0.28	1	$ 0.28	$ 0.28		$ 0.28	1	$ 0.28	$ -	0.00%	$ 0.28	1	$ 0.28	$ -	0.00%	$ 0.28	1	$ 0.28	$ -	0.00%	$ 0.28	1	$ 0.28	$ -	0.00%
Rate Rider for Recovery of Stranded Meter Assets - effective until Dec. 31, 2024	per 30 days									-$ 0.02	1	-$ 0.02	-$ 0.02		-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per 30 days									-$ 0.75	1	-$ 0.75	-$ 0.75		-$ 0.75	1	-$ 0.75	$ -	0.00%	-$ 0.75	1	-$ 0.75	$ -	0.00%	-$ 0.75	1	-$ 0.75	$ -	0.00%	-$ 0.75	1	-$ 0.75	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per 30 days									-$ 0.12	1	-$ 0.12	-$ 0.12		-$ 0.12	1	-$ 0.12	$ -	0.00%	-$ 0.12	1	-$ 0.12	$ -	0.00%	-$ 0.12	1	-$ 0.12	$ -	0.00%	-$ 0.12	1	-$ 0.12	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per 30 days									-$ 0.01	1	-$ 0.01	-$ 0.01		-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per 30 days									-$ 0.02	1	-$ 0.02	-$ 0.02		-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per 30 days									-$ 0.63	1	-$ 0.63	-$ 0.63		-$ 0.63	1	-$ 0.63	$ -	0.00%	-$ 0.63	1	-$ 0.63	$ -	0.00%	-$ 0.63	1	-$ 0.63	$ -	0.00%	-$ 0.63	1	-$ 0.63	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per 30 days									-$ 0.02	1	-$ 0.02	-$ 0.02		-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per 30 days									-$ 0.45	1	-$ 0.45	-$ 0.45		-$ 0.45	1	-$ 0.45	$ -	0.00%	-$ 0.45	1	-$ 0.45	$ -	0.00%	-$ 0.45	1	-$ 0.45	$ -	0.00%	-$ 0.45	1	-$ 0.45	$ -	0.00%
Rate Rider for Disposition of AR Credits - effective until Dec. 31, 2024	per 30 days									-$ 0.08	1	-$ 0.08	-$ 0.08		-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%
Rate Rider for Recovery of Stranded Meters Assets - effective until Dec. 31, 2019.	per 30 days	$ 0.28	1	$ 0.28	$ 0.28	1	$ 0.28	$ -	0.00%		1	$ -	-$ 0.28			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per 30 days	-$ 0.48	1	-$ 0.48		1	$ -	$ 0.48			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per 30 days	-$ 1.48	1	-$ 1.48		1	$ -	$ 1.48			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per 30 days	$ 0.10	1	$ 0.10	$ 0.10	1	$ 0.10	$ -	0.00%		1	$ -	-$ 0.10			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per 30 days	$ 0.03	1	$ 0.03	$ 0.03	1	$ 0.03	$ -	0.00%		1	$ -	-$ 0.03			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per 30 days	$ 0.46	1	$ 0.46	$ 0.46	1	$ 0.46	$ -	0.00%		1	$ -	-$ 0.46			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.88	1	$ 0.88	$ 0.88	1	$ 0.88	$ -	0.00%		1	$ -	-$ 0.88			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.28	1	$ 0.28	$ 0.28	1	$ 0.28	$ -	0.00%		1	$ -	-$ 0.28			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.01063	750	$ 7.97	$ 0.00552	750	$ 4.14	-$ 3.83	-48.07%		750	$ -	-$ 4.14			750	$ -	$ -			750	$ -	$ -			750	$ -	$ -			750	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kWh	$ 0.00041	750	$ 0.31		750	$ -	-$ 0.31			750	$ -	$ -			750	$ -	$ -			750	$ -	$ -			750	$ -	$ -			750	$ -	$ -	
Sub-Total A (excluding pass through)				**$ 40.98**			**$ 43.63**	**$ 2.65**	**6.47%**			**$ 41.31**	**-$ 2.32**	**-5.32%**			**$ 42.68**	**$ 1.37**	**3.32%**			**$ 43.75**	**$ 1.07**	**2.51%**			**$ 45.64**	**$ 1.89**	**4.32%**			**$ 47.47**	**$ 1.83**	**4.01%**
Line Losses on Cost of Power	per kWh	$ 0.0820	28	$ 2.31	$ 0.0820	28	$ 2.31	$ -	0.00%	$ 0.0820	22	$ 1.81	-$ 0.50	-21.54%	$ 0.0820	22	$ 1.81	$ -	0.00%	$ 0.0820	22	$ 1.81	$ -	0.00%	$ 0.0820	22	$ 1.81	$ -	0.00%	$ 0.0820	22	$ 1.81	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until Dec. 31, 2018.	per kWh	-$ 0.00320	750	-$ 2.40		750	$ -	$ 2.40				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account (2018) Applicable only for Class B Customers - effective until Dec. 31, 2018	per kWh	$ 0.00007	750	$ 0.05		750	$ -	-$ 0.05				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Global Adjustment Account (2018) Applicable only for Non-RPP Customers - effective until Dec. 31, 2018.	per kWh	-$ 0.00112		$ -			$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	per 30 days	$ 0.56	1	$ 0.56	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%			$ -	-$ 0.56				$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 41.50**			**$ 46.50**	**$ 5.00**	**12.04%**			**$ 43.68**	**-$ 2.82**	**-6.06%**			**$ 45.05**	**$ 1.37**	**3.14%**			**$ 46.12**	**$ 1.07**	**2.37%**			**$ 47.45**	**$ 1.33**	**2.88%**			**$ 49.28**	**$ 1.83**	**3.86%**
Retail Transmissioin Rate - Network Service Rate	per kWh	$ 0.00759	778	$ 5.91	$ 0.00826	778	$ 6.43	$ 0.52	8.83%	$ 0.00825	772	$ 6.37	-$ 0.06	-0.90%	$ 0.00825	772	$ 6.37	$ -	0.00%	$ 0.00825	772	$ 6.37	$ -	0.00%	$ 0.00825	772	$ 6.37	$ -	0.00%	$ 0.00825	772	$ 6.37	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	per kWh	$ 0.00617	778	$ 4.80	$ 0.00680	778	$ 5.29	$ 0.49	10.21%	$ 0.00679	772	$ 5.24	-$ 0.05	-0.93%	$ 0.00679	772	$ 5.24	$ -	0.00%	$ 0.00679	772	$ 5.24	$ -	0.00%	$ 0.00679	772	$ 5.24	$ -	0.00%	$ 0.00679	772	$ 5.24	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				**$ 52.21**			**$ 58.22**	**$ 6.01**	**11.51%**			**$ 55.30**	**-$ 2.93**	**-5.02%**			**$ 56.67**	**$ 1.37**	**2.48%**			**$ 57.74**	**$ 1.07**	**1.89%**			**$ 59.07**	**$ 1.33**	**2.30%**			**$ 60.90**	**$ 1.83**	**3.10%**
Wholesale Market Service Rate - not including CBR	per kWh	$ 0.0032	778	$ 2.49	$ 0.0032	778	$ 2.49	$ -	0.00%	$ 0.0032	772	$ 2.47	-$ 0.02	-0.78%	$ 0.0032	772	$ 2.47	$ -	0.00%	$ 0.0032	772	$ 2.47	$ -	0.00%	$ 0.0032	772	$ 2.47	$ -	0.00%	$ 0.0032	772	$ 2.47	$ -	0.00%
Rural and Remote Rate Protection Charge (RRRP)	per kWh	$ 0.0003	778	$ 0.23	$ 0.0003	778	$ 0.23	$ -	0.00%	$ 0.0003	772	$ 0.23	-$ 0.00	-0.78%	$ 0.0003	772	$ 0.23	$ -	0.00%	$ 0.0003	772	$ 0.23	$ -	0.00%	$ 0.0003	772	$ 0.23	$ -	0.00%	$ 0.0003	772	$ 0.23	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	778	$ 0.31	$ 0.0004	778	$ 0.31	$ -	0.00%	$ 0.0004	772	$ 0.31	-$ 0.00	-0.78%	$ 0.0004	772	$ 0.31	$ -	0.00%	$ 0.0004	772	$ 0.31	$ -	0.00%	$ 0.0004	772	$ 0.31	$ -	0.00%	$ 0.0004	772	$ 0.31	$ -	0.00%
Standard Supply Service - Administrative Charge (if applicable)	per 30 days	$ 0.25	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	488	$ 31.69	$ 0.0650	488	$ 31.69	$ -	0.00%	$ 0.0650	488	$ 31.69	$ -	0.00%	$ 0.0650	488	$ 31.69	$ -	0.00%	$ 0.0650	488	$ 31.69	$ -	0.00%	$ 0.0650	488	$ 31.69	$ -	0.00%	$ 0.0650	488	$ 31.69	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	128	$ 11.99	$ 0.0940	128	$ 11.99	$ -	0.00%	$ 0.0940	128	$ 11.99	$ -	0.00%	$ 0.0940	128	$ 11.99	$ -	0.00%	$ 0.0940	128	$ 11.99	$ -	0.00%	$ 0.0940	128	$ 11.99	$ -	0.00%	$ 0.0940	128	$ 11.99	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	135	$ 17.82	$ 0.1320	135	$ 17.82	$ -	0.00%	$ 0.1320	135	$ 17.82	$ -	0.00%	$ 0.1320	135	$ 17.82	$ -	0.00%	$ 0.1320	135	$ 17.82	$ -	0.00%	$ 0.1320	135	$ 17.82	$ -	0.00%	$ 0.1320	135	$ 17.82	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	600	$ 46.20	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	150	$ 13.35	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 116.99**			**$ 123.00**	**$ 6.01**	**5.1%**			**$ 120.05**	**-$ 2.95**	**-2.4%**			**$ 121.42**	**$ 1.37**	**1.1%**			**$ 122.49**	**$ 1.07**	**0.9%**			**$ 123.82**	**$ 1.33**	**1.1%**			**$ 125.65**	**$ 1.83**	**1.5%**
8% Provincial Rebate		-8%		-$ 9.36	-8%		-$ 9.84	-$ 0.48	5.1%	-8%		-$ 9.60	$ 0.24	-2.4%	-8%		-$ 9.71	-$ 0.11	1.1%	-8%		-$ 9.80	-$ 0.09	0.9%	-8%		-$ 9.91	-$ 0.11	1.1%	-8%		-$ 10.05	-$ 0.15	1.5%
HST		13%		$ 15.21	13%		$ 15.99	$ 0.78	5.1%	13%		$ 15.61	-$ 0.38	-2.4%	13%		$ 15.78	$ 0.18	1.1%	13%		$ 15.92	$ 0.14	0.9%	13%		$ 16.10	$ 0.17	1.1%	13%		$ 16.33	$ 0.24	1.5%
Total Bill on TOU (after Tax & Rebate)				**$ 122.84**			**$ 129.15**	**$ 6.31**	**5.1%**			**$ 126.05**	**-$ 3.10**	**-2.4%**			**$ 127.49**	**$ 1.44**	**1.1%**			**$ 128.62**	**$ 1.12**	**0.9%**			**$ 130.01**	**$ 1.40**	**1.1%**			**$ 131.93**	**$ 1.92**	**1.5%**
Loss Factor (%)		3.76%			3.76%					2.95%					2.95%					2.95%					2.95%					2.95%				

Appendix 2-W
Bill Impacts

Customer Class: RESIDENTIAL SERVICE

TOU / non-TOU: TOU

Consumption 212 kWh ○ May 1 - October 31 ● November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		2018 Current Board-Approved			2019 Expected			Impact		2020 Proposed			Impact		2021 Proposed			Impact		2022 Proposed			Impact		2023 Proposed			Impact		2024 Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change
Service Charge	per 30 days	$ 32.63	1	$ 32.63	$ 37.46	1	$ 37.46	$ 4.83	14.80%	$ 42.14	1	$ 42.14	$ 4.68	12.49%	$ 43.51	1	$ 43.51	$ 1.37	3.25%	$ 44.58	1	$ 44.58	$ 1.07	2.46%	$ 46.47	1	$ 46.47	$ 1.89	4.24%	$ 48.30	1	$ 48.30	$ 1.83	3.94%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per 30 days									$ 0.09	1	$ 0.09	$ 0.09		$ 0.09	1	$ 0.09	$ -	0.00%	$ 0.09	1	$ 0.09	$ -	0.00%	$ 0.09	1	$ 0.09	$ -	0.00%	$ 0.09	1	$ 0.09	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per 30 days									$ 0.90	1	$ 0.90	$ 0.90		$ 0.90	1	$ 0.90	$ -	0.00%	$ 0.90	1	$ 0.90	$ -	0.00%	$ 0.90	1	$ 0.90	$ -	0.00%	$ 0.90	1	$ 0.90	$ -	0.00%
Rate Rider for Recovery of Monthly Billing - effective until Dec. 31, 2024	per 30 days									$ 0.28	1	$ 0.28	$ 0.28		$ 0.28	1	$ 0.28	$ -	0.00%	$ 0.28	1	$ 0.28	$ -	0.00%	$ 0.28	1	$ 0.28	$ -	0.00%	$ 0.28	1	$ 0.28	$ -	0.00%
Rate Rider for Recovery of Stranded Meter Assets - effective until Dec. 31, 2024	per 30 days									-$ 0.02	1	-$ 0.02	-$ 0.02		-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per 30 days									-$ 0.75	1	-$ 0.75	-$ 0.75		-$ 0.75	1	-$ 0.75	$ -	0.00%	-$ 0.75	1	-$ 0.75	$ -	0.00%	-$ 0.75	1	-$ 0.75	$ -	0.00%	-$ 0.75	1	-$ 0.75	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per 30 days									-$ 0.12	1	-$ 0.12	-$ 0.12		-$ 0.12	1	-$ 0.12	$ -	0.00%	-$ 0.12	1	-$ 0.12	$ -	0.00%	-$ 0.12	1	-$ 0.12	$ -	0.00%	-$ 0.12	1	-$ 0.12	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per 30 days									-$ 0.01	1	-$ 0.01	-$ 0.01		-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per 30 days									-$ 0.02	1	-$ 0.02	-$ 0.02		-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per 30 days									-$ 0.63	1	-$ 0.63	-$ 0.63		-$ 0.63	1	-$ 0.63	$ -	0.00%	-$ 0.63	1	-$ 0.63	$ -	0.00%	-$ 0.63	1	-$ 0.63	$ -	0.00%	-$ 0.63	1	-$ 0.63	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per 30 days									-$ 0.02	1	-$ 0.02	-$ 0.02		-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per 30 days									-$ 0.45	1	-$ 0.45	-$ 0.45		-$ 0.45	1	-$ 0.45	$ -	0.00%	-$ 0.45	1	-$ 0.45	$ -	0.00%	-$ 0.45	1	-$ 0.45	$ -	0.00%	-$ 0.45	1	-$ 0.45	$ -	0.00%
Rate Rider for Disposition of AR Credits - effective until Dec. 31, 2024	per 30 days									-$ 0.08	1	-$ 0.08	-$ 0.08		-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%
Rate Rider for Recovery of Stranded Meters Assets - effective until Dec. 31, 2019.	per 30 days	$ 0.28	1	$ 0.28	$ 0.28	1	$ 0.28	$ -	0.00%		1	$ -	-$ 0.28			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per 30 days	-$ 0.48	1	-$ 0.48		1	$ -	$ 0.48			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per 30 days	-$ 1.48	1	-$ 1.48		1	$ -	$ 1.48			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per 30 days	$ 0.10	1	$ 0.10	$ 0.10	1	$ 0.10	$ -	0.00%		1	$ -	-$ 0.10			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per 30 days	$ 0.03	1	$ 0.03	$ 0.03	1	$ 0.03	$ -	0.00%		1	$ -	-$ 0.03			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per 30 days	$ 0.46	1	$ 0.46	$ 0.46	1	$ 0.46	$ -	0.00%		1	$ -	-$ 0.46			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.88	1	$ 0.88	$ 0.88	1	$ 0.88	$ -	0.00%		1	$ -	-$ 0.88			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.28	1	$ 0.28	$ 0.28	1	$ 0.28	$ -	0.00%		1	$ -	-$ 0.28			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.01063	212	$ 2.25	$ 0.00552	212	$ 1.17	-$ 1.08	-48.07%		212	$ -	-$ 1.17			212	$ -	$ -			212	$ -	$ -			212	$ -	$ -			212	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kWh	$ 0.00041	212	$ 0.09		212	$ -	-$ 0.09			212	$ -	$ -			212	$ -	$ -			212	$ -	$ -			212	$ -	$ -			212	$ -	$ -	
Sub-Total A (excluding pass through)				**$ 35.04**			**$ 40.66**	**$ 5.62**	**16.04%**			**$ 41.31**	**$ 0.65**	**1.60%**			**$ 42.68**	**$ 1.37**	**3.32%**			**$ 43.75**	**$ 1.07**	**2.51%**			**$ 45.64**	**$ 1.89**	**4.32%**			**$ 47.47**	**$ 1.83**	**4.01%**
Line Losses on Cost of Power	per kWh	$ 0.0820	8	$ 0.65	$ 0.0820	8	$ 0.65	$ -	0.00%	$ 0.0820	6	$ 0.51	-$ 0.14	-21.54%	$ 0.0820	6	$ 0.51	$ -	0.00%	$ 0.0820	6	$ 0.51	$ -	0.00%	$ 0.0820	6	$ 0.51	$ -	0.00%	$ 0.0820	6	$ 0.51	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until Dec. 31, 2018.	per kWh	-$ 0.00320	212	-$ 0.68		212	$ -	$ 0.68				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account (2018) Applicable only for Class B Customers - effective until Dec. 31, 2018	per kWh	$ 0.00007	212	$ 0.01		212	$ -	-$ 0.01				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Global Adjustment Account (2018) Applicable only for Non-RPP Customers - effective until Dec. 31, 2018.	per kWh	-$ 0.00112		$ -			$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	per 30 days	$ 0.56	1	$ 0.56	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%			$ -	-$ 0.56				$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 35.59**			**$ 41.87**	**$ 6.28**	**17.65%**			**$ 42.38**	**$ 0.51**	**1.22%**			**$ 43.75**	**$ 1.37**	**3.23%**			**$ 44.82**	**$ 1.07**	**2.45%**			**$ 46.15**	**$ 1.33**	**2.97%**			**$ 47.98**	**$ 1.83**	**3.97%**
Retail Transmissioin Rate - Network Service Rate	per kWh	$ 0.00759	220	$ 1.67	$ 0.00826	220	$ 1.82	$ 0.15	8.83%	$ 0.00825	218	$ 1.80	-$ 0.02	-0.90%	$ 0.00825	218	$ 1.80	$ -	0.00%	$ 0.00825	218	$ 1.80	$ -	0.00%	$ 0.00825	218	$ 1.80	$ -	0.00%	$ 0.00825	218	$ 1.80	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	per kWh	$ 0.00617	220	$ 1.36	$ 0.00680	220	$ 1.50	$ 0.14	10.21%	$ 0.00679	218	$ 1.48	-$ 0.01	-0.93%	$ 0.00679	218	$ 1.48	$ -	0.00%	$ 0.00679	218	$ 1.48	$ -	0.00%	$ 0.00679	218	$ 1.48	$ -	0.00%	$ 0.00679	218	$ 1.48	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				**$ 38.62**			**$ 45.19**	**$ 6.57**	**17.01%**			**$ 45.67**	**$ 0.48**	**1.06%**			**$ 47.04**	**$ 1.37**	**3.00%**			**$ 48.11**	**$ 1.07**	**2.27%**			**$ 49.44**	**$ 1.33**	**2.76%**			**$ 51.27**	**$ 1.83**	**3.70%**
Wholesale Market Service Rate - not including CBR	per kWh	$ 0.0032	220	$ 0.70	$ 0.0032	220	$ 0.70	$ -	0.00%	$ 0.0032	218	$ 0.70	-$ 0.01	-0.78%	$ 0.0032	218	$ 0.70	$ -	0.00%	$ 0.0032	218	$ 0.70	$ -	0.00%	$ 0.0032	218	$ 0.70	$ -	0.00%	$ 0.0032	218	$ 0.70	$ -	0.00%
Rural and Remote Rate Protection Charge (RRRP)	per kWh	$ 0.0003	220	$ 0.07	$ 0.0003	220	$ 0.07	$ -	0.00%	$ 0.0003	218	$ 0.07	-$ 0.00	-0.78%	$ 0.0003	218	$ 0.07	$ -	0.00%	$ 0.0003	218	$ 0.07	$ -	0.00%	$ 0.0003	218	$ 0.07	$ -	0.00%	$ 0.0003	218	$ 0.07	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	220	$ 0.09	$ 0.0004	220	$ 0.09	$ -	0.00%	$ 0.0004	218	$ 0.09	-$ 0.00	-0.78%	$ 0.0004	218	$ 0.09	$ -	0.00%	$ 0.0004	218	$ 0.09	$ -	0.00%	$ 0.0004	218	$ 0.09	$ -	0.00%	$ 0.0004	218	$ 0.09	$ -	0.00%
Standard Supply Service - Administrative Charge (if applicable)	per 30 days	$ 0.25	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	138	$ 8.96	$ 0.0650	138	$ 8.96	$ -	0.00%	$ 0.0650	138	$ 8.96	$ -	0.00%	$ 0.0650	138	$ 8.96	$ -	0.00%	$ 0.0650	138	$ 8.96	$ -	0.00%	$ 0.0650	138	$ 8.96	$ -	0.00%	$ 0.0650	138	$ 8.96	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	36	$ 3.39	$ 0.0940	36	$ 3.39	$ -	0.00%	$ 0.0940	36	$ 3.39	$ -	0.00%	$ 0.0940	36	$ 3.39	$ -	0.00%	$ 0.0940	36	$ 3.39	$ -	0.00%	$ 0.0940	36	$ 3.39	$ -	0.00%	$ 0.0940	36	$ 3.39	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	38	$ 5.04	$ 0.1320	38	$ 5.04	$ -	0.00%	$ 0.1320	38	$ 5.04	$ -	0.00%	$ 0.1320	38	$ 5.04	$ -	0.00%	$ 0.1320	38	$ 5.04	$ -	0.00%	$ 0.1320	38	$ 5.04	$ -	0.00%	$ 0.1320	38	$ 5.04	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	600	$ 46.20	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	150	$ 13.35	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 57.11**			**$ 63.68**	**$ 6.57**	**11.5%**			**$ 64.15**	**$ 0.47**	**0.7%**			**$ 65.52**	**$ 1.37**	**2.1%**			**$ 66.59**	**$ 1.07**	**1.6%**			**$ 67.92**	**$ 1.33**	**2.0%**			**$ 69.75**	**$ 1.83**	**2.7%**
8% Provincial Rebate		-8%		-$ 4.57	-8%		-$ 5.09	-$ 0.53	11.5%	-8%		-$ 5.13	-$ 0.04	0.7%	-8%		-$ 5.24	-$ 0.11	2.1%	-8%		-$ 5.33	-$ 0.09	1.6%	-8%		-$ 5.43	-$ 0.11	2.0%	-8%		-$ 5.58	-$ 0.15	2.7%
HST		13%		$ 7.42	13%		$ 8.28	$ 0.85	11.5%	13%		$ 8.34	$ 0.06	0.7%	13%		$ 8.52	$ 0.18	2.1%	13%		$ 8.66	$ 0.14	1.6%	13%		$ 8.83	$ 0.17	2.0%	13%		$ 9.07	$ 0.24	2.7%
Total Bill on TOU (after Tax & Rebate)				**$ 59.96**			**$ 66.86**	**$ 6.90**	**11.5%**			**$ 67.36**	**$ 0.50**	**0.7%**			**$ 68.79**	**$ 1.44**	**2.1%**			**$ 69.92**	**$ 1.12**	**1.6%**			**$ 71.31**	**$ 1.40**	**2.0%**			**$ 73.24**	**$ 1.92**	**2.7%**
Loss Factor (%)		3.76%			3.76%					2.95%					2.95%					2.95%					2.95%					2.95%				

Appendix 2-W
Bill Impacts

Customer Class: RESIDENTIAL SERVICE

TOU / non-TOU: TOU

Consumption 650 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		2018 Current Board-Approved			2019 Expected			Impact		2020 Proposed			Impact		2021 Proposed			Impact		2022 Proposed			Impact		2023 Proposed			Impact		2024 Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change
Service Charge	per 30 days	$ 32.63	1	$ 32.63	$ 37.46	1	$ 37.46	$ 4.83	14.80%	$ 42.14	1	$ 42.14	$ 4.68	12.49%	$ 43.51	1	$ 43.51	$ 1.37	3.25%	$ 44.58	1	$ 44.58	$ 1.07	2.46%	$ 46.47	1	$ 46.47	$ 1.89	4.24%	$ 48.30	1	$ 48.30	$ 1.83	3.94%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per 30 days									$ 0.09	1	$ 0.09	$ 0.09		$ 0.09	1	$ 0.09	$ -	0.00%	$ 0.09	1	$ 0.09	$ -	0.00%	$ 0.09	1	$ 0.09	$ -	0.00%	$ 0.09	1	$ 0.09	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per 30 days									$ 0.90	1	$ 0.90	$ 0.90		$ 0.90	1	$ 0.90	$ -	0.00%	$ 0.90	1	$ 0.90	$ -	0.00%	$ 0.90	1	$ 0.90	$ -	0.00%	$ 0.90	1	$ 0.90	$ -	0.00%
Rate Rider for Recovery of Monthly Billing - effective until Dec. 31, 2024	per 30 days									$ 0.28	1	$ 0.28	$ 0.28		$ 0.28	1	$ 0.28	$ -	0.00%	$ 0.28	1	$ 0.28	$ -	0.00%	$ 0.28	1	$ 0.28	$ -	0.00%	$ 0.28	1	$ 0.28	$ -	0.00%
Rate Rider for Recovery of Stranded Meter Assets - effective until Dec. 31, 2024	per 30 days									-$ 0.02	1	-$ 0.02	-$ 0.02		-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per 30 days									-$ 0.75	1	-$ 0.75	-$ 0.75		-$ 0.75	1	-$ 0.75	$ -	0.00%	-$ 0.75	1	-$ 0.75	$ -	0.00%	-$ 0.75	1	-$ 0.75	$ -	0.00%	-$ 0.75	1	-$ 0.75	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per 30 days									-$ 0.12	1	-$ 0.12	-$ 0.12		-$ 0.12	1	-$ 0.12	$ -	0.00%	-$ 0.12	1	-$ 0.12	$ -	0.00%	-$ 0.12	1	-$ 0.12	$ -	0.00%	-$ 0.12	1	-$ 0.12	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per 30 days									-$ 0.01	1	-$ 0.01	-$ 0.01		-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per 30 days									-$ 0.02	1	-$ 0.02	-$ 0.02		-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per 30 days									-$ 0.63	1	-$ 0.63	-$ 0.63		-$ 0.63	1	-$ 0.63	$ -	0.00%	-$ 0.63	1	-$ 0.63	$ -	0.00%	-$ 0.63	1	-$ 0.63	$ -	0.00%	-$ 0.63	1	-$ 0.63	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per 30 days									-$ 0.02	1	-$ 0.02	-$ 0.02		-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per 30 days									-$ 0.45	1	-$ 0.45	-$ 0.45		-$ 0.45	1	-$ 0.45	$ -	0.00%	-$ 0.45	1	-$ 0.45	$ -	0.00%	-$ 0.45	1	-$ 0.45	$ -	0.00%	-$ 0.45	1	-$ 0.45	$ -	0.00%
Rate Rider for Disposition of AR Credits - effective until Dec. 31, 2024	per 30 days									-$ 0.08	1	-$ 0.08	-$ 0.08		-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%
Rate Rider for Recovery of Stranded Meters Assets - effective until Dec. 31, 2019.	per 30 days	$ 0.28	1	$ 0.28	$ 0.28	1	$ 0.28	$ -	0.00%		1	$ -	-$ 0.28			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per 30 days	-$ 0.48	1	-$ 0.48		1	$ -	$ 0.48			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per 30 days	-$ 1.48	1	-$ 1.48		1	$ -	$ 1.48			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per 30 days	$ 0.10	1	$ 0.10	$ 0.10	1	$ 0.10	$ -	0.00%		1	$ -	-$ 0.10			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per 30 days	$ 0.03	1	$ 0.03	$ 0.03	1	$ 0.03	$ -	0.00%		1	$ -	-$ 0.03			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per 30 days	$ 0.46	1	$ 0.46	$ 0.46	1	$ 0.46	$ -	0.00%		1	$ -	-$ 0.46			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.88	1	$ 0.88	$ 0.88	1	$ 0.88	$ -	0.00%		1	$ -	-$ 0.88			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.28	1	$ 0.28	$ 0.28	1	$ 0.28	$ -	0.00%		1	$ -	-$ 0.28			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.01063	650	$ 6.91	$ 0.00552	650	$ 3.59	-$ 3.32	-48.07%		650	$ -	-$ 3.59			650	$ -	$ -			650	$ -	$ -			650	$ -	$ -			650	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kWh	$ 0.00041	650	$ 0.27		650	$ -	-$ 0.27			650	$ -	$ -			650	$ -	$ -			650	$ -	$ -			650	$ -	$ -			650	$ -	$ -	
Sub-Total A (excluding pass through)				**$ 39.88**			**$ 43.08**	**$ 3.20**	**8.03%**			**$ 41.31**	**-$ 1.77**	**-4.10%**			**$ 42.68**	**$ 1.37**	**3.32%**			**$ 43.75**	**$ 1.07**	**2.51%**			**$ 45.64**	**$ 1.89**	**4.32%**			**$ 47.47**	**$ 1.83**	**4.01%**
Line Losses on Cost of Power	per kWh	$ 0.0820	24	$ 2.00	$ 0.0820	24	$ 2.00	$ -	0.00%	$ 0.0820	19	$ 1.57	-$ 0.43	-21.54%	$ 0.0820	19	$ 1.57	$ -	0.00%	$ 0.0820	19	$ 1.57	$ -	0.00%	$ 0.0820	19	$ 1.57	$ -	0.00%	$ 0.0820	19	$ 1.57	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until Dec. 31, 2018.	per kWh	-$ 0.00320	650	-$ 2.08		650	$ -	$ 2.08				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account (2018) Applicable only for Class B Customers - effective until Dec. 31, 2018	per kWh	$ 0.00007	650	$ 0.05		650	$ -	-$ 0.05				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Global Adjustment Account (2018) Applicable only for Non-RPP Customers - effective until Dec. 31, 2018.	per kWh	-$ 0.00112		$ -			$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	per 30 days	$ 0.56	1	$ 0.56	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%			$ -	-$ 0.56				$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 40.41**			**$ 45.64**	**$ 5.24**	**12.96%**			**$ 43.44**	**-$ 2.20**	**-4.82%**			**$ 44.81**	**$ 1.37**	**3.15%**			**$ 45.88**	**$ 1.07**	**2.39%**			**$ 47.21**	**$ 1.33**	**2.90%**			**$ 49.04**	**$ 1.83**	**3.88%**
Retail Transmissioin Rate - Network Service Rate	per kWh	$ 0.00759	674	$ 5.12	$ 0.00826	674	$ 5.57	$ 0.45	8.83%	$ 0.00825	669	$ 5.52	-$ 0.05	-0.90%	$ 0.00825	669	$ 5.52	$ -	0.00%	$ 0.00825	669	$ 5.52	$ -	0.00%	$ 0.00825	669	$ 5.52	$ -	0.00%	$ 0.00825	669	$ 5.52	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	per kWh	$ 0.00617	674	$ 4.16	$ 0.00680	674	$ 4.59	$ 0.42	10.21%	$ 0.00679	669	$ 4.54	-$ 0.04	-0.93%	$ 0.00679	669	$ 4.54	$ -	0.00%	$ 0.00679	669	$ 4.54	$ -	0.00%	$ 0.00679	669	$ 4.54	$ -	0.00%	$ 0.00679	669	$ 4.54	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				**$ 49.69**			**$ 55.80**	**$ 6.11**	**12.30%**			**$ 53.51**	**-$ 2.29**	**-4.11%**			**$ 54.88**	**$ 1.37**	**2.56%**			**$ 55.95**	**$ 1.07**	**1.95%**			**$ 57.28**	**$ 1.33**	**2.38%**			**$ 59.11**	**$ 1.83**	**3.20%**
Wholesale Market Service Rate - not including CBR	per kWh	$ 0.0032	674	$ 2.16	$ 0.0032	674	$ 2.16	$ -	0.00%	$ 0.0032	669	$ 2.14	-$ 0.02	-0.78%	$ 0.0032	669	$ 2.14	$ -	0.00%	$ 0.0032	669	$ 2.14	$ -	0.00%	$ 0.0032	669	$ 2.14	$ -	0.00%	$ 0.0032	669	$ 2.14	$ -	0.00%
Rural and Remote Rate Protection Charge (RRRP)	per kWh	$ 0.0003	674	$ 0.20	$ 0.0003	674	$ 0.20	$ -	0.00%	$ 0.0003	669	$ 0.20	-$ 0.00	-0.78%	$ 0.0003	669	$ 0.20	$ -	0.00%	$ 0.0003	669	$ 0.20	$ -	0.00%	$ 0.0003	669	$ 0.20	$ -	0.00%	$ 0.0003	669	$ 0.20	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	674	$ 0.27	$ 0.0004	674	$ 0.27	$ -	0.00%	$ 0.0004	669	$ 0.27	-$ 0.00	-0.78%	$ 0.0004	669	$ 0.27	$ -	0.00%	$ 0.0004	669	$ 0.27	$ -	0.00%	$ 0.0004	669	$ 0.27	$ -	0.00%	$ 0.0004	669	$ 0.27	$ -	0.00%
Standard Supply Service - Administrative Charge (if applicable)	per 30 days	$ 0.25	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	423	$ 27.46	$ 0.0650	423	$ 27.46	$ -	0.00%	$ 0.0650	423	$ 27.46	$ -	0.00%	$ 0.0650	423	$ 27.46	$ -	0.00%	$ 0.0650	423	$ 27.46	$ -	0.00%	$ 0.0650	423	$ 27.46	$ -	0.00%	$ 0.0650	423	$ 27.46	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	111	$ 10.39	$ 0.0940	111	$ 10.39	$ -	0.00%	$ 0.0940	111	$ 10.39	$ -	0.00%	$ 0.0940	111	$ 10.39	$ -	0.00%	$ 0.0940	111	$ 10.39	$ -	0.00%	$ 0.0940	111	$ 10.39	$ -	0.00%	$ 0.0940	111	$ 10.39	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	117	$ 15.44	$ 0.1320	117	$ 15.44	$ -	0.00%	$ 0.1320	117	$ 15.44	$ -	0.00%	$ 0.1320	117	$ 15.44	$ -	0.00%	$ 0.1320	117	$ 15.44	$ -	0.00%	$ 0.1320	117	$ 15.44	$ -	0.00%	$ 0.1320	117	$ 15.44	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	600	$ 46.20	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	150	$ 13.35	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 105.86**			**$ 111.97**	**$ 6.11**	**5.8%**			**$ 109.66**	**-$ 2.31**	**-2.1%**			**$ 111.03**	**$ 1.37**	**1.2%**			**$ 112.10**	**$ 1.07**	**1.0%**			**$ 113.43**	**$ 1.33**	**1.2%**			**$ 115.26**	**$ 1.83**	**1.6%**
8% Provincial Rebate		-8%		-$ 8.47	-8%		-$ 8.96	-$ 0.49	5.8%	-8%		-$ 8.77	$ 0.19	-2.1%	-8%		-$ 8.88	-$ 0.11	1.2%	-8%		-$ 8.97	-$ 0.09	1.0%	-8%		-$ 9.07	-$ 0.11	1.2%	-8%		-$ 9.22	-$ 0.15	1.6%
HST		13%		$ 13.76	13%		$ 14.56	$ 0.79	5.8%	13%		$ 14.26	-$ 0.30	-2.1%	13%		$ 14.43	$ 0.18	1.2%	13%		$ 14.57	$ 0.14	1.0%	13%		$ 14.75	$ 0.17	1.2%	13%		$ 14.98	$ 0.24	1.6%
Total Bill on TOU (after Tax & Rebate)				**$ 111.15**			**$ 117.57**	$ 6.42	5.8%			**$ 115.14**	-$ 2.43	-2.1%			**$ 116.58**	$ 1.44	1.2%			**$ 117.70**	$ 1.12	1.0%			**$ 119.10**	$ 1.40	1.2%			**$ 121.02**	$ 1.92	1.6%
Loss Factor (%)		3.76%			3.76%					2.95%					2.95%					2.95%					2.95%					2.95%				

Appendix 2-W
Bill Impacts

Customer Class: COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE

TOU / non-TOU: TOU

Consumption 300 kWh ● May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

Charge Unit		2018 Current Board-Approved			2019 Expected			Impact		2020 Proposed			Impact		2021 Proposed			Impact		2022 Proposed			Impact		2023 Proposed			Impact		2024 Proposed			Impact	
		Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change
Service Charge	per 30 days	$ 26.80	1	$ 26.80	$ 30.56	1	$ 30.56	$ 3.76	14.03%	$ 33.40	1	$ 33.40	$ 2.84	9.29%	$ 34.49	1	$ 34.49	$ 1.09	3.26%	$ 35.34	1	$ 35.34	$ 0.85	2.46%	$ 36.84	1	$ 36.84	$ 1.50	4.24%	$ 38.29	1	$ 38.29	$ 1.45	3.94%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per 30 days									$ 0.06	1	$ 0.06	$ 0.06		$ 0.06	1	$ 0.06	$ -	0.00%	$ 0.06	1	$ 0.06	$ -	0.00%	$ 0.06	1	$ 0.06	$ -	0.00%	$ 0.06	1	$ 0.06	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per 30 days									$ 0.61	1	$ 0.61	$ 0.61		$ 0.61	1	$ 0.61	$ -	0.00%	$ 0.61	1	$ 0.61	$ -	0.00%	$ 0.61	1	$ 0.61	$ -	0.00%	$ 0.61	1	$ 0.61	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per 30 days									-$ 0.51	1	-$ 0.51	-$ 0.51		-$ 0.51	1	-$ 0.51	$ -	0.00%	-$ 0.51	1	-$ 0.51	$ -	0.00%	-$ 0.51	1	-$ 0.51	$ -	0.00%	-$ 0.51	1	-$ 0.51	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per 30 days									-$ 0.08	1	-$ 0.08	-$ 0.08		-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per 30 days									-$ 0.01	1	-$ 0.01	-$ 0.01		-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per 30 days									-$ 0.43	1	-$ 0.43	-$ 0.43		-$ 0.43	1	-$ 0.43	$ -	0.00%	-$ 0.43	1	-$ 0.43	$ -	0.00%	-$ 0.43	1	-$ 0.43	$ -	0.00%	-$ 0.43	1	-$ 0.43	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per 30 days									-$ 0.02	1	-$ 0.02	-$ 0.02		-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per 30 days									-$ 0.30	1	-$ 0.30	-$ 0.30		-$ 0.30	1	-$ 0.30	$ -	0.00%	-$ 0.30	1	-$ 0.30	$ -	0.00%	-$ 0.30	1	-$ 0.30	$ -	0.00%	-$ 0.30	1	-$ 0.30	$ -	0.00%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per 30 days	-$ 0.19	1	-$ 0.19		1	$ -	$ 0.19			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per 30 days	-$ 0.59	1	-$ 0.59		1	$ -	$ 0.59			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per 30 days	$ 0.04	1	$ 0.04	$ 0.04	1	$ 0.04	$ -	0.00%		1	$ -	-$ 0.04			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per 30 days	$ 0.01	1	$ 0.01	$ 0.01	1	$ 0.01	$ -	0.00%		1	$ -	-$ 0.01			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per 30 days	$ 0.18	1	$ 0.18	$ 0.18	1	$ 0.18	$ -	0.00%		1	$ -	-$ 0.18			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.19	1	$ 0.19	$ 0.19	1	$ 0.19	$ -	0.00%		1	$ -	-$ 0.19			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.09	1	$ 0.09	$ 0.09	1	$ 0.09	$ -	0.00%		1	$ -	-$ 0.09			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.01627	300	$ 4.88	$ 0.00845	300	$ 2.54	-$ 2.35	-48.06%		300	$ -	-$ 2.54			300	$ -	$ -			300	$ -	$ -			300	$ -	$ -			300	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kWh	$ 0.00068	300	$ 0.20		300	$ -	-$ 0.20			300	$ -	$ -			300	$ -	$ -			300	$ -	$ -			300	$ -	$ -			300	$ -	$ -	
Sub-Total A (excluding pass through)				**$ 31.62**			**$ 33.61**	**$ 1.99**	**6.29%**			**$ 32.72**	**-$ 0.88**	**-2.63%**			**$ 33.81**	**$ 1.09**	**3.33%**			**$ 34.66**	**$ 0.85**	**2.51%**			**$ 36.16**	**$ 1.50**	**4.33%**			**$ 37.61**	**$ 1.45**	**4.01%**
Line Losses on Cost of Power	per kWh	$ 0.0820	11	$ 0.92	$ 0.0820	11	$ 0.92	$ -	0.00%	$ 0.0820	9	$ 0.73	-$ 0.20	-21.54%	$ 0.0820	9	$ 0.73	$ -	0.00%	$ 0.0820	9	$ 0.73	$ -	0.00%	$ 0.0820	9	$ 0.73	$ -	0.00%	$ 0.0820	9	$ 0.73	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until Dec. 31, 2018.	per kWh	-$ 0.00392	300	-$ 1.18		300	$ -	$ 1.18				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account (2018) Applicable only for Class B Customers - effective until Dec. 31, 2018	per kWh	$ 0.00007	300	$ 0.02		300	$ -	-$ 0.02				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Global Adjustment Account (2018) Applicable only for Non-RPP Customers - effective until Dec. 31, 2018.	per kWh	-$ 0.00112		$ -			$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	per 30 days	$ 0.56	1	$ 0.56	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%			$ -	-$ 0.56				$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 31.94**			**$ 35.09**	**$ 3.15**	**9.85%**			**$ 34.01**	**-$ 1.08**	**-3.09%**			**$ 35.10**	**$ 1.09**	**3.21%**			**$ 35.95**	**$ 0.85**	**2.42%**			**$ 36.89**	**$ 0.94**	**2.62%**			**$ 38.34**	**$ 1.45**	**3.93%**
Retail Transmissioin Rate - Network Service Rate	per kWh	$ 0.00759	311	$ 2.36	$ 0.00826	311	$ 2.57	$ 0.21	8.83%	$ 0.00825	309	$ 2.55	-$ 0.02	-0.90%	$ 0.00825	309	$ 2.55	$ -	0.00%	$ 0.00825	309	$ 2.55	$ -	0.00%	$ 0.00825	309	$ 2.55	$ -	0.00%	$ 0.00825	309	$ 2.55	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	per kWh	$ 0.00617	311	$ 1.92	$ 0.00680	311	$ 2.12	$ 0.20	10.21%	$ 0.00679	309	$ 2.10	-$ 0.02	-0.93%	$ 0.00679	309	$ 2.10	$ -	0.00%	$ 0.00679	309	$ 2.10	$ -	0.00%	$ 0.00679	309	$ 2.10	$ -	0.00%	$ 0.00679	309	$ 2.10	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				**$ 36.23**			**$ 39.78**	**$ 3.55**	**9.80%**			**$ 38.65**	**-$ 1.13**	**-2.83%**			**$ 39.74**	**$ 1.09**	**2.82%**			**$ 40.59**	**$ 0.85**	**2.14%**			**$ 41.53**	**$ 0.94**	**2.32%**			**$ 42.98**	**$ 1.45**	**3.49%**
Wholesale Market Service Rate - not including CBR	per kWh	$ 0.0032	311	$ 1.00	$ 0.0032	311	$ 1.00	$ -	0.00%	$ 0.0032	309	$ 0.99	-$ 0.01	-0.78%	$ 0.0032	309	$ 0.99	$ -	0.00%	$ 0.0032	309	$ 0.99	$ -	0.00%	$ 0.0032	309	$ 0.99	$ -	0.00%	$ 0.0032	309	$ 0.99	$ -	0.00%
Rural and Remote Rate Protection Charge (RRRP)	per kWh	$ 0.0003	311	$ 0.09	$ 0.0003	311	$ 0.09	$ -	0.00%	$ 0.0003	309	$ 0.09	-$ 0.00	-0.78%	$ 0.0003	309	$ 0.09	$ -	0.00%	$ 0.0003	309	$ 0.09	$ -	0.00%	$ 0.0003	309	$ 0.09	$ -	0.00%	$ 0.0003	309	$ 0.09	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	311	$ 0.12	$ 0.0004	311	$ 0.12	$ -	0.00%	$ 0.0004	309	$ 0.12	-$ 0.00	-0.78%	$ 0.0004	309	$ 0.12	$ -	0.00%	$ 0.0004	309	$ 0.12	$ -	0.00%	$ 0.0004	309	$ 0.12	$ -	0.00%	$ 0.0004	309	$ 0.12	$ -	0.00%
Standard Supply Service - Administrative Charge (if applicable)	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	195	$ 12.68	$ 0.0650	195	$ 12.68	$ -	0.00%	$ 0.0650	195	$ 12.68	$ -	0.00%	$ 0.0650	195	$ 12.68	$ -	0.00%	$ 0.0650	195	$ 12.68	$ -	0.00%	$ 0.0650	195	$ 12.68	$ -	0.00%	$ 0.0650	195	$ 12.68	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	51	$ 4.79	$ 0.0940	51	$ 4.79	$ -	0.00%	$ 0.0940	51	$ 4.79	$ -	0.00%	$ 0.0940	51	$ 4.79	$ -	0.00%	$ 0.0940	51	$ 4.79	$ -	0.00%	$ 0.0940	51	$ 4.79	$ -	0.00%	$ 0.0940	51	$ 4.79	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	54	$ 7.13	$ 0.1320	54	$ 7.13	$ -	0.00%	$ 0.1320	54	$ 7.13	$ -	0.00%	$ 0.1320	54	$ 7.13	$ -	0.00%	$ 0.1320	54	$ 7.13	$ -	0.00%	$ 0.1320	54	$ 7.13	$ -	0.00%	$ 0.1320	54	$ 7.13	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	300	$ 23.10	$ 0.0770	300	$ 23.10	$ -	0.00%	$ 0.0770	300	$ 23.10	$ -	0.00%	$ 0.0770	300	$ 23.10	$ -	0.00%	$ 0.0770	300	$ 23.10	$ -	0.00%	$ 0.0770	300	$ 23.10	$ -	0.00%	$ 0.0770	300	$ 23.10	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	0	$ -	$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -	
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 62.29**			**$ 65.84**	**$ 3.55**	**5.7%**			**$ 64.70**	**-$ 1.14**	**-1.7%**			**$ 65.79**	**$ 1.09**	**1.7%**			**$ 66.64**	**$ 0.85**	**1.3%**			**$ 67.58**	**$ 0.94**	**1.4%**			**$ 69.03**	**$ 1.45**	**2.1%**
8% Provincial Rebate		-8%		-$ 4.98	-8%		-$ 5.27	-$ 0.28	5.7%	-8%		-$ 5.18	$ 0.09	-1.7%	-8%		-$ 5.26	-$ 0.09	1.7%	-8%		-$ 5.33	-$ 0.07	1.3%	-8%		-$ 5.41	-$ 0.08	1.4%	-8%		-$ 5.52	-$ 0.12	2.1%
HST		13%		$ 8.10	13%		$ 8.56	$ 0.46	5.7%	13%		$ 8.41	-$ 0.15	-1.7%	13%		$ 8.55	$ 0.14	1.7%	13%		$ 8.66	$ 0.11	1.3%	13%		$ 8.79	$ 0.12	1.4%	13%		$ 8.97	$ 0.19	2.1%
Total Bill on TOU (after Tax & Rebate)				**$ 65.40**			**$ 69.13**	**$ 3.73**	**5.7%**			**$ 67.94**	**-$ 1.19**	**-1.7%**			**$ 69.08**	**$ 1.14**	**1.7%**			**$ 69.97**	**$ 0.89**	**1.3%**			**$ 70.96**	**$ 0.99**	**1.4%**			**$ 72.48**	**$ 1.52**	**2.1%**
Loss Factor (%)		3.76%			3.76%					2.95%					2.95%					2.95%					2.95%					2.95%				

Appendix 2-W
Bill Impacts

Customer Class: COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE

TOU / non-TOU: TOU

Consumption 198 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		2018 Current Board-Approved			2019 Expected			Impact		2020 Proposed			Impact		2021 Proposed			Impact		2022 Proposed			Impact		2023 Proposed			Impact		2024 Proposed			Impact	
Charge Unit		Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change
Service Charge	per 30 days	$ 26.80	1	$ 26.80	$ 30.56	1	$ 30.56	$ 3.76	14.03%	$ 33.40	1	$ 33.40	$ 2.84	9.29%	$ 34.49	1	$ 34.49	$ 1.09	3.26%	$ 35.34	1	$ 35.34	$ 0.85	2.46%	$ 36.84	1	$ 36.84	$ 1.50	4.24%	$ 38.29	1	$ 38.29	$ 1.45	3.94%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per 30 days									$ 0.06	1	$ 0.06	$ 0.06		$ 0.06	1	$ 0.06	$ -	0.00%	$ 0.06	1	$ 0.06	$ -	0.00%	$ 0.06	1	$ 0.06	$ -	0.00%	$ 0.06	1	$ 0.06	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per 30 days									$ 0.61	1	$ 0.61	$ 0.61		$ 0.61	1	$ 0.61	$ -	0.00%	$ 0.61	1	$ 0.61	$ -	0.00%	$ 0.61	1	$ 0.61	$ -	0.00%	$ 0.61	1	$ 0.61	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per 30 days									-$ 0.51	1	-$ 0.51	-$ 0.51		-$ 0.51	1	-$ 0.51	$ -	0.00%	-$ 0.51	1	-$ 0.51	$ -	0.00%	-$ 0.51	1	-$ 0.51	$ -	0.00%	-$ 0.51	1	-$ 0.51	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per 30 days									-$ 0.08	1	-$ 0.08	-$ 0.08		-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per 30 days									-$ 0.01	1	-$ 0.01	-$ 0.01		-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per 30 days									-$ 0.43	1	-$ 0.43	-$ 0.43		-$ 0.43	1	-$ 0.43	$ -	0.00%	-$ 0.43	1	-$ 0.43	$ -	0.00%	-$ 0.43	1	-$ 0.43	$ -	0.00%	-$ 0.43	1	-$ 0.43	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per 30 days									-$ 0.02	1	-$ 0.02	-$ 0.02		-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per 30 days									-$ 0.30	1	-$ 0.30	-$ 0.30		-$ 0.30	1	-$ 0.30	$ -	0.00%	-$ 0.30	1	-$ 0.30	$ -	0.00%	-$ 0.30	1	-$ 0.30	$ -	0.00%	-$ 0.30	1	-$ 0.30	$ -	0.00%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per 30 days	-$ 0.19	1	-$ 0.19		1	$ -	$ 0.19			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per 30 days	-$ 0.59	1	-$ 0.59		1	$ -	$ 0.59			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per 30 days	$ 0.04	1	$ 0.04	$ 0.04	1	$ 0.04	$ -	0.00%		1	$ -	-$ 0.04			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per 30 days	$ 0.01	1	$ 0.01	$ 0.01	1	$ 0.01	$ -	0.00%		1	$ -	-$ 0.01			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per 30 days	$ 0.18	1	$ 0.18	$ 0.18	1	$ 0.18	$ -	0.00%		1	$ -	-$ 0.18			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.19	1	$ 0.19	$ 0.19	1	$ 0.19	$ -	0.00%		1	$ -	-$ 0.19			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.09	1	$ 0.09	$ 0.09	1	$ 0.09	$ -	0.00%		1	$ -	-$ 0.09			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.01627	198	$ 3.22	$ 0.00845	198	$ 1.67	-$ 1.55	-48.06%		198	$ -	-$ 1.67			198	$ -	$ -			198	$ -	$ -			198	$ -	$ -			198	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kWh	$ 0.00068	198	$ 0.13		198	$ -	-$ 0.13			198	$ -	$ -			198	$ -	$ -			198	$ -	$ -			198	$ -	$ -			198	$ -	$ -	
Sub-Total A (excluding pass through)				**$ 29.89**			**$ 32.74**	**$ 2.86**	**9.56%**			**$ 32.72**	**-$ 0.02**	**-0.07%**			**$ 33.81**	**$ 1.09**	**3.33%**			**$ 34.66**	**$ 0.85**	**2.51%**			**$ 36.16**	**$ 1.50**	**4.33%**			**$ 37.61**	**$ 1.45**	**4.01%**
Line Losses on Cost of Power	per kWh	$ 0.0820	7	$ 0.61	$ 0.0820	7	$ 0.61	$ -	0.00%	$ 0.0820	6	$ 0.48	-$ 0.13	-21.54%	$ 0.0820	6	$ 0.48	$ -	0.00%	$ 0.0820	6	$ 0.48	$ -	0.00%	$ 0.0820	6	$ 0.48	$ -	0.00%	$ 0.0820	6	$ 0.48	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until Dec. 31, 2018.	per kWh	-$ 0.00392	198	-$ 0.78		198	$ -	$ 0.78				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account (2018) Applicable only for Class B Customers - effective until Dec. 31, 2018	per kWh	$ 0.00007	198	$ 0.01		198	$ -	-$ 0.01				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Global Adjustment Account (2018) Applicable only for Non-RPP Customers - effective until Dec. 31, 2018.	per kWh	-$ 0.00112		$ -			$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	per 30 days	$ 0.56	1	$ 0.56	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%										
Sub-Total B - Distribution (includes Sub-Total A)				**$ 30.29**			**$ 33.91**	**$ 3.62**	**11.95%**			**$ 33.76**	**-$ 0.15**	**-0.46%**			**$ 34.85**	**$ 1.09**	**3.23%**			**$ 35.70**	**$ 0.85**	**2.44%**			**$ 36.64**	**$ 0.94**	**2.63%**			**$ 38.09**	**$ 1.45**	**3.96%**
Retail Transmissioin Rate - Network Service Rate	per kWh	$ 0.00759	205	$ 1.56	$ 0.00826	205	$ 1.70	$ 0.14	8.83%	$ 0.00825	204	$ 1.68	-$ 0.02	-0.90%	$ 0.00825	204	$ 1.68	$ -	0.00%	$ 0.00825	204	$ 1.68	$ -	0.00%	$ 0.00825	204	$ 1.68	$ -	0.00%	$ 0.00825	204	$ 1.68	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	per kWh	$ 0.00617	205	$ 1.27	$ 0.00680	205	$ 1.40	$ 0.13	10.21%	$ 0.00679	204	$ 1.38	-$ 0.01	-0.93%	$ 0.00679	204	$ 1.38	$ -	0.00%	$ 0.00679	204	$ 1.38	$ -	0.00%	$ 0.00679	204	$ 1.38	$ -	0.00%	$ 0.00679	204	$ 1.38	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				**$ 33.12**			**$ 37.01**	**$ 3.89**	**11.73%**			**$ 36.82**	**-$ 0.18**	**-0.49%**			**$ 37.91**	**$ 1.09**	**2.96%**			**$ 38.76**	**$ 0.85**	**2.24%**			**$ 39.70**	**$ 0.94**	**2.42%**			**$ 41.15**	**$ 1.45**	**3.65%**
Wholesale Market Service Rate - not including CBR	per kWh	$ 0.0032	205	$ 0.66	$ 0.0032	205	$ 0.66	$ -	0.00%	$ 0.0032	204	$ 0.65	-$ 0.01	-0.78%	$ 0.0032	204	$ 0.65	$ -	0.00%	$ 0.0032	204	$ 0.65	$ -	0.00%	$ 0.0032	204	$ 0.65	$ -	0.00%	$ 0.0032	204	$ 0.65	$ -	0.00%
Rural and Remote Rate Protection Charge (RRRP)	per kWh	$ 0.0003	205	$ 0.06	$ 0.0003	205	$ 0.06	$ -	0.00%	$ 0.0003	204	$ 0.06	-$ 0.00	-0.78%	$ 0.0003	204	$ 0.06	$ -	0.00%	$ 0.0003	204	$ 0.06	$ -	0.00%	$ 0.0003	204	$ 0.06	$ -	0.00%	$ 0.0003	204	$ 0.06	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	205	$ 0.08	$ 0.0004	205	$ 0.08	$ -	0.00%	$ 0.0004	204	$ 0.08	$ 0.00	-0.78%	$ 0.0004	204	$ 0.08	$ -	0.00%	$ 0.0004	204	$ 0.08	$ -	0.00%	$ 0.0004	204	$ 0.08	$ -	0.00%	$ 0.0004	204	$ 0.08	$ -	0.00%
Standard Supply Service - Administrative Charge (if applicable)	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	129	$ 8.37	$ 0.0650	129	$ 8.37	$ -	0.00%	$ 0.0650	129	$ 8.37	$ -	0.00%	$ 0.0650	129	$ 8.37	$ -	0.00%	$ 0.0650	129	$ 8.37	$ -	0.00%	$ 0.0650	129	$ 8.37	$ -	0.00%	$ 0.0650	129	$ 8.37	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	34	$ 3.16	$ 0.0940	34	$ 3.16	$ -	0.00%	$ 0.0940	34	$ 3.16	$ -	0.00%	$ 0.0940	34	$ 3.16	$ -	0.00%	$ 0.0940	34	$ 3.16	$ -	0.00%	$ 0.0940	34	$ 3.16	$ -	0.00%	$ 0.0940	34	$ 3.16	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	36	$ 4.70	$ 0.1320	36	$ 4.70	$ -	0.00%	$ 0.1320	36	$ 4.70	$ -	0.00%	$ 0.1320	36	$ 4.70	$ -	0.00%	$ 0.1320	36	$ 4.70	$ -	0.00%	$ 0.1320	36	$ 4.70	$ -	0.00%	$ 0.1320	36	$ 4.70	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	198	$ 15.25	$ 0.0770	198	$ 15.25	$ -	0.00%	$ 0.0770	198	$ 15.25	$ -	0.00%	$ 0.0770	198	$ 15.25	$ -	0.00%	$ 0.0770	198	$ 15.25	$ -	0.00%	$ 0.0770	198	$ 15.25	$ -	0.00%	$ 0.0770	198	$ 15.25	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	0	$ -	$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -	
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 50.41**			**$ 54.29**	**$ 3.89**	**7.7%**			**$ 54.10**	**-$ 0.19**	**-0.3%**			**$ 55.19**	**$ 1.09**	**2.0%**			**$ 56.04**	**$ 0.85**	**1.5%**			**$ 56.98**	**$ 0.94**	**1.7%**			**$ 58.43**	**$ 1.45**	**2.5%**
8% Provincial Rebate		-8%		-$ 4.03	-8%		-$ 4.34	-$ 0.31	7.7%	-8%		-$ 4.33	$ 0.02	-0.3%	-8%		-$ 4.42	-$ 0.09	2.0%	-8%		-$ 4.48	-$ 0.07	1.5%	-8%		-$ 4.56	-$ 0.08	1.7%	-8%		-$ 4.67	-$ 0.12	2.5%
HST		13%		$ 6.55	13%		$ 7.06	$ 0.51	7.7%	13%		$ 7.03	-$ 0.02	-0.3%	13%		$ 7.18	$ 0.14	2.0%	13%		$ 7.29	$ 0.11	1.5%	13%		$ 7.41	$ 0.12	1.7%	13%		$ 7.60	$ 0.19	2.5%
Total Bill on TOU (after Tax & Rebate)				**$ 52.93**			**$ 57.01**	**$ 4.08**	**7.7%**			**$ 56.81**	**-$ 0.20**	**-0.3%**			**$ 57.95**	**$ 1.14**	**2.0%**			**$ 58.85**	**$ 0.89**	**1.5%**			**$ 59.83**	**$ 0.99**	**1.7%**			**$ 61.36**	**$ 1.52**	**2.5%**
Loss Factor (%)		3.76%			3.76%					2.95%					2.95%					2.95%					2.95%					2.95%				

Appendix 2-W
Bill Impacts

Customer Class: GENERAL SERVICE LESS THAN 50 kW SERVICE

TOU / non-TOU: TOU

Consumption 2,000 **kWh** ● May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	2018 Current Board-Approved			2019 Expected			Impact		2020 Proposed			Impact		2021 Proposed			Impact		2022 Proposed			Impact		2023 Proposed			Impact		2024 Proposed			Impact	
		Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change
Service Charge	per 30 days	$ 34.45	1	$ 34.45	$ 35.78	1	$ 35.78	$ 1.33	3.86%	$ 37.07	1	$ 37.07	$ 1.29	3.61%	$ 38.28	1	$ 38.28	$ 1.21	3.26%	$ 39.22	1	$ 39.22	$ 0.94	2.46%	$ 40.88	1	$ 40.88	$ 1.66	4.23%	$ 42.49	1	$ 42.49	$ 1.61	3.94%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per kWh									$ 0.00011	2,000	$ 0.22	$ -	0.00%	$ 0.00011	2,000	$ 0.22	$ -	0.00%	$ 0.00011	2,000	$ 0.22	$ -	0.00%	$ 0.00011	2,000	$ 0.22	$ -	0.00%	$ 0.00011	2,000	$ 0.22	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per kWh									$ 0.00106	2,000	$ 2.12	$ 2.12		$ 0.00106	2,000	$ 2.12	$ -	0.00%	$ 0.00106	2,000	$ 2.12	$ -	0.00%	$ 0.00106	2,000	$ 2.12	$ -	0.00%	$ 0.00106	2,000	$ 2.12	$ -	0.00%
Rate Rider for Recovery of Monthly Billing - effective until Dec. 31, 2024	per kWh									$ 0.00010	2,000	$ 0.20	$ 0.20		$ 0.00010	2,000	$ 0.20	$ -	0.00%	$ 0.00010	2,000	$ 0.20	$ -	0.00%	$ 0.00010	2,000	$ 0.20	$ -	0.00%	$ 0.00010	2,000	$ 0.20	$ -	0.00%
Rate Rider for Recovery of Stranded Meter Assets - effective until Dec. 31, 2024	per 30 days									-$ 0.10	1	-$ 0.10	-$ 0.10		-$ 0.10	1	-$ 0.10	$ -	0.00%	-$ 0.10	1	-$ 0.10	$ -	0.00%	-$ 0.10	1	-$ 0.10	$ -	0.00%	-$ 0.10	1	-$ 0.10	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per kWh									-$ 0.00089	2,000	-$ 1.78	-$ 1.78		-$ 0.00089	2,000	-$ 1.78	$ -	0.00%	-$ 0.00089	2,000	-$ 1.78	$ -	0.00%	-$ 0.00089	2,000	-$ 1.78	$ -	0.00%	-$ 0.00089	2,000	-$ 1.78	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per kWh									-$ 0.00015	2,000	-$ 0.30	-$ 0.30		-$ 0.00015	2,000	-$ 0.30	$ -	0.00%	-$ 0.00015	2,000	-$ 0.30	$ -	0.00%	-$ 0.00015	2,000	-$ 0.30	$ -	0.00%	-$ 0.00015	2,000	-$ 0.30	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per kWh									-$ 0.00001	2,000	-$ 0.02	-$ 0.02		-$ 0.00001	2,000	-$ 0.02	$ -	0.00%	-$ 0.00001	2,000	-$ 0.02	$ -	0.00%	-$ 0.00001	2,000	-$ 0.02	$ -	0.00%	-$ 0.00001	2,000	-$ 0.02	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per kWh									-$ 0.00002	2,000	-$ 0.04	-$ 0.04		-$ 0.00002	2,000	-$ 0.04	$ -	0.00%	-$ 0.00002	2,000	-$ 0.04	$ -	0.00%	-$ 0.00002	2,000	-$ 0.04	$ -	0.00%	-$ 0.00002	2,000	-$ 0.04	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per kWh									-$ 0.00074	2,000	-$ 1.48	-$ 1.48		-$ 0.00074	2,000	-$ 1.48	$ -	0.00%	-$ 0.00074	2,000	-$ 1.48	$ -	0.00%	-$ 0.00074	2,000	-$ 1.48	$ -	0.00%	-$ 0.00074	2,000	-$ 1.48	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per kWh									-$ 0.00003	2,000	-$ 0.06	-$ 0.06		-$ 0.00003	2,000	-$ 0.06	$ -	0.00%	-$ 0.00003	2,000	-$ 0.06	$ -	0.00%	-$ 0.00003	2,000	-$ 0.06	$ -	0.00%	-$ 0.00003	2,000	-$ 0.06	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per kWh									-$ 0.00053	2,000	-$ 1.06	-$ 1.06		-$ 0.00053	2,000	-$ 1.06	$ -	0.00%	-$ 0.00053	2,000	-$ 1.06	$ -	0.00%	-$ 0.00053	2,000	-$ 1.06	$ -	0.00%	-$ 0.00053	2,000	-$ 1.06	$ -	0.00%
Rate Rider for Disposition of AR Credits - effective until Dec. 31, 2024	per kWh									-$ 0.00005	2,000	-$ 0.10	-$ 0.10		-$ 0.00005	2,000	-$ 0.10	$ -	0.00%	-$ 0.00005	2,000	-$ 0.10	$ -	0.00%	-$ 0.00005	2,000	-$ 0.10	$ -	0.00%	-$ 0.00005	2,000	-$ 0.10	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.79	1	$ 0.79	$ 0.79	1	$ 0.79	$ -	0.00%		1	$ -	-$ 0.79			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%		1	$ -	-$ 0.25			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of Stranded Meters Assets - effective until Dec. 31, 2019.	per 30 days	$ 1.55	1	$ 1.55	$ 1.55	1	$ 1.55	$ -	0.00%		1	$ -	-$ 1.55			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.03187	2,000	$ 63.74	$ 0.03310	2,000	$ 66.20	$ 2.46	3.86%	$ 0.03429	2,000	$ 68.58	$ 2.38	3.60%	$ 0.03541	2,000	$ 70.82	$ 2.24	3.27%	$ 0.03628	2,000	$ 72.56	$ 1.74	2.46%	$ 0.03782	2,000	$ 75.64	$ 3.08	4.24%	$ 0.03931	2,000	$ 78.62	$ 2.98	3.94%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per kWh	-$ 0.00051	2,000	-$ 1.02		2,000	$ -	$ 1.02			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per kWh	-$ 0.00156	2,000	-$ 3.12		2,000	$ -	$ 3.12			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per kWh	$ 0.00013	2,000	$ 0.26	$ 0.00013	2,000	$ 0.26	$ -	0.00%		2,000	$ -	-$ 0.26			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per kWh	$ 0.00003	2,000	$ 0.06	$ 0.00003	2,000	$ 0.06	$ -	0.00%		2,000	$ -	-$ 0.06			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per kWh	$ 0.00049	2,000	$ 0.98	$ 0.00049	2,000	$ 0.98	$ -	0.00%		2,000	$ -	-$ 0.98			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per kWh	$ 0.00076	2,000	$ 1.52	$ 0.00076	2,000	$ 1.52	$ -	0.00%		2,000	$ -	-$ 1.52			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per kWh	$ 0.00024	2,000	$ 0.48	$ 0.00024	2,000	$ 0.48	$ -	0.00%		2,000	$ -	-$ 0.48			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kWh	-$ 0.00019	2,000	-$ 0.38		2,000	$ -	$ 0.38			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Sub-Total A (excluding pass through)				**$ 99.56**			**$ 107.87**	**$ 8.31**	**8.35%**			**$ 103.25**	**-$ 4.62**	**-4.28%**			**$ 106.70**	**$ 3.45**	**3.34%**			**$ 109.38**	**$ 2.68**	**2.51%**			**$ 114.12**	**$ 4.74**	**4.33%**			**$ 118.71**	**$ 4.59**	**4.02%**
Line Losses on Cost of Power	per kWh	$ 0.0820	75	$ 6.17	$ 0.0820	75	$ 6.17	$ -	0.00%	$ 0.0820	59	$ 4.84	-$ 1.33	-21.54%	$ 0.0820	59	$ 4.84	$ -	0.00%	$ 0.0820	59	$ 4.84	$ -	0.00%	$ 0.0820	59	$ 4.84	$ -	0.00%	$ 0.0820	59	$ 4.84	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until Dec. 31, 2018.	per kWh	-$ 0.00317	2,000	-$ 6.34		2,000	$ -	$ 6.34				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account (2018) Applicable only for Class B Customers - effective until Dec. 31, 2018	per kWh	$ 0.00007	2,000	$ 0.14		2,000	$ -	-$ 0.14				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Global Adjustment Account (2018) Applicable only for Non-RPP Customers - effective until Dec. 31, 2018.	per kWh	-$ 0.00112		$ -			$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	per 30 days	$ 0.56	1	$ 0.56	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%			$ -	-$ 0.56				$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 100.09**			**$ 114.60**	**$ 14.51**	**14.50%**			**$ 108.65**	**-$ 5.95**	**-5.19%**			**$ 112.10**	**$ 3.45**	**3.18%**			**$ 114.78**	**$ 2.68**	**2.39%**			**$ 118.96**	**$ 4.18**	**3.64%**			**$ 123.55**	**$ 4.59**	**3.86%**
Retail Transmissioin Rate - Network Service Rate	per kWh	$ 0.00739	2,075	$ 15.34	$ 0.00804	2,075	$ 16.68	$ 1.35	8.80%	$ 0.00803	2,059	$ 16.53	-$ 0.15	-0.90%	$ 0.00803	2,059	$ 16.53	$ -	0.00%	$ 0.00803	2,059	$ 16.53	$ -	0.00%	$ 0.00803	2,059	$ 16.53	$ -	0.00%	$ 0.00803	2,059	$ 16.53	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	per kWh	$ 0.00552	2,075	$ 11.46	$ 0.00608	2,075	$ 12.62	$ 1.16	10.14%	$ 0.00607	2,059	$ 12.50	-$ 0.12	-0.94%	$ 0.00607	2,059	$ 12.50	$ -	0.00%	$ 0.00607	2,059	$ 12.50	$ -	0.00%	$ 0.00607	2,059	$ 12.50	$ -	0.00%	$ 0.00607	2,059	$ 12.50	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				**$ 126.88**			**$ 143.90**	**$ 17.02**	**13.42%**			**$ 137.68**	**-$ 6.22**	**-4.32%**			**$ 141.13**	**$ 3.45**	**2.51%**			**$ 143.81**	**$ 2.68**	**1.90%**			**$ 147.99**	**$ 4.18**	**2.91%**			**$ 152.58**	**$ 4.59**	**3.10%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0032	2,075	$ 6.64	$ 0.0032	2,075	$ 6.64	$ -	0.00%	$ 0.0032	2,059	$ 6.59	-$ 0.05	-0.78%	$ 0.0032	2,059	$ 6.59	$ -	0.00%	$ 0.0032	2,059	$ 6.59	$ -	0.00%	$ 0.0032	2,059	$ 6.59	$ -	0.00%	$ 0.0032	2,059	$ 6.59	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0003	2,075	$ 0.62	$ 0.0003	2,075	$ 0.62	$ -	0.00%	$ 0.0003	2,059	$ 0.62	-$ 0.00	-0.78%	$ 0.0003	2,059	$ 0.62	$ -	0.00%	$ 0.0003	2,059	$ 0.62	$ -	0.00%	$ 0.0003	2,059	$ 0.62	$ -	0.00%	$ 0.0003	2,059	$ 0.62	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	2,075	$ 0.83	$ 0.0004	2,075	$ 0.83			$ 0.0004	2,059	$ 0.82	-$ 0.01	-0.78%	$ 0.0004	2,059	$ 0.82	$ -	0.00%	$ 0.0004	2,059	$ 0.82	$ -	0.00%	$ 0.0004	2,059	$ 0.82	$ -	0.00%	$ 0.0004	2,059	$ 0.82	$ -	0.00%
Standard Supply Service Charge	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	1,300	$ 84.50	$ 0.0650	1,300	$ 84.50	$ -	0.00%	$ 0.0650	1,300	$ 84.50	$ -	0.00%	$ 0.0650	1,300	$ 84.50	$ -	0.00%	$ 0.0650	1,300	$ 84.50	$ -	0.00%	$ 0.0650	1,300	$ 84.50	$ -	0.00%	$ 0.0650	1,300	$ 84.50	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	340	$ 31.96	$ 0.0940	340	$ 31.96	$ -	0.00%	$ 0.0940	340	$ 31.96	$ -	0.00%	$ 0.0940	340	$ 31.96	$ -	0.00%	$ 0.0940	340	$ 31.96	$ -	0.00%	$ 0.0940	340	$ 31.96	$ -	0.00%	$ 0.0940	340	$ 31.96	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	360	$ 47.52	$ 0.1320	360	$ 47.52	$ -	0.00%	$ 0.1320	360	$ 47.52	$ -	0.00%	$ 0.1320	360	$ 47.52	$ -	0.00%	$ 0.1320	360	$ 47.52	$ -	0.00%	$ 0.1320	360	$ 47.52	$ -	0.00%	$ 0.1320	360	$ 47.52	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	600	$ 46.20	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	1,400	$ 124.60	$ 0.0890	1,400	$ 124.60	$ -	0.00%	$ 0.0890	1,400	$ 124.60	$ -	0.00%	$ 0.0890	1,400	$ 124.60	$ -	0.00%	$ 0.0890	1,400	$ 124.60	$ -	0.00%	$ 0.0890	1,400	$ 124.60	$ -	0.00%	$ 0.0890	1,400	$ 124.60	$ -	0.00%
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164		$ -	$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 299.20**			**$ 316.22**	**$ 17.02**	**5.7%**			**$ 309.94**	**-$ 6.28**	**-2.0%**			**$ 313.39**	**$ 3.45**	**1.1%**			**$ 316.07**	**$ 2.68**	**0.9%**			**$ 320.25**	**$ 4.18**	**1.3%**			**$ 324.84**	**$ 4.59**	**1.4%**
8% Provincial Rebate		-8%		-$ 23.94	-8%		-$ 25.30	-$ 1.36	5.7%	-8%		-$ 24.80	$ 0.50	-2.0%	-8%		-$ 25.07	-$ 0.28	1.1%	-8%		-$ 25.29	-$ 0.21	0.9%	-8%		-$ 25.62	-$ 0.33	1.3%	-8%		-$ 25.99	-$ 0.37	1.4%
HST		13%		$ 38.90	13%		$ 41.11	$ 2.21	5.7%	13%		$ 40.29	-$ 0.82	-2.0%	13%		$ 40.74	$ 0.45	1.1%	13%		$ 41.09	$ 0.35	0.9%	13%		$ 41.63	$ 0.54	1.3%	13%		$ 42.23	$ 0.60	1.4%
Total Bill on TOU (after Tax & Rebate)				**$ 314.16**			**$ 332.03**	**$ 17.87**	**5.7%**			**$ 325.44**	**-$ 6.60**	**-2.0%**			**$ 329.06**	**$ 3.62**	**1.1%**			**$ 331.87**	**$ 2.81**	**0.9%**			**$ 336.26**	**$ 4.39**	**1.3%**			**$ 341.08**	**$ 4.82**	**1.4%**
Total Bill on RPP (before Taxes)				**$ 306.02**			**$ 323.04**	**$ 17.02**	**5.6%**			**$ 316.76**	**-$ 6.28**	**-1.9%**			**$ 320.21**	**$ 3.45**	**1.1%**			**$ 322.89**	**$ 2.68**	**0.8%**			**$ 327.07**	**$ 4.18**	**1.3%**			**$ 331.66**	**$ 4.59**	**1.4%**
8% Provincial Rebate		-8%		-$ 24.48	-8%		-$ 25.84	-$ 1.36	5.6%	-8%		-$ 25.34	$ 0.50	-1.9%	-8%		-$ 25.62	-$ 0.28	1.1%	-8%		-$ 25.83	-$ 0.21	0.8%	-8%		-$ 26.17	-$ 0.33	1.3%	-8%		-$ 26.53	-$ 0.37	1.4%
HST		13%		$ 39.78	13%		$ 42.00	$ 2.21	5.6%	13%		$ 41.18	-$ 0.82	-1.9%	13%		$ 41.63	$ 0.45	1.1%	13%		$ 41.98	$ 0.35	0.8%	13%		$ 42.52	$ 0.54	1.3%	13%		$ 43.12	$ 0.60	1.4%
Total Bill on RPP (after Tax & Rebate)				**$ 321.32**			**$ 339.19**	**$ 17.87**	**5.6%**			**$ 332.60**	**-$ 6.60**	**-1.9%**			**$ 336.22**	**$ 3.62**	**1.1%**			**$ 339.03**	**$ 2.81**	**0.8%**			**$ 343.42**	**$ 4.39**	**1.3%**			**$ 348.24**	**$ 4.82**	**1.4%**
Loss Factor (%)		3.76%			3.76%					2.95%					2.95%					2.95%					2.95%					2.95%				

Appendix 2-W
Bill Impacts

Customer Class: GENERAL SERVICE LESS THAN 50 kW SERVICE

TOU / non-TOU: TOU

Consumption 2,800 **kWh** ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	2018 Current Board-Approved			2019 Expected			Impact		2020 Proposed			Impact		2021 Proposed			Impact		2022 Proposed			Impact		2023 Proposed			Impact		2024 Proposed			Impact	
		Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change
Service Charge	per 30 days	$ 34.45	1	$ 34.45	$ 35.78	1	$ 35.78	$ 1.33	3.86%	$ 37.07	1	$ 37.07	$ 1.29	3.61%	$ 38.28	1	$ 38.28	$ 1.21	3.26%	$ 39.22	1	$ 39.22	$ 0.94	2.46%	$ 40.88	1	$ 40.88	$ 1.66	4.23%	$ 42.49	1	$ 42.49	$ 1.61	3.94%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per kWh									$ 0.00011	2,800	$ 0.31	$ 0.31		$ 0.00011	2,800	$ 0.31	$ -	0.00%	$ 0.00011	2,800	$ 0.31	$ -	0.00%	$ 0.00011	2,800	$ 0.31	$ -	0.00%	$ 0.00011	2,800	$ 0.31	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per kWh									$ 0.00106	2,800	$ 2.97	$ 2.97		$ 0.00106	2,800	$ 2.97	$ -	0.00%	$ 0.00106	2,800	$ 2.97	$ -	0.00%	$ 0.00106	2,800	$ 2.97	$ -	0.00%	$ 0.00106	2,800	$ 2.97	$ -	0.00%
Rate Rider for Recovery of Monthly Billing - effective until Dec. 31, 2024	per kWh									$ 0.00010	2,800	$ 0.28	$ 0.28		$ 0.00010	2,800	$ 0.28	$ -	0.00%	$ 0.00010	2,800	$ 0.28	$ -	0.00%	$ 0.00010	2,800	$ 0.28	$ -	0.00%	$ 0.00010	2,800	$ 0.28	$ -	0.00%
Rate Rider for Recovery of Stranded Meter Assets - effective until Dec. 31, 2024	per 30 days									-$ 0.10	1	-$ 0.10	-$ 0.10		-$ 0.10	1	-$ 0.10	$ -	0.00%	-$ 0.10	1	-$ 0.10	$ -	0.00%	-$ 0.10	1	-$ 0.10	$ -	0.00%	-$ 0.10	1	-$ 0.10	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per kWh									-$ 0.00089	2,800	-$ 2.49	-$ 2.49		-$ 0.00089	2,800	-$ 2.49	$ -	0.00%	-$ 0.00089	2,800	-$ 2.49	$ -	0.00%	-$ 0.00089	2,800	-$ 2.49	$ -	0.00%	-$ 0.00089	2,800	-$ 2.49	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per kWh									-$ 0.00015	2,800	-$ 0.42	-$ 0.42		-$ 0.00015	2,800	-$ 0.42	$ -	0.00%	-$ 0.00015	2,800	-$ 0.42	$ -	0.00%	-$ 0.00015	2,800	-$ 0.42	$ -	0.00%	-$ 0.00015	2,800	-$ 0.42	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per kWh									-$ 0.00001	2,800	-$ 0.03	-$ 0.03		-$ 0.00001	2,800	-$ 0.03	$ -	0.00%	-$ 0.00001	2,800	-$ 0.03	$ -	0.00%	-$ 0.00001	2,800	-$ 0.03	$ -	0.00%	-$ 0.00001	2,800	-$ 0.03	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per kWh									-$ 0.00002	2,800	-$ 0.06	-$ 0.06		-$ 0.00002	2,800	-$ 0.06	$ -	0.00%	-$ 0.00002	2,800	-$ 0.06	$ -	0.00%	-$ 0.00002	2,800	-$ 0.06	$ -	0.00%	-$ 0.00002	2,800	-$ 0.06	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per kWh									-$ 0.00074	2,800	-$ 2.07	-$ 2.07		-$ 0.00074	2,800	-$ 2.07	$ -	0.00%	-$ 0.00074	2,800	-$ 2.07	$ -	0.00%	-$ 0.00074	2,800	-$ 2.07	$ -	0.00%	-$ 0.00074	2,800	-$ 2.07	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per kWh									-$ 0.00003	2,800	-$ 0.08	-$ 0.08		-$ 0.00003	2,800	-$ 0.08	$ -	0.00%	-$ 0.00003	2,800	-$ 0.08	$ -	0.00%	-$ 0.00003	2,800	-$ 0.08	$ -	0.00%	-$ 0.00003	2,800	-$ 0.08	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per kWh									-$ 0.00053	2,800	-$ 1.48	-$ 1.48		-$ 0.00053	2,800	-$ 1.48	$ -	0.00%	-$ 0.00053	2,800	-$ 1.48	$ -	0.00%	-$ 0.00053	2,800	-$ 1.48	$ -	0.00%	-$ 0.00053	2,800	-$ 1.48	$ -	0.00%
Rate Rider for Disposition of AR Credits - effective until Dec. 31, 2024	per kWh									-$ 0.00005	2,800	-$ 0.14	-$ 0.14		-$ 0.00005	2,800	-$ 0.14	$ -	0.00%	-$ 0.00005	2,800	-$ 0.14	$ -	0.00%	-$ 0.00005	2,800	-$ 0.14	$ -	0.00%	-$ 0.00005	2,800	-$ 0.14	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.79	1	$ 0.79	$ 0.79	1	$ 0.79	$ -	0.00%		1	$ -	-$ 0.79			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%		1	$ -	-$ 0.25			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of Stranded Meters Assets - effective until Dec. 31, 2019.	per 30 days	$ 1.55	1	$ 1.55	$ 1.55	1	$ 1.55	$ -	0.00%		1	$ -	-$ 1.55			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.03187	2,800	$ 89.24	$ 0.03310	2,800	$ 92.68	$ 3.44	3.86%	$ 0.03429	2,800	$ 96.01	$ 3.33	3.60%	$ 0.03541	2,800	$ 99.15	$ 3.14	3.27%	$ 0.03628	2,800	$ 101.58	$ 2.44	2.46%	$ 0.03782	2,800	$ 105.90	$ 4.31	4.24%	$ 0.03931	2,800	$ 110.07	$ 4.17	3.94%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per kWh	-$ 0.00051	2,800	-$ 1.43		2,800	$ -	$ 1.43			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per kWh	-$ 0.00156	2,800	-$ 4.37		2,800	$ -	$ 4.37			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per kWh	$ 0.00013	2,800	$ 0.36	$ 0.00013	2,800	$ 0.36	$ -	0.00%		2,800	$ -	-$ 0.36			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per kWh	$ 0.00003	2,800	$ 0.08	$ 0.00003	2,800	$ 0.08	$ -	0.00%		2,800	$ -	-$ 0.08			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per kWh	$ 0.00049	2,800	$ 1.37	$ 0.00049	2,800	$ 1.37	$ -	0.00%		2,800	$ -	-$ 1.37			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per kWh	$ 0.00076	2,800	$ 2.13	$ 0.00076	2,800	$ 2.13	$ -	0.00%		2,800	$ -	-$ 2.13			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per kWh	$ 0.00024	2,800	$ 0.67	$ 0.00024	2,800	$ 0.67	$ -	0.00%		2,800	$ -	-$ 0.67			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kWh	-$ 0.00019	2,800	-$ 0.53		2,800	$ -	$ 0.53			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -	
Sub-Total A (excluding pass through)				**$ 124.57**			**$ 135.67**	**$ 11.10**	**8.91%**			**$ 129.76**	**-$ 5.91**	**-4.35%**			**$ 134.11**	**$ 4.35**	**3.35%**			**$ 137.48**	**$ 3.38**	**2.52%**			**$ 143.46**	**$ 5.97**	**4.34%**			**$ 149.24**	**$ 5.78**	**4.03%**
Line Losses on Cost of Power	per kWh	$ 0.0820	105	$ 8.63	$ 0.0820	105	$ 8.63	$ -	0.00%	$ 0.0820	83	$ 6.77	-$ 1.86	-21.54%	$ 0.0820	83	$ 6.77	$ -	0.00%	$ 0.0820	83	$ 6.77	$ -	0.00%	$ 0.0820	83	$ 6.77	$ -	0.00%	$ 0.0820	83	$ 6.77	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until Dec. 31, 2018.	per kWh	-$ 0.00317	2,800	-$ 8.88		2,800	$ -	$ 8.88				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account (2018) Applicable only for Class B Customers - effective until Dec. 31, 2018	per kWh	$ 0.00007	2,800	$ 0.20		2,800	$ -	-$ 0.20				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Global Adjustment Account (2018) Applicable only for Non-RPP Customers - effective until Dec. 31, 2018.	per kWh	-$ 0.00112		$ -			$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	per 30 days	$ 0.56	1	$ 0.56	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%				-$ 0.56				$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 125.08**			**$ 144.86**	**$ 19.78**	**15.82%**			**$ 137.09**	**-$ 7.77**	**-5.36%**			**$ 141.44**	**$ 4.35**	**3.17%**			**$ 144.82**	**$ 3.38**	**2.39%**			**$ 150.23**	**$ 5.41**	**3.74%**			**$ 156.01**	**$ 5.78**	**3.85%**
Retail Transmissioin Rate - Network Service Rate	per kWh	$ 0.00739	2,905	$ 21.47	$ 0.00804	2,905	$ 23.36	$ 1.89	8.80%	$ 0.00803	2,883	$ 23.15	-$ 0.21	-0.90%	$ 0.00803	2,883	$ 23.15	$ -	0.00%	$ 0.00803	2,883	$ 23.15	$ -	0.00%	$ 0.00803	2,883	$ 23.15	$ -	0.00%	$ 0.00803	2,883	$ 23.15	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	per kWh	$ 0.00552	2,905	$ 16.04	$ 0.00608	2,905	$ 17.66	$ 1.63	10.14%	$ 0.00607	2,883	$ 17.50	-$ 0.17	-0.94%	$ 0.00607	2,883	$ 17.50	$ -	0.00%	$ 0.00607	2,883	$ 17.50	$ -	0.00%	$ 0.00607	2,883	$ 17.50	$ -	0.00%	$ 0.00607	2,883	$ 17.50	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				**$ 162.59**			**$ 185.88**	**$ 23.30**	**14.33%**			**$ 177.74**	**-$ 8.15**	**-4.38%**			**$ 182.09**	**$ 4.35**	**2.45%**			**$ 185.46**	**$ 3.38**	**1.85%**			**$ 190.87**	**$ 5.41**	**2.92%**			**$ 196.66**	**$ 5.78**	**3.03%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0032	2,905	$ 9.30	$ 0.0032	2,905	$ 9.30	$ -	0.00%	$ 0.0032	2,883	$ 9.22	-$ 0.07	-0.78%	$ 0.0032	2,883	$ 9.22	$ -	0.00%	$ 0.0032	2,883	$ 9.22	$ -	0.00%	$ 0.0032	2,883	$ 9.22	$ -	0.00%	$ 0.0032	2,883	$ 9.22	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0003	2,905	$ 0.87	$ 0.0003	2,905	$ 0.87	$ -	0.00%	$ 0.0003	2,883	$ 0.86	-$ 0.01	-0.78%	$ 0.0003	2,883	$ 0.86	$ -	0.00%	$ 0.0003	2,883	$ 0.86	$ -	0.00%	$ 0.0003	2,883	$ 0.86	$ -	0.00%	$ 0.0003	2,883	$ 0.86	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	2,905	$ 1.16	$ 0.0004	2,905	$ 1.16			$ 0.0004	2,883	$ 1.15	-$ 0.01	-0.78%	$ 0.0004	2,883	$ 1.15	$ -	0.00%	$ 0.0004	2,883	$ 1.15	$ -	0.00%	$ 0.0004	2,883	$ 1.15	$ -	0.00%	$ 0.0004	2,883	$ 1.15	$ -	0.00%
Standard Supply Service Charge	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	1,820	$ 118.30	$ 0.0650	1,820	$ 118.30	$ -	0.00%	$ 0.0650	1,820	$ 118.30	$ -	0.00%	$ 0.0650	1,820	$ 118.30	$ -	0.00%	$ 0.0650	1,820	$ 118.30	$ -	0.00%	$ 0.0650	1,820	$ 118.30	$ -	0.00%	$ 0.0650	1,820	$ 118.30	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	476	$ 44.74	$ 0.0940	476	$ 44.74	$ -	0.00%	$ 0.0940	476	$ 44.74	$ -	0.00%	$ 0.0940	476	$ 44.74	$ -	0.00%	$ 0.0940	476	$ 44.74	$ -	0.00%	$ 0.0940	476	$ 44.74	$ -	0.00%	$ 0.0940	476	$ 44.74	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	504	$ 66.53	$ 0.1320	504	$ 66.53	$ -	0.00%	$ 0.1320	504	$ 66.53	$ -	0.00%	$ 0.1320	504	$ 66.53	$ -	0.00%	$ 0.1320	504	$ 66.53	$ -	0.00%	$ 0.1320	504	$ 66.53	$ -	0.00%	$ 0.1320	504	$ 66.53	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	600	$ 46.20	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	2,200	$ 195.80	$ 0.0890	2,200	$ 195.80	$ -	0.00%	$ 0.0890	2,200	$ 195.80	$ -	0.00%	$ 0.0890	2,200	$ 195.80	$ -	0.00%	$ 0.0890	2,200	$ 195.80	$ -	0.00%	$ 0.0890	2,200	$ 195.80	$ -	0.00%	$ 0.0890	2,200	$ 195.80	$ -	0.00%
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164		$ -	$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 403.74**			**$ 427.04**	**$ 23.30**	**5.8%**			**$ 418.80**	**-$ 8.23**	**-1.9%**			**$ 423.15**	**$ 4.35**	**1.0%**			**$ 426.53**	**$ 3.38**	**0.8%**			**$ 431.94**	**$ 5.41**	**1.3%**			**$ 437.72**	**$ 5.78**	**1.3%**
8% Provincial Rebate		-8%		-$ 32.30	-8%		-$ 34.16	-$ 1.86	5.8%	-8%		-$ 33.50	$ 0.66	-1.9%	-8%		-$ 33.85	-$ 0.35	1.0%	-8%		-$ 34.12	-$ 0.27	0.8%	-8%		-$ 34.55	-$ 0.43	1.3%	-8%		-$ 35.02	-$ 0.46	1.3%
HST		13%		$ 52.49	13%		$ 55.51	$ 3.03	5.8%	13%		$ 54.44	-$ 1.07	-1.9%	13%		$ 55.01	$ 0.56	1.0%	13%		$ 55.45	$ 0.44	0.8%	13%		$ 56.15	$ 0.70	1.3%	13%		$ 56.90	$ 0.75	1.3%
Total Bill on TOU (after Tax & Rebate)				**$ 423.93**			**$ 448.39**	**$ 24.46**	**5.8%**			**$ 439.74**	**-$ 8.65**	**-1.9%**			**$ 444.31**	**$ 4.56**	**1.0%**			**$ 447.85**	**$ 3.54**	**0.8%**			**$ 453.53**	**$ 5.68**	**1.3%**			**$ 459.61**	**$ 6.07**	**1.3%**
Total Bill on RPP (before Taxes)				**$ 416.17**			**$ 439.47**	**$ 23.30**	**5.6%**			**$ 431.23**	**-$ 8.23**	**-1.9%**			**$ 435.58**	**$ 4.35**	**1.0%**			**$ 438.95**	**$ 3.38**	**0.8%**			**$ 444.37**	**$ 5.41**	**1.2%**			**$ 450.15**	**$ 5.78**	**1.3%**
8% Provincial Rebate		-8%		-$ 33.29	-8%		-$ 35.16	-$ 1.86	5.6%	-8%		-$ 34.50	$ 0.66	-1.9%	-8%		-$ 34.85	-$ 0.35	1.0%	-8%		-$ 35.12	-$ 0.27	0.8%	-8%		-$ 35.55	-$ 0.43	1.2%	-8%		-$ 36.01	-$ 0.46	1.3%
HST		13%		$ 54.10	13%		$ 57.13	$ 3.03	5.6%	13%		$ 56.06	-$ 1.07	-1.9%	13%		$ 56.63	$ 0.56	1.0%	13%		$ 57.06	$ 0.44	0.8%	13%		$ 57.77	$ 0.70	1.2%	13%		$ 58.52	$ 0.75	1.3%
Total Bill on RPP (after Tax & Rebate)				**$ 436.98**			**$ 461.44**	**$ 24.46**	**5.6%**			**$ 452.79**	**-$ 8.65**	**-1.9%**			**$ 457.36**	**$ 4.56**	**1.0%**			**$ 460.90**	**$ 3.54**	**0.8%**			**$ 466.58**	**$ 5.68**	**1.2%**			**$ 472.65**	**$ 6.07**	**1.3%**
Loss Factor (%)		3.76%			3.76%					2.95%					2.95%					2.95%					2.95%					2.95%				

Appendix 2-W
Bill Impacts

Customer Class: GENERAL SERVICE 50 TO 999 kW SERVICE

TOU / non-TOU: non-TOU — **SPOT Class B**

Consumption: 180 kW | 200 kVA | 79,000 kWh — ● May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

Charge Unit		2018 Current Board-Approved			2019 Expected			Impact		2020 Proposed			Impact		2021 Proposed			Impact		2022 Proposed			Impact		2023 Proposed			Impact		2024 Proposed			Impact	
		Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change
Service Charge	per 30 days	$ 49.55	1	$ 49.55	$ 51.46	1	$ 51.46	$ 1.91	3.85%	$ 52.17	1	$ 52.17	$ 0.71	1.38%	$ 53.87	1	$ 53.87	$ 1.70	3.26%	$ 55.20	1	$ 55.20	$ 1.33	2.47%	$ 57.54	1	$ 57.54	$ 2.34	4.24%	$ 59.80	1	$ 59.80	$ 2.26	3.93%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per kVA									$ 0.0191	200	$ 3.82	$ 3.82		$ 0.0191	200	$ 3.82	$ -	0.00%	$ 0.0191	200	$ 3.82	$ -	0.00%	$ 0.0191	200	$ 3.82	$ -	0.00%	$ 0.0191	200	$ 3.82	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per kVA									$ 0.1825	200	$ 36.50	$ 36.50		$ 0.1825	200	$ 36.50	$ -	0.00%	$ 0.1825	200	$ 36.50	$ -	0.00%	$ 0.1825	200	$ 36.50	$ -	0.00%	$ 0.1825	200	$ 36.50	$ -	0.00%
Rate Rider for Recovery of Stranded Meter Assets - effective until Dec. 31, 2024	per 30 days									-$ 0.37	1	-$ 0.37	-$ 0.37		-$ 0.37	1	-$ 0.37	$ -	0.00%	-$ 0.37	1	-$ 0.37	$ -	0.00%	-$ 0.37	1	-$ 0.37	$ -	0.00%	-$ 0.37	1	-$ 0.37	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per kVA									-$ 0.1523	200	-$ 30.46	-$ 30.46		-$ 0.1523	200	-$ 30.46	$ -	0.00%	-$ 0.1523	200	-$ 30.46	$ -	0.00%	-$ 0.1523	200	-$ 30.46	$ -	0.00%	-$ 0.1523	200	-$ 30.46	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per kVA									-$ 0.0251	200	-$ 5.02	-$ 5.02		-$ 0.0251	200	-$ 5.02	$ -	0.00%	-$ 0.0251	200	-$ 5.02	$ -	0.00%	-$ 0.0251	200	-$ 5.02	$ -	0.00%	-$ 0.0251	200	-$ 5.02	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per kVA									-$ 0.0009	200	-$ 0.18	-$ 0.18		-$ 0.0009	200	-$ 0.18	$ -	0.00%	-$ 0.0009	200	-$ 0.18	$ -	0.00%	-$ 0.0009	200	-$ 0.18	$ -	0.00%	-$ 0.0009	200	-$ 0.18	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per kVA									-$ 0.0033	200	-$ 0.66	-$ 0.66		-$ 0.0033	200	-$ 0.66	$ -	0.00%	-$ 0.0033	200	-$ 0.66	$ -	0.00%	-$ 0.0033	200	-$ 0.66	$ -	0.00%	-$ 0.0033	200	-$ 0.66	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per kVA									-$ 0.1272	200	-$ 25.44	-$ 25.44		-$ 0.1272	200	-$ 25.44	$ -	0.00%	-$ 0.1272	200	-$ 25.44	$ -	0.00%	-$ 0.1272	200	-$ 25.44	$ -	0.00%	-$ 0.1272	200	-$ 25.44	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per kVA									-$ 0.0050	200	-$ 1.00	-$ 1.00		-$ 0.0050	200	-$ 1.00	$ -	0.00%	-$ 0.0050	200	-$ 1.00	$ -	0.00%	-$ 0.0050	200	-$ 1.00	$ -	0.00%	-$ 0.0050	200	-$ 1.00	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per kVA									-$ 0.0901	200	-$ 18.02	-$ 18.02		-$ 0.0901	200	-$ 18.02	$ -	0.00%	-$ 0.0901	200	-$ 18.02	$ -	0.00%	-$ 0.0901	200	-$ 18.02	$ -	0.00%	-$ 0.0901	200	-$ 18.02	$ -	0.00%
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	per kVA									-$ 0.0276	200	-$ 5.52	-$ 5.52		-$ 0.0276	200	-$ 5.52	$ -	0.00%	-$ 0.0276	200	-$ 5.52	$ -	0.00%	-$ 0.0276	200	-$ 5.52	$ -	0.00%	-$ 0.0276	200	-$ 5.52	$ -	0.00%
Rate Rider for Disposition of AR Credits - effective until Dec. 31, 2024	per kVA									-$ 0.0004	200	-$ 0.08	-$ 0.08		-$ 0.0004	200	-$ 0.08	$ -	0.00%	-$ 0.0004	200	-$ 0.08	$ -	0.00%	-$ 0.0004	200	-$ 0.08	$ -	0.00%	-$ 0.0004	200	-$ 0.08	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 1.01	1	$ 1.01	$ 1.01	1	$ 1.01	$ -	0.00%		1	$ -	$ 1.01			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.30	1	$ 0.30	$ 0.30	1	$ 0.30	$ -	0.00%		1	$ -	$ 0.30			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of Stranded Meters Assets - effective until Dec. 31, 2019.	per 30 days	$ 4.64	1	$ 4.64	$ 4.64	1	$ 4.64	$ -	0.00%		1	$ -	$ 4.64			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	per kVA	$ 7.7987	200	$ 1,559.74	$ 8.0989	200	$ 1,619.78	$ 60.04	3.85%	$ 8.36780	200	$ 1,673.56	$ 53.78	3.32%	$ 8.6406	200	$ 1,728.12	$ 54.56	3.26%	$ 8.85320	200	$ 1,770.64	$ 42.52	2.46%	$ 9.22860	200	$ 1,845.72	$ 75.08	4.24%	$ 9.59130	200	$ 1,918.26	$ 72.54	3.93%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per kVA	-$ 0.0814	200	-$ 16.28		200	$ -	$ 16.28			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per kVA	-$ 0.2512	200	-$ 50.24		200	$ -	$ 50.24			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per kVA	$ 0.0114	200	$ 2.28	$ 0.0114	200	$ 2.28	$ -	0.00%		200	$ -	$ 2.28			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per kVA	$ 0.0047	200	$ 0.94	$ 0.0047	200	$ 0.94	$ -	0.00%		200	$ -	$ 0.94			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per kVA	$ 0.0781	200	$ 15.62	$ 0.0781	200	$ 15.62	$ -	0.00%		200	$ -	$ 15.62			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per kVA	$ 0.1659	200	$ 33.18	$ 0.1659	200	$ 33.18	$ -	0.00%		200	$ -	$ 33.18			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per kVA	$ 0.0498	200	$ 9.96	$ 0.0498	200	$ 9.96	$ -	0.00%		200	$ -	$ 9.96			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kVA	$ 0.0912	200	$ 18.24		200	$ -	-$ 18.24			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -	
Sub-Total A (excluding pass through)				**$ 1,628.94**			**$ 1,739.17**	**$ 110.23**	**6.77%**			**$ 1,679.30**	**-$ 59.87**	**-3.44%**			**$ 1,735.56**	**$ 56.26**	**3.35%**			**$ 1,779.41**	**$ 43.85**	**2.53%**			**$ 1,856.83**	**$ 77.42**	**4.35%**			**$ 1,931.63**	**$ 74.80**	**4.03%**
Line Losses on Cost of Power	per kWh	$ 0.1164	2,970	$ 345.75	$ 0.1164	2,970	$ 345.75	$ -	0.00%	$ 0.1164	2,331	$ 271.27	-$ 74.48	-21.54%	$ 0.1164	2,331	$ 271.27	$ -	0.00%	$ 0.1164	2,331	$ 271.27	$ -	0.00%	$ 0.1164	2,331	$ 271.27	$ -	0.00%	$ 0.1164	2,331	$ 271.27	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until Dec. 31, 2018.	per kVA	-$ 0.7597	200	-$ 151.94		200	$ -	$ 151.94				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Deferral/Variance Accounts (2018) for Non-Wholesale Market Participants - effective until Dec. 31, 2018.	per kVA	-$ 0.5191	200	-$ 103.82		200	$ -	$ 103.82				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account (2018) Applicable only for Class B Customers - effective until Dec. 31, 2018	per kVA	$ 0.0277	200	$ 5.54		200	$ -	-$ 5.54				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Global Adjustment Account (2018) Applicable only for Non-RPP Customers - effective until Dec. 31, 2018.	per kWh	-$ 0.00112	79,000	-$ 88.48		79,000	$ -	$ 88.48				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 1,635.99**			**$ 2,084.92**	**$ 448.93**	**27.44%**			**$ 1,950.57**	**-$ 134.35**	**-6.44%**			**$ 2,006.83**	**$ 56.26**	**2.88%**			**$ 2,050.68**	**$ 43.85**	**2.19%**			**$ 2,128.10**	**$ 77.42**	**3.78%**			**$ 2,202.90**	**$ 74.80**	**3.51%**
Retail Transmissioin Rate - Network Service Rate	per kW	$ 2.5690	180	$ 462.42	$ 2.7564	180	$ 496.15	$ 33.73	7.29%	$ 2.7525	180	$ 495.45	-$ 0.70	-0.14%	$ 2.7525	180	$ 495.45	$ -	0.00%	$ 2.7525	180	$ 495.45	$ -	0.00%	$ 2.7525	180	$ 495.45	$ -	0.00%	$ 2.7525	180	$ 495.45	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	per kW	$ 2.0515	180	$ 369.27	$ 2.2295	180	$ 401.31	$ 32.04	8.68%	$ 2.2259	180	$ 400.66	-$ 0.65	-0.16%	$ 2.2259	180	$ 400.66	$ -	0.00%	$ 2.2259	180	$ 400.66	$ -	0.00%	$ 2.2259	180	$ 400.66	$ -	0.00%	$ 2.2259	180	$ 400.66	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				**$ 2,467.68**			**$ 2,982.39**	**$ 514.70**	**20.86%**			**$ 2,846.68**	**-$ 135.70**	**-4.55%**			**$ 2,902.94**	**$ 56.26**	**1.98%**			**$ 2,946.79**	**$ 43.85**	**1.51%**			**$ 3,024.21**	**$ 77.42**	**2.63%**			**$ 3,099.01**	**$ 74.80**	**2.47%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0032	81,970	$ 262.31	$0.0032	81,970	$ 262.31	$ -	0.00%	$ 0.0032	81,331	$ 260.26	-$ 2.05	-0.78%	$0.0032	81,331	$ 260.26	$ -	0.00%	$ 0.0032	81,331	$ 260.26	$ -	0.00%	$ 0.0032	81,331	$ 260.26	$ -	0.00%	$ 0.0032	81,331	$ 260.26	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0003	81,970	$ 24.59	$0.0003	81,970	$ 24.59	$ -	0.00%	$ 0.0003	81,331	$ 24.40	-$ 0.19	-0.78%	$0.0003	81,331	$ 24.40	$ -	0.00%	$ 0.0003	81,331	$ 24.40	$ -	0.00%	$ 0.0003	81,331	$ 24.40	$ -	0.00%	$ 0.0003	81,331	$ 24.40	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	81,970	$ 32.79	$0.0004	81,970	$ 32.79	$ -	0.00%	$ 0.0004	81,331	$ 32.53	-$ 0.26	-0.78%	$0.0004	81,331	$ 32.53	$ -	0.00%	$ 0.0004	81,331	$ 32.53	$ -	0.00%	$ 0.0004	81,331	$ 32.53	$ -	0.00%	$ 0.0004	81,331	$ 32.53	$ -	0.00%
Standard Supply Service Charge	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	50,560	$ 3,286.40	$0.0650	50,560	$ 3,286.40	$ -	0.00%	$ 0.0650	50,560	$ 3,286.40	$ -	0.00%	$0.0650	50,560	$ 3,286.40	$ -	0.00%	$ 0.0650	50,560	$ 3,286.40	$ -	0.00%	$ 0.0650	50,560	$ 3,286.40	$ -	0.00%	$ 0.0650	50,560	$ 3,286.40	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	14,220	$ 1,336.68	$0.0940	14,220	$ 1,336.68	$ -	0.00%	$ 0.0940	14,220	$ 1,336.68	$ -	0.00%	$0.0940	14,220	$ 1,336.68	$ -	0.00%	$ 0.0940	14,220	$ 1,336.68	$ -	0.00%	$ 0.0940	14,220	$ 1,336.68	$ -	0.00%	$ 0.0940	14,220	$ 1,336.68	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	14,220	$ 1,877.04	$0.1320	14,220	$ 1,877.04	$ -	0.00%	$ 0.1320	14,220	$ 1,877.04	$ -	0.00%	$0.1320	14,220	$ 1,877.04	$ -	0.00%	$ 0.1320	14,220	$ 1,877.04	$ -	0.00%	$ 0.1320	14,220	$ 1,877.04	$ -	0.00%	$ 0.1320	14,220	$ 1,877.04	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	750	$ 57.75	$0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	78,250	$ 6,964.25	$0.0890	78,250	$ 6,964.25	$ -	0.00%	$ 0.0890	78,250	$ 6,964.25	$ -	0.00%	$0.0890	78,250	$ 6,964.25	$ -	0.00%	$ 0.0890	78,250	$ 6,964.25	$ -	0.00%	$ 0.0890	78,250	$ 6,964.25	$ -	0.00%	$ 0.0890	78,250	$ 6,964.25	$ -	0.00%
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$0.1164	0	$ -	$ -		$ 0.1164	-	$ -	$ -		$0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164	79,000	$ 9,195.60	$0.1164	79,000	$ 9,195.60	$ -	0.00%	$ 0.1164	79,000	$ 9,195.60	$ -	0.00%	$0.1164	79,000	$ 9,195.60	$ -	0.00%	$ 0.1164	79,000	$ 9,195.60	$ -	0.00%	$ 0.1164	79,000	$ 9,195.60	$ -	0.00%	$ 0.1164	79,000	$ 9,195.60	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price (before Taxes)				**$11,983.22**			**$12,497.92**	**$ 514.70**	**4.3%**			**$12,359.72**	**-$ 138.20**	**-1.1%**			**$12,415.98**	**$ 56.26**	**0.5%**			**$12,459.83**	**$ 43.85**	**0.4%**			**$12,537.25**	**$ 77.42**	**0.6%**			**$12,612.05**	**$ 74.80**	**0.6%**
8% Provincial Rebate		-8%			-8%					-8%			$ -		-8%			$ -		-8%			$ -		-8%			$ -		-8%			$ -	
HST		13%		$ 1,557.82	13%		$ 1,624.73	$ 66.91	4.3%	13%		$ 1,606.76	-$ 17.97	-1.1%	13%		$ 1,614.08	$ 7.31	0.5%	13%		$ 1,619.78	$ 5.70	0.4%	13%		$ 1,629.84	$ 10.06	0.6%	13%		$ 1,639.57	$ 9.72	0.6%
Total Bill on Average IESO Wholesale Market Price (after Tax and Rebate)				**$13,541.04**			**$14,122.65**	**$ 581.61**	**4.3%**			**$13,966.48**	**-$ 156.17**	**-1.1%**			**$14,030.06**	**$ 63.57**	**0.5%**			**$14,079.61**	**$ 49.55**	**0.4%**			**$14,167.09**	**$ 87.48**	**0.6%**			**$14,251.62**	**$ 84.52**	**0.6%**
Total Bill on RPP (before Taxes)				**$ 9,809.62**			**$10,324.32**	**$ 514.70**	**5.2%**			**$10,186.12**	**-$ 138.20**	**-1.3%**			**$10,242.38**	**$ 56.26**	**0.6%**			**$10,286.23**	**$ 43.85**	**0.4%**			**$10,363.65**	**$ 77.42**	**0.8%**			**$10,438.45**	**$ 74.80**	**0.7%**
8% Provincial Rebate		-8%			-8%					-8%			$ -		-8%			$ -		-8%			$ -		-8%			$ -		-8%			$ -	
HST		13%		$ 1,275.25	13%		$ 1,342.16	$ 66.91	5.2%	13%		$ 1,324.20	-$ 17.97	-1.3%	13%		$ 1,331.51	$ 7.31	0.6%	13%		$ 1,337.21	$ 5.70	0.4%	13%		$ 1,347.27	$ 10.06	0.8%	13%		$ 1,357.00	$ 9.72	0.7%
Total Bill on RPP (after Tax and Rebate)				**$11,084.87**			**$11,666.48**	**$ 581.61**	**5.2%**			**$11,510.32**	**-$ 156.17**	**-1.3%**			**$11,573.89**	**$ 63.57**	**0.6%**			**$11,623.44**	**$ 49.55**	**0.4%**			**$11,710.93**	**$ 87.48**	**0.8%**			**$11,795.45**	**$ 84.52**	**0.7%**
Loss Factor (%)		3.76%			3.76%					2.95%					2.95%					2.95%					2.95%					2.95%				

Appendix 2-W
Bill Impacts

Customer Class: GENERAL SERVICE 1,000 TO 4,999 kW SERVICE

TOU / non-TOU: non-TOU — SPOT B

Consumption: 1,800 kW | 2,000 kVA | 900,000 kWh — ● May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

Charge Unit		2018 Current Board-Approved			2019 Expected			Impact		2020 Proposed			Impact		2021 Proposed			Impact		2022 Proposed			Impact		2023 Proposed			Impact		2024 Proposed			Impact	
		Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change
Service Charge	per 30 days	$ 946.52	1	$ 946.52	$ 982.96	1	$ 982.96	$ 36.44	3.85%	$ 940.29	1	$ 940.29	-$ 42.67	-4.34%	$ 970.94	1	$ 970.94	$ 30.65	3.26%	$ 994.83	1	$ 994.83	$ 23.89	2.46%	$ 1,037.01	1	$ 1,037.01	$ 42.18	4.24%	$ 1,077.76	1	$ 1,077.76	$ 40.75	3.93%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per kVA									$ 0.0144	2,000	$ 28.80	$ 28.80		$ 0.0144	2,000	$ 28.80	$ -	0.00%	$ 0.0144	2,000	$ 28.80	$ -	0.00%	$ 0.0144	2,000	$ 28.80	$ -	0.00%	$ 0.0144	2,000	$ 28.80	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per kVA									$ 0.1377	2,000	$ 275.40	$ 275.40		$ 0.1377	2,000	$ 275.40	$ -	0.00%	$ 0.1377	2,000	$ 275.40	$ -	0.00%	$ 0.1377	2,000	$ 275.40	$ -	0.00%	$ 0.1377	2,000	$ 275.40	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effffective until Dec. 31, 2024	per kVA									-$ 0.1149	2,000	-$ 229.80	-$ 229.80		-$ 0.1149	2,000	-$ 229.80	$ -	0.00%	-$ 0.1149	2,000	-$ 229.80	$ -	0.00%	-$ 0.1149	2,000	-$ 229.80	$ -	0.00%	-$ 0.1149	2,000	-$ 229.80	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per kVA									-$ 0.0190	2,000	-$ 38.00	-$ 38.00		-$ 0.0190	2,000	-$ 38.00	$ -	0.00%	-$ 0.0190	2,000	-$ 38.00	$ -	0.00%	-$ 0.0190	2,000	-$ 38.00	$ -	0.00%	-$ 0.0190	2,000	-$ 38.00	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per kVA									-$ 0.0004	2,000	-$ 0.80	-$ 0.80		-$ 0.0004	2,000	-$ 0.80	$ -	0.00%	-$ 0.0004	2,000	-$ 0.80	$ -	0.00%	-$ 0.0004	2,000	-$ 0.80	$ -	0.00%	-$ 0.0004	2,000	-$ 0.80	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per kVA									-$ 0.0025	2,000	-$ 5.00	-$ 5.00		-$ 0.0025	2,000	-$ 5.00	$ -	0.00%	-$ 0.0025	2,000	-$ 5.00	$ -	0.00%	-$ 0.0025	2,000	-$ 5.00	$ -	0.00%	-$ 0.0025	2,000	-$ 5.00	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per kVA									-$ 0.0960	2,000	-$ 192.00	-$ 192.00		-$ 0.0960	2,000	-$ 192.00	$ -	0.00%	-$ 0.0960	2,000	-$ 192.00	$ -	0.00%	-$ 0.0960	2,000	-$ 192.00	$ -	0.00%	-$ 0.0960	2,000	-$ 192.00	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per kVA									-$ 0.0038	2,000	-$ 7.60	-$ 7.60		-$ 0.0038	2,000	-$ 7.60	$ -	0.00%	-$ 0.0038	2,000	-$ 7.60	$ -	0.00%	-$ 0.0038	2,000	-$ 7.60	$ -	0.00%	-$ 0.0038	2,000	-$ 7.60	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per kVA									-$ 0.0680	2,000	-$ 136.00	-$ 136.00		-$ 0.0680	2,000	-$ 136.00	$ -	0.00%	-$ 0.0680	2,000	-$ 136.00	$ -	0.00%	-$ 0.0680	2,000	-$ 136.00	$ -	0.00%	-$ 0.0680	2,000	-$ 136.00	$ -	0.00%
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	per kVA									-$ 0.0208	2,000	-$ 41.60	-$ 41.60		-$ 0.0208	2,000	-$ 41.60	$ -	0.00%	-$ 0.0208	2,000	-$ 41.60	$ -	0.00%	-$ 0.0208	2,000	-$ 41.60	$ -	0.00%	-$ 0.0208	2,000	-$ 41.60	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 18.89	1	$ 18.89	$ 18.89	1	$ 18.89	$ -	0.00%		1	$ -	-$ 18.89			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -		
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 5.48	1	$ 5.48	$ 5.48	1	$ 5.48	$ -	0.00%		1	$ -	-$ 5.48			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -		
Distribution Volumetric Rate	per kVA	$ 6.1355	2,000	$ 12,271.00	$ 6.37170	2,000	$ 12,743.40	$ 472.40	3.85%	$ 6.6114	2,000	$ 13,222.80	$ 479.40	3.76%	$ 6.8269	2,000	$ 13,653.80	$ 431.00	3.26%	$ 6.99480	2,000	$ 13,989.60	$ 335.80	2.46%	$ 7.29140	2,000	$ 14,582.80	$ 593.20	4.24%	$ 7.5780	2,000	$ 15,156.00	$ 573.20	3.93%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per kVA	-$ 0.0653	2,000	-$ 130.60		2,000	$ -	$ 130.60			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -		
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per kVA	-$ 0.2017	2,000	-$ 403.40		2,000	$ -	$ 403.40			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -		
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per kVA	$ 0.0056	2,000	$ 11.20	$ 0.0056	2,000	$ 11.20	$ -	0.00%		2,000	$ -	-$ 11.20			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -		
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per kVA	$ 0.0038	2,000	$ 7.60	$ 0.0038	2,000	$ 7.60	$ -	0.00%		2,000	$ -	-$ 7.60			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -		
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per kVA	$ 0.0627	2,000	$ 125.40	$ 0.0627	2,000	$ 125.40	$ -	0.00%		2,000	$ -	-$ 125.40			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -		
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per kVA	$ 0.1226	2,000	$ 245.20	$ 0.1226	2,000	$ 245.20	$ -	0.00%		2,000	$ -	-$ 245.20			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -		
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per kVA	$ 0.0356	2,000	$ 71.20	$ 0.0356	2,000	$ 71.20	$ -	0.00%		2,000	$ -	-$ 71.20			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -		
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kVA	$ 0.1051	2,000	$ 210.20		2,000	$ -	-$ 210.20			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -		
Sub-Total A (excluding pass through)				**$ 13,378.69**			**$ 14,211.33**	**$ 832.64**	**6.22%**			**$ 13,816.49**	**-$ 394.84**	**-2.78%**			**$ 14,278.14**	**$ 461.65**	**3.34%**			**$ 14,637.83**	**$ 359.69**	**2.52%**			**$ 15,273.21**	**$ 635.38**	**4.34%**			**$ 15,887.16**	**$ 613.95**	**4.02%**
Line Losses on Cost of Power	per kWh	$ 0.1164	33,840	$ 3,938.98	$ 0.1164	33,840	$ 3,938.98	$ -	0.00%	$ 0.1164	26,550	$ 3,090.42	-$ 848.56	-21.54%	$ 0.1164	26,550	$ 3,090.42	$ -	0.00%	$ 0.1164	26,550	$ 3,090.42	$ -	0.00%	$ 0.1164	26,550	$ 3,090.42	$ -	0.00%	$ 0.1164	26,550	$ 3,090.42	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until Dec. 31, 2018.	per kVA	-$ 0.8339	2,000	-$ 1,667.80		2,000	$ -	$ 1,667.80				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -		
Rate Rider for Disposition of Deferral/Variance Accounts (2018) for Non-Wholesale Market Participants - effective until Dec. 31, 2018.	per kVA	-$ 0.5704	2,000	-$ 1,140.80		2,000	$ -	$ 1,140.80				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -		
Rate Rider for Disposition of Capacity Based Recovery Account (2018) Applicable only for Class B Customers - effective until Dec. 31, 2018	per kVA	$ 0.0295	2,000	$ 59.00		2,000	$ -	-$ 59.00				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -		
Rate Rider for Disposition of Global Adjustment Account (2018) Applicable only for Non-RPP Customers - effective until Dec. 31, 2018.	per kWh	-$ 0.00112	900,000	-$ 1,008.00		900,000	$ -	$ 1,008.00				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)				**$ 13,560.07**			**$ 18,150.31**	**$ 4,590.24**	**33.85%**			**$ 16,906.91**	**-$ 1,243.40**	**-6.85%**			**$ 17,368.56**	**$ 461.65**	**2.73%**			**$ 17,728.25**	**$ 359.69**	**2.07%**			**$ 18,363.63**	**$ 635.38**	**3.58%**			**$ 18,977.58**	**$ 613.95**	**3.34%**
Retail Transmissioin Rate - Network Service Rate	per kW	$ 2.4821	1,800	$ 4,467.78	$ 2.6631	1,800	$ 4,793.58	$ 325.80	7.29%	$ 2.6594	1,800	$ 4,786.92	$ 6.66	-0.14%	$ 2.6594	1,800	$ 4,786.92	$ -	0.00%	$ 2.6594	1,800	$ 4,786.92	$ -	0.00%	$ 2.6594	1,800	$ 4,786.92	$ -	0.00%	$ 2.6594	1,800	$ 4,786.92	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	per kW	$ 2.0494	1,800	$ 3,688.92	$ 2.2272	1,800	$ 4,008.96	$ 320.04	8.68%	$ 2.2236	1,800	$ 4,002.48	-$ 6.48	-0.16%	$ 2.2236	1,800	$ 4,002.48	$ -	0.00%	$ 2.2236	1,800	$ 4,002.48	$ -	0.00%	$ 2.2236	1,800	$ 4,002.48	$ -	0.00%	$ 2.2236	1,800	$ 4,002.48	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				**$ 21,716.77**			**$ 26,952.85**	**$ 5,236.08**	**24.11%**			**$ 25,696.31**	**-$ 1,256.54**	**-4.66%**			**$ 26,157.96**	**$ 461.65**	**1.80%**			**$ 26,517.65**	**$ 359.69**	**1.38%**			**$ 27,153.03**	**$ 635.38**	**2.40%**			**$ 27,766.98**	**$ 613.95**	**2.26%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0032	933,840	$ 2,988.29	$ 0.0032	933,840	$ 2,988.29	$ -	0.00%	$ 0.0032	926,550	$ 2,964.96	-$ 23.33	-0.78%	$ 0.0032	926,550	$ 2,964.96	$ -	0.00%	$ 0.0032	926,550	$ 2,964.96	$ -	0.00%	$ 0.0032	926,550	$ 2,964.96	$ -	0.00%	$ 0.0032	926,550	$ 2,964.96	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0003	933,840	$ 280.15	$ 0.0003	933,840	$ 280.15	$ -	0.00%	$ 0.0003	926,550	$ 277.97	-$ 2.19	-0.78%	$ 0.0003	926,550	$ 277.97	$ -	0.00%	$ 0.0003	926,550	$ 277.97	$ -	0.00%	$ 0.0003	926,550	$ 277.97	$ -	0.00%	$ 0.0003	926,550	$ 277.97	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	933,840	$ 373.54	$ 0.0004	933,840	$ 373.54	$ -	0.00%	$ 0.0004	926,550	$ 370.62	-$ 2.92	-0.78%	$ 0.0004	926,550	$ 370.62	$ -	0.00%	$ 0.0004	926,550	$ 370.62	$ -	0.00%	$ 0.0004	926,550	$ 370.62	$ -	0.00%	$ 0.0004	926,550	$ 370.62	$ -	0.00%
Standard Supply Service Charge	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	576,000	$ 37,440.00	$ 0.0650	576,000	$ 37,440.00	$ -	0.00%	$ 0.0650	576,000	$ 37,440.00	$ -	0.00%	$ 0.0650	576,000	$ 37,440.00	$ -	0.00%	$ 0.0650	576,000	$ 37,440.00	$ -	0.00%	$ 0.0650	576,000	$ 37,440.00	$ -	0.00%	$ 0.0650	576,000	$ 37,440.00	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	162,000	$ 15,228.00	$ 0.0940	162,000	$ 15,228.00	$ -	0.00%	$ 0.0940	162,000	$ 15,228.00	$ -	0.00%	$ 0.0940	162,000	$ 15,228.00	$ -	0.00%	$ 0.0940	162,000	$ 15,228.00	$ -	0.00%	$ 0.0940	162,000	$ 15,228.00	$ -	0.00%	$ 0.0940	162,000	$ 15,228.00	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	162,000	$ 21,384.00	$ 0.1320	162,000	$ 21,384.00	$ -	0.00%	$ 0.1320	162,000	$ 21,384.00	$ -	0.00%	$ 0.1320	162,000	$ 21,384.00	$ -	0.00%	$ 0.1320	162,000	$ 21,384.00	$ -	0.00%	$ 0.1320	162,000	$ 21,384.00	$ -	0.00%	$ 0.1320	162,000	$ 21,384.00	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	750	$ 57.75	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	899,250	$ 80,033.25	$ 0.0890	899,250	$ 80,033.25	$ -	0.00%	$ 0.0890	899,250	$ 80,033.25	$ -	0.00%	$ 0.0890	899,250	$ 80,033.25	$ -	0.00%	$ 0.0890	899,250	$ 80,033.25	$ -	0.00%	$ 0.0890	899,250	$ 80,033.25	$ -	0.00%	$ 0.0890	899,250	$ 80,033.25	$ -	0.00%
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164	900,000	$ 104,760.00	$ 0.1164	900,000	$ 104,760.00	$ -	0.00%	$ 0.1164	900,000	$ 104,760.00	$ -	0.00%	$ 0.1164	900,000	$ 104,760.00	$ -	0.00%	$ 0.1164	900,000	$ 104,760.00	$ -	0.00%	$ 0.1164	900,000	$ 104,760.00	$ -	0.00%	$ 0.1164	900,000	$ 104,760.00	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price (before Taxes)				**$ 130,118.99**			**$ 135,355.07**	**$ 5,236.08**	**4.0%**			**$ 134,070.11**	**-$ 1,284.97**	**-0.9%**			**$ 134,531.76**	**$ 461.65**	**0.3%**			**$ 134,891.45**	**$ 359.69**	**0.3%**			**$ 135,526.83**	**$ 635.38**	**0.5%**			**$ 136,140.78**	**$ 613.95**	**0.5%**
8% Provincial Rebate		-8%			-8%					-8%			$ -		-8%			$ -		-8%			$ -		-8%			$ -		-8%			$ -	
HST		13%		$ 16,915.47	13%		$ 17,596.16	$ 680.69	4.0%	13%		$ 17,429.11	-$ 167.05	-0.9%	13%		$ 17,489.13	$ 60.01	0.3%	13%		$ 17,535.89	$ 46.76	0.3%	13%		$ 17,618.49	$ 82.60	0.5%	13%		$ 17,698.30	$ 79.81	0.5%
Total Bill on Average IESO Wholesale Market Price (after Tax and Rebate)				**$ 147,034.46**			**$ 152,951.23**	**$ 5,916.77**	**4.0%**			**$ 151,499.22**	-$ 1,452.01	-0.9%			**$ 152,020.88**	$ 521.66	0.3%			**$ 152,427.33**	$ 406.45	0.3%			**$ 153,145.31**	$ 717.98	0.5%			**$ 153,839.08**	$ 693.76	0.5%
Total Bill on RPP (before Taxes)				**$ 105,449.99**			**$ 110,686.07**	**$ 5,236.08**	**5.0%**			**$ 109,401.11**	**-$ 1,284.97**	**-1.2%**			**$ 109,862.76**	**$ 461.65**	**0.4%**			**$ 110,222.45**	**$ 359.69**	**0.3%**			**$ 110,857.83**	**$ 635.38**	**0.6%**			**$ 111,471.78**	**$ 613.95**	**0.6%**
8% Provincial Rebate		-8%			-8%					-8%			$ -		-8%			$ -		-8%			$ -		-8%			$ -		-8%			$ -	
HST		13%		$ 13,708.50	13%		$ 14,389.19	$ 680.69	5.0%	13%		$ 14,222.14	-$ 167.05	-1.2%	13%		$ 14,282.16	$ 60.01	0.4%	13%		$ 14,328.92	$ 46.76	0.3%	13%		$ 14,411.52	$ 82.60	0.6%	13%		$ 14,491.33	$ 79.81	0.6%
Total Bill on RPP (after Tax and Rebate)				**$ 119,158.49**			**$ 125,075.26**	**$ 5,916.77**	**5.0%**			**$ 123,623.25**	-$ 1,452.01	-1.2%			**$ 124,144.91**	$ 521.66	0.4%			**$ 124,551.36**	$ 406.45	0.3%			**$ 125,269.34**	$ 717.98	0.6%			**$ 125,963.11**	$ 693.76	0.6%
Loss Factor (%)		3.76%			3.76%					2.95%					2.95%					2.95%					2.95%					2.95%				

Appendix 2-W
Bill Impacts

Customer Class: LARGE USE SERVICE

TOU / non-TOU: non-TOU — SPOT A Non-WMP

Consumption: 8,900 kW | 9,700 kVA | 4,100,000 kWh — ● May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		2018 Current Board-Approved			2019 Expected			Impact		2020 Proposed			Impact		2021 Proposed			Impact		2022 Proposed			Impact		2023 Proposed			Impact		2024 Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change
Service Charge	per 30 days	$ 4,178.03	1	$ 4,178.03	$ 4,338.88	1	$ 4,338.88	$ 160.85	3.85%	$ 4,128.03	1	$ 4,128.03	-$ 210.85	-4.86%	$ 4,262.60	1	$ 4,262.60	$ 134.57	3.26%	$ 4,367.46	1	$ 4,367.46	$ 104.86	2.46%	$ 4,552.64	1	$ 4,552.64	$ 185.18	4.24%	$ 4,731.56	1	$ 4,731.56	$ 178.92	3.93%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31,	per kVA									$ 0.0164	9,700	$ 159.08	$ 159.08		$ 0.0164	9,700	$ 159.08	$ -	0.00%	$ 0.0164	9,700	$ 159.08	$ -	0.00%	$ 0.0164	9,700	$ 159.08	$ -	0.00%	$ 0.0164	9,700	$ 159.08	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per kVA									$ 0.1559	9,700	$ 1,512.23	$ 1,512.23		$ 0.1559	9,700	$ 1,512.23	$ -	0.00%	$ 0.1559	9,700	$ 1,512.23	$ -	0.00%	$ 0.1559	9,700	$ 1,512.23	$ -	0.00%	$ 0.1559	9,700	$ 1,512.23	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effffective until Dec. 31, 2024	per kVA									-$ 0.1301	9,700	-$ 1,261.97	$ 1,261.97		-$ 0.1301	9,700	-$ 1,261.97	$ -	0.00%	-$ 0.1301	9,700	-$ 1,261.97	$ -	0.00%	-$ 0.1301	9,700	-$ 1,261.97	$ -	0.00%	-$ 0.1301	9,700	-$ 1,261.97	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per kVA									-$ 0.0215	9,700	-$ 208.55	-$ 208.55		-$ 0.0215	9,700	-$ 208.55	$ -	0.00%	-$ 0.0215	9,700	-$ 208.55	$ -	0.00%	-$ 0.0215	9,700	-$ 208.55	$ -	0.00%	-$ 0.0215	9,700	-$ 208.55	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per kVA									-$ 0.0004	9,700	-$ 3.88	-$ 3.88		-$ 0.0004	9,700	-$ 3.88	$ -	0.00%	-$ 0.0004	9,700	-$ 3.88	$ -	0.00%	-$ 0.0004	9,700	-$ 3.88	$ -	0.00%	-$ 0.0004	9,700	-$ 3.88	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per kVA									-$ 0.0028	9,700	-$ 27.16	-$ 27.16		-$ 0.0028	9,700	-$ 27.16	$ -	0.00%	-$ 0.0028	9,700	-$ 27.16	$ -	0.00%	-$ 0.0028	9,700	-$ 27.16	$ -	0.00%	-$ 0.0028	9,700	-$ 27.16	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per kVA									-$ 0.1086	9,700	-$ 1,053.42	-$ 1,053.42		-$ 0.1086	9,700	-$ 1,053.42	$ -	0.00%	-$ 0.1086	9,700	-$ 1,053.42	$ -	0.00%	-$ 0.1086	9,700	-$ 1,053.42	$ -	0.00%	-$ 0.1086	9,700	-$ 1,053.42	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per kVA									-$ 0.0043	9,700	-$ 41.71	-$ 41.71		-$ 0.0043	9,700	-$ 41.71	$ -	0.00%	-$ 0.0043	9,700	-$ 41.71	$ -	0.00%	-$ 0.0043	9,700	-$ 41.71	$ -	0.00%	-$ 0.0043	9,700	-$ 41.71	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per kVA									-$ 0.0769	9,700	-$ 745.93	-$ 745.93		-$ 0.0769	9,700	-$ 745.93	$ -	0.00%	-$ 0.0769	9,700	-$ 745.93	$ -	0.00%	-$ 0.0769	9,700	-$ 745.93	$ -	0.00%	-$ 0.0769	9,700	-$ 745.93	$ -	0.00%
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	per kVA									-$ 0.0236	9,700	-$ 228.92	-$ 228.92		-$ 0.0236	9,700	-$ 228.92	$ -	0.00%	-$ 0.0236	9,700	-$ 228.92	$ -	0.00%	-$ 0.0236	9,700	-$ 228.92	$ -	0.00%	-$ 0.0236	9,700	-$ 228.92	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 85.84	1	$ 85.84	$ 85.84	1	$ 85.84	$ -	0.00%		1	$ -	-$ 85.84			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 25.18	1	$ 25.18	$ 25.18	1	$ 25.18	$ -	0.00%		1	$ -	-$ 25.18			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	per kVA	$ 6.5820	9,700	$ 63,845.40	$ 6.8354	9,700	$ 66,303.38	$ 2,457.98	3.85%	$ 7.1092	9,700	$ 68,959.24	$ 2,655.86	4.01%	$ 7.3410	9,700	$ 71,207.70	$ 2,248.46	3.26%	$ 7.5216	9,700	$ 72,959.52	$ 1,751.82	2.46%	$ 7.8405	9,700	$ 76,052.85	$ 3,093.33	4.24%	$ 8.1486	9,700	$ 79,041.42	$ 2,988.57	3.93%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per kVA	-$ 0.0675	9,700	-$ 654.75		9,700	$ -	$ 654.75			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per kVA	-$ 0.2084	9,700	-$ 2,021.48		9,700	$ -	$ 2,021.48			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per kVA	$ 0.0044	9,700	$ 42.68	$ 0.0044	9,700	$ 42.68	$ -	0.00%		9,700	$ -	-$ 42.68			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per kVA	$ 0.0039	9,700	$ 37.83	$ 0.0039	9,700	$ 37.83	$ -	0.00%		9,700	$ -	-$ 37.83			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per kVA	$ 0.0648	9,700	$ 628.56	$ 0.0648	9,700	$ 628.56	$ -	0.00%		9,700	$ -	-$ 628.56			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per kVA	$ 0.1382	9,700	$ 1,340.54	$ 0.1382	9,700	$ 1,340.54	$ -	0.00%		9,700	$ -	-$ 1,340.54			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per kVA	$ 0.0406	9,700	$ 393.82	$ 0.0406	9,700	$ 393.82	$ -	0.00%		9,700	$ -	-$ 393.82			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kVA	$ 0.2763	9,700	$ 2,680.11		9,700	$ -	-$ 2,680.11			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -	
Sub-Total A (excluding pass through)				**$ 70,581.76**			**$ 73,196.71**	**$ 2,614.95**	**3.70%**			**$ 71,187.04**	**-$ 2,009.67**	**-2.75%**			**$ 73,570.07**	**$ 2,383.03**	**3.35%**			**$ 75,426.75**	**$ 1,856.68**	**2.52%**			**$ 78,705.26**	**$ 3,278.51**	**4.35%**			**$ 81,872.75**	**$ 3,167.49**	**4.02%**
Line Losses on Cost of Power	per kWh	$ 0.1164	76,670	$ 8,924.39	$ 0.1164	76,670	$ 8,924.39	$ -	0.00%	$ 0.1164	70,520	$ 8,208.53	$ 715.86	-8.02%	$ 0.1164	70,520	$ 8,208.53	$ -	0.00%	$ 0.1164	70,520	$ 8,208.53	$ -	0.00%	$ 0.1164	70,520	$ 8,208.53	$ -	0.00%	$ 0.1164	70,520	$ 8,208.53	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until Dec. 31, 2018.	per kVA	-$ 0.8782	9,700	-$ 8,518.54		9,700	$ -	$ 8,518.54			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -	
Rate Rider for Disposition of Deferral/Variance Accounts (2018) for Non-Wholesale Market Participants - effective until Dec. 31, 2018.	per kVA	-$ 0.5945	9,700	-$ 5,766.65		9,700	$ -	$ 5,766.65			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account (2018) Applicable only for Class B Customers - effective until Dec. 31, 2018	per kVA	$ 0.0032		$ -			$ -	$ -					$ -					$ -					$ -					$ -					$ -		
Rate Rider for Disposition of Global Adjustment Account (2018) Applicable only for Non-RPP Customers - effective until Dec. 31, 2018.	per kVA	-$ 0.00112		$ -			$ -	$ -					$ -					$ -					$ -					$ -					$ -		
Sub-Total B - Distribution (includes Sub-Total A)				**$ 65,220.96**			**$ 82,121.10**	**$ 16,900.14**	**25.91%**			**$ 79,395.57**	**-$ 2,725.53**	**-3.32%**			**$ 81,778.60**	**$ 2,383.03**	**3.00%**			**$ 83,635.28**	**$ 1,856.68**	**2.27%**			**$ 86,913.79**	**$ 3,278.51**	**3.92%**			**$ 90,081.28**	**$ 3,167.49**	**3.64%**
Retail Transmissioin Rate - Network Service Rate	per kW	$ 2.8295	8,900	$ 25,182.55	$ 3.0359	8,900	$ 27,019.51	$ 1,836.96	7.29%	$ 3.0316	8,900	$ 26,981.24	-$ 38.27	-0.14%	$ 3.0316	8,900	$ 26,981.24	$ -	0.00%	$ 3.0316	8,900	$ 26,981.24	$ -	0.00%	$ 3.0316	8,900	$ 26,981.24	$ -	0.00%	$ 3.0316	8,900	$ 26,981.24	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	per kW	$ 2.2769	8,900	$ 20,264.41	$ 2.4745	8,900	$ 22,023.05	$ 1,758.64	8.68%	$ 2.4705	8,900	$ 21,987.45	-$ 35.60	-0.16%	$ 2.4705	8,900	$ 21,987.45	$ -	0.00%	$ 2.4705	8,900	$ 21,987.45	$ -	0.00%	$ 2.4705	8,900	$ 21,987.45	$ -	0.00%	$ 2.4705	8,900	$ 21,987.45	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				**$ 110,667.92**			**$ 131,163.66**	**$ 20,495.74**	**18.52%**			**$ 128,364.26**	**-$ 2,799.40**	**-2.13%**			**$ 130,747.29**	**$ 2,383.03**	**1.86%**			**$ 132,603.97**	**$ 1,856.68**	**1.42%**			**$ 135,882.48**	**$ 3,278.51**	**2.47%**			**$ 139,049.97**	**$ 3,167.49**	**2.33%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0032	4,176,670	$ 13,365.34	$ 0.0032	4,176,670	$ 13,365.34	$ -	0.00%	$ 0.0032	4,170,520	$ 13,345.66	-$ 19.68	-0.15%	$ 0.0032	4,170,520	$ 13,345.66	$ -	0.00%	$ 0.0032	4,170,520	$ 13,345.66	$ -	0.00%	$ 0.0032	4,170,520	$ 13,345.66	$ -	0.00%	$ 0.0032	4,170,520	$ 13,345.66	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0003	4,176,670	$ 1,253.00	$ 0.0003	4,176,670	$ 1,253.00	$ -	0.00%	$ 0.0003	4,170,520	$ 1,251.16	-$ 1.84	-0.15%	$ 0.0003	4,170,520	$ 1,251.16	$ -	0.00%	$ 0.0003	4,170,520	$ 1,251.16	$ -	0.00%	$ 0.0003	4,170,520	$ 1,251.16	$ -	0.00%	$ 0.0003	4,170,520	$ 1,251.16	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004		$ -	$ 0.0004		$ -					$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Standard Supply Service Charge	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	2,624,000	$ 170,560.00	$ 0.0650	2,624,000	$ 170,560.00	$ -	0.00%	$ 0.0650	2,624,000	$ 170,560.00	$ -	0.00%	$ 0.0650	2,624,000	$ 170,560.00	$ -	0.00%	$ 0.0650	2,624,000	$ 170,560.00	$ -	0.00%	$ 0.0650	2,624,000	$ 170,560.00	$ -	0.00%	$ 0.0650	2,624,000	$ 170,560.00	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	738,000	$ 69,372.00	$ 0.0940	738,000	$ 69,372.00	$ -	0.00%	$ 0.0940	738,000	$ 69,372.00	$ -	0.00%	$ 0.0940	738,000	$ 69,372.00	$ -	0.00%	$ 0.0940	738,000	$ 69,372.00	$ -	0.00%	$ 0.0940	738,000	$ 69,372.00	$ -	0.00%	$ 0.0940	738,000	$ 69,372.00	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	738,000	$ 97,416.00	$ 0.1320	738,000	$ 97,416.00	$ -	0.00%	$ 0.1320	738,000	$ 97,416.00	$ -	0.00%	$ 0.1320	738,000	$ 97,416.00	$ -	0.00%	$ 0.1320	738,000	$ 97,416.00	$ -	0.00%	$ 0.1320	738,000	$ 97,416.00	$ -	0.00%	$ 0.1320	738,000	$ 97,416.00	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	750	$ 57.75	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	4,099,250	$ 364,833.25	$ 0.0890	4,099,250	$ 364,833.25	$ -	0.00%	$ 0.0890	4,099,250	$ 364,833.25	$ -	0.00%	$ 0.0890	4,099,250	$ 364,833.25	$ -	0.00%	$ 0.0890	4,099,250	$ 364,833.25	$ -	0.00%	$ 0.0890	4,099,250	$ 364,833.25	$ -	0.00%	$ 0.0890	4,099,250	$ 364,833.25	$ -	0.00%
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164	4,100,000	$ 477,240.00	$ 0.1164	4,100,000	$ 477,240.00	$ -	0.00%	$ 0.1164	4,100,000	$ 477,240.00	$ -	0.00%	$ 0.1164	4,100,000	$ 477,240.00	$ -	0.00%	$ 0.1164	4,100,000	$ 477,240.00	$ -	0.00%	$ 0.1164	4,100,000	$ 477,240.00	$ -	0.00%	$ 0.1164	4,100,000	$ 477,240.00	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price (before Taxes)				**$ 602,526.51**			**$ 623,022.25**	**$ 20,495.74**	**3.4%**			**$ 620,201.33**	**-$ 2,820.92**	**-0.5%**			**$ 622,584.36**	**$ 2,383.03**	**0.4%**			**$ 624,441.04**	**$ 1,856.68**	**0.3%**			**$ 627,719.55**	**$ 3,278.51**	**0.5%**			**$ 630,887.04**	**$ 3,167.49**	**0.5%**
8% Provincial Rebate		-8%			-8%					-8%			$ -		-8%					-8%					-8%			$ -			-8%			$ -	
HST		13%		$ 78,328.45	13%		$ 80,992.89	$ 2,664.45	3.4%	13%		$ 80,626.17	-$ 366.72	-0.5%	13%		$ 80,935.97	$ 309.79	0.4%	13%			$ 241.37	0.3%	13%		$ 81,603.54	$ 426.21	0.5%	13%		$ 82,015.31	$ 411.77	0.5%
Total Bill on Average IESO Wholesale Market Price (after Tax and Rebate)				**$ 680,854.96**			**$ 704,015.15**	**$ 23,160.19**	**3.4%**			**$ 700,827.50**	**-$ 3,187.65**	**-0.5%**			**$ 703,520.32**	**$ 2,692.82**	**0.4%**			**$ 705,618.37**	**$ 2,098.05**	**0.3%**			**$ 709,323.09**	**$ 3,704.72**	**0.5%**			**$ 712,902.35**	**$ 3,579.26**	**0.5%**
Total Bill on RPP (before Taxes)				**$ 490,177.51**			**$ 510,673.25**	**$ 20,495.74**	**4.2%**			**$ 507,852.33**	**-$ 2,820.92**	**-0.6%**			**$ 510,235.36**	**$ 2,383.03**	**0.5%**			**$ 512,092.04**	**$ 1,856.68**	**0.4%**			**$ 515,370.55**	**$ 3,278.51**	**0.6%**			**$ 518,538.04**	**$ 3,167.49**	**0.6%**
8% Provincial Rebate		-8%			-8%					-8%			$ -		-8%					-8%					-8%			$ -			-8%			$ -	
HST		13%		$ 63,723.08	13%		$ 66,387.52	$ 2,664.45	4.2%	13%		$ 66,020.80	-$ 366.72	-0.6%	13%		$ 66,330.60	$ 309.79	0.5%	13%		$ 66,571.96	$ 241.37	0.4%	13%		$ 66,998.17	$ 426.21	0.6%	13%		$ 67,409.94	$ 411.77	0.6%
Total Bill on RPP (after Tax and Rebate)				**$ 553,900.59**			**$ 577,060.78**	**$ 23,160.19**	**4.2%**			**$ 573,873.13**	**-$ 3,187.65**	**-0.6%**			**$ 576,565.95**	**$ 2,692.82**	**0.5%**			**$ 578,664.00**	**$ 2,098.05**	**0.4%**			**$ 582,368.72**	**$ 3,704.72**	**0.6%**			**$ 585,947.98**	**$ 3,579.26**	**0.6%**
Loss Factor (%)		1.87%			1.87%					1.72%					1.72%					1.72%					1.72%					1.72%				

Appendix 2-W
Bill Impacts

Customer Class: STREET LIGHTING SERVICE

TOU / non-TOU: non-TOU | **16,000** Devices | SPOT CLASS B | **2,700** kW | **2,700** kVA | ● May 1 - October 31 | ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

Consumption **955,000** kWh

	Charge Unit	2018 Current Board-Approved			2019 Expected			Impact		2020 Proposed			Impact		2021 Proposed			Impact		2022 Proposed			Impact		2023 Proposed			Impact		2024 Proposed			Impact	
		Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change
Service Charge (per device)	per device per 30 days	$ 1.55	16,000	$ 24,800.00	$ 1.61	16,000	$ 25,760.00	$ 960.00	3.87%	$ 1.66	16,000	$ 26,560.00	$ 800.00	3.11%	$ 1.71	16,000	$ 27,360.00	$ 800.00	3.01%	$ 1.75	16,000	$ 28,000.00	$ 640.00	2.34%	$ 1.82	16,000	$ 29,120.00	$ 1,120.00	4.00%	$ 1.89	16,000	$ 30,240.00	$ 1,120.00	3.85%
Distribution Volumetric Rate	per kVA	$ 34.4231	2,700	$ 92,942.37	$ 35.7484	2,700	$ 96,520.68	$ 3,578.31	3.85%	$ 36.9360	2,700	$ 99,727.20	$ 3,206.52	3.32%	$ 38.1401	2,700	$ 102,978.27	$ 3,251.07	3.26%	$ 39.0783	2,700	$ 105,511.41	$ 2,533.14	2.46%	$ 40.7352	2,700	$ 109,985.04	$ 4,473.63	4.24%	$ 42.3361	2,700	$ 114,307.47	$ 4,322.43	3.93%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per kVA									$ 0.1071	2,700	$ 289.17	$ 289.17		$ 0.1071	2,700	$ 289.17	$ -	0.00%	$ 0.1071	2,700	$ 289.17	$ -	0.00%	$ 0.1071	2,700	$ 289.17	$ -	0.00%	$ 0.1071	2,700	$ 289.17	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per kVA									$ 1.0207	2,700	$ 2,755.89	$ 2,755.89		$ 1.0207	2,700	$ 2,755.89	$ -	0.00%	$ 1.0207	2,700	$ 2,755.89	$ -	0.00%	$ 1.0207	2,700	$ 2,755.89	$ -	0.00%	$ 1.0207	2,700	$ 2,755.89	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per kVA									-$ 0.8516	2,700	-$ 2,299.32	-$ 2,299.32		-$ 0.8516	2,700	-$ 2,299.32	$ -	0.00%	-$ 0.8516	2,700	-$ 2,299.32	$ -	0.00%	-$ 0.8516	2,700	-$ 2,299.32	$ -	0.00%	-$ 0.8516	2,700	-$ 2,299.32	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per kVA									-$ 0.1407	2,700	-$ 379.89	-$ 379.89		-$ 0.1407	2,700	-$ 379.89	$ -	0.00%	-$ 0.1407	2,700	-$ 379.89	$ -	0.00%	-$ 0.1407	2,700	-$ 379.89	$ -	0.00%	-$ 0.1407	2,700	-$ 379.89	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per kVA									-$ 0.0088	2,700	-$ 23.76	-$ 23.76		-$ 0.0088	2,700	-$ 23.76	$ -	0.00%	-$ 0.0088	2,700	-$ 23.76	$ -	0.00%	-$ 0.0088	2,700	-$ 23.76	$ -	0.00%	-$ 0.0088	2,700	-$ 23.76	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per kVA									-$ 0.0187	2,700	-$ 50.49	-$ 50.49		-$ 0.0187	2,700	-$ 50.49	$ -	0.00%	-$ 0.0187	2,700	-$ 50.49	$ -	0.00%	-$ 0.0187	2,700	-$ 50.49	$ -	0.00%	-$ 0.0187	2,700	-$ 50.49	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per kVA									-$ 0.7114	2,700	-$ 1,920.78	-$ 1,920.78		-$ 0.7114	2,700	-$ 1,920.78	$ -	0.00%	-$ 0.7114	2,700	-$ 1,920.78	$ -	0.00%	-$ 0.7114	2,700	-$ 1,920.78	$ -	0.00%	-$ 0.7114	2,700	-$ 1,920.78	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per kVA									-$ 0.0279	2,700	-$ 75.33	-$ 75.33		-$ 0.0279	2,700	-$ 75.33	$ -	0.00%	-$ 0.0279	2,700	-$ 75.33	$ -	0.00%	-$ 0.0279	2,700	-$ 75.33	$ -	0.00%	-$ 0.0279	2,700	-$ 75.33	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per kVA									-$ 0.5037	2,700	-$ 1,359.99	-$ 1,359.99		-$ 0.5037	2,700	-$ 1,359.99	$ -	0.00%	-$ 0.5037	2,700	-$ 1,359.99	$ -	0.00%	-$ 0.5037	2,700	-$ 1,359.99	$ -	0.00%	-$ 0.5037	2,700	-$ 1,359.99	$ -	0.00%
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	per kVA									-$ 0.1543	2,700	-$ 416.61	-$ 416.61		-$ 0.1543	2,700	-$ 416.61	$ -	0.00%	-$ 0.1543	2,700	-$ 416.61	$ -	0.00%	-$ 0.1543	2,700	-$ 416.61	$ -	0.00%	-$ 0.1543	2,700	-$ 416.61	$ -	0.00%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per kVA	-$ 0.5347	2,700	-$ 1,443.69		2,700	$ -	$ 1,443.69			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per kVA	-$ 1.6506	2,700	-$ 4,456.62		2,700	$ -	$ 4,456.62			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per kVA	$ 0.0741	2,700	$ 200.07	$ 0.0741	2,700	$ 200.07	$ -	0.00%		2,700	$ -	-$ 200.07			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per kVA	$ 0.0312	2,700	$ 84.24	$ 0.0312	2,700	$ 84.24	$ -	0.00%		2,700	$ -	-$ 84.24			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per kVA	$ 0.5133	2,700	$ 1,385.91	$ 0.5133	2,700	$ 1,385.91	$ -	0.00%		2,700	$ -	-$ 1,385.91			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per kVA		2,700	$ -		2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per kVA	$ 0.0478	2,700	$ 129.06	$ 0.0478	2,700	$ 129.06	$ -	0.00%		2,700	$ -	-$ 129.06			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kVA		2,700	$ -		2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -	
Sub-Total A (excluding pass through)				**$ 113,641.34**			**$ 124,079.96**	**$ 10,438.62**	**9.19%**			**$ 122,806.09**	**-$ 1,273.87**	**-1.03%**			**$ 126,857.16**	**$ 4,051.07**	**3.30%**			**$ 130,030.30**	**$ 3,173.14**	**2.50%**			**$ 135,623.93**	**$ 5,593.63**	**4.30%**			**$ 141,066.36**	**$ 5,442.43**	**4.01%**
Line Losses on Cost of Power	per kWh	$ 0.1164	35,908	$ 4,179.69	$ 0.1164	35,908	$ 4,179.69	$ -	0.00%	$ 0.1164	28,173	$ 3,279.28	-$ 900.41	-21.54%	$ 0.1164	28,173	$ 3,279.28	$ -	0.00%	$ 0.1164	28,173	$ 3,279.28	$ -	0.00%	$ 0.1164	28,173	$ 3,279.28	$ -	0.00%	$ 0.1164	28,173	$ 3,279.28	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until Dec. 31, 2018.	per kVA	-$ 1.0860	2,700	-$ 2,932.20		2,700	$ -	$ 2,932.20			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -	
Rate Rider for Disposition of Deferral/Variance Accounts (2018) for Non-Wholesale Market Participants - effective until Dec. 31, 2018.	per kVA		2,700	$ -		2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account (2018) Applicable only for Class B Customers - effective until Dec. 31, 2018	per kVA	$ 0.0236	2,700	$ 63.72		2,700	$ -	-$ 63.72			2,700		$ -			2,700		$ -			2,700		$ -			2,700		$ -			2,700		$ -	
Rate Rider for Disposition of Global Adjustment Account (2018) Applicable only for Non-RPP Customers - effective until Dec. 31, 2018.	per kWh	-$ 0.00112	955,000	-$ 1,069.60		955,000	$ -	$ 1,069.60			955,000		$ -			955,000		$ -			955,000		$ -			955,000		$ -			955,000		$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 113,882.95**			**$ 128,259.65**	**$ 14,376.70**	**12.62%**			**$ 126,085.37**	**-$ 2,174.28**	**-1.70%**			**$ 130,136.44**	**$ 4,051.07**	**3.21%**			**$ 133,309.58**	**$ 3,173.14**	**2.44%**			**$ 138,903.21**	**$ 5,593.63**	**4.20%**			**$ 144,345.64**	**$ 5,442.43**	**3.92%**
Retail Transmission Rate - Network Service Rate	per kW	$ 2.2849	2,700	$ 6,169.23	$ 2.4516	2,700	$ 6,619.32	$ 450.09	7.30%	$ 2.4481	2,700	$ 6,609.87	-$ 9.45	-0.14%	$ 2.4481	2,700	$ 6,609.87	$ -	0.00%	$ 2.4481	2,700	$ 6,609.87	$ -	0.00%	$ 2.4481	2,700	$ 6,609.87	$ -	0.00%	$ 2.4481	2,700	$ 6,609.87	$ -	0.00%
Retail Transmission Rate - Line and Transformation Connection Service Rate	per kW	$ 2.4461	2,700	$ 6,604.47	$ 2.6583	2,700	$ 7,177.41	$ 572.94	8.68%	$ 2.6541	2,700	$ 7,166.07	-$ 11.34	-0.16%	$ 2.6541	2,700	$ 7,166.07	$ -	0.00%	$ 2.6541	2,700	$ 7,166.07	$ -	0.00%	$ 2.6541	2,700	$ 7,166.07	$ -	0.00%	$ 2.6541	2,700	$ 7,166.07	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				**$ 126,656.65**			**$ 142,056.38**	**$ 15,399.73**	**12.16%**			**$ 139,861.31**	**-$ 2,195.07**	**-1.55%**			**$ 143,912.38**	**$ 4,051.07**	**2.90%**			**$ 147,085.52**	**$ 3,173.14**	**2.20%**			**$ 152,679.15**	**$ 5,593.63**	**3.80%**			**$ 158,121.58**	**$ 5,442.43**	**3.56%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0032	990,908	$ 3,170.91	$ 0.0032	990,908	$ 3,170.91	$ -	0.00%	$ 0.0032	983,173	$ 3,146.15	-$ 24.75	-0.78%	$ 0.0032	983,173	$ 3,146.15	$ -	0.00%	$ 0.0032	983,173	$ 3,146.15	$ -	0.00%	$ 0.0032	983,173	$ 3,146.15	$ -	0.00%	$ 0.0032	983,173	$ 3,146.15	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0003	990,908	$ 297.27	$ 0.0003	990,908	$ 297.27	$ -	0.00%	$ 0.0003	983,173	$ 294.95	-$ 2.32	-0.78%	$ 0.0003	983,173	$ 294.95	$ -	0.00%	$ 0.0003	983,173	$ 294.95	$ -	0.00%	$ 0.0003	983,173	$ 294.95	$ -	0.00%	$ 0.0003	983,173	$ 294.95	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	990,908	$ 396.36	$ 0.0004	990,908	$ 396.36	$ -	0.00%	$ 0.0004	983,173	$ 393.27	-$ 3.09	-0.78%	$ 0.0004	983,173	$ 393.27	$ -	0.00%	$ 0.0004	983,173	$ 393.27	$ -	0.00%	$ 0.0004	983,173	$ 393.27	$ -	0.00%	$ 0.0004	983,173	$ 393.27	$ -	0.00%
Standard Supply Service Charge	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	611,200	$ 39,728.00	$ 0.0650	611,200	$ 39,728.00	$ -	0.00%	$ 0.0650	611,200	$ 39,728.00	$ -	0.00%	$ 0.0650	611,200	$ 39,728.00	$ -	0.00%	$ 0.0650	611,200	$ 39,728.00	$ -	0.00%	$ 0.0650	611,200	$ 39,728.00	$ -	0.00%	$ 0.0650	611,200	$ 39,728.00	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	171,900	$ 16,158.60	$ 0.0940	171,900	$ 16,158.60	$ -	0.00%	$ 0.0940	171,900	$ 16,158.60	$ -	0.00%	$ 0.0940	171,900	$ 16,158.60	$ -	0.00%	$ 0.0940	171,900	$ 16,158.60	$ -	0.00%	$ 0.0940	171,900	$ 16,158.60	$ -	0.00%	$ 0.0940	171,900	$ 16,158.60	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	171,900	$ 22,690.80	$ 0.1320	171,900	$ 22,690.80	$ -	0.00%	$ 0.1320	171,900	$ 22,690.80	$ -	0.00%	$ 0.1320	171,900	$ 22,690.80	$ -	0.00%	$ 0.1320	171,900	$ 22,690.80	$ -	0.00%	$ 0.1320	171,900	$ 22,690.80	$ -	0.00%	$ 0.1320	171,900	$ 22,690.80	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	750	$ 57.75	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	954,250	$ 84,928.25	$ 0.0890	954,250	$ 84,928.25	$ -	0.00%	$ 0.0890	954,250	$ 84,928.25	$ -	0.00%	$ 0.0890	954,250	$ 84,928.25	$ -	0.00%	$ 0.0890	954,250	$ 84,928.25	$ -	0.00%	$ 0.0890	954,250	$ 84,928.25	$ -	0.00%	$ 0.0890	954,250	$ 84,928.25	$ -	0.00%
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164	-	$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164	955,000	$ 111,162.00	$ 0.1164	955,000	$ 111,162.00	$ -	0.00%	$ 0.1164	955,000	$ 111,162.00	$ -	0.00%	$ 0.1164	955,000	$ 111,162.00	$ -	0.00%	$ 0.1164	955,000	$ 111,162.00	$ -	0.00%	$ 0.1164	955,000	$ 111,162.00	$ -	0.00%	$ 0.1164	955,000	$ 111,162.00	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price (before Taxes)				**$ 241,683.44**			**$ 257,083.17**	**$ 15,399.73**	**6.4%**			**$ 254,857.93**	**-$ 2,225.24**	**-0.9%**			**$ 258,909.00**	**$ 4,051.07**	**1.6%**			**$ 262,082.14**	**$ 3,173.14**	**1.2%**			**$ 267,675.77**	**$ 5,593.63**	**2.1%**			**$ 273,118.20**	**$ 5,442.43**	**2.0%**
8% Provincial Rebate		-8%			-8%					-8%			$ -		-8%			$ -		-8%			$ -		-8%			$ -		-8%			$ -	
HST		13%		$ 31,418.85	13%		$ 33,420.81	$ 2,001.96	6.4%	13%		$ 33,131.53	-$ 289.28	-0.9%	13%		$ 33,658.17	$ 526.64	1.6%	13%		$ 34,070.68	$ 412.51	1.2%	13%		$ 34,797.85	$ 727.17	2.1%	13%		$ 35,505.37	$ 707.52	2.0%
Total Bill on Average IESO Wholesale Market Price (after Tax and Rebate)				**$ 273,102.29**			**$ 290,503.98**	**$ 17,401.69**	**6.4%**			**$ 287,989.46**	**-$ 2,514.52**	**-0.9%**			**$ 292,567.17**	**$ 4,577.71**	**1.6%**			**$ 296,152.82**	**$ 3,585.65**	**1.2%**			**$ 302,473.62**	**$ 6,320.80**	**2.1%**			**$ 308,623.57**	**$ 6,149.95**	**2.0%**
Total Bill on RPP (before Taxes)				**$ 215,507.44**			**$ 230,907.17**	**$ 15,399.73**	**7.1%**			**$ 228,681.93**	**-$ 2,225.24**	**-1.0%**			**$ 232,733.00**	**$ 4,051.07**	**1.8%**			**$ 235,906.14**	**$ 3,173.14**	**1.4%**			**$ 241,499.77**	**$ 5,593.63**	**2.4%**			**$ 246,942.20**	**$ 5,442.43**	**2.3%**
8% Provincial Rebate		-8%			-8%					-8%			$ -		-8%			$ -		-8%			$ -		-8%			$ -		-8%			$ -	
HST		13%		$ 28,015.97	13%		$ 30,017.93	$ 2,001.96	7.1%	13%		$ 29,728.65	-$ 289.28	-1.0%	13%		$ 30,255.29	$ 526.64	1.8%	13%		$ 30,667.80	$ 412.51	1.4%	13%		$ 31,394.97	$ 727.17	2.4%	13%		$ 32,102.49	$ 707.52	2.3%
Total Bill on RPP (after Tax and Rebate)				**$ 243,523.41**			**$ 260,925.10**	**$ 17,401.69**	**7.1%**			**$ 258,410.58**	**-$ 2,514.52**	**-1.0%**			**$ 262,988.29**	**$ 4,577.71**	**1.8%**			**$ 266,573.94**	**$ 3,585.65**	**1.4%**			**$ 272,894.74**	**$ 6,320.80**	**2.4%**			**$ 279,044.69**	**$ 6,149.95**	**2.3%**
Loss Factor (%)		3.76%			3.76%					2.95%					2.95%					2.95%					2.95%					2.95%				

Appendix 2-W
Bill Impacts

Customer Class: UNMETERED SCATTERED LOAD SERVICE

TOU / non-TOU: non-TOU | RPP

Consumption: 285 kWh | 1 Connection | ● May 1 - October 31 | ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

Charge Unit	2018 Current Board-Approved			2019 Expected			Impact		2020 Proposed			Impact		2021 Proposed			Impact		2022 Proposed			Impact		2023 Proposed			Impact		2024 Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change
Service Charge	per 30 days	$ 6.87	1	$ 6.87	$ 7.13	1	$ 7.13	$ 0.26	3.78%	$ 7.38	1	$ 7.38	$ 0.25	3.51%	$ 7.62	1	$ 7.62	$ 0.24	3.25%	$ 7.81	1	$ 7.81	$ 0.19	2.49%	$ 8.14	1	$ 8.14	$ 0.33	4.23%	$ 8.46	1	$ 8.46	$ 0.32	3.93%
Connection Charge (per connection)	per connection per 30 days	$ 0.71	1	$ 0.71	$ 0.74	1	$ 0.74	$ 0.03	4.23%	$ 0.77	1	$ 0.77	$ 0.03	4.05%	$ 0.80	1	$ 0.80	$ 0.03	3.90%	$ 0.82	1	$ 0.82	$ 0.02	2.50%	$ 0.85	1	$ 0.85	$ 0.03	3.66%	$ 0.88	1	$ 0.88	$ 0.03	3.53%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per kWh									$ 0.00022	285	$ 0.06	$ 0.06		$ 0.00022	285	$ 0.06	$ -	0.00%	$ 0.00022	285	$ 0.06	$ -	0.00%	$ 0.00022	285	$ 0.06	$ -	0.00%	$ 0.00022	285	$ 0.06	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per kWh									$ 0.00211	285	$ 0.60	$ 0.60		$ 0.00211	285	$ 0.60	$ -	0.00%	$ 0.00211	285	$ 0.60	$ -	0.00%	$ 0.00211	285	$ 0.60	$ -	0.00%	$ 0.00211	285	$ 0.60	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per kWh									-$ 0.00176	285	-$ 0.50	-$ 0.50		-$ 0.00176	285	-$ 0.50	$ -	0.00%	-$ 0.00176	285	-$ 0.50	$ -	0.00%	-$ 0.00176	285	-$ 0.50	$ -	0.00%	-$ 0.00176	285	-$ 0.50	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per kWh									-$ 0.00029	285	-$ 0.08	-$ 0.08		-$ 0.00029	285	-$ 0.08	$ -	0.00%	-$ 0.00029	285	-$ 0.08	$ -	0.00%	-$ 0.00029	285	-$ 0.08	$ -	0.00%	-$ 0.00029	285	-$ 0.08	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per kWh									-$ 0.00002	285	-$ 0.01	-$ 0.01		-$ 0.00002	285	-$ 0.01	$ -	0.00%	-$ 0.00002	285	-$ 0.01	$ -	0.00%	-$ 0.00002	285	-$ 0.01	$ -	0.00%	-$ 0.00002	285	-$ 0.01	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per kWh									-$ 0.00004	285	-$ 0.01	-$ 0.01		-$ 0.00004	285	-$ 0.01	$ -	0.00%	-$ 0.00004	285	-$ 0.01	$ -	0.00%	-$ 0.00004	285	-$ 0.01	$ -	0.00%	-$ 0.00004	285	-$ 0.01	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per kWh									-$ 0.00147	285	-$ 0.42	-$ 0.42		-$ 0.00147	285	-$ 0.42	$ -	0.00%	-$ 0.00147	285	-$ 0.42	$ -	0.00%	-$ 0.00147	285	-$ 0.42	$ -	0.00%	-$ 0.00147	285	-$ 0.42	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per kWh									-$ 0.00006	285	-$ 0.02	-$ 0.02		-$ 0.00006	285	-$ 0.02	$ -	0.00%	-$ 0.00006	285	-$ 0.02	$ -	0.00%	-$ 0.00006	285	-$ 0.02	$ -	0.00%	-$ 0.00006	285	-$ 0.02	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per kWh									-$ 0.00104	285	-$ 0.30	-$ 0.30		-$ 0.00104	285	-$ 0.30	$ -	0.00%	-$ 0.00104	285	-$ 0.30	$ -	0.00%	-$ 0.00104	285	-$ 0.30	$ -	0.00%	-$ 0.00104	285	-$ 0.30	$ -	0.00%
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	per kWh									-$ 0.00032	285	-$ 0.09	-$ 0.09		-$ 0.00032	285	-$ 0.09	$ -	0.00%	-$ 0.00032	285	-$ 0.09	$ -	0.00%	-$ 0.00032	285	-$ 0.09	$ -	0.00%	-$ 0.00032	285	-$ 0.09	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue (per connection) - effective until Dec. 31, 2019	per connection per 30 days	$ 0.02	1	$ 0.02	$ 0.02	1	$ 0.02	$ -	0.00%		1	$ -	-$ 0.02			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue (per connection) - effective until Dec. 31, 2019	per connection per 30 days	$ 0.01	1	$ 0.01	$ 0.01	1	$ 0.01	$ -	0.00%		1	$ -	-$ 0.01			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.16	1	$ 0.16	$ 0.16	1	$ 0.16	$ -	0.00%		1	$ -	-$ 0.16			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.05	1	$ 0.05	$ 0.05	1	$ 0.05	$ -	0.00%		1	$ -	-$ 0.05			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.08632	285	$ 24.60	$ 0.08964	285	$ 25.55	$ 0.95	3.85%	$ 0.09273	285	$ 26.43	$ 0.88	3.45%	$ 0.09575	285	$ 27.29	$ 0.86	3.26%	$ 0.09811	285	$ 27.96	$ 0.67	2.46%	$ 0.10227	285	$ 29.15	$ 1.19	4.24%	$ 0.10629	285	$ 30.29	$ 1.15	3.93%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per kWh	$ 0.00203	285	$ 0.58	$ 0.00203	285	$ 0.58	$ -	0.00%		285	$ -	-$ 0.58			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per kWh	$ 0.00062	285	$ 0.18	$ 0.00062	285	$ 0.18	$ -	0.00%		285	$ -	-$ 0.18			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -	
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per kWh	-$ 0.00096	285	-$ 0.27		285	$ -	$ 0.27			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per kWh	-$ 0.00296	285	-$ 0.84		285	$ -	$ 0.84			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per kWh	$ 0.00029	285	$ 0.08	$ 0.00029	285	$ 0.08	$ -	0.00%		285	$ -	-$ 0.08			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per kWh	$ 0.00006	285	$ 0.02	$ 0.00006	285	$ 0.02	$ -	0.00%		285	$ -	-$ 0.02			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per kWh	$ 0.00092	285	$ 0.26	$ 0.00092	285	$ 0.26	$ -	0.00%		285	$ -	$ -			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kWh		285	$ -		285	$ -	$ -			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -	
Sub-Total A (excluding pass through)				**$ 32.42**			**$ 34.77**	**$ 2.35**	**7.26%**			**$ 33.82**	**-$ 0.96**	**-2.75%**			**$ 34.95**	**$ 1.13**	**3.34%**			**$ 35.83**	**$ 0.88**	**2.53%**			**$ 37.38**	**$ 1.55**	**4.31%**			**$ 38.87**	**$ 1.50**	**4.00%**
Line Losses on Cost of Power	per kWh	$ 0.0770	11	$ 0.83	$ 0.0770	11	$ 0.83	$ -	0.00%	$ 0.0770	8	$ 0.65	-$ 0.18	-21.54%	$ 0.0770	8	$ 0.65	$ -	0.00%	$ 0.0770	8	$ 0.65	$ -	0.00%	$ 0.0770	8	$ 0.65	$ -	0.00%	$ 0.0770	8	$ 0.65	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until Dec. 31, 2018.	per kWh	-$ 0.00316	285	-$ 0.90		285	$ -	$ 0.90			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account (2018) Applicable only for Class B Customers - effective until Dec. 31, 2018	per kWh	$ 0.00007	285	$ 0.02		285	$ -	-$ 0.02			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -	
Rate Rider for Disposition of Global Adjustment Account (2018) Applicable only for Non-RPP Customers - effective until Dec. 31, 2018.	per kWh	-$ 0.00112		$ -			$ -	$ -					$ -					$ -					$ -					$ -					$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 32.37**			**$ 35.60**	**$ 3.23**	**9.99%**			**$ 34.46**	**-$ 1.14**	**-3.19%**			**$ 35.60**	**$ 1.13**	**3.28%**			**$ 36.48**	**$ 0.88**	**2.48%**			**$ 38.02**	**$ 1.55**	**4.24%**			**$ 39.52**	**$ 1.50**	**3.93%**
RTSR - Network	per kWh	$ 0.00460	296	$ 1.36	$ 0.00500	296	$ 1.48	$ 0.12	8.70%	$ 0.00500	293	$ 1.47	-$ 0.01	-0.78%	$ 0.00500	293	$ 1.47	$ -	0.00%	$ 0.00500	293	$ 1.47	$ -	0.00%	$ 0.00500	293	$ 1.47	$ -	0.00%	$ 0.00500	293	$ 1.47	$ -	0.00%
RTSR - Line and Transformation Connection	per kWh	$ 0.00390	296	$ 1.15	$ 0.00430	296	$ 1.27	$ 0.12	10.26%	$ 0.00429	293	$ 1.26	-$ 0.01	-1.01%	$ 0.00429	293	$ 1.26	$ -	0.00%	$ 0.00429	293	$ 1.26	$ -	0.00%	$ 0.00429	293	$ 1.26	$ -	0.00%	$ 0.00429	293	$ 1.26	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				**$ 34.88**			**$ 38.35**	**$ 3.47**	**9.95%**			**$ 37.19**	**-$ 1.16**	**-3.02%**			**$ 38.32**	**$ 1.13**	**3.04%**			**$ 39.20**	**$ 0.88**	**2.30%**			**$ 40.75**	**$ 1.55**	**3.94%**			**$ 42.24**	**$ 1.50**	**3.67%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0032	296	$ 0.95	$ 0.0032	296	$ 0.95	$ -	0.00%	$ 0.0032	293	$ 0.94	-$ 0.01	-0.78%	$ 0.0032	293	$ 0.94	$ -	0.00%	$ 0.0032	293	$ 0.94	$ -	0.00%	$ 0.0032	293	$ 0.94	$ -	0.00%	$ 0.0032	293	$ 0.94	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0003	296	$ 0.09	$ 0.0003	296	$ 0.09	$ -	0.00%	$ 0.0003	293	$ 0.09	-$ 0.00	-0.78%	$ 0.0003	293	$ 0.09	$ -	0.00%	$ 0.0003	293	$ 0.09	$ -	0.00%	$ 0.0003	293	$ 0.09	$ -	0.00%	$ 0.0003	293	$ 0.09	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	296	$ 0.12	$ 0.0004	296	$ 0.12	$ -	0.00%	$ 0.0004	293	$ 0.12	-$ 0.00	-0.78%	$ 0.0004	293	$ 0.12	$ -	0.00%	$ 0.0004	293	$ 0.12	$ -	0.00%	$ 0.0004	293	$ 0.12	$ -	0.00%	$ 0.0004	293	$ 0.12	$ -	0.00%
Standard Supply Service Charge	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	185	$ 12.04	$ 0.0650	185	$ 12.04	$ -	0.00%	$ 0.0650	185	$ 12.04	$ -	0.00%	$ 0.0650	185	$ 12.04	$ -	0.00%	$ 0.0650	185	$ 12.04	$ -	0.00%	$ 0.0650	185	$ 12.04	$ -	0.00%	$ 0.0650	185	$ 12.04	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	48	$ 4.55	$ 0.0940	48	$ 4.55	$ -	0.00%	$ 0.0940	48	$ 4.55	$ -	0.00%	$ 0.0940	48	$ 4.55	$ -	0.00%	$ 0.0940	48	$ 4.55	$ -	0.00%	$ 0.0940	48	$ 4.55	$ -	0.00%	$ 0.0940	48	$ 4.55	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	51	$ 6.77	$ 0.1320	51	$ 6.77	$ -	0.00%	$ 0.1320	51	$ 6.77	$ -	0.00%	$ 0.1320	51	$ 6.77	$ -	0.00%	$ 0.1320	51	$ 6.77	$ -	0.00%	$ 0.1320	51	$ 6.77	$ -	0.00%	$ 0.1320	51	$ 6.77	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	285	$ 21.95	$ 0.0770	285	$ 21.95	$ -	0.00%	$ 0.0770	285	$ 21.95	$ -	0.00%	$ 0.0770	285	$ 21.95	$ -	0.00%	$ 0.0770	285	$ 21.95	$ -	0.00%	$ 0.0770	285	$ 21.95	$ -	0.00%	$ 0.0770	285	$ 21.95	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	-	$ -	$ 0.0890	-	$ -	$ -		$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -	
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164		$ -	$ 0.1164	-	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Total Bill on RPP (before Taxes)				**$ 58.23**			**$ 61.70**	**$ 3.47**	**6.0%**			**$ 60.53**	**-$ 1.17**	**-1.9%**			**$ 61.66**	**$ 1.13**	**1.9%**			**$ 62.54**	**$ 0.88**	**1.4%**			**$ 64.09**	**$ 1.55**	**2.5%**			**$ 65.58**	**$ 1.50**	**2.3%**
8% Provincial Rebate	-8%		-$ 4.66	-8%		-$ 4.94	-$ 0.28	6.0%	-8%		-$ 4.84	$ 0.09	-1.9%	-8%		-$ 4.93	-$ 0.09	1.9%	-8%		-$ 5.00	-$ 0.07	1.4%	-8%		-$ 5.13	-$ 0.12	2.5%	-8%		-$ 5.25	-$ 0.12	2.3%
HST	13%		$ 7.57	13%		$ 8.02	$ 0.45	6.0%	13%		$ 7.87	-$ 0.15	-1.9%	13%		$ 8.02	$ 0.15	1.9%	13%		$ 8.13	$ 0.11	1.4%	13%		$ 8.33	$ 0.20	2.5%	13%		$ 8.53	$ 0.19	2.3%
Total Bill on RPP (after Tax and Rebate)			**$ 61.14**			**$ 64.78**	**$ 3.64**	**6.0%**			**$ 63.56**	**-$ 1.23**	**-1.9%**			**$ 64.74**	**$ 1.19**	**1.9%**			**$ 65.67**	**$ 0.93**	**1.4%**			**$ 67.29**	**$ 1.62**	**2.5%**			**$ 68.86**	**$ 1.57**	**2.3%**
Loss Factor (%)	3.76%			3.76%					2.95%					2.95%					2.95%					2.95%					2.95%				

DEFERRAL AND VARIANCE ACCOUNTS

This schedule summarizes Toronto Hydro's deferral and variance accounts ("DVA"). Once approved for clearance, account balances are recovered through separate rate riders and not included in revenue requirement.

Toronto Hydro utilizes these DVAs in accordance with the methodologies and requirements of the OEB, as set out in the Accounting Procedures Handbook ("APH"), and other directions issued by the OEB from time to time.

1. SUMMARY OF DVA BALANCES

A detailed continuity of account balances in the format provided by the OEB, including carrying costs, is shown in Exhibit 9, Tab 2, Schedule 1. The principal balances and carrying charges as of December 31, 2017 are summarized in Table 1 below.

Table 1: Summary of DVA Balances ($ Millions)

	Principal Balance as of Dec 31, 2017	Carrying Charge Balance as of Dec 31, 2017	Balances as of Dec 31, 2017
Group 1 Accounts			
Retail Settlement Variance Account ("RSVA")	(43.0)	(0.9)	(43.9)
Disposition and Recovery/Refund of Regulatory Balances ("RARA")	39.8	2.4	42.2
Smart Meter Entity Charges	(0.5)	0.0	(0.5)
Group 2 Accounts			
Stranded Meter Costs	7.3	0.2	7.5

	Principal Balance as of Dec 31, 2017	Carrying Charge Balance as of Dec 31, 2017	Balances as of Dec 31, 2017
IFRS-USGAAP Transitional PP&E[1] Amounts	12.4	—	12.4
LRAM Variance Account ("LRAMVA")	16.1	0.2	16.3
Impact for USGAAP Deferral	85.3	—	85.3
Capital Related Revenue Requirement Variance Account ("CRRRVA")	(22.7)	(0.3)	(23.0)
Externally Driven Capital Variance Account ("EDCVA")	(1.3)	0.0	(1.3)
Derecognition	(15.5)	(0.4)	(15.9)
Wireless Attachments	(0.4)	0.0	(0.4)
Monthly Billing	4.0	0.1	4.1
Operating Centers Consolidation Program ("OCCP")	27.1	0.1	27.2
Other Post-Employment Benefits ("OPEB") Cash vs Accrual	4.2	—	4.2
Renewable Generation Connection Funding Adder Deferral Account – Provincial Rate Protection Payment Variances	(2.4)	—	(2.4)
Total Balance	**110.4**	**1.4**	**111.8**

1.1 Group 1 Accounts

RSVA: Accounts include the following OEB Accounts:

1580 – Wholesale Market Service Charges ($RSVA_{WMS}$)

1584 – Retail Transmission Network Charge ($RSVA_{NW}$)

1586 – Retail Transmission Connection Charge ($RSVA_{CN}$)

1588 – Power ($RSVA_{Power}$)

1589 – Global Adjustment ($RSVA_{GA}$)

[1] International Financial Reporting Standards ("IFRS"); United States Generally Accepted Accounting Principles ("USGAAP"); Property, plant and equipment ("PP&E").

1550 – Low Voltage Variance Account

RARA: Disposition and Recovery/Refund of Regulatory Balances:

1595: RARA accounts contain residual amounts related to clearance of DVAs previously approved by the OEB for recovery through rate riders.

SME: Smart Metering Entity

1551 – Smart Metering Entity Charges

1.2 Group 2 Accounts

Toronto Hydro's Other Regulatory Asset accounts include:

1555 – sub account – Stranded meters

1575 – IFRS USGAAP Transitional PP&E Amounts

1568 – LRAMVA

1508 – sub account – Impact for USGAAP Deferral

1508 – sub account – CRRRVA

1508 – sub account – Externally Driven Capital

1508 – sub account – Derecognition

1508 – sub account – Wireless Attachments

1508 – sub account – Monthly Billing

1508 – sub account – OCCP

1508 – sub account – OPEB Cash vs Accrual

1533 – Renewable Generation Connection Funding Adder Deferral Account, sub account – Provincial Rate Protection Payment Variances

The OEB's Filing Requirements for Electricity Distribution Rate Applications (July 12, 2018) ("Filing Requirements") require a breakdown of energy sales and cost of power expenses, as reported in the Audited Financial Statements by distributors, mapped to a Uniform System Of Accounts ("USofA") account number. This information can be found in Exhibit 9, Tab 2, Schedule 2.

With respect to Global Adjustment ("GA") charges, Toronto Hydro confirms that Independent Electricity System Operator ("IESO") GA charges are prorated into Regulated Price Plan ("RPP") and non-RPP amounts. Values in the RSVA Global Adjustment account 1589 reflect the non-RPP portions only.

In accordance with the Filing Requirements, Toronto Hydro confirms that its RPP settlement process with the IESO is consistent with the description provided in the 2017 Custom Incentive Rate-("CIR") setting update application (EB-2016-0254).

2. CARRYING CHARGES

Carrying charges have been applied to specific accounts using the OEB's Prescribed Interest Rates.

For the periods up to 2018 Q3, the rates are as determined by the OEB. For the periods 2018 Q4 through 2019 Q4, the 2018 Q3 rate has been applied as a forecast. Toronto Hydro proposes to update these rates for the actual approved rates at the time of clearance of these accounts.

Table 2: Interest on Carrying charges

OEB Interest Rates Applied Calculation of Carrying Charges			
Quarter	Annual %	Quarter	Annual %
Q1 2014	1.47%	Q3 2016	1.10%
Q2 2014	1.47%	Q4 2016	1.10%
Q3 2014	1.47%	Q1 2017	1.10%
Q4 2014	1.47%	Q2 2017	1.10%
Q1 2015	1.47%	Q3 2017	1.10%
Q2 2015	1.10%	Q4 2017	1.50%
Q3 2015	1.10%	Q1 2018	1.50%
Q4 2015	1.10%	Q2 2018	1.89%
Q1 2016	1.10%	Q3 2018	1.89%
Q2 2016	1.10%		

3. PLANNED DISPOSITION OF REGULATORY ASSETS

On July 31, 2009, the OEB issued its Report of the Board on Electricity Distributors Deferral and Variance Account Review Initiative ("EDDVAR") (EB-2008-0046). The OEB indicated that, "at the time of rebasing, all accounts should be reviewed and disposed of unless otherwise justified by the distributor or as required by a specific OEB decision or guideline".[2]

In the Filing Requirements, the OEB outlined the requirements for filing of information on DVAs. The following information meets those requirements.

Below, Toronto Hydro sets out the accounts it proposes to clear beginning January 1, 2020, along with the proposed method of clearance. The amounts proposed for clearance include the balances as reflected in the audited financial statements for the fiscal year ended December 31, 2017. The amounts also include the forecasted carrying

[2] EDDVAR, p. 2 of the Executive Summary.

costs calculated to December 2019. Continuity schedules for all accounts proposed for disposition are provided in Exhibit 9, Tab 2, Schedule 1.

4. TORONTO HYDRO IS REQUESTING DISPOSITION OF THE FOLLOWING REGULATORY ASSET ACCOUNTS

4.1 Account 1555 – Stranded Meters

In Toronto Hydro's previous application (EB-2104-0116), the OEB approved the disposition of Account 1555 – Stranded Meters. The amount approved for disposition was a $15.8 million debit (recovery) from customers, which was based on the estimated net book value ("NBV") of stranded conventional meters. The estimate was based on the 2013 year-end NBV of $16.9 million, less $1.1 million of depreciation calculated from January 1, 2014 until December 2014.

As per the OEB's APH Frequently Asked Questions, Toronto Hydro needs to bring forward the trued-up account balance for OEB's review in a subsequent rate setting proceeding.

The actual December 31, 2014 NBV of stranded conventional meters was $14.4 million. The amount proposed for clearing is a $1.4 million credit (refund) to customers.

4.2 Account 1575 – IFRS USGAAP Transitional PP&E Amounts

In EB-0214-0116, the OEB approved the disposition of Account 1575 – IFRS USGAAP Transitional PP&E Amounts. The amount approved for disposition was a $30.5 million debit (recovery) from customers, which was based on the estimated transitional impact.

As per the OEB's APH Frequently Asked Questions, Toronto Hydro needs to bring forward the trued-up account balance for OEB's review in a subsequent rate setting proceeding.

The actual IFRS USGAAP Transitional PP&E amount was $28.9 million. The amount proposed for clearing is a $1.6 million credit (refund) to customers.

4.3 Account 1508 – Other Regulatory Assets, Subaccount – Impact for USGAAP Deferral Account

The amount proposed for clearing is an $85.3 million debit (recovery) from customers. This account captures the impact of the change in the accounting for OPEB as a result of transition to a different accounting framework.

In its EB 2012-0079 Decision and Order issued on June 7, 2012, the OEB approved the use of account 1508 to capture the difference related to OPEB costs arising from transition from Canadian Generally Accepted Accounting Principles ("GAAP") to United States GAAP ("US GAAP") on January 1, 2012. In its EB 2014-0116 Decision and Order issued on December 29, 2015, the OEB accepted Toronto Hydro's request to continue to use this deferral account to capture accounting differences related to OPEB costs arising from its transition from US GAAP to International Financial Reporting Standards ("IFRS") on January 1, 2015. The differences related mainly to changes in the accounting treatment of actuarial gains and losses arising from updated actuarial assumptions and experience adjustments recognized in other comprehensive income, but never amortized into profit or loss under IFRS.

No carrying charges were applied to the balance in this account.

On September 14, 2017, the OEB issued its final report on the regulatory treatment of pension and OPEB costs (EB-2015-0040), stating that utilities may propose disposition of this particular account if the gains and losses that are tracked in this account do not substantially offset over time. Toronto Hydro is seeking recovery of this balance in the current application as changes in the underlying actuarial assumptions, in particular changes in discount rate, are not expected to substantially offset the actuarial loss incurred to date. The discount rate that Toronto Hydro uses is based on the yield of high quality corporate bonds that result in a similar cash flow pattern to the OPEB plans. For Toronto Hydro, the average plan duration is approximately 16.7 years based on the valuation as at January 1, 2016. Toronto Hydro's actuaries expect the Government of Canada bond rates to remain stable with no significant changes for the foreseeable future.

Historically, the Canadian Institute of Actuaries ("CIA") Fiera Capital rate has followed the same trend as the 30-year Government Bond Yield.

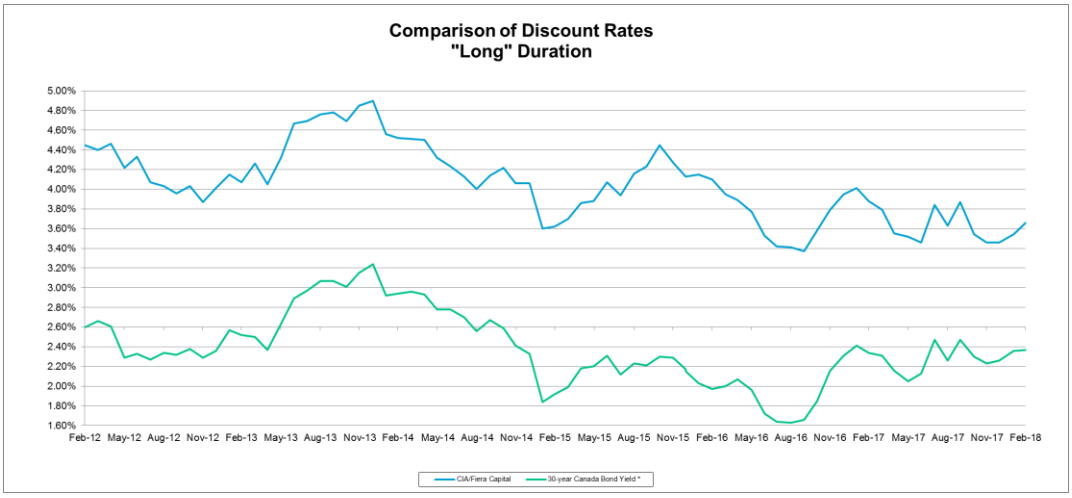

Figure 1: Historical discount rates

Based on the current projected 30-year Government bond rate, Toronto Hydro does not expect significant changes to the discount rate that would substantially offset the actuarial loss incurred to date. The discount rate used as at December 31, 2017 was 3.5 percent. Based on the projected 30-year Government bond rate and applying the average spread between the 30-year Government bond rate and the CIA Fiera rate, the projected discount rate is expected to increase and remain stable at 4.0 percent over the next seven years. As at December 31, 2017, Toronto Hydro's actuary estimated that a 1 percent increase in the discount rate would reduce the obligation by $46.8 million, with a corresponding reduction of the balance in this account by $46.8 million. Keeping all other assumptions constant, a 50 basis points ("bps") increase to 4.0 percent would offset the current actuarial loss ($85.3 million as at December 31, 2017) by an estimated $23.4 million. As such, the increase in discount rate will not substantially offset over time.



Figure 2: Projected Discount rate (2018-2024)

As at December 31, 2017, the balance in this account was $85.3 million debit (recovery) from customers. Toronto Hydro is proposing to clear this balance over five years. Although Toronto Hydro has proposed the disposition of the balances accumulated in this account, the OPEB plans will continue to experience actuarial gains or losses as a result of changes in actuarial assumptions in the future. Therefore, the utility requests the continuance of this account to record these expected changes. /C /C /C /C

4.4 Account 1508 – Other Regulatory Assets, Subaccount – CRRRVA

The balance in the Capital-Related Revenue Requirement Variance Account, all of which is proposed for clearance, is a $59.4 million credit (refund) to customers. The account balance reflects the variance between the cumulative 2015 to 2019 capital related revenue requirement included in rates and the actual capital in-service additions ("ISA") related revenue requirement over the same period. Balances in the CRRRVA include carrying charges and exclude balances that are captured in the Externally Driven Capital and Derecognition variance accounts.

The CRRRVA was approved by the OEB to protect ratepayers in the event Toronto Hydro's actual revenue requirement related to capital was less than the amount funded in the approved revenue requirement for the rate period. The utility forecasts actual capital related revenue requirement will be lower; as a result, there is a credit to customers. There are two reasons for the variance.

First, $36.8 million of the variance is due to a decision by Toronto Hydro to not spend that money funded through approved rates. Toronto Hydro discovered a discrepancy in the estimated useful life used to calculate the depreciation for meters in the 2015-2019 CIR forecast. The forecasted depreciation for meters was based on an estimated useful

life of four years whereas the actual depreciation for meters is based on a useful life of 15 years. The effect was more approved capital-related revenue requirement funding through 2015-2019 rates than Toronto Hydro proposed during that rate-setting process. Toronto Hydro decided that the corresponding amount should not be spent and that the balance with interest should be returned to customers through the clearance of the CRRRVA.

Second, the remaining variance is due to the difference between the forecasted and actual mix of capital programs and the forecasted and actual timing of that capital work going in-service. Toronto Hydro has hundreds of individual capital projects each year, and the selection and timing of those projects varies with dynamic customer and system needs, as well as weather, field conditions, permitting, site access, third party co-ordination, and other factors. A regular part of Toronto Hydro's operation is rebalancing the mix and timing of capital projects to adjust for these factors. Most of this variance was driven by later than forecasted in-service dates for several significant projects.

- The in-service date of the ERP system was delayed from 2016 to an expected completion date of 2018 (Exhibit 2B, Schedule E4).
- The in-service date of Copeland TS – Phase 1 was delayed from 2015-2016 to 2017-2018 (Exhibit 2B, Schedule E7.4).
- The in-service dates associated with capital contributions to Hydro One Networks Incorporated ("Hydro One") were in 2016 instead of 2015 (Exhibit 2B, Schedule E7.4).

The following table summarizes the balances in the account by year.

Table 3: CRRVA Balance

	2015 Historical	2016 Historical	2017 Historical	2018 Bridge	2019 Bridge	Total
Proposed Capital-Related RR, 2015-2019 CIR (1B-T2-S3-P10, Table 3)	437.8	465.0	517.3	567.2	607.3	2,594.6
RR impact from 10% reduction in capital spending	(7.3)	(8.7)	(10.7)	(17.7)	(24.1)	(68.6)
Capital-Related RR (Rate Order, Feb. 29, 2016 - Table 2)	430.5	456.3	506.6	549.5	583.2	2,526.0
RR impact from the application of stretch factor to capital funding[3]	-	(2.6)	(5.4)	(8.4)	(11.7)	(28.1)
Capital-Related RR in Approved 2015-2019 Rates	430.5	453.7	501.2	541.0	571.5	2,497.9
Sub-account 1508 - Externally Driven Capital Variance Account	(0.2)	(0.5)	(0.7)	(0.6)	(0.3)	(2.2)
Sub-account 1508 - Derecognition Variance Account	(12.9)	1.3	(3.9)	(10.4)	(14.8)	(40.8)
Other Adjustments[4]	(1.2)	0.6	(1.4)	(4.3)	0.2	(6.1)
Capital-Related RR in Approved Rates eligible for CRRRVA	416.2	455.1	495.3	525.6	556.6	2,448.8
Actual Historic & Forecast Bridge Capital-Related RR	413.6	449.3	481.0	503.7	543.6	2,391.2
Sub-account 1508 - CRRRVA	(2.7)	(5.8)	(14.3)	(21.9)	(13.0)	(57.6)

Note: Rounding differences may exist.

[3] Decision on Draft Rate Order, February 25, 2016, p. 3; Draft Rate Order, February 29, 2016, p. 5.
[4] These adjustments are primarily to account for variances in opening 2015 rate base and disposals. As is the case for Externally Driven Capital and Derecognition, these capital-related variances are outside the OEB-approved scope of the CRRRVA.

In EB-2014-0116, Toronto Hydro proposed a Capital-Related Revenue Requirement of $2,594.6 million over the 2015-2019 period. The OEB's decision reduced the proposed capital expenditures by 10 percent, applied the stretch factor to the part of the Customer Price Cap Index ("CPCI") that escalated capital funding, and established variance accounts related to Externally Driven Capital and Derecognition, as well as the CRRRVA. The resulting Capital-Related Revenue Requirement to fund capital expenditures in the period was $2,448.8 million.

Based on actual (2015-2017) and forecast (2018-2019) ISA for capital expenditures, the Capital-Related Revenue Requirement over the 2015-2019 period is forecast to be $2,391.2 million.

The variance between the funded amount of $2,448.8 million and the forecast amount of $2,391.2 million is $57.6 million. $1.8 million in associated carrying charges are calculated for the period. Toronto Hydro proposes to clear the balance of $59.4 million as a credit to customers. Toronto Hydro proposes clearance at this time in order to mitigate intergenerational inequities associated with delaying clearance until Toronto Hydro's rebasing application following the audit of the final balance (e.g. 2025).

Toronto Hydro proposes to continue this variance account for the 2020-24 CIR period. This is to: (i) protect customers against cumulative underspend during the plan period; (ii) recognize the dynamic nature of Toronto Hydro's capital program; and (iii) ensure that Toronto Hydro has the flexibility to optimize the implementation of its capital investment strategy. Continuing the CRRRVA will also ensure that if the final audited 2015-2019 balance in the CRRRVA varies from the $2,391.2 million forecast in this

Application, the $59.4 million being cleared at this time can be supplemented with a future clearance.

4.5 Account 1508 – Other Regulatory Assets, Subaccount – Externally Driven Capital Variance Account

The amount proposed for clearance in the Externally Driven Capital Variance account is a $2.3 million credit (refund) to customers. In addition, Toronto Hydro requests the continuation of this variance account for the 2020-2024 CIR period.

The Externally Driven Capital Variance Account, proposed and approved in EB-2014-0116, captures the difference between the capital embedded in base distribution rates related to externally driven capital spending and capital related to actual and bridge externally driven capital spending as it occurred over the 2015- 2019 plan period. In the 2015 decision, the OEB approved a revenue requirement associated with $4.0 million of annual in-service amounts for work related to externally driven projects over the five-year rate period. The fact that expenditures underlying this program can be volatile and difficult to predict was the basis for the approval of this account. The OEB directed Toronto Hydro to use the Externally Driven Capital Variance Account to record the revenue requirement impact for externally driven work that varies from the approved amounts.

Table 4 sets out the variance from the approved revenue requirement and actual and forecast spend from 2015 to 2019.

Table 4: Historic Externally Driven Capital Spending and Variance ($ Millions)

	Historical & Bridge Spending					
Year	**2015 Actual**	**2016 Actual**	**2017 Actual**	**2018 Forecast**	**2019 Forecast**	**Total 2015-2019**
Total Project Cost	3.8	9.0	12.5	25.5	21.2	72.0
Customer Contributions	1.6	6.4	9.9	17.9	12.9	48.7
Toronto Hydro Cost	2.2	2.6	2.6	7.5	8.3	23.2
Approved Capital Spend	4.0	4.0	4.0	4.0	4.0	20.0
Variance	-1.8	-1.4	-1.4	3.5	4.3	3.2

The revenue requirement associated with the variance is the basis for the amount requested to be cleared. Table 5 below summarizes this calculation.

Table 5: Revenue Requirement for Externally Driven Capital ($ Millions)

	Actual			Forecast		
	2015	**2016**	**2017**	**2018**	**2019**	**Total**
Approved Externally Driven Capital ISA	4.0	4.0	4.0	4.0	4.0	20.0
Actual and Bridge Externally Driven Capital ISA	0.2	0.1	2.4	7.6	7.9	18.2
Variance	(3.8)	(3.9)	(1.6)	3.6	3.9	(1.8)
Revenue requirement impact	(0.2)	(0.5)	(0.7)	(0.6)	(0.2)	(2.2)
Externally Driven Capital Variance Account	(0.2)	(0.5)	(0.7)	(0.6)	(0.2)	(2.2)
Externally Driven Capital Variance Account – carrying charges	-	-	-	-	(0.1)	(0.1)
Total	**(0.2)**	**(0.5)**	**(0.7)**	**(0.6)**	**(0.3)**	**(2.3)**

Revenue Requirement Calculation	Actual			Forecast		
	2015	**2016**	**2017**	**2018**	**2019**	**Total**
Rate Base	(1.9)	(5.6)	(8.1)	(6.9)	(3.0)	

Revenue Requirement Calculation	Actual			Forecast		
	2015	2016	2017	2018	2019	Total
Return on equity	(0.1)	(0.2)	(0.3)	(0.3)	(0.1)	(1.0)
Interest	-	(0.1)	(0.2)	(0.2)	(0.1)	(0.6)
Depreciation	(0.1)	(0.2)	(0.2)	(0.1)	(0.1)	(0.7)
PILs	-	-	-	-	0.1	0.1
Revenue Requirement	(0.2)	(0.5)	(0.7)	(0.6)	(0.2)	(2.2)

4.5.1 Major Projects in 2015-2019 Period

Major projects with significant construction activities planned for the 2015-2019 period, such as the Metrolinx Eglinton Crosstown LRT, Metrolinx Finch LRT, Toronto Transit Commission Scarborough Extension, and Union Pearson GO transit electrification, were delayed by a variety of factors outside of Toronto Hydro's control. These factors included changes to City and provincial funding priorities, changes in scope, unforeseen project complications, longer than expected agreement negotiation periods, delayed release or modification of budgets and delays in concluding qualified stakeholder procurement. As such, the cost of relocation and expansion work anticipated for the 2015-2019 period either did not materialize or was deferred into the 2020-2024 period.

4.5.2 Continued Need for Variance Account

To reconcile the variable, non-discretionary nature of the work with its resulting bill impact, Toronto Hydro proposes to continue this variance account and, therefore, has only included spend for relocation and expansion work that is currently committed in its Distribution System Plan for the 2020-2024 period (e.g. Metrolinx Eglinton Crosstown LRT and Metrolinx Finch LRT). If and when the major projects identified in section 4.1 of Exhibit 2B, E5.2 materialize in the 2020-2024 application period, program spending will rise significantly. These include pending projects with Metrolinx (Regional Express Rail) and Toronto Transit Commission (Easier Access Program and Scarborough Subway

Extension). The utility has taken this approach in order to avoid imposing revenue requirement costs on ratepayers for unpredictable capital work.

4.6 Account 1508 – Other Regulatory Assets, Subaccount – Derecognition

The amount proposed for clearing is $42.1 million credit (refund) to customers. The account balance reflects the variance between the amount included in the 2015 revenue requirement and the amounts included in the 2016- 2019 C-Factor calculations and the actual/forecast amounts associated with derecognition of assets over the same period.

In EB-2014-0116, the OEB approved the establishment of a derecognition variance account to capture amounts which vary from the amount included in the 2015 revenue requirement and the amounts included in the 2016-2019 C-Factor calculations.

Toronto Hydro proposed this account on the basis that Toronto Hydro is likely to experience a significant degree of ongoing volatility in year-over-year losses on derecognition over the CIR period, due to the dynamic nature of the capital program and operating environment.

The volatility from its forecasted losses on derecognition over the 2015-2019 period was due to (i) the variety of asset ages in the distribution system; (ii) the dynamic nature of its capital program; and (iii) the materialization of external factors and constraints. The difficulty of accurately forecasting this amount and the associated potential volatility are described in Exhibit 4B, Tab 1, Schedule 2.

Table 6 shows the variance calculation between the amount included in the 2015 revenue requirement and the amounts included in the 2016- 2019 C-Factor calculations and the actual and forecasted amounts associated with derecognition of assets over the same period.

Table 6: Derecognition ($ Millions)

	Actual			Forecast		
	2015	**2016**	**2017**	**2018**	**2019**	**Total**
Losses on derecognition included in approved rates	33.9	26.6	28.0	29.4	32.6	150.5
Actual and forecast losses on derecognition	24.1	27.0	24.5	20.8	20.1	116.5
Variance	(9.8)	0.4	(3.5)	(8.6)	(12.5)	(34.0)
PILs	(3.4)	0.2	(1.2)	(3.0)	(4.5)	(11.9)
Capital revenue requirement	0.4	0.7	0.7	1.2	2.1	5.1
Derecognition variance account	(12.8)	1.3	(4.0)	(10.4)	(14.9)	(40.8)
Derecognition variance account – carrying charges	(0.1)	(0.1)	(0.2)	(0.3)	(0.6)	(1.3)
Total	**(12.9)**	**1.2**	**(4.2)**	**(10.7)**	**(15.5)**	**(42.1)**

Capital revenue requirement calculation	Actual			Forecast		
	2015	**2016**	**2017**	**2018**	**2019**	**Total**
Rate Base	4.9	9.6	11.1	17.1	27.6	70.3
Return on equity	0.2	0.4	0.4	0.6	1.0	2.6
Interest expense	0.1	0.2	0.2	0.4	0.7	1.6
PILs	0.1	0.1	0.1	0.2	0.4	0.9
Capital revenue requirement	0.4	0.7	0.7	1.2	2.1	5.1

Input Assumptions	**2015**	**2016**	**2017**	**2018**	**2019**
Half year rule	50.00%	50.00%	50.00%	50.00%	50.00%
Long term debt	4.28%	4.28%	4.28%	4.28%	4.28%
Short term debt	1.38%	1.38%	1.38%	1.38%	1.38%
Return on equity	9.30%	9.30%	9.30%	9.30%	9.30%
PILs rate	26.50%	26.50%	26.50%	26.50%	26.50%

The volatility experienced during the 2015- 2019 period demonstrates the continued need for this variance account to ensure that ratepayers and the utility are held harmless from any variances in this amount. Toronto Hydro requests for the continuation of this variance account.

4.7 Account 1508 – Other Regulatory Assets, Subaccount – Wireless Attachments

The amount proposed for clearing is a $0.6 million credit (refund) to customers. In the approved Settlement Agreement for EB-2013-0234, Toronto Hydro and intervenors agreed on the establishment of Deferral Accounts for the costs and revenues associated with wireless pole attachments. The OEB ordered that the net of the costs and revenues inclusive of carrying charges in the subaccounts be brought forward for disposition in Toronto Hydro's next rate application.

Revenues recorded in the deferral account are the actual revenues received through the negotiated contracts with wireless carriers, as well as the one-time revenues collected directly to cover the one-time costs, such as any make-ready costs incurred by Toronto Hydro to accommodate an attachment on its pole. Cost recorded in the deferral account are one-time costs incurred.

Table 7 shows the details of the actuals and forecasted costs and revenues included in the Deferral Accounts.

Table 7: Wireless attachment costs and revenues ($ Thousands)

	Actual	Forecast		
	2015- 2017	2018	2019	Total
THESL Wireless Attachment Costs	38	-	-	38
THESL Wireless Attachments Revenues	(450)	(100)	(100)	(650)
THESL Wireless Attachment Costs – carrying charges	2	1	1	4
THESL Wireless Attachments Revenues – carrying charges	(12)	(10)	(12)	(34)
Total	**(422)**	**(109)**	**(111)**	**(642)**

The OEB performed their policy review of pole attachment charges and concluded their findings in EB-2015-0304. The indirect charges for wireless attachments are aligned with those stated in EB-2015-0304. Revenues received by Toronto Hydro for its wireless attachments were in excess to the costs, thus the need to clear the $0.6 million credit in this account. Toronto Hydro requests continuance of this account to capture the ongoing nature of wireless pole attachment costs and revenues. /C /C

4.8 Account 1508 – Other Regulatory Assets, Subaccount – Monthly Billing

Toronto Hydro's Monthly Billing Deferral Account approved in EB-2014-0116, is intended to record the incremental costs and savings resulting from the mandatory transition to monthly billing for non-seasonal residential and all GS<50 kW customers as of December 31, 2016.[5]

In order to implement the mandatory transition, Toronto Hydro incurred $3.3 million in capital costs, and expects to incur an additional $15.9 million in operational costs from

[5] EB-2014-0198, Notice of Amendment to a Code, Amendments to the Distribution System Code (April 15, 2015).

2016 through the end of 2019.[6] These ongoing operational costs are offset by $6.0 million in working capital benefits attained over the same period.

The mandatory transition to monthly billing resulted in 3.8 million additional Toronto Hydro bills issued in 2017, representing an almost 70 percent increase (see Figure 3 below). In order to mitigate the cost impact associated with this increase, Toronto Hydro invested in various hardware and software upgrades, promoted electronic billing, and implemented a combination of automation, process improvements, and outsourcing, as detailed in the sections below. Overall, Toronto Hydro has continued to ensure customer satisfaction throughout the transition and has managed to improve its billing accuracy metrics during this period.

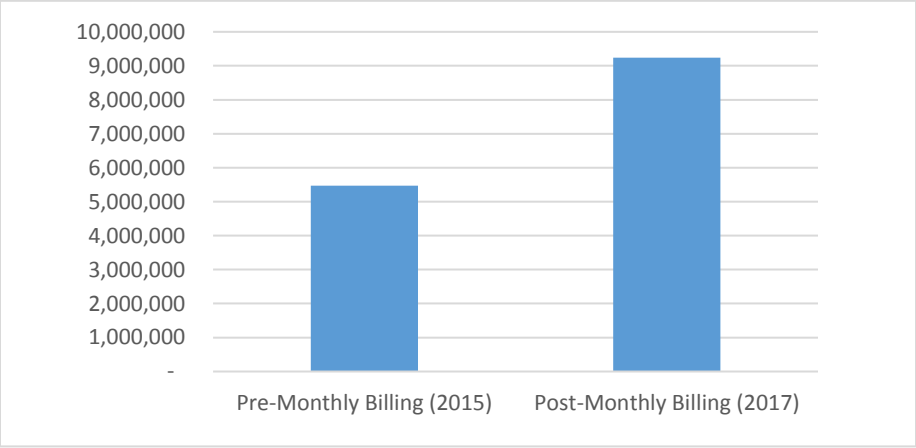

Figure 3: Total Bills Issued in 2015 and 2017

4.8.1 Capital Costs

As shown in Table 8, below, Toronto Hydro incurred $3.3 million in capital costs in order to implement the mandatory transition to monthly billing. This amount is slightly above

[6] In its 2015-2019 CIR Application, the utility did not include any costs or savings associated with the mandatory transition to monthly billing.

the favourable scenario presented by Toronto Hydro in its costs submission to the OEB on the mandatory transition.[7]

Table 8: Capital Costs Associated with the Implementation of Monthly Billing ($ Millions)

Actual Capital Costs versus Estimates Provided to the OEB	Labour	Hardware & Software	Total
Actual Capital Costs	$ 2.3	$ 1.0	$ 3.3
Estimated Base Case (Favourable Scenario)	$ 1.6	$ 1.4	$ 3.0
Estimated Base Case (Conservative Scenario)	$ 3.0	$ 1.4	$ 4.4

Toronto Hydro's transition to monthly billing required preparation for a significant increase in the number of bills issued, and a corresponding increase in transactions. Approximately $1.0 million was spent on hardware and software licences, performance tuning, and other minor modifications to upgrade billing system capacity to accommodate the increases in transaction volumes. Without system upgrades and increased data storage capacity, this additional volume of transactions would have slowed down Toronto Hydro's Customer Information System ("CIS"), creating billing delays, slower system performance, and reduced productivity.

Toronto Hydro incurred $2.3 million in incremental labour costs to implement the software and hardware upgrades. This includes project management, database and middleware support, software development, reporting, and IT application support. This figure excludes operational staff supporting the project part-time as subject matter

[7] These estimates were provided to the OEB in submissions dated October 9, 2014, as part of the OEB's EB-2014-0198 consultation concerning Electricity and Natural Gas Distributors' Residential Customer Billing Practices and Performance.

experts, at an estimated cost of $0.4 million, which Toronto Hydro covered and did not include in the Monthly Billing Deferral account.

As part of its monthly billing implementation plan, Toronto Hydro identified the processes impacted by an increase in billing frequency and transaction volumes, and utilized mitigation strategies such as automated communication with its field service vendor to reduce costs and improve processing time. This, combined with other strategies, described below, helped to reduce the financial impact of the increase in billing and transaction volumes and assisted in maintaining or enhancing customer service.

4.8.2 Operational Costs

Toronto Hydro forecasts $15.9 million over the 2015-2019 period ($1.6 million in 2016 and an average of $4.8 million per year from 2017 through 2019) in incremental operational costs to manage the monthly billing volumes, as illustrated in Table 9, below. This is much lower than Toronto Hydro's estimate of $6.1 million per year included as part of the OEB's monthly billing consultation. The variance is primarily due to mitigation efforts aimed at controlling labour costs through outsourcing, the use of automation solutions, and process improvements.

Table 9: Operational Costs Associated with the Implementation of Monthly Billing ($ Millions)

Operational Costs & Materials	Estimate – Base Case 9 (per year)	Average Annual Cost (Excluding 2016)	2016_{10} Actual	2017 Actual	2018 Forecast	2019 Forecast	Total Cost
Postage	2.6	2.3	0.6	2.2	2.4	2.4	7.7
Printing & Paper	0.5	0.4	0.1	0.3	0.4	0.4	1.2
Internal Labour	1.2	0.2	0.4	0.8	0.9	0.9	3.0
External Labour	0.9	0.3	0.3	0.5	0.5	0.5	1.9
Payment Processing	0.5	0.7	0.1	0.4	0.4	0.4	1.2
Manual Meter Reads	0.1	0.7	0.0	0.1	0.1	0.1	0.2
Communication activities	0.2	0.2	0.1	0.2	0.1	0.1	0.6
Collection activities	0.1	0.0	0.0	0.0	0.0	0.0	0.1
Total	**6.1**	**4.8**	**1.6**	**4.6**	**4.8**	**4.9**	**15.9**

As mentioned above, following the implementation of monthly billing, Toronto Hydro experienced an almost 70 percent increase in total bills issued per year. The increase in billing volumes is the primary driver of operational costs over the 2016-2019 period. Specifically, postage, printing, and paper account for approximately 55 percent of these operational costs, as shown in Figure 4.

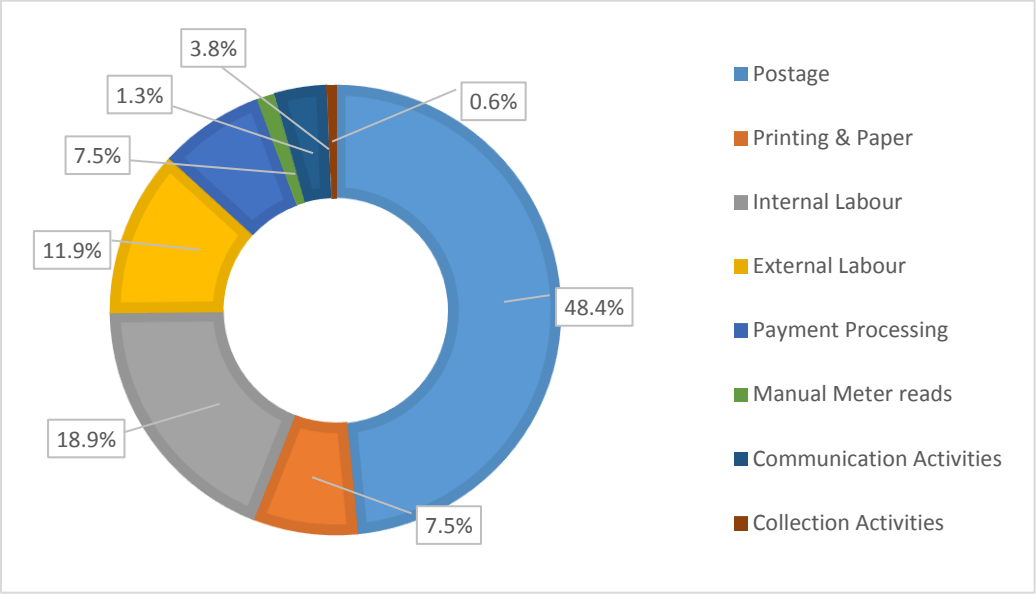

Figure 4: 2016-2019 Recurring Operational Costs of Monthly Billing, Postage, Printing, and Paper

The largest increase in Toronto Hydro's operational costs results from an additional 3.8 million bills[8] issued per year. Specifically, this results in increased postage, printing, and paper costs. In order to mitigate against the financial impact of these increases, Toronto Hydro engages in significant efforts to convert customers from paper to electronic bills ("eBills"), as shown in Table 10, below.

Table 10: Number of Toronto Hydro Customers Enrolled in eBilling

	2015 Actual	2016 Actual	2017 Actual	2018 Forecast	2019 Forecast
Number of Customers on eBills	127,951	185,740	224,420	251,420	275,420
Number of Total Customers	755,737	761,082	767,057	772,772	779,871
Bills Issued Annually	5,470,242	6,623,683	9,242,759	9,273,264	9,358,452

[8] Comparing total annual billing volumes of 2015 (the last full year before monthly billing) and 2017 (the first full year after monthly billing implementation).

Over 95,000 enrolments in eBilling occurred during 2016 and 2017 as a result of several marketing/communication campaigns, enhancements to the online move-in functionality, and other strategies to encourage uptake of enrolment in eBilling. Toronto Hydro expects to continue these efforts. In 2017, Toronto Hydro sent out over 2.7 million eBills. Each customer converted to eBilling represents approximately $9.52 in savings annually as a result of a reduction in postage, printing, and paper costs.

4.8.3 Labour

The increase in billing frequency resulting from the transition to monthly billing has also resulted in additional labour requirements (see Table 11, below). A subset of all bills require manual verification or intervention before issuing, so additional effort is required in order to process a higher volume of bills and sustain service level targets for timely and accurate billing. Similarly, there is higher frequency and volume of payments received, which requires additional effort in order to post payments and resolve related issues.

Failure to appropriately manage this increase in volumes and resulting workload could potentially result in inaccurate billing. The Distribution System Code's service quality requirements mandate a distributor to issue an accurate bill to a customer at least 98 percent of the time.[9] An "accurate bill" is defined as "a bill that contains correct customer information, correct meter readings, and correct rates that result in an accurately calculated bill."[10] Issuance of inaccurate bills can also result in inconvenience and payment processing delays, which would negatively impact customer experience and working capital.

[9] Distribution System Code (March 15, 2018), s. 7.11.
[10] Ibid at s. 7.1.

Table 11: Additional Labour Required for Incremental Monthly Billing Volumes

Department	Internal		External (Outsourced)	
	Number of Employees	2017 Annual Cost ($M)	Number of Employees	2017 Annual Cost ($M)
Remittance	2	0.2	2	0.1
Billing	7	0.6	2	0.1
Data Management	-	-	3	0.2
Collections	-	-	-	-
Call Centre	1	0.1	2	0.1
Total	**10**	**0.8**	**9**	**0.5**

To mitigate against the increase in labour costs stemming from the implementation of monthly billing, Toronto Hydro undertook a number of initiatives, including automation, process improvements, and outsourcing. For instance:

- The replacement of "gatekeeper systems", which gather and transmit data from meters to Toronto Hydro's billing system, resulted in more timely and accurate data being gathered automatically. This reduced the labour (and associated costs) required to manually collect and estimate meter reads, as well as improved customer service by enabling the issuance of more accurate bills.
- Introducing automated communication with Toronto Hydro's field service vendor resulted in reduction in labour required to process meter upgrades or exchanges. This automation was required to mitigate the reduction in time available, from 60 days to 30 days under a monthly billing schedule, to process meter changes in the CIS before the next bill was to be issued. This had a net favourable impact on labour, which was used to offset upward pressure on labour elsewhere in the billing process.

Due to these productivity efforts, Toronto Hydro was able to generate efficiencies in bill issuances and considerably improved the Full Time Equivalent ("FTE") per bill issued metric, as shown in Figure 5, below.

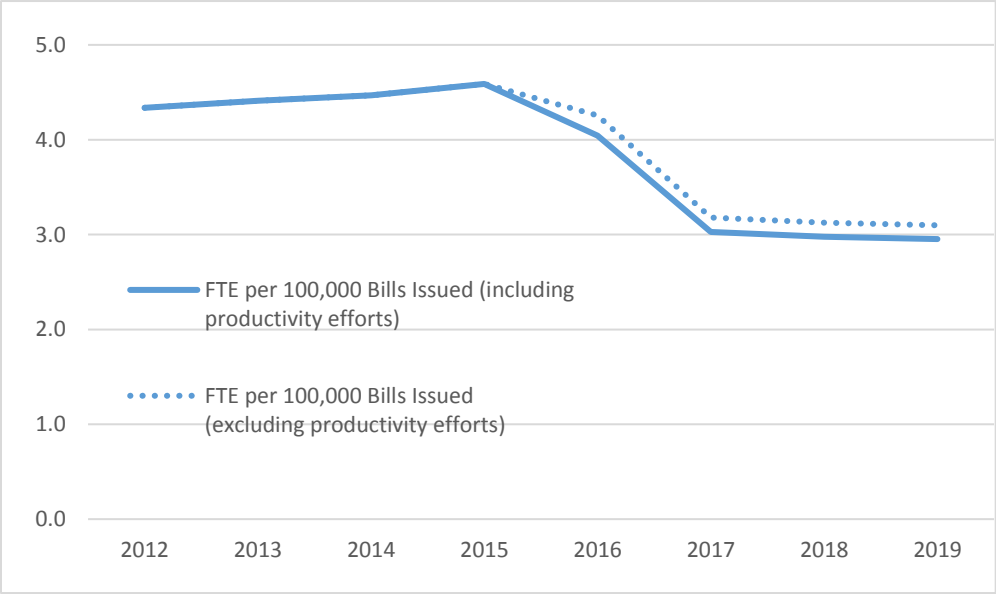

Figure 5: Number of FTEs per 100,000 Bills Issued

4.8.4 Other Costs

Toronto Hydro completes over 9,500 manual meter reads each month due to connection issues between the meter and Toronto Hydro's system. The increase in billing frequency requires more frequent manual meter reads for these properties, increasing meter-reading costs by $0.1 million per year.

The volume of overdue bill payment reminder calls and letters has also risen due to the increased frequency of bills, and costs have increased slightly, totaling approximately $0.1 million over the 2016-2019 period.

4.8.5 Savings and Benefits

In the Draft Report titled Electricity and Natural Gas Distributors' Residential Customer Billing Practices and Performance,[11] the OEB anticipated the following three benefits arising from utilities transitioning to monthly billing:

- Improved cash flow leading to a reduction in working capital costs;
- A decrease in bad debt, as customers would be better able to manage their bills; and
- An improvement in corporate communications, given more frequent engagements with customers.[12]

Toronto Hydro has confirmed through its Lead-Lag Study for Working Capital Allowance (see Exhibit 2A, Tab 3, Schedule 2) that the conversion to monthly billing has decreased Toronto Hydro's working capital costs approximately by $1.9 million per year, beginning in 2017.

However, Toronto Hydro has been unable to isolate any reductions or increases in its bad debt from the conversion to monthly billing. This is attributable to other recent factors that have had an impact on residential bad debt (notably the rate reductions under the Ontario Fair Hydro Plan, a cooler-than-average summer in 2017, and an increase in unpaid balances due to the winter disconnection moratorium for residential customers). While Toronto Hydro expects monthly billing to have a positive impact on bad debt, it does not expect these benefits to be material. In addition, given the long-term nature of bad debt and the varying factors that affect it in any given year, Toronto

[11] EB-2014-0198, Draft Report of the Board: Electricity and Natural Gas Distributors' Residential Customer Billing Practices and Performance (September 18, 2014).
[12] Ibid.

Hydro does not believe there to be any meaningful way to isolate the contributory impact of monthly billing on its bad debt totals.

Table 12: Toronto Hydro's Bad Debt ($ Millions)

2015 Actual	2016 Actual	2017 Actual	2018 Forecast	2019 Forecast
6.6	5.2	5.3	6.5	6.7

In terms of corporate communications, the implementation of monthly billing has provided Toronto Hydro with additional flexibility in terms of customer communications via on-bill messaging and inserts. Specifically, Toronto Hydro is now afforded six additional opportunities to make changes to existing messaging or introduce new messaging. However, while the introduction of monthly billing has allowed customers to be exposed to on-bill messages more frequently, this change has not resulted in any quantifiable financial benefit for Toronto Hydro.

Overall, Toronto Hydro has included $6.0 million in benefits to this account, comprised of working capital cost savings for 2016 through 2019.

4.8.6 Account Balance Calculations

The requested clearance is based on the revenue requirement associated with the costs in the Monthly Billing Deferral account. The proposed clearance amount is $11.5 million (to be collected from customers). The following table summarizes the calculation.

Table 13: Monthly Billing Revenue Requirement ($ Millions)

Monthly Billing	Actual			Forecast		
	2015	2016	2017	2018	2019	Total
Operating costs	-	1.6	4.6	4.8	4.9	15.9
Working capital savings	-	(0.4)	(1.9)	(1.9)	(1.9)	(6.1)
Capital related revenue requirement	-	(0.0)	0.1	0.6	1.0	1.7
Total	**-**	**1.2**	**2.8**	**3.5**	**4.0**	**11.5**

Capital revenue requirement calculation	Actual			Forecast		
	2015	2016	2017	2018	2019	Total
Rate Base	-	0.8	2.1	0.4	-	3.3
Return on equity	-	0.0	0.1	0.1	0.1	0.3
Interest expense	-	0.0	0.0	0.1	0.0	0.1
Depreciation	-	0.1	0.4	0.6	0.7	1.8
PILs	-	(0.1)	(0.4)	(0.2)	0.2	(0.5)
Capital revenue requirement	-	(0.0)	0.1	0.6	1.0	1.7

Input Assumptions	2015	2016	2017	2018	2019
Half year rule	50.00%	50.00%	50.00%	50.00%	50.00%
Long term debt	4.28%	4.28%	4.28%	4.28%	4.28%
Short term debt	1.38%	1.38%	1.38%	1.38%	1.38%
Return on equity	9.30%	9.30%	9.30%	9.30%	9.30%
PILs rate	26.50%	26.50%	26.50%	26.50%	26.50%
Pre-tax equity rate	12.65%	12.65%	12.65%	12.65%	12.65%
Useful Life	5 years	5 years	5 years	5 years	5 years
Depreciation rate	20.0%	20.0%	20.0%	20.0%	20.0%
Half Year	50%	50%	50%	50%	50%
CCA Class	Class 12	Class 12	Class 12	Class 12	Class 12
CCA Rate	100%	100%	100%	100%	100%
CCA Half Year	50%	50%	50%	50%	50%

4.9 Account 1508 – Other Regulatory Assets, Subaccount – OCCP

The amount proposed for clearance is a $71.2 million credit (refund) to customers.

Toronto Hydro incorporated the estimated net gains on the sale of the 5800 Yonge and 28 Underwriters properties, grossed up for PILs tax savings, as a credit (refund) to customers in the previous application (EB-2014-0116). However, since the timing and the final amount of the net gain from the sale of both properties were not known at the time of rate finalization, the OEB approved a variance account in which Toronto Hydro would track the difference between the total forecasted gains net of tax with the forecasted gross up for the PILs tax savings, and the actual gains net of tax with the actual gross up for the PILs tax savings.

A table summarizing the forecast and actual gains net of tax, grossed up for PILs tax savings is shown below. Both properties were sold to third parties at market prices prevailing at the time of sale.

Table 14: Gain net of tax, gross up for PILs tax savings related to Toronto Hydro's OCCP ($ Millions)

Property	Forecasted net gain, grossed up for PILs tax savings included in rates	Date of Actual Sale	Actual net gain, grossed up for PILs tax savings	Variance
28 Underwriters	12.1	March 3, 2015	8.1	(4.0)
5800 Yonge	60.4	April 16, 2018	134.1	73.7
Total	**72.5**		**142.2**	**69.7**

Toronto Hydro notes that the balance in this account reported in the 2017 RRR did not include the variance related to 5800 Yonge as the property was sold subsequent to December 31, 2017.

4.10 Account 1508 – Other Regulatory Assets, Subaccount – OPEB Cash vs Accrual

In May 2015, the OEB began an industry-wide consultation on rate-regulated utility pensions and OPEBs (EB-2015-0040). Pending the outcome of the consultation, in its Decision and Order (EB-2014-0116) dated December 29, 2015, the OEB requested Toronto Hydro to account for OPEBs on a cash rather than accrual basis for rate making purposes and to establish a variance account to track the difference between the cash and accrual methods. In its Decision and Rate Order (EB-2014-0116) dated March 1, 2016, the OEB approved the accounting order for Account 1508, Other Regulatory Assets, Sub-account: OPEB Cash vs Accrual Variance Account, for Toronto Hydro to record the difference between (i) the forecasted OPEBs costs related to its OM&A programs using the accounting accrual method; and (ii) the OPEBs cash payments made to the plan.

On September 14, 2017, the OEB issued its final report on the consultation. It established (i) the use of the accrual accounting method as the default method on which to set rates for pension and OPEB amounts in cost-based applications, unless that method does not result in just and reasonable rates in the circumstances of any given utility; and (ii) the use of a variance account to track the difference between the forecasted accrual amount in rates and actual cash payments made, with asymmetric carrying charges in favour of ratepayers applied to the differential. See section 10.2 for discussion on these new variance accounts.

In accordance with the OEB's direction in the report, Toronto Hydro will continue to record amounts into the previously approved variance account until January 1, 2020 (the effective date of Toronto Hydro's next cost-based rate order).

As at December 31, 2017, the balance in this account was $4.2 million debit. Toronto Hydro expects the balance in this account to be $8.9 million debit (recovery) from customers as at January 1, 2020.

No carrying charges were applied to the balance in this account.

Table 15: Cash versus Accrual Variance ($ Millions)

	Actual			Forecasted		
	2015	**2016**	**2017**	**2018**	**2019**	**Total**
Forecasted OPEB costs (OM&A programs)	10.2	10.4	10.6	10.8	11.1	53.1
Estimated Capital Depreciation Collected for OPEB	2.2	2.4	2.6	2.8	3.0	13.0
Amount collected through rates (A)	12.4	12.8	13.2	13.6	14.1	66.1
Less: Cash payments (B)	9.1	10.8	10.9	9.3	9.9	50.0
Difference (C) = (A) – (B)	3.3	2.0	2.3	4.3	4.2	16.1
OpEx/Capex split (D)	56.2%	57.4%	55.0%	55.1%	55.2%	
Cash versus accrual variance (C) x (D)	1.8	1.1	1.3	2.4	2.3	8.9

4.11 Account 1533 – Renewable Generation Connection Funding Adder Deferral Account, Sub-account Provincial Rate Protection Payment Variances

Toronto Hydro received approval in EB-2014-0116 for Renewable Enabling Investments ("REI") eligible for provincial rate protection. Toronto Hydro tracks the difference between the revenue requirement associated with Renewable Enabling Improvements

that is funded through Provincial Rate Protection and collected through payments from the IESO and revenue requirement based on actual REI investments, as it occurs over the 2015-2019 CIR period. Toronto Hydro requests continuance of this account for the 2020-2024 period. /C /C

As at the end of 2017, the variance in this account is a $2.4 million credit, as spending on some of the specific projects has been deferred or delayed. Current projections for investment on these approved projects over the 2018-2019 period indicates that the balance of the variance account will be $5.1 million at the end of 2019. Table 16 below provides details.

Table 16: Provincially Funded Renewable Eligible Investment Variance Account ($ Millions)

	2015	2016	2017	2018	2019
Approved Revenue Requirement	0.3	0.9	1.5	2.1	2.6
Actual/Forecast Revenue Requirement	-	-	0.1	0.5	1.6
Variance Account Balance	(0.3)	(0.9)	(1.4)	(1.6)	(1.0)

Toronto Hydro seeks approval to clear this account and return the projected $5.1 million variance to the IESO.

5. TORONTO HYDRO IS NOT SEEKING CLEARANCE IN THIS APPLICATION OF BALANCES IN THE FOLLOWING ACCOUNTS

5.1 All RSVA Accounts

Toronto Hydro will propose to clear the RSVA accounts for 2017 amounting to a $43.9 million credit (refund) to customers as part of Toronto Hydro's 2019 Custom Incentive Rate-setting Update Application. The accounts included are Account 1550 – Low Voltage Variance Account, Account 1580 – Wholesale Market Services, Account 1584 –

Network, Account 1586 – Connection, Account 1588 – Power, and Account 1589 – Global Adjustment.

Toronto Hydro will update the evidence and propose to clear the RSVA accounts for the 2018 period when the 2018 RRR Report is finalized.

5.2 Account 1551 – Smart Metering Entity Charges

On March 28, 2007, the IESO was designated as the Smart Metering Entity (the "SME") by Ontario Regulation. In its role as the SME, the IESO is managing the development of the meter data management/repository ("MDM/R") to collect, manage, store and retrieve information related to the metering of customers' use of electricity in Ontario.

Effective May 1, 2013, the Smart Metering Entity charge levied and collected by the SME from all distributors identified in the OEB's annual Yearbook of Electricity Distributors was set at $0.788 per month for each Residential and General Service <50 kW customer for each distributor. The Smart Metering Entity charge is in effect from May 1, 2013 to October 31, 2018.

On March 1, 2018, the OEB issued its Decision and Order (EB-2017-0290) approving a new Smart Metering Entity charge of $0.57 per month for each Residential and General Service <50 kW customer, effective from January 1, 2018 to December 31, 2022.

The previously approved Smart Metering Entity charge of $0.788 per month was collected for the first three months of 2018 and resulted in an accumulated credit of $0.66 per smart meter. The credit was recorded to the Smart Meter Entity Charges

variance account in April 2018 and the variance will be disposed as part of the Group 1 deferral and variance accounts in a future rate application.

Toronto Hydro records in Account 1551 amounts paid to the IESO through the Smart Metering Entity charge, and amounts recovered from customers through the distribution Rate Rider for Smart Metering Entity Charge. Toronto Hydro will propose to clear the Smart Metering Entity Charges account for 2017 amounting to a $0.5 million credit (refund) to customers as part of Toronto Hydro's 2019 Custom Incentive Rate-setting Update Application.

5.3 Account 1568 – LRAMVA

In Toronto Hydro's EB-2017-0077 Decision and Rate Order, the OEB approved the disposition of Toronto Hydro's LRAMVA amounts for the 2015 and 2016 periods.

At the time of filing this application, the 2017 Final CDM Annual Report and Persistence Savings Report from the IESO was not available. Toronto Hydro will propose to clear the LRAMVA amount for the 2017 period, if significant, as part of Toronto Hydro's 2019 Customer Incentive Rate-setting Update Application.

Toronto Hydro will update the evidence and propose to clear the LRAMVA amount for the 2018 period when the 2018 Final CDM Annual Report and Persistence Savings Report is available from the IESO.

6. SUMMARY OF PROPOSED DVA DISPOSITIONS

Toronto Hydro's proposed disposition of regulatory assets and liabilities is summarized in the following table.

Table 17: Summary of Proposed Dispositions ($ Millions)

	Principal Balance	Carrying Charges up to December 31, 2019	Balances for clearance as at December 31, 2019
Stranded Meter Costs	(1.4)	—	(1.4)
IFRS-USGAAP Transitional PP&E Amounts	(1.6)	—	(1.6)
Impact for USGAAP Deferral	85.3	—	85.3
CRRRVA	(57.6)	(1.8)	(59.4)
Externally Driven Capital	(2.2)	(0.1)	(2.3)
Derecognition	(40.8)	(1.3)	(42.1)
Wireless Attachments	(0.6)	—	(0.6)
Monthly Billing	11.5	0.3	11.8
OCCP	(69.7)	(1.5)	(71.2)
OPEB Cash vs Accrual	8.9	—	8.9
Excess Expansion Deposits (see section 10.1)	(5.1)	(0.4)	(5.5)
Total Balance	**(73.3)**	**(4.8)**	**(78.1)**

Toronto Hydro confirms that it has not made any adjustments to previously approved DVAs. The balances proposed for clearance match the account balances filed in the RRR as of 2017 year end, forecasted to the end of 2019.

7. DVA ALLOCATION AND RECOVERY METHOD

Toronto Hydro proposes to allocate the DVA balances to the customer classes based on the methodologies described in the OEB's EDDVAR report. For accounts where the EDDVAR report indicated allocation was to be determined on a case-by-case basis, Toronto Hydro has proposed an allocator.

For each of the accounts requested for clearance, the following table shows the proposed rate class allocator.

Table 18: Proposed Rate Class Allocator

Account	Allocator
Stranded Meter Costs	Same proration as 2015 CIR, originally based on number of Residential, General Service <50 kW and 50-999 kW customers at time of conversion to smart meters.
IFRS-USGAAP Transitional PP&E Amounts	2017 Distribution Revenue
Impact for USGAAP Deferral	2017 Distribution Revenue
CRRRVA	2017 Distribution Revenue
Externally Driven Capital	2017 Distribution Revenue
Derecognition	2017 Distribution Revenue
Wireless Attachments	Forecast 2020 Revenue Offsets excluding Street Light direct allocation
Monthly Billing	October 2016 number of customers
OCCP	2017 Distribution Revenue
OPEB Cash vs Accrual	2017 Distribution Revenue
Excess Expansion Deposits	2017 Distribution Revenue, excluding Residential, CSMUR, and General Service <50 kW

8. DEVELOPMENT OF RATE RIDERS

Toronto Hydro proposes a single fixed rate rider for those classes that are charged a fully fixed distribution rate (Residential and CSMUR), and a single volumetric rate rider for all other classes for the clearance of all DVA amounts, with the exception of Stranded Meters, which is to be recovered through a fixed charge for all applicable rate classes, as indicated in the OEB's Smart Meter Funding and Cost Recovery Guidelines.

Toronto Hydro proposes a recovery period of 60 months for all DVA accounts, beginning January 2020, in order to minimize the bill impacts to all affected customers.

The derivation of the rate riders is shown in Exhibit 9, Tab 3, Schedule 1.
The impacts of all proposed rate riders combined with the distribution rate changes are found in Exhibit 8, Tab 6, Schedule 1.

9. NEW DEFERRAL AND/OR VARIANCE ACCOUNTS

Toronto Hydro is seeking OEB's approval for the following new Deferral and Variance Accounts.

9.1 Variance Account for Excess Expansion Deposits

Toronto Hydro requests a variance account to record the excess expansion deposits and to clear the balance to ratepayers through an OEB-approved rate rider in the current CIR application. The amount proposed for clearance is $5.5 million credit (refund) to customers.

Pursuant to the OEB's Distribution System Code ("DSC"), Toronto Hydro may collect an expansion deposit from a customer who wants to connect to Toronto Hydro's distribution system if Toronto Hydro must expand its system (i.e. construct new facilities or increase the capacity of existing facilities) in order to connect the customer. Expansion deposits allow distributors to manage the financial risk that future distribution revenues will be insufficient to recover the costs incurred to construct and maintain the new assets (net of capital contributions recovered from customers).

During the Customer Connection Horizon specified in the Offer-to-Connect ("OTC") contract, the utility has an obligation to annually return the expansion deposit to the customer in proportion to the actual connections (for residential developments) or actual demand (for commercial and industrial developments) materialized in the year. If the forecast connections/demand do not materialize during the specified Customer Connection Horizon, utilities retain the excess portion of the expansion deposit. Although section 3.2.23 of the DSC provides that the utility does not have to return any remaining portions of the expansion deposit to the customer beyond the Customer Connection Horizon, Toronto Hydro proposed that the balance be returned to the ratepayers in order to protect ratepayer interests and to accord with the principles of just and reasonable ratemaking.

Table 19 provides details of the excess expansion deposit balances through to December 31, 2019, including carrying charges.

Table 19: Excess Expansion Deposits ($ Millions)

	Principal Balance as at Dec 31	Carrying Charge Balance	Total Balance as at Dec 31
2016	4.0	0.1	4.1
2017	5.1	0.2	5.3
2018	5.1	0.3	5.4
2019	5.1	0.4	5.5

9.2 Account 1522 Sub-account: Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges

In May 2015, the OEB began an industry-wide consultation on rate-regulated utility pensions and OPEBs (EB-2015-0040) and a final "Regulatory Treatment of Pension and OPEB Costs" report was issued on September 14, 2017.

As directed in the final report, Toronto Hydro will establish the following accounts to track the difference between the forecasted accrual amount in rates and actual cash payments made, with asymmetric carrying charges in favour of ratepayers applied to the differential:

1) Account 1522, Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential;
2) Account 1522, Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Contra Account; and
3) Account 1522, Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges.

Toronto Hydro will start using the three new accounts effective January 1, 2020, but will not submit a draft accounting order as directed in the OEB report. At a later time, Toronto Hydro will apply for disposition of the balance in the Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges account when the credit (refund) to customers is material.

Toronto Hydro will include in its forecasted accrual amount, the portion of OPEB costs related to its OM&A programs. It will include in its actual cash payment all the

payments made in the year related to its OPEB plans. It will use the Construction Work In Progress ("CWIP") rate prescribed by the OEB to determine the carrying charges.

The sample accounting entries for the new accounts are provided below.

A. To record the difference between the total OPEB accrual amount approved in rates and the actual cash amount paid (assuming accrual amount exceeds the cash payments). The reverse entry will be recorded if actual cash payments exceed the accrual amount. These accounts are strictly used for tracking purposes to calculate the carrying charges.
   - Dr. Account 1522, Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Contra Account
   - Cr. Account 1522, Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential

B. To record total annual carrying charges on the monthly opening cumulative credit balance in Account 1522, Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential at the OEB prescribed CWIP rate (assuming the account is in a credit position).
   - Dr. Account 6035, Other Interest Expense
   - Cr. Account 1522, Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges

Draft Accounting Orders

As directed by the OEB, a utility-specific accounting order is not required.[13]

[13] EB-2015-0040, Ontario Energy Board, Report on Regulatory Treatment of Pension and Other Post-employment Benefit (OPEBs) Costs (September 14, 2017).

APPENDIX A: DRAFT ACCOUNTING ORDERS

Variance Account for Excess Expansion Deposits

Toronto Hydro shall establish an account to record any excess expansion deposits as a credit to the variance account.

Carrying charges will apply to the opening balances in the accounts (exclusive of accumulated interest) at the OEB-approved rate for deferral and variance accounts.

Toronto Hydro will establish the following variance accounts to record the amounts described above:

- Account 1508, Other Regulatory Assets, Subaccount Excess Expansion Deposits
- Account 1508, Other Regulatory Assets, Subaccount Excess Expansion Deposits Carrying Charges

Toronto Hydro will use the following account to record the OEB-approved rate rider associated with the Excess Expansion Deposits being cleared to ratepayers:

- Account 1508 Other Regulatory Assets, Subaccount Excess Expansion Deposits (Rate Rider Account)

The sample accounting entries for the variance accounts are provided below.

1) To record the excess expansion deposits to the variance account:
    - Dr. 2335 Non-Current Customer Deposits
    - Cr. 1508 Other Regulatory Assets, Subaccount Excess Expansion Deposits

2) To record the annual carrying charges in subaccount:
   - Dr. 6035 Other Interest Expense
   - Cr. 1508 Other Regulatory Assets, Subaccount Excess Expansion Deposits Carrying Charges

3) To record the refunding of the rate rider to customers. The offsetting credit will be to Account 1100 Customer Accounts Receivable since the ratepayers' bills should be reduced by the rate rider refund:
   - Dr. 4080 Distribution Services Revenue
   - Cr. 1100 Customer Accounts Receivable
   - Dr. 1508 Other Regulatory Assets, Subaccount Excess Expansion Deposits (Rate Rider Account)
   - Cr. 4080 Distribution Services Revenue

APPENDIX E

DECISION AND RATE ORDER

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

EB-2014-0116

MARCH 1, 2016

NEW VARIANCE AND DEFERRAL ACCOUNTS – ACCOUNTING ORDERS

1. VARIANCE ACCOUNT FOR EXTERNALLY DRIVEN CAPITAL – ACCOUNTING ORDER

The OEB approved the revenue requirement associated with $4.0 million of annual in-service amounts for work related to third party initiated relocation and expansion projects (externally driven capital work). Since expenditures under this program can be volatile and difficult to predict, Toronto Hydro will record to this variance account the revenue requirement impact of the amounts for this type of work that vary from the approved amounts. For example, if Toronto Hydro puts in service $10 million of externally driven capital work in 2015, it will record the revenue requirement impact related to the $6 million to the variance account. This symmetrical variance account will record variances above and below $4.0 million and amounts recorded or recordable in this account will not be recorded in the Capital-Related Revenue Requirement Variance Account.

Carrying charges will apply to the opening revenue requirement balances in the account (exclusive of accumulated interest) at the OEB-approved rate for deferral and variance accounts.

At a later date, Toronto Hydro will apply to clear the revenue requirement associated with the balances in these accounts to ratepayers.

Toronto Hydro will establish the following variance accounts to record the amounts described above:

- Account 1508, Other Regulatory Assets, Subaccount THESL Externally Driven Revenue Requirement
- Account 1508, Other Regulatory Assets, Subaccount THESL Externally Driven Revenue Requirement Carrying Charges

The sample accounting entries for the variance accounts are provided below.

A. To record the revenue requirement in the Externally Driven Capital Variance Account:
   - DR 1508 Other Regulatory Assets, Subaccount THESL Externally Driven Revenue Requirement
   - CR 4080 Distribution Services Revenue

B. To record the carrying charges in subaccount THESL Externally Driven Revenue Requirement:
   - DR 1508 Other Regulatory Assets, Subaccount THESL Externally Driven Revenue Requirement Carrying Charges
   - CR 4405 Interest and Dividend Income

2. VARIANCE ACCOUNT FOR DERECOGNITION – ACCOUNTING ORDER

Under Modified IFRS, the gain or loss associated with the derecognition of assets is required to be recorded as a depreciation expense during the period in which the item is derecognized. Due to the dynamic nature of Toronto Hydro's capital program and operating environment, Toronto Hydro is likely to experience a significant degree of ongoing volatility in year over year losses on derecognition over the CIR Period. To manage this volatility, Toronto Hydro will record to a variance account the amounts which vary from the OEB-approved amounts.

Carrying charges will apply to the opening balances in the account (exclusive of accumulated interest) at the OEB-approved rate for deferral and variance accounts.

At a later date, Toronto Hydro will apply to clear the balances in these accounts to ratepayers.

Toronto Hydro will establish the following variance accounts to record the amounts described above:

- Account 1508, Other Regulatory Assets, Subaccount THESL Derecognition Amounts
- Account 1508, Other Regulatory Assets, Subaccount THESL Derecognition Amounts Carrying Charges

The sample accounting entries for the variance accounts are provided below.

A. To record the amounts that vary from the amounts included in the 2015 Revenue Requirement and the amounts included in the 2016-2019 C-Factor calculations related to the Derecognition amounts:
   - DR 1508 Other Regulatory Assets, Subaccount THESL Derecognition Amounts
   - CR 4080 Distribution Services Revenue

B. To record the carrying charges in subaccount THESL Derecognition Amounts:
   - DR 1508 Other Regulatory Assets, Subaccount THESL Derecognition Amounts Carrying Charges
   - CR 4405 Interest and Dividend Income

3. DEFERRAL ACCOUNT FOR THE MANDATORY TRANSITION TO MONTHLY BILLING – ACCOUNTING ORDER

The OEB requires that all distributors transition customers in the Residential and General Service less than 50 kW (GS < 50kW) rate classes to monthly billing by December 31, 2016. The OEB approved a deferral account in which Toronto Hydro will record the incremental costs and savings that result from this mandatory transition. Since the timing and costs of the transition are yet unknown, no amount related to these incremental costs and savings were included in the Application.[1] Toronto Hydro will also record in a deferral account the revenue requirement associated with the capital cost amounts in the Mandatory Transition to Monthly Billing Deferral Account.

Carrying charges will apply to the opening revenue requirement balances in the accounts (exclusive of accumulated interest) at the OEB-approved rate for deferral and variance accounts.

At a later date, Toronto Hydro will apply to clear the balances in this account to ratepayers.

Toronto Hydro will record as a debit to the deferral account the incremental costs of the mandatory transition to monthly billing.

Toronto Hydro will calculate and record as a credit to the deferral account the incremental savings (if any) arising from benefits realised in the course of the mandatory transition to monthly billing.

Toronto Hydro will establish the following deferral accounts to record the amounts described above:

[1] EB-2014-0116, Toronto Hydro-Electric System Limited Decision and Order (December 29, 2015) at pp. 51-52.

- Account 1508, Other Regulatory Assets, Subaccount Mandatory Transition to Monthly Billing Costs and Savings
- Account 1508, Other Regulatory Assets, Subaccount Mandatory Transition to Monthly Billing Costs and Savings Revenue Requirement
- Account 1508, Other Regulatory Assets, Subaccount Mandatory Transition to Monthly Billing Costs and Savings Revenue Requirement Carrying Charges

The sample accounting entries for the deferral accounts are provided below.

A. To record on a monthly basis the incremental costs of the mandatory transition to monthly billing:
   - DR 1508 Other Regulatory Assets, Subaccount Mandatory Transition to Monthly Billing Costs and Savings
   - CR XXXX Operating, Maintenance and Administration Expenses / Property Plant and Equipment / Depreciation Expense / Construction Work-in-Progress (various accounts - dependent on the type of costs)

B. To record on a monthly basis the incremental savings of the mandatory transition to monthly billing:
   - DR XXXX Operating, Maintenance and Administration Expenses / Property Plant and Equipment / Depreciation Expense / Construction Work-in-Progress (various accounts – dependent on the type of costs)
   - CR 1508, Other Regulatory Assets, Subaccount Mandatory Transition to Monthly Billing Costs and Savings

C. To record the revenue requirement on the capital costs in the Mandatory Transition to Monthly Billing Deferral Account:
   - DR 1508 Other Regulatory Assets, Subaccount Mandatory Transition to Monthly Billing Costs and Savings Revenue Requirement
   - CR 4080 Distribution Services Revenue

D. To record the carrying charges in subaccount Mandatory Transition to Monthly Billing Revenue Requirement:

- DR 1508 Other Regulatory Assets, Subaccount Mandatory Transition to Monthly Billing Costs and Savings Revenue Requirement Carrying Charges
- CR 4405 Interest and Dividend Income

4. VARIANCE ACCOUNT FOR GAINS ON SALE OF PROPERTIES RELATED TO THE COMPANY'S OPERATING CENTERS CONSOLIDATION PROGRAM (OCCP) – ACCOUNTING ORDER

Toronto Hydro will be clearing to ratepayers, through an OEB-approved rate rider, the forecasted net gains on the sale of the 5800 Yonge and 28 Underwriters properties, grossed up for the PILs tax savings. However, since the timing of the sale of both properties and the final amount of the net gain from the sale of both properties are not known at the time of rate finalization, the OEB approved a variance account in which Toronto Hydro will track the difference between the total forecasted gains net of tax with the forecasted gross up for the PILs tax savings and the actual gains net of tax with the actual gross up for the PILs tax savings.

Carrying charges will apply to the opening balances in the accounts (exclusive of accumulated interest) at the OEB-approved rate for deferral and variance accounts.

At a later date, Toronto Hydro will apply to clear the balances in this account to ratepayers.

Toronto Hydro will establish the following variance accounts to record the amounts described above:

- Account 1508, Other Regulatory Assets, Subaccount OCCP Gains Variance Account
- Account 1508, Other Regulatory Assets, Subaccount OCCP Gains Variance Account Carrying Charges

Toronto Hydro will use the following account to record the OEB-approved rate rider associated with the forecasted gains being cleared to ratepayers:

- Account 1508 Other Regulatory Assets, Subaccount Regulatory Deferred Gain on Disposal (Rate Rider Account)

The sample accounting entries for the variance accounts are provided below.

December 31, 2015 entries

A. Record the OEB-approved net forecasted gains to be cleared to customers through a rate rider:
   - DR 4080 Distribution Services Revenue
   - CR 1508 Other Regulatory Assets, Subaccount Regulatory Deferred Gain on Disposal (Rate Rider Account)

B. Record the variance between the approved net forecasted gains and the actual net gains as at the end of 2015:
   - DR 1508 Other Regulatory Assets, Subaccount OCCP Gains Variance Account
   - CR 4080 Distribution Services Revenue

2016 and future years' entries

C. Record the refunding of the rate rider to customers. The offsetting credit will be to Account 1100 Customer Accounts Receivable since the ratepayers' bills should be reduced by the rate rider refund:
   - DR 4080 Distribution Services Revenue
   - CR 1100 Customer Accounts Receivable
   - DR 1508 Other Regulatory Assets, Subaccount Regulatory Deferred Gain on Disposal (Rate Rider Account)
   - CR 4080 Distribution Services Revenue

D. Record the actual PILs tax savings materialized, which is being given back to ratepayers. The PILs tax savings is the result of the rate rider cash refund to customers:

- DR 2294 Accrual for Taxes, "Payments in Lieu of Taxes", Etc.
- CR 6110 Income Taxes
- DR 4080 Distribution Services Revenue
- CR 1508 Other Regulatory Assets, Subaccount OCCP Gains Variance Account

E. Record the actual sale of the property, net of taxes (assuming a net gain).

- DR 1005 Cash
- DR XXXX Accumulated Depreciation of PP&E (various accounts – depends on type of asset)
- CR XXXX Property, plant and equipment (various accounts – depends on type of asset)
- CR 2294 Accrual for Taxes, "Payments in Lieu of Taxes", Etc.
- CR 4355 Gain on Disposition of Utility and Other Property

F. Record the reclassification of the actual net after-tax gain to Account 1508 Other Regulatory Assets, Subaccount OCCP Gains Variance Account

- DR 4355 Gain on Disposition of Utility and Other Property
- CR 1508 Other Regulatory Assets, Subaccount OCCP Gains Variance Account

G. Record the carrying charges based on the net of the balances in Account 1508 subaccount OCCP Gains Variance Account and Account 1508 subaccount Regulatory Deferred Gain on Disposal (Rate Rider Account). The carrying charges are determined using simple interest applied on the monthly net opening balances:

- DR 6035 Other Interest Expense / CR 4405 Interest and Dividend Income
- CR/DR 1508 Other Regulatory Assets, Subaccount OCCP Gains Variance Account Carrying Charges

5. VARIANCE ACCOUNT FOR 2015 OPENING RATE BASE TO CAPTURE PRUDENCE-BASED ICM DISALLOWANCES – ACCOUNTING ORDER

At this time, the ICM True-up process has not been completed. As such, differences in the amount of ICM-eligible work that should be included in the 2015 opening rate base could occur as a result of the OEB's findings during that process. This variance account will capture any differences between amounts included in 2015 rate base and any revenue requirements associated with disallowances based on prudence that may result from the ICM True-Up. Specifically, this variance account will track the revenue requirement impact of any capital in-service additions and the related depreciation expense included in the 2015 revenue requirement through the CIR Decision that are found to be imprudent in the ICM True-Up.

Carrying charges will apply to the opening revenue requirement balances in the account (exclusive of accumulated interest) at the OEB-approved rate for deferral and variance accounts.

At a later date, Toronto Hydro will apply to clear the balances in this account to ratepayers.

Toronto Hydro will establish the following variance accounts to record the amounts described above:

- Account 1508 Other Regulatory Assets, Subaccount THESL ICM True-Up Revenue Requirement Variance Account
- Account 1508, Other Regulatory Assets, Subaccount THESL ICM True-Up Revenue Requirement Variance Account Carrying Charges

The sample accounting entries for the variance accounts are provided below.

A. To record the revenue requirement associated with disallowed rate base:
    - DR 4080 Distribution Services Revenue
    - CR 1508 Other Regulatory Assets, Subaccount THESL ICM True-Up Revenue Requirement Variance Account

B. To record the carrying charges in subaccount THESL ICM True-Up Revenue Requirement Variance Account:
    - DR 6035 Other Interest Expense

- CR 1508 Other Regulatory Assets, Subaccount THESL ICM True-Up Revenue Requirement Variance Account Carrying Charges

6. VARIANCE ACCOUNT FOR CAPITAL-RELATED REVENUE REQUIREMENT (CRRRVA) – ACCOUNTING ORDER

In order to address the possibility that Toronto Hydro may not bring its entire capital program in-service during the CIR Period, Toronto Hydro will record in a variance account the variance between the cumulative 2015 to 2019 capital related revenue requirement included in rates and the actual capital in-service additions related revenue requirement over the period. Toronto Hydro will record the variance on a cumulative basis to ensure that Toronto Hydro has the flexibility to optimize the implementation of its capital investment strategy, which may involve shifting the timing of project spending within the CIR Period.

Carrying charges will apply to the opening balances in the account (exclusive of accumulated interest) at the OEB-approved rate for deferral and variance accounts.

At a later date, Toronto Hydro will apply to clear the balances in this account to ratepayers.

Toronto Hydro will establish the following Variance Accounts to record the amounts described above:

- Account 1508, Other Regulatory Assets, Subaccount Capital Related Revenue Requirement Variance Account
- Account 1508, Other Regulatory Assets, Subaccount Capital Related Revenue Requirement Variance Account Carrying Charges

The sample accounting entry for the variance accounts are provided below.

A. To record the difference between the cumulative 2015 to 2019 capital related revenue requirement included in rates and the actual capital in-service additions related revenue requirement over the period (see note 1 below):
    - DR 4080 Distribution Services Revenue

- CR 1508 Other Regulatory Assets, Subaccount Capital Related Revenue Requirement Variance Account

B. To record the carrying charges in subaccount Capital Related Revenue Requirement Variance Account:

- DR 6035 Other Interest Expense
- CR 1508 Other Regulatory Assets, Subaccount Capital Related Revenue Requirement Variance Account Carrying Charges

Note:

1. Capital Related Revenue Requirement Variance Account calculation: Record the net of:
   i. The approved revenue requirement associated with the cumulative 2015 to 2019 capital related revenue requirement;
   AND
   ii. The actual capital in-service additions related revenue requirement over the period.

   This account will be asymmetrical in nature.

7. OTHER POST-EMPLOYMENT BENEFITS (OPEBS) CASH VERSUS ACCRUAL VARIANCE ACCOUNT – ACCOUNTING ORDER

The OEB has initiated an industry-wide policy consultation on rate-regulated utility OPEBs. Pending a final conclusion on the treatment of OPEBs, for ratemaking purposes, the OEB requires Toronto Hydro to calculate recovery for OPEBs using cash payments instead of the accounting cost calculated under the accrual method. As such, Toronto Hydro will record in a variance account the difference between (i) the forecasted OPEBs costs related to Toronto Hydro's OM&A programs using the accounting accrual method and (ii) the OPEBs cash payments made to the plan.

At a later date, Toronto Hydro will apply to clear the balances in this account to ratepayers.

Toronto Hydro will establish the following variance accounts to record the amounts described above:

- Account 1508, Other Regulatory Assets, Subaccount Other Post-Employment Benefits Cash vs Accrual Variance Account

The sample accounting entry for the variance accounts are provided below.

A. To record the difference between the forecasted OPEBs costs and the OPEBs plan payments made:
   - DR 1508 Other Regulatory Assets, Subaccount Other Post-Employment Benefits Cash vs Accrual Variance Account
   - CR 5646 Employee Pensions and OPEB

8. EARNINGS SHARING MECHANISM (ESM) VARIANCE ACCOUNT

Toronto Hydro shall establish an account to record amounts related to any earnings outside of Toronto Hydro's approved annual return on equity (ROE) exceeding a +/- 100 basis-point dead band, to be shared on an equal basis between Toronto Hydro and its ratepayers. The earnings variance will only arise from differences between the non-capital related revenue requirement embedded in rates and the actual non-capital related revenue requirement. The ratepayer share of the earnings shall be grossed up for any tax impacts and credited to this account.

Carrying charges will apply to the opening balances in the account (exclusive of accumulated interest) at the OEB-approved rate for deferral and variance accounts.

At a later date, Toronto Hydro will apply to clear the balances in this account to ratepayers.

Toronto Hydro will establish the following variance accounts to record the amounts described above:

- Account 1508, Other Regulatory Assets, Subaccount Earnings Sharing Mechanism Variance Account
- Account 1508, Other Regulatory Assets, Subaccount Earnings Sharing Mechanism Variance Account Carrying Charges

The sample accounting entry for the variance accounts are provided below.

A. To record half (50%) of the amounts related to any earnings outside of Toronto Hydro's approved ROE +/- 100 basis points:
   - DR 4080 Distribution Services Revenue
   - CR 1508 Other Regulatory Assets, Subaccount Earnings Sharing Mechanism Variance Account

B. To record the carrying charges in subaccount Earnings Sharing Mechanism Variance Account:
   - DR 6035 Other Interest Expense
   - CR 1508 Other Regulatory Assets, Subaccount Earnings Sharing Mechanism Variance Account Carrying Charges

Account Descriptions	Account Number	2012									
		Opening Principal Amounts as of Jan-1-12	Transactions(1) Debit / (Credit) during 2012	OEB-Approved Disposition during 2012	Principal Adjustments(2) during 2012	Closing Principal Balance as of Dec-31-12	Opening Interest Amounts as of Jan-1-12	Interest Jan-1 to Dec-31-12	OEB-Approved Disposition during 2012	Interest Adjustments(2) during 2012	Closing Interest Amounts as of Dec-31-12
Group 1 Accounts											
LV Variance Account	1550	$0				$0	$0				$0
Smart Metering Entity Charge Variance Account	1551										
RSVA - Wholesale Market Service Charge[9]	1580	$0				$0	$0				$0
Variance WMS – Sub-account CBR Class A[9]	1580										
Variance WMS – Sub-account CBR Class B[9]	1580										
RSVA - Retail Transmission Network Charge	1584	$0				$0	$0				$0
RSVA - Retail Transmission Connection Charge	1586	$0				$0	$0				$0
RSVA - Power (excluding Global Adjustment)[12]	1588	$0				$0	$0				$0
RSVA - Global Adjustment [12]	1589	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2012)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2013)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2014)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2015)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$0				$0	$0				$0
Not to be disposed of until a year after rate rider has expired and that balance has been audited											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
RSVA - Global Adjustment 12	**1589**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508	$0	$61,499,000			$61,499,000	$0				$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - EIP	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Derecognition	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - OCCP	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$0				$0	$0				$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$0	$61,499,000	$0	$0	$61,499,000	$0	$0	$0	$0	$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0			-$2,314,616	-$2,314,616	$0			-$83,852	-$83,852
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0			-$1,100,000	-$1,100,000	$0			-$34,148	-$34,148
Total of Group 1 and Group 2 Accounts (including 1592)		$0	$61,499,000	$0	-$3,414,616	$58,084,384	$0	$0	$0	-$118,000	-$118,000
LRAM Variance Account[11]	**1568**	$0				$0	$0				$0
Total including Account 1568		$0	$61,499,000	$0	-$3,414,616	$58,084,384	$0	$0	$0	-$118,000	-$118,000
Renewable Generation Connection Capital Deferral Account[8]	1531	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account[8]	1532	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555	$0			$59,226,643	$59,226,643	$0			$0	$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555	$0			-$27,078,565	-$27,078,565	$0			$350,269	$350,269
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555	$0			$0	$0	$0			$0	$0
Smart Meter OM&A Variance[4]	1556	$0			$22,925,549	$22,925,549	$0			$0	$0
Meter Cost Deferral Account (MIST Meters)[10]	1557										
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575	$0				$0					
Accounting Changes Under CGAAP Balance + Return Component[5]	1576	$0				$0					

Account Descriptions	Account Number	2013 Opening Principal Amounts as of Jan-1-13	2013 Transactions(1) Debit / (Credit) during 2013	2013 OEB-Approved Disposition during 2013	2013 Principal Adjustments(2) during 2013	2013 Closing Principal Balance as of Dec-31-13	2013 Opening Interest Amounts as of Jan-1-13	2013 Interest Jan-1 to Dec-31-13	2013 OEB-Approved Disposition during 2013	2013 Interest Adjustments(2) during 2013	2013 Closing Interest Amounts as of Dec-31-13
Group 1 Accounts											
LV Variance Account	1550										
Smart Metering Entity Charge Variance Account	1551										
RSVA - Wholesale Market Service Charge[9]	1580										
Variance WMS – Sub-account CBR Class A[9]	1580										
Variance WMS – Sub-account CBR Class B[9]	1580										
RSVA - Retail Transmission Network Charge	1584										
RSVA - Retail Transmission Connection Charge	1586										
RSVA - Power (excluding Global Adjustment)[12]	1588										
RSVA - Global Adjustment [12]	1589										
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595										
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595										
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595										
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Disposition and Recovery/Refund of Regulatory Balances (2014)[7]	1595										
Disposition and Recovery/Refund of Regulatory Balances (2015)[7]	1595										
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595										
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595										
Not to be disposed of until a year after rate rider has expired and that balance has been audited											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
RSVA - Global Adjustment 12	**1589**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508	$61,499,000	-$22,718,000			$38,781,000	$0				$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - EIP	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Derecognition	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - OCCP	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$0				$0	$0				$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$61,499,000	-$22,718,000	$0	$0	$38,781,000	$0	$0	$0	$0	$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$2,314,616				-$2,314,616	-$83,852	-$34,020			-$117,872
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$1,100,000	$0			-$1,100,000	-$34,148	-$16,169			-$50,317
Total of Group 1 and Group 2 Accounts (including 1592)		$58,084,384	-$22,718,000	$0	$0	$35,366,384	-$118,000	-$50,189	$0	$0	-$168,189
LRAM Variance Account[11]	**1568**	$0				$0	$0				$0
Total including Account 1568		$58,084,384	-$22,718,000	$0	$0	$35,366,384	-$118,000	-$50,189	$0	$0	-$168,189
Renewable Generation Connection Capital Deferral Account[8]	1531	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account[8]	1532	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555	$59,226,643	-$59,226,643			$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555	-$27,078,565	$27,078,565			$0	$350,269	-$350,269			$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555	$0	$16,876,471		-$1,085,160	$15,791,311	$0				$0
Smart Meter OM&A Variance[4]	1556	$22,925,549	-$22,925,549			$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[10]	1557										
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575	$0			$30,506,428	$30,506,428					
Accounting Changes Under CGAAP Balance + Return Component[5]	1576	$0				$0					

Account Descriptions	Account Number	2014 Opening Principal Amounts as of Jan-1-14	2014 Transactions(1) Debit / (Credit) during 2014	2014 OEB-Approved Disposition during 2014	2014 Principal Adjustments(2) during 2014	2014 Closing Principal Balance as of Dec-31-14	2014 Opening Interest Amounts as of Jan-1-14	2014 Interest Jan-1 to Dec-31-14	2014 OEB-Approved Disposition during 2014	2014 Interest Adjustments(2) during 2014	2014 Closing Interest Amounts as of Dec-31-14
Group 1 Accounts											
LV Variance Account	1550	$0	$1,680,006			$1,680,006	$0	$48,585			$48,585
Smart Metering Entity Charge Variance Account	1551	$0	$230,907			$230,907	$0	$10,096			$10,096
RSVA - Wholesale Market Service Charge[9]	1580	$0	-$104,177,755			-$104,177,755	$0	-$4,243,265			-$4,243,265
Variance WMS – Sub-account CBR Class A[9]	1580		$0					$0			
Variance WMS – Sub-account CBR Class B[9]	1580		$0					$0			
RSVA - Retail Transmission Network Charge	1584	$0	$60,297,064			$60,297,064	$0	$1,969,184			$1,969,184
RSVA - Retail Transmission Connection Charge	1586	$0	$28,085,714			$28,085,714	$0	$981,663			$981,663
RSVA - Power (excluding Global Adjustment)[12]	1588	$0	-$18,770,687			-$18,770,687	$0	$0			$0
RSVA - Global Adjustment [12]	1589	$0	$85,657,811			$85,657,811	$0	$2,633,307			$2,633,307
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$0	-$363,600			-$363,600	$0	-$318,137			-$318,137
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$0	-$2,483,823			-$2,483,823	$0	$1,563,823			$1,563,823
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595	$0	$109,729			$109,729	$0	-$261,355			-$261,355
Disposition and Recovery/Refund of Regulatory Balances (2012)[7]	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2013)[7]	1595	$0	$95,890			$95,890	$0	-$55,626			-$55,626
Disposition and Recovery/Refund of Regulatory Balances (2014)[7]	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2015)[7]	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$0				$0	$0				$0
Not to be disposed of until a year after rate rider has expired and that balance has been audited											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$50,361,255	$0	$0	$50,361,255	$0	$2,328,275	$0	$0	$2,328,275
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	-$35,296,556	$0	$0	-$35,296,556	$0	-$305,032	$0	$0	-$305,032
RSVA - Global Adjustment 12	**1589**	$0	$85,657,811	$0	$0	$85,657,811	$0	$2,633,307	$0	$0	$2,633,307
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508	$38,781,000	$48,551,000			$87,332,000	$0				$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - EIP	1508	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Regulatory Assets - Sub-Account - Derecognition	1508	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	$0	-$112,142	$0	$0	-$112,142	$0	-$738	$0	$0	-$738
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Regulatory Assets - Sub-Account - OCCP	1508	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$38,781,000	$48,438,858	$0	$0	$87,219,858	$0	-$738	$0	$0	-$738
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$2,314,616				-$2,314,616	-$117,872	-$34,020			-$151,892
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$1,100,000				-$1,100,000	-$50,317	-$16,170			-$66,487
Total of Group 1 and Group 2 Accounts (including 1592)		$35,366,384	$98,800,113	$0	$0	$134,166,497	-$168,189	$2,277,347	$0	$0	$2,109,157
LRAM Variance Account[11]	**1568**	$0				$0	$0				$0
Total including Account 1568		$35,366,384	$98,800,113	$0	$0	$134,166,497	-$168,189	$2,277,347	$0	$0	$2,109,157
Renewable Generation Connection Capital Deferral Account[8]	1531	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account[8]	1532	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555	$15,791,311			-$1,387,244	$14,404,067	$0				$0
Smart Meter OM&A Variance[4]	1556	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[10]	1557	$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575	$30,506,428	$0	$0	$0	$30,506,428		$0	$0	$0	
Accounting Changes Under CGAAP Balance + Return Component[5]	1576	$0				$0					

Account Descriptions	Account Number	2015 Opening Principal Amounts as of Jan-1-15	2015 Transactions(1) Debit / (Credit) during 2015	2015 OEB-Approved Disposition during 2015	2015 Principal Adjustments(2) during 2015	2015 Closing Principal Balance as of Dec-31-15	2015 Opening Interest Amounts as of Jan-1-15	2015 Interest Jan-1 to Dec-31-15	2015 OEB-Approved Disposition during 2015	2015 Interest Adjustments(2) during 2015	2015 Closing Interest Amounts as of Dec-31-15
Group 1 Accounts											
LV Variance Account	1550	$1,680,006	$447,453			$2,127,459	$48,585	$22,355			$70,940
Smart Metering Entity Charge Variance Account	1551	$230,907	-$103,295			$127,611	$10,096	$2,861			$12,957
RSVA - Wholesale Market Service Charge[9]	1580	-$104,177,755	-$53,058,389			-$157,236,144	-$4,243,265	-$1,397,797			-$5,641,062
Variance WMS – Sub-account CBR Class A[9]	1580	$0	$554,306			$554,306	$0	$1,757			$1,757
Variance WMS – Sub-account CBR Class B[9]	1580	$0	$5,967,910			$5,967,910	$0	$19,743			$19,743
RSVA - Retail Transmission Network Charge	1584	$60,297,064	$6,453,241			$66,750,305	$1,969,184	$753,147			$2,722,331
RSVA - Retail Transmission Connection Charge	1586	$28,085,714	$7,451,237			$35,536,950	$981,663	$375,400			$1,357,063
RSVA - Power (excluding Global Adjustment)[12]	1588	-$18,770,687	-$3,662,931			-$22,433,618	$0	-$261,729			-$261,729
RSVA - Global Adjustment [12]	1589	$85,657,811	$8,710,805			$94,368,616	$2,633,307	$1,177,873			$3,811,180
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	-$363,600	$0			-$363,600	-$318,137	-$48,826			-$366,963
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	-$2,483,823	$0			-$2,483,823	$1,563,823	$17,095			$1,580,918
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595	$109,729	$0			$109,729	-$261,355	$1,308			-$260,047
Disposition and Recovery/Refund of Regulatory Balances (2012)[7]	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2013)[7]	1595	$95,890				$95,890	-$55,626	$1,139			-$54,487
Disposition and Recovery/Refund of Regulatory Balances (2014)[7]	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2015)[7]	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$0				$0	$0				$0
Not to be disposed of until a year after rate rider has expired and that balance has been audited											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$50,361,255	-$27,239,665	$0	$0	$23,121,590	$2,328,275	$664,326	$0	$0	$2,992,600
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$35,296,556	-$35,950,470	$0	$0	-$71,247,026	-$305,032	-$513,547	$0	$0	-$818,579
RSVA - Global Adjustment 12	**1589**	$85,657,811	$8,710,805	$0	$0	$94,368,616	$2,633,307	$1,177,873	$0	$0	$3,811,180
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508	$87,332,000	-$6,142,424			$81,189,576	$0				$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	$0	-$2,679,349			-$2,679,349	$0	-$13,714			-$13,714
Other Regulatory Assets - Sub-Account - EIP	1508	$0	-$155,757	$0	$0	-$155,757	$0	$0	$0	$0	$0
Other Regulatory Assets - Sub-Account - Derecognition	1508	$0	-$12,913,378	$0	$0	-$12,913,378	$0	-$41,430	$0	$0	-$41,430
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	-$112,142	-$100,000	$0	$0	-$212,142	-$738	-$1,780	$0	$0	-$2,518
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$0	$339,784	$0	$0	$339,784	$0	$0	$0	$0	$0
Other Regulatory Assets - Sub-Account - OCCP	1508	$0	-$5,844,028	$0	$0	-$5,844,028	$0	-$66,137	$0	$0	-$66,137
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$0	$1,840,000	$0	$0	$1,840,000	$0	$0	$0	$0	$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$87,219,858	-$25,655,152	$0	$0	$61,564,705	-$738	-$123,061	$0	$0	-$123,799
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$2,314,616				-$2,314,616	-$151,892	-$27,603			-$179,495
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$1,100,000				-$1,100,000	-$66,487	-$13,114			-$79,601
Total of Group 1 and Group 2 Accounts (including 1592)		$134,166,497	-$52,894,817	$0	$0	$81,271,679	$2,109,157	$500,548	$0	$0	$2,609,705
LRAM Variance Account[11]	**1568**	$0	$9,112,988			$9,112,988	$0	$216,135			$216,135
Total including Account 1568		$134,166,497	-$43,781,829	$0	$0	$90,384,667	$2,109,157	$716,683	$0	$0	$2,825,840
Renewable Generation Connection Capital Deferral Account[8]	1531	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account[8]	1532	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555	$14,404,067				$14,404,067	$0				$0
Smart Meter OM&A Variance[4]	1556	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[10]	1557	$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575	$30,506,428		$0	-$1,558,360	$28,948,068		$0	$0	$0	
Accounting Changes Under CGAAP Balance + Return Component[5]	1576	$0				$0					

Account Descriptions	Account Number	2016 Opening Principal Amounts as of Jan-1-16	2016 Transactions(1) Debit / (Credit) during 2016	2016 OEB-Approved Disposition during 2016	2016 Principal Adjustments(2) during 2016	2016 Closing Principal Balance as of Dec-31-16	2016 Opening Interest Amounts as of Jan-1-16	2016 Interest Jan-1 to Dec-31-16	2016 OEB-Approved Disposition during 2016	2016 Interest Adjustments(2) during 2016	2016 Closing Interest Amounts as of Dec-31-16
Group 1 Accounts											
LV Variance Account	1550	$2,127,459	$312,025	$1,192,584		$1,246,899	$70,940	$15,001	$64,774		$21,166
Smart Metering Entity Charge Variance Account	1551	$127,611	-$379,776	$435,919		-$688,084	$12,957	$14,090	$16,147		$10,900
RSVA - Wholesale Market Service Charge[9]	1580	-$157,236,144	-$26,035,861			-$183,272,005	-$5,641,062	-$1,776,861			-$7,417,923
Variance WMS – Sub-account CBR Class A[9]	1580	$554,306		$554,306		$0	$1,757		$1,757		$0
Variance WMS – Sub-account CBR Class B[9]	1580	$5,967,910	$1,535,334			$7,503,244	$19,743	$14,282	$19,743		$14,282
RSVA - Retail Transmission Network Charge	1584	$66,750,305	-$16,414,401			$50,335,904	$2,722,331	$664,278			$3,386,608
RSVA - Retail Transmission Connection Charge	1586	$35,536,950	-$29,949,890			$5,587,061	$1,357,063	$271,369			$1,628,432
RSVA - Power (excluding Global Adjustment)[12]	1588	-$22,433,618	-$4,099,996		-$804,747	-$27,338,361	-$261,729	-$265,904			-$527,633
RSVA - Global Adjustment [12]	1589	$94,368,616	-$14,088,418		$804,747	$81,084,945	$3,811,180	$1,131,533			$4,942,712
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	-$363,600		-$363,600		$0	-$366,963	-$26,599	-$393,562		-$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	-$2,483,823		-$2,483,823		-$0	$1,580,918	-$66,708	$1,514,210		-$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595	$109,729		$109,729		-$0	-$260,047	-$12,853	-$272,900		$0
Disposition and Recovery/Refund of Regulatory Balances (2012)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2013)[7]	1595	$95,890				$95,890	-$54,487	$966			-$53,521
Disposition and Recovery/Refund of Regulatory Balances (2014)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2015)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0	$8,704,230	-$45,304,160		$54,008,390	$0	-$28,061	-$131,074		$103,013
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$0				$0	$0				$0
Not to be disposed of until a year after rate rider has expired and that balance has been audited											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$23,121,590	-$80,416,753	-$45,859,045	$0	-$11,436,118	$2,992,600	-$65,468	$819,096	$0	$2,108,037
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$71,247,026	-$66,328,336	-$45,859,045	-$804,747	-$92,521,064	-$818,579	-$1,197,000	$819,096	$0	-$2,834,676
RSVA - Global Adjustment 12	**1589**	$94,368,616	-$14,088,418	$0	$804,747	$81,084,945	$3,811,180	$1,131,533	$0	$0	$4,942,712
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508	$81,189,576	-$21,022,000			$60,167,576	$0				$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	-$2,679,349	-$5,791,209			-$8,470,558	-$13,714	-$54,531			-$68,245
Other Regulatory Assets - Sub-Account - EIP	1508	-$155,757	-$472,141	$0	$0	-$627,897	$0	-$1,154	$0	$0	-$1,154
Other Regulatory Assets - Sub-Account - Derecognition	1508	-$12,913,378	$1,290,093	$0	$0	-$11,623,285	-$41,430	-$169,801	$0	$0	-$211,231
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	-$212,142	-$100,016	$0	$0	-$312,158	-$2,518	-$2,815	$0	$0	-$5,333
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$339,784	$1,653,589	$0	$0	$1,993,373	$0	$7,871	$0	$0	$7,871
Other Regulatory Assets - Sub-Account - OCCP	1508	-$5,844,028	$14,486,588	$0	$0	$8,642,560	-$66,137	-$11,273	$0	$0	-$77,409
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$1,840,000	$1,131,000	$0	$0	$2,971,000	$0	$0	$0	$0	$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$61,564,705	-$8,824,096	$0	$0	$52,740,609	-$123,799	-$231,702	$0	$0	-$355,502
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$2,314,616		-$2,314,616		$0	-$179,495	-$4,244	-$183,739		$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$1,100,000		-$1,100,000		$0	-$79,601	-$2,017	-$81,619		$2
Total of Group 1 and Group 2 Accounts (including 1592)		$81,271,679	-$89,240,850	-$49,273,661	$0	$41,304,491	$2,609,705	-$303,431	$553,737	$0	$1,752,537
LRAM Variance Account[11]	**1568**	$9,112,988	$4,319,627	$3,452,615	$1,278,369	$11,258,369	$216,135	$109,612	$131,074		$194,673
Total including Account 1568		$90,384,667	-$84,921,223	-$45,821,046	$1,278,369	$52,562,860	$2,825,840	-$193,819	$684,811	$0	$1,947,210
Renewable Generation Connection Capital Deferral Account[8]	1531	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account[8]	1532	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	$0	-$1,026,599	$0	$0	-$1,026,599	$0	$0	$0	$0	$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555	$14,404,067	-$3,102,224			$11,301,843	$0	$110,022			$110,022
Smart Meter OM&A Variance[4]	1556	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[10]	1557	$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575	$28,948,068	-$9,933,709		$0	$19,014,359	$0	$0	$0	$0	
Accounting Changes Under CGAAP Balance + Return Component[5]	1576	$0				$0	$0				

Account Descriptions	Account Number	2017 Opening Principal Amounts as of Jan-1-17	2017 Transactions(1) Debit / (Credit) during 2017	2017 OEB-Approved Disposition during 2017	2017 Principal Adjustments(2) during 2017	2017 Closing Principal Balance as of Dec-31-17	2017 Opening Interest Amounts as of Jan-1-17	2017 Interest Jan-1 to Dec-31-17	2017 OEB-Approved Disposition during 2017	2017 Interest Adjustments(2) during 2017	2017 Closing Interest Amounts as of Dec-31-17
Group 1 Accounts											
LV Variance Account	1550	$1,246,899	$394,328	$934,874		$706,353	$21,166	$6,808	$19,906		$8,068
Smart Metering Entity Charge Variance Account	1551	-$688,084	-$113,182	-$308,308		-$492,958	$10,900	-$15,080	-$7,181		$3,001
RSVA - Wholesale Market Service Charge[9]	1580	-$183,272,005	-$25,199,715	-$157,236,144		-$51,235,576	-$7,417,923	-$555,630	-$7,370,570		-$602,984
Variance WMS – Sub-account CBR Class A[9]	1580	$0				$0	$0				$0
Variance WMS – Sub-account CBR Class B[9]	1580	$7,503,244	$524,231	$5,967,910		$2,059,564	$14,282	$20,888	$85,385		-$50,215
RSVA - Retail Transmission Network Charge	1584	$50,335,904	$8,096,178	$66,750,305		-$8,318,223	$3,386,608	-$83,173	$3,456,545		-$153,109
RSVA - Retail Transmission Connection Charge	1586	$5,587,061	$8,333,125	$35,536,950		-$21,616,765	$1,628,432	-$278,307	$1,747,948		-$397,823
RSVA - Power (excluding Global Adjustment)[12]	1588	-$27,338,361	-$3,337,116	-$22,433,618		-$8,241,858	-$527,633	-$93,593	-$508,477		-$112,749
RSVA - Global Adjustment [12]	1589	$81,084,945	$56,920,194	$94,368,616		$43,636,523	$4,942,712	$274,057	$4,812,604		$404,166
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$0				$0	-$0				-$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	-$0				-$0	-$0				-$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595	-$0				-$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2012)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2013)[7]	1595	$95,890		$95,890		-$0	-$53,521		-$53,433		-$88
Disposition and Recovery/Refund of Regulatory Balances (2014)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2015)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$54,008,390	-$13,829,257			$40,179,133	$103,013	-$18,718		-$993,537	-$909,242
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$0	$2,791,740			$2,791,740	$0	$142,065			$142,065
Not to be disposed of until a year after rate rider has expired and that balance has been audited											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$11,436,118	$31,788,786	$23,676,474	$0	-$3,323,807	$2,108,037	-$742,748	$2,182,727	-$993,537	-$1,810,976
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$92,521,064	-$25,131,408	-$70,692,141	$0	-$46,960,331	-$2,834,676	-$1,016,805	-$2,629,877	-$993,537	-$2,215,141
RSVA - Global Adjustment 12	**1589**	$81,084,945	$56,920,194	$94,368,616	$0	$43,636,523	$4,942,712	$274,057	$4,812,604	$0	$404,166
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508	$60,167,576	$25,093,000			$85,260,576	$0				$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	-$8,470,558	-$14,277,069			-$22,747,626	-$68,245	-$208,682			-$276,927
Other Regulatory Assets - Sub-Account - EIP	1508	-$627,897	-$698,387	$0	$0	-$1,326,285	-$1,154	-$3,252	$0	$0	-$4,406
Other Regulatory Assets - Sub-Account - Derecognition	1508	-$11,623,285	-$3,870,968	$0	$0	-$15,494,253	-$211,231	-$192,636	$0	$0	-$403,867
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	-$312,158	-$100,000	$0	$0	-$412,158	-$5,333	-$4,396	$0	$0	-$9,729
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$1,993,373	$2,024,793	$0	$0	$4,018,166	$7,871	$37,270	$0	$0	$45,142
Other Regulatory Assets - Sub-Account - OCCP	1508	$8,642,560	$18,394,134	$0	$0	$27,036,693	-$77,409	$212,645	$0	$0	$135,235
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$2,971,000	$1,300,000	$0	$0	$4,271,000	$0	$0	$0	$0	$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$52,740,609	$27,865,503	$0	$0	$80,606,113	-$355,502	-$159,051	$0	$0	-$514,552
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0				$0	$2				$2
Total of Group 1 and Group 2 Accounts (including 1592)		$41,304,491	$59,654,289	$23,676,474	$0	$77,282,306	$1,752,537	-$901,798	$2,182,727	-$993,537	-$2,325,526
LRAM Variance Account[11]	**1568**	$11,258,369	$9,612,739	$4,810,834		$16,060,274	$194,673	$156,370	$139,236		$211,807
Total including Account 1568		$52,562,860	$69,267,028	$28,487,308	$0	$93,342,580	$1,947,210	-$745,428	$2,321,963	-$993,537	-$2,113,718
Renewable Generation Connection Capital Deferral Account[8]	1531	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account[8]	1532	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	-$1,026,599	-$1,400,410	$0	$0	-$2,427,009	$0	$0	$0	$0	$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555	$11,301,843	-$3,985,516			$7,316,327	$110,022	$109,435			$219,457
Smart Meter OM&A Variance[4]	1556	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[10]	1557	$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575	$19,014,359	-$6,583,043	$0	$0	$12,431,316	$0	$0	$0	$0	$0
Accounting Changes Under CGAAP Balance + Return Component[5]	1576	$0				$0	$0				$0

		2018					Projected Interest on Dec-31-17 Balances					2.1.7 RRR		
Account Descriptions	**Account Number**	**Principal Disposition during 2018 - instructed by OEB**	**Interest Disposition during 2018 - instructed by OEB**	**Adjustment for 2018 & 2019 forecast**	**Closing Principal Balances as of Dec 31-17 Adjusted for Dispositions during 2018**	**Closing Interest Balances as of Dec 31-17 Adjusted for Dispositions during 2018**	**Projected Interest from Jan 1, 2018 to December 31, 2018 on Dec 31 -17 balance adjusted for disposition during 2018 (6)**	**Projected Interest from January 1, 2019 to December 31, 2019 on Dec 31 -17 balance adjusted for disposition during 2018 (6)**	**Total Interest**	**Total Claim**		**As of Dec 31-17**	**Variance RRR vs. 2017 Balance (Principal + Interest)**	
Group 1 Accounts														
LV Variance Account	1550	$312,025	$5,861		$394,328	$2,207	$7,068	$7,453	$16,729		$411,056.75	$714,420	-$1	*Rounding*
Smart Metering Entity Charge Variance Account	1551	-$379,776	$13,241		-$113,182	-$10,240	-$8,836	-$9,317	-$28,393		-$141,575.19	-$489,957	-$0	
RSVA - Wholesale Market Service Charge[9]	1580	-$26,035,861	-$498,414		-$25,199,715	-$104,570	-$451,705	-$476,275	-$1,032,549		-$26,232,264.19	-$49,829,210	$2,009,350	
Variance WMS – Sub-account CBR Class A[9]	1580				$0	$0			$0		$0.00	$0	$0	
Variance WMS – Sub-account CBR Class B[9]	1580	$1,535,334	-$52,680		$524,230	$2,465	$9,397	$9,908	$21,770		$545,999.96	$0	-$2,009,349	
RSVA - Retail Transmission Network Charge	1584	-$16,414,401	-$205,715		$8,096,178	$52,606	$145,124	$153,018	$350,747		$8,446,925.44	-$8,471,333	-$0	
RSVA - Retail Transmission Connection Charge	1586	-$29,949,890	-$446,320		$8,333,125	$48,497	$149,371	$157,496	$355,364		$8,688,489.35	-$22,014,588	-$0	
RSVA - Power (excluding Global Adjustment)[12]	1588	-$4,904,742	-$98,572		-$3,337,116	-$14,177	-$59,818	-$63,071	-$137,067		-$3,474,183.01	-$8,354,608	$0	
RSVA - Global Adjustment [12]	1589	-$13,283,670	$57,211		$56,920,193	$346,955	$1,020,294	$1,075,792	$2,443,041		$59,363,234.28	$44,040,688	-$1	*Rounding*
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595				$0	-$0			-$0	Check to Dispose of Account	$0.00	$0	$0	
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595				-$0	-$0			-$0	Check to Dispose of Account	$0.00	$0	$0	
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595				-$0	$0			$0	Check to Dispose of Account	$0.00	$0	$0	
Disposition and Recovery/Refund of Regulatory Balances (2012)[7]	1595				$0	$0			$0	Check to Dispose of Account	$0.00	$0	$0	
Disposition and Recovery/Refund of Regulatory Balances (2013)[7]	1595				-$0	-$88			-$88	Check to Dispose of Account	$0.00	$0	$88	*Immaterial difference*
Disposition and Recovery/Refund of Regulatory Balances (2014)[7]	1595				$0	$0			$0	Check to Dispose of Account	$0.00	$0	$0	
Disposition and Recovery/Refund of Regulatory Balances (2015)[7]	1595				$0	$0			$0	Check to Dispose of Account	$0.00	$0	$0	
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595				$40,179,133	-$909,242			-$909,242	Check to Dispose of Account	$0.00	$39,269,891	$1	*Rounding*
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595				$2,791,740	$142,065			$142,065	Check to Dispose of Account	$0.00	$2,933,805	-$0	
Not to be disposed of until a year after rate rider has expired and that balance has been audited														
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$89,120,981	-$1,225,388		$85,797,174	-$585,588	$810,896	$855,003	$1,080,311		$47,607,683.39	-$5,134,696	$87	
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$75,837,311	-$1,282,599		$28,876,980	-$932,542	-$209,399	-$220,788	-$1,362,729		-$11,755,550.89	-$49,175,384	$88	
RSVA - Global Adjustment 12	**1589**	-$13,283,670	$57,211		$56,920,193	$346,955	$1,020,294	$1,075,792	$2,443,041		$59,363,234.28	$44,040,688	-$1	
Group 2 Accounts														
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508				$0	$0			$0		$0.00		$0	
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508				$0	$0			$0		$0.00		$0	
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508				$0	$0			$0		$0.00		$0	
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508			$0	$85,260,576	$0	$0	$0	$0	Check to Dispose of Account	$85,260,576.00	$85,260,576	-$0	
Other Regulatory Assets - Sub-Account - CRRRVA	1508			-$34,868,480	-$57,616,106	-$276,927	-$576,771	-$956,327	-$1,810,025	Check to Dispose of Account	-$59,426,130.45	-$23,024,553	-$0	
Other Regulatory Assets - Sub-Account - EIP	1508			-$921,078	-$2,247,363	-$4,406	-$40,017	-$39,348	-$83,771	Check to Dispose of Account	-$2,331,133.98	-$1,330,691	-$0	
Other Regulatory Assets - Sub-Account - Derecognition	1508			-$25,262,942	-$40,757,196	-$403,867	-$291,629	-$618,290	-$1,313,786	Check to Dispose of Account	-$42,070,982.24	-$15,898,121	$0	
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508			-$200,000	-$612,158	-$9,729	-$8,930	-$11,412	-$30,071	Check to Dispose of Account	-$642,229.80	-$421,887	-$0	
Other Regulatory Assets - Sub-Account - Monthly Billing	1508			$7,464,365	$11,482,531	$45,142	$100,312	$176,163	$321,617	Check to Dispose of Account	$11,804,147.98	$4,063,307	-$0	
Other Regulatory Assets - Sub-Account - OCCP	1508			-$96,754,354	-$69,717,661	$135,235	-$583,365	-$968,487	-$1,416,616	Check to Dispose of Account	-$71,134,277.43	$27,171,929	$0	
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508			$4,674,000	$8,945,000	$0	$0	$0	$0	Check to Dispose of Account	$8,945,000.00	$4,271,000	$0	
Retail Cost Variance Account - Retail	1518				$0	$0			$0		$0.00		$0	
Misc. Deferred Debits	1525				$0	$0			$0	Check to Dispose of Account	$0.00		$0	
Retail Cost Variance Account - STR	1548				$0	$0			$0		$0.00		$0	
Board-Approved CDM Variance Account	1567				$0	$0			$0		$0.00		$0	
Extra-Ordinary Event Costs	1572				$0	$0			$0		$0.00		$0	
Deferred Rate Impact Amounts	1574				$0	$0			$0		$0.00		$0	
RSVA - One-time	1582				$0	$0			$0		$0.00		$0	
Other Deferred Credits	2425				$0	$0			$0	Check to Dispose of Account	$0.00		$0	
Group 2 Sub-Total		$0	$0		-$65,262,377	-$514,552	-$1,400,400	-$2,417,701	-$4,332,653		-$69,595,029.92	$80,091,560	-$1	
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592				$0	$0			$0		$0.00	-$0	-$0	
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592				$0	$2			$2		$2.17	$0	-$2	*Rounding*
Total of Group 1 and Group 2 Accounts (including 1592)		-$89,120,981	-$1,225,388		$20,534,797	-$1,100,138	-$589,504	-$1,562,698	-$3,252,340		-$21,987,344.36	$74,956,864	$84	
LRAM Variance Account[11]	**1568**	$6,447,545	$121,812		$9,612,729	$89,995			$89,995		$9,702,724.17	$16,272,081	-$0	
Total including Account 1568		-$82,673,436	-$1,103,576		$30,147,526	-$1,010,142	-$589,504	-$1,562,698	-$3,162,345		-$12,284,620.19	$91,228,945	$84	
Renewable Generation Connection Capital Deferral Account[8]	1531				$0	$0			$0		$0.00		$0	
Renewable Generation Connection OM&A Deferral Account[8]	1532				$0	$0			$0		$0.00		$0	
Renewable Generation Connection Funding Adder Deferral Account	1533	$0	$0	-$2,707,856	-$5,134,865	$0	$0	$0	$0		-$5,134,864.93	-$2,427,009	$0	
Smart Grid Capital Deferral Account	1534				$0	$0			$0		$0.00		$0	
Smart Grid OM&A Deferral Account	1535				$0	$0			$0		$0.00		$0	
Smart Grid Funding Adder Deferral Account	1536				$0	$0			$0		$0.00		$0	
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555				$0	$0			$0		$0.00		$0	
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555				$0	$0			$0		$0.00		$0	
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555			-$8,703,571	-$1,387,244	$219,457			$219,457		$0.00	$7,535,784	$0	
Smart Meter OM&A Variance[4]	1556				$0	$0			$0		$0.00		$0	
Meter Cost Deferral Account (MIST Meters)[10]	1557				$0	$0			$0		$0.00		$0	
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575			-$13,989,676	-$1,558,360		$0			Check to Dispose of Account	$0.00	$12,431,316	$0	
Accounting Changes Under CGAAP Balance + Return Component[5]	1576				$0					Check to Dispose of Account	$0.00		$0	

Notes

[1] For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year. Do not include interest, adjustments, or OEB approved dispositions in this column.

[2] Please provide explanations for the nature of the adjustments. If the adjustment relates to previously OEB Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

[3] As per the January 6, 2011 Letter from the OEB regarding the implementation of the Ontario Clean Energy Benefit:

"By way of exception... The Board does anticipate that licensed distributors that cannot adapt their invoices as of January 1, 2011 will require a variance account for OCEB purposes... The Board expects that any principal balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will be addressed through the monthly settlement process with the IESO or the host distributor, as applicable."

[4] Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance Account rate rider. For details on how to dispose of balances in Smart Meter accounts see the OEB's Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

The Stranded meters were approved for clearing by OEB as of FY 2016. The balances are cleared in the account 1555 (Stranded meter accounts). there is no claim balances to this account as of Dec 2017. The balance left in the account is the remaining recoveries.

[5] The OEB requires that disposition of Account 1575 and Account 1576 shall require the use of separate rate riders. In the "Adjustments during 2016" column of the continuity schedule, please enter the amounts to be included in the Account 1575 and 1576 rate rider calculation from the applicable Chapter 2-E appendix line "Amount included in Deferral and Variance Account Rate Rider Calculation".

Depending on the disposition period, balances may exist in Account 1575 and Account 1576 even if the accounts have been approved for disposition in a previous decision. Report these account balances in the continuity schedule if this is the case and leave the checkbox "Check to Dispose of Account" in the Total Claim column unchecked.

[6] If the LDC's rate year begins on January 1, 2018, the projected interest is recorded from January 1, 2017 to December 31, 2017 on the December 31, 2016 balances adjusted for the disposed balances approved by the OEB in the 2017 rate decision. If the LDC's rate year begins on May 1, 2018, the projected interest is recorded from January 1, 2017 to April 30, 2018 on the December 31, 2016 balances adjusted for the disposed interest balances approved by the OEB in the 2017 rate decision.

[7] The individual sub-accounts as well as the total for all Account 1595 sub-accounts are to agree to the RRR data. Differences need to be explained.

For each Account 1595 sub-account, the transfer of the balance approved for disposition into Account 1595 is to be recorded in the "OEB Approved Disposition" column. The recovery/refund is to be recorded in the "Transaction" column. The two are not to be netted together and recorded in one column in the first year.

The audited balance in the account is only to be disposed a year after the recovery/refund period has been completed. Generally, no further transactions would be expected to flow through the account after that. Any vintage year of Account 1595 is only to be disposed once on a final basis. No further dispositions of these accounts are generally expected thereafter, unless justified by the distributor. Select the "Check to dispose of account" checkbox in Total Claims column if the account is requested for disposition.

[8] As per the Filing Requirements for 2018 rate applications, request for rate protection on eligible investments are subject to a materiality threshold. If the materiality threshold is met, per the APH March 2015 Guidance, the Direct Benefits portion of Account 1531 should be transferred to rate base. The Direct Benefits portion of Account 1532 should be included in the DVA continuity schedule to be requested for disposition. In this continuity schedule, Account 1531 is listed for reference only. Account 1532 is included in the Group 2 allocation of balances that are used to calculate the rate riders. Only input the Direct Benefits portion of the account balances in this continuity schedule.

[9] Account 1580 RSVA WMS balance inputted into this schedule is to exclude any amounts relating to CBR. CBR amounts are to be inputted into Account 1580, sub-accounts CBR Class A and B separately. There is no disposition of Account 1580, sub-account CBR Class A, accounting guidance for this sub-account is to be followed. If a balance exists for Account 1580, sub-account CBR Class A as at Dec. 31, 2016, the balance must be explained.

[10] Account 1557 is to be recovered in a manner similar to the Smart Meter accounts. Distributors should request for disposition upon completion of the MIST meter deployment. A prudence review and disposition should be done in the application, outside of this continuity schedule.

[11] Input the LRAMVA balance in the continuity schedule as calculated from the LRAMVA model. The associated rate riders will be calculated in the DVA continuity schedule.

[12] Effective May 23, 2017, per the OEB's letter titled *Guidance on Disposition of Accounts 1588 and 1589* , applicants must reflect RPP Settlement true-up claims pertaining to the period that is being requested for disposition in Accounts 1588 and 1589 . This is to include true ups that impact the GA as well. The amount requested for disposition starts with the audited account balance. If the audited account balance does not reflect the true-up claims for that year, the impacts of the true-up claims are to be shown in the Adjustment column in that year. Note that this true-up claim will need to be reversed in the amount requested for disposition in the following year. However, if the RPP Settlement true-up claim was not reflected at the end of the last year of the account balance that was previously disposed, then no adjustment would have to be made in the first year at the beginning of the current period being requested for disposition. This way the adjustment is appropriately captured in the last year of the previously disposed period and the first year of the current period requested for disposition.

Note that if a distributor has any balance in Account 1589 that pertains to Class A, this must be excluded from the balance requested for disposition.

December 31, 2017 - Reconciliation of Sale of Electricity and Cost of Power Expense
Filing Requirement 2.9 - Deferral and Variance Accounts

The sale of electricity and cost of power expense have been reconciled to the Audited Financial Statements and the net profit is zero as shown in the tables below.

The IESO Global Adjustment charge is pro-rated into the RPP and Non-RPP portions.

Table 1: Sale of Electricity and Cost of Power Expense

SALE OF ELECTRICITY		
USofA		**Dec 31 2017 RRR ($,000's)**
4006	Residential Energy Sales	-474,761
4010	Commercial Energy Sales	-1,569,021
4020	Energy Sales to Large Users	-181,584
4025	Street Lighting Energy Sales	-19,279
4035	General Energy Sales	-251,022
4050	Revenue Adjustment	39,211
4062	Billed WMS	-100,285
4066	Billed NW	-151,982
4068	Billed CN	-113,436
4075	Billed - LV	0
	Total Sale of Electricity Revenue	**-2,822,160**
	Board filing 2.1.13 Sale of Electricity	**-2,822,160**
COST OF POWER EXPENSE		
USofA		**Dec 31 2017 RRR ($,000's)**
4705	Power Purchased	1,172,692
4707	Charges - Global Adjustment	1,283,765
4708	Charges-WMS	100,285
4714	Charges-NW	151,982
4716	Charges-CN	113,436
4750	Charges - LV	0
	Total Cost of Power Expense	**2,822,160**
	Board filing 2.1.13 Cost of Power Expense	**2,822,160**

December 31, 2017 - Sale of Electricity and Cost of Power Expense
THESL Audited Financial Statements (AFS) Mapped to USofA Accounts
Filing Requirement 2.9 - Deferral and Variance Accounts

The sale of electricity and cost of power expense have been reconciled to the Audited Financial Statements and the net profit is zero as shown in the tables below.
reconciled to the RRR filed Sale of electricity and Cost of power expense OEB accounts.

Table 2: USofA Balances Mapped and Reconciled to the AFS - Sale of Electricity and Cost of Power Expense - Year ended December 31, 2017

	THESL Consolidated Audited 2017	Less: Net Movement adjustment	Adjusted THESL Consolidated Audited 2017	Dec 31 2017 RRR	Difference	Notes
	($,000s) (1)	($,000s) (2)	($,000s) (3)=(1)-(2)	($,000s) (4)	($,000s) (5)=(3)-(4)	
Sale of electricity	-3,017,754	-28,013	-2,989,741	**-2,822,160**	-167,581	**1**
Cost of power expense	3,063,485	73,744	2,989,741	**2,822,160**	167,581	**2**

Note 1: "Sale of electricity" difference of ($167,581): Adjusted AFS balance of ($2,989,741) versus RRR balance of ($2,822,160), as follows: **($,000s)**

For RRR Reporting, THESL booked to "Cost of Power expense" the amount of the IESO settlement invoices charge type 142, in the credit amount of $167,581.
For the AFS, THESL book IESO settlement invoices charge type 142 to COP revenue. -167,581

Note 2: "Cost of power expense" difference of $167,581: Adjusted AFS balance of $2,989,741 versus RRR balance of $2,822,160, as follows: **($,000s)**

For RRR Reporting, THESL booked to "Cost of Power expense" the amount of the IESO settlement invoices charge type 142, in the credit amount of $167,581.
For the AFS, THESL book IESO settlement invoices charge type 142 to COP revenue. 167,581

Rate Riders Development

	% to split by Class	Total	Residential	CS Muti-Units Residential	GS < 50 kW	GS - 50 to 999 kW	GS > 1,000 to 4,999 kW	Large User =>5,000 kW	Street Lighting	USL (Connections)	USL (Customer)
	Allocators										
	2016 kWh	100.0%	20.0%	0.9%	9.6%	40.6%	19.4%	8.8%	0.5%	0.2%	0.0%
	2017 Distribution Revenue	100.0%	39.7%	3.7%	14.2%	27.0%	8.5%	4.4%	2.0%	0.5%	0.0%
	2020 Revenue Offsets	100.0%	49.2%	4.0%	20.4%	18.3%	3.5%	1.5%	2.3%	0.8%	0.0%
	2009/10 Reg Assets Allocation	100.0%	18.2%	0.7%	8.2%	42.4%	19.6%	10.2%	0.5%	0.2%	0.0%
	2013 Non-RPP kWh	100.0%	2.1%	0.0%	2.4%	48.3%	31.0%	15.4%	0.8%	0.0%	0.0%
	LRAMVA	100.0%	7.2%	0.3%	29.8%	48.2%	7.3%	7.3%	0.0%	0.0%	0.0%
	2013 SM Entity Rider Recovery	100.0%	85.2%	5.2%	9.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Stranded Meters	100.0%	51.4%	0.0%	31.8%	16.8%	0.0%	0.0%	0.0%	0.0%	0.0%
	2020 kWh forecast	100.0%	19.3%	1.2%	9.7%	41.0%	19.5%	8.6%	0.5%	0.2%	0.0%
	Monthly Billing Conversion	100.0%	89.6%	0.0%	10.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Distribution Revenue GS>50 kW	100.0%	0.0%	0.0%	0.0%	63.6%	20.0%	10.5%	4.7%	1.2%	0.0%
	AR Credits	100.0%	83.5%	0.0%	15.0%	1.5%	0.0%	0.0%	0.0%	0.0%	0.0%
	Other Allocators 5	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Other Allocators 6	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Other Allocators 7	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Other Allocators 8	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Other Allocators 9	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

	RA Balance by Class	Allocators (Drop Down)	Total	Residential	CS Muti-Units Residential	GS < 50 kW	GS - 50 to 999 kW	GS > 1,000 to 4,999 kW	Large User =>5,000 kW	Street Lighting	USL (Connections)	USL (Customer)	
1	Stranded Meters	Stranded Meters	- 1,387,244	- 713,195	-	- 441,086	- 232,962	-	-	-	-	-	/C
2	Wireless pole attachments Rev	2020 Revenue Offsets	- 642,230	- 316,243	- 25,559	- 131,157	- 117,558	- 22,533	- 9,534	- 14,644	- 5,003	-	/C
3	Impact for USGAAP (Actuarial loss on OPEB)	2017 Distribution Revenue	85,260,576	33,832,134	3,161,726	12,064,619	23,036,048	7,256,312	3,784,727	1,690,071	434,940	-	/C
4	IFRS-CGAAP PP&E	2017 Distribution Revenue	- 1,558,360	- 618,371	- 57,789	- 220,512	- 421,044	- 132,628	- 69,176	- 30,890	- 7,950	-	
5	CRRRVA	2017 Distribution Revenue	- 59,426,130	- 23,580,802	- 2,203,705	- 8,408,970	- 16,055,993	- 5,057,608	- 2,637,933	- 1,177,969	- 303,151	-	
6	Monthly Billing (OpEx)	Monthly Billing Conversion	15,845,692	14,205,293	-	1,640,399	-	-	-	-	-	-	
7	Monthly Billing	Monthly Billing Conversion	- 4,041,544	- 3,623,150	-	- 418,394	-	-	-	-	-	-	
8	External Driven Capital	2017 Distribution Revenue	- 2,331,134	- 925,014	- 86,446	- 329,862	- 629,835	- 198,397	- 103,479	- 46,209	- 11,892	-	
9	OPEB cash vs accrual	2017 Distribution Revenue	8,945,000	3,549,453	331,708	1,265,743	2,416,796	761,286	397,070	177,312	45,631	-	
10	Derecognition	2017 Distribution Revenue	- 42,070,982	- 16,694,129	- 1,560,122	- 5,953,166	- 11,366,908	- 3,580,555	- 1,867,536	- 833,949	- 214,617	-	
11	Deferred Gain on disposals	2017 Distribution Revenue	- 11,749,417	- 4,662,270	- 435,705	- 1,662,577	- 3,174,505	- 999,963	- 521,558	- 232,902	- 59,937	-	
12	Operations Consolidation Plan Sharing Variance	2017 Distribution Revenue	- 71,134,277	- 28,226,696	- 2,637,879	- 10,065,706	- 19,219,347	- 6,054,058	- 3,157,659	- 1,410,053	- 362,878	-	
13	Excess Expansion Deposits	Distribution Revenue GS>50 kW	- 5,473,272	-	-	-	- 3,482,742	- 1,097,057	- 572,200	- 255,516	- 65,757	-	
14	AR Credits	AR Credits	- 3,407,868	- 2,844,480	-	- 510,430	- 52,044	- 415	-	-	- 499	-	
	Total		- 93,171,192	- 30,617,471	- 3,513,770	- 13,171,100	- 29,300,095	- 9,125,615	- 4,757,278	- 2,134,750	- 551,113		

Note: The rate riders table (Exhibit 9, Tab 3, Schedule 1) lists all forecasted regulatory account balances proposed for clearance by THESL over the 2020-2024 period ($93.2M). The other two schedules are subsets of this list. The summary of amounts proposed for disposition of $78.0 million (Exhibit 9, Tab 1, Schedule 1) excludes accounts for which balances are not expected to recur. The continuity schedule total of $69.6 million (Exhibit 9, Tab 2, Schedule 1) lists only the regulatory accounts previously approved by the OEB for tracking.

	Load / Customers / Devices / Connections Forecast		Total	Residential	CS Muti-Units Residential	GS < 50 kW	GS - 50 to 999 kW	GS > 1,000 to 4,999 kW	Large User =>5,000 kW	Street Lighting	USL (Connections)	USL (Customer)
	2020 Forecast Dist Billing Determinants (Jan - Dec)											
	kVA		40,408,069	NA	NA	NA	24,899,249	10,392,864	4,789,334	326,622	NA	-
	kWh		23,371,287,137	4,510,636,914	277,127,203	2,267,638,936	9,587,728,582	4,561,528,177	2,009,923,443	115,390,403	41,313,479	-
	Number of Customers		784,331	615,965	85,161	71,499	10,374	430	44	1	-	857
	Devices/Connections		177,564	NA	NA	NA	NA	NA	NA	165,292	12,272	-

	Rate Riders	RR Pass-through or not	Proposed Recovery Period (years)	Amount	Allocators	Rate Rider Start Year	Rate Rider End Year	Billing Unit	Residential	CS Muti-Units Residential	GS < 50 kW	GS - 50 to 999 kW	GS > 1,000 to 4,999 kW	Large User =>5,000 kW	Street Lighting	USL (Connections)	USL (Customer)
	Volumetric Rate Riders																
1	Stranded Meters	Not Pass-through	5.00	- 1,387,244	Stranded Meters	2020	2024	Customers [1]	- 0.02	-	- 0.10	- 0.37	-	-	-	-	-
2	Wireless pole attachments Rev	Not Pass-through	5.00	- 642,230	2020 Revenue Offsets	2020	2024	Cust.+ Usage [1]	- 0.01	-	- 0.00001	- 0.00090	- 0.00040	- 0.00040	- 0.00880	- 0.00002	-
3	Impact for USGAAP (Actuarial loss on OPEB)	Not Pass-through	5.00	85,260,576	2017 Distribution Revenue	2020	2024	Cust.+ Usage [1]	0.90	0.61	0.00106	0.18250	0.13770	0.15590	1.02070	0.00211	-
4	IFRS-CGAAP PP&E	Not Pass-through	5.00	- 1,558,360	2017 Distribution Revenue	2020	2024	Cust.+ Usage [1]	- 0.02	- 0.01	- 0.00002	- 0.00330	- 0.00250	- 0.00280	- 0.01870	- 0.00004	-
5	CRRRVA	Not Pass-through	5.00	- 59,426,130	2017 Distribution Revenue	2020	2024	Cust.+ Usage [1]	- 0.63	- 0.43	- 0.00074	- 0.12720	- 0.09600	- 0.10860	- 0.71140	- 0.00147	-
6	Monthly Billing (OpEx)	Not Pass-through	5.00	15,845,692	Monthly Billing Conversion	2020	2024	Cust.+ Usage [1]	0.38	-	0.00014	-	-	-	-	-	-
7	Monthly Billing	Not Pass-through	5.00	- 4,041,544	Monthly Billing Conversion	2020	2024	Cust.+ Usage [1]	- 0.10	-	- 0.00004	-	-	-	-	-	-
8	External Driven Capital	Not Pass-through	5.00	- 2,331,134	2017 Distribution Revenue	2020	2024	Cust.+ Usage [1]	- 0.02	- 0.02	- 0.00003	- 0.00500	- 0.00380	- 0.00430	- 0.02790	- 0.00006	-
9	OPEB cash vs accrual	Not Pass-through	5.00	8,945,000	2017 Distribution Revenue	2020	2024	Cust.+ Usage [1]	0.09	0.06	0.00011	0.01910	0.01440	0.01640	0.10710	0.00022	-
10	Derecognition	Not Pass-through	5.00	- 42,070,982	2017 Distribution Revenue	2020	2024	Cust.+ Usage [1]	- 0.45	- 0.30	- 0.00053	- 0.09010	- 0.06800	- 0.07690	- 0.50370	- 0.00104	-
11	Deferred Gain on disposals	Not Pass-through	5.00	- 11,749,417	2017 Distribution Revenue	2020	2024	Cust.+ Usage [1]	- 0.12	- 0.08	- 0.00015	- 0.02510	- 0.01900	- 0.02150	- 0.14070	- 0.00029	-
12	Operations Consolidation Plan Sharing Variance	Not Pass-through	5.00	- 71,134,277	2017 Distribution Revenue	2020	2024	Cust.+ Usage [1]	- 0.75	- 0.51	- 0.00089	- 0.15230	- 0.11490	- 0.13010	- 0.85160	- 0.00176	-
13	Excess Expansion Deposits	Not Pass-through	5.00	- 5,473,272	Distribution Revenue GS>50 kW	2020	2024	Cust.+ Usage [1]	-	-	-	- 0.02760	- 0.02080	- 0.02360	- 0.15430	- 0.00032	-
14	AR Credits	Not Pass-through	5.00	- 3,407,868	AR Credits	2020	2024	Cust.+ Usage [1]	- 0.08	-	- 0.00005	- 0.00040	-	-	-	-	-

[1] "Customers" means Residential, GS < 50 kW and GS 50 to 999 kW rates recovery are based on $/cust/30 days
[1] "Cust.+Usage" means Residential and CSMUR rates recovery are based on $/cust/30 days and all other Rate classes recovery are based on $/kWh or $/kVA or $/Device or $/Connection

Exhibit U List / Table of Contents

Tab	Schedule	App.	Section	
1A	**APPLICATION UPDATE ADMINISTRATION AND RATIONALE**			
	1		Table of Contents	
	2		Application Update Summary	
		A	Application Update Commitments	
1B	**OUTCOMES AND PERFROMANCE**			
	1		Outcomes and Performance Management	
			1 Overview	
			2 Electricity Distributor Scorecard ("EDS")	
			3 2020-2024 Custom Performance Measures	
			4 Service Quality Performance	
			5 Reliability Performance	
			6 2015-2019 DSP Performance Measures	
			7 2018 Corporate Scorecard Update	
1C	**FINANCIAL INFORMATION**			
	1		Financial Information Overview	
	2		2018 Financial Statements and Notes	
	3		2018 RRR Reconciliation	
	4		THC 2017 and 2018 Management Discussion and Analysis	
	5		THC 2018 Annual Information Form	
2	**RATE BASE AND CAPITAL EXPENDITURES**			
	1		Rate Base Variance Overview	
			1 Rate Base Update	
			2 Gross Assets	
			3 Working Capital Allowance	
		A	In-Service Additions for the 2015-2019 Plan	
		B	OEB Appendix 2-BA Fixed Asset Continuity Schedules	+ excel
		C	Gross Assets by USoA	
	2		Capital Expenditures Variance Analysis	
			1 Capital Expenditure	
			2 System O&M	
		A	OEB Appendix 2-AA: Capital Projects Summary	+ excel
		B	OEB Appendix 2-AB: Capital Expenditure Summaries	+ excel
		C	OEB Appendix 2-AB: Capital Expenditure Summaries (JTC1.2 Version)	+ excel
	3		Overhead Costs Overview	
		A	OEB Appendix 2-D: Overhead Expenses	+ excel
3	**OPERATING REVENUE**			
	1		Load, Customers, and Revenues	
		A	OEB Appendix 2-IB: Customer, Connections, Load Forecast and Revenues Data and Analysis	+ excel
		B	CDM Plan Detailed List of Programs, Election of Funding Mechanism and Annual Milestones	+ excel
		C	IESO Verified CDM Savings	+ excel
		D	Approved CDM Plan	+ excel
		E	CDM Load Forecast to LRAM Reconciliation	+ excel
		F	Regression Model Input Data	+ excel
		G	Regression Model Statistical Results	+ excel
	2		Revenue Offsets	
		A	OEB Appendix 2-H: Other Operating Revenues	+ excel
4A	**OPERATING COSTS: OM&A**			
	1		Operating Costs: OM&A Variance Overview	
			1 OM&A Overview	
			2 OM&A Programs and Expenditures	
		A	OEB Appendix 2-JA: Summary of Recoverable OM&A Expenses	+ excel
		B	OEB Appendix 2-JB: Recoverable OM&A Cost Driver Table	+ excel
		C	OEB Appendix 2-JC: OM&A Programs Table	+ excel

- D OEB Appendix 2-L: Recoverable OM&A Cost per Customer per FTE + excel
- 2 Non-Affiliate Services
- 3 Workforce Staffing and Compensation
  - A OEB Appendix 2-K: Employee Costs Table + excel
  - B OEB Detailed Appendix 2-K: Employee Costs Table
  - C Actuarial Valuation Report 2018
- 4 Shared Services
  - A OEB Appendix 2-N: Shared Services and Corporate Cost Allocation + excel

4B OPERATING COSTS: DEPRECIATION AND PILs

- 1 Depreciation
  - 1 Depreciation and Amortization
  - 2 Decrecognition
  - A Summary of Depreciation Expense + excel
  - B OEB Appendix 2-C: Depreciation and Amortization Expense + excel
- 2 PILs
  - 1 Corporate Taxes

5 COST OF CAPTIAL

- 1 Cost of Capital

6 REVENUE REQUIREMENT

- 1 Revenue Requirement
  - 1 Base Revenue Requirement
  - 2 Overall Revenue Deficiency

7 COST OF CAPTIAL

- 1 Cost Allocation
  - A Cost Allocation Model + excel

8 RATE DESIGN

- 1 Rate Design Variance Overview
  - 1 Rate Design
  - 2 Bill Impacts Tables
  - A OEB Appendix 2-W: Bill Impacts + excel

9 DEFERRAL AND VARIANCE ACCOUNTS

- 1 Deferral and Variance Accounts Overview
  - 1 Summary of DVA Balances
  - 2 Carrying Charges
  - 3 Disposition of Accounts
  - 4 Toronto Hydro Seeks Clearance of Group 1 Accounts
  - 5 Summary of Proposed DVA Dispositions
  - 6 Rate Riders
  - 7 2018 Earnings Sharing Mechanism ("ESM") Calculation
  - A DVA Continuity Schedule + excel
  - B GA Analysis Workform + excel
  - C Account 1595 Workform + excel
  - D Group 1 DVA Rate Rider Model + excel
  - E Group 2 DVA Rate Rider Table + excel
  - F Energy Sales and Cost of Power

APPLICATION UPDATE SUMMARY

1. INTRODUCTION

Since filing its 2020-2024 Custom IR Application ("the Application") in August of 2018, Toronto Hydro has (i) received final approval for 2019 rates, (ii) closed-out its 2018 financial and operational year, and (iii) begun to execute its operational plans for the final year (2019) of the utility's 2015-2019 Custom IR rate period. This update amends Toronto Hydro's evidence to reflect these developments.

This standalone submission (Exhibit U, or "the Exhibit") provides 2018 actuals for key financial figures in the Application. These update items were previously outlined in Toronto Hydro's response to interrogatory 1A-Staff-1. The Exhibit also provides 2018 performance measure results and an updated 2018 Earnings-Sharing Mechanism calculation. For the remaining forecast period, Toronto Hydro has updated a subset of 2019 and 2020-2024 figures where the consequential impacts of 2018 actuals are material, or where the utility has made a prior commitment to update the information.[1] For example, updated items also include the 2019-2024 Load Forecast and 2020-2024 Bill Impacts. Otherwise, Toronto Hydro is not proposing any changes to its 2020-2024 business plan.

A Table of Contents for the update can be found at Exhibit U, Tab 1A, Schedule 1. For reference purposes, the Exhibit is organized to mirror the structure of the exhibits initially filed, i.e. Exhibits 1A through 9. For example, updates related to the Distribution System Plan, filed at Exhibit 2B, are provided in Tab 2; those associated with Operating Costs:

[1] Appendix A to this schedule identifies all commitments made to date with respect to updates to be included in this filing, and provides references to where this updated information can be found in this Exhibit.

OM&A, filed at Exhibit 4A, are provided in Tab 4A. Variance explanations for the updated figures are embedded throughout the respective schedules.

There are several changes to the 2019 bridge and 2020 test year forecasts that the utility expects will have an impact on the 2020 revenue requirement. These changes are discussed throughout the schedules in this Exhibit and are summarized in Tab 6. Toronto Hydro is accordingly amending its application to reflect these changes. However, the net impact to revenue requirement of these changes is estimated to be less than the utility's materiality threshold. Therefore, Toronto Hydro is not updating its 2020 revenue requirement at this time. Toronto Hydro proposes to flow these changes through the revenue requirement work form and cost allocation models as part of the Draft Rate Order process.

2. UPDATE OVERVIEW

This update reflects the completion of the fourth out of five years of the utility's 2015-2019 Custom IR period. Results from 2018 indicate that the utility remains on pace to successfully execute its five-year Distribution System Plan. This is demonstrated across outcome categories, as well as through the utility's success in managing the most challenging series of adverse weather events experienced in a single year since 2013. Tab 1B of this update provides a complete overview of outcome performance results for 2018.

2.1 Update on the Execution of the 2015-2019 Capital Expenditure Plan

Toronto Hydro's capital expenditures in 2018 were $435.6 million and the utility is on track for $443.0 million in investments in 2019. This puts the utility on pace for $2,379.4 million in total capital expenditures during the 2015-2019 period, which is

virtually unchanged from the $2,383.5 previously forecast in this application. Variance analysis for 2018-2019 is provided in Tab 2, Schedule 2 of this update.

As noted in Tab 2, Schedule 1, the utility is projecting total in-service additions for the 2015-2019 period to be within one percent of the amount which formed the basis of the OEB-approved capital related revenue requirement ("CRRR") for 2015-2019. Changes in project energization timing in 2018-2019 have contributed to slightly lower than forecast rate base amounts in these years, and have generated an increase of $18.5 million in the amount that Toronto Hydro is requesting be returned to customers through disposition of the CRRR Variance Account. (For a full summary of updates to DVAs, please refer to Tab 9 of this Exhibit.) Despite these changes in project energization timing, Toronto Hydro expects the actual Net Fixed Assets component of its 2020 opening rate base to be within one percent of the originally filed amount.

2.2 2018 OM&A Results

Toronto Hydro's Operations, Maintenance, and Administration ("OM&A") expenditures in 2018 were $268.3 million, which is 2.7 percent higher than the $261.2 million initially forecasted in Exhibit 4A of this application. The Emergency Response program had the largest variance in 2018 as a result of the utility having to respond to four extreme weather events throughout the year. The financial impact due to extreme weather was offset by one-time reductions in other OM&A programs such as Supply Chain and Customer Care. Tab 4A, Schedule 1 of this update explains the material changes to the program expenditures resulting from the 2018 OM&A results.

2.3 Earnings Sharing Mechanism ("ESM") Update

The utility did not surpass its ESM threshold in 2018. Toronto Hydro has provided an updated ESM calculation for 2018 in Tab 9, Schedule 1, Section 7.

2.4 Load Forecast and Revenue Offsets Updates

Toronto Hydro updated its load and customer growth forecasts as detailed in Tab 3, Schedule 1. There is no change to the growth factor component of Toronto Hydro's proposed custom rate-setting formula for 2021-2024 rates.

Revenue offsets in 2018 were $3.3 million higher than originally forecast in this application. The difference was primarily due to higher revenues from pole attachments and accident claims. As discussed in the Revenue Offsets Variance Analysis schedule (Exhibit U, Tab 3, Schedule 2), changes to revenue offsets in 2019 are expected to carry-forward into 2020. One of these changes is driven by the recently finalized revisions to the OEB's Customer Service Rules. Toronto Hydro is requesting that these changes, which impact 2020 revenue requirement, be approved by the OEB as part of the 2020 test year.

2.5 Bill Impacts Update

As a result of the variances and forecast updates detailed in this Exhibit, there is a reduction to the proposed average annual bill impact for 2020-2024. Toronto Hydro's five-year proposal would result in an average annual increase of $0.52 (1.1 percent) on the distribution portion of the Residential bill. This compares to $0.77 (1.7 percent) set out in the originally filed application. For the first year of the plan, Residential customers would experience a decrease of $3.53. This compares to a decrease of $3.10 set out in the originally filed application. It may be possible to further smooth the effects of the rate decrease in the first year of the plan followed by successive modest increases, though to

do so may involve a departure from typical deferral and variance account clearance approaches.

Table 3 provides a summary of the total bill impacts for typical customers in all classes.

Table 3: Bill Impacts – Change in Monthly Bill

	Change in bill	2020 Proposed	2021 Proposed	2022 Proposed	2023 Proposed	2024 Proposed
Residential	$/30 days	-3.53	0.99	1.12	1.40	1.92
	%	*-2.7*	*0.8*	*0.9*	*1.1*	*1.5*
Competitive Sector Multi-Unit Residential	$/30 days	-1.74	1.01	0.89	0.99	1.51
	%	*-2.5*	*1.5*	*1.3*	*1.4*	*2.1*
General Service <50 kW	$/30 days	-5.29	2.22	2.82	4.40	4.82
	%	*-1.6*	*0.7*	*0.9*	*1.3*	*1.4*
General Service 50-999 kW	$/30 days	-442.30	262.16	49.57	87.53	84.57
	%	*-3.1*	*1.9*	*0.4*	*0.6*	*0.6*
General Service 1,000-4,999 kW	$/30 days	-4,334.08	2,782.72	408.13	720.88	696.44
	%	*-2.8*	*1.9*	*0.3*	*0.5*	*0.5*
Large Use	$/30 days	-406.96	-1,054.39	2,102.70	3,713.96	3,588.48
	%	*-0.1*	*-0.1*	*0.3*	*0.5*	*0.5*
Street Lighting	$/30 days	-7,309.35	6,962.19	3,587.48	6,323.55	6,152.69
	%	*-2.5*	*2.5*	*1.2*	*2.2*	*2.0*
Unmetered Scattered Load	$/30 days	-6.04	0.82	0.80	1.42	1.37
	%	*-9.3*	*1.4*	*1.4*	*2.4*	*2.2*

APPENDIX A: APPLICATION UPDATE COMMITMENTS

Commitment Reference	Details	Application Update Reference
Exhibit 1A, Tab 3, Schedule 1, App B	Rate Framework (Exhibit 1B, Tab 4, Schedule 1)	No change at this time
	Income Tax/PILs Workform (Exhibit 4B, Tab 2, Schedule 2)	Exhibit U, Tab 4B, Schedule 2 and Schedule 4
	Rate Design (Exhibit 8, Tab 1, Schedule 1)	Exhibit U, Tab 8, Schedule 1
	Wireline Pole Attachment Rate (Exhibit 8, Tab 2, Schedule 1)	Exhibit U, Tab 8, Schedule 1
	Deferral and Variance Accounts – Retail Settlement Variance Accounts (Exhibit 9, tab 1, Schedule 1)	Exhibit U, Tab 9, Schedule 1
	Deferral and Variance Accounts – Lost Revenue Adjustment Mechanism Variance Account (Exhibit 9, Tab 1, Schedule 1)	Exhibit U, Tab 9, Schedule 1
	Carrying Charges (Exhibit 9, Tab 1, Schedule 1)	Exhibit U, Tab 9, Schedule 1
	Earning Sharing Mechanism ("ESM") – 2018 Calculation (Exhibit 1B, Tab 4, Schedule 1)	Exhibit U, Tab 9, Schedule 1
	ESM – 2019 Calculation (Exhibit 1B, Tab 4, Schedule 1)	To be updated as part of Toronto Hydro's 2021 annual rate application
	2018 Financial Figures	Exhibit U
1A-Staff-1	Outcomes and Performance	Exhibit U, Tab 1B, Schedule 1
	Capital Expenditures (OEB Appendix 2-AA and 2-AB	Exhibit U, Tab 2, Schedule 2, App A and B
	Overhead Expense (OEB Appendix 2-D)	Exhibit U, Tab 2, Schedule 3, App A
	Fixed Asset Continuity Schedule (OEB Appendix 2-BA)	Exhibit U, Tab 2, Schedule 1, App A
	Other Operating Revenues (OEB Appendix 2-H)	Exhibit U, Tab 3, Schedule 5
	OM&A Expenditures (OEB Appendix 2-JA to 2-JC	Exhibit U, Tab 4A, Schedule 1, App A to C
	Recoverable OM&A Cost per Customer and FTE (OEB Appendix 2-L)	Exhibit U, Tab 4A, Schedule 1, App D
	Employee Costs/Compensation Table (OEB Appendix 2-K)	Exhibit U, Tab 4A, Schedule 4, App A

Commitment Reference	Details	Application Update Reference
	Shared Services and Corporate Cost Allocation (OEB Appendix 2-N)	Exhibit U, Tab 4A, Schedule 5, App A
	Year-End Deferral and Variance Account balances for 2018 actuals (Exhibit 9)	Exhibit U, Tab 9, Schedule 1
1B-BOMA-23	Year-End 2018 Financial Information	Exhibit U
1B-BOMA-28	2018 Actuals for Efficiency Assessment, Total Cost per customer, and Total Cost per km of line	Not available at this time, see Exhibit U, Tab 1B, Schedule 1 for more details.
1B-BOMA-46 (b)	Toronto Hydro's 2018 Annual Short Term Debt Portion and Expense	No change at this time
1B-SEC-8	2018 Corporate Scorecard Results	Exhibit U, Tab 1B, Schedule 1, Section 6
1C-Staff-50	Annual RRR Submission	Exhibit U, Tab 1C, Schedule 3
	2018 Audited Financial Statements	Exhibit U, Tab 1C, Schedule 2
2A-Staff-53	Appendix 2-Z	No change at this time. See Exhibit U, Tab 2, Schedule 1, Section 3 for more details.
	Updated assumptions used for the cost of power calculation	No change at this time. See Exhibit U, Tab 2, Schedule 1, Section 3 for more details.
2A-AMPCO-12	2018 Actual Depreciation Expenses	Exhibit U, Tab 4B, Schedule 1 and Schedule 3
2A-AMPCO-15	Updated OEB Appendix 2-AA	Exhibit U, Tab 2, Schedule 2, App A
2A-BOMA-48	2018 actual year-end and actual Closing PP&E	Exhibit U, Tab 4B, Schedule 1 and Schedule 3
2A-BOMA-50	2018 System Access Capital Expenditures	Exhibit U, Tab 2, Schedule 2
2A-VECC-8	2018 Actual Year-end CWIP	Exhibit U, Tab 2, Schedule 2
2B-Staff-60	Updated Capital Expenditure Forecast for the 2015-2019 period	Exhibit U, Tab 2, Schedule 2
	Updated In-Service Additions for the 2015-2019 period	Exhibit U, Tab 2, Schedule 1, App A
3-Staff-101	Load Forecast update including actual load up to December 2018 in its regression model	Exhibit U, Tab 3
3-SEC-74	OEB Appendix 2-H	Exhibit U, Tab 3, Schedule 5
3-VECC-30	2018 year to date values for the schedules set out on pages 1-2 of Exhibit 3, Tab 2, Schedule 1.	Exhibit U, Tab 3, Schedule 2

Commitment Reference	Details	Application Update Reference
4A-Staff-133 (c)	Updated 2018 actuarial assumptions (OPEB costs)	Exhibit U, Tab 4A, Schedule 1 and Schedule 2, Section 1.20
4A-AMPCO-96 (a)(b)	2018 Corporate performance results	Exhibit U, Tab 1B,
4A-AMPCO-100 (a)	Updated Appendix 2-K including 2018 actuals	Exhibit U, Tab 4A, Schedule 4, App A
4A-AMPCO-104 (b)	2018 Actuals for Exhibit 4A, Tab 4, Schedule 4, p. 15, Table 7	Exhibit U, Tab 4A, Schedule 4
4A-AMPCO-105	2018 Actuals for Exhibit 4A, Tab 4, Schedule 4, p. 15, Table 8	Exhibit U, Tab 4A, Schedule 4
4A-PWU-12 (d)	Actual 2018 data for Exhibit 4A, Tab 4, Schedule 2, p. 1 (Appendix 2-K Table	Exhibit U, Tab 4A, Schedule 4
4A-SEC-75	Updated Appendix 2-JA, JB, and JC to include 2018 Actuals	Exhibit U, Tab 4A, Schedule 1, Appendix A to C
4A-VECC-32	Updated Table 1 (Historical OM&A by Program) for 2018 actual results at Exhibit 4A, Tab 1, Schedule 1, p. 2	Exhibit U, Tab 4A, Schedule 1
6-EP-59	2018 ESM Amounts at Exhibit 6, Tab 1, Schedule 6	Exhibit U, Tab 6, Schedule 1
9-Staff-160	In its update of DVA balances for 2018, include for disposition any 2018 balances in Account 1551	Exhibit U, Tab 9, Schedule 1
9-Staff-165	Completed version of the latest OEB issued DVA continuity schedule	Exhibit U, Tab 9, Schedule 2
TC, Day 4, Feb. 22nd, pp. 110-111	Update interrogatory responses to 3-VECC-25 and 3-VECC-26	Exhibit U, Tab 3, Schedule 1, App C and D
JTC2.8	2018 Actual Performance and Reliability metrics	Exhibit U, Tab 1B, Schedule 1
JTC2.25	2018 consolidated balance sheet	Toronto Hydro committed to provide the balance, however, it is not available at the time of the Application Update
JTC4.25.4	Unit Costs for 2018	Exhibit U, Tab 1B, Schedule 1

OUTCOMES AND PERFORMANCE MEASUREMENT VARIANCE ANALYSIS

1. OVERVIEW

This Schedule provides 2018 results for Toronto Hydro's performance measures. The evidence is structured as follows:

- Section 1: Overview
- Section 2: Electricity Distributor Scorecard Updates
- Section 3: 2020-2024 Custom Performance Measures Updates
- Section 4: Service Quality Updates
- Section 5: Reliability Performance Updates
- Section 6: 2015-2019 Distribution System Plan Measures Updates
- Section 7: 2018 Corporate Scorecard Update

As demonstrated in the pages that follow, Toronto Hydro's performance trends remained stable or positive in 2018 for the majority of measures.

2. ELECTRICITY DISTRIBUTOR SCORECARD ("EDS")

Table 1 below provides an updated EDS for 2018 results. Please note that these results are preliminary. Final results will be submitted later in 2019, in accordance with the OEB's usual timelines for scorecard reporting.

Table 1: Toronto Hydro EDS Performance – 2014-2018

Performance Outcomes	Performance Categories	Measures		2014	2015	2016	2017	2018	Target		Average
									Industry	Distributor	
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		91.50%	96.90%	97.70%	98.32%	99.80%	90.00%		96.84%
		Scheduled Appointments Met On Time		99.80%	99.90%	99.50%	99.37%	99.66%	90.00%		99.65%
		Telephone Calls Answered On Time		71.90%	76.80%	64.70%	77.92%	80.15%	65.00%		74.29%
	Customer Satisfaction	First Contact Resolution		81.00%	84.00%	86.00%	88.00%	89.00%			85.60%
		Billing Accuracy		96.62%	97.54%	98.86%	99.24%	99.25%	98.00%		98.30%
		Customer Satisfaction Survey Results		91.00%	91.00%	83.00%	83.00%	92.00%			88.00%
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness			71.00%	71.00%	69.00%	69.00%			70.00%
		Level of Compliance with Ontario Regulation 22/04		C	C	C	C	C		C	N/A
		Serious Electrical Incident Index	Number of General Public Incidents	3	0	0	1	6		2	2.00
			Rate per 10, 100, 1000 km of line	0.295	0	0	0.035	0.209		0.074	0.108
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted		0.89	0.99	0.91	0.91	0.81		1.11	0.90
		Average Number of Times that Power to a Customer is Interrupted		1.18	1.31	1.28	1.18	1.14		1.36	1.22
	Asset Management	Distribution System Plan Implementation Progress		147%	100%	101%	99%	95%			108.40%
	Cost Control	Efficiency Assessment		5	5	5	5				
		Total Cost per Customer		$967	$1,000	$1,044	$1,042				
		Total Cost per Km of Line		$70,688	$73,309	$27,819	$27,825				
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings			12.51%	34.58%	63.11%			1,576.05 GWh	
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		97.12%	100.00%	100.00%	81.08%	100.00%			95.64%
		New Micro-embedded Generation Facilities Connected On Time		100.00%	100.00%	100.00%	92.41%	100.00%	90.00%		98.48%
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.68	0.67	0.61	0.64	0.53			0.63
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.65	1.57	1.45	1.34	1.2			1.44
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.58%	9.30%	9.30%	9.30%	9.30%			N/A
			Achieved	7.41%	10.71%	12.18%	9.08%	9.33%			N/A

2.1 Service Quality: New Residential/Small Business Services Connected On Time

In 2018, Toronto Hydro continued its improved performance as exhibited over the CIR term. 2018 performance was 99.80 percent compared to 98.32 percent in 2017.

2.2 Service Quality: Schedule Appointments Met on Time

The 2018 performance improved relative to both 2016 and 2017 performance. In 2018, performance was at 99.66 percent compared to 99.37 percent in 2017 and 99.50 percent in 2016.

2.3 Service Quality: Telephone Calls Answered on Time

2018 performance continued its improved trend over the CIR term. In 2018, performance was 80.15 percent compared to the 2017 performance of 77.92 percent.

2.4 Customer Satisfaction: First Contact Resolution

In 2018, Toronto Hydro continued its improved performance trend. Over the period of 2013 to 2018 First Contact Resolution performance has improved by approximately 16 percent with 2018 performance at 89 percent.

2.5 Customer Satisfaction: Billing Accuracy

Similar to First Contact Resolution, Toronto Hydro's focus on customer outcomes has delivered annually improved outcomes for the Billing Accuracy measure. In 2018, Billing Accuracy was 99.25 percent compared to 99.24 percent in 2017 and 98.86 percent in 2016.

2.6 Customer Satisfaction: Customer Satisfaction Survey Results

In 2018, Toronto Hydro continued its efforts to improve its customer satisfaction results. These efforts resulted in 2018 performance improving to 92 percent compared to 83 percent in 2016-2017.

2.7 Safety: Level of Public Awareness of Electrical Safety

Public awareness of electrical safety maintained its 2017 level of 69 percent in 2018.

2.8 Safety: Compliance with Ontario Regulation 22/04

In 2018, Toronto Hydro maintained a level of 'Compliant' with Ontario Regulation 22/04.

2.9 Safety: Serious Electrical Incident Index

Toronto Hydro experienced a significant increase in the number of reported incidents in 2018. This increase was primarily driven by four traffic incidents which damaged poles and brought down primary distribution lines, which qualified as serious electrical incidences.

2.10 System Reliability: SAIDI/SAIFI

Toronto Hydro achieved improvements in both SAIDI and SAIFI in 2018. SAIDI was measured at 0.81, which is a reduction from the 0.91 in 2017 and 2016. SAIFI in 2018 reduced to 1.14 versus the 1.18 in 2017 and 1.28 in 2016. Reliability performance in 2018 is discussed in further detail in Section 5 below.

2.11 Asset Management: Distribution System Plan ("DSP") Implementation Progress

The DSP Implementation Progress metric measures Toronto Hydro's annual progress towards completing its 2015 to 2019 capital program. In 2018, Toronto Hydro capital expenditures equalled 95 percent of planned expenditures.

2.12 Efficiency Assessment

This 2018 results for this metric will not be finalized until September 2019.

2.13 Total Cost per Customer and Total Cost per km of Line

This 2018 results for this metric will not be finalized until September 2019.

2.14 Net Cumulative Energy Savings

The 2018 results for this metric will not be finalized until September 2019.

2.15 Connection of Renewable Generation

In 2018, Toronto Hydro completed 100 percent of Renewable Generation Connection Impact Assessments on time, and connected 100 percent of new Micro-Embedded Generation Facilities on time.

2.16 Financial Ratios

2.16.1 Current Ratio

The Current Ratio in 2018 was 0.53 compared to 0.64 in 2017. The slight reduction in this ratio reflects the issuance of approximately $240 million in debt.

2.16.2 Debt to Equity Ratio

The Debt to Equity Ratio was 1.20 in 2018 compared with 1.34 in 2017. The 2018 value reflects the provision of approximately $43 million in dividends in 2018.

2.16.3 Achieved Return on Equity

In 2018, the achieved return on equity was 9.33 percent compared to the OEB Approved 9.3 percent established in Toronto Hydro's 2015 to 2019 Custom IR application.

3. TORONTO HYDRO'S 2020-2024 CUSTOM PERFORMANCE MEASURES

Toronto Hydro's pre-filed evidence at Exhibit 2B, Section C2, detailed 15 custom measures for the 2020-2024 plan period. These measures are incremental to the measures contained in the EDS and the Electricity Service Quality Requirements ("ESQR"), for a total of 44 unique measures to be reported to the OEB annually. This section provides 2013 to 2018 data for the custom measures where historical information is available.

3.1 Customer Service

3.1.1 Number of Customers on eBills

As shown in Figure 1, as of the end of 2018, over 261,000 Toronto Hydro customers opted to receive eBills, this is an increase of over 300 percent in the last six years.

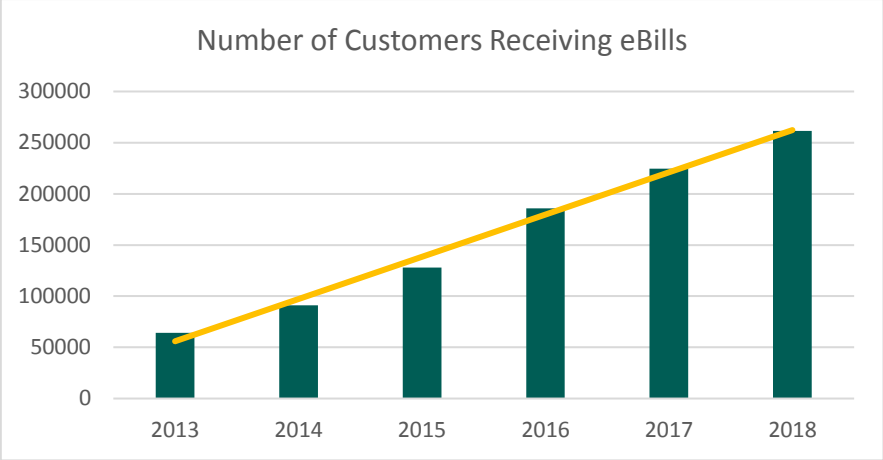


Figure 1: Number of Customers on eBills 2013 – 2018

3.2 Safety

3.2.1 Total Recordable Injury Frequency ("TRIF")

The TRIF measure tracks the proportion of recordable injuries to hours worked. Figure 2, below, illustrates Toronto Hydro's TRIF performance over the last five years.[1]

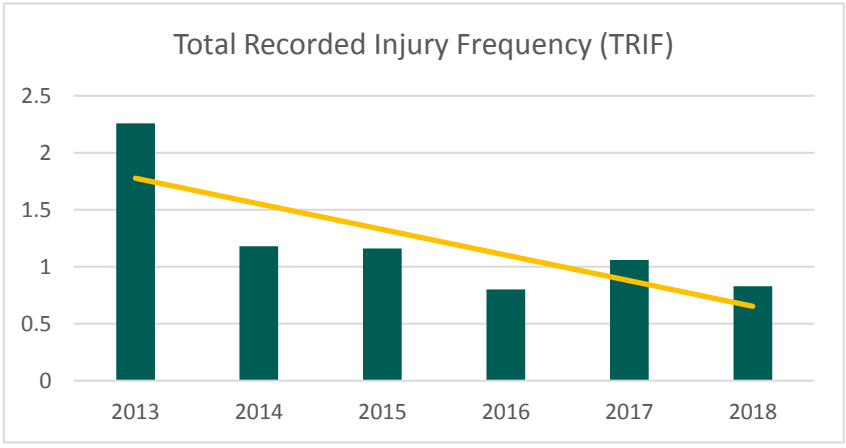


Figure 2: Total Recordable Injury Frequency Performance 2013 – 2018

[1] The TRIF is normalized to 200 hours- representing 100 workers working a 40-hour week for 50 weeks per year to allow for comparisons between companies utilizing this metric.

3.2.2 Box Construction Conversion[2]

The Box Construction Conversion measure tracks Toronto Hydro's performance on the reduction in the number of box construction poles in its distribution system. Between 2013 and 2018, the number of box construction poles were reduced from approximately 6,400 to approximately 2,900 as at the end of 2018.

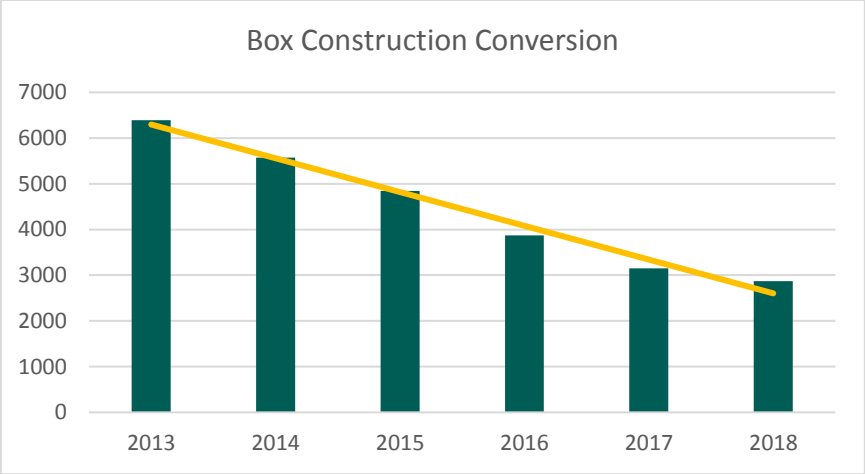


Figure 3: Box Construction Conversion Performance for 2013 - 2018

3.2.3 Network Units Modernization

The Network Units Modernization measure tracks Toronto Hydro's progress on the installation of network units that have submersible protectors. As shown in Figure 4, the percentage of modernized Network Units increased to 58 percent in 2018 from 56 percent in 2017.

[2] Please note that, due to recordkeeping limitations, the rate of box construction pole removals between 2013 and 2017 is inclusive of non-box framed poles on box-construction feeders.

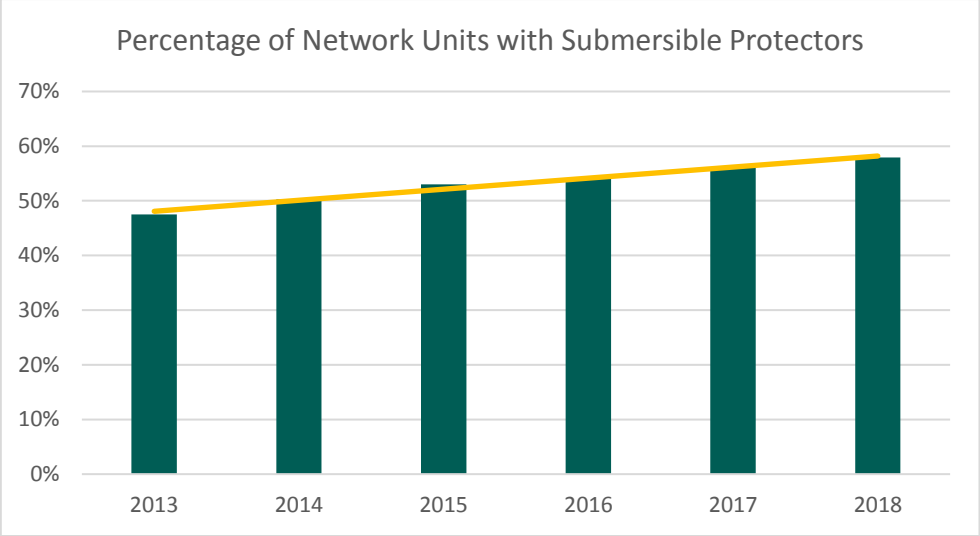


Figure 4: Network Unit Modernization: Percentage of Network Units with Submersible Protectors Performance for 2013-2018

3.3 Reliability

3.3.1 System Average Interruption Duration Index ("SAIDI") & System Average Interruption Frequency Index ("SAIFI") Resulting from Defective Equipment

As Figures 5 and 6, below, demonstrate, there was a slight improvement in the level of reliability related to Defective Equipment caused outages in these years. This is attributable to Toronto Hydro's investments in the system renewal programs. For a comprehensive discussion of Toronto Hydro's system renewal and modernization efforts, please refer to Exhibit 2B, Section E2.

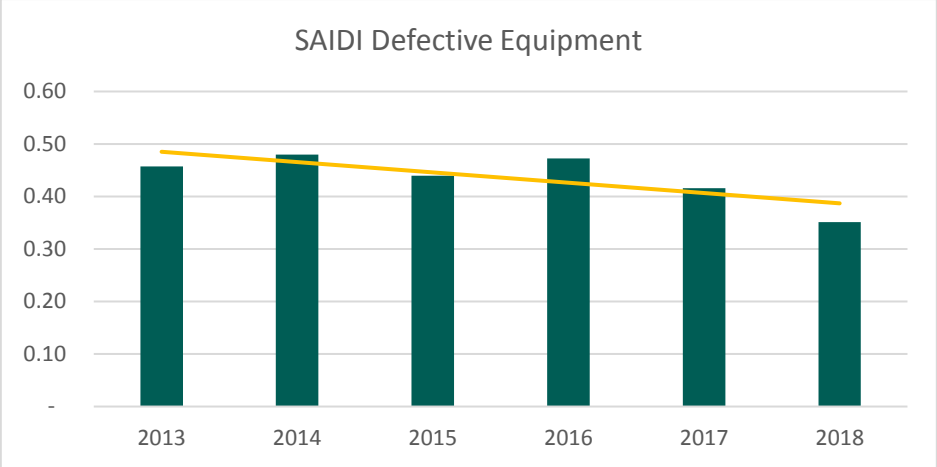


Figure 5: SAIDI (Defective Equipment) Performance 2013-2018

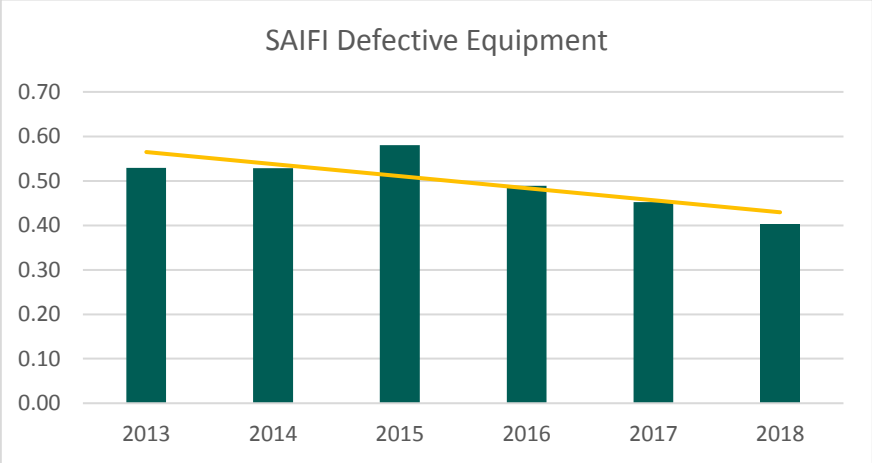


Figure 6: SAIFI (Defective Equipment) Performance 2013-2018

3.3.2 Feeders Experiencing Sustained Interruptions (FESI-7/6) - Worst Performing Feeders

FESI-7 System and FESI-6 Large Customer measures track the performance of feeders that experience the highest number of outages.[3] Between 2013 and 2018, FESI-7 System and

[3] These measures exclude interruptions caused by Major Event Days, Loss of Supply, scheduled outages, station bus-level interruptions and on the secondary side of the distribution transformer (e.g. on service wires or secondary bus).

FESI-6 Large Customers performance experienced a demonstrable improvement, as shown in Figures 7 and 8 below.

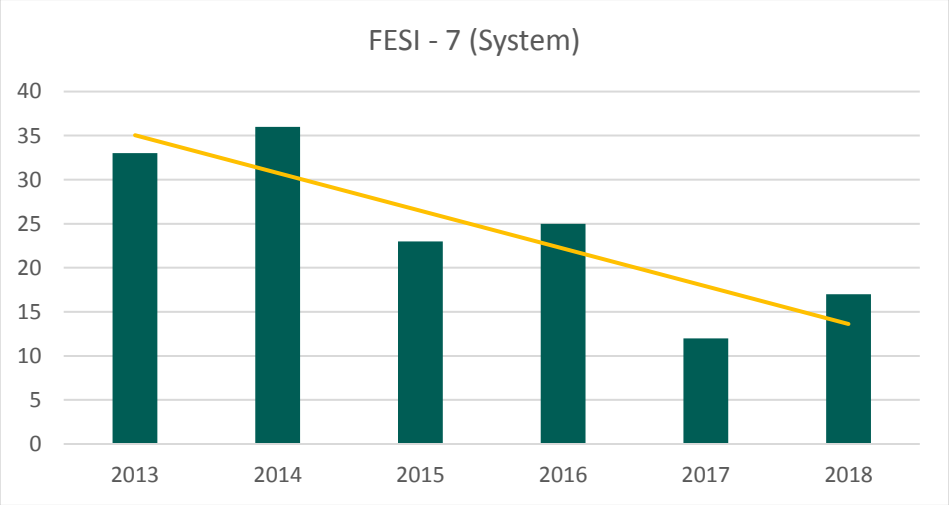


Figure 7: FESI-7 System Performance between 2013 and 2018

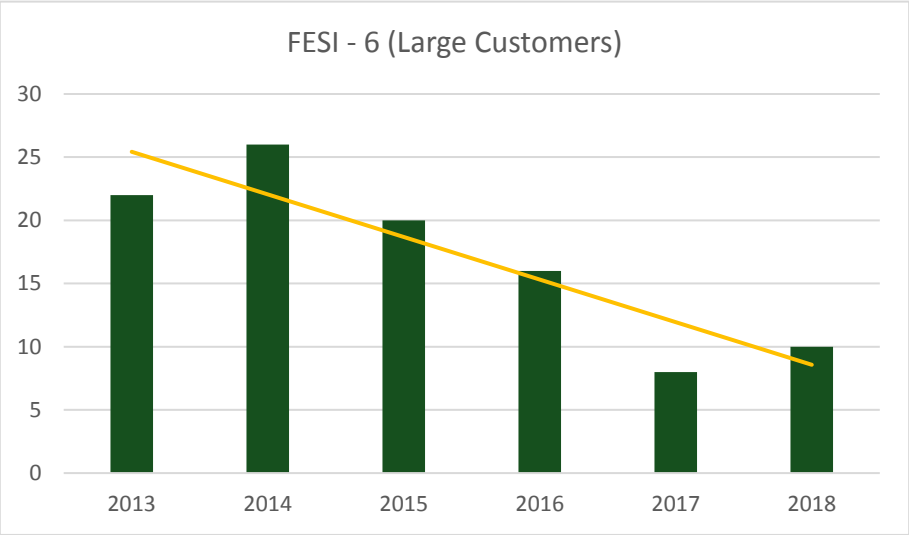


Figure 8: FESI-6 Large Customer Performance between 2013 and 2018

3.3.3 System Capacity

The System Capacity measure tracks potential capacity constraints at the station level by measuring the ability of each station to connect at least one large customer.[4] As seen in Figure 9 below, Toronto Hydro has averaged 15 stations with capacity constraints between 2013 and 2018, with a moderate deterioration in performance in 2018.

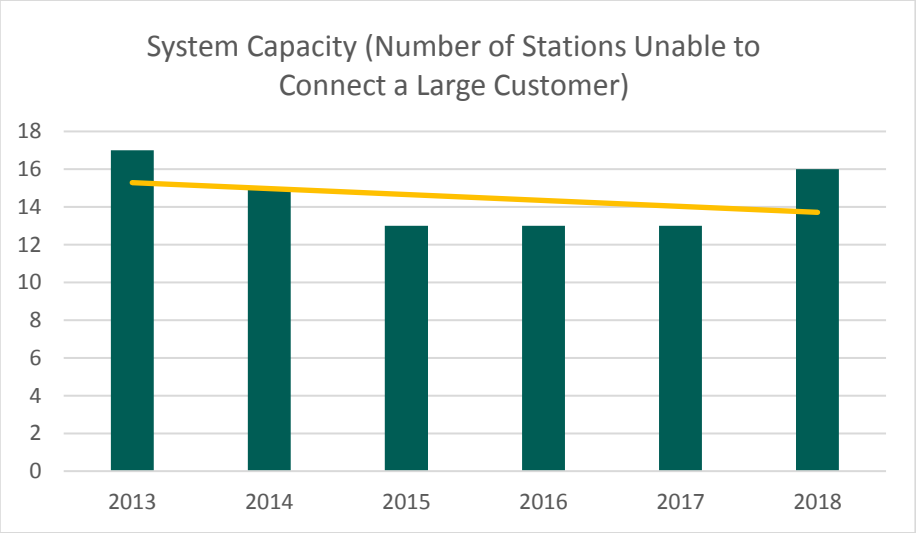


Figure 9: System Capacity (Number of Stations Unable To Connect a Large Customer) Performance for 2013 – 2018

3.3.4 System Health – Asset Condition (Wood Poles)

Toronto Hydro does not have updated asset condition assessment results at this time. As noted elsewhere in this update, Toronto Hydro migrated its data – including core asset data – to a new enterprise software system partway through 2018. As a result of this unique situation, the current state assessment of the distribution system assets for 2019 has not been completed as of this submission.

[4] Large customer for the purposes of this measure is defined as a customer with a peak load of approximately 10 MVA or higher.

3.3.5 Direct Buried Cable Replacement

The Direct Buried Cable Replacement measure will track the number of circuit-kilometres of direct buried cable that remains in the distribution system during the 2020-2024 plan period. As shown in Figure 10, as of year-end 2018, Toronto Hydro's underground distribution system contained approximately 774 circuit-kilometres of direct buried cable.

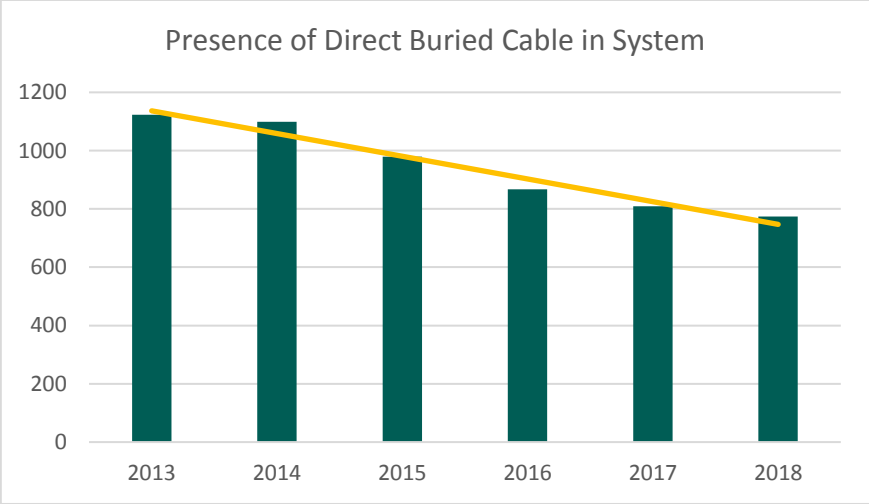


Figure 10: Presence of Direct Buried Cable 2013-2018

3.4 Financial

Toronto Hydro plans to monitor and publically report on the Average Wood Pole Replacement Cost and the Vegetation Management Cost per Kilometre over the 2020-2024 period. In its response to undertaking JTC4.25.4, Toronto Hydro committed to provide 2018 data for the unit costs reported into the UMS Unit Cost Study, which is inclusive of the aforementioned unit categories. See Table 2 below for the 2018 unit costs and an updated three-year average. While there is significant volatility in the year-over-year results, the data nonetheless demonstrates stable or improving unit cost performance over the last three years

Table 2: 2018 Unit Costs

	Category	Category (THESL Asset Name)	Per Unit of Measurement (i.e., each, per meter/foot, per kilometre/mile, per hectar, etc.)	2016		2017		2018		Updated 3-Yr Weighted Average Unit Cost
				Number of Units (if known)	Unit Costs (2016)	Number of Units (if known)	Unit Costs (2017)	Number of Units (if known)	Unit Costs (2017)	
1	Wooden Pole Replacement	Wooden Poles	Each	3592	$7,538	2759	$6,454	2066	$6,255	$6,868
3	UG XLPE Replacement	U-G Pri Cable- XLPE (In Duct)	Meter	311,618	$96	355284	$125	340874	$109	$110
5	Vegetation Management - Tree Trimming		Km	1,649	$2,137.0	1676	$2,147	1,364	$2,158	$2,147
7	Pole Test and Treat		Each	15,986	$17.55	14671	$18	10,308	$18	$18
8	Overhead Line Patrol & IR Scan		Kilometer	7,497	$44.0	7045	$44	7,147	$44	$44
9	Vault Inspection	Network Vault Inspection	Each	3,090	$345.0	3095	$355	3,101	$365	$355
		Submersible Vault Inspection	Each	2,770	$145.0	3073	$155	2,689	$165	$155
		Building Vault Inspection	Each	1,450	$320.0	1211	$330	1,576	$340	$330
10	OH Manual Switches	O-H Switches	Each	360	$26,359	371	$18,336	395	$17,967	$20,772
11	OH Remote/Motor Operated Switches									
12	Overhead (Poletop) Transformer Replacement	O-H Transformers	Each	804	$12,220	716	$10,969	465	$10,280	$11,314
13	Padmount Transformer Replacement	U-G Transformers	Each	579	$23,091	1060	$20,596	506	$29,100	$23,275
14	Underground (submersible and vault) Transformer Replacement									
15	Network Transformer Replacement	Network Unit (Tx & Protector)	Each	63	$106,034	62	$90,666	45	$84,846	$94,821
16	Network Protector Replacement									
17	Oil Breaker Replacement	Subst Eq Indr Brk	Each	4	$92,213	0	$-	6	$78,573	$84,029
18	SF6 Breaker Replacement									
19	Vacuum Breaker Replacement									
20	Station Switchgear (Air) Replacement	Subst Eq Swtch Air	Each	1	$1,374,809	2	$1,264,981	$1	$1,443,675	$1,337,111.37

3.5 Environment

3.5.1 Oil Spills Containing Polychlorinated Biphenyl ('PCB')

The Oil Spills Containing PCBs measure tracks Toronto Hydro's progress towards reducing the risk of oil spills containing PCBs. Figure 11, below, displays the number of oil spills containing PCBs during 2013 and 2018.

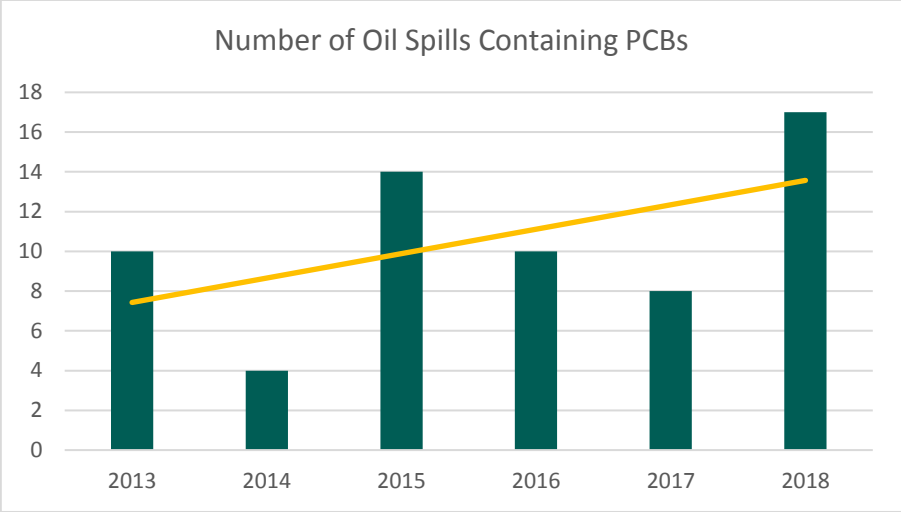


Figure 11: Oil Spills Containing PCBs 2013-2018

3.5.2 Waste Diversion

As stated in Exhibit 2B, Section C2, Toronto Hydro intends to begin reporting on the new Waste Diversion Rate performance measure during the 2020-2024 period.

4. 2015-2019 DSP PERFORMANCE MEASURES

4.1 Reliability

4.1.1 Customer Average Interruption Duration Index ("CAIDI")

Figure 12 shows the performance for this measure over the 2013-2018 period. Toronto Hydro's CAIDI performance improved in 2018, returning to its 2016 performance level.

Toronto Hydro's improvement in this reliability measure can be attributed to the utility's distribution system investments, grid operations performance, and various external factors that affect average outage duration.

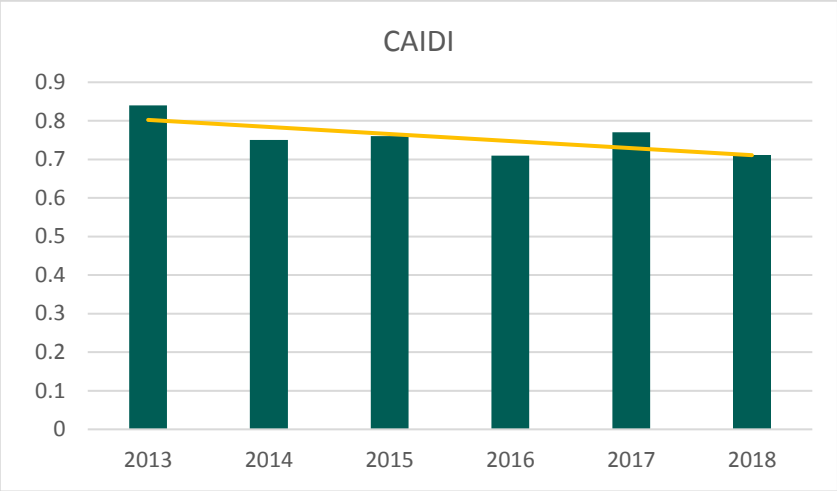


Figure 12: CAIDI Performance from 2013 – 2018

4.1.2 Momentary Average Interruption Frequency Index ("MAIFI")

MAIFI measures the average frequency of momentary interruptions (i.e. less than one minute) that affect Toronto Hydro's customers. Figure 13, below, shows the utility's performance for this measure over the 2013-2018 period. The five-year annual frequency value for the period 2014 to 2018 is 2.64 compared to the corresponding value of 2.74 reported in the utility's last Rate Application (for the period 2009 to 2013). For 2018, MAIFI was 2.78. This result represents an increase from the prior years, which is due to a number of drivers including weather.

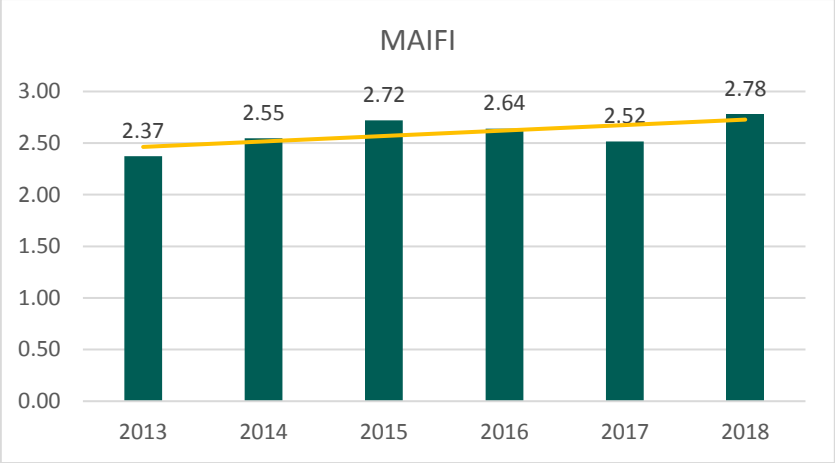


Figure 13: MAIFI Performance from 2013 – 2018

4.1.3 Outages caused by Defective Equipment

Figure 14, below, shows the utility's performance in this measure over the 2013-2018 period. In 2018, Toronto Hydro recorded 441 outages caused by defective equipment. The overall declining trend is indicative of Toronto Hydro's achievements in directing capital expenditures toward the renewal and modernization of its core distribution system assets.

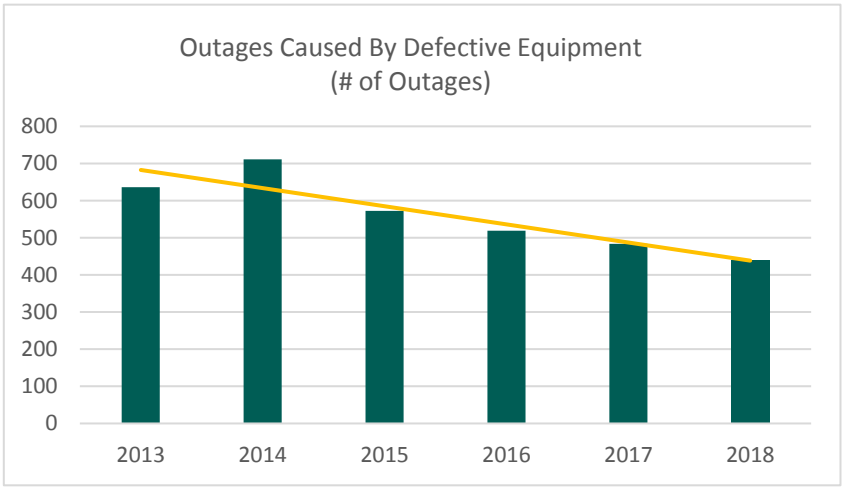


Figure 14: Outages by Defective Equipment Performance from 2013 – 2018

4.2 Stations Capacity Availability

The Stations Capacity Availability tracks the number of Transformer Stations where station demand is forecasted to exceed 90 percent of the station's firm capacity within the next five years. Figure 15 below shows the utility's performance in this measure over the 2013-2018 period. Two stations are forecasted to be loaded > 90% in the next five years.[5]

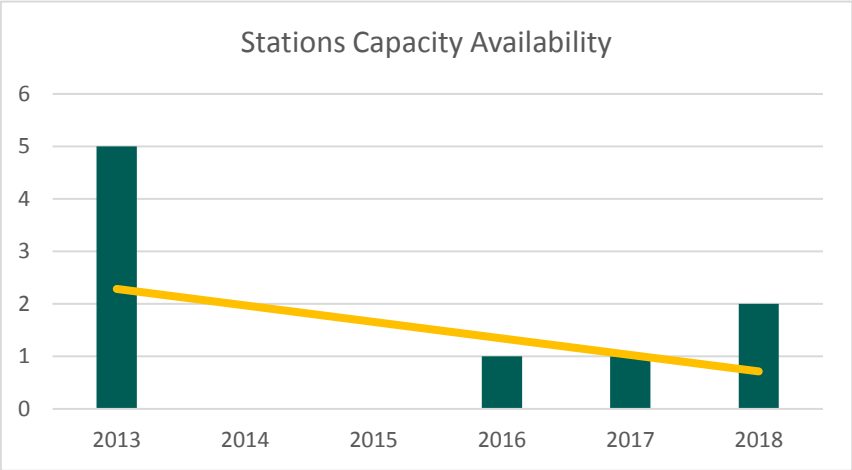


Figure 15: Stations from 2013 – 2018

4.3 Planning Efficiency: Engineering and Support Costs

This measure monitors the proportion of capital project expenditures attributable to indirect labour costs. The result of 10 percent for 2018 was comparable to the 2017 result of 9 percent.

[5] Please note that these are preliminary results and are subject to change based on additional loading analysis. Final results will be published in Toronto Hydro's final 2018 EDS.

4.4 Supply Chain Efficiency: Materials Handling On-Cost

This measure monitors the proportion capital project expenditures attributable to indirect supply chain and warehousing costs. The 2018 rate has remained flat at 10 percent when compared to 2017.

4.5 Construction Efficiency

4.5.1 Internal vs. Contractor Cost Benchmarking

Toronto Hydro expects to finalize the 2018 Contractor Efficiency: Internal vs Contractor Benchmarking measure value by the end of Q3, 2019. This time span is needed to accommodate two dependencies. The first is the need to use Audited Financial information, which was completed in March, 2019. The second is the fact that the calculation process typically takes two to three months given the comprehensive nature of the underlying analysis. The timeline for 2018 results is further extended due to the fact that Toronto Hydro migrated enterprise software systems partway through 2018, resulting in a longer lead time to gather a quality data extract from which the metric's analysis is performed.

4.5.2 Standard Asset Assembly Labour Input

This annual progress report addresses the status of Toronto Hydro's framework for standardizing the estimation, management and reporting of construction work progress by the utility's internal crews. In 2018, Toronto Hydro migrated enterprise software systems and is now working toward implementing its asset assembly processes in this new environment.

5. SERVICE QUALITY PERFORMANCE

As stated in Exhibit 1B, Tab 2, Schedule 3, Toronto Hydro monitors and reports its performance results for the Electricity Service Quality Requirements ("ESQRs") in accordance with the OEB's Reporting and Record-keeping Requirements ("RRR"). This section provides the reported Service Quality Requirements for the last six years (2013 - 2018).

Table 3: Summary of Toronto Hydro's ESQR Performance

ESQR	OEB Standard	Avg. 2014-2018	2013	2014	2015	2016	2017	2018
Connection of New Services-Low Voltage ("LV")	90	96.8	94.2	91.5	96.9	97.7	98.3	99.8
Connection of New Service-High Voltage ("HV")	90	99.7	100.0	100.0	100.0	100.0	98.4	100.0
Micro Embedded Generation Facilities	90	98.5	100.0	100.0	100.0	100.0	92.4	100.0
Appointment Scheduling	90	84.2	96.6	96.2	89.0	72.0	81.8	82.4
Appointment Met	90	99.7	99.6	99.8	99.9	99.5	99.4	99.7
Rescheduling a Missed Appointment	100	98.9	98.4	94.6	100.0	100.0	100.0	100.0
Telephone Accessibility	65	74.3	82.0	71.9	76.8	64.7	77.9	80.2
Telephone Call Abandon Rate	10	1.9	1.2	1.7	1.6	3.1	1.9	1.4
Written Response to Enquires	80	94.7	98.9	85.8	97.5	93.1	99.0	98.30
Billing Accuracy	98	98.3	NA	96.6	97.5	98.9	99.2	99.3
Emergency Response (Urban)	80	90.3	74.4	92.0	87.2	91.8	93.6	88.6
Reconnection Performance Standard	85	99.8	100.0	100.0	100.0	99.7	99.4	99.7

5.1 Connections of New Services – Low Voltage

In 2018, Toronto Hydro continued the trend of improving its results in this measure. The 2018 result of 99.8 percent is a half a percent increase from the 2017 result of 99.3 percent.

5.2 Connections of New Service – High Voltage

The 2018 result for high voltage new service connections was 100 percent. This is a return to the results for the years of 2013 to 2016.

5.3 Micro-Embedded Generation Facilities

The 2018 result for Micro Embedded Generation Facilities was 100 percent. This is a return to the results for the years of 2013 to 2016.

5.4 Appointments Scheduling

Appointments scheduled in 2018 increased to 82.40 percent compared to 81.8 percent in 2017. As described in the pre-filed evidence Exhibit 1B, Tab 2, Schedule 3, pages 4 and 5, Toronto Hydro has made several process improvements to increase performance in this measure. Over the two years of 2017 and 2018, performance in this commitment to improve has resulted in the measure increasing from 72 percent in 2016 to 82.4 percent in 2018.

5.5 Appointments Met

In 2018, the appointments met performance was 99.66 percent which is an increase from the 2017 result of 99.40 percent.

5.6 Rescheduling a Missed Appointment

In 2018, Toronto Hydro rescheduled 100 percent of the missed appointments within the OEB prescribed timeline. The 100 percent in 2018 for this measure marks the fourth year in a row where the utility has met the OEB standard.

5.7 Telephone Accessibility

Telephone accessibility in 2018 was 80.15 percent which is an improvement over the 2017 result of 77.9 percent and 2016 result of 64.7 percent. The continued improved performance of this measure over the 2017 and 2018 years is partially attributable to Toronto Hydro extending its Call Centre weekday business hours which has resulted in more manageable call volumes

5.8 Telephone Call Abandon Rate

The telephone call abandon rate went down to 1.4 in 2018 when compared with 2017's 1.9 and 2016's 3.1.

5.9 Written Responses to Enquiries

In 2018, the Written Response to Enquires measure performance was 98.30 percent which is comparable to the 2017 performance of 98.96 percent.

5.10 Billing Accuracy

The Billing Accuracy performance continued its five year improvement trend in 2018. The 2018 performance was 99.25 percent, which is a significant improvement from the 2013 performance of 96.6 percent.

5.11 Emergency Response

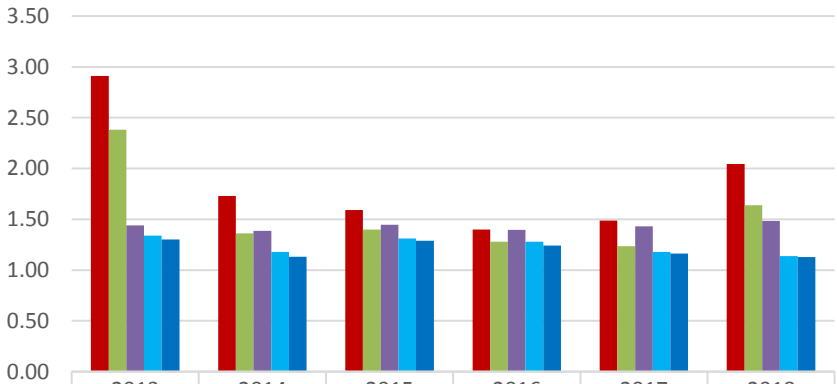
Toronto Hydro's Emergency Response performance decreased in 2018 when compared to the prior year. The 86.63 percent performance in 2018 compares to 93.6 percent in 2017. Over the course of 2018, Toronto Hydro experienced 11 significant weather events as compared to five in 2017. The total number of calls during a number of these events surpassed the number of field resources available for the company to respond within sixty minutes.

5.12 Reconnection Performance Standard

In 2018, Toronto Hydro's reconnection performance standard result was 99.65 percent, which is a slight increase from the 99.38 percent in 2017.

6. RELIABILITY PERFORMANCE

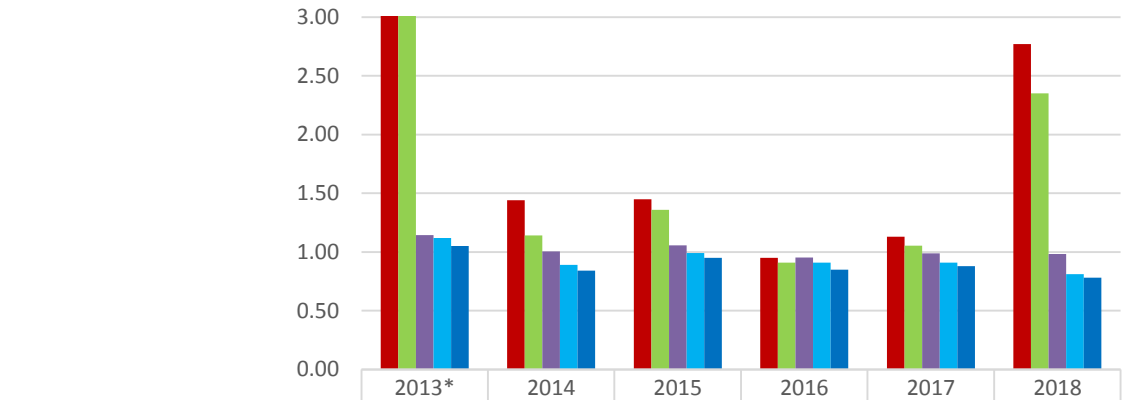
6.1 System Overview



	2013	2014	2015	2016	2017	2018
Total SAIFI	2.91	1.73	1.59	1.40	1.49	2.04
SAIFI Excluding LoS	2.38	1.36	1.40	1.28	1.24	1.64
SAIFI Excluding MED's	1.44	1.39	1.45	1.40	1.43	1.48
SAIFI Excluding MED's and LoS	1.34	1.18	1.31	1.28	1.18	1.14
SAIFI Excluding MED's, LoS and Scheduled Outages	1.30	1.13	1.29	1.24	1.16	1.13

Figure 16: System Level SAIFI

Toronto Hydro's 2018 System Level SAIFI performance decreased relative to 2017. This decrease in performance can be attributed to an increase in adverse weather events and loss of supply events.



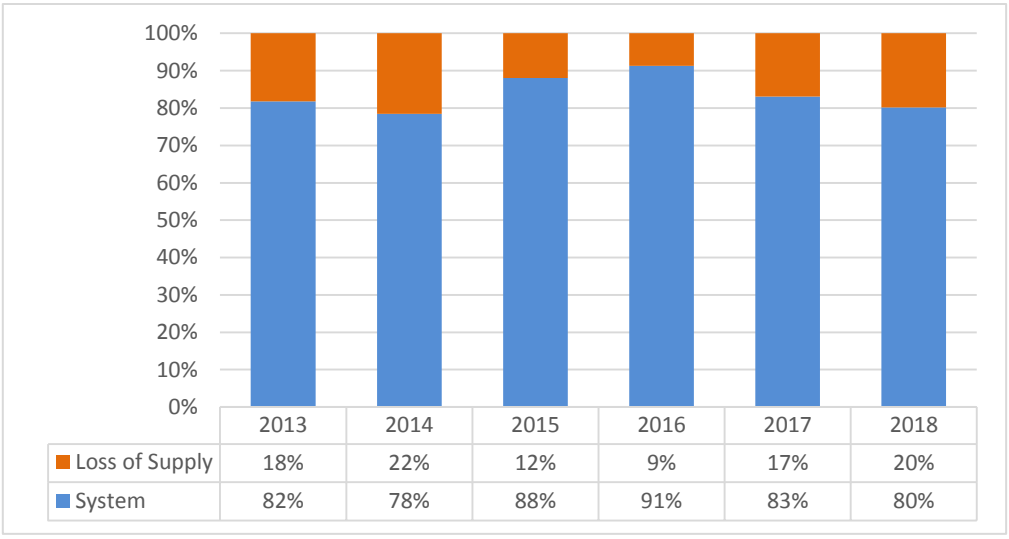
	2013*	2014	2015	2016	2017	2018
Total SAIDI	21.07	1.44	1.45	0.95	1.13	2.77
SAIDI Excluding LoS	17.70	1.14	1.36	0.91	1.05	2.35
SAIDI Excluding MED's	1.14	1.00	1.06	0.95	0.99	0.98
SAIDI Excluding MED's and LoS	1.12	0.89	0.99	0.91	0.91	0.81
SAIDI Excluding MED's, LoS and Scheduled Outages	1.05	0.84	0.95	0.85	0.88	0.78

* 2013 Values cut off above the chart due to the high SAIFI and SAIDI values prior to excluding MEDs.

Figure 17: System Level SAIDI

Toronto Hydro's 2018 System Level SAIDI performance decreased relative to 2017. This decrease in performance can be attributed to an increase in adverse weather events and loss of supply events.

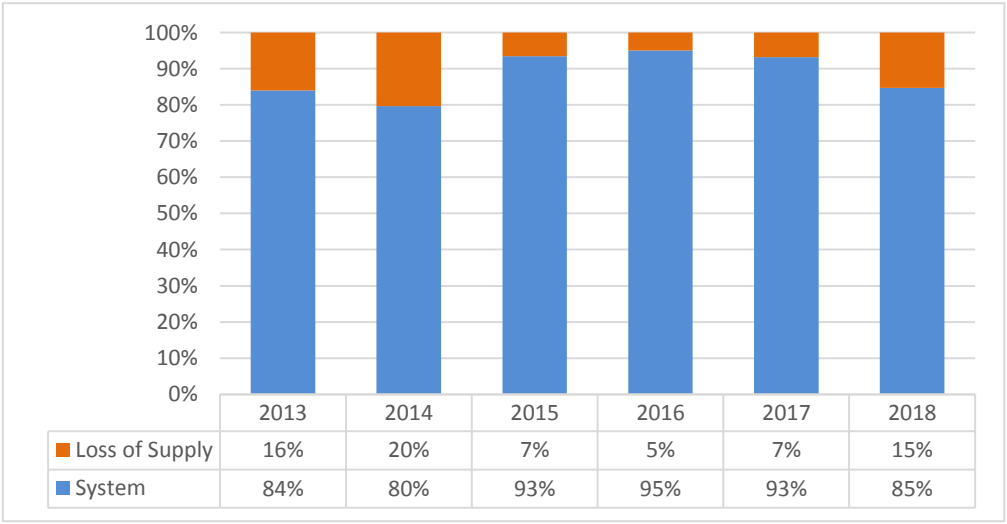
6.2 Loss of Supply ("LoS")



	2013	2014	2015	2016	2017	2018
Loss of Supply	18%	22%	12%	9%	17%	20%
System	82%	78%	88%	91%	83%	80%

Figure 18: Loss of Supply Impact on Total SAIFI

Figure 18 above shows a slight increase from 2017 to 2018 in the Loss of Supply impact on SAIFI.



	2013	2014	2015	2016	2017	2018
Loss of Supply	16%	20%	7%	5%	7%	15%
System	84%	80%	93%	95%	93%	85%

Figure 19: Loss of Supply Impact on Total SAIDI

Figure 19 above shows an increase from 2017 to 2018 in the Loss of Supply impact on SAIDI.

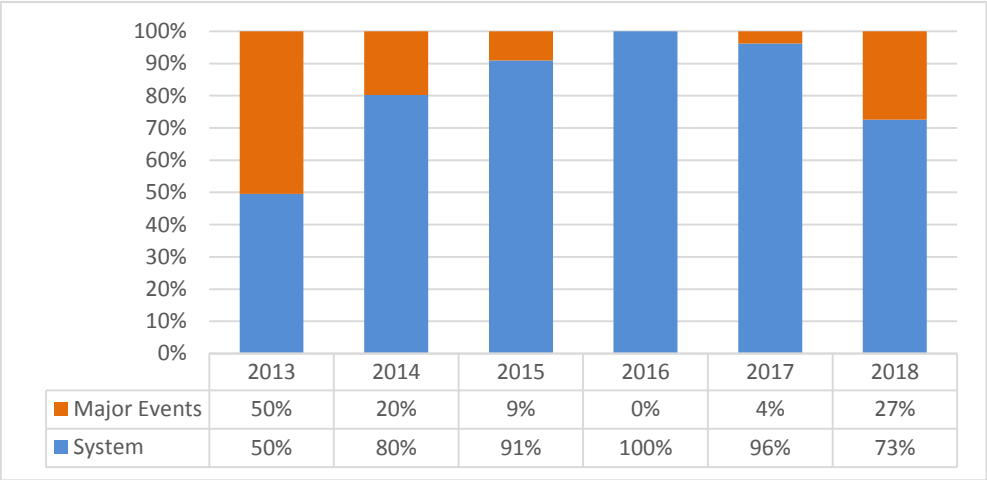
6.3 Major Event Days

Major Event Days ("MEDs") experienced by Toronto Hydro since 2013 are shown in Table 4, below, including those in 2018.

Table 4: Major Event Days (including 2018)

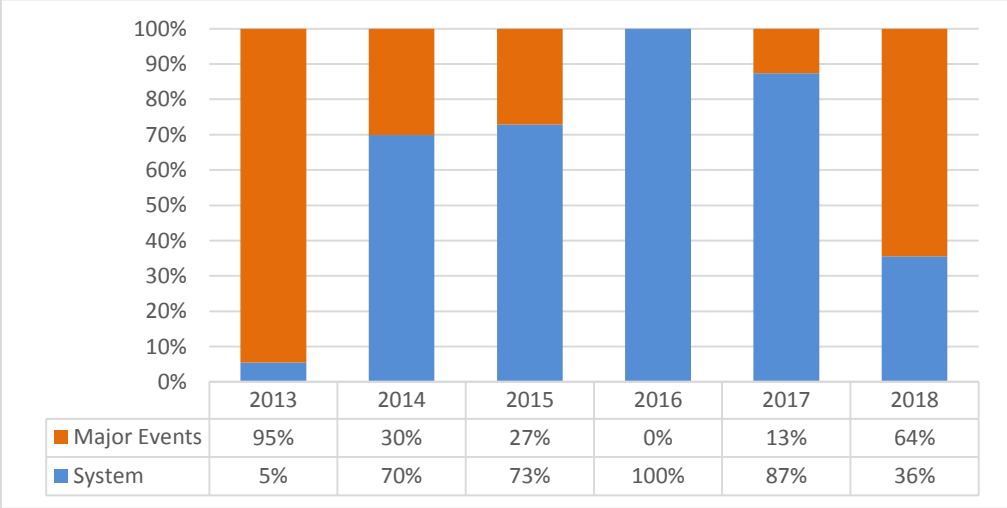
Dates	Description	Number of Outages	Total Customers Interrupted	Total Customer Hours Interrupted
July 8, 2013	Major Storm (Thunderstorm)	56	324,672	2,377,913
July 9, 2013	Major Storm (Thunderstorm)	44	41,502	91,646
December 21, 2013	Freezing Rain Ice Storm	42	175,928	3,204,481
December 22, 2013	Freezing Rain Ice Storm	208	441,547	8,295,093
December 23, 2013	Freezing Rain Ice Storm	25	29,530	196,633
December 24, 2013	Freezing Rain Ice Storm	23	13,983	149,337
December 25, 2013	Freezing Rain Ice Storm	18	20,225	92,924
December 26, 2013	Freezing Rain Ice Storm	20	19,147	91,458
April 15, 2014	Loss of Supply to Manby TS	27	113,035	129,479
June 17, 2014	Major Thunderstorm	38	55,442	88,496
November 24, 2014	Wind Storm	46	82,053	99,027
March 3, 2015	Freezing Rain	49	107,242	291,672
October 15, 2017	Wind Storm	31	43,175	107,846
April 4, 2018	Wind Storm	68	97,378	112,230
April 15, 2018	Freezing Rain	47	85,281	164,214
May 4, 2018	Wind Storm	98	164,261	800,390
June 13, 2018	Wind Storm	31	35,366	96,504
July 28, 2018	Loss of Supply Finch TS (Tx Fire)	22	45,475	192,195

Toronto Hydro experienced its highest number of Major Event Days (MED) in 2018 since 2013. This increase in MEDs significantly affected 2018 performance on SAIDI and SAIFI as shown in the following two Figures 20 and 21 below. These events include a number of major weather events, as well as a loss of supply to one of Toronto Hydro's transformer stations.



	2013	2014	2015	2016	2017	2018
Major Events	50%	20%	9%	0%	4%	27%
System	50%	80%	91%	100%	96%	73%

Figure 20: Major Event Days Impact on Total SAIFI



	2013	2014	2015	2016	2017	2018
Major Events	95%	30%	27%	0%	13%	64%
System	5%	70%	73%	100%	87%	36%

Figure 21: Major Event Days Impact on Total SAIDI

6.4 Scheduled Outages

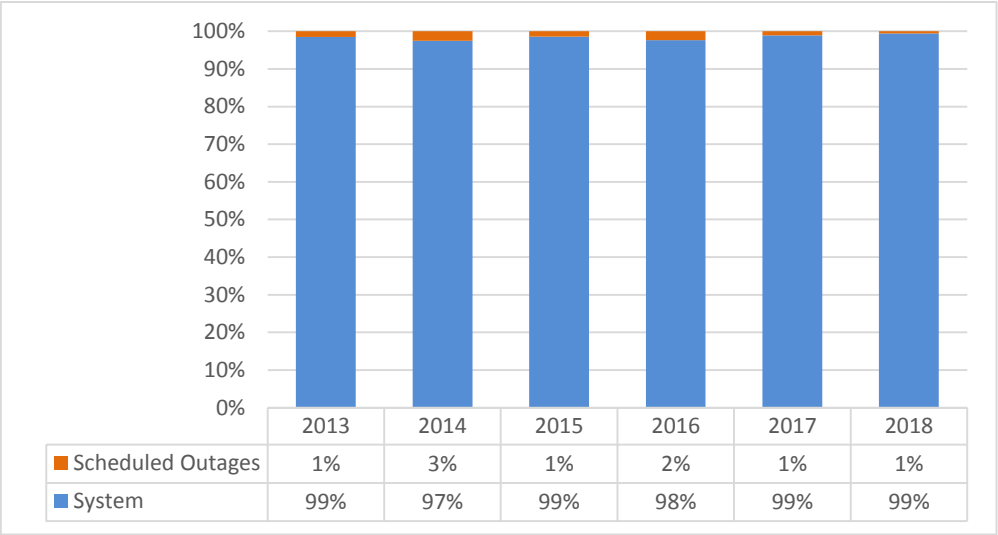


Figure 22: Scheduled Outages Impact on Total SAIFI

As shown in Figure 22, there was no significant variance in 2018 compared to prior years in the impact of scheduled outages on Total SAIFI.

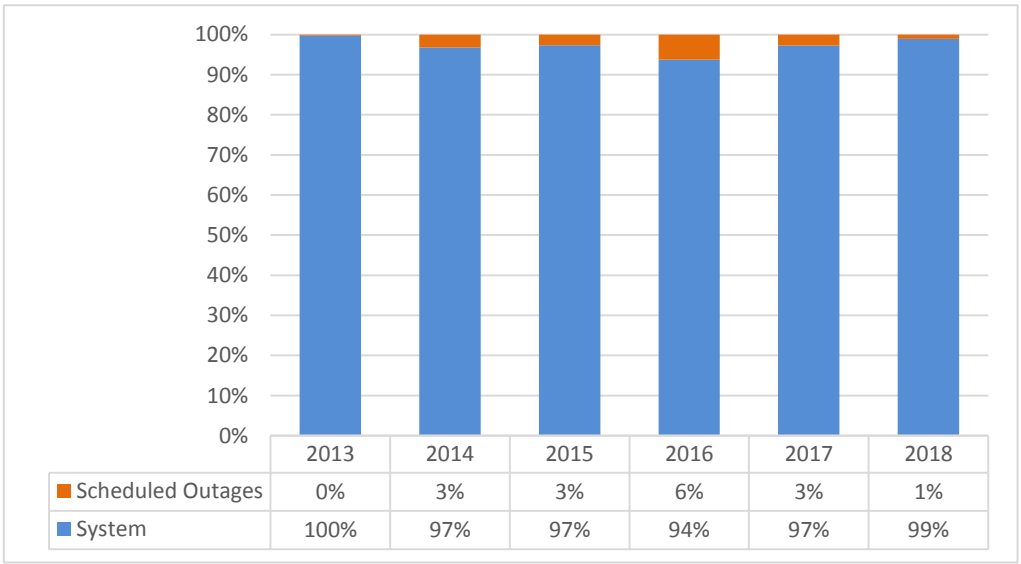


Figure 23: Scheduled Outages Impact on Total SAIDI

As shown in Figure 23, there was an improvement in performance in 2018 with the impact of scheduled outages on Total SAIDI.

6.5 System Reliability Excluding Loss of Supply, Major Event Days, and Scheduled Outages

Figure 24 and 25 below show the continuing stable performance with a gradual downward trend in SAIDI and SAIFI when Loss of Supply, MED's and Scheduled Outages are excluded.

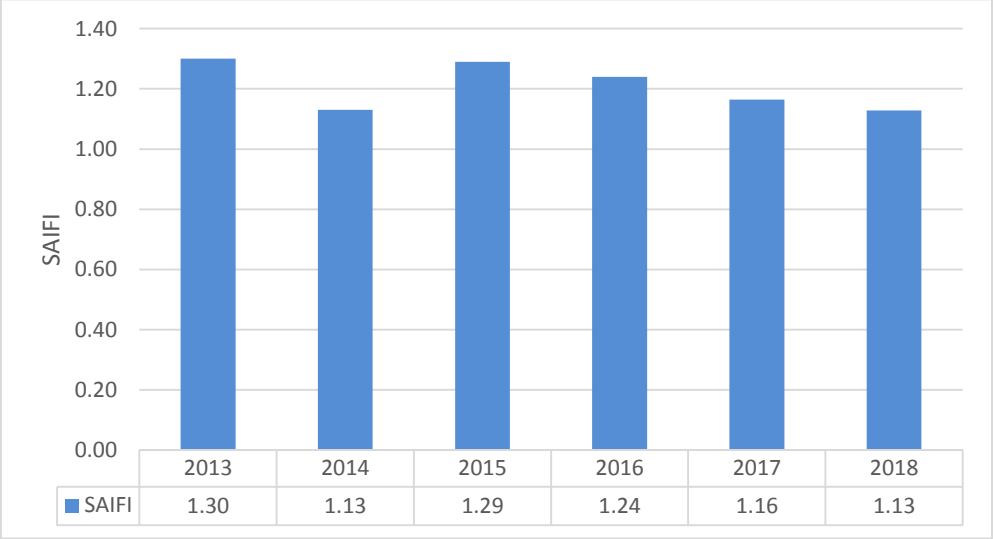


Figure 24: System SAIFI Excluding MEDs, Loss of Supply and Scheduled Outages

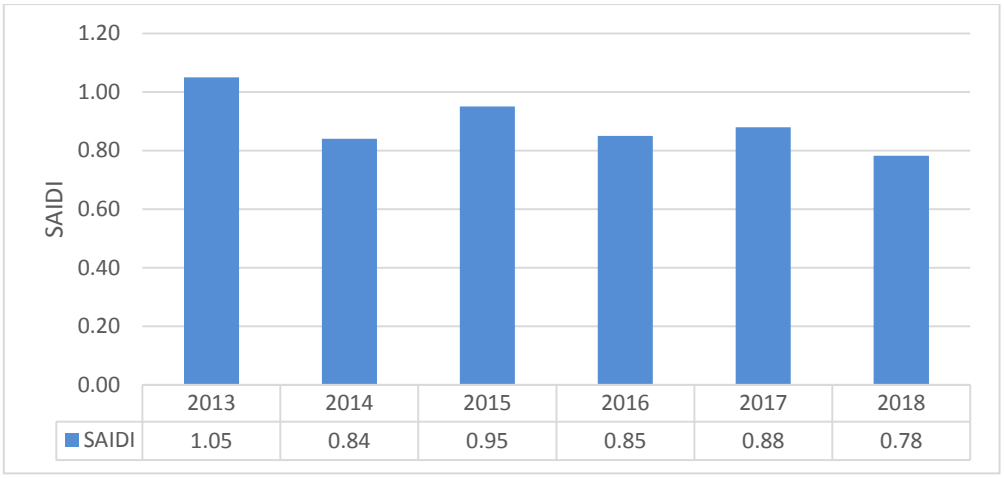
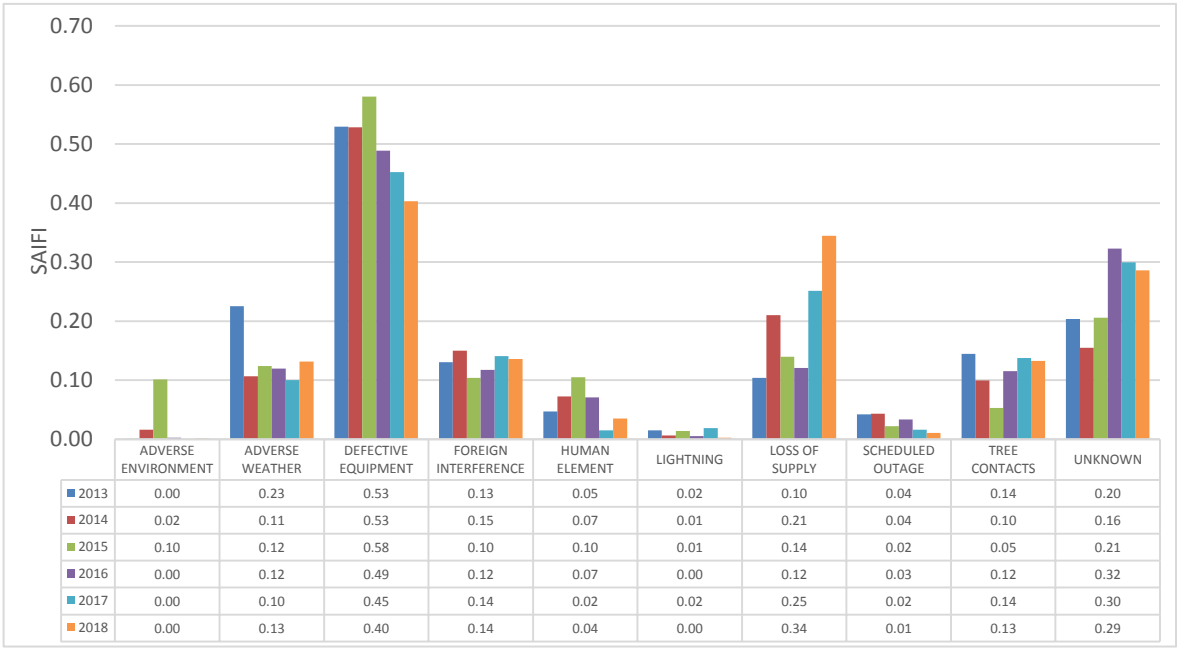


Figure 25: System SAIDI Excluding MEDs, Loss of Supply and Scheduled Outages

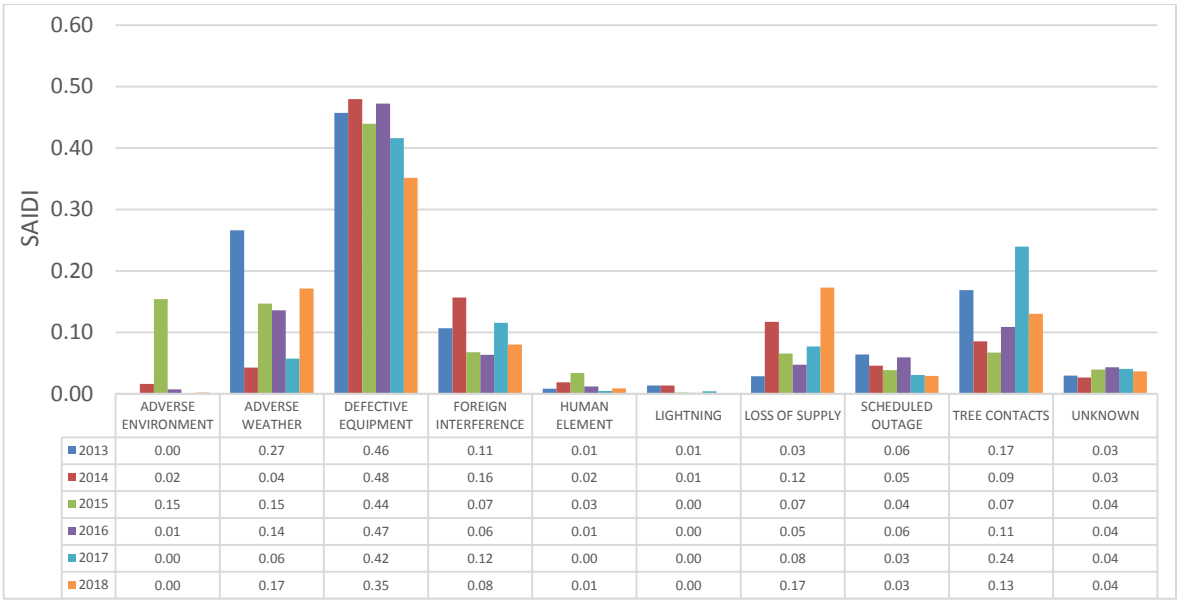
6.6 Cause Code Analysis

Figures 26 and 27 provide an updated set of Cause Code Analysis for SAIDI and SAIFI excluding MEDs.



	ADVERSE ENVIRONMENT	ADVERSE WEATHER	DEFECTIVE EQUIPMENT	FOREIGN INTERFERENCE	HUMAN ELEMENT	LIGHTNING	LOSS OF SUPPLY	SCHEDULED OUTAGE	TREE CONTACTS	UNKNOWN
2013	0.00	0.23	0.53	0.13	0.05	0.02	0.10	0.04	0.14	0.20
2014	0.02	0.11	0.53	0.15	0.07	0.01	0.21	0.04	0.10	0.16
2015	0.10	0.12	0.58	0.10	0.10	0.01	0.14	0.02	0.05	0.21
2016	0.00	0.12	0.49	0.12	0.07	0.00	0.12	0.03	0.12	0.32
2017	0.00	0.10	0.45	0.14	0.02	0.02	0.25	0.02	0.14	0.30
2018	0.00	0.13	0.40	0.14	0.04	0.00	0.34	0.01	0.13	0.29

Figure 26: SAIFI Cause Code Breakdown (Excluding MEDs)

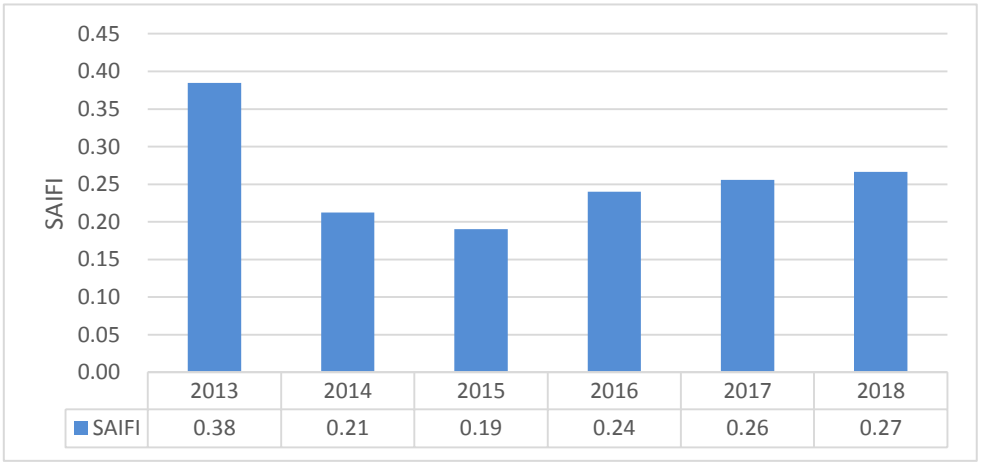


	ADVERSE ENVIRONMENT	ADVERSE WEATHER	DEFECTIVE EQUIPMENT	FOREIGN INTERFERENCE	HUMAN ELEMENT	LIGHTNING	LOSS OF SUPPLY	SCHEDULED OUTAGE	TREE CONTACTS	UNKNOWN
2013	0.00	0.27	0.46	0.11	0.01	0.01	0.03	0.06	0.17	0.03
2014	0.02	0.04	0.48	0.16	0.02	0.01	0.12	0.05	0.09	0.03
2015	0.15	0.15	0.44	0.07	0.03	0.00	0.07	0.04	0.07	0.04
2016	0.01	0.14	0.47	0.06	0.01	0.00	0.05	0.06	0.11	0.04
2017	0.00	0.06	0.42	0.12	0.00	0.00	0.08	0.03	0.24	0.04
2018	0.00	0.17	0.35	0.08	0.01	0.00	0.17	0.03	0.13	0.04

Figure 27: SAIDI Cause Code Breakdown (Excluding MEDs)

6.7 Weather Impacts

Figures 28 and 29 below illustrate the cumulative weather reliability impacts on the system. Of note is the continuing impact of weather on Toronto Hydro's SAIDI and SAIFI performance.



	2013	2014	2015	2016	2017	2018
SAIFI	0.38	0.21	0.19	0.24	0.26	0.27

Figure 28: Weather Impacts to SAIFI

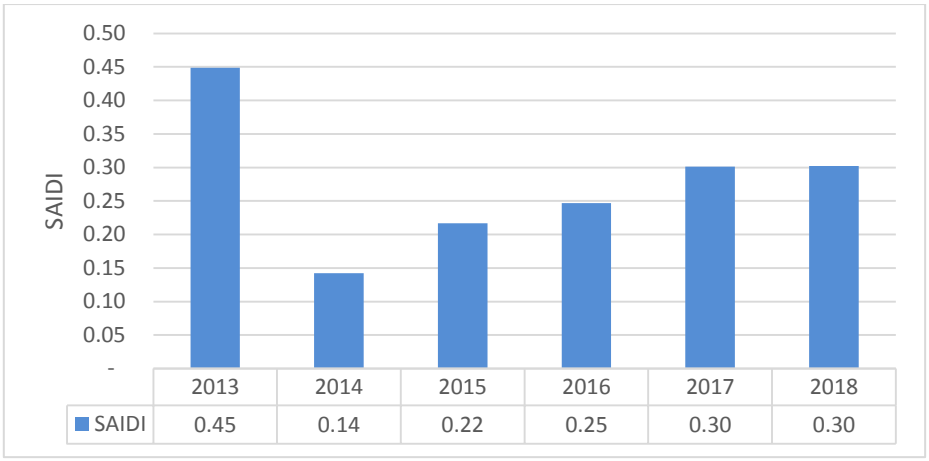


Figure 29: Weather Impacts to SAIDI

6.8 Foreign Interference Impacts

Figures 30 and 31 below illustrate the impact of animal contact, dig-ins, vehicles, and other foreign objects on SAIDI and SAIFI. The 2018 cause analysis is consistent with prior year's results.

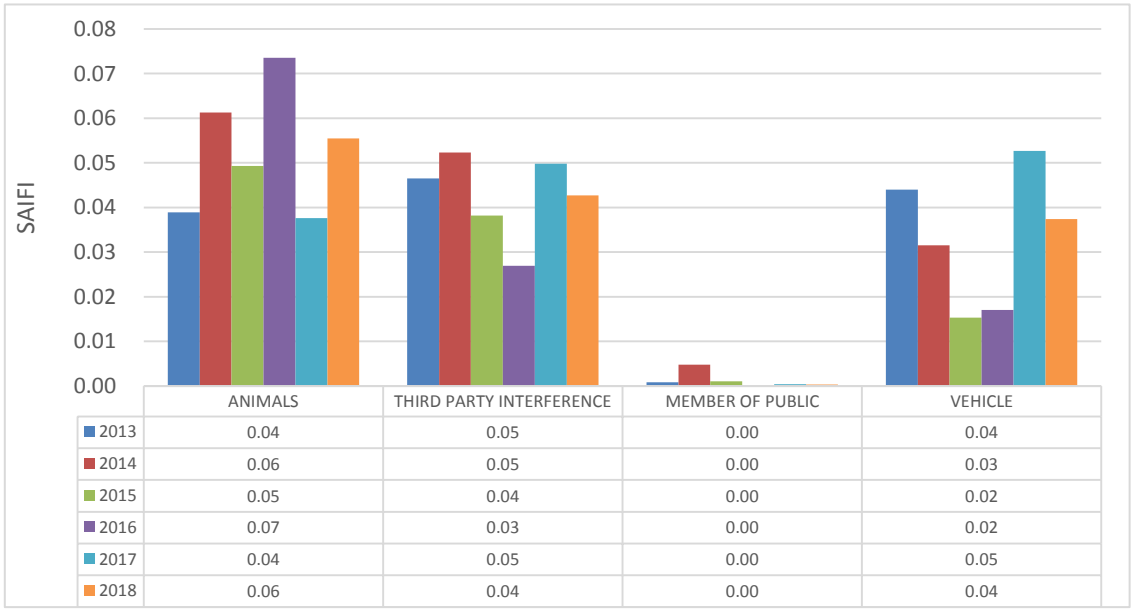
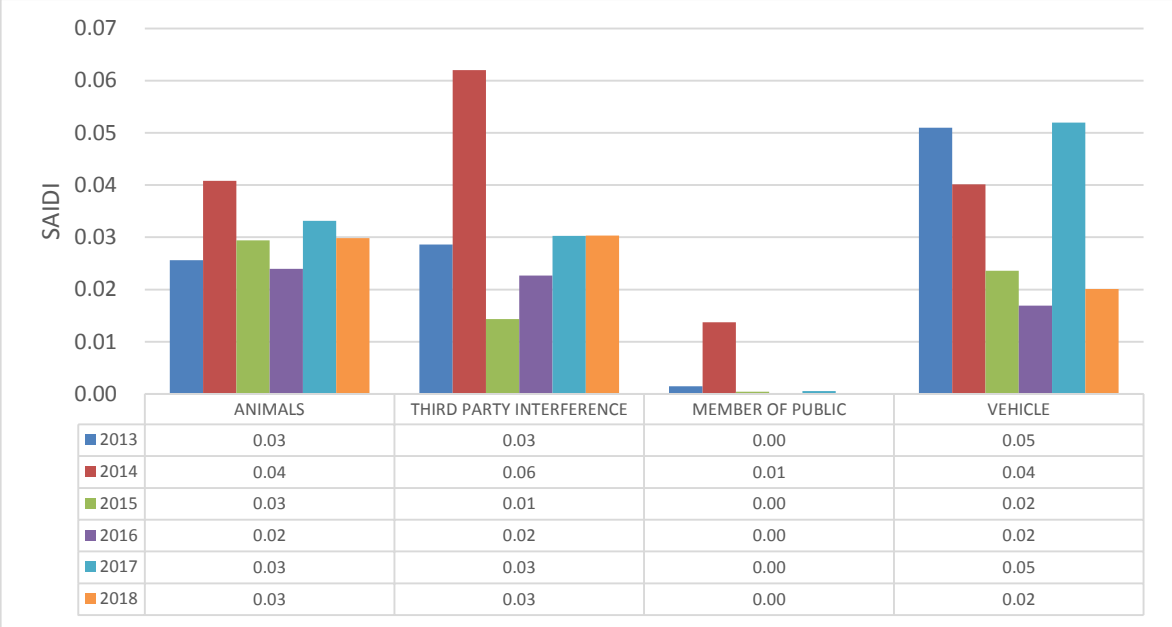


Figure 30: Foreign Interference – Root Cause SAIFI

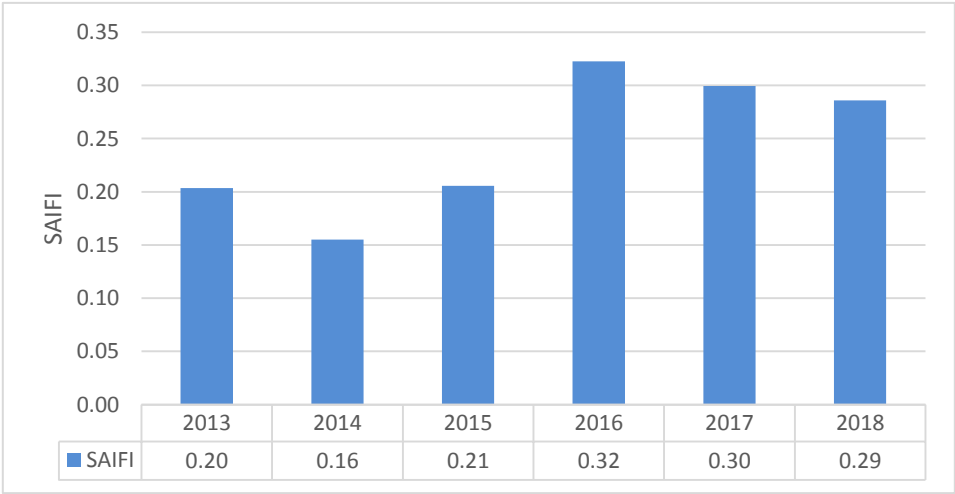


	ANIMALS	THIRD PARTY INTERFERENCE	MEMBER OF PUBLIC	VEHICLE
2013	0.03	0.03	0.00	0.05
2014	0.04	0.06	0.01	0.04
2015	0.03	0.01	0.00	0.02
2016	0.02	0.02	0.00	0.02
2017	0.03	0.03	0.00	0.05
2018	0.03	0.03	0.00	0.02

Figure 31: Foreign Interference – Root Cause SAIDI

6.9 Unknown Impacts

Figures 32 and 33 below illustrate the impact of Unknown Impacts to SAIDI and SAIFI. The 2018 results are consistent with prior years.



	2013	2014	2015	2016	2017	2018
SAIFI	0.20	0.16	0.21	0.32	0.30	0.29

Figure 32: Unknown Impacts to SAIFI

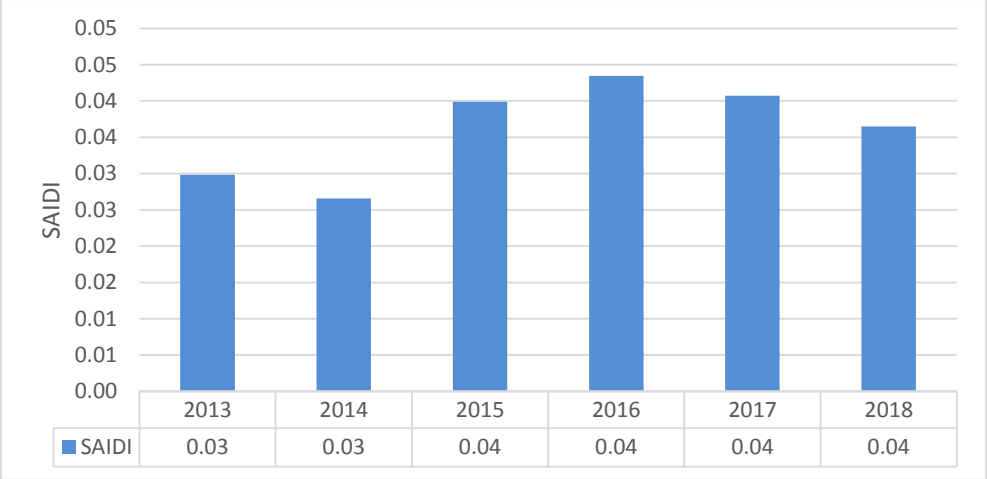


Figure 33: Unknown Impacts to SAIDI

6.10 Defective Equipment Impacts

As shown in Figures 34 and 35, Defective Equipment Impacts on SAIDI and SAIFI have improved over the CIR period.

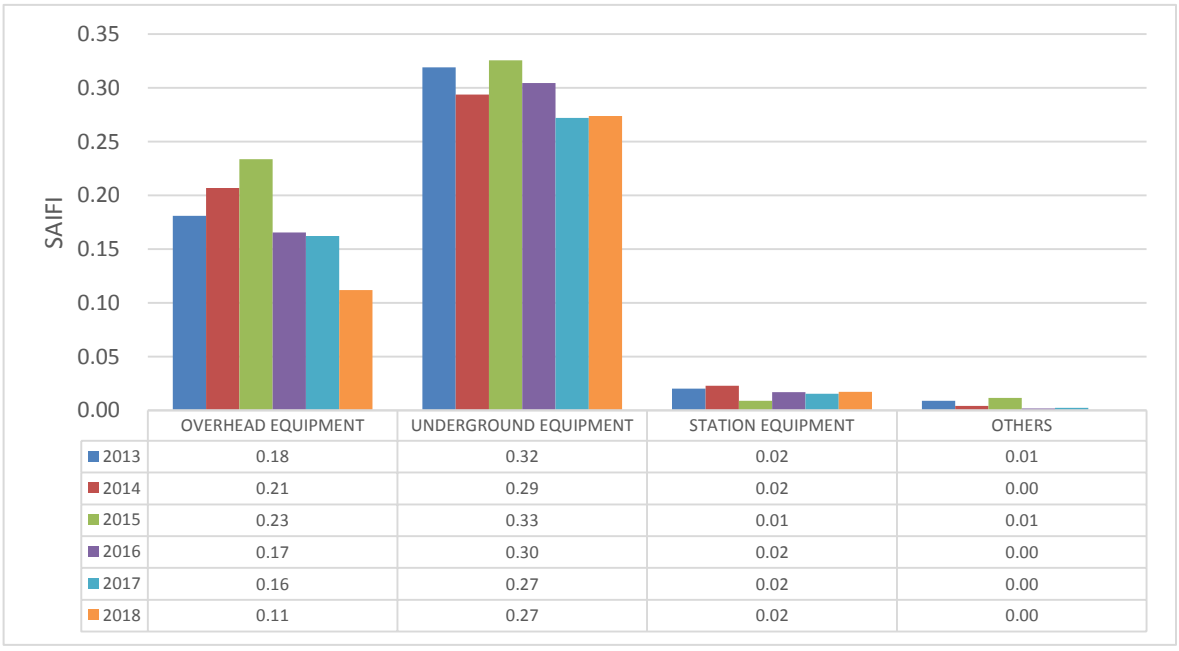
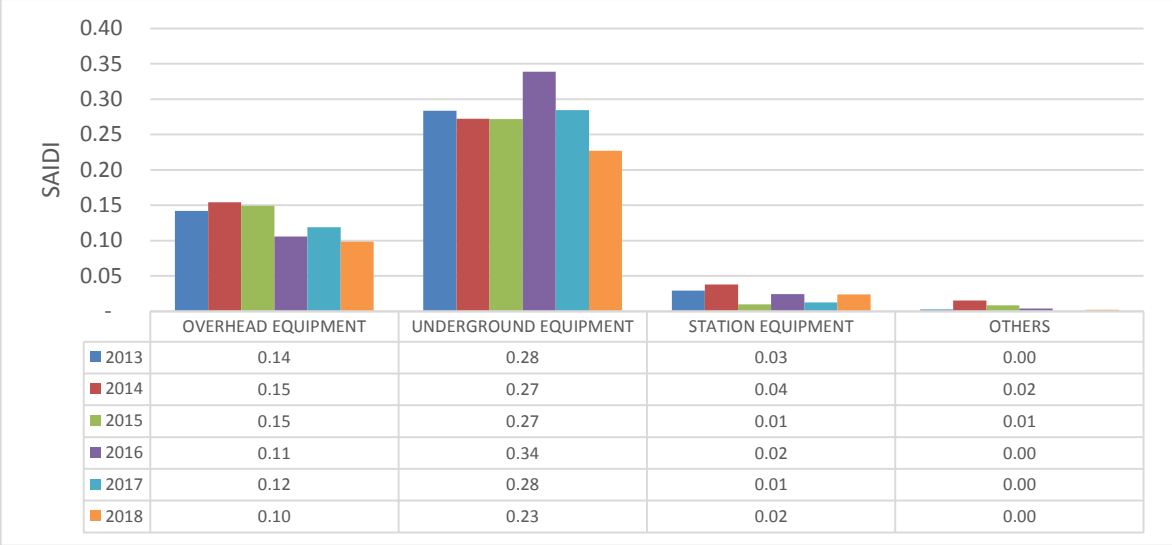


Figure 35: Defective Equipment SAIFI

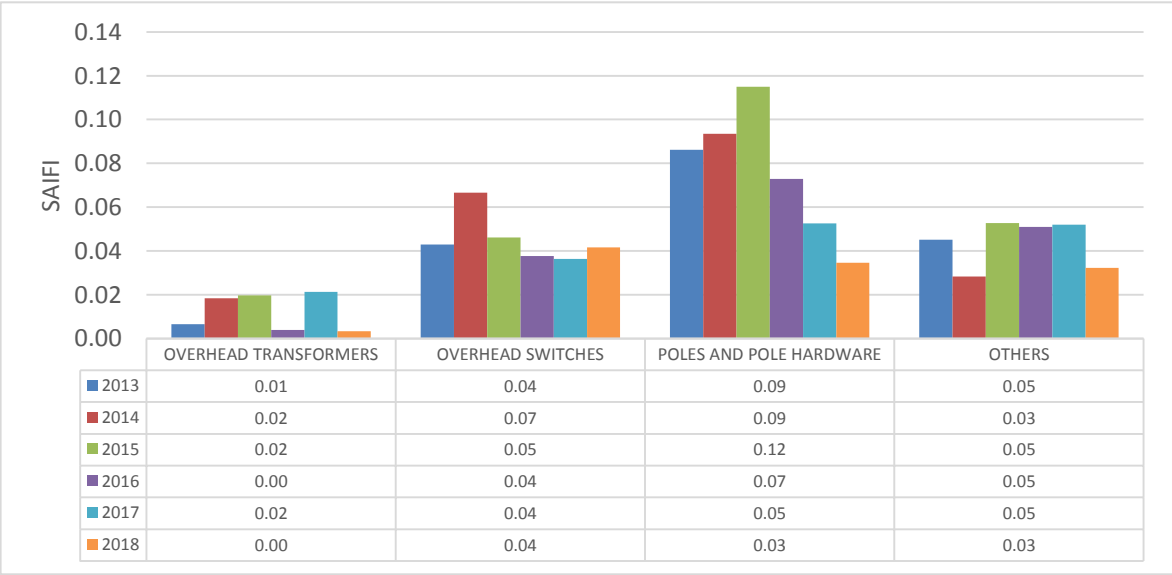


	OVERHEAD EQUIPMENT	UNDERGROUND EQUIPMENT	STATION EQUIPMENT	OTHERS
2013	0.14	0.28	0.03	0.00
2014	0.15	0.27	0.04	0.02
2015	0.15	0.27	0.01	0.01
2016	0.11	0.34	0.02	0.00
2017	0.12	0.28	0.01	0.00
2018	0.10	0.23	0.02	0.00

Figure 35: Defective Equipment SAIDI

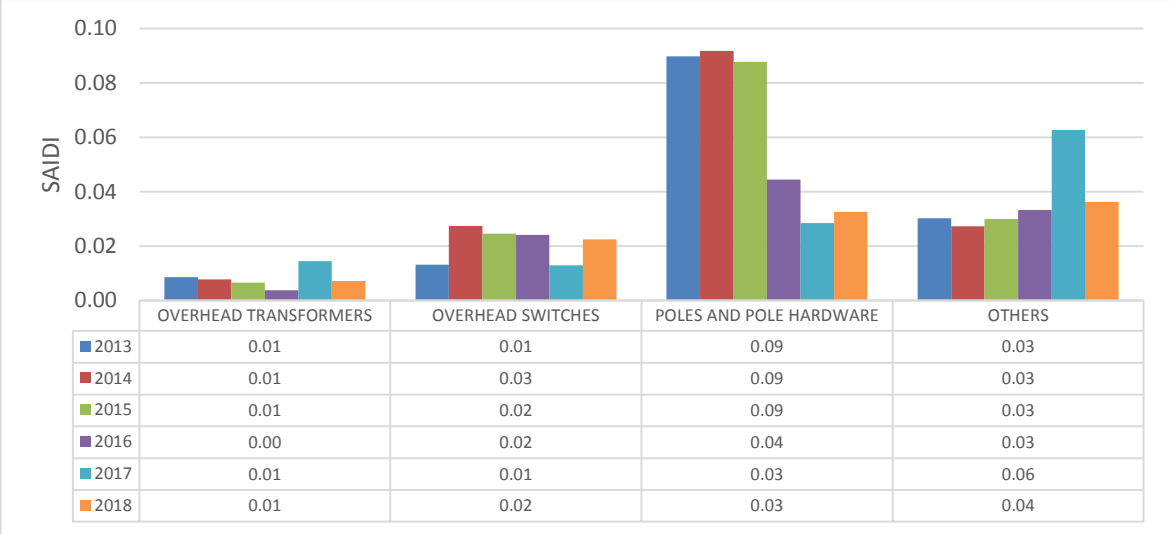
6.10.1 Overhead Defective Equipment

Figures 36 and 37 illustrate the trend of stable or improving outcomes continuing under most of the categories of Overhead Defective Equipment.



	OVERHEAD TRANSFORMERS	OVERHEAD SWITCHES	POLES AND POLE HARDWARE	OTHERS
2013	0.01	0.04	0.09	0.05
2014	0.02	0.07	0.09	0.03
2015	0.02	0.05	0.12	0.05
2016	0.00	0.04	0.07	0.05
2017	0.02	0.04	0.05	0.05
2018	0.00	0.04	0.03	0.03

Figure 36: Defective Equipment SAIFI – Overhead

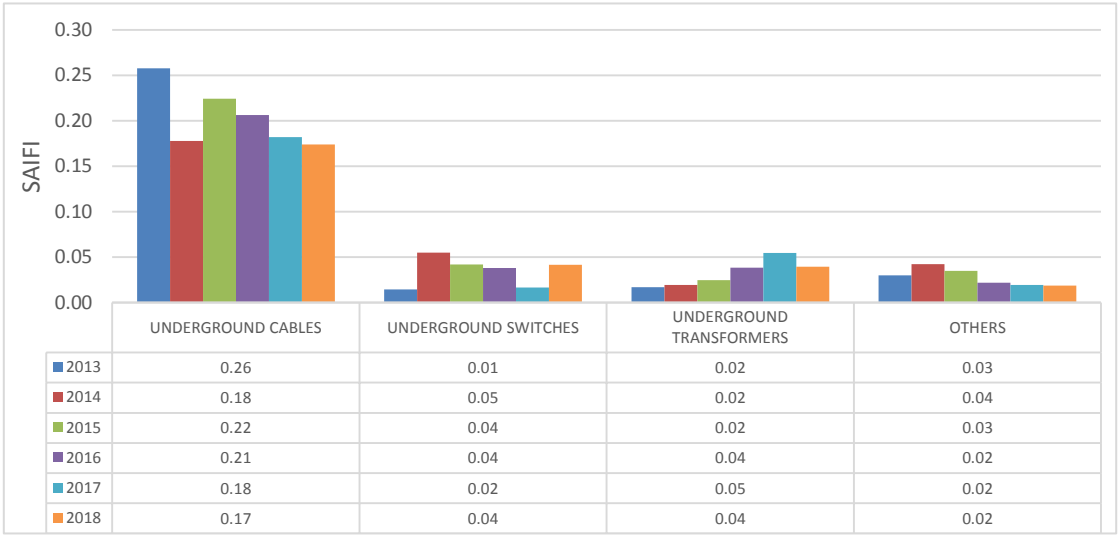


	OVERHEAD TRANSFORMERS	OVERHEAD SWITCHES	POLES AND POLE HARDWARE	OTHERS
2013	0.01	0.01	0.09	0.03
2014	0.01	0.03	0.09	0.03
2015	0.01	0.02	0.09	0.03
2016	0.00	0.02	0.04	0.03
2017	0.01	0.01	0.03	0.06
2018	0.01	0.02	0.03	0.04

Figure 37: Defective Equipment SAIDI – Overhead

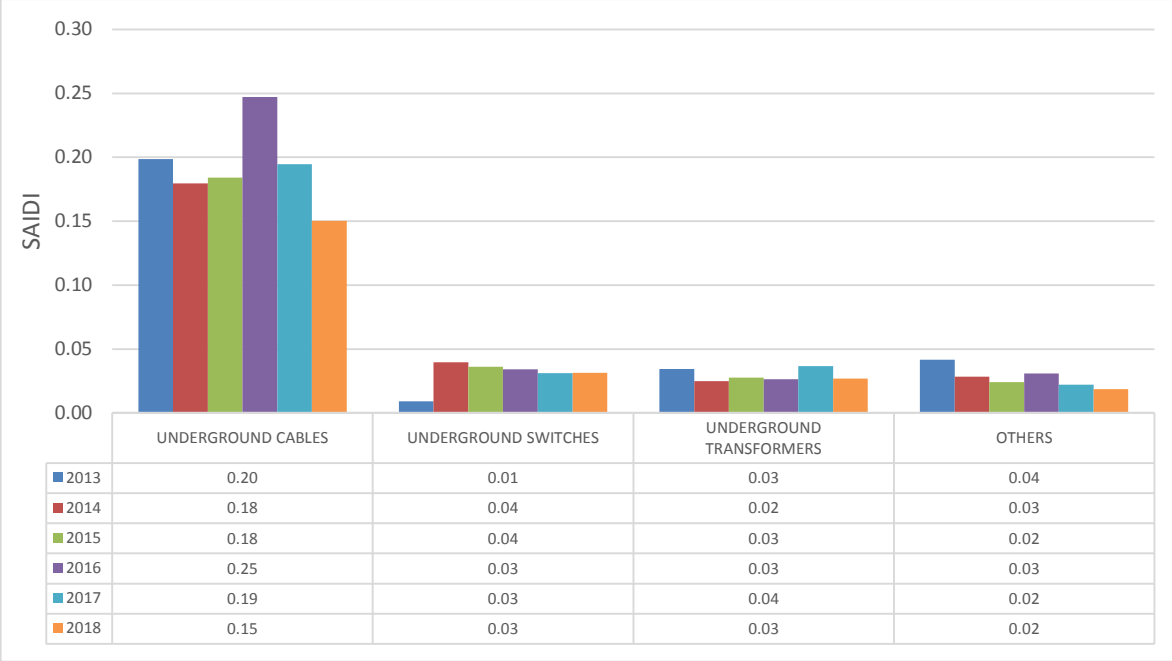
6.10.2 Underground Defective Equipment

Figures 38 and 39, the cause codes for Underground Defective Equipment, illustrate the continuing stable or improving outcomes across all categories, with the exception of underground transformers, which have demonstrated a slight worsening trend in SAIFI.



	UNDERGROUND CABLES	UNDERGROUND SWITCHES	UNDERGROUND TRANSFORMERS	OTHERS
2013	0.26	0.01	0.02	0.03
2014	0.18	0.05	0.02	0.04
2015	0.22	0.04	0.02	0.03
2016	0.21	0.04	0.04	0.02
2017	0.18	0.02	0.05	0.02
2018	0.17	0.04	0.04	0.02

Figure 38: Defective Equipment SAIFI – Underground



	UNDERGROUND CABLES	UNDERGROUND SWITCHES	UNDERGROUND TRANSFORMERS	OTHERS
2013	0.20	0.01	0.03	0.04
2014	0.18	0.04	0.02	0.03
2015	0.18	0.04	0.03	0.02
2016	0.25	0.03	0.03	0.03
2017	0.19	0.03	0.04	0.02
2018	0.15	0.03	0.03	0.02

Figure 39: Defective Equipment SAIDI – Underground

7. 2018 CORPORATE SCORECARD UPDATE

In response to interrogatories 1B-SEC-8 and 4A-AMPCO-96, Toronto Hydro committed to providing the 2018 Corporate Scorecard. Table 5 below is the 2018 Corporate Scorecard updated to include 2018 results.

Table 5: 2018 Corporate Scorecard

Key Performance Indicator	2018 Target		2018 Result
New Services Connected on Time	96.5%		99.8%
Bill Accuracy	98.8%		99.3%
First Contact Resolution	86%		89%
Total Recordable Injury Frequency (TRIF)	1.45		0.83
Employee Engagement	6.0		7.1
SAIFI (# - Defective Equipment Only)	0.54		0.40
SAIDI (Minutes - Defective Equipment Only)	29.00		21.08
1-Year Distribution System Plan Investment ($M)	**Lower Target**	**Upper Target**	435.8
	418.0	451.0	
5-Year CIR Distribution System Plan Investment ($M)	**Lower Target**	**Upper Target**	1943.8
	1928.0	1957.2	
Consolidated Net Income ($M)	148.0		167.3

FINANCIAL INFORMATION OVERVIEW

In accordance with section 2.1.9 of the OEB's Filing Requirements,[1] Exhibit U, Tab 1C provides the following updated financial information:

- Toronto Hydro's Audited Financial Statements for 2018 (Schedule 2);
- Reconciliation of the financial results shown in the Audited Financial Statements with regulatory financial results for 2018 (Schedule 3);
- Toronto Hydro Corporation's Management's Discussion & Analysis for 2018 (Schedule 4); and
- Toronto Hydro Corporation's Annual Information Form for 2018 (Schedule 5).

Please note that at the time of the application update there is no updated public debt offering information.

[1] Ontario Energy Board Filing Requirements for Electricity Distribution Rate Applications – Chapter 2 (July 12, 2018).

Toronto Hydro-Electric System Limited
EB-2018-0165
Exhibit U
Tab 1C
Schedule 2
FILED: April 30, 2019
(49 pages)

Financial Statements

Toronto Hydro-Electric System Limited

DECEMBER 31, 2018 and 2017

KPMG LLP
Bay Adelaide Centre
333 Bay Street, Suite 4600
Toronto, ON M5H 2S5
Canada
Tel 416-777-8500
Fax 416-777-8818

INDEPENDENT AUDITORS' REPORT

To the Shareholder of Toronto Hydro-Electric System Limited

Opinion

We have audited the financial statements of Toronto Hydro-Electric System Limited (the Entity), which comprise:

- the balance sheets as at December 31, 2018 and December 31, 2017
- the statements of income for the years then ended
- the statements of comprehensive income for the years then ended
- the statements of changes in equity for the years then ended
- the statements of cash flows for the years then ended
- and notes to the financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2018 and December 31, 2017, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards (IFRS).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "***Auditors' Responsibilities for the Audit of the Financial Statements***" section of our auditors' report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

KPMG LLP is a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International Cooperative ("KPMG International"), a Swiss entity.
KPMG Canada provides services to KPMG LLP.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Entity to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represents the underlying transactions and events in a manner that achieves fair presentation.

- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.



Chartered Professional Accountants, Licensed Public Accountants
Toronto, Canada
March 5, 2019

Toronto Hydro-Electric System Limited

BALANCE SHEETS

[in millions of Canadian dollars]

As at December 31	2018 $	2017 $
ASSETS		
Current		
Accounts receivable *[notes 4 and 14[b]]*	**210.4**	217.2
Unbilled revenue *[note 14[b]]*	**279.7**	276.0
Materials and supplies	**8.1**	9.3
Other assets *[note 5]*	**10.7**	12.7
Assets held for sale	**-**	8.7
Total current assets	**508.9**	523.9
Property, plant and equipment *[note 6]*	**4,349.9**	4,107.8
Intangible assets *[note 7]*	**318.9**	296.2
Deferred tax assets *[note 20]*	**0.3**	57.0
Other assets *[note 5]*	**5.8**	3.0
Total assets	**5,183.8**	4,987.9
Regulatory balances *[note 8]*	**125.9**	199.9
Total assets and regulatory balances	**5,309.7**	5,187.8
LIABILITIES AND EQUITY		
Current		
Bank indebtedness	**21.5**	125.0
Accounts payable and accrued liabilities *[note 9]*	**521.7**	513.3
Income tax payable	**4.8**	12.5
Customer deposits	**48.1**	49.2
Deferred revenue *[note 10]*	**12.4**	9.9
Deferred conservation credit *[note 3[c]]*	**8.2**	9.3
Notes payable to related party *[notes 11 and 22]*	**304.9**	60.0
Other liabilities *[note 23]*	**0.3**	1.5
Total current liabilities	**921.9**	780.7
Notes payable to related party *[notes 11 and 22]*	**1,785.7**	2,029.9
Customer deposits	**31.7**	8.9
Deferred revenue *[note 10]*	**277.7**	178.8
Post-employment benefits *[note 12]*	**275.9**	313.0
Other liabilities *[note 23]*	**2.0**	0.2
Total liabilities	**3,294.9**	3,311.5
Equity		
Share capital *[note 16]*	**556.3**	556.3
Retained earnings	**1,267.5**	1,147.2
Contributed surplus	**12.8**	12.8
Total equity	**1,836.6**	1,716.3
Total liabilities and equity	**5,131.5**	5,027.8
Regulatory balances *[note 8]*	**178.2**	160.0
Total liabilities, equity and regulatory balances	**5,309.7**	5,187.8

Commitments, contingencies and subsequent events *[notes 2, 23 and 24]*

See accompanying notes to the financial statements.

Toronto Hydro-Electric System Limited

STATEMENTS OF INCOME

[in millions of Canadian dollars]

Year ended December 31	**2018** **$**	2017 **$**
		[note 25[p]]
Revenues		
Energy sales *[note 17]*	**2,704.1**	2,810.2
Distribution revenue *[note 17]*	**674.2**	724.2
Other *[note 17]*	**80.5**	96.7
	3,458.8	3,631.1
Expenses		
Energy purchases	**2,646.3**	2,855.9
Operating expenses *[note 18]*	**297.1**	284.2
Depreciation and amortization *[notes 6 and 7]*	**235.9**	222.3
	3,179.3	3,362.4
Finance costs *[note 19]*	**(78.3)**	(81.0)
Gain on disposals of property, plant and equipment	**108.6**	9.8
Income before income taxes	**309.8**	197.5
Income tax expense *[note 20]*	**(81.6)**	(44.2)
Net income	**228.2**	153.3
Net movements in regulatory balances *[note 8]*	**(111.9)**	(13.1)
Net movements in regulatory balances arising from deferred tax assets *[note 8]*	**47.0**	13.2
Net income after net movements in regulatory balances	**163.3**	153.4

STATEMENTS OF COMPREHENSIVE INCOME

[in millions of Canadian dollars]

Year ended December 31	**2018** **$**	2017 **$**
Net income after net movements in regulatory balances	**163.3**	153.4
Other comprehensive income		
Items that will not be reclassified to income or loss		
Remeasurements of post-employment benefits, net of tax [2018 - ($9.9), 2017 - $6.7] *[note 12]*	**27.3**	(18.4)
Net movements in regulatory balances related to OCI, net of tax [2018 - ($9.9), 2017 - $6.7] *[note 12]*	**(27.3)**	18.4
Other comprehensive income, net of tax	**-**	-
Total comprehensive income	**163.3**	153.4

See accompanying notes to the financial statements.

Toronto Hydro-Electric System Limited

STATEMENTS OF CHANGES IN EQUITY

[in millions of Canadian dollars]

Year ended December 31	**2018 $**	2017 **$**
Share capital ***[note 16]***	**556.3**	556.3
Retained earnings, beginning of year	**1,147.2**	995.9
Transition adjustment *[note 25[p]]*	**(0.3)**	-
Net income after net movements in regulatory balances	**163.3**	153.4
Dividends *[notes 16 and 22]*	**(42.7)**	(2.1)
Retained earnings, end of year	**1,267.5**	1,147.2
Contributed surplus	**12.8**	12.8
Total equity	**1,836.6**	1,716.3

See accompanying notes to the financial statements.

Toronto Hydro-Electric System Limited

STATEMENTS OF CASH FLOWS

[in millions of Canadian dollars]

Year ended December 31	**2018** **$**	2017 $
OPERATING ACTIVITIES		
Net income after net movements in regulatory balances	**163.3**	153.4
Net movements in regulatory balances *[note 8]*	**111.9**	13.1
Net movements in regulatory balances arising from deferred tax assets *[note 8]*	**(47.0)**	(13.2)
Adjustments		
Depreciation and amortization *[notes 6 and 7]*	**235.9**	222.3
Amortization of deferred revenue *[note 10]*	**(5.3)**	(4.7)
Finance costs	**78.3**	81.0
Income tax expense	**81.6**	44.2
Post-employment benefits	**0.1**	7.4
Gain on disposals of property, plant and equipment	**(108.6)**	(9.8)
Other	**0.6**	1.1
Capital contributions received *[note 10]*	**106.5**	50.8
Net change in other non-current assets and liabilities	**(2.6)**	(6.5)
Increase in customer deposits	**21.7**	4.0
Changes in non-cash working capital balances *[note 21]*	**3.5**	60.7
Income tax paid	**(41.8)**	(22.1)
Net cash provided by operating activities	**598.1**	581.7
INVESTING ACTIVITIES		
Purchase of property, plant and equipment *[note 21]*	**(431.8)**	(433.8)
Purchase of intangible assets *[note 21]*	**(54.5)**	(93.4)
Proceeds on disposals of property, plant and equipment	**117.4**	12.5
Net cash used in investing activities	**(368.9)**	(514.7)
FINANCING ACTIVITIES		
Issuance of notes payable to related party *[note 11]*	**-**	198.6
Repayment of notes payable to related party *[note 11]*	**-**	(245.1)
Repayment of lease liability	**(1.8)**	(3.0)
Dividends paid *[note 16]*	**(42.7)**	(2.1)
Interest received	**0.6**	0.3
Interest paid	**(81.8)**	(90.2)
Net cash used in financing activities	**(125.7)**	(141.5)
Net decrease (increase) in bank indebtedness during the year	**103.5**	(74.5)
Bank indebtedness, beginning of year	**(125.0)**	(50.5)
Bank indebtedness, end of year	**(21.5)**	(125.0)

See accompanying notes to the financial statements.

1. NATURE OF BUSINESS

Toronto Hydro-Electric System Limited was incorporated on June 23, 1999 under the *Business Corporations Act (Ontario)* in accordance with *the Electricity Act*. LDC is wholly-owned by the Corporation and is domiciled in Canada, with its registered office located at 14 Carlton Street, Toronto, Ontario, M5B 1K5.

LDC distributes electricity to customers located in the City and is subject to rate regulation. LDC is also engaged in the delivery of CDM activities.

2. BASIS OF PRESENTATION

LDC's audited financial statements for the years ended December 31, 2018 and 2017 have been prepared in accordance with IFRS as issued by the IASB.

The financial statements are presented in Canadian dollars, LDC's functional currency, and have been prepared on the historical cost basis, except for post-employment benefits which are recorded at actuarial value.

LDC has evaluated the events and transactions occurring after the balance sheet date through March 5, 2019 when LDC's financial statements were authorized for issuance by LDC's Board of Directors, and identified no events and transactions which required recognition in the LDC's financial statements and/or disclosure in the notes to the LDC's financial statements.

The summary of significant accounting policies has been disclosed in note 25.

3. REGULATION

The OEB has regulatory oversight of electricity matters in Ontario. The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to approve the amounts paid to non-contracted generators, the responsibility to provide rate protection for rural or remote electricity customers, and the responsibility for ensuring that electricity distribution companies fulfill their obligations to connect and service customers.

LDC is required to charge its customers for the following amounts (all of which, other than distribution rates, represent a pass-through of amounts payable to third parties):

- *Commodity Charge* – The commodity charge represents the market price of electricity consumed by customers and is passed through the IESO back to operators of generating stations. It includes the global adjustment, which represents the difference between the market price of electricity and the rates paid to regulated and contracted generators.

- *Retail Transmission Rate* – The retail transmission rate represents the costs incurred in respect of the transmission of electricity from generating stations to local distribution networks. Retail transmission rates are passed through back to operators of transmission facilities.

- *WMS Charge* – The WMS charge represents various wholesale market support costs, such as the cost of the IESO to administer the wholesale electricity system, operate the electricity market, and maintain reliable operation of the provincial grid. Wholesale charges are passed through back to the IESO.

- *Distribution Rate* – The distribution rate is designed to recover the costs incurred by LDC in delivering electricity to customers, including the OEB-allowed cost of capital. Distribution rates are regulated by the OEB and include fixed and variable (usage-based) components, based on a forecast of LDC's customers and load.

a) Electricity Distribution Rates

The OEB's regulatory framework for electricity distributors is designed to support the cost-effective planning and operation of the electricity distribution network and to provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price.

The OEB typically regulates the electricity rates for distributors using a combination of detailed cost of service reviews and IRM adjustments. A cost of service review uses a future test-year to establish rates, and provides for revenues required to recover the forecasted costs of providing the regulated service, and a fair and reasonable return on rate base. IRM adjustments are typically used for one or more years following a cost of service review and provide for adjustments to rates based on an inflationary factor net of a productivity factor and an efficiency factor as determined relative to other electricity distributors.

On August 31, 2018, LDC filed its 2019 rate application seeking OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2019 and ending on December 31, 2019. On December 13, 2018, the OEB issued a decision and rate order approving LDC's 2019 rates and providing for other deferral and variance account dispositions.

On August 15, 2018, LDC filed a CIR application seeking approval of LDC's 2020 test-year revenue requirement on a cost of service basis and the corresponding electricity distribution rates effective January 1, 2020, and the subsequent annual rate adjustments based on a custom index specific to LDC for the period commencing on January 1, 2021 and ending on December 31, 2024. The rate application requests approvals to fund capital expenditures of approximately $2.8 billion over the 2020-2024 period. The rate application also seeks approval to include in LDC's rate base capital amounts that were incurred prior to 2020.

b) Ontario's Fair Hydro Plan

On March 2, 2017, the Government of Ontario announced the OFHP, which includes a number of initiatives, some of which affect LDC or its customers.

OFHP includes the OREC, which came into effect on January 1, 2017. The OREC provides eligible customers with financial assistance in the form of an 8% rebate of the pre-tax cost of their electricity. The OREC rebates are administered by LDC and paid by the IESO in the month following customer billing. Current accounts receivable and unbilled revenue include the amount owing by the IESO to LDC. No effect on revenue or expense is recognized by LDC in respect of the OREC rebates.

OFHP also includes the OFHA, which enacted the Ontario Fair Hydro Plan Act, 2017 and amended the Electricity Act, 1998 and the Ontario Energy Board Act, 1998. The OFHA came into effect on June 1, 2017 and its impact is reflected in the financial statements. The OFHA provides eligible customers with financial assistance through various changes to commodity pricing, new or amended programs, and eliminating or reducing certain provincial charges on the electricity bill. The OFHA reduces the total electricity bill for eligible customers and, accordingly, reduces current accounts receivable, unbilled revenue, accounts payable and accrued liabilities for LDC. No effect on distribution revenue or expense is recognized by LDC in respect of the OFHA.

c) CDM Activities

The objective of the CDM programs is to reduce electricity consumption in the Province of Ontario by a total of 7 terawatt hours between January 1, 2015 and December 31, 2020, of which LDC's share is approximately 1,576 GWh of energy savings.

Under the energy conservation agreement with the IESO, LDC has a joint CDM plan with Oakville Hydro Electricity Distribution Inc. ["Oakville Hydro"] for the delivery of CDM programs over the 2015-2020 period. The IESO reimburses LDC for all adequately documented incurred costs, with an option to receive a portion of its funding in advance. Cost efficiency incentives may be awarded if LDC's electricity savings meet or exceed certain CDM plan

targets for programs under the full cost recovery funding method, including a mid-term incentive based on a review of the 2015-2017 period.

The joint CDM plan provides combined funding of approximately $421.0 million, including participant incentives and program administration costs, with an energy savings target of approximately 1,648 GWh. The program for Oakville Hydro under the joint CDM plan started on January 1, 2016. LDC received $162.4 million from the IESO as at December 31, 2018 [2017 - $102.3 million] to deliver the CDM programs. Amounts received but not yet spent are presented on the balance sheets under current liabilities as deferred conservation credit. On September 26, 2018, $15.8 million was confirmed by the IESO as the joint mid-term incentive, of which $14.9 million representing LDC's portion was received in November 2018.

4. ACCOUNTS RECEIVABLE

Accounts receivable consist of the following:

	2018 $	2017 $
Trade receivables	**200.2**	188.6
Due from related parties *[note 22]*	**5.8**	14.8
CDM mid-term incentive *[note 3[c]]*	**—**	12.2
Other	**4.4**	1.6
	210.4	217.2

5. OTHER ASSETS

Other assets consist of the following:

	2018 $	2017 $
Prepaid expenses	**9.4**	11.3
Deferred financing costs	**1.6**	1.6
Other	**5.5**	2.8
Total other assets	**16.5**	15.7
Less: Current portion of other assets relating to:		
Prepaid expenses	**9.4**	11.3
Deferred financing costs	**0.4**	0.4
Other	**0.9**	1.0
Current portion of other assets	**10.7**	12.7
Non-current portion of other assets	**5.8**	3.0

6. PROPERTY, PLANT AND EQUIPMENT

PP&E consist of the following:

	Distribution assets	Land and buildings	Equipment and other	Construction in progress	Total
	$	$	$	$	$
Cost					
Balance as at January 1, 2017	3,376.3	321.5	173.9	448.2	4,319.9
Additions/(Transfers)	404.4	84.8	32.8	(77.1)	444.9
Assets held for sale *[note 8[d]]*	—	(11.8)	—	—	(11.8)
Disposals and retirements	(31.5)	(3.2)	(0.3)	—	(35.0)
Balance as at December 31, 2017	3,749.2	391.3	206.4	371.1	4,718.0
Additions/(Transfers)	**363.6**	**18.7**[(1)]	**20.3**	**51.1**	**453.7**
Disposals and retirements	**(32.0)**	**(0.4)**	**(0.6)**	—	**(33.0)**
Balance as at December 31, 2018	**4,080.8**	**409.6**	**226.1**	**422.2**	**5,138.7**
Accumulated depreciation					
Balance as at January 1, 2017	347.3	26.3	70.0	—	443.6
Depreciation	138.1	13.6	24.7	—	176.4
Assets held for sale *[note 8[d]]*	—	(3.1)	—	—	(3.1)
Disposals and retirements	(5.9)	(0.5)	(0.3)	—	(6.7)
Balance as at December 31, 2017	479.5	36.3	94.4	—	610.2
Depreciation	**147.6**	**15.0**	**25.3**	—	**187.9**
Disposals and retirements	**(8.4)**	**(0.3)**	**(0.6)**	—	**(9.3)**
Balance as at December 31, 2018	**618.7**	**51.0**	**119.1**	—	**788.8**
Carrying amount					
Balance as at December 31, 2017	3,269.7	355.0	112.0	371.1	4,107.8
Balance as at December 31, 2018	**3,462.1**	**358.6**	**107.0**	**422.2**	**4,349.9**

(1) Includes transitional adjustment for the recognition of the right-of-use assets upon adoption of IFRS 16 *Leases* ["IFRS 16"] on January 1, 2018 *[note 25[p]]*.

As at December 31, 2018, "Land and buildings" included right-of-use assets related to leases of land and office space with cost of $8.8 million [December 31, 2017 - $7.2 million], accumulated depreciation of $0.7 million [December 31, 2017 - $0.4 million], and carrying amount of $8.1 million [December 31, 2017 - $6.8 million]. For the year ended December 31, 2018, LDC recorded depreciation expense of $0.3 million [2017 - $0.1 million] related to the right-of-use assets.

As at December 31, 2018, "Equipment and other" included right-of-use assets with cost of $11.0 million [December 31, 2017 - $11.0 million], accumulated depreciation of $11.0 million [December 31, 2017 - $10.0 million], and carrying amount of $nil [December 31, 2017 - $1.0 million]. For the year ended December 31, 2018, LDC recorded depreciation expense of $1.0 million [2017 - $2.0 million] related to the right-of-use assets.

For the year ended December 31, 2018, borrowing costs in the amount of $3.7 million [2017 - $6.2 million] were capitalized to PP&E and credited to finance costs, with an average capitalization rate of 3.61% [2017 - 3.73%].

"Construction in progress" additions are net of transfers to the other PP&E categories.

7. INTANGIBLE ASSETS

Intangible assets consist of the following:

	Computer software	Contributions	Software in development	Contributions for work in progress	Total
	$	$	$	$	$
Cost					
Balance as at January 1, 2017	113.5	75.5	20.2	70.1	279.3
Additions/(Transfers)	23.4	—	34.0	44.0	101.4
Balance as at December 31, 2017	136.9	75.5	54.2	114.1	380.7
Additions/(Transfers)	**73.8**	**88.6**	**(39.2)**	**(74.6)**	**48.6**
Disposals and retirement	**(2.9)**	**—**	**—**	**—**	**(2.9)**
Balance as at December 31, 2018	**207.8**	**164.1**	**15.0**	**39.5**	**426.4**
Accumulated amortization					
Balance as at January 1, 2017	57.4	4.1	—	—	61.5
Amortization	20.0	3.0	—	—	23.0
Balance as at December 31, 2017	77.4	7.1	—	—	84.5
Amortization	**20.9**	**3.6**	**—**	**—**	**24.5**
Disposals and retirements	**(1.5)**	**—**	**—**	**—**	**(1.5)**
Balance as at December 31, 2018	**96.8**	**10.7**	**—**	**—**	**107.5**
Carrying amount					
Balance as at December 31, 2017	59.5	68.4	54.2	114.1	296.2
Balance as at December 31, 2018	**111.0**	**153.4**	**15.0**	**39.5**	**318.9**

For the year ended December 31, 2018, borrowing costs in the amount of $5.2 million [2017 - $3.6 million] were capitalized to intangible assets and credited to finance costs, with an average capitalization rate of 3.61% [2017 - 3.73%].

"Software in development" and "Contributions for work in progress" additions are net of transfers to the other intangible asset categories.

"Computer software" is externally acquired. The remaining amortization periods for computer software and contributions range from less than one year to 10 years, and from 10 to 25 years, respectively.

"Contributions" represent payments made to HONI for dedicated infrastructure in order to receive connections to transmission facilities.

8. REGULATORY BALANCES

Debit balances consist of the following:

	January 1, 2018	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2018	Remaining recovery/ reversal period (months)	Carrying charges applicable
	$	$	$	$	$		
OPEB net actuarial loss	**85.3**	**(37.2)**	**—**	**—**	**48.1**	note 8[a]	—
LRAM	**16.7**	**18.7**	**(6.4)**	**—**	**29.0**	note 8[b]	(1)
Foregone revenue	**44.0**	**—**	**(20.8)**	**—**	**23.2**	12	—
Gain on disposal	**19.1**	**—**	**—**	**(19.1)**	**—**	note 8[d]	(1)
IFRS transitional adjustments	**15.0**	**—**	**(8.0)**	**—**	**7.0**	12	—
OPEB cash versus accrual	**4.2**	**1.2**	**—**	**—**	**5.4**	note 8[f]	—
Stranded meters	**7.5**	**—**	**(3.9)**	**—**	**3.6**	12	(1)
Named properties	**3.1**	**—**	**(1.5)**	**—**	**1.6**	12	—
Capital contributions	**1.0**	**—**	**(0.5)**	**—**	**0.5**	12	—
Other	**4.0**	**3.5**	**—**	**—**	**7.5**	—	(1)
	199.9	**(13.8)**	**(41.1)**	**(19.1)**	**125.9**		

	January 1, 2017	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2017	Remaining recovery/ reversal period (months)	Carrying charges applicable
	$	$	$	$	$		
OPEB net actuarial loss	60.2	25.1	—	—	85.3	note 8[a]	—
LRAM	10.5	11.0	(4.8)	—	16.7	note 8[b]	(1)
Foregone revenue	64.3	—	(20.3)	—	44.0	24	—
Gain on disposal	8.6	(8.1)	18.6	—	19.1	note 8[d]	(1)
IFRS transitional adjustments	22.8	—	(7.8)	—	15.0	24	—
OPEB cash versus accrual	2.9	1.3	—	—	4.2	note 8[f]	—
Stranded meters	11.4	—	(3.9)	—	7.5	24	(1)
Named properties	4.6	—	(1.5)	—	3.1	24	—
Capital contributions	1.5	—	(0.5)	—	1.0	24	—
Smart meters	2.1	—	(3.1)	1.0	—	—	—
Other	1.9	2.1	—	—	4.0	—	(1)
	190.8	31.4	(23.3)	1.0	199.9		

(1) Carrying charges were added to the regulatory balance in accordance with the OEB's direction, at a rate of 1.50% for January 1, 2018 to March 31, 2018, 1.89% for April 1, 2018 to September 30, 2018 and 2.17% for October 1, 2018 to December 31, 2018 [January 1, 2017 to September 30, 2017 - 1.10% and October 1, 2017 to December 31, 2017 - 1.50%].

Credit balances consist of the following:

	January 1, 2018	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2018	Remaining recovery/ reversal period (months)	Carrying charges applicable
	$	$	$	$	$		
Gain on disposal	**—**	**99.0**	**(18.1)**	**(19.1)**	**61.8**	note 8[d]	(1)
Capital-related revenue requirement	**25.0**	**31.5**	**—**	**—**	**56.5**	note 8[j]	(1)
Derecognition	**15.9**	**5.9**	**—**	**—**	**21.8**	note 8[k]	(1)
Settlement variances (2)	**41.0**	**58.2**	**(80.0)**	**—**	**19.2**	note 8[l]	(1)
Development charges	**5.3**	**2.6**	**—**	**—**	**7.9**	note 8[m]	(1)
Deferred taxes	**58.8**	**(56.9)**	**—**	**—**	**1.9**	note 8[n]	—
Tax-related variances	**9.3**	**—**	**(8.2)**	**—**	**1.1**	—	(1)
Smart meters	**0.3**	**—**	**—**	**—**	**0.3**	—	—
Other	**4.4**	**3.7**	**(0.4)**	**—**	**7.7**	—	(1)
	160.0	**144.0**	**(106.7)**	**(19.1)**	**178.2**		

	January 1, 2017	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2017	Remaining recovery/ reversal period (months)	Carrying charges applicable
	$	$	$	$	$		
Capital-related revenue requirement	8.8	16.2	—	—	25.0	note 8[j]	(1)
Derecognition	12.8	3.1	—	—	15.9	note 8[k]	(1)
Settlement variances	62.8	(45.2)	23.4	—	41.0	note 8[l]	(1)
Development charges	—	5.3	—	—	5.3	note 8[m]	(1)
Deferred taxes	65.3	(6.5)	—	—	58.8	note 8[n]	—
Tax-related variances	17.5	—	(8.2)	—	9.3	12	(1)
Smart meters	—	—	(0.7)	1.0	0.3	—	—
Other	2.2	2.7	(0.5)	—	4.4	—	(1)
	169.4	(24.4)	14.0	1.0	160.0		

(1) Carrying charges were added to the regulatory balance in accordance with the OEB's direction, at a rate of 1.50% for January 1, 2018 to March 31, 2018, 1.89% for April 1, 2018 to September 30, 2018 and 2.17% for October 1, 2018 to December 31, 2018 [January 1, 2017 to September 30, 2017 - 1.10% and October 1, 2017 to December 31, 2017 - 1.50%].
(2) In 2018, a reclassification between settlement variances and accounts payable, with a corresponding impact to energy purchases and net movements in regulatory balances, was recorded in the amount of $50.4 million. The immaterial adjustment arose in 2017 and was reflected prospectively in 2018.

The "Balances arising in the period" column consists of new additions to regulatory balances (for both debits and credits). The "Recovery/reversal" column consists of amounts disposed through OEB-approved rate riders or transactions reversing an existing regulatory balance. The "Other movements" column consists of impairment and reclassification between the regulatory debit and credit balances. In addition, the "Other movements" column includes reclassification of regulatory deferral accounts considered to be insignificant into the "Other" categories. There was no impairment recorded for the year ended December 31, 2018.

Reconciliation between the net movements in regulatory balances shown in the regulatory debit and credit balances tables and the net movements presented on the statements of income and the statements of comprehensive income is as follows:

	2018 $	2017 $
Total movements per regulatory debit balances table	**(74.0)**	9.1
Total movements per regulatory credit balances table	**(18.2)**	9.4
Total net movements	**(92.2)**	18.5
Net movements per financial statements:		
Net movements in regulatory balances	**(111.9)**	(13.1)
Net movements in regulatory balances arising from deferred tax assets	**47.0**	13.2
Net movements in regulatory balances related to OCI, net of tax	**(27.3)**	18.4
Total net movements per financial statements	**(92.2)**	18.5

Regulatory developments in Ontario's electricity industry and other governmental policy changes may affect the electricity distribution rates charged by LDC and the costs LDC is permitted to recover. There is a risk that the OEB may disallow the recovery of a portion of certain costs incurred in the current period through future rates or disagree with the proposed recovery period. In the event that the disposition of these balances is assessed to no longer be probable based on management's judgment, any impairment will be recorded in the period when the assessment is made.

The regulatory balances of LDC consist of the following:

a) OPEB net actuarial loss

This regulatory balance accumulates the actuarial gains and losses arising from changes in actuarial assumptions and experience adjustments recognized in OCI. The balance arising during the year ended December 31, 2018 of $37.2 million is related to the actuarial gain recorded for the year [2017 – $25.1 million actuarial loss] *[note 13[a]]*. The net position is an actuarial loss that is recoverable in future rates. LDC is seeking disposition of the balance in the 2020 – 2024 rate application *[note 3[a]]*. The timing of disposition of the balance is currently unknown.

b) Lost revenue adjustment mechanism

This regulatory balance relates to the difference between the level of CDM program activities included in LDC's load forecast used to set approved rates and the actual impact of CDM activities achieved. New variances are accrued based on current CDM activities. Approved variances for 2017 will be disposed through OEB-approved rate riders over 12 months commencing on January 1, 2019. Variances pertaining to years subsequent to 2017 have yet to be applied for disposition.

c) Foregone revenue

This regulatory balance relates to the revenue that LDC would have recovered in 2015 and 2016 if new OEB-approved rates were implemented as of May 1, 2015 and January 1, 2016, respectively. In the 2015 - 2019 CIR decision and rate order, the OEB approved foregone revenue rate riders over 46 months commencing on March 1, 2016 for May 1, 2015 to December 31, 2015 based on approved 2015 rates and for January 1, 2016 to February 29, 2016 based on approved 2016 rates.

d) Gain on disposal

This regulatory balance consists of the net of amounts disposed through the OEB-approved rate riders offset by the related tax savings (credits) and the after-tax gain realized on two significant LDC properties (credits). As part of the 2015 – 2019 CIR decision and rate order, LDC agreed to a rate rider that would pass the total forecasted net gains along with future tax savings on both properties back to ratepayers, effective from March 1, 2016 to December 31, 2018. The gain on disposal of the two properties was realized by LDC in 2015 and 2018, respectively. In the second quarter of 2017, LDC realized a gain in connection with the disposal of a third property.

The balance arising during the year ended December 31, 2018 relates to a realized gain of $98.6 million (net of tax and selling costs of $14.9 million), in connection with the disposal of the second property by LDC in 2018. The proceeds on the disposition of this property were $122.2 million. The actual realized gain and tax savings that exceeded the approved rate riders reduce future electricity distribution rates for customers. LDC is seeking disposition of this incremental balance in the 2020 – 2024 rate application *[note 3[a]]*. The timing of disposition of the incremental balance is currently unknown.

e) IFRS transitional adjustments

This regulatory balance relates to the differences arising from accounting policy changes for PP&E and intangible assets due to the transition from US GAAP to IFRS in 2014, primarily related to derecognition of certain assets and additional capitalized borrowing costs. In the 2015 – 2019 CIR decision and rate order, the OEB approved disposition of the balance over 46 months commencing on March 1, 2016.

f) OPEB cash versus accrual

This regulatory balance relates to the difference between LDC's forecasted OPEB costs determined on an accrual basis and the cash payments made under the OPEB plans. The OEB directed LDC to track the difference as a temporary arrangement, pending the OEB's conclusion on the sector-wide policy consultation it initiated on the regulatory treatment of pension and OPEB costs. On September 14, 2017, the OEB issued its final report on the consultation and established the use of the accrual accounting method as the default method on which to set rates for OPEB costs. LDC will continue to track the cash versus accrual difference until December 2019. LDC is seeking disposition of the balance in the 2020 – 2024 rate application *[note 3[a]]*. The timing of disposition of the balance is currently unknown.

g) Stranded meters and smart meters

These regulatory balances relate to the provincial government's decision to install smart meters throughout Ontario.

The net book value of stranded meters related to the deployment of smart meters was reclassified from PP&E to a new regulatory balance as at December 31, 2013. In the 2015 – 2019 CIR decision and rate order, the OEB approved LDC's request for recovery of the forecasted net book value of the stranded meters as at December 31, 2014 over 46 months commencing on March 1, 2016.

On January 16, 2014, the OEB approved LDC's request for incremental revenue and disposition of the smart meter regulatory balances to be recovered through rates over 36 months commencing on May 1, 2014. The OEB ruling on smart meters also permitted the recovery in principle of LDC's allowed cost of capital on smart meters since 2008, with a rate order issued to this effect. This allows LDC to recover the incremental revenue requirement associated with these assets for the period during which they remained outside of rate base.

h) Named properties

As part of 2010 rates, LDC had forecasted net gains on certain properties which were planned for sale between 2007 and 2011. This regulatory balance relates to the excess of those forecasted net gains over the actual net gains realized

upon the sale of the named properties. In the 2015 – 2019 CIR decision and rate order, the OEB approved disposition of this variance over 46 months commencing on March 1, 2016.

i) Capital contributions

This regulatory balance relates to the difference between amounts included in rates for HONI capital contributions and actual contributions made in 2010 and 2011. In the 2015 – 2019 CIR decision and rate order, the OEB approved disposition of this variance over 46 months commencing on March 1, 2016.

j) Capital-related revenue requirement

This regulatory balance relates to the asymmetrical variance between the cumulative 2015 to 2019 capital-related revenue requirement included in rates and the actual capital-related revenue requirement over the same period. If the cumulative 2015 to 2019 capital-related revenue requirement included in rates exceeds the actual capital-related revenue requirement over the same rate period, LDC must apply for disposition of this account in order to clear the balance to ratepayers through a rate rider. This account was approved by the OEB in the 2015 – 2019 CIR decision and rate order. LDC is seeking disposition of the balance in the 2020 – 2024 rate application *[note 3[a]]*. The timing of disposition of the balance is currently unknown

k) Derecognition

This regulatory balance relates to the difference between the revenue requirement on derecognition of PP&E and intangible assets included in the OEB-approved rates and the actual amounts of derecognition. This account was approved by the OEB in the 2015 – 2019 CIR decision and rate order. LDC is seeking disposition of the balance in the 2020 – 2024 rate application *[note 3[a]]*. The timing of disposition of the balance is currently unknown.

l) Settlement variances

This account includes the variances between amounts charged by LDC to customers, based on regulated rates, and the corresponding cost of electricity and non-competitive electricity service costs incurred by LDC. LDC has deferred the variances between the costs incurred and the related recoveries in accordance with the criteria set out in the accounting principles prescribed by the OEB. New variances are accrued based on current charges while approved variances up to 2017, including carrying charges forecasted to the end of 2018, will be disposed through OEB-approved rate riders over 12 months commencing on January 1, 2019. Settlement variances pertaining to years subsequent to 2017 have yet to be applied for disposition.

m) Development charges

This regulatory balance relates to excess expansion deposits retained by LDC where the requested number of connections or electricity demand were not met by the connecting customer. Pursuant to the OEB's Distribution System Code, LDC may collect expansion deposits on offers to connect from specific customers to guarantee the payment of additional costs relating to expansion projects. During the customer connection horizon, LDC has an obligation to annually return the expansion deposit to the connecting customer in proportion to the actual connections or electricity demand that occurred in that year. If the number of connections or electricity demand requested by the customer do not materialize by the end of the connection horizon, LDC retains the excess expansion deposit not otherwise returned to the connecting customer.

The excess expansion deposits were recorded as a regulatory balance on the balance sheets, with a corresponding offset in net movements in regulatory balances. LDC is seeking disposition of the balance in the 2020 – 2024 rate application *[note 3[a]]*. The timing of disposition of the balance is currently unknown.

n) Deferred taxes

This regulatory credit balance relates to both deferred tax amounts reclassified under IFRS 14 *Regulatory Deferral Accounts* ["IFRS 14"] *[note 25[a]]* and the expected future electricity distribution rate reduction for customers arising from timing differences in the recognition of deferred tax assets. LDC did not apply for disposition of the balance since it is reversed through timing differences in the recognition of deferred tax assets.

The amounts reclassified under IFRS 14 include the deferred tax asset related to regulatory balances of $1.1 million as at December 31, 2018 [December 31, 2017 - $34.9 million deferred tax liability], and the recognition of a regulatory balance in respect of additional temporary differences for which a deferred tax amount was recognized of $1.0 million as at December 31, 2018 [December 31, 2017 - $8.5 million]. The deferred tax amount related to the expected future electricity distribution rate reduction for customers was $4.0 million as at December 31, 2018 [December 31, 2017 - $32.4 million].

o) Tax-related variance accounts

This regulatory credit balance arose from favourable income tax reassessments on certain prior year tax positions received, which differed from those assumed in previous applications for electricity distribution rates. In the 2015 – 2019 CIR decision and rate order, the OEB approved disposition of the balance over 10-34 months commencing on March 1, 2016.

9. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

Accounts payable and accrued liabilities consist of the following:

	2018 $	2017 $
Trade payables	**335.1**	323.7
Accrued liabilities	**124.1**	129.6
Due to related parties *[note 22]*	**60.5**	58.3
Other	**2.0**	1.7
	521.7	513.3

10. DEFERRED REVENUE

Deferred revenue consists of capital contributions received from electricity customers and developers to construct or acquire PP&E and revenue from ancillary services which have not yet been recognized into other revenue *[note 25[i]]*.

	2018 $	2017 $
Capital contributions, beginning of year	**187.8**	143.2
Capital contributions received	**106.5**	50.8
Amortization	**(5.3)**	(4.7)
Other	**(0.8)**	(1.5)
Capital contributions, end of year	**288.2**	187.8
Other, beginning of year	**0.9**	1.0
Other received	**8.3**	7.9
Revenue recognized	**(7.3)**	(8.0)
Other, end of year	**1.9**	0.9
Total deferred revenue	**290.1**	188.7
Less: Current portion of deferred revenue relating to:		
Capital contributions	**10.5**	9.0
Other	**1.9**	0.9
Current portion of deferred revenue	**12.4**	9.9
Non-current portion of deferred revenue	**277.7**	178.8

11. NOTES PAYABLE TO RELATED PARTY

Notes payable to related party consist of the following:

	2018 $	2017 $
Notes payable to related party:		
4.54% Long-term note payable to the Corporation due November 12, 2019	**245.1**	245.1
5.59% Long-term note payable to the Corporation due May 21, 2040	**200.0**	200.0
3.59% Long-term note payable to the Corporation due November 18, 2021	**300.0**	300.0
2.96% Long-term note payable to the Corporation due April 10, 2023	**250.0**	250.0
4.01% Long-term note payable to the Corporation due April 9, 2063	**200.0**	200.0
4.13% Long-term note payable to the Corporation due September 16, 2044	**200.0**	200.0
3.60% Long-term note payable to the Corporation due July 28, 2045	**200.0**	200.0
3.988% Long-term note payable to the Corporation due April 9, 2063	**45.0**	45.0
2.572% Long-term note payable to the Corporation due August 25, 2026	**200.0**	200.0
3.535% Long-term note payable to the Corporation due February 28, 2048	**200.0**	200.0
6.16% Demand note payable to the Corporation due on demand	**45.0**	45.0
3.32% Demand note payable to the Corporation due on the earlier of demand and January 1, 2022	**15.0**	15.0
Total notes payable to related party	**2,100.1**	2,100.1
Less: Unamortized debt issuance costs	**9.5**	10.2
Current portion of notes payable to related party *[note 22]*	**304.9**	60.0
Long-term portion of notes payable to related party *[note 22]*	**1,785.7**	2,029.9

All notes payable to the Corporation are unsecured, rank equally and will be settled in cash.

On November 14, 2017, LDC issued a promissory note to the Corporation. The principal amount of the promissory note is $200.0 million payable on February 28, 2048, which bears interest at a rate of 3.535% per annum. Interest is calculated and payable semi-annually in arrears on February 28 and August 28 of each year. The net proceeds from the promissory note were used to repay certain existing indebtedness of LDC and for general corporate purposes.

12. EMPLOYEE FUTURE BENEFITS

Pension

LDC's eligible employees participate in a defined benefit pension plan through OMERS. As at December 31, 2018, the OMERS plan was 96.0% funded [December 31, 2017 - 94.0%]. OMERS has a strategy to return the plan to a fully funded position. LDC is not able to assess the implications, if any, of this strategy or of the withdrawal of other participating entities from the OMERS plan on its future contributions. For the year ended December 31, 2018, LDC's contributions were $18.0 million [2017 - $17.5 million], representing less than five percent of total contributions to the OMERS plan. LDC expects to contribute approximately $19.8 million to the OMERS plan in 2019.

Post-employment benefits other than pension

a) Benefit obligation

	2018 $	2017 $
Balance, beginning of year	**313.0**	280.5
Current service cost	**4.6**	4.0
Interest cost	**10.8**	11.0
Benefits paid	**(10.9)**	(11.0)
Experience loss (gain) [(1)]	**(8.2)**	1.9
Actuarial gain arising from changes in demographic assumptions [(1)]	**(22.4)**	—
Actuarial loss (gain) arising from changes in financial assumptions [(1)]	**(11.4)**	26.3
Transfer from related parties	**0.4**	0.3
Balance, end of year	**275.9**	313.0

[(1)] Actuarial loss (gain) on accumulated sick leave credits of ($4.7) million [2017 - $3.1 million] is recognized in benefit cost *[note 12[c]]* and $(0.1) million in transfer from related parties [2017 - $nil], and actuarial loss (gain) on medical, dental and life insurance benefits of ($37.2) million [2017 - $25.1 million] is recognized in OCI *[note 12[d]]*.

b) Amounts recognized in regulatory balances

As at December 31, 2018, the amount recognized in regulatory balances related to net actuarial loss was $48.1 million [December 31, 2017 - $85.3 million] *[note 8[a]]*.

c) Benefit cost recognized

	2018 $	2017 $
Current service cost	**4.6**	4.0
Interest cost	**10.8**	11.0
Actuarial loss (gain) on other employee benefits *[note 12[a]]*	**(4.7)**	3.1
Benefit cost	**10.7**	18.1
Capitalized to PP&E and intangible assets	**4.8**	8.1
Charged to operating expenses	**5.9**	10.0

d) Amounts recognized in OCI

	2018 $	2017 $
Actuarial loss (gain) *[note 12[a]]*	**(37.2)**	25.1
Income tax expense (recovery) in OCI *[note 20]*	**9.9**	(6.7)
Remeasurements of post-employment benefits, net of tax	**(27.3)**	18.4
Net movements in regulatory balances related to OCI, net of tax	**27.3**	(18.4)
OCI, net of tax	**—**	—

e) Significant assumptions

	2018	2017
Discount rate (%) used in the calculation of:		
Benefit obligation as at December 31	**3.75**	3.50
Assumed medical and dental cost trend rates (%) as at December 31:		
Rate of increase in dental costs assumed for next year	**4.00**	4.00
Rate of increase in medical costs assumed for next year		
For pre July 2000 retirements	**5.00**	5.00
For other retirements	**5.00**	5.50
Rate that medical cost trend rate gradually declines to		
For pre July 2000 retirements	**5.00**	5.00
For other retirements	**5.00**	5.00
Year that the medical cost trend rate reaches the ultimate trend rate		
For pre July 2000 retirements	**2015**	2015
For other retirements	**2018**	2018

f) Sensitivity analysis

Significant actuarial assumptions for benefit obligation measurement purposes are discount rate and assumed medical and dental cost trend rates. The weighted average duration of the benefit obligation as at December 31, 2018 was 16.7 [2017 – 16.7]. The sensitivity analysis below has been determined based on reasonably possible changes of the assumptions, in isolation of one another, occurring at the end of the reporting period. This analysis may not be representative of the actual change since it is unlikely that changes in the assumptions would occur in isolation of one another as some of the assumptions may be correlated.

Changes in key assumptions would have had the following effect on the benefit obligation:

	Change in assumption	2018 $	2017 $
Benefit obligation		**275.9**	313.0
Discount rate	1% ↑	**(41.3)**	(46.8)
	1% ↓	**53.1**	60.2
Medical and dental cost trend rate	1% ↑	**35.7**	40.2
	1% ↓	**(31.9)**	(36.0)

13. CAPITAL MANAGEMENT

LDC's main objectives when managing capital are to:

- ensure ongoing access to funding to maintain, refurbish and expand the electricity distribution system;
- ensure sufficient liquidity is available (either through cash and cash equivalents or borrowings through TH Energy or the Corporation) to meet the needs of the business; and
- minimize finance costs while taking into consideration current and future industry, market and economic risks and conditions.

LDC monitors forecasted cash flows, capital expenditures, debt repayment and key credit ratios similar to those used by key rating agencies. LDC manages capital by preparing short-term and long-term cash flow forecasts. In addition, LDC borrows from TH Energy or the Corporation as required to help fund some of the periodic net cash outflows and to maintain available liquidity. There have been no changes in LDC's approach to capital management during the year. As at December 31, 2018, LDC's definition of capital included equity, bank indebtedness, borrowings through the Corporation and obligations under leases, including the current portion thereof, and has remained unchanged from the definition as at December 31, 2017. As at December 31, 2018, equity amounted to $1,836.6 million [December 31, 2017 - $1,716.3 million], and bank indebtedness, borrowings through the Corporation and obligations under leases, including the current portion thereof, amounted to $2,113.6 million [December 31, 2017 - $2,216.4 million].

14. FINANCIAL INSTRUMENTS

a) Recognition and measurement

As at December 31, 2018 and December 31, 2017, the fair values of cash and cash equivalents, accounts receivable, unbilled revenue, bank indebtedness, and accounts payable approximated their carrying amounts due to the short maturity of these instruments *[note 25[j]]*. The fair value of customer deposits approximates their carrying amounts taking into account interest accrued on the outstanding balance. Obligations under leases are measured based on a discounted cash flow analysis and approximate the carrying amounts as management believes that the fixed interest rates are representative of current market rates.

The carrying amounts and fair values of LDC's notes payable to related party consist of the following:

	2018 $		2017 $	
	Carrying amount	**Fair value [(1)]**	**Carrying amount**	**Fair value [(1)]**
Long-term notes payable to the Corporation				
4.54% due November 12, 2019	**244.9**	**249.5**	244.7	255.6
5.59% due May 21, 2040	**198.9**	**249.3**	198.9	263.9
3.59% due November 18, 2021	**299.4**	**307.6**	299.2	313.9
2.96% due April 10, 2023	**249.4**	**250.7**	249.2	255.8
4.01% due April 9, 2063	**198.7**	**201.1**	198.7	217.4
4.13% due September 16, 2044	**198.5**	**208.0**	198.5	221.1
3.60% due July 28, 2045	**198.7**	**190.7**	198.7	202.9
3.988% due April 9, 2063	**44.5**	**45.0**	44.5	48.7
2.572% due August 25, 2026	**199.0**	**192.4**	198.9	195.4
3.535% due February 28, 2048	**198.6**	**187.9**	198.6	202.5
Demand note payable to the Corporation due on demand	**45.0**	**45.0**	45.0	45.0
Demand note payable to the Corporation due on the earlier of demand and January 1, 2022	**15.0**	**15.3**	15.0	15.6
	2,090.6	**2,142.5**	2,089.9	2,237.8

[(1)] The fair value measurement of financial instruments for which the fair value has been disclosed is included in Level 2 of the fair value hierarchy *[note 25[k]]*.

b) Financial risks

The following is a discussion of financial risks and related mitigation strategies that have been identified by LDC for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks listed.

Credit risk

LDC is exposed to credit risk as a result of the risk of counterparties defaulting on their obligations. LDC monitors and limits its exposure to credit risk on a continuous basis. The credit risk related to cash and cash equivalents is mitigated by LDC's treasury policies on assessing and monitoring the credit exposures of counterparties.

LDC's exposure to credit risk primarily relates to accounts receivable and unbilled revenue. LDC is subject to credit risk with respect to customer non-payment of electricity bills. As at December 31, 2018, LDC had approximately 772,000 customers. LDC obtains security instruments from certain customers in accordance with direction provided by the OEB. As at December 31, 2018, LDC held security deposits in the amount of $79.8 million [December 31, 2017 - $58.2 million], of which $51.9 million [December 31, 2017 - $29.8 million] was related to security deposits on offers to connect to guarantee the payment of additional costs related to expansion projects. LDC's security instruments may not provide sufficient protection from counterparties defaulting on their obligations. As at December 31, 2018, there were no significant concentrations of credit risk with respect to any customer. The credit risk and mitigation strategies with respect to unbilled revenue are the same as those for accounts receivable.

LDC did not have any single customer that generated more than 10% of total revenue for the years ended December 31, 2018 and December 31, 2017.

Credit risk associated with accounts receivable and unbilled revenue is as follows:

	2018 $	2017 $
Accounts receivable (net of loss allowance)		
Outstanding for not more than 30 days	**185.7**	180.3
Outstanding for more than 30 days and not more than 120 days	**20.2**	32.6
Outstanding for more than 120 days	**4.5**	4.3
Total accounts receivable	**210.4**	217.2
Unbilled revenue (net of loss allowance)	**279.7**	276.0
Total accounts receivable and unbilled revenue	**490.1**	493.2

Unbilled revenue represents amounts for which LDC has a contractual right to receive cash through future billings and are unbilled at period-end. Unbilled revenue is considered in conjunction with accounts receivable and is included in the loss allowance as at December 31, 2018 and December 31, 2017.

LDC has a broad base of customers. As at December 31, 2018 and December 31, 2017, LDC's accounts receivable and unbilled revenue which were not past due or impaired were assessed by management to have no significant collection risk and no additional loss allowance was required for these balances.

Reconciliation between the opening and closing loss allowance balances for accounts receivable and unbilled revenue is as follows:

	2018 $	2017 $
Balance, beginning of year	**(10.2)**	(9.7)
Transitional adjustment *[note 25[p]]*	**(0.3)**	—
Loss allowance	**(4.3)**	(6.2)
Write-offs	**4.4**	5.9
Recoveries	**(0.2)**	(0.2)
Balance, end of year	**(10.6)**	(10.2)

c) Market risks

Interest rate risk

LDC is exposed to fluctuations in interest rates for the valuation of its post-employment benefit obligations *[note 12[f]]*. LDC is also exposed to short-term interest rate risk on the net of cash and cash equivalents and customer deposits. Notes payable to related party bear interest based on the prevailing market conditions at the time of issuance.

As at December 31, 2018, aside from the valuation of its post-employment benefit obligations, LDC was exposed to interest rate risk predominately from cash and cash equivalents (bank indebtedness) and customer deposits, while most of its remaining obligations were either non-interest bearing or bear fixed interest rates, and its financial assets were predominately short-term in nature and mostly non-interest bearing. LDC estimates that a 100 basis point increase (decrease) in short-term interest rates, with all other variables held constant, would result in an increase (decrease) of approximately $1.0 million to annual finance costs.

Liquidity risk

LDC is exposed to liquidity risk related to its ability to fund its obligations as they become due. LDC monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and financial requirements. LDC has access to credit facilities and borrowings through the Corporation and monitors cash balances daily. LDC's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing finance costs.

Liquidity risks associated with financial commitments are as follows:

2018	Due within 1 year $	Due within 2 years $	Due within 3 years $	Due within 4 years $	Due within 5 years $	Due after 5 years $
Bank indebtedness	**21.5**	—	—	—	—	—
Accounts payable and accrued liabilities [(1)]	**502.3**	—	—	—	—	—
Obligations under lease	**0.3**	**0.3**	**0.3**	**0.2**	**0.1**	**0.1**
Long-term notes payable to the Corporation						
4.54% due November 12, 2019	**245.1**	—	—	—	—	—
5.59% due May 21, 2040	—	—	—	—	—	**300.0**
3.59% due November 18, 2021	—	—	**300.0**	—	—	—
2.96% due April 10, 2023	—	—	—	—	**250.0**	—
4.01% due April 9, 2063	—	—	—	—	—	**200.0**
4.13% due September 16, 2044	—	—	—	—	—	**200.0**
3.60% due July 28, 2045	—	—	—	—	—	**200.0**
3.988% due April 9, 2063	—	—	—	—	—	**45.0**
2.572% due August 25, 2026	—	—	—	—	—	**200.0**
3.535% due February 28, 2048	—	—	—	—	—	**200.0**
Demand note payable to the Corporation due on demand	**45.0**	—	—	—	—	—
Demand note payable to the Corporation due on the earlier of demand and January 1, 2022	**15.0**	—	—	—	—	—
Interest payments on long-term notes payable and demand notes payable	**79.8**	**67.3**	**67.3**	**56.3**	**52.4**	**1,092.7**
	909.0	**67.6**	**367.6**	**56.5**	**302.5**	**2,437.8**

[(1)] Accounts payable and accrued liabilities exclude $19.4 million of accrued interest on long-term notes payable and demand notes payable included within "Interest payments on long-term notes payable and demand notes payable".

Foreign exchange risk

As at December 31, 2018, LDC had limited exposure to the changing values of foreign currencies. While LDC purchases goods and services which are payable in US dollars, and purchases US currency to meet the related commitments when required, the impact of these transactions is not material to the financial statements.

15. FINANCIAL ASSISTANCE

As at December 31, 2018, $33.3 million [December 31, 2017 - $38.4 million] of letters of credit had been issued by the Corporation, on behalf of LDC, under its $75.0 million demand facility mainly to support LDC's prudential requirements with the IESO.

16. SHARE CAPITAL

Share capital consists of the following:

	2018 $	2017 $
Authorized		
The authorized share capital of LDC consists of an unlimited number of common shares without par value.		
Issued and outstanding		
1,000 common shares, of which all were fully paid.	**556.3**	556.3

Dividends

On May 14, 2018, the Board of Directors of LDC declared dividends in the amount of $42.7 million to the Corporation [2017 - $2.1 million], which was paid out on June 29, 2018.

17. REVENUES

Revenues consist of the following:

	2018 $	2017 $
		Restated *[note 25[p]]*
Revenue from contracts with customers		
Energy sales	**2,704.1**	2,810.2
Distribution revenue	**674.2**	724.2
Ancillary services revenue	**22.9**	17.6
Street lighting services	**8.0**	9.2
Pole and duct rentals	**15.7**	15.8
Other regulatory service charges	**11.7**	13.3
Miscellaneous	**9.0**	13.7
Revenue from other sources		
Capital contributions	**5.3**	4.7
CDM mid-term incentive *[note 3[c]]*	**2.7**	12.2
Other	**5.2**	10.2
	3,458.8	3,631.1

Energy sales and Distribution revenue by customer class are as follows:

	2018 $	2017 $
		Restated *[note 25[p]]*
Residential service [1]	**815.4**	902.3
General service [2]	**2,337.3**	2,394.5
Large users [3]	**225.6**	237.6
Total energy sales and distribution revenue	**3,378.3**	3,534.4

[1] "Residential Service" means a service that is for domestic or household purposes, including single family or individually metered multifamily units and seasonal occupancy.
[2] "General Service" means a service supplied to premises other than those receiving "Residential Service" and "Large Users" and typically includes small businesses and bulk-metered multi-unit residential establishments. This service is provided to customers with a monthly peak demand of less than 5,000 kW averaged over a twelve-month period.
[3] "Large Users" means a service provided to a customer with a monthly peak demand of 5,000 kW or greater averaged over a twelve-month period.

18. OPERATING EXPENSES

Operating expenses consist of the following:

	2018 $	2017 $
Salaries and benefits	**230.1**	225.4
External services	**143.5**	131.9
Other support costs [1]	**21.9**	21.6
Materials and supplies	**20.2**	21.3
Less: Capitalized costs	**(118.6)**	(116.0)
	297.1	284.2

[1] Includes taxes other than income taxes, utilities, rental, communication, insurance, and other general and administrative expenses.

For the year ended December 31, 2018, LDC recognized operating expenses of $11.7 million related to materials and supplies used to service electricity distribution assets [2017 - $13.0 million].

19. FINANCE COSTS

Finance costs consist of the following:

	2018 $	2017 $
Interest income	**(0.6)**	(0.3)
Interest expense		
Interest on long-term debt [(1)]	**82.2**	87.1
Interest on short-term debt	**4.7**	3.3
Other interest	**0.9**	0.7
Capitalized borrowing costs	**(8.9)**	(9.8)
	78.3	81.0

[(1)] Includes amortization of debt issuance costs, discounts and premiums.

20. INCOME TAXES

Income tax expense differs from the amount that would have been recorded using the combined statutory Canadian federal and provincial income tax rate. Reconciliation of income tax expense computed at the statutory income tax rate to the income tax provision is set out below:

	2018 $	2017 $
Rate reconciliation before net movements in regulatory balances		
Income before income taxes	**309.8**	197.5
Statutory Canadian federal and provincial income tax rate	**26.5%**	26.5%
Expected income tax expense	**82.1**	52.3
Non-taxable amounts	**(9.4)**	(10.0)
Gain on disposal	**8.0**	1.3
Other	**0.9**	0.6
Income tax expense	**81.6**	44.2
Effective tax rate	**26.3%**	22.4%
Rate reconciliation after net movements in regulatory balances		
Net income after net movements in regulatory balances, before income tax [(1)]	**197.9**	184.4
Statutory Canadian federal and provincial income tax rate	**26.5%**	26.5%
Expected income tax expense	**52.4**	48.9
Temporary differences recoverable in future rates	**(25.5)**	(17.4)
Gain on disposal	**8.0**	1.3
Other	**(0.3)**	(1.8)
Income tax expense and income tax recorded in net movements in regulatory balances	**34.6**	31.0
Effective tax rate	**17.5%**	16.8%

[(1)] Income tax includes income tax expense and income tax recorded in net movements in regulatory balances.

Income tax expense as presented in the statements of income and statements of comprehensive income are as follows:

	2018 $	2017 $
Income tax expense	**81.6**	44.2
Income tax recorded in net movements in regulatory balances	**(47.0)**	(13.2)
Income tax expense and income tax recorded in net movements in regulatory balances	**34.6**	31.0
Income tax expense (recovery) in OCI *[note 12[d]]*	**9.9**	(6.7)
Income tax expense (recovery) in OCI recorded in net movements in regulatory balances	**(9.9)**	6.7
Income tax expense in OCI	**—**	—

Components of income tax expense and income tax recorded in net movements in regulatory balances are as follows:

	2018 $	2017 $
Current tax expense		
Current year	**35.3**	32.0
Adjustment for tax positions taken in prior periods	**(0.6)**	(1.1)
	34.7	30.9
Deferred tax expense		
Origination and reversal of temporary differences	**(0.1)**	0.1
Income tax expense and income tax recorded in net movements in regulatory balances	**34.6**	31.0

Deferred tax assets consist of the following:

	Net balance January 1, 2018 $	Recognized in net income $	Recognized in OCI $	Net balance December 31, 2018 $
PP&E and intangible assets	**(14.9)**	**(31.0)**	**—**	**(45.9)**
Post-employment benefits	**82.9**	**—**	**(9.9)**	**73.0**
Other taxable temporary differences	**(11.0)**	**(15.8)**	**—**	**(26.8)**
	57.0	**(46.8)**	**(9.9)**	**0.3**

	Net balance January 1, 2017 $	Recognized in net income $	Recognized in OCI $	Net balance December 31, 2017 $
PP&E and intangible assets	11.7	(26.6)	—	(14.9)
Post-employment benefits	74.3	1.9	6.7	82.9
Other taxable temporary differences	(22.2)	11.2	—	(11.0)
	63.8	(13.5)	6.7	57.0

LDC had recorded a net deferred tax asset as it expects to earn sufficient taxable income to realize the future reversal of deductible temporary differences.

21. STATEMENTS OF CASH FLOWS

Changes in non-cash working capital provided (used) cash as follows:

	2018 $	2017 $
Accounts receivable	**6.8**	8.7
Unbilled revenue	**(4.6)**	43.7
Materials and supplies	**1.2**	0.4
Other current assets	**2.0**	0.8
Accounts payable and accrued liabilities	**5.6**	(4.2)
Income tax payable	**(7.7)**	3.5
Deferred revenue	**2.5**	5.6
Deferred conservation credit	**(1.1)**	3.8
Other current liabilities	**(1.2)**	(1.6)
	3.5	60.7

Reconciliation between the amounts presented on the statements of cash flows and total additions to PP&E and intangible assets is as follows:

	2018 $	2017 $
Purchase of PP&E, cash basis	**431.8**	433.8
Net change in accruals related to PP&E	**19.3**	9.5
Other	**2.6**	1.6
Total additions to PP&E	**453.7**	444.9
Purchase of intangible assets, cash basis	**54.5**	93.4
Net change in accruals related to intangible assets	**(5.9)**	8.0
Total additions to intangible assets	**48.6**	101.4

Summary of changes in liabilities arising from financing activities:

	2017 $	Cash flows [1] $	Non-cash changes $		2018 $
			Foreign exchange	Other	
Year ended December 31					
Dividends payable	**—**	**(42.7)**	**—**	**42.7**	**—**
Notes payable to related party *[note 11]*	**2,089.9**	**—**	**—**	**0.7**	**2,090.6**
Accrued interest [2]	**17.7**	**(81.8)**	**—**	**83.5**	**19.4**
Lease liability [3]	**1.5**	**(1.8)**	**—**	**1.6**	**1.3**
	2,109.1	**(126.3)**	**—**	**128.5**	**2,111.3**

	2016 $	Cash flows [1] $	Non-cash changes $		2017 $
			Foreign exchange	Other	
Year ended December 31					
Dividends payable	—	(2.1)	—	2.1	—
Notes payable to related party *[note 11]*	2,135.5	(46.5)	—	0.9	2,089.9
Accrued interest [2]	18.5	(90.2)	—	89.4	17.7
Lease liability [3]	4.6	(3.0)	(0.1)	—	1.5
	2,158.6	(141.8)	(0.1)	92.4	2,109.1

(1) Cash inflows and cash outflows arising from notes payable to related parties are presented on a net basis.
(2) Included within accounts payable and accrued liabilities *[note 14[c]]*.
(3) Included within other liabilities.

22. RELATED PARTY TRANSACTIONS

For LDC, transactions with related parties include transactions with the City, which is the sole shareholder of the Corporation, the Corporation, and TH Energy, a wholly-owned subsidiary of the Corporation.

	City $	Corporation $	TH Energy $
For period ended December 31, 2018			
Revenues	**255.5**	**—**	**8.4**
Operating expenses (recoveries) and capital expenditures	**18.1**	**2.0**	**(0.8)**
Finance costs	**—**	**84.5**	**—**
Dividends declared and paid	**—**	**42.7**	**—**
As at December 31, 2018			
Accounts receivable	**4.5**	**—**	**1.3**
Unbilled revenue	**22.6**	**—**	**—**
Accounts payable and accrued liabilities	**40.3**	**20.2**	**—**
Current portion of notes payable to related party	**—**	**304.9**	**—**
Long-term portion of notes payable to related party	**—**	**1,785.7**	**—**
Customer deposits	**17.3**	**—**	**—**
Deferred revenue	**2.1**	**—**	**—**

	City $	Corporation $	TH Energy $
For period ended December 31, 2017			
Revenues	263.1	—	10.7
Operating expenses and capital expenditures	22.1	1.6	(1.1)
Finance costs	—	87.0	—
Dividends declared and paid	—	2.1	—
As at December 31, 2017			
Accounts receivable	12.7	—	2.1
Unbilled revenue	24.7	—	—
Accounts payable and accrued liabilities	40.0	18.3	—
Current portion of notes payable to related party	—	60.0	—
Long-term portion of notes payable to related party	—	2,029.9	—
Customer deposits	15.7	—	—
Deferred revenue	1.5	—	—

Revenues represent amounts charged to the City primarily for electricity and ancillary services, and to TH Energy for street lighting and ancillary services. Operating expenses and capital expenditures represent amounts charged by the City for purchased road cut repairs, property taxes and other services, and the Corporation for purchased corporate and management services. Operating expense recoveries represent amounts charged to TH Energy for the provision of goods and services. Finance costs represent interest charged by the Corporation on the notes payable *[note 19]*. Dividends are paid to the Corporation *[note 16]*.

Accounts receivable represent receivables from the City primarily for electricity and ancillary services, and TH Energy for the provision of goods and services. Unbilled revenue represents receivables from the City mainly related to electricity provided and not yet billed. Accounts payable and accrued liabilities represent amounts payable to the City

related to road cut repairs and other services. Included in the accounts payable and accrued liabilities are amounts payable to the Corporation for purchased corporate and management services and interest accruing on the notes payable to the Corporation. Notes payable to related party represent amounts borrowed from the Corporation *[note 11]*. Customer deposits represent amounts received from the City for future expansion projects. Deferred revenue represents amounts received from the City primarily for the construction of electricity distribution assets.

Key management personnel include LDC's senior executive officers and members of the Board of Directors. The compensation costs associated with the key management personnel are as follows:

	2018 $	2017 $
Short-term employee benefits	**4.5**	4.3
Post-employment benefits	**1.0**	1.1
Termination benefits	**1.8**	—
	7.3	5.4

23. COMMITMENTS

Capital projects

As at December 31, 2018, the future minimum payments for capital projects and other commitments were as follows:

	Capital projects [1] and other $
Less than one year	**25.4**
Between one and five years	**10.1**
Total amount of future minimum payments [2]	**35.5**

[1] Mainly commitments for construction services.
[2] Refer to note 14 for financial commitments excluded from the table above.

Leases

As at December 31, 2018, the contractual undiscounted cash flows related to leases were as follows:

	2018 $		
	Future minimum lease payments	Interest	Present value of minimum lease payments
Less than one year	**0.3**	**—**	**0.3**
Between one and five years	**1.0**	**0.1**	**0.9**
More than five years	**0.1**	**—**	**0.1**
	1.4	**0.1**	**1.3**
Current portion included within other liabilities			**0.3**
Non-current portion included within other liabilities			**1.0**

24. CONTINGENCIES

Legal Proceedings

In the ordinary course of business, LDC is subject to various legal actions and claims from customers, suppliers, former employees and other parties. On an ongoing basis, LDC assesses the likelihood of any adverse judgments or outcomes as well as potential ranges of probable costs and losses. A determination of the provision required, if any, for these contingencies is made after an analysis of each individual issue. The provision may change in the future due to new developments in each matter or changes in approach, such as a change in settlement strategy. If damages were awarded under these actions, LDC would make a claim under any applicable liability insurance policies which LDC believes would cover any damages which may become payable by LDC in connection with these actions, subject to such claim not being disputed by the insurers.

25. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

a) Regulation

The following regulatory treatments have resulted in accounting treatments which differ from those prescribed by IFRS for enterprises operating in an unregulated environment and regulated entities that did not adopt IFRS 14:

Regulatory Balances

In January 2014, the IASB issued IFRS 14 as an interim standard giving entities conducting rate-regulated activities the option of continuing to recognize regulatory balances according to their previous GAAP. Regulatory balances provide useful information about LDC's financial position, financial performance and cash flows. IFRS 14 is restricted to first-time adopters of IFRS and remains in force until either repealed or replaced by permanent guidance on rate-regulated accounting from the IASB.

LDC has determined that certain debit and credit balances arising from rate-regulated activities qualify for the application of regulatory accounting treatment in accordance with IFRS 14 and the accounting principles prescribed by the OEB in the "Accounting Procedures Handbook for Electricity Distributors". Under rate-regulated accounting, the timing and recognition of certain expenses and revenues may differ from those otherwise expected under other IFRS in order to appropriately reflect the economic impact of regulatory decisions regarding LDC's regulated revenues and expenditures. These amounts arising from timing differences are recorded as regulatory debit and credit balances on LDC's balance sheets, and represent existing rights and obligations regarding cash flows expected to be recovered from or refunded to customers, based on decisions and approvals by the OEB. Regulatory balances can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment or if future OEB direction is determined by management to be probable. In the event that the disposition of these balances is assessed to no longer be probable based on management's judgment, the balances are recorded in LDC's statements of income in the period when the assessment is made. Regulatory balances, which do not meet the definition of an asset or liability under any other IFRS, are segregated on the balance sheets and are presented on the statements of income and the statements of comprehensive income as net movements in regulatory balances and net movements in regulatory balances related to OCI, net of tax. The netting of regulatory debit and credit balances is not permitted. The measurement of regulatory balances is subject to certain estimates and assumptions, including assumptions made in the interpretation of the OEB's regulations and decisions.

b) Cash and cash equivalents

Cash and cash equivalents include cash in bank accounts and short-term investments with terms to maturity of 90 days or less from their date of acquisition. On the statements of cash flows, cash and cash equivalents (bank indebtedness) include bank overdrafts that are repayable on demand and form an integral part of LDC's cash management.

c) Accounts receivable and unbilled revenue

Accounts receivable are recorded at the invoiced amount and overdue amounts bear interest at OEB-approved rates. Unbilled revenue is recorded based on an estimated amount for electricity delivered and for other services provided and not yet billed. The estimate is primarily based on the customers' previous billings with adjustments mainly for assumptions related to seasonality and weighted average price. The carrying amount of accounts receivable and unbilled revenue is reduced through a loss allowance, if applicable, and the amount of the related impairment loss is recognized in the statements of income. The impairment loss is the difference between an asset's carrying amount and the estimated future cash flows. When LDC considers that there are no realistic prospects of recovery of the financial assets, the relevant amounts are written off. If the amount of impairment loss subsequently decreases due to an event occurring after the impairment was recognized, then the previously recognized impairment loss is reversed through net income.

Accounts receivable and unbilled revenue are assessed at each reporting date to determine whether there is objective evidence of impairment, which includes default or delinquency by a debtor, indications that a debtor or issuer will enter bankruptcy, and adverse changes in the payment status of borrowers or issuers. Accounts receivable and unbilled revenue that are not individually assessed for impairment are collectively assessed for impairment by grouping together receivables with similar risk characteristics, and LDC considers historical trends on the timing of recoveries and the amount of loss incurred, adjusted for forward-looking factors specific to the current economic and credit conditions.

Effective January 1, 2018, LDC measures the loss allowance at an amount equal to the lifetime expected credit losses ["ECL"] for all trade receivables or contract assets that result from transactions with customers and do not contain a significant financing component. A provision matrix is used by LDC to measure the lifetime ECL of accounts receivable from individual customers. Loss rates are calculated using a 'roll rate' method based on the probability of a trade receivable progressing through successive stages of delinquency to write-off and are based on the average of actual credit loss experience over the past three years, as it more accurately reflects anticipated credit loss. Roll rates are calculated separately for exposures in different customer classes.

d) Materials and supplies

Materials and supplies consist primarily of small consumable materials mainly related to the maintenance of the electricity distribution infrastructure. LDC classifies all major construction related components of its electricity distribution infrastructure to PP&E. Materials and supplies are carried at the lower of cost and net realizable value, with cost determined on a weighted average cost basis net of a provision for obsolescence.

e) Property, plant and equipment

PP&E are measured at cost less accumulated depreciation and any accumulated impairment losses, if applicable. The cost of PP&E represents the original cost, consisting of direct materials and labour, contracted services, borrowing costs, and directly attributable overhead. Subsequent costs are capitalized only if it is probable that the future economic benefits associated with the expenditure will flow to LDC and the costs can be measured reliably. If significant parts of an item of PP&E have different useful lives, then they are accounted for as separate major components of PP&E. The carrying amount of an item of PP&E is derecognized on disposal of the asset or when no future economic benefits are expected to accrue to LDC from its continued use. Any gain or loss arising on derecognition is recorded in the statements of income in the period in which the asset is derecognized. The gain or loss on disposal of an item of PP&E is determined as the sale proceeds less the carrying amount of the asset and costs of removal and is recognized in the statements of income.

Depreciation begins when an asset becomes available for use. Depreciation is provided on a straight-line basis over the estimated useful lives at the following annual rates:

Distribution assets:	
Distribution lines	1.7% to 5.0%
Transformers	3.3% to 5.0%
Meters	2.5% to 6.7%
Stations	2.0% to 10.0%
Buildings	1.3% to 5.0%
Equipment and other:	
Other capital assets	4.0% to 25.0%
Right-of-use assets	1.0% to 21.1%

Right-of-use assets are depreciated over the shorter of the lease term and their useful lives unless it is reasonably certain that LDC will obtain ownership by the end of the lease term, in which case they are depreciated to the end of the useful life of the underlying assets. Right-of-use assets are recognized for contracts that are, or contain, leases. Construction in progress relates to assets not currently available for use and therefore is not depreciated. The depreciation method and useful lives are reviewed at each financial year-end and adjusted if appropriate. There are no residual values for items of PP&E.

f) Intangible assets

Intangible assets are measured at cost less accumulated amortization and any accumulated impairment losses, if applicable.

Amortization begins when an asset becomes available for use. Amortization is provided on a straight-line basis over the estimated useful lives at the following annual rates:

Computer software	10.0% to 25.0%
Contributions	4.0%

Software in development and contributions for work in progress relate to assets not currently available for use and therefore are not amortized. Contributions represent payments made to HONI for dedicated infrastructure in order to receive connections to transmission facilities. The amortization method and useful lives are reviewed at each financial year-end and adjusted if appropriate.

g) Impairment of non-financial assets

LDC reviews the carrying amounts of its non-financial assets other than materials and supplies and deferred tax assets at each reporting date to determine whether there is any indication of impairment, in which case the assets' recoverable amounts are estimated. For impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent on the cash inflows of other assets or CGUs. LDC has determined that its assets are a single CGU due to interdependencies of its assets to generate cash flows. An impairment loss is recognized if the carrying amount of an asset or CGU exceeds its recoverable amount. Impairment losses are recognized in the statements of income, and are allocated to reduce the carrying amounts of assets in the CGU on a pro rata basis. An impairment loss recognized in prior periods is reversed when an asset's recoverable amount has increased, but not exceeding the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior years.

h) Capitalized borrowing costs

Borrowing costs directly attributable to the acquisition, construction or development of qualifying assets that necessarily take a substantial period of time to get ready for their intended use are capitalized, until such time as the assets are substantially ready for their intended use. The interest rate for capitalization is LDC's weighted average

cost of borrowing, and is applied to the carrying amount of the construction-in-progress assets or assets under development including borrowing costs previously capitalized, net of capital contributions received. Capitalization commences immediately as the expenditure on a qualifying asset is incurred. Borrowing costs are included in the cost of PP&E and intangible assets for financial reporting purposes, and charged to operations through depreciation and amortization expense over the useful lives of the related assets.

i) Revenue recognition

LDC assesses each contract with the customer to identify the performance obligation. Revenue is recognized when the control of the goods or services has been transferred to the customer at a point of time or over time. The transaction price and the payment terms are agreed upon in the contract between LDC and the customer.

Revenues from energy sales and electricity distribution are recorded on the basis of cyclical billings and include an estimated amount for electricity delivered and not yet billed. The performance obligation is satisfied over time when the electricity is simultaneously received and consumed by the customer. The majority of billings cycle and payment terms are on a monthly basis. These revenues are impacted by energy demand primarily driven by outside temperature, and customer class usage patterns and composition.

Energy sales arise from charges to customers for electricity consumed, based on regulated rates. Energy sales include amounts billed or billable to customers for commodity charges, retail transmission charges, and WMS charges at current rates. These charges are passed through to customers over time and are considered revenue by LDC due to the collection risk of the related balances. LDC applies judgment to determine whether revenues are recorded on a gross or net basis. LDC has primary responsibility for the delivery of electricity to the customer. For any given period, energy sales should be equal to the cost of energy purchased. However, a difference between energy sales and energy purchases arises when there is a timing difference between the amounts charged by LDC to customers, based on regulated rates, and the electricity and non-competitive electricity service costs billed monthly by the IESO to LDC. This difference is recorded as a settlement variance, representing future amounts to be recovered from or refunded to customers through future billing rates approved by the OEB. In accordance with IFRS 14, this settlement variance is presented within regulatory balances on the balance sheets and within net movements in regulatory balances on the statements of income.

Distribution revenue is recorded based on OEB-approved distribution rates to recover the costs incurred by LDC in delivering electricity to customers. Distribution revenue also includes revenue related to the collection of OEB-approved rate riders.

Other revenue includes revenue from services ancillary to the electricity distribution, delivery of street lighting services, pole and duct rentals, other regulatory service charges, capital contributions and CDM programs.

Capital contributions received in advance from electricity customers and developers to construct or acquire PP&E for the purpose of connecting a customer to a network are recorded as deferred revenue and amortized into other revenue at an equivalent rate to that used for the depreciation of the related PP&E. Capital contributions received from developers to construct or acquire PP&E for the purpose of connecting future customers to the distribution network are considered out of scope of IFRS 15 *Revenue from Contracts with Customers* ["IFRS 15"].

Revenues and costs associated with CDM programs are presented using the net basis of accounting and recorded in accordance with IAS 20 *Accounting for Government Grants and Disclosure of Government Assistance*. Cost efficiency incentives related to the CDM programs, included as part of other revenue, are recognized when it is probable that future economic benefits will flow to the entity and the amount can be reasonably measured.

LDC has not incurred any additional costs to obtain or fulfil contracts with its customers nor any kind of variable considerations from the above mentioned revenue generating activities.

j) Financial instruments

All financial assets and financial liabilities are classified as "Amortized cost". These financial instruments are recognized initially at fair value adjusted for any directly attributable transaction costs. Subsequently, they are measured at amortized cost using the effective interest method less any impairment for the financial assets. The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's length transaction between willing parties.

LDC uses the following methods and assumptions to estimate the fair value of each class of financial instruments for which carrying amounts are included in the balance sheets:

- Cash and cash equivalents are classified as "Amortized cost" and are measured at fair value. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Accounts receivable and unbilled revenue are classified as "Amortized cost" and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Bank indebtedness is classified as "Amortized cost" and is initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Accounts payable are classified as "Amortized cost" and are initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value because of the short maturity of these instruments.

- Customer deposits are classified as "Amortized cost" and are initially measured at fair value. Subsequent measurements are recorded at cost plus accrued interest. The carrying amounts approximate fair value taking into account interest accrued on the outstanding balance.

- Obligations under leases are classified as "Amortized cost" and are initially measured at fair value, or the present value of the minimum lease payments if lower. Subsequent measurements are based on a discounted cash flow analysis and approximate the carrying amount as management believes that the fixed interest rates are representative of current market rates.

- Notes payable to related party are classified as "Amortized cost" and are initially measured at fair value. The carrying amounts are carried at amortized cost, based on the fair value of the notes payable at issuance, which was the fair value of the consideration received adjusted for transaction costs. The fair values of the notes payable are based on the present value of contractual cash flows, discounted at LDC's current borrowing rate for similar debt instruments *[note 14[a]]*. Debt issuance costs incurred in connection with LDC's debt offerings are capitalized as part of the carrying amount of the notes payable and amortized over the term of the related notes payable, using the effective interest method, and the amortization is included in finance costs.

k) Fair value measurements

LDC utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. A fair value hierarchy exists that prioritizes observable and unobservable inputs used to measure fair value. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect LDC's assumptions with respect to how market participants would price an asset or liability. The fair value hierarchy includes three levels of inputs that may be used to measure fair value:

- Level 1: Unadjusted quoted prices in active markets for identical assets or liabilities. An active market for the asset or liability is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis;
- Level 2: Other than quoted prices included within Level 1 that are observable for the assets or liabilities, either directly or indirectly; and
- Level 3: Unobservable inputs, supported by little or no market activity, used to measure the fair value of the assets or liabilities to the extent that observable inputs are not available.

l) Employee benefits

(i) Short-term employee benefits

Short-term employee benefit obligations that are due to be settled wholly within twelve months after the end of the annual reporting period in which the employees render the related service are measured on an undiscounted basis and are expensed as the related service is provided. A liability is recognized for the amount expected to be paid if LDC has a present legal or constructive obligation to pay this amount as a result of past service provided by the employee and the obligation can be estimated reliably.

(ii) Multi-employer pension plan

LDC's full-time employees participate in a pension plan through OMERS. The OMERS plan is a jointly sponsored, multi-employer defined benefit pension plan established in 1962 by the province of Ontario for employees of municipalities, local boards and school boards. Both participating employers and employees are required to make plan contributions equally based on participating employees' contributory earnings, and share equally in funding gains or losses. The plan assets and pension obligations are not segregated in separate accounts for each member entity. The OMERS plan is accounted for as a defined contribution plan and the contribution payable is recognized as an employee benefit expense in the statements of income in the period when the service is rendered by the employee, since it is not practicable to determine LDC's portion of pension obligations or of the fair value of plan assets.

(iii) Post-employment benefits other than pension

LDC has a number of unfunded benefit plans providing post-employment benefits (other than pension) to its employees. LDC pays certain medical, dental and life insurance benefits under unfunded defined benefit plans on behalf of its retired employees. LDC also pays accumulated sick leave credits, up to certain established limits based on service, in the event of retirement, termination or death of certain employees.

The cost of providing benefits under the benefit plans is actuarially determined using the projected unit credit method, which incorporates management's best estimate of future salary levels, retirement ages of employees, health care costs, and other actuarial factors. Changes in actuarial assumptions and experience adjustments give rise to actuarial gains and losses. Actuarial gains and losses on medical, dental and life insurance benefits are recognized in OCI as they arise. Actuarial gains and losses related to rate-regulated activities are subsequently reclassified from OCI to a regulatory balance on the balance sheets. Actuarial gains and losses on accumulated sick leave credits are recognized in the statements of income in the period in which they arise.

The measurement date used to determine the present value of the benefit obligation is December 31 of the applicable year. The latest actuarial valuation was performed as at January 1, 2018.

m) Customer deposits

Security deposits from electricity customers are cash collections to guarantee the payment of electricity bills. This liability includes related interest amounts owed to the customers with a corresponding amount charged to finance costs. Deposits that are refundable upon demand are classified as a current liability.

Security deposits on offers to connect are cash collections from specific customers to guarantee the payment of additional costs relating to expansion projects. This liability includes related interest amounts owed to the customers with a corresponding amount charged to finance costs. Deposits are classified as a current liability when LDC no longer has an unconditional right to defer payment of the liability for at least 12 months after the reporting period.

n) Income taxes

Under the *Electricity Act*, LDC is required to make PILs to the Ontario Electricity Financial Corporation. These payments are calculated in accordance with the ITA and the TA as modified by regulations made under the Electricity Act and related regulations. This effectively results in LDC paying income taxes equivalent to what would be imposed under the Federal and Ontario Tax Acts.

LDC uses the liability method of accounting for income taxes. Under the liability method, current income taxes payable are recorded based on taxable income. LDC recognizes deferred tax assets and liabilities for the future tax consequences of events that have been included in the financial statements or income tax returns. Deferred tax assets and liabilities are determined based on the difference between the carrying value of assets and liabilities on the balance sheets and their respective tax basis, using the tax rates enacted or substantively enacted by the balance sheet date that are in effect for the year in which the differences are expected to reverse. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when it is probable that they will be realized, and are measured at the best estimate of the tax amount expected to be paid to or recovered from the taxation authorities. Deferred tax assets are reviewed at each reporting date and reduced to the extent that it is no longer probable that the related tax benefits will be realized. The calculation of current and deferred taxes requires management to make certain judgments with respect to changes in tax interpretations, regulations and legislation, and to estimate probable outcomes on the timing and reversal of temporary differences and tax authority audits of income tax.

Rate-regulated accounting requires the recognition of regulatory balances and related deferred tax assets and liabilities for the amount of deferred taxes expected to be refunded to or recovered from customers through future electricity distribution rates. A gross up to reflect the income tax benefits associated with reduced revenues resulting from the realization of deferred tax assets is recorded within regulatory credit balances. Deferred taxes that are not included in the rate-setting process are charged or credited to the statements of income.

The benefits of the refundable and non-refundable apprenticeship and other ITCs are credited against the related expense in the statements of income.

o) Use of judgments and estimates

The preparation of LDC's financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions which affect the application of accounting policies, reported assets, liabilities and regulatory balances, and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported revenues and expenses for the year. The estimates are based on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities as well as for identifying and assessing the accounting treatment with respect to commitments and contingencies. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the IESO, the Ontario Ministry of Energy or the Ontario Ministry of Finance.

Information about judgments in applying accounting policies that have the most significant effects on the amounts recognized in the financial statements is included in note 25[i] relating to principal versus agent determination for recording revenue on a gross or net basis.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to estimates are recognized prospectively. Assumptions and estimates with a significant risk of resulting in a material adjustment within the next financial year are used in the following:

- Note 25[a] – Recognition and measurement of regulatory balances;
- Note 25[i] – Revenue recognition – measurement of unbilled revenue, determination of the CDM incentive;
- Notes 25[e] and 25[f] – Determination of useful lives of depreciable assets;
- Notes 25[l] and 12 – Measurement of post-employment benefits – key actuarial assumptions;
- Notes 25[n] and 20 – Recognition of deferred tax assets – availability of future taxable income against which deductible temporary differences and tax loss carryforwards can be used; and
- Note 24 – Recognition and measurement of provisions and contingencies.

p) Changes in accounting policies

Effective January 1, 2018, LDC has adopted new IFRS standards and applied the following new accounting policies in preparing the financial statements:

Revenue from Contracts with Customers

In May 2014, the IASB issued IFRS 15 effective for annual periods beginning on or after January 1, 2018, which replaced existing revenue recognition guidance, including IAS 18 *Revenue* and IFRIC 18 *Transfers of Assets from Customers*. IFRS 15 contains a five step model that applies to contracts with customers that specifies that revenue is recognized when or as an entity transfers control of goods or services to a customer at the amount to which the entity expects to be entitled. Depending on whether certain criteria are met, revenue is recognized at a point in time or over time.

LDC adopted IFRS 15 using the modified retrospective approach with the following practical expedients:

- LDC did not restate completed contracts that began and ended in the same annual reporting period or completed contracts at the beginning of the earliest period presented; and
- LDC did not disclose the amount of consideration allocated to the remaining performance obligations nor did it provide an explanation of when LDC expects to recognize that amount as revenue for comparative periods presented in the financial statements.

LDC recognizes revenue in the amount that it has a right to invoice when the amount directly corresponds with the value of LDC's performance to date.

The adoption of IFRS 15 resulted in a $207.6 million income statement reclassification between energy sales and energy purchases for the comparative year ended December 31, 2017, and had no impact to opening retained earnings as at January 1, 2018. LDC updated the impact previously disclosed in the audited financial statements for the year ended December 31, 2017 to include the additional income statement reclassification between energy sales and energy purchases for the comparative year ended December 31, 2017.

Financial Instruments

In July 2014, the IASB issued the final version of IFRS 9 *Financial Instruments* ["IFRS 9"] effective for annual periods beginning on or after January 1, 2018, which replaced IAS 39 *Financial Instruments: Recognition and Measurement* ["IAS 39"]. IFRS 9 includes revised guidance on the classification and measurement of financial instruments, including a new expected credit loss model for measuring impairment on financial assets, and new general hedge accounting requirements. It also carries forward the guidance on recognition and derecognition of financial instruments from IAS 39. LDC adopted IFRS 9 retrospectively on January 1, 2018. Despite the retrospective adoption of IFRS 9, LDC is not required, upon initial application, to restate comparatives.

i) Classification and measurement of financial instruments

IFRS 9 largely retains the existing requirements in IAS 39 for the classification and measurement of financial liabilities. However, it eliminates the previous IAS 39 categories for financial assets of held to maturity, loans and receivables and available for sale.

Under IFRS 9, on initial recognition, a financial asset is classified and measured at amortized cost, fair value through other comprehensive income, or fair value through profit or loss. The classification of financial assets under IFRS 9 is generally based on the business model in which a financial asset is managed and its contractual cash flow characteristics.

The adoption of IFRS 9 has not had a significant effect on LDC's accounting policies related to financial instruments. The impact of IFRS 9 on the classification and measurement of financial instruments is set out below.

	IAS 39	IFRS 9
Financial Instrument	**Measurement basis**	**Measurement basis**
Cash and cash equivalents	Loans and receivables	Amortized cost
Accounts receivable	Loans and receivables	Amortized cost
Unbilled revenue	Loans and receivables	Amortized cost
Bank indebtedness	Financial liability – amortized cost	Amortized cost
Customer deposits	Financial liability – amortized cost	Amortized cost
Leases	Financial liability – amortized cost	Amortized cost
Notes payable to related party	Financial liability – amortized cost	Amortized cost
Accounts payable	Financial liability – amortized cost	Amortized cost

	IAS 39	IFRS 9
Financial Instrument	**Carrying amount as at January 1, 2018 $**	**Carrying amount as at January 1, 2018 $**
Cash and cash equivalents	—	—
Accounts receivable	217.2	217.8
Unbilled revenue	276.0	275.1
Bank indebtedness	125.0	125.0
Customer deposits	58.1	58.1
Leases [(1)]	3.1	3.1
Notes payable to related party	2,029.9	2,029.9
Accounts payable	323.7	323.7

[(1)] Includes transitional adjustment for the recognition of new leases upon adoption of IFRS 16 on January 1, 2018 *[note 25[q]]*.

ii) Impairment of financial assets

Loss allowances for accounts receivable and unbilled revenue are always measured at an amount equal to lifetime ECL. Lifetime ECL are the ECL that result from all possible default events over the expected life of a financial instrument.

When determining whether the credit risk of a financial asset has increased significantly since initial recognition and when estimating ECL, LDC considers reasonable and supportable information that is relevant and available without undue cost or effort. This includes both quantitative and qualitative information and analysis, based on LDC's historical experience, adjusted for forward-looking factors specific to the current credit environment.

LDC assumes that credit risk on a financial asset has increased if it is more than 30 days past due date.

LDC considers a financial asset to be in default when the borrower is unlikely to pay its credit obligations to LDC in full, without recourse by LDC, such as realising security (if any is held).

If the amount of impairment loss subsequently decreases due to an event occurring after the impairment was recognized, then the previously recognized impairment loss is reversed through net income.

Leases

In January 2016, the IASB issued IFRS 16, which replaced IAS 17 *Leases* ["IAS 17"] and related interpretations. IFRS 16 introduces a single lessee accounting model eliminating the previous distinction between finance and operating leases. IFRS 16 requires the recognition of lease-related assets and liabilities on the balance sheet, except for short-term leases and leases of low value underlying assets. Lessor accounting remained substantially unchanged.

Although IFRS 16 is effective for annual periods beginning on or after January 1, 2019, LDC early adopted IFRS 16 on January 1, 2018 using the modified retrospective approach, in accordance with the transitional provisions in IFRS 16. The comparative information has not been restated and continues to be reported under IAS 17 and IFRIC 4 *Determining whether an Arrangement contains a Lease*. In applying this approach, LDC elected to use practical expedients that allowed it to exclude the initial direct costs from the measurement of the right-of use assets at the date of the initial application, and to use hindsight in determining the lease term. As a practical expedient permitted by IFRS 16, LDC applied IFRS 16 to existing contracts that were previously identified as leases applying IAS 17 and IFRIC 4 *Determining whether an Arrangement contains a Lease,* and did not apply IFRS 16 to contracts that were not previously identified as containing a lease.

The adoption of IFRS 16 resulted in an increase of $1.6 million in total assets and total liabilities each for recognition of right-of-use assets and lease liabilities, respectively, and had no impact to opening retained earnings as at January 1, 2018.

The adoption of IFRS 15, IFRS 9 and IFRS 16 resulted in no changes to the balance sheet as at December 31, 2017 and statements of cash flows for the year ended December 31, 2017.

Transition to IFRS 15

STATEMENTS OF INCOME	Note	December 31, 2017 $	Transitional adjustments $	December 31, 2017 $
				Restated
Revenues				
Energy sales	A	3,017.8	(207.6)	**2,810.2**
Distribution revenue		724.2	—	**724.2**
Other		96.7	—	**96.7**
		3,838.7	(207.6)	**3,631.1**
Expenses				
Energy purchases	A	3,063.5	(207.6)	**2,855.9**
Operating expenses		284.2	—	**284.2**
Depreciation and amortization		222.3	—	**222.3**
		3,570.0	(207.6)	**3,362.4**
Finance costs		(81.0)	—	**(81.0)**
Gain on disposals of property, plant and equipment		9.8	—	**9.8**
Income before income taxes		197.5	—	**197.5**
Income tax expense		(44.2)	—	**(44.2)**
Net income		153.3	—	**153.3**
Net movements in regulatory balances		(13.1)	—	**(13.1)**
Net movements in regulatory balances arising from deferred tax assets		13.2	—	**13.2**
Net income after net movements in regulatory balances		153.4	—	**153.4**

A. Energy sales and energy purchases

Energy sales are based on the cost and usage of electricity by the customer. For Regulated Price Plan ["RPP"] customers, the OEB has set a fixed rate which should approximate the cost of energy purchased. LDC recovers the difference between amounts billed to RPP customers for electricity charges and the cost to purchase the energy from the IESO ["RPP Settlement Amount"].

In 2017, the Government of Ontario announced the Ontario's Fair Hydro Plan, which included a number of initiatives aimed at decreasing electricity bills. For eligible non-RPP customers, the bill reduction was implemented through a reduction in the Global Adjustment charges that they would have otherwise paid ["GA Modifier"]. LDC recovers the GA Modifier from the IESO.

The RPP Settlement Amount and the GA Modifier will be recorded differently under IFRS 15 than they were under IAS 18. Under IAS 18, energy sales were recorded at the fair value of the consideration received or receivable, including amounts received from the electricity customers and the IESO. Consequently, both the RPP Settlement Amount and the GA Modifier were recorded as energy sales. Under IFRS 15, revenue is recognized at the transaction price as per the contract with electricity customers only, and would therefore exclude amounts that are received or receivable from the IESO. As such, the RPP Settlement Amount and the GA Modifier received or receivable from IESO will be recorded as a reduction/addition from/to energy purchases instead of energy sales.

Transition to IFRS 9

Reconciliation of loss allowance balance from IAS 39 to IFRS 9:

	Note	Loss allowance under IAS 39 as at December 31, 2017 $	Transitional adjustments $	Loss allowance under IFRS 9 as at January 1, 2018 $
ASSETS				
Current				
Loss allowance	A	(10.2)	(0.3)	**(10.5)**

A. Impairment of financial assets

Under IAS 39, accounts receivable would first be provisioned for when it is deemed that the collection is unlikely. Upon adoption of IFRS 9, LDC measures the loss allowance at an amount equal to the lifetime ECL for trade receivables or contract assets that result from transactions that are within the scope of IFRS 15, and do not contain a significant financing component. LDC uses a provision matrix to measure the lifetime ECL of accounts receivable from individual customers which accounts for exposures in different customer classes. The revised impairment allowance resulted in a restatement of opening retained earnings as at January 1, 2018.

Transition to IFRS 16

LDC determined the cumulative effect of applying IFRS 16 on January 1, 2018 to be $nil impact in opening retained earnings and recorded $1.6 million as right-of-use assets and $1.6 million as lease liabilities.

The office space leases were recognized as operating leases under IAS 17, and the corresponding lease payments were recorded as expenses on a straight-line basis over the lease term. Upon transition, LDC recognized right-of-use assets and lease liabilities for these leases. The lease liabilities were measured at the present value of the remaining lease payments, discounted at the incremental borrowing rate as at January 1, 2018. The right-of-use assets were measured at an amount equal to the lease liabilities.

	Operating leases as at December 31, 2017 $	Transitional adjustments $	Leases as at January 1, 2018 $
ASSETS			
Current			
Property, plant and equipment	—	1.6	**1.6**
Total assets	—	1.6	**1.6**
LIABILITIES AND EQUITY			
Current			
Other liabilities	—	0.3	**0.3**
Total current liabilities	—	0.3	**0.3**
Other liabilities	—	1.3	**1.3**
Total liabilities	—	1.6	**1.6**

The weighted average incremental borrowing rate applied to the lease liabilities was 1.92%.

q) Future accounting pronouncements

A number of new interpretations and amendments to existing standards have been issued but are not yet effective for the year ended December 31, 2018, and have not been applied in preparing the financial statements.

IFRIC 23 *Uncertainty over Income Tax Treatments*

On June 7, 2017, the IASB issued IFRIC 23 *Uncertainty over Income Tax Treatments*. The interpretation provides guidance on the accounting for current and deferred tax assets and liabilities in situations in which there is uncertainty over income tax treatments. The interpretation is applicable for annual reporting periods beginning on or after January 1, 2019.

Annual Improvements to IFRS Standards 2015-2017 Cycle

On December 12, 2017, as part of its annual improvements process, the IASB issued narrow-scope amendments to the following standards:

IFRS 3 *Business Combinations* – the amendments clarify that when an entity obtains control of a business that is a joint operation, it re-measures previously held interests in that business.

IFRS 11 *Joint Arrangements* – the amendments clarify that when an entity obtains joint control of a business that is a joint operation, it does not re-measure previously held interests in that business.

IAS 12 *Income Taxes* – the amendments clarify that an entity recognizes income tax consequences of dividends in profit or loss, other comprehensive income or equity, depending on where the entity recognized the originating transaction or event that generated the distributable profits giving rise to the dividend.

IAS 23 *Borrowing Costs* – the amendments clarify that an entity treats as general borrowings any borrowings made specifically to obtain a qualifying asset that remain outstanding when the asset is ready for its intended use or sale.

The amendments are effective for annual reporting periods beginning on or after January 1, 2019.

Definition of Material (Amendments to IAS 1 *Presentation of Financial Statements* and IAS 8 *Accounting Policies, Changes in Accounting Estimates and Errors)*

On October 31, 2018, the IASB issued amendments to IAS 1 and IAS 8 – the amendments clarify the definition of 'material' and align the definition used in the Conceptual Framework and the standards themselves. The amendments are effective for annual reporting periods beginning on or after January 1, 2020.

LDC anticipates that the adoption of these accounting pronouncements will not have a material impact on LDC's financial statements, if any.

GLOSSARY

CDM – Conservation and demand management

CIR – Custom Incentive Rate-setting

City – City of Toronto

Corporation – Toronto Hydro Corporation

Electricity Act – *Electricity Act, 1998* (Ontario), as amended

GAAP – Generally Accepted Accounting Principles

GWh – Gigawatt hour

HONI – Hydro One Networks Inc.

IAS – International Accounting Standard

IASB – International Accounting Standards Board

IESO – Independent Electricity System Operator. The IESO and the Ontario Power Authority were merged under the name Independent Electricity System Operator on January 1, 2015.

IFRIC – International Financial Reporting Interpretations Committee

IFRS – International Financial Reporting Standards

IRM – Incentive Regulation Mechanism

ITA – *Income Tax Act* (Canada), as amended

LDC – Toronto Hydro-Electric System Limited

LRAM – Lost revenue adjustment mechanism

OCI – Other comprehensive income

OEB – Ontario Energy Board

OFHP – Ontario's Fair Hydro Plan

OFHA – *Fair Hydro Act, 2017* (Ontario)

OMERS – Ontario Municipal Employees Retirement System

OPA – Ontario Power Authority. The IESO and the OPA were merged under the name Independent Electricity System Operator on January 1, 2015.

OPEB – Other post-employment benefits

OREC – *Ontario Rebate for Electricity Consumers Act*, 2016 (Ontario).

PILs – Payments in lieu of corporate taxes

PP&E – Property, plant and equipment

TA – *Taxation Act, 2007* (Ontario), as amended

TH Energy – Toronto Hydro Energy Services Inc.

US GAAP – United States Generally Accepted Accounting Principles

WMS – Wholesale Market Service

Toronto Hydro-Electric System Limited - 2.1.13

Filing: April 30, 2019

Balance Sheet
December 31, 2018

		Regulated 2018 Actual OEB Acct TB	Regulated 2018 Actual (in thousands)	Unregulated 2018 Actual (in thousands)	Consol Adj 2018 Actual (in thousands)	Calculated THESL Consol 2018 Actual (in thousands)	Audited THESL Consol 2018 Actual (in thousands)	Diff	Comment
Assets									
Current Assets									
Cash and cash equivalents	1005_Cash	-	-						
	1010_Cash Advances and Working Funds	-	-						
		-	-	36,075	(36,075)	-	-	-	
Accounts receivable	1100_Customer Accounts Receivable	184,241,206	184,241						
	1104_Accounts Receivable - Recoverable Work	8,852,448	8,852						
	1110_Other Accounts Receivable	22,359,139	22,359						
	1130_Accumulated Provision for Uncollectible Accounts-- Credit	(9,684,040)	(9,684)						
	1200_Accounts Receivable from Associated Companies	1,271,934	1,272						
		207,040,687	207,041	15,087	(11,850)	210,277	210,277	(0)	
Unbilled revenue	1120_Accrued Utility Revenues	279,551,573	279,552	1,094		280,645			
	1130_Accumulated Provision for Uncollectible Accounts-- Credit	(938,144)	(938)			(938)			
		278,613,429	278,613	1,094		279,707	279,707	0	
Income tax receivable	2294_Accrual for Taxes Payments in Lieu of Taxes Etc.	-	-			-	-	-	
Materials and supplies	1330_Plant Materials and Operating Supplies	8,067,927	8,068			8,068	8,068	-	
Other assets	1180_Prepayments	10,690,150	10,690			10,690	10,690	-	
	1190_Miscellaneous Current and Accrued Assets	1,005,039	1,005			1,005		(1,005)	Note 1
		19,763,117	19,763	-	-	19,763	18,758	(1,005)	
Property, plant and equipment	1805_Land	7,006,432	7,006						
	1808_Buildings and Fixtures	137,260,787	137,261						
	1815_Transformer Station Equipment - Normally Primary above 50 kV	37,862,575	37,863						
	1820_Distribution Station Equipment - Normally Primary below 50 kV	213,516,777	213,517						
	1830_Poles Towers and Fixtures	380,783,918	380,784						
	1835_Overhead Conductors and Devices	428,315,901	428,316						
	1840_Underground Conduit	1,205,589,193	1,205,589						
	1845_Underground Conductors and Devices	862,204,571	862,205						
	1850_Line Transformers	566,668,052	566,668						
	1855_Services	124,625,454	124,625						
	1860_Meters	220,072,783	220,073						
	1905_Land	17,358,657	17,359						
	1908_Buildings and Fixtures	239,369,154	239,369						
	1910_Leasehold Improvements	753,840	754						
	1915_Office Furniture and Equipment	19,990,318	19,990						
	1920_Computer Equipment - Hardware	66,761,063	66,761						
	1930_Transportation Equipment	36,083,642	36,084						
	1935_Stores Equipment	7,066	7						
	1940_Tools Shop and Garage Equipment	23,350,605	23,351						
	1945_Measurement and Testing Equipment	480,243	480						
	1950_Power Operated Equipment	1,265,194	1,265						
	1955_Communication Equipment	49,888,402	49,888						
	1960_Miscellaneous Equipment	270,978	271						
	1970_Load Management Controls - Customer Premises	3,022,834	3,023						
	1975_Load Management Controls - Utility Premises	-	-						
	1980_System Supervisory Equipment	39,715,786	39,716						
	1995_Contributions and Grants - Credit	-	-						
	1612_Land Rights	-	-						
	2005_Property Under Finance Leases	19,747,714	19,748						
	2055_Construction Work in Progress--Electric	421,490,336	421,490						
	2075_Non-Rate Regulated Property Owned or Under Finance Leases	2,002,023	2,002						
	2105_Accum. Depreciation of Electric Utility Plant - Property Plant & Equipment	(785,786,375)	(785,786)						
	2120_Accumulated Amortization of Electric Utility Plant - Intangibles	-	-						
	2180_Accumulated Depreciation of Non Rate-Regulated Property	(166,835)	(167)						
		4,339,511,084	4,339,511	10,397	-	4,349,909	4,349,909	(0)	

Toronto Hydro-Electric System Limited - 2.1.13

Filing: April 30, 2019

Balance Sheet
December 31, 2018

		Regulated 2018 Actual OEB Acct TB	Regulated 2018 Actual (in thousands)	Unregulated 2018 Actual (in thousands)	Consol Adj 2018 Actual (in thousands)	Calculated THESL Consol 2018 Actual (in thousands)	Audited THESL Consol 2018 Actual (in thousands)	Diff	Comment
Assets									
Intangible assets	1609_Capital Contributions Paid	164,168,403	164,168						
	1611_Computer Software	207,911,095	207,911						
	2055_Construction Work in Progress--Electric	54,308,043	54,308						
	2120_Accumulated Amortization of Electric Utility Plant - Intangibles	(107,489,135)	(107,489)						
		318,898,406	318,898	-	-	318,898	318,898	-	
Deferred tax assets	1495_Deferred Taxes - Non-Current Assets	3,983,368	3,983	-	-	3,983	301	(3,682)	Note 2
Other assets	1460_Other Non-Current Assets	5,827,697	5,828	-	-	5,828	5,828	(0)	
Regulatory balances	1508_Other Regulatory Assets	88,334,901	88,335						
	1520_Power Purchase Variance Account	-	-						
	1521_Special Purpose Chg Assessment Variance Account	-	-						
	1533_Renewable Generation Connection Funding Adder Deferral Account	(4,300,876)	(4,301)						
	1550_Low Voltage Variance Acct	727,114	727						
	1551_Smart Metering Entity Charge Variance Acct	(851,633)	(852)						
	1555_Smart Meter Capital Offset Variance	3,605,333	3,605						
	1556_Smart Meter Operating Variance	-	-						
	1562_Deferred Payments in Lieu of Taxes	-	-						
	1563_Deferred PILs Contra Account	-	-						
	1568_LRAM Variance Account	28,403,169	28,403						
	1575_IFRS-UGAAP Transitional PPE Amounts	5,690,456	5,690						
	1580_RSVAWMS	(30,044,735)	(30,045)						
	1584_RSVANW	17,296,882	17,297						
	1586_RSVACN	26,023,060	26,023						
	1588_RSVAPOWER	(8,935,056)	(8,935)						
	1589_RSVAGA	(16,850,741)	(16,851)						
	1592_PILs and Tax Variance for 2006 and Subsequent Years	(0)	(0)						
	1595_Disposition Recovery Reg Balances Control Acct	18,497,244	18,497						
		127,595,118	127,595	-	-	127,595	125,975	(1,620)	Note 3
Total Assets		5,301,232,906	5,301,233	62,653	(47,925)	5,315,961	5,309,653	(6,307)	
Liabilities and Equity									
Joint Bank indebtedness	2225_Notes and Loans Payable	(57,600,892)	(57,601)	-	36,075	(21,526)	(21,526)	-	
Advance from related party		-	-	-	-	-	-	-	
Accounts payable and accrued liabilities	2205_Accounts Payable	(394,839,788)	(394,840)						
	2208_Customer Credit Balances	(19,126,616)	(19,127)						
	2220_Miscellaneous Current and Accrued Liabilities	(17,971,051)	(17,971)						
	2240_Accounts Payable to Associated Companies Notes	(32,037,213)	(32,037)						
	2250_Debt Retirement Charges(DRC) Payable	7,983	8						
	2290_Commodity Taxes	(15,547,903)	(15,548)						
	2292_Payroll Deductions / Expenses Payable	(48,257,724)	(48,258)						
		(527,772,312)	(527,772)	(5,737)	11,850	(521,659)	(521,659)	0	
Income tax payable	2294_Accrual for Taxes Payments in Lieu of Taxes Etc.	(4,628,278)	(4,628)	-		(4,628)	(4,823)	(195)	Note 4
Customer deposits	2210_Customer Deposits	(48,133,787)	(48,134)			(48,134)	(48,134)		
Deferred revenue	2220_Miscellaneous Current and Accrued Liabilities	(1,920,833)	(1,921)	-		(1,921)			
	2210_Customer Deposits	(5,777,407)	(5,777)			(5,777)			
		(7,698,240)	(7,698)	-	-	(7,698)	(12,450)	(4,752)	Note 5
Deferred conservation credit		-	-	(8,199)		(8,199)	(8,199)	-	
Other liabilities	2285_Obligations Under Finance Leases--Current	(276,781)	(277)			(277)			
	2220_Miscellaneous Current and Accrued Liabilities	(54,792)	(55)			(55)			
		(331,573)	(332)	-	-	(332)	(332)	-	
Notes payable to related party	2242_ Payable to Associated Companies	(304,883,415)	(304,883)			(304,883)	(304,883)		
	2260_Current Portion of Long Term Debt	-	-	-		-	-		
			-						
		(304,883,415)	(304,883)	-	-	(304,883)	(304,883)	-	
Notes payable to related party	2550_Advances from Associated Companies	(1,785,725,107)	(1,785,725)			(1,785,725)	(1,785,725)	0	
	2505_Debentures Outstanding - Long Term Portion	-	-			-	-	-	
		(1,785,725,107)	(1,785,725)	-	-	(1,785,725)	(1,785,725)	0	

Toronto Hydro-Electric System Limited - 2.1.13

Filing: April 30, 2019

Balance Sheet
December 31, 2018

		Regulated 2018 Actual OEB Acct TB	Regulated 2018 Actual (in thousands)	Unregulated 2018 Actual (in thousands)	Consol Adj 2018 Actual (in thousands)	Calculated THESL Consol 2018 Actual (in thousands)	Audited THESL Consol 2018 Actual (in thousands)	Diff	Comment
Assets									
Customer deposits	2335_Non-Current Customer Deposits	(31,741,951)	(31,742)			(31,742)	(31,742)	-	
Deferred revenue	2440_Deferred Revenues	(218,352,047)	(218,352)			(218,352)			
	2320_Other Miscellaneous Non-Current Liabilities	-	-			-			
	2335_Non-Current Customer Deposits	(64,075,330)	(64,075)			(64,075)			
		(282,427,378)	(282,427)	-	-	(282,427)	(277,676)	4,752	Note 5
Post-employment benefits	2306_POEB Liability	(274,566,000)	(274,566)	(1,294)		(275,860)	(275,860)	0	
Other liabilities	2325_Obligations Under Finance Lease--Non-Current	(1,029,726)	(1,030)			(1,030)			
	2320_Other Miscellaneous Non-Current Liabilities	(19,270,253)	(19,270)	(773)		(20,044)			
		(20,299,979)	(20,300)	(773)	-	(21,073)	(1,954)	19,120	Note 6
Total Liabilities		(3,345,808,911)	(3,345,809)	(16,003)	47,925	(3,313,886)	(3,294,962)	18,925	
Share Capital	3005_Common Shares Issued	(527,816,668)	(527,817)	(28,461)		(556,278)	(556,278)	0	
Retained Earnings	3045_Unappropriated Retained Earnings	(1,451,906,538)	(1,451,907)						
	3046_Balance Transferred From Income	(159,610,982)	(159,611)						
	3049_Dividends Payable-Common Shares	366,326,000	366,326						
	3055_Adjustment to Retained Earnings	(5,687,746)	(5,688)						
		(1,250,879,266)	(1,250,879)	(18,189)	-	(1,269,069)	(1,267,442)	1,626	Note 7
Contributed Surplus	3010_Contributed Surplus	(12,757,392)	(12,757)			(12,757)	(12,757)	-	
Regulatory balances	1508_Other Regulatory Assets	(158,923,922)	(158,924)						
	1595_Disposition Recovery Reg Balances Control Acct	(1,063,378)	(1,063)						
	2350_Deferred Tax - Non-Current Liability	(3,983,369)	(3,983)						
		(163,970,669)	(163,971)	-	-	(163,971)	(178,214)	(14,244)	Note 8
Total liabilities, equity and regulatory balances		(5,301,232,906)	(5,301,233)	(62,653)	47,925	(5,315,961)	(5,309,653)	6,307	
		-	-	-	-	-	-	(0)	

Toronto Hydro-Electric System Limited - 2.1.13
Balance Sheet
December 31, 2018

Filing: April 30, 2019

	Regulated 2018 Actual OEB Acct TB	Regulated 2018 Actual (in thousands)	Unregulated 2018 Actual (in thousands)	Consol Adj 2018 Actual (in thousands)	Calculated THESL Consol 2018 Actual (in thousands)	Audited THESL Consol 2018 Actual (in thousands)	Diff	Comment
Assets								

Notes: The Uniform System of Account balances are mapped and reconciled to the audited financial statements (AFS) (in dollars thousands).

Note 1: This relates to the CIR Costs Deferral re-instatement on the Balance Sheet.
For OSC purposes, as a result of the OEB's Decision with regards to the DRO, the CIR costs were considered no longer recoverable, and as such it was considered impaired and written-off to the P&L.
For RRR purposes, since the CIR Costs were approved to be recovered over the 5 year term in the original OEB Decision on December 29, 2015 with regards to the 2015-2019 CIR Application, the CIR costs were re-instated on the balance sheet and will be amortized over the 5 years. The current portion re-instated CIR costs on the balance sheet was $1,005.

Note 2: Difference in "Deferred tax assets" of ($3,682): Calculated balance of $3,983 & AFS balance of $301, a difference of ($3,682), as follows:
a. The deferred tax balance related to regulatory balances and gross up in respect of deferred tax assets are recorded in regulatory balances in accordance with IFRS 14 for AFS.
For purposes of RRR reporting, these balances are reclassified to deferred tax assets in the amount of ($2,175).
b. For purposes of RRR reporting, an adjustment was made to remove deferred income tax asset in respect of the non-rate regulated assets in the amount of ($1,507).

Note 3: Difference in "Regulatory balances - deferred debits" of ($1,620): Calculated balance of $127,595 & AFS balance of $125,975, a difference of ($1,620), is due to balances considered regulatory balances for the AFS but not for the purpose of RRR reporting in accordance with APH.

Note 4: Difference in "Income tax payable" of ($195): Calculated balance of ($4,628) & AFS balance of ($4,823), a difference of ($195), as follows:
The difference represents the non-regulated business income tax payable included in the AFS.

Note 5: Difference in "Deferred revenue - current", offset by difference in "Deferred revenue - long-term" of $4,752 as follows:
For the AFS the Deferred revenue was split between current and long-term. For the RRR purposes, the Deferred revenue is not split between current and long-term.

Note 6: Difference in "Other liabilities" of $19,120: Calculated balance of ($21,073) & AFS balance of ($1,954), a difference of $19,120, primarily related to a deferral of gain on sale of surplus property in a regulatory account for the AFS and recorded as miscellaneous liability for RRR reporting and deferral of excess expansion deposits withholdings in a regulatory account for the AFS and recorded as miscellaneous liability for RRR reporting.

Note 7: Difference in "Retained Earnings" of $1,626: Calculated balance of ($1,269,069) & AFS balance of ($1,267,442), a difference of $1,626.
Adjustments have been made to certain AFS income statement items to arrive at the RRR reporting as follows:

A. Adjustments made to certain AFS income statement items in prior years as follows:

a. Reduction for prior years' AFS Distribution revenue booked for Smart Meter "net revenue requirement" on the disposition of Account 1555 "Smart Meter Capital & Recovery" and 1556 "Smart Meter OM&A Variance account" balances. The amount is recorded to Distribution revenue for RRR reporting, to OEB account 4080 as the amount is billed to THESL customers in the future.	$	284
b. For purposes of RRR reporting, an adjustment was made to remove deferred income tax asset in respect of the non-rate regulated assets related to prior year.		1,968
c. This relates to the reversal of the Account 1575 IFRS-GAAP Transitional PP&E Return on Rate Base. For RRR purposes, as per the APH, Article 510, "The return on rate base shall not be recorded in this account. On disposition of the account balance, the return is applied prospectively in rates as an adjustment to the revenue requirement." In the AFS, the return on rate base was accrued at year-end 2015 since the OEB approved the disposition of Account 1575 with the return on rate base of $4,755k. As such, for 2015 RRR purposes, the $4,755k accrual was reversed. As such, in the AFS, the disposition of the account 1575 includes offsetting entries on the balance sheet related to the disposition of the return on rate base, whereas for RRR purposes, the collection of the return on rate base is recorded in the income statement in accordance with the OEB's Accounting Procedures Handbook Guidance - March 2015 - #6.		(2,599)
d. This relates to the CIR Costs Deferral re-instatement on the Balance Sheet. For OSC purposes, as a result of the OEB's Decision with regards to the DRO, the CIR costs were considered no longer recoverable, and as such it was considered impaired and written-off to the P&L. For RRR purposes, since the CIR Costs were approved to be recovered over the 5 year term in the original OEB Decision on December 29, 2015 with regards to the 2015-2019 CIR Application, the CIR costs were re-instated on the balance sheet and will be amortized over the 5 years.		2,010
e. The difference represents the non-regulated business current income tax expense included in the AFS.		3,445

B. Adjustments made to certain AFS income statement items in 2018, with these differences as explained in the Income Statement attached.

a. The total impact on net income or difference for the year 2018 was ($3,482), per the Income Statement attached.		(3,482)
Total difference:		1,626

Note 8: Difference in "Regulatory balances - deferred credits" of ($14,244): Calculated balance of ($163,971) & AFS balance of ($178,214), a difference of ($14,244), as follows:

a. The deferred tax balance related to regulatory balances and gross up in respect of deferred tax assets are recorded in regulatory balances in accordance with IFRS 14 for AFS. For purposes of RRR reporting, these balances are reclassified to deferred tax assets.

b. Deferral of gain on sale of surplus property in a regulatory account for the AFS and recorded as miscellaneous liabilities for RRR reporting.

c. Deferral of excess expansion deposit withholdings in a regulatory account for the AFS and recorded as miscellaneous liabilities for RRR reporting.

Toronto Hydro-Electric System Limited - 2.1.13

Filing: April 30, 2019

Statement of Income
December 31, 2018

		Regulated 2018 Actual OEB Acct TB	Regulated 2018 Actual (in thousands)	Unregulated 2018 Actual (in thousands)	Net Movement Adj 2018 Actual (in thousands)	Consol Adj 2018 Actual (in thousands)	Calculated THESL Consol 2018 Actual (in thousands)	Audited THESL Consol 2018 Actual (in thousands)	Diff	Comment
Revenue										
Energy sales	4006_Residential Energy Sales	(461,396,285)	(461,396)							
	4010_Commercial Energy Sales	(1,481,101,528)	(1,481,102)							
	4020_Energy Sales to Large Users	(171,948,906)	(171,949)							
	4025_Street Lighting Energy Sales	(7,014,632)	(7,015)							
	4035_General Energy Sales	(231,514,879)	(231,515)							
	4050_Revenue Adjustment	(1,608,619)	(1,609)							
	4055_Energy Sales For Retailers/Others	-	-							
	4062_Billed WMS	(93,145,209)	(93,145)							
	4066_Billed NW	(156,049,886)	(156,050)							
	4068_Billed CN	(126,606,946)	(126,607)							
	4075_Billed LV	-	-							
	4076_Billed Smart Metering Entity Charge	(5,619,840)	(5,620)							
		(2,736,006,729)	(2,736,007)	-	(84,473)	-	(2,820,479)	(2,704,128)	116,352	Note 1
Distribution revenue	4080_Distribution Services Revenue	(729,185,740)	(729,186)		53,786	-	(675,400)	(674,164)	1,235	Note 2
		(3,465,192,469)	(3,465,192)	-	(30,686)	-	(3,495,879)	(3,378,292)	117,587	
Other income	4082_Retail Services Revenues	(238,364)	(238)							
	4084_Service Transaction Requests (STR) Revenues	(11,492)	(11)							
	4086_SSS Administration Revenue	(2,313,558)	(2,314)							
	4090_Electric Services Incidental to Energy Sales	-	-							
	4210_Rent from Electric Property	(15,325,972)	(15,326)							
	4215_Other Utility Operating Income	(1,106,826)	(1,107)							
	4220_Other Electric Revenues	(8,035,739)	(8,036)							
	4225_Late Payment Charges	(3,323,433)	(3,323)							
	4235_Miscellaneous Service Revenues	(5,961,505)	(5,962)							
	4245_ Government Assistance Directly Credited to Income	(5,263,537)	(5,264)							
	4325_Revenues from Merchandise Jobbing Etc.	(32,130,502)	(32,131)							
	4310_Regulatory Credits	(6,740,860)	(6,741)							
	4330_Costs and Expenses of Merchandising Jobbing Etc.	27,406,949	27,407							
		(53,044,837)	(53,045)	(3,957)	(3,284)	203	(60,083)	(80,570)	(20,488)	Note 3
Costs										
Energy purchases	4705_Power Purchased	1,225,222,495	1,225,222							
	4707_Charges - Global Adjustment	1,129,362,354	1,129,362							
	4708_Charges-WMS	85,665,853	85,666							
	4714_Charges-NW	156,049,886	156,050							
	4716_Charges-CN	126,606,946	126,607							
	4730_Rural Rate Assistance Expense	7,479,356	7,479							
	4750_Charges LV	-	-							
	4751_Charges Smart Metering Entity Chg	5,619,840	5,620							
		2,736,006,729	2,736,007	-	26,631	-	2,762,638	2,646,286	(116,352)	Note 4

Toronto Hydro-Electric System Limited - 2.1.13
Statement of Income
December 31, 2018

Filing: April 30, 2019

		Regulated 2018 Actual OEB Acct TB	Regulated 2018 Actual (in thousands)	Unregulated 2018 Actual (in thousands)	Net Movement Adj 2018 Actual (in thousands)	Consol Adj 2018 Actual (in thousands)	Calculated THESL Consol 2018 Actual (in thousands)	Audited THESL Consol 2018 Actual (in thousands)	Diff	Comment
Revenue										
Operating expenses	4380_Expenses of Non-Rate Regulated Operations	6,250,355	6,250							
	4398_Foreign Exchange Gains and Losses Including Amortization	128,336	128							
	5005_Distribution Operation Supervision and Engineering	25,122,607	25,123							
	5010_Distribution Load Dispatching	8,911,483	8,911							
	5012_Station Buildings and Fixtures Expense	-	-							
	5014_Transformer Station Equipment - Operation Labour	260,644	261							
	5015_Transformer Station Equipment - Operation Supplies and Expenses	39,487	39							
	5016_Distribution Station Equipment - Operation Labour	2,950,453	2,950							
	5017_Distribution Station Equipment - Operation Supplies and Expenses	5,721,842	5,722							
	5020_Overhead Distribution Lines and Feeders - Operation Labour	559,171	559							
	5025_Overhead Distribution Lines & Feeders - Operation Supplies and Expen	2,442,860	2,443							
	5035_Overhead Distribution Transformers- Operation	-	-							
	5040_Underground Distribution Lines and Feeders - Operation Labour	633,763	634							
	5045_Underground Distribution Lines & Feeders - Operation Supplies & Expe	2,701,801	2,702							
	5055_Underground Distribution Transformers - Operation	28,678	29							
	5065_Meter Expense	844,093	844							
	5070_Customer Premises - Operation Labour	884,921	885							
	5075_Customer Premises - Materials and Expenses	620,652	621							
	5085_Miscellaneous Distribution Expense	5,999,047	5,999							
	5105_Maintenance Supervision and Engineering	18,384,920	18,385							
	5110_Maintenance of Buildings and Fixtures - Distribution Stations	14,766,343	14,766							
	5112_Maintenance of Transformer Station Equipment	855,947	856							
	5114_Maintenance of Distribution Station Equipment	4,106,595	4,107							
	5120_Maintenance of Poles Towers and Fixtures	580,620	581							
	5125_Maintenance of Overhead Conductors and Devices	22,912,643	22,913							
	5130_Maintenance of Overhead Services	293,614	294							
	5135_Overhead Distribution Lines and Feeders - Right of Way	3,309,297	3,309							
	5145_Maintenance of Underground Conduit	12,201	12							
	5150_Maintenance of Underground Conductors and Devices	6,429,793	6,430							
	5155_Maintenance of Underground Services	8,874	9							
	5160_Maintenance of Line Transformers	-	-							
	5165_Maintenance of Street Lighting and Signal Systems	2,317,467	2,317							
	5305_Supervision	508,240	508							
	5310_Meter Reading Expense	4,349,216	4,349							
	5315_Customer Billing	9,626,222	9,626							
	5320_Collecting	13,746,474	13,746							
	5335_Bad Debt Expense	4,304,579	4,305							
	5410_Community Relations - Sundry	-	-							
	5415_Energy Conservation	-	-							
	5420_Community Safety Program	2,392,140	2,392							
	5605_Executive Salaries and Expenses	6,153,303	6,153							
	5610_Management Salaries and Expenses	-	-							
	5615_General Administrative Salaries and Expenses	50,745,406	50,745							
	5620_Office Supplies and Expenses	38,532	39							
	5625_Administrative Expense Transferred Credit	-	-							
	5630_Outside Services Employed	8,352,546	8,353							
	5635_Property Insurance	1,527,244	1,527							
	5640_Injuries and Damages	2,101,422	2,101							
	5655_Regulatory Expenses	4,924,577	4,925							
	5660_General Advertising Expenses	-	-							
	5665_Miscellaneous General Expenses	34,805	35							
	5675_Maintenance of General Plant	13,777,820	13,778							
	5680_Electrical Safety Authority Fees	353,541	354							
	5685_Independent Electricity System Operator Fees and Penalties	200,000	200							
	6105_Taxes Other Than Income Taxes	4,889,126	4,889							
	6205_Donations	1,058,655	1,059							
	4375_Revenues from Non-Utility Operations	(5,670,327)	(5,670)							
		261,492,029	261,492	3,775	5,876	(203)	270,939	297,163	26,224	Note 5

Toronto Hydro-Electric System Limited - 2.1.13
Statement of Income
December 31, 2018

Filing: April 30, 2019

		Regulated 2018 Actual OEB Acct TB	Regulated 2018 Actual (in thousands)	Unregulated 2018 Actual (in thousands)	Net Movement Adj 2018 Actual (in thousands)	Consol Adj 2018 Actual (in thousands)	Calculated THESL Consol 2018 Actual (in thousands)	Audited THESL Consol 2018 Actual (in thousands)	Diff	Comment
Revenue										
Depreciation and amortization	5705_Depreciation Expense - Property Plant and Equipment	216,029,011	216,029							
	5715_Amortization of Intangibles and Other Electric Plant	25,816,258	25,816							
	4380_Expenses of Non-Rate Regulated Operations	133,468	133							
		241,978,737	241,979	622		-	242,600	235,860	(6,741)	Note 6
		(278,759,812)	(278,760)	440	(1,464)	-	(279,784)	(279,554)	230	
Finance costs										
Interest Income	4375_Revenues from Non-Utility Operations	-	-							
	4405_Interest and Dividend Income	-	-							
		-	-	(594)		-	(594)	(594)	-	
Interest Expense, Long-term Debt	6030_Interest on Debt to Associated Companies	82,216,266	82,216	-			82,216	82,216	-	
Interest Expense, Other	5615_General Administrative Salaries and Expenses	2,132,679	2,133					-	-	
	5420_Community Safety Program	30,892	31					-	-	
	6035_Other Interest Expense	5,887,403	5,887			-			-	
	6040_Allowance for Borrowed Funds Used During Construction--Credit	(8,902,534)	(8,903)					-	-	
		(851,560)	(852)		(2,428)	-	(3,280)	(3,280)	-	
Gain on disposals of property, plant and equipment	4355_Gain on Disposition of Utility and Other Property	(576,205)	(576)							
	4335_Profits and Losses from Financial Instrument Hedges	-	-							
		(576,205)	(576)	-	(108,050)		(108,627)	(108,627)	-	
Income Tax Expense	6110_Income Taxes	34,553,535	34,554	-		-	34,554	34,748	195	Note 7
	6115_Provision for Deferred Taxes - Income Statement	3,806,795	3,807		46,994		50,801	46,894	(3,907)	Note 8
Net Income		(159,610,982)	(159,611)	(154)	(64,948)	-	(224,713)	(228,195)	(3,482)	
Net movements in regulatory balances, net of tax		-			64,948		64,948	64,948	-	
Net income after net movements in regulatory balances		(159,610,982)	(159,611)	(154)	-	-	(159,765)	(163,247)	(3,482)	

Toronto Hydro-Electric System Limited - 2.1.13
Statement of Income
December 31, 2018

Filing: April 30, 2019

	Regulated 2018 Actual OEB Acct TB	Regulated 2018 Actual (in thousands)	Unregulated 2018 Actual (in thousands)	Net Movement Adj 2018 Actual (in thousands)	Consol Adj 2018 Actual (in thousands)	Calculated THESL Consol 2018 Actual (in thousands)	Audited THESL Consol 2018 Actual (in thousands)	Diff	Comment
Revenue									
Notes: The Uniform System of Account balances are mapped and reconciled to the audited financial statements (AFS) (in dollars thousands).									
Note 1: Difference in "Energy sales" of $116,352: Calculated balance of ($2,820,479) & AFS balance of ($2,704,128), a difference of $116,352, as follows:									
a. For RRR reporting, the Global Adjustment (GA) modifier is presented gross in Energy sales as it should keep THESL financially whole/neutral for THESL's billing to customers who qualified for the GA credit. For AFS, the GA modifier is netted with Energy purchases per the new IFRS 15, which requires Energy sales to be recorded at the price customer pays.								110,732	
b. Smart Metering Entity charge: As per AFS GAAP, THESL books the Smart Metering entity revenue and charge on a net basis, while for RRR it is booked on a gross basis, in the prescribed regulatory accounts 4076 "Billed Smart Metering Entity Charge" and 4751 "Charges Smart Metering Entity Charge":								5,620	
								116,352	
Note 2: Difference in "Distribution revenue" of $1,235: Calculated balance of ($675,400) & AFS balance of ($674,164), a difference of $1,235, as follows: This relates to the reversal of the Account 1575 IFRS-GAAP Transitional PP&E Return on Rate Base. For RRR purposes, as per the APH, Article 510, "The return on rate base shall not be recorded in this account. On disposition of the account balance, the return is applied prospectively in rates as an adjustment to the revenue requirement." In the AFS, the return on rate base was accrued at year-end 2015 since the OEB approved the disposition of Account 1575 with the return on rate base of $4,755. For 2015 RRR purposes, the $4,755 accrual has been reversed. As such, in the AFS, the disposition of the account 1575 includes offsetting entries on the balance sheet related to the disposition of the return on rate base, whereas for RRR purposes, the collection of the return on rate base is recorded in the income statement in accordance with the OEB's Accounting Procedures Handbook Guidance - March 2015 - #6.								1,235	
Note 3: Difference in "Other income" of ($20,488): Calculated balance of ($60,083) & AFS balance of ($80,570), a difference of ($20,488), as follows:									
a. Demand Billable Charges: As per AFS GAAP, THESL booked demand billable charges on a gross basis while for RRR it is reported on a net basis:								(27,407)	
b. As per the OEB's Accounting Procedures Handbook Guidance - March 2015 - #6, the approved disposition of the account balance for both Account 1575 and Account 1576 would be reflected as an offset to depreciation expense over the approved amortization period." As well, based on the OEB's Accounting Procedures Handbook Guidance - March 2015 - #6, to ensure that only the return on rate base component is recorded in distribution revenues, the offsetting credit entry is recorded in OEB Account 4310 Regulatory Credits.								6,741	
c. Relates to entry recorded for IFRS that should have been reclassed between Other income and Operating expenses but was considered immaterial for the AFS There is no net income impact in IFRS. For RRR, the differences have already been corrected.								178	
Total difference:								(20,488)	
Note 4: Difference in "Energy purchases" of ($116,352): Calculated balance of $2,762,638 & AFS balance of $2,646,286, a difference of ($116,352), as follows:									
a. For RRR reporting, the Global Adjustment (GA) modifier is presented gross in Energy sales as it should keep THESL financially whole/neutral for THESL's billing to customers who qualified for the GA credit. For AFS, the GA modifier is netted with Energy purchases per the new IFRS 15, which requires Energy sales to be recorded at the price customer pays.								(110,732)	
b. Smart Metering Entity charge: As per AFS GAAP, THESL books the Smart Metering entity revenue and charge on a net basis, while for RRR it is booked on a gross basis, in the prescribed regulatory accounts 4076 "Billed Smart Metering Entity Charge" and 4751 "Charges Smart Metering Entity Charge"								(5,620)	
								(116,352)	
Note 5: Difference in "Operating expenses" of $26,224: Calculated balance of $270,939 & AFS balance of $297,163, a difference of $26,224, as follows:									
a. Demand Billable Charges: As per AFS GAAP, THESL booked demand billable charges on a gross basis while for RRR it is reported on a net basis:								27,407	
b. This relates to the CIR Costs Deferral re-instatement on the Balance Sheet. For OSC purposes, as a result of the OEB's Decision with regards to the DRO, the CIR costs were considered no longer recoverable, and as such it was considered impaired and written-off to the P&L. For RRR purposes, since the CIR Costs were approved to be recovered over the 5 year term in the original OEB Decision on December 29, 2015 with regards to the 2015-2019 CIR Application, the CIR costs were re-instated on the balance sheet and will be amortized over the 5 years.								(1,005)	
c. Relates to entry recorded for IFRS that should have been reclassed between Other income and Operating expenses but was considered immaterial for the AFS There is no net income impact in IFRS. For RRR, the differences have already been corrected.								(178)	
Total difference:								26,224	
Note 6: Difference in "Depreciation and amortization" of ($6,741): Calculated balance of $242,600 & AFS balance of $235,860, a difference of ($6,741), as follows: As per the OEB's Accounting Procedures Handbook Guidance - March 2015 - #6, the approved disposition of the account balance for both Account 1575 and Account 1576 would be reflected as an offset to depreciation expense over the approved amortization period." As well, based on the OEB's Accounting Procedures Handbook Guidance - March 2015 - #6, to ensure that only the return on rate base component is recorded in distribution revenues, the offsetting credit entry is recorded in OEB Account 4310 Regulatory Credits.								(6,741)	
Note 7: Difference in "Income tax expense - Income taxes" of $195: Calculated balance of $34,554 & AFS balance of $34,748, a difference of $195, as follows: The difference represents the non-regulated business current income tax expense included in the AFS.								195	
Note 8: Difference in "Income tax expense - Provision for deferred taxes" of ($3,907): Calculated balance of $50,801 & AFS balance of $46,894, a difference of ($3,907), as follows: For purposes of RRR reporting, an adjustment was made to remove deferred income tax asset in respect of the non-rate regulated assets.								(3,907)	

Toronto Hydro-Electric System Limited
EB-2018-0165
Exhibit U
Tab 1C
Schedule 4
FILED: April 30, 2019
(38 pages)



FINANCIAL REPORT
DECEMBER 31, 2018

TORONTO HYDRO CORPORATION

TABLE OF CONTENTS

Glossary	3
Management's Discussion and Analysis	4
Executive Summary	5
Introduction	5
Business of Toronto Hydro Corporation	6
Electricity Distribution – Industry Overview	7
Results of Operations	8
Summary of Quarterly Results of Operations	15
Financial Position	16
Liquidity and Capital Resources	17
Corporate Developments	22
Legal Proceedings	23
Share Capital	23
Transactions with Related Parties	24
Controls and Procedures	24
Risk Management and Risk Factors	25
Critical Accounting Estimates	32
Significant Accounting Policies	33
Changes in Accounting Policies	33
Future Accounting Pronouncements	35
Forward-Looking Information	36
Selected Annual Information	38
Additional Information	38
Consolidated Finanical Statements	39
Notes to the Consolidated Financial Statements	48

GLOSSARY

CDM – Conservation and demand management

CIR – Custom Incentive Rate-setting

City – City of Toronto

Copeland Station – The Clare R. Copeland transformer station, formerly called "Bremner Station"

Corporation – Toronto Hydro Corporation

Electricity Act – *Electricity Act, 1998* (Ontario), as amended

ERM – Enterprise risk management

ERP – Enterprise resource planning

GWh – Gigawatt hour

HONI – Hydro One Networks Inc.

IAS – International Accounting Standard

IASB – International Accounting Standards Board

IESO – Independent Electricity System Operator

IFRIC – International Financial Reporting Interpretations Committee

IFRS – International Financial Reporting Standards

ITA – Income Tax Act (Canada), as amended

kW – Kilowatt

LDC – Toronto Hydro-Electric System Limited

LRAM – Lost revenue adjustment mechanism

MD&A – Management's Discussion and Analysis

MEU – Municipal electricity utility

OCI – Other comprehensive income

OEB – Ontario Energy Board

OEB Act – Ontario Energy Board Act, 1998

(Ontario), as amended

OFHP – Ontario's Fair Hydro Plan

OPEB – Other post-employment benefits

OREC – *Ontario Rebate for Electricity Consumers Act*, 2016 (Ontario).

PILs – Payments in lieu of corporate taxes

PP&E – Property, plant and equipment

TA – Taxation Act, 2007 (Ontario), as amended

TH Energy – Toronto Hydro Energy Services Inc.

WMS – Wholesale Market Service



MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE YEARS ENDED DECEMBER 31, 2018 AND 2017

Executive Summary

- Net income after net movements in regulatory balances for the three months and year ended December 31, 2018 was $31.9 million and $167.3 million, respectively, compared to $35.1 million and $156.5 million for the comparable periods in 2017;
- Capital expenditures were primarily related to the renewal of the electricity infrastructure of LDC and were $157.3 million and $511.3 million for the three months and year ended December 31, 2018, respectively, compared to $148.9 million and $552.9 million for the comparable periods in 2017;
- On January 16, 2018, the Corporation entered into an agreement to sell a property, including land and building, to a third party and closed the sale on April 17, 2018. The gain of $98.6 million, net of tax and selling costs, was recognized and deferred as a regulatory credit balance, which reduces future electricity distribution rates for customers;
- On August 31, 2018, LDC filed its 2019 rate application seeking OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2019 and ending on December 31, 2019. On December 13, 2018, the OEB issued a decision and rate order approving LDC's 2019 rates and providing for other deferral and variance account dispositions;
- On August 15, 2018, LDC filed a CIR application seeking approval of LDC's 2020 test-year revenue requirement on a cost of service basis and the corresponding electricity distribution rates effective January 1, 2020, and the subsequent annual rate adjustments based on a custom index specific to LDC for the period commencing on January 1, 2021 and ending on December 31, 2024. The rate application requests approvals to fund capital expenditures of approximately $2.8 billion over the 2020-2024 period. The rate application also seeks approval to include in LDC's rate base capital amounts that were incurred prior to 2020; and
- On March 6, 2019, the Board of Directors of the Corporation declared a quarterly dividend in the amount of $25.1 million with respect to the first quarter of 2019, payable to the City by March 29, 2019.

Introduction

This MD&A should be read in conjunction with the Corporation's audited consolidated financial statements and accompanying notes as at and for the years ended December 31, 2018 and 2017, which were prepared in accordance with IFRS (the "Consolidated Financial Statements").

Copies of these documents are available on the System for Electronic Document Analysis and Retrieval website at www.sedar.com.

Business of Toronto Hydro Corporation

The Corporation is a holding company which wholly owns two subsidiaries:

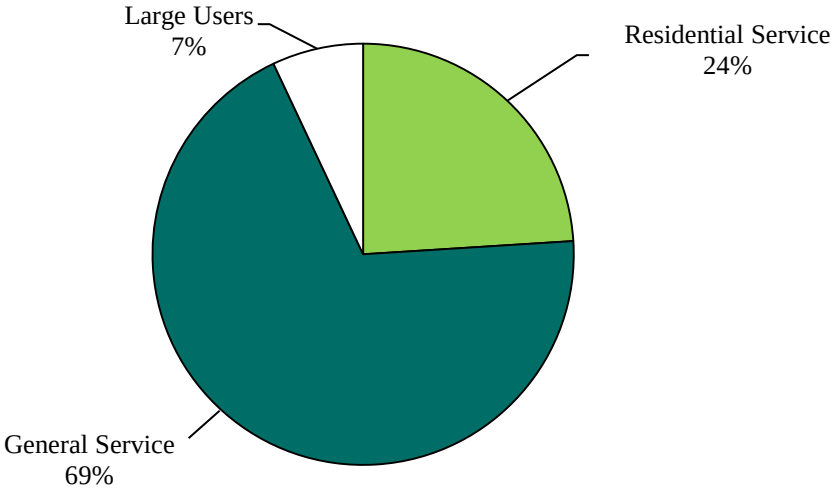
- LDC - distributes electricity and engages in CDM activities; and
- TH Energy - provides street lighting and expressway lighting services in the City.

The Corporation supervises the operations of, and provides corporate, management services and strategic direction to its subsidiaries. The City is the sole shareholder of the Corporation.

The principal business of the Corporation and its subsidiaries is the distribution of electricity by LDC. LDC owns and operates an electricity distribution system, delivering electricity to approximately 772,000 customers located in the City. LDC serves the largest city in Canada and distributes approximately 19% of the electricity consumed in Ontario. The business of LDC and other electricity distributors is regulated by the OEB, which has broad powers relating to licensing, standards of conduct and service, and the regulation of electricity distribution rates charged by LDC and other electricity distributors in Ontario. For the year ended December 31, 2018, LDC earned energy sales and distribution revenue of $3,378.3 million from general service users[1], residential service users[2] and large users[3].

LDC Energy Sales and Distribution Revenue by Class

Year ended December 31, 2018



[1] "General Service" means a service supplied to premises other than those receiving "Residential Service" and "Large Users" and typically includes small businesses and bulk-metered multi-unit residential establishments. This service is provided to customers with a monthly peak demand of less than 5,000 kW averaged over a twelve-month period.

[2] "Residential Service" means a service that is for domestic or household purposes, including single family or individually metered multi-family units and seasonal occupancy.

[3] "Large Users" means a service provided to a customer with a monthly peak demand of 5,000 kW or greater averaged over a twelve-month period.

Electricity Distribution – Industry Overview

In April 1999, the Government of Ontario began restructuring the province's electricity industry. Under regulations passed pursuant to the restructuring, LDC and other electricity distributors purchase electricity from the wholesale market administered by the IESO and recover the costs of electricity and certain other costs from customers in accordance with rate-setting procedures mandated by the OEB.

The OEB has regulatory oversight of electricity matters in Ontario. The OEB Act sets out the OEB's authority to issue a distribution licence that must be obtained by owners or operators of an electricity distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, separation of accounts for distribution and other activities, and requirements for rate-setting and other legal filings.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to approve the amounts paid to non-contracted generators, the responsibility to provide rate protection for rural or remote electricity customers, and the responsibility for ensuring that electricity distribution companies fulfill their obligations to connect and service customers.

LDC is required to charge its customers for the following amounts (all of which, other than distribution rates, represent a pass-through of amounts payable to third parties):

- *Commodity Charge* – The commodity charge represents the market price of electricity consumed by customers and is passed through the IESO back to operators of generating stations. It includes the global adjustment, which represents the difference between the market price of electricity and the rates paid to regulated and contracted generators.

- *Retail Transmission Rate* – The retail transmission rate represents the costs incurred in respect of the transmission of electricity from generating stations to local distribution networks. Retail transmission rates are passed through back to operators of transmission facilities.

- *WMS Charge* – The WMS charge represents various wholesale market support costs, such as the cost of the IESO to administer the wholesale electricity system, operate the electricity market, and maintain reliable operation of the provincial grid. Wholesale charges are passed through back to the IESO.

- *Distribution Rate* – The distribution rate is designed to recover the costs incurred by LDC in delivering electricity to customers, including the OEB-allowed cost of capital. Distribution rates are regulated by the OEB and include fixed and variable (usage-based) components, based on a forecast of LDC's customers and load.

LDC is required to satisfy and maintain prudential requirements with the IESO, which include credit support with respect to outstanding market obligations in the form of letters of credit, cash deposits or guarantees from third parties with prescribed credit ratings.

The Corporation is exempt from tax under the ITA if not less than 90% of the capital of the Corporation is owned by the City and not more than 10% of the income of the Corporation is derived from activities carried on outside the municipal geographical boundaries of the City. In addition, the Corporation's subsidiaries are also exempt from tax under the ITA provided that all of their capital is owned by the Corporation and not more than 10% of their respective income is from activities carried on outside the municipal geographical boundaries of the City. A corporation exempt from tax under the ITA is also exempt from tax under the TA.

The Corporation and each of its subsidiaries are MEUs for purposes of the PILs regime contained in the Electricity Act. The Electricity Act provides that a MEU that is exempt from tax under the ITA and the TA is required to make, for each taxation year, a PILs payment to the Ontario Electricity Financial Corporation in an amount equal to the tax that it would be liable to pay under the ITA and the TA if it were not exempt from tax. The PILs regime came into effect on October 1, 2001, at which time the Corporation and each of its subsidiaries were deemed to have commenced a new taxation year for purposes of determining their respective liabilities for PILs payments.

Results of Operations

Net Income after Net Movements in Regulatory Balances

Consolidated Statements of Income
Three months ended December 31
(in millions of Canadian dollars)

	2018 $	2017 $	Change $
		[Restated][1]	
Revenues			
Energy sales	660.2	638.9	21.3
Distribution revenue	163.9	181.7	(17.8)
Other	23.4	27.7	(4.3)
	847.5	848.3	(0.8)
Expenses			
Energy purchases	621.6	660.7	(39.1)
Operating expenses	73.5	77.8	(4.3)
Depreciation and amortization	67.3	62.0	5.3
	762.4	800.5	(38.1)
Finance costs	(18.8)	(18.9)	0.1
Gain on disposals of PP&E	0.2	0.2	-
Income before income taxes	66.5	29.1	37.4
Income tax expense	(16.2)	(11.1)	(5.1)
Net income	50.3	18.0	32.3
Net movements in regulatory balances	(26.3)	10.9	(37.2)
Net movements in regulatory balances arising from deferred tax assets	7.9	6.2	1.7
Net income after net movements in regulatory balances	31.9	35.1	(3.2)

[1] These numbers have been restated to account for the impact of adopting IFRS 15 *Revenue from Contracts with Customers* ("IFRS 15"). Additional details on IFRS 15 are discussed in the "Changes in Accounting Policies" section of this MD&A.

The decrease in net income after net movements in regulatory balances for the three months ended December 31, 2018 was primarily due to higher depreciation related to new in-service asset additions ($5.3 million), amounts being deferred into capital related regulatory accounts for future refunds to customers ($4.2 million) and higher income taxes (including regulatory balances arising from deferred tax assets) ($3.4 million). These variances were partially offset by higher 2018 electricity distribution rates ($8.9 million) and higher electricity consumption ($0.6 million).

The net decrease in distribution revenue is due to the implementation of the OEB-approved 2018 rate riders, which returned $27.5 million to customers. However, the 2018 rate riders do not impact net income after net movements in regulatory balances as there are corresponding offsets in net movements in regulatory balances, given IFRS treatment.

Consolidated Statements of Income
Year ended December 31
(in millions of Canadian dollars)

	2018 $	2017 $	Change $
		[Restated][1]	
Revenues			
Energy sales	2,704.1	2,810.2	(106.1)
Distribution revenue	674.2	724.2	(50.0)
Other	94.4	107.7	(13.3)
	3,472.7	3,642.1	(169.4)
Expenses			
Energy purchases	2,646.3	2,855.9	(209.6)
Operating expenses	307.5	293.0	14.5
Depreciation and amortization	238.3	224.2	14.1
	3,192.1	3,373.1	(181.0)
Finance costs	(74.6)	(77.7)	3.1
Gain on disposals of PP&E	108.6	9.8	98.8
Income before income taxes	314.6	201.1	113.5
Income tax expense	(82.4)	(44.7)	(37.7)
Net income	232.2	156.4	75.8
Net movements in regulatory balances	(111.9)	(13.1)	(98.8)
Net movements in regulatory balances arising from deferred tax assets	47.0	13.2	33.8
Net income after net movements in regulatory balances	167.3	156.5	10.8

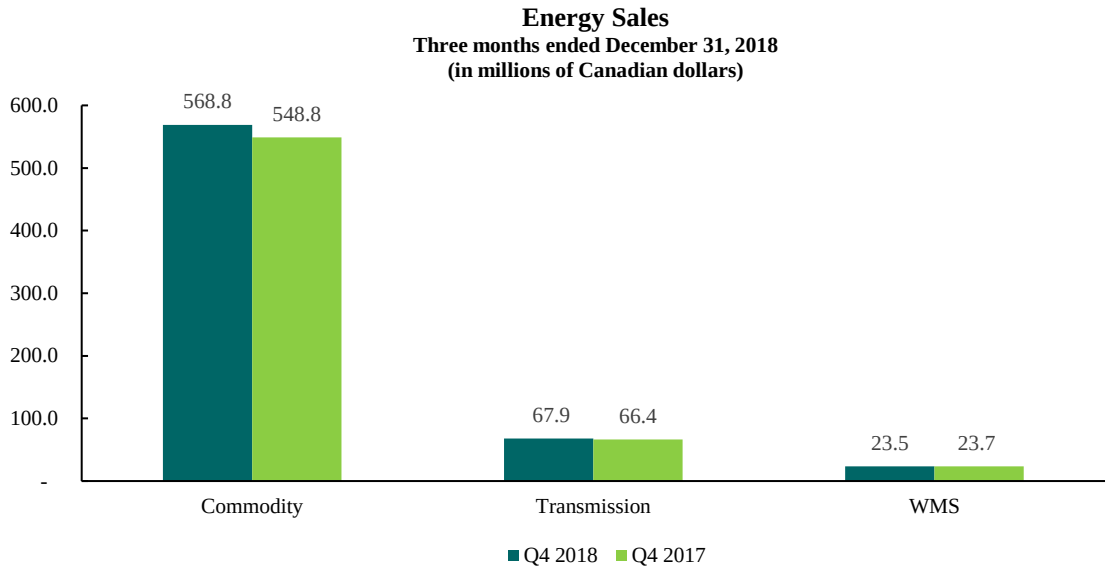
[1] These numbers have been restated to account for the impact of adopting IFRS 15. Additional details on IFRS 15 are discussed in the "Changes in Accounting Policies" section of this MD&A.

The increase in net income after net movements in regulatory balances for the year ended December 31, 2018 was primarily due to higher 2018 electricity distribution rates ($33.1 million), higher electricity consumption ($21.0 million), higher LRAM ($7.7 million) and lower finance costs due to a lower average amount of outstanding debentures in the current year ($3.1 million). These variances were partially offset by amounts being deferred into capital related regulatory accounts for future refunds to customers ($18.1 million), higher operating expenses related to emergency power restoration due to major storms in 2018 and system maintenance ($14.5 million), higher depreciation related to new in-service asset additions ($14.1 million) and lower other revenue related to the recognition of the CDM mid-term incentive in 2017 ($9.5 million).

The net decrease in distribution revenue is due to the implementation of the OEB-approved 2018 rate riders, which returned $102.2 million to customers. The gain on disposals of PP&E is primarily due to the gain realized on a property sale deferred as a regulatory credit balance, which reduces future electricity distribution rates for customers. The 2018 rate riders and gain on disposal do not impact net income after net movements in regulatory balances as there are corresponding offsets in net movements in regulatory balances, given IFRS treatment.

Energy Sales

LDC's energy sales arise from charges to customers for electricity consumed, based on regulated rates. Energy sales include amounts billed or billable to customers for commodity charges, retail transmission charges, and WMS charges at current rates. These charges are passed through to customers over time and are considered revenue by LDC. For any given period, energy sales should be equal to the cost of energy purchased. However, a difference between energy sales and energy purchases arises when there is a timing difference between the amounts charged by LDC to customers, based on regulated rates, and the electricity and non-competitive electricity service costs billed monthly by the IESO to LDC. This difference is recorded as a settlement variance, representing amounts to be recovered from or refunded to customers through future rates approved by the OEB. In accordance with IFRS 14 *Regulatory Deferral Accounts* ("IFRS 14"), this settlement variance is presented within regulatory balances on the Corporation's consolidated balance sheets ("Consolidated Balance Sheets") and within net movements in regulatory balances on the Corporation's consolidated statements of income ("Consolidated Statements of Income").



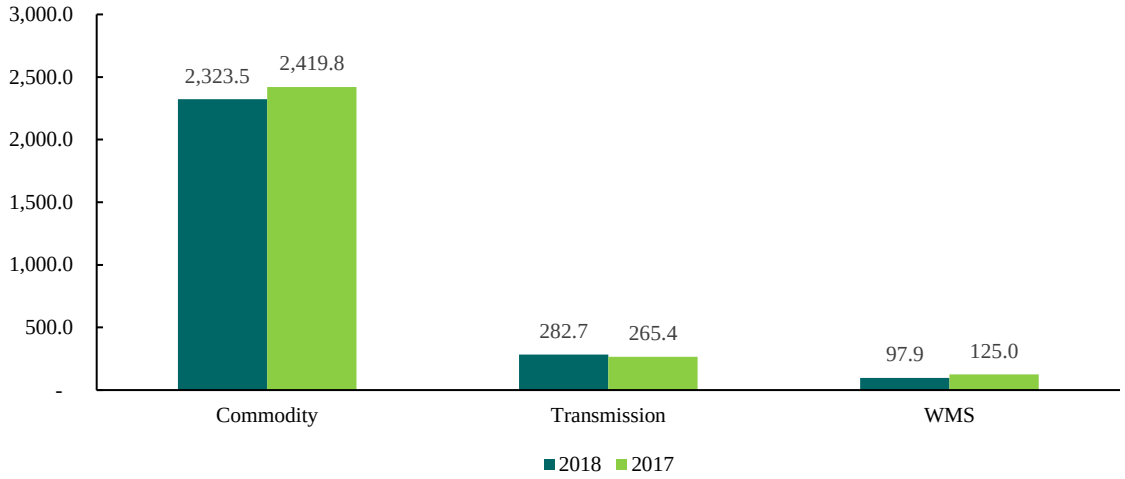
Energy sales for the three months ended December 31, 2018 were $660.2 million compared to $638.9 million for the comparable period in 2017. The increase was primarily due to higher commodity charges ($20.0 million) and higher retail transmission charges ($1.5 million).

Energy Purchases, Energy Sales, and Settlement Variances
Three months ended December 31, 2018
(in millions of Canadian dollars)

	Energy Purchases $	Energy Sales $	Settlement Variances $
Commodity charges	536.3	568.8	(32.5)
Retail transmission charges	69.4	67.9	1.5
WMS charges	15.9	23.5	(7.6)
Total	621.6	660.2	(38.6)

For the three months ended December 31, 2018, LDC recognized $660.2 million in energy sales to customers and was billed $621.6 million for energy purchases from the IESO. The difference between energy sales and energy purchases represents a $38.6 million settlement variance for the period. The settlement variance was recorded as an increase to the regulatory credit balance ($39.4 million including carrying charges on the accumulated settlement variance balance) on the Consolidated Balance Sheets, and presented within net movements in regulatory balances on the Consolidated Statements of Income.

Energy Sales
Year ended December 31, 2018
(in millions of Canadian dollars)



Energy sales for the year ended December 31, 2018 were $2,704.1 million compared to $2,810.2 million for the comparable period in 2017. The decrease was due to lower commodity charges ($96.3 million) and lower WMS charges ($27.1 million), partially offset by retail transmission charges ($17.3 million).

Energy Purchases, Energy Sales, and Settlement Variances
Year ended December 31, 2018
(in millions of Canadian dollars)

	Energy Purchases $	Energy Sales $	Settlement Variances $
Commodity charges	2,244.2	2,323.5	(79.3)
Retail transmission charges	309.0	282.7	26.3
WMS charges	93.1	97.9	(4.8)
Total	2,646.3	2,704.1	(57.8)

For the year ended December 31, 2018, LDC recognized $2,704.1 million in energy sales to customers and was billed $2,646.3 million for energy purchases from the IESO. The difference between energy sales and energy purchases represents a $57.8 million settlement variance for the period. The settlement variance was recorded as an increase to the regulatory credit balance ($58.2 million including carrying charges on the accumulated settlement variance balance; see the regulatory credit balance table in note 8 to the Consolidated Financial Statements) on the Consolidated Balance Sheets, and presented within net movements in regulatory balances on the Consolidated Statements of Income.

Distribution Revenue

Distribution revenue is recorded based on OEB-approved distribution rates to recover the costs incurred by LDC in delivering electricity to customers, and includes revenue collected through OEB-approved rate riders.

Distribution revenue for the three months and year ended December 31, 2018 was $163.9 million and $674.2 million, respectively, compared to $181.7 million and $724.2 million for the comparable periods in 2017.

The net decrease in distribution revenue for the three months ended December 31, 2018 was primarily due to lower revenue collected through OEB-approved rate riders ($27.5 million), partially offset by higher electricity distribution rates ($8.9 million) and higher electricity consumption ($0.6 million).

The net decrease in distribution revenue for the year ended December 31, 2018 was primarily due to lower revenue collected through OEB-approved rate riders ($104.6 million), partially offset by higher electricity distribution rates ($33.1 million) and higher electricity consumption ($21.0 million). The OEB-approved rate riders do not impact net income after net movements in regulatory balances as there is an offsetting increase in net movements in regulatory balances.

Other Revenue

Other revenue includes revenue from services ancillary to electricity distribution, delivery of street lighting services, pole and duct rentals, other regulatory service charges, capital contributions and CDM programs.

Other revenue for the three months and year ended December 31, 2018 was $23.4 million and $94.4 million, respectively, compared to $27.7 million and $107.7 million for the comparable periods in 2017.

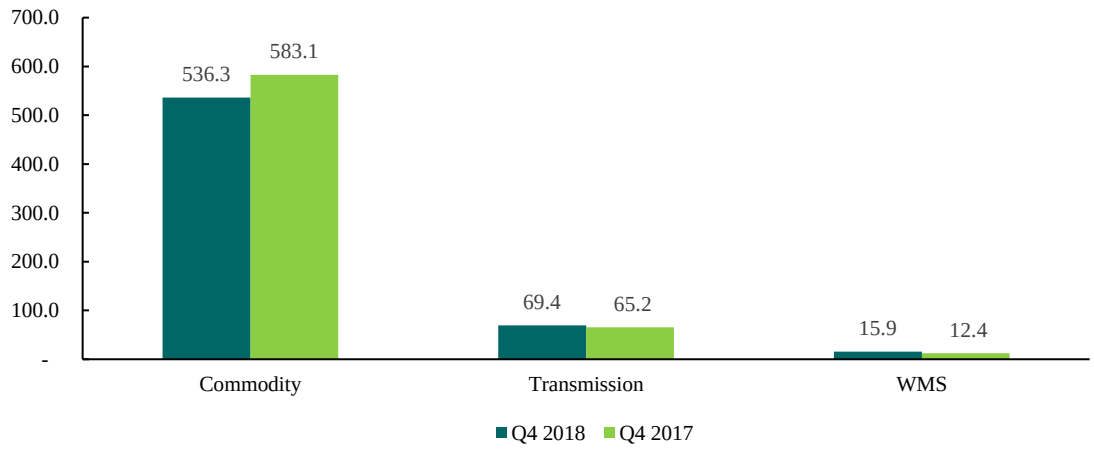
The decrease in other revenue for the three months ended December 31, 2018 was primarily due to lower revenue in connection with ancillary services and the recognition of the CDM mid-term incentive in 2017.

The decrease in other revenue for the year ended December 31, 2018 was primarily due to the recognition of the CDM mid-term incentive in 2017.

Energy Purchases

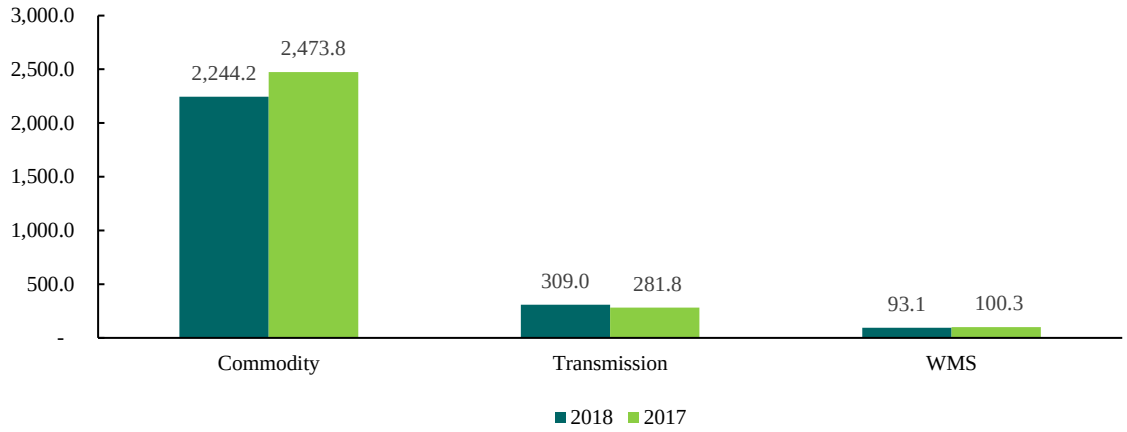
LDC's energy purchases consist of actual charges for electricity generated by third parties, which are passed through to customers over time in the form of energy sales. Energy purchases are billed monthly by the IESO and include commodity charges, retail transmission charges and WMS charges.

LDC Energy Purchases
Three months ended December 31, 2018
(in millions of Canadian dollars)



Energy purchases for the three months ended December 31, 2018 were $621.6 million compared to $660.7 million for the comparable period in 2017. The decrease was primarily due to lower commodity charges ($46.8 million), partially offset by higher retail transmission charges ($4.2 million) and higher WMS charges ($3.5 million).

LDC Energy Purchases
Year ended December 31, 2018
(in millions of Canadian dollars)



Energy purchases for the year ended December 31, 2018 were $2,646.3 million compared to $2,855.9 million for the comparable period in 2017. The decrease was primarily due to lower commodity charges ($229.6 million) and lower WMS charges ($7.2 million), partially offset by higher retail transmission charges ($27.2 million).

Operating Expenses

Operating expenses for the three months and year ended December 31, 2018 were $73.5 million and $307.5 million, respectively, compared to $77.8 million and $293.0 million for the comparable periods in 2017.

The decrease in operating expenses for the three months ended December 31, 2018 was primarily due to lower ancillary service costs and lower contractor costs, partially offset by higher system maintenance costs.

The increase in operating expenses for the year ended December 31, 2018 was primarily due to costs related to emergency power restoration due to major storms in 2018 and higher system maintenance costs.

Depreciation and Amortization

Depreciation and amortization expense for the three months and year ended December 31, 2018 was $67.3 million and $238.3 million, respectively, compared to $62.0 million and $224.2 million for the comparable periods in 2017.

The increase in depreciation and amortization for the three months ended December 31, 2018 was primarily due to new in-service asset additions in 2018 and higher derecognition of assets removed from service, partially offset by certain assets being fully depreciated.

The increase in depreciation and amortization for the year ended December 31, 2018 was primarily due to new in-service asset additions in 2018, partially offset by certain assets being fully depreciated and a decrease in derecognition of assets removed from service.

Finance Costs

Finance costs for the three months and year ended December 31, 2018 were $18.8 million and $74.6 million, respectively, compared to $18.9 million and $77.7 million for the comparable periods in 2017. The decrease was primarily due to a lower average amount of outstanding debentures ($2,034.5 million) in 2018 compared with 2017 ($2,078.4 million).

Gain on Disposals of PP&E

Gain on disposals of PP&E for the three months and year ended December 31, 2018 was $0.2 million and $108.6 million, respectively, compared to $0.2 million and $9.8 million for the comparable periods in 2017. The variance in gain on disposals of PP&E for the year ended December 31, 2018 was primarily due to the gain realized on the sale of a property in the second quarter of 2018 ($108.1 million). The realized gain of $98.6 million, net of tax and selling costs, was recorded as a regulatory credit balance on the Consolidated Balance Sheets with a corresponding offset in net movements in regulatory balances. LDC has been returning the total forecasted net gains on sale of certain

properties along with the future tax savings back to rate payers through a rate rider effective from March 1, 2016 to December 31, 2018 as part of the 2015 - 2019 CIR decision and rate order. The actual realized gain and tax savings that exceeded the approved rate riders reduce future electricity distribution rates for customers. LDC has requested disposition of this incremental balance in the 2020 – 2024 rate application over a 60-month period commencing on January 1, 2020.

Income Tax Expense and Income Tax Recorded in Net Movements in Regulatory Balances

Income tax expense and income tax recorded in net movements in regulatory balances for the three months and year ended December 31, 2018 were $8.3 million and $35.4 million, respectively, compared to $4.9 million and $31.5 million for the comparable periods in 2017.

The unfavourable variance in income tax expense and income tax recorded in net movements in regulatory balances for the three months ended December 31, 2018 was primarily due to lower net deductions for permanent and temporary differences between accounting and tax treatments.

The unfavourable variance in income tax expense and income tax recorded in net movements in regulatory balances for the year ended December 31, 2018 was primarily due to the tax recognized on property disposition and higher income before taxes (including net movements in regulatory balance), offset by higher net deductions for permanent and temporary differences between accounting and tax treatments.

Net Movements in Regulatory Balances

In accordance with IFRS 14, the Corporation separately presents regulatory balances and related net movements on the Consolidated Balance Sheets and Consolidated Statements of Income.

The decrease in the regulatory debit ($74.0 million) and increase in the regulatory credit ($18.2 million) balances for the year ended December 31, 2018 equals the sum ($92.2 million) of net movements in regulatory balances, net movements in regulatory balances arising from deferred tax assets and net movements in regulatory balances related to OCI, shown for the period (see "Financial Position" below). Energy purchases record the actual cost of power purchased which varies from month to month. Since the selling price of power within energy sales is fixed for set periods of time, a gain or loss usually results, and is part of the calculation of net income. However, per OEB regulations, such gains or losses on energy sales are deferred within balance sheet regulatory variance accounts for later disposition to or from rate payers via rate riders after approval by the OEB. Deferrals of gains or losses on energy sales (see discussion on "settlement variance" under "Results of Operations" above), or disposition of past deferrals in electricity rates will usually represent the largest single element of the net movements in regulatory balances for a given period.

Net movements in regulatory balances for the three months and year ended December 31, 2018 were a charge of $26.3 million and a charge of $111.9 million, respectively, compared to a recovery of $10.9 million and a charge of $13.1 million for the comparable periods in 2017. The charge of $26.3 million for the three months ended December 31, 2018 was primarily due to the timing difference between the electricity costs billed monthly by the IESO and LDC's billing to customers and amounts being deferred into capital-related regulatory accounts for future refunds to customers, partially offset by amounts disposed through OEB-approved rate riders. The recovery of $10.9 million for the three months ended December 31, 2017 was primarily due to the timing difference between the electricity costs billed monthly by the IESO and LDC's billing to customers, partially offset by amounts disposed through OEB-approved rate riders and amounts being deferred into capital-related regulatory accounts for future refunds to customers.

The charge of $111.9 million for the year ended December 31, 2018 was primarily due to the gain realized on disposal of a property in the second quarter of 2018, the timing difference between the electricity costs billed monthly by the IESO and LDC's billing to customers and amounts being deferred into capital-related regulatory accounts for future refunds to customers, partially offset by amounts disposed through OEB-approved rate riders, and LRAM. The charge of $13.1 million for the year ended December 31, 2017 was primarily due to the timing difference between the electricity costs billed monthly by the IESO and LDC's billing to customers, partially offset by amounts disposed through OEB-approved rate riders and amounts being deferred into capital-related regulatory accounts for future refunds to customers.

Summary of Quarterly Results of Operations

The table below presents a summary of the Corporation's results of operations for eight quarters including and immediately preceding December 31, 2018.

Summary of Quarterly Results of Operations
(in millions of Canadian dollars)

	December 31, 2018 $	September 30, 2018 $	June 30, 2018 $	March 31, 2018 $
Energy sales	660.2	741.1	660.4	642.4
Distribution revenue	163.9	175.8	162.9	171.6
Other	23.4	21.7	28.0	21.3
Revenues	847.5	938.6	851.3	835.3
Net income after net movements in regulatory balances	31.9	50.4	42.5	42.5

	December 31, 2017 $ *[Restated]* [1]	September 30, 2017 $ *[Restated]* [1]	June 30, 2017 $ *[Restated]* [1]	March 31, 2017 $ *[Restated]* [1]
Energy sales	638.9	738.4	662.1	770.8
Distribution revenue	181.7	186.1	178.2	178.2
Other	27.7	36.6	23.0	20.4
Revenues	848.3	961.1	863.3	969.4
Net income after net movements in regulatory balances	35.1	46.8	35.0	39.6

[1] These numbers have been restated to account for the impact of adopting IFRS 15. Additional details on IFRS 15 are discussed in the "Changes in Accounting Policies" section of this MD&A.

The Corporation's revenues, all other things being equal, are impacted by temperature fluctuations and unexpected weather conditions. Revenues would tend to be higher in the first quarter as a result of higher energy consumption for winter heating, and in the third quarter due to air conditioning/cooling. The Corporation's revenues are also impacted by fluctuations in electricity prices and the timing and recognition of regulatory decisions and rate orders. The variation from the seasonal trend for the first quarter of 2018 was due to lower energy sales primarily related to lower commodity charges.

Financial Position

The following table outlines the significant changes in the Consolidated Balance Sheets as at December 31, 2018 as compared to the Consolidated Balance Sheets as at December 31, 2017.

Consolidated Balance Sheets Data
(in millions of Canadian dollars)

Balance Sheet Account	Increase (Decrease) $	Explanation of Significant Change
Assets		
PP&E and intangible assets	271.4	The increase was primarily due to capital expenditures, partially offset by depreciation and derecognition.
Deferred tax assets	(56.7)	The decrease was primarily due to lower net deductible temporary differences between tax and accounting values of PP&E and intangible assets, and regulatory balances.
Liabilities and Equity		
Commercial paper	(46.0)	The decrease was primarily due to proceeds received on disposition of a property in the second quarter of 2018 offset by issuances required for general corporate purposes (see "Liquidity and Capital Resources" below).
Accounts payable and accrued liabilities	9.1	The decrease was primarily due to timing of payments, partially offset by the cessation of debt retirement charges.
Customer deposits	21.7	The increase was primarily due to expansion security deposits received, net of refunds.
Deferred revenue	101.1	The increase was primarily due to capital contributions received.
Post-employment benefits	(37.1)	The decrease was primarily due to the recognized actuarial gain driven by the updated actuarial assumptions.
Retained earnings	73.1	The increase was due to net income after net movements in regulatory balances ($167.3 million), offset by dividends paid ($93.9 million).
Regulatory Balances		
Regulatory debit balances	(74.0)	The decrease was primarily due to the amounts disposed through OEB-approved rate riders and the actuarial gain incurred on the valuation of post-employment benefit obligation recorded as a decrease to the regulatory debit balance.

Consolidated Balance Sheets Data
(in millions of Canadian dollars)

Balance Sheet Account	Increase (Decrease) $	Explanation of Significant Change
Regulatory credit balances	18.2	The increase was primarily due to the balance of gain realized on disposal of a property in the second quarter of 2018 and higher amounts being deferred into capital-related regulatory accounts, partially offset by amounts disposed through OEB-approved rate riders and deferred taxes.

Liquidity and Capital Resources

The Corporation's current assets and current liabilities amounted to $517.1 million and $975.4 million, respectively, as at December 31, 2018, resulting in a working capital deficit of $458.3 million. The deficit is attributable to the Corporation's preference for utilizing its Commercial Paper Program and Working Capital Facility (both defined below) before issuing additional debentures to fulfill the Corporation's ongoing liquidity requirements, including funding of significant capital spending in the current year. The Corporation seeks to maintain an optimal mix of short-term and long-term debt in order to lower overall financing costs and to enhance borrowing flexibility.

The Corporation's primary sources of liquidity and capital resources are cash provided by operating activities, issuances of commercial paper, amounts available to be drawn against its credit facilities, and borrowings from debt capital markets. The Corporation's liquidity and capital resource requirements are mainly for capital expenditures to maintain and improve the electricity distribution system of LDC, for energy purchases and to meet financing obligations.

The amount available under the Revolving Credit Facility (defined below) and the outstanding borrowings under the Revolving Credit Facility and Commercial Paper Program are as follows:

(in millions of Canadian dollars)	Revolving Credit Facility Limit $	Revolving Credit Facility Borrowings $	Commercial Paper Outstanding $	Revolving Credit Facility Availability $
December 31, 2018	800.0	-	113.0	687.0
December 31, 2017	800.0	-	159.0	641.0

The Corporation is a party to a $20.0 million demand facility with a Canadian chartered bank for the purpose of working capital management ("Working Capital Facility"). As at December 31, 2018, $12.6 million had been drawn under the Working Capital Facility, compared to $11.7 million as at December 31, 2017.

Consolidated Statements of Cash Flow Data
(in millions of Canadian dollars)

	Three months ended December 31		Year ended December 31	
	2018 $	2017 $	2018 $	2017 $
Working capital facility, beginning of period	(7.4)	(10.1)	(11.7)	(7.1)
Net cash provided by operating activities	277.2	211.4	596.7	584.7
Net cash used in investing activities	(106.4)	(132.3)	(376.9)	(520.9)
Net cash used in financing activities	(176.0)	(80.7)	(220.7)	(68.4)
Working capital facility, end of period	(12.6)	(11.7)	(12.6)	(11.7)

Operating Activities

Net cash provided by operating activities for the three months and year ended December 31, 2018 was $277.2 million and $596.7 million, respectively, compared to $211.4 million and $584.7 million for the comparable periods in 2017. The increase in net cash provided by operating activities for the three months ended December 31, 2018 was primarily due to higher working capital related to timing differences in the settlement of receivables and payables and changes in regulatory balances.

The increase in net cash provided by operating activities for the year ended December 31, 2018 was primarily due to higher capital contributions, higher customer deposits, higher net income after net movements in regulatory balances and changes in non-cash items, partially offset by lower working capital related to timing differences in the settlement of receivables and higher income taxes paid.

Investing Activities

Net cash used in investing activities for the three months and year ended December 31, 2018 was $106.4 million and $376.9 million, respectively, compared to $132.3 million and $520.9 million for the comparable periods in 2017.

The decrease in net cash used in investing activities for the three months ended December 31, 2018 was primarily due to lower cash spending on capital projects in the fourth quarter of 2018.

The decrease in net cash used in investing activities for the year ended December 31, 2018 was primarily due to proceeds received on disposition of a property in the second quarter of 2018 and lower cash spending on capital projects in 2018.

Electricity distribution is a capital-intensive business. As the municipal electricity distribution company serving the largest city in Canada, LDC continues to invest in the renewal of existing aging infrastructure to address safety, reliability and customer service requirements.

The following table summarizes the Corporation's capital expenditures (on an accrual basis), both PP&E and intangible assets, for the periods indicated.

Capital Expenditures
(in millions of Canadian dollars)

	Three months ended December 31		Year ended December 31	
	2018 $	2017 $	2018 $	2017 $
Regulated LDC				
Distribution system				
Planned [1]	120.6	103.1	369.7	373.0
Reactive	13.1	12.8	63.8	48.1
Copeland Station	2.2	4.9	9.9	23.2
Facilities consolidation	-	-	-	35.2
Technology assets	14.9	20.3	54.4	54.9
Other [2]	1.4	5.3	4.0	10.5
Regulated capital expenditures	152.2	146.4	501.8	544.9
Unregulated capital expenditures [3]	5.1	2.5	9.5	8.0
Total capital expenditures	157.3	148.9	511.3	552.9

[1] Includes, among other initiatives, the replacement of underground and overhead infrastructures, station programs, and the delivery of customer connections.
[2] Includes fleet capital and buildings.
[3] Primarily relates to street lighting and generation equipment.

The total regulated capital expenditures for the three months and year ended December 31, 2018 were $152.2 million and $501.8 million, respectively, compared to $146.4 million and $544.9 million for the comparable periods in 2017.

For the three months ended December 31, 2018, the increase in regulated capital expenditures was primarily related to higher spending on customer connections ($11.0 million), partially offset by lower spending on the ERP project ($5.1 million). The ERP project relates to the implementation of an ERP system, which is an information system that performs critical back-office processes, such as finance, human resources and supply chain activities to support the Corporation's operations. The Corporation completed the implementation of the ERP system on October 1, 2018.

For the year ended December 31, 2018, the decrease in regulated capital expenditures was primarily related to lower spending on the facilities consolidation program ($35.2 million) which was completed by the end of 2017, station programs related to the renewal of aging station infrastructure ($23.0 million) and underground infrastructure ($16.0 million), partially offset by higher spending on customer connections ($24.8 million).

The largest capital initiatives in 2018 include the delivery of customer connections, and the replacement of underground and overhead infrastructures.

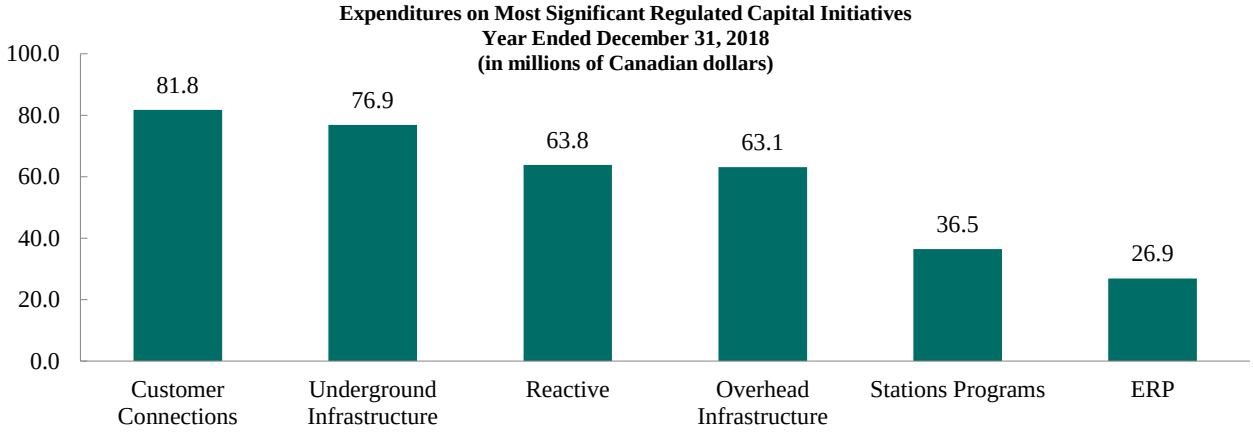
The delivery of customer connections includes spending related to new service and upgrades to existing service for specific commercial customers. For the year ended December 31, 2018, capital expenditures for the delivery of customer connections were $81.8 million.

The replacement of underground infrastructure includes replacing direct buried cables, transformer switches, handwells and other aging underground infrastructure. The replacement of overhead infrastructure includes replacing poles, overhead transformers, conductors, overhead switches and other aging overhead infrastructure and equipment. Both initiatives will allow LDC to continue to provide ongoing safe and reliable service to its customers. For the year ended December 31, 2018, capital expenditures for the underground and overhead infrastructures were $76.9 million and $63.1 million, respectively.

Copeland Station will be the first transformer station built in downtown Toronto since the 1960's and will be the second underground transformer station in Canada. When in service, it will provide electricity to buildings and neighbourhoods in the central-southwest area of Toronto. During the fourth quarter of 2018, the Corporation received approval from HONI, the electricity transmission provider, and the IESO for energization of the project and successfully energized one of two Copeland Station power transformers with associated cables and switchgear, as well as the station service transformer and equipment. The second power transformer and associated switchgear is

anticipated to be energized in the first half of 2019 following HONI's completion of additional servicing to some of their equipment. As at December 31, 2018, the cumulative capital expenditures on the Copeland Station project amounted to $202.6 million, plus capitalized borrowing costs. All capital expenditures related to Copeland Station are recorded to PP&E.

Copeland Station is one of the most complex projects ever undertaken by the Corporation and the expected completion date is in the first half of 2019. The total capital expenditures required to complete the project has increased from $200.0 million to approximately $204.0 million, plus capitalized borrowing costs. The increase in costs and delay in completion date are attributable to a variety of factors, including contractor performance and construction delays. On January 25, 2018, the Corporation was informed that Carillion Construction Inc., the general contractor for the Copeland Station Project, filed for creditor protection under the Companies' Creditors Arrangement Act after its affiliate, Carillion plc, went into compulsory liquidation in the United Kingdom. Other contractors have taken on part of the remaining work to contribute to the completion of the project. See "Risk Management and Risk Factors" below for further information on the Copeland Station project.



Financing Activities

Net cash used in financing activities for the three months and year ended December 31, 2018 was $176.0 million and $220.7 million, respectively, compared to $80.7 million and $68.4 million for the comparable periods in 2017.

The increase in cash used in financing activities for the three months ended December 31, 2018 was primarily due to the Corporation's Series 13 debenture issuance in November 2017, higher repayment of commercial paper, net of issuances in 2018 and higher dividends paid compared to the prior year due to a change in the timing of the dividend payments, partially offset by the repayment of the Corporation's Series 2 debenture in 2017. In 2017, the dividends consisted of two instalments of $6.25 million each paid in the first and second quarter and a final instalment of $62.5 million paid in the third quarter in connection with receipt of the equity investment from the City. The Corporation's Dividend Policy was then amended for fiscal 2018 and subsequent fiscal years to provide that dividends be declared and paid in four equal quarterly instalments.

The increase in cash used in financing activities for the year ended December 31, 2018 was primarily due to the funding from the equity injection received from the City in June 2017, the Corporation's Series 13 debenture issuance in November 2017 and higher dividends paid, partially offset by the repayment of the Corporation's Series 2 debentures in 2017 and lower commercial paper, net of issuances.

The Corporation is a party to a credit agreement with a syndicate of Canadian chartered banks which established a revolving credit facility expiring on October 10, 2022 ("Revolving Credit Facility"), pursuant to which it may borrow up to $800.0 million, of which up to $210.0 million is available in the form of letters of credit. As at December 31, 2018, the Corporation was in compliance with all covenants included in its Revolving Credit Facility agreement.

On August 23, 2018, the maturity date of the Revolving Credit Facility was extended by one year from October 10, 2022 to October 10, 2023.

The Corporation has a commercial paper program allowing up to $600.0 million of unsecured short-term promissory notes ("Commercial Paper Program") to be issued in various maturities of no more than one year. The Commercial Paper Program is backstopped by the Revolving Credit Facility; hence, available borrowing under the Revolving

Credit Facility is reduced by the amount of commercial paper outstanding at any point in time. Proceeds from the Commercial Paper Program are used for general corporate purposes. Borrowings under the Commercial Paper Program bear interest based on the prevailing market conditions at the time of issuance.

For the three months and year ended December 31, 2018, the average aggregate outstanding borrowings under the Corporation's Revolving Credit Facility, Working Capital Facility and Commercial Paper Program were $289.2 million and $239.6 million, respectively, with a weighted average interest rate of 1.92% and 1.68% (compared to $140.2 million and $210.3 million, respectively, with a weighted average interest rate of 1.21% and 0.93% for the comparable periods in 2017).

Additionally, the Corporation is a party to a $75.0 million demand facility with a Canadian chartered bank for the purpose of issuing letters of credit mainly to support LDC's prudential requirements with the IESO ("Prudential Facility"). As at December 31, 2018, $33.3 million of letters of credit had been issued against the Prudential Facility.

The Corporation filed a base shelf prospectus dated May 8, 2017 with the securities commissions or similar regulatory authorities in each of the provinces of Canada. These filings allow the Corporation to make offerings of unsecured debt securities of up to $1.0 billion during the 25-month period following the date of the prospectus.

As at December 31, 2018, the Corporation had debentures outstanding in the principal amount of $2.0 billion. These debentures will mature between 2019 and 2063. As at December 31, 2018, the Corporation was in compliance with all covenants included in its trust indenture and supplemental trust indentures.

The following table sets out the current credit ratings of the Corporation:

Credit Ratings
As at December 31, 2018

	DBRS		Standard & Poor's	
	Credit Rating	Trend	Credit Rating	Outlook
Issuer rating	A	Stable	A	Stable
Senior unsecured debentures	A	Stable	A	-
Commercial paper	R-1 (low)	Stable	-	-

The Corporation believes that it has sufficient available sources of liquidity and capital to satisfy working capital requirements for the next twelve months.

For the year ended December 31, 2018, the Board of Directors of the Corporation declared and the Corporation paid dividends to the City totalling $93.9 million (2017 - $75.0 million).

On March 6, 2019, the Board of Directors of the Corporation declared a quarterly dividend in the amount of $25.1 million, payable to the City by March 29, 2019.

Summary of Contractual Obligations and Other Commitments

The following table presents a summary of the Corporation's debentures, major contractual obligations and other commitments.

Summary of Contractual Obligations and Other Commitments
As at December 31, 2018
(in millions of Canadian dollars)

	Total $	2019 $	2020/2021 $	2022/2023 $	After 2023 $
Commercial paper [1]	113.0	113.0	-	-	-
Debentures – principal repayment	2,045.0	250.0	300.0	250.0	1,245.0
Debentures – interest payments	1,395.6	77.2	131.9	107.0	1,079.5
Capital projects [2] and other	35.5	25.4	9.9	0.2	-
Leases	1.4	0.3	0.6	0.4	0.1
Total contractual obligations and other commitments	3,590.5	465.9	442.4	357.6	2,324.6

[1] The notes under the Commercial Paper Program were issued at a discount and are repaid at their principal amount.
[2] Primarily commitments for construction services.

Corporate Developments

Appointment of Chief Financial Officer

On August 27, 2018, the Corporation appointed Aida Cipolla to the position of Executive Vice-President and Chief Financial Officer ("CFO"). Ms. Cipolla replaced Sean Bovingdon, the former CFO who left the Corporation. Ms. Cipolla had been formerly the Corporation's Controller since December 2015.

Electricity Distribution Rates

The OEB's regulatory framework for electricity distributors is designed to support the cost-effective planning and operation of the electricity distribution network and to provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price.

The OEB typically regulates the electricity rates for distributors using a combination of detailed cost of service reviews and IRM adjustments. A cost of service review uses a future test-year to establish rates, and provides for revenues required to recover the forecasted costs of providing the regulated service, and a fair and reasonable return on rate base. IRM adjustments are typically used for one or more years following a cost of service review and provide for adjustments to rates based on an inflationary factor net of a productivity factor and an efficiency factor as determined relative to other electricity distributors.

On August 31, 2018, LDC filed its 2019 rate application seeking OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2019 and ending on December 31, 2019. On December 13, 2018, the OEB issued a decision and rate order approving LDC's 2019 rates and providing for other deferral and variance account dispositions.

On August 15, 2018, LDC filed a CIR application seeking approval of LDC's 2020 test-year revenue requirement on a cost of service basis and the corresponding electricity distribution rates effective January 1, 2020, and the subsequent annual rate adjustments based on a custom index specific to LDC for the period commencing on January 1, 2021 and ending on December 31, 2024. The rate application requests approvals to fund capital expenditures of approximately $2.8 billion over the 2020-2024 period. The rate application also seeks approval to include in LDC's rate base capital amounts that were incurred prior to 2020.

CDM Activities

The objective of the CDM programs is to reduce electricity consumption in the Province of Ontario by a total of 7 terawatt hours between January 1, 2015 and December 31, 2020, of which LDC's share is approximately 1,576 GWh of energy savings.

Under the energy conservation agreement with the IESO, LDC has a joint CDM plan with Oakville Hydro Electricity Distribution Inc. ("Oakville Hydro") for the delivery of CDM programs over the 2015-2020 period. The IESO reimburses LDC for all adequately documented incurred costs, with an option to receive a portion of its funding in advance. Cost efficiency incentives may be awarded if LDC's electricity savings meet or exceed certain CDM plan targets for programs under the full cost recovery funding method, including a mid-term incentive based on a review of the 2015-2017 period.

The joint CDM plan provides combined funding of approximately $421.0 million, including participant incentives and program administration costs, with an energy savings target of approximately 1,648 GWh. The program for Oakville Hydro under the joint CDM plan started on January 1, 2016. LDC received $162.4 million from the IESO as at December 31, 2018 (2017 - $102.3 million) to deliver the CDM programs. Amounts received but not yet spent are presented on the consolidated balance sheets under current liabilities as deferred conservation credit. On September 26, 2018, $15.8 million was confirmed by the IESO as the joint mid-term incentive, of which $14.9 million representing LDC's portion was received in November 2018.

Legal Proceedings

In the ordinary course of business, the Corporation is subject to various legal actions and claims from customers, suppliers, former employees and other parties. On an ongoing basis, the Corporation assesses the likelihood of any adverse judgments or outcomes as well as potential ranges of probable costs and losses. A determination of the provision required, if any, for these contingencies is made after an analysis of each individual issue. The provision may change in the future due to new developments in each matter or changes in approach, such as a change in settlement strategy. If damages were awarded under these actions, the Corporation and its subsidiaries would make a claim under any applicable liability insurance policies which the Corporation believes would cover any damages which may become payable by the Corporation and its subsidiaries in connection with these actions, subject to such claim not being disputed by the insurers. There have been no material changes in legal proceedings as disclosed in note 24 to the Consolidated Financial Statements.

Share Capital

Share capital consists of the following:

(in millions of Canadian dollars)	**2018 $**	**2017 $**
Authorized		
The authorized share capital of the Corporation consists of an unlimited number of common shares without par value.		
Issued and outstanding		
1,200 common shares, of which all were fully paid.	817.8	817.8

Transactions with Related Parties

As the City is the sole shareholder of the Corporation, the Corporation and the City are considered related parties. The Corporation provides electricity, street lighting and ancillary services to the City. All transactions with the City are conducted on terms similar to those offered to unrelated parties.

Summary of Transactions with Related Parties
(in millions of Canadian dollars)

	Year ended December 31	
	2018 **$**	**2017** **$**
Revenues	276.7	283.3
Operating expenses and capital expenditures	18.3	22.2
Dividends declared and paid	93.9	75.0

Summary of Amounts Due to/from Related Parties
(in millions of Canadian dollars)

	As at December 31	
	2018 **$**	**2017** **$**
Accounts receivable	9.8	13.8
Unbilled revenue	23.9	26.3
Accounts payable and accrued liabilities	40.5	40.1
Customer deposits	17.3	15.7
Deferred revenue	2.5	1.9

Revenues represent amounts charged to the City primarily for electricity, street lighting and ancillary services. Operating expenses and capital expenditures represent amounts charged by the City for purchased road cut repairs, property taxes and other services. Dividends are paid to the City.

Accounts receivable represent receivables from the City primarily for electricity, street lighting and ancillary services. Unbilled revenue represents receivables from the City mainly related to electricity provided and not yet billed. Accounts payable and accrued liabilities represent amounts payable to the City related to road cut repairs and other services. Customer deposits represent amounts received from the City for future expansion projects. Deferred revenue represents amounts received from the City primarily for the construction of electricity distribution assets.

Controls and Procedures

For purposes of certain Canadian securities regulations, the Corporation is a "Venture Issuer". As such, it is exempt from certain requirements of National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings. Accordingly, the Chief Executive Officer and Chief Financial Officer have reviewed the Consolidated Financial Statements and the MD&A for the three months and year ended December 31, 2018 and 2017. Based on their knowledge and exercise of reasonable diligence, they have concluded that these documents fairly present in all material respects the financial condition, financial performance and cash flows of the Corporation as at the date of and for the period presented.

Risk Management and Risk Factors

The Corporation faces various risks that could impact the achievement of its strategic objectives. It adopts an enterprise wide approach to risk management, based on an overall enterprise risk philosophy, and achieved through a process of consolidating and aligning the various views of risk across the enterprise via a risk governance structure. The Corporation's ERM framework utilizes industry best practices and international guidelines and focuses on identifying emerging trends in risks and related opportunities particular to the Corporation through a comprehensive evaluation of the Corporation's business and the industry generally. The Corporation views ERM as a management activity undertaken to add value and improve overall operations. It helps the Corporation by enabling the attainment of its strategic goals and objectives through a systematic, disciplined approach towards identifying, evaluating, treating, monitoring and reporting of risks. Risk assessment is built into our decision-making process at all levels. Accordingly, ERM is an integral part of the strategic management of the Corporation and is routinely considered in forecasting, planning and executing all aspects of the business.

The ERM framework is operationalized by a consistent, disciplined methodology that clearly defines the risk management process which incorporates subjective elements, risk quantification, risk trends and risk interdependencies.

While the Corporation's philosophy is that ERM is the responsibility of all business units at all levels, in strategic and functional matters, the ERM governance structure is comprised of three key levels.

At the first level is the Board, which maintains a general understanding of the Corporation's risk profile, the risk categories and the types of risks to which the Corporation may be exposed, and the practices used to identify, assess, measure and manage those risks. The risk profile is a list of key risks that may impede the Corporation from achieving certain or all of its strategic objectives, and which are most material to its operational success.

The second level is the executive team, which ensures systems are in place to identify, manage, and monitor risks and trends. Through input from the business and other considerations, the executive team assesses the appropriateness and consistent application of systems to manage risks within the Corporation. The executive team also ensures that key risks are brought forward to the attention of the Board for discussion and action, as required.

Finally, the third level is the senior leadership team. The senior leadership team supports the executive team and is a collection of subject matter experts from across the Corporation who actively engage in the day-to-day management of risks. Working with the executive team, this group oversees the Corporation's risk profile and its performance against the defined risk philosophy. The senior leadership team understands changes in risk status and trends and determines appropriate risk responses and action plans. They also work to ensure effective, efficient, complete and transparent risk reporting to the executive team.

The Corporation is continually reviewing its ERM program to ensure the organization is focused upon and responsive to risks of the greatest significance, likelihood and impact. In 2018, the Corporation re-oriented its program to the key strategic and functional risk categories facing the organization, and the sub-component risks making up those categories. This allows the Corporation's executive leadership and responsible business units to concentrate on these risks and undertake deeper dives into root causes and risk trends in these areas on both a short-interval and long-term basis. By focusing in particular on the strategic risks to the organization, decision-making is strengthened and the Corporation has a greater ability to realize opportunities central to its interests.

The Corporation's business is subject to a variety of risks including those key risk areas and major component risks described in the following sections. There can be no assurance that any steps the Corporation may take to manage risks will avoid future loss resulting from the occurrence of such risks.

Strategic Risks

Oversight Risk

Risk that provincial government or regulator activity (laws, frameworks or policies) impedes the Corporation's effective performance, and its ability to meet its objectives and serve its customers.

Regulatory and Energy Policy Risk

The Corporation is subject to the risk that its business activities may be impeded through the actions of regulatory authorities or by changes in regulation. There is a risk that future changes to Ontario's regulatory model, manner of regulation, and/or broader energy policy framework does not align with the Corporation's business direction and could materially adversely affect the Corporation's strategic goals and financial results.

Ontario's electricity industry regulatory and other energy policy developments may affect the electricity distribution rates charged by LDC and the costs LDC is permitted to recover. This may in turn have a material adverse effect on the financial performance of the Corporation and/or LDC's ability to deliver effective and efficient operations and reliable service to its customers, and as well as create barriers to LDC achieving its strategic objectives. Among other things, there can be no assurance that:

- the OEB will approve LDC's electricity distribution rates at levels that will permit LDC to maintain safe and reliable service to its customers and earn the allowed rate of return on the investment in the business;
- the OEB will approve and permit recovery through rates of past and future expenditures incurred by LDC in providing distribution services to customers, in a timely manner or at all;
- the OEB will adopt the other rate-setting principles, formulae, and inputs in a manner that result in rates that properly support LDC's activities;
- the regulatory instruments that are made available to LDC will be sufficient to address LDC's operations, needs and circumstances in respect of future applications for electricity distribution rates; and
- the OEB will not permit other parties to provide distribution services in LDC's licensed area, or permit loads within LDC's service area to become electrically served by a means other than through LDC's electricity distribution system.

Any future regulatory decision to disallow or limit the recovery of costs could lead to potential asset impairment and charges to results from operations, which could have a material adverse effect on the Corporation.

LDC actively participates in industry engagement efforts in order to mitigate the above risks and realize potential opportunities in regulatory and energy policy development. Through these types of engagements, the Corporation monitors proposed regulatory and energy policy changes that may impede its business. LDC also employs a comprehensive organizational regulatory application program to ensure that all applications to the OEB achieve the highest utility standard of evidence gathering, preparation and presentation.

Emerging Government Policy Risk

The Corporation is subject to the risk that the policy priorities of provincial and federal governments and regulatory bodies beyond those specifically applicable to the energy space, including policies of more general application, and the implementation of policies by such bodies, may impact the Corporation's ability to deliver effective and efficient operations, meet business objectives, report on its activities and capitalize upon new opportunities. Developments and changes in any of the laws, rules, regulations and policies applicable to the businesses carried on by the Corporation, and the manner of implementation and application of the same, could materially adversely affect the Corporation. This may include developments with respect to labour and employment laws, changes to accounting standards and financial reporting requirements, environmental obligations and public safety rules, among others. The Corporation actively engages with government entities and participates in industry organizations to monitor emerging policies and where possible plays an advocacy role.

Franchise Risk

Risk that restrictions in LDC's business model and/or external conditions impede its ability to maintain and grow its right to be the sole provider of electricity distribution services in the City (its franchise) and serve its customers. The Corporation is subject to the risk that it is displaced from its strategic position or fails to gain a strategic advantage, which could materially adversely affect the Corporation's strategic goals and financial results.

The OEB has the authority to grant municipal distribution licences, has issued to LDC a licence stipulating a service area that reflects the territory within the City, and has not granted any other distribution licence that permits distribution within LDC's service area. In addition, there is a legal framework in place that establishes LDC, as the holder of the municipal distribution licence in the City, to be the sole provider of distribution activities across municipal rights of way. There is no assurance that these frameworks will continue to exist sufficiently or at all in order to provide LDC the opportunity to be the comprehensive distribution provider in the City.

While other regulated and unregulated entities have always competed with LDC and its predecessors to provide customers with other sources of energy, including electricity, the pervasiveness of this competition and its effects on LDC's distribution business have varied over time and continue to vary based on many factors, including the relative price of energy source (e.g., natural gas, grid-supplied electricity, behind-the-meter generation), technology development (e.g. energy storage), government-based incentives, regulatory frameworks, and compliance frameworks especially for non-utility entities.

There can be no assurance that the future nature, prevalence, or effects of these forms of competition will be comparable to current or historic experience. Failure to effectively scan our external and internal environment could lead to missed business opportunities and loss of competitive advantage.

Risks to the Corporation’s franchise interests may also result from impairment to the Corporation's image in the community, public confidence or brand. The Corporation is committed to delivering safe and reliable electricity to its customers in an environmentally responsible manner at optimal costs. Negative perceptions regarding this commitment could impact the public’s perception of the Corporation. In addition, events and/or external factors that draw negative media attention to the Corporation could cause reputational damages and impact the Corporation’s business and relationship with its stakeholders. These factors could lead customers, governments and regulators to look more favourably to alternative services and service providers to utility-based electricity distribution.

The Corporation has dedicated personnel focused on monitoring external competitive factors, including alternative service providers and technologies, and developing strategies for further enhancing the LDC’s interactive grid which support the reliability of its core infrastructure grid operations, promote greater value, and deliver solutions for its customers. Additionally, the Corporation maintains relationships with its customers to better understand the specific needs and expectations of each class of customer. The Corporation also conducts customer research and consultations in the ordinary course of its operations, and as part of the development of its rate application whereby it directly considered customer preferences and feedback, in addition to other inputs, as part of developing its business plan. The Corporation also has dedicated personnel focused on the utility’s key account customers, which respond to issues raised by large commercial and industrial customers and assists with their energy management needs. Through these types of engagements, the Corporation can monitor its customers’ specific needs and can work with them to develop energy solutions.

Governance Risk

Risk that municipal activity (laws, policies, or intervention) impedes the Corporation’s effective performance, and ability to meet its objectives and serve its customers.

The Corporation is a government-controlled enterprise whose sole shareholder is the City. The operations of the Corporation and its subsidiaries are influenced by the broad by-law enactment and enforcement powers of the City. Additionally, as the Corporation’s sole shareholder, the City has set out the governing objectives and principles, including financial objectives, for the Corporation through the Shareholder Direction, as described above. Under the Shareholder Direction, the City has the power to direct the Corporation and its subsidiaries to conduct their affairs and govern their operations in accordance with such rules, policies, directives or objectives as are directed by City Council from time to time. Certain conflicts may arise where the City’s goals and objectives in implementing such rules, policies, directives or objectives differ from the Shareholder Direction principles and could materially adversely affect the Corporation's business, operations, financial condition or prospects.

The Corporation engages on a systematic basis with the City Mayor, City Councillors, the City Manager's office, and other departments and agencies to ensure a sharing of perspectives on the vital interests of the Corporation and its customers. Through such engagements the parties review and consider the challenges to the Corporation achieving the objectives and principles set out under the Shareholder Direction, and in particular the impact that proposed changes in city by-laws or municipal policies may create for the Corporation's ability to meet its business objectives and serve its customers.

Functional Risks

Human Capital Risk

Risk that the Corporation is unable to maintain necessary resource talent and skilled resources.

The Corporation is subject to the risk that human resources may not be available with the necessary knowledge, skills and education to support the Corporation's future talent requirements. All retirements pose risks for knowledge management and business continuity at the Corporation. Development and retention of talent to meet the evolving needs of the business requires LDC to focus on a series of proactive activities and programs to mitigate these risks, such as strategic workforce planning, promotion of apprenticeship programs, investments in colleges and universities, succession planning, knowledge transfer and a robust training program.

The Corporation's ability to operate successfully in the electricity industry in Ontario will continue to depend in part on its ability to make changes to existing work processes and conditions in order to adapt to changing circumstances. The Corporation's ability to make such changes, in turn, will continue to depend in part on its relationship with its labour unions, including negotiating collective bargaining agreements with the Society of United Professionals and PWU. There can be no assurance that the Corporation will be able to secure the support of its labour unions.

The Corporation's ability to develop its work processes to meet changing circumstances also depends on its ability to access adequate resources from its external contractor community. One way in which the Corporation seeks to mitigate this risk is through its use of business practices and internal procedures to identify a diverse group of reputable third party service providers and entering into contracts with, and monitoring the performance of, these third-party service providers.

Operations Risk

Risk that the Corporation is not able to effectively meet the needs of its customers and a growing city, and maintain the security and reliability of the grid at acceptable levels.

Asset Management Risk

The Corporation is subject to the risk that it may be unable to maintain continuous supply due to failure of the distribution infrastructure and assets which could materially adversely affect the Corporation. Electricity distribution is a capital-intensive business. As the municipal electricity distribution company serving the largest city in Canada, LDC continues to invest in the renewal of existing aging infrastructure and in the development of new infrastructure (such as the Copeland Station project) to address safety, reliability and customer service requirements now and in the future.

LDC estimates that approximately 33% of its electricity distribution assets have already exceeded or will reach the end of their expected useful lives by 2025. Asset condition assessment demographics also indicate substantial asset investment needs for a number of critical assets during this period. At the same time, Toronto is a growing city, and LDC must make upgrades to keep pace with urban intensification and electrification and ensure good stewardship of the distribution system. Further, extreme weather is no longer an infrequent experience, and has instead become a regular condition of operating a distribution system. For example, the Corporation experienced four extreme weather events in the first half of 2018, leaving nearly 160,000 customers without electricity. In addition, as the City, Ontario and the Government of Canada implement policies and programs to respond to climate change and adoption of electric vehicles and fuel-switching potentially increases, the pressures on the Corporation's system will only increase, and such factors may drive a need for incremental capital expenditures for system upgrades so that the grid can handle increased loads.

LDC's ability to continue to provide a safe work environment for its employees and a reliable and safe distribution service to its customers and the general public will depend on, among other things, the ability of the Corporation to

fund additional infrastructure investments, and the OEB allowing recovery of costs in respect of LDC's maintenance program and capital expenditure requirements for distribution plant refurbishment and replacement.

One of LDC's largest capital initiatives currently in progress is the construction of Copeland Station, which is also one of the most complex projects ever undertaken by the Corporation. The expected completion date for the Copeland Station is in the first half of 2019. The total capital expenditures required to complete the project has increased from $200.0 million to approximately $204.0 million, plus capitalized borrowing costs. The increase in costs and delay in completion date are attributable to a variety of factors, including contractor performance and construction delays. There may be additional unforeseen delays and expenditures prior to the completion of the project. On January 25, 2018, the Corporation was informed that Carillion Construction Inc., the general contractor for the Copeland Station Project, filed for creditor protection under the Companies' Creditors Arrangement Act after its affiliate, Carillion plc, went into compulsory liquidation in the United Kingdom. Other contractors have taken on part of the remaining work to contribute to the completion of the project. All capital projects for new and replacement infrastructure have risks related to delays or increased costs due to many factors, including: necessary modifications to project plans; the availability, scheduling and cost of materials, equipment and qualified personnel; LDC's ability to obtain necessary environmental and other regulatory and government approvals; and the impact of weather conditions, site conditions and contractor performance.

LDC is focused on overcoming the above challenges and executing its capital and maintenance programs. It uses a variety of asset and project management tools to implement its plans, measures progress on a recurring short interval basis, and regularly monitors and manages the health of its assets. However, if LDC is unable to carry out these plans in a timely and optimal manner or becomes subject to significant unforeseen equipment failures, equipment performance will degrade. Such degradation may compromise the reliability of distribution assets, the ability to deliver sufficient electricity and/or customer supply security and increase the costs of operating and maintaining these assets.

The Corporation's ability to operate effectively is also in part dependent on the development, maintenance and management of complex information technology systems. Computer systems are employed to operate LDC's electricity distribution system, and the Corporation's financial, billing and business systems to capture data and to produce timely and accurate information. Specifically, on October 1, 2018, the Corporation successfully completed the implementation of, and transitioned to, a new ERP system. The ERP system is being used to operate the Corporation's financial, and business systems to capture data and to produce timely and accurate information. Failure of the newly implemented ERP system could have a material adverse effect on the Corporation's business, operations, financial condition or prospects. The Corporation has mitigation strategies, access to consultants with ERP expertise and is developing an internal ERP centre of excellence to help assist in the implementation, and support of ERP for users. Additionally, in respect of the Corporation's operational technology systems in general, there is isolation from business systems and independent operation which mitigates against wider systemic risk to the business systems.

Security Risk

The Corporation is subject to the risk that it may be unable to preserve the confidentiality, integrity, authenticity, availability, accountability and non-repudiation of information assets.

LDC's electricity distribution infrastructure and technology systems are potentially vulnerable to damage or interruption from cyber-attacks, breaches or other compromises, which could result in business interruption, service disruptions, theft of intellectual property and confidential information (about customers, suppliers, counterparties and employees), additional regulatory scrutiny, litigation and reputational damage. The Corporation has implemented security controls aligned with industry best practices and standards including the National Institute of Standards and Technology Cybersecurity Framework and the OEB's Ontario Cyber Security Framework, and maintains cyber insurance. Cyber-attacks, breaches or other compromises of electricity distribution infrastructure and technology systems could result in service disruptions and system failures, including as a result of a failure to provide electricity to customers, property damage, corruption or unavailability of critical data or confidential employee or customer information. A significant breach could materially adversely affect the financial performance of the Corporation or its reputation and standing with customers, regulators and in the financial markets. It could also expose the Corporation to third-party claims.

LDC must also comply with legislative and licence requirements relating to the collection, use and disclosure of personal information (including the personal information of customers), as well as information provided by suppliers, contractors, employees, counterparties, and others. Such information could be exposed in the event of a cybersecurity

incident or other unauthorized access, which could materially adversely affect the Corporation and also result in third-party claims against the Corporation.

Preventative controls are employed to protect information and technology assets against cyber-attacks and mitigate their effects. Detective controls are employed to continuously monitor information systems so that the Corporation can respond appropriately to minimize the damage in the event of a cyber-attack. Even with these measures in place, since the techniques used to obtain unauthorized access, disable or degrade service, or sabotage systems change frequently and often are not recognized until launched against a target, the Corporation may be unable to anticipate these techniques or to implement adequate preventative measures. As such, there can be no assurance that such measures will be effective in protecting LDC's electricity distribution infrastructure or assets, or the personal information of its customers, from a cyber-attack or the effects therefrom.

The Corporation is subject to the risk of external threats to its physical and perimeter security. This includes the security of the Corporation's facilities including office buildings and distribution stations. In order to safeguard its assets and staff, the Corporation has developed policies and guidelines around physical and perimeter security and facilities related emergency preparedness. The Corporation has also implemented electronic security technologies to ensure that only authorized personnel have access to the Corporation facilities.

Business Interruption Risk

The Corporation is subject to the risk that it may be unable to maintain continuing and sustainable business operations, or recover from business interruption, in an effective manner. The Corporation's operations are exposed to the effects of natural and other unexpected occurrences such as extreme storm and other weather conditions and natural disasters, as well as terrorism and pandemics. The Corporation has implemented various initiatives aimed at improving the system's resiliency to increasingly frequent extreme weather events caused by climate change. These initiatives include updating major equipment specifications, revising planning guidelines, investigating the load forecast impact, revising design practices, and enhancing maintenance programs. The Corporation has also implemented a Grid Emergency Management (GEM) program to prepare for and respond to major power outage events and has incorporated recommendations from the independent review panel of experts formed to review the Corporation's response to the 2013 Ice Storm that affected Toronto. Although the Corporation's facilities and operations are constructed, operated and maintained to withstand such occurrences, there can be no assurance that they will successfully do so in all circumstances. Any major damage to the Corporation's facilities or interruption of the Corporation's operations arising from these occurrences could result in lost revenues and repair costs that can be substantial. Although the Corporation has insurance which it considers to be consistent with industry practice, if it sustained a large uninsured loss caused by natural or other unexpected occurrences, LDC may apply to the OEB for the recovery of the loss related to the electricity distribution system. There can be no assurance that the OEB would approve, in whole or in part, such an application.

Safety Risk

Risk to the Corporation employees or the general public of serious/fatal injuries and illnesses relating to or impacting upon the Corporation activities.

Occupational Health and Safety Risk

The Corporation is subject to the risk that employees may be exposed to serious or fatal injuries or illness as a result of the work environment in which they operate. Due to the nature of the Corporation's business and business activities, occupational safety is an integral part of our corporate culture. Employees could be exposed to hazards when performing their work duties. This includes hazards such as electrical contact, working in confined spaces, fires and explosions, slips, trips and falls and motor vehicle accidents. The Corporation is subject to compliance with provincial Health and Safety legislation. The Corporation's management approach to occupational safety is to meet or excel on legal compliance and eliminate or safeguard known occupational hazards and risks. The Corporation also uses an IRS (Internal Responsibility System) to clearly define responsibility and accountability for safety at each level within the organization. There are processes in place to develop and nurture good leadership practices through recruitment, education, training and performance management practices that encourage the application of our corporate values, including safety. LDC received OHSAS 18001 certification in 2013 and conducts annual third party audits to maintain certification, in addition occupational health and safety legal compliance audits are conducted every two years.

Public Safety Risk

Due to the nature of the Corporation's business of operating and maintaining its distribution system, the Corporation is subject to the risk of public injuries or fatalities. The Corporation mitigates risks to public safety through equipment inspection, replacement and maintenance, employee training, communications programs and reactive and emergency work. The Corporation also has developed specific construction standards and design practices and new products for use in the distribution system go through a thorough review and introduction process. The selection process for new products and the development of standards promotes customer health and safety.

Financial Risk

Risk that the Corporation is unable to maintain its financial health and performance at acceptable levels.

Market and Credit Risk

The Corporation is directly and indirectly subject to various market and credit fluctuations which could materially adversely affect the Corporation. For example, LDC is exposed to credit risk with respect to customer non-payment of electricity bills. LDC is permitted, at certain times of the year, to mitigate the risk of customer non-payment using any means permitted by law, including security deposits (i.e. letters of credit, surety bonds, cash deposits or lock-box arrangements, under terms prescribed by the OEB), late payment penalties, pre-payment, pre-authorized payment, load limiters or disconnection. While LDC would be liable for the full amount of the default, there can be no assurance that the OEB would allow recovery of the bad debt expense. Established practice in such cases is that the OEB would examine any electricity distributor's application for recovery of extraordinary bad debt expenses on a case-by-case basis. LDC's security interest or other measures, if any, may also not provide sufficient protection. Additionally, security interests and other measures taken by, or in favour of, LDC, if any, may not provide sufficient protection.

The Corporation is exposed to fluctuations in interest rates for the valuation of its post-employment benefit obligations. The Corporation estimates that a 1% (100 basis point) increase in the discount rate used to value these obligations would decrease the accrued benefit obligation of the Corporation, as at December 31, 2018, by $41.3 million, and a 1% (100 basis point) decrease in the discount rate would increase the accrued benefit obligation, as at December 31, 2018, by $53.1 million.

The Corporation is exposed to short-term interest rate risk on the short-term borrowings under its Commercial Paper Program and Working Capital Facility, and customer deposits, while most of its remaining obligations were either non-interest bearing or bear fixed interest rates, and its financial assets were predominately short-term in nature and mostly non-interest bearing. The Corporation manages interest rate risk by monitoring its mix of fixed and floating rate instruments, and taking action as necessary to maintain an appropriate balance. The Corporation estimates that a 100 basis point increase (decrease) in short-term interest rates, with all other variables held constant, would result in an increase (decrease) of approximately $2.1 million to annual finance costs.

The Corporation had limited exposure to the changing values of foreign currencies. While the Corporation purchases goods and services which are payable in US dollars, and purchases US currency to meet the related commitments when required, the impact of these transactions as at December 31, 2018 was not material.

Capital Structure Risk

The Corporation is subject to the risk that it may not be able to optimize its debt to equity ratio or access capital markets at effective rates. There can be no assurance that debt or equity financing will be available or sufficient to meet the Corporation's requirements, objectives, or strategic opportunities. If and when financing is available, there can be no assurance that it will be on acceptable terms to the Corporation.

The Corporation relies on debt financing through its medium term notes program, Commercial Paper Program or existing credit facilities to finance the Corporation's daily operations, repay existing indebtedness, and fund capital expenditures. The Corporation's ability to arrange sufficient and cost-effective debt financing could be materially adversely affected by a number of factors, including financial market conditions and activity in the global capital markets, the regulatory environment in Ontario, the Corporation's business, operations, financial condition or prospects, compliance with covenants, the ratings assigned to the Corporation or the debentures issued under the Corporation's medium term notes program by credit rating agencies, the rating assigned to short-term borrowings under the Commercial Paper Program by a credit rating agency, and the availability of the commercial paper market. In the event the Corporation is unable to maintain an R-1 (low) credit rating for its Commercial Paper Program, the

Corporation has sufficient liquidity through its Revolving Credit Facility to repay its commercial paper obligations as they become due. The Corporation's only source of external equity financing is its existing shareholder, the City of Toronto.

The Corporation regularly reviews the external market environment and has regular engagements with its credit rating agencies, securities dealers and investor community to monitor capital structure risk.

Compliance Risk

Risk that the Corporation does not meet its material compliance obligations under legal and regulatory instruments.

The Corporation is committed to complying with applicable legal and regulatory requirements and other requirements to which the organization subscribes. The Corporation has a Corporate Compliance program that strengthens the organization's culture of compliance and provides reasonable assurance, to the Corporation's senior leadership and the Corporation's Board of Directors, of adherence with material compliance requirements. There can be no assurance that the Corporation will comply with applicable future laws, rules, regulations and policies. Failure by the Corporation to comply with applicable laws, rules, regulations and policies may subject the Corporation to civil or regulatory proceedings that could have a material adverse effect on the Corporation. The OEB may not allow recovery in rates for the costs of coming into or maintaining compliance with these laws, rules, regulations and policies.

Critical Accounting Estimates

The preparation of the Corporation's Consolidated Financial Statements in accordance with IFRS requires management to make judgments, estimates and assumptions which affect the application of accounting policies, reported assets, liabilities and regulatory balances, and the disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements, and the reported revenues and expenses for the year. The estimates are based on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities as well as for identifying and assessing the accounting treatment with respect to commitments and contingencies. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the IESO, the Ontario Ministry of Energy or the Ontario Ministry of Finance.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to estimates are recognized prospectively. Assumptions and estimates with a significant risk of resulting in a material adjustment within the next financial year are used in the following notes to the Consolidated Financial Statements:

- Note 25(b) – Recognition and measurement of regulatory balances;
- Note 25(j) – Revenue recognition – measurement of unbilled revenue, determination of the CDM incentive;
- Notes 25(f) and 25(g) – Determination of useful lives of depreciable assets;
- Notes 25(m) and 13 – Measurement of post-employment benefits – key actuarial assumptions;
- Notes 25(o) and 20 – Recognition of deferred tax assets – availability of future taxable income against which deductible temporary differences and tax loss carryforwards can be used; and
- Note 24 – Recognition and measurement of provisions and contingencies.

Significant Accounting Policies

The Corporation's Consolidated Financial Statements have been prepared in accordance with IFRS with respect to the preparation of financial information. The Consolidated Financial Statements are presented in Canadian dollars, which is the Corporation's functional currency. The significant accounting policies of the Corporation are summarized in note 25 to the Consolidated Financial Statements.

Changes in Accounting Policies

Effective January 1, 2018, the Corporation has adopted new IFRS standards and applied the following new accounting policies in preparing the Consolidated Financial Statements:

Revenue from Contracts with Customers

In May 2014, the IASB issued IFRS 15 effective for annual periods beginning on or after January 1, 2018, which replaced existing revenue recognition guidance, including IAS 18 *Revenue* and IFRIC 18 *Transfers of Assets from Customers*. IFRS 15 contains a five step model that applies to contracts with customers that specifies that revenue is recognized when or as an entity transfers control of goods or services to a customer at the amount to which the entity expects to be entitled. Depending on whether certain criteria are met, revenue is recognized at a point in time or over time.

The Corporation adopted IFRS 15 using the modified retrospective approach with the following practical expedients:

- The Corporation did not restate completed contracts that began and ended in the same annual reporting period or completed contracts at the beginning of the earliest period presented; and

- The Corporation did not disclose the amount of consideration allocated to the remaining performance obligations nor did it provide an explanation of when the Corporation expects to recognize that amount as revenue for comparative periods presented in the Consolidated Financial Statements.

The Corporation recognizes revenue in the amount that it has a right to invoice when the amount directly corresponds with the value of the Corporation's performance to date.

The adoption of IFRS 15 resulted in a $207.6 million income statement reclassification between energy sales and energy purchases for the comparative year ended December 31, 2017, and had no impact to opening retained earnings as at January 1, 2018. The Corporation updated the impact previously disclosed in the 2017 audited consolidated financial statements for the year ended December 31, 2017 to include the additional income statement reclassification between energy sales and energy purchases for the comparative year ended December 31, 2017. Refer to note 25(q) of the Consolidated Financial Statements for details on the transitional adjustment.

Financial Instruments

In July 2014, the IASB issued the final version of IFRS 9 *Financial Instruments* ("IFRS 9") effective for annual periods beginning on or after January 1, 2018, which replaced IAS 39 *Financial Instruments: Recognition and Measurement* ("IAS 39"). IFRS 9 includes revised guidance on the classification and measurement of financial instruments, including a new expected credit loss model for measuring impairment on financial assets, and new general hedge accounting requirements. It also carries forward the guidance on recognition and derecognition of financial instruments from IAS 39. The Corporation adopted IFRS 9 retrospectively on January 1, 2018. Despite the retrospective adoption of IFRS 9, the Corporation is not required, upon initial application, to restate comparatives.

i) Classification and measurement of financial instruments

IFRS 9 largely retains the existing requirements in IAS 39 for the classification and measurement of financial liabilities. However, it eliminates the previous IAS 39 categories for financial assets of held to maturity, loans and receivables and available for sale.

Under IFRS 9, on initial recognition, a financial asset is classified and measured at amortized cost, fair value through other comprehensive income, or fair value through profit or loss. The classification of financial assets under IFRS 9 is generally based on the business model in which a financial asset is managed and its contractual cash flow characteristics.

The adoption of IFRS 9 has not had a significant effect on the Corporation's accounting policies related to financial instruments. The impact of IFRS 9 on the classification and measurement of financial instruments is set out below.

Financial Instrument	IAS 39 Measurement basis	IFRS 9 Measurement basis
Cash and cash equivalents	Loans and receivables	Amortized cost
Accounts receivable	Loans and receivables	Amortized cost
Unbilled revenue	Loans and receivables	Amortized cost
Working capital facility	Financial liability – amortized cost	Amortized cost
Commercial paper	Financial liability – amortized cost	Amortized cost
Customer deposits	Financial liability – amortized cost	Amortized cost
Leases	Financial liability – amortized cost	Amortized cost
Debentures	Financial liability – amortized cost	Amortized cost
Accounts payable	Financial liability – amortized cost	Amortized cost

Financial Instrument	IAS 39 Carrying amount as at January 1, 2018 $	IFRS 9 Carrying amount as at January 1, 2018 $
Cash and cash equivalents	—	—
Accounts receivable	217.7	218.3
Unbilled revenue	278.3	277.4
Working capital facility	11.7	11.7
Commercial paper	159.0	159.0
Customer deposits	58.1	58.1
Leases [(1)]	3.1	3.1
Debentures	2,034.0	2,034.0
Accounts payable	325.1	325.1

[(1)] Includes transitional adjustment for the recognition of new leases upon adoption of IFRS 16 *Leases* ("IFRS 16") on January 1, 2018. Refer to note 25(q) of the Consolidated Financial Statements for details on the transitional adjustment

ii) Impairment of financial assets

Loss allowances for accounts receivable and unbilled revenue are always measured at an amount equal to life time expected credit losses ("ECL"). Lifetime ECL are the ECL that result from all possible default events over the expected life of a financial instrument.

When determining whether the credit risk of a financial asset has increased significantly since initial recognition and when estimating ECL, the Corporation considers reasonable and supportable information that is relevant and available without undue cost or effort. This includes both quantitative and qualitative information and analysis, based on the Corporation's historical experience, adjusted for forward-looking factors specific to the current credit environment.

The Corporation assumes that credit risk on a financial asset has increased if it is more than 30 days past due date.

The Corporation considers a financial asset to be in default when the borrower is unlikely to pay its credit obligations to the Corporation in full, without recourse by the Corporation, such as realising security (if any is held).

If the amount of impairment loss subsequently decreases due to an event occurring after the impairment was recognized, then the previously recognized impairment loss is reversed through net income.

Leases

In January 2016, the IASB issued IFRS 16 *Leases* ("IFRS 16"), which replaced IAS 17 *Leases* ("IAS 17") and related interpretations. IFRS 16 introduces a single lessee accounting model eliminating the previous distinction between finance and operating leases. IFRS 16 requires the recognition of lease-related assets and liabilities on the balance sheet, except for short-term leases and leases of low value underlying assets. Lessor accounting remained substantially unchanged.

Although IFRS 16 is effective for annual periods beginning on or after January 1, 2019, the Corporation early adopted IFRS 16 on January 1, 2018 using the modified retrospective approach, in accordance with the transitional provisions

in IFRS 16. The comparative information has not been restated and continues to be reported under IAS 17 and IFRIC 4 *Determining whether an Arrangement contains a Lease*. In applying this approach, the Corporation elected to use practical expedients that allowed it to exclude the initial direct costs from the measurement of the right-of use assets at the date of the initial application, and to use hindsight in determining the lease term. As a practical expedient permitted by IFRS 16, the Corporation applied IFRS 16 to existing contracts that were previously identified as leases applying IAS 17 and IFRIC 4, and did not apply IFRS 16 to contracts that were not previously identified as containing a lease.

The adoption of IFRS 16 resulted in an increase of $1.6 million in total assets and total liabilities each for recognition of right-of-use assets and lease liabilities, respectively, and had no impact to opening retained earnings as at January 1, 2018. Refer to note 25(q) of the Consolidated Financial Statements for details on the transitional adjustment.

The adoption of IFRS 15, IFRS 9 and IFRS 16 resulted in no changes to the consolidated balance sheets as at December 31, 2017 or consolidated statements of cash flows for the year ended December 31, 2017.

Future Accounting Pronouncements

A number of new interpretations and amendments to existing standards have been issued but are not yet effective for the year ended December 31, 2018, and have not been applied in preparing the Consolidated Financial Statements.

IFRIC 23 Uncertainty over Income Tax Treatments

On June 7, 2017, the IASB issued IFRIC 23 *Uncertainty over Income Tax Treatments*. The interpretation provides guidance on the accounting for current and deferred tax assets and liabilities in situations in which there is uncertainty over income tax treatments. The interpretation is applicable for annual reporting periods beginning on or after January 1, 2019.

Annual Improvements to IFRS Standards 2015-2017 Cycle

On December 12, 2017, as part of its annual improvements process, the IASB issued narrow-scope amendments to the following standards:

IFRS 3 *Business Combinations* – the amendments clarify that when an entity obtains control of a business that is a joint operation, it re-measures previously held interests in that business.

IFRS 11 *Joint Arrangements* – the amendments clarify that when an entity obtains joint control of a business that is a joint operation, it does not re-measure previously held interests in that business.

IAS 12 *Income Taxes* – the amendments clarify that an entity recognizes income tax consequences of dividends in profit or loss, other comprehensive income or equity, depending on where the entity recognized the originating transaction or event that generated the distributable profits giving rise to the dividend.

IAS 23 *Borrowing Costs* – the amendments clarify that an entity treats as general borrowings any borrowings made specifically to obtain a qualifying asset that remain outstanding when the asset is ready for its intended use or sale.

The amendments are effective for annual reporting periods beginning on or after January 1, 2019.

Definition of Material (Amendments to IAS 1 Presentation of Financial Statements and IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors)

On October 31, 2018, the IASB issued amendments to IAS 1 and IAS 8 – the amendments clarify the definition of 'material' and align the definition used in the Conceptual Framework and the standards themselves. The amendments are effective for annual reporting periods beginning on or after January 1, 2020.

The Corporation anticipates that the adoption of these accounting pronouncements will not have a material impact on the Corporation's consolidated financial statements, if any.

Forward-Looking Information

Certain information included in this MD&A constitutes "forward-looking information" within the meaning of applicable securities legislation. The purpose of the forward-looking information is to provide the Corporation's current expectations regarding future results of operations, performance, business prospects and opportunities and may not be appropriate for other purposes. All information, other than statements of historical fact, which address activities, events or developments that we expect or anticipate may or will occur in the future, are forward-looking information. The words "anticipates", "believes", "budgets", "committed", "can", "could", "estimates", "expects", "focus", "forecasts", "future", "intends", "may", "might", "plans", "propose", "projects", "schedule", "seek", "should", "trend", "will", "would", "objective", "outlook" or the negative or other variations of these words or other comparable words or phrases, are intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects the Corporation's current beliefs and is based on information currently available to the Corporation.

Specific forward-looking information in the MD&A includes, but is not limited to, the statements regarding the settlement variance and other regulatory balance variances as described in the section entitled "Results of Operations"; the statements regarding the reduction in future electricity distribution rates for customers as described in the section entitled "Results of Operations"; the effect of changes in energy consumption on future revenue as described in the section entitled "Summary of Quarterly Results of Operations"; the Corporation's plans to lower overall financing costs and enhance borrowing flexibility as described in the section entitled "Liquidity and Capital Resources"; the Corporation's available sources of liquidity and capital resources and the sufficiency thereof to satisfy working capital requirements for the next twelve months as described in the section entitled "Liquidity and Capital Resources"; the planned and proposed capital initiatives and the expected results of such initiatives as described in the section entitled "Liquidity and Capital Resources"; the expected capital expenditures required to complete Copeland Station and the anticipated completion date for Copeland Station as described in the section entitled "Liquidity and Capital Resources" and the subsection entitled "Asset Management Risk"; the extension of the Revolving Credit Facility maturity date as referenced under the section entitled "Liquidity and Capital Resources"; the anticipated contractual obligations and other commitments of the Corporation over the next five years as set out in the section entitled "Liquidity and Capital Resources"; the payment of dividends as described in the section entitled "Liquidity and Capital Resources"; electricity distribution rates and rate applications as described in the section entitled "Corporate Developments"; approvals related to LDC's CIR application as described in the section entitled "Corporate Developments"; the plans to meet CDM targets and to receive reimbursement and/or cost efficiency incentives from the IESO as described in the section entitled "Corporate Developments"; the Corporation's reliance on debt financing through its medium term notes program, Commercial Paper Program or existing credit facilities to finance the Corporation's daily operations, repay existing indebtedness, and fund capital expenditures as described in the subsection entitled "Capital Structure Risk"; the effect of changes in interest rates and discount rates on future revenue requirements and future post-employment benefit obligations, respectively, as described in the subsection entitled "Market and Credit Risk"; the Corporation's plans to train and retain skilled employees, mitigate risks from retiring employees, maintain the support of its labour unions and enter into agreements with, and monitor the performance of, its third party providers as described in the subsection entitled "Human Capital Risk"; and the expectation that approximately 33% of its electricity distribution assets have already exceeded or will reach the end of their expected useful lives by 2025 as described in the subsection entitled "Asset Management Risk".

The forward-looking information is based on estimates and assumptions made by the Corporation's management in light of past experience and perception of historical trends, current conditions and expected future developments, as well as other factors that management believes to be reasonable in the circumstances, including, but not limited to, the amount of indebtedness of the Corporation, changes in funding requirements, no unforeseen changes in the demand for energy consumption, the future course of the economy and financial markets, no unforeseen delays and costs in the Corporation's capital projects (including Copeland Station), no unforeseen changes to project plans, no significant changes in weather compared to historical seasonal trends, no unforeseen changes in the legislative and operating framework for electricity distribution in Ontario, the receipt of applicable regulatory approvals and requested rate orders, no unexpected delays in obtaining required approvals, the receipt of applicable IESO approvals for cost efficiency CDM incentives, the ability of the Corporation to obtain and retain qualified staff, materials, equipment and services in a timely and cost efficient manner, continued contractor performance, compliance with covenants, the receipt of favourable judgments, no unforeseen changes in electricity distribution rate orders or rate setting methodologies, no unfavourable changes in environmental regulation, the ratings issued by credit rating agencies, the level of interest rates and the Corporation's ability to borrow and assumptions regarding general business and economic conditions.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to, risks associated with the execution of LDC's capital and maintenance programs necessary to maintain the performance of aging distribution assets and make required infrastructure improvements; risks associated with capital projects, including Copeland Station; risks associated with electricity industry regulatory developments and other governmental policy changes including factors relating to LDC's distribution activities; risks associated with increased competition from regulated and unregulated entities; risks associated with the timing and results of regulatory decisions regarding LDC's revenue requirements, cost recovery and rates; risks associated with information system security and with maintaining complex information technology systems; risks associated with maintaining the security of the Corporation's information assets; risks associated with failure of the newly implemented ERP system; risk of external threats to LDC's facilities and operations posed by unexpected weather conditions caused by climate change and other factors, terrorism and pandemics and LDC's limited insurance coverage for losses resulting from these events; risk to the Corporation's employees and the general public of serious/fatal injuries and illnesses relating to or impacting upon its activities; risks of municipal government activity, including the risk that the City could introduce rules, policies or directives that can potentially limit the Corporation's ability to meet its business objectives as laid out in the Shareholder Direction principles; risks related to LDC's work force demographic and its potential inability to train and retain skilled employees; risks of being unable to retain necessary qualified external contracting forces relating to its capital, maintenance and reactive infrastructure program; risks associated with possible labour disputes and LDC's ability to negotiate appropriate collective agreements; risk that the Corporation may fail to monitor the external environment and or develop and pursue strategies through appropriate business models, thus failing to gain a strategic advantage; risk that Toronto Hydro is not able to arrange sufficient and cost-effective debt financing to repay maturing debt and to fund capital expenditures and other obligations; risk that the Corporation is unable to maintain its financial health and performance at acceptable levels; risk that insufficient debt or equity financing will be available to meet the Corporation's requirements, objectives, or strategic opportunities; risk of downgrades to the Corporation's credit rating; risks related to the timing and extent of changes in prevailing interest rates and discounts rates and their effect on future revenue requirements and future post-employment benefit obligations; risk associated with the impairment to the Corporation's image in the community, public confidence or brand; risk associated with the Corporation failing to meet its material compliance obligations under legal and regulatory instruments; risk of substantial and currently undetermined or underestimated environmental costs and liabilities; risk that assumptions that form the basis of the LDC's recorded environmental liabilities and related regulatory balances may change; risk that the presence or release of hazardous or harmful substances could lead to claims by third parties and/or governmental orders and other factors which are discussed in more detail under the section entitled "Risk Management and Risk Factors" in this MD&A. Please review the section "Risk Management and Risk Factors" in detail. All of the forward-looking information included in this MD&A is qualified by the cautionary statements in this "Forward-Looking Information" section and the "Risk Management and Risk Factors" section in this MD&A. These factors are not intended to represent a complete list of the factors that could affect the Corporation; however, these factors should be considered carefully and readers should not place undue reliance on forward-looking information made herein. Furthermore, the forward-looking information contained herein is dated as of the date of this MD&A or as of the date specified in this MD&A, as the case may be, and the Corporation has no intention and undertakes no obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

Selected Annual Information

The following table sets forth selected annual financial information for the three years ended December 31, 2018, 2017 and 2016. This information has been derived from the Corporation's consolidated financial statements.

Selected Annual Consolidated Financial Information
(in millions of Canadian dollars)

	2018 $	2017 $ *[Restated]*[6]	2016 $ *[Restated]*[6]
Year Ended December 31			
Total Revenues [1]	3,472.7	3,642.1	3,996.0
Net income after net movements in regulatory balances [1]	167.3	156.5	151.4
As at December 31			
Total assets and regulatory balances [2]	5,360.1	5,226.2	4,954.4
Total debentures [2,3]	2,034.9	2,034.0	2,084.6
Other non-current financial liabilities [4]	33.9	9.1	17.3
Total equity [2]	1,833.5	1,760.4	1,428.9
Dividends [5]	93.9	75.0	63.4

[1] See "Results of Operations" for further details on distribution revenue, other revenue, and net income after net movements in regulatory balances.

[2] See "Financial Position" for further details of significant changes in assets, debentures and shareholder's equity.

[3] Total debentures include current and long-term debentures.

[4] Other non-current financial liabilities include primarily non-current obligations under capital lease and non-current customer deposits. Under IFRS, deposits that are due or will be due on demand within one year from the end of the reporting period have been reclassified to other current financial liabilities.

[5] See "Liquidity and Capital Resources" for further details on dividends.

[6] These numbers have been restated to account for the impact of adopting IFRS 15. Additional details on IFRS 15 are discussed in the "Changes in Accounting Policies" section of this MD&A.

Additional Information

Additional information with respect to the Corporation (including its annual information form) is available on the System for Electronic Document Analysis and Retrieval website at www.sedar.com.
Toronto, Canada

March 6, 2019



ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2018

March 21, 2019

TABLE OF CONTENTS

PART 1 - FORWARD-LOOKING INFORMATION 4
PART 2 - GLOSSARY OF DEFINED TERMS 6
PART 3 - CORPORATE STRUCTURE 11
3.1 Name, Address, Incorporation 11
3.2 Inter-corporate Relationships 11
PART 4 - BUSINESS OF TORONTO HYDRO 12
4.1 Industry Structure 12
4.2 Toronto Hydro Corporation 13
4.3 Toronto Hydro-Electric System Limited ("LDC") 13
(a) LDC's Electricity Distribution System 13
(i) Control Centre 13
(ii) Terminal Stations 13
(iii) Transmission System Terminal Stations 13
(iv) Distribution Transformers and Municipal Substations 14
(v) Wires 14
(vi) Metering 14
(vii) Reliability of Distribution System 14
(b) LDC's Service Area and Customers 15
(c) LDC's Real Property 16
(d) Regulation of LDC 16
(i) Legislative Framework 16
(ii) Licences 17
(iii) Industry Codes 17
(e) Distribution Rates 19
(i) Rate Setting Mechanism 19
(ii) Other Regulated Charges 20
(f) Competitive Conditions 20
4.4 Toronto Hydro Energy Services Inc. 20
4.5 Environmental Matters 20
(a) Environmental Protection Requirements 20
(b) Financial and Operational Effects of Environmental Protection Requirements 21
(c) Environmental Policy and Oversight 21
4.6 Additional Information Regarding Toronto Hydro 21
(a) Employees 21
(b) Specialized Skills and Knowledge 22
(c) Health and Safety 22
(d) Code of Business Conduct and Whistleblower Procedure 23
(e) Insurance 23
(f) Intangible Property 23
(g) Seasonal Effects 24
PART 5 - GENERAL DEVELOPMENT OF THE BUSINESS 24
5.1 Business Operations 24
(a) Three Year History 24
(b) Business Operations 24
5.2 Rate Applications 24
(a) 2015-2019 Rate Application 24
(b) 2020-2024 Rate Application 25
5.3 Ontario's Fair Hydro Plan 25
5.4 Conservation and Demand Management 25
PART 6 - RELATIONSHIP WITH THE CITY 26
6.1 Shareholder Direction 26
(a) Shareholder Objectives and Principles 26
(b) Shareholder Approval 27
(c) Financial Performance 27

(d) Credit Rating 27
(e) Equity Contribution 27
(f) Dividends 27
6.2 Services Provided to the City 28
6.3 Shareholder Engagement 28
PART 7 - TAXATION 28
7.1 Tax Regime 28
7.2 PILs Recoveries through Rates 29
PART 8 - RISK FACTORS 30
PART 9 - CAPITAL STRUCTURE 37
9.1 Share Capital 37
9.2 Debentures 38
9.3 Credit Facilities 38
9.4 Credit Rating 39
PART 10 - DIRECTORS AND OFFICERS 39
10.1 Nomination of Directors 39
10.2 Committees of the Board of Directors 40
(a) Audit Committee 40
(b) Corporate Governance and Nominating Committee 40
(c) Human Resources and Environment Committee 41
10.3 Directors 41
10.4 Executive Officers 53
10.5 Cease Trade Orders, Bankruptcies, Penalties or Sanctions 53
10.6 Independence 54
10.7 Board Orientation and Continuing Education 54
10.8 Board, Committee and Director Assessments 54
10.9 Board Oversight and Management of Risks 55
10.10 Indebtedness of Directors and Executive Officers 55
PART 11 - AUDIT COMMITTEE 56
11.1 Composition, Independence and Financial Literacy 56
11.2 Audit Committee Charter 56
11.3 Policy on the Provision of Services by the External Auditors 56
11.4 External Auditors Service Fees 57
PART 12 - EXECUTIVE COMPENSATION 57
PART 13 - LEGAL PROCEEDINGS 67
PART 14 - MATERIAL CONTRACTS 68
PART 15 - NAMED AND INTERESTS OF EXPERTS 68
PART 16 - TRANSFER AGENTS AND REGISTRARS 69
PART 17 - ADDITIONAL INFORMATION 69
ANNEX A - CHARTER – AUDIT COMMITTEE A-1
ANNEX B - MANDATE – BOARD OF DIRECTORS B-1

PART 1 - FORWARD-LOOKING INFORMATION

Certain information included in this AIF constitutes "forward-looking information" within the meaning of applicable securities legislation. The purpose of the forward-looking information is to provide the Corporation's current expectations regarding future results of operations, performance, business prospects and opportunities and may not be appropriate for other purposes. All information, other than statements of historical fact, which address activities, events or developments that we expect or anticipate may or will occur in the future, are forward-looking information. The words "anticipates", "believes", "budgets", "committed", "can", "could", "estimates", "expects", "focus", "forecasts", "future", "intends", "may", "might", "plans", "propose", "projects", "schedule", "seek", "should", "trend", "will", "would", "objective", "outlook" or the negative or other variations of these words or other comparable words or phrases, are intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects the Corporation's current beliefs and is based on information currently available to the Corporation.

Specific forward-looking information in this AIF includes, but is not limited to, the statements regarding: anticipated capacity to be provided by Copeland Station, the expected completion date of Copeland Station and the expected capital expenditures required to complete Copeland Station as described in the sections entitled "LDC's Electricity Distribution System" and "Asset Management Risk"; wage increases for employees as described in the section entitled "Employees"; the effect of changes in energy consumption on future revenue as described in the section entitled "Seasonal Effects"; electricity distribution rates and rate applications as described in the section entitled "Rate Applications"; the plans to meet CDM targets and to receive reimbursement and/or cost efficiency incentives from the IESO as described in the section entitled "Conservation and Demand Management"; the effects of the Corporation or a subsidiary ceasing to be exempt from tax under the ITA and the TA and the payment of transfer taxes and the prescribed transfer tax rate for any future transfer of interest by the Corporation and its subsidiaries, or any changes to tax rates, as described in the section entitled "Tax Regime"; the Corporation's reliance on debt financing through its MTN Program, CP Program or existing credit facilities to finance Toronto Hydro's daily operations, repay existing indebtedness, and fund capital expenditures as described in the section entitled "Capital Structure Risk"; the effect of changes in interest rates and discount rates on future revenue requirements and future post-employment benefit obligations, respectively, as described in the section entitled "Market and Credit Risk"; the Corporation's plans to attract, train and retain skilled employees, mitigate risks from retiring employees, maintain the support of its labour unions and enter into agreements with, and monitor the performance of, its third party providers as described in the section entitled "Human Capital Risk"; the expectation that approximately 33% of Toronto Hydro's electricity distribution assets have already exceeded or will reach the end of their expected useful lives by 2025 as described in the section entitled "Asset Management Risk"; the expectation that none of the legal actions and claims as described further in the section entitled "Legal Proceedings" would have a material adverse effect on the Corporation and the ability to claim under applicable liability insurance policies and/or pay any damages with respect to legal actions and claims as described in the section entitled "Legal Proceedings".

The forward-looking information is based on estimates and assumptions made by the Corporation's management in light of past experience and perception of historical trends, current conditions and expected future developments, as well as other factors that management believes to be reasonable in the circumstances, including, but not limited to, the amount of indebtedness of the Corporation, changes in funding requirements, the future course of the economy and financial markets, no unforeseen delays and costs in the Corporation's capital projects (including Copeland Station), no unforeseen changes to project plans, no significant changes in weather compared to historical seasonal trends, no unforeseen changes in the legislative and operating framework for electricity distribution in Ontario, the receipt of applicable regulatory approvals and requested rate orders, no unexpected delays in obtaining required approvals, the receipt of applicable IESO approvals for cost efficiency CDM incentives, the ability of the Corporation to obtain and retain qualified staff, materials, equipment and services in a timely and cost efficient manner, continued contractor performance, compliance with covenants, the receipt of favourable judgments, no unforeseen changes in electricity distribution rate orders or rate setting methodologies, no unfavourable changes in environmental regulation, the ratings issued by credit rating agencies, the level of interest rates and the Corporation's ability to borrow and assumptions regarding general business and economic conditions.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to, risks associated with the execution of LDC's capital and maintenance programs necessary to maintain the performance of aging distribution

assets and make required infrastructure improvements; risks associated with capital projects, including Copeland Station; risks associated with electricity industry regulatory developments and other governmental policy changes including factors relating to LDC's distribution activities**;** risks associated with increased competition from regulated and unregulated entities; risks associated with the timing and results of regulatory decisions regarding LDC's revenue requirements, cost recovery and rates; risks associated with information system security and with maintaining complex information technology systems; risks associated with maintaining the security of Toronto Hydro's information assets; risks associated with failure of the newly implemented ERP system; risk of external threats to LDC's facilities and operations posed by unexpected weather conditions caused by climate change and other factors, terrorism and pandemics and LDC's limited insurance coverage for losses resulting from these events; risk to Toronto Hydro's employees or the general public of serious/fatal injuries and illnesses relating to or impacting upon Toronto Hydro's activities; risks of municipal government activity, including the risk that the City could introduce rules, policies or directives that can potentially limit Toronto Hydro's ability to meet its business objectives as laid out in the Shareholder Direction principles; risks related to LDC's work force demographic and its potential inability to attract, train and retain skilled employees; risks of being unable to retain necessary qualified external contracting forces relating to its capital, maintenance and reactive infrastructure program; risks associated with possible labour disputes and LDC's ability to negotiate appropriate collective agreements; risk that Toronto Hydro may fail to monitor the external environment and or develop and pursue strategies through appropriate business models, thus failing to gain a strategic advantage; risk that Toronto Hydro is not able to arrange sufficient and cost-effective debt financing to repay maturing debt and to fund capital expenditures and other obligations; risk that the Corporation is unable to maintain its financial health and performance at acceptable levels; risk that insufficient debt or equity financing will be available to meet the Corporation's requirements, objectives, or strategic opportunities; risk of downgrades to the Corporation's credit rating; risks related to the timing and extent of changes in prevailing interest rates and discounts rates and their effect on future revenue requirements and future post-employment benefit obligations; risk associated with the impairment to the Corporation's image in the community, public confidence or brand; risk associated with the Corporation failing to meet its material compliance obligations under legal and regulatory instruments; risk of substantial and currently undetermined or underestimated environmental costs and liabilities; risk that assumptions that form the basis of the LDC's recorded environmental liabilities and related regulatory balances may change; risk that the presence or release of hazardous or harmful substances could lead to claims by third parties and/or governmental orders and other factors which are discussed in more detail under Part 8 "Risk Factors" in this AIF.

All of the forward-looking information included in this AIF is qualified by the cautionary statements in this "Forward-Looking Information" section and the "Risk Factors" section of this AIF. These factors are not intended to represent a complete list of the factors that could affect the Corporation; however, these factors should be considered carefully and readers should not place undue reliance on forward-looking information made herein. Furthermore, the forward-looking information contained herein is dated as of the date of this AIF or as of the date specified in this AIF, as the case may be, and the Corporation has no intention and undertakes no obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

PART 2 - GLOSSARY OF DEFINED TERMS

In addition to terms defined elsewhere in this AIF, the below defined terms shall have the following meanings:

"Affiliate Relationships Code" refers to the Affiliate Relationships Code for Electricity Distributors and Transmitters that was published by the OEB and became effective on April 1, 1999, as amended.

"AIF" refers to the Corporation's Annual Information Form for the year ended December 31, 2018.

"Board" refers to the board of directors of the Corporation.

"CAIDI" refers to the Customer Average Interruption Duration Index and is a measure (in hours) of the average duration of interruptions experienced by customers, not including MED. CAIDI represents the quotient obtained by dividing SAIDI by SAIFI.

"Canadian Environmental Protection Act" refers to the *Canadian Environmental Protection Act, 1999* (Canada), as amended.

"Capital Assets" refers to the sum of property, plant and equipment and intangible assets, net of accumulated depreciation and amortization. See note 6 and note 7 to the Consolidated Financial Statements.

"CDM" refers to conservation and demand management.

"CDS" refers to CDS Clearing and Depository Services Inc.

"CEA" refers to the Canadian Electricity Association.

"CEO" refers to the President and Chief Executive Officer of the Corporation.

"CFO" refers to the Executive Vice-President and Chief Financial Officer.

"CIR" refers to Custom Incentive Rate-setting.

"City" refers to the city incorporated under the *City of Toronto Act, 1997* (Ontario), as amended.

"City Council" refers to Toronto City Council.

"City Councillor" refers to a councillor of Toronto City Council.

"Conservation and Demand Management Code" refers to the Conservation and Demand Management Code for Electricity Distributors that was published and became effective on September 16, 2010.

"Consolidated Financial Statements" refers to the comparative audited consolidated financial statements of the Corporation together with the auditors' report thereon and the notes thereto as at and for the years ended December 31, 2018 and December 31, 2017, a copy of which is available on the SEDAR website at www.sedar.com.

"Consumer Price Index" refers to the index measuring price movements published by Statistics Canada.

"Consumer Protection Act" refers to the *Consumer Protection Act, 2002* (Ontario), as amended.

"Copeland Station" refers to the Clare R. Copeland transformer station, formerly called "Bremner Station".

"Corporation" refers to Toronto Hydro Corporation.

"CPAB" refers to Canadian Public Accountability Board.

"CP Program" refers to the commercial paper program established by the Corporation under which the Corporation issues commercial paper. See section 9.3 under the heading "Credit Facilities".

"CUPE One" refers to the Canadian Union of Public Employees, Local One.

"Dangerous Goods Transportation Act" refers to the *Dangerous Goods Transportation Act, 1990* (Ontario), as amended.

"DBRS" refers to DBRS Limited.

"Debentures" has the meaning set forth under section 9.2 under the heading "Debentures".

"Distribution System Code" refers to the Distribution System Code that was published by the OEB on July 14, 2000, as amended.

"EHSMS" refers to the Environment, Health and Safety Management System.

"Electricity Act" refers to the *Electricity Act, 1998* (Ontario), as amended.

"Electricity Property" refers to a municipal corporation's or an MEU's interest in real or personal property used in connection with generating, transmitting, distributing or retailing electricity.

"Electricity Restructuring Act" refers to the *Electricity Restructuring Act, 2004* (Ontario), as amended.

"Energy Competition Act" refers to the *Energy Competition Act, 1998* (Ontario), as amended.

"Energy Consumer Protection Act" refers to the *Energy Consumer Protection Act, 2010* (Ontario), as amended.

"Environmental Protection Act" refers to the *Environmental Protection Act, 1990* (Ontario), as amended.

"ERM" refers to Enterprise Risk Management.

"ERP" refers to Enterprise Resource Planning.

"Fire Protection and Prevention Act" refers to the *Fire Protection and Prevention Act, 1997* (Ontario), as amended.

"GWh" refers to a gigawatt-hour, a standard unit for measuring electrical energy produced or consumed over time. One GWh is equal to one million kWh.

"Hydro One" refers to Hydro One Limited, Hydro One Inc. or Hydro One Networks Inc. and their respective subsidiaries, as appropriate.

"ICD.D" refers to the designation granted by the Institute of Corporate Directors, through the Directors Education Program jointly developed by the Institute of Corporate Directors and the University of Toronto's Rotman School of Management.

"ICM" refers to Incremental Capital Module. See section 4.3(e)(i) under the heading "Rate Setting Mechanism" for more information.

"IEEE" refers to the Institute of Electrical and Electronic Engineers.

"IESO" refers to the Independent Electricity System Operator. Through amendments to the Electricity Act, the operations of the IESO and the OPA were merged under the name Independent Electricity System Operator on January 1, 2015, bringing together real-time operations of the grid with long-term planning, procurement and conservation efforts.

"IRM" refers to Incentive Regulation Mechanism. See section 4.3(e)(i) under the heading "Rate Setting Mechanism" for more information.

"ISO" refers to the International Organization for Standardization.

"ITA" refers to the *Income Tax Act, 1985* (Canada), as amended.

"kW" refers to a kilowatt, a common measure of electrical power equal to 1,000 Watts.

"kWh" refers to a kilowatt-hour, a standard unit for measuring electrical energy produced or consumed over time. One kWh is the amount of electricity consumed by ten 100 Watt light bulbs burning for one hour.

"LDC" refers to the Corporation's wholly-owned subsidiary, Toronto Hydro-Electric System Limited.

"Management's Discussion and Analysis" or "MD&A" refers to Management's Discussion and Analysis of Financial Condition and Results of Operations of the Corporation for the year ended December 31, 2018, a copy of which is available on the SEDAR website at www.sedar.com.

"MED" refers to Major Event Days as defined by IEEE Std 1366-2012, IEEE Guide for Electric Power Distribution Reliability Indices.

"MEU" refers to a Municipal Electricity Utility in the Province of Ontario.

"Moody's" refers to Moody's Canada Inc.

"MTN Program" refers to the medium term note program established by the Corporation under which the Corporation issues debentures. See section 9.2 under the heading "Debentures" for the debentures currently outstanding.

"Named Executive Officer" or **"NEO"** means, collectively, the Corporation's CEO, the CFO, and/or a person serving in either of those capacities during the year and the three most highly compensated executive officers of Toronto Hydro who were serving as executive officers as at December 31, 2018, and each individual who would be amongst the three most highly compensated executive officers for Toronto Hydro, but for the fact that such individual was not an executive officer on December 31, 2018, if any.

"Oakville Hydro" refers to Oakville Hydro Electricity Distribution Inc.

"OBCA" refers to the *Business Corporations Act, 1990* (Ontario), as amended.

"OEB" refers to the Ontario Energy Board.

"OEB Act" refers to the *Ontario Energy Board Act, 1998* (Ontario), as amended.

"OEFC" refers to the Ontario Electricity Financial Corporation.

"OFHA" refers to the *Fair Hydro Act, 2017* (Ontario).

"OFHP" refers to Ontario's Fair Hydro Plan.

"OHSAS" refers to the Occupational Health and Safety Assessment Series.

"OMERS" refers to the Ontario Municipal Employees Retirement System, a multi-employer, contributory, defined benefit pension plan established in 1962 by the Province for employees of municipalities, local boards and school boards in Ontario.

"OPA" refers to the Ontario Power Authority. Through amendments to the Electricity Act, the operations of the IESO and the OPA were merged under the name Independent Electricity System Operator on January 1, 2015, bringing together real-time operations of the grid with long-term planning, procurement and conservation efforts.

"Open Access" refers to the opening of the Province's wholesale and retail electricity markets to competition pursuant to the requirement under the Electricity Act that transmitters and distributors of electricity in the Province provide generators, retailers and consumers with non-discriminatory access to their transmission and electricity distribution systems. Open Access commenced on May 1, 2002.

"OPG" refers to Ontario Power Generation Inc.

"OREC" refers to *Ontario Rebate for Electricity Consumers Act*, 2016 (Ontario).

"OSC" refers to the Ontario Securities Commission.

"PCBs" refers to polychlorinated biphenyls, a synthetic chemical compound consisting of chlorine, carbon and hydrogen. PCBs are used primarily as insulating and cooling elements in electrical equipment. Secondary uses include hydraulic and heat transfer fluids, flame proofing adhesives, paints, sealants and cable insulating paper.

"PILs" refers to the Payments In Lieu of Corporate Taxes regime contained in the Electricity Act pursuant to which MEUs that are exempt from tax under the ITA and the TA are required to make, for each taxation year, payments in lieu of corporate taxes to the OEFC. See note 25(o) and note 20 to the Consolidated Financial Statements.

"PP&E" refers to property, plant and equipment.

"Province" refers to the Province of Ontario.

"Prudential Facility" refers to a $75.0 million demand facility that the Corporation entered into with a Canadian chartered bank for the purpose of issuing letters of credit mainly to support LDC's prudential requirements with the IESO. See section 9.3 under the heading "Credit Facilities".

"PWU" refers to the Power Workers' Union.

"Residential Tenancies Act" refers to the *Residential Tenancies Act, 2006* (Ontario), as amended.

"Retail Settlement Code" refers to the Retail Settlement Code that was published by the OEB on December 13, 2000 and became effective on the commencement of Open Access (except with respect to "Service Agreements", as that term is defined in the Retail Settlement Code, which came into effect on March 1, 2001), as amended.

"**Revolving Credit Facility**" refers to the Corporation's credit agreement with a syndicate of Canadian chartered banks which established a revolving credit facility. See section 9.3 under the heading "Credit Facilities".

"S&P" refers to Standard & Poor's Financial Services LLC, a subsidiary of S&P Global Inc.

"SAIDI" means System Average Interruption Duration Index and is a measure (in hours) of the annual system average interruption duration for customers served, not including MED. SAIDI represents the quotient obtained by dividing the total customer hours of interruptions longer than one minute by the number of customers served.

"SAIFI" means System Average Interruption Frequency Index and is a measure of the frequency of service interruptions for customers served, not including MED. SAIFI represents the quotient obtained by dividing the total number of customer interruptions longer than one minute by the number of customers served.

"SEDAR" refers to the Canadian Securities Administrators' System for Electronic Document Analysis and Retrieval. SEDAR's website is www.sedar.com.

"Shareholder Direction" refers to the Shareholder Direction adopted by the Council of the City with respect to the Corporation, as amended and/or restated from time to time, pursuant to which the City has set out certain corporate governance principles with respect to the Corporation.

"Smart Meter" refers to a metering device capable of recording and transmitting hourly consumption information of a residential or general service customer.

"Standard Supply Customers" refers to persons connected to an electricity distributor's distribution system who are not served by retailers or whose retailer is unable to sell them electricity or who request the distributor to sell electricity to them.

"Standard Supply Service" refers to an electricity distributor's obligation to sell electricity to Standard Supply Customers, or to give effect to such rates as determined by the OEB under section 79.16 of the OEB Act.

"Standard Supply Service Code" refers to the Standard Supply Service Code for Electricity Distributors that was published by the OEB on December 8, 1999 and became effective on the commencement of Open Access, as amended.

"TA" refers to the *Taxation Act, 2007* (Ontario), as amended.

"Technical Standards and Safety Act" refers to the *Technical Standards and Safety Act, 2000* (Ontario), as amended.

"TH Energy" refers to the Corporation's wholly-owned subsidiary, Toronto Hydro Energy Services Inc.

"Toronto Hydro" refers to Toronto Hydro Corporation and its subsidiaries.

"Total Recordable Injury Frequency" refers to the number of recordable injuries multiplied by 200,000 divided by exposure hours, as per CEA standards.

"Transfer By-law" refers to By-law No. 374-1999 of the City made under section 145 of the Electricity Act pursuant to which the Toronto Hydro-Electric Commission and the City transferred their assets and liabilities and employees in respect of the electricity distribution system to LDC and in respect of electricity generation, co-generation and energy services to TH Energy. The Transfer By-law permits the Treasurer of the City to adjust the fair market value of the assets and the consideration paid in respect of the electricity distribution assets transferred to LDC as a consequence of OEB rate orders and permitted rates of return for 2000 or any subsequent year.

"Transportation of Dangerous Goods Act" refers to the *Transportation of Dangerous Goods Act, 1992* (Canada), as amended.

"Unit Smart Meter" refers to a unit Smart Meter installed by LDC in a unit of a multi-unit complex where the multi-unit complex is not connected solely to a bulk meter, and includes such other meters as may be prescribed by the Energy Consumer Protection Act.

"Watt" or **"W"** refers to a common measure of electrical power. One Watt equals the power used when one ampere of current flows through an electrical circuit with a potential of one volt.

"Working Capital Facility" refers to a $20.0 million demand facility the Corporation entered into with a Canadian chartered bank for the purpose of working capital management. See section 9.3 under the heading "Credit Facilities".

Unless otherwise specified, all references to statutes are to statutes of the Province and all references to dollars are to Canadian dollars.

PART 3 - CORPORATE STRUCTURE

3.1 Name, Address, Incorporation

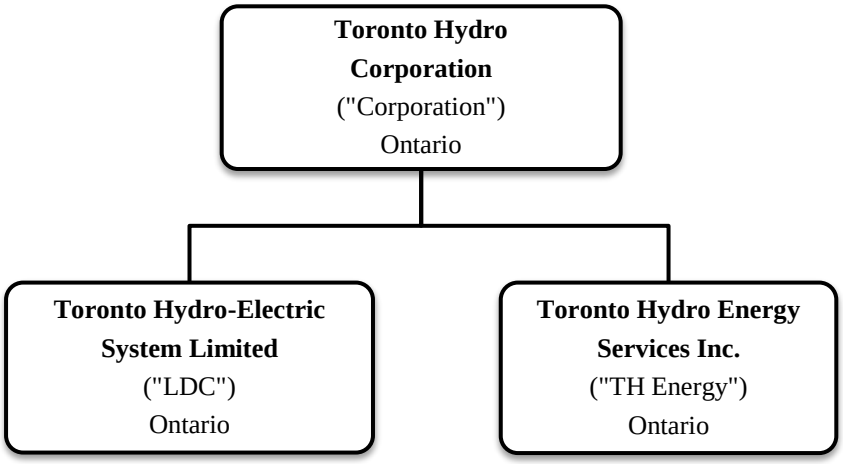
On January 1, 1998, the former municipalities of Metropolitan Toronto, Toronto, East York, Etobicoke, North York, Scarborough and York amalgamated to form the City. At the same time, the electric commissions of Toronto, East York, Etobicoke, North York, Scarborough and York were combined to form the Toronto Hydro-Electric Commission. Toronto Hydro is the successor to the Toronto Hydro-Electric Commission.

The Corporation, LDC and TH Energy were incorporated under the OBCA on June 23, 1999. Pursuant to the Transfer By-law, the Toronto Hydro-Electric Commission and the City transferred their assets and liabilities in respect of the electricity distribution system to LDC and electricity generation, co-generation and energy services to TH Energy.

The registered and head office of the Corporation is located at 14 Carlton Street, Toronto, Ontario, M5B 1K5.

3.2 Inter-corporate Relationships

The sole shareholder of the Corporation is the City. The Corporation, in turn, owns 100% of the shares of the subsidiaries listed below:



PART 4 - BUSINESS OF TORONTO HYDRO

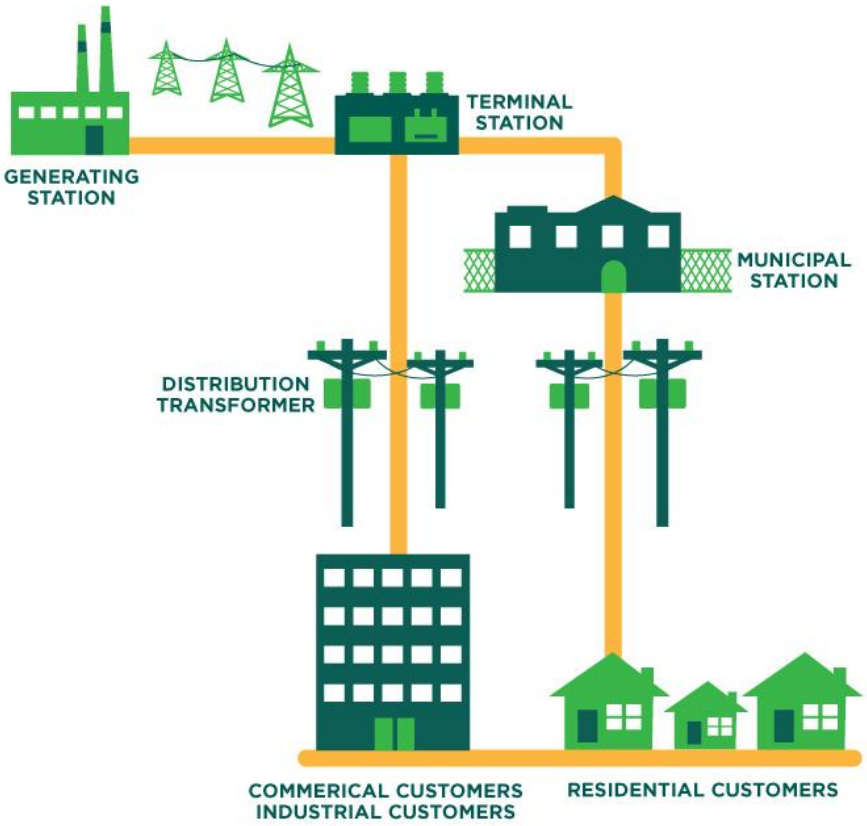
4.1 Industry Structure

The electricity industry in the Province is divided into four principal segments:

- Generation - the production of electricity at generating stations using nuclear, fossil, hydro, solar, wind or other sources of energy;
- Transmission - the transfer of electricity from generating stations to local areas using large, high-voltage power lines;
- Distribution - the delivery of electricity to homes and businesses within local areas using relatively low-voltage power lines; and
- Retailing - the purchase of electricity from generators and its sale to consumers together with a range of related services.

Electricity produced at generating stations is boosted to high voltages by nearby transformers so that the electricity can be transmitted long distances over transmission lines with limited power loss. The voltage is then reduced (stepped down) at terminal stations for supply to electricity distributors or large customers. Electricity distributors carry the electricity to distribution transformers that further reduce the voltage for supply to local customers. Electricity is distributed in the Province through a network of local electricity distributors that includes municipal electricity distributors, privately owned electricity distributors, and Hydro One.

The following diagram illustrates the basic structure of an electricity infrastructure system:



4.2 Toronto Hydro Corporation

Toronto Hydro Corporation is a holding company which wholly owns two subsidiaries:

- LDC – distributes electricity and engages in CDM activities; and
- TH Energy – provides street lighting and expressway lighting services in the City.

The Corporation supervises the operations of, and provides corporate, management services and strategic direction to its subsidiaries. The City is the sole shareholder of the Corporation.

4.3 Toronto Hydro-Electric System Limited ("LDC")

The principal business of Toronto Hydro is the distribution of electricity by LDC. LDC owns and operates $4.7 billion of Capital Assets comprised primarily of an electricity distribution system that delivers electricity to approximately 772,000 customers located in the City. LDC serves the largest city in Canada and distributes approximately 19% of the electricity consumed in the Province.

(a) LDC's Electricity Distribution System

Electricity produced at generating stations is transmitted through transmission lines owned by Hydro One to terminal stations at which point the voltage is then reduced (or stepped down) to distribution-level voltages. Distribution-level voltages are then distributed across LDC's electricity distribution system to distribution class transformers at which point the voltage is further reduced (or stepped down) for supply to end use customers. Electricity typically passes through a meter before reaching a distribution board or service panel that directs the electricity to end use circuits.

LDC's electricity distribution system is serviced from 1 control centre, 34 terminal stations and 1 transmission system terminal station, and is comprised of approximately 17,400 primary switches, approximately 60,560 distribution transformers, 146 in-service municipal substations, approximately 15,515 circuit kilometres of overhead wires supported by approximately 179,400 poles and approximately 13,207 circuit kilometres of underground wires.

(i) *Control Centre*

LDC has one control centre. The control centre co-ordinates and monitors the distribution of electricity throughout LDC's electricity distribution assets, and provides isolation and work protection for LDC's construction and maintenance crews and external customers. LDC's control centre utilizes supervisory control and data acquisition (SCADA) systems to monitor, operate, sectionalize and restore the electricity distribution system.

(ii) *Terminal Stations*

LDC receives electricity at 34 terminal stations at which high voltage is stepped down to distribution-level voltages. These terminal stations contain power transformers and high-voltage switching equipment that are owned by Hydro One. These terminal stations also contain equipment such as circuit breakers, switches and station busses.

(iii) *Transmission System Terminal Stations*

LDC receives electricity at Cavanagh transmission system terminal station at which high voltage is stepped down to distribution-level voltages. The transmission system terminal station contains power transformers, high-voltage switching equipment, and low-voltage equipment such as circuit breakers, switches and station busses that are owned by LDC.

One of LDC's largest capital initiatives currently in progress is the construction of Copeland Station in response to the developing need for distribution solutions in the downtown core of the City. Copeland Station will be considered a transmission system terminal station.

Copeland Station will be the first transformer station built in downtown Toronto since the 1960's and will be the second underground transformer station in Canada. It will provide electricity to buildings and neighbourhoods in the

central-southwest area of Toronto. During 2018, the testing on high voltage cable, the protection and control equipment, and the supervisory control and data acquisition system were all completed. The Corporation received approval from HONI, the electricity transmission provider, and the IESO for energization of the project and successfully energized one of two Copeland Station power transformers with associated cables and switchgear. The second power transformer and associated switchgear is anticipated to be energized in the first half of 2019 following the HONI's completion of additional servicing to some of their equipment. As at December 31, 2018, the cumulative capital expenditures on the Copeland Station project amounted to $202.6 million, plus capitalized borrowing costs. All capital expenditures related to Copeland Station are recorded to PP&E. The total capital expenditures required to complete the project has increased from $200.0 million to approximately $204.0 million, plus capitalized borrowing costs. There may be additional unforeseen delays and expenditures prior to completion of the project. See Part 8 under the heading "Risk Factors" below for further information on the Copeland Station project.

(iv) *Distribution Transformers and Municipal Substations*

Electricity at distribution voltages is distributed from the terminal stations to distribution transformers that are typically located in buildings or vaults or mounted on poles or surface pads that are used to reduce or step down voltages to utilization levels for supply to customers. The electricity distribution system includes approximately 60,560 distribution transformers. The electricity distribution system also includes 146 in-service municipal substations that are located in various parts of the City and are used to reduce or step down electricity voltage prior to delivery to distribution transformers. LDC also delivers electricity at distribution voltages directly to certain commercial and industrial customers that own their own substations.

(v) *Wires*

LDC distributes electricity through a network comprised of an overhead circuit of approximately 15,515 kilometres supported by approximately 179,400 poles and an underground circuit of approximately 13,207 kilometres.

(vi) *Metering*

LDC provides its customers with meters through which electricity passes before reaching a distribution board or service panel that directs the electricity to end use circuits on the customer's premises. The meters are used to measure electricity consumption. LDC owns the meters and is responsible for their maintenance and accuracy.

As part of its metering services, LDC also installs Unit Smart Meters in multi-unit complexes that fall within the Competitive Sector Multi-Unit Residential rate class. As at December 31, 2018, LDC had installed approximately 77,000 Unit Smart Meters in these types of multi-unit complexes.

(vii) *Reliability of Distribution System*

The table below sets forth certain industry recognized measurements of system reliability with respect to LDC's electricity distribution system and the composite measures reported by LDC and the CEA for the twelve month periods ending December 31 in the years indicated below.

	LDC 2018	**LDC 2017**	**CEA 2017[(1)]**
SAIDI	0.98	0.99	7.15
SAIFI	1.48	1.43	2.53
CAIDI	0.66	0.69	2.82

Note:

(1) Data was extracted from the CEA's 2017 Service Continuity Report on Distribution System Performance in Electrical Utilities, excluding significant events. At the date of this AIF, such report for the year 2018 has not been published by the CEA.

(b) LDC's Service Area and Customers

LDC is the sole provider of electricity distribution services in the City, and serves approximately 772,000 customers. The City is the largest city in Canada with a population of approximately 2.9 million. The City is a financial centre with large and diversified service and industrial sectors.

The table below sets out LDC's customer classes and certain operating data with respect to each class for each of the years in the two-year period ended December 31, 2018:

	Year ended December 31	
	2018	**2017** [4]
Residential Service [1]		
Number of customers (as at December 31)..……..	689,560	685,292
kWh	5,418,189,931	4,933,060,853
Revenue	$815,401,037	$902,313,523
% of total service revenue	24.1%	25.5%
General Service [2]		
Number of customers (as at December 31)	82,292	82,233
kWh	17,806,672,372	17,276,676,523
Revenue	$2,337,309,219	$2,394,421,297
% of total service revenue	69.2%	67.8%
Large Users [3]		
Number of customers (as at December 31)	38	44
kWh	2,066,558,040	2,171,461,259
Revenue.....	$225,602,981	$237,594,414
% of total service revenue	6.7%	6.7%
Total		
Number of customers (as at December 31)	771,890	767,569
kWh.....	25,291,420,343	24,381,198,635
Revenue	$3,378,313,237	$3,534,329,234

Notes:

(1) "Residential Service" means a service that is for domestic or household purposes, including single family or individually metered multi-family units and seasonal occupancy.

(2) "General Service" means a service supplied to premises other than those receiving "Residential Service" and "Large Users" and typically includes small businesses and bulk-metered multi-unit residential establishments. This service is provided to customers with a monthly peak demand of less than 5,000 kW averaged over a twelve-month period.

(3) "Large Users" means a service provided to a customer with a monthly peak demand of 5,000 kW or greater averaged over a twelve-month period.

(4) Effective January 1, 2018, the Corporation adopted IFRS 15 *Revenue from Contracts with Customers* ("IFRS 15") and resulted in $207.6 million income statement reclassification between energy sales and energy purchases for the year ended December 31, 2017. The 2017 revenue has been restated in accordance with IFRS 15.

(c) LDC's Real Property

The following table sets forth summary information with respect to the principal real property owned, leased or otherwise used by LDC as at December 31, 2018:

Property	Total
Terminal stations	34 sites
Transmission system terminal stations	1 site
Municipal substations	146 sites
Decommissioned municipal substations	24 sites
Control centre[1]	1 site
Operation centres[2]	5 sites
Other[3]	32 sites

Notes:

(1) LDC's control centre is located within one of its operation centres.

(2) LDC's operation centres accommodate office, staff, crews, vehicles, equipment and material necessary to operate and monitor the electricity distribution system.

(3) Other properties include locations under construction (including Copeland Station), small work centres and surplus properties.

Under the OEB Act, electricity distributors are entitled to apply to the OEB for authority to expropriate land required in connection with new or expanded electricity distribution lines or interconnections. If, after a hearing, the OEB is of the opinion that the expropriation of land is in the public interest, the OEB may make an order authorizing expropriation upon payment of specified compensation. The Electricity Act grandfathered thousands of existing unregistered easements, principally for distribution over third-party lands. The Electricity Act also authorizes electricity distributors to locate assets on, over or under public streets and highways.

(d) Regulation of LDC

(i) *Legislative Framework*

The Electricity Act and the OEB Act provide the broad legislative framework for the Province's electricity market.

The Electricity Act restructured the Province's electricity industry. Under the Electricity Act, the former Ontario Hydro was reorganized into five separate corporations (listed below under their current names):

- OPG, the entity responsible for the former Ontario Hydro's generation business;
- Hydro One, the entity responsible for the former Ontario Hydro's electricity transmission, distribution and energy services businesses;
- OEFC, the entity responsible for managing and retiring the former Ontario Hydro's outstanding indebtedness and remaining liabilities;
- IESO, a non-profit corporation responsible for central market operations, long-term planning, procurement and conservation efforts; and
- Electrical Safety Authority, a non-profit corporation responsible for the electric installation inspection function.

Additionally, the Electricity Act requires electricity distributors in the Province to keep their distribution businesses separate from their other businesses.

The business of LDC and other electricity distributors is regulated by the OEB, which has broad powers relating to licensing, standards of conduct and service, the regulation of electricity distribution rates charged by LDC and other electricity distributors and transmission rates charged by Hydro One and other transmitters. The OEB Act states that,

subject to certain exceptions, LDC and other electricity distributors shall not carry on any business activity other than the distribution of electricity, except through affiliated companies. As an exception to the general restriction on its business activities, the OEB Act permits LDC to provide additional services related to the promotion of CDM activities and alternative, cleaner and renewable sources of energy and energy storage. As well, the OEB may authorize LDC to carry on a non-distribution business activity.

Through amendments to the Electricity Act, the operations and responsibilities of the IESO were amended on January 1, 2015 such that it was additionally authorized to implement an integrated power system supply plan and deliver CDM programs in the Province, bringing together real-time operations of the grid with long-term planning, procurement and conservation efforts.

The Energy Consumer Protection Act came into force on January 1, 2011. The Energy Consumer Protection Act amends several statutes, including the OEB Act, the Electricity Act, the Consumer Protection Act and the Residential Tenancies Act. The Energy Consumer Protection Act also enables and sets out the requirements relating to LDC's installation of Unit Smart Meters in multi-unit complexes and provides new rules regarding the manner in which energy consumers are to be billed for their electricity consumption.

On December 3, 2015, Bill 112 – Strengthening Consumer Protection and Electricity System Oversight Act, 2015 received Royal Assent and certain provisions thereunder were proclaimed into force effective as of March 4, 2016. The bill's measures as proclaimed into force amend the Energy Consumer Protection Act and the OEB Act by further enhancing consumer protection and increasing the OEB's powers with regard to utility regulation, including increases to potential administrative penalties for non-compliance. The bill also eliminates limitations on LDC affiliate lines of business and gives the OEB the discretion to authorize LDC and other electricity distributors to carry on a non-distribution business activity.

(ii) *Licences*

Distribution Licence

The OEB has granted LDC a distribution licence. The term of the current licence is until October 16, 2023. The licence allows LDC to own and operate an electricity distribution system in the City. Among other things, the licence provides that LDC must keep financial records associated with distributing electricity separate from its financial records associated with other activities, may not impose charges for the distribution of electricity except in accordance with distribution rate orders approved by the OEB and must comply with industry codes established by the OEB.

Electricity Generation Licence

On December 18, 2002, the OEB issued an electricity generation licence to TH Energy and TREC Windpower Co-operative (No.1) Incorporated (the co-venturers), in connection with a wind turbine located at Exhibition Place in the City. The licence allows the co-venturers to generate electricity or provide ancillary services for sale through the IESO-administered markets, or directly to another person, subject to certain terms and conditions. This licence terminates on December 17, 2022, although the term may be extended by the OEB.

(iii) *Industry Codes*

The OEB has established the Affiliate Relationships Code, the Distribution System Code, the Retail Settlement Code, the Standard Supply Service Code, and the Conservation and Demand Management Code. These codes prescribe minimum standards of conduct, as well as standards of service, for electricity distributors in the non-competitive electricity market, and have been assigned the following ranking in the event there is a conflict between them:

(1) Affiliate Relationships Code
(2) Distribution System Code
(3) Retail Settlement Code
(4) Standard Supply Service Code
(5) Conservation and Demand Management Code

These codes are summarized below.

Affiliate Relationships Code

The Affiliate Relationships Code establishes standards and conditions for the interaction between electricity distributors and their affiliated companies. It is intended to minimize the potential for an electricity distributor to cross-subsidize competitive or non-monopoly activities, protect the confidentiality of consumer information collected by an electricity distributor and ensure that there is no preferential access to regulated services. The Affiliate Relationships Code prescribes standards of conduct for an electricity distributor with respect to the following: the degree of separation from affiliates; sharing of services and resources; transfer pricing; financial transactions with affiliates; equal access to services; and confidentiality of customer information.

Distribution System Code

The Distribution System Code establishes the minimum conditions that an electricity distributor must meet in carrying out its obligations to distribute electricity under its licence and under the Energy Competition Act, and has been amended as the regulatory environment has evolved. Generally, the Distribution System Code prescribes the rights and responsibilities of electricity distributors and electricity distribution customers with respect to the following: connections; connection agreements and conditions of service; expansion projects; alternative bids (available to customers for work otherwise done by an electricity distributor); metering; operations; disconnection and security deposits; and other matters.

Retail Settlement Code

The Retail Settlement Code outlines the obligations of an electricity distributor with respect to its relationship with retail market participants and its role as a retail market settlements administrator. Under the terms of the Retail Settlement Code, an electricity distributor is required to do the following: unbundle the costs of competitive electricity services and non-competitive electricity services; record, in variance accounts, the difference between amounts billed by the IESO to the electricity distributor for competitive and non-competitive electricity services, and the aggregate amounts billed by the electricity distributor to consumers, retailers and others for the same services; and provide electricity billing and settlement services to retailers and customers.

Standard Supply Service Code

The Standard Supply Service Code requires an electricity distributor to act as a default supplier and provide Standard Supply Service to persons connected to the electricity distributor's distribution system. The Standard Supply Service Code also specifies the conditions and manner by which OEB approved Standard Supply Service rates are to be charged to customers. Under the Standard Supply Service Code, an electricity distributor's rates for Standard Supply Service must be approved by the OEB and must consist of the price of electricity and an administrative charge that will allow the electricity distributor to cover its costs of providing the service.

Conservation and Demand Management Code

CDM activities over the January 1, 2015 to December 31, 2020 timeframe are governed by the OEB's Conservation and Demand Management Requirement Guidelines for Electricity Distributors issued on December 19, 2014. See section 5.4 under the heading "Conservation and Demand Management" for more information on LDC's CDM activities.

(e) Distribution Rates

(i) *Rate Setting Mechanism*

The OEB's regulatory framework for electricity distributors is designed to support the cost-effective planning and operation of the electricity distribution network and to provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price.

The OEB typically regulates the electricity rates for distributors using a combination of detailed cost of service reviews and IRM adjustments. A cost of service review uses a future test-year to establish rates, and provides for revenues required to recover the forecasted costs of providing the regulated service, and a fair and reasonable return on rate base (i.e. the aggregate of approved investment in PP&E and intangible assets excluding work in progress, less accumulated depreciation and amortization and unamortized capital contributions from customers, plus an allowance for working capital). IRM adjustments are typically used for one or more years following a cost of service review and provide for adjustments to rates based on an inflationary factor net of a productivity factor and an efficiency factor as determined relative to other electricity distributors.

Administratively, the OEB currently regulates the electricity rates for distributors through one of three specific rate-setting methods: Price Cap Incentive Rate-setting (suitable for most distributors), CIR (suitable for distributors with large or highly variable capital requirements), and Annual Incentive Rate-setting Index (suitable for distributors requiring limited rate adjustments). Under each of these methods, the OEB also allows recovery of costs arising from significant events satisfying certain criteria which are considered external to the regulatory regime and beyond the control of management.

Under the Price Cap Incentive Rate-setting method, rates are set on a single forward test-year cost of service basis for the first year and indexed for four subsequent years through an industry-standard IRM adjustment (using the 4th generation price cap index formula). Under this method, the ICM is available to address any incremental capital investment needs that may arise during the term. In order to determine whether a distributor is eligible for the ICM, the OEB conducts a review of the distributor's ICM application by way of a detailed examination of evidence and consideration of a number of criteria, such as materiality, need and prudence.

Under the CIR method, rates are set for a minimum period of five years, typically on a forward test-year cost of service basis for the first year with subsequent annual adjustments based on a distributor-specific custom index. The particular mechanics through which rates are set and adjusted are determined by the OEB on a case-by-case basis.

The Annual Incentive Rate-setting Index method sets a distributor's rates through an industry-standard IRM adjustment (using a limited form of the 4th generation price cap index formula) for one or more years.

Under each method, actual operating conditions may vary from forecasts such that actual returns achieved can differ from approved returns. Approved electricity rates are generally not adjusted as a result of actual costs or revenues being different from forecasted amounts, other than for certain prescribed costs that are eligible for deferral for future collection from, or refund to, customers.

On July 31, 2014, LDC filed a rate application with the OEB under the CIR method which sought approval of LDC's 2015 test-year revenue requirement on a cost of service basis and the corresponding electricity distribution rates effective May 1, 2015, and the subsequent annual rate adjustments based on a custom index specific to LDC for the period commencing on January 1, 2016 and ending on December 31, 2019. On December 29, 2015, the OEB issued its CIR decision and on March 1, 2016, the OEB issued its CIR rate order.

On August 15, 2018, LDC filed a rate application with the OEB under the CIR method which sought approval of LDC’s 2020 test-year revenue requirement on a cost of service basis and the corresponding electricity distribution rates effective January 1, 2020, and the subsequent annual rate adjustments based on a custom index specific to LDC for the period commencing on January 1, 2021 and ending on December 31, 2024.

See section 5.2 under the heading "Rate Applications" for more information on LDC's rate applications.

(ii) *Other Regulated Charges*

The OEB's 2006 Electricity Distribution Rate Handbook provides standard rates and guidelines to electricity distributors with respect to other regulated charges that are non-competitive in nature, required under OEB codes and guidelines, governed by the market rules or are under the direction of the Province, including transmission charges and retail service charges relating to services provided by electricity distributors to electricity retailers in accordance with the Retail Settlement Code. As part of its rate application filed on July 31, 2014, LDC sought the OEB's approval to update its other regulated charges commencing on May 1, 2015. In the CIR decision and rate order, the OEB approved updates to these other regulated charges.

(f) Competitive Conditions

The OEB distribution licence issued to LDC stipulates a service area that reflects the territory within the City. By law, only the OEB can grant such a licence for a service area and only an entity with such a licence can provide licenced services to the public-at-large within a service area. The OEB has not granted any other distribution licence that permits distribution within LDC's service area. In addition to this regulatory barrier to entry, there are other barriers to entry, including the cost of constructing an electricity distribution system, physical space limitations within and legal access to the right-of-way, the specialized skills associated with the distribution business, the level of expertise required to achieve operational and regulatory compliance, and LDC's relationships with its customers. Notwithstanding the existing barriers to entry, other regulated and unregulated entities have always competed with LDC and its predecessors to provide customers with other sources of energy, including electricity. The pervasiveness of this competition and its effects on LDC's distribution business have varied over time and continue to vary based on many factors, including the relative price of energy source (e.g., natural gas, grid-supplied electricity, behind-the-meter generation), government-based incentives, and technology advancements (e.g., multi-unit building sub-metering, micro-grids, electricity storage, virtual power).

4.4 Toronto Hydro Energy Services Inc.

TH Energy owns and operates $42.2 million of Capital Assets as of December 31, 2018. TH Energy owns certain street lighting assets located in the City, and has an agreement with the City to provide street lighting system maintenance and capital improvement services to the City. TH Energy sub-contracts street lighting services to LDC.

TH Energy also operates a wind turbine located at the Better Living Centre (Exhibition Place) in a joint venture with TREC Windpower Cooperative (No.1) Incorporated.

4.5 Environmental Matters

(a) Environmental Protection Requirements

Toronto Hydro is subject to extensive federal, provincial and local regulation relating to the protection of the environment. The principal federal legislation is the Canadian Environmental Protection Act which regulates the use, import, export and storage of toxic substances, including PCBs and ozone-depleting substances. Toronto Hydro is also subject to the federal Transportation of Dangerous Goods Act which prescribes safety standards and requirements for the handling and transportation of hazardous goods including PCBs and sets reporting, training and inspection requirements relating thereto.

The principal provincial legislation is the Environmental Protection Act which regulates releases and spills of contaminants, including PCBs, ozone-depleting substances and other halocarbons, contaminated sites, waste management, and the monitoring and reporting of airborne contaminant discharge. The provincial Technical Standards and Safety Act also applies to Toronto Hydro's operations with respect to the handling of and training related to compressed gas, propane and liquid fuels. The provincial Fire Protection and Prevention Act requires Toronto Hydro to incorporate procedures and training for dealing with any spills of flammable or combustible liquids. The provincial Dangerous Goods Transportation Act prescribes safety standards and requirements for the transportation of dangerous goods on provincial highways and sets out inspection requirements related thereto.

Municipal by-laws regulate discharges of industrial sewage and storm water run-off to the municipal sewer system and the reporting of the release of certain toxic substances into the environment.

(b) Financial and Operational Effects of Environmental Protection Requirements

In 2018, LDC spent approximately $3.1 million to meet environmental protection requirements. This includes costs for hazardous and non-hazardous waste disposal, testing, asbestos abatement, site remediation, wood and concrete pole removal, manifest and tonnage fees, Stewardship Ontario fees and the 2018 expenditure for the submersible transformer replacement program.

Toronto Hydro recognizes a liability for its best estimate of the future removal and handling costs for contamination in electricity distribution equipment in service. The liability is recognized when the decommissioning provision is incurred and when the fair value is determined. Actual future environmental costs may vary materially from the estimates used in the calculation of the decommissioning provision on Toronto Hydro's balance sheet.

(c) Environmental Policy and Oversight

Toronto Hydro has a strong commitment to the environment through the enforcement of a well-defined Environmental Policy. Conformance with the Environmental Policy is managed by Toronto Hydro's Environmental, Health and Safety department led by the Executive Vice-President and Chief Human Resources & Safety Officer. The content of the Environmental Policy is reviewed and approved annually by the Board.

Toronto Hydro's Environmental Policy identifies several core environmental principles, which include:

- Commitment from leadership to provide suitable and sufficient resources for the environmental management system;
- Compliance with all applicable laws, codes and standards;
- Continual improvement of environmental performance through the establishment of annual objectives, targets and programs;
- Employee engagement through education, training and providing general awareness of the Environmental Policy requirements and the environmental management system;
- Stakeholder engagement including consultation and engagement of environmental issues within the community and various stakeholders such as suppliers, customers, regulators, industry and the public;
- Pollution prevention through the implementation of policies, programs and procedures; and
- Integration of environmental considerations into our business processes.

LDC manages its environmental aspects in conformance with ISO 14001:2015 and was re-certified on January 18, 2019 as meeting the requirements of the ISO 14001:2015 standard by a third party auditor.

Legislative environmental reporting for federal, provincial and municipal governments is compiled and submitted annually. Third party environmental compliance audits are also conducted biennially in conformance with LDC's environment, health and safety audit plan.

Toronto Hydro's environmental policies, programs and procedures are reviewed and approved by management. Quarterly updates are presented to the Board's Human Resources and Environment Committee covering current environmental risks, environmental compliance audit findings, mitigation strategies and other material environmental matters.

4.6 Additional Information Regarding Toronto Hydro

(a) Employees

At December 31, 2018, Toronto Hydro had approximately 1,400 employees. Included in Toronto Hydro's employees are 723 members of bargaining units represented by the Power Workers' Union ("PWU"), 70 engineers represented by the Society of United Professionals, and an additional 75 Information Technology (IT) Professionals who will soon also be represented by the Society of United Professionals. Toronto Hydro employees currently represented by PWU were formerly represented by Canadian Union of Public Employees, Local One ("CUPE One"), which merged

with PWU on October 6, 2016. The Society of United Professionals was certified as the bargaining agent for IT Professionals at Toronto Hydro on November 21, 2018. Toronto Hydro expects to receive notice to bargain by the end of March 2019, and to thereafter bargain with the Society of United Professionals for a first collective agreement to represent these employees.

On May 24, 2018, the PWU ratified collective agreements governing inside and outside employees for a four-year period beginning February 1, 2018 and expiring January 31, 2022. The collective agreements implemented wage increases of 2.3% effective on each of February 1, 2018, February 1, 2019, February 1, 2020, and February 1, 2021. The collective agreements also contain cost of living escalator clauses in the third and fourth years of the current agreements that provide for wage adjustments corresponding to the percentage change in the Consumer Price Index. The escalator clauses only become effective if certain prescribed thresholds are exceeded.

Full time employees of Toronto Hydro participate in the OMERS pension plan. Plan benefits are determined based on a formula that takes into account the highest 5-year average contributory earnings and the number of years of service and are indexed to increases in the Consumer Price Index, subject to an annual maximum of 6%. Any increase in the Consumer Price Index above 6% per year is carried forward for later years. Both participating employers and participating employees are required to make equal plan contributions based on participating employees' eligible contributory earnings. All obligations to make payments to retirees under the OMERS pension plan are the responsibility of OMERS.

In addition to OMERS, Toronto Hydro provides other employment and post-employment benefits to employees, including medical, dental and life insurance benefits. See note 25(m) and note 13 to the Consolidated Financial Statements.

(b) Specialized Skills and Knowledge

Trades and technical jobs play a critical role in the safe and reliable design, construction and maintenance of LDC's electricity distribution system. These jobs include overhead, underground, and stations trades as well as control room operators, designers and engineers. LDC hires experienced workers when available, along with apprentices for trades and technical positions. Trade apprentices require between 4 and 6 years to become fully competent and capable of performing all aspects of their job. LDC provides trades, legislative and compliance training through its apprenticeship program.

(c) Health and Safety

Toronto Hydro is committed to a safe and injury free work environment for all employees, contractors, visitors and the public. Through LDC's EHSMS, based on British Standards Institution OHSAS 18001:2007 Standard "*Occupational Health and Safety Management System - Requirements*", LDC maintains and reviews procedures, programs and the Occupational Health and Safety Policy which outlines several core principles including:

- Compliance
- Continual Improvement
- Engagement and Consultation
- Communication
- Accountability
- Risk Management
- Contractor Management
- Incident Investigation
- Performance Monitoring

The content of the Occupational Health and Safety Policy is reviewed and approved annually by the Board.

Toronto Hydro's health and safety performance is reviewed periodically by the Human Resources and Environment Committee of the Board. In 2018, the Total Recordable Injury Frequency was 0.83 recordable injuries per 200,000 hours worked compared to 1.06 in 2017.

LDC's legislated occupational health and safety requirements come under provincial jurisdiction exclusively and all legislated occupational health and safety reporting requirements are complied with. Management assurance that these requirements are met is accomplished by commissioning third party health and safety compliance audits conducted in conformance with LDC's environmental, health and safety audit plan.

Toronto Hydro's occupational health and safety policies, programs and procedures are reviewed and approved by management. Quarterly updates are presented to the Board covering current occupational health and safety risks, performance, compliance audit findings, mitigation strategies and other occupational health and safety matters.

(d) Code of Business Conduct and Whistleblower Procedure

All employees, officers and directors of Toronto Hydro are required to comply with the principles set out in the Code of Business Conduct and Whistleblower Procedure (the "Code"), which was originally implemented by Toronto Hydro in 2003, and is reviewed, revised and approved by the Board from time to time. The Code provides guidance to all employees in situations of potential perceived conflict of interest. All employees, officers and directors of Toronto Hydro are required to complete training in respect of the Code and sign an attestation in accordance with the Code upon commencement of employment and every three years thereafter.

The Code provides for the appointment of an Ethics Officer and establishes a direct hotline to the Ethics Officer by which perceived violations of the principles set out in the Code may be reported, anonymously or otherwise. Where the complaint involves the conduct of a director or officer of Toronto Hydro, the Ethics Officer is required to report it to the Chair of the Human Resources and Environment Committee of the Board, or, where such conduct relates to questionable auditing or accounting matters, to the Chair of the Audit Committee of the Board, who oversees the investigation of that complaint. In addition to the provisions of the Code, the Ethics Officer reports quarterly to the Human Resources and Environment Committee of the Board on the nature of complaints received and the Director, Internal Audit and Compliance reports quarterly to the Audit Committee on matters related to audit and accounting. A copy of Toronto Hydro's Code of Business Conduct and Whistleblower Procedure is available on the SEDAR website at www.sedar.com.

(e) Insurance

Toronto Hydro's current insurance policies provide coverage for a variety of losses and expenses which might arise from time to time, including:

- comprehensive general liability insurance;
- all risk property, property terrorism, boiler and machinery insurance;
- automobile liability insurance;
- directors and officers liability insurance;
- cyber insurance;
- crime insurance; and
- insurance covering loss or damage on certain physical assets.

Toronto Hydro believes that the coverage, amounts and terms of its insurance arrangements are consistent with industry practice.

(f) Intangible Property

The Corporation owns various intangible assets, such as computer software systems used in the course of business, and intellectual property, including the "Toronto Hydro" brand name and the trademark Toronto Hydro & Star Design. The Corporation also owns the trademarks peakSAVER®, POWERSHIFT® and PEAKSAVER PLUS®. The trademarks peakSAVER® and PEAKSAVER PLUS® have been licensed by the Corporation to the IESO and sub-licensed to various electricity distributors in the Province for the promotion of a province-wide demand response CDM program.

(g) Seasonal Effects

Toronto Hydro's revenues, all other things being equal, are impacted by temperature fluctuations and unexpected weather conditions. Revenues would tend to be higher in the first quarter as a result of higher energy consumption for winter heating, and in the third quarter due to air conditioning/cooling. Toronto Hydro's revenues are also impacted by fluctuations in electricity prices and the timing and recognition of regulatory decisions and rate orders.

PART 5 - GENERAL DEVELOPMENT OF THE BUSINESS

5.1 Business Operations

(a) Three Year History

The following table sets forth selected annual financial information of the Corporation for the three years ended December 31, 2018, 2017 and 2016. This information has been derived from the Consolidated Financial Statements and is presented in millions of dollars.

	Year ended December 31		
	2018	**2017**	**2016**
Net income after net movements in regulatory balances	$167.3	$156.5	$151.4
Capital expenditures	$511.3	$552.9	$551.7
Total assets and regulatory balances	$5,360.1	$5,226.2	$4,954.4
Total equity	$1,833.5	$1,760.4	$1,428.9

(b) Business Operations

Over the past three years, Toronto Hydro continued to streamline its business operations to focus on LDC's core businesses of distributing electricity and engaging in CDM activities. See section 5.4 under the heading "Conservation and Demand Management" for more information on LDC's CDM activities.

5.2 Rate Applications

The following is an overview of LDC's rate applications from 2015 to date.

(a) 2015-2019 Rate Application

On July 31, 2014, LDC filed a rate application with the OEB under the CIR method which sought approval of LDC's 2015 test-year revenue requirement on a cost of service basis and the corresponding electricity distribution rates effective May 1, 2015, and the subsequent annual rate adjustments based on a custom index specific to LDC for the period commencing on January 1, 2016 and ending on December 31, 2019. The rate application included requests for approval of capital expenditures of approximately $2.5 billion over the 2015-2019 period. The rate application also sought approval to include in LDC's rate base capital amounts that were prudently incurred prior to 2015, subject to review by the OEB. In addition, LDC sought approval to recover the net book value of stranded meters.

On December 29, 2015, the OEB issued its CIR decision and on March 1, 2016, the OEB issued its CIR rate order, both in relation to the 2015-2019 rate application filed on July 31, 2014. The CIR decision and rate order approved a rate base of $3,232.0 million and revenue requirement of $633.1 million for 2015, and rates calculated on that basis. The CIR decision and rate order also approved, on an interim basis, subsequent annual rate adjustments based on a custom index for the period commencing on January 1, 2016 and ending on December 31, 2019. The OEB-approved revenue requirement generates an increase in funded capital expenditures over the CIR period.

The OEB approved new deferral and variance accounts including accounts to capture variances related to revenue requirement for ICM capital work undertaken from 2012 to 2014 and revenue requirement associated with capital work during the CIR term. The OEB approved recovery of the $15.8 million forecasted net book value relating to the

stranded meters. The OEB also approved foregone revenue rate riders for the May 1, 2015 to February 29, 2016 period as well as other requested rate riders. In addition, the OEB approved the transfer of LDC's street lighting assets into rate base effective January 1, 2015 at a transfer price of $39.8 million, representing the opening net book value of the assets in 2015. The financial impact of the OEB's CIR decision and rate order has been reflected in 2015.

The rates for 2015 and 2016 were implemented on March 1, 2016, with effective dates of May 1, 2015 and January 1, 2016, respectively.

On August 22, 2016, LDC filed its 2017 rate application seeking OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2017 and ending on December 31, 2017. On December 21, 2016, the OEB issued a decision finalizing LDC's 2017 rates and providing for other deferral and variance account dispositions.

On August 23, 2017, LDC filed its 2018 rate application seeking OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2018 and ending on December 31, 2018. On December 14, 2017, the OEB issued a decision finalizing LDC's 2018 rates and providing for other deferral and variance account dispositions.

On August 31, 2018, LDC filed its 2019 rate application seeking OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2019 and ending on December 31, 2019. On December 13, 2018, the OEB issued a decision and rate order approving LDC's 2019 rates and providing for other deferral and variance account dispositions.

(b) 2020-2024 Rate Application

On August 15, 2018, LDC filed a CIR application seeking approval of LDC's 2020 test-year revenue requirement on a cost of service basis and the corresponding electricity distribution rates effective January 1, 2020, and the subsequent annual rate adjustments based on a custom index specific to LDC for the period commencing on January 1, 2021 and ending on December 31, 2024. The rate application requests approvals to fund capital expenditures of approximately $2.8 billion over the 2020-2024 period. The rate application also seeks approval to include in LDC's rate base capital amounts that were incurred prior to 2020.

5.3 Ontario's Fair Hydro Plan

On March 2, 2017, the Government of Ontario announced the OFHP which includes a number of initiatives, some of which affect LDC or its customers.

OFHP includes the OREC, which came into effect on January 1, 2017. The OREC provides eligible customers with financial assistance in the form of an 8% rebate of the pre-tax cost of their electricity. The OREC rebates are administered by LDC and paid by the IESO in the month following customer billing. Current accounts receivable and unbilled revenue include the amount owing by the IESO to LDC. No effect on revenue or expense is recognized by LDC in respect of the OREC rebates.

OFHP also includes the OFHA, which enacted the Ontario Fair Hydro Plan Act, 2017 and amended the Electricity Act, 1998 and the Ontario Energy Board Act, 1998. The OFHA came into effect on June 1, 2017 and its impact is reflected in the Consolidated Financial Statements. The OFHA provides eligible customers with financial assistance through various changes to commodity pricing, new or amended programs, and eliminating or reducing certain provincial charges on the electricity bill. The OFHP reduces electricity bills by 25% on average for eligible customers, which includes the 8% OREC rebate. The OFHA reduces the total electricity bill for eligible customers and, accordingly, reduces current accounts receivable, unbilled revenue, accounts payable and accrued liabilities for LDC. No effect on distribution revenue or expense is recognized by LDC in respect of the OFHA.

5.4 Conservation and Demand Management

The objective of the CDM programs is to reduce electricity consumption in the Province of Ontario by a total of 7 terawatt hours between January 1, 2015 and December 31, 2020, of which LDC's share is approximately 1,576 GWh of energy savings.

Under the energy conservation agreement with the IESO, LDC has a joint CDM plan with Oakville Hydro for the delivery of CDM programs over the 2015-2020 period. The IESO reimburses LDC for all adequately documented incurred costs, with an option to receive a portion of its funding in advance. Cost efficiency incentives may be awarded if LDC's electricity savings meet or exceed certain CDM plan targets for programs under the full cost recovery funding method, including a mid-term incentive based on a review of the 2015-2017 period.

The joint CDM plan provides combined funding of approximately $421.0 million, including participant incentives and program administration costs, with an energy savings target of approximately 1,648 GWh. The program for Oakville Hydro under the joint CDM plan started on January 1, 2016. LDC received $162.4 million from the IESO as at December 31, 2018 to deliver the CDM programs. Amounts received but not yet spent are presented on the consolidated balance sheets under current liabilities as deferred conservation credit. On September 26, 2018, $15.8 million was confirmed by the IESO as the joint mid-term incentive, of which $14.9 million representing LDC's portion was received in November 2018.

PART 6 - RELATIONSHIP WITH THE CITY

6.1 Shareholder Direction

As sole shareholder of the Corporation, the City has adopted the Shareholder Direction that sets out the following corporate governance principles with respect to Toronto Hydro:

- the objectives and principles that govern the operations of Toronto Hydro;
- the matters in addition to those set out in the OBCA that require the approval of the City as the sole shareholder of the Corporation; and
- certain financial and administrative arrangements between the Corporation and the City.

The Shareholder Direction requires Toronto Hydro to conduct its affairs and govern its operations in accordance with such rules, policies, directives or objectives as directed by City Council from time to time.

(a) Shareholder Objectives and Principles

The Shareholder Direction provides that the following objectives and principles shall govern the operations of Toronto Hydro:

- to operate Toronto Hydro on an efficient and commercially prudent basis;
- to optimize the City's return on equity as the sole shareholder of the Corporation and operate Toronto Hydro with a view to meeting the financial performance objectives of the City as set out in the Shareholder Direction;
- to provide a reliable, effective and efficient electricity distribution system that supports the electricity demands of residents and businesses in the City;
- to operate Toronto Hydro in an environmentally responsible manner consistent with the City's energy, climate change and urban forestry objectives and, as appropriate, utilizing emerging green technologies;
- to ensure that the business is managed in material compliance with all law; and
- to engage in recruitment and procurement practices designed to attract employees and suppliers from the City's diverse community.

The Shareholder Direction provides that the Board is responsible for determining and implementing the appropriate balance among these objectives and principles and for causing Toronto Hydro to conduct its affairs in accordance with the same.

(b) Shareholder Approval

In addition to those matters set out in the OBCA, the following matters, among others, require the approval of the City as the sole shareholder of the Corporation:

- subject to certain exceptions in the case of LDC, creating any security over the assets of the Corporation or LDC;
- in the case of LDC, providing any financial assistance to any person other than in accordance with the Shareholder Direction;
- in the case of the Corporation and LDC, making any investment in or providing any financial assistance to any subsidiary of the Corporation (other than LDC), other than trade payables incurred in the ordinary course of business on customary terms and an investment in or financial assistance to a subsidiary that originally was an investment in or financial assistance to LDC, in excess of 12% of the shareholder's equity of LDC as shown in its most recent financial statements; and
- acquiring any interest in the electricity distribution system, undertaking or securities of a distributor operating outside the City unless, among other things, the acquisition does not adversely affect the dividend payable to the City and there is no dilution of the City's shareholding in the Corporation.

The City has authorized the Corporation to provide financial assistance to its subsidiaries for the purpose of enabling them to carry on their respective businesses, including, in the case of LDC, for the purpose of satisfying the prudential requirements of the IESO. The Shareholder Direction limits the financial assistance that may be provided by the Corporation to its subsidiaries to an aggregate amount of $500.0 million, except in the case of LDC, which financial assistance is unlimited.

(c) Financial Performance

The Shareholder Direction provides that the Board will use its best efforts to ensure that Toronto Hydro meets certain financial performance standards, including those relating to the credit rating and dividends.

(d) Credit Rating

The Shareholder Direction provides that the Corporation will obtain and maintain a rating of A minus or higher (or its equivalent rating, depending on the credit rating agency) on its senior debt securities, as rated by two accredited credit rating agencies in Ontario (which include S&P, DBRS and Moody's). See section 9.4 under the heading "Credit Rating" for more information on the Corporation’s credit ratings as at December 31, 2018.

(e) Equity Contribution

In December 2016, City Council approved making an equity contribution to the Corporation. On June 28, 2017, the Corporation issued 200 common shares to the City for total proceeds of $250.0 million, net of share issue costs and expenses.

(f) Dividends

In connection with receipt of the equity contribution of $250.0 million from the City on June 28, 2017, the Board declared dividends payable to the City and approved amendments to the Corporation’s Dividend Policy, as follows:

- In respect of fiscal 2017, an aggregate amount of $75.0 million shall be paid to the City, consisting of two previously declared installments of $6.25 million each and a further $62.5 million. The $62.5 million was paid to the City on July 7, 2017.

- In respect of fiscal 2018 and subsequent fiscal years, 60% of the Corporation's consolidated net income after net movements in regulatory balances for the prior fiscal year shall be declared separately in four equal quarterly instalments, with each instalment payable to the City on the last business day of each fiscal quarter.

The revised Dividend Policy was set out in further detail, including that any dividends will be subject to restrictions imposed by law and the Shareholder Direction, in an amendment of the Shareholder Direction, which included the Corporation's former Dividend Policy. These changes also superseded the Board's previous decision announced in November 2016 that it would reduce dividend payments to the City to $25.0 million per year until further notice.

The Corporation declared and paid dividends to the City totalling $63.35 million in 2016, $75.0 million in 2017, and $93.9 million in 2018.

On March 6, 2019, the Board declared a quarterly dividend in the amount of $25.1 million, payable to the City by March 29, 2019.

LDC declared and paid $nil dividends to the Corporation in 2016, and declared and paid $2.1 million in 2017 and $42.7 million in 2018.

TH Energy declared and paid $nil dividends to the Corporation in 2016, 2017, and 2018.

6.2 Services Provided to the City

Toronto Hydro provides certain services to the City at commercial and regulated rates, including street lighting services. Ongoing street lighting services are provided by TH Energy and sub-contracted to LDC. See section 4.4 under the heading "Toronto Hydro Energy Services Inc." for more information. See note 22 to the Consolidated Financial Statements.

6.3 Shareholder Engagement

The Corporation believes that regular and constructive engagement with the City, its sole shareholder, is an important part of creating an open, candid and informed dialogue. In addition to the Corporation's annual shareholder meetings, representatives of the Corporation engage with the City through formal attendance at City of Toronto Council meetings and other engagements with Councillors throughout the year as required. Other means of communications with the City include the Corporation's annual and quarterly financial and management reports, and ward-specific updates.

PART 7- TAXATION

7.1 Tax Regime

The Corporation is exempt from tax under the ITA, if not less than 90% of the capital of the Corporation is owned by the City and not more than 10% of the income of the Corporation is derived from activities carried on outside the municipal geographical boundaries of the City. In addition, the Corporation's subsidiaries are also exempt from tax under the ITA provided that all of their capital is owned by the Corporation and not more than 10% of their respective income is from activities carried on outside the municipal geographical boundaries of the City. A corporation exempt from tax under the ITA is also exempt from tax under the TA.

The Corporation and each of its subsidiaries are MEUs for purposes of the PILs regime contained in the Electricity Act. The Electricity Act provides that a MEU that is exempt from tax under the ITA and the TA is required to make, for each taxation year, a PILs payment to the OEFC in an amount equal to the tax that it would be liable to pay under the ITA and the TA if it were not exempt from tax. The PILs regime came into effect on October 1, 2001, at which time the Corporation and each of its subsidiaries were deemed to have commenced a new taxation year for purposes of determining their respective liabilities for PILs payments.

If the Corporation or a subsidiary ceases to be exempt from tax under the ITA and the TA, it will become subject to tax under those statutes, will no longer be required to make PILs payments to the OEFC, and will be deemed to have

disposed of its assets for proceeds of disposition equal to their fair market value at that time and to have reacquired its assets at the same amount with the result that:

- such corporation would become liable to make a PILs payment in respect of any income or gains arising as a result of these deemed dispositions; and
- the amount of annual taxes payable by the corporation under the ITA, and the TA may be different from the PILs payment that would be payable without a loss of tax-exempt status to reflect, among other things, the consequences of these deemed dispositions and acquisitions.

The Electricity Act also provides that a municipal corporation or an MEU is required to pay a transfer tax when it transfers Electricity Property. An interest in Electricity Property includes any interest in a corporation, partnership or other entity that derives its value in whole or in part from Electricity Property. The transfer tax is the prescribed percentage (22% for transfers occurring between January 1, 2016 and December 31, 2018, and 33% for transfers occurring thereafter) of the fair market value of the interest transferred. The amount of transfer tax payable where the interest that is transferred is an interest in a corporation, partnership or other entity, is calculated in accordance with a special rule. The amount of transfer tax payable by an MEU on a transfer of Electricity Property may be reduced by:

- any PILs payment made by the MEU in respect of the part of the taxation year up to and including the date that the transfer takes place or a previous taxation year;
- any amount that the MEU has paid as tax under Part III of the TA in respect of the part of the taxation year up to and including the date of the transfer or a previous taxation year; and
- any amounts that the MEU would be liable to pay as tax under Part I of the ITA in respect of the taxation year if that tax were computed on the basis that the MEU had no income other than the capital gain realized on the transfer of its interest in the property.

Transfers of Electricity Property made to a MEU, Hydro One or OPG, or subsidiary of either of them and where the transferee is exempt from tax under the ITA at the time of transfer, the transfer will be an excluded transfer and thereby exempt from the transfer tax. Capital gains arising from a transfer of Electricity Property occurring between January 1, 2016 and December 31, 2018 are also exempt from the transfer tax.

In addition, a refund of transfer tax may be made where such tax had been paid on the sale or transfer of Electricity Property and where the proceeds of that transfer were reinvested in certain other capital or depreciable assets used in connection with generating, transmitting, distributing or retailing electricity in Ontario and, subject to certain deeming rules, before the end of the second taxation year following the taxation year in which the liability to pay the transfer tax arose.

PILs payments are deductible in computing the transfer tax only to the extent that they have not been previously applied to reduce transfer tax payable by a municipal corporation or a MEU.

7.2 PILs Recoveries through Rates

The OEB's Filing Requirements for Electricity Distribution Rate Applications provides for electricity distribution rate adjustments to permit recoveries relating to PILs payments. These recoveries are recalculated and submitted for recovery by LDC in each cost of service or rebasing distribution rate application. LDC is also generally at risk for variances between forecasted and actual PILs paid, excluding variances arising from changes in tax legislation not assumed in the setting of rates for the period in question, which variances are disposed of through deferral accounts under cost of service, IRM or CIR. See note 8(n) to the Consolidated Financial Statements.

PART 8 - RISK FACTORS

Risk Management

Toronto Hydro faces various risks that could impact the achievement of its strategic objectives. It adopts an enterprise wide approach to risk management, based on an overall enterprise risk philosophy, and achieved through a process of consolidating and aligning the various views of risk across the enterprise via a risk governance structure. Toronto Hydro's ERM framework utilizes industry best practices and international guidelines and focuses on identifying emerging trends in risks and related opportunities particular to Toronto Hydro through a comprehensive evaluation of Toronto Hydro's business and the industry generally. Toronto Hydro views ERM as a management activity undertaken to add value and improve overall operations. It helps Toronto Hydro by enabling the attainment of its strategic goals and objectives through a systematic, disciplined approach towards identifying, evaluating, treating, monitoring and reporting of risks. Risk assessment is built into our decision-making process at all levels. Accordingly, ERM is an integral part of the strategic management of Toronto Hydro and is routinely considered in forecasting, planning and executing all aspects of the business.

The ERM framework is operationalized by a consistent, disciplined methodology that clearly defines the risk management process which incorporates subjective elements, risk quantification, risk trends and risk interdependencies.

While Toronto Hydro's philosophy is that ERM is the responsibility of all business units at all levels, in strategic and functional matters, the ERM governance structure is comprised of three key levels.

At the first level is the Board, which maintains a general understanding of Toronto Hydro's risk profile, the risk categories and the types of risks to which Toronto Hydro may be exposed, and the practices used to identify, assess, measure and manage those risks. The risk profile is a list of key risks that may impede the Corporation from achieving certain or all of its strategic objectives, and which are most material to its operational success.

The second level is the executive team, which ensures systems are in place to identify, manage, and monitor risks and trends. Through input from the business and other considerations, the executive team assesses the appropriateness and consistent application of systems to manage risks within Toronto Hydro. The executive team also ensures that key risks are brought forward to the attention of the Board for discussion and action, as required.

Finally, the third level is the senior leadership team. The senior leadership team supports the executive team and is a collection of subject matter experts from across Toronto Hydro who actively engage in the day-to-day management of risks. Working with the executive team, this group oversees Toronto Hydro's risk profile and its performance against the defined risk philosophy. The senior leadership team understands changes in risk status and trends and determines appropriate risk responses and action plans. They also work to ensure effective, efficient, complete and transparent risk reporting to the executive team.

Toronto Hydro is continually reviewing its ERM program to ensure the organization is focused upon and responsive to risks of the greatest significance, likelihood and impact. In 2018, Toronto Hydro re-oriented its program to the key strategic and functional risk categories facing the organization, and the sub-component risks making up those categories. This allows Toronto Hydro's executive leadership and responsible business units to concentrate on these risks and undertake deeper dives into root causes and risk trends in these areas on both a short-interval and long-term basis. By focusing in particular on the strategic risks to the organization, decision-making is strengthened and Toronto Hydro has a greater ability to realise opportunities central to its interests.

Toronto Hydro's business is subject to a variety of risks including those key risk areas and major component risks described in the following sections. There can be no assurance that any steps Toronto Hydro may take to manage risks will avoid future loss resulting from the occurrence of such risks.

Strategic Risks

Oversight Risk

Risk that provincial government or regulator activity (laws, frameworks or policies) impedes the Corporation's effective performance, and its ability to meet its objectives and serve its customers.

Regulatory and Energy Policy Risk

Toronto Hydro is subject to the risk that its business activities may be impeded through the actions of regulatory authorities or by changes in regulation. There is a risk that future changes to Ontario's regulatory model, manner of regulation, and/or broader energy policy framework does not align with Toronto Hydro's business direction and could materially adversely affect the Corporation's strategic goals and financial results.

Ontario's electricity industry regulatory and other energy policy developments may affect the electricity distribution rates charged by LDC and the costs LDC is permitted to recover. This may in turn have a material adverse effect on the financial performance of the Corporation and/or LDC's ability to deliver effective and efficient operations and reliable service to its customers, and as well as create barriers to LDC achieving its strategic objectives. Among other things, there can be no assurance that:

- the OEB will approve LDC's electricity distribution rates at levels that will permit LDC to maintain safe and reliable service to its customers and earn the allowed rate of return on the investment in the business;
- the OEB will approve and permit recovery through rates of past and future expenditures incurred by LDC in providing distribution services to customers, in a timely manner or at all;
- the OEB will adopt the other rate-setting principles, formulae, and inputs in a manner that result in rates that properly support LDC's activities;
- the regulatory instruments that are made available to LDC will be sufficient to address LDC's operations, needs and circumstances in respect of future applications for electricity distribution rates; and
- the OEB will not permit other parties to provide distribution services in LDC's licensed area, or permit loads within LDC's service area to become electrically served by a means other than through LDC's electricity distribution system.

Any future regulatory decision to disallow or limit the recovery of costs could lead to potential asset impairment and charges to results from operations, which could have a material adverse effect on Toronto Hydro.

LDC actively participates in industry engagement efforts in order to mitigate the above risks and realize potential opportunities in regulatory and energy policy development. Through these types of engagements, the Corporation monitors proposed regulatory and energy policy changes that may impede its business. LDC also employs a comprehensive organizational regulatory application program to ensure that all applications to the OEB achieve the highest utility standard of evidence gathering, preparation and presentation.

Emerging Government Policy Risk

Toronto Hydro is subject to the risk that the policy priorities of provincial and federal governments and regulatory bodies beyond those specifically applicable to the energy space, including policies of more general application, and the implementation of policies by such bodies, may impact Toronto Hydro's ability to deliver effective and efficient operations, meet business objectives, report on its activities and capitalize upon new opportunities. Developments and changes in any of the laws, rules, regulations and policies applicable to the businesses carried on by Toronto Hydro, and the manner of implementation and application of the same, could materially adversely affect Toronto Hydro. This may include developments with respect to labour and employment laws, changes to accounting standards and financial reporting requirements, environmental obligations and public safety rules, among others. The

Corporation actively engages with government entities and participates in industry organizations to monitor emerging policies and where possible plays an advocacy role.

Franchise Risk

Risk that restrictions in LDC's business model and/or external conditions impede its ability to maintain and grow its right to be the sole provider of electricity distribution services in the City (its franchise) and serve its customers. Toronto Hydro is subject to the risk that it is displaced from its strategic position or fails to gain a strategic advantage, which could materially adversely affect the Corporation's strategic goals and financial results.

The OEB has the authority to grant municipal distribution licences, has issued to LDC a licence stipulating a service area that reflects the territory within the City, and has not granted any other distribution licence that permits distribution within LDC's service area. In addition, there is a legal framework in place that establishes LDC, as the holder of the municipal distribution licence in the City, to be the sole provider of distribution activities across municipal rights of way. There is no assurance that these frameworks will continue to exist sufficiently or at all in order to provide LDC the opportunity to be the comprehensive distribution provider in the City.

While other regulated and unregulated entities have always competed with LDC and its predecessors to provide customers with other sources of energy, including electricity, the pervasiveness of this competition and its effects on LDC's distribution business have varied over time and continue to vary based on many factors, including the relative price of energy source (e.g., natural gas, grid-supplied electricity, behind-the-meter generation), technology development (e.g. energy storage), government-based incentives, regulatory frameworks, and compliance frameworks especially for non-utility entities.

There can be no assurance that the future nature, prevalence, or effects of these forms of competition will be comparable to current or historic experience. Failure to effectively scan our external and internal environment could lead to missed business opportunities and loss of competitive advantage.

Risks to Toronto Hydro's franchise interests may also result from impairment to Toronto Hydro's image in the community, public confidence or brand. Toronto Hydro is committed to delivering safe and reliable electricity to its customers in an environmentally responsible manner at optimal costs. Negative perceptions regarding this commitment could impact the public's perception of Toronto Hydro. In addition, events and/or external factors that draw negative media attention to Toronto Hydro could cause reputational damages and impact Toronto Hydro's business and relationship with its stakeholders. These factors could lead customers, governments and regulators to look more favourably to alternative services and service providers to utility-based electricity distribution.

Toronto Hydro has dedicated personnel focused on monitoring external competitive factors, including alternative service providers and technologies, and developing strategies for further enhancing the LDC's interactive grid which support the reliability of its core infrastructure grid operations, promote greater value, and deliver solutions for its customers. Additionally, Toronto Hydro maintains relationships with its customers to better understand the specific needs and expectations of each class of customer. The Corporation also conducts customer research and consultations in the ordinary course of its operations, and as part of the development of its rate application whereby it directly considered customer preferences and feedback, in addition to other inputs, as part of developing its business plan. Toronto Hydro also has dedicated personnel focused on the utility's key account customers, which respond to issues raised by large commercial and industrial customers and assists with their energy management needs. Through these types of engagements, the Corporation can monitor its customers' specific needs and can work with them to develop energy solutions.

Governance Risk

Risk that municipal activity (laws, policies, or intervention) impedes the Corporation's effective performance, and ability to meet its objectives and serve its customers.

The Corporation is a government-controlled enterprise whose sole shareholder is the City. The operations of the Corporation and its subsidiaries are influenced by the broad by-law enactment and enforcement powers of the City. Additionally, as the Corporation's sole shareholder, the City has set out the governing objectives and principles, including financial objectives, for the Corporation through the Shareholder Direction, as described above. Under the Shareholder Direction, the City has the power to direct the Corporation and its subsidiaries to conduct their affairs and govern their operations in accordance with such rules, policies, directives or objectives as are directed by City Council from time to time. Certain conflicts may arise where the City's goals and objectives in implementing such rules, policies, directives or objectives differ from the Shareholder Direction principles and could materially adversely affect the Corporation's business, operations, financial condition or prospects.

The Corporation engages on a systematic basis with the City Mayor, City Councillors, the City Manager's office, and other departments and agencies to ensure a sharing of perspectives on the vital interests of Toronto Hydro and its customers. Through such engagements the parties review and consider the challenges to Toronto Hydro achieving the objectives and principles set out under the Shareholder Direction, and in particular the impact that proposed changes in city by-laws or municipal policies may create for Toronto Hydro's ability to meet its business objectives and serve its customers.

Functional Risks

Human Capital Risk

Risk that the Corporation is unable to maintain necessary resource talent and skilled resources.

Toronto Hydro is subject to the risk that human resources may not be available with the necessary knowledge, skills and education to support Toronto Hydro's future talent requirements. All retirements pose risks for knowledge management and business continuity at Toronto Hydro. Development and retention of talent to meet the evolving needs of the business requires LDC to focus on a series of proactive activities and programs to mitigate these risks, such as strategic workforce planning, promotion of apprenticeship programs, investments in colleges and universities, succession planning, knowledge transfer and a robust training program.

Toronto Hydro's ability to operate successfully in the electricity industry in Ontario will continue to depend in part on its ability to make changes to existing work processes and conditions in order to adapt to changing circumstances. Toronto Hydro's ability to make such changes, in turn, will continue to depend in part on its relationship with its labour unions, including negotiating collective bargaining agreements with the Society of United Professionals and PWU. There can be no assurance that Toronto Hydro will be able to secure the support of its labour unions.

Toronto Hydro's ability to develop its work processes to meet changing circumstances also depends on its ability to access adequate resources from its external contractor community. One way in which Toronto Hydro seeks to mitigate this risk is through its use of business practices and internal procedures to identify a diverse group of reputable third party service providers and entering into contracts with, and monitoring the performance of, these third-party service providers.

Operations Risk

Risk that the Corporation is not able to effectively meet the needs of its customers and a growing city, and maintain the security and reliability of the grid at acceptable levels.

Asset Management Risk

Toronto Hydro is subject to the risk that it may be unable to maintain continuous supply due to failure of the distribution infrastructure and assets which could materially adversely affect the Corporation. Electricity distribution

is a capital-intensive business. As the municipal electricity distribution company serving the largest city in Canada, LDC continues to invest in the renewal of existing aging infrastructure and in the development of new infrastructure (such as the Copeland Station project) to address safety, reliability and customer service requirements now and in the future.

LDC estimates that approximately 33% of its electricity distribution assets have already exceeded or will reach the end of their expected useful lives by 2025. Asset condition assessment demographics also indicate substantial asset investment needs for a number of critical assets during this period. At the same time, Toronto is a growing city, and LDC must make upgrades to keep pace with urban intensification and electrification and ensure good stewardship of the distribution system. Further, extreme weather is no longer an infrequent experience, and has instead become a regular condition of operating a distribution system. For example, Toronto Hydro experienced four extreme weather events in the first half of 2018, leaving nearly 160,000 customers without electricity. In addition, as the City, Ontario and the Government of Canada implement policies and programs to respond to climate change, and adoption of electric vehicles and fuel-switching potentially increases, the pressures on Toronto Hydro's system will only increase, and such factors may drive a need for incremental capital expenditures for system upgrades so that the grid can handle increased loads.

LDC's ability to continue to provide a safe work environment for its employees and a reliable and safe distribution service to its customers and the general public will depend on, among other things, the ability of Toronto Hydro to fund additional infrastructure investments, and the OEB allowing recovery of costs in respect of LDC's maintenance program and capital expenditure requirements for distribution plant refurbishment and replacement.

As described in section 4.3(a)(iii) under the heading "Transmission System Terminal Stations", one of LDC's largest capital initiatives currently in progress is the construction of Copeland Station, which is also one of the most complex projects ever undertaken by Toronto Hydro. The expected completion date for the Copeland Station is in the first half of 2019. The total capital expenditures required to complete the project has increased from $200.0 million to approximately $204.0 million, plus capitalized borrowing costs. The increase in costs and delay in completion date are attributable to a variety of factors, including contractor performance and construction delays. There may be additional unforeseen delays and expenditures prior to the completion of the project. On January 25, 2018, Toronto Hydro was informed that Carillion Construction Inc., the general contractor for the Copeland Station Project, filed for creditor protection under the Companies' Creditors Arrangement Act after its affiliate, Carillion plc, went into compulsory liquidation in the United Kingdom. Other contractors have taken on part of the remaining work to contribute to the completion of the project. All capital projects for new and replacement infrastructure have risks related to delays or increased costs due to many factors, including: necessary modifications to project plans; the availability, scheduling and cost of materials, equipment and qualified personnel; LDC's ability to obtain necessary environmental and other regulatory and government approvals; and the impact of weather conditions, site conditions and contractor performance.

LDC is focused on overcoming the above challenges and executing its capital and maintenance programs. It uses a variety of asset and project management tools to implement its plans, measures progress on a recurring short interval basis, and regularly monitors and manages the health of its assets. However, if LDC is unable to carry out these plans in a timely and optimal manner or becomes subject to significant unforeseen equipment failures, equipment performance will degrade. Such degradation may compromise the reliability of distribution assets, the ability to deliver sufficient electricity and/or customer supply security and increase the costs of operating and maintaining these assets.

Toronto Hydro's ability to operate effectively is also in part dependent on the development, maintenance and management of complex information technology systems. Computer systems are employed to operate LDC's electricity distribution system, and Toronto Hydro's financial, billing and business systems to capture data and to produce timely and accurate information. Specifically, on October 1, 2018, the Corporation successfully completed the implementation of, and transitioned to, a new ERP system. The ERP system is being used to operate the Corporation's financial, and business systems to capture data and to produce timely and accurate information. Failure of the newly implemented ERP system could have a material adverse effect on the Corporation's business, operations, financial condition or prospects. The Corporation has mitigation strategies, access to consultants with ERP expertise and is developing an internal ERP centre of excellence to help assist in the implementation, and support of ERP for users. Additionally, in respect of Toronto Hydro's operational technology systems in general, there is isolation from business systems and independent operation which mitigates against wider systemic risk to the business systems.

Security Risk

Toronto Hydro is subject to the risk that it may be unable to preserve the confidentiality, integrity, authenticity, availability, accountability and non-repudiation of information assets.

LDC's electricity distribution infrastructure and technology systems are potentially vulnerable to damage or interruption from cyber-attacks, breaches or other compromises, which could result in business interruption, service disruptions, theft of intellectual property and confidential information (about customers, suppliers, counterparties and employees), additional regulatory scrutiny, litigation and reputational damage. Toronto Hydro has implemented security controls aligned with industry best practices and standards including the National Institute of Standards and Technology Cybersecurity Framework and the OEB's Ontario Cyber Security Framework, and maintains cyber insurance. Cyber-attacks, breaches or other compromises of electricity distribution infrastructure and technology systems could result in service disruptions and system failures, including as a result of a failure to provide electricity to customers, property damage, corruption or unavailability of critical data or confidential employee or customer information. A significant breach could materially adversely affect the financial performance of the Corporation or its reputation and standing with customers, regulators and in the financial markets. It could also expose Toronto Hydro to third-party claims.

LDC must also comply with legislative and licence requirements relating to the collection, use and disclosure of personal information (including the personal information of customers), as well as information provided by suppliers, contractors, employees, counterparties, and others. Such information could be exposed in the event of a cybersecurity incident or other unauthorized access, which could materially adversely affect Toronto Hydro and also result in third-party claims against Toronto Hydro.

Preventative controls are employed to protect information and technology assets against cyber-attacks and mitigate their effects. Detective controls are employed to continuously monitor information systems so that Toronto Hydro can respond appropriately to minimize the damage in the event of a cyber-attack. Even with these measures in place, since the techniques used to obtain unauthorized access, disable or degrade service, or sabotage systems change frequently and often are not recognized until launched against a target, Toronto Hydro may be unable to anticipate these techniques or to implement adequate preventative measures. As such, there can be no assurance that such measures will be effective in protecting LDC's electricity distribution infrastructure or assets, or the personal information of its customers, from a cyber-attack or the effects therefrom.

Toronto Hydro is subject to the risk of external threats to its physical and perimeter security. This includes the security of the Corporation's facilities including office buildings and distribution stations. In order to safeguard its assets and staff, the Corporation has developed policies and guidelines around physical and perimeter security and facilities related emergency preparedness. The Corporation has also implemented electronic security technologies to ensure that only authorized personnel have access to Toronto Hydro facilities.

Business Interruption Risk

Toronto Hydro is subject to the risk that it may be unable to maintain continuing and sustainable business operations, or recover from business interruption, in an effective manner. Toronto Hydro's operations are exposed to the effects of natural and other unexpected occurrences such as extreme storm and other weather conditions and natural disasters, as well as terrorism and pandemics. The Corporation has implemented various initiatives aimed at improving the system's resiliency to increasingly frequent extreme weather events caused by climate change. These initiatives include updating major equipment specifications, revising planning guidelines, investigating the load forecast impact, revising design practices, and enhancing maintenance programs. The Corporation has also implemented a Grid Emergency Management (GEM) program to prepare for and respond to major power outage events and has incorporated recommendations from the independent review panel of experts formed to review Toronto Hydro's response to the 2013 Ice Storm that affected Toronto. Although Toronto Hydro's facilities and operations are constructed, operated and maintained to withstand such occurrences, there can be no assurance that they will successfully do so in all circumstances. Any major damage to Toronto Hydro's facilities or interruption of Toronto Hydro's operations arising from these occurrences could result in lost revenues and repair costs that can be substantial. Although Toronto Hydro has insurance which it considers to be consistent with industry practice, if it sustained a large uninsured loss caused by natural or other unexpected occurrences, LDC may apply to the OEB for the recovery

of the loss related to the electricity distribution system. There can be no assurance that the OEB would approve, in whole or in part, such an application.

Safety Risk

Risk to Toronto Hydro employees or the general public of serious/fatal injuries and illnesses relating to or impacting upon Toronto Hydro activities.

Occupational Health and Safety Risk

Toronto Hydro is subject to the risk that employees may be exposed to serious or fatal injuries or illness as a result of the work environment in which they operate. Due to the nature of Toronto Hydro's business and business activities, occupational safety is an integral part of our corporate culture. Employees could be exposed to hazards when performing their work duties. This includes hazards such as electrical contact, working in confined spaces, fires and explosions, slips, trips and falls and motor vehicle accidents. Toronto Hydro is subject to compliance with provincial Health and Safety legislation. Toronto Hydro's management approach to occupational safety is to meet or excel on legal compliance and eliminate or safeguard known occupational hazards and risks. The Corporation also uses an IRS (Internal Responsibility System) to clearly define responsibility and accountability for safety at each level within the organization. There are processes in place to develop and nurture good leadership practices through recruitment, education, training and performance management practices that encourage the application of our corporate values, including safety. LDC received OHSAS 18001 certification in 2013 and conducts annual third party audits to maintain certification, in addition occupational health and safety legal compliance audits are conducted every two years.

Public Safety Risk

Due to the nature of the Corporation's business of operating and maintaining its distribution system, Toronto Hydro is subject to the risk of public injuries or fatalities. Toronto Hydro mitigates risks to public safety through equipment inspection, replacement and maintenance, employee training, communications programs and reactive and emergency work. Toronto Hydro also has developed specific construction standards and design practices and new products for use in the distribution system go through a thorough review and introduction process. The selection process for new products and the development of standards promotes customer health and safety.

Financial Risk

Risk that the Corporation is unable to maintain its financial health and performance at acceptable levels.

Market and Credit Risk

Toronto Hydro is directly and indirectly subject to various market and credit fluctuations which could materially adversely affect the Corporation. For example, LDC is exposed to credit risk with respect to customer non-payment of electricity bills. LDC is permitted, at certain times of the year, to mitigate the risk of customer non-payment using any means permitted by law, including security deposits (i.e. letters of credit, surety bonds, cash deposits or lock-box arrangements, under terms prescribed by the OEB), late payment penalties, pre-payment, pre-authorized payment, load limiters or disconnection. While LDC would be liable for the full amount of the default, there can be no assurance that the OEB would allow recovery of the bad debt expense. Established practice in such cases is that the OEB would examine any electricity distributor's application for recovery of extraordinary bad debt expenses on a case-by-case basis. LDC's security interest or other measures, if any, may also not provide sufficient protection. Additionally, security interests and other measures taken by, or in favour of, LDC, if any, may not provide sufficient protection.

Toronto Hydro is exposed to fluctuations in interest rates for the valuation of its post-employment benefit obligations. Toronto Hydro estimates that a 1% (100 basis point) increase in the discount rate used to value these obligations would decrease the accrued benefit obligation of Toronto Hydro, as at December 31, 2018, by $41.3 million, and a 1% (100 basis point) decrease in the discount rate would increase the accrued benefit obligation, as at December 31, 2018, by $53.1 million.

The Corporation is exposed to short-term interest rate risk on the short-term borrowings under its CP Program and Working Capital Facility, and customer deposits, while most of its remaining obligations were either non-interest

bearing or bear fixed interest rates, and its financial assets were predominately short-term in nature and mostly non-interest bearing. Toronto Hydro manages interest rate risk by monitoring its mix of fixed and floating rate instruments, and taking action as necessary to maintain an appropriate balance. Toronto Hydro estimates that a 100 basis point increase (decrease) in short-term interest rates, with all other variables held constant, would result in an increase (decrease) of approximately $2.1 million to annual finance costs.

Toronto Hydro had limited exposure to the changing values of foreign currencies. While Toronto Hydro purchases goods and services which are payable in US dollars, and purchases US currency to meet the related commitments when required, the impact of these transactions as at December 31, 2018 was not material.

Capital Structure Risk

Toronto Hydro is subject to the risk that it may not be able to optimize its debt to equity ratio or access capital markets at effective rates. There can be no assurance that debt or equity financing will be available or sufficient to meet the Corporation's requirements, objectives, or strategic opportunities. If and when financing is available, there can be no assurance that it will be on acceptable terms to the Corporation.

The Corporation relies on debt financing through its MTN Program, CP Program or existing credit facilities to finance Toronto Hydro's daily operations, repay existing indebtedness, and fund capital expenditures. The Corporation's ability to arrange sufficient and cost-effective debt financing could be materially adversely affected by a number of factors, including financial market conditions and activity in the global capital markets, the regulatory environment in Ontario, the Corporation's business, operations, financial condition or prospects, compliance with covenants, the ratings assigned to the Corporation or the debentures issued under the Corporation's MTN Program by credit rating agencies, the rating assigned to short-term borrowings under the CP Program by a credit rating agency, and the availability of the commercial paper market. In the event the Corporation is unable to maintain an R-1 (low) credit rating for its CP Program, the Corporation has sufficient liquidity through its Revolving Credit Facility to repay its commercial paper obligations as they become due. The Corporation's only source of external equity financing is its existing shareholder, the City of Toronto.

The Corporation regularly reviews the external market environment and has regular engagements with its credit rating agencies, securities dealers and investor community to monitor capital structure risk.

Compliance Risk

Risk that the Corporation does not meet its material compliance obligations under legal and regulatory instruments.

Toronto Hydro is committed to complying with applicable legal and regulatory requirements and other requirements to which the organization subscribes. The Corporation has a Corporate Compliance program that strengthens the organization's culture of compliance and provides reasonable assurance, to Toronto Hydro's senior leadership and the Corporation's Board of Directors, of adherence with material compliance requirements. There can be no assurance that Toronto Hydro will comply with applicable future laws, rules, regulations and policies. Failure by Toronto Hydro to comply with applicable laws, rules, regulations and policies may subject Toronto Hydro to civil or regulatory proceedings that could have a material adverse effect on Toronto Hydro. The OEB may not allow recovery in rates for the costs of coming into or maintaining compliance with these laws, rules, regulations and policies.

PART 9 - CAPITAL STRUCTURE

9.1 Share Capital

The authorized capital of the Corporation consists of an unlimited number of common shares without par value, of which 1,200 common shares are issued and outstanding as at the date of this AIF.

The City is the sole shareholder of the Corporation. See note 16 to the Consolidated Financial Statements.

9.2 Debentures

As at December 31, 2018, the Corporation had the following debentures (the "Debentures") outstanding, which have been issued pursuant to its MTN Program:

- $250.0 million of 4.49% Series 3 senior unsecured debentures, due November 12, 2019;
- $200.0 million of 5.54% Series 6 senior unsecured debentures due May 21, 2040;
- $300.0 million of 3.54% Series 7 senior unsecured debentures, due November 18, 2021;
- $250.0 million of 2.91% Series 8 senior unsecured debentures due April 10, 2023;
- $245.0 million of 3.96% Series 9 senior unsecured debentures due April 9, 2063;
- $200.0 million of 4.08% Series 10 senior unsecured debentures due September 16, 2044;
- $200.0 million of 3.55% Series 11 senior unsecured debentures due July 28, 2045;
- $200.0 million of 2.52% Series 12 senior unsecured debentures due August 25, 2026; and
- $200.0 million of 3.485% Series 13 senior unsecured debentures due February 28, 2048.

The Debentures are not listed, posted for trading or quoted on any stock exchange or quotation system.

The Debentures have been issued under the CDSX book entry system administered by CDS Clearing and Depository Services Inc. ("CDS") with BNY Trust Company of Canada as trustee. Accordingly, a nominee of CDS is the registered holder of the Debentures and beneficial ownership of the Debentures is evidenced through book entry credits to securities accounts of CDS participants (e.g., banks, trust companies and securities dealers), who act as agents on behalf of beneficial owners who are their customers, rather than by physical certificates representing the Debentures.

9.3 Credit Facilities

The Corporation has a Revolving Credit Facility, pursuant to which it may borrow up to $800.0 million, of which up to $210.0 million is available in the form of letters of credit. On July 30, 2015, the borrowing capacity under the Revolving Credit Facility was increased by $100.0 million from $700.0 million to $800.0 million and the maturity date extended by one year from October 10, 2019 to October 10, 2020. On August 19, 2016, the maturity date was extended by an additional year to October 10, 2021. On August 1, 2017, the maturity date of the Revolving Credit Facility was extended by one year from October 10, 2021 to October 10, 2022. On August 23, 2018, the maturity date of the Revolving Credit Facility was extended by one year from October 10, 2022 to October 10, 2023. Borrowings under the Revolving Credit Facility bear interest at fluctuating rates plus an applicable margin based on the Corporation's credit rating.

The Revolving Credit Facility contains certain covenants, the most significant of which is a requirement that the Corporation's debt to capitalization ratio not exceed 75%. As at December 31, 2018, the Corporation was in compliance with all covenants included in its Revolving Credit Facility agreement.

The Corporation has a CP Program allowing up to $600.0 million of unsecured short-term promissory notes to be issued in various maturities of no more than one year. On July 30, 2015, the amount the Corporation may issue under this program was increased by $100.0 million from $500.0 million to $600.0 million. The CP Program is backstopped by the Revolving Credit Facility; hence, available borrowing under the Revolving Credit Facility is reduced by the amount of commercial paper outstanding at any point in time. Proceeds from the CP Program are used for general corporate purposes. Borrowings under the CP Program bear interest based on the prevailing market conditions at the time of issuance.

Additionally, the Corporation has a Prudential Facility and a Working Capital Facility. The available amount under the Revolving Credit Facility as well as outstanding borrowings under the Revolving Credit Facility and CP Program are as follows:

	Revolving Credit Facility Limit	Revolving Credit Facility Borrowings	Commercial Paper Outstanding	Revolving Credit Facility Availability
December 31, 2018.	$800.0 million	-	$113.0 million	$687.0 million
December 31, 2017.	$800.0 million	-	$159.0 million	$641.0 million

For the year ended December 31, 2018, the average aggregate outstanding borrowings under the Corporation's Revolving Credit Facility, Working Capital Facility and CP Program were $239.6 million with a weighted average interest rate of 1.68%.

As at December 31, 2018, $12.6 million had been drawn under the Working Capital Facility and $33.3 million of letters of credit had been issued against the Prudential Facility.

9.4 Credit Rating

As at December 31, 2018, the credit ratings of the Corporation were as follows:

	DBRS		S&P	
	Credit Rating	**Trend**	**Credit Rating**	**Outlook**
Issuer rating	A	Stable	A	Stable
Debentures	A	Stable	A	-
Commercial paper	R-1 (low)	Stable	-	-

DBRS rates long-term debt instruments by rating categories ranging from a high of "AAA" to a low of "D". All rating categories other than AAA and D also contain the subcategories "(high)" and "(low)" to indicate relative standing within the major rating categories. The absence of either a "(high)" or "(low)" designation indicates the rating is in the middle of the category. An A rating is the third highest of the ten rating categories. Long-term debt instruments which are rated in the "A" category by DBRS are considered to be of good credit quality, with substantial capacity for the payment of financial obligations. Entities in the "A" category, however, may be vulnerable to future events, but qualifying negative factors are considered manageable.

DBRS rates short-term debt instruments by rating categories ranging from a high of "R-1 (high)" to a low of "D". An R-1 (low) rating is the third highest of the ten rating categories. Short-term debt instruments which are rated in the "R-1 (low)" category by DBRS are considered to be of good credit quality, with substantial capacity for the payment of financial obligations. Entities in the "R-1 (low)" category, however, may be vulnerable to future events, but qualifying negative factors are considered manageable.

S&P rates long-term debt instruments by rating categories ranging from a high of "AAA" to a low of "D". Ratings from "AA" to "CCC" may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories. An A rating is the third highest of the ten rating categories. Long-term debt instruments which are rated in the "A" category by S&P are considered somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher-rated categories; however, the obligor's capacity to meet its financial commitment on the obligation is still strong.

Credit ratings are intended to provide investors with an independent measure of the credit quality of an issue of securities. A rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the rating agency.

For the years ended December 31, 2018 and 2017, payments were made to both DBRS and S&P for credit rating services only.

PART 10 - DIRECTORS AND OFFICERS

10.1 Nomination of Directors

As at the date of this AIF, the Board consists of eleven directors, all of whom are appointed by the sole shareholder of the Corporation, the City.

Pursuant to the Shareholder Direction, in electing directors to the Board, the City gives due regard to the qualifications of a candidate, including: experience or knowledge; commercial sensitivity and acumen; independence of judgment; and personal integrity. The City seeks candidates with experience and knowledge in: public utility commissions or boards of major corporations or other commercial enterprises; corporate finance; corporate governance; market development; large system operation and management; urban energy industries; and public policy issues and laws

relating to Toronto Hydro, the electricity industry, environmental matters, labour relations and occupational health and safety issues. Each citizen director is elected to serve for a term of up to two years or until his or her successor is appointed, and may be elected for a maximum of four consecutive terms for a maximum of eight consecutive years or such longer term until a successor is appointed. Each City Councillor director is elected to serve for two years or until his or her successor is elected. As at the date of this AIF, female directors constituted 36.4% (4 of 11) of the members of the Corporation's Board.

10.2 Committees of the Board of Directors

The Board had established three standing committees (Audit Committee, Corporate Governance and Nominating Committee, and Human Resources and Environment Committee) as shown in the following chart.



(a) Audit Committee

The Audit Committee is responsible for overseeing the adequacy and effectiveness of financial reporting, accounting systems, internal financial control structures and financial risk management systems. The Audit Committee reviews the Corporation's quarterly and annual financial statements as well as financial statements prepared in connection with the requirements of applicable regulatory authorities, reviews the audit plans of the external auditors, oversees the internal audit of the Corporation, reviews and makes recommendations to the Board with respect to the payment of dividends or distribution of capital by the Corporation, and recommends the external auditor to the Board for appointment by the Corporation's sole shareholder. See Part 11 under the heading "Audit Committee" below for further information on the Audit Committee.

(b) Corporate Governance and Nominating Committee

The Corporate Governance and Nominating Committee is responsible for considering and making recommendations to the Board with respect to matters relating to the corporate governance of Toronto Hydro, including board and committee composition and mandates, and guidelines for assessing the effectiveness of the Board and its committees and procedures to ensure that the Board functions independently from management.

As part of its governance function, the Corporate Governance and Nominating Committee reviews a skills matrix for all potential director candidates, which is then forwarded to the Corporation's sole shareholder by the Board. The Corporate Governance and Nominating Committee also nominates independent candidates for appointment to the Board of Directors of LDC for approval by the Corporation's Board of Directors as required by the Affiliate Relationships Code. The Corporate Governance and Nominating Committee reviews and approves all orientation and education materials and programs for new and current directors undertaken by management.

The Corporate Governance and Nominating Committee is comprised of Tamara Kronis (Chair), Brian Chu, Mary Ellen Richardson and Councillor Paul Ainslie. Ms. Kronis, Mr. Chu and Ms. Richardson are each independent within the meaning of applicable Canadian securities laws. Since the City is the sole shareholder of the Corporation, Councillor Ainslie is not independent within the meaning of applicable Canadian securities laws.

(c) Human Resources and Environment Committee

The Human Resources and Environment Committee is responsible for reviewing and assisting the Board in overseeing the recruitment and assessment of the CEO and the compensation of the CEO, reviewing and approving the compensation of the executive officers, reviewing and making recommendations to the Board concerning executive compensation disclosure under applicable securities laws, and reviewing and making recommendations to the Board regarding the compensation structure and benefit plans and programs of Toronto Hydro. The Human Resources and Environment Committee is also responsible for reviewing and approving the parameters of collective bargaining negotiations, the oversight of health and safety related matters and processes, and the oversight of environmental related matters and processes of Toronto Hydro. See section 12.1(a) under the heading "Human Resources and Environment Committee" for further information on the Human Resources and Environment Committee.

(d) Other Committees

In 2018, the Board of Directors established a Steering Committee, consisting of the Chair of the Board and the Chairs of the respective standing committees, to assist the Board and its standing committees in fulfilling their responsibilities by providing effective and timely guidance on emerging, time-sensitive, significant issues arising with respect to matters that overlap with the mandates of the standing Board committees. The Steering committee does not replace any of the functions of the Board or its standing committees unless otherwise expressly delegated by the Board from time to time. The role of the Steering Committee is to provide advice and recommendations to the respective Board committees(s) that will enable them to successfully carry out their responsibilities and ultimately properly advise and make recommendations to the Board.

Further, the Board of Directors may establish ad-hoc committees from time to time for a specific task or subject matter.

10.3 Directors

The following summaries set forth, for each of the directors of the Corporation, his or her name, province and country of residence, the date on which he or she became a director and the expiry date of his or her current term, his or her relevant education and experience, principal occupations within the five preceding years and board memberships with other reporting issuers. The following tables also summarize the attendance of individual directors at the Board and standing committee meetings held during 2018 and 2019 as of the date of this AIF.

David McFadden, Chair of the Board
Ontario, Canada

Director since:	December 10, 2015
Expiry of current term:	December 10, 2019, or effective date of appointment of a successor director

Mr. McFadden is a lawyer whose practice focused on the energy, infrastructure, financial services and aerospace industries. He was formerly Counsel at Gowling WLG, and a former member of the firm's Board of Trustees and Executive Committee. Mr. McFadden currently serves as Chair of the Board of Directors of 407 International Inc. and PCI Geomatics Inc. He also serves on the Board of Directors of Cricket Energy Holdings Inc. He is also a Vice-Chair of the Electricity Transformation Network of Ontario of the Independent Electricity System Operator and serves on the Advisory Board of the MaRS Advanced Energy Centre and on the Council for Clean & Reliable Electricity. Mr. McFadden was named the Energy Leader of the Year by the Ontario Energy Association in 2013. In the past, Mr. McFadden served as the Chair of the Board of Directors of the Ontario Energy Association. Mr. McFadden has also served as co-chair of the Electricity Transition Committee of the Ontario Government, and also served on the Ontario Government's Electricity Distribution Sector Review Panel and the Ontario Government's Electricity Conservation and Supply Task Force. Mr. McFadden has also been active in the higher education sector. He served as Chair of the Ontario Centres of Excellence from 2004-2010 and currently is a member of the Board of Governors of York University. Mr. McFadden holds a Bachelor of Laws at Osgoode Hall Law School and a Bachelor of Arts at the University of Toronto, and is a member of the Law Society of Ontario.

Mr. McFadden currently serves as Chair of the Board of Directors. He is also an *ex-officio* member of the Audit Committee, Human Resources and Environment Committee, and Corporate Governance and Nominating Committee.

Principal Occupation:
Corporate Director

Board/Committee Membership	**2018 Attendance**	
Board	5 of 5	100%
Other Committees[(1)]	1 of 1	100%
	2019 Attendance[(2)]	
Board	1 of 1	100%

Board Memberships for other Reporting Issuers:
407 International Inc.

Notes:

(1) Committees other than the three standing committees (Audit Committee, Corporate Governance and Nominating Committee, and Human Resources and Environment Committee).

(2) 2019 attendance is for the period of January 1, 2019 to the date of this AIF.

Brian Chu, Vice-Chair of the Board
Ontario, Canada

Director since:	December 10, 2015
Expiry of current term:	December 10, 2019, or effective date of appointment of a successor director

Mr. Chu is a founding partner of the law firm of Bogart Robertson & Chu LLP, whose practice focuses on corporate and commercial real estate law. Mr. Chu currently serves on the Board of Directors of the Technical Standards & Safety Authority and is a member of its Safety and Regulatory Affairs Committee. He also previously served as Trustee and Chair of the Centennial Centre of Science and Technology (Ontario Science Centre). He was formerly President of Laidlaw Foundation, Chair of the Board of Governors of Ontario College of Arts and Design, and Vice-Chair of Centennial College. Mr. Chu has been a member of the Canadian Tax Foundation since 1986. Mr. Chu holds a Juris Doctor from the University of Toronto and is a member of the Law Society of Ontario. Mr. Chu has extensive experience in compensation practices and policies, including determining executive compensation and setting, as well as communicating and reviewing, chief executive officer performance objectives. In his role at the Ontario Science Centre, he was accountable to the Minister of Tourism, Culture and Sport on all matters related to the hiring and termination of the chief executive officer. Mr. Chu is also responsible for human resources matters, salary and compensation relating to all staff at Bogart Robertson & Chu LLP.

Mr. Chu currently serves as Vice-Chair of the Board of Directors, is the Chair of the Human Resources and Environment Committee and a member of the Corporate Governance and Nominating Committee. Mr. Chu also served as a director of the Corporation from August 1, 2005 to April 14, 2013, during which time he served as a member of the Audit Committee and the Corporate Governance Committee, the Chair of the Corporate Governance Committee (from August 25, 2005 to November 30, 2008) and the Chair of the Audit Committee (from December 1, 2008 to April 14, 2013).

Principal Occupation:
Partner at Bogart Robertson & Chu LLP

Board/Committee Membership	**2018 Attendance**	
Board	5 of 5	100%
Corporate Governance and Nominating Committee	4 of 4	100%
Human Resources and Environment Committee	4 of 4	100%
Other Committees[(1)]	1 of 1	100%
	2019 Attendance[(2)]	
Board	1 of 1	100%
Corporate Governance and Nominating Committee	1 of 1	100%
Human Resources and Environment Committee	1 of 1	100%

Board Memberships for other Reporting Issuers:
None

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Notes:

(1) Committees other than the three standing committees (Audit Committee, Corporate Governance and Nominating Committee, and Human Resources and Environment Committee).

(2) 2019 attendance is for the period of January 1, 2019 to the date of this AIF.

Heather Zordel
Ontario, Canada

Director since: December 10, 2015
Expiry of current term: December 10, 2019, or effective date of appointment of a successor director

Ms. Zordel is a lawyer with extensive experience in corporate finance, securities regulatory compliance and corporate governance. A partner in the Securities Group at Gardiner Roberts LLP, she is also a Commissioner of the Ontario Securities Commission, a Bencher of the Law Society of Ontario (LSO), a part-time adjudicator for the Law Society Tribunal, and a Board Member for the Lawyers' Professional Indemnity Company (LawPro) and the Condominium Authority of Ontario. Ms. Zordel is an audit committee member for the LSO and LawPro. Academically, she is the Co-Director and a Course Director for the Osgoode Part-time LL.M. program in securities law. Ms. Zordel has a Bachelor of Commerce from the University of Saskatchewan and a LL.B./J.D./LL.M. (Securities) from Osgoode Hall Law School.

Ms. Zordel currently serves as Chair of the Board of Directors of TH Energy.

Principal Occupation:
Partner and Securities Lawyer, Gardiner Roberts LLP
Former Partner at Cassels Brock and Blackwell LLP

Board/Committee Membership	**2018 Attendance**	
Board	5 of 5	100%
Audit Committee	5 of 5	100%
	2019 Attendance(1)	
Board	1 of 1	100%
Audit Committee	1 of 1	100%

Board Memberships for other Reporting Issuers:
None

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Note:

(1) 2019 attendance is for the period of January 1, 2019 to the date of this AIF.

The Honourable Howard Wetston, Senator
Ontario, Canada

Director since: December 10, 2015
Expiry of current term: December 10, 2019, or effective date of appointment of a successor director

The Honourable Mr. Wetston, Senator was appointed to the Senate of Canada and assumed office on November 10, 2016. Mr. Wetston is a distinguished lawyer with a breadth of experience and expertise in competition law and policy, securities regulation, energy regulation and administrative law. In 2016, Mr. Wetston was awarded the Order of Canada for his significant contributions as a public servant, jurist and regulator. Mr. Wetston has served as Chair and Chief Executive Officer of the OSC, as Vice-Chair of the OSC, and as Chair and Chief Executive Officer of the OEB. During his time as Chair and Chief Executive Officer of the OSC, Mr. Wetston played a significant role in Canadian and international securities regulatory bodies by serving as a senior member of the Canadian Securities Administrators and as a Vice Chair of the International Organization of Securities Commissions. Mr. Wetston has served as a Judge of the Federal Court of Canada, Trial Division, an ex-officio member of the Federal Court's Appeal Division, and Director of Investigations and Research at the Bureau of Competition Policy. Mr. Wetston is a Senior Fellow of the C.D. Howe Institute and has served on several Advisory Boards, including the Program on Ethics in Law and Business at the University of Toronto, and the Shannon School of Business at Cape Breton University. He is a Board member of Spark Power Corp. Mr. Wetston is also a Trustee of the International Valuations Standards Council and a Member of the C.D. Howe Institute's Competition Policy Counsel. Mr. Wetston holds a Bachelor of Laws from Dalhousie University and a Bachelor of Science from Mount Allison University, and holds an ICD.D designation from the Institute of Corporate Directors and he has also received special recognition as a Board Diversity Champion from Catalyst Canada Honours. Mr. Wetston holds honorary doctorate degrees from Cape Breton University and Dalhousie University and he is a recipient of the Queen Elizabeth II Diamond Jubilee Medal.

Mr. Wetston currently serves as Chair of the Board of Directors of LDC.

Principal Occupation:
Senator

Board/Committee Membership	**2018 Attendance**	
Board	4 of 5	80%
	2019 Attendance(1)	
Board	1 of 1	100%

Board Memberships for other Reporting Issuers:
Spark Power Group Inc., parent company to Spark Power Corp.

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Note:

(1) 2019 attendance is for the period of January 1, 2019 to the date of this AIF.

Juliana Lam
Ontario, Canada

Director since: April 26, 2017
Expiry of current term: April 26, 2019, or effective date of appointment of a successor director

Ms. Lam has extensive executive level financial management experience in diverse industries including mining, manufacturing, services and distribution. She is currently serving as Executive Vice-President and Chief Operating Officer of Chartered Professional Accountants of Ontario. Prior to that, Ms. Lam was the Executive Vice-President and Chief Financial Officer of Uranium One Inc. Previously, Ms. Lam served as Senior Vice-President, Finance at Kinross Gold Corporation, Chief Financial Officer of Nexans Canada Inc., and has held senior finance roles within other publicly traded companies. She holds a Bachelor of Arts from the University of Toronto, an MBA from the Richard Ivey School of Business, University of Western Ontario, is a Chartered Professional Accountant (CPA, CA), and holds the ICD.D designation from the Institute of Corporate Directors. In addition to being a member of the board and the board committees of Toronto Hydro Corporation, Ms. Lam serves the community on the boards and board committees of two not-for-profit organizations in the Greater Toronto Area.

Ms. Lam currently serves as a member of the Board of Directors of TH Energy.

Principal Occupation:
Executive Vice-President & Chief Operating Officer, Chartered Professional Accountants of Ontario
Former Executive Vice-President & Chief Financial Officer, Uranium One Inc.

Board/Committee Membership	**2018 Attendance**	
Board	5 of 5	100%
Audit Committee	5 of 5	100%
Human Resources and Environment Committee	4 of 4	100%
	2019 Attendance(1)	
Board	1 of 1	100%
Audit Committee	1 of 1	100%
Human Resources and Environment Committee	1 of 1	100%

Board Memberships for other Reporting Issuers:
None

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Note:

(1) 2019 attendance is for the period of January 1, 2019 to the date of this AIF.

Mary Ellen Richardson
Ontario, Canada

Director since:	December 11, 2016
Expiry of current term:	December 10, 2019, or effective date of appointment of a successor director

Ms. Richardson is an independent consultant to the energy sector, with extensive experience in the oil, natural gas and electricity industries. Ms. Richardson currently serves as a member of the Board of Directors, is a member of the Human Resources and Governance Committee and the Finance and Audit Committee of Markham District Energy Inc. In the past, Ms. Richardson has served as President of the Canadian District Energy Association, Vice-President, Corporate Affairs and Vice-President, Conversation Programs and External Relations at the OPA, President of the Association of Major Power Consumers in Ontario, and was a member of the Board of Directors and Human Resources Committee of Guelph Municipal Holdings Inc. Ms. Richardson has also served on the management board of the Ontario Centre of Excellence in Energy, on the Board of Directors of Environmental Careers Organization of Canada, on the Ontario Government's Electricity Conservation and Supply Task Force, on the Executive of the Stakeholders' Alliance for Competition and Customer Choice, and on Hydro One's Customer Advisory Board. Ms. Richardson holds an Honours degree in Economics from the University of Calgary, and the ICD.D designation.

Ms. Richardson currently serves as a member of the Board of Directors of the LDC.

Principal Occupation:
President, Mary Ellen Richardson Inc.

Board/Committee Membership	**2018 Attendance**	
Board	4 of 5	80%
Corporate Governance and Nominating Committee	3 of 4	75%
	2019 Attendance(1)	
Board	1 of 1	100%
Corporate Governance and Nominating Committee	1 of 1	100%

Board Memberships for other Reporting Issuers:
None

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Note:

(1) 2019 attendance is for the period of January 1, 2019 to the date of this AIF.

Michael Nobrega
Ontario, Canada

Director since: May 10, 2016
Expiry of current term: December 10, 2019, or effective date of appointment of a successor director

Mr. Nobrega is a Chartered Accountant with extensive experience in finance and business. Mr. Nobrega has served as President & Chief Executive Officer of OMERS, Chief Investment Officer of OMERS, and as President & Chief Executive Officer of Borealis (OMERS) Infrastructure. Mr. Nobrega is currently interim President and Chief Executive Officer of Waterfront Toronto, and is the Chair of Ontario Centres of Excellence. Mr. Nobrega is also a member of the Board of Directors of IBI Group Inc. In the past, Mr. Nobrega was also president of a merchant bank, a tax partner at Arthur Anderson, Chartered Accountants, and a member of the Board of Directors of the Global Risk Institute. Mr. Nobrega earned an Honours Bachelor of Arts (Economics and Mathematics) from the University of Toronto, where, in 2002, he was honoured with the Arbor Award for outstanding community service. He holds a chartered accountancy designation from the Institutes of Chartered Accountants of Ontario and Canada, and was named a Fellow of the Institute of Chartered Accountants of Ontario in 2009. Mr. Nobrega has considerable experience in executive compensation matters from his years as the Chief Executive Officer of OMERS and Borealis (OMERS) Infrastructure. He is familiar with the structure of compensation systems and related benefit programs, and is experienced in executive performance evaluation.

Principal Occupation:
Interim President and CEO, Waterfront Toronto
Chair, Ontario Centres of Excellence
Former President & Chief Executive Officer of OMERS (from March 2007- March 2014)

Board/Committee Membership	**2018 Attendance**	
Board	5 of 5	100%
Audit Committee	5 of 5	100%
Human Resources and Environment Committee	4 of 4	100%
Other Committees[(1)]	1 of 1	100%
	2019 Attendance[(2)]	
Board	1 of 1	100%
Audit Committee	1 of 1	100%
Human Resources and Environment Committee	1 of 1	100%

Board Memberships for other Reporting Issuers:
IBI Group Inc.
CellCube Energy Storage Systems Inc.

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Notes:

(1) Committees other than the three standing committees (Audit Committee, Corporate Governance and Nominating Committee, and Human Resources and Environment Committee).

(2) 2019 attendance is for the period of January 1, 2019 to the date of this AIF.

Tamara Kronis
Ontario, Canada

Director since: December 10, 2015
Expiry of current term: December 10, 2019, or effective date of appointment of a successor director

Ms. Kronis is a Toronto-based entrepreneur, goldsmith and lawyer. She is currently the Founder and CEO of Studio1098, a custom fine jewellery design studio, where she works as a goldsmith, gemmologist and jewellery designer. Prior to opening Studio1098, Ms. Kronis worked as a commercial lawyer whose practice included several transactions related to the Ontario energy market. Her past experience includes positions as Legal Counsel, Vertex Customer Management/Vertex Outsourcing, Associate Lawyer at Torys LLP, Director of Advocacy at EGALE Canada and Trial Assistant, United Nations (International Criminal Tribunal for the Former Yugoslavia). Ms. Kronis holds a Master of Arts in Political Science and a Bachelor of Laws from the University of Toronto, and a Bachelor of Arts in Politics and Economics from Brandeis University. She is a Fellow of the Canadian Gemmological Association and the Gemmological Association of Great Britain. Ms. Kronis is a member of the Law Society of Ontario.

Ms. Kronis currently serves as a member of the Board of Directors of TH Energy.

Principal Occupation:
Founder and CEO, Studio1098

Board/Committee Membership	**2018 Attendance**	
Board	5 of 5	100%
Corporate Governance and Nominating Committee	4 of 4	100%
Other Committees[(1)]	1 of 1	100%
	2019 Attendance[(2)]	
Board	1 of 1	100%
Corporate Governance and Nominating Committee	1 of 1	100%

Board Memberships for other Reporting Issuers:
None

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Notes:

(1) Committees other than the three standing committees (Audit Committee, Corporate Governance and Nominating Committee, and Human Resources and Environment Committee).

(2) 2019 attendance is for the period of January 1, 2019 to the date of this AIF.

Denzil Minnan-Wong
Ontario, Canada

Director since: December 3, 2014
Expiry of current term: December 31, 2020, or effective date of appointment of a successor director

Deputy Mayor Minnan-Wong is the City Councillor for Ward 16 – Don Valley East, and was previously City Councillor for Ward 34 – Don Valley East since 1997. Deputy Mayor Minnan-Wong is currently serving as Chair of City Council's Civic Appointments Committee, Chair of City Council's Striking Committee, and member of City Council's Executive Committee. He also sits on City Council's Committee of Revision, North York Community Council, City Council's Infrastructure and Environment Committee, and the Toronto Transit Commission Board. Deputy Mayor Minnan-Wong's past experience includes serving as Chair of City Council's Employee and Labour Relations Committee, Chair of City Council's Public Works and Infrastructure Committee, Chair of City Council's Economic Development Committee, Chair of North York Community Council, and a member of City Council's Planning and Transportation Committee, City Council's Works and Emergency Services Committee, City Council's Audit Committee, City Council's Corporations Nominating Panel and the Toronto Financial Service Advisory Committee. He was formerly on the Board of Directors for BUILD Toronto, and Invest Toronto. Deputy Mayor Minnan-Wong holds a Juris Doctor from Osgoode Hall Law School, and is a member of the Law Society of Ontario.

Principal Occupation:
Deputy Mayor and Councillor, City of Toronto

Board/Committee Membership	**2018 Attendance**	
Board	3 of 5	60%
	2019 Attendance(1)	
Board	1 of 1	100%

Board Memberships for other Reporting Issuers:
None

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Note:

(1) 2019 attendance is for the period of January 1, 2019 to the date of this AIF.

Paul Ainslie
Ontario, Canada

Director since: February 10, 2015
Expiry of current term: December 31, 2020, or effective date of appointment of a successor director

Councillor Ainslie is the City Councillor for Ward 24 – Scarborough Guildwood, and was previously City Councillor for Ward 43 – Scarborough East since December 2006. Councillor Ainslie is currently serving as Chair of the General Government and Licensing Committee and is the Mayor's designate on the Board of Directors for the Toronto Public Library. Councillor Ainslie also sits on the City Council's Executive Committee, Scarborough Community Council, and the Toronto Zoo Board of Management. Mr. Ainslie is a member of the Board of Directors of the Canadian National Exhibition Association, Municipal Section, the Ontario Good Roads Association, Toronto and Region Conservation Authority, and the Guild Renaissance Group. Councillor Ainslie's past experience includes serving as Co-Chair of the Rouge Valley Health System Centenary Buy A Bed fundraising campaign and Chair of the Board of Directors of Haliburton Club.

Principal Occupation:
Councillor, City of Toronto

Board/Committee Membership	**2018 Attendance**	
Board	4 of 5	80%
Corporate Governance and Nominating Committee	2 of 4	50%
	2019 Attendance(1)	
Board	1 of 1	100%
Corporate Governance and Nominating Committee	0 of 1	0%

Board Memberships for other Reporting Issuers:
None

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Note:

(1) 2019 attendance is for the period of January 1, 2019 to the date of this AIF.

Stephen Holyday
Ontario, Canada

Director since: December 3, 2014
Expiry of current term: December 31, 2020, or effective date of appointment of a successor director

Deputy Mayor Holyday is the Mayor's designate to the Board effective as of December 3, 2014. Deputy Mayor Holyday has been the City Councillor for Ward 2 - Etobicoke Centre, and was previously City Councillor for Ward 3 - Etobicoke Centre since December 2014. Deputy Mayor Holyday is currently serving as a Mayor's Designate, Chair of City Council's Special Committee on Governance, and Chair of City Council's Audit Committee. Deputy Mayor Holyday also sits on City Council's General Government and Licensing Committee, City Council's Striking Committee, and Etobicoke York Community Council. Deputy Mayor Holyday is a member of the Board of Directors of the Hockey Hall of Fame, Exhibition Place Board of Governors and a member of the Canadian National Exhibition Association. Before being elected to public office, Stephen Holyday was Manager, Service Management at the Ontario Ministry of Energy. He holds a Bachelor of Technology in Architectural Science from Ryerson University. Through his previous experience as Vice-Chair of City Council's Employee and Labour Relations Committee, Mr. Holyday is familiar with compensation systems and related benefit programs at all levels.

Principal Occupation:
Deputy Mayor and Councillor, City of Toronto
Acting Manager and Manager, Service Management, Ontario Ministry of Energy (From May 2009 to November 2014)

Board/Committee Membership	**2018 Attendance**	
Board	5 of 5	100%
Human Resources and Environment Committee	3 of 4	75%
	2019 Attendance(1)	
Board	1 of 1	100%
Human Resources and Environment Committee	1 of 1	100%

Board Memberships for other Reporting Issuers:
None

Note:

(1) 2019 attendance is for the period of January 1, 2019 to the date of this AIF.

10.4 Executive Officers

The following table sets forth the name, province and country of residence, office, and principal occupation for each of the executive officers of the Corporation. 66.7% (2 out of 3) of the executive officers of the Corporation are female. 42.9% (3 out of 7) of the executive officers of LDC are female.

Name	Residence	Office	Principal Occupation
Anthony Haines[(1)]	Ontario, Canada	President and Chief Executive Officer	President and Chief Executive Officer, Toronto Hydro Corporation
Aida Cipolla[(2)]	Ontario, Canada	Executive Vice-President, Chief Financial Officer	Executive Vice-President, Chief Financial Officer, Toronto Hydro Corporation
Amanda Klein[(3)]	Ontario, Canada	Executive Vice-President, Public and Regulatory Affairs and Chief Legal Officer	Executive Vice-President, Public and Regulatory Affairs and Chief Legal Officer, Toronto Hydro Corporation

Notes:

(1) Mr. Haines has been the President of LDC since September 2006. He was also appointed the CEO of the Corporation effective October 1, 2009.

(2) Ms. Cipolla was Manager, Corporate Accounting and External Reporting of LDC (from December 3, 2012 to December 20, 2015) and then Controller of LDC (from December 21, 2015 to August 26, 2018). Ms. Cipolla was appointed as the Corporation's Executive Vice-President and Chief Financial Officer effective as of August 27, 2018. She replaced Sean Bovingdon, the former CFO who left the Corporation.

(3) Ms. Klein was Director, Rates and Regulatory Affairs of LDC (from August 23, 2012 to December 31, 2014) until her appointment as Vice-President, Regulatory Affairs and General Counsel of the Corporation effective January 1, 2015. Ms. Klein was appointed Executive Vice-President, Regulatory Affairs and General Counsel of the Corporation effective September 1, 2016. There was a change in Ms. Klein's position and title as Executive Vice-President, Public and Regulatory Affairs and Chief Legal Officer effective as of October 1, 2018.

10.5 Cease Trade Orders, Bankruptcies, Penalties or Sanctions

1. No director or executive officer of the Corporation is, as at the date of this AIF, or has within ten (10) years prior to the date of this AIF:

   (a) been a director, chief executive officer or chief financial officer of any company (including the Corporation) that was the subject of a cease trade or similar order or an order that denied the company access to any exemption under securities legislation for a period of more than 30 consecutive days, where such order was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer;

   (b) been a director, chief executive officer or chief financial officer of any company (including the Corporation) that was the subject of a cease trade or similar order or an order that denied the company access to any exemption under securities legislation for a period of more than 30 consecutive days, where such order was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer;

2. No director, executive officer of the Corporation or, to the Corporation's knowledge, the City is, as at the date of this AIF, or has within ten (10) years prior to the date of this AIF:

   (a) been a director or executive officer of any company (including the Corporation) that, while that person was acting in that capacity or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or

(b) become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold the assets of such director or executive officer.

3. No director, executive officer of the Corporation or, to the Corporation's knowledge, the City, has been subject to:

(a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or

(b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

10.6 Independence

As at the date of this AIF, the Board consists of eleven directors, all of whom are appointed by the City in its capacity as sole shareholder of the Corporation. Three of the directors are Councillors of the City and are not considered independent because of their positions. None of the other directors have a direct or indirect material relationship with the Corporation and are independent within the meaning of applicable Canadian securities law.

No members of management sit on the Board. The Board meets regularly to discuss the management of the Corporation. A portion of each Board and Board committee meeting is reserved for Directors to meet without management present. Under its mandate, the Board is authorized to retain independent legal counsel and other advisors if it considers this appropriate. The mandate also provides that the Board shall have unrestricted access to the officers of the Corporation and is authorized to invite officers and employees of the Corporation and others to attend or participate in its meetings and proceedings if it considers this appropriate. The full text of the Board's written mandate is attached as Annex B.

The Corporation has developed a written position description for the Chair of the Board. The Chair is responsible for reporting to the Board, leading the directors and managing the day-to-day activities of the Board. The Chair is also responsible for engaging in discussions with the shareholder and its representatives as are necessary and desirable, maintaining an active and cooperative relationship with the CEO and other senior management of the Corporation, acting as the principal interface between the Board and the CEO of the Corporation, and providing advice and counsel to the CEO and other senior management of the Corporation.

The Board has also developed written position descriptions for the chair of each Board committee and the CEO.

10.7 Board Orientation and Continuing Education

Each new director, upon joining the Board, is given an orientation session with comprehensive set of materials designed to provide him/her with a summary of the key organizational, financial, regulatory, and operational aspects of Toronto Hydro. These materials also contain information on the various Toronto Hydro boards and their committees.

On an on-going basis, as part of regular and special board meetings, directors receive presentations, reports and training on topics related to Toronto Hydro's businesses and the obligations and responsibilities of directors. Topics covered are either suggested by management or requested by the directors. As well, directors receive information from management in response to any actions arising at a board meeting or otherwise. Educational programs through external service providers are also made available to the directors.

10.8 Board, Committee and Director Assessments

The Corporate Governance and Nominating Committee oversees a process used to evaluate the effectiveness of the Board as a whole, its committees and the individual directors. The process may be facilitated by an independent consultant with expertise in board assessments as selected by the Board. Alternatively, the Board may complete an internal assessment. The process may consist of an in-person interview and/or a written questionnaire evaluating the Board, its committees and the individual directors that are completed periodically by each director. The directors'

responses to the questionnaire and/or interviews related to the operation of the Board and its committees are compiled into a summary report that is reviewed by the Chair of the Board. This report and recommended remedial actions are presented to the Board for review, consideration and implementation.

10.9 Board Oversight and Management of Risks

In accordance with its mandate, the Board is responsible for overseeing the identification of the principal risks of the business and implementation of appropriate systems to manage these risks. In 2009, Toronto Hydro adopted an ERM program to add value and improve the Corporation's operations through enabling the attainment of its strategic goals and objectives. The ERM program helps the Corporation achieve this by bringing a systematic and disciplined approach towards identifying, evaluating, treating, monitoring and reporting of risks applicable to Toronto Hydro. Accordingly, ERM is an integral part of the strategic management of the Corporation's business and is routinely considered in forecasting, planning and executing all aspects of Toronto Hydro's operations. The ERM program follows industry best practices and international guidelines, adopting a rigorous top-down / bottom-up approach towards the management of risks.

See Part 8 under the heading "Risk Factors – Risk Management" above for further information on ERM.

10.10 Indebtedness of Directors and Executive Officers

No director, executive officer, employee, former director, former executive officer or former employee or associate of any director or executive officer of the Corporation or any of its subsidiaries had any outstanding indebtedness to the Corporation or any of its subsidiaries except routine indebtedness or had any indebtedness that was the subject of a guarantee, support agreement, letter of credit or other similar arrangement or understanding provided by the Corporation or any of its subsidiaries.

PART 11 - AUDIT COMMITTEE

11.1 Composition, Independence and Financial Literacy

The Audit Committee is comprised of Michael Nobrega (Chair), Juliana Lam and Heather Zordel, each of whom is independent and financially literate within the meaning of applicable Canadian securities laws.

11.2 Audit Committee Charter

Under the terms of its charter, the Audit Committee is responsible for: managing the relationship between Toronto Hydro and its external auditors; overseeing the external audit; overseeing the internal audit; reviewing and recommending to the Board for approval the financial statements, management's discussion and analysis and interim reports of the Corporation and its subsidiaries, the annual information form and other public disclosure of financial information extracted from the financial statements of the Corporation; overseeing internal financial control structure and financial risk management systems; establishing and reviewing certain procedures and policies; reviewing policy reporting; and reviewing and making recommendations to the Board with respect to the payment of dividends or distribution of capital by the Corporation.

The full text of the Corporation's Audit Committee Charter is attached as Annex A.

11.3 Policy on the Provision of Services by the External Auditors

The Audit Committee has developed a Policy on the Provision of Services by the External Auditors. Under the terms of the Policy:

- the external auditors may not provide services to Toronto Hydro that impair or have the potential to impair the independence and objectivity of the external auditors in relation to the external audit function (generally, prohibited services include services where the external auditors participate in activities that are normally undertaken by management of Toronto Hydro, are remunerated through a "success fee" structure, act in an advocacy role for Toronto Hydro or may be required to audit their own work);

- the Audit Committee has pre-approved certain audit and permitted non-audit services as services that the auditors may provide to Toronto Hydro, including: services that constitute the agreed scope of the external audit or interim reviews of Toronto Hydro; services that are outside the agreed scope of, but are consistent with, the external audit or interim reviews of Toronto Hydro; tax services that do not compromise the independence and objectivity of the external auditors in relation to the external audit; and other services of an advisory nature that do not compromise the independence and objectivity of the external auditors in relation to the external audit work; and

- an authorization process has been established which provides, among other things: the Chief Financial Officer may authorize in advance all engagements of the external auditors to provide pre-approved services (other than audit services) to Toronto Hydro up to a maximum of $25,000 for any engagement and up to a maximum of $100,000 for all engagements in any fiscal quarter (the Chief Financial Officer must report all such authorized engagements to the Audit Committee at its next meeting); the Chair of the Audit Committee may authorize in advance all engagements of the external auditors to provide pre-approved services (other than audit services) to Toronto Hydro up to a maximum of $50,000 for any engagement and up to a maximum of $100,000 for all engagements in any fiscal quarter (the Chair must report all such authorized engagements to the Audit Committee at its next meeting); and the Audit Committee must authorize in advance all engagements of the external auditors to provide pre-approved services to Toronto Hydro above the prescribed thresholds and all engagements to provide services that are not pre-approved services regardless of the dollar value of the services.

Exceptions can be made to this Policy where the exceptions are in the interests of Toronto Hydro and appropriate arrangements are established to ensure the independence and objectivity of the external auditors in relation to the external audit. Any exception must be authorized by the Audit Committee and must be reported to the Board.

11.4 External Auditors Service Fees

The table below sets out the fees charged by Toronto Hydro's external auditor, KPMG LLP, on an accrual basis, for each of last two fiscal years in respect of the services noted below.

	Year ended December 31,	
	2018	**2017**
Audit fees[(1)]	$659,830	$683,720
Audit-related fees[(2)]	$31,270	$32,000

Notes:

(1) Fees for audit services and interim reviews, excluding CPAB levy.

(2) Fees for assurance and related services that are reasonably related to the performance of the audit or review of the Corporation's financial statements and are not reported under (1) above, specifically French translation.

PART 12 - EXECUTIVE COMPENSATION

12.1 Compensation Governance

(a) Human Resources and Environment Committee

(i) *Composition and Independence*

The Human Resources and Environment Committee, under the direction of the Board has oversight for Toronto Hydro's senior executive compensation program. The Human Resources and Environment Committee is comprised of Brian Chu (Chair), Juliana Lam, Michael Nobrega, and Deputy Mayor Stephen Holyday. Mr. Chu, Ms. Lam, and Mr. Nobrega are each independent within the meaning of applicable Canadian securities laws. Since the City is the sole shareholder of the Corporation, Deputy Mayor Holyday is not independent within the meaning of applicable Canadian securities laws. The appointment of one of the Corporation's City Councillor directors to the Human Resources and Environment Committee is a requirement under the Shareholder Direction.

(ii) *Human Resources and Environment Committee Charter*

The Human Resources and Environment Committee operates under a written charter adopted by the Board. One of the primary functions of the Human Resources and Environment Committee is to advise and assist the Board in overseeing Toronto Hydro's compensation program and assessing the performance and compensation of the CEO and the other officers of Toronto Hydro. Specifically, under the terms of its charter, the Human Resources and Environment Committee is responsible for assisting the Board in fulfilling its responsibilities with respect to: the recruitment and assessment of the performance of the CEO; the review and approval of the compensation of the CEO and the other senior executive officers of Toronto Hydro; the review and approval of senior executive compensation policies; the review and approval of senior executive compensation disclosure; the review of the alignment of compensation programs with Toronto Hydro's strategic plans and risk profile; and the general oversight of the compensation structure and benefit plans and programs for Toronto Hydro.

(b) Compensation Risk Oversight

Toronto Hydro has a rigorous risk management and governance structure in place to assist the Board with its oversight and management of all of Toronto Hydro's risks, including risks related to Toronto Hydro's compensation policies and practices. While the Board and the Human Resources and Environment Committee have not conducted a formal assessment of the implications of risks specifically associated with Toronto Hydro's compensation policies and practices, the Human Resources and Environment Committee has and continues to consider the Corporation's strategic objectives, plans and risk strategy in its review and recommendations regarding Toronto Hydro's compensation program. In addition to Toronto Hydro's ERM program, the practices, processes and systems in place to identify and mitigate compensation policies and practices that could encourage an executive officer to take inappropriate or excessive risks include: the periodic review and audit of Toronto Hydro's senior executive compensation program by

Toronto Hydro's internal auditor; the development and application of a management control reporting system providing transparency and control to compensation measures; the use of a balanced scorecard of corporate, divisional and individual performance objectives; the periodic benchmarking of Toronto Hydro's compensation program; the review of Toronto Hydro's compensation program by an independent compensation consultant and, from time to time, the OEB; and the application of maximum payout amounts for achievement of individual performance goals. See Part 8 under the heading "Risk Factors – Risk Management" and section 10.9 under the heading "Board Oversight and Management of Risks" for more information on Toronto Hydro's ERM program, section 12.2(c)(ii) under the heading "Benchmarking" for more information on Toronto Hydro's benchmarking of its compensation program, section 12.2(c)(iii) under the heading "Compensation Consultants and Advisors" for more information on the Corporation's compensation consultant and section 12.2(d)(ii) under the heading "Performance-Based Incentive Compensation" for more information on Toronto Hydro's performance-based incentive compensation program.

12.2 Compensation Discussion and Analysis

(a) Named Executive Officers

This Compensation Discussion and Analysis describes and explains all significant elements of compensation awarded to, earned by, paid to, or payable to the NEOs for the financial year ended December 31, 2018. The NEOs are:

(i) **Anthony Haines**
President and Chief Executive Officer, Toronto Hydro Corporation

(ii) **Sean Bovingdon**[(1)]
Former Executive Vice-President and Chief Financial Officer, Toronto Hydro Corporation

(iii) **Aida Cipolla**[(2)]
Executive Vice-President and Chief Financial Officer, Toronto Hydro Corporation

(iv) **Dino Priore**
Executive Vice-President and Chief Engineering and Construction Officer, Toronto Hydro-Electric System Limited

(v) **Ben La Pianta**[(3)]
Executive Vice-President and Chief Customer Care and Electric Operations Officer, Toronto Hydro-Electric System Limited

(vi) **Amanda Klein**
Executive Vice-President, Public and Regulatory Affairs and Chief Legal Officer, Toronto Hydro-Electric System Limited

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Notes:

(1) Effective, August 26, 2018, Mr. Bovingdon ceased his role as Executive Vice-President and Chief Financial Officer.

(2) Effective August 27, 2018, Ms. Cipolla began her role as Executive Vice-President and Chief Financial Officer.

(3) Effective January 1, 2018 Mr. La Pianta began his role as Executive Vice-President and Chief Customer Care and Electric Operations & Procurement Officer. Effective October 1, 2018, the position and title of Mr. La Pianta was changed to Executive Vice-President and Chief Customer Care and Electric Operations Officer.

(b) General Objectives of Compensation Program

Toronto Hydro's senior executive compensation program is designed to attract and retain executives who have the skills and experience to help the Corporation achieve its strategic goals, to motivate executives to achieve such corporate goals and to reward senior executives for superior performance and achievement of corporate, divisional and individual objectives.

(c) Process for Establishing Compensation

(i) *Policies and Practices*

Toronto Hydro's overall senior executive compensation policy, structure and program is developed and supervised by the Human Resources and Environment Committee with the assistance of a compensation consultant, and approved by the Board. See section 12.2(c)(iii) under the heading "Compensation Consultants and Advisors" for more information on the compensation consultant.

Pursuant to the terms of its charter, the Human Resources and Environment Committee has the responsibility to annually, and more frequently if appropriate, review and make recommendations to the Board with respect to the individual performance-based incentive compensation goals and objectives related to the compensation of the CEO and to assess the CEO's performance against those goals and objectives. The Human Resources and Environment Committee also makes recommendations to the Board with respect to the overall compensation and benefits of the CEO. The Board ultimately sets and approves the CEO's compensation.

The CEO has the responsibility to annually, and more frequently if appropriate, review and approve the individual performance-based incentive compensation goals and objectives related to the compensation of the other senior executive officers, including the NEOs, and assess the other senior executive officers' performance against those goals and objectives. The CEO proposes the other senior executive officers' performance-based incentive compensation and overall compensation, subject to the Human Resources and Environment Committee's review and approval.

(ii) *Benchmarking*

Toronto Hydro periodically benchmarks the compensation it provides to the NEOs to ensure reasonableness, competitiveness and effectiveness of Toronto Hydro's compensation program, including the level and type of compensation provided. The Human Resources and Environment Committee periodically engages a compensation consultant to conduct executive compensation benchmarking for the NEOs, to ensure that Toronto Hydro is able to attract, retain and motivate high-performing senior executives in the markets in which we compete for talent.

Toronto Hydro's objective is to pay competitively with other Canadian Utility and Energy Industry companies of comparable size and complexity. NEO compensation is generally benchmarked against:

- industry comparators in the public sector of like size: publicly owned utility / energy companies in Canada with revenues of approximately ½ to 2x Toronto Hydro's distribution revenue and / or total revenue;
- publicly and privately owned (including publicly traded) utility / energy companies in Canada with revenues of approximately ½ to 2x Toronto Hydro's distribution revenue and / or total revenue;
- industrial companies in the Greater Toronto Area ("GTA");
- industrial companies in Canada; and
- public sector organizations in Canada.

The benchmark data comes from proprietary compensation surveys, and publicly disclosed executive compensation information in Canada.

Toronto Hydro's flow-through revenue for electricity transmission and generation is excluded for purposes of identifying comparable general industry (i.e., non-local-distribution-company) peer companies, except in the case of the CFO, where the Toronto Hydro's full revenue is also considered because Toronto Hydro believes this role's accountability for cash management more closely matches organizations with similar total revenues. The senior executive compensation information derived from the benchmarking analysis is designed to assist the Human Resources and Environment Committee in establishing, over a reasonable period of time, total cash compensation for NEOs in the range of the median total cash compensation of the benchmark data. Total cash compensation to NEOs

may exceed the median of the marketplace when corporate, divisional and individual performance significantly exceeds objectives.

(iii) *Compensation Consultants and Advisors*

The Human Resources and Environment Committee began engaging the services of Willis Towers Watson for senior executive compensation consulting services in 2016. The consulting services provided to the Human Resources and Environment Committee include providing advice on the competitiveness and appropriateness of Toronto Hydro's senior executive compensation program, compensation benchmarking services, and other compensation related matters that may arise from time to time. The Corporation also engages Willis Towers Watson for actuarial services. The Human Resources and Environment Committee or the Board is required to pre-approve the actuarial services Willis Towers Watson provides to Toronto Hydro in accordance with the Corporation's Policy on the Provision of Services by Compensation Advisors. The actuarial services provided by Willis Towers Watson do not present any conflicts with the services provided as compensation advisor to the Human Resources and Environment Committee.

The table below sets out the fees billed by Willis Towers Watson for each of last two fiscal years in respect of the services noted below.

	Year ended December 31,	
	2018	**2017**
Executive Compensation – Related Fees [(1)]	$20,779	$94,906
All Other Fees [(2)]	$88,050	$42,427

Notes:

(1) Aggregate fees billed by Willis Towers Watson, or any of its affiliates, for services related to determining compensation for any of Toronto Hydro's directors and executive officers.

(2) Aggregate fees billed by Willis Towers Watson, or any of its affiliates, for services related to employee compensation and benefits management consultation or actuarial services that are not reported under (1) above.

(d) Elements of Compensation

The principal components of compensation for NEOs are:

- base salary;
- performance-based incentive compensation;
- personal benefits and perquisites;
- pension plan;
- post-employment benefits;
- retirement allowances; and
- termination payments.

As the Corporation has a single shareholder that is the registered and beneficial owner of all of its issued and outstanding shares, the Corporation is not able to offer an equity incentive plan or other stock-based compensation to its NEOs.

(i) *Base Salary*

In accordance with the general objectives and process for establishing compensation noted above, Toronto Hydro provides NEOs with a base salary to compensate them for services rendered during the fiscal year. Toronto Hydro provides reasonably competitive market-based base salaries to help attract, motivate, and retain NEOs who are critical to the Corporation's success.

Annually, adjustments to base salaries for NEOs are driven by market benchmarking data and the NEO's individual performance rating. The performance rating is determined, in the case of the CEO, by the Human Resources and Environment Committee and, in the case of the other NEOs, by the CEO, based on the achievement of performance-based incentive compensation objectives, knowledge, skills, and competencies related to day-to-day performance, as

well as demonstration of desired corporate behaviours, subject to the Human Resources and Environment Committee's review and approval.

(ii) *Performance-Based Incentive Compensation*

All NEOs receive a portion of their annual compensation in the form of performance-based cash payments. The performance-based incentive compensation is designed to retain, motivate and reward NEOs for reaching corporate, divisional and individual performance objectives established at the beginning of each calendar year.

The annual performance-based incentive compensation is calculated as a percentage of the NEO's base salary for the year and, if earned, paid in one lump sum in the next fiscal year.

In order for a NEO to earn and receive the performance-based incentive compensation, the Corporation and the NEO must each achieve certain pre-determined performance objectives. Each NEO's performance-based incentive compensation is based on a weighting of corporate, divisional and individual performance objectives, whose weightings and objectives are determined at the start of each year and vary by role to reflect the performance focus of the role. The weighting and objectives are reviewed and set each year in order to reflect the Corporation's overall strategy and objectives.

Each year the board reviews and approves the Corporation's objectives. Each performance objective is weighted to reflect relative importance and includes threshold, target and outstanding expectations of performance. Specific performance targets are approved by the Board giving consideration to the Corporation's business plans and priorities for the upcoming year, the prior year's performance and a review of forecasted results based on a historical analysis of performance. Similarly divisional objectives are approved by the CEO and reviewed by the Human Resources and Environment Committee to recognize unique divisional priorities and ensure alignment with the Corporation's overall objectives.

The CEO's individual objectives are reviewed and approved by the Board. The individual objectives of the other NEOs are reviewed and approved by the CEO. Each NEO's individual objectives are based on areas of strategic and operational emphasis related to their respective responsibilities and portfolios.

The NEO's individual objectives are intended to be reasonably difficult to attain and to encourage success in the NEO's performance. Individual objectives are often but not always achieved by a NEO in any given year. NEOs review their objectives and measurements throughout the year, with one formal mid-year review with the Chair of the Board (in the case of the CEO), and with the CEO (in the case of the other NEOs), to track achievement to-date and revise performance goals as may be necessary to reflect any change in corporate strategy or priorities.

In the case of the CEO, an annual performance evaluation in respect of his individual performance goals is conducted by the Chair of the Board who provides a recommendation to the Human Resources and Environment Committee regarding the performance-based incentive compensation to be paid to the CEO. The amount paid to the CEO is approved by the Board after review of the recommendation of the Human Resources and Environment Committee.

In the case of each of the other NEOs, an annual performance evaluation in respect of the individual objectives for each individual is conducted by the CEO, who proposes the amount of performance-based incentive compensation to be paid to each other NEO. The Human Resources and Environment Committee reviews and approves the amounts of performance-based incentive compensation to be paid to each of the other NEOs.

(iii) *Personal Benefits and Perquisites*

Toronto Hydro provides NEOs with other personal benefits and perquisites that Toronto Hydro believes are reasonable and consistent with its overall compensation program to better enable the Corporation to attract and retain superior employees for key positions. Benefits include group health, dental, group life insurance, short-term and long-term disability, accidental death & dismemberment, a gym subsidy, and educational reimbursements, all of which are generally available to all salaried employees.

(iv) *Pension Plan*

All full-time employees of Toronto Hydro, including the NEOs, are required to participate in the OMERS pension plan. Pursuant to the terms of the OMERS pension plan, NEOs are required to make equal plan contributions based on their eligible pensionable earnings. In 2018, Toronto Hydro and each NEO was required to contribute 9.0% equally of the first $55,900 of pensionable earnings and thereafter 14.6% equally on all earnings over $55,900 and up to $175,223. From $175,223 and up to a maximum of $391,300, contributions continue equally at 14.6% towards a Retirement Compensation Arrangement (RCA), which is governed separately under the Canadian Income Tax Act. The OMERS pension plan is generally available to all other salaried employees. See section 4.6 (a) under the heading "Employees" for more information on the OMERS pension plan.

(v) *Post-employment Benefits*

NEOs are eligible to receive post-employment health, dental and life insurance benefits after a minimum of five years of service with Toronto Hydro if they retire from Toronto Hydro and begin collecting under the OMERS pension plan upon retirement. The post-employment benefits provided to eligible NEOs are the same as are generally available to all other salaried employees. Post-employment benefits aid in attracting and retaining key executives to ensure the long-term success of Toronto Hydro.

(vi) *Retirement Allowances*

From time to time, in certain circumstances, Toronto Hydro enters into retirement allowance agreements with its NEOs. The retirement allowance agreements are designed to recognize service, and to promote retention, stability and continuity, of the NEOs. These agreements are made on a case-by-case basis based on a NEO's years of service and position. Any retirement allowance provided to the CEO is approved by the Board after review of the recommendation of the Human Resources and Environment Committee. In the case of each of the other NEOs, any retirement allowance agreement is proposed by the CEO and reviewed and amended or approved by the Human Resources and Environment Committee. Retirement allowance payments are typically paid in one or two lump sum instalments following termination or retirement of the NEO.

(vii) *Termination Payments*

From time to time, Toronto Hydro enters into agreements with NEOs which provide for payments upon termination. These agreements are made on a case-by-case basis based on the NEO's age, years of service and position. Any such agreement for the CEO is approved by the Board after review of the recommendation of the Human Resources and Environment Committee. In the case of each of the other NEOs, any such agreement is proposed by the CEO and reviewed and approved by the Human Resources and Environment Committee. Typically, termination payments are paid either as a lump sum or as salary continuation for an agreed period following termination.

12.3 Compensation of Named Executive Officers

(a) Summary Compensation Table

The following table provides a summary of the compensation earned during the years ended December 31, 2018, 2017 and 2016, by the NEOs:

Summary Compensation Table[1]

NEO Name and Principal Position	Year	Salary[2] ($)	Non-Equity Incentive Plan Compensation[3] ($)	All Other Compensation[4] ($)	Total Compensation ($)
Anthony Haines President and Chief Executive Officer, Toronto Hydro Corporation	2018 2017 2016	$583,999 $548,490 $522,286	$570,068 $528,138 $508,551	$16,053 $10,452 $10,301	$1,170,120 $1,087,080 $1,041,138
Sean Bovingdon[5] Former Executive Vice-President and Chief Financial Officer, Toronto Hydro Corporation	2018 2017	$262,632 $274,039	$153,273 $166,500	$1,727 $200,000	$417,632 $640,539
Aida Cipolla[6] Executive Vice-President and Chief Financial Officer, Toronto Hydro Corporation	2018 2017 2016	$215,668[6] $185,478 $163,246	$111,400 $71,250 $61,750	$1,560 $1,560 $1,058	$328,628 $258,288 $226,054
Dino Priore Executive Vice-President and Chief Engineering and Construction Officer, Toronto Hydro –Electric System Limited	2018 2017 2016	$377,561 $338,019 $326,019	$224,808 $211,371 $192,889	$4,580 $4,108 $2,330	$606,949 $553,498 $521,238
Ben La Pianta Executive Vice-President and Chief Customer Care and Electric Operations Officer, Toronto Hydro –Electric System Limited	2018 2017 2016	$346,704 $298,103 $287,100	$207,482 $195,137 $169,295	$9,133 $5,005 $3,823	$563,319 $498,245 $460,218
Amanda Klein Executive Vice-President, Public and Regulatory Affairs and Chief Legal Officer, Toronto Hydro –Electric System Limited	2018 2017 2016	$283,000 $237,767 $209,154	$169,800 $124,803 $114,819	$2,863 $0 $178	$455,663 $362,570 $324,151

Notes:

(1) Amounts shown in this table are in Canadian dollars and have been rounded to the nearest dollar.

(2) Amounts shown reflect actual amounts paid during the year.

(3) Each NEO's annual performance-based incentive compensation for a fiscal year is determined and paid in the next fiscal year. Accordingly, amounts reflected in respect of a particular year (i.e. 2017) represent the annual performance-based incentive compensation earned by the NEO for the achievement of performance objectives in respect of that fiscal year (i.e. 2017) but which amounts are paid in the following fiscal year (i.e. 2018).

(4) Amounts shown in this column reflect all other compensation earned by the NEO during the year. The amounts shown include the aggregate value of perquisites and other personal benefits provided to the NEO, where such perquisites and personal benefits are not generally available to all employees and have been calculated by using the actual cost. In 2018, 2017 and 2016, perquisites and personal benefits were not worth $50,000 or more for any NEO, nor were they worth 10% or more of any NEO's total salary for the year, with the exception of Mr. Bovingdon. Mr. Bovingdon received a one-time $200,000 relocation allowance when he joined the Corporation in 2017.

(5) Effective August 26, 2018, Mr. Bovingdon ceased to be Executive Vice-President and Chief Financial Officer of the Corporation. See section 12.3(b)(vii) under the heading "Termination Payments" for a discussion regarding additional amounts respecting termination.

(6) Effective August 27, 2018, Ms. Cipolla is the Executive Vice-President and Chief Financial Officer and her annual base salary was $250,563. Prior to this role, Ms. Cipolla was the Corporation's Controller since December 2015. Her 2018 performance-based incentive compensation was in respect of her role as the Controller and Executive Vice-President and Chief Financial Officer.

(b) Compensation of NEOs in 2018 – Narrative Discussion

(i) *Base Salaries*

The NEOs' annual base salaries for 2018 were: $584,685 in the case of Mr. Haines, $388,359 in the case of Mr. Bovingdon, $250,563 in the case of Ms. Cipolla, $379,744 in the case of Mr. Priore, $350,476 in the case of Mr. La Pianta, and $283,000 in the case of Ms. Klein.

(ii) *Performance-Based Incentive Compensation*

The targets and component weightings for the 2018 performance-based incentive compensation were as follows:

Position	Target Performance-Based Incentive (% of salary)	Individual Performance (% weighting)	Divisional Performance (% weighting)	Corporate Performance (% weighting)
CEO	65%	20%	—	80%
CFO	40%	20%	20%	60%
Other NEOs	40%	20%	20%	60%

The performance-based incentive compensation amount payable to each NEO may exceed the respective target % of base salary indicated above when results exceed corporate, divisional and individual objectives and may be below the respective target % of base salary indicated above when the corporate, divisional and individual objectives are not achieved. The component weightings outlined above have been unchanged since 2011.

The performance objectives of the Corporation for 2018 were as follows:

Corporate Key Performance Indicators	Measure	Target	Weight (%)
Consolidated Net Income ($M)	Net Income after net movements in regulatory balances per the Corporation's Consolidated Financial Statements.	$148.0	40%
1-Year Distribution System Plan Investment ($M) (1)	TH Board approved cumulative regulated capital investments (not necessarily in service) as defined in the Distribution System Plan for the current year.	$435.0	5%
5-Year CIR Distribution System Plan Investment ($M) (1)	TH Board approved cumulative regulated capital investments (not necessarily in service) as defined in the Distribution System Plan for the five year rate period.	$1,942.6	5%
System Average Interruption Duration Index (SAIDI) (in minutes) (Defective equipment only)	Measure of the annual system average interruption duration per customer served, not including Major Event Days.	29.00	10%
System Average Interruption Frequency Index (SAIFI) (number of interruptions) (Defective equipment only)	Measure of the frequency of service interruptions per customer served, not including Major Event Days.	0.54	10%
First Contact Resolution	Percentage of telephone and email enquiries resolved in one contact, within a 21 day time period	86%	5%
Bill Accuracy	The percentage of issued bills that are considered accurate or inaccurate as defined by the Ontario Energy Board.	98.8%	5%
New Services Connected On Time	Percentage of connections for new low-voltage (<750 volts) service requests completed within five business days from the day on which all applicable service conditions are satisfied, or at such later date as agreed to by the customer	96.5%	5%
Employee Engagement	Average number of engagement sessions attended per employee per year	6.0	5%
Safety – Total Recordable Injury Frequency (TRIF)	Number of recordable injuries x 200,000 / exposure hours.	1.45	10%

Note:
(1) This is a non-GAAP measure as it includes all eligible capital expenditures, net of capital contributions related to regulated operations.

Corporate KPIs are cascaded down in the organization to create appropriate divisional performance objectives with strong line of sight.

Divisional KPIs support operational, financial, customer and employee targets. Weightings for these KPIs ranged from 5% to 25% of divisional performance. All divisional KPIs support achievement in the Corporation's four areas of focus: Customer, People, Operations, and Financial. These measures are aimed at increasing customer satisfaction, improving reliability, accomplishing LDC's work program safely and meeting regulatory requirements. Prioritization of these KPI's is determined based on divisional accountabilities. Some examples of Divisional measures are Customer Connection Index, Safety Inspections per Leader, Distribution System Health Index & Operating Expenses.

Performance-based incentives also include individual performance objectives which are set annually and are tied to business priorities and each individual's particular accountabilities. The number and weighting of individual objectives vary by individual and from year to year. Examples of the 2018 individual performance objectives for the NEOs include, but are not limited to, continuous improvement of operational processes to enhance performance and engagement.

In 2018, the Corporation exceeded all of its corporate targets represented by its KPIs. The NEOs exceeded the majority of their divisional and individual performance targets for 2018. Each of the corporate, divisional and individual performance targets were reasonably difficult to attain and served to encourage success in the NEOs performance and in the Corporation's overall results.

(iii) *Personal Benefits and Perquisites*

In 2018, the NEOs received personal benefits and perquisites as described in section 12.2(d)(iii) under the heading "Personal Benefits and Perquisites", and as quantified in the Summary Compensation Table in section 12.3(a) above.

(iv) *Pension Plan*

In 2018, each of the NEOs participated in the OMERS pension plan. The OMERS pension plan is a group pension plan that is generally available to all salaried employees. See section 4.6(a) under the heading "Employees" and section 12.2(d)(iv) under the heading "Pension Plan" for further information on the OMERS pension plan.

(v) *Post-employment Benefits*

As of December 31, 2018, Mr. Haines, Mr. Priore, Mr. La Pianta and Ms. Cipolla have each provided Toronto Hydro with more than five years of service and are eligible for post-employment medical, dental and life insurance benefits if they retire from Toronto Hydro and begin collecting under the OMERS pension plan upon retirement.

(vi) *Retirement Allowance*

Mr. Haines is the only NEO entitled to retirement allowances, which allowances are calculated based on completed years of service and are payable in the form of lump-sum cash payments following Mr. Haines' termination (without cause) or retirement from the Corporation.

Under the terms of Mr. Haines' existing retirement allowance (the "Existing Allowance"), if Mr. Haines is terminated (without cause) or retires from the Corporation during 2019, he will receive a $750,000 retirement allowance. The amount of the Existing Allowance payable to Mr. Haines will thereafter be increased by an additional $125,000 per year (from 2019 to 2020) for each full calendar year of service completed. The maximum Existing Allowance payable to Mr. Haines is $1,000,000, which Mr. Haines will earn if he remains in active service for the Corporation until December 31, 2020. In the event that Mr. Haines becomes permanently disabled while in active service for the Corporation, he will be deemed to remain in active service for the Corporation until December 31, 2020, at which point he will be considered to have retired and earned the maximum Existing Allowance of $1,000,000. In the event of the death of Mr. Haines while in active service for the Corporation, the Existing Allowance which Mr. Haines would have earned as of the date of his death will be paid to his designated beneficiary or to the legal representative of Mr. Haines' estate.

As part of his compensation package, Mr. Haines also participates in the OMERS defined benefit pension plan. See "Pension Plan" above in section 12.3(b)(iv). OMERS made significant unilateral changes to its defined benefit pension plan that significantly reduce the value of Mr. Haines' pension benefit under the OMERS pension plan. In order to mitigate the impact of these changes in a manner consistent with the terms of his existing employment relationship with the Corporation, the Corporation has awarded Mr. Haines a second retirement allowance (the "Second Allowance"). Under the terms of the Second Allowance, if Mr. Haines is terminated (without cause) or retires from the Corporation during 2019, he will receive a $975,000 retirement allowance. The amount of the Second Allowance payable to Mr. Haines will thereafter be increased by an additional $225,000 per year (from 2019 to 2021) for each full calendar year of service completed. The maximum Second Allowance payable to Mr. Haines is $1,650,000, which Mr. Haines will earn if he remains in active service for the Corporation until December 31, 2021. In the event that Mr. Haines becomes permanently disabled while in active service for the Corporation, he will be deemed to remain in active service for the Corporation until December 31, 2021, at which point he will be considered to have retired and earned the maximum Second Allowance of $1,650,000. The provisions relating to entitlement on death are identical to those established for the Existing Allowance.

(vii) *Termination Payments*

Mr. Haines has entered into an agreement with the Corporation which provides for certain payments upon termination.

If the employment of Mr. Haines is terminated without cause by the Corporation, then Mr. Haines is entitled to a payment equal to 24 months of base salary and performance pay that would have been paid had he continued to work for 24 months (approximately $2,240,541 as at December 31, 2018), with the performance pay calculated based on the average annual performance pay earned by Mr. Haines during the 3 years preceding the date of termination. Mr. Haines would also be entitled to continued group health and dental benefit coverage for a period of 24 months from the date of termination.

Ms. Cipolla has entered into an agreement with the Corporation which provides for certain payments upon termination.

If the employment of Ms. Cipolla is terminated without cause by the Corporation, then Ms. Cipolla is entitled to one (1) month of severance pay for each completed year of employment, to a minimum of twelve (12) months and a maximum of eighteen (18) months, and would continue to be eligible for performance pay that would otherwise have been earned during the severance period. Ms. Cipolla would be entitled to benefits during the severance period.

In addition, and in connection with Mr. Bovingdon ceasing employment with the Corporation, Mr. Bovingdon was entitled to a termination payment in the aggregate amount of $580,569, representing 12 months of working notice of termination or pay in lieu thereof and performance pay that would otherwise have been earned and/or paid during the 12 month period of which $137,644 has been paid as of December 31, 2018, $341,019 is payable by December 31, 2019 and $101,906 will be payable by the end of 2020.

12.4 Compensation of Directors

(a) Director Compensation Table

Director Name	Total[(1)] ($)
David McFadden	$75,000
Brian Chu	$26,500
Heather Zordel	$26,500
Howard Wetston	$21,500
Juliana Lam	$26,500
Mary Ellen Richardson	$22,500
Michael Nobrega	$27,500
Tamara Kronis	$26,500
Deputy Mayor Denzil Minnan-Wong	$Nil
Councillor Paul Ainslie	$Nil
Deputy Mayor Stephen Holyday	$Nil

Note:

(1) There was no compensation paid to directors during 2018 other than in respect of director retainer fees and meeting attendance fees.

(b) Compensation of Directors – Narrative Discussion

Directors of the Corporation, other than Councillors of the City, are compensated for their services as directors through a combination of retainer fees and meeting attendance fees. These fees are set by the sole shareholder of the Corporation, the City. The annual retainer fees are as follows: chair of the Board – $75,000 and each of the other directors – $12,500. The meeting attendance fees are as follows: each meeting of the Board and the subsidiaries attended – $1,000 and each meeting of the Audit Committee, Corporate Governance and Nominating Committee, Human Resources and Environment Committee, or other Board committee attended – $1,000, subject to annual maximum fees per committee member of $5,000 for the Audit Committee, Corporate Governance Committee, Human Resources and Environment Committee or any other committee of the Board. The Board does, from time to time and in the normal course, strike ad hoc committees to streamline and expedite certain matters as they come before the Board. Any compensation Directors have earned from their attendance at these committees has been included in the table above. The Chair receives no meeting attendance fees. Councillors receive no remuneration for their services as directors of the Corporation. The other directors, other than the Chair, are subject to a maximum annual total retainer and attendance fees of $30,000.

PART 13 - LEGAL PROCEEDINGS

In the ordinary course of business, Toronto Hydro is subject to various legal actions and claims from customers, suppliers, former employees and other parties. As at the date hereof, the Corporation believes that none of these legal actions and claims from customers, suppliers, former employees and other parties in which it is currently involved or has been involved since the beginning of the most recently completed financial year, would be expected to have a material adverse effect on the Corporation. On an ongoing basis, Toronto Hydro assesses the likelihood of any adverse judgments or outcomes as well as potential ranges of probable costs and losses. A determination of the provision required, if any, for these contingencies is made after an analysis of each individual issue. The provision may change in the future due to new developments in each matter or changes in approach, such as a change in settlement strategy.

If damages were awarded under these actions, Toronto Hydro would make a claim under any applicable liability insurance policies which Toronto Hydro believes would cover any damages which may become payable by Toronto Hydro in connection with these actions, subject to such claim not being disputed by the insurers.

PART 14 - MATERIAL CONTRACTS

The following are material contracts (other than contracts entered into in the ordinary course of business) that the Corporation has entered into in the most recently completed financial year, or before the most recently completed financial year if such material contract is still in effect:

(a) trust indenture dated as of May 7, 2003 between Toronto Hydro Corporation and CIBC Mellon Trust Company (now BNY Trust Company of Canada) (the "**Trust Indenture**");

(b) a third supplemental trust indenture dated as of November 12, 2009 relating to the issuance of Series 3 senior unsecured debentures in the aggregate principal amount of $250,000,000;

(c) a sixth supplemental trust indenture dated as of May 20, 2010 relating to the issuance of Series 6 senior unsecured debentures in the aggregate principal amount of $200,000,000;

(d) a seventh supplemental trust indenture made as of September 20, 2011 amending the definition of "GAAP" under the Trust Indenture;

(e) an eighth supplemental trust indenture dated as of November 18, 2011 relating to the issuance of Series 7 senior unsecured debentures in the aggregate principal amount of $300,000,000;

(f) a ninth supplemental trust indenture dated as of April 9, 2013 relating to the issuance of Series 8 senior unsecured debentures in the aggregate principal amount of $250,000,000;

(g) a tenth supplemental trust indenture dated as of April 9, 2013, as amended and restated as of September 2, 2015, relating to the issuance of Series 9 senior unsecured debentures in the aggregate principal amount of $245,000,000;

(h) an eleventh supplemental trust indenture dated as of September 16, 2014 relating to the issuance of Series 10 senior unsecured debentures in the aggregate principal amount of $200,000,000;

(i) a twelfth supplemental trust indenture dated as of March 16, 2015 relating to the issuance of Series 11 senior unsecured debentures in the aggregate principal amount of $200,000,000;

(j) a thirteenth supplemental trust indenture dated as of June 14, 2016 relating to the issuance of Series 12 senior unsecured debentures in the aggregate principal amount of $200,000,000; and

(k) a fourteenth supplemental trust indenture dated as of November 14, 2017 relating to the issuance of Series 13 senior unsecured debentures in the aggregate principal amount of $200,000,000.

Each of these supplemental trust indentures supplement the terms of the Trust Indenture, which contains customary covenants and representations by the Corporation for the public issuance of debt securities in the Canadian capital market.

Copies of these material contracts are available on the SEDAR website at www.sedar.com.

PART 15 - NAMED AND INTERESTS OF EXPERTS

The external auditor of the Corporation is KPMG LLP. KPMG LLP is independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Ontario.

PART 16 - TRANSFER AGENTS AND REGISTRARS

The trustee and registrar for the outstanding Debentures of the Corporation is BNY Trust Company of Canada, located in Toronto, Ontario.

PART 17 - ADDITIONAL INFORMATION

Additional information relating to the Corporation, including additional financial information provided in the Consolidated Financial Statements and Management's Discussion and Analysis, is available on the SEDAR website at www.sedar.com.

ANNEX A - CHARTER – AUDIT COMMITTEE

1. General

(1) The board of directors ***(Board)*** of Toronto Hydro Corporation ***(Corporation)*** has established the Audit Committee ***(Committee)*** to assist the Board and the boards of directors of the Corporation's subsidiary entities in fulfilling their respective corporate governance and oversight responsibilities with respect to financial reporting, internal financial control structure, financial risk management systems, internal audit and external audit functions.

(2) The composition, responsibilities and authority of the Committee are set out in this Charter.

(3) This Charter and the by-laws of the Corporation and such other procedures, not inconsistent therewith, as the Committee may adopt from time to time shall govern the meetings and procedures of the Committee.

2. Composition

(1) The Committee shall be composed of at least three persons who are directors of the Corporation ***(Members)***:

(a) all Members must be *independent,* (as determined by the Board in accordance with the meaning of "independence", as the context requires, given to it in the Canadian Securities Administrators' National Instrument 52-110 Audit Committees, as the same may be amended and/or replaced from time to time) ; and

(b) at least one of whom, including the chair of the Committee (***Chair***) is *financially literate* (ie, have the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the accounting issues that can reasonably be expected to be raised by the financial statements of the Corporation).

(2) In addition to the Members, the Committee shall also include at least one director of Toronto Hydro-Electric System Limited who is not also a director of the Corporation (***THESL Members***). The THESL Members shall be invited to all the meetings of the Committee, shall be entitled to receive all Committee materials and to participate in all Committee discussions and deliberations, but shall have no voting rights.

(3) Members and THESL Members shall be appointed by the Board on the recommendation of the Chair of the Board and the Chair of the THESL Board, respectively, and shall serve until they resign, cease to be a director of the respective board, as applicable, or are removed or replaced by the Board.

(4) The Board shall designate one of the Members as Chair. The Committee shall periodically review the position description of the Chair and make recommendations to the Board.

(5) The Executive Vice-President and Chief Financial Officer (***Designated Representative)*** shall be appointed from time to time to act as the principal interface between the Committee and other senior management of the Corporation and its subsidiary entities.

(6) The Secretary of the Corporation shall be secretary of the Committee ***(Secretary)***.

(7) The Chair of the Corporation's Board of Directors shall be an *ex-officio* Member of the Committee with all of the responsibilities and privileges thereof, but shall only count towards meeting quorum if he or she is present at the meeting.

3. Responsibilities

The Committee shall assist the Board and the boards of directors of the Corporation's subsidiary entities in fulfilling their corporate governance and oversight responsibilities with respect to financial reporting, internal financial control structure, financial risk management systems, internal audit functions, external audit functions, and the payment of dividends by the Corporation and its subsidiary entities.

The Committee has specifically recognized its responsibilities for overseeing the identification of the principal financial and audit risks of the Corporation and its subsidiary entities and overseeing the implementation of appropriate systems to manage these risks. In particular, the Committee shall have the responsibilities set out below.

(1) *Managing the Relationship between the Corporation and its Subsidiaries and their External Auditors*

The Committee shall be responsible for managing the relationship between the Corporation and its subsidiary entities and their external auditors, including:

(a) appointing and replacing the external auditors, subject to the Boards of Directors and shareholder approval;

(b) setting the compensation of the external auditors subject to the approval of the board of directors or shareholder, as applicable;

(c) overseeing the work of the external auditors, including resolving disagreements between management and the external auditors with respect to financial reporting;

(d) pre-approving all audit services and permitted non-audit services to be provided to the Corporation and its subsidiary entities by the external auditors in accordance with the "Policy on the Provision of Services by the External Auditors";

(e) having the external auditors report to the Committee in a timely manner with respect to all required matters, including those set out in paragraph 3(2);

(f) ensuring the rotation of the audit partner having primary responsibility for the external audits of the Corporation and its subsidiary entities, the audit partner responsible for reviewing the external audit and the external auditors at such intervals as may be required; and

(g) reviewing and assessing the performance, independence and objectivity of the external auditors.

(2) *Overseeing the External Audits*

The Committee shall be responsible for overseeing the external audits of the Corporation and its subsidiary entities, including:

(a) reviewing and approving the engagement letters and the audit plans, including financial risk areas identified by the external auditors and management;

(b) reviewing and assessing the accounting and reporting practices and principles used by the Corporation and its subsidiary entities in preparing their financial statements, including:

(1) all significant accounting policies and practices used, including changes from preceding years and any proposed changes for future years;

(2) all significant financial reporting issues, estimates and judgments made;

(3) all alternative treatments of financial information discussed by the external auditors and management, the results of such discussions and the treatments preferred by the external auditors;

(4) any major issues identified by the external auditors with respect to the adequacy of internal control systems and procedures and any special audit steps adopted in light of material deficiencies and weaknesses;

(5) the effect of regulatory and accounting initiatives and off-balance sheet transactions or structures on the financial statements;

(6) any errors or omissions in, and any required restatement of, the financial statements for preceding years;

(7) all significant tax issues;

(8) the reporting of all material contingent liabilities; and

(9) any material written communications between the external auditors and management;

(c) reviewing and assessing the results of the external audit and the external auditors' opinion on the financial statements;

(d) reviewing and discussing with the external auditors and management any management or internal control letters issued or proposed to be issued by the external auditors;

(e) reviewing and discussing with the external auditors any problems or difficulties encountered by them in the course of their audit work and management's response (including any restrictions on the scope of activities or access to requested information and any significant disagreements with management); and

(f) reviewing and discussing with legal counsel any legal matters that may have a material impact on the financial statements, operations, assets or compliance policies of the Corporation and its subsidiary entities and any material reports or enquiries received by the Corporation and its subsidiary entities from regulators or government agencies.

(3) ***Overseeing the Internal Audits***

The Committee shall be responsible for overseeing the internal audits of the Corporation and its subsidiary entities, including:

(a) periodically reviewing the Internal Audit Charter and making recommendations to the Board;

(b) reviewing and approving the audit plans, including significant risk exposures identified by the internal auditor and management;

(c) reviewing and discussing with the internal auditor and management the results of any internal audits;

(d) reviewing and discussing with the internal auditors any problems or difficulties encountered by them in the course of their audit work and management's response (including any restrictions on the scope of activities or access to requested information and any significant disagreements with management);

(e) appointing and replacing the internal auditor;

(f) reviewing and assessing the performance of the internal auditor;

(g) ensuring the Committee is kept informed of emerging trends and successful practices in internal auditing; and

(h) confirming there is effective and efficient coordination of activities between internal and external auditors.

(4) ***Reviewing and Recommending to the Respective Boards for Approval the Financial Statements, MD&A and Interim Reports of the Corporation and its Subsidiaries***

The Committee shall review and recommend to each respective board of directors, as applicable, for approval, the financial statements, management's discussion and analysis of financial condition and results of operations ***(MD&A)*** and interim financial reports of the Corporation and its subsidiaries, annual information form **(*AIF*)** (other than executive compensation) of the Corporation and other public disclosure of financial information extracted from the financial statements of the Corporation and its subsidiaries with particular focus on:

(a) the quality and appropriateness of accounting and reporting practices and principles and any changes thereto;

(b) major estimates or judgments, including alternative treatments of financial information discussed by management and the external auditors, the results of such discussions and the treatment preferred by the external auditors;

(c) material financial risks;

(d) material transactions;

(e) material adjustments;

(f) compliance with loan agreements;

(g) material off-balance sheet transactions and structures;

(h) compliance with accounting standards;

(i) compliance with legal and regulatory requirements;

(j) controls; and

(k) disagreements with management.

(5) ***Overseeing Internal Financial Control Structure and Financial Risk Management Systems***

The Committee shall be responsible for overseeing the internal financial control structure and financial risk management systems of the Corporation and its subsidiary entities, including:

(a) reviewing and discussing with management and the external auditors the quality and adequacy of internal control over financial reporting structures of the Corporation and its subsidiary entities, including any major deficiencies or weakness and the steps taken by management to rectify these deficiencies or weaknesses;

(b) reviewing and discussing with management, the internal auditor and the external auditors the risk assessment and risk management policies of the Corporation and its subsidiary entities, the major financial risk exposures of the Corporation and its subsidiary entities, and the steps taken by management to monitor and control these exposures;

(c) reviewing and discussing with the Chief Executive Officer and the Chief Financial Officer of the Corporation the procedures undertaken by them in connection with the certifications required to be given by them in connection with annual and other filings required to be made by the Corporation under applicable securities laws; and

(d) periodically reviewing the Treasury Policy Register and making recommendations to the Board in respect of such policy and reviewing performance under this policy with Management.

(6) ***Establish and Review Certain Procedures and Policies***

The Committee shall establish adequate policies and procedures, or require that adequate policies and procedures are established, with respect to the following, and shall annually, or on such other schedule as stated herein, assess the adequacy of these procedures:

(a) the review of the public disclosure of financial information extracted from the financial statements of the Corporation;

(b) the receipt, retention and treatment of complaints received by the Corporation with respect to accounting, internal controls or auditing matters;

(c) the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters;

(d) the approval by the Committee of the hiring policies for any present or former partner or employee of the current and former external auditor into a position of senior management with the Corporation or its subsidiaries; and

(e) the periodic review of the Policy on the Provision of Services by the External Auditors and Expense Reimbursement Policy, and provision of recommendations to the Board in respect of the same.

(7) ***Review of Policy Reporting***

(a) The Committee shall be responsible, on a quarterly basis, for reviewing and reporting to the Board in respect of the report of Internal Audit with respect to incidents regarding questionable accounting or auditing matters investigated under the Code of Business Conduct and Whistleblower Procedure during the previous quarter.

(b) The Committee shall be responsible for reviewing, on a quarterly basis, the report of Internal Audit concerning executive and Board expense reimbursements made in accordance with the Corporation's Expense Reimbursement Policy for the immediately preceding quarter.

(8) ***Review and Recommendations for Dividend Payment***

(a) The Committee shall be responsible for reviewing and making recommendations to each respective board of directors, as applicable, with respect to the declaration of dividends or distribution of capital by the Corporation or its subsidiary entities.

4. Authority

(1) The Committee is authorized to carry out its responsibilities as set out in this Charter and to make recommendations to the Board and the boards of directors of the Corporation's subsidiaries arising therefrom.

(2) The Committee may delegate by written policy to the Chair and the Executive Vice-President and Chief Financial Officer of the Corporation ***(CFO)*** the authority, within specified limits, to authorize in advance all engagements of the external auditors to provide pre-approved services to the Corporation and its subsidiary entities. The Chair and the CFO shall report all engagements authorized by them to the Committee at its next meeting.

(3) The Committee shall have direct and unrestricted access to the external and internal auditors, officers and employees and information and records of the Corporation and its subsidiary entities.

(4) The Committee is authorized to retain, and to set and pay the compensation of, independent legal counsel and other advisors if it considers this appropriate.

(5) The Committee is authorized to invite officers and employees of the Corporation and its subsidiaries and outsiders with relevant experience and expertise to attend or participate in its meetings and proceedings if it considers this appropriate.

(6) The external auditors shall have direct and unrestricted access to the Committee and shall report directly to the Committee.

(7) The Corporation shall pay directly or reimburse the Committee for the expenses incurred by the Committee in carrying out its responsibilities, in accordance with the Corporation's Expense Reimbursement Policy.

5. Meetings and Proceedings

(1) The Committee shall meet as frequently as required but not less frequently than four times each year.

(2) Any Member or THESL Member or the Secretary may call a meeting of the Committee. The external auditors or the CFO may ask a Member to call a meeting of the Committee. The Chair, along with the Designated Representative, is responsible for the agenda of each meeting of the Committee, including input from the officers and employees of the Corporation and its subsidiary entities, external auditors, other Members and THESL Members, and other directors of the Corporation as appropriate. Meetings will include presentations by management and others when appropriate and allow sufficient time to permit a full and open discussion of agenda items.

(3) Unless waived by all Members and THESL Members, a notice of each meeting of the Committee confirming the date, time, place and agenda of the meeting, together with any supporting materials, shall be forwarded, electronically or otherwise, to each Member and THESL Member at least three days before the date of the meeting.

(4) The quorum for each meeting of the Committee is at least 50% of the Members. In the absence of the Chair, the other Members may appoint one of their number as chair of a meeting. The Chair of a meeting shall not have a second or casting vote.

(5) The Chair or a delegate of the Chair shall report to the Board following each meeting of the Committee.

(6) The Secretary or a delegate of the Secretary shall keep minutes of all meetings of the Committee, including all resolutions passed by the Committee. Minutes of all meetings shall be distributed to the Members and THESL Members. The minutes shall be available for review by the other directors of the Corporation after approval thereof by the Committee.

(7) An individual who is not a Member may be invited to attend a meeting of the Committee for all or part of the meeting. A standing invitation to all meetings shall be given to the President and Chief Executive Officer of the Corporation and the CFO, except where the meeting, or part of the meeting, is for Members only or a private session with the internal auditor or the external auditors. A standing invitation should be given to the internal auditor and the engagement partners of the external auditors for all meetings where financial information is reviewed and approved.

(8) The Committee shall meet regularly alone and in private sessions with the Vice President, Audit and Corporate Compliance, the external auditors and management of the Corporation to facilitate full communication.

6. Review

(1) This Charter shall be reviewed by the Corporate Governance and Nominating Committee of the Corporation every three (3) years and any recommended changes shall be referred first to the Audit Committee for review and comment and second, after consideration of the input from the Audit Committee, to the Board of the Corporation for consideration and disposition.

(2) In addition to the triennial review, the Audit Committee may at any time review the Charter and make recommendations to the Corporate Governance and Nominating Committee for their review and recommendations to the Board with respect thereto.

ANNEX B - MANDATE – BOARD OF DIRECTORS

1. General

(1) The board of directors ***(Board)*** of *Toronto Hydro Corporation* ***(Corporation)*** is responsible for supervising the management of the business and affairs of the Corporation and its subsidiary entities ***(Group)***.

(2) The composition, responsibilities, and authority of the Board are set out in this Mandate.

(3) This Mandate, the Shareholder Direction issued by the City of Toronto ***(Shareholder)*** and the by-laws of the Corporation and such other procedures, not inconsistent therewith, as the Board may adopt from time to time shall govern the meetings and procedures of the Board.

2. Composition

(1) The directors of the Corporation ***(Directors)*** should have a mix of competencies and skills necessary to enable the Board and Board committees to properly discharge their responsibilities.

(2) All of the Directors shall be residents of Canada.

(3) The Shareholder shall appoint Directors every two years.

(4) In appointing Directors the Shareholder shall give due regard to the qualifications of the candidates including:

(a) experience on a public utility commission or board of a major corporation or other commercial enterprise and/or the completion of formal training in directorship / governance;

(b) experience in regulated electricity utility sector at a senior management level;

(c) experience at an executive level in resource and performance management / compensation, including ability to appoint and evaluate the performance of the CEO and senior executives; oversee strategic human resource management, including workforce planning, compensation models, and labour relations; and oversee large scale organizational change;

(d) educational background, including university degrees and professional designations;

(e) experience or knowledge with respect to:

i) strategic planning, including ability to identify and critically assess strategic opportunities and threats to the organization;

ii) risk management, including ability to assess key risks to the organization on an enterprise basis and monitor the risk management framework systems;

iii) corporate finance / accounting / audit / securities, including ability to analyze financial statements, assess financial viability, contribute to financial planning, oversee budgets, and oversee funding arrangements;

iv) corporate governance;

v) market development, innovation and development of new strategic business lines;

vi) large system operation and management;

vii) urban energy industries;

viii) public policy issues and laws relating to the Corporation and its subsidiary entities and the electricity industry;

ix) environmental matters, including experience in environmental management;

x) labour relations;

xi) occupational health and safety issues;

xii) information technology governance, including privacy, data management and security;

xiii) legal and regulatory compliance, including ability to monitor compliance of legal and regulatory requirements;

xiv) stakeholder engagement / advocacy / communications, including ability to effectively engage and communicate to industry stakeholders and advocate on behalf of the organization;

(f) the following interpersonal skills and attributes:

i) leadership, including ability to make, and take responsibility for, decisions and take necessary actions in the best interest of the organization, set appropriate Board and organizational culture and represent the organization favourably;

ii) personal integrity / ethics, including understanding and fulfilling the duties and responsibilities of a director, being transparent and declaring any activities or conduct that might be a potential conflict, and maintaining Board confidentiality;

iii) communications skills, including ability to listen constructively and appropriately debate others' viewpoints, develop and deliver cogent arguments, and communicate effectively with a broad range of stakeholders;

iv) constructive questioning, including preparedness to ask questions and challenge management and peer directors in a constructive and appropriate manner;

v) critical and innovative thinking / decision making, including ability to critically analyze complex and detailed information, readily distill key issues, and develop innovative approaches and solutions to problems;

vi) influencing and negotiating, including ability to negotiate outcomes and influence others to agree with those outcomes and gain stakeholder support for the Board's decisions;

vii) crisis management, including ability to constructively manage crises, provide leadership around solutions and contribute to communications strategy with stakeholders;

viii) individual and team contribution, including ability to work as part of a team, and demonstrate the passion and time to make a genuine and active contribution to the Board and the organization;

ix) commercial sensitivity and acumen; and

x) independence of judgement

(g) at least three directors with financial management expertise.

(5) The Board shall appoint a Chair of the Board upon the nomination of the Shareholder from time to time.

(6) The Secretary of the Corporation shall be secretary of the Board ***(Secretary)***.

3. Responsibilities

(1) The Board is responsible for supervising the management of the business and affairs of the *Group*, including the following specific matters:

a) establishing sound financial principles and performance objectives;

b) approving any dividend payment or distribution of capital;

c) appointing the officers of the Corporation;

d) approving the overall business strategy and related business plan;

e) approving the financing strategy, including the selection of financial institutions and related banking authorities;

f) directing labour and employee relations matters; and

g) approving the financial statements in accordance with the requirements of the *Business Corporations Act* (Ontario).

(2) In discharging their responsibilities, the Directors owe the following duties to the Corporation:

a fiduciary duty: they must act honestly and in good faith with a view to the best interests of the Corporation; and

a duty of care: they must exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances.

In discharging their responsibilities, the Directors are entitled to rely on the honesty and integrity of the senior officers of the Corporation and the auditors and other professional advisors of the Corporation.

In discharging their responsibilities, the Directors are also entitled to directors and officers liability insurance purchased by the Corporation and indemnification from the Corporation to the fullest extent permitted by law and the constating documents of the Corporation.

(3) The Board has specifically recognized its responsibilities for:

(a) to the extent feasible, satisfying itself as to the integrity of the President and Chief Executive Officer ***(CEO)*** and other senior officers of the Group and that the CEO and other senior officers of the Group create a culture of integrity throughout the Group;

(b) adopting a strategic planning process and approving annually (or more frequently if appropriate) a strategic plan which takes into account, among other things, the opportunities and risks of the business of the Group;

(c) considering and overseeing the strategic development of new business opportunities and innovation;

(d) overseeing the identification of the principal risks of the business of the Group and overseeing the implementation of appropriate systems to manage these risks;

(e) interaction of the Board with the Shareholder in accordance with the Shareholder Direction subject to the duties of the Directors at law;

(f) overseeing the integrity of the internal control and management information systems of the Group;

(g) succession planning (including appointing, training and monitoring the senior officers of the Corporation);

(h) recruiting and assessing the performance of the CEO, the compensation of the CEO and other officers of the Group, executive compensation disclosure and oversight of the compensation structure and benefit plans and programs of the Group;

(i) assessing the effectiveness of the Board;

(j) adopting a disclosure policy for the Group;

(k) developing and overseeing the orientation of new Directors, and the continuing education of existing Directors, of the Group; and

(l) developing the approach of the Corporation to corporate governance including a periodic review of the Code of Business Conduct and Whistleblower Procedure of the Group.

(4) In addition to those matters which must by law be approved by the Board, the Board oversees the development of, and reviews and approves, significant corporate plans and initiatives, including the annual business plan and budget, major acquisitions and dispositions and other significant matters of corporate strategy or policy, including the Environmental Policy, Occupational Health and Safety Policy, Code of Business Conduct and Whistleblower Procedure, Disclosure Policy, Signing Policy and Treasury Policy.

(5) In undertaking its responsibilities and overseeing and authorizing the activities of the Corporation, the Board shall consider the interests of its customers, as well as considering and balancing the interests of such other stakeholders as appropriate in the circumstances.

(6) The Board shall periodically review the Shareholder Direction and make recommendations to the Shareholder to facilitate and clarify interaction and communication between the Shareholder and the Board.

(7) The Board shall periodically review the performance of the Board and the Corporation's subsidiary entities against the Shareholder Direction.

(8) The Board shall periodically review the structure and mandate of each Board committee, the effectiveness of each committee, and the appointment and removal of committee members.

(9) The Board shall periodically review performance under the Environmental Policy with management.

(10) To assist the Directors in discharging their responsibilities, the Board expects management of the Corporation to:

(a) review and update annually (or more frequently if appropriate) the strategic plan and report regularly to the Board on the implementation of the strategic plan in light of evolving conditions;

(b) prepare and present to the Board annually (or more frequently if appropriate) a business plan and budget and report regularly to the Board on the Group's performance against the business plan and budget; and

(c) report regularly to the Board on the Corporation's business and affairs and on any matters of material consequence for the Corporation and its Shareholder.

Additional expectations are developed and communicated during the annual strategic planning and budgeting process and during regular Board and Board committee meetings.

(11) The Board considers that generally management should speak for the Corporation in its communications with securities holders and the public. The Board reviews the Corporation's continuous and timely material disclosure with securities holders and the public. All disclosures on behalf of the Corporation are to be made in compliance with the Corporation's disclosure policy.

(12) Directors are expected to attend Board meetings and meetings of Board committees of which they are members. Directors are also expected to spend the time needed, and to meet as frequently as necessary, to discharge their responsibilities.

(13) Directors are expected to undertake such activities as are required from them to remain current in their knowledge of issues relating to the business of the Group and matters relating to any Board committee of which they are members.

(14) Directors are expected to comply with the Code of Business Conduct and Whistleblower Procedure of the Group.

4. Authority

(1) The Board is authorized to carry out its responsibilities as set out in this Mandate.

(2) The Board is authorized to retain, and to set and pay the compensation of, independent legal counsel and other advisors if it considers this appropriate.

(3) The Board is authorized to invite officers and employees of the Corporation and others to attend or participate in its meetings and proceedings if it considers this appropriate.

(4) The Directors have unrestricted access to the officers of the Corporation. The Directors will use their judgment to ensure that any such contact is not disruptive to the operations of the Corporation and, except for the chair of any committee established by the Board, will advise the Chair and the CEO of the Corporation of any direct communications between them and the officers of the Corporation.

(5) The Board and the Directors have unrestricted access to the advice and services of the Secretary.

(6) The Board may delegate certain of its functions to Board committees, each of which will have its own charter.

5. Meetings and Proceedings

(1) The Board shall meet as frequently as is determined to be necessary but not less than four times each year.

(2) Any Director or the Secretary may call a meeting of the Board.

(3) The Chair is responsible for the agenda of each meeting of the Board, including input from other Directors and the officers and employees of the Corporation as appropriate. Meetings will include presentations by management and others when appropriate and allow sufficient time to permit a full and open discussion of agenda items.

(4) Unless waived by all Directors, a notice of each meeting of the Board confirming the date, time, place and agenda of the meeting, together with any supporting materials, shall be forwarded to each Director at least 48 hours before the date of the meeting.

(5) The quorum for each meeting of the Board is a majority of the number of Directors. In the absence of the Chair, the other Directors shall appoint one of their number as chair of a meeting. The chair of a meeting shall not have a second or casting vote.

(6) The Secretary or his delegate shall keep minutes of all meetings of the Board, including all resolutions passed by the Board. Minutes of meetings shall be distributed to the Directors.

(7) An individual who is not a Director may be invited to attend a meeting of the Board for all or part of the meeting.

(8) The Directors shall meet alone regularly to facilitate full communication.

6. Review

(1) This Mandate shall be reviewed by the Corporate Governance Committee every 3 years and any recommended changes shall be brought to the Board of the Corporation for consideration and disposition.

RATE BASE VARIANCE ANALYSIS

1. RATE BASE UPDATE

Exhibit 2A provides information about Toronto Hydro's rate base and capital expenditures. This schedule provides a summary of the 2018 actuals for rate base, explains the material variances, and identifies material changes to the 2019 bridge and 2020 test year as a result of the 2018 actuals. This schedule also provides equivalent updates for capital in-service additions ("ISAs") and construction work in progress ("CWIP"). For updates to capital expenditures, please refer to Tab 2, Schedule 2 of this Exhibit.

Table 1 shows Toronto Hydro's updated asset net book values ("NBV"), working capital allowance ("WCA"), and rate base for 2018 actual results. Actual rate base for 2018 was $4,123.9 million. This is 2.0 percent lower than previously forecast, primarily due to project energization timing differences. (See Exhibit U, Tab 9, Schedule 1, section 3.4 for more information.) Toronto Hydro has updated the 2019 rate base forecast to $4,422.7 million, reflecting consequential changes from 2018 actuals. This is 1.3 percent lower than previously filed.

Table 1: Rate Base Summary ($ Millions) - Application Update

	OEB Approved[1]	Actual				Bridge	Forecast
	2015	2015	2016	2017	2018	2019	2020
Opening PP&E NBV	2,849.0	2,843.2	3,085.4	3,462.0	3,744.7	4,038.8	4,270.4
Closing PP&E NBV	3,134.7	3,085.4	3,462.0	3,744.7	4,038.8	4,232.3	4,489.8
Average PP&E NBV	**2,991.8**	**2,964.3**	**3,273.7**	**3,603.4**	**3,891.8**	**4,135.6**	**4,380.1**
Working Capital Allowance	240.2	247.9	275.8	247.4	232.1	287.2	235.2
Rate Base	**3,232.0**	**3,212.2**	**3,549.5**	**3,850.8**	**4,123.9**	**4,422.7**	**4,615.3**

Toronto Hydro's 2020 rate base forecast is unchanged. The utility estimates that the impact of rate base variances in 2018 and 2019 on the forecast Net Fixed Assets component of 2020 opening rate base will be less than one percent. As discussed in Section 3 below, Toronto Hydro proposes to update its 2020 working capital allowance ("WCA") during the rate order process in this proceeding.

1.1 In-Service Additions ("ISAs") and Construction Work in Progress ("CWIP") Update

Appendix A to this schedule provides an update to Toronto Hydro's response to 2B-Staff-75, part (a) (ii). The utility projects its net total five-year in-service additions to be about one percent greater than the forecast amount which formed the basis of Toronto Hydro's approved capital-related revenue requirement for the 2015-2019 period.

Table 2 provides an update to CWIP values for the 2015-2019 period.

Table 2: Historical, Bridge, and Forecasted Construction Work in Progress ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Forecast
Opening CWIP	522.1	577.7	502.9	485.8	396.4	343.5
Additions (CAPEX)	490.6	508.4	496.6	434.9	425.3	514.0
Deductions (In Service Additions)	(435.3)	(584.3)	(520.3)	(524.4)	(440.6)	(489.8)
Other	0.3	1.1	6.5	0.0	-	-
Closing CWIP	577.7	502.9	485.8	396.4	381.1	367.7

1.2 Fixed Asset Continuity Statements

The continuity statements (OEB Appendix 2-BA) are filed at Exhibit U, Tab 1, Schedule 1, Appendix B.

1.3 Rate Base Variance Analysis[1]

1.3.1 2017 Historical versus 2018 Historical Year

Rate base increased by $273.1 million from 2017 to 2018. The increase in average PP&E NBV of $288.4 million was primarily due to assets coming into service. This was partially offset by WCA, which decreased by $15.3 million, primarily due to lower cost of power expenses related to declining commodity costs.

1.3.2 2018 Historical versus 2019 Bridge Year

Rate base is forecasted to increase by $298.9 million from 2018 to 2019. The increase in average PP&E NBV of $243.8 million is primarily due to assets coming into service. WCA is expected to increase by $55.1 million, primarily due to projected increases in commodity costs.

1.3.3 2019 Bridge versus 2020 Test Year

Rate base is forecasted to increase by $192.6 million from 2019 to 2020. The $244.5 million increase in average PP&E NBV is primarily due to assets coming into service. WCA is expected to decrease by $52.0 million primarily due to a lower WCA rate resulting from the utility's latest lead-lag study, which is partially offset by a projected increase in commodity costs. As discussed in Section 3 below, Toronto Hydro proposes to update its 2020 WCA as part of the rate order process in this proceeding.

[1] Rate base variance analysis for the 2015-2017 period can be found in Exhibit 2A, Tab 1, Schedule 1, at page 3.

1.4 Property, Plant and Equipment

1.4.1 Overview

Table 2 below presents an updated summary of Toronto Hydro's distribution asset balances before and after accumulated depreciation, and excluding CWIP, for the Historical (2015 to 2018), Bridge (2019), and Forecast (2020) years.

Table 3: Gross and Net PP&E – Years Ending December 31 ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Forecast
Land and Buildings	76.2	129.9	141.4	161.6	171.0	169.8
Other Distribution Assets	170.0	238.5	267.3	434.6	507.6	612.7
General Plant	127.7	185.2	247.5	240.1	241.4	243.0
TS Primary Above 50	5.8	6.0	36.9	37.9	38.9	39.1
Distribution System	149.9	156.8	184.5	213.5	233.9	277.9
Poles, Wires	2,172.2	2,430.6	2,663.8	2,876.9	3,132.8	3,426.9
Contributions and Grants	(58.2)	(90.5)	(118.0)	(156.6)	(235.2)	(322.6)
Line Transformers	412.4	465.3	515.4	566.7	640.8	714.2
Services and Meters	262.0	290.0	321.8	344.7	385.3	451.0
Equipment	61.5	100.4	120.8	131.3	140.5	145.9
IT Assets	27.3	47.2	58.7	66.8	74.2	89.0
Gross Assets	**3,406.8**	**3,959.4**	**4,440.1**	**4,917.5**	**5,331.0**	**5,846.8**
Accumulated Depreciation	(320.6)	(496.8)	(684.3)	(876.9)	(1,097.7)	(1,357.0)
Closing PP&E NBV (MIFRS)	**3,086.2**	**3,462.6**	**3,755.8**	**4,040.6**	**4,233.4**	**4,489.8**
Adjustments to Closing PP&E NBV						
Assets held for Sale	-	-	(8.7)	-	-	-
Monthly Billing	(0.7)	(0.6)	(2.3)	(1.7)	(1.1)	-
Closing PP&E NBV	**3,085.4**	**3,462.0**	**3,744.7**	**4,038.8**	**4,232.3**	**4,489.8**

1.4.2 2017 Historical versus 2018 Historical[2]

Actual asset NBV for 2018 was $4,040.6 million compared to $3,755.8 million in 2017. The increase of $284.8 million to $4,040.6 million is primarily due to assets coming into service.

Table 4: 2017 Historical versus 2018 Historical ($ Millions)

	2017 Actual	2018 Actual	Variance ($)	Variance (%)
Land and Buildings	141.4	161.6	20.2	14.3%
Other Distribution Assets	267.3	434.6	167.3	62.6%
General Plant	247.5	240.1	(7.3)	-3.0%
TS Primary Above 50	36.9	37.9	0.9	2.6%
Distribution System	184.5	213.5	29.0	15.7%
Poles, Wires	2,663.8	2,876.9	213.1	8.0%
Contributions and Grants	(118.0)	(156.6)	(38.6)	32.7%
Line Transformers	515.4	566.7	51.3	10.0%
Services and Meters	321.8	344.7	22.9	7.1%
Equipment	120.8	131.3	10.6	8.7%
IT Assets	58.7	66.8	8.1	13.8%
Gross Assets	**4,440.1**	**4,917.5**	**477.4**	**10.8%**
Accumulated Depreciation	(684.3)	(876.9)	(192.6)	28.1%
Closing PP&E NBV (MIFRS)	**3,755.8**	**4,040.6**	**284.8**	**7.6%**

[2] PP&E variances for the 2015-2017 period can be found at Exhibit 2A, Tab 1, Schedule 1, pages 6-8.

1.4.3 2018 Historical versus 2019 Bridge

Forecasted asset NBV for 2019 is $4,233.4 million compared to $4,040.6 million in 2018. The increase of $192.8 million is primarily due to assets coming into service.

Table 5: 2018 Historical versus 2019 Bridge ($ Millions)

	2018 Actual	2019 Bridge	Variance ($)	Variance (%)
Land and Buildings	161.6	171.0	9.3	5.8%
Other Distribution Assets	434.6	507.6	73.0	16.8%
General Plant	240.1	241.4	1.3	0.5%
TS Primary Above 50	37.9	38.9	1.0	2.7%
Distribution System	213.5	233.9	20.4	9.5%
Poles, Wires	2,876.9	3,132.8	255.9	8.9%
Contributions and Grants	(156.6)	(235.2)	(78.7)	50.2%
Line Transformers	566.7	640.8	74.2	13.1%
Services and Meters	344.7	385.3	40.6	11.8%
Equipment	131.3	140.5	9.2	7.0%
IT Assets	66.8	74.2	7.4	11.1%
Gross Assets	**4,917.5**	**5,331.0**	**413.6**	**8.4%**
Accumulated Depreciation	(876.9)	(1,097.7)	(220.7)	25.2%
Closing PP&E NBV (MIFRS)	**4,040.6**	**4,233.4**	**192.8**	**4.8%**

1.4.4 2019 Bridge versus 2020 Forecast

Forecasted asset NBV in 2020 is $4,489.8 million compared to $4,233.4 million in 2019. The increase of $256.4 million is primarily due to assets coming into service. The 2020 NBV opening balance includes an adjustment of $1.1 million for the addition of the assets resulting from the monthly billing program.[3]

Table 6: 2019 Bridge versus 2020 Forecast ($ Millions)

	2019 Bridge	2020 Forecast	Variance ($)	Variance (%)
Land and Buildings	171.0	169.8	(1.2)	-0.7%
Other Distribution Assets	507.6	612.7	105.1	20.7%
General Plant	241.4	243.0	1.6	0.7%
TS Primary Above 50	38.9	39.1	0.2	0.5%
Distribution System	233.9	277.9	44.0	18.8%
Poles, Wires	3,132.8	3,426.9	294.1	9.4%
Contributions and Grants	(235.2)	(322.6)	(87.4)	37.1%
Line Transformers	640.8	714.2	73.4	11.5%
Services and Meters	385.3	451.0	65.7	17.0%
Equipment	140.5	145.9	5.4	3.9%
IT Assets	74.2	89.0	14.8	20.0%
Gross Assets	**5,331.0**	**5,846.8**	**515.8**	**9.7%**
Accumulated Depreciation	(1,097.7)	(1,357.0)	(259.3)	23.6%
Closing PP&E NBV (MIFRS)	**4,233.4**	**4,489.8**	**256.4**	**6.1%**

[3] See Exhibit 9.

2. GROSS ASSETS

2.1 Breakdown by Function

Table 7: Breakdown of Ending Balance of Gross Assets by Function ($ Millions)

Gross Assets	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Forecast
High Voltage Plant	5.8	6.0	36.9	37.9	38.9	39.1
Distribution Plant	3,047.0	3,471.1	3,803.4	4,196.4	4,551.0	4,996.0
General Plant	354.0	482.3	599.8	683.2	741.1	811.7
Gross Fixed Assets Before CWIP	**3,406.8**	**3,959.4**	**4,440.1**	**4,917.5**	**5,331.0**	**5,846.8**
CWIP	577.7	502.9	485.8	396.4	381.1	367.7
Total Including CWIP	**3,984.5**	**4,462.3**	**4,925.9**	**5,313.9**	**5,716.6**	**6,214.5**

Note: Variances due to rounding may exist

2.2 Breakdown by Major Plant Account

Appendix C presents the gross assets breakdown by major plant account based on the uniform system of accounts for 2015-2020.

3. WORKING CAPITAL ALLOWANCE

The Working Capital Allowance filed at Exhibit 2A, Tab 3, Schedule 1 was based on the updated Lead/Lag study applied to forecast revenue, cost of power and eligible expenses.

The response to interrogatory 2A-Staff-53 included an estimate of the Working Capital Allowance reflecting the Cost of Power as calculated using the OEB's Appendix 2-Z. This resulted in a Working Capital Allowance of $202.9 million, compared with the pre-filed value of $235.2 million. The lower Working Capital Allowance would reduce 2020 revenue requirement by approximately $2.2 million. As noted in 2A-Staff-53, Toronto Hydro proposes to include the updated Cost of Power forecast, based on the OEB's Appendix 2-Z (with the most up-to-date forecasts of energy prices), during the Draft Rate Order process.

Toronto Hydro notes that the Ontario Energy Board's revised Customer Service Rules – specifically the extension of the bill payment dates – are expected to have an impact on the collection lag component of the Lead/Lag study. Toronto Hydro estimates the impact of these changes on 2020 revenue requirement to be an increase of $1.6 million. The utility requests that this change be approved by the OEB as part of the 2020 test year and in the calculation of the custom capital factor in the 2021-2024 rate years. However, as the net impact of this is expected to partially offset the change in WCA flowing from the updated Cost of Power, in the interest of efficiency, Toronto Hydro has not updated the 2020 revenue requirement and 2021-2024 custom capital factor at this time. If the change is approved by the OEB, the utility proposes to incorporate it during the Draft Rate Order process.

In-Service Additions for the 2015-2019 Period

	Historical												Bridge			Historical/Bridge		
	2015			2016			2017			2018			2019			2015-2019		
In-Service Additions	**CIR Filing (-10%)**	**Actual**	**Var.**	**CIR Filing (-10%)**	**Actual**	**Var.**	**CIR Filing (-10%)**	**Actual**	**Var.**	**CIR Filing (-10%)**	**Actual**	**Var.**	**CIR Filing (-10%)**	**Forecast**	**Var.**	**CIR Filing (-10%)**	**Actual / Forecast**	**Var.**
Gross	526.8	465.4	-12%	635.6	617.1	-3%	474.4	549.0	16%	413.2	563.6	36%	493.2	519.7	5%	2,543.1	2,714.8	7%
Customer Contributions	(14.3)	(30.1)	110%	(14.4)	(32.8)	127%	(14.9)	(28.7)	93%	(15.5)	(39.2)	153%	(16.0)	(79.1)	394%	(75.1)	(209.9)	180%
Net	**512.5**	**435.3**	**-15%**	**621.1**	**584.3**	**-6%**	**459.5**	**520.3**	**13%**	**397.7**	**524.4**	**32%**	**477.2**	**440.6**	**-8%**	**2,468.0**	**2,504.8**	**1%**

Rounding variances may exist

Notes:

In-Service Additions excludes Other Non Rate-Regulated Utility Assets

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year 2018

CCA Class	OEB Account	Description	Cost (Historical) Opening Balance	Additions	Disposals	Closing Balance	Accumulated Depreciation (Historical) Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 136,960,666	$ 73,814,110	($ 2,863,680)	$ 207,911,095	($ 77,314,695)	($ 20,892,805)	$ 1,478,618	($ 96,728,883)	$ 111,182,213
N/A	1612	Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 7,006,433	$ -	($ 1)	$ 7,006,432	$ -	$ -	$ -	$ -	$ 7,006,432
1	1808	Buildings	$ 116,632,610	$ 20,897,786	($ 269,609)	$ 137,260,787	($ 9,689,454)	($ 3,308,486)	$ 259,617	($ 12,738,324)	$ 124,522,463
47	1815	Transformer Station Equipment >50 kV	$ 36,917,966	$ 944,609	$ -	$ 37,862,575	($ 1,863,155)	($ 1,298,265)	$ -	($ 3,161,419)	$ 34,701,155
47	1820	Distribution Station Equipment <50 kV	$ 184,513,183	$ 30,319,716	($ 1,316,122)	$ 213,516,777	($ 28,844,525)	($ 8,622,713)	$ 531,283	($ 36,935,955)	$ 176,580,822
47	1830	Poles, Towers & Fixtures	$ 362,478,012	$ 21,287,951	($ 2,982,045)	$ 380,783,918	($ 36,669,123)	($ 10,921,669)	$ 452,096	($ 47,138,696)	$ 333,645,222
47	1835	Overhead Conductors & Devices	$ 390,547,495	$ 41,090,486	($ 3,322,079)	$ 428,315,901	($ 33,325,134)	($ 10,827,432)	$ 402,885	($ 43,749,681)	$ 384,566,221
47	1840	Underground Conduit	$ 1,127,938,656	$ 78,574,199	($ 923,662)	$ 1,205,589,193	($ 154,477,992)	($ 44,888,220)	$ 496,841	($ 198,869,371)	$ 1,006,719,822
47	1845	Underground Conductors & Devices	$ 782,844,420	$ 87,194,048	($ 7,833,777)	$ 862,204,692	($ 77,543,562)	($ 25,369,256)	$ 1,617,529	($ 101,295,289)	$ 760,909,403
47	1850	Line Transformers	$ 515,354,184	$ 62,025,718	($ 10,711,850)	$ 566,668,052	($ 77,429,407)	($ 23,997,546)	$ 3,384,391	($ 98,042,562)	$ 468,625,490
47	1855	Services (Overhead & Underground)	$ 122,134,425	$ 3,010,082	($ 519,052)	$ 124,625,454	($ 8,668,122)	($ 2,947,558)	$ 38,585	($ 11,577,095)	$ 113,048,359
47	1860	Meters	$ 79,895,152	$ 8,057,288	($ 834,542)	$ 87,117,898	($ 12,964,895)	($ 4,490,265)	$ 194,656	($ 17,260,504)	$ 69,857,394
47	1860	Meters (Smart Meters)	$ 119,808,247	$ 16,301,957	($ 3,155,319)	$ 132,954,885	($ 39,208,620)	($ 11,528,648)	$ 1,235,352	($ 49,501,916)	$ 83,452,969
N/A	1905	Land	$ 17,738,379	$ -	($ 379,722)	$ 17,358,657	$ -	$ -	$ -	$ -	$ 17,358,657
1	1908	Buildings & Fixtures	$ 246,710,392	$ 4,456,339	($ 11,797,576)	$ 239,369,154	($ 29,323,031)	($ 11,318,351)	$ 3,060,414	($ 37,580,968)	$ 201,788,186
13	1910	Leasehold Improvements	$ 753,840	$ -	$ -	$ 753,840	($ 734,624)	($ 10,481)	$ -	($ 745,106)	$ 8,734
8	1915	Office Furniture & Equipment	$ 18,953,218	$ 673,247	$ 363,852	$ 19,990,318	($ 7,295,578)	($ 2,051,264)	$ 426	($ 9,346,416)	$ 10,643,902
50	1920	Computer Equipment - Hardware	$ 58,683,341	$ 8,077,721	$ -	$ 66,761,063	($ 28,967,065)	($ 10,714,855)	$ -	($ 39,681,921)	$ 27,079,142
10	1930	Transportation Equipment	$ 33,718,724	$ 2,912,073	($ 547,155)	$ 36,083,642	($ 21,592,028)	($ 3,636,383)	$ 547,155	($ 24,681,256)	$ 11,402,386
8	1935	Stores Equipment	$ 7,066	$ -	$ -	$ 7,066	($ 7,066)	$ -	$ -	($ 7,066)	$ -
8	1940	Tools, Shop & Garage Equipment	$ 21,151,564	$ 2,199,041	$ -	$ 23,350,605	($ 9,064,186)	($ 2,257,857)	$ -	($ 11,322,044)	$ 12,028,562
8	1945	Measurement & Testing Equipment	$ 480,243	$ -	$ -	$ 480,243	($ 274,545)	($ 59,822)	$ -	($ 334,367)	$ 145,875
8	1950	Service Equipment	$ 845,773	$ 544,550	($ 125,129)	$ 1,265,194	($ 481,618)	($ 159,091)	$ 28,724	($ 611,984)	$ 653,210
8	1955	Communications Equipment	$ 45,358,046	$ 4,530,356	$ -	$ 49,888,402	($ 10,349,452)	($ 4,690,337)	$ -	($ 15,039,789)	$ 34,848,612
8	1960	Miscellaneous Equipment	$ 270,978	$ -	$ -	$ 270,978	($ 148,393)	($ 37,310)	$ -	($ 185,703)	$ 85,275
47	1970	Load Management Controls Customer Premises	$ 3,022,834	$ -	$ -	$ 3,022,834	($ 3,022,834)	$ -	$ -	($ 3,022,834)	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 35,587,033	$ 6,524,511	($ 393,736)	$ 41,717,808	($ 8,735,164)	($ 2,802,429)	$ 85,125	($ 11,452,469)	$ 30,265,340
47	2440	Contributions & Grants (Formally known as Account 1995)	($ 117,959,106)	($ 39,248,789)	$ 635,109	($ 156,572,786)	$ 11,205,218	$ 5,263,537	($ 112,504)	$ 16,356,251	($ 140,216,535)
N/A	1609	Capital Contributions Paid	$ 75,574,497	$ 88,593,906	$ -	$ 164,168,403	($ 7,221,863)	($ 3,538,390)	$ -	($ 10,760,252)	$ 153,408,151
N/A	2005	Property Under Capital Leases	$ 18,170,834	$ 1,576,880	$ -	$ 19,747,714	($ 10,349,973)	($ 1,320,504)	$ -	($ 11,670,476)	$ 8,077,238
		Sub-Total	**$ 4,442,099,105**	**$ 524,357,783**	**($ 46,976,096)**	**$ 4,919,480,793**	**($ 684,360,885)**	**($ 206,426,400)**	**$ 13,701,192**	**($ 877,086,094)**	**$ 4,042,394,698**
		Less Socialized Renewable Energy Generation Investments (input as negative)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	($ 2,002,023)	$ -	$ -	($ 2,002,023)	$ 33,367	$ 133,468	$ -	$ 166,835	($ 1,835,187)
		Total PP&E	**$ 4,440,097,082**	**$ 524,357,783**	**($ 46,976,096)**	**$ 4,917,478,770**	**($ 684,327,518)**	**($ 206,292,932)**	**$ 13,701,192**	**($ 876,919,259)**	**$ 4,040,559,511**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)						$ -			
		Total						**($ 206,292,932)**			

10		Transportation
		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	($ 961,328)
Stores Equipment	$ -
Net Depreciation	($ 205,331,604)

Notes:
Fixed Asset Continuity Schedule includes monthly billing
Socialized Renewable Energy Generation Investments include Energy Storage program
Other Non Rate-Regulated Utility Assets includes Generation Protection, Monitoring and Control program

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year 2019

			Cost (Bridge)				Accumulated Depreciation (Bridge)				
CCA Class	**OEB Account**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 207,911,095	$ 40,029,185	$ -	$ 247,940,281	($ 96,728,883)	($ 27,968,318)	$ -	($ 124,697,201)	$ 123,243,080
N/A	1612	Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 7,006,432	$ -	$ -	$ 7,006,432	$ -	$ -	$ -	$ -	$ 7,006,432
1	1808	Buildings	$ 137,260,787	$ 9,342,754	$ -	$ 146,603,541	($ 12,738,324)	($ 3,576,986)	$ -	($ 16,315,310)	$ 130,288,231
47	1815	Transformer Station Equipment >50 kV	$ 37,862,575	$ 1,030,716	$ -	$ 38,893,291	($ 3,161,419)	($ 1,339,480)	$ -	($ 4,500,900)	$ 34,392,391
47	1820	Distribution Station Equipment <50 kV	$ 213,516,777	$ 20,600,010	($ 220,453)	$ 233,896,334	($ 36,935,955)	($ 9,828,871)	$ 64,678	($ 46,700,148)	$ 187,196,185
47	1830	Poles, Towers & Fixtures	$ 380,783,918	$ 28,474,609	($ 6,687,576)	$ 402,570,951	($ 47,138,696)	($ 11,163,183)	$ 1,605,971	($ 56,695,908)	$ 345,875,043
47	1835	Overhead Conductors & Devices	$ 428,315,901	$ 42,197,486	($ 2,275,088)	$ 468,238,300	($ 43,749,681)	($ 11,552,701)	$ 379,755	($ 54,922,627)	$ 413,315,673
47	1840	Underground Conduit	$ 1,205,589,193	$ 101,150,177	($ 620,190)	$ 1,306,119,180	($ 198,869,371)	($ 47,764,130)	$ 157,745	($ 246,475,756)	$ 1,059,643,424
47	1845	Underground Conductors & Devices	$ 862,204,692	$ 98,357,471	($ 4,710,197)	$ 955,851,966	($ 101,295,289)	($ 26,963,221)	$ 439,621	($ 127,818,888)	$ 828,033,077
47	1850	Line Transformers	$ 566,668,052	$ 82,017,280	($ 7,856,970)	$ 640,828,362	($ 98,042,562)	($ 25,545,270)	$ 1,089,782	($ 122,498,051)	$ 518,330,312
47	1855	Services (Overhead & Underground)	$ 124,625,454	$ 17,117,258	($ 330,315)	$ 141,412,397	($ 11,577,095)	($ 3,062,482)	$ 19,049	($ 14,620,528)	$ 126,791,869
47	1860	Meters	$ 87,117,898	$ 19,232,313	($ 1,296,379)	$ 105,053,832	($ 17,260,504)	($ 4,819,143)	$ 178,367	($ 21,901,280)	$ 83,152,552
47	1860	Meters (Smart Meters)	$ 132,954,885	$ 8,807,217	($ 2,919,112)	$ 138,842,990	($ 49,501,916)	($ 11,966,280)	$ 670,045	($ 60,798,152)	$ 78,044,838
N/A	1905	Land	$ 17,358,657	$ -	$ -	$ 17,358,657	$ -	$ -	$ -	$ -	$ 17,358,657
1	1908	Buildings & Fixtures	$ 239,369,154	$ 1,250,623	$ -	$ 240,619,777	($ 37,580,968)	($ 11,325,101)	$ -	($ 48,906,069)	$ 191,713,707
13	1910	Leasehold Improvements	$ 753,840	$ -	$ -	$ 753,840	($ 745,106)	($ 8,734)	$ -	($ 753,840)	$ -
8	1915	Office Furniture & Equipment	$ 19,990,318	$ 448,337	$ -	$ 20,438,655	($ 9,346,416)	($ 2,067,790)	$ -	($ 11,414,206)	$ 9,024,448
50	1920	Computer Equipment - Hardware	$ 66,761,063	$ 7,398,534	$ -	$ 74,159,596	($ 39,681,921)	($ 10,812,376)	$ -	($ 50,494,297)	$ 23,665,300
10	1930	Transportation Equipment	$ 36,083,642	$ 4,995,050	$ -	$ 41,078,692	($ 24,681,256)	($ 3,141,469)	$ -	($ 27,822,725)	$ 13,255,967
8	1935	Stores Equipment	$ 7,066	$ -	$ -	$ 7,066	($ 7,066)	$ -	$ -	($ 7,066)	$ -
8	1940	Tools, Shop & Garage Equipment	$ 23,350,605	$ 5,530,796	$ -	$ 28,881,401	($ 11,322,044)	($ 2,443,955)	$ -	($ 13,765,998)	$ 15,115,403
8	1945	Measurement & Testing Equipment	$ 480,243	$ 19,437	$ -	$ 499,679	($ 334,367)	($ 61,540)	$ -	($ 395,908)	$ 103,772
8	1950	Service Equipment	$ 1,265,194	$ 122,762	$ -	$ 1,387,956	($ 611,984)	($ 131,053)	$ -	($ 743,037)	$ 644,919
8	1955	Communications Equipment	$ 49,888,402	$ 802,266	$ -	$ 50,690,668	($ 15,039,789)	($ 4,719,684)	$ -	($ 19,759,473)	$ 30,931,195
8	1960	Miscellaneous Equipment	$ 270,978	$ -	$ -	$ 270,978	($ 185,703)	($ 37,310)	$ -	($ 223,012)	$ 47,965
47	1970	Load Management Controls Customer Premises	$ 3,022,834	$ -	$ -	$ 3,022,834	($ 3,022,834)	$ -	$ -	($ 3,022,834)	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 41,717,808	$ 10,865,041	($ 503,552)	$ 52,079,297	($ 11,452,469)	($ 3,134,194)	$ 54,408	($ 14,532,254)	$ 37,547,043
47	2440	Contributions & Grants (Formally known as Account 1995)	($ 156,572,786)	($ 79,065,880)	$ 395,247	($ 235,243,420)	$ 16,356,251	$ 5,711,872	($ 20,148)	$ 22,047,976	($ 213,195,444)
N/A	1609	Capital Contributions Paid	$ 164,168,403	$ 26,301,319	$ -	$ 190,469,722	($ 10,760,252)	($ 7,235,447)	$ -	($ 17,995,699)	$ 172,474,023
N/A	2005	Property Under Capital Leases	$ 19,747,714	$ -	$ -	$ 19,747,714	($ 11,670,476)	($ 652,639)	$ -	($ 12,323,115)	$ 7,424,599
		Sub-Total	**$ 4,919,480,793**	**$ 447,024,759**	**($ 27,024,585)**	**$ 5,339,480,967**	**($ 877,086,094)**	**($ 225,609,486)**	**$ 4,639,274**	**($ 1,098,056,306)**	**$ 4,241,424,660**
		Less Socialized Renewable Energy Generation Investments (input as negative)	$ -	($ 2,730,141)	$ -	($ 2,730,141)	$ -	$ 34,127	$ -	$ 34,127	($ 2,696,014)
		Less Other Non Rate-Regulated Utility Assets (input as negative)	($ 2,002,023)	($ 3,702,262)	$ -	($ 5,704,285)	$ 166,835	$ 202,609	$ -	$ 369,444	($ 5,334,841)
		Total PP&E	**$ 4,917,478,770**	**$ 440,592,356**	**($ 27,024,585)**	**$ 5,331,046,541**	**($ 876,919,259)**	**($ 225,372,751)**	**$ 4,639,274**	**($ 1,097,652,736)**	**$ 4,233,393,805**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)						$ -			
		Total						**($ 225,372,751)**			

10		Transportation
		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	($ 1,759,521)
Stores Equipment	$ -
Net Depreciation	($ 223,613,230)

Notes:
Fixed Asset Continuity Schedule includes monthly billing
Socialized Renewable Energy Generation Investments include Energy Storage program
Other Non Rate-Regulated Utility Assets includes Generation Protection, Monitoring and Control program

Appendix A: Gross Assets Breakdown by Major Plant Account – Detailed by Uniform System of Account ($ Million)

	Description	2015 Actuals MIFRS	2016 Actuals MIFRS	2017 Actuals MIFRS	2018 Actuals MIFRS	2019 Bridge MIFRS	2020 Forecast MIFRS
1815	Transformer Station Equipment	5.8	6.0	36.9	37.9	38.9	39.1
	Subtotal High Voltage Plant	5.8	6.0	36.9	37.9	38.9	39.1
1805	Land	7.1	7.1	7.0	7.0	7.0	7.0
1808	Buildings and Fixtures	51.4	105.1	116.6	137.3	146.6	145.4
1820	Distribution Station Equipment	149.9	156.8	184.5	213.5	233.9	277.9
1830	Poles, Towers and Fixtures	311.0	339.5	362.5	380.8	402.6	435.8
1835	O/H Conductors and Devices	299.4	349.5	390.5	428.3	468.2	515.0
1840	U/G Conduit	952.0	1,051.0	1,127.9	1,205.6	1,306.1	1,432.3
1845	U/G Conductors and Devices	609.9	690.6	782.8	862.2	955.9	1,043.7
1850	Line Transformers	412.4	465.3	515.4	566.7	640.8	714.2
1855	Services	93.3	109.1	122.1	124.6	141.4	175.3
1860	Meters (includes Smart Meters)	168.7	180.9	199.7	220.1	243.9	275.7
1970	Load Management-Customer	3.0	3.0	3.0	3.0	3.0	3.0
1980	System Supervisory Equipment	25.4	28.2	33.6	39.7	46.4	55.2
1609	Capital Contributions Paid	21.7	75.6	75.6	164.2	190.5	238.0
2440	Contributed Capital	(58.2)	(90.5)	(118.0)	(156.6)	(235.2)	(322.6)
	Subtotal Distribution Plant	3,047.0	3,471.1	3,803.4	4,196.4	4,551.0	4,996.0
1611	Computer Software	101.6	113.6	137.0	207.9	247.9	298.3
1905	Land	17.7	17.7	17.7	17.4	17.4	17.4
1612	Land Rights	-	-	-	1.6	1.6	
1908	Buildings and Fixtures	126.9	184.5	246.7	239.4	240.6	242.2
1910	Leasehold Improvements	0.8	0.8	0.8	0.8	0.8	0.8
1915	Office Furniture and Equipment	10.8	15.4	19.0	20.0	20.4	21.1
1920	Computer Equipment	27.3	47.2	58.7	66.8	74.2	89.0
1930	Transportation Equipment	26.6	29.9	33.7	36.1	41.1	46.2
1935	Stores Equipment	0.0	0.0	0.0	0.0	0.0	0.0
1940	Tools, Shop and Garage Equipment	14.7	17.8	21.2	23.4	26.2	28.4
1945	Measurement & Test Equipment	0.5	0.5	0.5	0.5	0.5	0.5
1950	Power Operated Equipment	0.6	0.7	0.8	1.3	1.4	1.2
1955	Communication Equipment	8.0	35.9	45.4	49.9	50.7	48.3
1960	Miscellaneous Equipment	0.3	0.3	0.3	0.3	0.3	0.3
2005	Property Under Capital Leases	18.2	18.2	18.2	18.2	18.2	18.2
	Subtotal General Plant	354.0	482.3	599.8	683.2	741.1	811.7
	GROSS FIXED ASSETS BEFORE CWIP	3,406.8	3,959.4	4,440.1	4,917.5	5,331.0	5,846.8
2055	Construction Work-in-Process	577.7	502.9	485.8	396.4	381.1	367.7
	TOTAL INCLUDING CWIP	3,984.5	4,462.3	4,925.9	5,313.9	5,712.2	6,214.5

CAPITAL EXPENDITURES VARIANCE ANALYSIS

1. CAPITAL EXPENDITURES

This schedule provides a summary of the capital expenditure variances resulting from the update of 2018 actuals. This information is supplemental to the comprehensive 2015-2019 Distribution System Plan ("DSP") variance analysis provided in Exhibit 2B, Section E4, and the detailed 2015-2019 capital program-level variance analyses provided in Exhibit 2B, Sections E5 to E8.

Updated OEB Appendices 2-AA and 2-AB (initially filed at Exhibit 2A, Tab 4, Schedules 2 and 3, and discussed further in Exhibit 2B, Section E4) can be found as Appendices A and B to this schedule. Toronto Hydro has updated these Appendices for 2018 actual expenditures and any consequential 2019 forecast adjustments.

Toronto Hydro is also providing, as Appendix C to this schedule, an updated OEB Appendix 2-AB in the format requested by OEB Staff in undertaking JTC1.2, wherein:

- the portfolio and Gross Total Expenditure lines reflect all capital expenditures made by the utility, including capital contributions made to Hydro One;
- the Capital Contributions Received line includes all capital contributions to the utility from its customers; and
- the Net Total Expenditures line represents the difference between the Gross Total Expenditures and the Capital Contributions Received.

1.1 Update to Plan versus Actual Variances for 2015-2019

As explained in Exhibit 2B, Section E4.1, the OEB approved the utility's custom rate setting mechanism and a resulting capital related revenue requirement ("CRRR") of $2,497.9 million for the 2015-2019 period. Toronto Hydro's forecast capital spending continues to be slightly less than approved for the period, resulting in a refund to customers through the CRRR Variance Account.[1] As a result primarily of variances in project energization timing in 2018 and 2019, this refund has been updated to $77.9 million from $59.4 million.[2] As discussed in Exhibit U, Tab 2, Schedule 1, Section 1, despite shifts in energization timing over the 2015-2019 period, Toronto Hydro's total in-service additions ("ISA") are forecast to be within one percent of the ISA amount that formed the basis of the OEB-approved CRRR for the period, indicating successful completion of the funded 2015-2019 Distribution System Plan.

Toronto Hydro's capital expenditures totalled $435.6 million in 2018. The utility is on pace for $443.0 million in capital expenditures in 2019. Overall, Toronto Hydro expects to spend $2,379.4 million during the 2015-2019 period, which is four percent less than the $2,489.3 million forecast in the utility's 2015-2019 DSP, and is virtually unchanged from the $2,383.5 previously forecast in this application. Table 1, below, presents the breakdown of plan[3] versus actuals by year and by category.

[1] See Exhibit 9, Tab 1, Schedule 1 for more information.
[2] See Exhibit U, Tab 9, Schedule 1, Section 4.5
[3] As noted in Exhibit 2B, Section E4, "plan" refers to the utility's 2015-2019 Distribution System Plan as originally filed.

Table 1: Historical Capital Expenditure Summary ($ Millions)

Category	Historical												Bridge		
	2015			2016			2017			2018			2019		
	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	For.	Var.
System Access	86.1	58.3	(32%)	95.3	79.0	(17%)	104.9	65.5	(38%)	95.8	88.0	(8%)	92.3	112.1	21%
System Renewal	251.7	304.1	21%	239.6	266.1	11%	256.2	250.3	(2%)	275.9	245.5	(11%)	287.3	244.2	(15%)
System Service	76.5	37.9	(50%)	70.7	53.3	(25%)	65.1	72.4	11%	52.6	31.0	(41%)	80.2	41.5	(48%)
General Plant	104.6	79.4	(24%)	101.5	109.5	8%	30.3	98.9	226%	34.2	58.4	71%	30.3	46.4	53%
Other	12.2	11.6	(5%)	11.6	3.7	(68%)	10.8	10.7	(1%)	11.5	12.7	10%	12.1	(1.3)	(111%)
Total CAPEX	**531.1**	**491.4**	**(7%)**	**518.8**	**511.6**	**(1%)**	**467.4**	**497.8**	**7%**	**470.0**	**435.6**	**(7%)**	**502.2**	**443.0**	**(12%)**
System O&M	128.8		116.1		(10%)		126.5		126.3		139.6		131.0		

1.2 System Access Update

In 2018, Toronto Hydro invested $88.0 million in the demand and compliance driven activities that constitute its System Access programs. The utility forecasts $112.1 million in additional investments in 2019. Overall, the utility is on pace to spend $402.9 million during the 2015-2019 period, which is about 15 percent less than the $474.5 million originally forecast in the utility's 2015-2019 DSP, and about 0.5 percent greater than initially forecast in this application.

As discussed in the following sections, variances over the 2018-2019 period are primarily driven by variances in the Externally Initiated Plant Relocations and Expansion program as a result of third party schedule delays. Variances in other programs are minor.

1.2.1 Customer Connections

Over the 2015-2019 period, Toronto Hydro's net capital expenditures for the Customer Connections program have not materially changed from the forecast expenditures

provided in Exhibit 2B, Section E5.1. In 2018, Toronto Hydro's expenditures in this program were $44.0 million.

Table 2: Historical and Forecast Customer Connections Program Costs ($ Millions)

	Actual				Bridge
	2015	**2016**	**2017**	**2018**	**2019**
Customer Connection	32.6	39.6	22.1	43.5	39.8
Generation Connection	(0.9)	0.4	(0.2)	0.5	0.0
Total	**31.7**	**40.1**	**21.9**	**44.0**	**39.8**

Customer Connections

In 2018, Toronto Hydro's net capital expenditures under the Customer Connection segment were essentially on budget, coming in at $43.5 million versus the $44.8 million previously forecast in this application. Toronto Hydro is forecasting a slight increase in 2019 expenditures, from the $37.6 million previously filed to $39.8 million.

Table 3: Historical and Forecast Customer Connection Segment Costs ($ Millions)

		Actual				Bridge
		2015	**2016**	**2017**	**2018**	**2019**
Customer Connection	*Gross*	68.3	67.1	58.6	81.1	83.6
	Capital Contribution	(35.7)	(27.4)	(36.5)	(37.6)	(43.8)
	Net	**32.6**	**39.6**	**22.1**	**43.5**	**39.8**

Generation Connections

Toronto Hydro spent a gross amount of $1.1 million connecting 322 distributed generation facilities in 2018. The utility continues to forecast $2.8 million of additional expenditures in 2019. Overall, Toronto Hydro forecasts $6.3 million of fully recoverable expenditures in this program during the 2015-2019 period, which is $2.8 million lower

than the $9.1 million previously filed in this application. Variances are generally caused by factors outside of the utility's control, including customer-driven connection delays.

Table 4: Historical & Forecast Generation Connection Segment Costs ($ Millions)

		Actual				Bridge
		2015	**2016**	**2017**	**2018**	**2019**
Generation Connection	*Gross*	0.9	0.6	0.8	1.1	2.8
	Customer Contribution†	(1.8)	(0.2)	(1.0)	(0.5)	(2.8)
	Net[4]	**(0.9)**	**0.4**	**(0.2)**	**0.5**	**0**

1.2.2 Externally Initiated Plant Relocations and Expansion

Toronto Hydro continues to execute Externally Initiated Plan Relocations projects in accordance with coordination requirements and third-party project specifications and timelines. The utility spent a gross amount of $23.4 million in 2018, with $18.4 million in associated capital contributions. Due to project delays outside of Toronto Hydro's control, amounts related to the Metrolinx ECLRT were shifted from 2018 to 2019. The utility anticipates $69.8 million in expenditures in 2019, offset by $57.9 million in capital contributions. Toronto Hydro is on pace to invest a net amount of $24.3 million in this program during 2015-2019, which is approximately 5 percent greater than the amount previously forecast in this application. As stated in Exhibit 2B, Section E5.2.3.2, the scope, timing, and pacing of externally initiated relocation projects are driven by operational and planning decisions of third parties, which are beyond Toronto Hydro's control.

[4] All DG connections are 100 percent funded by capital contributions from the customer, and consequently, there should be zero net expenditure for DG connections. However, due to the pacing and timing of a DG installation, capital contributions may be collected from the customer in one year whereas the gross expenditures may span several years. As a result, the 2015-2017 historical yearly total net expenditures do not equal zero.

Table 5: Historical and Forecast Externally Initiated Plant Relocations and Expansion Program Costs ($ Millions)

	Actual				Bridge
	2015	**2016**	**2017**	**2018**	**2019**
Total Project Cost	3.8	9.0	12.5	23.4	69.8
Capital Contributions	(1.6)	(6.4)	(9.9)	(18.4)	(57.9)
Net Cost	**2.2**	**2.6**	**2.6**	**5.0**	**11.9**

1.2.3 Load Demand

Toronto Hydro spent $16.4 million on Load Demand projects in 2018. The utility forecasts $23.5 million in expenditures in 2019. These amounts are aligned with the 2018-2019 forecasts previously filed in this application, with a minor variance of 2.6 percent. Variances in 2018 and 2019 are generally due to evolving localized capacity needs, resulting in the reprioritization of work.

Table 6: Historical and Forecast Load Demand Program Costs ($ Millions)

	Actual				Bridge
	2015	**2016**	**2017**	**2018**	**2019**
Load Demand	9.9	16.8	16.2	16.4	23.5

1.2.4 Metering

Toronto Hydro invested $22.0 million in the Metering program in 2018 and forecasts spending another $26.1 million in 2019. Overall, the utility's 2015-2019 capital expenditures for this program are expected to be approximately $104.8 million, a decrease of one percent from the previous forecast in Exhibit 2B, Section E5.4.

Increased compliance spending on wholesale metering in 2018-2019 has largely been offset by a reduction in residential and small commercial and industrial metering expenditures. Despite this reduction, Toronto Hydro remains on track to complete the

replacement of all 2G smart meters with 4G models by the end of 2019. Required suite metering investments over 2018-2019 are also lower than previously forecast due to lower than forecast need from new buildings. Although there has been some change in the timing of projects, overall spending on system upgrades has remained consistent with the forecast in Exhibit 2B, Section E5.4.

Table 7: Historical and Forecast Metering Program Costs ($ Millions)

	Actual				Bridge
	2015	2016	2017	2018	2019
Metering	14.5	17.4	24.8	22.0	26.1

1.2.5 GPMC

Toronto Hydro spent $0.6 million on Generation Protection, Monitoring, and Control work in 2018. The utility deferred expenditures of $7.5 million to 2019. As a result, Toronto Hydro forecasts $10.9 million in expenditures for 2019. Despite the variances in timing discussed below, Toronto Hydro's forecast spending for the 2015-2019 period is unchanged from the total amount previously forecast in this application.

Table 8: Historical and Forecast Generation Protection, Monitoring, and Control Program Costs ($ Millions)

	Actual				Bridge
	2015	2016	2017	2018	2019
Generation Protection, Monitoring, and Control	-	2.1	0.0	0.6	10.9

In section E5.5.4.1, Toronto Hydro stated that it would install bus-tie reactors at Leslie TS and Richview TS in 2019. However, as a result of the level of interest in renewable generation in the areas served by Leslie TS and Richview TS and higher than anticipated costs, Toronto Hydro determined that these projects should be deferred. The associated

cost reduction of $2.0 million (including the $0.8 million previously deferred into 2018) has been absorbed by other necessary monitoring and control initiatives in this program.

Negotiations of contractual agreements with customers to purchase over 200 monitoring and control systems ("MCS") and the execution of these agreements has taken longer than anticipated. Toronto Hydro deferred costs from 2018 into 2019 to execute all planned MCS contracts by the end of 2019.

The adoption of new wireless SCADA infrastructure over the 2015-2019 period under the Information Technology and Operational Technology Systems program (see Exhibit 2B, Section E8.4), as well as changes in scope and further evaluation and assessment of two-way communication systems, has delayed Toronto Hydro's procurement process for the radio communication link for the MCSs. As a result, a portion of this work has been deferred to 2019. Toronto Hydro still expects radio communication infrastructure installment to be completed by end of 2019.

Lastly, over the 2018-2019 period, Toronto Hydro is proceeding with planned implementation of energy monitoring and control capabilities (DG SCADA Management) to monitor and control distributed generation connected to the grid. Through a lengthy competitive process, Toronto Hydro managed to achieve cost reductions. Rather than the budgeted $6.6 million, capital expenditures for this work are expected to be roughly $4.8 million.

1.3 System Renewal Update

In 2018, Toronto Hydro invested $245.5 million in System Renewal projects. The utility forecasts $244.2 million in additional investments in 2019. Overall, the utility expects to

spend $1,310.2 million during the 2015-2019 period, which is essentially unchanged from the $1,310.8 million initially forecast in the 2015-2019 DSP, and the $1,303.3 million previously forecast in this application.

Table 9: System Renewal Expenditures: 2015-2019 ($ Millions)

	Actual				Bridge
	2015	2016	2017	2018	2019
System Renewal	304.1	266.1	250.3	245.5	244.2

As discussed in the following sections, variances over the 2018-2019 period are primarily driven by variances in the Area Conversions program, Underground System Renewal – Horseshoe program, and Overhead System Renewal program. Variances in the remaining programs are minor.

1.3.1 Area Conversions

Toronto Hydro invested $34.4 million in the Area Conversions program in 2018. The utility forecasts an additional $36.0 million in 2019. Overall, Toronto Hydro is on pace to spend $171.6 million during the 2015-2019 period, which is about 6 percent more than the $162.2 million initially forecast in the 2015-2019 DSP, and about 8 percent less than the amount previously forecast in this application.

Table 10: Historical & Forecast Area Conversions Program Expenditures ($ Millions)

	Actual				Bridge
	2015	2016	2017	2018	2019
Rear-Lot Conversion	26.7	14.5	8.2	5.0	5.5
Box Construction Conversion	19.6	13.6	18.7	29.4	30.5
Total	**46.3**	**28.1**	**26.9**	**34.4**	**36.0**

Rear-Lot Conversion

Toronto Hydro invested $5.0 million in Rear Lot Conversion projects in 2018 and is forecasting an additional $5.5 million in 2019. The utility anticipates completing conversion projects for 257 customers over the two-year period. Overall, Toronto Hydro is on pace to invest $59.9 million in Rear Lot Conversion projects during the 2015-2019 period, which is aligned with the original forecast in the 2015-2019 DSP and about 8 percent less than the amount previously forecast in this application.

Lower than forecast expenditures in 2018-2019 is the result of project reprioritization between years. Toronto Hydro advanced a portion of the Jamestown rear lot project (originally scheduled for 2021-2022 as noted in Exhibit 2B, Section E6.1.4.1) as the urgency of the work increased following a significant decline in reliability performance in the area. To resource this work and the continuation of the multi-phase Thorncrest rear lot project, Toronto Hydro deferred other rear lot work, including a large scope of work ($4.2 million) in the Forest Hill rear lot area. The net result of these project timing changes was a $5.2 million deferral of expenditures to the 2020-2024 period. This deferral also facilitated the allocation of resources to urgent, incremental work in the Overhead System Renewal program.

Box Construction Conversion

Toronto Hydro invested $29.4 million in Box Construction Conversion projects in 2018 and forecasts an additional $30.5 million in 2019. The utility anticipates the conversion of 1,646 poles over the two year period. Overall, Toronto Hydro is on pace to invest $111.7 million in Box Construction Conversion projects during the 2015-2019 period, which is about 9 percent more than the $102.9 million initially forecast in the utility's

2015-2019 DSP and about 7 percent less than the amount previously forecast in this application.

Lower than forecast expenditures and pole replacement units in 2018-2019 are due to project deferrals. In 2018, Toronto Hydro deferred a portion of its planned investments into 2019 due to project execution challenges. This in turn resulted in the deferral of some 2019 projects. As noted in the Box Construction segment (Exhibit 2B, Section E6.1), projects consist of multiple phases, and as a result, unit attainment may only be recorded once all phases of a project are complete. For projects carrying over into 2019, a significant portion of the work is already complete, and Toronto Hydro expects the poles replaced to be included as part of the 2020 units achieved.

1.3.2 Underground System Renewal - Horseshoe

In 2018, Toronto Hydro invested $69.1 million in the Underground System Renewal – Horseshoe program installing 156 circuit-kilometres of primary cables, 251 transformers, and 39 switches. The utility forecasts $55.8 million of additional investments in 2019 to install an incremental 131 circuit-kilometres of primary cable, 264 transformers, and 28 switches. Overall, Toronto Hydro is on pace to invest $404.2 million during the 2015-2019 period, which is about 12 percent less than the $459.3 million initially forecast in the utility's 2015-2019 DSP, and about 4 percent less than the amount previously forecast in this application.

Table 11: Historical & Forecast Underground System Renewal – Horseshoe Program Expenditures ($ Millions)

	Actual				Bridge
	2015	2016	2017	2018	2019
Underground System Renewal Horseshoe	115.5	80.7	83.1	69.1	55.8

Lower than forecast expenditures are the result of the following factors:

- In 2018, work executed in this program was executed as planned. Minor variances in unit replacements are attributed to changes in detailed designs, which required fewer units to be replaced, and spill-over of unit achievements from 2019 to 2020 as a result of projects being partially completed in 2019.
- Toronto Hydro deferred some work from 2019 to allow incremental work in the Overhead System Renewal program to proceed on an urgent basis.

1.3.3 Underground System Renewal – Downtown

The Underground System Renewal – Downtown program is a new program starting in 2020.

1.3.4 Network System Renewal

Toronto Hydro invested $18.8 million in the Network System Renewal program in 2018 and is tracking to spend another $32.2 million in 2019. Overall, Toronto Hydro projects total 2015-2019 capital expenditures of $92.7 million, which is essentially aligned with both the original 2015-2019 DSP and the forecast previously provided in this application.

Table 12: Historical & Forecast Network System Renewal Program Expenditures ($ Millions)

	Actual				Bridge
	2015	**2016**	**2017**	**2018**	**2019**
Legacy Network Equipment Renewal (ATS & RPB)	1.0	1.1	3.3	3.9	1.6
Network Unit Renewal	4.7	7.6	8.3	7.5	8.7
Network Vault Renewal	4.6	8.0	2.3	6.6	18.3
Network Circuit Reconfiguration	-	0.0	0.7	0.7	3.7
Total	**10.2**	**16.8**	**14.7**	**18.8**	**32.2**

Investments within each segment of the Network System Renewal program are adjusted for each year to prioritize execution based on evolving requirements throughout the program. Toronto Hydro forecasts a minor increase of $2.4 million over the previously forecasted 2018-2019 amounts in this application. Higher than expected costs in the Legacy Network Equipment Renewal, Network Vault Renewal, and Network Circuit Reconfiguration segments were partially offset by a decrease in the Network Unit Renewal segment. Generally, Toronto Hydro is on pace to complete the volume of work previously forecast, with minor reductions in the number of network unit replacements and minor adjustments to the projects completed under the Network Circuit Reconfiguration project.

1.3.5 Overhead System Renewal

In 2018, Toronto Hydro invested $30.4 million in the Overhead System Renewal program, installing 1,510 poles, 412 transformers, 90 switches, and 102 circuit-kilometres of primary conductor. The utility forecasts $24.8 million of additional investments in 2019 to install an incremental 1,330 poles, 310 transformers, 13 switches, and 50 circuit-kilometers of primary conductor. Overall, Toronto Hydro forecasts $202.9 million of expenditures during the 2015-2019 period, which is an additional 10 percent increase on the amount previously forecast in this application.

Table 13: Historical & Forecast Overhead System Renewal Program Expenditures ($ Millions)

	Actual				Bridge
	2015	2016	2017	2018	2019
Overhead System Renewal	61.0	51.0	35.7	30.4	24.8

Variances in 2018-2019 are primarily the result of emerging needs on the overhead system in the Horseshoe area of the City. Incremental work has included:

- additional porcelain insulator replacements to mitigate the risk of pole fires;
- additional circuit renewal work to address poor reliability, including poor reliability on Bathurst TS feeders serving large industrial customers;
- accelerated conversion work on feeders from Leslie MS to allow for the urgent decommissioning of deteriorating Leslie MS stations equipment.

As noted above, additional investment in the Overhead System Renewal program was enabled in part by the reprioritization of work in the Underground System Renewal – Horseshoe and Rear Lot Conversion projects.

1.3.6 Stations Renewal

Toronto Hydro invested $21.9 million in the Stations Renewal program in 2018, which is $2.2 million greater than the initial 2018 bridge year forecast in this application. Overall, as shown in the table below, Toronto Hydro expects to spend a total of $85.6 million in this program during 2015-2019 period, which amounts to a 0.4 percent variance relative to the previous forecast filed in this application. Please refer to Exhibit 2B, Section E6.6.4, for a detailed discussion of Toronto Hydro's accomplishments in this program relative to the originally filed 2015-2019 DSP.

Table 14: Historical & Forecast Stations Renewal Program Expenditures ($ Millions)

Segment	Actual				Bridge
	2015	2016	2017	2018	2019
Transformer Stations	7.6	6.3	7.0	8.3	7.5
Municipal Stations	3.2	3.0	7.6	6.7	8.0
Control and Monitoring	0.3	1.3	2.9	3.0	4.1
Battery and Ancillary Systems	0.1	0.8	1.4	3.9	2.4
Total	**11.3**	**11.6**	**19.0**	**21.9**	**22.0**

Transformer Stations and Municipal Stations

Toronto Hydro has deferred $6.5 million of planned expenditures in the Transformer Stations segment from 2019 to the 2020-2024 period. Due to site-specific complexities, design coordination work between Toronto Hydro and Hydro One remains ongoing for projects at Duplex TS and Strachan TS; the utility has deferred capital contributions for these projects accordingly. Toronto Hydro expects to complete this work in the 2020-2024 period. There are no in-service addition implications, as these projects were not scheduled for energization in the 2015-2019 period.

The utility has also deferred two breaker replacements from the Transformer Stations segment in order to fund higher priority power transformer replacements in the Municipal Stations segment.

Control and Monitoring

Toronto Hydro is on track to complete all planned units of work in the Control and Monitoring segment in 2018-2019. Minor variances versus the initial bridge year forecasts are due to typical cost variances between high-level estimates and final costs.

Battery and Ancillary Systems

Toronto Hydro expects to incur higher than forecast costs for Battery and Ancillary Systems in the 2018-2019 bridge years. A one-off fire suppression system installation project at Cavanaugh TS has cost more than initially estimated due to project complexities encountered during the project lifecycle. Toronto Hydro also plans to complete a greater number of station battery replacements than planned to accommodate telecom system upgrades in certain areas of the City.

1.3.7 Reactive and Corrective Capital

An upward trend in reactive capital investment needs continued in 2018. Toronto Hydro invested $66.1 million in the Reactive and Corrective Capital program, $7.7 million more than previously forecast in this application. Overall for 2015-2019, Toronto Hydro forecasts $281.6 million of expenditures in this program, an additional increase of about 5 percent over the previous forecast in this application.

Table 15: Historical & Forecast Reactive and Corrective Capital Program Expenditures ($ Millions)

	Actual				Bridge
	2015	**2016**	**2017**	**2018**	**2019**
Reactive Capital	39.0	50.2	52.5	62.2	59.5
Worst Performing Feeder	3.0	4.1	3.0	3.9	4.2
Total	**42.0**	**54.3**	**55.5**	**66.1**	**63.7**

The increase in spending is due to a higher than anticipated volume of reactive work requests. In 2018, there was a significant number of severe weather events leading to the reactive replacement of damaged assets. Overall, there was a 130 percent increase in the

number of reactive work requests issued during the weeks in which major storms occurred.

Another driver of the increase in reactive work requests was a larger number of deficient assets such as transformers. In 2018, Toronto Hydro saw a 44 percent increase from the 2013-2018 average number of transformer-related reactive work requests to address deficiencies such as oil leaks and corrosion, which is consistent with the overall pattern of aging, deterioration, and PCB spill risks for these asset types. Toronto Hydro has revised its 2019 forecast expenditures upwards to reflect recent trends.

1.4 System Service Update

In 2018, Toronto Hydro invested $31 million in System Service projects. The utility forecasts $41.5 million in additional investments in 2019. Overall, the utility expects to spend $236.2 million during the 2015-2019 period, which is about 32 percent less than the $345 million initially forecast in the 2015-2019 DSP, and about 4 percent less than the amount previously forecast in this application.[5]

Table 16: System Service Expenditures: 2015-2024 ($ Millions)

	Actual				Bridge
	2015	2016	2017	2018	2019
System Service	37.9	53.3	72.4	31.0	41.5

As discussed in the following sections, variances over the 2018-2019 period are primarily driven by variances in the Stations Expansion and System Enhancement programs.

[5] Refer to Exhibit 2B, Section E4.1.2 for discussion of lower than forecast spending in System Service during the 2015-2019 period.

1.4.1 System Enhancements

Toronto Hydro invested $9.4 million in the System Enhancements program in 2018 and forecasts an additional $4.0 million in 2019. Overall, Toronto Hydro is on pace to invest $48.2 million during the 2015-2019 period, which less than the amount initially forecast in the utility's 2015-2019 DSP, and about 6 percent more than the amount previously forecasted in this application.

Table 17: Historical & Forecast System Enhancement Program Expenditures ($ Millions)

	Actual				Bridge
	2015	**2016**	**2017**	**2018**	**2019**
Contingency Enhancement	6.7	15.9	12.1	9.4	2.7
Customer-Owned Station Protection	-	-	-	-	1.3
Total	**6.7**	**15.9**	**12.1**	**9.4**	**4.0**

Contingency Enhancements

Toronto Hydro invested $9.4 million in Contingency Enhancement work in 2018 and forecasts $2.7 million in additional investments in 2019. Overall, this is approximately double the investment previously forecast for the 2018-2019 period in this application. This increase is related to (1) emerging reliability and contingency needs in certain areas due to load growth and other factors; and (2) the ongoing build-out of feeder automation networks. For example, Toronto Hydro has increased the number of forecasted SCADA-enabled inter-feeder tie-points for 2018-2019 from seven to 14 feeders, and the number of sectionalizing points from three to 12 feeders. The utility is also continuing projects during 2018-2019 to upgrade undersized conductors and undersized trunk egress cables at Fairchild TS and Bathurst TS, which will support long-term improvements in reliability and system operability in these growing areas.

Customer-Owned Station Protection ("COSP")

Toronto Hydro deferred COSP work planned for 2018 into 2019 due to delays in the initial inspection portion of the program. The utility expects this work to be completed in 2019.

1.4.2 Energy Storage

Renewable Enabling Energy Storage Systems

Toronto Hydro spent $0.1 million on renewable enabling Energy Storage System projects in 2018 and forecasts $7.9 million in investments in 2019. The utility has deferred $5.8 million in investments from 2018 to 2019 due the timing of an RFP process and vendor selection, as well as challenges associated with land acquisition. For a full discussion of the utility's 2015-2019 investments in this program compared to the original 2015-2019 DSP, please refer to Exhibit 2B, Section E7.2.3.3.

Table 18: Historical & Forecast Renewable Enabling ESS Expenditures ($ Millions)

	Actual				Bridge
	2015	2016	2017	2018	2019
REI Investments	-	-	-	**0.1**	**7.9**

Customer Specific Energy Storage Systems

In 2018, Toronto Hydro invested and recovered $8.4 million of investments associated with the Metrolinx Eglinton Cross Town Light Rail Transit (ECLRT) Energy Storage System. The utility forecasts $19.4 million in additional investments, which are also 100 percent recoverable, in 2019. Toronto Hydro continues to be on pace to complete this project by the end of 2019.

Table 19: Historical & Forecast Customer Specific ESS Expenditures ($ Millions)

	Actual	Bridge	Total
	2018	2019	
Metrolinx ECLRT	8.4	19.4	**27.8**

1.4.3 Network Condition Monitoring and Control

There are no historical or bridge expenditures associated with the Network Condition Monitoring and Control program over the 2015-2019 period as it is a new independent program starting in 2020. Similar work was completed on a smaller scale in the 2015-2019 period and was funded through the Network System Renewal program.

1.4.4 Stations Expansion

In 2018, Toronto Hydro invested $21.0 million in the Stations Expansion program and forecasts an additional $29.1 million in 2019. Overall, Toronto Hydro is on pace to invest $167.0 million in Station Expansion projects during the 2015-2019 period, which is about 11 percent less than the $188.6 million initially forecast in the utility's 2015-2019 DSP,[6] and about 7 percent less than the amount previously forecasted in this application.

Table 20: Historical & Forecast Station Expansion Program Expenditures ($ Millions)

	Actual				Bridge
	2015	2016	2017	2018	2019
Copeland TS Expansion	20.5	19.1	22.0	8.7	9.1
Hydro One Contributions	2.5	15.3	37.4	12.3	16.4
Local Demand Response	--	--	0.1	0.1	3.6
Total	**23.0**	**34.4**	**59.4**	**21.0**	**29.1**

[6] EB-2014-0116, Exhibit 2B, Section E7.9 Stations Expansion and Exhibit 2B, Section E7.10 Local Demand Response

Copeland TS Expansion

Toronto Hydro invested $8.7 million in Copeland TS Expansion work in 2018, which includes expenditures on both Copeland TS Phase 1 and 2. The utility has budgeted another $9.1 million of investments in 2019. A substantial portion of the Copeland Phase 1 assets have been energized. Toronto Hydro expects all remaining work related to Copeland Phase 1 to be complete and the project fully energized in 2019. The increase of $2.5 million in Copeland TS Expansion expenditures over the previous forecast in this application is largely due to the cost of replacing the General Contractor for the completion of energization and delays experienced by Hydro One.

Hydro One Contribution

Toronto Hydro made $12.3 million in capital contributions to Hydro One in 2018 and forecasts $16.4 million 2019. Expenditures over the 2015-2019 period are forecast to be 16 percent lower than previously forecast in this application. The variance in 2018-2019 is attributed to delays in the execution of agreements with Hydro One. Toronto Hydro has deferred approximately $4.4 million of investments from 2018 to 2019 due to work delays at Basin TS, Horner TS, and Gerrard TS-Carlaw TS and has consequently deferred $9.4 million of capital contributions associated with Horner TS from 2019 into the 2020-2024 period.

In 2019, triggered by true up processes and timelines, Toronto Hydro expects to reconcile past Hydro One capital contributions by:

1. incurring $4.3 million in additional capital contributions for the Midtown Toronto Transmission Reinforcement project (Leaside TS x Bridgman TS), identified as the Leaside-Birch project in the utility's 2015-2019 DSP; and

2. recovering $4.9 million in capital contributions made for the Bridgman PT project and the Runnymede TS J-Q bus installation project.

Local Demand Response

Toronto Hydro invested $0.1 million in Local DR work in 2018 and has deferred the remaining expenditures into 2019 to adjust to certain design challenges in the execution of this unique project. The utility expects to complete the planned work by end of 2019.

1.5 General Plant Update

In 2018, Toronto Hydro invested $58.4 million in General Plant activities. The utility forecasts $46.4 million in additional investments in 2019. Overall, the utility expects to spend $392.7 million during the 2015-2019 period, which is about 31 percent more than the $300.9 million initially forecast in the 2015-2019 DSP, and about one percent less than the amount previously forecast in this application.[7]

Table 21: General Plant Expenditures: 2015-2019 ($ Millions)

	Actual				Bridge
	2015	2016	2017	2018	2019
General Plant	79.4	109.5	98.9	58.4	46.4

1.5.1 Control Operations Reinforcement

The Control Operations Reinforcement program is a new one-time program during the 2020-2024 period.

[7] Refer to Exhibit 2B, Section E4.1.3 for discussion of higher than forecast spending in General Plant during the 2015-2019 period.

1.5.2 Facilities Management and Security

Toronto Hydro invested $1.7 million in the Facilities Management and Security program in 2018 and forecasts an additional $3.5 million in 2019. Overall, Toronto Hydro is on pace to invest $36.0 million in facilities projects during the 2015-2019 period, which is aligned with the amount previously filed in this application.

Table 22: Historical & Forecast Facilities Management and Security Program Expenditures ($ Millions)

	Actual				Bridge
	2015	**2016**	**2017**	**2018**	**2019**
Work Centres	11.4	5.3	4.2	1.2	1.8
Stations	3.2	2.8	1.6	0.5	0.5
Security Improvements	0.7	0.9	0.5	0.1	1.3
Total	**15.3**	**9.0**	**6.3**	**1.7**	**3.5**

In 2018, Toronto Hydro shifted planned expenditures from the Stations and Security Improvements segments to the Work Centres segment to address several potential health and safety risks, such as slip, trip, fall, lighting, and space hazards. As noted in Exhibit 2B, Section E8.2, Toronto Hydro's Carlton, and Commissioners work centres are in need of several improvements to address potential safety hazards both reactively and proactively. In 2019, Toronto Hydro is focussed on investing in the Stations and Security Improvements segments while continuing to address health and safety concerns under the Work Centres segment.

1.5.3 Fleet and Equipment Services

Toronto Hydro invested $2.9 million in the Fleet and Equipment Services program in 2018 and plans to invest an additional $3.6 million in 2019. Toronto Hydro is on pace to spend $19.0 million on Fleet and Equipment Services work during the 2015-2019 period, which

is aligned with the forecast expenditures previously provided in this application. For a discussion of the variance between the planned and actual expenditures in the 2015-2019 period, please refer to Exhibit 2B, Section E8.3.

Table 23: Historical & Forecast Fleet and Equipment Services Program Expenditures ($ Millions)

	Actual				Bridge
	2015	2016	2017	2018	2019
Heavy Duty Vehicles	2.2	2.9	3.3	1.5	2.7
Light Duty Vehicles	1.3	0.8	0.3	0.7	0.8
Equipment	0.6	0.1	1.1	0.8	0.1
Total	**4.1**	**3.7**	**4.7**	**2.9**	**3.6**

1.5.4 Information Technology and Operational Technology Systems ("IT/OT")

Toronto Hydro invested $53.7 million in the IT/OT program in 2018, which is $10.9 million less than the 2018 bridge year forecast in this application. Overall, as shown in Table 24, below, Toronto Hydro is forecasting $225.3 million of expenditures in this program during the 2015-2019 period, which is 2.6 percent less than the forecast previously provided in this application. Please refer to Exhibit 2B, Section E8.4.4, for a discussion of Toronto Hydro's accomplishments during the 2015-2019 period.

Table 24: Historical & Forecast IT/OT Program Expenditures ($ Millions)

Segments	Actual				Bridge
	2015	2016	2017	2018	2019
IT Hardware	7.5	9.3	10.1	7.8	8.8
IT Software	14.8	21.7	40.3	40.1	23.0
Communication Infrastructure	6.1	17.6	4.9	5.8	7.5
Total	**28.4**	**48.6**	**55.4**	**53.7**	**39.3**

IT Hardware

In 2018, Toronto Hydro's spending was as forecasted in the application. In 2019, Toronto Hydro anticipates spending an additional $1.0 million above the amount originally forecasted in the application. The increase is attributable to additional hardware required to accommodate higher than anticipated IT storage and backup needs.

IT Software

In 2018, Toronto Hydro spent $40.1 million, which is $10.7 million less than forecast in the Application. The majority of the variance can be attributed to a re-assessment of business needs following implementation of the ERP. Some of the variance is also attributable to the extension of the lifecycle of a data warehousing solution given the lack of replacement options available at this time. In 2019, Toronto Hydro expects to complete some of the deferred work following an assessment of availability of adequate vendor solutions, and business needs and priorities.

Communication Infrastructure

In 2018, the variance for this segment was negligible. Similarly, the forecast for 2019 has increased by a negligible amount. Overall, this segment experienced a 1.2 percent increase compared to the forecast provided in the application.

1.6 Other Capital

For the 2015-2019 period, Toronto Hydro's Other Capital expenditures are forecast to be 36 percent lower than originally planned. Please refer to Exhibit 2B, Section E4.1.4 for a discussion of the 2015-2019 variances in this category.[8]

[8] Please note that the negative amount in 2019 is due to regular movements in pre-capitalized inventory balances over time.

Table 25: Other Capital Expenditures: 2015-2024 ($ Millions)

	Actual				Bridge
	2015	2016	2017	2018	2019
Other Capital	11.6	3.7	10.7	12.7	(1.3)

2. SYSTEM O&M

In 2018, Toronto Hydro spent $139.6 million in System O&M expenditures and forecasts $131.0 million in investments in 2019. Expenditures in 2018 are $12.7 million more than the amount previously forecast in this application. This variance is primarily driven by increased maintenance work attributed to major storm events. Please see Exhibit U, Tab 4A, Schedule 1, for OM&A program variance analysis resulting from 2018 actuals.

Table 26: System O&M Expenditures 2015-2020 ($ Millions)

	Actual				Bridge
	2015	2016	2017	2018	2019
System O&M	116.1	126.5	126.3	139.6	131.0

OEB Appendix 2-AA
Capital Programs Table

Programs ($M)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Customer and Generation Connections	31.7	40.1	21.9	44.0	39.8	42.9	43.9	44.8	45.6	46.3
Externally Initiated Plant Relocations & Expansion	2.2	2.6	2.6	5.0	11.9	11.4	20.8	4.6	4.7	4.5
Generation Protection, Monitoring and Control	-	2.1	0.0	0.6	10.9	3.7	2.3	2.4	2.5	2.7
Load Demand	9.9	16.8	16.2	16.4	23.5	11.3	11.4	18.5	22.6	23.6
Metering	14.5	17.4	24.8	22.0	26.1	22.6	14.8	23.6	30.6	39.2
System Access Total	**58.3**	**79.0**	**65.5**	**88.0**	**112.1**	**91.8**	**93.3**	**93.9**	**106.0**	**116.4**
Area Conversions	46.3	28.2	26.9	34.4	36.0	41.4	47.2	46.3	50.4	35.6
Network System Renewal	10.2	16.8	14.7	18.8	32.2	18.6	19.3	18.5	17.7	18.3
Reactive and Corrective Capital	42.0	54.3	55.5	66.1	63.7	61.2	62.4	63.5	64.4	65.8
Stations Renewal	11.3	11.6	19.0	21.9	22.0	27.5	35.3	29.4	27.0	22.4
Underground Renewal - Downtown	-	-	-	(0.0)	-	15.1	22.5	23.9	30.0	30.6
Underground Renewal - Horseshoe	115.5	80.7	83.1	69.1	55.8	93.0	88.7	90.3	93.1	95.2
Overhead Infrastructure Relocation	0.9	3.1	2.6	0.3	1.6	-	-	-	-	-
SCADAMATE R1 Renewal	3.5	4.9	2.1	1.1	1.9	-	-	-	-	-
PILC Piece Outs & Leakers	6.0	5.7	1.8	0.8	0.1	-	-	-	-	-
Underground Legacy Infrastructure	7.4	9.9	9.0	2.7	6.0	-	-	-	-	-
Overhead System Renewal	61.0	51.0	35.7	30.4	24.8	49.8	50.4	51.3	56.5	57.7
System Renewal Total	**304.1**	**266.1**	**250.3**	**245.5**	**244.2**	**306.6**	**325.7**	**323.1**	**339.0**	**325.5**
Energy Storage Systems	-	-	-	0.1	7.9	1.0	3.7	3.8	1.0	1.0
Network Condition Monitoring and Control	-	-	-	-	-	7.6	10.2	12.6	15.3	17.4
Overhead Momentary Reduction	0.0	-	-	-	0.3	-	-	-	-	-
Stations Expansion	23.0	34.5	59.4	21.0	29.1	19.5	40.0	49.3	12.5	15.2
System Enhancements	7.1	17.2	12.2	9.4	4.0	6.2	6.2	5.6	4.8	4.9
Handwell Upgrades	4.7	0.8	0.8	0.0	-	-	-	-	-	-
Polymer SMD-20 Renewal	3.0	0.3	0.0	0.4	-	-	-	-	-	-
Design Enhancement	0.0	0.6	(0.0)	0.0	0.2	-	-	-	-	-
System Service Total	**37.9**	**53.3**	**72.4**	**31.0**	**41.5**	**34.2**	**60.1**	**71.3**	**33.6**	**38.5**
Facilities Management and Security	15.4	9.0	6.3	1.7	3.5	11.6	11.8	12.1	12.3	12.6
Fleet and Equipment	4.1	3.7	4.7	2.9	3.6	8.6	8.9	8.5	8.7	7.8
IT/OT Systems	28.4	48.6	55.4	53.7	39.3	54.8	55.7	49.5	56.6	64.8
Control Operations Reinforcement	-	-	-	-	-	3.9	17.4	18.9	-	-
Operating Centers Consolidation Plan	31.6	48.3	32.2	-	-	-	-	-	-	-
Program Support	-	0.0	0.4	-	-	-	-	-	-	-
General Plant Total	**79.4**	**109.5**	**98.9**	**58.4**	**46.4**	**78.8**	**93.7**	**89.0**	**77.7**	**85.2**
AFUDC	10.8	12.5	9.8	8.9	4.0	6.0	8.2	8.7	8.9	7.7
Miscellaneous	0.8	(8.8)	0.9	3.8	(5.3)	1.0	0.8	1.2	0.6	1.0
Other Total	**11.6**	**3.7**	**10.7**	**12.7**	**(1.3)**	**7.0**	**9.0**	**9.8**	**9.5**	**8.7**
Subtotal	**491.4**	**511.6**	**497.8**	**435.6**	**443.0**	**518.4**	**581.8**	**587.1**	**565.7**	**574.4**
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets (input as negative)	(0.8)	(3.2)	(1.2)	(0.7)	(17.7)	(4.4)	(3.1)	(3.2)	(3.3)	(3.5)
Total	**490.6**	**508.4**	**496.6**	**434.9**	**425.3**	**514.0**	**578.8**	**583.9**	**562.4**	**570.9**

OEB Appendix 2-AB

Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period:

CATEGORY	2015			2016			2017			2018			2019			2020	2021	2022	2023	2024
	CIR Filing Plan	Actual	Var	CIR Filing Plan	Actual	Var	CIR Filing Plan	Actual	Var	CIR Filing Plan	Actual	Var	CIR Filing Plan	Bridge	Var	Forecast	Forecast	Forecast	Forecast	Forecast
	$ M			*$ M*			*$ M*			*$ M*			*$ M*			*$ M*	*$ M*	*$ M*	*$ M*	*$ M*
System Access	86.1	58.3	-32.3%	95.3	79.0	-17.2%	104.9	65.5	-37.6%	95.8	88.0	-8.1%	92.3	112.1	21.4%	91.8	93.3	93.9	106.0	116.4
System Renewal	251.7	304.1	20.8%	239.6	266.1	11.0%	256.2	250.3	-2.3%	275.9	245.5	-11.0%	287.3	244.2	-15.0%	306.6	325.7	323.1	339.0	325.5
System Service	76.5	37.9	-50.4%	70.7	53.3	-24.6%	65.1	72.4	11.3%	52.6	31.0	-41.0%	80.2	41.5	-48.2%	34.2	60.1	71.3	33.6	38.5
General Plant	104.6	79.4	-24.1%	101.5	109.5	7.9%	30.3	98.9	226.4%	34.2	58.4	70.6%	30.3	46.4	53.2%	78.8	93.7	89.0	77.7	85.2
Other	12.2	11.6	-4.8%	11.6	3.7	-67.9%	10.8	10.7	-1.4%	11.5	12.7	10.5%	12.1	(1.3)	-111.1%	7.0	9.0	9.8	9.5	8.7
TOTAL EXPENDITURE	531.1	491.4	-7.5%	518.8	511.6	-1.4%	467.4	497.8	6.5%	470.0	435.6	-7.3%	502.2	443.0	-11.8%	518.4	581.8	587.1	565.7	574.4
Capital Contributions Paid	(6.6)	(4.0)	-40.0%	(29.1)	(16.6)	-42.9%	(48.2)	(37.4)	-22.5%	(32.1)	(12.4)	-61.2%	(30.5)	(18.5)	-39.4%	(12.8)	(16.1)	(15.2)	(16.8)	(14.6)
Net Capital Expenditures	524.5	487.5	-7.1%	489.7	495.0	1.1%	419.2	460.5	9.9%	438.0	423.2	-3.4%	471.6	424.5	-10.0%	505.6	565.7	571.9	548.9	559.8
System O&M	128.8	116.1	-9.9%		126.5	-		126.3	-		139.6	-		131.0	-	130.4				

Note: Variances due to rounding may exist

Notes to the Table:

1. Historical “previous plan” data is not required unless a plan has previously been filed. However, use the last Board-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including the
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year): 12

Explanatory Notes on Variances (complete only if applicable)
Notes on shifts in forecast vs. historical budgets by category
Refer to respective category sections for discussion on historical vs forecast shifts: Section E5 for System Access, Section E6 for System Renewal, Section E7 for System Service and Section E8 for General Plant. For variance explanations as a result of updated financial information, refer to Exhibit U, Tab 2, Schedule 2.
Notes on year over year Plan vs. Actual variances for Total Expenditures
Refer to Section E4 on Variance analysis for between Plan vs Actuals. For variance explanations as a result of updated financial information, refer to Exhibit U, Tab 2, Schedule 2.
Notes on Plan vs. Actual variance trends for individual expenditure categories
Refer to Section E4 on Variance analysis for between Plan vs Actuals. For variance explanations as a result of updated financial information, refer to Exhibit U, Tab 2, Schedule 2.

OEB Appendix 2-AB

Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period: 2020

CATEGORY	2015			2016			2017			2018			2019			2020	2021	2022	2023	2024
	CIR Filing Plan	Actual	Var	CIR Filing Plan	Actual	Var	CIR Filing Plan	Actual	Var	CIR Filing Plan	Actual	Var	CIR Filing Plan	Bridge	Var	Forecast	Forecast	Forecast	Forecast	Forecast
	$ M			$ M			$ M			$ M			$ M			$ M	$ M	$ M	$ M	$ M
System Access	103.3	97.4	-5.8%	112.8	113.0	0.2%	122.0	113.0	-7.4%	113.8	153.0	34.4%	111.9	236.0	110.9%	160.4	189.6	181.3	193.8	207.2
System Renewal	251.7	304.1	20.8%	239.6	266.1	11.0%	256.2	250.3	-2.3%	275.9	245.5	-11.0%	287.3	244.2	-15.0%	306.6	325.7	323.1	339.0	325.5
System Service	76.5	37.9	-50.4%	70.7	53.3	-24.6%	65.1	72.4	11.3%	52.6	31.0	-41.0%	80.2	41.5	-48.2%	58.5	72.2	77.1	33.6	38.5
General Plant	104.6	79.4	-24.1%	101.5	109.5	7.9%	30.3	98.9	226.4%	34.2	58.4	70.6%	30.3	46.4	53.2%	78.8	93.7	89.0	77.7	85.2
Other	12.2	13.5	10.9%	11.6	3.7	-67.9%	10.8	10.7	-1.4%	11.5	13.0	13.2%	12.1	(1.3)	-111.1%	7.0	9.0	9.8	9.5	8.7
GROSS TOTAL EXPENDITURE	548.3	532.3	-2.9%	536.2	545.6	1.8%	484.5	545.3	12.5%	488.0	500.9	2.6%	521.7	566.9	8.7%	611.3	690.2	680.4	653.6	665.2
Capital Contributions Received	(17.2)	(40.9)	138.1%	(17.4)	(34.0)	95.3%	(17.1)	(47.5)	177.1%	(18.0)	(65.3)	262.7%	(19.6)	(123.9)	533.0%	(92.9)	(108.4)	(93.2)	(87.8)	(90.9)
NET TOTAL EXPENDITURE	531.1	491.4	-7.5%	518.8	511.6	-1.4%	467.4	497.8	6.5%	470.0	435.6	-7.3%	502.2	443.0	-11.8%	518.4	581.8	587.1	565.7	574.4
System O&M	128.8	116.1	-9.9%		126.5			126.3			139.6			131.0		130.4				

Note: Variances due to rounding may exist

Notes to the Table:

1. Historical “previous plan” data is not required unless a plan has previously been filed. However, use the last Board-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including the
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year): 12

Explanatory Notes on Variances (complete only if applicable)
Notes on shifts in forecast vs. historical budgets by category
Refer to respective category sections for discussion on historical vs forecast shifts. Section E5 for System Access, Section E6 for System Renewal, Section E7 for System Service and Section E8 for General Plant. For variance explanations as a result of updated financial information, refer to Exhibit U, Tab 2, Schedule 2.
Notes on year over year Plan vs. Actual variances for Total Expenditures
Refer to Section E4 on Variance analysis for between Plan vs Actuals. For variance explanations as a result of updated financial information, refer to Exhibit U, Tab 2, Schedule 2.
Notes on Plan vs. Actual variance trends for individual expenditure categories
Refer to Section E4 on Variance analysis for between Plan vs Actuals. For variance explanations as a result of updated financial information, refer to Exhibit U, Tab 2, Schedule 2.

OVERHEAD COSTS UPDATE

An updated OEB Appendix 2-D has been filed at Exhibit U, Tab 2, Schedule 3, Appendix A. As mentioned in Exhibit 2A, Tab 5, Schedule 2, there have been no changes in the utility's overhead expense capitalization policy since its last rebasing application.

Appendix 2-D
Overhead Expense

Applicants are to provide a breakdown of OM&A before capitalization in the below table. OM&A before capitalization may be broken down by cost center, program, drivers or another format best suited to focus on capitalized vs. uncapitalized OM&A.

OM&A Before Capitalization	2015 Historical Year	2016 Historical Year	2017 Historical Year	2018 Historical Year	2019 Bridge Year	2020 Test Year
Operations	146.9	155.1	153.6	154.5	166.7	169.0
Maintenance	73.6	65.1	68.5	77.4	71.2	72.0
Billing and Collecting	36.8	34.0	35.9	34.7	41.5	45.8
Community Relations	3.5	2.5	2.4	3.0	2.7	2.8
Administrative and General	90.4	98.2	104.5	108.3	104.9	109.4
Taxes Other Than Income Taxes	5.2	4.6	5.3	4.9	5.4	5.5
Donations	1.0	1.0	1.0	0.8	0.9	1.0
Total OM&A Before Capitalization (B)	$ 357.4	$ 360.6	$ 371.1	$ 383.6	$ 393.4	$ 405.6

Applicants are to provide a breakdown of capitalized OM&A in the below table. Capitalized OM&A may be broken down using the categories listed in the table below if possible. Otherwise, applicants are to provide its own break down of capitalized OM&A.

Capitalized OM&A	2015 Historical Year	2016 Historical Year	2017 Historical Year	2018 Historical Year	2019 Bridge Year	2020 Test Year	Directly Attributable? (Yes/No)	Explanation for Change in Overhead Capitalized
Labour Capitalization	(99.1)	(95.6)	(101.1)	(101.4)	(109.8)	(112.5)	Yes	
Vehicle Capitalization	(4.2)	(4.3)	(4.5)	(4.2)	(3.9)	(4.1)	Yes	
Material Handling On-cost	(10.2)	(10.8)	(10.3)	(9.6)	(11.6)	(11.5)	Yes	
Total Capitalized OM&A (A)	(113.4)	(110.8)	(115.9)	(115.3)	(125.2)	(128.1)		
% of Capitalized OM&A (=A/B)	-32%	-31%	-31%	-30%	-32%	-32%		

OPERATING REVENUE VARIANCE ANALYSIS

1. LOAD, CUSTOMERS, AND REVENUES

Exhibit 3, Tab 1, includes information about Toronto Hydro's total load, customer, and distribution revenue forecast. This schedule provides an updated load and customer forecast for the period 2018 through 2024. Table 1 below summarizes the forecasted loads, distribution revenue and customers, and compares to the originally filed ("original") forecast.

Table 1: Total Load, Revenues, and Customers

Year		Total Normalized GWh		Total Normalized MVA		Total Distribution Revenue ($M)		Total Customers	
		Original	Update[1]	Original	Update[1]	Original	Update	Original	Update
2013	Actual	25,245.1	25,312.2	42,737.5	42,828.4	531.9	533.5	724,144	724,144
2014	Actual	25,132.0	25,200.9	41,866.4	41,960.8	536.6	537.7	735,262	735,262
2015	Actual	25,031.1	25,097.8	41,320.7	41,410.4	628.0	629.5	747,811	747,811
2016	Actual	24,909.3	24,964.8	41,335.6	41,414.0	661.4	657.6	759,031	759,031
2017	Actual	24,427.6	24,498.5	40,731.3	40,744.9	693.6	700.4	765,559	765,559
2018	Bridge / Actual	24,378.2	24,609.4	40,925.0	40,220.7	740.7	740.6	771,079	769,571
2019	Bridge	24,123.8	24,195.5	40,761.1	40,662.4	771.5	773.7	776,786	776,890
2020	Forecast	24,036.0	24,044.0	40,408.1	40,232.3	796.9	800.2	784,330	784,236
2021	Forecast	23,818.0	23,763.4	40,275.5	39,999.7	824.2	824.9	790,944	790,979
2022	Forecast	23,651.8	23,651.0	40,200.6	39,918.9	846.8	848.2	798,591	799,336
2023	Forecast	23,475.3	23,541.8	40,104.6	39,857.0	885.2	886.7	806,238	805,850
2024	Forecast	23,396.7	23,494.7	40,166.6	39,887.4	924.2	927.1	813,886	811,785

Note 1: Historical and forecast loads for Update reflect normalization based on average HDD and CDD over 2009-2018 period.

Toronto Hydro's detailed and updated load forecasts by rate class, customer forecast by rate class, and forecast of distribution revenues by rate class (OEB Appendix 2-IB) are shown in Appendix A to this schedule.

1.1 Load Forecast Update

Toronto Hydro's original load forecast was based on regression models using actual historical loads and input variables to the end of 2017, and forecasts of input variables for the 2018-2024 period. For the updated forecast, regression models were re-run using actual historical loads and input variables to the end of 2018. Specifically, the updated load forecasts include the following:

a) 2018 actual kWh and kVA billing determinants by class;
b) updated 10 year historical average HDD and CDD: 2009-2018 period, compared to 2008-2017 period in the original forecast;
c) updated forecasts of model input variables: updated forecasts of GDP and Unemployment rates based on the latest (January 2019) Conference Board of Canada forecast; and
d) re-estimated model co-efficients: models were tested for goodness of fit and reasonableness of independent variable co-efficients. Model specifications remained unchanged for all classes except for GS 1,000-4,999 kW class. The unemployment rate variable was found to be statistically insignificant for the specific rate class and was removed from the model in this update.

The updated load forecast models also incorporate the latest information related to actual IESO verified CDM savings to the end of 2017, and non-verified 2018 results. For the 2019-2024 forecast period, the CDM savings included in the forecast are based on the latest CDM plan submitted to the IESO.

Toronto Hydro notes the very recent Provincial directives on conservation programs in the province. However, at time of preparation of the load forecast for the update, the potential impacts are unknown, and therefore Toronto Hydro has included the latest

forecast for CDM savings through the forecast period. Details of the CDM forecast are provided in Appendix B to this schedule. Updated tables originally provided in response to 3-VECC-25 and 3-VECC-26 are also provided in Appendix C and D.

The underlying CDM savings forecast for the purpose of LRAMVA calculations over the 2020-2024 period are also filed as Appendix E. As discussed during the Technical Conference, these savings include persistence of 2019 forecast CDM savings. Persistence of 2018 savings is not included, as the actual results of these programs are known and included (even if they are not yet verified by the IESO).

Board Staff's interrogatory 3-Staff-106 inquired about the impacts on the load forecast due to the TTC Spadina extension, and the proposed Eglinton Crosstown project. The updated historical loads now contain the full impact of the Spadina extension and therefore are reflected in the load forecast. As noted in Toronto Hydro's interrogatory response, the load impacts of the Eglinton Crosstown project are uncertain in both level and timing, and would not have a material impact on rate setting for the CIR period. They have not been reflected in the updated load forecast.

Similarly, no consideration of EV loads or DER for purpose of customer load shedding has been included in the updated load forecast, for the reasons indicated in the original evidence.

A summary of the billing unit load forecasts, by class, is provided in Table 2.

Table 2: Billing Unit Load Forecast by Class

Rate Class		2018	2019	2020	2021	2022	2023	2024
Residential (GWh)	Original	4,580.0	4,532.0	4,510.6	4,458.7	4,422.7	4,386.7	4,366.4
	Updated	4,770.3	4,543.9	4,531.2	4,488.5	4,462.0	4,435.6	4,425.2
CSMUR (GWh)	Original	256.2	263.9	277.1	286.9	300.3	313.8	328.4
	Updated	266.8	278.1	297.8	314.7	336.4	352.4	367.6
GS <50 kW (GWh)	Original	2,307.4	2,281.5	2,267.6	2,238.8	2,214.3	2,187.5	2,169.9
	Updated	2,361.2	2,308.4	2,299.0	2,276.4	2,263.7	2,251.3	2,242.4
GS 50-999 kW (MVA)	Original	25,259.1	25,224.7	24,899.2	24,849.5	24,840.9	24,813.6	24,875.7
	Updated	24,863.0	25,304.9	24,899.0	24,780.6	24,747.8	24,722.8	24,752.9
GS 1000-4999 kW (MVA)	Original	10,443.0	10,383.8	10,392.9	10,334.3	10,283.8	10,232.6	10,228.5
	Updated	10,219.7	10,393.7	10,406.7	10,362.1	10,352.3	10,350.5	10,370.6
Large User (MVA)	Original	4,897.2	4,826.4	4,789.3	4,764.6	4,748.4	4,730.2	4,733.9
	Updated	4,812.6	4,637.9	4,600.4	4,530.2	4,491.6	4,455.9	4,435.7
Street lighting (MVA)	Original	325.7	326.1	326.6	327.1	327.6	328.1	328.6
	Updated	325.5	325.8	326.3	326.8	327.3	327.7	328.2
USL (GWh)	Original	41.2	41.2	41.3	41.2	41.2	41.2	41.3
	Updated	40.5	40.5	40.6	40.5	40.5	40.5	40.6

1.2 Customer Forecast

Similar to the load forecast, the forecast of customers by rate class has also been updated to reflect the latest actuals (to end of 2018). As noted in Exhibit 3, Tab 1, Schedule 1, section 6, most of the customer forecasts are based on extrapolation models. Details of the models used for each rate class are provided in the following table.

Table 3: Customer Forecast Models

Rate Class	Type of model (e.g. linear trend)	Period used for model	Model Explanation
Residential	Linear Trend	2002-2018	Full historical data set used for trend
CSMUR	Based on estimated projections	N/A	Based on CMHC's forecast of housing starts for multi-unit developments in Toronto. Toronto Hydro uses its professional judgment to estimate the market share of the units from this forecast that will be serviced by Toronto Hydro.
GS <50 kW	Linear Trend	2014-2018	Shorter period than full data set to reflect latest trend in the class.
GS 50-999 kW	Linear Trend	2002-2018	Full historical data set used for trend
GS 1000-4999 kW	Latest actual	N/A	Customer numbers for this group relatively stable
Large User	Latest actual	N/A	Customer numbers for this group relatively stable
Street lighting	Linear Trend	2007-2018	Full historical data set used for trend
USL	Latest actual	N/A	Customer numbers for this group relatively stable

A summary of the customer forecasts, by class, is provided in Table 2.

Table 4: Customer Forecast by Class

Rate Class		2018	2019	2020	2021	2022	2023	2024
Residential	Original	612,675	614,320	615,965	617,609	619,254	620,899	622,544
	Updated	612,169	613,542	615,118	616,694	618,269	619,845	621,421
CSMUR	Original	75,371	79,347	85,161	90,045	95,962	101,879	107,796
	Updated	74,523	80,204	85,852	90,897	97,558	102,374	106,611
GS <50 kW	Original	71,306	71,403	71,499	71,596	71,692	71,788	71,885
	Updated	71,170	71,466	71,599	71,732	71,864	71,997	72,130
GS 50-999 kW	Original	10,396	10,385	10,374	10,363	10,352	10,341	10,330
	Updated	10,515	10,447	10,417	10,387	10,357	10,327	10,297
GS 1000-4999 kW	Original	430	430	430	430	430	430	430
	Updated	432	430	430	430	430	430	430
Large User	Original	44	44	44	44	44	44	44
	Updated	44	38	38	38	38	38	38

Rate Class		2018	2019	2020	2021	2022	2023	2024
Street lighting (devices)	Original	164,756	165,024	165,292	165,560	165,828	166,096	166,364
	Updated	164,662	164,828	165,274	165,535	165,796	166,057	166,318
USL (connections)	Original	12,272	12,272	12,272	12,272	12,272	12,272	12,272
	Updated	12,245	12,180	12,180	12,180	12,180	12,180	12,180
USL (customers)	Original	857	857	857	857	857	857	857
	Updated	837	825	825	825	825	825	825

An update to Exhibit 3, Tab 1, Schedule 1, Appendix A1 and Appendix A2 are provided as Appendix F and Appendix G, showing details of the historical and forecast model inputs and model statistical results.

OEB Appendix 2-IB
Customer, Connections, Load Forecast and Revenues Data and Analysis

This sheet is to be filled in accordance with the instructions documented in section 2.3.2 of Chapter 2 of the Filing Requirements for Distribution Rate Applications, in terms of one set of tables per customer class.

Color coding for Cells: Data input | Drop-down List | No data entry required | Blank or calculated value

Distribution System (Total)

	Calendar Year (for 2020 Cost of Service)		Consumption (kWh) [3]				
				Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2013*		Actual	24,602,483,277	24,614,578,389		
Historical	*2014*		Actual	24,558,531,773	24,505,064,297		
Historical	*2015*		Actual	24,428,042,829	24,404,398,486	Board-approved	
Historical	*2016*		Actual	24,567,033,429	24,275,284,295		
Historical	*2017*		Actual	23,598,572,231	23,822,039,462		
Historical	*2018*		Actual	24,371,454,893	23,928,196,254		
Bridge Year	*2019*		Forecast		23,525,784,369		
Test Year	*2020*		Forecast		23,377,600,153		
Test Year	*2021*		Forecast		23,103,887,065		
Test Year	*2022*		Forecast		22,994,400,874		
Test Year	*2023*		Forecast		22,888,042,435		
Test Year	*2024*		Forecast		22,842,029,746		

Variance Analysis	Year	Year-over-year		Versus Board-approved
	2013			
	2014	-0.2%	-0.4%	
	2015	-0.5%	-0.4%	
	2016	0.6%	-0.5%	
	2017	-3.9%	-1.9%	
	2018	3.3%	0.4%	
	2019		-1.7%	
	2020		-0.6%	
	2021		-1.2%	
	2022		-0.5%	
	2023		-0.5%	
	2024		-0.2%	
	Geometric Mean	-0.2%	-0.7%	

Customer Class Analysis (one for each Customer Class, excluding MicroFIT and Standby)

OEB Appendix 2-IB
Customer, Connections, Load Forecast and Revenues Data and Analysis

1 **Customer Class:** Residential — Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2020 Cost of Service)	Customers				Consumption (kWh) [3]				Consumption (kWh) per Customer			
							Actual (Weather actual)	Weather-normalized	Weather-normalized		Actual (Weather actual)	Weather-normalized	Weather-normalized
Historical	*2013*	Actual	606,350			Actual	4,988,814,396	5,003,113,071		Actual	8,228	8,251	
Historical	*2014*	Actual	609,928			Actual	4,879,959,207	4,889,931,927		Actual	8,001	8,017	
Historical	*2015*	Actual	610,961	Board-approved	612,985	Actual	4,807,191,038	4,808,717,399	Board-approved	4,909,898,145	Actual	7,868	7,871 Board-approved	8,010
Historical	*2016*	Actual	611,021			Actual	4,903,931,991	4,782,426,081			Actual	8,026	7,827	
Historical	*2017*	Actual	611,660			Actual	4,545,714,645	4,621,607,673			Actual	7,432	7,556	
Historical	*2018*	Actual	612,169			Actual	4,927,526,992	4,770,271,625			Actual	8,049	7,792	
Bridge Year	*2019*	Forecast	613,542			Forecast		4,543,879,091			Forecast		7,406	
Test Year	*2020*	Forecast	615,118			Forecast		4,531,218,421			Forecast		7,366	
Test Year	*2021*	Forecast	616,694			Forecast		4,488,479,794			Forecast		7,278	
Test Year	*2022*	Forecast	618,269			Forecast		4,462,016,247			Forecast		7,217	
Test Year	*2023*	Forecast	619,845			Forecast		4,435,552,699			Forecast		7,156	
Test Year	*2024*	Forecast	621,421			Forecast		4,425,206,261			Forecast		7,121	

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2013			*2013*				*2013*			
	2014	0.6%		*2014*	-2.2%	-2.3%		*2014*	-2.8%	-2.8%	
	2015	0.2%		*2015*	-1.5%	-1.7%		*2015*	-1.7%	-1.8%	
	2016	0.0%		*2016*	2.0%	-0.5%		*2016*	2.0%	-0.6%	
	2017	0.1%		*2017*	-7.3%	-3.4%		*2017*	-7.4%	-3.5%	
	2018	0.1%		*2018*	8.4%	3.2%		*2018*	8.3%	3.1%	
	2019	0.2%		*2019*		-4.7%		*2019*		-5.0%	
	2020	0.3%		*2020*		-0.3%		*2020*		-0.5%	
	2021	0.3%		*2021*		-0.9%		*2021*		-1.2%	
	2022	0.3%		*2022*		-0.6%		*2022*		-0.8%	
	2023	0.3%		*2023*		-0.6%		*2023*		-0.8%	
	2024	0.3%	0.3%	*2024*		-0.2%	-7.7%	*2024*		-0.5%	-8.0%
	Geometric Mean	0.2%		Geometric Mean	-0.3%	-1.2%		Geometric Mean	-0.5%	-1.5%	

	Calendar Year (for 2020 Cost of Service)	Revenues			
Historical	*2013*	Actual	$ 212,060,221		
Historical	*2014*	Actual	$ 213,456,483		
Historical	*2015*	Actual	$ 250,173,765	Board-approved	$ 252,506,394
Historical	*2016*	Actual	$ 259,722,123		
Historical	*2017*	Actual	$ 275,943,904		
Historical	*2018*	Actual	$ 293,738,060		
Bridge Year	*2019*	Forecast	$ 304,906,894		
Test Year	*2020*	Forecast	$ 316,462,218		
Test Year	*2021*	Forecast	$ 326,685,424		
Test Year	*2022*	Forecast	$ 335,568,591		
Test Year	*2023*	Forecast	$ 350,677,309		
Test Year	*2024*	Forecast	$ 366,405,979		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2013		
	2014	0.7%	
Note 2	*2015*	17.2%	
	2016	3.8%	
	2017	6.2%	
	2018	6.4%	
	2019	3.8%	
	2020	3.8%	
	2021	3.2%	
	2022	2.7%	
	2023	4.5%	
	2024	4.5%	25.3%
	Geometric Mean	5.6%	

OEB Appendix 2-IB
Customer, Connections, Load Forecast and Revenues Data and Analysis

2 **Customer Class:** CSMUR — Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2020 Cost of Service)	Customers				Consumption (kWh) [3]				Consumption (kWh) per Customer				
							Actual (Weather actual)	Weather-normalized		Weather-normalized		Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2013*	Actual	36,156			Actual	133,317,285	130,096,054			Actual	3,687	3,598		
Historical	*2014*	Actual	43,022			Actual	158,440,481	153,947,355			Actual	3,683	3,578		
Historical	*2015*	Actual	54,516	Board-approved	54,122	Actual	203,724,686	202,136,385	Board-approved	213,116,822	Actual	3,737	3,708	Board-approved	3.938
Historical	*2016*	Actual	65,685			Actual	231,489,091	231,291,163			Actual	3,524	3,521		
Historical	*2017*	Actual	71,041			Actual	245,275,381	247,801,250			Actual	3,453	3,488		
Historical	*2018*	Actual	74,523			Actual	270,836,212	266,754,658			Actual	3,634	3,579		
Bridge Year	*2019*	Forecast	80,204			Forecast		278,114,515			Forecast		3,468		
Test Year	*2020*	Forecast	85,852			Forecast		297,763,685			Forecast		3,468		
Test Year	*2021*	Forecast	90,897			Forecast		314,675,582			Forecast		3,462		
Test Year	*2022*	Forecast	97,558			Forecast		336,411,558			Forecast		3,448		
Test Year	*2023*	Forecast	102,374			Forecast		352,414,588			Forecast		3,442		
Test Year	*2024*	Forecast	106,611			Forecast		367,617,638			Forecast		3,448		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2013			*2013*				*2013*			
Note 3	*2014*	19.0%		*2014*	18.8%	18.3%		*2014*	-0.1%	-0.6%	
Note 3	*2015*	26.7%		*2015*	28.6%	31.3%		*2015*	1.5%	3.6%	
Note 3	*2016*	20.5%		*2016*	13.6%	14.4%		*2016*	-5.7%	-5.0%	
	2017	8.2%		*2017*	6.0%	7.1%		*2017*	-2.0%	-0.9%	
	2018	4.9%		*2018*	10.4%	7.6%		*2018*	5.3%	2.6%	
	2019	7.6%		*2019*		4.3%		*2019*		-3.1%	
	2020	7.0%		*2020*		7.1%		*2020*		0.0%	
	2021	5.9%		*2021*		5.7%		*2021*		-0.2%	
	2022	7.3%		*2022*		6.9%		*2022*		-0.4%	
	2023	4.9%		*2023*		4.8%		*2023*		-0.2%	
	2024	4.1%	58.6%	*2024*		4.3%	39.7%	*2024*		0.2%	-11.9%
	Geometric Mean	11.4%		Geometric Mean	19.4%	10.9%		Geometric Mean	-0.4%	-0.4%	

	Calendar Year (for 2020 Cost of Service)	Revenues			
Historical	*2013*	Actual	$ 10,916,837		
Historical	*2014*	Actual	$ 13,110,388		
Historical	*2015*	Actual	$ 17,785,616	Board-approved	$ 18,002,535
Historical	*2016*	Actual	$ 21,936,125		
Historical	*2017*	Actual	$ 25,564,379		
Historical	*2018*	Actual	$ 28,639,564		
Bridge Year	*2019*	Forecast	$ 32,193,282		
Test Year	*2020*	Forecast	$ 34,899,181		
Test Year	*2021*	Forecast	$ 38,054,484		
Test Year	*2022*	Forecast	$ 41,852,057		
Test Year	*2023*	Forecast	$ 45,786,430		
Test Year	*2024*	Forecast	$ 49,684,990		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2013		
Note 3	*2014*	20.1%	
Note 3	*2015*	35.7%	
Note 3	*2016*	23.3%	
Note 3	*2017*	16.5%	
Note 3	*2018*	12.0%	
Note 3	*2019*	12.4%	
	2020	8.4%	176.0%
	2021	9.0%	
	2022	10.0%	
Note 3	*2023*	9.4%	
Note 3	*2024*	8.5%	
	Geometric Mean	16.4%	

OEB Appendix 2-IB
Customer, Connections, Load Forecast and Revenues Data and Analysis

3 **Customer Class:** GS < 50 kW Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2020 Cost of Service)	Customers				Consumption (kWh) [3]				Consumption (kWh) per Customer			
							Actual (Weather actual)	Weather-normalized	Weather-normalized		Actual (Weather actual)	Weather-normalized	Weather-normalized
Historical	*2013*	Actual	68,312			Actual	2,171,642,035	2,175,762,283		Actual	31790.1	31,850	
Historical	*2014*	Actual	69,078			Actual	2,253,840,657	2,257,190,348		Actual	32627.5	32,676	
Historical	*2015*	Actual	70,628	Board-approved	69,131	Actual	2,366,876,161	2,367,505,018	Board Approved	2,118,402,162	Actual	33511.9	33,521 Board Approved
Historical	*2016*	Actual	70,499			Actual	2,371,216,399	2,337,491,516			Actual	33634.8	33,156
Historical	*2017*	Actual	71,116			Actual	2,311,840,421	2,332,595,227			Actual	32508.0	32,800
Historical	*2018*	Actual	71,170			Actual	2,404,335,418	2,361,181,460			Actual	33783.0	33,177
Bridge Year	*2019*	Forecast	71,466			Forecast		2,308,351,146			Forecast		32,300
Test Year	*2020*	Forecast	71,599			Forecast		2,299,006,608			Forecast		32,109
Test Year	*2021*	Forecast	71,732			Forecast		2,276,427,231			Forecast		31,735
Test Year	*2022*	Forecast	71,864			Forecast		2,263,652,846			Forecast		31,499
Test Year	*2023*	Forecast	71,997			Forecast		2,251,299,520			Forecast		31,269
Test Year	*2024*	Forecast	72,130			Forecast		2,242,389,081			Forecast		31,088

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2013			*2013*				*2013*			
	2014	1.1%		*2014*	3.8%	3.7%		*2014*	2.6%	2.6%	
	2015	2.2%		*2015*	5.0%	4.9%		*2015*	2.7%	2.6%	
	2016	-0.2%		*2016*	0.2%	-1.3%		*2016*	0.4%	-1.1%	
	2017	0.9%		*2017*	-2.5%	-0.2%		*2017*	-3.3%	-1.1%	
	2018	0.1%		*2018*	4.0%	1.2%		*2018*	3.9%	1.1%	
	2019	0.4%		*2019*		-2.2%		*2019*		-2.6%	
	2020	0.2%		*2020*		-0.4%		*2020*		-0.6%	
	2021	0.2%		*2021*		-1.0%		*2021*		-1.2%	
	2022	0.2%		*2022*		-0.6%		*2022*		-0.7%	
	2023	0.2%		*2023*		-0.5%		*2023*		-0.7%	
	2024	0.2%	3.6%	*2024*		-0.4%	8.5%	*2024*		-3.8%	
	Geometric Mean	0.5%		Geometric Mean	2.6%	0.3%		Geometric Mean	1.5%	-0.2%	

	Calendar Year (for 2020 Cost of Service)	Revenues			
Historical	*2013*	Actual	$ 69,733,891		
Historical	*2014*	Actual	$ 72,600,510		
Historical	*2015*	Actual	$ 89,474,756	Board-approved	$ 82,174,475
Historical	*2016*	Actual	$ 92,077,386		
Historical	*2017*	Actual	$ 98,790,549		
Historical	*2018*	Actual	$ 105,081,166		
Bridge Year	*2019*	Forecast	$ 107,580,797		
Test Year	*2020*	Forecast	$ 111,698,483		
Test Year	*2021*	Forecast	$ 114,497,852		
Test Year	*2022*	Forecast	$ 116,905,336		
Test Year	*2023*	Forecast	$ 121,448,904		
Test Year	*2024*	Forecast	$ 126,033,676		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2013		
	2014	4.1%	
Note 2	*2015*	23.2%	
	2016	2.9%	
	2017	7.3%	
	2018	6.4%	
	2019	2.4%	
	2020	3.8%	
	2021	2.5%	
	2022	2.1%	
	2023	3.9%	
	2024	3.8%	35.9%
	Geometric Mean	6.1%	

OEB Appendix 2-IB
Customer, Connections, Load Forecast and Revenues Data and Analysis

4 **Customer Class:** GS 50-999 kW — Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kVA

	Calendar Year (for 2020 Cost of Service)	Customers				Consumption (kWh) [3]				Consumption (kWh) per Customer			
						Actual (Weather actual)	Weather-normalized		Weather-normalized	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2013*	Actual	11,885			Actual 9,901,798,273	9,902,973,517			Actual 833,134	833,233		
Historical	*2014*	Actual	11,852			Actual 10,026,512,948	9,994,682,007			Actual 845,976	843,291		
Historical	*2015*	Actual	10,364	Board-approved	12,054	Actual 9,931,112,876	9,918,272,056	Board-approved	9,848,614,894	Actual 958,232	956,993	Board-approved	817,041
Historical	*2016*	Actual	10,475			Actual 9,975,508,523	9,877,187,647			Actual 952,316	942,930		
Historical	*2017*	Actual	10,407			Actual 9,622,771,103	9,705,438,682			Actual 924,644	932,588		
Historical	*2018*	Actual	10,515			Actual 9,921,831,647	9,760,734,208			Actual 943,588	928,268		
Bridge Year	*2019*	Forecast	10,447			Forecast	9,648,026,310			Forecast	923,521		
Test Year	*2020*	Forecast	10,417			Forecast	9,608,309,249			Forecast	922,368		
Test Year	*2021*	Forecast	10,387			Forecast	9,523,712,332			Forecast	916,888		
Test Year	*2022*	Forecast	10,357			Forecast	9,486,718,400			Forecast	915,972		
Test Year	*2023*	Forecast	10,327			Forecast	9,453,024,513			Forecast	915,370		
Test Year	*2024*	Forecast	10,297			Forecast	9,443,587,171			Forecast	917,120		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2013			*2013*				*2013*			
	2014	-0.3%		*2014*	1.3%	0.9%		*2014*	1.5%	1.2%	
Note 2	*2015*	-12.6%		*2015*	-1.0%	-0.8%		*2015*	13.3%	13.5%	
	2016	1.1%		*2016*	0.4%	-0.4%		*2016*	-0.6%	-1.5%	
	2017	-0.6%		*2017*	-3.5%	-1.7%		*2017*	-2.9%	-1.1%	
	2018	1.0%		*2018*	3.1%	0.6%		*2018*	2.0%	-0.5%	
	2019	-0.6%		*2019*		-1.2%		*2019*		-0.5%	
	2020	-0.3%		*2020*		-0.4%		*2020*		-0.1%	
	2021	-0.3%		*2021*		-0.9%		*2021*		-0.6%	
	2022	-0.3%		*2022*		-0.4%		*2022*		-0.1%	
	2023	-0.3%		*2023*		-0.4%		*2023*		-0.1%	
	2024	-0.3%	-13.6%	*2024*		-0.1%	-2.4%	*2024*		0.2%	12.9%
	Geometric Mean	-1.4%		Geometric Mean	0.1%	-0.5%		Geometric Mean	3.2%	1.0%	

	Calendar Year (for 2020 Cost of Service)	Transformer Allowance kVa			
Historical	*2013*	Actual	5,677,788		
Historical	*2014*	Actual	6,043,033		
Historical	*2015*	Actual	6,255,491		
Historical	*2016*	Actual	6,426,851		
Historical	*2017*	Actual	6,355,256		
Historical	*2018*	Actual	6,627,879		
Bridge Year	*2019*	Forecast	6,478,563		
Test Year	*2020*	Forecast	6,373,898		
Test Year	*2021*	Forecast	6,344,371		
Test Year	*2022*	Forecast	6,336,176		
Test Year	*2023*	Forecast	6,329,840		
Test Year	*2024*	Forecast	6,336,814		

	Calendar Year (for 2020 Cost of Service)	Revenues				Demand (kVA)				Demand (kVA) per Customer			
						Actual (Weather actual)	Weather-normalized		Weather-normalized	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2013*	Actual	$ 148,321,289			Actual 25,938,018	25,947,963			Actual 2182	2183		
Historical	*2014*	Actual	$ 148,888,895			Actual 25,788,227	25,748,810			Actual 2176	2173		
Historical	*2015*	Actual	$ 170,879,886	Board-approved	$ 180,346,188	Actual 25,388,280	25,388,672	Board-approved	26,395,826	Actual 2450	2450	Board-approved	2,190
Historical	*2016*	Actual	$ 178,409,499			Actual 25,684,305	25,423,741			Actual 2452	2427		
Historical	*2017*	Actual	$ 188,518,928			Actual 24,835,921	25,046,941			Actual 2386	2407		
Historical	*2018*	Actual	$ 197,548,326			Actual 25,282,327	24,862,996			Actual 2404	2365		
Bridge Year	*2019*	Forecast	$ 209,109,363			Forecast	25,304,929			Forecast	2422		
Test Year	*2020*	Forecast	$ 213,178,385			Forecast	24,899,004			Forecast	2390		
Test Year	*2021*	Forecast	$ 218,651,192			Forecast	24,780,594			Forecast	2386		
Test Year	*2022*	Forecast	$ 223,853,389			Forecast	24,747,778			Forecast	2389		
Test Year	*2023*	Forecast	$ 233,318,593			Forecast	24,722,788			Forecast	2394		
Test Year	*2024*	Forecast	$ 243,640,524			Forecast	24,752,904			Forecast	2404		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2013			*2013*				*2013*			
	2014	0.4%		*2014*	-0.6%	-0.8%		*2014*	-0.3%	-0.5%	
Note 2	*2015*	14.8%		*2015*	-1.6%	-1.4%		*2015*	12.6%	12.8%	
	2016	4.4%		*2016*	1.2%	0.1%		*2016*	0.1%	-0.9%	
	2017	5.7%		*2017*	-3.3%	-1.5%		*2017*	-2.7%	-0.8%	
	2018	4.8%		*2018*	1.8%	-0.7%		*2018*	0.8%	-1.8%	
	2019	5.9%		*2019*		1.8%		*2019*		2.4%	
	2020	1.9%		*2020*		-1.6%		*2020*		-1.3%	
	2021	2.6%		*2021*		-0.5%		*2021*		-0.2%	
	2022	2.4%		*2022*		-0.1%		*2022*		0.2%	
	2023	4.2%		*2023*		-0.1%		*2023*		0.2%	
	2024	4.4%	18.2%	*2024*		0.1%	-5.7%	*2024*		0.4%	9.2%
	Geometric Mean	5.1%		Geometric Mean	-0.6%	-0.5%		Geometric Mean	2.5%	1.0%	

OEB Appendix 2-IB
Customer, Connections, Load Forecast and Revenues Data and Analysis

5 **Customer Class:** GS 1000-4999 kW — Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kVA

	Calendar Year (for 2020 Cost of Service)	Customers				Consumption (kWh) [3]				Consumption (kWh) per Customer				
							Actual (Weather actual)	Weather-normalized		Weather-normalized		Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2013	Actual	516			Actual	4,933,804,363	4,929,739,251			Actual	9,561,636	9,553,758		
Historical	2014	Actual	447			Actual	4,882,286,646	4,858,037,398			Actual	10,922,341	10,868,093		
Historical	2015	Actual	432	Board-approved	440	Actual	4,807,842,082	4,798,904,169	Board-approved	4,654,535,571	Actual	11,129,264	11,108,574	Board-approved	10,578,490
Historical	2016	Actual	443			Actual	4,753,125,810	4,729,735,833			Actual	10,729,404	10,676,605		
Historical	2017	Actual	431			Actual	4,589,196,040	4,617,746,316			Actual	10,647,787	10,714,029		
Historical	2018	Actual	432			Actual	4,656,922,361	4,604,450,883			Actual	10,779,913	10,658,451		
Bridge Year	2019	Forecast	430			Forecast		4,617,393,040			Forecast		10,738,123		
Test Year	2020	Forecast	430			Forecast		4,595,015,405			Forecast		10,686,082		
Test Year	2021	Forecast	430			Forecast		4,547,794,726			Forecast		10,576,267		
Test Year	2022	Forecast	430			Forecast		4,521,102,881			Forecast		10,514,193		
Test Year	2023	Forecast	430			Forecast		4,498,196,256			Forecast		10,460,922		
Test Year	2024	Forecast	430			Forecast		4,485,496,354			Forecast		10,431,387		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2013			2013				2013			
Note 4	2014	-13.4%		2014	-1.0%	-1.5%		2014	14.2%	13.8%	
	2015	-3.4%		2015	-1.5%	-1.2%		2015	1.9%	2.2%	
	2016	2.5%		2016	-1.1%	-1.4%		2016	-3.6%	-3.9%	
	2017	-2.7%		2017	-3.4%	-2.4%		2017	-0.8%	0.4%	
	2018	0.2%		2018	1.5%	-0.3%		2018	1.2%	-0.5%	
	2019	-0.5%		2019		0.3%		2019		0.7%	
	2020	0.0%		2020		-0.5%		2020		-0.5%	
	2021	0.0%		2021		-1.0%		2021		-1.0%	
	2022	0.0%		2022		-0.6%		2022		-0.6%	
	2023	0.0%		2023		-0.5%		2023		-0.5%	
	2024	0.0%	-2.3%	2024		-0.3%	-1.3%	2024		-0.3%	1.0%
	Geometric Mean	-1.8%		Geometric Mean	-1.4%	-0.9%		Geometric Mean	3.0%	0.9%	

	Calendar Year (for 2020 Cost of Service)	Transformer Allowance kVa			
Historical	2013	Actual	8,869,214		
Historical	2014	Actual	8,796,124		
Historical	2015	Actual	8,758,785		
Historical	2016	Actual	8,807,222		
Historical	2017	Actual	8,540,919		
Historical	2018	Actual	8,681,971		
Bridge Year	2019	Forecast	8,688,218		
Test Year	2020	Forecast	8,698,598		
Test Year	2021	Forecast	8,661,828		
Test Year	2022	Forecast	8,653,831		
Test Year	2023	Forecast	8,652,323		
Test Year	2024	Forecast	8,668,603		

	Calendar Year (for 2020 Cost of Service)	Revenues				Demand (kVA)				Demand (kVA) per Customer				
							Actual (Weather actual)	Weather-normalized		Weather-normalized		Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2013	Actual	$ 49,244,312			Actual	11,071,372	11,063,303			Actual	21,456	21,441		
Historical	2014	Actual	$ 47,728,955			Actual	10,765,500	10,721,411			Actual	24,084	23,985		
Historical	2015	Actual	$ 55,018,607	Board-approved	$ 55,588,622	Actual	10,620,705	10,608,801	Board-approved	10,671,871	Actual	24,585	24,557	Board-approved	24,254
Historical	2016	Actual	$ 57,159,426			Actual	10,586,541	10,531,012			Actual	23,897	23,772		
Historical	2017	Actual	$ 60,058,849			Actual	10,215,013	10,277,353			Actual	23,701	23,845		
Historical	2018	Actual	$ 63,165,673			Actual	10,337,416	10,219,659			Actual	23,929	23,657		
Bridge Year	2019	Forecast	$ 66,957,040			Forecast		10,393,741			Forecast		24,171		
Test Year	2020	Forecast	$ 69,800,867			Forecast		10,406,674			Forecast		24,202		
Test Year	2021	Forecast	$ 71,752,739			Forecast		10,362,104			Forecast		24,098		
Test Year	2022	Forecast	$ 73,584,709			Forecast		10,352,308			Forecast		24,075		
Test Year	2023	Forecast	$ 76,919,599			Forecast		10,350,511			Forecast		24,071		
Test Year	2024	Forecast	$ 80,532,751			Forecast		10,370,633			Forecast		24,118		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2013			2013				2013			
Note 2	2014	-3.1%		2014	-2.8%	-3.1%		2014	12.2%	11.9%	
	2015	15.3%		2015	-1.3%	-1.1%		2015	2.1%	2.4%	
	2016	3.9%		2016	-0.3%	-0.7%		2016	-2.8%	-3.2%	
	2017	5.1%		2017	-3.5%	-2.4%		2017	-0.8%	0.3%	
	2018	5.2%		2018	1.2%	-0.6%		2018	1.0%	-0.8%	
	2019	6.0%		2019		1.7%		2019		2.2%	
	2020	4.2%		2020		0.1%		2020		0.1%	
	2021	2.8%		2021		-0.4%		2021		-0.4%	
	2022	2.6%		2022		-0.1%		2022		-0.1%	
	2023	4.5%		2023		0.0%		2023		0.0%	
	2024	4.7%	25.6%	2024		0.2%	-2.5%	2024		0.2%	-0.2%
	Geometric Mean	5.0%		Geometric Mean	-1.7%	-0.6%		Geometric Mean	2.8%	1.2%	

OEB Appendix 2-IB
Customer, Connections, Load Forecast and Revenues Data and Analysis

6 **Customer Class:** Large Use — Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kVA

	Calendar Year (for 2020 Cost of Service)	Customers				Consumption (kWh) [3]				Consumption (kWh) per Customer			
						Actual (Weather actual)	Weather-normalized		Weather-normalized	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2013	Actual	52			Actual 2,317,813,992	2,317,601,280			Actual 44,573,346	44,569,255		
Historical	2014	Actual	47			Actual 2,202,455,832	2,196,239,262			Actual 46,860,762	46,728,495		
Historical	2015	Actual	44	Board-approved	49	Actual 2,156,018,802	2,153,586,276	Board-approved	2,228,386,374	Actual 49,000,427	48,945,143	Board-approved	45,477,273
Historical	2016	Actual	42			Actual 2,175,392,445	2,160,782,885			Actual 51,795,058	51,447,212		
Historical	2017	Actual	44			Actual 2,127,297,946	2,140,373,619			Actual 48,347,681	48,644,855		
Historical	2018	Actual	44			Actual 2,034,120,651	2,008,921,808			Actual 46,230,015	45,657,314		
Bridge Year	2019	Forecast	38			Forecast	1,973,960,059			Forecast	51,946,317		
Test Year	2020	Forecast	38			Forecast	1,889,478,427			Forecast	49,723,117		
Test Year	2021	Forecast	38			Forecast	1,796,298,178			Forecast	47,271,005		
Test Year	2022	Forecast	38			Forecast	1,767,816,828			Forecast	46,521,495		
Test Year	2023	Forecast	38			Forecast	1,740,689,851			Forecast	45,807,628		
Test Year	2024	Forecast	38			Forecast	1,720,190,903			Forecast	45,268,182		

Variance Analysis	Year	Customers Year-over-year	Customers Test Year Versus Board-approved	Consumption (kWh) Year	Consumption (kWh) Year-over-year: Actual (Weather actual)	Consumption (kWh) Year-over-year: Weather-normalized	Consumption (kWh) Test Year Versus Board-approved	Consumption (kWh) per Customer Year	Consumption (kWh) per Customer Year-over-year: Actual (Weather actual)	Consumption (kWh) per Customer Year-over-year: Weather-normalized	Consumption (kWh) per Customer Test Year Versus Board-approved
	2013			2013				2013			
	2014	-9.6%		2014	-5.0%	-5.2%		2014	5.1%	4.8%	
	2015	-6.4%		2015	-2.1%	-1.9%		2015	4.6%	4.7%	
	2016	-4.5%		2016	0.9%	0.3%		2016	5.7%	5.1%	
	2017	4.8%		2017	-2.2%	-0.9%		2017	-6.7%	-5.4%	
	2018	0.0%		2018	-4.4%	-6.1%		2018	-4.4%	-6.1%	
	2019	-13.6%		2019		-1.7%		2019		13.8%	
	2020	0.0%		2020		-4.3%		2020		-4.3%	
	2021	0.0%		2021		-4.9%		2021		-4.9%	
	2022	0.0%		2022		-1.6%		2022		-1.6%	
	2023	0.0%		2023		-1.5%		2023		-1.5%	
	2024	0.0%	-22.4%	2024		-1.2%	-15.2%	2024		-1.2%	9.3%
	Geometric Mean	-3.1%		Geometric Mean	-3.2%	-2.9%		Geometric Mean	0.9%	0.2%	

	Calendar Year (for 2020 Cost of Service)	Transformer Allowance kVa			
Historical	2013	Actual	5,297,783		
Historical	2014	Actual	5,037,228		
Historical	2015	Actual	4,961,605		
Historical	2016	Actual	5,040,441		
Historical	2017	Actual	4,944,707		
Historical	2018	Actual	4,814,758		
Bridge Year	2019	Forecast	4,544,019		
Test Year	2020	Forecast	4,507,133		
Test Year	2021	Forecast	4,438,539		
Test Year	2022	Forecast	4,400,675		
Test Year	2023	Forecast	4,365,743		
Test Year	2024	Forecast	4,345,829		

	Calendar Year (for 2020 Cost of Service)	Revenues				Demand (kVA)				Demand (kVA) per Customer			
						Actual (Weather actual)	Weather-normalized		Weather-normalized	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2013	Actual	$ 28,480,997			Actual 5,493,794	5,493,928			Actual 105,650	105,652		
Historical	2014	Actual	$ 27,002,470			Actual 5,177,346	5,166,660			Actual 110,156	109,929		
Historical	2015	Actual	$ 30,728,825	Board-approved	$ 29,054,341	Actual 5,090,547	5,088,775	Board-approved	5,305,030	Actual 115,694	115,654	Board-approved	108,266
Historical	2016	Actual	$ 32,178,414			Actual 5,170,992	5,134,655			Actual 123,119	122,254		
Historical	2017	Actual	$ 34,275,778			Actual 5,065,201	5,095,503			Actual 115,118	115,807		
Historical	2018	Actual	$ 34,250,928			Actual 4,873,591	4,812,584			Actual 110,763	109,377		
Bridge Year	2019	Forecast	$ 34,072,361			Forecast	4,637,881			Forecast	122,050		
Test Year	2020	Forecast	$ 35,147,422			Forecast	4,600,360			Forecast	121,062		
Test Year	2021	Forecast	$ 35,673,516			Forecast	4,530,224			Forecast	119,216		
Test Year	2022	Forecast	$ 36,257,882			Forecast	4,491,580			Forecast	118,199		
Test Year	2023	Forecast	$ 37,515,423			Forecast	4,455,940			Forecast	117,262		
Test Year	2024	Forecast	$ 38,932,355			Forecast	4,435,652			Forecast	116,728		

Variance Analysis	Year	Revenues Year-over-year	Revenues Test Year Versus Board-approved	Demand (kVA) Year	Demand (kVA) Year-over-year: Actual (Weather actual)	Demand (kVA) Year-over-year: Weather-normalized	Demand (kVA) Test Year Versus Board-approved	Demand (kVA) per Customer Year	Demand (kVA) per Customer Year-over-year: Actual (Weather actual)	Demand (kVA) per Customer Year-over-year: Weather-normalized	Demand (kVA) per Customer Test Year Versus Board-approved
	2013			2013				2013			
Note 2	2014	-5.2%		2014	-5.8%	-6.0%		2014	4.3%	4.0%	
	2015	13.8%		2015	-1.7%	-1.5%		2015	5.0%	5.2%	
	2016	4.7%		2016	1.6%	0.9%		2016	6.4%	5.7%	
	2017	6.5%		2017	-2.0%	-0.8%		2017	-6.5%	-5.3%	
	2018	-0.1%		2018	-3.8%	-5.6%		2018	-3.8%	-5.6%	
	2019	-0.5%		2019		-3.6%		2019		11.6%	
	2020	3.2%		2020		-0.8%		2020		-0.8%	
	2021	1.5%		2021		-1.5%		2021		-1.5%	
	2022	1.6%		2022		-0.9%		2022		-0.9%	
	2023	3.5%		2023		-0.8%		2023		-0.8%	
	2024	3.8%	21.0%	2024		-0.5%	-13.3%	2024		-0.5%	11.8%
	Geometric Mean	3.2%		Geometric Mean	-3.0%	-2.1%		Geometric Mean	1.2%	1.0%	

OEB Appendix 2-IB
Customer, Connections, Load Forecast and Revenues Data and Analysis

7 **Customer Class:** Street Lighting — Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kVA

	Calendar Year (for 2020 Cost of Service)	Connections				Consumption (kWh) [3]				Consumption (kWh) per Connection			
							Actual (Weather actual)	Weather-normalized	Weather-normalized		Actual (Weather actual)	Weather-normalized	Weather-normalized
Historical	*2013*	Actual	163,426			Actual	114,205,296	114,205,296		Actual	699	699	
Historical	*2014*	Actual	163,810			Actual	114,087,684	114,087,684		Actual	696	696	
Historical	*2015*	Actual	164,008	Board-approved	164,098	Actual	114,178,674	114,178,674	Board-approved 114,092,929	Actual	696	696	Board-approved 695
Historical	*2016*	Actual	164,296			Actual	114,988,504	114,988,504		Actual	700	700	
Historical	*2017*	Actual	164,537			Actual	115,072,181	115,072,181		Actual	699	699	
Historical	*2018*	Actual	164,662			Actual	115,403,897	115,403,897		Actual	701	701	
Bridge Year	*2019*	Forecast	164,828			Forecast		115,582,493		Forecast		701	
Test Year	*2020*	Forecast	165,274			Forecast		116,219,746		Forecast		703	
Test Year	*2021*	Forecast	165,535			Forecast		116,021,507		Forecast		701	
Test Year	*2022*	Forecast	165,796			Forecast		116,204,400		Forecast		701	
Test Year	*2023*	Forecast	166,057			Forecast		116,387,293		Forecast		701	
Test Year	*2024*	Forecast	166,318			Forecast		116,953,726		Forecast		703	

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2013			*2013*				*2013*			
	2014	0.2%		*2014*	-0.1%	-0.1%		*2014*	-0.3%	-0.3%	
	2015	0.1%		*2015*	0.1%	0.1%		*2015*	0.0%	0.0%	
	2016	0.2%		*2016*	0.7%	0.7%		*2016*	0.5%	0.5%	
	2017	0.1%		*2017*	0.1%	0.1%		*2017*	-0.1%	-0.1%	
	2018	0.1%		*2018*	0.3%	0.3%		*2018*	0.2%	0.2%	
	2019	0.1%		*2019*		0.2%		*2019*		0.1%	
	2020	0.3%		*2020*		0.6%		*2020*		0.3%	
	2021	0.2%		*2021*		-0.2%		*2021*		-0.3%	
	2022	0.2%		*2022*		0.2%		*2022*		0.0%	
	2023	0.2%		*2023*		0.2%		*2023*		0.0%	
	2024	0.2%	0.7%	*2024*		0.5%	1.9%	*2024*		0.3%	1.1%
	Geometric Mean	0.2%		Geometric Mean	0.3%	0.2%		Geometric Mean	0.1%	0.1%	

	Calendar Year (for 2020 Cost of Service)	Revenues				Demand (kVA)				Demand (kVA) per Connection			
							Actual (Weather actual)	Weather-normalized	Weather-normalized		Actual (Weather actual)	Weather-normalized	Weather-normalized
Historical	*2013*	Actual	$ 12,108,215			Actual	323,205	323,205		Actual	2.0	2.0	
Historical	*2014*	Actual	$ 12,259,078			Actual	323,887	323,887		Actual	2.0	2.0	
Historical	*2015*	Actual	$ 12,269,663	Board-approved	$ 12,281,306	Actual	324,136	324,136	Board-approved 324,479	Actual	2.0	2.0	Board-approved 2.0
Historical	*2016*	Actual	$ 12,793,477			Actual	324,629	324,629		Actual	2.0	2.0	
Historical	*2017*	Actual	$ 13,706,308			Actual	325,116	325,116		Actual	2.0	2.0	
Historical	*2018*	Actual	$ 14,465,487			Actual	325,497	325,497		Actual	2.0	2.0	
Bridge Year	*2019*	Forecast	$ 15,047,142			Forecast		325,821		Forecast		2.0	
Test Year	*2020*	Forecast	$ 15,606,851			Forecast		326,300		Forecast		2.0	
Test Year	*2021*	Forecast	$ 16,087,184			Forecast		326,776		Forecast		2.0	
Test Year	*2022*	Forecast	$ 16,503,368			Forecast		327,256		Forecast		2.0	
Test Year	*2023*	Forecast	$ 17,220,081			Forecast		327,732		Forecast		2.0	
Test Year	*2024*	Forecast	$ 17,969,471			Forecast		328,212		Forecast		2.0	

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2013			*2013*				*2013*			
	2014	1.2%		*2014*	0.2%	0.2%		*2014*	0.0%	0.0%	
	2015	0.1%		*2015*	0.1%	0.1%		*2015*	0.0%	0.0%	
	2016	4.3%		*2016*	0.2%	0.2%		*2016*	0.0%	0.0%	
	2017	7.1%		*2017*	0.1%	0.1%		*2017*	0.0%	0.0%	
	2018	5.5%		*2018*	0.1%	0.1%		*2018*	0.0%	0.0%	
	2019	4.0%		*2019*		0.1%		*2019*		0.0%	
	2020	3.7%		*2020*		0.1%		*2020*		-0.1%	
	2021	3.1%		*2021*		0.1%		*2021*		0.0%	
	2022	2.6%		*2022*		0.1%		*2022*		0.0%	
	2023	4.3%		*2023*		0.1%		*2023*		0.0%	
	2024	4.4%	27.1%	*2024*		0.1%	0.6%	*2024*		0.0%	-0.2%
	Geometric Mean	4.0%		Geometric Mean	0.2%	0.2%		Geometric Mean	0.0%	0.0%	

OEB Appendix 2-IB
Customer, Connections, Load Forecast and Revenues Data and Analysis

8 **Customer Class:** Unmetered Scattered Load — Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2020 Cost of Service)	Customers				Consumption (kWh) [3]				Consumption (kWh) per Customer				
							Actual (Weather actual)	Weather-normalized		Weather-normalized		Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2013	Actual	873			Actual	41,087,638	41,087,638			Actual	47,065	47,065		
Historical	2014	Actual	888			Actual	40,948,317	40,948,317			Actual	46,113	46,113		
Historical	2015	Actual	866	Board-approved	898	Actual	41,098,509	41,098,509	Board-approved	41,132,354	Actual	47,458	47,458	Board-approved	45,804
Historical	2016	Actual	866			Actual	41,380,666	41,380,666			Actual	47,784	47,784		
Historical	2017	Actual	860			Actual	41,404,515	41,404,515			Actual	48,145	48,145		
Historical	2018	Actual	837			Actual	40,477,714	40,477,714			Actual	48,360	48,360		
Bridge Year	2019	Forecast	825			Forecast		40,477,714			Forecast		49,064		
Test Year	2020	Forecast	825			Forecast		40,588,612			Forecast		49,198		
Test Year	2021	Forecast	825			Forecast		40,477,714			Forecast		49,064		
Test Year	2022	Forecast	825			Forecast		40,477,714			Forecast		49,064		
Test Year	2023	Forecast	825			Forecast		40,477,714			Forecast		49,064		
Test Year	2024	Forecast	825			Forecast		40,588,612			Forecast		49,198		

Variance Analysis	Year	Customers: Year-over-year	Customers: Test Year Versus Board-approved	Consumption (kWh): Year-over-year		Consumption (kWh): Test Year Versus Board-approved	Consumption (kWh) per Customer: Year-over-year		Consumption (kWh) per Customer: Test Year Versus Board-approved
	2013			2013			2013		
	2014	1.7%		2014	-0.3%		2014	-2.0%	
	2015	-2.5%		2015	0.4%		2015	2.9%	
	2016	0.0%		2016	0.7%		2016	0.7%	
	2017	-0.7%		2017	0.1%		2017	0.8%	
	2018	-2.7%		2018	-2.2%		2018	0.4%	
	2019	-1.4%		2019			2019		
	2020	0.0%		2020			2020		
	2021	0.0%		2021			2021		
	2022	0.0%		2022			2022		
	2023	0.0%		2023			2023		
	2024	0.0%	-8.1%	2024		-1.3%	2024		7.4%
	Geometric Mean	-0.6%		Geometric Mean	-0.4%	-0.1%	Geometric Mean	0.7%	0.4%

	Calendar Year (for 2020 Cost of Service)	Connections				Consumption (kWh) per Connection				
							Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2013	Actual	11,784			Actual	3,487	3,487		
Historical	2014	Actual	11,754			Actual	3,484	3,484		
Historical	2015	Actual	11,942	Board-approved	11,720	Actual	3,442	3,442	Board-approved	3,510
Historical	2016	Actual	12,056			Actual	3,432	3,432		
Historical	2017	Actual	12,196			Actual	3,395	3,395		
Historical	2018	Actual	12,245			Actual	3,306	3,306		
Bridge Year	2019	Forecast	12,180			Forecast		3,323		
Test Year	2020	Forecast	12,180			Forecast		3,332		
Test Year	2021	Forecast	12,180			Forecast		3,323		
Test Year	2022	Forecast	12,180			Forecast		3,323		
Test Year	2023	Forecast	12,180			Forecast		3,323		
Test Year	2024	Forecast	12,180			Forecast		3,332		

Variance Analysis	Year	Connections: Year-over-year	Connections: Test Year Versus Board-approved	Consumption (kWh) per Connection: Year-over-year		Consumption (kWh) per Connection: Test Year Versus Board-approved
	2013			2013		
	2014	-0.3%		2014	-0.1%	
	2015	1.6%		2015	-1.2%	
	2016	1.0%		2016	-0.3%	
	2017	1.2%		2017	-1.1%	
	2018	0.4%		2018	-2.6%	
	2019	-0.5%		2019		
	2020	0.0%		2020		
	2021	0.0%		2021		
	2022	0.0%		2022		
	2023	0.0%		2023		
	2024	0.0%	3.9%	2024		-5.0%
	Geometric Mean	0.3%		0	-1.8%	-0.5%

OEB Appendix 2-IB
Customer, Connections, Load Forecast and Revenues Data and Analysis

	Calendar Year (for 2020 Cost of Service	Revenues			
Historical	*2013*	Actual	$ 2,616,211		
Historical	*2014*	Actual	$ 2,661,624		
Historical	*2015*	Actual	$ 3,170,482	Board-approved	$ 3,173,355
Historical	*2016*	Actual	$ 3,314,179		
Historical	*2017*	Actual	$ 3,557,840		
Historical	*2018*	Actual	$ 3,669,773		
Bridge Year	*2019*	Forecast	$ 3,812,584		
Test Year	*2020*	Forecast	$ 3,440,724		
Test Year	*2021*	Forecast	$ 3,543,122		
Test Year	*2022*	Actual	$ 3,630,671		
Test Year	*2023*	Forecast	$ 3,784,557		
Test Year	*2024*	Forecast	$ 3,943,950		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2013		
	2014	1.7%	
Note 2	*2015*	19.1%	
	2016	4.5%	
	2017	7.4%	
	2018	3.1%	
	2019	3.9%	
	2020	-9.8%	
	2021	3.0%	
	2022	2.5%	
	2023	4.2%	
	2024	4.2%	8.4%
	Geometric Mean	4.2%	

Notes:

1 2015 Revenues are calculated on the rates that would have been applied if test year rate implementation was January 1, 2015.
2 Variances due to 2015 test year rate increases
3 CSMUR variances driven mainly strong rate of growth in number of customer and resulting electricity sales to the class.
4 Variance driven mainly by customer rate-class reclassification

Toronto Hydro-Electric System Limited
EB-2018-0165
Exhibit U
Tab 3
Schedule 1
Appendix B
FILED: April 30, 2019
(2 pages)

CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO could only be achieved with funding in addition to the CDM Plan Budget.

LDC 1:	TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	CDM-000409

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program							Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)													
												2015		2016		2017		2018		2019		2020		Total 2015 - 2020	
					Residential	Low-income	Small business	Commercial (including Multi-Family)	Agriculture	Institutional	Industrial	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs	SAVE ON ENERGY AUDIT FUNDING PROGRAM			01-Jul-2015			Yes	Yes		Yes	Yes	$87,099	78	$589,927	806	$490,689	3,089	$843,810	10,627	$807,212	10,000	$515,146	5,000	**$3,333,884**	**29,599**
	SAVE ON ENERGY BUSINESS REFRIGERATION INCENTIVE PROGRAM			01-Sep-2016			Yes	Yes		Yes		$0	0	$0	0	$974,845	3,471	$2,002,425	8,695	$1,333,283	4,986	$1,325,886	4,945	**$5,636,438**	**18,846**
	SAVE ON ENERGY COUPON PROGRAM			01-Jul-2015	Yes	Yes						$2,198,646	15,586	$6,325,639	75,466	$28,833,518	154,796	$11,246,773	57,485	$2,319,530	10,000	$1,211,169	4,104	**$52,135,275**	**317,309**
	SAVE ON ENERGY ENERGY MANAGER PROGRAM			01-Jul-2015						Yes	Yes	$11,681	0	$710,398	10,277	$4,916,985	8,704	$2,366,450	3,941	$2,409,850	4,022	$2,164,050	3,561	**$12,579,414**	**30,159**
	SAVE ON ENERGY ENERGY PERFORMANCE PROGRAM			01-Jan-2015				Yes		Yes	Yes	$0	0	$0	0	$20,000	0	$194,000	0	$194,000	0	$194,000	0	**$602,000**	**0**
	SAVE ON ENERGY EXISTING BUILDING COMMISSIONING PROGRAM			01-Feb-2016				Yes		Yes	Yes	$0	0	$539,587	0	$705,212	1,199	$239,661	382	$106,086	0	$109,269	0	**$1,699,815**	**1,581**
	SAVE ON ENERGY HEATING & COOLING PROGRAM			01-Jul-2015	Yes	Yes						$2,535,506	4,022	$4,444,112	9,237	$3,527,141	3,349	$3,901,906	4,067	$2,720,318	3,000	$2,043,949	2,163	**$19,172,932**	**25,838**
	SAVE ON ENERGY HIGH PERFORMANCE NEW CONSTRUCTION PROGRAM			01-Jul-2015			Yes	Yes		Yes	Yes	$104,736	77	$1,604,652	3,677	$3,735,641	6,259	$2,029,841	3,111	$2,436,056	4,000	$1,962,732	2,964	**$11,873,658**	**20,088**
	SAVE ON ENERGY HOME ASSISTANCE PROGRAM			01-Sep-2015		Yes						$1,947	283	$1,119,803	1,171	$3,229,399	1,952	$196,222	302	$3,249,977	5,000	$3,314,981	5,100	**$11,112,329**	**13,784**
	SAVE ON ENERGY MONITORING & TARGETING PROGRAM			01-May-2016						Yes	Yes	$0	0	$0	0	$20,000	0	$20,000	1	$20,000	1	$20,000	1	**$80,000**	**1**
	SAVE ON ENERGY NEW CONSTRUCTION PROGRAM			01-Jul-2015	Yes							$400	39	$54,294	238	$442,175	1,007	$441,084	491	$443,689	500	$529,859	787	**$1,911,501**	**3,063**
	SAVE ON ENERGY PROCESS & SYSTEMS UPGRADES PROGRAM			01-Jul-2015				Yes		Yes	Yes	$27,425	0	$426,596	339	$5,197,067	31,448	$4,571,778	18,090	$5,136,078	21,060	$30,748,416	155,790	**$46,107,360**	**226,727**
	SAVE ON ENERGY RETROFIT PROGRAM			01-Jul-2015			Yes	Yes		Yes	Yes	$3,285,077	32,024	$26,503,158	160,024	$34,141,413	197,868	$31,465,524	182,017	$31,217,416	180,000	$30,579,363	175,000	**$157,191,951**	**926,762**
	SAVE ON ENERGY SMALL BUSINESS LIGHTING PROGRAM			01-Jul-2015			Yes					$0	0	$166,782	56	$1,519,280	3,991	$2,465,191	8,305	$1,910,606	6,000	$1,447,998	4,077	**$7,509,857**	**22,420**
	SAVE ON ENERGY SMART THERMOSTAT PROGRAM			01-Jan-2015	Yes	Yes						$0	0	$0	0	$0	0	$441,789	741	$0	0	$0	0	**$441,789**	**741**
		ADAPTIVE THERMOSTAT LOCAL PROGRAM		15-Apr-2016	Yes	Yes	Yes	Yes	Yes	Yes	Yes	$0	0	$26,672	0	$501,323	1,054	$380,388	755	$379,099	750	$384,984	750	**$1,672,465**	**3,308**
		DATA CENTRE PILOT		14-Jul-2016								$0	0	$0	0	$0	0	$0	0	$0	0	$0	0	**$0**	**0**
		DIRECT INSTALL - HYDRONIC PILOT		01-Jul-2015								$0	668	$0	0	$0	0	$0	0	$0	0	$0	0	**$0**	**668**
		DIRECT INSTALL - RTU CONTROLS PILOT		01-Jul-2015			Yes	Yes	Yes	Yes	Yes	$0	0	$0	372	$0	0	$0	0	$0	0	$0	0	**$0**	**372**
		ELECTRONICS TAKEBACK PILOT PROGRAM		15-Apr-2016	Yes	Yes	Yes	Yes	Yes	Yes	Yes	$0	0	$0	1,145	$0	0	$0	0	$0	0	$0	0	**$0**	**1,145**
		HOME DEPOT HOME APPLIANCE MARKET UPLIFT CONSERVATION FUND PILOT PROGRAM		01-Jan-2015	Yes	Yes	Yes	Yes	Yes	Yes	Yes	$0	0	$0	10	$0	0	$0	0	$0	0	$0	0	**$0**	**10**
		MURB In-Suite Direct Install Lighting Program		01-Jan-2015								$0	0	$0	0	$0	0	$1,142,587	430	$2,711,299	6,000	$2,722,220	6,000	**$6,576,106**	**12,430**
		OPSAVER LOCAL PROGRAM		01-Sep-2016								$0	0	$0	0	$159,764	0	$502,285	1,459	$662,347	8,000	$633,130	13,422	**$1,957,525**	**13,422**
		PUMPSAVER 2.0		01-Sep-2016								$0	0	$0	0	$0	0	$1,846,013	6,762	$1,273,427	4,000	$871,519	2,000	**$3,990,959**	**12,762**
		PUMPSAVER LOCAL PROGRAM		01-Sep-2016								$0	0	$100,075	834	$3,254,578	13,914	$0	0	$0	0	$0	0	**$3,354,653**	**14,748**
		RTUSAVER		01-Jan-2017		Yes	Yes	Yes	Yes	Yes	Yes	$0	0	$0	0	$16,272	0	$2,068,149	3,297	$1,903,332	3,000	$1,903,332	3,000	**$5,891,085**	**9,297**
		SOCIAL BENCHMARKING LOCAL PROGRAM		01-Jan-2016	Yes	Yes	Yes	Yes	Yes	Yes	Yes	$0	0	$0	0	$4,078,842	14,211	$2,586,817	14,211	$2,586,817	14,211	$2,586,817	14,211	**$11,839,293**	**14,211**
		SWIMMING POOL EFFICIENCY LOCAL PROGRAM		01-Apr-2017	Yes							$0	0	$0	0	$376,548	1,029	$419,626	778	$411,598	750	$411,598	750	**$1,619,370**	**3,307**
		TRUCKLOAD EVENT PILOT PROGRAM		01-Sep-2016	Yes	Yes	Yes	Yes	Yes	Yes	Yes	$0	0	$0	3,305	$0	0	$0	0	$0	0	$0	0	**$0**	**3,305**
		WHOLE HOME PILOT		30-Jan-2017	Yes	Yes	Yes	Yes	Yes	Yes	Yes	$0	0	$0	0	$50,000	0	$51,600	0	$51,600	0	$51,600	0	**$204,800**	**0**
												$0	0	$0	0	$0	0	$0	0	$0	0	$0	0	**$0**	**0**
																								$0	
																								$0	
FCR TOTAL												**8,252,517**	**52,777**	**42,611,695**	**266,957**	**96,190,691**	**447,339**	**71,423,919**	**325,947**	**64,283,619**	**285,280**	**85,732,016**	**403,627**	**368,494,456**	**1,725,903**
Pay for Performance Programs																								**$0**	
P4P TOTAL												**$0**	**0.0**	**$0**	**0.0**	**$0**	**0.0**	**$0**	**0.0**	**$0**	**0.0**	**$0**	**0.0**	**$0**	**0**

CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO could only be achieved with funding in addition to the CDM Plan Budget.

LDC 1:	TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	CDM-000409

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program							2015		2016		2017		2018		2019		2020		Total 2015 - 2020	
					Residential	Low-income	Small business	Commercial (including A	Agriculture	Institutional	Industrial	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) *(Not funded through 2015-2020 CDM Framework)*	LEGACY - BI-ANNUAL RETAILER EVENT INITIATIVE												6,775												6,609
	LEGACY - DIRECT INSTALL LIGHTING AND WATER HEATING INITIATIVE												9,596												6,445
	LEGACY - EFFICIENCY: EQUIPMENT REPLACEMENT INCENTIVE INITIATIVE												160,780												159,686
	LEGACY - ENERGY AUDIT INITIATIVE												7,008												7,008
	LEGACY - ENERGY MANAGER PROGRAM												8,403												5,013
	LEGACY - EXISTING BUILDING COMMISSIONING INCENTIVE INITIATIVE												522												243
	LEGACY - HVAC INCENTIVES INITIATIVE												3,399												3,399
	LEGACY - LOW INCOME INITIATIVE												1,740												1,248
	LEGACY - NEW CONSTRUCTION AND MAJOR RENOVATION INITIATIVE												25,577												25,566
	LEGACY - P4P FOR CLASS B OFFICE PILOT PROGRAM												2,469												2,469
	LEGACY - PROCESS AND SYSTEMS UPGRADES INITIATIVES - PROJECT INCENTIVE INITIATIVE												5,327												5,327
	LEGACY - PROGRAM ENABLED SAVINGS												311												311
2011-2014 CDM Framework (and 2015 extension) TOTAL												**$0**	**231,907.9**											**0.0**	**223,324**
TARGET GAP TOTAL																								**$0**	
CDM PLAN TOTAL												**$8,252,517**	**284,684.5**	**$42,611,695**	**266,956.8**	**$96,190,691**	**447,339.1**	**$71,423,919**	**325,946.8**	**$64,283,619**	**285,280.3**	**$85,732,016**	**403,626.7**	**$368,494,456**	**1,949,227**
MINIMUM ANNUAL SAVINGS CHECK													**True**		**True**		**True**		**True**		**True**		**True**		

Option
Yes
No

Program Types
Regional
Local
Provincial

2011-2014 Province Wide Programs
Aboriginal Program
Audit Funding
Bi-Annual Retailer Event
Conservation Instant Coupon Booklet
Direct Install Lighting
Energy Manager (PSUI)
Existing Building Commissioning
Heating and Cooling Initiative
High Performance New Construction
Low Income Home Assistance Program
Monitoring and Targeting (PSUI)
Other
peaksaverPLUS
Process and Systems Upgrades Program
Program Enabled Savings
Residential New Construction
Retrofit Initiative

2015-2020 CDM Programs
Audit Funding Program
Energy Manager Program
Existing Building Commissioning
High Performance New Construction
Home Assistance Program
Process and Systems Upgrades Program
Monitoring and Targeting Program
Coupon Program
New Construction Program
Heating and Cooling Program
Retrofit
Small Business Lighting
Whole Home Pilot Program

UPDATE TO 3-VECC-25

Table 1: Verified Gross CDM Savings per IESO/OPA Reports

Verified Gross CDM Savings per IESO/OPA Reports (MWh)																				
Program Year	Calendar Year																			
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
2006	56,010	56,010	56,010	56,010	9,964	9,964	9,138	9,138	8,604	8,604	8,145	8,145	8,145	8,145	7,400	6,206	6,206	6,206	3,341	**341,389**
2007	-	325,918	237,877	226,833	226,833	226,824	40,551	40,551	40,551	18,405	15,514	12,062	12,062	12,062	12,062	5,774	1,403	1,256	1,256	**1,457,795**
2008	-	-	198,427	196,101	195,318	195,318	189,358	182,963	161,114	132,580	118,377	89,579	87,072	87,072	85,420	85,153	85,032	82,365	16,808	**2,188,058**
2009	-	-	-	207,499	183,543	183,543	183,487	182,023	177,457	170,241	157,083	106,015	74,958	58,123	36,220	26,986	26,976	26,616	23,866	**1,824,635**
2010	-	-	-	-	412,648	376,505	376,497	376,461	374,876	319,471	253,239	236,281	209,686	99,652	24,345	24,345	24,176	24,160	24,160	**3,156,503**
2011	-	-	-	-	-	290,029	289,158	287,288	280,372	278,421	274,558	263,083	262,934	243,971	238,509	208,193	207,404	206,173	35,115	**3,365,210**
2012	-	-	-	-	-	-	148,470	146,814	144,960	139,327	134,919	123,593	117,465	117,404	114,059	77,560	67,968	62,334	49,951	**1,444,823**
2013	-	-	-	-	-	-	-	185,316	182,084	175,009	169,472	155,245	147,549	147,471	143,269	138,920	120,027	93,232	88,365	**1,745,959**
2014	-	-	-	-	-	-	-	-	301,636	289,914	280,742	257,174	244,424	244,296	237,336	237,336	231,486	198,351	161,708	**2,684,402**
2015	-	-	-	-	-	-	-	-	-	404,267	389,832	385,053	384,740	384,278	383,152	375,930	375,834	372,162	291,543	**3,746,792**
2016	-	-	-	-	-	-	-	-	-	-	390,281	390,281	390,281	390,281	286,325	283,121	283,121	283,121	269,273	**2,966,084**
	56,010	**381,928**	**492,314**	**686,443**	**1,028,306**	**1,282,183**	**1,236,660**	**1,410,555**	**1,671,655**	**1,936,239**	**2,192,161**	**2,026,510**	**1,939,315**	**1,792,756**	**1,568,098**	**1,469,524**	**1,429,631**	**1,355,975**	**965,386**	**24,921,649**

Table 2: Cumulative Annual Gross CDM Savings (MWh)

Year	CUMULATIVE ANNUAL GROSS CDM SAVINGS (MWh)						
	Residential	CSMUR	GS<50 kW	GS50 -999 kW	GS1,000 – 4,999 kW	LU	**Total**
2006	23,311	-	-	-	-	-	**23,311**
2007	103,758	-	15,342	16,418	15,360	15,176	**166,054**
2008	235,152	-	68,853	72,194	70,403	69,562	**516,164**
2009	278,982	82	99,383	103,820	108,691	118,935	**709,892**
2010	337,794	339	172,007	177,242	187,203	205,179	**1,079,763**
2011	374,635	599	222,968	240,000	225,696	221,152	**1,285,051**
2012	412,941	913	279,602	329,834	262,093	250,368	**1,535,750**
2013	431,024	967	324,436	407,657	280,159	261,249	**1,705,493**
2014	457,816	1,225	369,622	502,026	324,608	283,352	**1,938,649**
2015	497,648	1,931	412,922	653,204	425,570	353,433	**2,344,707**
2016	555,301	4,081	435,450	811,045	525,668	420,890	**2,752,435**

Table 3: Reconciliation of CDM Verified Results and Cumulative CDM Savings Used in Load Forecast

Year	CDM Verified Results	Persistence Variance	Realization Rates Variance	Line Loss Varinace	CDM in Load Forecast Appendix A-1
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
2006	56,009.98	-	-33,366.83	667.97	23,311.13
2007	381,927.82	-	-220,454.10	4,579.96	166,053.68
2008	492,314.24	88,040.36	-78,163.74	13,973.49	516,164.35
2009	686,443.43	101,199.36	-96,695.23	18,944.79	709,892.35
2010	1,028,306.14	151,343.44	-128,416.61	28,530.35	1,079,763.33
2011	1,282,182.89	151,350.22	-182,706.82	34,225.20	1,285,051.49
2012	1,236,660.45	344,676.81	-86,652.76	41,065.74	1,535,750.24
2013	1,410,554.91	355,617.64	-106,481.63	45,801.85	1,705,492.77
2014	1,671,655.17	395,250.49	-180,480.16	52,223.25	1,938,648.76
2015	1,936,238.54	534,933.22	-189,500.30	63,035.59	2,344,707.05
2016	2,192,161.23	669,291.64	-182,944.27	73,926.59	2,752,435.20

Update to IR 3-VECC-26

Table 1: Residential Gross Annualized CDM Savings (MWh)

Program Year	Calendar Year							
	2017	2018	2019	2020	2021	2022	2023	2024
2017	149,145	149,145	149,145	149,145	149,145	149,145	149,145	149,145
2018		52,794	52,794	52,794	52,794	52,794	52,794	52,794
2019			17,323	17,323	17,323	17,323	17,323	17,323
2020				12,049	12,049	12,049	12,049	12,049
2021					12,049	12,049	12,049	12,049
2022						12,049	12,049	12,049
2023							12,049	12,049
2024								12,049
Total	149,145	201,939	219,262	231,311	243,359	255,408	267,457	279,506

Table 2: CSMUR Gross Annualized CDM Savings (MWh)

Program Year	Calendar Year							
	2017	2018	2019	2020	2021	2022	2023	2024
2017	6,410	6,410	6,410	6,410	6,410	6,410	6,410	6,410
2018		2,488	2,488	2,488	2,488	2,488	2,488	2,488
2019			1,914	1,914	1,914	1,914	1,914	1,914
2020				1,670	1,670	1,670	1,670	1,670
2021					1,670	1,670	1,670	1,670
2022						1,670	1,670	1,670
2023							1,670	1,670
2024								1,670
Total	6,410	8,898	10,812	12,482	14,152	15,821	17,491	19,161

Table 3: GS <50 kW Gross Annualized CDM Savings (MWh)

Program Year	Calendar Year							
	2017	2018	2019	2020	2021	2022	2023	2024
2017	17,945	17,945	17,945	17,945	17,945	17,945	17,945	17,945
2018		38,252	38,252	38,252	38,252	38,252	38,252	38,252
2019			27,966	27,966	27,966	27,966	27,966	27,966
2020				25,679	25,679	25,679	25,679	25,679
2021					25,165	25,165	25,165	25,165
2022						25,165	25,165	25,165
2023							25,165	25,165
2024								25,165
Total	17,945	56,196	84,162	109,841	135,006	160,170	185,335	210,500

Table 4: GS 50 -999 kW Gross Annualized CDM Savings (MWh)

Program Year	Calendar Year							
	2017	2018	2019	2020	2021	2022	2023	2024
2017	146,150	146,150	146,150	146,150	146,150	146,150	146,150	146,150
2018		156,457	156,457	156,457	156,457	156,457	156,457	156,457
2019			160,578	160,578	160,578	160,578	160,578	160,578
2020				161,578	161,578	161,578	161,578	161,578
2021					131,156	131,156	131,156	131,156
2022						131,156	131,156	131,156
2023							131,156	131,156
2024								131,156
Total	146,150	302,606	463,184	624,762	755,918	887,073	1,018,229	1,149,385

Update to IR 3-VECC-26

Table 5: GS 1,000 – 4,999 kW Gross Annualized CDM Savings (MWh)

Program Year	Calendar Year							
	2017	2018	2019	2020	2021	2022	2023	2024
2017	39,247	39,247	39,247	39,247	39,247	39,247	39,247	39,247
2018		61,159	61,159	61,159	61,159	61,159	61,159	61,159
2019			61,404	73,831	73,831	73,831	73,831	73,831
2020				67,888	67,888	67,888	67,888	67,888
2021					56,235	56,235	56,235	56,235
2022						56,235	56,235	56,235
2023							56,235	56,235
2024								56,235
Total	39,247	100,405	161,810	242,125	298,359	354,594	410,829	467,064

Table 6: Large Use Gross Annualized CDM Savings (MWh)

Program Year	Calendar Year							
	2017	2018	2019	2020	2021	2022	2023	2024
2017	23,554	23,554	23,554	23,554	23,554	23,554	23,554	23,554
2018		32,633	32,633	32,633	32,633	32,633	32,633	32,633
2019			38,606	38,606	38,606	38,606	38,606	38,606
2020				168,390	168,390	168,390	168,390	168,390
2021					44,425	44,425	44,425	44,425
2022						44,425	44,425	44,425
2023							44,425	44,425
2024								44,425
Total	23,554	56,187	94,794	263,184	307,608	352,033	396,458	440,883

Table 7: Total Gross Annualized CDM Savings (MWh)

Prog.Year	Calendar Year							
	2017	2018	2019	2020	2021	2022	2023	2024
2017	382,450	382,450	382,450	382,450	382,450	382,450	382,450	382,450
2018	-	343,782	343,782	343,782	343,782	343,782	343,782	343,782
2019	-	-	307,791	320,218	320,218	320,218	320,218	320,218
2020	-	-	-	437,253	437,253	437,253	437,253	437,253
2021	-	-	-	-	270,699	270,699	270,699	270,699
2022	-	-	-	-	-	270,699	270,699	270,699
2023	-	-	-	-	-	-	270,699	270,699
2024	-	-	-	-	-	-	-	270,699
Total	382,450	726,232	1,034,023	1,483,703	1,754,402	2,025,101	2,295,800	2,566,498

Table 8: Cumulative Gross CDM Savings (MWh)

Year	CUMULATIVE GROSS CDM SAVINGS (MWh)						
	Residential	CSMUR	GS<50 kW	GS50 -999 kW	GS1,000 – 4,999 kW	LU	Total
2017	674,883,556	9,187,997	452,975,585	961,316,571	594,400,720	456,748,516	**3,149,512,945**
2018	775,731,922	13,641,844	482,555,931	1,117,414,607	646,789,310	485,614,048	**3,521,747,663**
2019	810,683,363	15,889,275	516,310,319	1,280,740,887	709,886,468	522,036,360	**3,855,546,672**
2020	825,632,666	17,726,295	543,850,402	1,446,602,804	776,648,270	631,440,077	**4,241,900,514**
2021	838,036,838	19,445,512	570,005,687	1,596,308,583	840,165,544	735,737,120	**4,599,699,283**
2022	850,441,009	21,164,728	595,912,691	1,731,333,441	898,059,207	780,926,170	**4,877,837,246**
2023	862,845,180	22,883,944	621,819,695	1,866,358,299	955,952,870	826,115,220	**5,155,975,208**
2024	875,249,351	24,603,160	647,726,699	2,001,383,157	1,013,846,533	871,304,269	**5,434,113,170**

Update to IR 3-VECC-26

Table 9: Residential – Gross Annual CDM Savings (MWh)

Prog. Year	Calendar Year							
	2017	2018	2019	2020	2021	2022	2023	2024
2006-2016	593,370	593,370	593,370	593,370	593,370	593,370	593,370	593,370
2017	81,579	153,560	153,560	153,560	153,560	153,560	153,560	153,560
2018		28,877	54,357	54,357	54,357	54,357	54,357	54,357
2019			9,475	17,836	17,836	17,836	17,836	17,836
2020				6,590	12,405	12,405	12,405	12,405
2021					6,590	12,405	12,405	12,405
2022						6,590	12,405	12,405
2023							6,590	12,405
2024								6,590
Total	674,949	775,807	810,762	825,713	838,118	850,524	862,929	875,334

Table 10: CSMUR – Gross Annual CDM Savings (MWh)

Prog. Year	Calendar Year							
	2017	2018	2019	2020	2021	2022	2023	2024
2006 - 2016	5,683	5,683	5,683	5,683	5,683	5,683	5,683	5,683
2017	3,506	6,599	6,599	6,599	6,599	6,599	6,599	6,599
2018		1,361	2,561	2,561	2,561	2,561	2,561	2,561
2019			1,047	1,971	1,971	1,971	1,971	1,971
2020				913	1,719	1,719	1,719	1,719
2021					913	1,719	1,719	1,719
2022						913	1,719	1,719
2023							913	1,719
2024								913
Total	9,189	13,643	15,891	17,728	19,447	21,167	22,886	24,606

Table 11: GS < 50kW – Gross Annual CDM Savings (MWh)

Prog. Year	Calendar Year							
	2017	2018	2019	2020	2021	2022	2023	2024
2006 - 2016	443,204	443,204	443,204	443,204	443,204	443,204	443,204	443,204
2017	9,815	18,476	18,476	18,476	18,476	18,476	18,476	18,476
2018		20,923	39,384	39,384	39,384	39,384	39,384	39,384
2019			15,297	28,793	28,793	28,793	28,793	28,793
2020				14,046	26,439	26,439	26,439	26,439
2021					14,046	26,439	26,439	26,439
2022						14,046	26,439	26,439
2023							14,046	26,439
2024								14,046
Total	453,020	482,603	516,360	543,903	570,342	596,782	623,221	649,660

Table 12: GS 50-999 kW – Gross Annual CDM Savings (MWh)

Prog. Year	Calendar Year							
	2017	2018	2019	2020	2021	2022	2023	2024
2006 - 2016	881,470	881,470	881,470	881,470	881,470	881,470	881,470	881,470
2017	79,940	150,476	150,476	150,476	150,476	150,476	150,476	150,476
2018		85,578	161,088	161,088	161,088	161,088	161,088	161,088
2019			87,832	165,331	165,331	165,331	165,331	165,331
2020				88,379	166,360	166,360	166,360	166,360
2021					88,379	166,360	166,360	166,360
2022						88,379	166,360	166,360
2023							88,379	166,360
2024								88,379
Total	961,410	1,117,523	1,280,865	1,446,743	1,613,104	1,779,464	1,945,824	2,112,185

Update to IR 3-VECC-26

Table 13: GS 1,000 – 4,999 kW – Gross Annual CDM Savings (MWh)

Prog. Year	Calendar Year							
	2017	2018	2019	2020	2021	2022	2023	2024
2006-2016	572,991	572,991	572,991	572,991	572,991	572,991	572,991	572,991
2017	21,467	40,408	40,408	40,408	40,408	40,408	40,408	40,408
2018		33,452	62,969	62,969	62,969	62,969	62,969	62,969
2019			33,587	63,222	63,222	63,222	63,222	63,222
2020				37,133	69,897	69,897	69,897	69,897
2021					37,133	69,897	69,897	69,897
2022						37,133	69,897	69,897
2023							37,133	69,897
2024								37,133
Total	594,458	646,852	709,955	776,724	846,621	916,519	986,416	1,056,314

Table 14: Large Use – Gross Annual CDM Savings (MWh)

Prog. Year	Calendar Year							
	2017	2018	2019	2020	2021	2022	2023	2024
2006-2016	444,020	444,020	444,020	444,020	444,020	444,020	444,020	444,020
2017	12,728	23,959	23,959	23,959	23,959	23,959	23,959	23,959
2018		17,635	33,195	33,195	33,195	33,195	33,195	33,195
2019			20,862	39,270	39,270	39,270	39,270	39,270
2020				90,996	171,286	171,286	171,286	171,286
2021					90,996	171,286	171,286	171,286
2022						90,996	171,286	171,286
2023							90,996	171,286
2024								90,996
Total	456,749	485,614	522,036	631,440	802,726	974,012	1,145,298	1,316,584

Table 15: Total – Gross Annual CDM Savings (MWh)

Prog. Year	Calendar Year							
	2017	2018	2019	2020	2021	2022	2023	2024
2006-2016	2,940,739	2,940,739	2,940,739	2,940,739	2,940,739	2,940,739	2,940,739	2,940,739
2017	209,035	393,478	393,478	393,478	393,478	393,478	393,478	393,478
2018	-	187,825	353,553	353,553	353,553	353,553	353,553	353,553
2019	-	-	168,100	316,423	316,423	316,423	316,423	316,423
2020	-	-	-	238,057	448,108	448,108	448,108	448,108
2021	-	-	-	-	238,057	448,108	448,108	448,108
2022	-	-	-	-	-	238,057	448,108	448,108
2023	-	-	-	-	-	-	238,057	448,108
2024	-	-	-	-	-	-	-	238,057
Total	3,149,775	3,522,043	3,855,870	4,242,251	4,690,359	5,138,467	5,586,575	6,034,683

Line No.	A	B	C	D	E	F	G	H
	Load Forecast Energy Impacts			D=B+C		F=D+E		H=FxG
	RES		Cumulative 2018 Persistence	Cumulative Incremental Gross (For Load Forecast)	2020-2024 Load Forecast/LRAM Methodology Variance	Cumulative Incremental Gross (For LRAM)	Gross to Net Ratio	Net Cumulative
1	2020 CDM Forecast	801,974	(778,251)	23,723.65	3,857.28	27,581	101.6%	28,027
2	2021 CDM Forecast	814,023	(778,251)	35,772.39	3,084.97	38,857	100.8%	39,167
3	2022 CDM Forecast	826,072	(778,251)	47,821.12	2,312.67	50,134	100.3%	50,307
4	2023 CDM Forecast	838,121	(778,251)	59,869.85	1,540.37	61,410	100.1%	61,447
5	2024 CDM Forecast	850,169	(778,251)	71,918.59	768.06	72,687	99.9%	72,587
6								
	CSMUR		Cumulative 2018 Persistence	Cumulative Incremental Gross (For Load Forecast)	2020-2024 Load Forecast/LRAM Methodology Variance	Cumulative Incremental Gross (For LRAM)	Gross to Net Ratio	Net Cumulative
7	2020 CDM Forecast	17,218	(14,417)	2,801	689.16	3,490	103.4%	3,607
8	2021 CDM Forecast	18,888	(14,417)	4,471	649.83	5,121	103.0%	5,272
9	2022 CDM Forecast	20,558	(14,417)	6,141	610.51	6,752	102.8%	6,938
10	2023 CDM Forecast	22,228	(14,417)	7,811	571.18	8,382	102.6%	8,603
11	2024 CDM Forecast	23,898	(14,417)	9,481	531.86	10,013	102.5%	10,268
12								
	GS<50		Cumulative 2018 Persistence	Cumulative Incremental Gross (For Load Forecast)	2020-2024 Load Forecast/LRAM Methodology Variance	Cumulative Incremental Gross (For LRAM)	Gross to Net Ratio	Net Cumulative
13	2020 CDM Forecast	528,267	(486,659)	41,608	12,031.48	53,639	91.04%	48,831
14	2021 CDM Forecast	553,672	(486,659)	67,013	11,552.84	78,566	90.99%	71,485
15	2022 CDM Forecast	578,837	(486,659)	92,178	10,878.44	103,057	90.96%	93,741
16	2023 CDM Forecast	604,002	(486,659)	117,343	9,168.00	126,511	90.94%	115,053
17	2024 CDM Forecast	629,166	(486,659)	142,507	5,925.19	148,433	90.93%	134,971
18								
	GS 50-1000kW		Cumulative 2018 Persistence	Cumulative Incremental Gross (For Load Forecast)	2020-2024 Load Forecast/LRAM Methodology Variance	Cumulative Incremental Gross (For LRAM)	Gross to Net Ratio	Net Cumulative
19	2020 CDM Forecast	1,405,151	(1,158,734)	246,416	75,548.50	321,965	81.8%	263,251
20	2021 CDM Forecast	1,550,567	(1,158,734)	391,832	61,072.88	452,905	83.1%	376,145
21	2022 CDM Forecast	1,681,723	(1,158,734)	522,988	60,591.48	583,580	83.8%	488,829
22	2023 CDM Forecast	1,812,878	(1,158,734)	654,144	59,977.68	714,122	84.2%	601,390
23	2024 CDM Forecast	1,944,034	(1,158,734)	785,300	52,270.07	837,570	84.6%	708,471
24								
	GS1-5MW		Cumulative 2018 Persistence	Cumulative Incremental Gross (For Load Forecast)	2020-2024 Load Forecast/LRAM Methodology Variance	Cumulative Incremental Gross (For LRAM)	Gross to Net Ratio	Net Cumulative
25	2020 CDM Forecast	754,394	(656,924)	97,470	31,711.48	129,181	86.3%	111,523
26	2021 CDM Forecast	816,091	(656,924)	159,167	26,125.77	185,293	86.4%	160,098
27	2022 CDM Forecast	872,326	(656,924)	215,402	25,898.94	241,301	86.4%	208,583
28	2023 CDM Forecast	928,560	(656,924)	271,636	25,659.37	297,296	86.5%	257,057
29	2024 CDM Forecast	984,795	(656,924)	327,871	22,674.29	350,546	86.5%	303,173
30								
	LU		Cumulative 2018 Persistence	Cumulative Incremental Gross (For Load Forecast)	2020-2024 Load Forecast/LRAM Methodology Variance	Cumulative Incremental Gross (For LRAM)	Gross to Net Ratio	Net Cumulative
31	2020 CDM Forecast	620,763	(492,700)	128,063	78,627.05	206,690	93.5%	193,202
32	2021 CDM Forecast	723,296	(492,700)	230,597	20,064.37	250,661	91.9%	230,317
33	2022 CDM Forecast	767,721	(492,700)	275,022	19,349.74	294,372	90.8%	267,155
34	2023 CDM Forecast	812,146	(492,700)	319,447	18,566.71	338,013	89.9%	304,019
35	2024 CDM Forecast	856,571	(492,700)	363,872	15,668.07	379,540	89.1%	338,284
36								
	Total Company		Cumulative 2018 Persistence	Cumulative Incremental Gross (For Load Forecast)	2020-2024 Load Forecast/LRAM Methodology Variance	Cumulative Incremental Gross (For LRAM)	Gross to Net Ratio	Net Cumulative
37	2020 CDM Forecast	4,127,767	(3,587,685)	540,082	202,464.95	742,547	87.3%	648,442
38	2021 CDM Forecast	4,476,538	(3,587,685)	888,853	122,550.66	1,011,404	87.3%	882,484
39	2022 CDM Forecast	4,747,237	(3,587,685)	1,159,552	119,641.78	1,279,194	87.2%	1,115,553
40	2023 CDM Forecast	5,017,936	(3,587,685)	1,430,251	115,483.30	1,545,734	87.2%	1,347,569
41	2024 CDM Forecast	5,288,634	(3,587,685)	1,700,950	97,837.54	1,798,787	87.2%	1,567,754

LRAM Energy Impact Breakdown

	I	J	K	L	M	N	O	P
	MWh	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	***Total***
1	2020 CDM Forecast	16,124.48	11,902.91					**28,027.39**
2	2021 CDM Forecast	16,124.48	11,139.95	11,902.91				**39,167.34**
3	2022 CDM Forecast	16,124.48	11,139.95	11,139.95	11,902.91			**50,307.29**
4	2023 CDM Forecast	16,124.48	11,139.95	11,139.95	11,139.95	11,902.91		**61,447.24**
5	2024 CDM Forecast	16,124.48	11,139.95	11,139.95	11,139.95	11,139.95	11,902.91	**72,587.19**
6	**Total**	**80,622.40**	**56,462.71**	**45,322.76**	**34,182.81**	**23,042.86**	**11,902.91**	**251,536.43**
	MWh	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	***Total***
7	2020 CDM Forecast	1,902.17	1,705.22					**3,607.39**
8	2021 CDM Forecast	1,902.17	1,665.07	1,705.22				**5,272.46**
9	2022 CDM Forecast	1,902.17	1,665.07	1,665.07	1,705.22			**6,937.52**
10	2023 CDM Forecast	1,902.17	1,665.07	1,665.07	1,665.07	1,705.22		**8,602.59**
11	2024 CDM Forecast	1,902.17	1,665.07	1,665.07	1,665.07	1,665.07	1,705.22	**10,267.66**
12	**Total**	**9,510.83**	**8,365.49**	**6,700.42**	**5,035.36**	**3,370.29**	**1,705.22**	**34,687.61**
	MWh	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	***Total***
13	2020 CDM Forecast	25,510.01	23,320.56					**48,830.57**
14	2021 CDM Forecast	25,297.89	23,316.03	22,870.66				**71,484.58**
15	2022 CDM Forecast	24,832.18	23,171.66	22,866.13	22,870.66			**93,740.63**
16	2023 CDM Forecast	23,869.37	22,725.46	22,721.76	22,866.13	22,870.66		**115,053.37**
17	2024 CDM Forecast	22,277.45	21,959.70	22,275.56	22,721.76	22,866.13	22,870.66	**134,971.25**
18	**Total**	**121,786.90**	**114,493.42**	**90,734.10**	**68,458.54**	**45,736.78**	**22,870.66**	**464,080.41**
	MWh	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	***Total***
19	2020 CDM Forecast	123,574.57	139,676.61					**263,251.18**
20	2021 CDM Forecast	123,524.77	139,546.31	113,073.61				**376,144.68**
21	2022 CDM Forecast	123,306.51	139,505.70	112,943.30	113,073.61			**488,829.12**
22	2023 CDM Forecast	123,167.73	139,302.17	112,902.70	112,943.30	113,073.61		**601,389.51**
23	2024 CDM Forecast	117,672.97	139,179.73	112,699.17	112,902.70	112,943.30	113,073.61	**708,471.48**
24	**Total**	**611,246.55**	**697,210.51**	**451,618.78**	**338,919.61**	**226,016.91**	**113,073.61**	**2,438,085.97**

Cumulative Net Breakdown

	I	J	K	L	M	N	O	P
	MWh	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	***Total***
25	2020 CDM Forecast	52,651.63	58,871.66					**111,523.30**
26	2021 CDM Forecast	52,629.42	58,787.22	48,681.23				**160,097.87**
27	2022 CDM Forecast	52,537.65	58,767.74	48,596.79	48,681.23			**208,583.42**
28	2023 CDM Forecast	52,517.55	58,684.39	48,577.31	48,596.79	48,681.23		**257,057.26**
29	2024 CDM Forecast	50,158.10	58,665.27	48,493.96	48,577.31	48,596.79	48,681.23	**303,172.66**
30	**Total**	**260,494.35**	**293,776.29**	**194,349.29**	**145,855.33**	**97,278.02**	**48,681.23**	**1,040,434.51**
	MWh	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	***Total***
31	2020 CDM Forecast	47,264.88	145,937.49					**193,202.37**
32	2021 CDM Forecast	47,179.99	145,603.50	37,533.93				**230,317.42**
33	2022 CDM Forecast	46,892.76	145,528.48	37,199.94	37,533.93			**267,155.11**
34	2023 CDM Forecast	46,886.68	145,273.68	37,124.92	37,199.94	37,533.93		**304,019.14**
35	2024 CDM Forecast	44,286.93	145,268.24	36,870.11	37,124.92	37,199.94	37,533.93	**338,284.07**
36	**Total**	**232,511.24**	**727,611.38**	**148,728.90**	**111,858.79**	**74,733.87**	**37,533.93**	**1,332,978.11**
	MWh	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	***Total***
37	2020 CDM Forecast	267,027.75	381,414.46					**648,442.20**
38	2021 CDM Forecast	266,658.72	380,058.08	235,767.55				**882,484.35**
39	2022 CDM Forecast	265,595.74	379,778.60	234,411.18	235,767.55			**1,115,553.07**
40	2023 CDM Forecast	264,467.97	378,790.71	234,131.70	234,411.18	235,767.55		**1,347,569.11**
41	2024 CDM Forecast	252,422.10	377,877.96	233,143.81	234,131.70	234,411.18	235,767.55	**1,567,754.30**

MWh

Line No.	A	B	C	D	E	F	G	H
	Load Forecast Demand Impacts			D=(B+C)		F=D+E		H=FxG
	GS 50-1000MW		Cumulative 2018 Persistence	Cumulative Incremental Gross (For Load Forecast)	2020-2024 Load Forecast/LRAM Methodology Variance	Cumulative Incremental Gross (For LRAM)	Gross to Net Ratio	Net Cumulative
1	2020 CDM Forecast	2,703	(2,291)	412	118	531	86.23%	458
2	2021 CDM Forecast	2,957	(2,291)	666	115	781	86.58%	676
3	2022 CDM Forecast	3,208	(2,291)	917	114	1,032	86.75%	895
4	2023 CDM Forecast	3,459	(2,291)	1,168	114	1,282	86.86%	1,113
5	2024 CDM Forecast	3,710	(2,291)	1,419	100	1,519	86.95%	1,320
6								
	GS1-5MW		Cumulative 2018 Persistence	Cumulative Incremental Gross (For Load Forecast)	2020-2024 Load Forecast/LRAM Methodology Variance	Cumulative Incremental Gross (For LRAM)	Gross to Net Ratio	Net Cumulative
7	2020 CDM Forecast	1,379	(1,265)	114	33	148	86.61%	128
8	2021 CDM Forecast	1,451	(1,265)	186	32	218	86.64%	189
9	2022 CDM Forecast	1,521	(1,265)	257	32	289	86.65%	250
10	2023 CDM Forecast	1,592	(1,265)	327	32	359	86.65%	311
11	2024 CDM Forecast	1,662	(1,265)	398	28	426	86.66%	369
12								1,247
	LU		Cumulative 2018 Persistence	Cumulative Incremental Gross (For Load Forecast)	2020-2024 Load Forecast/LRAM Methodology Variance	Cumulative Incremental Gross (For LRAM)	Gross to Net Ratio	Net Cumulative
13	2020 CDM Forecast	1,287	(1,167)	120	47	167	86.09%	144
14	2021 CDM Forecast	1,373	(1,167)	206	32	238	85.40%	203
15	2022 CDM Forecast	1,444	(1,167)	277	32	309	85.02%	263
16	2023 CDM Forecast	1,516	(1,167)	349	32	381	84.79%	323
17	2024 CDM Forecast	1,587	(1,167)	420	28	448	84.59%	379
18								
	Total Company		Cumulative 2018 Persistence	Cumulative Incremental Gross (For Load Forecast)	2020-2024 Load Forecast/LRAM Methodology Variance	Cumulative Incremental Gross (For LRAM)	Gross to Net Ratio	Net Cumulative
19	2020 CDM Forecast	5,369	(4,723)	646	199	845	86.27%	729
20	2021 CDM Forecast	5,781	(4,723)	1,058	179	1,238	86.36%	1,069
21	2022 CDM Forecast	6,174	(4,723)	1,451	179	1,630	86.41%	1,408
22	2023 CDM Forecast	6,567	(4,723)	1,844	178	2,022	86.44%	1,747
23	2024 CDM Forecast	6,959	(4,723)	2,236	156	2,392	86.46%	2,068
24								

I	J	K	L	M	N	O	P
LRAM Demand Impact Breakdown							
MW	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	***Total***
2020 CDM Forecast	232.32	225.18					**457.50**
2021 CDM Forecast	232.30	225.14	218.91				**676.35**
2022 CDM Forecast	232.07	225.13	218.87	218.91			**894.98**
2023 CDM Forecast	231.80	224.91	218.86	218.87	218.91		**1,113.34**
2024 CDM Forecast	220.43	224.66	218.63	218.86	218.87	218.91	**1,320.35**
Total	**1,148.93**	**1,125.02**	**875.26**	**656.63**	**437.77**	**218.91**	4,462.52
MW	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	***Total***
2020 CDM Forecast	64.74	63.21					**127.95**
2021 CDM Forecast	64.74	63.20	61.15				**189.08**
2022 CDM Forecast	64.69	63.20	61.13	61.15			**250.17**
2023 CDM Forecast	64.65	63.15	61.13	61.13	61.15		**311.22**
2024 CDM Forecast	61.39	63.11	61.09	61.13	61.13	61.15	**369.00**
Total	**320.21**	**315.87**	**244.50**	**183.41**	**122.28**	**61.15**	1,247.43
MW	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	***Total***
2020 CDM Forecast	56.71	87.08	-	-	-	-	**143.79**
2021 CDM Forecast	56.71	86.91	59.83	-	-	-	**203.45**
2022 CDM Forecast	56.69	86.91	59.67	59.83	-	-	**263.11**
2023 CDM Forecast	56.68	86.90	59.67	59.67	59.83	-	**322.75**
2024 CDM Forecast	53.14	86.89	59.66	59.67	59.67	59.83	**378.86**
Total	**279.93**	**434.70**	**238.83**	**179.17**	**119.50**	**59.83**	1,311.96
MW	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	***Total***
2020 CDM Forecast	353.77	375.47					**729.24**
2021 CDM Forecast	353.75	375.26	339.89				**1,068.89**
2022 CDM Forecast	353.46	375.24	339.67	339.89			**1,408.26**
2023 CDM Forecast	353.14	374.96	339.65	339.67	339.89		**1,747.31**
2024 CDM Forecast	334.96	374.66	339.38	339.65	339.67	339.89	**2,068.21**
Total	**1,749.07**	**1,875.60**	**1,358.59**	**1,019.21**	**679.56**	**339.89**	7,021.91

MW

Model Input Data

Month	Purchased Energy per day, kWh (by customer class)								Cumulative CDM impacts per day, kWh						HDD10 per day	CDD18 per day	GDP	Time Trend			Blackout Dummy	DewPoint Temperature	Business Days Percent	Shoulder Flag	Customer Numbers			
	Residential	Competitive Sector Multi-Unit Residential (CSMUR)	GS<50 kW	GS 50-999 kW	GS 1000-4999 kW	Large Use	Street lighting	Unmetered Scattered Load	Residential	CSMUR	GS<50 kW	GS 50-999 kW	GS 1000-4999 kW	Large Use				Residential	GS<50 kW & GS 1,000-4,999 kW	Large Use					CSMUR	GS<50 kW (excluding FIT)	GS 50-999 kW	Large Use
Jul 2002	19,204,876		8,649,128	31,276,255	16,527,279	8,820,370	256,949	166,002							0.00	6.21	243,228	0	1	1	0	15.57	71.0	1	66,908	10,576	46	
Aug 2002	18,511,523		8,183,954	29,604,261	15,721,190	8,346,209	246,772	159,547							0.00	4.60	243,960	0	2	2	0	22.06	67.7	1	66,827	10,586	46	
Sep 2002	16,114,720		7,687,179	28,298,565	14,984,372	7,895,845	269,652	158,251							0.00	2.92	244,692	0	3	3	0	13.55	66.7	1	66,826	10,619	46	
Oct 2002	14,513,865		6,947,084	25,956,564	13,645,056	7,127,650	306,016	155,740							2.96	0.32	245,223	0	4	4	0	4.79	71.0	0	66,859	10,669	46	
Nov 2002	15,395,003		7,232,335	27,256,662	13,902,998	7,204,315	363,235	158,333							7.14	0.00	245,755	0	5	5	0	-0.53	70.0	0	66,838	10,680	46	
Dec 2002	17,264,325		7,335,346	28,296,964	13,783,673	7,157,154	373,118	162,451							11.98	0.00	246,286	0	6	6	0	-5.56	64.5	1	66,934	10,708	46	
Jan 2003	18,311,915		7,916,178	30,509,950	14,995,396	7,598,243	403,495	163,775							18.27	0.00	246,791	0	7	7	0	-11.63	71.0	1	66,987	10,732	46	
Feb 2003	17,946,872		8,123,903	30,717,592	14,953,503	7,633,376	371,971	162,553							16.96	0.00	247,295	0	8	8	0	-11.31	71.4	1	67,139	10,786	46	
Mar 2003	16,306,690		7,612,193	28,018,838	14,110,408	7,296,898	339,070	159,786							10.79	0.00	247,800	0	9	9	0	-5.52	67.7	1	67,113	10,794	46	
Apr 2003	14,622,587		7,121,777	26,707,917	13,805,589	7,149,673	288,109	160,638							5.34	0.08	247,644	0	10	10	0	-1.84	66.7	0	67,040	10,809	46	
May 2003	13,572,543		6,652,815	24,857,765	13,226,484	7,017,781	236,326	153,861							0.17	0.00	247,488	0	11	11	0	6.50	67.7	0	67,126	10,828	46	
Jun 2003	14,771,959		7,206,195	27,040,865	14,519,362	7,638,136	232,369	158,462							0.00	1.76	247,333	0	12	12	0	11.94	70.0	1	66,958	10,845	46	
Jul 2003	16,298,890		7,827,787	29,154,832	15,538,655	7,771,092	252,559	163,533							0.00	3.82	247,015	0	13	13	0	14.71	71.0	1	67,046	10,848	46	
Aug 2003	15,735,506		7,524,161	27,792,398	14,449,168	7,483,754	238,901	159,766							0.00	4.13	246,698	0	14	14	1	16.04	64.5	1	67,040	10,850	46	
Sep 2003	14,015,178		6,905,035	26,228,274	14,274,728	7,348,513	279,868	157,630							0.04	0.80	246,381	0	15	15	0	11.65	70.0	1	66,964	10,851	46	
Oct 2003	13,928,118		6,717,373	25,744,347	13,778,426	6,912,996	326,382	159,766							2.26	0.00	247,421	0	16	16	0	4.73	71.0	0	67,018	10,892	46	
Nov 2003	15,092,616		6,999,278	26,923,503	13,922,169	7,029,585	383,778	161,194							5.35	0.00	248,462	0	17	17	0	1.60	66.7	0	66,892	10,874	46	
Dec 2003	16,844,234		7,272,589	27,677,189	13,794,288	6,932,811	400,325	161,702							10.11	0.00	249,502	0	18	18	0	-3.98	67.7	1	67,064	10,908	47	
Jan 2004	17,978,692		7,904,747	30,816,801	15,143,333	8,177,818	405,204	167,312							19.39	0.00	249,936	0	19	19	0	-13.06	67.7	1	66,973	10,939	47	
Feb 2004	17,170,190		7,700,344	29,663,529	14,662,859	7,211,845	356,252	163,516							13.78	0.00	250,369	0	20	20	0	-8.28	69.0	1	67,046	10,971	47	
Mar 2004	15,629,667		7,263,222	27,958,514	14,414,022	7,168,856	341,915	162,663							7.90	0.00	250,803	0	21	21	0	-2.07	74.2	1	67,001	10,986	47	
Apr 2004	14,026,791		6,860,879	26,007,834	13,599,975	7,142,223	284,717	160,004							3.88	0.00	251,911	0	22	22	0	0.57	66.7	0	66,920	11,007	47	
May 2004	13,190,260		6,697,193	25,467,554	13,536,594	6,883,795	236,779	158,600							0.61	0.28	253,019	0	23	23	0	7.92	64.5	0	66,875	11,018	47	
Jun 2004	13,682,848		6,996,090	26,877,869	14,725,457	7,501,466	230,928	161,946							0.00	1.05	254,127	0	24	24	0	11.15	73.3	1	66,789	11,038	47	
Jul 2004	14,728,572		7,410,303	28,203,152	15,020,716	7,789,243	247,688	164,679							0.00	2.79	254,823	0	25	25	0	15.50	67.7	1	66,753	11,045	47	
Aug 2004	14,329,725		7,313,804	27,825,836	14,779,013	7,491,884	232,359	160,171							0.00	1.92	255,520	0	26	26	0	14.06	67.7	1	66,715	11,076	47	
Sep 2004	13,952,065		7,074,372	27,537,276	15,242,637	7,559,001	287,188	163,732							0.00	1.37	256,216	0	27	27	0	12.85	70.0	1	66,658	11,104	47	
Oct 2004	13,466,693		6,596,275	25,678,284	13,594,246	6,960,710	322,754	159,158							0.83	0.05	256,741	0	28	28	0	6.00	64.5	0	66,496	11,097	47	
Nov 2004	14,734,158		6,925,586	26,942,928	14,049,875	7,104,274	380,877	161,489							4.67	0.00	257,266	0	29	29	0	0.48	73.3	0	66,585	11,119	47	
Dec 2004	16,962,969		7,498,072	29,200,693	14,274,620	7,287,318	393,686	167,781							12.75	0.00	257,792	0	30	30	0	-6.05	67.7	1	66,505	11,146	47	
Jan 2005	17,644,488		7,884,202	31,067,950	14,884,092	7,502,345	415,029	163,047							16.84	0.00	258,499	0	31	31	0	-10.68	64.5	1	66,464	11,167	47	
Feb 2005	16,986,994		7,790,034	29,965,306	14,769,846	7,412,682	380,503	159,982							14.01	0.00	259,205	0	32	32	0	-7.08	71.4	1	66,628	11,184	47	
Mar 2005	15,704,996		7,441,105	28,955,758	14,554,549	7,319,912	357,292	157,327							11.65	0.00	259,912	0	33	33	0	-6.16	67.7	1	66,630	11,198	47	
Apr 2005	13,765,854		6,766,118	26,139,356	13,762,751	6,903,337	296,587	153,933							2.77	0.00	260,253	0	34	34	0	-0.56	70.0	0	66,556	11,426	48	
May 2005	13,739,592		6,518,052	25,117,342	13,271,845	6,822,412	231,600	149,054							0.92	0.03	260,593	0	35	35	0	4.06	67.7	0	66,482	11,185	47	
Jun 2005	17,351,693		7,803,803	30,831,062	16,622,447	8,214,883	239,904	151,947							0.00	4.88	260,933	0	36	36	0	15.35	73.3	1	66,471	11,214	47	
Jul 2005	18,839,649		8,166,152	31,728,614	16,122,802	7,757,701	249,964	158,882							0.00	6.09	261,772	0	37	37	0	15.96	64.5	1	66,459	11,233	47	
Aug 2005	17,458,775		7,764,782	30,249,616	16,074,354	7,558,624	245,451	155,642							0.00	4.54	262,611	0	38	38	0	15.82	71.0	1	66,448	11,242	47	
Sep 2005	14,755,814		7,084,612	28,045,770	15,354,144	7,374,681	280,008	153,375							0.00	1.74	263,451	0	39	39	0	12.99	70.0	1	66,437	11,255	47	
Oct 2005	13,612,493		6,553,620	26,087,500	14,169,462	6,868,355	320,937	152,229							1.33	0.25	264,067	0	40	40	0	7.19	64.5	0	66,426	11,267	47	
Nov 2005	14,817,652		6,910,069	27,534,293	14,466,500	7,025,394	380,230	149,728							5.37	0.00	264,683	0	41	41	0	1.10	73.3	0	66,414	11,286	47	
Dec 2005	16,564,476		7,437,910	29,721,095	14,596,020	7,011,795	390,672	156,298							13.46	0.00	265,299	0	42	42	0	-6.47	64.5	1	66,403	11,498	47	
Jan 2006	16,528,280		7,352,899	28,878,874	14,408,784	6,987,662	407,562	155,071	919						9.80	0.00	266,390	0	43	43	0	-2.82	67.7	1	66,392	11,349	47	
Feb 2006	16,386,367		7,542,777	29,982,830	15,093,663	7,321,461	384,419	156,294	1,742						13.58	0.00	267,482	0	44	44	0	-7.75	71.4	1	66,380	11,358	46	
Mar 2006	15,149,542		7,166,823	28,307,388	14,682,471	7,162,165	354,233	153,057	2,657						8.67	0.00	268,573	0	45	45	0	-5.33	74.2	1	66,369	11,358	47	
Apr 2006	13,403,677		6,457,396	25,422,610	13,533,302	6,820,677	292,933	150,215	11,561						2.58	0.00	268,728	0	46	46	0	0.65	60.0	0	66,358	11,375	47	
May 2006	13,406,037		6,470,721	25,888,725	14,286,344	7,184,146	237,248	150,833	11,606						0.31	0.84	268,883	0	47	47	0	7.88	71.0	0	66,346	11,377	46	
Jun 2006	15,451,886		7,089,496	28,261,902	15,667,781	7,630,593	229,557	164,514	31,912						0.00	2.45	269,038	0	48	48	0	12.56	73.3	1	66,335	11,397	48	
Jul 2006	17,364,153		7,820,058	31,081,220	16,376,255	8,226,171	250,990	173,228	34,832						0.00	5.40	268,784	0	49	49	0	17.38	64.5	1	66,324	11,389	48	
Aug 2006	16,091,548		7,335,937	29,427,040	15,969,371	7,769,925	246,501	167,021	158,772						0.00	3.28	268,529	0	50	50	0	14.60	71.0	1	66,313	11,417	49	
Sep 2006	13,630,359		6,438,984	25,986,422	14,337,632	7,055,393	275,432	158,610	172,366						0.05	0.43	268,274	0	51	51	0	11.65	66.7	1	66,301	11,430	49	
Oct 2006	13,539,041		6,406,977	26,187,123	14,215,738	6,993,313	327,134	162,871	77,332						2.42	0.04	269,122	0	52	52	0	4.76	67.7	0	66,290	11,441	49	
Nov 2006	14,672,047		6,757,402	27,548,591	14,482,704	7,137,127	385,452	162,055	83,723						4.78	0.00	269,971	0	53	53	0	2.07	73.3	0	66,279	11,426	49	
Dec 2006	15,905,028		6,862,288	27,901,327	13,823,127	6,798,357	386,505	161,258	174,382						8.15	0.00	270,819	0	54	54	0	-2.39	61.3	1	66,267	11,444	49	
Jan 2007	16,860,542		7,271,758	29,655,760	14,728,039	6,827,632	411,032	163,099	176,241		619	662	620	612	12.87	0.00	271,104	0	55	55	0	-6.55	71.0	1	66,256	11,426	49	
Feb 2007	17,559,780		7,779,608	31,920,692	15,448,530	7,368,713	389,657	166,716	200,631		2,518	2,695	2,521	2,491	18.43	0.00	271,390	0	56	56	0	-12.36	71.4	1	66,245	11,452	49	
Mar 2007	15,835,869		7,080,109	28,724,775	14,455,093	7,075,744	353,562	161,555	188,933		4,843	5,183	4,849	4,791	9.77	0.00	271,675	0	57	57	0	-5.63	71.0	1	66,233	11,502	48	
Apr 2007	14,015,785		6,614,987	26,882,008	13,826,904	6,949,028	299,516	161,255	95,034		2,683	2,871	2,686	2,654	4.86	0.00	272,337	0	58	58	0	0.02	63.3	0	66,222	11,476	49	
May 2007	13,193,760		6,358,708	26,056,580	14,129,655	6,799,020	234,356	156,695	95,619		3,811	4,078	3,816	3,770	0.19	0.72	273,000	0	59	59	0	5.76	71.0	0	66,211	11,469	48	
Jun 2007	15,356,609		7,195,124	29,659,945	15,737,684	7,646,739	236,262	164,442	254,239		13,609	14,563	13,625	13,462	0.00	3.31	273,662	0	60	60	0	12.19	70.0	1	66,199	11,440	49	
Jul 2007	15,996,547		7,165,384	29,130,162	15,095,626	6,920,126	242,518	159,383	257,728		17,060	18,257	17,081	16,876	0.00	3.42	274,654	0	61	61	0	14.04	67.7	1	66,188	11,497	49	
Aug 2007	16,310,715		7,397,331	30,383,781	16,092,600	7,888,569	250,774	164,834	304,904		32,761	35,059	32,800	32,408	0.00	4.55	275,647	0	62	62	0	14.51	71.0	1	66,177	11,537	49	
Sep 2007	14,648,382		6,773,712	27,726,358	14,881,500	7,365,566	279,044	159,347	673,950		153,296	164,047	153,478	151,644	0.01	1.58	276,639	0	63	63	0	11.56	63.3	1	66,166	11,556	49	
Oct 2007	13,669,526		6,417,300	26,458,047	14,461,050	6,811,240	323,853	159,820	268,175		61,241	65,536	61,313	60,581	0.49	0.64	276,870	0	64	64	0	9.24	71.0	0	66,154	11,550	49	
Nov 2007	14,885,949		6,793,419	27,999,974	14,498,864	7,138,206	383,672	162,357	288,120		66,945	71,640	67,024	66,224	7.43	0.00	277,101	0	65	65	0	-1.40	73.3	0	66,143	11,586	49	
Dec 2007	16,952,833		7,162,959	29,656,718	14,288,014	7,134,747	389,185	164,376	605,185		143,379	153,435	143,549	141,834	12.35	0.00	277,333	0	66	66	0	-5.84	61.3	1	66,245	11,590	49	
Jan 2008	17,303,818		7,255,552	30,117,101	14,544,566	7,290,645	411,876	163,183	633,075		160,535	170,615	161,912	159,978	12.25	0.00	276,668	1	67	67	0	-6.16	71.0	1	66,054	11,754	49	
Feb 2008	17,133,103		7,467,755	31,053,267	14,825,158	7,423,436	384,450	164,250	678,400		172,630	183,407	174,175	172,094	15.27	0.00	276,004	2	68	68	0	-9.12	69.0	1	66,150	11,863	48	
Mar 2008	15,932,193		7,025,196	29,231,975	14,423,537	7,278,631	358,313	163,413	639,565		164,527	174,613	166,185	164,200	11.68	0.00	275,339	3	69	69	0	-7.00	61.3	1	66,093	11,929	48	
Apr 2008	13,569,546		6,232,609	26,561,753	13,834,754	7,030,859	295,774	159,698	324,877		85,681	90,717	86,764	85,727	2.60	0.00	275,487	4	70	70	0	0.71	73.3	0	66,152	11,977	48	
May 2008	12,997,434		6,008,329	25,595,496	13,402,249	6,551,008	234,952	157,052	317,418		84,776	89,652	85,954	84,927	0.45	0.08	275,634	5	71	71	0	3.87	67.7	0	66,094	12,016	49	
Jun 2008	15,225,020		6,815,659	28,778,409	15,179,659	7,389,078	232,922	161,925	813,699		220,491	232,859	223,872	221,197	0.00	2.38	275,782	6	72	72	0	13.65	70.0	1	66,311	12,066	49	
Jul 2008	16,372,699		7,450,961	30,676,404	15,600,553	7,729,728	248,421	162,898	908,690		286,193	298,022	294,329	290,812	0.00	3.58	275,861	7	73	73	0	14.83	71.0	1	66,286	12,063	49	
Aug 2008	14,993,967		6,974,647	29,212,143	14,708,046	7,223,683	239,612	156,724	909,611		286,760	298,589	294,935	291,411	0.00	2.06	275,941	8	74	74	0	13.64	64.5	1	66,226	12,077	49	
Sep 2008	14,475,078		6,546,717	27,751,922	14,836,846	7,147,376	286,630	161,934	943,468		300,311	312,794	309,311	305,616	0.00	0.89	276,020	9	75	75	0	12.06	70.0	1	66,293	12,105	48	
Oct 2008	13,520,757		5,978,097	26,183,872	13,787,454	6,468,382	329,428	161,317	373,284		119,139	124,064	122,736	121,270	2.00	0.00	274,048	10	76	76	0	3.37	71.0	0	65,867	12,095	48	
Nov 2008	15,034,445		6,371,446	27,954,146	13,933,956	6,742,182	386,520	162,065	387,786		124,376	129,468	128,183	126,651	7.31	0.00	272,076	11	77	77	0	-1.22	66.7	0	66,084	12,128	47	
Dec 2008	16,999,025		6,907,975	29,515,669	13,697,323	6,569,481	380,803	159,641	779,128		250,370	260,581	258,072	254,989	13.12	0.00	270,104	12	78	78	0	-7.49	67.7	1	65,917	12,156	47	
Jan 2009	18,085,109		7,449,513	31,830,043	14,394,700	6,916,937	417,231	166,009	781,026		251,847	262,057	259,773	256,669	18.78	0.00	268,103	13	79	79	0	-12.88	67.7	1	65,700	12,147	47	
Feb 2009	17,161,604		7,141,763	30,274,237	14,137,158	7,032,492	382,752	169,699	872,363		284,782	296,087	294,459	290,941	13.66	0.00	266,102	14	80	80	0	-8.48	67.9	1	66,133	12,181	47	
Mar 2009	15,537,555		6,762,583	28,734,498	13,852,975	6,706,802	356,765	163,022	790,830		259,470	269,680	268,551	265,342	9.22	0.00	264,101	15	81	81	0	-6.38	71.0	1	66,140	12,189	47	
Apr 2009	13,566,450		6,184,035	26,569,246	13,069,618	6,464,118	303,012	163,555	397,057		131,454	136,547	136,293	134,664	3.20	0.04	264,115	16	82	82	0	-1.44	66.7	0	65,846	12,163	47	
May 2009	12,630,429		5,839,729	25,359,397	12,918,802	6,198,502	236,904	158,517	387,097		129,428	134,356	134,446	132,840	0.41	0.22	264,129	17	83	83	0	4.55	64.5	0	65,798	12,208	47	
Jun 2009	13,893,651		6,355,937	27,601,014	14,186,089	7,154,419	235,165	164,224	985,346		331,286	343,778	344,492	340,377	0.00	1.14	264,143	18	84	84	0	11.08	73.3	1	66,074	12,231	47	
Jul 2009	14,421,448		6,433,015	27,746,325	14,098,821	7,580,400	242,648	158,771	1,037,777		385,965	415,173	477,154	657,619	0.00	1.41	265,544	19	85	85	0	13.43	67.7	1	65,854	12,287	47	
Aug 2009	15,905,175		6,889,426	30,110,630	15,188,061	7,600,951	251,837	163,149	1,048,237		394,099	423,306	486,520	666,873	0.00	2.94	266,946	20	86	86	0	15.53	64.5	1	66,047	12,295	47	
Sep 2009	14,229,262		6,247,175	27,597,597	14,339,504	7,169,548	285,097	152,004	1,087,394		410,633	423,124	435,862	430,655	0.04	0.70	268,348	21	87	87	0	11.96	70.0	1	66,100	12,337	47	
Oct 2009	13,259,165		5,848,076	26,632,712	13,429,012	6,599,010	333,095	154,586	431,034		163,591	168,519	173,786	171,709	1.96	0.00	269,334	22	88	88	0	4.55	67.7	0	65,873	12,316	47	
Nov 2009	14,141,334		5,944,580	27,039,895	13,455,164	6,448,557	388,982	155,243	446,880		170,193	175,285	180,902	178,740	4.15	0.00	270,320	23	89	89	0	2.75	70.0	0	65,835	12,384	47	
Dec 2009	17,105,538		6,581,648	29,804,130	13,785,482	6,547,808	391,443	156,359	912,877		354,366	364,577	377,827	373,313	12.36	0.00	271,306	24	90	90	0	-5.94	67.7	1	65,883	12,444	47	

Model Input Data

Month	Purchased Energy per day, kWh (by customer class)								Cumulative CDM impacts per day, kWh						HDD10 per day	CDD18 per day	GDP	Time Trend			Blackout Dummy	DewPoint Temperature	Business Days Percent	Shoulder Flag	Customer Numbers			
	Residential	Competitive Sector Multi-Unit Residential (CSMUR)	GS<50 kW	GS 50-999 kW	GS 1000-4999 kW	Large Use	Street lighting	Unmetered Scattered Load	Residential	CSMUR	GS<50 kW	GS 50-999 kW	GS 1000-4999 kW	Large Use				Residential	GS<50 kW & GS 1,000-4,999 kW	Large Use					CSMUR	GS<50 kW (excluding FIT)	GS 50-999 kW	Large Use
Jan 2010	17,924,992		6,976,445	31,213,806	14,241,881	6,887,447	418,962	161,385	977,385		452,832	463,043	476,293	470,602	15.23	0.00	271,953	25	91	90	0	-8.41	64.5	1		65,607	12,597	47
Feb 2010	17,226,261		7,008,354	31,219,988	14,309,939	6,940,328	386,994	160,271	1,087,680		509,859	521,163	535,833	529,431	13.37	0.00	272,599	26	92	90	0	-7.22	67.9	1		66,056	12,574	47
Mar 2010	14,736,357		6,346,826	28,434,459	13,753,127	6,649,951	357,966	157,363	989,507		471,335	481,545	494,795	488,883	5.73	0.00	273,246	27	93	90	0	-3.39	74.2	1		66,156	12,703	47
Apr 2010	12,477,897		5,668,790	26,385,054	12,962,111	6,020,159	301,056	151,092	496,279		239,289	244,381	250,990	247,991	1.01	0.00	273,933	28	94	90	0	0.83	66.7	0		65,995	12,826	47
May 2010	13,534,058		5,880,416	27,651,502	13,731,068	6,523,040	245,168	148,588	481,284		233,117	238,046	244,441	241,520	0.58	1.47	274,619	29	95	90	0	8.64	64.5	0		65,681	12,829	47
Jun 2010	15,798,830		6,509,809	29,271,497	14,797,216	7,140,037	236,789	146,396	1,242,974		626,035	638,527	654,738	646,915	0.00	1.96	275,306	30	96	90	0	13.92	73.3	1		65,799	12,873	47
Jul 2010	19,201,876		7,334,276	33,142,955	16,003,442	7,951,562	251,509	146,894	1,210,379		616,917	658,986	764,661	1,081,536	0.00	5.32	275,972	31	97	90	0	17.44	67.7	1		66,029	12,906	46
Aug 2010	17,547,175		6,982,545	32,038,022	15,859,052	7,873,418	250,633	145,629	1,221,641		634,107	676,176	781,851	1,098,521	0.00	4.48	276,637	32	98	90	0	17.11	67.7	1		65,895	12,916	46
Sep 2010	14,247,209		6,223,643	28,280,435	14,471,534	6,895,759	287,534	139,740	1,287,982		694,736	707,228	723,439	714,796	0.00	1.05	277,303	33	99	90	0	12.14	70.0	1		65,794	12,978	46
Oct 2010	12,717,913		5,531,390	26,621,990	13,346,576	6,100,189	333,276	141,068	510,156		277,188	282,116	288,511	285,064	1.15	0.00	278,027	34	100	90	0	5.44	64.5	0		66,041	12,980	46
Nov 2010	14,323,060		5,940,255	28,209,107	13,648,636	6,455,800	388,390	140,793	533,706		296,418	301,511	308,119	304,438	5.58	0.00	278,751	35	101	90	0	0.43	73.3	0		65,976	13,021	46
Dec 2010	17,371,279		6,756,652	30,994,726	13,745,366	7,095,603	392,178	139,025	1,077,737		606,009	616,220	629,470	621,949	13.81	0.00	279,474	36	102	90	0	-7.07	67.7	1		66,167	13,168	50
Jan 2011	17,965,617		6,927,647	32,102,264	14,127,431	7,206,767	418,421	129,836	1,080,094		608,925	620,888	631,727	623,882	17.01	0.00	280,433	37	103	90	0	-10.16	64.5	1		65,996	13,266	50
Feb 2011	17,529,602		7,001,158	32,127,156	14,366,063	7,338,692	388,767	127,365	1,198,046		676,921	691,822	701,543	692,552	15.36	0.00	281,392	38	104	90	0	-9.13	67.9	1		65,942	13,314	50
Mar 2011	15,874,592		6,666,235	30,212,577	14,021,973	7,223,723	360,148	125,860	1,091,123		622,562	642,726	642,283	632,921	10.48	0.00	282,351	39	105	90	0	-5.22	74.2	1		65,945	13,246	50
Apr 2011	13,373,937		5,903,347	27,529,036	12,896,350	6,751,637	303,774	125,469	548,501		315,821	329,073	324,456	319,195	3.56	0.00	282,199	40	106	90	0	0.87	63.3	0		65,856	12,938	50
May 2011	12,445,752		5,576,188	26,949,664	12,907,764	6,939,061	242,522	118,094	536,015		312,072	328,768	318,973	313,167	0.23	0.42	282,047	41	107	90	0	9.25	67.7	0		66,224	12,795	50
Jun 2011	15,136,619		6,572,629	29,598,238	14,434,050	7,817,235	234,769	117,692	1,379,371		816,610	874,307	828,328	810,765	0.00	1.74	281,895	42	108	90	0	12.47	73.3	1		66,681	12,845	50
Jul 2011	19,602,554		7,463,855	33,339,840	15,288,401	8,098,236	253,286	127,864	1,351,322		810,567	879,855	818,486	806,564	0.00	6.41	283,481	43	109	90	0	15.75	64.5	1		66,723	12,824	50
Aug 2011	16,685,431		7,202,543	32,002,545	14,932,286	7,864,672	246,519	118,097	1,355,817		816,125	888,755	822,788	810,248	0.00	3.94	285,068	44	110	90	0	15.21	71.0	1		66,900	12,824	50
Sep 2011	14,050,791		6,525,174	29,338,870	14,168,564	7,607,759	285,201	115,240	1,407,871		851,851	930,740	855,607	834,124	0.00	1.32	286,655	45	111	90	0	13.04	70.0	1		67,017	12,791	51
Oct 2011	12,942,861		5,749,023	27,141,971	12,995,566	6,701,139	334,303	116,146	560,076		341,825	376,412	342,004	332,888	1.61	0.08	287,409	46	112	90	0	6.66	64.5	0		67,039	12,701	51
Nov 2011	14,150,147		6,135,800	28,148,892	13,177,961	6,001,090	390,581	117,427	591,831		369,400	414,870	365,929	354,710	3.86	0.00	288,163	47	113	90	0	2.40	73.3	0		67,161	12,562	51
Dec 2011	16,454,135		6,760,958	30,000,241	13,449,851	6,123,030	402,229	119,781	1,227,567		791,282	912,900	772,883	744,755	9.23	0.00	288,917	48	114	90	0	-2.70	64.5	1		67,244	12,587	52
Jan 2012	17,189,290		7,144,766	30,695,585	13,908,310	7,139,900	423,256	121,978	1,318,263		836,029	965,231	720,161	684,942	11.71	0.00	289,160	49	115	90	0	-5.43	67.7	1		67,442	12,357	52
Feb 2012	16,056,605		6,947,844	30,511,792	13,901,887	7,211,780	391,701	115,971	1,239,429		812,547	944,672	712,471	679,535	10.33	0.00	289,403	50	116	90	0	-4.71	69.0	1		67,517	12,195	51
Mar 2012	14,125,525		6,610,789	28,422,488	13,508,455	7,082,771	360,155	117,866	1,140,005		785,940	907,987	709,942	679,960	4.68	0.01	289,645	51	117	90	0	0.49	71.0	1		67,517	12,125	51
Apr 2012	13,415,652		6,349,242	27,018,421	12,782,948	6,973,939	315,028	117,376	995,241		710,347	835,934	683,939	658,279	3.36	0.00	290,210	52	118	90	0	-1.32	63.3	0		67,507	12,037	52
May 2012	13,133,097		6,298,435	27,692,283	14,562,308	7,173,183	238,309	113,581	955,594		703,197	830,050	695,244	665,093	0.00	1.18	290,775	53	119	90	0	8.69	71.0	0		67,473	12,116	52
Jun 2012	16,449,199		6,920,052	29,902,107	15,260,262	7,435,603	236,599	112,514	1,111,035		755,304	894,814	732,899	695,829	0.00	3.39	291,340	54	120	90	0	13.08	70.0	1		67,360	12,129	52
Jul 2012	19,456,208		7,859,012	33,204,579	15,803,145	7,859,647	251,219	120,795	1,303,638		822,921	963,891	753,720	706,725	0.00	6.35	291,612	55	121	90	0	15.46	67.7	1		67,365	12,159	52
Aug 2012	16,963,481		7,106,370	30,946,391	15,510,339	7,844,744	250,899	115,291	1,251,040		796,229	953,581	754,493	715,161	0.00	3.62	291,885	56	122	90	0	15.18	71.0	1		67,464	12,175	52
Sep 2012	14,046,286		6,506,846	28,041,323	14,413,342	7,400,942	287,762	116,419	1,054,138		736,653	892,776	728,372	689,919	0.02	1.19	292,157	57	123	90	0	10.73	63.3	1		67,607	12,183	52
Oct 2012	13,242,942		6,120,297	26,747,664	14,156,783	7,215,165	334,221	113,648	931,032		687,406	831,252	697,308	669,654	1.58	0.04	291,762	58	124	90	0	6.55	71.0	0		67,845	12,184	52
Nov 2012	14,790,898		6,720,938	28,210,819	14,268,656	7,099,906	387,559	118,414	1,053,014		739,475	873,854	712,837	688,378	6.59	0.00	291,366	59	125	90	0	-1.36	73.3	0		67,924	12,205	52
Dec 2012	16,106,072		6,849,155	28,845,345	13,587,636	6,820,259	390,271	115,694	1,184,117		780,674	919,514	691,393	674,899	8.36	0.00	290,971	60	126	90	0	-2.73	61.3	1		67,904	12,225	52
Jan 2013	17,123,333		7,418,873	30,634,027	14,654,298	6,999,070	416,577	117,661	1,375,993		970,087	1,192,975	769,801	714,709	12.14	0.00	291,445	61	127	90	0	-6.04	67.7	1		67,921	12,259	53
Feb 2013	17,019,837		7,505,055	31,515,122	14,769,489	7,151,307	388,030	116,401	1,339,910		976,513	1,209,265	788,781	734,391	14.55	0.00	291,919	62	128	90	0	-7.66	67.9	1		67,944	12,262	53
Mar 2013	15,441,826		6,950,492	28,834,513	14,484,635	7,204,748	365,740	118,337	1,189,928		911,966	1,122,225	758,877	709,511	9.90	0.00	292,393	63	129	90	0	-5.16	67.7	1		68,017	12,206	53
Apr 2013	13,781,403		6,522,474	27,541,564	14,314,860	6,964,997	307,864	115,232	1,038,826		824,253	1,033,171	731,082	686,888	4.51	0.00	293,714	64	130	90	0	0.13	66.7	0		68,028	12,199	53
May 2013	12,978,737	344,698	6,668,144	26,598,851	13,945,408	7,219,587	253,838	119,480	997,442	2,332	815,956	1,025,899	743,166	693,998	0.46	0.75	295,035	65	131	90	0	7.63	71.0	0	35,811	68,025	12,074	53
Jun 2013	14,654,454	357,299	6,725,030	28,830,537	15,242,003	7,057,222	227,370	110,637	1,159,690	2,556	876,418	1,105,944	783,417	726,069	0.00	2.04	296,356	66	132	90	0	12.91	70.0	1	36,156	68,220	11,885	52
Jul 2013	17,596,372	416,733	7,756,647	31,685,353	15,690,464	7,582,708	251,581	122,290	1,360,727	2,849	954,877	1,191,320	805,673	737,439	0.00	4.45	296,993	67	133	90	0	16.14	67.7	1	36,777	68,313	11,924	51
Aug 2013	15,770,492	395,981	7,236,606	29,939,127	15,420,606	7,467,653	250,283	113,167	1,305,826	2,832	923,906	1,178,577	806,500	746,241	0.00	3.03	297,631	68	134	90	0	14.20	71.0	1	37,407	68,386	11,913	51
Sep 2013	13,613,479	375,178	6,616,791	27,712,222	14,725,640	7,303,337	289,793	114,468	1,100,302	2,736	854,777	1,103,425	778,578	719,903	0.00	0.91	298,268	69	135	90	0	11.10	63.3	1	37,871	68,468	11,923	51
Oct 2013	13,018,661	370,361	6,324,666	26,756,876	14,431,160	7,172,470	333,570	112,883	971,804	2,529	797,633	1,027,385	745,373	698,757	1.60	0.01	299,160	70	136	90	0	6.51	71.0	0	38,174	68,558	11,890	51
Nov 2013	15,053,411	401,648	7,027,355	28,607,720	14,514,980	7,034,713	392,104	116,709	1,099,128	2,664	858,051	1,080,038	761,973	718,295	8.12	0.00	300,051	71	137	90	0	-2.60	73.3	0	38,253	68,586	11,904	51
Dec 2013	17,018,027	447,865	7,426,848	30,014,923	14,019,894	6,930,691	392,785	113,251	1,235,973	2,898	905,857	1,136,471	739,050	704,230	14.20	0.00	300,942	72	138	90	0	-7.70	61.3	1	38,602	68,595	11,914	51
Jan 2014	18,837,350	504,749	8,361,525	32,856,560	15,384,595	7,305,563	414,695	119,065	1,461,521	3,604	1,105,198	1,469,137	891,933	775,178	18.64	0.00	300,719	73	139	90	0	-12.65	71.0	1	39,542	68,617	11,904	51
Feb 2014	17,625,995	463,676	7,942,566	32,326,644	15,725,347	7,343,277	392,326	114,207	1,423,195	3,507	1,112,518	1,489,197	913,924	796,525	18.33	0.00	300,496	74	140	90	0	-12.29	67.9	1	40,438	68,570	11,913	52
Mar 2014	16,365,607	448,348	7,755,734	30,888,681	15,109,271	7,265,256	359,544	117,291	1,263,891	3,198	1,038,982	1,382,009	879,277	769,540	14.28	0.00	300,273	75	141	90	0	-9.74	67.7	1	41,224	68,638	11,970	50
Apr 2014	14,008,764	383,650	6,757,314	27,748,285	13,512,418	6,922,565	317,075	116,254	1,103,396	2,868	939,052	1,272,339	847,072	745,003	4.22	0.00	302,104	76	142	90	0	-1.06	66.7	0	42,022	68,723	11,931	45
May 2014	12,193,265	377,883	6,455,952	27,615,215	14,267,396	6,635,439	237,737	110,813	1,059,440	2,954	929,600	1,263,384	861,073	752,714	0.23	0.38	303,936	77	143	90	0	6.75	67.7	0	42,409	68,856	11,886	48
Jun 2014	14,362,245	432,326	7,148,962	29,879,616	14,951,950	7,224,040	236,512	114,787	1,231,773	3,238	998,483	1,361,959	907,710	787,499	0.00	2.27	305,768	78	144	90	0	12.44	70.0	1	43,022	68,952	11,852	47
Jul 2014	14,952,825	447,715	7,370,235	30,444,149	14,971,801	7,039,103	250,699	117,902	1,445,306	3,609	1,087,869	1,467,098	933,497	799,830	0.00	2.29	307,010	79	145	90	0	13.11	71.0	1	43,554	69,058	11,767	46
Aug 2014	14,641,040	452,321	7,244,285	29,857,964	14,917,763	6,974,514	250,712	113,340	1,386,992	3,588	1,052,584	1,451,406	934,455	809,378	0.00	2.64	308,252	80	146	90	0	14.34	64.5	1	44,190	69,002	11,779	46
Sep 2014	13,488,940	452,371	7,212,176	28,770,119	14,765,092	6,735,694	291,310	118,367	1,168,693	3,466	973,827	1,358,856	902,103	780,811	0.03	1.00	309,494	81	147	90	0	16.91	70.0	1	44,785	69,896	10,845	45
Oct 2014	12,737,878	438,137	6,822,741	26,973,512	14,096,396	6,612,482	334,641	112,446	1,032,208	3,203	908,724	1,265,214	863,630	757,876	1.16	0.04	310,295	82	148	90	0	6.71	71.0	0	45,725	70,194	10,622	46
Nov 2014	15,038,105	491,299	7,624,423	29,138,642	14,300,641	6,565,942	389,010	116,963	1,167,447	3,375	977,558	1,330,056	882,863	779,067	8.14	0.00	311,095	83	149	90	0	-2.38	66.7	0	46,681	70,190	10,632	43
Dec 2014	16,119,263	510,443	7,772,535	29,527,625	13,985,324	6,381,557	392,326	114,542	1,312,797	3,671	1,032,021	1,399,553	856,304	763,812	9.98	0.00	311,895	84	150	90	0	-3.56	67.7	1	47,754	70,354	10,537	43
Jan 2015	17,860,289	614,110	8,751,184	32,591,273	14,903,205	6,923,063	415,927	117,177	1,588,681	5,680	1,234,666	1,911,548	1,016,349	966,900	17.56	0.00	312,449	85	151	90	0	-12.09	67.7	1	48,980	70,387	10,502	44
Feb 2015	18,485,093	630,879	9,030,270	34,209,360	15,582,841	7,390,728	393,044	118,223	1,547,021	5,527	1,242,844	1,937,649	1,198,180	993,526	22.60	0.00	312,996	86	152	90	0	-16.85	67.9	1	49,914	70,351	10,492	44
Mar 2015	15,528,943	552,995	8,146,278	30,449,220	14,735,852	7,057,208	362,171	116,102	1,373,856	5,041	1,160,693	1,798,182	1,152,756	959,868	11.85	0.00	313,547	87	153	90	0	-8.04	71.0	1	50,816	70,390	10,478	44
Apr 2015	13,191,273	482,393	7,171,596	27,632,038	14,107,586	6,752,261	308,340	113,366	1,199,397	4,520	1,049,057	1,655,487	1,110,535	929,261	3.15	0.00	314,460	88	154	90	0	-0.29	66.7	0	51,933	70,376	10,435	44
May 2015	12,537,416	521,710	7,320,727	27,528,762	14,269,832	6,717,759	244,319	116,240	1,151,617	4,655	1,038,498	1,643,835	1,128,891	938,880	0.05	1.10	315,374	89	155	90	0	7.72	64.5	0	53,094	70,421	10,380	44
Jun 2015	13,594,466	537,734	7,392,320	28,702,264	14,942,227	6,995,292	236,354	113,937	1,338,944	5,104	1,115,450	1,772,094	1,190,033	982,268	0.00	1.08	316,288	90	156	90	0	12.16	73.3	1	54,516	70,436	10,364	44
Jul 2015	16,611,532	638,808	8,438,995	31,734,954	15,496,789	7,050,227	251,098	119,626	1,571,056	5,688	1,215,308	1,908,895	1,223,840	997,650	0.00	3.69	317,577	91	157	90	0	13.78	71.0	1	57,061	70,393	10,368	44
Aug 2015	15,780,681	605,648	7,808,045	30,467,452	15,293,390	7,286,293	252,434	110,850	1,507,668	5,655	1,175,889	1,888,478	1,225,097	1,009,558	0.00	2.86	318,866	92	158	90	0	14.46	64.5	1	58,994	70,324	10,376	44
Sep 2015	15,037,926	643,506	7,909,572	30,809,706	15,361,895	7,288,661	289,680	121,494	1,270,376	5,462	1,087,906	1,768,058	1,182,682	973,926	0.00	2.73	320,154	93	159	90	0	13.76	70.0	1	60,600	70,329	10,388	44
Oct 2015	12,561,658	566,054	6,880,856	27,165,796	14,149,749	6,781,108	334,582	112,578	1,122,016	5,048	1,015,177	1,646,217	1,132,243	945,318	1.55	0.00	320,725	94	160	90	0	4.21	67.7	0	61,353	70,308	10,425	44
Nov 2015	13,507,088	576,072	7,367,611	27,985,179	14,251,053	6,886,279	391,355	115,988	1,269,021	5,319	1,092,074	1,730,584	1,157,458	971,750	4.06	0.00	321,296	95	161	90	0	1.95	70.0	0	62,050	70,331	10,446	44
Dec 2015	14,575,804	591,114	7,542,310	28,627,975	13,700,879	6,633,371	390,109	115,720	1,427,017	5,785	1,152,917	1,821,010	1,122,639	952,723	5.87	0.00	321,867	96	162	90	0	0.61	67.7	1	62,647	70,300	10,475	44
Jan 2016	16,905,232	702,951	8,296,922	31,303,890	14,589,555	7,077,736	424,021	117,777	1,772,732	12,004	1,302,026	2,373,457	1,444,393	1,151,445	13.63	0.00	323,625	97	163	90	0	-7.88	64.5	1	63,370	70,280	10,496	44
Feb 2016	16,036,882	684,766	8,260,157	31,358,669	14,817,878	7,136,726	391,053	115,831	1,666,720	11,277	1,265,456	2,322,905	1,428,971	1,142,355	12.29	0.00	325,382	98	164	90	0	-7.42	69.0	1	63,732	70,271	10,510	44
Mar 2016	14,386,913	610,747	7,791,991	29,550,266	14,442,395	7,004,562	362,703	115,865	1,533,020	10,652	1,224,018	2,232,698	1,423,897	1,143,071	7.51	0.00	327,139	99	165	90	0	-2.61	67.7	1	64,294	70,233	10,510	44
Apr 2016	13,316,857	583,931	7,362,729	28,341,950	14,282,348	6,999,358	306,864	117,208	1,338,350	9,553	1,106,291	2,055,522	1,371,744	1,106,623	5.59	0.00	326,960	100	166	90	0	-4.20	70.0	0	64,680	70,214	10,508	44
May 2016	13,129,784	584,064	7,200,135	28,032,831	14,392,114	7,108,040	246,533	113,804	1,285,034	9,838	1,095,155	2,041,053	1,394,419	1,118,078	0.41	1.19	326,780	101	167	90	0	5.65	67.7	0	64,917	70,165	10,502	44
Jun 2016	15,660,600	650,589	7,860,446	30,101,670	15,135,778	7,329,068	235,732	115,825	1,494,063	10,786	1,176,306	2,200,306	1,469,942	1,169,747	0.00	2.79	326,600	102	168	90	0	8.94	73.3	1	65,685	70,122	10,475	42
Jul 2016	18,559,188	718,708	8,625,104	33,007,906	15,718,295	7,601,116	252,779	117,703	1,753,065	12,020	1,281,612	2,370,164	1,511,700	1,188,064	0.00	5.71	327,168	103	169	90	0	14.33	64.5	1	65,758	70,175	10,359	44
Aug 2016	19,400,047	768,645	8,903,033	34,570,269	16,279,283	7,755,391	251,938	120,594	1,682,334	11,950	1,240,043	2,344,812	1,513,253	1,202,246	0.00	6.30	327,737	104	170	90	0	16.42	71.0	1	66,456	70,149	10,310	44
Sep 2016	14,844,846	676,823	7,668,790	30,522,551	15,299,229	7,309,325	291,217	114,998	1,417,551	11,542	1,147,260	2,195,294	1,460,861	1,159,813	0.00	2.31	328,305	105	171	90	0	12.53	70.0	1	66,796	70,128	10,318	44
Oct 2016	12,177,966	615,120	7,016,560	27,550,296	14,294,548	6,974,029	335,878	113,952	1,252,003	10,669	1,070,562	2,044,011	1,398,559	1,125,745	1.46	0.13	328,965	106	172	90	0	7.36	64.5	0	67,351	70,106	10,333	44
Nov 2016	13,478,836	630,733	7,356,201	28,324,064	14,328,205	7,039,077	390,978	115,363	1,416,039	11,242	1,151,655	2,148,765	1,429,705	1,157,222	3.62	0.00	329,625	107	173	90	0	2.35	73.3	0	67,985	70,068	10,343	44
Dec 2016	15,756,855	718,420	7,960,693	30,588,500	14,087,872	7,009,103	393,775	117,739	1,592,340	12,226	1,215,818	2,261,041	1,386,696	1,134,563	11.61	0.00	330,285	108	174	90	0	-5.55	64.5	1	68,472	70,109	10,352	44
Jan 2017	16,480,695	754,884	8,290,299	31,356,469	14,497,397	7,246,213	420,963	116,559	2,154,484	27,027	1,354,430	2,813,214	1,633,251	1,249,545	11.64	0.00	331,991	109	175	90	0	-5.38	67.7	1	69,066	70,064	10,364	44
Feb 2017	15,648,066	717,350	8,157,446	31,031,301	14,616,437	7,239,837	392,596	115,453	2,097,987	26,297	1,363,401	2,851,627	1,673,520	1,283,955	10.26	0.00	333,696	110	176	90	0	-5.22	67.9	1	69,376	70,097	10,386	44
Mar 2017	15,154,920	712,713	8,100,646	30,678,174	14,631,711	7,210,048	362,401	118,682	1,863,150	23,984	1,273,282	2,646,375	1,610,076	1,240,457	10.55	0.00	335,402	111	177	90	0	-6.63	74.2	1	69,954	70,467	10,370	44
Apr 2017	12,748,785	611,881	7,164,591	27,367,757	13,752,407	6,815,849	305,235	114,265	1,626,559	21,508	1,150,816	2,436,371	1,551,104	1,200,904	1.92	0.00	336,181	112	178	90	0	2.48	60.0	0	70,312	70,659	10,399	44
May 2017	12,300,434	621,833	7,039,866	27,390,899	14,212,213	6,986,874	248,809	116,324	1,561,762	22,150	1,139,233	2,419,222	1,576,743	1,213,334	0.72	0.29	336,960	113	179	90	0	6.31	71.0	0	70,637	70,602	10,448	44
Jun 2017	14,184,753	692,294	7,713,934

Model Input Data

Month	Purchased Energy per day, kWh (by customer class)								Cumulative CDM impacts per day, kWh						HDD10 per day	CDD18 per day	GDP	Time Trend			Blackout Dummy	DewPoint Temperature	Business Days Percent	Shoulder Flag	Customer Numbers			
	Residential	Competitive Sector Multi-Unit Residential (CSMUR)	GS<50 kW	GS 50-999 kW	GS 1000-4999 kW	Large Use	Street lighting	Unmetered Scattered Load	Residential	CSMUR	GS<50 kW	GS 50-999 kW	GS 1000-4999 kW	Large Use				Residential	GS<50 kW & GS 1,000-4,999 kW	Large Use					CSMUR	GS<50 kW (excluding FIT)	GS 50-999 kW	Large Use
Jan 2018	18,005,194	883,304	8,809,537	33,215,018	14,962,879	7,298,499	422,522	115,054	2,476,431	40,128	1,442,877	3,270,022	1,777,201	1,328,513	15.62	0.00	342,710	121	187	90	0	-9.97	71.0	1	73,455	70,711	10,447	44
Feb 2018	16,560,149	802,626	8,537,724	31,888,468	14,685,369	7,139,581	391,074	115,453	2,411,491	39,045	1,452,434	3,314,673	1,821,019	1,365,098	11.82	0.00	343,763	122	188	90	0	-6.19	67.9	1	73,465	70,713	10,463	44
Mar 2018	15,175,018	748,767	8,034,963	30,268,340	14,274,981	6,961,427	363,128	113,942	2,141,562	35,610	1,356,430	3,076,092	1,751,983	1,318,852	9.87	0.00	344,816	123	189	90	0	-7.39	67.7	1	73,919	70,708	10,489	44
Apr 2018	14,248,720	725,951	7,750,941	29,354,457	14,086,517	6,857,805	307,536	115,419	1,869,616	31,933	1,225,967	2,831,988	1,687,813	1,276,799	6.67	0.00	345,469	124	190	90	0	-3.82	66.7	0	74,037	70,704	10,486	44
May 2018	13,322,593	711,128	7,447,894	28,486,123	14,450,080	6,973,326	246,135	112,418	1,795,137	32,888	1,213,627	2,812,054	1,715,712	1,290,015	0.06	1.40	346,121	125	191	90	0	8.04	71.0	0	74,081	70,714	10,463	44
Jun 2018	15,637,085	751,312	7,736,604	30,294,664	15,076,104	7,425,837	237,671	108,819	2,087,141	36,055	1,303,556	3,031,463	1,808,637	1,349,630	0.00	2.02	346,774	126	192	90	0	11.72	70.0	1	74,523	70,599	10,515	44
Jul 2018	19,817,641	879,507	8,838,210	34,426,020	16,032,434	7,164,055	252,218	118,485	2,448,956	40,182	1,420,254	3,265,485	1,860,017	1,370,763	0.00	5.41	347,368	127	193	90	0	15.37	67.7	1	75,000	70,645	10,530	44
Aug 2018	19,205,209	889,526	8,756,998	34,450,013	16,150,116	7,331,758	252,219	115,279	2,350,148	39,947	1,374,188	3,230,557	1,861,927	1,387,126	0.00	5.24	347,961	128	194	90	0	17.42	71.0	1	75,635	70,605	10,506	38
Sep 2018	15,716,276	823,780	7,924,686	31,466,330	15,337,200	7,017,087	292,261	116,652	1,980,257	38,585	1,271,368	3,024,558	1,797,464	1,338,168	0.00	2.55	348,554	129	195	90	0	13.94	63.3	1	76,188	70,652	10,422	38
Oct 2018	13,062,503	740,383	7,233,223	28,581,640	14,581,606	6,716,338	338,543	113,552	1,748,995	35,665	1,186,374	2,816,129	1,720,806	1,298,860	2.64	0.26	348,790	130	196	90	0	4.44	71.0	0	76,449	70,679	10,419	38
Nov 2018	15,251,327	810,750	7,987,746	30,394,748	14,647,124	6,617,801	391,974	110,009	1,978,145	37,580	1,276,238	2,960,453	1,759,129	1,335,178	8.55	0.00	349,025	131	197	90	0	-2.71	73.3	0	76,776	70,777	10,439	38
Dec 2018	16,229,086	845,463	8,194,131	29,726,304	14,563,781	6,498,382	414,751	114,887	2,224,430	40,871	1,347,342	3,115,142	1,706,209	1,309,035	10.18	0.00	349,260	132	198	90	0	-3.74	61.3	1	76,806	70,829	10,462	38
Jan 2019									2,588,009	46,739	1,543,805	3,747,983	1,950,575	1,428,155	15.20	0.00	350,233	133	199	90	0	-9.09	71.0	1	77,382	70,840	10,460	38
Feb 2019									2,520,143	45,477	1,554,031	3,799,160	1,998,668	1,467,484	14.26	0.00	351,206	134	200	90	0	-8.52	67.9	1	77,884	70,851	10,457	38
Mar 2019									2,238,053	41,476	1,451,311	3,525,707	1,922,896	1,417,769	9.41	0.00	352,180	135	201	90	0	-5.41	67.7	1	78,481	70,862	10,455	38
Apr 2019									1,953,854	37,194	1,311,723	3,245,924	1,852,467	1,372,562	3.72	0.00	352,856	136	202	90	0	-0.78	66.7	0	79,103	70,873	10,452	38
May 2019									1,876,019	38,306	1,298,519	3,223,076	1,883,087	1,386,769	0.31	0.84	353,533	137	203	90	0	7.32	71.0	0	79,699	70,884	10,450	38
Jun 2019									2,181,179	41,995	1,394,739	3,474,556	1,985,077	1,450,855	0.00	2.07	354,209	138	204	90	0	12.08	66.7	1	80,204	70,895	10,447	38
Jul 2019									2,559,296	46,801	1,519,600	3,742,783	2,041,470	1,473,574	0.00	4.48	354,894	139	205	90	0	14.97	71.0	1	80,703	70,906	10,445	38
Aug 2019									2,456,036	46,528	1,470,311	3,702,749	2,043,566	1,491,164	0.00	3.75	355,580	140	206	90	0	15.39	67.7	1	81,201	70,917	10,442	38
Sep 2019									2,069,480	44,942	1,360,299	3,466,641	1,972,814	1,438,534	0.01	1.61	356,265	141	207	90	0	12.84	66.7	1	81,699	70,929	10,440	38
Oct 2019									1,827,797	41,540	1,269,360	3,227,747	1,888,678	1,396,278	1.55	0.08	356,962	142	208	90	0	6.05	71.0	0	82,197	70,940	10,437	38
Nov 2019									2,067,273	43,771	1,365,510	3,393,166	1,930,740	1,435,320	5.91	0.00	357,660	143	209	90	0	-0.07	70.0	0	82,695	70,951	10,435	38
Dec 2019									2,324,654	47,604	1,441,588	3,570,465	1,872,658	1,407,216	11.08	0.00	358,357	144	210	90	0	-4.79	64.5	1	83,193	70,962	10,432	38
Jan 2020									2,635,733	52,142	1,626,152	4,233,364	2,134,018	1,727,455	15.20	0.00	359,068	145	211	90	0	-9.09	71.0	1	83,692	70,973	10,430	38
Feb 2020									2,478,111	48,986	1,580,477	4,143,198	2,111,233	1,713,818	14.26	0.00	359,779	146	212	90	0	-8.52	65.5	1	84,170	70,984	10,427	38
Mar 2020									2,279,323	46,272	1,528,724	3,982,303	2,103,736	1,714,892	9.41	0.00	360,489	147	213	90	0	-5.41	71.0	1	84,620	70,995	10,425	38
Apr 2020									1,989,884	41,494	1,381,690	3,666,286	2,026,684	1,660,211	3.72	0.00	361,220	148	214	90	0	-0.78	66.7	0	85,050	71,006	10,422	38
May 2020									1,910,613	42,735	1,367,783	3,640,480	2,060,184	1,677,396	0.31	0.84	361,951	149	215	90	0	7.32	64.5	0	85,460	71,017	10,420	38
Jun 2020									2,221,401	46,850	1,469,135	3,924,527	2,171,765	1,754,913	0.00	2.07	362,682	150	216	90	0	12.08	73.3	1	85,852	71,028	10,417	38
Jul 2020									2,606,491	52,212	1,600,655	4,227,491	2,233,462	1,782,393	0.00	4.48	363,415	151	217	90	0	14.97	71.0	1	86,224	71,039	10,415	38
Aug 2020									2,501,326	51,907	1,548,738	4,182,272	2,235,755	1,803,669	0.00	3.75	364,149	152	218	90	0	15.39	64.5	1	86,596	71,050	10,412	38
Sep 2020									2,107,642	50,138	1,432,858	3,915,588	2,158,349	1,740,009	0.01	1.61	364,882	153	219	90	0	12.84	70.0	1	86,968	71,061	10,410	38
Oct 2020									1,861,503	46,343	1,337,067	3,645,755	2,066,300	1,688,898	1.55	0.08	365,628	154	220	90	0	6.05	67.7	0	87,340	71,072	10,407	38
Nov 2020									2,105,394	48,831	1,438,347	3,832,597	2,112,318	1,736,121	5.91	0.00	366,374	155	221	90	0	-0.07	70.0	0	87,712	71,083	10,405	38
Dec 2020									2,367,521	53,108	1,518,482	4,032,857	2,048,773	1,702,128	11.08	0.00	367,120	156	222	90	0	-4.79	67.7	1	88,084	71,094	10,402	38
Jan 2021									2,675,332	57,199	1,704,358	4,671,466	2,308,546	2,012,784	15.20	0.00	367,888	157	223	90	0	-9.09	64.5	1	88,456	71,105	10,400	38
Feb 2021									2,605,176	55,656	1,715,647	4,735,253	2,365,465	2,068,213	14.26	0.00	368,657	158	224	90	0	-8.52	67.9	1	88,862	71,117	10,397	38
Mar 2021									2,313,567	50,759	1,602,245	4,394,422	2,275,788	1,998,147	9.41	0.00	369,425	159	225	90	0	-5.41	74.2	1	89,320	71,128	10,395	38
Apr 2021									2,019,780	45,519	1,448,140	4,045,702	2,192,434	1,934,434	3.72	0.00	370,202	160	226	90	0	-0.78	66.7	0	89,811	71,139	10,392	38
May 2021									1,939,318	46,879	1,433,563	4,017,225	2,228,673	1,954,457	0.31	0.84	370,980	161	227	90	0	7.32	64.5	0	90,337	71,150	10,390	38
Jun 2021									2,254,775	51,394	1,539,790	4,330,667	2,349,380	2,044,777	0.00	2.07	371,757	162	228	90	0	12.08	73.3	1	90,897	71,161	10,387	38
Jul 2021									2,645,650	57,276	1,677,635	4,664,984	2,416,123	2,076,796	0.00	4.48	372,533	163	229	90	0	14.97	67.7	1	91,491	71,172	10,385	38
Aug 2021									2,538,906	56,942	1,623,221	4,615,087	2,418,603	2,101,586	0.00	3.75	373,309	164	230	90	0	15.39	67.7	1	92,084	71,183	10,382	38
Sep 2021									2,139,307	55,001	1,501,768	4,320,803	2,334,867	2,027,412	0.01	1.61	374,084	165	231	90	0	12.84	70.0	1	92,678	71,194	10,380	38
Oct 2021									1,889,470	50,838	1,401,371	4,023,046	2,235,290	1,967,859	1.55	0.08	374,869	166	232	90	0	6.05	64.5	0	93,272	71,205	10,377	38
Nov 2021									2,137,025	53,567	1,507,521	4,229,224	2,285,071	2,022,882	5.91	0.00	375,653	167	233	90	0	-0.07	73.3	0	93,866	71,216	10,375	38
Dec 2021									2,403,091	58,258	1,591,511	4,450,208	2,216,330	1,983,274	11.08	0.00	376,438	168	234	90	0	-4.79	67.7	1	94,459	71,227	10,372	38
Jan 2022									2,714,930	62,257	1,781,822	5,066,605	2,467,622	2,136,410	15.20	0.00	377,258	169	235	90	0	-9.09	64.5	1	95,053	71,238	10,370	38
Feb 2022									2,643,736	60,577	1,793,624	5,135,788	2,528,463	2,195,243	14.26	0.00	378,078	170	236	90	0	-8.52	67.9	1	95,620	71,249	10,367	38
Mar 2022									2,347,812	55,247	1,675,068	4,766,128	2,432,607	2,120,873	9.41	0.00	378,898	171	237	90	0	-5.41	74.2	1	96,145	71,260	10,365	38
Apr 2022									2,049,675	49,543	1,513,958	4,387,911	2,343,509	2,053,247	3.72	0.00	379,699	172	238	90	0	-0.78	63.3	0	96,643	71,271	10,362	38
May 2022									1,968,023	51,024	1,498,719	4,357,025	2,382,246	2,074,500	0.31	0.84	380,499	173	239	90	0	7.32	67.7	0	97,114	71,282	10,360	38
Jun 2022									2,288,149	55,938	1,609,774	4,696,980	2,511,270	2,170,368	0.00	2.07	381,300	174	240	90	0	12.08	73.3	1	97,558	71,293	10,357	38
Jul 2022									2,684,810	62,340	1,753,885	5,059,575	2,582,611	2,204,354	0.00	4.48	382,088	175	241	90	0	14.97	64.5	1	97,975	71,305	10,355	38
Aug 2022									2,576,485	61,976	1,696,997	5,005,457	2,585,263	2,230,666	0.00	3.75	382,876	176	242	90	0	15.39	71.0	1	98,392	71,316	10,352	38
Sep 2022									2,170,972	59,864	1,570,024	4,686,281	2,495,757	2,151,936	0.01	1.61	383,663	177	243	90	0	12.84	70.0	1	98,809	71,327	10,350	38
Oct 2022									1,917,437	55,332	1,465,064	4,363,338	2,389,318	2,088,725	1.55	0.08	384,449	178	244	90	0	6.05	64.5	0	99,226	71,338	10,347	38
Nov 2022									2,168,656	58,303	1,576,038	4,586,956	2,442,529	2,147,128	5.91	0.00	385,234	179	245	90	0	-0.07	73.3	0	99,643	71,349	10,345	38
Dec 2022									2,438,660	63,409	1,663,845	4,826,632	2,369,051	2,105,086	11.08	0.00	386,020	180	246	90	0	-4.79	64.5	1	100,060	71,360	10,342	38
Jan 2023									2,754,529	67,314	1,859,286	5,461,744	2,626,698	2,260,035	15.20	0.00	386,801	181	247	90	0	-9.09	67.7	1	100,477	71,371	10,340	38
Feb 2023									2,682,296	65,497	1,871,601	5,536,322	2,691,461	2,322,273	14.26	0.00	387,583	182	248	90	0	-8.52	67.9	1	100,883	71,382	10,337	38
Mar 2023									2,382,056	59,735	1,747,890	5,137,833	2,589,426	2,243,599	9.41	0.00	388,364	183	249	90	0	-5.41	74.2	1	101,272	71,393	10,335	38
Apr 2023									2,079,571	53,568	1,579,777	4,730,119	2,494,584	2,172,060	3.72	0.00	389,145	184	250	90	0	-0.78	60.0	0	101,650	71,404	10,332	38
May 2023									1,996,728	55,169	1,563,875	4,696,825	2,535,818	2,194,543	0.31	0.84	389,925	185	251	90	0	7.32	71.0	0	102,017	71,415	10,330	38
Jun 2023									2,321,523	60,482	1,679,758	5,063,292	2,673,160	2,295,958	0.00	2.07	390,706	186	252	90	0	12.08	73.3	1	102,374	71,426	10,327	38
Jul 2023									2,723,969	67,404	1,830,134	5,454,166	2,749,100	2,331,911	0.00	4.48	391,485	187	253	90	0	14.97	64.5	1	102,719	71,437	10,325	38
Aug 2023									2,614,065	67,010	1,770,773	5,395,827	2,751,923	2,359,746	0.00	3.75	392,263	188	254	90	0	15.39	71.0	1	103,064	71,448	10,322	38
Sep 2023									2,202,636	64,726	1,638,280	5,051,759	2,656,647	2,276,460	0.01	1.61	393,042	189	255	90	0	12.84	66.7	1	103,409	71,459	10,320	38
Oct 2023									1,945,403	59,827	1,528,757	4,703,630	2,543,346	2,209,591	1.55	0.08	393,818	190	256	90	0	6.05	67.7	0	103,755	71,470	10,317	38
Nov 2023									2,200,287	63,039	1,644,556	4,944,688	2,599,988	2,271,374	5.91	0.00	394,594	191	257	90	0	-0.07	73.3	0	104,100	71,482	10,315	38
Dec 2023									2,474,229	68,560	1,736,180	5,203,056	2,521,773	2,226,899	11.08	0.00	395,371	192	258	90	0	-4.79	61.3	1	104,445	71,493	10,312	38
Jan 2024									2,794,128	72,371	1,936,750	5,856,883	2,785,774	2,383,661	15.20	0.00	395,958	193	259	90	0	-9.09	71.0	1	104,790	71,504	10,310	38
Feb 2024									2,627,034	67,990	1,882,351	5,732,138	2,756,030	2,364,844	14.26	0.00	396,545	194	260	90	0	-8.52	69.0	1	105,141	71,515	10,307	38
Mar 2024									2,416,300	64,222	1,820,713	5,509,538	2,746,244	2,366,326	9.41	0.00	397,133	195	261	90	0	-5.41	64.5	1	105,500	71,526	10,305	38
Apr 2024									2,109,467	57,592	1,645,595	5,072,328	2,645,659	2,290,873	3.72	0.00	397,720	196	262	90	0	-0.78	70.0	0	105,865	71,537	10,302	38
May 2024									2,025,432	59,313	1,629,031	5,036,625	2,689,390	2,314,586	0.31	0.84	398,307	197	263	90	0	7.32	71.0	0	106,235	71,548	10,300	38
Jun 2024									2,354,897	65,026	1,749,742	5,429,605	2,835,050	2,421,549	0.00	2.07	398,895	198	264	90	0	12.08	66.7	1	106,611	71,559	10,297	38
Jul 2024									2,763,129	72,468	1,906,383	5,848,757	2,915,589	2,459,468	0.00	4.48	399,482	199	265	90	0	14.97	71.0	1	106,992	71,570	10,295	38
Aug 2024									2,651,644	72,045	1,844,549	5,786,198	2,918,583	2,488,825	0.00	3.75	400,069	200	266	90	0	15.39	67.7	1	107,373	71,581	10,293	38
Sep 2024									2,234,301	69,589	1,706,536	5,417,238	2,817,536	2,400,984	0.01	1.61	400,657	201	267	90	0	12.84	66.7	1	107,754	71,592	10,290	38
Oct 2024									1,973,370	64,321	1,592,449	5,043,922	2,697,374	2,330,457	1.55	0.08	401,244	202	268	90	0	6.05	71.0	0	108,135	71,603	10,288	38
Nov 2024									2,231,918	67,775	1,713,073	5,302,420	2,757,446	2,395,619	5.91	0.00	401,831	203	269	90	0	-0.07	70.0	0	108,516	71,614	10,285	38
Dec 2024									2,509,798	73,711	1,808,515	5,579,480	2,674,494	2,348,712	11.08	0.00	402,419	204	270	90	0	-4.79	64.5	1	108,897	71,625	10,283	38

Residential Model

Dependent Variable: RES_DAY
Method: Least Squares
Date: 03/19/19 Time: 13:42
Sample: 2002M07 2018M12
Included observations: 198
White Heteroskedasticity-Consistent Standard Errors & Covariance

Variable	Coefficient	Std. Error	t-Statistic	Prob.
BLACKOUT	**(1,429,603)**	104,160	-13.73	0.000
CDD18_DAY	**1,003,361**	40,988	24.48	0.000
HDD10_DAY	**296,592**	9,160	32.38	0.000
SHOULDER_FLAG	**309,843**	90,705	3.42	0.001
TREND_2008	**(3,388)**	903	-3.75	0.000
C	**12,711,385**	74,509	170.60	0.000

R-squared	**92.8%**	Mean dependent var	15367630.88
Adjusted R-squared	**92.6%**	S.D. dependent var	1800000.11
S.E. of regression	488,231.0	Akaike info criterion	29.06
Sum squared resid	45,766,944,664,847.0	Schwarz criterion	29.16
Log likelihood	(2,871.4)	Hannan-Quinn criter.	29.11
F-statistic	497.1	Durbin-Watson stat	1.28
Prob(F-statistic)	0.0		

CSMUR Model

Dependent Variable: CSMUR_PERDAY
Method: Least Squares
Date: 03/06/19 Time: 03:01
Sample: 2013M05 2018M12
Included observations: 68
White Heteroskedasticity-Consistent Standard Errors & Covariance

Variable	Coefficient	Std. Error	t-Statistic	Prob.
CUST_NUM	**10**	0	46.21	0.000
DEW	**6,695**	1,236	5.42	0.000
CDD18_DAY	**16,881**	3,250	5.19	0.000
HDD10_DAY	**16,827**	1,703	9.88	0.000
C	**(128,948)**	19,874	(6.49)	0.000

R-squared	**97.8%**	Mean dependent var	612254.46
Adjusted R-squared	**97.7%**	S.D. dependent var	149460.03
S.E. of regression	22,750.7	Akaike info criterion	22.97
Sum squared resid	32,608,405,765.3	Schwarz criterion	23.14
Log likelihood	(776.1)	Hannan-Quinn criter.	23.04
F-statistic	707.1	Durbin-Watson stat	1.03
Prob(F-statistic)	0.0		

GS <50 kW Model

Dependent Variable: LESS50_DAY
Method: Least Squares
Date: 03/06/19 Time: 03:28
Sample: 2002M07 2018M12
Included observations: 198
White Heteroskedasticity-Consistent Standard Errors & Covariance

Variable	Coefficient	Std. Error	t-Statistic	Prob.
BLACKOUT	**(242,885)**	40,510	(6.00)	0.000
CDD18_DAY	**276,524**	10,328	26.77	0.000
BUS_DAYS_PERCENT	**9,195**	3,257	2.82	0.005
HDD10_DAY	**80,213**	2,999	26.74	0.000
NUMCUSTNETFIT	**329**	14	22.97	0.000
GDP	**13**	2	5.99	0.000
SHOULDER_FLAG	**165,990**	30,104	5.51	0.000
TREND_JUL2002	**(10,720)**	897	(11.96)	0.000
C	**(19,195,769)**	743,924	(25.80)	0.000

R-squared	**95.4%**	Mean dependent var	7186339.68
Adjusted R-squared	**95.2%**	S.D. dependent var	713059.28
S.E. of regression	156,782.0	Akaike info criterion	26.81
Sum squared resid	4,645,731,102,010.8	Schwarz criterion	26.96
Log likelihood	(2,644.9)	Hannan-Quinn criter.	26.86798814
F-statistic	485.7	Durbin-Watson stat	1.155036629
Prob(F-statistic)	0.0		

GS 50-999kW model

Dependent Variable: GS350_DAY
Method: Least Squares
Date: 03/19/19 Time: 15:00
Sample: 2002M07 2018M12
Included observations: 198
White Heteroskedasticity-Consistent Standard Errors & Covariance

Variable	Coefficient	Std. Error	t-Statistic	Prob.
BLACKOUT	**(1,636,149)**	92,191	(17.75)	0.000
BUS_DAYS_PERCENT	**45,438**	9,638	4.71	0.000
CDD18_DAY	**946,816**	31,103	30.44	0.000
CUST_NUMBERS	**363**	35	10.29	0.000
DEW	**74,836**	14,627	5.12	0.000
GDP	**30**	1	26.73	0.000
HDD10_DAY	**384,616**	19,957	19.27	0.000
SHOULDER_FLAG	**389,153**	83,381	4.67	0.000
C	**9,574,381**	872,957	10.97	0.000

R-squared	**96.4%**	Mean dependent var	29084310.74
Adjusted R-squared	**96.3%**	S.D. dependent var	2063120.60
S.E. of regression	399,314.0	Akaike info criterion	28.68
Sum squared resid	30,136,368,679,837.6	Schwarz criterion	28.83
Log likelihood	(2,830.1)	Hannan-Quinn criter.	28.73777209
F-statistic	633.7	Durbin-Watson stat	1.439752354
Prob(F-statistic)	0.0		

GS 1000-4999kW Model

Dependent Variable: GS450_DAY
Method: Least Squares
Date: 03/06/19 Time: 03:25
Sample: 2002M07 2018M12
Included observations: 198
White Heteroskedasticity-Consistent Standard Errors & Covariance

Variable	Coefficient	Std. Error	t-Statistic	Prob.
BLACKOUT	**(955,498)**	67,690	(14.12)	0.000
BUS_DAYS_PERCENT	**47,724**	6,435	7.42	0.000
DEW	**84,159**	10,570	7.96	0.000
GDP	**23**	3	7.79	0.000
HDD10_DAY	**151,943**	12,558	12.10	0.000
TREND_JUL2002	**(10,352)**	1,616	(6.41)	0.000
CDD18_DAY	**281,629**	28,298	9.95	0.000
C	**4,241,721**	866,858	4.89	0.000

R-squared	83.79%	Mean dependent var	14522469.65
Adjusted R-squared	**83.2%**	S.D. dependent var	771953.67
S.E. of regression	**31649028.9%**	Akaike info criterion	28.21
Sum squared resid	19,031,559,621,186.8	Schwarz criterion	28.34
Log likelihood	(2,784.5)	Hannan-Quinn criter.	28.26
F-statistic	140.3	Durbin-Watson stat	1.05449678
Prob(F-statistic)	0.0		

Large Use Model

Dependent Variable: LU_DAY
Method: Least Squares
Date: 03/06/19 Time: 03:38
Sample: 2002M07 2018M12
Included observations: 198
White Heteroskedasticity-Consistent Standard Errors & Covariance

Variable	Coefficient	Std. Error	t-Statistic	Prob.
BLACKOUT	**(368,060)**	60,337	(6.10)	0.000
BUS_DAYS_PERCENT	**15,711**	5,078	3.09	0.002
CDD18_DAY	**143,974**	25,215	5.71	0.000
CUST	**42,463**	8,550	4.97	0.000
DEW	**33,809**	9,129	3.70	0.000
GDP	**5**	1	4.10	0.000
HDD10_DAY	**61,792**	10,303	6.00	0.000
TREND_SPLINE_2010	**(8,450)**	1,154	(7.32)	0.000
C	**2,603,674**	744,157	3.50	0.001

R-squared	**70.4%**	Mean dependent var	7149049.95
Adjusted R-squared	**69.2%**	S.D. dependent var	425163.92
S.E. of regression	236,020.6	Akaike info criterion	27.63
Sum squared resid	10,528,384,295,470.9	Schwarz criterion	27.78
Log likelihood	(2,725.9)	Hannan-Quinn criter.	27.68611426
F-statistic	56.3	Durbin-Watson stat	1.261604392
Prob(F-statistic)	0.0		

OPERATING REVENUE: REVENUE OFFSETS VARIANCE ANALYSIS

1. OTHER REVENUE

Exhibit 3, Tab 2 includes information about the other revenue that Toronto Hydro received from non-distribution related services. This schedule provides a summary of the 2018 actuals, explains the material variances, and identifies material changes to the 2019 bridge and 2020 test year as a result of the 2018 actuals.

Table 1 below provides an updated summary of 2015-2019 Other Revenues. A more detailed breakdown of Other Revenue by Uniform System of Accounts is provided in the updated OEB Appendix 2-H, which is filed as Appendix A to this schedule.

Table 1: Other Revenue Summary

Description	Actual Year 2015	Actual Year 2016	Actual Year 2017	Actual Year 2018	Bridge Year 2019	Test Year 2020
Specific Service Charges	6.8	9.5	7.2	6.0	5.1	3.7
Late Payment Charges	4.1	4.5	3.7	3.3	3.7	3.8
Other Operating Revenues	10.8	12	13.4	11.8	12.4	12.0
Other Income or Deductions	16.1	18.7	21.4	26.1	27.6	27.4
Total Revenue Offset	**37.8**	**44.7**	**45.7**	**47.2**	**48.8**	**46.8**

Note 1: See Table 2 below for expected changes to the 2020 Test Year Forecast.

In 2018, Revenue Offsets were $3.3 million higher than originally forecasted in Exhibit 3, Tab 2, Schedule 1, page 1. The difference was primarily due to higher revenues from the pole attachments and accident claims, which are accounted for in the Other Income or Deductions category.

In 2019, Revenue Offsets are expected to be approximately $2.1 million higher than the original forecast as follows:

- Specific Service Charges are expected to decrease by $1.5 million as a result of the removal of the Collection of Account and Install/Remove Load Control Devices charges as of July 1 in accordance with the OEB rate order dated March 14, 2019, made under Phase 1 of the Customer Service Rules review (EB-2017-0183).
- Other Income and Deductions is expected to increase by $3.6 million due to lower merchandising and jobbing costs of $2 million as a result of capitalization of major assets related to accident claims, and a $1.6 million gain on disposition of a property which is expected to be sold in the second or third quarter of this year.

The 2019 changes to specific service charges revenues and merchandising and jobbing cost changes are expected to affect the 2020 forecast, as summarized in Table 2 below.

Table 2: Identified Changes in Other Revenues for 2020 Test Years ($ Millions)

	2020 Test Year Original Forecast	Identified Changes	Revised 2020 Test Year
Specific Service Charges	6.6	(3.0)	3.6
Late Payment Charges	3.8	-	3.8
Other Operating Revenues	12.0	-	12.0
Other Income or Deductions	25.4	2.0	27.4
Total	47.7	(1.0)	46.8

Toronto Hydro requests that these changes be approved by the OEB as part of the 2020 test year. However, as the net impact of these changes is only $1 million, in the interest efficiency, Toronto Hydro has decided not updated the 2020 revenue requirement. If the changes are approved by the OEB, the utility proposes to incorporate them in the 2020 revenue requirement as part of the Draft Rate Order process.

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2015 Actual	2016 Actual	2017 Actual	2018 Actual	Bridge Year	Test Year
		2015	2016	2017	2018	2019	2020
	Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
4235	Specific Service Charges	$6,786,826	$9,497,848	$7,186,822	$5,966,102	$5,107,243	$3,689,939
4225	Late Payment Charges	$4,126,310	$4,540,398	$3,696,196	$3,323,433	$3,732,947	$3,751,641
4082	Retailers' Fixed charge	$5,320	$5,280	$5,520	$5,280	$5,420	$5,420
4082	Retailers' Variable Charge	$257,269	$225,343	$178,662	$146,005	$171,386	$162,420
4082	Distributor Consolidated Billing (DCB) Charges	$143,718	$125,603	$106,118	$87,079	$99,207	$94,067
4082	Retail Consolidated Billing (RCB) Credit	-$9,072	-$8,351	-$635	$0	$0	$0
4084	Retailer Service Transaction Request	$13,764	$12,656	$10,350	$8,302	$9,282	$8,816
4084	Retailer Service Transaction Processing	$6,344	$5,722	$4,485	$3,190	$4,271	$4,081
4090/4086	SSS Admin Charge	$2,196,126	$2,317,539	$2,269,960	$2,313,558	$2,389,560	$2,407,409
4210	Parking Rental	$3,790	$1,200	$1,200	$4,408	$0	$0
4210	Property Rental	$41,516	$46,854	$53,414	$47,228	$0	$0
4215	TTC Rectification	$253,250	$303,900	$303,900	$303,900	$303,900	$303,900
4215	Settlement Discounts Taken	$404,384	$381,359	$523,847	$340,755	$389,382	$389,382
4215	Stale Dated Cheques	$453,706	$417,078	$736,416	$462,171	$533,368	$533,368
4220	Street Lighting	$7,055,723	$8,200,259	$9,229,601	$8,035,739	$8,536,375	$8,076,074
4325	Merchandise and Jobbing Revenue	$23,108,588	$32,769,384	$45,929,144	$47,400,242	$36,014,502	$37,732,615
4330	Merchandise and Jobbing Costs	-$14,047,565	-$19,805,704	-$29,913,621	-$27,406,949	-$15,651,688	-$15,991,089
4335	Gain/Loss on disposals	$211,338	$0	$0	$0	$0	$0
4375	Shared Services Recovery[1]	$2,927,027	$3,212,613	$4,829,010	$5,670,327	$5,494,615	$5,507,706
4355	Gain on Disposition of Utility and Other Property	$4,062,681	$2,132,160	$515,158	$576,205	$1,630,000	$0
4398	Foreign Exchange Gain/(Loss)	-$1,500,430	$162,383	$54,784	-$128,336	$0	$0
4405	Investment Interest Income	$1,298,537	$186,388	$9	$0	$120,000	$120,000
Specific Service Charges		$6,786,826	$9,497,848	$7,186,822	$5,966,102	$5,107,243	$3,689,939
Late Payment Charges		$4,126,310	$4,540,398	$3,696,196	$3,323,433	$3,732,947	$3,751,641
Other Operating Revenues		$10,825,837	$12,034,443	$13,422,839	$11,757,613	$12,442,150	$11,984,936
Other Income or Deductions		$16,060,177	$18,657,224	$21,414,483	$26,111,488	$27,607,430	$27,369,233
Total		**$37,799,149**	**$44,729,912**	**$45,720,340**	**$47,158,636**	**$48,889,769**	**$46,795,749**

Description	Account(s)
Specific Service Charges:	4235
Late Payment Charges:	4225
Other Distribution Revenues:	4080, 4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Income and Expenses:	4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4375, 4380, 4385, 4390, 4395, 4398, 4405, 4415

Appendix 2-H
Other Operating Revenue

Account Breakdown Details

Account 4235 -Specific Service Charges

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	Bridge Year	Test Year
	2015	2016	2017	2018	2019	2020
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Account Set Up Charge	$3,163,196	$3,315,852	$3,132,490	$2,686,465	$3,010,922	$3,027,508
NSF Collection Charges	$59,445	$111,704	$106,825	$116,209	$107,980	$108,541
Collection Service Charges	$2,986,342	$5,165,058	$3,130,010	$2,495,315	$1,437,643	$0
Connection-Reconnection Charge	$554,565	$873,835	$644,708	$516,900	$550,698	$553,890
Easement Letter	$24,978	$29,773	$39,955	$37,168	$0	$0
Misc Revenue	-$1,700	$1,625	$132,834	$114,046	$0	$0
Total	**$6,786,826**	**$9,497,848**	**$7,186,822**	**$5,966,102**	**$5,107,243**	**$3,689,939**

Account 4325 -Merchandise and Jobbing Revenue

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	Bridge Year	Test Year
	2015	2016	2017	2018	2019	2020
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Inventory Sales	$88,900	$1,722,500	$5,447,129	$2,899,790	$2,200,000	$2,200,000
Isolation	$779,822	$1,110,436	$3,245,726	$3,559,037	$3,205,922	$3,184,384
Customer and Temp Services	$4,433,778	$5,325,404	$4,771,188	$6,251,865	$4,465,678	$4,681,016
MicroFIT	$93,500	$71,060	$157,066	$69,000	$50,000	$62,500
Scrap Sales	$2,351,600	$3,264,400	$3,198,906	$2,955,541	$2,988,600	$3,048,400
Accident Claims	$2,422,022	$1,683,500	$3,281,539	$3,648,653	$2,502,500	$2,562,600
Pole & Duct Rental	$11,145,300	$18,051,800	$23,106,399	$26,147,228	$19,236,165	$20,624,017
Streetlighting[1]	$520,678	$459,415	$332,279	$377,304	$669,103	$669,103
Other[2]	$1,272,988	$1,080,869	$2,388,913	$1,491,825	$696,534	$700,595
Total	**$23,108,588**	**$32,769,384**	**$45,929,144**	**$47,400,242**	**$36,014,502**	**$37,732,615**

Account 4330 -Merchandise and Jobbing Costs

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	Bridge Year	Test Year
	2015	2016	2017	2018	2019	2020
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Inventory Sales	-$110,700	-$1,661,500	-$5,240,465	-$2,954,604	-$2,000,000	-$2,000,000
Isolation	-$663,612	-$915,208	-$3,681,121	-$4,968,289	-$3,672,322	-$3,654,584
Customer and Temp Services	-$3,638,181	-$4,372,001	-$3,751,142	-$4,683,780	-$4,051,478	-$4,260,816
MicroFIT	-$47,007	-$78,191	-$25,354	-$3,061	-$50,000	-$62,500
Scrap Sales	-$1,131,000	-$863,200	-$1,048,740	-$1,557,885	-$1,300,500	-$1,326,500
Accident Claims	-$2,267,530	-$2,321,000	-$3,026,630	-$761,183	-$265,600	-$320,800
Pole & Duct Rental	-$4,771,400	-$8,416,600	-$10,670,064	-$11,047,712	-$3,502,950	-$3,553,027
Streetlighting[1]	-$476,270	-$380,939	-$302,663	-$336,850	-$569,180	-$569,180
Other[2]	-$941,865	-$797,065	-$2,167,442	-$1,093,585	-$239,658	-$243,681
Total	**-$14,047,565**	**-$19,805,704**	**-$29,913,621**	**-$27,406,949**	**-$15,651,688**	**-$15,991,088**

Account 4405 - Investment Interest Income

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	Bridge Year	Test Year
	2015	2016	2017	2018	2019	2020
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Investment Interest Income	$1,298,537	$0	$9	$0	$120,000	$120,000
Regulated Assets Charges-Revenue	$0	$186,388	$0	$0	$0	$0
Total	**$1,298,537**	**$186,388**	**$9**	**$0**	**$120,000**	**$120,000**

Notes

1 The amounts reported as shared services recovery in account 4375 do not include the cost recovery associated with fleet, occupancy and IT services provided by THESL to THESI, THESU and THC presented as part of Appenix 2N. The recovery of these costs is included in the OM&A evidence as part of the Allocation and Recoveries program for an average annual value of $1.1M for the period 2015-2020.
Streetlighighting recoveries and costs related to emergency response, engineering and planning included in Appendix 2N are shown under the merchandising and jobbing section (4325 & 4330).

2 The "Other" category is composed of IT services related to Hydro One Telecom and other various adhoc services.

OPERATING COSTS: OM&A VARIANCE ANALYSIS

1. OM&A OVERVIEW

Toronto Hydro's total OM&A expenditures in 2018 were $268.3 million, which is $7.1 million, or 2.7 percent, higher than the original forecast in Exhibit 4A, Tab 1, Schedule 1.

The Emergency Response program had the largest variance in 2018. Expenditures in this program were $10.9 million higher than forecasted as a result of the utility having to respond to four weather related major event days throughout the year. The increase in Emergency Response was offset by decreases in several programs, including Supply Chain and Customer Care.

Toronto Hydro has identified a number of changes to its 2019 bridge and 2020 test year forecasts. These changes are presented in Table 2 and discussed below. The net impact of these changes to the 2020 revenue requirement is $0.5 million. In the interest of efficiency, Toronto Hydro has decided not to flow these changes through the OM&A appendices, the revenue requirement work form and cost allocation models. The utility requests that the OEB approve these changes as part of the 2020 test year, and proposes to make the updates as part of the rate order process.

Table 1: Identified Changes in OM&A for 2019 Bridge and 2020 Test Years

	CIR Application		Identified Changes		Updated Figures	
OM&A Programs ($millions)	**2019 Bridge**	**2020 Test**	**2019 Bridge**	**2020 Test**	**2019 Bridge**	**2020 Test**
Customer Driven Work	9.6	9.6	1.0	1.0	10.6	10.6
Asset and Program Management	15.3	13.1	-	0.8	15.3	13.9
Charitable Donations and LEAP	0.8	0.9	0.2	0.2	1.0	1.0
Common Costs and Adjustments	(1.3)	0.8	(1.4)	(1.5)	(2.7)	(0.7)
Total OM&A	**268.2**	**277.5**	**(0.2)**	**0.5**	**267.9**	**278.0**

In Common Cost and Adjustments, Toronto Hydro identified a reduction in post-employment benefits of $1.4 million in 2019 and $1.5 million in 2020 as a result of the most recent actuarial valuation (Exhibit U, Tab 4A, Schedule 3, Appendix C). In the Customer-Driven Work program, Toronto Hydro expects an increase of $1.0 million in 2019 and 2020 due to a higher demand for Toronto Hydro to facilitate safe entry into customer-owned vaults. The $0.8 million change to Asset Program Management in the 2020 test year relates to Local Demand Response costs that were inadvertently omitted from the original OM&A budget in Exhibit 4A. Similarly, the $0.2 million in LEAP costs relates to an omission in the original evidence.

2. OM&A PROGRAMS AND EXPENDITURES

This section explains the material changes to the program expenditures resulting from the 2018 update. For detailed information about the programs, including year over year variance analyses, please refer to the evidence in Exhibit 4A, Tab 2.

2.1 Preventative and Predictive Overhead Line Maintenance

There were no material changes in 2018. Please refer to Exhibit 4A, Tab 2, Schedule 1 for information about this program, including detailed variance analyses.

2.2 Preventative and Predictive Underground Line Maintenance

There were no material changes in 2018. Please refer to Exhibit 4A, Tab 2, Schedule 2 for information about this program, including detailed variance analyses.

2.3 Preventative and Predictive Station Maintenance

There were no material changes in 2018. Please refer to Exhibit 4A, Tab 2, Schedule 3 for information about this program, including detailed variance analyses.

2.4 Corrective Maintenance

Table 2 below provides the Historical (2015-2018), Bridge (2019), and Test Year (2020) expenditures for the Corrective Maintenance program by segment.

Table 2: Corrective Maintenance Program Costs by Segment ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Corrective Maintenance	16.1	16.8	20.3	19.6	17.0	17.2

The decrease of $1.2 million from 2017 to 2018 is due to the utility performing less corrective maintenance work in 2018 than in 2017, as illustrated by the number of Work Requests in Figure 1 below. A decrease of $2.6 million from 2018 to 2019 is expected due to aligning the 2019 work volumes with 2016 levels.

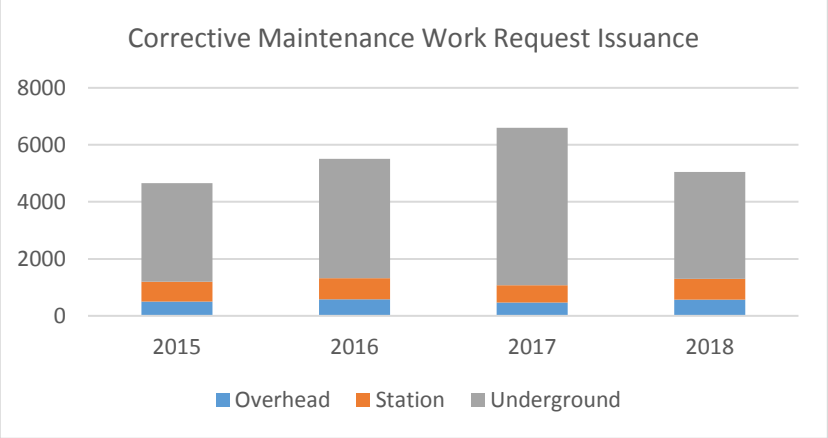

Figure 1: Historical Corrective Work Requests

2.5 Emergency Response

Table 3 below provides the Historical (2015-2018), Bridge (2019), and Test Year (2020) expenditures for the Emergency Response program by segment.

Table 3: Emergency Response Program Costs by Segment ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Emergency Response	16.5	15.2	15.9	27.3	16.5	16.6

In 2018, the cost of this program was $10.9 million higher than forecasted in Exhibit 4A, Tab 2, Schedule 5, and $11.4 million higher than in 2017. The variances are attributable to four weather related major event days that Toronto Hydro experienced in 2018. As shown in Table 4, the number of weather events in 2018 far-exceeded historical levels. In responding to these events, Toronto Hydro had to mobilize significant resources to restore power, mitigate safety and reliability issues, and address environmental risks. The utility also had to perform residual clean-up work to restore the system to normal conditions, such as performing feeder patrols, emergency inspections, and reconnections mandated by the Electrical Safety Authority.

Table 4: Major Event Days due to Extreme Weather (2015-2018)

Date	Cause
Mar 3, 2015	Freezing Rain
Oct 15, 2017	Wind Storm
Apr 4, 2018	Wind Storm
Apr 15, 2018	Freezing Rain
May 4, 2018	Wind Storm
Jun 13, 2018	Wind Storm

2.6 Disaster Preparedness Management

There were no material changes in 2018. Please refer to Exhibit 4A, Tab 2, Schedule 6 for information about this program, including detailed variance analyses.

2.7 Control Centre Operations

There were no material changes in 2018. Please refer to Exhibit 4A, Tab 2, Schedule 7 for information about this program, including detailed variance analyses.

2.8 Customer Driven Work

Table 5 below provides the Historical (2015-2018), Bridge (2019), and Test Year (2020) expenditures for the Customer-Driven Work program by segment.

Table 5: Customer-Driven Work Program Costs by Segment ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Customer Connections	2.1	2.4	2.3	3.2	3.1	3.2
Public Safety and Damage Prevention	4.0	4.2	5.9	4.1	4.7	4.5
Customer-Owned Equipment Services	4.1	3.4	3.5	3.5	2.8	2.9
Total	**10.2**	**10.0**	**11.6**	**10.9**	**10.6**	**10.6**

In 2018, the Public Safety and Damage Prevention decreased by $1.8 million as a result of Toronto Hydro having to suspend one of its contractors due to performance issues. This decrease was offset by an increase of $0.9 million in the Customer Connections segment for having to design and execute higher complexity projects.

In the Customer-Owned Equipment Services segment, 2018 costs were in line with 2017, but $1.6 million higher than forecasted in Exhibit 4A, Tab 2, Schedule 8 due to increases in volume of customer requests for Toronto Hydro to facilitate safe entry into customer-owned vaults.

2.9 Asset and Program Management

Table 6 below provides the Historical (2015-2018), Bridge (2019), and Test Year (2020) expenditures for the Asset and Program Management program by segment.

Table 6: Asset and Program Management Program Costs by Segment ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
System Planning	6.6	10.1	6.6	8.1	7.7	7.7
Local Demand Response	0.0	0.0	0.0	0.9	2.3	0.8
Standards & Policies	2.5	2.6	2.9	2.7	2.7	2.8
Program Management & Support	2.0	5.3	2.0	2.9	2.6	2.6
Total	**11.2**	**18.1**	**11.5**	**14.7**	**15.3**	**13.9**

The expenditures in this program in 2018 were overall in line with the forecast in Exhibit 4A, Tab 2, Schedule 9. The only material variance was the Local Demand Response segment, where the expenditures in 2018 were $0.8 million lower than forecasted due to lower than anticipated costs associated with contractual demand response capacity. These costs are expected to carry over into 2019 to continue the activities undertaken in 2018 and deliver the full scope of the local demand response initiative.

2.10 Work Program Execution

Table 7 below provides the Historical (2015-2018), Bridge (2019), and Test Year (2020) expenditures for the Work Program Execution program by segment.

Table 7: Work Program Execution Program Costs by Segment ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
External Work Execution	3.6	3.5	3.2	5.0	1.5	1.6
Internal Work Execution	15.9	16.0	17.4	14.4	18.7	20.2
Total	**19.5**	**15.9**	**20.5**	**19.4**	**20.3**	**21.8**

The expenditures in this program in 2018 were overall in line with the forecast in Exhibit 4A, Tab 2, Schedule 10. However, there were material variances at the segment level due to an increase in the amount and percentage of reactive work that Toronto Hydro had to complete in 2018. To manage the additional workload, Toronto Hydro relied more

heavily on external resources. This led higher costs than forecasted in the External Work Execution segment. The increase was mitigated at the program level by commensurate reductions to the Internal Work Execution segment.

2.11 Fleet and Equipment Services

There were no material changes in 2018. Please refer to Exhibit 4A, Tab 2, Schedule 11 for information about this program, including detailed variance analyses.

2.12 Facilities Management

Table 8 below provides the Historical (2015-2018), Bridge (2019), and Test Year (2020) expenditures for the Facilities Management program by segment.

Table 8: Facilities Management Program Costs by Segment ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Facilities Maintenance Services	14.6	15.4	15.3	15.3	14.7	15.1
Rentals & Leases	5.2	5.3	1.7	0.3	0.4	0.4
Utilities & Communications	2.4	2.4	2.6	2.6	3.0	3.1
Property Taxes	5.2	4.6	5.6	4.9	5.4	5.5
Total	**27.4**	**27.8**	**25.3**	**23.1**	**23.4**	**24.0**

The expenditures in this program in 2018 were overall in line with the forecast in Exhibit 4A, Tab 2, Schedule 12. However, there was an increase of $1.2 million in the Facilities Maintenance Services segment because of higher than anticipated costs in 2018 for maintenance work at Toronto Hydro's Milner, Carlton, and Commissioners facilities, as well as the utility's substations. This increase was offset by lower expenses for property taxes and utilities and communications.

2.13 Supply Chain Services

Table 9 below provides the Historical (2015-2018), Bridge (2019), and Test Year (2020) expenditures for the Supply Chain Services program by segment.

Table 9: Supply Chain Services Program Costs by Segment ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Supply Chain Services	**10.4**	**13.4**	**11.4**	**10.4**	**12.3**	**12.6**

In 2018, the costs of the Supply Chain program were approximately $1.3 million lower than forecasted in Exhibit 4A, Tab 2, Schedule 13, and $1 million lower than in 2017. The difference is due to changes in the accounting treatment for open bin equipment whereby the cost of this equipment has been allocated to OM&A and capital programs, and various credits to the Supply Chain program budget due to cable equipment returns and other operational adjustments. These changes are not expected to carry into 2019 budget, and that is the main reason why the increase from 2018 to 2019 is expected to be higher than what is presented in the evidence at Exhibit 4A, Tab 2, Schedule 13, page 14.

2.14 Customer Care

Table 10 below provides the Historical (2015-2018), Bridge (2019), and Test Year (2020) expenditures for the Customer Care program by segment.

Table 10: Customer Care Program Costs by Segment ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Billing, Remittance & Meter Data Management	15.7	13.4	15.5	15.0	16.2	20.7
Collections	10.8	10.3	9.2	8.0	12.4	12.6
Customer Relationship Management	11.4	11.6	11.5	10.5	10.6	11.3
Communications & Public Affairs	3.1	2.9	3.3	4.2	4.7	4.9
Total	**41.0**	**38.1**	**39.6**	**37.7**	**44.0**	**49.4**

In 2018, Customer Care program costs were $5.3 million lower than the forecast provided in Exhibit 4A, Tab 2, Schedule 14, and $1.9 million lower than 2017 actuals. The variance is attributable to lower labour costs due to various drivers including the effect of the winter disconnection moratorium, and lower than forecasted bad debt expenses in 2018.

As explained in the response to undertaking JTC3.10, Toronto Hydro applies professional judgement to assess a number of quantitative and qualitative factors when forecasting bad debt expense. With regard to these considerations, Toronto Hydro anticipated bad debt to climb in 2018. Although this expectation did not materialize in 2018, Toronto Hydro continues to believe that it is reasonable, based on the trends and indicators discussed in the undertaking response to JTC3.10, to expect an increase in bad debt over the forecast period. Therefore, Toronto Hydro has provisioned for an increase of $2.6M in bad debt expenses in 2019 relative to 2018 actuals.

In addition to the increase in bad debt, in 2019 Toronto Hydro forecasts an increase of $1.3 million for field collection costs and collection agency fees, $0.9 million for internal labour requirements, $0.7 million for billing related costs such as postage and bank fees, and printing due to inflationary pressures and customer growth, and $0.6 million for outsourced labour costs due to the continuing effects of the minimum wage increase.

2.15 Human Resources and Safety

There were no material changes in 2018. Please refer to Exhibit 4A, Tab 2, Schedule 15 for information about this program, including detailed variance analyses.

2.16 Finance

There were no material changes in 2018. Please refer to Exhibit 4A, Tab 2, Schedule 16 for information about this program, including detailed variance analyses.

2.17 Information Technology

Table 11 below provides the Historical (2015-2018), Bridge (2019), and Test Year (2020) expenditures for the Information Technology program by segment.

Table 11: Information Technology Program Costs by Segment ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
IT Governance	2.7	2.9	3.0	3.2	3.3	3.4
IT Operations	27.9	28.3	30.9	31.4	35.3	35.6
Project Execution	1.6	1.4	1.6	3.2	1.6	1.7
Security & Enterprise Architecture	2.7	2.4	2.9	3.2	3.3	3.4
Total	**34.4**	**35.0**	**38.4**	**41.0**	**43.5**	**44.0**

In 2018, the cost of the program was aligned with the forecast in Exhibit 4A, Tab 4, Schedule 17. However, there were variances at the segment level. In the Projection Execution segment, there was a one-time increase for additional labour resources required to support migration and training activities related to then ERP project. This increase was offset by lower than forecasted costs in the IT Operations segment related to maintenance for newly implemented or upgraded systems. The unrealized maintenance costs are expected to commence in 2019, contributing to a higher increase from 2018 to 2019 in the IT Operations segment. Additional labour requirements to support new systems and higher costs for purchased services contracts are also contributing to the variance between 2018 and 2019.

2.18 Legal and Regulatory

Table 12 below provides the Historical (2015-2018), Bridge (2019), and Test Year (2020) expenditures for the Legal and Regulatory program by segment.

Table 12: Legal and Regulatory Program Costs by Segment ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Legal Services	4.5	4.7	5.4	5.7	5.1	5.3
Regulatory Affairs	6.7	7.5	7.6	7.6	9.1	8.9
Amortized Costs of 2015-2019 CIR Application	0.9	1.1	1.0	1.0	1.0	-
Amortized Costs of 2020-2024 CIR Application	-	-	-	-	-	1.7
Total	**12.1**	**13.4**	**14.0**	**14.3**	**15.1**	**15.9**

The cost of the program in 2018 was approximately $1 million lower than the forecast in Exhibit 4A, Tab 4, Schedule 18. The differences are attributable to lower than expected OEB fees and external services costs in the Regulatory Affairs segment, offset by higher than forecasted litigation claims costs in the Legal Services segment. The external services costs that were expected to materialize in 2018 were related to supporting regulatory work activities while internal staff are reallocated to the rate application. These costs are now forecasted to materialize in 2019. Furthermore, the duration for which external services will be required is expected to increase commensurate with the timeline of the rate application lasting through three quarters of 2019.

2.19 Charitable Donations (LEAP)

There were no material changes in 2018. Please refer to Exhibit 4A, Tab 2, Schedule 19 for information about this program, including detailed variance analyses.

2.20 Common Costs and Adjustments

Table 13 below provides the Historical (2015-2018), Bridge (2019), and Test Year (2020) common corporate costs and adjustments.

Table 13: Common Corporate Costs and Adjustments Summary ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Ongoing or Recurring	1.1	(0.1)	1.6	(1.4)	(1.3)	0.8
Total	**1.1**	**(0.1)**	**1.6**	**(1.4)**	**(1.3)**	**0.8**

Note: Variances due to rounding may exist.

From 2017 to 2018, costs decreased by $3.0 million primarily due to differences in forecast and actual employee benefit cost and corporate risk and compliance activities. These reductions were offset by higher tax related charges.

OEB Appendix 2-JA
Summary of Recoverable OM&A Expenses

(in $ Millions)

	Last Rebasing Year (2015 Board-Approved)	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Bridge Year	2020 Test Year
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Operations	-	$ 48.6	$ 56.9	$ 55.1	$ 57.7	$ 60.2	$ 59.4
Maintenance	-	$ 67.1	$ 63.1	$ 64.3	$ 74.0	$ 67.1	$ 67.7
SubTotal	**-**	**$ 115.7**	**$ 120.0**	**$ 119.3**	**$ 131.7**	**$ 127.3**	**$ 127.1**
%Change (year over year)			3.7%	-0.5%	10.4%	-3.4%	-0.1%
%Change (Test Year vs Last Rebasing Year - Actual)							9.9%
Billing and Collecting	-	$ 36.7	$ 33.4	$ 34.9	$ 32.5	$ 38.4	$ 38.8
Community Relations	-	$ 3.5	$ 2.5	$ 2.3	$ 2.4	$ 2.7	$ 2.8
Administrative and General	-	$ 81.9	$ 88.3	$ 92.5	$ 95.9	$ 93.4	$ 95.0
Taxes Other Than Income Taxes	-	$ 5.2	$ 4.6	$ 5.3	$ 4.9	$ 5.4	$ 5.5
Donations	-	$ 1.0	$ 1.0	$ 1.0	$ 0.8	$ 0.9	$ 1.0
SubTotal	**-**	**$ 128.3**	**$ 129.9**	**$ 135.9**	**$ 136.6**	**$ 140.9**	**$ 143.1**
%Change (year over year)			1.2%	4.7%	0.5%	3.1%	1.5%
%Change (Test Year vs Last Rebasing Year - Actual)							11.5%
Total	**$ 243.9**	**$ 244.0**	**$ 249.8**	**$ 255.3**	**$ 268.3**	**$ 268.2**	**$ 270.2**
%Change (year over year)			2.4%	2.2%	5.1%	-0.1%	0.8%
Cash vs. Accrual OPEB and Monthly Billing	-	-	-	-	-	-	$ 7.3
Total - including Cash vs. Accrual OPEB and Monthly Billing	**$ 243.9**	**$ 244.0**	**$ 249.8**	**$ 255.3**	**$ 268.3**	**$ 268.2**	**$ 277.5**
%Change (year over year)			2.4%	2.2%	5.1%	-0.1%	3.5%

	Last Rebasing Year (2015 Board-Approved)	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Bridge Year	2020 Test Year
Operations	-	$ 48.6	$ 56.9	$ 55.1	$ 57.7	$ 60.2	$ 59.4
Maintenance	-	$ 67.1	$ 63.1	$ 64.3	$ 74.0	$ 67.1	$ 67.7
Billing and Collecting	-	$ 36.7	$ 33.4	$ 34.9	$ 32.5	$ 38.4	$ 38.8
Community Relations	-	$ 3.5	$ 2.5	$ 2.3	$ 2.4	$ 2.7	$ 2.8
Administrative and General	-	$ 81.9	$ 88.3	$ 92.5	$ 95.9	$ 93.4	$ 95.0
Taxes Other Than Income Taxes	-	$ 5.2	$ 4.6	$ 5.3	$ 4.9	$ 5.4	$ 5.5
Donations	-	$ 1.0	$ 1.0	$ 1.0	$ 0.8	$ 0.9	$ 1.0
Cash vs. Accrual OPEB and Monthly Billing	-	-	-	-	-	-	$ 7.3
Total	**$ 243.9**	**$ 244.0**	**$ 249.8**	**$ 255.3**	**$ 268.3**	**$ 268.2**	**$ 277.5**
%Change (year over year)			2.4%	2.2%	5.1%	-0.1%	3.5%

OEB Appendix 2-JA
Summary of Recoverable OM&A Expenses

	Last Rebasing Year (2015 Board-Approved)	2015 Actuals	Variance 2015 BA - 2015 Actuals	2016 Actuals	Variance 2016 Actuals vs. 2015 Actuals	2017 Actuals	Variance 2017 Actuals vs. 2016 Actuals	2018 Actuals	Variance 2018 Actuals vs. 2017 Actuals	2019 Bridge Year	Variance 2019 Bridge vs. 2018 Actuals	2020 Test Year	Variance 2020 Test vs. 2019 Bridge
Operations	-	$ 48.6	$ (48.6)	$ 56.9	$ 8.3	$ 55.1	$ (1.9)	$ 57.7	$ 2.7	$ 60.2	$ 2.5	$ 59.4	$ (0.8)
Maintenance	-	$ 67.1	$ (67.1)	$ 63.1	$ (4.1)	$ 64.3	$ 1.2	$ 74.0	$ 9.7	$ 67.1	$ (6.9)	$ 67.7	$ 0.6
Billing and Collecting	-	$ 36.7	$ (36.7)	$ 33.4	$ (3.4)	$ 34.9	$ 1.5	$ 32.5	$ (2.4)	$ 38.4	$ 5.9	$ 38.8	$ 0.4
Community Relations	-	$ 3.5	$ (3.5)	$ 2.5	$ (1.0)	$ 2.3	$ (0.2)	$ 2.4	$ 0.1	$ 2.7	$ 0.3	$ 2.8	$ 0.1
Administrative and General	-	$ 81.9	$ (81.9)	$ 88.3	$ 6.4	$ 92.5	$ 4.1	$ 95.9	$ 3.5	$ 93.4	$ (2.5)	$ 95.0	$ 1.5
Taxes Other Than Income Taxes	-	$ 5.2	$ (5.2)	$ 4.6	$ (0.5)	$ 5.3	$ 0.6	$ 4.9	$ (0.4)	$ 5.4	$ 0.5	$ 5.5	$ 0.1
Donations	-	$ 1.0	$ (1.0)	$ 1.0	$ (0.0)	$ 1.0	$ (0.0)	$ 0.8	$ (0.1)	$ 0.9	$ 0.1	$ 1.0	$ 0.0
Cash vs. Accrual OPEB and Monthly Billing	-	-	-	-	-	-	-	-	-	-	-	$ 7.3	$ 7.3
Total OM&A Expenses	$ 243.9	$ 244.0	$ (244.0)	$ 249.8	$ 5.8	$ 255.3	$ 5.4	$ 268.3	$ 13.0	$ 268.2	$ (0.1)	$ 277.5	$ 9.3
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Recoverable OM&A Expenses	$ 243.9	$ 244.0	$ (244.0)	$ 249.8	$ 5.8	$ 255.3	$ 5.4	$ 268.3	$ 13.0	$ 268.2	$ (0.1)	$ 277.5	$ 9.3
Variance from previous year					$ 5.8		$ 5.4		$ 13.0		$ (0.1)		$ 9.3
Percent change (year over year)					2.4%		2.2%		5.1%		-0.1%		3.5%
Percent Change: Test year vs. Most Current Actual													3.7%
Simple average of % variance for all years													2.6%
Compound Annual Growth Rate for all years													2.6%

Note:

1 Recoverable OM&A that is included on these tables should be identical to the recoverable OM&A that is shown for the corresponding periods on Appendix 2-JB.

OEB Appendix 2-JB
Recoverable OM&A Cost Driver Table

OM&A	Last Rebasing Year (2015 Board-Approved)	2016 Actuals	2017 Actuals	2018 Actuals	2019 Bridge Year	2020 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Opening Balance	**$243.9**	**$244.0**	**$249.8**	**$255.3**	**$268.3**	**$268.2**
Distribution Operations						
Predictive and Preventative Maintenance Overhead	-	$1.3	($0.9)	($0.2)	$0.2	($0.7)
Predictive and Preventative Maintenance Underground	-	$0.3	$0.3	$1.4	$0.6	$0.2
Predictive and Preventative Maintenance Stations	-	($0.3)	$0.3	$0.4	($0.3)	($0.1)
Corrective Maintenance	-	$0.7	$3.5	($0.8)	($2.6)	$0.2
Emergency Response	-	($1.2)	$0.7	$11.4	($10.8)	$0.1
Disaster Preparedness Management	-	$0.0	($0.2)	$0.7	($0.1)	($0.1)
Control Centre Operations	-	$0.0	$0.8	$0.9	$1.5	$0.1
Customer Driven Work	-	($0.2)	$1.7	($0.8)	($1.3)	$0.0
Asset and Program Management	-	$6.9	($6.6)	$3.2	$0.6	($2.2)
Work Program Execution	-	($0.0)	$1.0	($1.2)	$0.9	$1.5
Fleet and Equipment	-	($0.3)	$1.2	($0.9)	$0.8	$0.0
Supply Chain	-	$3.0	($2.0)	($1.0)	$1.9	$0.3
Customer Service and Communications						
Billing, Remittance & Meter Data Management	-	($2.3)	$2.2	($0.6)	$1.3	$4.5
Collections	-	($0.5)	($1.0)	($1.2)	$4.4	$0.1
Customer Relationship Management	-	$0.2	($0.1)	($1.0)	$0.0	$0.7
Communications & Public Affairs	-	($0.2)	$0.4	$0.9	$0.6	$0.1
LEAP	-	$0.2	($0.1)	$0.0	$0.0	$0.0
Human Resources and Safety						
Human Resource Services and Employee Labour Relations	-	$0.6	($0.0)	($0.5)	$0.2	$0.1
Environment Health and Safety	-	$0.1	($0.2)	$0.1	$0.2	$0.1
Talent Management & Organizational Effectiveness	-	$0.3	($0.3)	$0.9	($0.0)	$0.2
Information Technology						
IT Governance	-	$0.2	$0.0	$0.3	$0.0	$0.1
IT Operations	-	$0.4	$2.6	$0.4	$3.9	$0.3
Project Execution	-	$0.2	$0.2	$1.7	($1.6)	$0.1
Security & Enterprise Architecture	-	($0.2)	$0.4	$0.3	$0.1	$0.1
Common Corporate Costs						
Common Corporate Costs	-	($1.2)	$1.7	($3.0)	$0.1	$2.1

OEB Appendix 2-JB
Recoverable OM&A Cost Driver Table

OM&A	Last Rebasing Year (2015 Board-Approved)	2016 Actuals	2017 Actuals	2018 Actuals	2019 Bridge Year	2020 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Opening Balance	**$243.9**	**$244.0**	**$249.8**	**$255.3**	**$268.3**	**$268.2**
Facilities Management						
Facilities Maintenance Services	-	$0.9	($0.1)	($0.1)	($0.6)	$0.4
Rentals & Leases	-	$0.1	($3.6)	($1.5)	$0.1	$0.0
Utilities & Communications	-	($0.1)	$0.3	($0.0)	$0.4	$0.1
Property Taxes	-	($0.6)	$1.0	($0.7)	$0.5	$0.1
Other Various						
Finance	-	($1.1)	($1.4)	$1.4	$1.2	$0.0
Legal and Regulatory	-	$1.3	$0.6	$0.3	$0.8	$0.7
Allocations and Recoveries	-	($2.9)	$3.0	$2.1	($3.1)	$0.0
Closing Balance	**$244.0**	**$249.8**	**$255.3**	**$268.3**	**$268.2**	**$277.5**

Notes:

1 For each year, a detailed explanation for each cost driver and associated amount is required in Exhibit 4.

2 For purposes of assessing incremental cost drivers, the closing balance for each year becomes the opening balance for the next year.

3 Opening Balance for "Last Rebasing Year" (cell B15) should be equal to the Board-Approved amount.

OEB Appendix 2-JC
OM&A Programs Table

(in $ Millions)

Programs	Last Rebasing Year (2015 Board-Approved)	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Bridge Year	2020 Test Year	Variance (Test Year vs. 2018 Actuals)	Variance (Test Year vs. Last Rebasing Year (2015 Board-Approved)
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**		
Distribution Operations									
Predictive and Preventative Maintenance Overhead	-	6.3	7.6	6.7	6.5	6.8	6.0	(0.5)	6.0
Predictive and Preventative Maintenance Underground	-	2.6	2.9	3.2	4.7	5.2	5.5	0.8	5.5
Predictive and Preventative Maintenance Stations	-	5.6	5.3	5.6	6.0	5.6	5.6	(0.4)	5.6
Corrective Maintenance	-	16.1	16.8	20.3	19.6	17.0	17.2	(2.4)	17.2
Emergency Response	-	16.4	15.2	15.9	27.4	16.5	16.6	(10.7)	16.6
Disaster Preparedness Management	-	2.3	2.4	2.2	2.9	2.8	2.7	(0.2)	2.7
Control Centre Operations	-	5.4	5.4	6.3	7.2	8.7	8.7	1.6	8.7
Customer Driven Work	-	10.2	10.0	11.6	10.9	9.6	9.6	(1.3)	9.6
Asset and Program Management	-	11.2	18.1	11.5	14.7	15.3	13.1	(1.6)	13.1
Work Program Execution	-	19.5	19.5	20.5	19.4	20.3	21.8	2.4	21.8
Fleet and Equipment	-	10.1	9.8	11.0	10.1	11.0	11.0	0.8	11.0
Supply Chain	-	10.4	13.4	11.4	10.4	12.3	12.6	2.2	12.6
Sub-Total	-	116.1	126.5	126.3	139.6	131.0	130.4	(9.2)	130.4
Customer Care									
Billing, Remittance & Meter Data Management	-	15.7	13.4	15.5	15.0	16.2	20.7	5.7	20.7
Collections	-	10.8	10.3	9.2	8.0	12.4	12.6	4.5	12.6
Customer Relationship Management	-	11.4	11.6	11.5	10.5	10.6	11.3	0.7	11.3
Communications & Public Affairs	-	3.1	2.9	3.3	4.2	4.7	4.9	0.7	4.9
Sub-Total	-	41.0	38.1	39.6	37.7	44.0	49.4	11.7	49.4
Charitable Donations and LEAP									
LEAP	-	0.7	0.9	0.8	0.8	0.8	0.9	0.0	0.9
Sub-Total	-	0.7	0.9	0.8	0.8	0.8	0.9	0.0	0.9

OEB Appendix 2-JC
OM&A Programs Table

(in $ Millions)

Programs	Last Rebasing Year (2015 Board-Approved)	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Bridge Year	2020 Test Year	Variance (Test Year vs. 2018 Actuals)	Variance (Test Year vs. Last Rebasing Year (2015 Board-Approved)
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**		
Human Resources and Safety									
Human Resource Services and Employee Labour Relations	-	4.6	5.2	5.1	4.6	4.8	5.0	0.4	5.0
Environment Health and Safety	-	2.5	2.7	2.5	2.6	2.8	2.9	0.3	2.9
Talent Management & Organizational Effectiveness	-	7.0	7.3	7.0	7.9	7.9	8.1	0.2	8.1
Sub-Total	-	14.1	15.2	14.7	15.1	15.5	15.9	0.9	15.9
Information Technology									
IT Governance	-	2.7	2.9	3.0	3.2	3.3	3.4	0.1	3.4
IT Operations	-	27.9	28.3	30.9	31.4	35.3	35.6	4.2	35.6
Project Execution	-	1.2	1.4	1.6	3.2	1.6	1.7	(1.5)	1.7
Security & Enterprise Architecture	-	2.7	2.4	2.9	3.2	3.3	3.4	0.2	3.4
Sub-Total	-	34.4	35.0	38.4	41.0	43.5	44.0	3.0	44.0
Common Costs and Adjustments									
Common Corporate Costs	-	1.1	(0.1)	1.6	(1.4)	(1.3)	0.8	2.2	0.8
Sub-Total	-	1.1	(0.1)	1.6	(1.4)	(1.3)	0.8	2.2	0.8
Facilities Management									
Facilities Maintenance Services	-	14.6	15.4	15.3	15.3	14.7	15.1	(0.2)	15.1
Rentals & Leases	-	5.2	5.3	1.7	0.3	0.4	0.4	0.1	0.4
Utilities & Communications	-	2.4	2.4	2.6	2.6	3.0	3.1	0.5	3.1
Property Taxes	-	5.2	4.6	5.6	4.9	5.4	5.5	0.7	5.5
Sub-Total	-	27.4	27.8	25.3	23.1	23.4	24.0	1.0	24.0
Finance									
Controllership	-	8.4	7.3	6.4	7.0	7.2	7.0	0.0	7.0
External Reporting	-	2.5	2.7	2.7	2.7	3.1	3.2	0.4	3.2
Financial Services	-	5.2	5.0	4.6	5.3	5.9	6.1	0.8	6.1
Sub-Total	-	16.1	15.0	13.6	15.0	16.2	16.2	1.2	16.2

OEB Appendix 2-JC
OM&A Programs Table

(in $ Millions)

Programs	Last Rebasing Year (2015 Board-Approved)	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Bridge Year	2020 Test Year	Variance (Test Year vs. 2018 Actuals)	Variance (Test Year vs. Last Rebasing Year (2015 Board-Approved)
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**		
Legal and Regulatory									
Legal and Regulatory Program	-	12.1	13.4	14.0	14.3	15.1	15.9	1.5	15.9
Sub-Total	-	12.1	13.4	14.0	14.3	15.1	15.9	1.5	15.9
Allocations and Recoveries									
On-cost recovery	-	(10.6)	(11.5)	(11.3)	(10.6)	(11.8)	(11.8)	(1.1)	(11.8)
Fleet Recovery Offset	-	(12.5)	(12.4)	(11.5)	(10.6)	(11.4)	(11.6)	(0.9)	(11.6)
IT and Occupancy Charges	-	(0.7)	(1.1)	(1.0)	(1.0)	(1.0)	(1.0)	(0.1)	(1.0)
Shared Services	-	4.8	2.9	4.8	5.1	4.4	4.6	(0.6)	4.6
Other Allocated Costs	-	0.0	0.1	0.2	0.3	(0.1)	(0.1)	(0.4)	(0.1)
Sub-Total	-	(19.0)	(21.9)	(18.9)	(16.8)	(20.0)	(19.9)	(3.1)	(19.9)
Miscellaneous	-	-	-	-		-	-	-	-
Total	**243.9**	**244.0**	**249.8**	**255.3**	**268.3**	**268.2**	**277.5**	**9.2**	**33.6**

Notes:

as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the OM&A budget in the miscellaneous category

OEB Appendix 2-L
Recoverable OM&A Cost per Customer and per FTE [1]

	Last Rebasing Year (2015 Board-Approved)	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Bridge Year	2020 Test Year
Reporting Basis							
OM&A Costs							
O&M	-	$ 115.7	$ 120.0	$ 119.3	$ 131.7	$ 127.3	$ 127.1
Admin Expenses	-	$ 128.3	$ 129.9	$ 135.9	$ 136.6	$ 140.9	$ 150.4
Total Recoverable OM&A from Appendix 2-JB [5]	**$ 243.9**	**$ 244.0**	**$ 249.8**	**$ 255.3**	**$ 268.3**	**$ 268.2**	**$ 277.5**
Number of Customers [2,4]	**747,812**	**747,812**	**759,032**	**765,560**	**769,691**	**776,787**	**784,331**
Number of FTEs [3,4,6]	**1,630**	**1,630**	**1,605**	**1,589**	**1,545**	**1,646**	**1,639**
Customers/FTEs	**458.89**	**458.89**	**472.96**	**481.92**	**498.18**	**472.04**	**478.52**
OM&A cost per customer							
O&M per customer	**-**	**154.7**	**158.0**	**155.8**	**171.1**	**163.8**	**162.1**
Admin per customer	**-**	**171.6**	**171.1**	**177.6**	**177.5**	**181.4**	**191.7**
Total OM&A per customer	**326.2**	**326.3**	**329.1**	**333.4**	**348.6**	**345.2**	**353.8**
OM&A cost per FTE							
O&M per FTE	**-**	**70,984.6**	**74,748.3**	**75,105.8**	**85,242.6**	**77,339.4**	**77,563.5**
Admin per FTE	**-**	**78,732.1**	**80,913.3**	**85,579.5**	**88,415.8**	**85,617.0**	**91,737.1**
Total OM&A per FTE	**149,666.7**	**149,716.7**	**155,661.6**	**160,685.4**	**173,658.4**	**162,956.4**	**169,300.6**

Notes:

1 If it has been more than four years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than four years ago, a minimum of three years of actual information is required.

2 The method of calculating the number of customers is the year end method

3 The method of calculating the number of FTEs is the mid year average

4 The number of customers and the number of FTEs should correspond to mid-year or average of January 1 and December 31 figures.

5 For the test year, the applicant should take into account the system O&M (line 22 of Appendix 2-AB) in developing its forecasted OM&A.

6 Difference to compensation table (appendix 2-K) FTE figures due to students

PURCHASES OF NON-AFFILIATE SERVICES

The evidence at Exhibit 4A, Tab 3, Schedule 1 provides detailed information about Toronto Hydro's procurement practices, including a copy of Toronto Hydro's Procurement Policy at Appendix A, and at Appendix B, a listing of the services that were sole sourced in 2015-2017. Table 1 below lists and describes the non-affiliate services that were procured in 2018 pursuant to the sole source methodology in the Procurement Policy.

Table 1: 2018 Sole Sourced Non-Affiliate Services

Vendor	Nature of the Transaction	Cost
Bell Canada	Purchase of demand reduction services for capacity management	$2,226,000
Renewable Energy Systems (RES)	Installation of a Battery Energy Storage System (BESS)	$2,995,000
Siemens	Maintenance and support for EnergyIP for Operational Data Store (ODS) System	$2,220,000
Dynatrace Corporation of Canada	Support services for suite of Dynatrace application monitoring products	$1,190,000

WORKFORCE STAFFING AND COMPENSATION

Toronto Hydro's workforce and compensation evidence is detailed in Exhibit 4A, Tab 4. This schedule provides a summary of the 2018 actual compensation costs and explains the materials variances resulting from the 2018 actuals.

1. Employee Cost Breakdown (OEB Appendix 2-K)

Toronto Hydro's updated historical (2015-2018) and forecast (2019-2020) staffing levels and compensation costs (i.e. OEB Appendix 2-K) are filed as Appendix A to this Schedule. A more detailed view of the compensation table broken down by employee category is provided in Appendix B.[1]

2. Compensation Costs

Table 1 below summarizes Toronto Hydro's total compensation costs, which include base salary wages, overtime and incentive payments, and actual and accrued benefits.

Table 1: Total Compensation ($ Millions)

Year	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Management (including executive)	15.9	18.1	19.2	20.0	20.3	21.0
Non-Management (union and non-union)	195.2	194.3	197.3	197.7	215.2	223.2
Total	**211.1**	**212.4**	**216.4**	**217.7**	**235.5**	**244.2**

[1] For 2018, IT professionals were non-unionized. The breakdown provided here does not include the IT professionals in the Society union category.

In 2018, Toronto Hydro's total compensation was $8.2 million below the forecast in Exhibit 4A, Tab 4. This variance is mainly attributable to a lower number of FTEs than forecasted, as explained below in section 3.

In 2019, Toronto Hydro expects total compensation costs to increase by $17.8 million relative to 2018 Actuals. This variance is primarily driven by general salary increases, expected FTE increases, and associated benefit costs.

3. Staffing Levels

Toronto Hydro hired a lower number of FTEs in 2018 than the utility forecasted. This was in large part due to the delay experienced in hiring Certified Power Line Persons (CPLP) resources as a result of the utility's efforts to negotiate a harmonized Power Line Technician ("PLT") role with the Power Workers Union (PWU) during the 2017-2018 labour bargaining process. The PLT role offers Toronto Hydro access to trades that have broader skillset as PLTs can work on both underground and overhead distribution assets. The role provides the utility more resource flexibility to execute planned work and respond to operational challenges on the ground, such as weather related contingencies. Toronto Hydro pursued this role in the bargaining process as part of its continuous efforts to find efficiencies in the execution of its capital and operational work programs. Despite Toronto Hydro's best efforts, the PLT role could not be negotiated with the PWU, and this contributed to delays in hiring CPLP trades.

The remainder of the variance is due to vacancies resulting from the utility's efforts to manage cost pressures within the rates set for the 2015 to 2019 period.

4. Unionization of Information Technology Employees

The Society of United Professionals were certified as the bargaining agent for Information Technology ("IT") Professionals on November 21, 2018. This bargaining unit represents 75 employees. Toronto Hydro received notice to bargain in March 2019, and is in the process of initiating bargaining with the Society of United Professionals for a first collective agreement. Table 2 below, provides the 2018 costs for IT professionals. Note that the amounts shown below may not be reflective of union wages following the first collective agreement.

Table 2: 2018 FTE and Total Compensation for IT Professionals ($ Millions)

Category	Totals
FTEs	78
Total Salaries and Wages	$9.62
Total Benefits	$2.90
Total Compensation	$12.52

5. Benefits and Pension

Table 3 below includes the historical (2015-2018) and forecast (2019-2020) cost of employee benefits.

Table 3: Employee Benefit Costs (2015-2020) ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Employee Benefit Total Cost	52.8	52.1	53.3	51.0	59.5	64.8

Toronto Hydro's benefit cost in 2018 were $51 million, which is $4.7 million lower than the utility's forecast in the Exhibit 4A, Tab 4. The variance is due to the staffing levels as discussed above, and an actuarial gain of $4.7 million as a result of the updated valuation.

Table 4 below summarizes Toronto Hydro's historical (2015-2018) and forecast (2019-2020) pension costs, including capitalized and expensed amounts each year.

Table 4: Pension Costs (2015-2020) ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Pension Contributions	16.9	16.8	16.9	17.3	19.2	19.6
Less: Amount Capitalized	7.3	7.1	7.7	8.0	8.5	8.7
Amount Expensed in Each Year	9.5	9.8	9.2	9.3	10.7	10.9

Table 5 below, presents Toronto Hydro's historical (2015-2018) and forecasted (2019-2020) post-employment benefit costs, including capitalized and expensed amounts.

Table 5: Post-employment Benefit Costs (2015-2020) ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Benefit Costs	17.7	15.3	18.0	10.6	15.7	16.0
Capitalized Amounts	7.7	6.4	8.1	4.8	7.0	7.2
Expensed Amounts	10.0	8.9	9.9	5.8	8.7	8.8

The 2018 actuals for post-employment benefit costs reflects a gain of $4.7 million as a result of the actuarial valuation as of January 1, 2018. This study is attached as Appendix C to this Schedule.

OEB Appendix 2-K
EMPLOYEE COSTS/ COMPENSATION TABLE

	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Bridge	2020 Test
Number of Employees (FTEs including Part-Time)						
Management (including executive)	61	69	69	72	68	67
Non-Management (union and non-union)	1422	1415	1403	1353	1455	1450
TOTAL	**1483**	**1484**	**1473**	**1425**	**1523**	**1517**
Total Salary and Wages (including overtime and incentive pay)						
Management (including executive)	$ 12,292,778	$ 14,152,809	$ 14,971,880	$ 15,718,629	$ 15,478,739	$ 15,719,811
Non-Management (union and non-union)	$ 145,975,363	$ 146,148,053	$ 148,139,852	$ 151,009,285	$ 160,518,242	$ 163,720,633
TOTAL	**$ 158,268,141**	**$ 160,300,862**	**$ 163,111,731**	**$ 166,727,914**	**$ 175,996,982**	**$ 179,440,444**
Total Benefits (Current + Accrued)						
Management (including executive)	$ 3,573,323	$ 3,919,134	$ 4,202,856	$ 4,306,945	$ 4,844,923	$ 5,260,044
Non-Management (union and non-union)	$ 49,254,110	$ 48,138,488	$ 49,111,532	$ 46,686,723	$ 54,655,848	$ 59,509,241
TOTAL	**$ 52,827,432**	**$ 52,057,622**	**$ 53,314,387**	**$ 50,993,668**	**$ 59,500,771**	**$ 64,769,286**
Total Compensation (Salary, Wages, & Benefits)						
Management (including executive)	$ 15,866,100	$ 18,071,943	$ 19,174,735	$ 20,025,575	$ 20,323,662	$ 20,979,856
Non-Management (union and non-union)	$ 195,229,473	$ 194,286,540	$ 197,251,383	$ 197,696,008	$ 215,174,090	$ 223,229,874
TOTAL	**$ 211,095,573**	**$ 212,358,484**	**$ 216,426,119**	**$ 217,721,582**	**$ 235,497,752**	**$ 244,209,730**

Updated JTC3.22
COMPENSATION TABLE BROKEN DOWN BY CATEGORY

	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Bridge	2020 Test
Number of Employees (FTEs including Part-Time)						
EXECUTIVE	6	6	7	5	5	5
MANAGERIAL	55	63	63	67	63	62
NON-MANAGEMENT, NON-UNION	433	467	487	498	575	571
CONTRACT FOR A DEFINED TERM	62	54	62	66	32	32
SOCIETY	53	56	60	65	68	69
PWU	874	837	794	724	779	778
TOTAL	**1483**	**1484**	**1473**	**1425**	**1523**	**1517**
Total Salary and Wages (including overtime and incentive pay)						
EXECUTIVE	$ 2,486,891	$ 2,397,404	$ 2,704,552	$ 2,378,602	$ 2,369,718	$ 2,447,034
MANAGERIAL	$ 9,805,887	$ 11,755,405	$ 12,267,327	$ 13,340,028	$ 13,109,022	$ 13,272,778
NON-MANAGEMENT, NON-UNION	$ 48,506,203	$ 52,019,203	$ 55,078,497	$ 59,303,319	$ 67,065,064	$ 68,706,809
CONTRACT FOR A DEFINED TERM	$ 4,069,184	$ 3,102,383	$ 3,720,714	$ 4,373,705	$ 2,021,081	$ 2,079,265
SOCIETY	$ 6,273,163	$ 6,387,993	$ 7,345,852	$ 7,857,253	$ 8,730,321	$ 9,026,473
PWU	$ 87,126,813	$ 84,638,474	$ 81,994,788	$ 79,475,009	$ 82,701,776	$ 83,908,086
TOTAL	**$ 158,268,141**	**$ 160,300,862**	**$ 163,111,731**	**$ 166,727,914**	**$ 175,996,982**	**$ 179,440,444**
Total Benefits (Current + Accrued)						
EXECUTIVE	$ 598,384	$ 566,562	$ 632,406	$ 539,960	$ 665,170	$ 734,128
MANAGERIAL	$ 2,974,938	$ 3,352,572	$ 3,570,450	$ 3,766,985	$ 4,179,752	$ 4,525,916
NON-MANAGEMENT, NON-UNION	$ 16,385,374	$ 17,012,868	$ 18,183,579	$ 18,346,608	$ 23,558,997	$ 25,786,722
CONTRACT FOR A DEFINED TERM	$ 325,760	$ 255,326	$ 298,873	$ 347,999	$ 154,150	$ 157,539
SOCIETY	$ 2,186,586	$ 2,147,661	$ 2,485,728	$ 2,558,950	$ 2,828,604	$ 3,115,494
PWU	$ 30,356,391	$ 28,722,633	$ 28,143,352	$ 25,433,165	$ 28,114,097	$ 30,449,486
TOTAL	**$ 52,827,432**	**$ 52,057,622**	**$ 53,314,387**	**$ 50,993,668**	**$ 59,500,771**	**$ 64,769,286**
Total Compensation (Salary, Wages, & Benefits)						
EXECUTIVE	$ 3,085,275	$ 2,963,967	$ 3,336,959	$ 2,918,562	$ 3,034,888	$ 3,181,162
MANAGERIAL	$ 12,780,825	$ 15,107,977	$ 15,837,777	$ 17,107,012	$ 17,288,774	$ 17,798,694
NON-MANAGEMENT, NON-UNION	$ 64,891,577	$ 69,032,071	$ 73,262,076	$ 77,649,927	$ 90,624,061	$ 94,493,531
CONTRACT FOR A DEFINED TERM	$ 4,394,944	$ 3,357,709	$ 4,019,587	$ 4,721,704	$ 2,175,231	$ 2,236,804
SOCIETY	$ 8,459,748	$ 8,535,654	$ 9,831,580	$ 10,416,204	$ 11,558,925	$ 12,141,967
PWU	$ 117,483,204	$ 113,361,107	$ 110,138,140	$ 104,908,173	$ 110,815,873	$ 114,357,572
TOTAL	**$ 211,095,573**	**$ 212,358,484**	**$ 216,426,119**	**$ 217,721,582**	**$ 235,497,752**	**$ 244,209,730**

Willis Towers Watson

Private and Confidential

January 14, 2019

Ms. Cynthia Chan
Toronto Hydro Corporation
14 Carlton Street
Toronto, ON
M5B 1K5

Dear Cynthia:

POST-EMPLOYMENT BENEFITS FOR EMPLOYEES OF TORONTO HYDRO
2018 YEAR-END DISCLOSURES AND ESTIMATED 2019-2024 BENEFIT EXPENSE
UNDER INTERNATIONAL ACCOUNTING STANDARDS

As requested, this letter and appendices have been prepared for Toronto Hydro Corporation ("the Company", or "Toronto Hydro") and present the Company's liabilities and costs in respect of the following post-retirement and post-employment benefits plans ("the Plans"):

- Extended health benefits for retirees and members on disability;
- Dental benefits for retirees and members on disability;
- Life insurance benefits for retirees;
- Vested and non-vested sick leave benefits;
- OMERS top up pension; and
- Executive retirement allowances.

This letter and appendices have been prepared for the Company and its external reporting, for the following purposes:

- Determining the final calculation of the 2018 benefit expense under International Financial Reporting Standards (IFRS) in accordance with International Accounting Standards Section 19 revised in 2011,

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Towers Watson Canada Inc.

- Providing the required information for year-end disclosure purposes as of December 31, 2018 under IAS 19 rev. 2011,

- Determining an estimate of the 2019-2024 benefit expense under IAS 19 rev. 2011.

The information contained in this letter and appendices are presented in thousands of Canadian dollars, and are in respect of the benefits mentioned above only.

The fiscal 2018 net periodic benefit cost is based on the results of the January 1, 2016 actuarial valuation.

The 2018 year-end disclosure obligation and extrapolations for 2019-2024 are based on the results of the January 1, 2018 actuarial valuation.

The balance of this letter sets out comments and notes to our calculations. Appendix A provides details of the relevant accounting results. Please refer to the January 1, 2016 and January 1, 2018 actuarial valuation reports prepared by Willis Towers Watson dated November 18, 2016 and December 17, 2018, respectively for the summaries of the plan provisions, the membership data and the actuarial basis used in the valuations.

Actuarial Assumptions and Methods

- The measurement date used for Fiscal 2018 year-end financial reporting is December 31, 2018.

- The 2018 benefit expense is based on a discount rate of 3.50% per annum and the defined benefit obligation ("DBO") at December 31, 2018 is based on a discount rate of 3.75% per annum, as instructed by the Company. The discount rates are based on long-term high-quality Canadian corporate bond yields at December 31, 2017 and December 31, 2018 respectively.

- Other than those noted in this letter, the actuarial methods and assumptions used for the determination of the 2018 net periodic benefit cost are consistent with those used for the 2017 year-end disclosures and the actuarial methods and assumptions used for the December 31, 2018 obligation are consistent with those used for the January 1, 2018 actuarial valuation.

- The obligation as of December 31, 2018 and the 2019-2024 expense estimates are based on extrapolations from the January 1, 2018 valuation results for the medical, dental, life insurance, sick leave, OMERS and retirement allowance benefit plans, assuming no experience gains or losses other than from actual benefit payments being different from expected, and reflecting changes in the assumptions during the extrapolation period such as changes in the discount rate.

Accounting Methods

- Under IAS 19 rev. 2011, we understand that Toronto Hydro has determined that both the non-vested sick leave benefit program and the vested sick leave benefit program should be included for post-employment benefits reporting. As such, these benefits are included in the financial information under IAS 19 rev. 2011 presented in this letter.

- On an ongoing basis, actuarial gains and losses for all benefit plans other than the sick leave benefits plan and the incentive plan retirement allowance will be immediately recognized in other comprehensive income. Actuarial gains and losses for the sick leave benefit plan and the incentive plan retirement allowance will be recognized immediately in expense.

- On an ongoing basis, the impact of plan changes will be immediately recognized in benefit expense.

Summary of Financial Results

The summary of Fiscal 2018 benefit expense, the defined benefit liability and the DBO as at December 31, 2018, under IAS 19 rev. 2011 is as follows (in $ 000s):

	Fiscal 2018 Net Periodic Benefit Costs	Defined Benefit Asset/(Liability) at December 31, 2018	DBO at December 31, 2018
Electric System Limited	$ 10,625	$ (270,910)	$ 270,910
Toronto Hydro Corporation	204	(2,697)	2,697
Energy Service Incorporated	29	(959)	959
LDC Unregulated	108	(1,294)	1,294
Consolidated	$ 10,966	$ (275,860)	$ 275,860

- Actual benefit payments for 2018 of $10,919,000 are based on information provided by the Company on January 9, 2019. We have projected 2019-2024 benefit payments based on the valuation assumptions.

The breakdown of net actuarial (gain)/loss as at December 31, 2018 is as follows (in $000s):

	Electric System Limited	Toronto Hydro Corporation	Energy Service Incorporated	LDC Unregulated
Demographic Assumptions:				
Sick Leave Program	$0	$0	$0	$0
Retirement Allowance #1	0	0	0	0
Other Plans	(22,034)	(142)	(68)	(144)
Economic Assumptions:				
Sick Leave Program	(433)	0	0	0
Retirement Allowance #1	0	(15)	0	0
Other Plans	(10,808)	(72)	(38)	(64)
Plan Experience:				
Sick Leave Program	(4,243)	0	(59)	0
Retirement Allowance #1	0	(61)	0	0
Other Plans	(3,164)	436	(1,070)	11
Total Net Actuarial (Gain)/Loss:				
Sick Leave Program	(4,676)	0	(59)	0
Retirement Allowance #1	0	(76)	0	0
Other Plans	(36,006)	222	(1,176)	(197)
Sub-Total	**$(40,682)**	**$146**	**$(1,235)**	**$(197)**

Other Comments

- We understand that the post-employment benefits plans are not pre-funded, and therefore our accounting results do not consider any expected investment income on plan assets.
- As directed by the Company, the full defined benefit liability has been classified as a non-current liability.
- Other than those described in this letter and appendices, the Company's management has confirmed that there have been no significant events, changes to the plan provisions or changes to plan membership since January 1, 2018 for all benefit plans, that would materially affect the results of our valuations.

Actuarial Certification

The Company may make a copy of this report available to its auditors, but we make no representation as to the suitability of this report for any purpose other than that for which it was originally provided and accept no responsibility or liability to the Company's auditors in this regard. We are aware that the information contained in this report will be used to support the audit of the Company's financial statements. Except where we expressly agree in writing, this report should not be disclosed or provided to any third party, other than as provided above. Willis Towers Watson accepts no responsibility for any consequences arising from any other party relying on this report or any advice relating to its contents.

In preparing these results, we have relied upon information and data provided to us orally, electronically and/or in writing by the Company and other persons or organizations designated by the Company. We have relied on all the data and information provided, including plan provisions and membership data as being complete and accurate. Based on discussions with and concurrence by the plan sponsor, assumptions or estimates may have been made if data were not available. We have not independently verified the accuracy or completeness of the data or information provided, but we have performed limited checks for consistency.

We are not aware of any errors or omissions in the data that would have a significant effect on the results of our calculations.

The results presented in this report are directly dependent upon the accuracy and completeness of the underlying data and information. Any material inaccuracy in the data, plan provisions or other information provided to us may have produced results that are not suitable for the purposes of this report and such inaccuracies may produce materially different results that could require that a revised report be issued.

The results summarized in this report involve actuarial calculations that require assumptions about future events. The Company is responsible for the selection of the assumptions, as required by IAS 19. Other assumptions may also be reasonable and appropriate and their use would produce different results.

The expense and obligation levels will change in the future as a result of future changes in the actuarial methods and assumptions, the membership data, the plan provisions, accounting rules, legislature, and the government health care programs, or as a result of future experience gains or losses. None of these changes has been anticipated at this time, but will be revealed in future accounting valuations.

The figures provided in this letter reflect, to the best of our knowledge, all of the Company's substantive commitments and obligations, as described herein. Furthermore, to the best of our knowledge, there are no other subsequent events, the occurrence of which is probable and the effects of which are reasonably estimable, which have not been reflected in the figures provided as of the date of our letter.

In our opinion:

- the membership data on which the valuation is based are sufficient and reliable for purposes of the valuation;
- the assumptions are appropriate for the purposes of the valuation(s);
- the methods employed in the valuation are appropriate for the purposes of the valuation(s);
- the calculations have been made in accordance with our understanding of the requirements of IAS 19 and the Company's accounting policies.

This report has been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada.

We are pleased to provide you with this year-end disclosure report. Please contact us if you need any additional information.

Willis Towers Watson

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Enclosures

cc: Claudia Oancea — Toronto Hydro Corporation
Cindy Dieng — Toronto Hydro Corporation

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2018 Year-End Disclosure Information ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Statement of Financial Position at Beginning of Period			**January 01, 2018**		
Defined Benefit Asset/(Liability) at Beginning of Period	(307,147)	(2,296)	(2,117)	(1,410)	(312,970)
Reconciliation of Defined Benefit Obligation			**2018**		
Defined Benefit Obligation at Beginning of Period	307,147	2,296	2,117	1,410	312,970
Employer Service Cost at Beginning of Period	4,554	197	14	57	4,822
Interest Cost	10,747	83	74	51	10,955
Net Actuarial (Gain) or Loss					
Sick Leave Plan	*(4,676)*	-	*(59)*	-	*(4,735)*
Retirement Allowance Benefit #1	-	*(76)*	-	-	*(76)*
Other Plans	*(36,006)*	*222*	*(1,176)*	*(197)*	*(37,157)*
Total Net Actuarial (Gain) or Loss	(40,682)	146	(1,235)	(197)	(41,968)
Benefits Paid Directly by the Employer	(10,856)	(25)	(11)	(27)	(10,919)
Defined Benefit Obligation at Current Period End	270,910	2,697	959	1,294	275,860
Change in Plan Assets			**2018**		
Fair Value of Plan Assets at Prior Period End	-	-	-	-	-
Employer Contributions	10,856	25	11	27	10,919
Benefits Paid	(10,856)	(25)	(11)	(27)	(10,919)
Fair Value of Plan Assets at Current Period End	-	-	-	-	-
Total Benefit (Expense)/Income for Period			**2018**		
Employer Service Cost at Beginning of Period	4,554	197	14	57	4,822
Interest Cost	10,747	83	74	51	10,955
Actuarial (Gain)/Loss Recognized in Expense	(4,676)	(76)	(59)	-	(4,811)
Total Benefit Expense/(Income)	10,625	204	29	108	10,966
Reconciliation of Balance Sheet			**2018**		
Defined Benefit Asset/(Liability) at Prior Period End	(307,147)	(2,296)	(2,117)	(1,410)	(312,970)
Total Benefit (Expense)/Income for Period	(10,625)	(204)	(29)	(108)	(10,966)
Benefits Paid Directly by the Employer	10,856	25	11	27	10,919
Gain/(Loss) Recognized via OCI	36,006	(222)	1,176	197	37,157
Defined Benefit Asset/(Liability) at Current Period End	(270,910)	(2,697)	(959)	(1,294)	(275,860)
Change in Accumulated Other Comprehensive Income			**2018**		
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Prior Period End	52,414	(1,099)	(1,226)	112	50,201
Actuarial (Gain)/Loss Recognized via OCI for Period	(36,006)	222	(1,176)	(197)	(37,157)
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Current Period End	16,408	(877)	(2,402)	(85)	13,044
Statement of Financial Position at End of Period			**December 31, 2018**		
Defined Benefit Asset/(Liability) at Current Period End	(270,910)	(2,697)	(959)	(1,294)	(275,860)
Breakdown of Defined Benefit Obligation: Current and Non-Current			**December 31, 2018**		
Current Liabilities	-	-	-	-	-
Non-Current Asset/(Liability)	(270,910)	(2,697)	(959)	(1,294)	(275,860)
Defined Benefit Asset/(Liability) at Current Period End	(270,910)	(2,697)	(959)	(1,294)	(275,860)

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2018 Year-End Disclosure Information ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Sensitivity to Changes in Medical and Dental Trend Rate Assumption					
Effect on total of service and interest cost for 2018					
1% point increase	2,231	9	15	20	2,275
1% point decrease	(1,990)	(6)	(13)	(17)	(2,026)
Effect on accrued benefit obligation at December 31, 2018					
1% point increase	35,180	203	123	201	35,707
1% point decrease	(31,476)	(180)	(110)	(172)	(31,938)
Sensitivity to Changes in Discount Rate Assumption					
Effect on total of service and interest cost for 2018					
1% point increase	(73)	(9)	1	(11)	(92)
1% point decrease	(132)	6	(4)	13	(117)
Effect on accrued benefit obligation at December 31, 2018					
1% point increase	(40,659)	(322)	(139)	(229)	(41,349)
1% point decrease	52,254	412	176	299	53,141
Sensitivity to Changes in Mortality Rates Assumption					
Effect on accrued benefit obligation at December 31, 2018					
Set back 1 year	9,755	62	32	49	9,898
Set forward 1 year	(9,521)	(60)	(31)	(48)	(9,660)
Key Assumptions					
Discount rate at Dec 31/18 (used for Dec 31/18 obligation)	3.75%	3.75%	3.75%	3.75%	3.75%
Discount rate at Dec 31/17 (used for 2018 Benefit Costs)	3.50%	3.50%	3.50%	3.50%	3.50%
Assumed medical and dental cost trend rate at December 31, 2018					
Dental care cost trend rate assumed for next year	4.00%	4.00%	4.00%	4.00%	4.00%
Health care cost trend rate assumed for next year	5.00%	5.00%	5.00%	5.00%	5.00%
Expected Benefit Payments					
Following Year	8,942	170	35	19	9,166
Following Year +1	9,201	139	36	20	9,396
Following Year +2	9,701	151	37	22	9,911
Following Year +3	10,186	156	37	26	10,405
Following Year +4	10,637	259	38	31	10,965
Following Year +5	11,009	1,566	38	34	12,647
Following Year +6	11,118	50	37	38	11,243
Modified Duration at the end of the year	17.2	11.5	16.1	19.5	16.7

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2019 Expense Estimate ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Statement of Financial Position at Beginning of Period			**January 01, 2019**		
Defined Benefit Asset/(Liability) at Beginning of Period	(270,910)	(2,697)	(959)	(1,294)	(275,860)
Reconciliation of Defined Benefit Obligation			**2019**		
Defined Benefit Obligation at Beginning of Period	270,910	2,697	959	1,294	275,860
Employer Service Cost at Beginning of Period	2,968	213	-	54	3,235
Interest Cost	10,103	106	35	50	10,294
Net Actuarial (Gain) or Loss	-	-	-	-	-
Benefits Paid Directly by the Employer	(8,942)	(170)	(35)	(19)	(9,166)
Defined Benefit Obligation at Current Period End	275,039	2,846	959	1,379	280,223
Change in Plan Assets			**2019**		
Fair Value of Plan Assets at Prior Period End	-	-	-	-	-
Employer Contributions	8,942	170	35	19	9,166
Benefits Paid	(8,942)	(170)	(35)	(19)	(9,166)
Fair Value of Plan Assets at Current Period End	-	-	-	-	-
Total Benefit (Expense)/Income for Period			**2019**		
Employer Service Cost at Beginning of Period	2,968	213	-	54	3,235
Interest Cost	10,103	106	35	50	10,294
Total Benefit Expense/(Income)	13,071	319	35	104	13,529
Reconciliation of Balance Sheet			**2019**		
Defined Benefit Asset/(Liability) at Prior Period End	(270,910)	(2,697)	(959)	(1,294)	(275,860)
Total Benefit (Expense)/Income for Period	(13,071)	(319)	(35)	(104)	(13,529)
Benefits Paid Directly by the Employer	8,942	170	35	19	9,166
Gain/(Loss) Recognized via OCI	-	-	-	-	-
Defined Benefit Asset/(Liability) at Current Period End	(275,039)	(2,846)	(959)	(1,379)	(280,223)
Change in Accumulated Other Comprehensive Income			**2019**		
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Prior Period End	16,408	(877)	(2,402)	(85)	13,044
Actuarial (Gain)/Loss Recognized via OCI for Period	-	-	-	-	-
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Current Period End	16,408	(877)	(2,402)	(85)	13,044
Statement of Financial Position at End of Period			**December 31, 2019**		
Defined Benefit Asset/(Liability) at Current Period End	(275,039)	(2,846)	(959)	(1,379)	(280,223)
Breakdown of Defined Benefit Obligation: Current and Non-Current			**December 31, 2019**		
Current Liabilities	-	-	-	-	-
Non-Current Asset/(Liability)	(275,039)	(2,846)	(959)	(1,379)	(280,223)
Defined Benefit Asset/(Liability) at Current Period End	(275,039)	(2,846)	(959)	(1,379)	(280,223)
Key Assumptions					
Discount rate at Dec 31/18 (used for December 31, 2019 obligation)	3.75%	3.75%	3.75%	3.75%	3.75%
Discount rate at Dec 31/18 (used for 2019 Benefit Costs)	3.75%	3.75%	3.75%	3.75%	3.75%
Assumed medical and dental cost trend rate at December 31, 2019					
Dental care cost trend rate assumed for next year	4.00%	4.00%	4.00%	4.00%	4.00%
Health care cost trend rate assumed for next year	5.00%	5.00%	5.00%	5.00%	5.00%
Expected Benefit Payments for Following Year	9,201	139	36	20	9,396

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2020 Expense Estimate ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Statement of Financial Position at Beginning of Period			**January 01, 2020**		
Defined Benefit Asset/(Liability) at Beginning of Period	(275,039)	(2,846)	(959)	(1,379)	(280,223)
Reconciliation of Defined Benefit Obligation			**2020**		
Defined Benefit Obligation at Beginning of Period	275,039	2,846	959	1,379	280,223
Employer Service Cost at Beginning of Period	3,079	221	-	56	3,356
Interest Cost	10,257	112	35	53	10,457
Net Actuarial (Gain) or Loss	-	-	-	-	-
Benefits Paid Directly by the Employer	(9,201)	(139)	(36)	(20)	(9,396)
Defined Benefit Obligation at Current Period End	279,174	3,040	958	1,468	284,640
Change in Plan Assets			**2020**		
Fair Value of Plan Assets at Prior Period End	-	-	-	-	-
Employer Contributions	9,201	139	36	20	9,396
Benefits Paid	(9,201)	(139)	(36)	(20)	(9,396)
Fair Value of Plan Assets at Current Period End	-	-	-	-	-
Total Benefit (Expense)/Income for Period			**2020**		
Employer Service Cost at Beginning of Period	3,079	221	-	56	3,356
Interest Cost	10,257	112	35	53	10,457
Total Benefit Expense/(Income)	13,336	333	35	109	13,813
Reconciliation of Balance Sheet			**2020**		
Defined Benefit Asset/(Liability) at Prior Period End	(275,039)	(2,846)	(959)	(1,379)	(280,223)
Total Benefit (Expense)/Income for Period	(13,336)	(333)	(35)	(109)	(13,813)
Benefits Paid Directly by the Employer	9,201	139	36	20	9,396
Gain/(Loss) Recognized via OCI	-	-	-	-	-
Defined Benefit Asset/(Liability) at Current Period End	(279,174)	(3,040)	(958)	(1,468)	(284,640)
Change in Accumulated Other Comprehensive Income			**2020**		
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Prior Period End	16,408	(877)	(2,402)	(85)	13,044
Actuarial (Gain)/Loss Recognized via OCI for Period	-	-	-	-	-
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Current Period End	16,408	(877)	(2,402)	(85)	13,044
Statement of Financial Position at End of Period			**December 31, 2020**		
Defined Benefit Asset/(Liability) at Current Period End	(279,174)	(3,040)	(958)	(1,468)	(284,640)
Breakdown of Defined Benefit Obligation: Current and Non-Current			**December 31, 2020**		
Current Liabilities	-	-	-	-	-
Non-Current Asset/(Liability)	(279,174)	(3,040)	(958)	(1,468)	(284,640)
Defined Benefit Asset/(Liability) at Current Period End	(279,174)	(3,040)	(958)	(1,468)	(284,640)
Key Assumptions					
Discount rate at Dec 31/18 (used for December 31, 2020 obligation)	3.75%	3.75%	3.75%	3.75%	3.75%
Discount rate at Dec 31/18 (used for 2020 Benefit Costs)	3.75%	3.75%	3.75%	3.75%	3.75%
Assumed medical and dental cost trend rate at December 31, 2020					
Dental care cost trend rate assumed for next year	4.00%	4.00%	4.00%	4.00%	4.00%
Health care cost trend rate assumed for next year	5.00%	5.00%	5.00%	5.00%	5.00%
Expected Benefit Payments for Following Year	9,701	151	37	22	9,911

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2021 Expense Estimate ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Statement of Financial Position at Beginning of Period			**January 01, 2021**		
Defined Benefit Asset/(Liability) at Beginning of Period	(279,174)	(3,040)	(958)	(1,468)	(284,640)
Reconciliation of Defined Benefit Obligation			**2021**		
Defined Benefit Obligation at Beginning of Period	279,174	3,040	958	1,468	284,640
Employer Service Cost at Beginning of Period	3,194	229	-	58	3,481
Interest Cost	10,407	120	35	57	10,619
Net Actuarial (Gain) or Loss	-	-	-	-	-
Benefits Paid Directly by the Employer	(9,701)	(151)	(37)	(22)	(9,911)
Defined Benefit Obligation at Current Period End	283,074	3,238	956	1,561	288,829
Change in Plan Assets			**2021**		
Fair Value of Plan Assets at Prior Period End	-	-	-	-	-
Employer Contributions	9,701	151	37	22	9,911
Benefits Paid	(9,701)	(151)	(37)	(22)	(9,911)
Fair Value of Plan Assets at Current Period End	-	-	-	-	-
Total Benefit (Expense)/Income for Period			**2021**		
Employer Service Cost at Beginning of Period	3,194	229	-	58	3,481
Interest Cost	10,407	120	35	57	10,619
Total Benefit Expense/(Income)	13,601	349	35	115	14,100
Reconciliation of Balance Sheet			**2021**		
Defined Benefit Asset/(Liability) at Prior Period End	(279,174)	(3,040)	(958)	(1,468)	(284,640)
Total Benefit (Expense)/Income for Period	(13,601)	(349)	(35)	(115)	(14,100)
Benefits Paid Directly by the Employer	9,701	151	37	22	9,911
Gain/(Loss) Recognized via OCI	-	-	-	-	-
Defined Benefit Asset/(Liability) at Current Period End	(283,074)	(3,238)	(956)	(1,561)	(288,829)
Change in Accumulated Other Comprehensive Income			**2021**		
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Prior Period End	16,408	(877)	(2,402)	(85)	13,044
Actuarial (Gain)/Loss Recognized via OCI for Period	-	-	-	-	-
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Current Period End	16,408	(877)	(2,402)	(85)	13,044
Statement of Financial Position at End of Period			**December 31, 2021**		
Defined Benefit Asset/(Liability) at Current Period End	(283,074)	(3,238)	(956)	(1,561)	(288,829)
Breakdown of Defined Benefit Obligation: Current and Non-Current			**December 31, 2021**		
Current Liabilities	-	-	-	-	-
Non-Current Asset/(Liability)	(283,074)	(3,238)	(956)	(1,561)	(288,829)
Defined Benefit Asset/(Liability) at Current Period End	(283,074)	(3,238)	(956)	(1,561)	(288,829)
Key Assumptions					
Discount rate at Dec 31/18 (used for December 31, 2021 obligation)	3.75%	3.75%	3.75%	3.75%	3.75%
Discount rate at Dec 31/18 (used for 2021 Benefit Costs)	3.75%	3.75%	3.75%	3.75%	3.75%
Assumed medical and dental cost trend rate at December 31, 2021					
Dental care cost trend rate assumed for next year	4.00%	4.00%	4.00%	4.00%	4.00%
Health care cost trend rate assumed for next year	5.00%	5.00%	5.00%	5.00%	5.00%
Expected Benefit Payments for Following Year	10,186	156	37	26	10,405

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2022 Expense Estimate ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Statement of Financial Position at Beginning of Period			**January 01, 2022**		
Defined Benefit Asset/(Liability) at Beginning of Period	(283,074)	(3,238)	(956)	(1,561)	(288,829)
Reconciliation of Defined Benefit Obligation			**2022**		
Defined Benefit Obligation at Beginning of Period	283,074	3,238	956	1,561	288,829
Employer Service Cost at Beginning of Period	3,314	238	-	60	3,612
Interest Cost	10,549	127	35	60	10,771
Net Actuarial (Gain) or Loss	-	-	-	-	-
Benefits Paid Directly by the Employer	(10,186)	(156)	(37)	(26)	(10,405)
Defined Benefit Obligation at Current Period End	286,751	3,447	954	1,655	292,807
Change in Plan Assets			**2022**		
Fair Value of Plan Assets at Prior Period End	-	-	-	-	-
Employer Contributions	10,186	156	37	26	10,405
Benefits Paid	(10,186)	(156)	(37)	(26)	(10,405)
Fair Value of Plan Assets at Current Period End	-	-	-	-	-
Total Benefit (Expense)/Income for Period			**2022**		
Employer Service Cost at Beginning of Period	3,314	238	-	60	3,612
Interest Cost	10,549	127	35	60	10,771
Total Benefit Expense/(Income)	13,863	365	35	120	14,383
Reconciliation of Balance Sheet			**2022**		
Defined Benefit Asset/(Liability) at Prior Period End	(283,074)	(3,238)	(956)	(1,561)	(288,829)
Total Benefit (Expense)/Income for Period	(13,863)	(365)	(35)	(120)	(14,383)
Benefits Paid Directly by the Employer	10,186	156	37	26	10,405
Gain/(Loss) Recognized via OCI	-	-	-	-	-
Defined Benefit Asset/(Liability) at Current Period End	(286,751)	(3,447)	(954)	(1,655)	(292,807)
Change in Accumulated Other Comprehensive Income			**2022**		
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Prior Period End	16,408	(877)	(2,402)	(85)	13,044
Actuarial (Gain)/Loss Recognized via OCI for Period	-	-	-	-	-
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Current Period End	16,408	(877)	(2,402)	(85)	13,044
Statement of Financial Position at End of Period			**December 31, 2022**		
Defined Benefit Asset/(Liability) at Current Period End	(286,751)	(3,447)	(954)	(1,655)	(292,807)
Breakdown of Defined Benefit Obligation: Current and Non-Current			**December 31, 2022**		
Current Liabilities	-	-	-	-	-
Non-Current Asset/(Liability)	(286,751)	(3,447)	(954)	(1,655)	(292,807)
Defined Benefit Asset/(Liability) at Current Period End	(286,751)	(3,447)	(954)	(1,655)	(292,807)
Key Assumptions					
Discount rate at Dec 31/18 (used for December 31, 2022 obligation)	3.75%	3.75%	3.75%	3.75%	3.75%
Discount rate at Dec 31/18 (used for 2022 Benefit Costs)	3.75%	3.75%	3.75%	3.75%	3.75%
Assumed medical and dental cost trend rate at December 31, 2022					
Dental care cost trend rate assumed for next year	4.00%	4.00%	4.00%	4.00%	4.00%
Health care cost trend rate assumed for next year	5.00%	5.00%	5.00%	5.00%	5.00%
Expected Benefit Payments for Following Year	10,637	259	38	31	10,965

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2023 Expense Estimate ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Statement of Financial Position at Beginning of Period			**January 01, 2023**		
Defined Benefit Asset/(Liability) at Beginning of Period	(286,751)	(3,447)	(954)	(1,655)	(292,807)
Reconciliation of Defined Benefit Obligation			**2023**		
Defined Benefit Obligation at Beginning of Period	286,751	3,447	954	1,655	292,807
Employer Service Cost at Beginning of Period	3,438	247	-	62	3,747
Interest Cost	10,683	134	35	64	10,916
Net Actuarial (Gain) or Loss	-	-	-	-	-
Benefits Paid Directly by the Employer	(10,637)	(259)	(38)	(31)	(10,965)
Defined Benefit Obligation at Current Period End	290,235	3,569	951	1,750	296,505
Change in Plan Assets			**2023**		
Fair Value of Plan Assets at Prior Period End	-	-	-	-	-
Employer Contributions	10,637	259	38	31	10,965
Benefits Paid	(10,637)	(259)	(38)	(31)	(10,965)
Fair Value of Plan Assets at Current Period End	-	-	-	-	-
Total Benefit (Expense)/Income for Period			**2023**		
Employer Service Cost at Beginning of Period	3,438	247	-	62	3,747
Interest Cost	10,683	134	35	64	10,916
Total Benefit Expense/(Income)	14,121	381	35	126	14,663
Reconciliation of Balance Sheet			**2023**		
Defined Benefit Asset/(Liability) at Prior Period End	(286,751)	(3,447)	(954)	(1,655)	(292,807)
Total Benefit (Expense)/Income for Period	(14,121)	(381)	(35)	(126)	(14,663)
Benefits Paid Directly by the Employer	10,637	259	38	31	10,965
Gain/(Loss) Recognized via OCI	-	-	-	-	-
Defined Benefit Asset/(Liability) at Current Period End	(290,235)	(3,569)	(951)	(1,750)	(296,505)
Change in Accumulated Other Comprehensive Income			**2023**		
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Prior Period End	16,408	(877)	(2,402)	(85)	13,044
Actuarial (Gain)/Loss Recognized via OCI for Period	-	-	-	-	-
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Current Period End	16,408	(877)	(2,402)	(85)	13,044
Statement of Financial Position at End of Period			**December 31, 2023**		
Defined Benefit Asset/(Liability) at Current Period End	(290,235)	(3,569)	(951)	(1,750)	(296,505)
Breakdown of Defined Benefit Obligation: Current and Non-Current			**December 31, 2023**		
Current Liabilities	-	-	-	-	-
Non-Current Asset/(Liability)	(290,235)	(3,569)	(951)	(1,750)	(296,505)
Defined Benefit Asset/(Liability) at Current Period End	(290,235)	(3,569)	(951)	(1,750)	(296,505)
Key Assumptions					
Discount rate at Dec 31/18 (used for December 31, 2023 obligation)	3.75%	3.75%	3.75%	3.75%	3.75%
Discount rate at Dec 31/18 (used for 2023 Benefit Costs)	3.75%	3.75%	3.75%	3.75%	3.75%
Assumed medical and dental cost trend rate at December 31, 2023					
Dental care cost trend rate assumed for next year	4.00%	4.00%	4.00%	4.00%	4.00%
Health care cost trend rate assumed for next year	5.00%	5.00%	5.00%	5.00%	5.00%
Expected Benefit Payments for Following Year	11,009	1,566	38	34	12,647

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2024 Expense Estimate ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Statement of Financial Position at Beginning of Period			**January 01, 2024**		
Defined Benefit Asset/(Liability) at Beginning of Period	(290,235)	(3,569)	(951)	(1,750)	(296,505)
Reconciliation of Defined Benefit Obligation			**2024**		
Defined Benefit Obligation at Beginning of Period	290,235	3,569	951	1,750	296,505
Employer Service Cost at Beginning of Period	3,567	256	-	64	3,887
Interest Cost	10,811	114	35	67	11,027
Net Actuarial (Gain) or Loss	-	-	-	-	-
Benefits Paid Directly by the Employer	(11,009)	(1,566)	(38)	(34)	(12,647)
Defined Benefit Obligation at Current Period End	293,604	2,373	948	1,847	298,772
Change in Plan Assets			**2024**		
Fair Value of Plan Assets at Prior Period End	-	-	-	-	-
Employer Contributions	11,009	1,566	38	34	12,647
Benefits Paid	(11,009)	(1,566)	(38)	(34)	(12,647)
Fair Value of Plan Assets at Current Period End	-	-	-	-	-
Total Benefit (Expense)/Income for Period			**2024**		
Employer Service Cost at Beginning of Period	3,567	256	-	64	3,887
Interest Cost	10,811	114	35	67	11,027
Total Benefit Expense/(Income)	14,378	370	35	131	14,914
Reconciliation of Balance Sheet			**2024**		
Defined Benefit Asset/(Liability) at Prior Period End	(290,235)	(3,569)	(951)	(1,750)	(296,505)
Total Benefit (Expense)/Income for Period	(14,378)	(370)	(35)	(131)	(14,914)
Benefits Paid Directly by the Employer	11,009	1,566	38	34	12,647
Gain/(Loss) Recognized via OCI	-	-	-	-	-
Defined Benefit Asset/(Liability) at Current Period End	(293,604)	(2,373)	(948)	(1,847)	(298,772)
Change in Accumulated Other Comprehensive Income			**2024**		
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Prior Period End	16,408	(877)	(2,402)	(85)	13,044
Actuarial (Gain)/Loss Recognized via OCI for Period	-	-	-	-	-
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Current Period End	16,408	(877)	(2,402)	(85)	13,044
Statement of Financial Position at End of Period			**December 31, 2024**		
Defined Benefit Asset/(Liability) at Current Period End	(293,604)	(2,373)	(948)	(1,847)	(298,772)
Breakdown of Defined Benefit Obligation: Current and Non-Current			**December 31, 2024**		
Current Liabilities	-	-	-	-	-
Non-Current Asset/(Liability)	(293,604)	(2,373)	(948)	(1,847)	(298,772)
Defined Benefit Asset/(Liability) at Current Period End	(293,604)	(2,373)	(948)	(1,847)	(298,772)
Key Assumptions					
Discount rate at Dec 31/18 (used for December 31, 2024 obligation)	3.75%	3.75%	3.75%	3.75%	3.75%
Discount rate at Dec 31/18 (used for 2024 Benefit Costs)	3.75%	3.75%	3.75%	3.75%	3.75%
Assumed medical and dental cost trend rate at December 31, 2024					
Dental care cost trend rate assumed for next year	4.00%	4.00%	4.00%	4.00%	4.00%
Health care cost trend rate assumed for next year	5.00%	5.00%	5.00%	5.00%	5.00%
Expected Benefit Payments for Following Year	11,118	50	37	38	11,243

SHARED SERVICES VARIANCE ANALYSIS

1. SHARED SERVICES

Exhibit 4A, Tab 5, Schedule 1 contains detailed information about shared services and corporate costs allocations between Toronto Hydro and its affiliated corporate entities. This schedules provides summary of the 2018 actuals, and explains the material variances resulting from the 2018 actuals.

An updated copy of OEB Appendix 2-N is filed as Appendix A to this schedule. This appendix provides cost information and allocation details relating to each shared service provided or received by Toronto Hydro in the historical years (2015 to 2018), the forecast years (2019 and 2020).

1.1 Toronto Hydro (TH) Energy

Table 1: Summary of the Cost of Shared Services Provided by and Received by Toronto Hydro to/from TH Energy ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Services Provided by Toronto Hydro	2.0	2.1	1.1	2.2	1.6	1.6
Services Received by Toronto Hydro	1.9	2.6	0.3	0.0	0.0	0.0

There are no material variances resulting from the 2018 actuals.

1.2 Non-Rate Regulated Toronto Hydro Activities

Table 2: Summary of the Cost of Services relating to Non-Rate Regulated Toronto Hydro Activities

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Services Provided by Toronto Hydro	1.3	1.7	1.9	1.7	1.6	1.7

There are no material variances resulting from the 2018 actuals.

1.3 Toronto Hydro Corporation (THC)

Table 3: Summary of the Cost of Shared Services Provided by and Received by Toronto Hydro to/from THC ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Services Provided by Toronto Hydro	1.2	1.3	3.2	3.2	3.9	3.9
Services Received by Toronto Hydro	4.8	2.9	4.8	5.1	4.4	4.6

In 2018, Toronto Hydro provided less services to its affiliate THC than what the utility forecast in Exhibit 4A, Tab 5. The value of the services received by Toronto Hydro from THC in 2018 was higher than forecasted primarily due to one-time costs associated with the transition of the CFO. These costs are expected to return to historical levels in the 2020 Test Year.

OEB Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2015

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
THESL	THESI	Fleet*	Fully allocated-cost	0.38	0.38
THESL	THESI	Emergency Calls / Streetlighting Relamping	Market**	0.52	0.48
THESI	THESL	Design	Market**	0.04	0.04
THESI	THESL	Emergency/Field Work	Market**	1.82	1.59

* A portion of the fleet charge is allocated from THESI to THESU.

** Because of cost-benefit impacts and impracticability, there was no study done to verify market amounts.

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
THESL	THESI	Finance/Treasury	Fully allocated-cost	2.9%	0.49
THESL	THESI	EHS	Fully allocated-cost	0.4%	0.01
THESL	THESI	Legal/Insurance	Fully allocated-cost	3.6%	0.18
THESL	THESI	HR&OE	Fully allocated-cost	1.3%	0.17
THESL	THESI	Procurement	Fully allocated-cost	1.7%	0.04
THESL	THESI	Consolidated Billing	Fully allocated-cost	0.0%	-
THESL	THESI	IT&S	Fully allocated-cost	0.8%	0.06
THESL	THESI	Facilities	Fully allocated-cost	0.5%	0.11
THESL	THESU	Finance/Treasury	Fully allocated-cost	2.3%	0.39
THESL	THESU	Legal/Insurance	Fully allocated-cost	0.6%	0.03
THESL	THESU	HR&OE	Fully allocated-cost	2.5%	0.37
THESL	THESU	Procurement	Fully allocated-cost	5.4%	0.12
THESL	THESU	IT&S	Fully allocated-cost	0.9%	0.07
THESL	THESU	Facilities	Fully allocated-cost	1.6%	0.37
THESL	THC	Finance/Treasury	Fully allocated-cost	2.8%	0.47
THESL	THC	Legal/Insurance	Fully allocated-cost	13.9%	0.71
THESL	THC	HR&OE	Fully allocated-cost	0.1%	0.01
THESL	THC	Procurement	Fully allocated-cost	0.2%	0.01
THESL	THC	IT&S	Fully allocated-cost	0.1%	0.01
THESL	THC	Facilities	Fully allocated-cost	0.2%	0.04
THC	THESL	Corporate Stewardship - CEO	Fully allocated-cost	95.0%	2.71
THC	THESL	Corporate Governance - Board of Directors	Fully allocated-cost	90.0%	0.22
THC	THESL	Finance Stewardship - CFO	Fully allocated-cost	95.0%	1.89
THC	THESI	Corporate Governance - Board of Directors	Fully allocated-cost	5.0%	0.01

OEB Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2016

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
THESL	THESI	Fleet*	Fully allocated-cost	0.43	0.43
THESL	THESI	Emergency Calls / Streetlighting Relamping	Market**	0.46	0.38
THESI	THESL	Emergency/Field Work	Market**	2.39	2.07
THESI	THESL	Design	Market**	0.19	0.16

* A portion of the fleet charge is allocated from THESI to THESU.

** Because of cost-benefit impacts and impracticability, there was no study done to verify market amounts.

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
THESL	THESI	Finance/Treasury/Insurance	Fully allocated-cost	3.0%	0.480
THESL	THESI	EHS	Fully allocated-cost	0.3%	0.006
THESL	THESI	Legal	Fully allocated-cost	4.6%	0.244
THESL	THESI	HR&OE	Fully allocated-cost	1.2%	0.163
THESL	THESI	Procurement	Fully allocated-cost	1.3%	0.075
THESL	THESI	Billing and Settlement Services	Fully allocated-cost	11.1%	0.049
THESL	THESI	IT&S	Fully allocated-cost	0.3%	0.11
THESL	THESI	Facilities	Fully allocated-cost	0.4%	0.11
THESL	THESU	Finance/Treasury/Insurance	Fully allocated-cost	2.3%	0.369
THESL	THESU	Legal	Fully allocated-cost	1.0%	0.056
THESL	THESU	HR&OE	Fully allocated-cost	2.4%	0.320
THESL	THESU	Procurement	Fully allocated-cost	3.7%	0.212
THESL	THESU	IT&S	Fully allocated-cost	0.7%	0.26
THESL	THESU	Facilities	Fully allocated-cost	2.0%	0.50
THESL	THC	Finance/Treasury/Insurance	Fully allocated-cost	2.5%	0.393
THESL	THC	Legal	Fully allocated-cost	15.4%	0.824
THESL	THC	HR&OE	Fully allocated-cost	0.0%	0.006
THESL	THC	Procurement	Fully allocated-cost	0.3%	0.014
THESL	THC	IT&S	Fully allocated-cost	0.0%	0.01
THESL	THC	Facilities	Fully allocated-cost	0.3%	0.07
THC	THESL	Corporate Stewardship - CEO	Fully allocated-cost	95.0%	1.88
THC	THESL	Corporate Governance - Board of Directors	Fully allocated-cost	90.0%	0.29
THC	THESL	Finance Stewardship - CFO	Fully allocated-cost	95.0%	0.69
THC	THESI	Corporate Governance - Board of Directors	Fully allocated-cost	5.0%	0.02

OEB Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2017

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
THESL	THESI	Fleet*	Fully allocated-cost	-	-
THESL	THESI	Emergency Calls / Streetlighting Relamping	Market**	0.33	0.30
THESI	THESL	Emergency/Field Work	Market**	0.21	0.21
THESI	THESL	Design	Market**	0.07	0.07

* A portion of the fleet charge is allocated from THESI to THESU.

** Because of cost-benefit impacts and impracticability, there was no study done to verify market amounts.

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
THESL	THESI	Finance/Treasury/Insurance	Fully allocated-cost	2.3%	0.32
THESL	THESI	EHS	Fully allocated-cost	0.3%	0.01
THESL	THESI	Legal	Fully allocated-cost	5.7%	0.33
THESL	THESI	HR&OE	Fully allocated-cost	0.0%	-
THESL	THESI	Procurement	Fully allocated-cost	1.1%	0.04
THESL	THESI	Billing and Settlement Services	Fully allocated-cost	5.0%	0.05
THESL	THESI	IT&S	Fully allocated-cost		-
THESL	THESI	Facilities	Fully allocated-cost		-
THESL	THESU	Finance/Treasury/Insurance	Fully allocated-cost	4.3%	0.61
THESL	THESU	Legal	Fully allocated-cost	1.9%	0.11
THESL	THESU	HR&OE	Fully allocated-cost	1.5%	0.21
THESL	THESU	Procurement	Fully allocated-cost	5.6%	0.21
THESL	THESU	IT&S	Fully allocated-cost	0.6%	0.25
THESL	THESU	Facilities	Fully allocated-cost	2.3%	0.54
THESL	THC	Finance/Treasury/Insurance	Fully allocated-cost	2.6%	0.37
THESL	THC	Legal	Fully allocated-cost	14.0%	0.82
THESL	THC	HR&OE	Fully allocated-cost	0.2%	0.03
THESL	THC	Office of the President	Fully allocated-cost	***	1.70
THESL	THC	Procurement	Fully allocated-cost	0.2%	0.01
THESL	THC	IT&S	Fully allocated-cost	0.03%	0.01
THESL	THC	Facilities	Fully allocated-cost	1.0%	0.22
THC	THESL	Corporate Stewardship - CEO	Fully allocated-cost	95.0%	3.02
THC	THESL	Corporate Governance - Board of Directors	Fully allocated-cost	90.0%	0.27
THC	THESL	Finance Stewardship - CFO	Fully allocated-cost	90.0%	1.47
THC	THESI	Corporate Governance - Board of Directors	Fully allocated-cost	5.0%	0.02

***Based on time allocation of multiple functions across the organization.

OEB Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2018

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
THESL	THESI	Fleet*	Fully allocated-cost	-	-
THESL	THESI	Emergency Calls / Streetlighting Relamping	Market**	1.37	1.30
THESI	THESL	Emergency/Field Work	Market**	0.02	0.02
THESI	THESL	Design	Market**	-	-

* A portion of the fleet charge is allocated from THESI to THESU.

** Because of cost-benefit impacts and impracticability, there was no study done to verify market amounts.

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
THESL	THESI	Finance/Treasury/Insurance	Fully allocated-cost	2.8%	0.47
THESL	THESI	EHS	Fully allocated-cost	0.0%	-
THESL	THESI	Legal	Fully allocated-cost	5.7%	0.36
THESL	THESI	HR&OE	Fully allocated-cost	0.0%	-
THESL	THESI	Procurement	Fully allocated-cost	1.0%	0.01
THESL	THESI	Billing and Settlement Services	Fully allocated-cost	4.5%	0.03
THESL	THESI	IT&S	Fully allocated-cost		
THESL	THESI	Facilities	Fully allocated-cost		
THESL	THESU	Finance/Treasury/Insurance	Fully allocated-cost	1.0%	0.49
THESL	THESU	Legal	Fully allocated-cost	1.8%	0.11
THESL	THESU	HR&OE	Fully allocated-cost	2.2%	0.30
THESL	THESU	Procurement	Fully allocated-cost	4.5%	0.05
THESL	THESU	IT&S	Fully allocated-cost	0.8%	0.35
THESL	THESU	Facilities	Fully allocated-cost	1.6%	0.35
THESL	THC	Finance/Treasury/Insurance	Fully allocated-cost	6.5%	1.08
THESL	THC	Legal	Fully allocated-cost	15.2%	0.96
THESL	THC	HR&OE	Fully allocated-cost	0.3%	0.04
THESL	THC	Office of the President	Fully allocated-cost	***	0.80
THESL	THC	Procurement	Fully allocated-cost	0.3%	0.00
THESL	THC	IT&S	Fully allocated-cost	0.1%	0.04
THESL	THC	Facilities	Fully allocated-cost	1.0%	0.23
THC	THESL	Corporate Stewardship - CEO	Fully allocated-cost	95.0%	3.07
THC	THESL	Corporate Governance - Board of Directors	Fully allocated-cost	90.0%	0.27
THC	THESL	Finance Stewardship - CFO	Fully allocated-cost	90.0%	1.80
THC	THESI	Corporate Governance - Board of Directors	Fully allocated-cost	5.0%	0.02
THC	THESI	Finance Stewardship - CFO	Fully allocated-cost	5.0%	0.10

***Based on time allocation of multiple functions across the organization.

OEB Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2019

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
THESL	THESI	Fleet*	Fully allocated-cost	-	-
THESL	THESI	Emergency Calls / Streetlighting Relamping	Market**	0.67	0.57
THESI	THESL	Emergency/Field Work	Market**	-	-
THESI	THESL	Design	Market**	-	-

* A portion of the fleet charge is allocated from THESI to THESU.

** Because of cost-benefit impacts and impracticability, there was no study done to verify market amounts.

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
THESL	THESI	Finance/Treasury/Insurance	Fully allocated-cost	2.2%	0.40
THESL	THESI	EHS	Fully allocated-cost	0.3%	0.01
THESL	THESI	Legal	Fully allocated-cost	5.8%	0.32
THESL	THESI	HR&OE	Fully allocated-cost	1.0%	0.13
THESL	THESI	Billing and Settlement Services	Fully allocated-cost	5.3%	0.05
THESL	THESI	Procurement	Fully allocated-cost	1.3%	0.05
THESL	THESI	IT&S	Fully allocated-cost		
THESL	THESI	Facilities	Fully allocated-cost		
THESL	THESU	Finance/Treasury/Insurance	Fully allocated-cost	1.9%	0.35
THESL	THESU	Legal	Fully allocated-cost	1.1%	0.06
THESL	THESU	HR&OE	Fully allocated-cost	2.7%	0.37
THESL	THESU	Procurement	Fully allocated-cost	3.7%	0.13
THESL	THESU	IT&S	Fully allocated-cost	0.8%	0.36
THESL	THESU	Facilities	Fully allocated-cost	1.3%	0.37
THESL	THC	Finance/Treasury/Insurance	Fully allocated-cost	5.9%	1.07
THESL	THC	Legal	Fully allocated-cost	15.4%	0.85
THESL	THC	HR&OE	Fully allocated-cost	0.1%	0.01
THESL	THC	Office of the President	Fully allocated-cost	***	1.70
THESL	THC	Procurement	Fully allocated-cost	0.3%	0.01
THESL	THC	IT&S	Fully allocated-cost	0.03%	0.04
THESL	THC	Facilities	Fully allocated-cost	1.4%	0.24
THC	THESL	Corporate Stewardship - CEO	Fully allocated-cost	95.0%	2.76
THC	THESL	Corporate Governance - Board of Directors	Fully allocated-cost	90.0%	0.36
THC	THESL	Finance Stewardship - CFO	Fully allocated-cost	95.0%	1.32
THC	THESI	Corporate Governance - Board of Directors	Fully allocated-cost	5.0%	0.02

***Based on time allocation of multiple functions across the organization.

OEB Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2020

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
THESL	THESI	Fleet*	Fully allocated-cost	-	-
THESL	THESI	Emergency Calls / Streetlighting Relamping	Market**	0.67	0.57
THESI	THESL	Emergency/Field Work	Market**	-	-
THESI	THESL	Design	Market**	-	-

* A portion of the fleet charge is allocated from THESI to THESU.

** Because of cost-benefit impacts and impracticability, there was no study done to verify market amounts.

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
THESL	THESI	Finance/Treasury/Insurance	Fully allocated-cost	2.2%	0.40
THESL	THESI	EHS	Fully allocated-cost	0.3%	0.01
THESL	THESI	Legal	Fully allocated-cost	5.8%	0.33
THESL	THESI	HR&OE	Fully allocated-cost	0.9%	0.13
THESL	THESI	Billing and Settlement Services	Fully allocated-cost	5.4%	0.05
THESL	THESI	Procurement	Fully allocated-cost	1.3%	0.05
THESL	THESI	IT&S	Fully allocated-cost		
THESL	THESI	Facilities	Fully allocated-cost		
THESL	THESU	Finance/Treasury/Insurance	Fully allocated-cost	1.9%	0.35
THESL	THESU	Legal	Fully allocated-cost	1.1%	0.06
THESL	THESU	HR&OE	Fully allocated-cost	2.7%	0.38
THESL	THESU	Procurement	Fully allocated-cost	3.7%	0.13
THESL	THESU	IT&S	Fully allocated-cost	0.8%	0.37
THESL	THESU	Facilities	Fully allocated-cost	3.7%	0.38
THESL	THC	Finance/Treasury/Insurance	Fully allocated-cost	5.6%	1.01
THESL	THC	Legal	Fully allocated-cost	15.4%	0.89
THESL	THC	HR&OE	Fully allocated-cost	0.1%	0.01
THESL	THC	Office of the President	Fully allocated-cost	***	1.70
THESL	THC	Procurement	Fully allocated-cost	0.3%	0.01
THESL	THC	IT&S	Fully allocated-cost	0.03%	0.04
THESL	THC	Facilities	Fully allocated-cost	1.4%	0.24
THC	THESL	Corporate Stewardship - CEO	Fully allocated-cost	95.0%	2.86
THC	THESL	Corporate Governance - Board of Directors	Fully allocated-cost	90.0%	0.36
THC	THESL	Finance Stewardship - CFO	Fully allocated-cost	95.0%	1.35
THC	THESI	Corporate Governance - Board of Directors	Fully allocated-cost	5.0%	0.02

***Based on time allocation of multiple functions across the organization.

OEB Appendix 2-N
Shared Services and Corporate Cost Allocation

Note:

1 **This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years. The required information includes:**

- ***Type of Service:***

Services such as billing, accounting, payroll, etc. The applicant must identify any costs related to the Board of Directors of the parent company that are allocated to the applicant.

- ***Pricing Methodology:***

Pricing Methodology includes approaches such as cost-base, market-base, tendering, etc. The applicant must provide evidence demonstrating the pricing methodology used. The applicant must also provide a description of why that pricing methodology was chosen, whether or not it is in conformity with ARC, and why it is appropriate.

- ***% Allocation:***

The applicant must provide the percentage of the costs allocated to the entity for the service being offered. The Applicant must also provide a description of the allocator and why it is an appropriate allocator.

OPERATING COSTS: DEPRECIATION VARIANCE ANALYSIS

1. DEPRECIATION AND AMORTIZATION

Exhibit 4B, Tab 1 includes detailed information about Toronto Hydro's depreciation and amortization rates and expenses. This schedules provides a summary of the utility's 2018 expenses, explains the material variances and identifies changes to 2019 forecasts. Toronto Hydro has not made any changes to the 2020-2024 forecast.

1.1 Decommissioning Provision

The tables below provide the historical (2015-2018) and forecasted (2019-2020) decommissioning costs and the related depreciation expense (Table 1), as well as the corresponding decommissioning liability and related accretion expenses (Table 2). There were no material variances in 2018.

Table 1: Historical and Forecasted Decommissioning Costs and Related Depreciation Expense ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Forecast
Decommissioning Costs	1.0	0.8	0.8	0.7	0.6	0.6
Related Depreciation Expense	0.1	0.1	0.1	0.1	0.1	0.1

Table 2: Historical and Forecasted Decommissioning Liability and Related Accretion Expense ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Forecast
Decommissioning Liability	1.9	1.5	1.5	1.4	1.3	1.2
Related Accretion Expense	-	-	-	-	-	-

1.2 Depreciation and Amortization Expense

Toronto Hydro's depreciation and amortization expense from 2015 to 2020 is presented in Table 3 below. This summary is supported by Appendix A, which provides a breakdown of 2015-2020 depreciation expense by Uniform System of Accounts. An updated version of OEB Appendix 2-C is filed as Appendix B to this schedule.

Table 3: Depreciation and Amortization Expense[1] 2015 to 2020 ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Forecast
Depreciation and Amortization Expense	166.0	179.1	192.5	205.3	223.6	242.9

The 2018 actual and 2019 bridge depreciation and amortization expenses are $5.4 million and $4.6 million lower, respectively, than the forecasts included in Exhibit 4B, Tab 1, Schedule 1, page 6.

The differences in 2018 are primarily due to timing differences associated with the completion of the ERP and Copeland TS projects. The depreciation expense for 2019 is expected to be lower due to the reduced opening balance for fixed assets in 2019, and changes in the timing of in-service additions in the year resulting from the work that is being carried over from 2018 into 2019.

[1] Includes depreciation of the decommissioning costs and excludes derecognition. For inofmraiton about asset derecognition please see section 2.1 below and Exhibit 4B, Tab 1, Schedule 2.

2. DERECOGNITION

2.1 Derecognition Expense

Table 4 below summarizes Toronto Hydro's 2015 to 2020 derecognition expense. The 2018 actual and 2019 bridge expenses are $3.7 million and $2.3 million higher, respectively, than the forecasts included in Exhibit 4B, Tab 1, Schedule 2, page 1.

The differences in 2018 relate to overhead and underground distribution assets, as well as software assets. Toronto Hydro updated 2019 forecast based on a four year average of derecognition as opposed to a three year average in the original filing.

Table 4: Derecognition from 2015 to 2020 ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge Updated	2020 Forecast
Derecognition	24.1	27.0	24.5	24.5	22.4	25.8

Table 1: Summary of Depreciation Expense

		2018 MIFRS			2019 MIFRS		
OEB	**Description**	**Depreciation Expense**	**Derecognition**	**Total Depreciation Expense**	**Depreciation Expense**	**Derecognition**	**Total Depreciation Expense**
1611	Computer Software (Formally known as Account 1925)	$ 20,892,805	$ 1,385,063	$ 22,277,868	$ 27,968,318	$ -	$ 27,968,318
1612	Land Rights	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ 3,308,486	$ 9,993	$ 3,318,479	$ 3,576,986	$ -	$ 3,576,986
1815	Transformer Station Equipment >50 kV	$ 1,298,265	$ -	$ 1,298,265	$ 1,339,480	$ -	$ 1,339,480
1820	Distribution Station Equipment <50 kV	$ 8,622,713	$ 751,097	$ 9,373,810	$ 9,828,871	$ 155,775	$ 9,984,646
1830	Poles, Towers & Fixtures	$ 10,921,669	$ 2,376,041	$ 13,297,709	$ 11,163,183	$ 5,081,606	$ 16,244,788
1835	Overhead Conductors & Devices	$ 10,827,432	$ 2,228,085	$ 13,055,516	$ 11,552,701	$ 1,895,332	$ 13,448,034
1840	Underground Conduit	$ 44,888,220	$ 267,741	$ 45,155,961	$ 47,764,130	$ 462,445	$ 48,226,575
1845	Underground Conductors & Devices	$ 25,369,256	$ 7,220,345	$ 32,589,601	$ 26,963,221	$ 4,270,576	$ 31,233,797
1850	Line Transformers	$ 23,997,546	$ 7,327,460	$ 31,325,006	$ 25,545,270	$ 6,767,188	$ 32,312,458
1855	Services (Overhead & Underground)	$ 2,947,558	$ 480,467	$ 3,428,026	$ 3,062,482	$ 311,266	$ 3,373,747
1860	Meters	$ 16,018,913	$ 2,559,854	$ 18,578,767	$ 16,785,423	$ 3,367,079	$ 20,152,502
1905	Land	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 11,318,351	$ 113,573	$ 11,431,924	$ 11,325,101	$ -	$ 11,325,101
1910	Leasehold Improvements	$ 10,481	$ -	$ 10,481	$ 8,734	$ -	$ 8,734
1915	Office Furniture & Equipment	$ 2,051,264	$ 3,544	$ 2,054,807	$ 2,067,790	$ -	$ 2,067,790
1920	Computer Equipment - Hardware	$ 10,714,855	$ -	$ 10,714,855	$ 10,812,376	$ -	$ 10,812,376
1930	Transportation Equipment	$ 3,636,383	$ -	$ 3,636,383	$ 3,141,469	$ -	$ 3,141,469
1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 2,257,857	$ -	$ 2,257,857	$ 2,443,955	$ -	$ 2,443,955
1945	Measurement & Testing Equipment	$ 59,822	$ -	$ 59,822	$ 61,540	$ -	$ 61,540
1950	Power Operated Equipment	$ 159,091	$ -	$ 159,091	$ 131,053	$ -	$ 131,053
1955	Communications Equipment	$ 4,690,337	$ -	$ 4,690,337	$ 4,719,684	$ -	$ 4,719,684
1960	Miscellaneous Equipment	$ 37,310	$ -	$ 37,310	$ 37,310	$ -	$ 37,310
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 2,802,429	$ 308,612	$ 3,111,041	$ 3,134,194	$ 449,144	$ 3,583,337
2440	Contributions & Grants	($ 5,263,537)	($ 522,605)	($ 5,786,142)	($ 5,711,872)	($ 375,099)	($ 6,086,971)
1609	Capital Contributions Paid	$ 3,538,390	$ -	$ 3,538,390	$ 7,235,447	$ -	$ 7,235,447
2005	Property Under Capital Leases	$ 1,320,504	$ -	$ 1,320,504	$ 652,639	$ -	$ 652,639
	Sub-Total	$ 206,426,400	$ 24,509,267	$ 230,935,667	$ 225,609,486	$ 22,385,311	$ 247,994,797
	Less Socialized Renewable Energy Generation Investments **(input as negative)**	$ -	$ -	$ -	($ 34,127)	$ -	($ 34,127)
	Less Other Non Rate-Regulated Utility Assets ***(input as negative)***	($ 133,468)	$ -	($ 133,468)	($ 202,609)	$ -	($ 202,609)
	Total	$ 206,292,932	$ 24,509,267	$ 230,802,199	$ 225,372,751	$ 22,385,311	$ 247,758,062
	Less: *Fully Allocated Depreciation*						
	Transportation	($ 961,328)		($ 961,328)	($ 1,759,521)		($ 1,759,521)
	Net Depreciation	**$ 205,331,604**	**$ 24,509,267**	**$ 229,840,871**	**$ 223,613,230**	**$ 22,385,311**	**$ 245,998,541**

OEB Appendix 2-C
Depreciation and Amortization Expense

This appendix is to be completed in conjunction with the accounting instructions in Appendix 2-B

Scenario that applies	Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012. ☐	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Rebasing for the first time with depreciation policy changes made in 2013. ☐	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Already rebased with depreciation policy changes in a prior rate application ☑	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).	2018	MIFRS

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$69,572,669	$36,877,357	$32,695,312	$67,387,997	$5,290,961	$62,097,036	$73,814,110	4.91	20.36%	6.89	14.51%	$6,655,322	$9,008,172	$5,353,961	$21,017,455	$20,892,805	**-$124,650**
1612	Land Rights	$0	$0	$0	$0	$0	$0	$0	-	0.00%	-	0.00%	$0	$0	$0	$0	$0	**$0**
1805	Land	$7,588,531	$0	$7,588,531	-$8,030	$0	-$8,030	$0	-	0.00%	-	0.00%	$0	$0	$0	$0	$0	**$0**
1808	Buildings	$29,677,626	$3,203,894	$26,473,732	$87,327,434	$5,350	$87,322,084	$20,897,786	18.08	5.53%	66.77	1.50%	$1,464,400	$1,307,735	$156,483	$2,928,618	$3,308,486	**$379,868**
1815	Transformer Station Equipment >50 kV	$5,839,955	$13,224	$5,826,730	$31,091,235	$0	$31,091,235	$944,609	14.45	6.92%	37.03	2.70%	$403,185	$839,565	$12,754	$1,255,504	$1,298,265	**$42,761**
1820	Distribution Station Equipment <50 kV	$112,667,455	$1,707,056	$110,960,399	$73,489,735	$0	$73,489,735	$30,319,716	19.20	5.21%	30.55	3.27%	$5,779,142	$2,405,269	$496,172	$8,680,583	$8,622,713	**-$57,871**
1830	Poles, Towers & Fixtures	$208,620,348	$763,354	$207,856,994	$169,783,390	$1,311,076	$168,472,314	$21,287,951	31.60	3.16%	38.06	2.63%	$6,576,912	$4,426,310	$279,652	$11,282,874	$10,921,669	**-$361,205**
1835	Overhead Conductors & Devices	$197,786,423	$735,569	$197,050,854	$200,296,773	$1,434,382	$198,862,391	$41,090,486	34.02	2.94%	44.52	2.25%	$5,792,421	$4,466,999	$461,503	$10,720,923	$10,827,432	**$106,508**
1840	Underground Conduit	$639,376,710	$5,008,668	$634,368,042	$490,165,792	$205,791	$489,960,001	$78,574,199	22.27	4.49%	33.03	3.03%	$28,489,806	$14,832,912	$1,189,367	$44,512,085	$44,888,220	**$376,135**
1845	Underground Conductors & Devices	$397,494,067	$6,633,322	$390,860,745	$402,623,384	$5,111,479	$397,511,905	$87,194,048	31.09	3.22%	37.25	2.68%	$12,571,810	$10,672,600	$1,170,515	$24,414,925	$25,369,256	**$954,331**
1850	Line Transformers	$305,215,157	$8,045,785	$297,169,373	$245,905,202	$1,520,860	$244,384,342	$62,025,718	18.14	5.51%	27.47	3.64%	$16,381,002	$8,898,024	$1,129,177	$26,408,203	$23,997,546	**-$2,410,657**
1855	Services (Overhead & Underground)	$61,419,385	$720,464	$60,698,921	$62,815,335	$76,476	$62,738,858	$3,010,082	40.50	2.47%	43.98	2.27%	$1,498,869	$1,426,559	$34,222	$2,959,650	$2,947,558	**-$12,091**
1860	Meters	$44,538,583	$1,198,476	$43,340,106	$38,342,883	$235,731	$38,107,151	$8,057,288	19.72	5.07%	20.75	4.82%	$2,198,305	$1,836,741	$194,178	$4,229,223	$4,490,265	**$261,042**
1860	Meters (Smart Meters)	$94,589,513	$2,176,233	$92,413,280	$34,509,395	$106,085	$34,403,310	$16,301,957	9.75	10.25%	15.00	6.67%	$9,474,408	$2,293,554	$543,399	$12,311,360	$11,528,648	**-$782,712**
1905	Land	$9,150,994	$0	$9,150,994	$9,250,332	$0	$9,250,332	$0	-	0.00%	-	0.00%	$0	$0	$0	$0	$0	**$0**
1908	Buildings & Fixtures	$65,356,634	$16,446,753	$48,909,881	$185,015,240	$2,372,563	$182,642,677	$4,456,339	12.89	7.76%	31.04	3.22%	$3,793,552	$5,883,283	$71,774	$9,748,608	$11,318,351	**$1,569,743**
1910	Leasehold Improvements	$701,434	$701,434	$0	$52,406	$0	$52,406	$0	3.03	32.97%	5.00	20.00%	$0	$10,481	$0	$10,481	$10,481	**$0**
1915	Office Furniture & Equipment	$9,802,431	$2,404,395	$7,398,035	$9,227,322	$0	$9,227,322	$673,247	5.87	17.02%	10.00	10.00%	$1,259,422	$922,732	$33,662	$2,215,817	$2,051,264	**-$164,553**
1920	Computer Equipment - Hardware	$11,192,631	$11,254,107	-$61,476	$47,490,710	$4,698,090	$42,792,621	$8,077,721	3.34	29.93%	4.92	20.34%	-$18,400	$8,703,776	$821,481	$9,506,857	$10,714,855	**$1,207,999**
1930	Transportation Equipment	$21,967,081	$15,357,998	$6,609,083	$12,088,500	$0	$12,088,500	$2,912,073	4.03	24.80%	7.32	13.66%	$1,639,126	$1,650,822	$198,838	$3,488,786	$3,636,383	**$147,597**
1935	Stores Equipment	$7,066	$7,066	$0	$0	$0	$0	$0	-	0.00%	-	0.00%	$0	$0	$0	$0	$0	**$0**
1940	Tools, Shop & Garage Equipment	$11,036,987	$3,173,694	$7,863,293	$10,159,910	$0	$10,159,910	$2,199,041	5.61	17.81%	9.95	10.05%	$1,400,830	$1,021,143	$110,510	$2,532,483	$2,257,857	**-$274,626**
1945	Measurement & Testing Equipment	$9,367,510	$35,289	$9,332,221	-$8,887,268	$0	-$8,887,268	$0	4.39	22.77%	4.39	22.77%	$2,124,778	-$2,023,470	$0	$101,308	$59,822	**-$41,486**
1950	Service Equipment	$615,688	$266,460	$349,228	$230,085	$0	$230,085	$544,550	5.09	19.66%	8.00	12.50%	$68,668	$28,761	$34,034	$131,463	$159,091	**$27,627**
1955	Communications Equipment	$4,593,288	$4,444,612	$148,676	$40,764,758	$0	$40,764,758	$4,530,356	2.94	34.04%	12.85	7.78%	$50,608	$3,171,712	$176,243	$3,398,563	$4,690,337	**$1,291,774**
1960	Miscellaneous Equipment	$267,071	$0	$267,071	$3,907	$0	$3,907	$0	7.23	13.82%	10.00	10.00%	$36,919	$391	$0	$37,310	$37,310	**$0**
1970	Load Management Controls Customer Premises	$3,022,834	$3,022,834	$0	$0	$0	$0	$0	2.85	35.12%	-	0.00%	$0	$0	$0	$0	$0	**$0**
1975	Load Management Controls Utility Premises	$0	$0	$0	$0	$0	$0	$0	-	0.00%	-	0.00%	$0	$0	$0	$0	$0	**$0**
1980	System Supervisor Equipment	$19,174,795	$1,725,140	$17,449,656	$18,172,795	$70,327	$18,102,468	$6,524,511	11.09	9.02%	14.96	6.68%	$1,573,518	$1,209,964	$218,048	$3,001,531	$2,802,429	**-$199,102**
1985	Miscellaneous Fixed Assets	$0	$0	$0	$0	$0	$0	$0	-	0.00%	-	0.00%	$0	$0	$0	$0	$0	**$0**
2440	Contributions & Grants (Formally known as Account 1995)	$0	$0	$0	-$120,141,389	-$6,053,553	-$114,087,836	-$39,248,789	-	0.00%	35.20	2.84%	$0	-$3,241,115	-$557,508	-$3,798,624	-$5,263,537	**-$1,464,913**
1609	Capital Contributions Paid	$19,104,312	$0	$19,104,312	$56,470,186	$0	$56,470,186	$88,593,906	21.68	4.61%	24.97	4.01%	$881,195	$2,261,726	$1,774,167	$4,917,089	$3,538,390	**-$1,378,699**
2005	Property Under Capital Leases	$7,191,090	$0	$7,191,090	$10,979,744	$10,979,744	$0	$1,576,880	80.42	1.24%	6.66	15.02%	$89,423	$0	$118,429	$207,852	$1,320,504	**$1,112,652**
	Sub-Total	**$2,366,938,267**	**$125,923,184**	**$2,241,015,083**	**$2,174,607,766**	**$27,365,363**	**$2,147,242,402**	**$524,357,783**					**$110,185,220**	**$82,014,646**	**$14,021,059**	**$206,220,925**	**$206,426,400**	**$205,475**
	Less Socialized Renewable Energy Generation Investments ***(input as negative)***	$0		$0	$0		$0	$0		0.00%	10.00	10.00%	$0	$0	$0	$0	$0	**$0**
	Less Other Non Rate-Regulated Utility Assets ***(input as negative)***	$0		$0	-$2,002,023		-$2,002,023	$0		0.00%	15.00	6.67%	$0	-$133,468	$0	-$133,468	-$133,468	**$0**
	Total	**$2,366,938,267**	**$125,923,184**	**$2,241,015,083**	**$2,172,605,743**	**$27,365,363**	**$2,145,240,380**	**$524,357,783**					**$110,185,220**	**$81,881,178**	**$14,021,059**	**$206,087,457**	**$206,292,932**	**$205,475**

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1 This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.

2 This is the opening gross book value of assets that have been acquired after the date of the utilities change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the gross book value of the prior year plus the prior year's additions.

3 A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as at January 1 of the year of policy changes. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the revised CGAAP as at January 1 of the year of policy changes.

4 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.

5 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

6 The applicant must provide an explanation of material variances in evidence.

7 This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change

8 This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

OEB Appendix 2-C
Depreciation and Amortization Expense

This appendix is to be completed in conjunction with the accounting instructions in Appendix 2-B

Scenario that applies	Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012. ☐	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Rebasing for the first time with depreciation policy changes made in 2013. ☐	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Already rebased with depreciation policy changes in a prior rate application ☑	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).	2019	MIFRS

		Book Values								Service Lives			Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$69,572,669	$36,877,357	$32,695,312	$141,202,106	$19,277,944	$121,924,162	$40,029,185	4.91	20.36%	6.66	15.03%	$6,655,322	$18,320,573	$3,007,433	$27,983,329	$27,968,318	**-$15,010**
1612	Land Rights	$0	$0	$0	$0	$0	$0	$0	-	0.00%	-	0.00%	$0	$0	$0	$0	$0	**$0**
1805	Land	$7,588,531	$0	$7,588,531	-$8,030	$0	-$8,030	$0	-	0.00%	-	0.00%	$0	$0	$0	$0	$0	**$0**
1808	Buildings	$29,677,626	$3,292,155	$26,385,471	$108,225,220	$5,350	$108,219,870	$9,342,754	18.08	5.53%	65.76	1.52%	$1,459,518	$1,645,597	$71,033	$3,176,148	$3,576,986	**$400,838**
1815	Transformer Station Equipment >50 kV	$5,839,955	$13,224	$5,826,730	$32,035,844	$0	$32,035,844	$1,030,716	14.45	6.92%	34.94	2.86%	$403,185	$916,780	$14,748	$1,334,713	$1,339,480	**$4,767**
1820	Distribution Station Equipment <50 kV	$112,667,455	$2,585,570	$110,081,886	$103,809,451	$0	$103,809,451	$20,600,010	19.20	5.21%	30.95	3.23%	$5,733,387	$3,354,157	$332,800	$9,420,344	$9,828,871	**$408,527**
1830	Poles, Towers & Fixtures	$208,620,348	$763,354	$207,856,994	$191,071,341	$1,397,281	$189,674,060	$28,474,609	31.60	3.16%	38.34	2.61%	$6,576,912	$4,947,551	$371,373	$11,895,836	$11,163,183	**-$732,653**
1835	Overhead Conductors & Devices	$197,786,423	$934,614	$196,851,809	$241,387,259	$1,713,413	$239,673,846	$42,197,486	34.02	2.94%	44.47	2.25%	$5,786,570	$5,389,226	$474,419	$11,650,216	$11,552,701	**-$97,515**
1840	Underground Conduit	$639,376,710	$7,697,861	$631,678,849	$568,739,992	$205,791	$568,534,200	$101,150,177	22.27	4.49%	33.18	3.01%	$28,369,033	$17,136,131	$1,524,379	$47,029,542	$47,764,130	**$734,588**
1845	Underground Conductors & Devices	$397,494,067	$6,914,611	$390,579,456	$489,817,432	$5,858,818	$483,958,614	$98,357,471	31.09	3.22%	37.06	2.70%	$12,562,762	$13,059,939	$1,327,120	$26,949,822	$26,963,221	**$13,399**
1850	Line Transformers	$305,215,157	$10,840,283	$294,374,874	$307,930,921	$1,520,860	$306,410,060	$82,017,280	18.14	5.51%	27.46	3.64%	$16,226,960	$11,160,087	$1,493,619	$28,880,666	$25,545,270	**-$3,335,396**
1855	Services (Overhead & Underground)	$61,419,385	$720,464	$60,698,921	$65,825,416	$77,979	$65,747,437	$17,117,258	40.50	2.47%	44.24	2.26%	$1,498,869	$1,486,107	$193,453	$3,178,429	$3,062,482	**-$115,947**
1860	Meters	$44,538,583	$1,198,476	$43,340,106	$46,400,170	$273,348	$46,126,822	$19,232,313	19.72	5.07%	20.83	4.80%	$2,198,305	$2,214,168	$461,592	$4,874,065	$4,819,143	**-$54,922**
1860	Meters (Smart Meters)	$94,589,513	$2,176,233	$92,413,280	$50,811,352	$106,085	$50,705,267	$8,807,217	9.75	10.25%	15.00	6.67%	$9,474,408	$3,380,351	$293,574	$13,148,333	$11,966,280	**-$1,182,053**
1905	Land	$9,150,994	$0	$9,150,994	$9,250,332	$0	$9,250,332	$0	-	0.00%	-	0.00%	$0	$0	$0	$0	$0	**$0**
1908	Buildings & Fixtures	$65,356,634	$5,140,983	$60,215,651	$189,471,579	$2,372,563	$187,099,016	$1,250,623	12.89	7.76%	30.99	3.23%	$4,670,451	$6,036,520	$20,175	$10,727,146	$11,325,101	**$597,955**
1910	Leasehold Improvements	$701,434	$701,434	$0	$52,406	$52,406	$0	$0	3.03	32.97%	5.00	20.00%	$0	$0	$0	$0	$8,734	**$8,734**
1915	Office Furniture & Equipment	$9,802,431	$2,499,302	$7,303,129	$9,900,570	$0	$9,900,570	$448,337	5.87	17.02%	10.00	10.00%	$1,243,266	$990,057	$22,417	$2,255,739	$2,067,790	**-$187,949**
1920	Computer Equipment - Hardware	$11,192,631	$11,254,520	-$61,889	$55,568,432	$13,726,866	$41,841,565	$7,398,534	3.34	29.93%	4.82	20.75%	-$18,524	$8,682,131	$767,598	$9,431,206	$10,812,376	**$1,381,170**
1930	Transportation Equipment	$21,967,081	$21,164,466	$802,615	$15,000,573	$0	$15,000,573	$4,995,050	4.03	24.80%	7.37	13.56%	$199,057	$2,034,725	$338,772	$2,572,554	$3,141,469	**$568,915**
1935	Stores Equipment	$7,066	$7,066	$0	$0	$0	$0	$0	-	0.00%	-	0.00%	$0	$0	$0	$0	$0	**$0**
1940	Tools, Shop & Garage Equipment	$11,036,987	$3,804,933	$7,232,054	$12,358,951	$0	$12,358,951	$5,530,796	5.61	17.81%	9.97	10.03%	$1,288,376	$1,240,166	$277,495	$2,806,037	$2,443,955	**-$362,082**
1945	Measurement & Testing Equipment	$9,367,510	$35,289	$9,332,221	-$8,887,268	$0	-$8,887,268	$19,437	4.39	22.77%	4.39	22.77%	$2,124,778	-$2,023,470	$2,213	$103,520	$61,540	**-$41,980**
1950	Service Equipment	$615,688	$390,650	$225,037	$774,636	$0	$774,636	$122,762	5.09	19.66%	8.00	12.50%	$44,249	$96,829	$7,673	$148,751	$131,053	**-$17,698**
1955	Communications Equipment	$4,593,288	$4,444,612	$148,676	$45,295,114	$2,487,921	$42,807,193	$802,266	2.94	34.04%	12.77	7.83%	$50,608	$3,351,163	$31,403	$3,433,173	$4,719,684	**$1,286,510**
1960	Miscellaneous Equipment	$267,071	$0	$267,071	$3,907	$0	$3,907	$0	7.23	13.82%	10.00	10.00%	$36,919	$391	$0	$37,310	$37,310	**$0**
1970	Load Management Controls Customer Premises	$3,022,834	$3,022,834	$0	$0	$0	$0	$0	2.85	35.12%	-	0.00%	$0	$0	$0	$0	$0	**$0**
1975	Load Management Controls Utility Premises	$0	$0	$0	$0	$0	$0	$0	-	0.00%	-	0.00%	$0	$0	$0	$0	$0	**$0**
1980	System Supervisor Equipment	$19,174,795	$1,993,489	$17,181,306	$24,697,306	$70,327	$24,626,979	$10,865,041	11.09	9.02%	14.98	6.68%	$1,549,320	$1,644,519	$362,768	$3,556,607	$3,134,194	**-$422,414**
1985	Miscellaneous Fixed Assets	$0	$0	$0	$0	$0	$0	$0	-	0.00%	-	0.00%	$0	$0	$0	$0	$0	**$0**
2440	Contributions & Grants (Formally known as Account 1995)	$0	$0	$0	-$159,390,178	-$6,958,091	-$152,432,087	-$79,065,880	-	0.00%	34.28	2.92%	$0	-$4,446,901	-$1,153,294	-$5,600,195	-$5,711,872	**-$111,677**
1609	Capital Contributions Paid	$19,104,312	$0	$19,104,312	$145,064,091	$0	$145,064,091	$26,301,319	21.68	4.61%	24.97	4.01%	$881,195	$5,809,859	$526,688	$7,217,742	$7,235,447	**$17,705**
2005	Property Under Capital Leases	$7,191,090	$0	$7,191,090	$12,556,624	$10,979,744	$1,576,880	$0	80.42	1.24%	6.66	15.02%	$89,423	$236,857	$0	$326,280	$652,639	**$326,359**
	Sub-Total	**$2,366,938,267**	**$128,473,782**	**$2,238,464,486**	**$2,698,965,549**	**$53,168,607**	**$2,645,796,942**	**$447,024,759**					**$109,104,347**	**$106,663,514**	**$10,769,452**	**$226,537,313**	**$225,609,486**	**-$927,827**
	Less Socialized Renewable Energy Generation Investments ***(input as negative)***	$0		$0	$0		$0	-$2,730,141		0.00%	10.00	10.00%	$0	$0	-$136,507	-$136,507	-$34,127	**$102,380**
	Less Other Non Rate-Regulated Utility Assets ***(input as negative)***	$0		$0	-$2,002,023		-$2,002,023	-$3,702,262		0.00%	15.00	6.67%	$0	-$133,468	-$123,409	-$256,877	-$202,609	**$54,268**
	Total	**$2,366,938,267**	**$128,473,782**	**$2,238,464,486**	**$2,696,963,526**	**$53,168,607**	**$2,643,794,920**	**$440,592,356**					**$109,104,347**	**$106,530,046**	**$10,509,536**	**$226,143,929**	**$225,372,751**	**-$771,178**

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1 This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.

2 This is the opening gross book value of assets that have been acquired after the date of the utilities change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the gross book value of the prior year plus the prior year's additions.
A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as at January 1 of the year of policy changes. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the revised CGAAP as at January 1 of the year of policy changes.

3

4 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.

5 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

6 The applicant must provide an explanation of material variances in evidence.

7 This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change

8 This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

OPERATING COSTS: PILs VARIANCE ANALYSIS

1. CORPORATE TAXES (PILS)

1.1 Tax Payable Filings

Table 1 below provides a summary of Toronto Hydro's actual PILs from 2014 to 2017, as well as the forecasted PILs for 2018 and 2019. A copy of Toronto Hydro's 2017 tax return can be found in Toronto Hydro's response to interrogatory 4B-Staff-142 (b) at Appendix A.

Table 1: Summary of PILs by Year ($ Millions)

	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Forecast	2019 Bridge	2020 Test
Income Taxes	10.5	3.2	18.8	29.4	32.6	22.1	34.7

Toronto Hydro's actual PILs for 2017 was the same as the forecast provided in Exhibit 4B, Tab 2, Schedule 1. The 2018 and 2019 PILs forecast are $1.8 million and $1.7 million higher, respectively, than the forecasts in Exhibit 4B, Tab 2, Schedule 1 at page 6. The differences are primarily due to project completion timing changes, particularly relating to timing differences accociated with the ERP and Copeland TS projects in 2018, and changes in the timing of in-service additions in 2019 resulting from the work that is being carried over from 2018 into 2019.

COST OF CAPITAL

Exhibit 5, Tab 1 includes information about Toronto Hydro's capital structure and financing plans. There were no changes to this information as a result of 2018 actuals.

REVENUE REQUIREMENT

1. BASE REVENUE REQUIREMENT

Exhibit 6 presents the 2020 revenue requirement that Toronto Hydro is asking the OEB to approve in its application. As part of this application update, a number of relatively minor changes have been identified throughout Exhibit U that affect the 2020 revenue requirement. These changes are summarized in Table 1 below. The estimated net impact of the changes is an increase in revenue requirement of $0.9 million.

Table 1: Identified Changes to 2020 Forecast Revenue Requirement ($ Millions)

	2020 Test Year	Identified Changes	Reference
OM&A Expenses (incl. property taxes)	277.5	0.5	Exhibit U, Tab 4A, Schedule 1, page 1
Amortization/Depreciation	268.7	-	
Income Taxes (Grossed up)	34.7	(0.1)	Exhibit U, Tab 2, Schedule 1, section 3
Deemed Interest Expense	100.8	(0.2)	
Return on Deemed Equity	162.8	(0.3)	
Service Revenue Requirement	**844.5**	**844.4**	
Revenue Offsets	47.7	(1.0)	Exhibit U, Tab 3, Schedule 2, page 2
Base Revenue Requirement	**796.8**	**797.7**	

In the interest of efficiency, Toronto Hydro has decided not to flow these changes through the revenue requirement work form and cost allocation models. The utility requests that the OEB approve these changes as part of the 2020 test year, and proposes to make the updates as part of the Draft Rate Order process.

2. OVERALL REVENUE DEFICIENCY

The overall revenue deficiency for 2020 is not expected to materially change as a result of this update.

COST ALLOCATION

Exhibit 7 provides information on the allocation of Toronto Hydro's total revenue requirement to rate classes as the basis for determining rates for the 2020 rebasing year. This schedule provides an update to the cost allocation model for 2020. Specifically, the model has been updated for the following:

a) Billing weighting factors have been corrected (Tab I5.2 of the model), as identified in interrogatory 7-Staff-144.

b) The forecast number of customers, kWh and kVA loads for 2020 have been updated (Tab I6.1 of the model) to reflect the updated load and customer forecasts (see Exhibit U, Tab 3, Schedule 1).

c) A correction to the number of bills for the Unmetered Scattered Load class (Tab I6.2 of the model). The original filing used the number of USL devices as the basis for number of bills. However, customers in this class receive a single monthly bill that contains charges for more than one device. The update correctly captures the number of bills issued to the USL class. (Tab I6.2 of the model)

d) Demands for the Large Use and GS 1000-4999 kW classes were adjusted (Tab I8 of the model). Due to the reduction in the number of customers in the Large Use class (who were reclassed into the GS 1000-4999 kW rate class in 2018), it was appropriate to reflect the reduction in Large Use class contribution to peak demands (and subsequently increase the contribution of the GS 1000-4999 kW class). Due to the small size of the Large Use class, if demand information for cost allocation purposes was left unadjusted, the updated load and customer forecast would have a material impact for the revenue to cost ratios for this class and not appropriately reflect cost causality.

The resulting revenue to cost ratios, before rate design, compared with the previously filed evidence, are provided in Table 1 below.

Table 1: Revenue to Cost Ratios from Cost Allocation Model

Rate Class	Original R/C ratio before Rate Design	Updated R/C ratio before Rate Design
Residential	103.2	103.2
CSMUR	101.4	102.2
GS <50 kW	89.6	88.9
GS 50-999 kW	105.3	105.8
GS 1000-4999 kW	94.9	90.8
Large Use	84.6	88.2
Street Lighting	108.9	108.9
USL	94.6	137.1

The main driver of the change in the USL class is the update for the number of bills issued. Due to the revenues for this class being small relative to other classes, the change results in a material change in the calculated revenue to cost ratio. This ratio is now outside the OEB's Guideline range for this class. This issue is addressed further in Exhibit U, Tab 8, Schedule 1.

The main driver of the change in the Large Use and GS 1000-4999 kW class is the update in the demands (CP and NCP) for these classes, due to the reclass of 6 Large Use customers into the GS 1000-4999 kW class.

For all rate classes other than the USL class, the resulting ratios are within the OEB's guideline ranges.

The updated Cost Allocation Model is filed as Appendix A to this schedule.

Ontario Energy Board

2019 Cost Allocation Model

EB-2018-0165

Sheet I6.1 Revenue Worksheet -

Total kWhs from Load Forecast	23,377,600,153
Total kWs from Load Forecast	40,232,337
Deficiency/sufficiency (RRWF 8. cell F51)	- 25,444,889
Miscellaneous Revenue (RRWF 5. cell F48)	47,687,081

			1	2	4	5	6	7	9	10
	ID	**Total**	**Residential**	**GS <50**	**GS - 50 to 999**	**GS - 1000 to 4999**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Competitive Sector Multi-Unit Residential**
Billing Data										
Forecast kWh	**CEN**	23,377,600,153	4,531,218,421	2,299,006,608	9,608,309,249	4,595,015,405	1,889,478,427	116,219,746	40,588,612	297,763,685
Forecast kW	**CDEM**	40,232,337			24,899,004	10,406,674	4,600,360	326,300		
Forecast kW, included in CDEM, of customers receiving line transformer allowance		19,579,628			6,373,898	8,698,598	4,507,133			
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-								
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	23,377,600,153	4,531,218,421	2,299,006,608	9,608,309,249	4,595,015,405	1,889,478,427	116,219,746	40,588,612	297,763,685
Existing Monthly Charge			$38.00	$36.30	$52.22	$997.38	$4,402.54	$1.63	$7.24	$31.00
Existing Distribution kWh Rate			$0.0055	$0.0331					$0.0897	$0.0085
Existing Distribution kW Rate					$8.22	$6.47	$6.94	$36.27	$0.75	
Existing TOA Rate			$0.63	$0.63	$0.63	$0.63	$0.63	$0.63	$0.63	$0.63
Additional Charges										
Distribution Revenue from Rates		$783,714,891	$305,551,446	$107,331,623	$211,142,740	$72,427,709	$33,914,273	$15,068,574	$3,822,500	$34,456,025
Transformer Ownership Allowance		$12,335,166	$0	$0	$4,015,556	$5,480,116	$2,839,494	$0	$0	$0
Net Class Revenue	**CREV**	$771,379,725	$305,551,446	$107,331,623	$207,127,185	$66,947,592	$31,074,780	$15,068,574	$3,822,500	$34,456,025

Ontario Energy Board

2019 Cost Allocation Model

EB-2018-0165

Sheet I6.2 Customer Data Worksheet -

			1	2	4	5	6	7	9	10
	ID	Total	Residential	GS <50	GS - 50 to 999	GS - 1000 to 4999	Large Use >5MW	Street Light	Unmetered Scattered Load	Competitive Sector Multi-Unit Residential
Billing Data										
Bad Debt 3 Year Historical Average	BDHA	$7,377,253	$3,890,292	$2,111,101	$828,264	$261,154	$0	$0	$0	$286,442
Late Payment 3 Year Historical Average	LPHA	$4,287,180	$2,487,420	$919,878	$596,564	$77,959	$16,058		$5,649	$183,652
Number of Bills	CNB	9,411,468	7,381,416.00	859,188.00	125,004.00	5,160.00	456.00	120.00	9,900.00	1,030,224.00
Number of Devices	CDEV							165,274		
Number of Connections (Unmetered)	CCON	103,999						91,819	12,180	
Total Number of Customers	CCA	784,280	615,118	71,599	10,417	430	38	1	825	85,852
Bulk Customer Base	CCB	-								
Primary Customer Base	CCP	802,785	615,118	71,599	10,417	430	38	18,506	825	85,852
Line Transformer Customer Base	CCLT	800,327	615,118	71,599	8,333	94	-	18,506	825	85,852
Secondary Customer Base	CCS	775,441	615,118	71,599	2,041	5	-	1	825	85,852
Weighted - Services	CWCS	689,087	615,118	71,599	2,041	5	-	-	-	325
Weighted Meter -Capital	CWMC	137,068,160	87,346,756	36,658,688	11,167,024	1,675,710	219,982	-	-	-
Weighted Meter Reading	CWMR	9,715,948	7,381,416	988,066	1,211,289	124,201	10,976	-	-	-
Weighted Bills	CWNB	11,415,791	7,381,416	2,319,808	625,020	30,444	3,055	84	25,740	1,030,224

Bad Debt Data

Historic Year:	2015	5,920,268	3,264,885	1,679,206	910,835	-				65,342
Historic Year:	2016	9,841,560	4,872,078	2,746,113	1,039,975	783,461				399,934
Historic Year:	2017	6,369,929	3,533,912	1,907,985	533,980	-				394,051
Three-year average		**7,377,253**	**3,890,292**	**2,111,101**	**828,264**	**261,154**	**-**	**-**	**-**	**286,442**

Street Lighting Adjustment Factors

NCP Test Results	4 NCP

	Primary Asset Data		Line Transformer Asset Data	
Class	**Customers/ Devices**	**4 NCP**	**Customers/ Devices**	**4 NCP**
Residential	615,118	4,129,569	615,118	4,129,569
Street Light	165,274	124,238	165,274	124,238

Street Lighting Adjustment Factors	
Primary	8.9309
Line Transformer	8.9309

Ontario Energy Board

2019 Cost Allocation Model

EB-2018-0165

Sheet I8 Demand Data Worksheet -

This is an input sheet for demand allocators.

CP TEST RESULTS	12 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

Customer Classes		Total	1 Residential	2 GS <50	4 GS - 50 to 999	5 GS - 1000 to 4999	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load	10 Competitive Sector Multi-Unit Residential
		CP Sanity Check	Pass	Pass	Pass	Check 4CP	Check 4CP and 12CP	Check 12CP	Check 4CP and 12CP	Pass
CO-INCIDENT PEAK										
1 CP										
Transformation CP	TCP1	4,262,830	972,614	578,946	1,662,853	764,853	239,922	-	3,548	40,093
Bulk Delivery CP	BCP1	4,262,830	972,614	578,946	1,662,853	764,853	239,922	-	3,548	40,093
Total Sytem CP	DCP1	4,262,830	972,614	578,946	1,662,853	764,853	239,922	-	3,548	40,093
4 CP										
Transformation CP	TCP4	16,449,304	3,718,466	1,992,718	6,532,784	3,069,430	966,675	-	16,832	152,399
Bulk Delivery CP	BCP4	16,449,304	3,718,466	1,992,718	6,532,784	3,069,430	966,675	-	16,832	152,399
Total Sytem CP	DCP4	16,449,304	3,718,466	1,992,718	6,532,784	3,069,430	966,675	-	16,832	152,399
12 CP										
Transformation CP	TCP12	45,262,168	8,853,188	5,623,085	18,460,316	8,322,601	3,323,660	171,288	58,103	449,926
Bulk Delivery CP	BCP12	45,262,168	8,853,188	5,623,085	18,460,316	8,322,601	3,323,660	171,288	58,103	449,926
Total Sytem CP	DCP12	45,262,168	8,853,188	5,623,085	18,460,316	8,322,601	3,323,660	171,288	58,103	449,926
NON CO_INCIDENT PEAK										
		NCP Sanity Check	Pass	Pass	Pass	Pass	Pass	Pass	Pass	Pass
1 NCP										
Classification NCP from Load Data Provider	DNCP1	4,603,543	1,085,007	601,583	1,674,421	782,816	364,037	31,399	5,833	58,447
Primary NCP	PNCP1	4,489,529	1,085,007	601,583	1,560,710	782,816	364,037	31,399	5,530	58,447
Line Transformer NCP	LTNCP1	3,383,973	1,085,007	601,583	1,399,700	202,306	-	31,399	5,530	58,447
Secondary NCP	SNCP1	2,218,380	1,085,007	601,583	419,910	16,504	-	31,399	5,530	58,447
4 NCP										
Classification NCP from Load Data Provider	DNCP4	17,678,767	4,129,569	2,275,913	6,481,669	3,096,720	1,325,478	124,238	22,521	222,660
Primary NCP	PNCP4	17,237,427	4,129,569	2,275,913	6,041,495	3,096,720	1,325,478	124,238	21,354	222,660
Line Transformer NCP	LTNCP4	12,980,524	4,129,569	2,275,913	5,418,227	788,565	-	124,238	21,354	222,660
Secondary NCP	SNCP4	8,464,488	4,129,569	2,275,913	1,625,468	65,287	-	124,238	21,354	222,660
12 NCP										
Classification NCP from Load Data Provider	DNCP12	48,381,915	10,395,631	6,389,304	18,220,979	8,564,929	3,805,731	320,510	63,331	621,500
Primary NCP	PNCP12	47,141,234	10,395,631	6,389,304	16,983,582	8,564,929	3,805,731	320,510	60,047	621,500
Line Transformer NCP	LTNCP12	35,213,790	10,395,631	6,389,304	15,231,478	2,195,321	-	320,510	60,047	621,500
Secondary NCP	SNCP12	22,537,005	10,395,631	6,389,304	4,569,443	180,571	-	320,510	60,047	621,500

Ontario Energy Board

2019 Cost Allocation Model

EB-2018-0165

Sheet O1 Revenue to Cost Summary Worksheet -

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	4 GS - 50 to 999	5 GS - 1000 to 4999	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load	10 Competitive Sector Multi-Unit Residential
crev	Distribution Revenue at Existing Rates	$771,379,725	$305,551,446	$107,331,623	$207,127,185	$66,947,592	$31,074,780	$15,068,574	$3,822,500	$34,456,025
mi	Miscellaneous Revenue (mi)	$47,687,081	$19,227,963	$8,463,061	$7,210,004	$1,444,895	$520,946	$9,005,538	$127,143	$1,687,531
		Miscellaneous Revenue Input equals Output								
	Total Revenue at Existing Rates	**$819,066,806**	**$324,779,409**	**$115,794,685**	**$214,337,189**	**$68,392,487**	**$31,595,725**	**$24,074,112**	**$3,949,644**	**$36,143,556**
	Factor required to recover deficiency (1 + D)	1.0330								
	Distribution Revenue at Status Quo Rates	$796,824,614	$315,630,428	$110,872,086	$213,959,524	$69,155,939	$32,099,819	$15,565,629	$3,948,590	$35,592,598
	Miscellaneous Revenue (mi)	$47,687,081	$19,227,963	$8,463,061	$7,210,004	$1,444,895	$520,946	$9,005,538	$127,143	$1,687,531
	Total Revenue at Status Quo Rates	**$844,511,695**	**$334,858,391**	**$119,335,147**	**$221,169,528**	**$70,600,834**	**$32,620,764**	**$24,571,168**	**$4,075,733**	**$37,280,129**
	Expenses									
di	Distribution Costs (di)	$126,815,041	$43,200,057	$19,858,165	$37,795,391	$15,239,907	$6,112,987	$1,416,594	$329,419	$2,862,520
cu	Customer Related Costs (cu)	$44,768,626	$28,551,737	$9,144,554	$2,964,784	$371,267	$12,785	$218,594	$102,269	$3,402,637
ad	General and Administration (ad)	$101,234,363	$40,901,585	$16,573,389	$23,716,793	$9,076,787	$3,739,764	$2,564,951	$336,523	$4,324,571
dep	Depreciation and Amortization (dep)	$260,980,412	$103,149,700	$43,520,685	$68,682,668	$24,056,013	$9,623,040	$3,865,370	$787,730	$7,295,207
INPUT	PILs (INPUT)	$33,544,822	$12,647,309	$5,250,916	$8,775,947	$3,270,281	$1,514,356	$751,274	$115,676	$1,219,063
INT	Interest	$97,374,932	$36,712,993	$15,242,520	$25,475,087	$9,493,072	$4,395,920	$2,180,821	$335,787	$3,538,732
	Total Expenses	**$664,718,195**	**$265,163,380**	**$109,590,229**	**$167,410,671**	**$61,507,327**	**$25,398,852**	**$10,997,603**	**$2,007,404**	**$22,642,730**
	Direct Allocation	**$22,495,532**	**$0**	**$0**	**$456,032**	**$951,591**	**$4,496,993**	**$8,034,208**	**$422,853**	**$8,133,855**
NI	Allocated Net Income (NI)	$157,297,967	$59,305,605	$24,622,532	$41,152,063	$15,334,963	$7,101,101	$3,522,865	$542,425	$5,716,414
	Revenue Requirement (includes NI)	**$844,511,695**	$324,468,984	$134,212,761	$209,018,766	$77,793,881	$36,996,946	$22,554,676	$2,972,681	$36,492,998
		Revenue Requirement Input equals Output								

EB-2018-0165

Sheet O1 Revenue to Cost Summary Worksheet -

	Rate Base Calculation									
	Net Assets									
dp	Distribution Plant - Gross	$4,690,749,227	$1,842,559,092	$768,203,854	$1,258,314,737	$458,523,436	$176,256,462	$55,526,926	$13,823,397	$117,541,322
gp	General Plant - Gross	$839,667,754	$314,887,139	$130,637,881	$218,273,061	$81,462,265	$38,869,747	$20,386,714	$2,968,007	$32,182,940
accum dep	Accumulated Depreciation	($1,209,717,480)	($476,308,741)	($201,391,666)	($315,771,679)	($113,649,531)	($46,497,428)	($18,364,710)	($3,642,639)	($34,091,086)
co	Capital Contribution	($73,594,426)	($30,652,768)	($12,254,589)	($18,914,367)	($6,303,924)	($2,329,502)	($924,086)	($233,144)	($1,982,045)
	Total Net Plant	$4,247,105,075	$1,650,484,722	$685,195,481	$1,141,901,752	$420,032,246	$166,299,279	$56,624,844	$12,915,621	$113,651,130
	Directly Allocated Net Fixed Assets	$133,001,496	$0	$0	$3,241,784	$6,764,514	$31,969,399	$42,348,089	$2,228,847	$46,448,864
COP	Cost of Power (COP)	$3,384,043,227	$655,920,150	$332,794,542	$1,390,858,498	$665,155,134	$273,512,962	$16,823,482	$5,875,437	$43,103,021
	OM&A Expenses	$272,818,030	$112,653,378	$45,576,108	$64,476,969	$24,687,961	$9,865,537	$4,200,139	$768,211	$10,589,728
	Directly Allocated Expenses	$4,679,814	$0	$0	$22,111	$46,138	$218,029	$2,872,171	$151,167	$1,370,198
	Subtotal	***$3,661,541,071***	***$768,573,528***	***$378,370,650***	***$1,455,357,578***	***$689,889,233***	***$283,596,528***	***$23,895,792***	***$6,794,815***	***$55,062,947***
	Working Capital	$235,187,789	$49,366,948	$24,303,471	$93,480,402	$44,312,905	$18,215,948	$1,534,872	$436,444	$3,536,798
	Total Rate Base	$4,615,294,360	$1,699,851,671	$709,498,951	$1,238,623,938	$471,109,665	$216,484,625	$100,507,805	$15,580,912	$163,636,793
			Rate Base Input equals Output							
	Equity Component of Rate Base	$1,846,117,744	$679,940,668	$283,799,581	$495,449,575	$188,443,866	$86,593,850	$40,203,122	$6,232,365	$65,454,717
	Net Income on Allocated Assets	$157,297,967	$69,695,011	$9,744,918	$53,302,825	$8,141,915	$2,724,919	$5,539,356	$1,645,477	$6,503,545
	Net Income on Direct Allocation Assets	$5,529,618	$0	$0	$134,779	$281,239	$1,329,147	$1,760,648	$92,666	$1,931,140
	Net Income	$162,827,585	$69,695,011	$9,744,918	$53,437,604	$8,423,154	$4,054,067	$7,300,003	$1,738,142	$8,434,685
	RATIOS ANALYSIS									
	REVENUE TO EXPENSES STATUS QUO%	100.00%	103.20%	88.91%	105.81%	90.75%	88.17%	108.94%	137.11%	102.16%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($25,444,889)	$310,424	($18,418,077)	$5,318,422	($9,401,395)	($5,401,220)	$1,519,436	$976,962	($349,442)
			Deficiency Input equals Output							
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	$0	$10,389,407	($14,877,614)	$12,150,762	($7,193,048)	($4,376,181)	$2,016,491	$1,103,052	$787,131
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.82%	10.25%	3.43%	10.79%	4.47%	4.68%	18.16%	27.89%	12.89%

Ontario Energy Board

2019 Cost Allocation Model

EB-2018-0165

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1 Residential	2 GS <50	4 GS - 50 to 999	5 GS - 1000 to 4999	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load	10 Competitive Sector Multi-Unit Residential
Customer Unit Cost per month - Avoided Cost	$5.11	$14.82	$23.60	$11.50	-$194.89	$0.15	$0.58	$2.69
Customer Unit Cost per month - Directly Related	$7.25	$20.40	$35.51	$32.68	-$168.22	$0.26	$0.98	$4.37
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$18.86	$35.20	$53.24	$129.36	-$76.93	$5.06	$2.81	$12.30
Existing Approved Fixed Charge	$38.00	$36.30	$52.22	$997.38	$4,402.54	$1.63	$7.24	$31.00

Information to be Used to Allocate PILs, ROD, ROE and A&G

	Total	1 Residential	2 GS <50	4 GS - 50 to 999	5 GS - 1000 to 4999	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load	10 Competitive Sector Multi-Unit Residential
General Plant - Gross Assets	$839,667,754	$314,887,139	$130,637,881	$218,273,061	$81,462,265	$38,869,747	$20,386,714	$2,968,007	$32,182,940
General Plant - Accumulated Depreciation	($375,982,230)	($140,998,589)	($58,496,377)	($97,737,220)	($36,476,766)	($17,404,901)	($9,128,661)	($1,329,000)	($14,410,716)
General Plant - Net Fixed Assets	$463,685,525	$173,888,550	$72,141,504	$120,535,841	$44,985,499	$21,464,846	$11,258,053	$1,639,008	$17,772,224
General Plant - Depreciation	$71,867,332	$26,951,254	$11,181,323	$18,682,035	$6,972,372	$3,326,869	$1,744,903	$254,032	$2,754,544
Total Net Fixed Assets Excluding General Plant	$3,916,418,640	$1,476,596,172	$613,053,977	$1,024,607,695	$381,811,260	$176,803,831	$87,712,594	$13,505,340	$142,327,770
Total Administration and General Expense	$101,234,363	$40,901,585	$16,573,389	$23,716,793	$9,076,787	$3,739,764	$2,564,951	$336,523	$4,324,571
Total O&M	$176,262,465	$71,751,793	$29,002,719	$40,782,287	$15,657,312	$6,343,801	$4,506,393	$582,804	$7,635,355

EB-2018-0165

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

			1	2	4	5	6	7	9	10	
USoA Account #	Accounts	Total	Residential	GS <50	GS - 50 to 999	GS - 1000 to 4999	Large Use >5MW	Street Light	Unmetered Scattered Load	Competitive Sector Multi-Unit Residential	
	Distribution Plant										
1860	Meters	$206,044,239	$131,301,798	$55,106,244	$16,786,546	$2,518,969	$330,682	$0	$0	$0	CWMC
	Accumulated Amortization										
	Accum. Amortization of Electric Utility Plant - Meters only	($95,621,684)	($60,934,968)	($25,573,886)	($7,790,355)	($1,169,011)	($153,464)	$0	$0	$0	
	Meter Net Fixed Assets	**$110,422,555**	**$70,366,831**	**$29,532,358**	**$8,996,191**	**$1,349,957**	**$177,218**	**$0**	**$0**	**$0**	
	Misc Revenue										
4082	Retail Services Revenues	($274,804)	($113,473)	($45,908)	($64,946)	($24,868)	($9,937)	($4,231)	($774)	($10,667)	CWNB
4084	Service Transaction Requests (STR) Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
4090	Electric Services Incidental to Energy Sales	($2,407,409)	($994,079)	($402,174)	($568,960)	($217,852)	($87,056)	($37,063)	($6,779)	($93,446)	CWNB
4220	Other Electric Revenues	($912,869)	($376,947)	($152,501)	($215,745)	($82,608)	($33,011)	($14,054)	($2,570)	($35,434)	NFA
4225	Late Payment Charges	($3,751,641)	($2,176,700)	($804,970)	($522,043)	($68,221)	($14,052)	$0	($4,943)	($160,711)	LPHA
	Sub-total	*($7,346,723)*	*($3,661,200)*	*($1,405,553)*	*($1,371,694)*	*($393,548)*	*($144,056)*	*($55,348)*	*($15,067)*	*($300,258)*	
	Operation										
5065	Meter Expense	$476,757	$303,813	$127,508	$38,842	$5,829	$765	$0	$0	$0	CWMC
5070	Customer Premises - Operation Labour	$1,470,099	$1,018,966	$118,606	$17,256	$712	$63	$152,101	$20,177	$142,217	CCA
5075	Customer Premises - Materials and Expenses	$640,352	$443,845	$51,663	$7,517	$310	$27	$66,253	$8,789	$61,947	CCA
	Sub-total	*$2,587,207*	*$1,766,625*	*$297,777*	*$63,614*	*$6,851*	*$856*	*$218,354*	*$28,965*	*$204,165*	
	Maintenance										
5175	Maintenance of Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	1860
	Billing and Collection										
5310	Meter Reading Expense	$2,857,700	$2,171,057	$290,615	$356,270	$36,531	$3,228	$0	$0	$0	CWMR
5315	Customer Billing	$9,470,331	$6,123,488	$1,924,470	$518,505	$25,256	$2,535	$70	$21,353	$854,655	CWNB
5320	Collecting	$22,254,548	$14,389,724	$4,522,356	$1,218,447	$59,349	$5,956	$164	$50,179	$2,008,373	CWNB
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
	Sub-total	$34,582,580	$22,684,268	$6,737,441	$2,093,222	$121,136	$11,719	$233	$71,532	$2,863,028	
	Total Operation, Maintenance and Billing	$37,169,787	$24,450,893	$7,035,218	$2,156,837	$127,987	$12,574	$218,588	$100,498	$3,067,193	
	Amortization Expense - Meters	$19,305,119	$12,302,197	$5,163,127	$1,572,799	$236,012	$30,983	$0	$0	$0	
	Allocated PILs	$846,165	$539,206	$226,318	$68,943	$10,344	$1,354	$0	$0	$0	
	Allocated Debt Return	$2,456,272	$1,565,223	$656,962	$200,131	$30,027	$3,929	$0	$0	$0	
	Allocated Equity Return	$3,967,824	$2,528,437	$1,061,247	$323,289	$48,504	$6,347	$0	$0	$0	
	Total	**$56,398,443**	**$37,724,757**	**$12,737,319**	**$2,950,305**	**$59,326**	**($88,869)**	**$163,240**	**$85,431**	**$2,766,935**	

EB-2018-0165

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

USoA Account #	Accounts	Total	1 Residential	2 GS <50	4 GS - 50 to 999	5 GS - 1000 to 4999	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load	10 Competitive Sector Multi-Unit Residential	
	Distribution Plant										
1860	Meters	$206,044,239	$131,301,798	$55,106,244	$16,786,546	$2,518,969	$330,682	$0	$0	$0	CWMC
	Accumulated Amortization										
	Accum. Amortization of Electric Utility Plant - Meters only	($95,621,684)	($60,934,968)	($25,573,886)	($7,790,355)	($1,169,011)	($153,464)	$0	$0	$0	
	Meter Net Fixed Assets	$110,422,555	$70,366,831	$29,532,358	$8,996,191	$1,349,957	$177,218	$0	$0	$0	
	Allocated General Plant Net Fixed Assets	$13,000,744	$8,286,616	$3,475,238	$1,058,321	$159,054	$21,515	$0	$0	$0	
	Meter Net Fixed Assets Including General Plant	$123,423,300	$78,653,447	$33,007,597	$10,054,511	$1,509,011	$198,733	$0	$0	$0	
	Misc Revenue										
4082	Retail Services Revenues	($274,804)	($113,473)	($45,908)	($64,946)	($24,868)	($9,937)	($4,231)	($774)	($10,667)	CWNB
4084	Service Transaction Requests (STR) Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
4090	Electric Services Incidental to Energy Sales	($2,407,409)	($994,079)	($402,174)	($568,960)	($217,852)	($87,056)	($37,063)	($6,779)	($93,446)	CWNB
4220	Other Electric Revenues	($912,869)	($376,947)	($152,501)	($215,745)	($82,608)	($33,011)	($14,054)	($2,570)	($35,434)	NFA
4225	Late Payment Charges	($3,751,641)	($2,176,700)	($804,970)	($522,043)	($68,221)	($14,052)	$0	($4,943)	($160,711)	LPHA
	Sub-total	*($7,346,723)*	*($3,661,200)*	*($1,405,553)*	*($1,371,694)*	*($393,548)*	*($144,056)*	*($55,348)*	*($15,067)*	*($300,258)*	
	Operation										
5065	Meter Expense	$476,757	$303,813	$127,508	$38,842	$5,829	$765	$0	$0	$0	CWMC
5070	Customer Premises - Operation Labour	$1,470,099	$1,018,966	$118,606	$17,256	$712	$63	$152,101	$20,177	$142,217	CCA
5075	Customer Premises - Materials and Expenses	$640,352	$443,845	$51,663	$7,517	$310	$27	$66,253	$8,789	$61,947	CCA
	Sub-total	*$2,587,207*	*$1,766,625*	*$297,777*	*$63,614*	*$6,851*	*$856*	*$218,354*	*$28,965*	*$204,165*	
	Maintenance										
5175	Maintenance of Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	1860
	Billing and Collection										
5310	Meter Reading Expense	$2,857,700	$2,171,057	$290,615	$356,270	$36,531	$3,228	$0	$0	$0	CWMR
5315	Customer Billing	$9,470,331	$6,123,488	$1,924,470	$518,505	$25,256	$2,535	$70	$21,353	$854,655	CWNB
5320	Collecting	$22,254,548	$14,389,724	$4,522,356	$1,218,447	$59,349	$5,956	$164	$50,179	$2,008,373	CWNB
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
	Sub-total	*$34,582,580*	*$22,684,268*	*$6,737,441*	*$2,093,222*	*$121,136*	*$11,719*	*$233*	*$71,532*	*$2,863,028*	
	Total Operation, Maintenance and Billing	$37,169,787	$24,450,893	$7,035,218	$2,156,837	$127,987	$12,574	$218,588	$100,498	$3,067,193	
	Amortization Expense - Meters	$19,305,119	$12,302,197	$5,163,127	$1,572,799	$236,012	$30,983	$0	$0	$0	
	Amortization Expense - General Plant assigned to Meters	*$2,015,005*	*$1,284,355*	*$538,633*	*$164,031*	*$24,652*	*$3,335*	*$0*	*$0*	*$0*	
	Admin and General	$21,213,850	$13,938,053	$4,020,223	$1,254,301	$74,196	$7,413	$124,416	$58,029	$1,737,220	
	Allocated PILs	$945,789	$602,704	$252,950	$77,054	$11,563	$1,518	$0	$0	$0	
	Allocated Debt Return	$2,745,465	$1,749,549	$734,271	$223,675	$33,564	$4,406	$0	$0	$0	
	Allocated Equity Return	$4,434,981	$2,826,194	$1,186,130	$361,321	$54,219	$7,118	$0	$0	$0	
	Total	**$80,483,273**	**$53,492,746**	**$17,524,998**	**$4,438,322**	**$168,645**	**($76,709)**	**$287,656**	**$143,461**	**$4,504,155**	

EB-2018-0165

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

			1	2	4	5	6	7	9	10	
USoA Account #	Accounts	Total	Residential	GS <50	GS - 50 to 999	GS - 1000 to 4999	Large Use >5MW	Street Light	Unmetered Scattered Load	Competitive Sector Multi-Unit Residential	
	Distribution Plant										
1565	Conservation and Demand Management Expenditures and Recoveries	$0	$0	$0	$0	$0	$0	$0	$0	$0	CDMPP
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	#N/A
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	BCP
1830-4	Poles, Towers and Fixtures - Primary	$53,669,039	$40,549,293	$4,719,889	$686,701	$28,346	$2,505	$1,219,922	$802,920	$5,659,464	PNCP
1830-5	Poles, Towers and Fixtures - Secondary	$34,312,992	$24,022,552	$2,796,196	$79,694	$195	$0	$3,585,855	$475,672	$3,352,827	SNCP
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	#N/A
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	BCP
1835-4	Overhead Conductors and Devices - Primary	$68,757,879	$51,949,568	$6,046,868	$879,764	$36,315	$3,209	$1,562,898	$1,028,657	$7,250,600	PNCP
1835-5	Overhead Conductors and Devices - Secondary	$43,959,956	$30,776,398	$3,582,336	$102,100	$250	$0	$4,594,004	$609,406	$4,295,461	SNCP
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	#N/A
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	BCP
1840-4	Underground Conduit - Primary	$220,743,819	$166,781,555	$19,413,174	$2,824,439	$116,589	$10,303	$5,017,607	$3,302,455	$23,277,696	PNCP
1840-5	Underground Conduit - Secondary	$87,988,795	$61,601,022	$7,170,285	$204,360	$501	$0	$9,195,207	$1,219,767	$8,597,653	SNCP
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	#N/A
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	BCP
1845-4	Underground Conductors and Devices - Primary	$159,500,636	$120,509,667	$14,027,181	$2,040,827	$84,243	$7,445	$3,625,522	$2,386,221	$16,819,530	PNCP
1845-5	Underground Conductors and Devices - Secondary	$63,577,177	$44,510,429	$5,180,961	$147,663	$362	$0	$6,644,088	$881,355	$6,212,319	SNCP
1850	Line Transformers	$156,379,002	$118,508,828	$13,794,286	$1,605,507	$18,180	$0	$3,565,327	$2,346,603	$16,540,273	LTNCP
1855	Services	$165,577,509	$147,803,787	$17,204,184	$490,337	$1,201	$0	$0	$0	$78,000	CWCS
1860	Meters	$206,122,239	$131,301,798	$55,106,244	$16,786,546	$2,518,969	$330,682	$0	$0	$78,000	CWMC
											0
	Sub-total	*$1,260,589,042*	*$938,314,897*	*$149,041,604*	*$25,847,938*	*$2,805,151*	*$354,145*	*$39,010,429*	*$13,053,056*	*$92,161,822*	
	Accumulated Amortization										
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	($279,813,864)	($200,635,099)	($41,834,814)	($9,445,461)	($1,220,981)	($157,675)	($7,041,594)	($2,418,927)	($17,059,314)	
	Customer Related Net Fixed Assets	$980,775,178	$737,679,798	$107,206,790	$16,402,477	$1,584,170	$196,470	$31,968,836	$10,634,129	$75,102,509	
	Allocated General Plant Net Fixed Assets	$116,398,924	$86,871,463	$12,615,625	$1,929,603	$186,649	$23,852	$4,103,252	$1,290,558	$9,377,921	
	Customer Related NFA Including General Plant	$1,097,174,102	$824,551,261	$119,822,415	$18,332,081	$1,770,819	$220,322	$36,072,087	$11,924,686	$84,480,430	
	Misc Revenue										
4082	Retail Services Revenues	($274,804)	($113,473)	($45,908)	($64,946)	($24,868)	($9,937)	($4,231)	($774)	($10,667)	CWNB
4084	Service Transaction Requests (STR) Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
4090	Electric Services Incidental to Energy Sales	($2,407,409)	($994,079)	($402,174)	($568,960)	($217,852)	($87,056)	($37,063)	($6,779)	($93,446)	CWNB
4220	Other Electric Revenues	($912,869)	($376,947)	($152,501)	($215,745)	($82,608)	($33,011)	($14,054)	($2,570)	($35,434)	NFA
4225	Late Payment Charges	($3,751,641)	($2,176,700)	($804,970)	($522,043)	($68,221)	($14,052)	$0	($4,943)	($160,711)	LPHA
4235	Miscellaneous Service Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
	Sub-total	*($7,346,723)*	*($3,661,200)*	*($1,405,553)*	*($1,371,694)*	*($393,548)*	*($144,056)*	*($55,348)*	*($15,067)*	*($300,258)*	

EB-2018-0165

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

	Operating and Maintenance										
5005	Operation Supervision and Engineering	$7,790,742	$5,931,316	$694,530	$88,888	$12,816	$4,579	$286,476	$95,860	$676,279	1815-1855
5010	Load Dispatching	$2,007,476	$1,528,350	$178,963	$22,904	$3,302	$1,180	$73,818	$24,701	$174,260	1815-1855
5020	Overhead Distribution Lines and Feeders - Operation Labour	$133,829	$98,220	$11,433	$1,166	$43	$4	$7,310	$1,945	$13,708	1830 & 1835
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$188,759	$138,534	$16,125	$1,644	$61	$5	$10,310	$2,743	$19,335	1830 & 1835
5035	Overhead Distribution Transformers- Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	1850
5040	Underground Distribution Lines and Feeders - Operation Labour	$127,555	$94,357	$10,983	$1,251	$48	$4	$5,872	$1,868	$13,169	1840 & 1845
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$616,551	$456,089	$53,088	$6,049	$234	$21	$28,384	$9,031	$63,656	1840 & 1845
5055	Underground Distribution Transformers - Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	1850
5065	Meter Expense	$476,757	$303,813	$127,508	$38,842	$5,829	$765	$0	$0	$0	CWMC
5070	Customer Premises - Operation Labour	$1,470,099	$1,018,966	$118,606	$17,256	$712	$63	$152,101	$20,177	$142,217	CCA
5075	Customer Premises - Materials and Expenses	$640,352	$443,845	$51,663	$7,517	$310	$27	$66,253	$8,789	$61,947	CCA
5085	Miscellaneous Distribution Expense	$1,397,837	$1,064,214	$124,615	$15,948	$2,299	$822	$51,400	$17,199	$121,340	1815-1855
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	1840 & 1845
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	1830 & 1835
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	O&M
5105	Maintenance Supervision and Engineering	$3,871,554	$2,947,526	$345,142	$44,172	$6,369	$2,275	$142,362	$47,637	$336,072	1815-1855
5120	Maintenance of Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	1830
5125	Maintenance of Overhead Conductors and Devices	$4,292,769	$3,150,553	$366,721	$37,394	$1,393	$122	$234,481	$62,384	$439,723	1835
5130	Maintenance of Overhead Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	1855
5135	Overhead Distribution Lines and Feeders - Right of Way	$771,935	$566,539	$65,945	$6,724	$250	$22	$42,165	$11,218	$79,072	1830 & 1835
5145	Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	1840
5150	Maintenance of Underground Conductors and Devices	$1,272,324	$941,192	$109,554	$12,482	$483	$42	$58,573	$18,637	$131,362	1845
5155	Maintenance of Underground Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	1855
5160	Maintenance of Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	1850
5175	Maintenance of Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	1860
	Sub-total	*$25,058,539*	*$18,683,514*	*$2,274,874*	*$302,236*	*$34,149*	*$9,931*	*$1,159,504*	*$322,189*	*$2,272,141*	

EB-2018-0165

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

	Billing and Collection										
5305	Supervision	$785,685	$508,021	$159,659	$43,017	$2,095	$210	$6	$1,772	$70,905	CWNB
5310	Meter Reading Expense	$2,857,700	$2,171,057	$290,615	$356,270	$36,531	$3,228	$0	$0	$0	CWMR
5315	Customer Billing	$9,470,331	$6,123,488	$1,924,470	$518,505	$25,256	$2,535	$70	$21,353	$854,655	CWNB
5320	Collecting	$22,254,548	$14,389,724	$4,522,356	$1,218,447	$59,349	$5,956	$164	$50,179	$2,008,373	CWNB
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
5335	Bad Debt Expense	$6,813,154	$3,592,822	$1,949,677	$764,931	$241,185	$0	$0	$0	$264,540	BDHA
5340	Miscellaneous Customer Accounts Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
	Sub-total	*$42,181,418*	*$26,785,112*	*$8,846,777*	*$2,901,170*	*$364,415*	*$11,929*	*$239*	*$73,304*	*$3,198,473*	
	Sub Total Operating, Maintenance and Biling	*$67,239,957*	*$45,468,626*	*$11,121,650*	*$3,203,406*	*$398,565*	*$21,860*	*$1,159,744*	*$395,493*	*$5,470,613*	
	Amortization Expense - Customer Related	$58,116,163	$41,569,429	$8,593,393	$2,046,722	$307,718	$56,984	$1,455,378	$507,477	$3,579,063	
	Amortization Expense - General Plant assigned to Meters	$18,040,848	$13,464,342	$1,955,315	$299,072	$28,929	$3,697	$635,969	$200,026	$1,453,498	
	Admin and General	$38,368,270	$25,919,058	$6,355,384	$1,862,929	$231,054	$12,887	$660,104	$228,366	$3,098,488	
	Allocated PILs	$8,400,514	$6,318,359	$918,245	$140,490	$13,569	$1,683	$273,819	$91,083	$643,266	
	Allocated Debt Return	$24,385,268	$18,341,124	$2,665,510	$407,819	$39,388	$4,885	$794,849	$264,399	$1,867,293	
	Allocated Equity Return	$39,391,586	$29,627,970	$4,305,824	$658,785	$63,626	$7,891	$1,283,988	$427,106	$3,016,397	
	PLCC Adjustment for Line Transformer	$8,199,926	$6,208,603	$722,620	$84,103	$952	$0	$188,490	$123,318	$871,840	
	PLCC Adjustment for Primary Costs	$19,676,211	$14,858,248	$1,729,526	$250,004	$10,270	$911	$445,627	$295,311	$2,086,315	
	PLCC Adjustment for Secondary Costs	$23,339,420	$16,787,817	$1,813,017	$258,076	$10,596	$0	$0	$1,269,143	$3,200,771	
	Total	$195,380,325	**$139,193,039**	**$30,244,606**	**$6,655,347**	**$667,482**	**($35,080)**	**$5,574,386**	**$411,111**	**$12,669,434**	

EB-2018-0165

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Below: Grouping to avoid disclosure

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS - 50 to 999	GS - 1000 to 4999	Large Use >5MW	Street Light	Unmetered Scattered Load	Competitive Sector Multi-Unit Residential
Distribution Plant									
CWMC	$ 206,044,239	$ 131,301,798	$ 55,106,244	$ 16,786,546	$ 2,518,969	$ 330,682	$ -	$ -	$ -
Accumulated Amortization									
Accum. Amortization of Electric Utility Plant - Meters only	$ (95,621,684)	$ (60,934,968)	$ (25,573,886)	$ (7,790,355)	$ (1,169,011)	$ (153,464)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 110,422,555	$ 70,366,831	$ 29,532,358	$ 8,996,191	$ 1,349,957	$ 177,218	$ -	$ -	$ -
Misc Revenue									
CWNB	$ (2,682,213)	$ (1,107,553)	$ (448,082)	$ (633,906)	$ (242,720)	$ (96,993)	$ (41,294)	$ (7,553)	$ (104,113)
NFA	$ (912,869)	$ (376,947)	$ (152,501)	$ (215,745)	$ (82,608)	$ (33,011)	$ (14,054)	$ (2,570)	$ (35,434)
LPHA	$ (3,751,641)	$ (2,176,700)	$ (804,970)	$ (522,043)	$ (68,221)	$ (14,052)	$ -	$ (4,943)	$ (160,711)
Sub-total	$ (7,346,723)	$ (3,661,200)	$ (1,405,553)	$ (1,371,694)	$ (393,548)	$ (144,056)	$ (55,348)	$ (15,067)	$ (300,258)
Operation									
CWMC	$ 476,757	$ 303,813	$ 127,508	$ 38,842	$ 5,829	$ 765	$ -	$ -	$ -
CCA	$ 2,110,451	$ 1,462,811	$ 170,269	$ 24,773	$ 1,023	$ 90	$ 218,354	$ 28,965	$ 204,165
Sub-total	$ 2,587,207	$ 1,766,625	$ 297,777	$ 63,614	$ 6,851	$ 856	$ 218,354	$ 28,965	$ 204,165
Maintenance									
1860	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Billing and Collection									
CWMR	$ 2,857,700	$ 2,171,057	$ 290,615	$ 356,270	$ 36,531	$ 3,228	$ -	$ -	$ -
CWNB	$ 31,724,879	$ 20,513,212	$ 6,446,826	$ 1,736,952	$ 84,605	$ 8,491	$ 233	$ 71,532	$ 2,863,028
Sub-total	$ 34,582,580	$ 22,684,268	$ 6,737,441	$ 2,093,222	$ 121,136	$ 11,719	$ 233	$ 71,532	$ 2,863,028
Total Operation, Maintenance and Billing	$ 37,169,787	$ 24,450,893	$ 7,035,218	$ 2,156,837	$ 127,987	$ 12,574	$ 218,588	$ 100,498	$ 3,067,193
Amortization Expense - Meters	$ 19,305,119	$ 12,302,197	$ 5,163,127	$ 1,572,799	$ 236,012	$ 30,983	$ -	$ -	$ -
Allocated PILs	$ 846,165	$ 539,206	$ 226,318	$ 68,943	$ 10,344	$ 1,354	$ -	$ -	$ -
Allocated Debt Return	$ 2,456,272	$ 1,565,223	$ 656,962	$ 200,131	$ 30,027	$ 3,929	$ -	$ -	$ -
Allocated Equity Return	$ 3,967,824	$ 2,528,437	$ 1,061,247	$ 323,289	$ 48,504	$ 6,347	$ -	$ -	$ -
Total	**$ 56,398,443**	**$ 37,724,757**	**$ 12,737,319**	**$ 2,950,305**	**$ 59,326**	**$ (88,869)**	**$ 163,240**	**$ 85,431**	**$ 2,766,935**

EB-2018-0165

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS - 50 to 999	GS - 1000 to 4999	Large Use >5MW	Street Light	Unmetered Scattered Load	Competitive Sector Multi-Unit Residential
Distribution Plant									
CWMC	$ 206,044,239	$ 131,301,798	$ 55,106,244	$ 16,786,546	$ 2,518,969	$ 330,682	$ -	$ -	$ -
Accumulated Amortization									
Accum. Amortization of Electric Utility Plant - Meters only	$ (95,621,684)	$ (60,934,968)	$ (25,573,886)	$ (7,790,355)	$ (1,169,011)	$ (153,464)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 110,422,555	$ 70,366,831	$ 29,532,358	$ 8,996,191	$ 1,349,957	$ 177,218	$ -	$ -	$ -
Allocated General Plant Net Fixed Assets	$ 13,000,744	$ 8,286,616	$ 3,475,238	$ 1,058,321	$ 159,054	$ 21,515	$ -	$ -	$ -
Meter Net Fixed Assets Including General Plant	$ 123,423,300	$ 78,653,447	$ 33,007,597	$ 10,054,511	$ 1,509,011	$ 198,733	$ -	$ -	$ -
Misc Revenue									
CWNB	$ (2,682,213)	$ (1,107,553)	$ (448,082)	$ (633,906)	$ (242,720)	$ (96,993)	$ (41,294)	$ (7,553)	$ (104,113)
NFA	$ (912,869)	$ (376,947)	$ (152,501)	$ (215,745)	$ (82,608)	$ (33,011)	$ (14,054)	$ (2,570)	$ (35,434)
LPHA	$ (3,751,641)	$ (2,176,700)	$ (804,970)	$ (522,043)	$ (68,221)	$ (14,052)	$ -	$ (4,943)	$ (160,711)
Sub-total	*$ (7,346,723)*	*$ (3,661,200)*	*$ (1,405,553)*	*$ (1,371,694)*	*$ (393,548)*	*$ (144,056)*	*$ (55,348)*	*$ (15,067)*	*$ (300,258)*
Operation									
CWMC	$ 476,757	$ 303,813	$ 127,508	$ 38,842	$ 5,829	$ 765	$ -	$ -	$ -
CCA	$ 2,110,451	$ 1,462,811	$ 170,269	$ 24,773	$ 1,023	$ 90	$ 218,354	$ 28,965	$ 204,165
Sub-total	*$ 2,587,207*	*$ 1,766,625*	*$ 297,777*	*$ 63,614*	*$ 6,851*	*$ 856*	*$ 218,354*	*$ 28,965*	*$ 204,165*
Maintenance									
1860	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Billing and Collection									
CWMR	$ 2,857,700	$ 2,171,057	$ 290,615	$ 356,270	$ 36,531	$ 3,228	$ -	$ -	$ -
CWNB	$ 31,724,879	$ 20,513,212	$ 6,446,826	$ 1,736,952	$ 84,605	$ 8,491	$ 233	$ 71,532	$ 2,863,028
Sub-total	*$ 34,582,580*	*$ 22,684,268*	*$ 6,737,441*	*$ 2,093,222*	*$ 121,136*	*$ 11,719*	*$ 233*	*$ 71,532*	*$ 2,863,028*
Total Operation, Maintenance and Billing	$ 37,169,787	$ 24,450,893	$ 7,035,218	$ 2,156,837	$ 127,987	$ 12,574	$ 218,588	$ 100,498	$ 3,067,193
Amortization Expense - Meters	$ 19,305,119	$ 12,302,197	$ 5,163,127	$ 1,572,799	$ 236,012	$ 30,983	$ -	$ -	$ -
Amortization Expense - General Plant assigned to Meters	$ 2,015,005	$ 1,284,355	$ 538,633	$ 164,031	$ 24,652	$ 3,335	$ -	$ -	$ -
Admin and General	$ 21,213,850	$ 13,938,053	$ 4,020,223	$ 1,254,301	$ 74,196	$ 7,413	$ 124,416	$ 58,029	$ 1,737,220
Allocated PILs	$ 945,789	$ 602,704	$ 252,950	$ 77,054	$ 11,563	$ 1,518	$ -	$ -	$ -
Allocated Debt Return	$ 2,745,465	$ 1,749,549	$ 734,271	$ 223,675	$ 33,564	$ 4,406	$ -	$ -	$ -
Allocated Equity Return	$ 4,434,981	$ 2,826,194	$ 1,186,130	$ 361,321	$ 54,219	$ 7,118	$ -	$ -	$ -
Total	**$ 80,483,273**	**$ 53,492,746**	**$ 17,524,998**	**$ 4,438,322**	**$ 168,645**	**$ (76,709)**	**$ 287,656**	**$ 143,461**	**$ 4,504,155**

EB-2018-0165

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	Residential	GS <50	GS - 50 to 999	GS - 1000 to 4999	Large Use >5MW	Street Light	Unmetered Scattered Load	Competitive Sector Multi-Unit Residential
	Distribution Plant									
	CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Poles, Towers and Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	PNCP	$ 502,671,373	$ 379,790,083	$ 44,207,112	$ 6,431,731	$ 265,493	$ 23,462	$ 11,425,948	$ 7,520,253	$ 53,007,290
	SNCP	$ 229,838,919	$ 160,910,401	$ 18,729,778	$ 533,818	$ 1,308	$ -	$ 24,019,154	$ 3,186,200	$ 22,458,260
	Overhead Conductors and Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LTNCP	$ 156,379,002	$ 118,508,828	$ 13,794,286	$ 1,605,507	$ 18,180	$ -	$ 3,565,327	$ 2,346,603	$ 16,540,273
	CWCS	$ 165,577,509	$ 147,803,787	$ 17,204,184	$ 490,337	$ 1,201	$ -	$ -	$ -	$ 78,000
	CWMC	$ 206,122,239	$ 131,301,798	$ 55,106,244	$ 16,786,546	$ 2,518,969	$ 330,682	$ -	$ -	$ 78,000
	Sub-total	*$ 1,260,589,042*	*$ 938,314,897*	*$ 149,041,604*	*$ 25,847,938*	*$ 2,805,151*	*$ 354,145*	*$ 39,010,429*	*$ 13,053,056*	*$ 92,161,822*
	Accumulated Amortization									
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	$ (279,813,864)	$ (200,635,099)	$ (41,834,814)	$ (9,445,461)	$ (1,220,981)	$ (157,675)	$ (7,041,594)	$ (2,418,927)	$ (17,059,314)
	Customer Related Net Fixed Assets	$ 980,775,178	$ 737,679,798	$ 107,206,790	$ 16,402,477	$ 1,584,170	$ 196,470	$ 31,968,836	$ 10,634,129	$ 75,102,509
	Allocated General Plant Net Fixed Assets	$ 116,398,924	$ 86,871,463	$ 12,615,625	$ 1,929,603	$ 186,649	$ 23,852	$ 4,103,252	$ 1,290,558	$ 9,377,921
	Customer Related NFA Including General Plant	$ 1,097,174,102	$ 824,551,261	$ 119,822,415	$ 18,332,081	$ 1,770,819	$ 220,322	$ 36,072,087	$ 11,924,686	$ 84,480,430
	Misc Revenue									
	CWNB	$ (2,682,213)	$ (1,107,553)	$ (448,082)	$ (633,906)	$ (242,720)	$ (96,993)	$ (41,294)	$ (7,553)	$ (104,113)
	NFA	$ (912,869)	$ (376,947)	$ (152,501)	$ (215,745)	$ (82,608)	$ (33,011)	$ (14,054)	$ (2,570)	$ (35,434)
	LPHA	$ (3,751,641)	$ (2,176,700)	$ (804,970)	$ (522,043)	$ (68,221)	$ (14,052)	$ -	$ (4,943)	$ (160,711)
	Sub-total	*$ (7,346,723)*	*$ (3,661,200)*	*$ (1,405,553)*	*$ (1,371,694)*	*$ (393,548)*	*$ (144,056)*	*$ (55,348)*	*$ (15,067)*	*$ (300,258)*
	Operating and Maintenance									
	1815-1855	$ 15,067,610	$ 11,471,406	$ 1,343,248	$ 171,912	$ 24,786	$ 8,855	$ 554,056	$ 185,397	$ 1,307,950
	1830 & 1835	$ 1,094,523	$ 803,293	$ 93,502	$ 9,534	$ 355	$ 31	$ 59,785	$ 15,906	$ 112,116
	1850	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1840 & 1845	$ 744,106	$ 550,446	$ 64,071	$ 7,300	$ 282	$ 25	$ 34,256	$ 10,899	$ 76,826
	CWMC	$ 476,757	$ 303,813	$ 127,508	$ 38,842	$ 5,829	$ 765	$ -	$ -	$ -
	CCA	$ 2,110,451	$ 1,462,811	$ 170,269	$ 24,773	$ 1,023	$ 90	$ 218,354	$ 28,965	$ 204,165
	O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1835	$ 4,292,769	$ 3,150,553	$ 366,721	$ 37,394	$ 1,393	$ 122	$ 234,481	$ 62,384	$ 439,723
	1855	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1845	$ 1,272,324	$ 941,192	$ 109,554	$ 12,482	$ 483	$ 42	$ 58,573	$ 18,637	$ 131,362
	1860	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Sub-total	*$ 25,058,539*	*$ 18,683,514*	*$ 2,274,874*	*$ 302,236*	*$ 34,149*	*$ 9,931*	*$ 1,159,504*	*$ 322,189*	*$ 2,272,141*

EB-2018-0165

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

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RATE DESIGN

1. RATE DESIGN

Updated 2020-24 proposed rates reflect the following:

a) Updated load and customer forecast, which impacts rebased 2020 rates, and the calculation of the growth factor, "g", in the Custom Price Cap Index proposal for setting rates in the 2021-24 period.
b) Updated results of the Cost Allocation model.
c) Updated rate riders for clearance of Group I and Group II deferral and variance accounts.

As noted in the Cost Allocation update section, the updated revenue to cost ratios for all classes, other than the USL class, are within the OEB's guideline ranges. The rates for the USL class have been designed to bring their revenue to cost ratio within the guideline for the class. Additionally, and as originally filed and ordered by the OEB, the CSMUR class rates have been designed to achieve a revenue to cost ratio of 1.0. The additional revenue responsibility necessary to achieve these adjustments has been allocated to the GS <50 kW, GS 1000-4999 kW, and Large Use classes proportionally to the amounts those classes were below their allocated costs (same treatment as originally proposal for reallocation of revenue responsibility).

The proposed revenue to cost ratios, after rate design, are provided and compared to the prefiled ratios, in Table 1.

Table 1: Revenue to Cost Ratios after Rate Design

Rate Class	Original R/C ratio	Updated R/C ratio	OEB's Guideline Ranges
Residential	103.2	103.2	85-115
CSMUR	100.0	100.0	
GS <50 kW	89.8	89.5	80-120
GS 50-999 kW	105.3	105.8	80-120
GS 1000-4999 kW	95.0	91.2	80-120
Large Use	85.0	88.8	85-115
Streetlighting	108.9	108.9	80-120
USL	94.7	120.0	80-120

The full calculation of the updated 2020 distribution rates is provided in the Revenue Requirement Workform filed as Appendix A under Exhibit U, Tab 6, Schedule 1.

The updated growth factor, "g", derived from the updated load and customer forecast, is unchanged from 0.2, as filed in Exhibit 1B, Tab 4, Schedule 1, section 3.4. Table 2 shows the derivation of the updated "g".

Table 2: Forecast Revenue at 2020 Proposed Rates

	2020	2021	2022	2023	2024	Annual Average ("g")
Revenue at 2020 Rates	$796.9	$797.3	$799.8	$801.8	$804.3	
Annual Growth Rate		0.0%	0.3%	0.2%	0.3%	0.2%

Updated rate riders associated with deferral and variance accounts are discussed and provided in Tab 9, Schedule 1.

2. BILL IMPACTS TABLES

The OEB Appendix 2-W Bill Impact tables, detailing the updated proposed rates, are provided for all rate classes at Appendix A to this schedule.

A summary of the bill impacts (including all rate riders) resulting from the utility's proposals is shown in Table 3 below.

Table 3: Bill Impacts – Change In Monthly Bill

	Change in bill	2020 Proposed	2021 Proposed	2022 Proposed	2023 Proposed	2024 Proposed
Residential	$/30 days	-3.53	0.99	1.12	1.40	1.92
	%	*-2.7*	*0.8*	*0.9*	*1.1*	*1.5*
Competitive Sector Multi-Unit Residential	$/30 days	-1.74	1.01	0.89	0.99	1.51
	%	*-2.5*	*1.5*	*1.3*	*1.4*	*2.1*
General Service <50 kW	$/30 days	-5.29	2.22	2.82	4.40	4.82
	%	*-1.6*	*0.7*	*0.9*	*1.3*	*1.4*
General Service 50-999 kW	$/30 days	-442.30	262.16	49.57	87.53	84.57
	%	*-3.1*	*1.9*	*0.4*	*0.6*	*0.6*
General Service 1,000-4,999 kW	$/30 days	-4,334.08	2,782.72	408.13	720.88	696.44
	%	*-2.8*	*1.9*	*0.3*	*0.5*	*0.5*
Large Use	$/30 days	-406.96	-1,054.39	2,102.70	3,713.96	3,588.48
	%	*-0.1*	*-0.1*	*0.3*	*0.5*	*0.5*
Street Lighting	$/30 days	-7,309.35	6,962.19	3,587.48	6,323.55	6,152.69
	%	*-2.5*	*2.5*	*1.2*	*2.2*	*2.0*
Unmetered Scattered Load	$/30 days	-6.04	0.82	0.80	1.42	1.37
	%	*-9.3*	*1.4*	*1.4*	*2.4*	*2.2*

OEB Appendix 2-W
Bill Impacts

2

Customer Class: RESIDENTIAL SERVICE

TOU / non-TOU: TOU

Consumption 750 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		2018 Current Board-Approved			2019 Current Board-Approved			Impact		2020 Proposed			Impact		2021 Proposed			Impact		2022 Proposed			Impact		2023 Proposed			Impact		2024 Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change
Service Charge	per 30 days	$ 32.63	1	$ 32.63	$ 37.48	1	$ 37.48	$ 4.85	14.86%	$ 42.17	1	$ 42.17	$ 4.69	12.51%	$ 43.54	1	$ 43.54	$ 1.37	3.25%	$ 44.61	1	$ 44.61	$ 1.07	2.46%	$ 46.50	1	$ 46.50	$ 1.89	4.24%	$ 48.33	1	$ 48.33	$ 1.83	3.94%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per 30 days									$ 0.09	1	$ 0.09	$ 0.09		$ 0.09	1	$ 0.09	$ -	0.00%	$ 0.09	1	$ 0.09	$ -	0.00%	$ 0.09	1	$ 0.09	$ -	0.00%	$ 0.09	1	$ 0.09	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per 30 days									$ 0.51	1	$ 0.51	$ 0.51		$ 0.51	1	$ 0.51	$ -	0.00%	$ 0.51	1	$ 0.51	$ -	0.00%	$ 0.51	1	$ 0.51	$ -	0.00%	$ 0.51	1	$ 0.51	$ -	0.00%
Rate Rider for Recovery of Monthly Billing - effective until Dec. 31, 2024	per 30 days									$ 0.28	1	$ 0.28	$ 0.28		$ 0.28	1	$ 0.28	$ -	0.00%	$ 0.28	1	$ 0.28	$ -	0.00%	$ 0.28	1	$ 0.28	$ -	0.00%	$ 0.28	1	$ 0.28	$ -	0.00%
Rate Rider for Recovery of Stranded Meter Assets - effective until Dec. 31, 2024	per 30 days									-$ 0.02	1	-$ 0.02	-$ 0.02		-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per 30 days									-$ 0.78	1	-$ 0.78	-$ 0.78		-$ 0.78	1	-$ 0.78	$ -	0.00%	-$ 0.78	1	-$ 0.78	$ -	0.00%	-$ 0.78	1	-$ 0.78	$ -	0.00%	-$ 0.78	1	-$ 0.78	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per 30 days									-$ 0.12	1	-$ 0.12	-$ 0.12		-$ 0.12	1	-$ 0.12	$ -	0.00%	-$ 0.12	1	-$ 0.12	$ -	0.00%	-$ 0.12	1	-$ 0.12	$ -	0.00%	-$ 0.12	1	-$ 0.12	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per 30 days									-$ 0.01	1	-$ 0.01	-$ 0.01		-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per 30 days									-$ 0.02	1	-$ 0.02	-$ 0.02		-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per 30 days									-$ 0.83	1	-$ 0.83	-$ 0.83		-$ 0.83	1	-$ 0.83	$ -	0.00%	-$ 0.83	1	-$ 0.83	$ -	0.00%	-$ 0.83	1	-$ 0.83	$ -	0.00%	-$ 0.83	1	-$ 0.83	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per 30 days									-$ 0.03	1	-$ 0.03	-$ 0.03		-$ 0.03	1	-$ 0.03	$ -	0.00%	-$ 0.03	1	-$ 0.03	$ -	0.00%	-$ 0.03	1	-$ 0.03	$ -	0.00%	-$ 0.03	1	-$ 0.03	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per 30 days									-$ 0.37	1	-$ 0.37	-$ 0.37		-$ 0.37	1	-$ 0.37	$ -	0.00%	-$ 0.37	1	-$ 0.37	$ -	0.00%	-$ 0.37	1	-$ 0.37	$ -	0.00%	-$ 0.37	1	-$ 0.37	$ -	0.00%
Rate Rider for Disposition of AR Credits - effective until Dec. 31, 2024	per 30 days									-$ 0.08	1	-$ 0.08	-$ 0.08		-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%
Rate Rider for Recovery of Stranded Meters Assets - effective until Dec. 31, 2019.	per 30 days	$ 0.28	1	$ 0.28	$ 0.28	1	$ 0.28	$ -	0.00%		1	$ -	-$ 0.28			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per 30 days	-$ 0.48	1	-$ 0.48		1	$ -	$ 0.48			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per 30 days	-$ 1.48	1	-$ 1.48		1	$ -	$ 1.48			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per 30 days	$ 0.10	1	$ 0.10	$ 0.10	1	$ 0.10	$ -	0.00%		1	$ -	-$ 0.10			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per 30 days	$ 0.03	1	$ 0.03	$ 0.03	1	$ 0.03	$ -	0.00%		1	$ -	-$ 0.03			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per 30 days	$ 0.46	1	$ 0.46	$ 0.46	1	$ 0.46	$ -	0.00%		1	$ -	-$ 0.46			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.88	1	$ 0.88	$ 0.88	1	$ 0.88	$ -	0.00%		1	$ -	-$ 0.88			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.28	1	$ 0.28	$ 0.28	1	$ 0.28	$ -	0.00%		1	$ -	-$ 0.28			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.01063	750	$ 7.97	$ 0.00553	750	$ 4.15	-$ 3.83	-47.98%		750	$ -	-$ 4.15			750	$ -	$ -			750	$ -	$ -			750	$ -	$ -			750	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kWh	$ 0.00041	750	$ 0.31	$ 0.00095	750	$ 0.71	$ 0.41	131.71%		750	$ -	-$ 0.71			750	$ -	$ -			750	$ -	$ -			750	$ -	$ -			750	$ -	$ -	
Sub-Total A (excluding pass through)				**$ 40.98**			**$ 44.37**	**$ 3.39**	**8.27%**			**$ 40.79**	**-$ 3.58**	**-8.07%**			**$ 42.16**	**$ 1.37**	**3.36%**			**$ 43.23**	**$ 1.07**	**2.54%**			**$ 45.12**	**$ 1.89**	**4.37%**			**$ 46.95**	**$ 1.83**	**4.06%**
Line Losses on Cost of Power	per kWh	$ 0.0820	28	$ 2.31	$ 0.0820	28	$ 2.31	$ -	0.00%	$ 0.0820	22	$ 1.81	-$ 0.50	-21.54%	$ 0.0820	22	$ 1.81	$ -	0.00%	$ 0.0820	22	$ 1.81	$ -	0.00%	$ 0.0820	22	$ 1.81	$ -	0.00%	$ 0.0820	22	$ 1.81	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	per kWh	-$ 0.00320	750	-$ 2.40	-$ 0.00052	750	-$ 0.39	$ 2.01	-83.75%	$ 0.00060	750	$ 0.45	$ 0.84	-215.38%			$ -	-$ 0.45				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	per kWh	$ 0.00007	750	$ 0.05	$ 0.00003	750	$ 0.02	-$ 0.03	-57.14%	-$ 0.00003	750	-$ 0.02	-$ 0.05	-200.00%			$ -	$ 0.02				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	per kWh	-$ 0.00112		$ -	$ 0.00068		$ -	$ -		-$ 0.00290		$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	per 30 days	$ 0.56	1	$ 0.56	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%			$ -	-$ 0.56				$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 41.50**			**$ 46.87**	**$ 5.37**	**12.94%**			**$ 43.59**	**-$ 3.28**	**-7.00%**			**$ 44.53**	**$ 0.94**	**2.16%**			**$ 45.60**	**$ 1.07**	**2.40%**			**$ 46.93**	**$ 1.33**	**2.92%**			**$ 48.76**	**$ 1.83**	**3.90%**
Retail Transmissioin Rate - Network Service Rate	per kWh	$ 0.00759	778	$ 5.91	$ 0.00796	778	$ 6.19	$ 0.29	4.87%	$ 0.00825	772	$ 6.37	$ 0.18	2.83%	$ 0.00825	772	$ 6.37	$ -	0.00%	$ 0.00825	772	$ 6.37	$ -	0.00%	$ 0.00825	772	$ 6.37	$ -	0.00%	$ 0.00825	772	$ 6.37	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	per kWh	$ 0.00617	778	$ 4.80	$ 0.00703	778	$ 5.47	$ 0.67	13.94%	$ 0.00679	772	$ 5.24	-$ 0.23	-4.17%	$ 0.00679	772	$ 5.24	$ -	0.00%	$ 0.00679	772	$ 5.24	$ -	0.00%	$ 0.00679	772	$ 5.24	$ -	0.00%	$ 0.00679	772	$ 5.24	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				**$ 52.21**			**$ 58.54**	**$ 6.33**	**12.12%**			**$ 55.20**	**-$ 3.34**	**-5.70%**			**$ 56.15**	**$ 0.94**	**1.71%**			**$ 57.22**	**$ 1.07**	**1.91%**			**$ 58.55**	**$ 1.33**	**2.32%**			**$ 60.38**	**$ 1.83**	**3.13%**
Wholesale Market Service Rate - not including CBR	per kWh	$ 0.0032	778	$ 2.49	$ 0.0032	778	$ 2.49	$ -	0.00%	$ 0.0032	772	$ 2.47	-$ 0.02	-0.78%	$ 0.0032	772	$ 2.47	$ -	0.00%	$ 0.0032	772	$ 2.47	$ -	0.00%	$ 0.0032	772	$ 2.47	$ -	0.00%	$ 0.0032	772	$ 2.47	$ -	0.00%
Rural and Remote Rate Protection Charge (RRRP)	per kWh	$ 0.0003	778	$ 0.23	$ 0.0003	778	$ 0.23	$ -	0.00%	$ 0.0003	772	$ 0.23	-$ 0.00	-0.78%	$ 0.0003	772	$ 0.23	$ -	0.00%	$ 0.0003	772	$ 0.23	$ -	0.00%	$ 0.0003	772	$ 0.23	$ -	0.00%	$ 0.0003	772	$ 0.23	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	778	$ 0.31	$ 0.0004	778	$ 0.31	$ -	0.00%	$ 0.0004	772	$ 0.31	-$ 0.00	-0.78%	$ 0.0004	772	$ 0.31	$ -	0.00%	$ 0.0004	772	$ 0.31	$ -	0.00%	$ 0.0004	772	$ 0.31	$ -	0.00%	$ 0.0004	772	$ 0.31	$ -	0.00%
Standard Supply Service - Administrative Charge (if applicable)	per 30 days	$ 0.25	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	488	$ 31.69	$ 0.0650	488	$ 31.69	$ -	0.00%	$ 0.0650	488	$ 31.69	$ -	0.00%	$ 0.0650	488	$ 31.69	$ -	0.00%	$ 0.0650	488	$ 31.69	$ -	0.00%	$ 0.0650	488	$ 31.69	$ -	0.00%	$ 0.0650	488	$ 31.69	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	128	$ 11.99	$ 0.0940	128	$ 11.99	$ -	0.00%	$ 0.0940	128	$ 11.99	$ -	0.00%	$ 0.0940	128	$ 11.99	$ -	0.00%	$ 0.0940	128	$ 11.99	$ -	0.00%	$ 0.0940	128	$ 11.99	$ -	0.00%	$ 0.0940	128	$ 11.99	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	135	$ 17.82	$ 0.1320	135	$ 17.82	$ -	0.00%	$ 0.1320	135	$ 17.82	$ -	0.00%	$ 0.1320	135	$ 17.82	$ -	0.00%	$ 0.1320	135	$ 17.82	$ -	0.00%	$ 0.1320	135	$ 17.82	$ -	0.00%	$ 0.1320	135	$ 17.82	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	600	$ 46.20	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	150	$ 13.35	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 116.99**			**$ 123.32**	**$ 6.33**	**5.4%**			**$ 119.96**	**-$ 3.36**	**-2.7%**			**$ 120.90**	**$ 0.94**	**0.8%**			**$ 121.97**	**$ 1.07**	**0.9%**			**$ 123.30**	**$ 1.33**	**1.1%**			**$ 125.13**	**$ 1.83**	**1.5%**
8% Provincial Rebate		-8%		-$ 9.36	-8%		-$ 9.87	-$ 0.51	5.4%	-8%		-$ 9.60	$ 0.27	-2.7%	-8%		-$ 9.67	-$ 0.08	0.8%	-8%		-$ 9.76	-$ 0.09	0.9%	-8%		-$ 9.86	-$ 0.11	1.1%	-8%		-$ 10.01	-$ 0.15	1.5%
HST		13%		$ 15.21	13%		$ 16.03	$ 0.82	5.4%	13%		$ 15.59	-$ 0.44	-2.7%	13%		$ 15.72	$ 0.12	0.8%	13%		$ 15.86	$ 0.14	0.9%	13%		$ 16.03	$ 0.17	1.1%	13%		$ 16.27	$ 0.24	1.5%
Total Bill on TOU (after Tax & Rebate)				**$ 122.84**			**$ 129.48**	**$ 6.64**	**5.4%**			**$ 125.96**	**-$ 3.53**	**-2.7%**			**$ 126.95**	**$ 0.99**	**0.8%**			**$ 128.07**	**$ 1.12**	**0.9%**			**$ 129.47**	**$ 1.40**	**1.1%**			**$ 131.39**	**$ 1.92**	**1.5%**
Loss Factor (%)		3.76%			3.76%					2.95%					2.95%					2.95%					2.95%					2.95%				

Appendix 2-W
Bill Impacts

2

Customer Class: RESIDENTIAL SERVICE

TOU / non-TOU: TOU

Consumption 212 kWh ○ May 1 - October 31 ● November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		2018 Current Board-Approved			2019 Current Board-Approved			Impact		2020 Proposed			Impact		2021 Proposed			Impact		2022 Proposed			Impact		2023 Proposed			Impact		2024 Proposed			Impact	
		Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change
Service Charge	per 30 days	$ 32.63	1	$ 32.63	$ 37.48	1	$ 37.48	$ 4.85	14.86%	$ 42.17	1	$ 42.17	$ 4.69	12.51%	$ 43.54	1	$ 43.54	$ 1.37	3.25%	$ 44.61	1	$ 44.61	$ 1.07	2.46%	$ 46.50	1	$ 46.50	$ 1.89	4.24%	$ 48.33	1	$ 48.33	$ 1.83	3.94%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per 30 days									$ 0.09	1	$ 0.09			$ 0.09	1	$ 0.09	$ -	0.00%	$ 0.09	1	$ 0.09	$ -	0.00%	$ 0.09	1	$ 0.09	$ -	0.00%	$ 0.09	1	$ 0.09	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per 30 days									$ 0.51	1	$ 0.51	$ 0.51		$ 0.51	1	$ 0.51	$ -	0.00%	$ 0.51	1	$ 0.51	$ -	0.00%	$ 0.51	1	$ 0.51	$ -	0.00%	$ 0.51	1	$ 0.51	$ -	0.00%
Rate Rider for Recovery of Monthly Billing - effective until Dec. 31, 2024	per 30 days									$ 0.28	1	$ 0.28	$ 0.28		$ 0.28	1	$ 0.28	$ -	0.00%	$ 0.28	1	$ 0.28	$ -	0.00%	$ 0.28	1	$ 0.28	$ -	0.00%	$ 0.28	1	$ 0.28	$ -	0.00%
Rate Rider for Recovery of Stranded Meter Assets - effective until Dec. 31, 2024	per 30 days									-$ 0.02	1	-$ 0.02	-$ 0.02		-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per 30 days									-$ 0.78	1	-$ 0.78	-$ 0.78		-$ 0.78	1	-$ 0.78	$ -	0.00%	-$ 0.78	1	-$ 0.78	$ -	0.00%	-$ 0.78	1	-$ 0.78	$ -	0.00%	-$ 0.78	1	-$ 0.78	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per 30 days									-$ 0.12	1	-$ 0.12	-$ 0.12		-$ 0.12	1	-$ 0.12	$ -	0.00%	-$ 0.12	1	-$ 0.12	$ -	0.00%	-$ 0.12	1	-$ 0.12	$ -	0.00%	-$ 0.12	1	-$ 0.12	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per 30 days									-$ 0.01	1	-$ 0.01	-$ 0.01		-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per 30 days									-$ 0.02	1	-$ 0.02	-$ 0.02		-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per 30 days									-$ 0.83	1	-$ 0.83	-$ 0.83		-$ 0.83	1	-$ 0.83	$ -	0.00%	-$ 0.83	1	-$ 0.83	$ -	0.00%	-$ 0.83	1	-$ 0.83	$ -	0.00%	-$ 0.83	1	-$ 0.83	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per 30 days									-$ 0.03	1	-$ 0.03	-$ 0.03		-$ 0.03	1	-$ 0.03	$ -	0.00%	-$ 0.03	1	-$ 0.03	$ -	0.00%	-$ 0.03	1	-$ 0.03	$ -	0.00%	-$ 0.03	1	-$ 0.03	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per 30 days									-$ 0.37	1	-$ 0.37	-$ 0.37		-$ 0.37	1	-$ 0.37	$ -	0.00%	-$ 0.37	1	-$ 0.37	$ -	0.00%	-$ 0.37	1	-$ 0.37	$ -	0.00%	-$ 0.37	1	-$ 0.37	$ -	0.00%
Rate Rider for Disposition of AR Credits - effective until Dec. 31, 2024	per 30 days									-$ 0.08	1	-$ 0.08	-$ 0.08		-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%
Rate Rider for Recovery of Stranded Meters Assets - effective until Dec. 31, 2019.	per 30 days	$ 0.28	1	$ 0.28	$ 0.28	1	$ 0.28	$ -	0.00%		1	$ -	-$ 0.28			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per 30 days	-$ 0.48	1	-$ 0.48		1	$ -	$ 0.48			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per 30 days	-$ 1.48	1	-$ 1.48		1	$ -	$ 1.48			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per 30 days	$ 0.10	1	$ 0.10	$ 0.10	1	$ 0.10	$ -	0.00%		1	$ -	-$ 0.10			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per 30 days	$ 0.03	1	$ 0.03	$ 0.03	1	$ 0.03	$ -	0.00%		1	$ -	-$ 0.03			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per 30 days	$ 0.46	1	$ 0.46	$ 0.46	1	$ 0.46	$ -	0.00%		1	$ -	-$ 0.46			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.88	1	$ 0.88	$ 0.88	1	$ 0.88	$ -	0.00%		1	$ -	-$ 0.88			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.28	1	$ 0.28	$ 0.28	1	$ 0.28	$ -	0.00%		1	$ -	-$ 0.28			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.01063	212	$ 2.25	$ 0.00553	212	$ 1.17	-$ 1.08	-47.98%		212	$ -	-$ 1.17			212	$ -	$ -			212	$ -	$ -			212	$ -	$ -			212	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kWh	$ 0.00041	212	$ 0.09	$ 0.00095	212	$ 0.20	$ 0.11	131.71%		212	$ -	-$ 0.20			212	$ -	$ -			212	$ -	$ -			212	$ -	$ -			212	$ -	$ -	
Sub-Total A (excluding pass through)				**$ 35.04**			**$ 40.88**	**$ 5.84**	**16.68%**			**$ 40.79**	**-$ 0.09**	**-0.23%**			**$ 42.16**	**$ 1.37**	**3.36%**			**$ 43.23**	**$ 1.07**	**2.54%**			**$ 45.12**	**$ 1.89**	**4.37%**			**$ 46.95**	**$ 1.83**	**4.06%**
Line Losses on Cost of Power	per kWh	$ 0.0820	8	$ 0.65	$ 0.0820	8	$ 0.65	$ -	0.00%	$ 0.0820	6	$ 0.51	-$ 0.14	-21.54%	$ 0.0820	6	$ 0.51	$ -	0.00%	$ 0.0820	6	$ 0.51	$ -	0.00%	$ 0.0820	6	$ 0.51	$ -	0.00%	$ 0.0820	6	$ 0.51	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	per kWh	-$ 0.00320	212	-$ 0.68	-$ 0.00052	212	-$ 0.11	$ 0.57	-83.75%	$ 0.00060	212	$ 0.13	$ 0.24	-215.38%			$ -	-$ 0.13					$ -	$ -					$ -	$ -					$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	per kWh	-$ 0.00007	212	-$ 0.01	-$ 0.00003	212	-$ 0.01	-$ 0.01	-57.14%	-$ 0.00003	212	-$ 0.01	-$ 0.01	-200.00%			$ -	$ 0.01					$ -	$ -					$ -	$ -					$ -	$ -	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	per kWh	-$ 0.00112		$ -	-$ 0.00068		$ -	$ -		-$ 0.00290		$ -	$ -				$ -	$ -					$ -	$ -					$ -	$ -					$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	per 30 days	$ 0.56	1	$ 0.56	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%			$ -	-$ 0.56					$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 35.59**			**$ 41.99**	**$ 6.40**	**17.99%**			**$ 41.98**	**-$ 0.01**	**-0.02%**			**$ 43.23**	**$ 1.25**	**2.98%**			**$ 44.30**	**$ 1.07**	**2.47%**			**$ 45.63**	**$ 1.33**	**3.00%**			**$ 47.46**	**$ 1.83**	**4.01%**
Retail Transmissioin Rate - Network Service Rate	per kWh	$ 0.00759	220	$ 1.67	$ 0.00796	220	$ 1.75	$ 0.08	4.87%	$ 0.00825	218	$ 1.80	$ 0.05	2.83%	$ 0.00825	218	$ 1.80	$ -	0.00%	$ 0.00825	218	$ 1.80	$ -	0.00%	$ 0.00825	218	$ 1.80	$ -	0.00%	$ 0.00825	218	$ 1.80	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	per kWh	$ 0.00617	220	$ 1.36	$ 0.00703	220	$ 1.55	$ 0.19	13.94%	$ 0.00679	218	$ 1.48	-$ 0.06	-4.17%	$ 0.00679	218	$ 1.48	$ -	0.00%	$ 0.00679	218	$ 1.48	$ -	0.00%	$ 0.00679	218	$ 1.48	$ -	0.00%	$ 0.00679	218	$ 1.48	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				**$ 38.62**			**$ 45.29**	**$ 6.67**	**17.28%**			**$ 45.27**	**-$ 0.02**	**-0.05%**			**$ 46.52**	**$ 1.25**	**2.76%**			**$ 47.59**	**$ 1.07**	**2.30%**			**$ 48.92**	**$ 1.33**	**2.79%**			**$ 50.75**	**$ 1.83**	**3.74%**
Wholesale Market Service Rate - not including CBR	per kWh	$ 0.0032	220	$ 0.70	$ 0.0032	220	$ 0.70	$ -	0.00%	$ 0.0032	218	$ 0.70	-$ 0.01	-0.78%	$ 0.0032	218	$ 0.70	$ -	0.00%	$ 0.0032	218	$ 0.70	$ -	0.00%	$ 0.0032	218	$ 0.70	$ -	0.00%	$ 0.0032	218	$ 0.70	$ -	0.00%
Rural and Remote Rate Protection Charge (RRRP)	per kWh	$ 0.0003	220	$ 0.07	$ 0.0003	220	$ 0.07	$ -	0.00%	$ 0.0003	218	$ 0.07	-$ 0.00	-0.78%	$ 0.0003	218	$ 0.07	$ -	0.00%	$ 0.0003	218	$ 0.07	$ -	0.00%	$ 0.0003	218	$ 0.07	$ -	0.00%	$ 0.0003	218	$ 0.07	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	220	$ 0.09	$ 0.0004	220	$ 0.09	$ -	0.00%	$ 0.0004	218	$ 0.09	-$ 0.00	-0.78%	$ 0.0004	218	$ 0.09	$ -	0.00%	$ 0.0004	218	$ 0.09	$ -	0.00%	$ 0.0004	218	$ 0.09	$ -	0.00%	$ 0.0004	218	$ 0.09	$ -	0.00%
Standard Supply Service - Administrative Charge (if applicable)	per 30 days	$ 0.25	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	138	$ 8.96	$ 0.0650	138	$ 8.96	$ -	0.00%	$ 0.0650	138	$ 8.96	$ -	0.00%	$ 0.0650	138	$ 8.96	$ -	0.00%	$ 0.0650	138	$ 8.96	$ -	0.00%	$ 0.0650	138	$ 8.96	$ -	0.00%	$ 0.0650	138	$ 8.96	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	36	$ 3.39	$ 0.0940	36	$ 3.39	$ -	0.00%	$ 0.0940	36	$ 3.39	$ -	0.00%	$ 0.0940	36	$ 3.39	$ -	0.00%	$ 0.0940	36	$ 3.39	$ -	0.00%	$ 0.0940	36	$ 3.39	$ -	0.00%	$ 0.0940	36	$ 3.39	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	38	$ 5.04	$ 0.1320	38	$ 5.04	$ -	0.00%	$ 0.1320	38	$ 5.04	$ -	0.00%	$ 0.1320	38	$ 5.04	$ -	0.00%	$ 0.1320	38	$ 5.04	$ -	0.00%	$ 0.1320	38	$ 5.04	$ -	0.00%	$ 0.1320	38	$ 5.04	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	600	$ 46.20	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	150	$ 13.35	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 57.11**			**$ 63.78**	**$ 6.67**	**11.7%**			**$ 63.75**	**-$ 0.03**	**0.0%**			**$ 65.00**	**$ 1.25**	**2.0%**			**$ 66.07**	**$ 1.07**	**1.6%**			**$ 67.40**	**$ 1.33**	**2.0%**			**$ 69.23**	**$ 1.83**	**2.7%**
8% Provincial Rebate		-8%		-$ 4.57	-8%		-$ 5.10	-$ 0.53	11.7%	-8%		-$ 5.10	$ 0.00	0.0%	-8%		-$ 5.20	-$ 0.10	2.0%	-8%		-$ 5.29	-$ 0.09	1.6%	-8%		-$ 5.39	-$ 0.11	2.0%	-8%		-$ 5.54	-$ 0.15	2.7%
HST		13%		$ 7.42	13%		$ 8.29	$ 0.87	11.7%	13%		$ 8.29	-$ 0.00	0.0%	13%		$ 8.45	$ 0.16	2.0%	13%		$ 8.59	$ 0.14	1.6%	13%		$ 8.76	$ 0.17	2.0%	13%		$ 9.00	$ 0.24	2.7%
Total Bill on TOU (after Tax & Rebate)				**$ 59.96**			**$ 66.97**	**$ 7.01**	**11.7%**			**$ 66.94**	-$ 0.03	0.0%			**$ 68.25**	$ 1.31	2.0%			**$ 69.37**	$ 1.12	1.6%			**$ 70.77**	$ 1.40	2.0%			**$ 72.69**	$ 1.92	2.7%
Loss Factor (%)		3.76%			3.76%					2.95%					2.95%					2.95%					2.95%					2.95%				

Appendix 2-W
Bill Impacts

2

Customer Class: RESIDENTIAL SERVICE

TOU / non-TOU: TOU

Consumption 650 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		2018 Current Board-Approved			2019 Current Board-Approved			Impact		2020 Proposed			Impact		2021 Proposed			Impact		2022 Proposed			Impact		2023 Proposed			Impact		2024 Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change
Service Charge	per 30 days	$ 32.63	1	$ 32.63	$ 37.48	1	$ 37.48	$ 4.85	14.86%	$ 42.17	1	$ 42.17	$ 4.69	12.51%	$ 43.54	1	$ 43.54	$ 1.37	3.25%	$ 44.61	1	$ 44.61	$ 1.07	2.46%	$ 46.50	1	$ 46.50	$ 1.89	4.24%	$ 48.33	1	$ 48.33	$ 1.83	3.94%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per 30 days									$ 0.09	1	$ 0.09			$ 0.09	1	$ 0.09	$ -	0.00%	$ 0.09	1	$ 0.09	$ -	0.00%	$ 0.09	1	$ 0.09	$ -	0.00%	$ 0.09	1	$ 0.09	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per 30 days									$ 0.51	1	$ 0.51	$ 0.51		$ 0.51	1	$ 0.51	$ -	0.00%	$ 0.51	1	$ 0.51	$ -	0.00%	$ 0.51	1	$ 0.51	$ -	0.00%	$ 0.51	1	$ 0.51	$ -	0.00%
Rate Rider for Recovery of Monthly Billing - effective until Dec. 31, 2024	per 30 days									$ 0.28	1	$ 0.28	$ 0.28		$ 0.28	1	$ 0.28	$ -	0.00%	$ 0.28	1	$ 0.28	$ -	0.00%	$ 0.28	1	$ 0.28	$ -	0.00%	$ 0.28	1	$ 0.28	$ -	0.00%
Rate Rider for Recovery of Stranded Meter Assets - effective until Dec. 31, 2024	per 30 days									-$ 0.02	1	-$ 0.02	-$ 0.02		-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per 30 days									-$ 0.78	1	-$ 0.78	-$ 0.78		-$ 0.78	1	-$ 0.78	$ -	0.00%	-$ 0.78	1	-$ 0.78	$ -	0.00%	-$ 0.78	1	-$ 0.78	$ -	0.00%	-$ 0.78	1	-$ 0.78	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per 30 days									-$ 0.12	1	-$ 0.12	$ 0.12		-$ 0.12	1	-$ 0.12	$ -	0.00%	-$ 0.12	1	-$ 0.12	$ -	0.00%	-$ 0.12	1	-$ 0.12	$ -	0.00%	-$ 0.12	1	-$ 0.12	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per 30 days									-$ 0.01	1	-$ 0.01	-$ 0.01		-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per 30 days									-$ 0.02	1	-$ 0.02	-$ 0.02		-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per 30 days									-$ 0.83	1	-$ 0.83	-$ 0.83		-$ 0.83	1	-$ 0.83	$ -	0.00%	-$ 0.83	1	-$ 0.83	$ -	0.00%	-$ 0.83	1	-$ 0.83	$ -	0.00%	-$ 0.83	1	-$ 0.83	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per 30 days									-$ 0.03	1	-$ 0.03	-$ 0.03		-$ 0.03	1	-$ 0.03	$ -	0.00%	-$ 0.03	1	-$ 0.03	$ -	0.00%	-$ 0.03	1	-$ 0.03	$ -	0.00%	-$ 0.03	1	-$ 0.03	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per 30 days									-$ 0.37	1	-$ 0.37	-$ 0.37		-$ 0.37	1	-$ 0.37	$ -	0.00%	-$ 0.37	1	-$ 0.37	$ -	0.00%	-$ 0.37	1	-$ 0.37	$ -	0.00%	-$ 0.37	1	-$ 0.37	$ -	0.00%
Rate Rider for Disposition of AR Credits - effective until Dec. 31, 2024	per 30 days									-$ 0.08	1	-$ 0.08	-$ 0.08		-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%
Rate Rider for Recovery of Stranded Meters Assets - effective until Dec. 31, 2019.	per 30 days	$ 0.28	1	$ 0.28	$ 0.28	1	$ 0.28	$ -	0.00%		1	$ -	-$ 0.28			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per 30 days	-$ 0.48	1	-$ 0.48		1	$ -	$ 0.48			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per 30 days	-$ 1.48	1	-$ 1.48		1	$ -	$ 1.48			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per 30 days	$ 0.10	1	$ 0.10	$ 0.10	1	$ 0.10	$ -	0.00%		1	$ -	-$ 0.10			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per 30 days	$ 0.03	1	$ 0.03	$ 0.03	1	$ 0.03	$ -	0.00%		1	$ -	-$ 0.03			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per 30 days	$ 0.46	1	$ 0.46	$ 0.46	1	$ 0.46	$ -	0.00%		1	$ -	-$ 0.46			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.88	1	$ 0.88	$ 0.88	1	$ 0.88	$ -	0.00%		1	$ -	-$ 0.88			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.28	1	$ 0.28	$ 0.28	1	$ 0.28	$ -	0.00%		1	$ -	-$ 0.28			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.01063	650	$ 6.91	$ 0.00553	650	$ 3.59	-$ 3.32	-47.98%		650	$ -	-$ 3.59			650	$ -	$ -			650	$ -	$ -			650	$ -	$ -			650	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kWh	$ 0.00041	650	$ 0.27	$ 0.00095	650	$ 0.62	$ 0.35	131.71%		650	$ -	-$ 0.62			650	$ -	$ -			650	$ -	$ -			650	$ -	$ -			650	$ -	$ -	
Sub-Total A (excluding pass through)				**$ 39.88**			**$ 43.72**	**$ 3.85**	**9.64%**			**$ 40.79**	**-$ 2.93**	**-6.71%**			**$ 42.16**	**$ 1.37**	**3.36%**			**$ 43.23**	**$ 1.07**	**2.54%**			**$ 45.12**	**$ 1.89**	**4.37%**			**$ 46.95**	**$ 1.83**	**4.06%**
Line Losses on Cost of Power	per kWh	$ 0.0820	24	$ 2.00	$ 0.0820	24	$ 2.00	$ -	0.00%	$ 0.0820	19	$ 1.57	-$ 0.43	-21.54%	$ 0.0820	19	$ 1.57	$ -	0.00%	$ 0.0820	19	$ 1.57	$ -	0.00%	$ 0.0820	19	$ 1.57	$ -	0.00%	$ 0.0820	19	$ 1.57	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	per kWh	-$ 0.00320	650	-$ 2.08	-$ 0.00052	650	-$ 0.34	$ 1.74	-83.75%	$ 0.00060	650	$ 0.39	$ 0.73	-215.38%			$ -	-$ 0.39				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	per kWh	-$ 0.00007	650	-$ 0.05	-$ 0.00003	650	-$ 0.02	-$ 0.03	-57.14%	-$ 0.00003	650	-$ 0.02	-$ 0.04	-200.00%			$ -	$ 0.02				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	per kWh	-$ 0.00112		$ -	-$ 0.00068		$ -	$ -		-$ 0.00290		$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	per 30 days	$ 0.56	1	$ 0.56	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%			$ -	-$ 0.56				$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 40.41**			**$ 45.97**	**$ 5.56**	**13.77%**			**$ 43.29**	**-$ 2.67**	**-5.82%**			**$ 44.29**	**$ 1.00**	**2.31%**			**$ 45.36**	**$ 1.07**	**2.42%**			**$ 46.69**	**$ 1.33**	**2.93%**			**$ 48.52**	**$ 1.83**	**3.92%**
Retail Transmissioin Rate - Network Service Rate	per kWh	$ 0.00759	674	$ 5.12	$ 0.00796	674	$ 5.37	$ 0.25	4.87%	$ 0.00825	669	$ 5.52	$ 0.15	2.83%	$ 0.00825	669	$ 5.52	$ -	0.00%	$ 0.00825	669	$ 5.52	$ -	0.00%	$ 0.00825	669	$ 5.52	$ -	0.00%	$ 0.00825	669	$ 5.52	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	per kWh	$ 0.00617	674	$ 4.16	$ 0.00703	674	$ 4.74	$ 0.58	13.94%	$ 0.00679	669	$ 4.54	-$ 0.20	-4.17%	$ 0.00679	669	$ 4.54	$ -	0.00%	$ 0.00679	669	$ 4.54	$ -	0.00%	$ 0.00679	669	$ 4.54	$ -	0.00%	$ 0.00679	669	$ 4.54	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				**$ 49.69**			**$ 56.08**	**$ 6.39**	**12.86%**			**$ 53.36**	**-$ 2.72**	**-4.85%**			**$ 54.36**	**$ 1.00**	**1.87%**			**$ 55.43**	**$ 1.07**	**1.97%**			**$ 56.76**	**$ 1.33**	**2.40%**			**$ 58.59**	**$ 1.83**	**3.22%**
Wholesale Market Service Rate - not including CBR	per kWh	$ 0.0032	674	$ 2.16	$ 0.0032	674	$ 2.16	$ -	0.00%	$ 0.0032	669	$ 2.14	-$ 0.02	-0.78%	$ 0.0032	669	$ 2.14	$ -	0.00%	$ 0.0032	669	$ 2.14	$ -	0.00%	$ 0.0032	669	$ 2.14	$ -	0.00%	$ 0.0032	669	$ 2.14	$ -	0.00%
Rural and Remote Rate Protection Charge (RRRP)	per kWh	$ 0.0003	674	$ 0.20	$ 0.0003	674	$ 0.20	$ -	0.00%	$ 0.0003	669	$ 0.20	-$ 0.00	-0.78%	$ 0.0003	669	$ 0.20	$ -	0.00%	$ 0.0003	669	$ 0.20	$ -	0.00%	$ 0.0003	669	$ 0.20	$ -	0.00%	$ 0.0003	669	$ 0.20	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	674	$ 0.27	$ 0.0004	674	$ 0.27	$ -	0.00%	$ 0.0004	669	$ 0.27	-$ 0.00	-0.78%	$ 0.0004	669	$ 0.27	$ -	0.00%	$ 0.0004	669	$ 0.27	$ -	0.00%	$ 0.0004	669	$ 0.27	$ -	0.00%	$ 0.0004	669	$ 0.27	$ -	0.00%
Standard Supply Service - Administrative Charge (if applicable)	per 30 days	$ 0.25	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	423	$ 27.46	$ 0.0650	423	$ 27.46	$ -	0.00%	$ 0.0650	423	$ 27.46	$ -	0.00%	$ 0.0650	423	$ 27.46	$ -	0.00%	$ 0.0650	423	$ 27.46	$ -	0.00%	$ 0.0650	423	$ 27.46	$ -	0.00%	$ 0.0650	423	$ 27.46	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	111	$ 10.39	$ 0.0940	111	$ 10.39	$ -	0.00%	$ 0.0940	111	$ 10.39	$ -	0.00%	$ 0.0940	111	$ 10.39	$ -	0.00%	$ 0.0940	111	$ 10.39	$ -	0.00%	$ 0.0940	111	$ 10.39	$ -	0.00%	$ 0.0940	111	$ 10.39	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	117	$ 15.44	$ 0.1320	117	$ 15.44	$ -	0.00%	$ 0.1320	117	$ 15.44	$ -	0.00%	$ 0.1320	117	$ 15.44	$ -	0.00%	$ 0.1320	117	$ 15.44	$ -	0.00%	$ 0.1320	117	$ 15.44	$ -	0.00%	$ 0.1320	117	$ 15.44	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	600	$ 46.20	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	150	$ 13.35	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	**$ 0.1164**		$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 105.86**			**$ 112.25**	**$ 6.39**	**6.0%**			**$ 109.51**	**-$ 2.74**	**-2.4%**			**$ 110.51**	**$ 1.00**	**0.9%**			**$ 111.58**	**$ 1.07**	**1.0%**			**$ 112.91**	**$ 1.33**	**1.2%**			**$ 114.74**	**$ 1.83**	**1.6%**
8% Provincial Rebate		-8%		-$ 8.47	-8%		-$ 8.98	-$ 0.51	6.0%	-8%		-$ 8.76	$ 0.22	-2.4%	-8%		-$ 8.84	-$ 0.08	0.9%	-8%		-$ 8.93	-$ 0.09	1.0%	-8%		-$ 9.03	-$ 0.11	1.2%	-8%		-$ 9.18	-$ 0.15	1.6%
HST		13%		$ 13.76	13%		$ 14.59	$ 0.83	6.0%	13%		$ 14.24	-$ 0.36	-2.4%	13%		$ 14.37	$ 0.13	0.9%	13%		$ 14.51	$ 0.14	1.0%	13%		$ 14.68	$ 0.17	1.2%	13%		$ 14.92	$ 0.24	1.6%
Total Bill on TOU (after Tax & Rebate)				**$ 111.15**			**$ 117.86**	**$ 6.71**	**6.0%**			**$ 114.99**	**-$ 2.88**	**-2.4%**			**$ 116.04**	**$ 1.05**	**0.9%**			**$ 117.16**	**$ 1.12**	**1.0%**			**$ 118.56**	**$ 1.40**	**1.2%**			**$ 120.48**	**$ 1.92**	**1.6%**
Loss Factor (%)		3.76%			3.76%					2.95%					2.95%					2.95%					2.95%					2.95%				

Appendix 2-W
Bill Impacts

2

Customer Class: COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE

TOU / non-TOU: TOU

Consumption 300 kWh ● May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		2018 Current Board-Approved			2019 Current Board-Approved			Impact		2020 Proposed			Impact		2021 Proposed			Impact		2022 Proposed			Impact		2023 Proposed			Impact		2024 Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change
Service Charge	per 30 days	$ 26.80	1	$ 26.80	$ 30.58	1	$ 30.58	$ 3.78	14.10%	$ 33.32	1	$ 33.32	$ 2.74	8.96%	$ 34.41	1	$ 34.41	$ 1.09	3.27%	$ 35.26	1	$ 35.26	$ 0.85	2.47%	$ 36.76	1	$ 36.76	$ 1.50	4.25%	$ 38.20	1	$ 38.20	$ 1.44	3.92%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per 30 days									$ 0.06	1	$ 0.06	$ 0.06		$ 0.06	1	$ 0.06	$ -	0.00%	$ 0.06	1	$ 0.06	$ -	0.00%	$ 0.06	1	$ 0.06	$ -	0.00%	$ 0.06	1	$ 0.06	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per 30 days									$ 0.34	1	$ 0.34	$ 0.34		$ 0.34	1	$ 0.34	$ -	0.00%	$ 0.34	1	$ 0.34	$ -	0.00%	$ 0.34	1	$ 0.34	$ -	0.00%	$ 0.34	1	$ 0.34	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per 30 days									-$ 0.52	1	-$ 0.52	-$ 0.52		-$ 0.52	1	-$ 0.52	$ -	0.00%	-$ 0.52	1	-$ 0.52	$ -	0.00%	-$ 0.52	1	-$ 0.52	$ -	0.00%	-$ 0.52	1	-$ 0.52	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per 30 days									-$ 0.08	1	-$ 0.08	-$ 0.08		-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per 30 days									-$ 0.01	1	-$ 0.01	-$ 0.01		-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per 30 days									-$ 0.55	1	-$ 0.55	-$ 0.55		-$ 0.55	1	-$ 0.55	$ -	0.00%	-$ 0.55	1	-$ 0.55	$ -	0.00%	-$ 0.55	1	-$ 0.55	$ -	0.00%	-$ 0.55	1	-$ 0.55	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per 30 days									-$ 0.02	1	-$ 0.02	-$ 0.02		-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per 30 days									-$ 0.24	1	-$ 0.24	-$ 0.24		-$ 0.24	1	-$ 0.24	$ -	0.00%	-$ 0.24	1	-$ 0.24	$ -	0.00%	-$ 0.24	1	-$ 0.24	$ -	0.00%	-$ 0.24	1	-$ 0.24	$ -	0.00%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per 30 days	-$ 0.19	1	-$ 0.19		1	$ -	$ 0.19			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per 30 days	-$ 0.59	1	-$ 0.59		1	$ -	$ 0.59			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per 30 days	$ 0.04	1	$ 0.04	$ 0.04	1	$ 0.04	$ -	0.00%		1	$ -	-$ 0.04			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per 30 days	$ 0.01	1	$ 0.01	$ 0.01	1	$ 0.01	$ -	0.00%		1	$ -	-$ 0.01			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per 30 days	$ 0.18	1	$ 0.18	$ 0.18	1	$ 0.18	$ -	0.00%		1	$ -	-$ 0.18			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.19	1	$ 0.19	$ 0.19	1	$ 0.19	$ -	0.00%		1	$ -	-$ 0.19			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.09	1	$ 0.09	$ 0.09	1	$ 0.09	$ -	0.00%		1	$ -	-$ 0.09			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.01627	300	$ 4.88	$ 0.00846	300	$ 2.54	-$ 2.34	-48.00%		300	$ -	-$ 2.54			300	$ -	$ -			300	$ -	$ -			300	$ -	$ -			300	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kWh	$ 0.00068	300	$ 0.20	$ 0.00126	300	$ 0.38	$ 0.17	85.29%		300	$ -	-$ 0.38			300	$ -	$ -			300	$ -	$ -			300	$ -	$ -			300	$ -	$ -	
Sub-Total A (excluding pass through)				**$ 31.62**			**$ 34.01**	**$ 2.39**	**7.56%**			**$ 32.30**	**-$ 1.71**	**-5.02%**			**$ 33.39**	**$ 1.09**	**3.37%**			**$ 34.24**	**$ 0.85**	**2.55%**			**$ 35.74**	**$ 1.50**	**4.38%**			**$ 37.18**	**$ 1.44**	**4.03%**
Line Losses on Cost of Power	per kWh	$ 0.0820	11	$ 0.92	$ 0.0820	11	$ 0.92	$ -	0.00%	$ 0.0820	9	$ 0.73	-$ 0.20	-21.54%	$ 0.0820	9	$ 0.73	$ -	0.00%	$ 0.0820	9	$ 0.73	$ -	0.00%	$ 0.0820	9	$ 0.73	$ -	0.00%	$ 0.0820	9	$ 0.73	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	per kWh	-$ 0.00392	300	-$ 1.18	-$ 0.0005	300	-$ 0.16	$ 1.01	-86%	$ 0.00045	300	$ 0.14	$ 0.30	-183.33%			$ -	-$ 0.14					$ -	$ -					$ -	$ -					$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	per kWh	$ 0.00007	300	$ 0.02	$ 0.0000	300	$ 0.01	-$ 0.01	-57%	-$ 0.00003	300	-$ 0.01	-$ 0.02	-200.00%			$ -	$ 0.01					$ -	$ -					$ -	$ -					$ -	$ -	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	per kWh	-$ 0.00112		$ -	$ 0.00068		$ -	$ -		-$ 0.00290		$ -	$ -				$ -	$ -					$ -	$ -					$ -	$ -					$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	per 30 days	$ 0.56	1	$ 0.56	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%			$ -	-$ 0.56				$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 31.94**			**$ 35.34**	**$ 3.39**	**10.62%**			**$ 33.71**	**-$ 1.63**	**-4.60%**			**$ 34.68**	**$ 0.96**	**2.86%**			**$ 35.53**	**$ 0.85**	**2.45%**			**$ 36.47**	**$ 0.94**	**2.65%**			**$ 37.91**	**$ 1.44**	**3.95%**
Retail Transmissioin Rate - Network Service Rate	per kWh	$ 0.00759	311	$ 2.36	$ 0.00796	311	$ 2.48	$ 0.12	4.87%	$ 0.00825	309	$ 2.55	$ 0.07	2.83%	$ 0.00825	309	$ 2.55	$ -	0.00%	$ 0.00825	309	$ 2.55	$ -	0.00%	$ 0.00825	309	$ 2.55	$ -	0.00%	$ 0.00825	309	$ 2.55	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	per kWh	$ 0.00617	311	$ 1.92	$ 0.00703	311	$ 2.19	$ 0.27	13.94%	$ 0.00679	309	$ 2.10	-$ 0.09	-4.17%	$ 0.00679	309	$ 2.10	$ -	0.00%	$ 0.00679	309	$ 2.10	$ -	0.00%	$ 0.00679	309	$ 2.10	$ -	0.00%	$ 0.00679	309	$ 2.10	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				**$ 36.23**			**$ 40.00**	**$ 3.78**	**10.42%**			**$ 38.36**	**-$ 1.65**	**-4.12%**			**$ 39.32**	**$ 0.96**	**2.51%**			**$ 40.17**	**$ 0.85**	**2.16%**			**$ 41.11**	**$ 0.94**	**2.34%**			**$ 42.55**	**$ 1.44**	**3.50%**
Wholesale Market Service Rate - not including CBR	per kWh	$ 0.0032	311	$ 1.00	$ 0.0032	311	$ 1.00	$ -	0.00%	$ 0.0032	309	$ 0.99	-$ 0.01	-0.78%	$ 0.0032	309	$ 0.99	$ -	0.00%	$ 0.0032	309	$ 0.99	$ -	0.00%	$ 0.0032	309	$ 0.99	$ -	0.00%	$ 0.0032	309	$ 0.99	$ -	0.00%
Rural and Remote Rate Protection Charge (RRRP)	per kWh	$ 0.0003	311	$ 0.09	$ 0.0003	311	$ 0.09	$ -	0.00%	$ 0.0003	309	$ 0.09	-$ 0.00	-0.78%	$ 0.0003	309	$ 0.09	$ -	0.00%	$ 0.0003	309	$ 0.09	$ -	0.00%	$ 0.0003	309	$ 0.09	$ -	0.00%	$ 0.0003	309	$ 0.09	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	311	$ 0.12	$ 0.0004	311	$ 0.12	$ -	0.00%	$ 0.0004	309	$ 0.12	-$ 0.00	-0.78%	$ 0.0004	309	$ 0.12	$ -	0.00%	$ 0.0004	309	$ 0.12	$ -	0.00%	$ 0.0004	309	$ 0.12	$ -	0.00%	$ 0.0004	309	$ 0.12	$ -	0.00%
Standard Supply Service - Administrative Charge (if applicable)	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	195	$ 12.68	$ 0.0650	195	$ 12.68	$ -	0.00%	$ 0.0650	195	$ 12.68	$ -	0.00%	$ 0.0650	195	$ 12.68	$ -	0.00%	$ 0.0650	195	$ 12.68	$ -	0.00%	$ 0.0650	195	$ 12.68	$ -	0.00%	$ 0.0650	195	$ 12.68	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	51	$ 4.79	$ 0.0940	51	$ 4.79	$ -	0.00%	$ 0.0940	51	$ 4.79	$ -	0.00%	$ 0.0940	51	$ 4.79	$ -	0.00%	$ 0.0940	51	$ 4.79	$ -	0.00%	$ 0.0940	51	$ 4.79	$ -	0.00%	$ 0.0940	51	$ 4.79	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	54	$ 7.13	$ 0.1320	54	$ 7.13	$ -	0.00%	$ 0.1320	54	$ 7.13	$ -	0.00%	$ 0.1320	54	$ 7.13	$ -	0.00%	$ 0.1320	54	$ 7.13	$ -	0.00%	$ 0.1320	54	$ 7.13	$ -	0.00%	$ 0.1320	54	$ 7.13	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	300	$ 23.10	$ 0.0770	300	$ 23.10	$ -	0.00%	$ 0.0770	300	$ 23.10	$ -	0.00%	$ 0.0770	300	$ 23.10	$ -	0.00%	$ 0.0770	300	$ 23.10	$ -	0.00%	$ 0.0770	300	$ 23.10	$ -	0.00%	$ 0.0770	300	$ 23.10	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	0	$ -	$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -	
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 62.29**			**$ 66.06**	**$ 3.78**	**6.1%**			**$ 64.41**	**-$ 1.66**	**-2.5%**			**$ 65.37**	**$ 0.96**	**1.5%**			**$ 66.22**	**$ 0.85**	**1.3%**			**$ 67.16**	**$ 0.94**	**1.4%**			**$ 68.60**	**$ 1.44**	**2.1%**
8% Provincial Rebate		-8%		-$ 4.98	-8%		-$ 5.29	-$ 0.30	6.1%	-8%		-$ 5.15	$ 0.13	-2.5%	-8%		-$ 5.23	-$ 0.08	1.5%	-8%		-$ 5.30	-$ 0.07	1.3%	-8%		-$ 5.37	-$ 0.08	1.4%	-8%		-$ 5.49	-$ 0.12	2.1%
HST		13%		$ 8.10	13%		$ 8.59	$ 0.49	6.1%	13%		$ 8.37	-$ 0.22	-2.5%	13%		$ 8.50	$ 0.13	1.5%	13%		$ 8.61	$ 0.11	1.3%	13%		$ 8.73	$ 0.12	1.4%	13%		$ 8.92	$ 0.19	2.1%
Total Bill on TOU (after Tax & Rebate)				**$ 65.40**			**$ 69.37**	**$ 3.96**	**6.1%**			**$ 67.63**	**-$ 1.74**	**-2.5%**			**$ 68.64**	**$ 1.01**	**1.5%**			**$ 69.53**	**$ 0.89**	**1.3%**			**$ 70.52**	**$ 0.99**	**1.4%**			**$ 72.03**	**$ 1.51**	**2.1%**
Loss Factor (%)		3.76%			3.76%					2.95%					2.95%					2.95%					2.95%					2.95%				

Appendix 2-W
Bill Impacts

2

Customer Class: COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE

TOU / non-TOU: TOU

Consumption 198 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	2018 Current Board-Approved Rate ($)	Volume	Charge ($)	2019 Current Board-Approved Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change	2020 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change	2021 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change	2022 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change	2023 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change	2024 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change
Service Charge	per 30 days	$ 26.80	1	$ 26.80	$ 30.58	1	$ 30.58	$ 3.78	14.10%	$ 33.32	1	$ 33.32	$ 2.74	8.96%	$ 34.41	1	$ 34.41	$ 1.09	3.27%	$ 35.26	1	$ 35.26	$ 0.85	2.47%	$ 36.76	1	$ 36.76	$ 1.50	4.25%	$ 38.20	1	$ 38.20	$ 1.44	3.92%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per 30 days									$ 0.06	1	$ 0.06	$ 0.06		$ 0.06	1	$ 0.06	$ -	0.00%	$ 0.06	1	$ 0.06	$ -	0.00%	$ 0.06	1	$ 0.06	$ -	0.00%	$ 0.06	1	$ 0.06	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per 30 days									$ 0.34	1	$ 0.34	$ 0.34		$ 0.34	1	$ 0.34	$ -	0.00%	$ 0.34	1	$ 0.34	$ -	0.00%	$ 0.34	1	$ 0.34	$ -	0.00%	$ 0.34	1	$ 0.34	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per 30 days									-$ 0.52	1	-$ 0.52	-$ 0.52		-$ 0.52	1	-$ 0.52	$ -	0.00%	-$ 0.52	1	-$ 0.52	$ -	0.00%	-$ 0.52	1	-$ 0.52	$ -	0.00%	-$ 0.52	1	-$ 0.52	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per 30 days									-$ 0.08	1	-$ 0.08	-$ 0.08		-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per 30 days									-$ 0.01	1	-$ 0.01	-$ 0.01		-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per 30 days									-$ 0.55	1	-$ 0.55	-$ 0.55		-$ 0.55	1	-$ 0.55	$ -	0.00%	-$ 0.55	1	-$ 0.55	$ -	0.00%	-$ 0.55	1	-$ 0.55	$ -	0.00%	-$ 0.55	1	-$ 0.55	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per 30 days									-$ 0.02	1	-$ 0.02	-$ 0.02		-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per 30 days									-$ 0.24	1	-$ 0.24	-$ 0.24		-$ 0.24	1	-$ 0.24	$ -	0.00%	-$ 0.24	1	-$ 0.24	$ -	0.00%	-$ 0.24	1	-$ 0.24	$ -	0.00%	-$ 0.24	1	-$ 0.24	$ -	0.00%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per 30 days	-$ 0.19	1	-$ 0.19		1	$ -	$ 0.19			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per 30 days	-$ 0.59	1	-$ 0.59		1	$ -	$ 0.59			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per 30 days	$ 0.04	1	$ 0.04	$ 0.04	1	$ 0.04	$ -	0.00%		1	$ -	-$ 0.04			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per 30 days	$ 0.01	1	$ 0.01	$ 0.01	1	$ 0.01	$ -	0.00%		1	$ -	-$ 0.01			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per 30 days	$ 0.18	1	$ 0.18	$ 0.18	1	$ 0.18	$ -	0.00%		1	$ -	-$ 0.18			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.19	1	$ 0.19	$ 0.19	1	$ 0.19	$ -	0.00%		1	$ -	-$ 0.19			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.09	1	$ 0.09	$ 0.09	1	$ 0.09	$ -	0.00%		1	$ -	-$ 0.09			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.01627	198	$ 3.22	$ 0.00846	198	$ 1.68	-$ 1.55	-48.00%		198	$ -	-$ 1.68			198	$ -	$ -			198	$ -	$ -			198	$ -	$ -			198	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kWh	$ 0.00068	198	$ 0.13	$ 0.00126	198	$ 0.25	$ 0.11	85.29%		198	$ -	-$ 0.25			198	$ -	$ -			198	$ -	$ -			198	$ -	$ -			198	$ -	$ -	
Sub-Total A (excluding pass through)				**$ 29.89**			**$ 33.01**	**$ 3.13**	**10.47%**			**$ 32.30**	**-$ 0.71**	**-2.16%**			**$ 33.39**	**$ 1.09**	**3.37%**			**$ 34.24**	**$ 0.85**	**2.55%**			**$ 35.74**	**$ 1.50**	**4.38%**			**$ 37.18**	**$ 1.44**	**4.03%**
Line Losses on Cost of Power	per kWh	$ 0.0820	7	$ 0.61	$ 0.0820	7	$ 0.61	$ -	0.00%	$ 0.0820	6	$ 0.48	-$ 0.13	-21.54%	$ 0.0820	6	$ 0.48	$ -	0.00%	$ 0.0820	6	$ 0.48	$ -	0.00%	$ 0.0820	6	$ 0.48	$ -	0.00%	$ 0.0820	6	$ 0.48	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	per kWh	-$ 0.00392	198	-$ 0.78	-$ 0.0005	198	-$ 0.11	$ 0.67	-86%	$ 0.00045	198	$ 0.09	$ 0.20	-183.33%			$ -	-$ 0.09				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	per kWh	$ 0.00007	198	$ 0.01	$ 0.0000	198	$ 0.01	-$ 0.01	-57%	-$ 0.00003	198	-$ 0.01	-$ 0.01	-200.00%			$ -	$ 0.01				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	per kWh	-$ 0.00112		$ -	$ 0.00068		$ -	$ -		-$ 0.00290		$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	per 30 days	$ 0.56	1	$ 0.56	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%			$ -	-$ 0.56				$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 30.29**			**$ 34.08**	**$ 3.79**	**12.51%**			**$ 33.42**	**-$ 0.66**	**-1.94%**			**$ 34.43**	**$ 1.01**	**3.01%**			**$ 35.28**	**$ 0.85**	**2.47%**			**$ 36.22**	**$ 0.94**	**2.66%**			**$ 37.66**	**$ 1.44**	**3.98%**
Retail Transmissioin Rate - Network Service Rate	per kWh	$ 0.00759	205	$ 1.56	$ 0.00796	205	$ 1.64	$ 0.08	4.87%	$ 0.00825	204	$ 1.68	$ 0.05	2.83%	$ 0.00825	204	$ 1.68	$ -	0.00%	$ 0.00825	204	$ 1.68	$ -	0.00%	$ 0.00825	204	$ 1.68	$ -	0.00%	$ 0.00825	204	$ 1.68	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	per kWh	$ 0.00617	205	$ 1.27	$ 0.00703	205	$ 1.44	$ 0.18	13.94%	$ 0.00679	204	$ 1.38	-$ 0.06	-4.17%	$ 0.00679	204	$ 1.38	$ -	0.00%	$ 0.00679	204	$ 1.38	$ -	0.00%	$ 0.00679	204	$ 1.38	$ -	0.00%	$ 0.00679	204	$ 1.38	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				**$ 33.12**			**$ 37.16**	**$ 4.04**	**12.21%**			**$ 36.49**	**-$ 0.68**	**-1.82%**			**$ 37.49**	**$ 1.01**	**2.76%**			**$ 38.34**	**$ 0.85**	**2.27%**			**$ 39.28**	**$ 0.94**	**2.45%**			**$ 40.72**	**$ 1.44**	**3.67%**
Wholesale Market Service Rate - not including CBR	per kWh	$ 0.0032	205	$ 0.66	$ 0.0032	205	$ 0.66	$ -	0.00%	$ 0.0032	204	$ 0.65	-$ 0.01	-0.78%	$ 0.0032	204	$ 0.65	$ -	0.00%	$ 0.0032	204	$ 0.65	$ -	0.00%	$ 0.0032	204	$ 0.65	$ -	0.00%	$ 0.0032	204	$ 0.65	$ -	0.00%
Rural and Remote Rate Protection Charge (RRRP)	per kWh	$ 0.0003	205	$ 0.06	$ 0.0003	205	$ 0.06	$ -	0.00%	$ 0.0003	204	$ 0.06	-$ 0.00	-0.78%	$ 0.0003	204	$ 0.06	$ -	0.00%	$ 0.0003	204	$ 0.06	$ -	0.00%	$ 0.0003	204	$ 0.06	$ -	0.00%	$ 0.0003	204	$ 0.06	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	205	$ 0.08	$ 0.0004	205	$ 0.08	$ -	0.00%	$ 0.0004	204	$ 0.08	-$ 0.00	-0.78%	$ 0.0004	204	$ 0.08	$ -	0.00%	$ 0.0004	204	$ 0.08	$ -	0.00%	$ 0.0004	204	$ 0.08	$ -	0.00%	$ 0.0004	204	$ 0.08	$ -	0.00%
Standard Supply Service - Administrative Charge (if applicable)	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	129	$ 8.37	$ 0.0650	129	$ 8.37	$ -	0.00%	$ 0.0650	129	$ 8.37	$ -	0.00%	$ 0.0650	129	$ 8.37	$ -	0.00%	$ 0.0650	129	$ 8.37	$ -	0.00%	$ 0.0650	129	$ 8.37	$ -	0.00%	$ 0.0650	129	$ 8.37	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	34	$ 3.16	$ 0.0940	34	$ 3.16	$ -	0.00%	$ 0.0940	34	$ 3.16	$ -	0.00%	$ 0.0940	34	$ 3.16	$ -	0.00%	$ 0.0940	34	$ 3.16	$ -	0.00%	$ 0.0940	34	$ 3.16	$ -	0.00%	$ 0.0940	34	$ 3.16	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	36	$ 4.70	$ 0.1320	36	$ 4.70	$ -	0.00%	$ 0.1320	36	$ 4.70	$ -	0.00%	$ 0.1320	36	$ 4.70	$ -	0.00%	$ 0.1320	36	$ 4.70	$ -	0.00%	$ 0.1320	36	$ 4.70	$ -	0.00%	$ 0.1320	36	$ 4.70	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	198	$ 15.25	$ 0.0770	198	$ 15.25	$ -	0.00%	$ 0.0770	198	$ 15.25	$ -	0.00%	$ 0.0770	198	$ 15.25	$ -	0.00%	$ 0.0770	198	$ 15.25	$ -	0.00%	$ 0.0770	198	$ 15.25	$ -	0.00%	$ 0.0770	198	$ 15.25	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	0	$ -	$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -	
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 50.41**			**$ 54.45**	**$ 4.04**	**8.0%**			**$ 53.77**	**-$ 0.68**	**-1.3%**			**$ 54.77**	**$ 1.01**	**1.9%**			**$ 55.62**	**$ 0.85**	**1.6%**			**$ 56.56**	**$ 0.94**	**1.7%**			**$ 58.00**	**$ 1.44**	**2.5%**
8% Provincial Rebate		-8%		-$ 4.03	-8%		-$ 4.36	-$ 0.32	8.0%	-8%		-$ 4.30	$ 0.05	-1.3%	-8%		-$ 4.38	-$ 0.08	1.9%	-8%		-$ 4.45	-$ 0.07	1.6%	-8%		-$ 4.53	-$ 0.08	1.7%	-8%		-$ 4.64	-$ 0.12	2.5%
HST		13%		$ 6.55	13%		$ 7.08	$ 0.53	8.0%	13%		$ 6.99	-$ 0.09	-1.3%	13%		$ 7.12	$ 0.13	1.9%	13%		$ 7.23	$ 0.11	1.6%	13%		$ 7.35	$ 0.12	1.7%	13%		$ 7.54	$ 0.19	2.5%
Total Bill on TOU (after Tax & Rebate)				**$ 52.93**			**$ 57.17**	**$ 4.24**	**8.0%**			**$ 56.46**	**-$ 0.72**	**-1.3%**			**$ 57.51**	**$ 1.06**	**1.9%**			**$ 58.40**	**$ 0.89**	**1.6%**			**$ 59.39**	**$ 0.99**	**1.7%**			**$ 60.90**	**$ 1.51**	**2.5%**
Loss Factor (%)		3.76%			3.76%					2.95%					2.95%					2.95%					2.95%					2.95%				

Appendix 2-W
Bill Impacts

Customer Class: GENERAL SERVICE LESS THAN 50 kW SERVICE

TOU / non-TOU: TOU

Consumption 2,000 kWh ● May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		2018 Current Board-Approved			2019 Current Board-Approved			Impact		2020 Proposed			Impact		2021 Proposed			Impact		2022 Proposed			Impact		2023 Proposed			Impact		2024 Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change
Service Charge	per 30 days	$ 34.45	1	$ 34.45	$ 35.80	1	$ 35.80	$ 1.35	3.92%	$ 37.23	1	$ 37.23	$ 1.43	3.99%	$ 38.44	1	$ 38.44	$ 1.21	3.25%	$ 39.39	1	$ 39.39	$ 0.95	2.47%	$ 41.06	1	$ 41.06	$ 1.67	4.24%	$ 42.67	1	$ 42.67	$ 1.61	3.92%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per kWh									$ 0.00010	2,000	$ 0.20	$ 0.20		$ 0.00010	2,000	$ 0.20	$ -	0.00%	$ 0.00010	2,000	$ 0.20	$ -	0.00%	$ 0.00010	2,000	$ 0.20	$ -	0.00%	$ 0.00010	2,000	$ 0.20	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per kWh									$ 0.00059	2,000	$ 1.18	$ 1.18		$ 0.00059	2,000	$ 1.18	$ -	0.00%	$ 0.00059	2,000	$ 1.18	$ -	0.00%	$ 0.00059	2,000	$ 1.18	$ -	0.00%	$ 0.00059	2,000	$ 1.18	$ -	0.00%
Rate Rider for Recovery of Monthly Billing - effective until Dec. 31, 2024	per kWh									$ 0.00011	2,000	$ 0.22	$ 0.22		$ 0.00011	2,000	$ 0.22	$ -	0.00%	$ 0.00011	2,000	$ 0.22	$ -	0.00%	$ 0.00011	2,000	$ 0.22	$ -	0.00%	$ 0.00011	2,000	$ 0.22	$ -	0.00%
Rate Rider for Recovery of Stranded Meter Assets - effective until Dec. 31, 2024	per 30 days									-$ 0.10	1	-$ 0.10	-$ 0.10		-$ 0.10	1	-$ 0.10	$ -	0.00%	-$ 0.10	1	-$ 0.10	$ -	0.00%	-$ 0.10	1	-$ 0.10	$ -	0.00%	-$ 0.10	1	-$ 0.10	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per kWh									-$ 0.00091	2,000	-$ 1.82	-$ 1.82		-$ 0.00091	2,000	-$ 1.82	$ -	0.00%	-$ 0.00091	2,000	-$ 1.82	$ -	0.00%	-$ 0.00091	2,000	-$ 1.82	$ -	0.00%	-$ 0.00091	2,000	-$ 1.82	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per kWh									-$ 0.00015	2,000	-$ 0.30	-$ 0.30		-$ 0.00015	2,000	-$ 0.30	$ -	0.00%	-$ 0.00015	2,000	-$ 0.30	$ -	0.00%	-$ 0.00015	2,000	-$ 0.30	$ -	0.00%	-$ 0.00015	2,000	-$ 0.30	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per kWh									-$ 0.00001	2,000	-$ 0.02	-$ 0.02		-$ 0.00001	2,000	-$ 0.02	$ -	0.00%	-$ 0.00001	2,000	-$ 0.02	$ -	0.00%	-$ 0.00001	2,000	-$ 0.02	$ -	0.00%	-$ 0.00001	2,000	-$ 0.02	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per kWh									-$ 0.00002	2,000	-$ 0.04	-$ 0.04		-$ 0.00002	2,000	-$ 0.04	$ -	0.00%	-$ 0.00002	2,000	-$ 0.04	$ -	0.00%	-$ 0.00002	2,000	-$ 0.04	$ -	0.00%	-$ 0.00002	2,000	-$ 0.04	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per kWh									-$ 0.00096	2,000	-$ 1.92	-$ 1.92		-$ 0.00096	2,000	-$ 1.92	$ -	0.00%	-$ 0.00096	2,000	-$ 1.92	$ -	0.00%	-$ 0.00096	2,000	-$ 1.92	$ -	0.00%	-$ 0.00096	2,000	-$ 1.92	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per kWh									-$ 0.00004	2,000	-$ 0.08	-$ 0.08		-$ 0.00004	2,000	-$ 0.08	$ -	0.00%	-$ 0.00004	2,000	-$ 0.08	$ -	0.00%	-$ 0.00004	2,000	-$ 0.08	$ -	0.00%	-$ 0.00004	2,000	-$ 0.08	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per kWh									-$ 0.00042	2,000	-$ 0.84	-$ 0.84		-$ 0.00042	2,000	-$ 0.84	$ -	0.00%	-$ 0.00042	2,000	-$ 0.84	$ -	0.00%	-$ 0.00042	2,000	-$ 0.84	$ -	0.00%	-$ 0.00042	2,000	-$ 0.84	$ -	0.00%
Rate Rider for Disposition of AR Credits - effective until Dec. 31, 2024	per kWh									-$ 0.00004	2,000	-$ 0.08	-$ 0.08		-$ 0.00004	2,000	-$ 0.08	$ -	0.00%	-$ 0.00004	2,000	-$ 0.08	$ -	0.00%	-$ 0.00004	2,000	-$ 0.08	$ -	0.00%	-$ 0.00004	2,000	-$ 0.08	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.79	1	$ 0.79	$ 0.79	1	$ 0.79	$ -	0.00%		1	$ -	-$ 0.79			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%		1	$ -	-$ 0.25			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of Stranded Meters Assets - effective until Dec. 31, 2019.	per 30 days	$ 1.55	1	$ 1.55	$ 1.55	1	$ 1.55	$ -	0.00%		1	$ -	-$ 1.55			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.03187	2,000	$ 63.74	$ 0.03312	2,000	$ 66.24	$ 2.50	3.92%	$ 0.03444	2,000	$ 68.88	$ 2.64	3.99%	$ 0.03556	2,000	$ 71.12	$ 2.24	3.25%	$ 0.03643	2,000	$ 72.86	$ 1.74	2.45%	$ 0.03797	2,000	$ 75.94	$ 3.08	4.23%	$ 0.03946	2,000	$ 78.92	$ 2.98	3.92%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per kWh	-$ 0.00051	2,000	-$ 1.02		2,000	$ -	$ 1.02			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per kWh	-$ 0.00156	2,000	-$ 3.12		2,000	$ -	$ 3.12			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per kWh	$ 0.00013	2,000	$ 0.26	$ 0.00013	2,000	$ 0.26	$ -	0.00%		2,000	$ -	-$ 0.26			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per kWh	$ 0.00003	2,000	$ 0.06	$ 0.00003	2,000	$ 0.06	$ -	0.00%		2,000	$ -	-$ 0.06			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per kWh	$ 0.00049	2,000	$ 0.98	$ 0.00049	2,000	$ 0.98	$ -	0.00%		2,000	$ -	-$ 0.98			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per kWh	$ 0.00076	2,000	$ 1.52	$ 0.00076	2,000	$ 1.52	$ -	0.00%		2,000	$ -	-$ 1.52			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per kWh	$ 0.00024	2,000	$ 0.48	$ 0.00024	2,000	$ 0.48	$ -	0.00%		2,000	$ -	-$ 0.48			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kWh	-$ 0.00019	2,000	-$ 0.38	$ 0.00020	2,000	$ 0.40	$ 0.78	-205.26%		2,000	$ -	-$ 0.40			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Sub-Total A (excluding pass through)				**$ 99.56**			**$ 108.33**	**$ 8.77**	**8.81%**			**$ 102.51**	**-$ 5.82**	**-5.37%**			**$ 105.96**	**$ 3.45**	**3.37%**			**$ 108.65**	**$ 2.69**	**2.54%**			**$ 113.40**	**$ 4.75**	**4.37%**			**$ 117.99**	**$ 4.59**	**4.05%**
Line Losses on Cost of Power	per kWh	$ 0.0820	75	$ 6.17	$ 0.0820	75	$ 6.17	$ -	0.00%	$ 0.0820	59	$ 4.84	-$ 1.33	-21.54%	$ 0.0820	59	$ 4.84	$ -	0.00%	$ 0.0820	59	$ 4.84	$ -	0.00%	$ 0.0820	59	$ 4.84	$ -	0.00%	$ 0.0820	59	$ 4.84	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	per kWh	-$ 0.00317	2,000	-$ 6.34	-$ 0.00050	2,000	-$ 1.00	$ 5.34	-84.23%	$ 0.00070	2,000	$ 1.40	$ 2.40	-240.00%			$ -	-$ 1.40				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	per kWh	$ 0.00007	2,000	$ 0.14	$ 0.00003	2,000	$ 0.06	-$ 0.08	-57.14%	-$ 0.00003	2,000	-$ 0.06	-$ 0.12	-200.00%			$ -	$ 0.06				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	per kWh	-$ 0.00112		$ -	$ 0.00068		$ -	$ -		-$ 0.00290		$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	per 30 days	$ 0.56	1	$ 0.56	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%				-$ 0.56				$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 100.09**			**$ 114.12**	**$ 14.03**	**14.02%**			**$ 109.25**	**-$ 4.87**	**-4.27%**			**$ 111.36**	**$ 2.11**	**1.93%**			**$ 114.05**	**$ 2.69**	**2.42%**			**$ 118.24**	**$ 4.19**	**3.67%**			**$ 122.83**	**$ 4.59**	**3.88%**
Retail Transmissioin Rate - Network Service Rate	per kWh	$ 0.00739	2,075	$ 15.34	$ 0.00775	2,075	$ 16.08	$ 0.75	4.87%	$ 0.00803	2,059	$ 16.53	$ 0.45	2.80%	$ 0.00803	2,059	$ 16.53	$ -	0.00%	$ 0.00803	2,059	$ 16.53	$ -	0.00%	$ 0.00803	2,059	$ 16.53	$ -	0.00%	$ 0.00803	2,059	$ 16.53	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	per kWh	$ 0.00552	2,075	$ 11.46	$ 0.00629	2,075	$ 13.05	$ 1.60	13.95%	$ 0.00607	2,059	$ 12.50	-$ 0.55	-4.25%	$ 0.00607	2,059	$ 12.50	$ -	0.00%	$ 0.00607	2,059	$ 12.50	$ -	0.00%	$ 0.00607	2,059	$ 12.50	$ -	0.00%	$ 0.00607	2,059	$ 12.50	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				**$ 126.88**			**$ 143.25**	**$ 16.37**	**12.91%**			**$ 138.28**	**-$ 4.97**	**-3.47%**			**$ 140.39**	**$ 2.11**	**1.53%**			**$ 143.08**	**$ 2.69**	**1.92%**			**$ 147.27**	**$ 4.19**	**2.93%**			**$ 151.86**	**$ 4.59**	**3.12%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0032	2,075	$ 6.64	$ 0.0032	2,075	$ 6.64	$ -	0.00%	$ 0.0032	2,059	$ 6.59	-$ 0.05	-0.78%	$ 0.0032	2,059	$ 6.59	$ -	0.00%	$ 0.0032	2,059	$ 6.59	$ -	0.00%	$ 0.0032	2,059	$ 6.59	$ -	0.00%	$ 0.0032	2,059	$ 6.59	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0003	2,075	$ 0.62	$ 0.0003	2,075	$ 0.62	$ -	0.00%	$ 0.0003	2,059	$ 0.62	-$ 0.00	-0.78%	$ 0.0003	2,059	$ 0.62	$ -	0.00%	$ 0.0003	2,059	$ 0.62	$ -	0.00%	$ 0.0003	2,059	$ 0.62	$ -	0.00%	$ 0.0003	2,059	$ 0.62	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	2,075	$ 0.83	$ 0.0004	2,075	$ 0.83			$ 0.0004	2,059	$ 0.82	-$ 0.01	-0.78%	$ 0.0004	2,059	$ 0.82	$ -	0.00%	$ 0.0004	2,059	$ 0.82	$ -	0.00%	$ 0.0004	2,059	$ 0.82	$ -	0.00%	$ 0.0004	2,059	$ 0.82	$ -	0.00%
Standard Supply Service Charge	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	1,300	$ 84.50	$ 0.0650	1,300	$ 84.50	$ -	0.00%	$ 0.0650	1,300	$ 84.50	$ -	0.00%	$ 0.0650	1,300	$ 84.50	$ -	0.00%	$ 0.0650	1,300	$ 84.50	$ -	0.00%	$ 0.0650	1,300	$ 84.50	$ -	0.00%	$ 0.0650	1,300	$ 84.50	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	340	$ 31.96	$ 0.0940	340	$ 31.96	$ -	0.00%	$ 0.0940	340	$ 31.96	$ -	0.00%	$ 0.0940	340	$ 31.96	$ -	0.00%	$ 0.0940	340	$ 31.96	$ -	0.00%	$ 0.0940	340	$ 31.96	$ -	0.00%	$ 0.0940	340	$ 31.96	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	360	$ 47.52	$ 0.1320	360	$ 47.52	$ -	0.00%	$ 0.1320	360	$ 47.52	$ -	0.00%	$ 0.1320	360	$ 47.52	$ -	0.00%	$ 0.1320	360	$ 47.52	$ -	0.00%	$ 0.1320	360	$ 47.52	$ -	0.00%	$ 0.1320	360	$ 47.52	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	600	$ 46.20	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	1,400	$ 124.60	$ 0.0890	1,400	$ 124.60	$ -	0.00%	$ 0.0890	1,400	$ 124.60	$ -	0.00%	$ 0.0890	1,400	$ 124.60	$ -	0.00%	$ 0.0890	1,400	$ 124.60	$ -	0.00%	$ 0.0890	1,400	$ 124.60	$ -	0.00%	$ 0.0890	1,400	$ 124.60	$ -	0.00%
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164		$ -	$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 299.20**			**$ 315.57**	**$ 16.37**	**5.5%**			**$ 310.54**	**-$ 5.04**	**-1.6%**			**$ 312.65**	**$ 2.11**	**0.7%**			**$ 315.34**	**$ 2.69**	**0.9%**			**$ 319.53**	**$ 4.19**	**1.3%**			**$ 324.12**	**$ 4.59**	**1.4%**
8% Provincial Rebate	-8%			-$ 23.94	-8%		-$ 25.25	-$ 1.31	5.5%	-8%		-$ 24.84	$ 0.40	-1.6%	-8%		-$ 25.01	-$ 0.17	0.7%	-8%		-$ 25.23	-$ 0.22	0.9%	-8%		-$ 25.56	-$ 0.34	1.3%	-8%		-$ 25.93	-$ 0.37	1.4%
HST	13%			$ 38.90	13%		$ 41.02	$ 2.13	5.5%	13%		$ 40.37	-$ 0.65	-1.6%	13%		$ 40.64	$ 0.27	0.7%	13%		$ 40.99	$ 0.35	0.9%	13%		$ 41.54	$ 0.54	1.3%	13%		$ 42.14	$ 0.60	1.4%
Total Bill on TOU (after Tax & Rebate)				**$ 314.16**			**$ 331.35**	**$ 17.19**	**5.5%**			**$ 326.07**	**-$ 5.29**	**-1.6%**			**$ 328.28**	**$ 2.22**	**0.7%**			**$ 331.11**	**$ 2.82**	**0.9%**			**$ 335.51**	**$ 4.40**	**1.3%**			**$ 340.33**	**$ 4.82**	**1.4%**
Total Bill on RPP (before Taxes)				**$ 306.02**			**$ 322.39**	**$ 16.37**	**5.4%**			**$ 317.36**	**-$ 5.04**	**-1.6%**			**$ 319.47**	**$ 2.11**	**0.7%**			**$ 322.16**	**$ 2.69**	**0.8%**			**$ 326.35**	**$ 4.19**	**1.3%**			**$ 330.94**	**$ 4.59**	**1.4%**
8% Provincial Rebate	-8%			-$ 24.48	-8%		-$ 25.79	-$ 1.31	5.4%	-8%		-$ 25.39	$ 0.40	-1.6%	-8%		-$ 25.56	-$ 0.17	0.7%	-8%		-$ 25.77	-$ 0.22	0.8%	-8%		-$ 26.11	-$ 0.34	1.3%	-8%		-$ 26.48	-$ 0.37	1.4%
HST	13%			$ 39.78	13%		$ 41.91	$ 2.13	5.4%	13%		$ 41.26	-$ 0.65	-1.6%	13%		$ 41.53	$ 0.27	0.7%	13%		$ 41.88	$ 0.35	0.8%	13%		$ 42.43	$ 0.54	1.3%	13%		$ 43.02	$ 0.60	1.4%
Total Bill on RPP (after Tax & Rebate)				**$ 321.32**			**$ 338.51**	**$ 17.19**	**5.4%**			**$ 333.23**	**-$ 5.29**	**-1.6%**			**$ 335.44**	**$ 2.22**	**0.7%**			**$ 338.27**	**$ 2.82**	**0.8%**			**$ 342.67**	**$ 4.40**	**1.3%**			**$ 347.49**	**$ 4.82**	**1.4%**
Loss Factor (%)		3.76%			3.76%					2.95%					2.95%					2.95%					2.95%					2.95%				

Appendix 2-W
Bill Impacts

Customer Class: GENERAL SERVICE LESS THAN 50 kW SERVICE

TOU / non-TOU: TOU

Consumption 2,800 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	2018 Current Board-Approved Rate ($)	Volume	Charge ($)	2019 Current Board-Approved Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change	2020 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change	2021 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change	2022 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change	2023 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change	2024 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change
Service Charge	per 30 days	$ 34.45	1	$ 34.45	$ 35.80	1	$ 35.80	$ 1.35	3.92%	$ 37.23	1	$ 37.23	$ 1.43	3.99%	$ 38.44	1	$ 38.44	$ 1.21	3.25%	$ 39.39	1	$ 39.39	$ 0.95	2.47%	$ 41.06	1	$ 41.06	$ 1.67	4.24%	$ 42.67	1	$ 42.67	$ 1.61	3.92%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per kWh									$ 0.00010	2,800	$ 0.28	$ 0.28		$ 0.00010	2,800	$ 0.28	$ -	0.00%	$ 0.00010	2,800	$ 0.28	$ -	0.00%	$ 0.00010	2,800	$ 0.28	$ -	0.00%	$ 0.00010	2,800	$ 0.28	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per kWh									$ 0.00059	2,800	$ 1.65	$ 1.65		$ 0.00059	2,800	$ 1.65	$ -	0.00%	$ 0.00059	2,800	$ 1.65	$ -	0.00%	$ 0.00059	2,800	$ 1.65	$ -	0.00%	$ 0.00059	2,800	$ 1.65	$ -	0.00%
Rate Rider for Recovery of Monthly Billing - effective until Dec. 31, 2024	per kWh									$ 0.00011	2,800	$ 0.31	$ 0.31		$ 0.00011	2,800	$ 0.31	$ -	0.00%	$ 0.00011	2,800	$ 0.31	$ -	0.00%	$ 0.00011	2,800	$ 0.31	$ -	0.00%	$ 0.00011	2,800	$ 0.31	$ -	0.00%
Rate Rider for Recovery of Stranded Meter Assets - effective until Dec. 31, 2024	per 30 days									-$ 0.10	1	-$ 0.10	-$ 0.10		-$ 0.10	1	-$ 0.10	$ -	0.00%	-$ 0.10	1	-$ 0.10	$ -	0.00%	-$ 0.10	1	-$ 0.10	$ -	0.00%	-$ 0.10	1	-$ 0.10	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per kWh									-$ 0.00091	2,800	-$ 2.55	-$ 2.55		-$ 0.00091	2,800	-$ 2.55	$ -	0.00%	-$ 0.00091	2,800	-$ 2.55	$ -	0.00%	-$ 0.00091	2,800	-$ 2.55	$ -	0.00%	-$ 0.00091	2,800	-$ 2.55	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per kWh									-$ 0.00015	2,800	-$ 0.42	-$ 0.42		-$ 0.00015	2,800	-$ 0.42	$ -	0.00%	-$ 0.00015	2,800	-$ 0.42	$ -	0.00%	-$ 0.00015	2,800	-$ 0.42	$ -	0.00%	-$ 0.00015	2,800	-$ 0.42	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per kWh									-$ 0.00001	2,800	-$ 0.03	-$ 0.03		-$ 0.00001	2,800	-$ 0.03	$ -	0.00%	-$ 0.00001	2,800	-$ 0.03	$ -	0.00%	-$ 0.00001	2,800	-$ 0.03	$ -	0.00%	-$ 0.00001	2,800	-$ 0.03	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per kWh									-$ 0.00002	2,800	-$ 0.06	-$ 0.06		-$ 0.00002	2,800	-$ 0.06	$ -	0.00%	-$ 0.00002	2,800	-$ 0.06	$ -	0.00%	-$ 0.00002	2,800	-$ 0.06	$ -	0.00%	-$ 0.00002	2,800	-$ 0.06	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per kWh									-$ 0.00096	2,800	-$ 2.69	-$ 2.69		-$ 0.00096	2,800	-$ 2.69	$ -	0.00%	-$ 0.00096	2,800	-$ 2.69	$ -	0.00%	-$ 0.00096	2,800	-$ 2.69	$ -	0.00%	-$ 0.00096	2,800	-$ 2.69	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per kWh									-$ 0.00004	2,800	-$ 0.11	-$ 0.11		-$ 0.00004	2,800	-$ 0.11	$ -	0.00%	-$ 0.00004	2,800	-$ 0.11	$ -	0.00%	-$ 0.00004	2,800	-$ 0.11	$ -	0.00%	-$ 0.00004	2,800	-$ 0.11	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per kWh									-$ 0.00042	2,800	-$ 1.18	-$ 1.18		-$ 0.00042	2,800	-$ 1.18	$ -	0.00%	-$ 0.00042	2,800	-$ 1.18	$ -	0.00%	-$ 0.00042	2,800	-$ 1.18	$ -	0.00%	-$ 0.00042	2,800	-$ 1.18	$ -	0.00%
Rate Rider for Disposition of AR Credits - effective until Dec. 31, 2024	per kWh									-$ 0.00004	2,800	-$ 0.11	-$ 0.11		-$ 0.00004	2,800	-$ 0.11	$ -	0.00%	-$ 0.00004	2,800	-$ 0.11	$ -	0.00%	-$ 0.00004	2,800	-$ 0.11	$ -	0.00%	-$ 0.00004	2,800	-$ 0.11	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.79	1	$ 0.79	$ 0.79	1	$ 0.79	$ -	0.00%		1	$ -	-$ 0.79			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%		1	$ -	-$ 0.25			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of Stranded Meters Assets - effective until Dec. 31, 2019.	per 30 days	$ 1.55	1	$ 1.55	$ 1.55	1	$ 1.55	$ -	0.00%		1	$ -	-$ 1.55			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.03187	2,800	$ 89.24	$ 0.03312	2,800	$ 92.74	$ 3.50	3.92%	$ 0.03444	2,800	$ 96.43	$ 3.70	3.99%	$ 0.03556	2,800	$ 99.57	$ 3.14	3.25%	$ 0.03643	2,800	$ 102.00	$ 2.44	2.45%	$ 0.03797	2,800	$ 106.32	$ 4.31	4.23%	$ 0.03946	2,800	$ 110.49	$ 4.17	3.92%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per kWh	-$ 0.00051	2,800	-$ 1.43		2,800	$ -	$ 1.43			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per kWh	-$ 0.00156	2,800	-$ 4.37		2,800	$ -	$ 4.37			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per kWh	$ 0.00013	2,800	$ 0.36	$ 0.00013	2,800	$ 0.36	$ -	0.00%		2,800	$ -	-$ 0.36			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per kWh	$ 0.00003	2,800	$ 0.08	$ 0.00003	2,800	$ 0.08	$ -	0.00%		2,800	$ -	-$ 0.08			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per kWh	$ 0.00049	2,800	$ 1.37	$ 0.00049	2,800	$ 1.37	$ -	0.00%		2,800	$ -	-$ 1.37			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per kWh	$ 0.00076	2,800	$ 2.13	$ 0.00076	2,800	$ 2.13	$ -	0.00%		2,800	$ -	-$ 2.13			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per kWh	$ 0.00024	2,800	$ 0.67	$ 0.00024	2,800	$ 0.67	$ -	0.00%		2,800	$ -	-$ 0.67			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kWh	-$ 0.00019	2,800	-$ 0.53	$ 0.00020	2,800	$ 0.56	$ 1.09	-205.26%		2,800	$ -	-$ 0.56			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -	
Sub-Total A (excluding pass through)				**$ 124.57**			**$ 136.31**	**$ 11.74**	**9.42%**			**$ 128.66**	**-$ 7.64**	**-5.61%**			**$ 133.01**	**$ 4.35**	**3.38%**			**$ 136.39**	**$ 3.39**	**2.55%**			**$ 142.38**	**$ 5.98**	**4.39%**			**$ 148.16**	**$ 5.78**	**4.06%**
Line Losses on Cost of Power	per kWh	$ 0.0820	105	$ 8.63	$ 0.0820	105	$ 8.63	$ -	0.00%	$ 0.0820	83	$ 6.77	-$ 1.86	-21.54%	$ 0.0820	83	$ 6.77	$ -	0.00%	$ 0.0820	83	$ 6.77	$ -	0.00%	$ 0.0820	83	$ 6.77	$ -	0.00%	$ 0.0820	83	$ 6.77	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	per kWh	-$ 0.00317	2,800	-$ 8.88	-$ 0.00050	2,800	-$ 1.40	$ 7.48	-84.23%	$ 0.00070	2,800	$ 1.96	$ 3.36	-240.00%			$ -	-$ 1.96				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	per kWh	$ 0.00007	2,800	$ 0.20	$ 0.00003	2,800	$ 0.08	-$ 0.11	-57.14%	-$ 0.00003	2,800	-$ 0.08	-$ 0.17	-200.00%			$ -	$ 0.08				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	per kWh	-$ 0.00112		$ -	$ 0.00068		$ -	$ -		-$ 0.00290		$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	per 30 days	$ 0.56	1	$ 0.56	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%			$ -	-$ 0.56				$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 125.08**			**$ 144.18**	**$ 19.10**	**15.27%**			**$ 137.87**	**-$ 6.31**	**-4.38%**			**$ 140.34**	**$ 2.47**	**1.79%**			**$ 143.73**	**$ 3.39**	**2.41%**			**$ 149.15**	**$ 5.42**	**3.77%**			**$ 154.93**	**$ 5.78**	**3.88%**
Retail Transmissioin Rate - Network Service Rate	per kWh	$ 0.00739	2,905	$ 21.47	$ 0.00775	2,905	$ 22.52	$ 1.05	4.87%	$ 0.00803	2,883	$ 23.15	$ 0.63	2.80%	$ 0.00803	2,883	$ 23.15	$ -	0.00%	$ 0.00803	2,883	$ 23.15	$ -	0.00%	$ 0.00803	2,883	$ 23.15	$ -	0.00%	$ 0.00803	2,883	$ 23.15	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	per kWh	$ 0.00552	2,905	$ 16.04	$ 0.00629	2,905	$ 18.27	$ 2.24	13.95%	$ 0.00607	2,883	$ 17.50	-$ 0.78	-4.25%	$ 0.00607	2,883	$ 17.50	$ -	0.00%	$ 0.00607	2,883	$ 17.50	$ -	0.00%	$ 0.00607	2,883	$ 17.50	$ -	0.00%	$ 0.00607	2,883	$ 17.50	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				**$ 162.59**			**$ 184.97**	**$ 22.38**	**13.77%**			**$ 178.52**	**-$ 6.46**	**-3.49%**			**$ 180.99**	**$ 2.47**	**1.38%**			**$ 184.37**	**$ 3.39**	**1.87%**			**$ 189.79**	**$ 5.42**	**2.94%**			**$ 195.58**	**$ 5.78**	**3.05%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0032	2,905	$ 9.30	$ 0.0032	2,905	$ 9.30	$ -	0.00%	$ 0.0032	2,883	$ 9.22	-$ 0.07	-0.78%	$ 0.0032	2,883	$ 9.22	$ -	0.00%	$ 0.0032	2,883	$ 9.22	$ -	0.00%	$ 0.0032	2,883	$ 9.22	$ -	0.00%	$ 0.0032	2,883	$ 9.22	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0003	2,905	$ 0.87	$ 0.0003	2,905	$ 0.87	$ -	0.00%	$ 0.0003	2,883	$ 0.86	-$ 0.01	-0.78%	$ 0.0003	2,883	$ 0.86	$ -	0.00%	$ 0.0003	2,883	$ 0.86	$ -	0.00%	$ 0.0003	2,883	$ 0.86	$ -	0.00%	$ 0.0003	2,883	$ 0.86	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	2,905	$ 1.16	$ 0.0004	2,905	$ 1.16			$ 0.0004	2,883	$ 1.15	-$ 0.01	-0.78%	$ 0.0004	2,883	$ 1.15	$ -	0.00%	$ 0.0004	2,883	$ 1.15	$ -	0.00%	$ 0.0004	2,883	$ 1.15	$ -	0.00%	$ 0.0004	2,883	$ 1.15	$ -	0.00%
Standard Supply Service Charge	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	1,820	$ 118.30	$ 0.0650	1,820	$ 118.30	$ -	0.00%	$ 0.0650	1,820	$ 118.30	$ -	0.00%	$ 0.0650	1,820	$ 118.30	$ -	0.00%	$ 0.0650	1,820	$ 118.30	$ -	0.00%	$ 0.0650	1,820	$ 118.30	$ -	0.00%	$ 0.0650	1,820	$ 118.30	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	476	$ 44.74	$ 0.0940	476	$ 44.74	$ -	0.00%	$ 0.0940	476	$ 44.74	$ -	0.00%	$ 0.0940	476	$ 44.74	$ -	0.00%	$ 0.0940	476	$ 44.74	$ -	0.00%	$ 0.0940	476	$ 44.74	$ -	0.00%	$ 0.0940	476	$ 44.74	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	504	$ 66.53	$ 0.1320	504	$ 66.53	$ -	0.00%	$ 0.1320	504	$ 66.53	$ -	0.00%	$ 0.1320	504	$ 66.53	$ -	0.00%	$ 0.1320	504	$ 66.53	$ -	0.00%	$ 0.1320	504	$ 66.53	$ -	0.00%	$ 0.1320	504	$ 66.53	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	600	$ 46.20	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	2,200	$ 195.80	$ 0.0890	2,200	$ 195.80	$ -	0.00%	$ 0.0890	2,200	$ 195.80	$ -	0.00%	$ 0.0890	2,200	$ 195.80	$ -	0.00%	$ 0.0890	2,200	$ 195.80	$ -	0.00%	$ 0.0890	2,200	$ 195.80	$ -	0.00%	$ 0.0890	2,200	$ 195.80	$ -	0.00%
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164		$ -	$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 403.74**			**$ 426.12**	**$ 22.38**	**5.5%**			**$ 419.58**	**-$ 6.55**	**-1.5%**			**$ 422.05**	**$ 2.47**	**0.6%**			**$ 425.44**	**$ 3.39**	**0.8%**			**$ 430.86**	**$ 5.42**	**1.3%**			**$ 436.64**	**$ 5.78**	**1.3%**
8% Provincial Rebate		-8%		-$ 32.30	-8%		-$ 34.09	-$ 1.79	5.5%	-8%		-$ 33.57	$ 0.52	-1.5%	-8%		-$ 33.76	-$ 0.20	0.6%	-8%		-$ 34.03	-$ 0.27	0.8%	-8%		-$ 34.47	-$ 0.43	1.3%	-8%		-$ 34.93	-$ 0.46	1.3%
HST		13%		$ 52.49	13%		$ 55.40	$ 2.91	5.5%	13%		$ 54.55	$ 0.85	-1.5%	13%		$ 54.87	$ 0.32	0.6%	13%		$ 55.31	$ 0.44	0.8%	13%		$ 56.01	$ 0.70	1.3%	13%		$ 56.76	$ 0.75	1.3%
Total Bill on TOU (after Tax & Rebate)				**$ 423.93**			**$ 447.43**	**$ 23.50**	**5.5%**			**$ 440.56**	**-$ 6.87**	**-1.5%**			**$ 443.15**	**$ 2.59**	**0.6%**			**$ 446.71**	**$ 3.56**	**0.8%**			**$ 452.40**	**$ 5.69**	**1.3%**			**$ 458.47**	**$ 6.07**	**1.3%**
Total Bill on RPP (before Taxes)				**$ 416.17**			**$ 438.55**	**$ 22.38**	**5.4%**			**$ 432.01**	**-$ 6.55**	**-1.5%**			**$ 434.48**	**$ 2.47**	**0.6%**			**$ 437.86**	**$ 3.39**	**0.8%**			**$ 443.29**	**$ 5.42**	**1.2%**			**$ 449.07**	**$ 5.78**	**1.3%**
8% Provincial Rebate		-8%		-$ 33.29	-8%		-$ 35.08	-$ 1.79	5.4%	-8%		-$ 34.56	$ 0.52	-1.5%	-8%		-$ 34.76	-$ 0.20	0.6%	-8%		-$ 35.03	-$ 0.27	0.8%	-8%		-$ 35.46	-$ 0.43	1.2%	-8%		-$ 35.93	-$ 0.46	1.3%
HST		13%		$ 54.10	13%		$ 57.01	$ 2.91	5.4%	13%		$ 56.16	$ 0.85	-1.5%	13%		$ 56.48	$ 0.32	0.6%	13%		$ 56.92	$ 0.44	0.8%	13%		$ 57.63	$ 0.70	1.2%	13%		$ 58.38	$ 0.75	1.3%
Total Bill on RPP (after Tax & Rebate)				**$ 436.98**			**$ 460.48**	**$ 23.50**	**5.4%**			**$ 453.61**	**-$ 6.87**	**-1.5%**			**$ 456.20**	**$ 2.59**	**0.6%**			**$ 459.76**	**$ 3.56**	**0.8%**			**$ 465.45**	**$ 5.69**	**1.2%**			**$ 471.52**	**$ 6.07**	**1.3%**
Loss Factor (%)		3.76%			3.76%					2.95%					2.95%					2.95%					2.95%					2.95%				

Appendix 2-W
Bill Impacts

Customer Class: GENERAL SERVICE 50 TO 999 kW SERVICE

TOU / non-TOU: non-TOU — SPOT Class B

180 kW
200 kVA — ● May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)
Consumption 79,000 kWh

		2018 Current Board-Approved			2019 Current Board-Approved			Impact		2020 Proposed			Impact		2021 Proposed			Impact		2022 Proposed			Impact		2023 Proposed			Impact		2024 Proposed			Impact	
Charge Unit		**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Service Charge	per 30 days	$ 49.55	1	$ 49.55	$ 51.50	1	$ 51.50	$ 1.95	3.94%	$ 52.19	1	$ 52.19	$ 0.69	1.34%	$ 53.89	1	$ 53.89	$ 1.70	3.26%	$ 55.22	1	$ 55.22	$ 1.33	2.47%	$ 57.56	1	$ 57.56	$ 2.34	4.24%	$ 59.82	1	$ 59.82	$ 2.26	3.93%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per kVA									$ 0.0173	200	$ 3.46	$ 3.46		$ 0.0173	200	$ 3.46	$ -	0.00%	$ 0.0173	200	$ 3.46	$ -	0.00%	$ 0.0173	200	$ 3.46	$ -	0.00%	$ 0.0173	200	$ 3.46	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per kVA									$ 0.1030	200	$ 20.60	$ 20.60		$ 0.1030	200	$ 20.60	$ -	0.00%	$ 0.1030	200	$ 20.60	$ -	0.00%	$ 0.1030	200	$ 20.60	$ -	0.00%	$ 0.1030	200	$ 20.60	$ -	0.00%
Rate Rider for Recovery of Stranded Meter Assets - effective until Dec. 31, 2024	per 30 days									-$ 0.37	1	-$ 0.37	-$ 0.37		-$ 0.37	1	-$ 0.37	$ -	0.00%	-$ 0.37	1	-$ 0.37	$ -	0.00%	-$ 0.37	1	-$ 0.37	$ -	0.00%	-$ 0.37	1	-$ 0.37	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per kVA									-$ 0.1574	200	-$ 31.48	-$ 31.48		-$ 0.1574	200	-$ 31.48	$ -	0.00%	-$ 0.1574	200	-$ 31.48	$ -	0.00%	-$ 0.1574	200	-$ 31.48	$ -	0.00%	-$ 0.1574	200	-$ 31.48	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per kVA									-$ 0.0252	200	-$ 5.04	-$ 5.04		-$ 0.0252	200	-$ 5.04	$ -	0.00%	-$ 0.0252	200	-$ 5.04	$ -	0.00%	-$ 0.0252	200	-$ 5.04	$ -	0.00%	-$ 0.0252	200	-$ 5.04	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per kVA									-$ 0.0009	200	-$ 0.18	-$ 0.18		-$ 0.0009	200	-$ 0.18	$ -	0.00%	-$ 0.0009	200	-$ 0.18	$ -	0.00%	-$ 0.0009	200	-$ 0.18	$ -	0.00%	-$ 0.0009	200	-$ 0.18	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per kVA									-$ 0.0033	200	-$ 0.66	-$ 0.66		-$ 0.0033	200	-$ 0.66	$ -	0.00%	-$ 0.0033	200	-$ 0.66	$ -	0.00%	-$ 0.0033	200	-$ 0.66	$ -	0.00%	-$ 0.0033	200	-$ 0.66	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per kVA									-$ 0.1669	200	-$ 33.38	-$ 33.38		-$ 0.1669	200	-$ 33.38	$ -	0.00%	-$ 0.1669	200	-$ 33.38	$ -	0.00%	-$ 0.1669	200	-$ 33.38	$ -	0.00%	-$ 0.1669	200	-$ 33.38	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per kVA									-$ 0.0068	200	-$ 1.36	-$ 1.36		-$ 0.0068	200	-$ 1.36	$ -	0.00%	-$ 0.0068	200	-$ 1.36	$ -	0.00%	-$ 0.0068	200	-$ 1.36	$ -	0.00%	-$ 0.0068	200	-$ 1.36	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per kVA									-$ 0.0738	200	-$ 14.76	-$ 14.76		-$ 0.0738	200	-$ 14.76	$ -	0.00%	-$ 0.0738	200	-$ 14.76	$ -	0.00%	-$ 0.0738	200	-$ 14.76	$ -	0.00%	-$ 0.0738	200	-$ 14.76	$ -	0.00%
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	per kVA									-$ 0.0404	200	-$ 8.08	-$ 8.08		-$ 0.0404	200	-$ 8.08	$ -	0.00%	-$ 0.0404	200	-$ 8.08	$ -	0.00%	-$ 0.0404	200	-$ 8.08	$ -	0.00%	-$ 0.0404	200	-$ 8.08	$ -	0.00%
Rate Rider for Disposition of AR Credits - effective until Dec. 31, 2024	per kVA									-$ 0.0004	200	-$ 0.08	-$ 0.08		-$ 0.0004	200	-$ 0.08	$ -	0.00%	-$ 0.0004	200	-$ 0.08	$ -	0.00%	-$ 0.0004	200	-$ 0.08	$ -	0.00%	-$ 0.0004	200	-$ 0.08	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 1.01	1	$ 1.01	$ 1.01	1	$ 1.01	$ -	0.00%		1	$ -	-$ 1.01			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.30	1	$ 0.30	$ 0.30	1	$ 0.30	$ -	0.00%		1	$ -	-$ 0.30			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of Stranded Meters Assets - effective until Dec. 31, 2019.	per 30 days	$ 4.64	1	$ 4.64	$ 4.64	1	$ 4.64	$ -	0.00%		1	$ -	-$ 4.64			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	per kVA	$ 7.7987	200	$ 1,559.74	$ 8.1052	200	$ 1,621.04	$ 61.30	3.93%	$ 8.37240	200	$ 1,674.48	$ 53.44	3.30%	$ 8.6453	200	$ 1,729.06	$ 54.58	3.26%	$ 8.85800	200	$ 1,771.60	$ 42.54	2.46%	$ 9.23360	200	$ 1,846.72	$ 75.12	4.24%	$ 9.59650	200	$ 1,919.30	$ 72.58	3.93%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per kVA	-$ 0.0814	200	-$ 16.28		200	$ -	$ 16.28			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per kVA	-$ 0.2512	200	-$ 50.24		200	$ -	$ 50.24			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per kVA	$ 0.0114	200	$ 2.28	$ 0.0114	200	$ 2.28	$ -	0.00%		200	$ -	-$ 2.28			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per kVA	$ 0.0047	200	$ 0.94	$ 0.0047	200	$ 0.94	$ -	0.00%		200	$ -	-$ 0.94			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per kVA	$ 0.0781	200	$ 15.62	$ 0.0781	200	$ 15.62	$ -	0.00%		200	$ -	-$ 15.62			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per kVA	$ 0.1659	200	$ 33.18	$ 0.1659	200	$ 33.18	$ -	0.00%		200	$ -	-$ 33.18			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per kVA	$ 0.0498	200	$ 9.96	$ 0.0498	200	$ 9.96	$ -	0.00%		200	$ -	-$ 9.96			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kVA	$ 0.0912	200	$ 18.24	$ 0.1948	200	$ 38.96	$ 20.72	113.60%		200	$ -	-$ 38.96			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -			200	$ -	$ -	
Sub-Total A (excluding pass through)				**$ 1,628.94**			**$ 1,779.43**	**$ 150.49**	**9.24%**			**$ 1,655.34**	**-$ 124.09**	**-6.97%**			**$ 1,711.62**	**$ 56.28**	**3.40%**			**$ 1,755.49**	**$ 43.87**	**2.56%**			**$ 1,832.95**	**$ 77.46**	**4.41%**			**$ 1,907.79**	**$ 74.84**	**4.08%**
Line Losses on Cost of Power	per kWh	$ 0.1164	2,970	$ 345.75	$ 0.1164	2,970	$ 345.75	$ -	0.00%	$ 0.1164	2,331	$ 271.27	-$ 74.48	-21.54%	$ 0.1164	2,331	$ 271.27	$ -	0.00%	$ 0.1164	2,331	$ 271.27	$ -	0.00%	$ 0.1164	2,331	$ 271.27	$ -	0.00%	$ 0.1164	2,331	$ 271.27	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	per kVA	-$ 0.7597	200	-$ 151.94	$ 0.2813	200	$ 56.26	$ 208.20	-137.03%	$ 0.44260	200	$ 88.52	$ 32.26	57.34%			$ -	-$ 88.52				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Deferral/Variance Accounts for Non-Wholesale Market Participants	per kVA	-$ 0.5191	200	-$ 103.82	-$ 0.4734	200	-$ 94.68	$ 9.14	-8.80%	-$ 0.16340	200	-$ 32.68	$ 62.00	-65.48%			$ -	$ 32.68				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	per kVA	$ 0.0277	200	$ 5.54	$ 0.0105	200	$ 2.10	-$ 3.44	-62.09%	-$ 0.01230	200	-$ 2.46	-$ 4.56	-217.14%				$ 2.46																
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	per kWh	-$ 0.00112	79,000	-$ 88.48	$ 0.00068	79,000	$ 53.72	$ 142.20	-160.71%	-$ 0.00290	79,000	-$ 229.10	-$ 282.82	-526.47%				$ 229.10																
Sub-Total B - Distribution (includes Sub-Total A)				**$ 1,635.99**			**$ 2,142.58**	**$ 506.59**	**30.97%**			**$ 1,750.89**	**-$ 391.69**	**-18.28%**			**$ 1,982.89**	**$ 232.00**	**13.25%**			**$ 2,026.76**	**$ 43.87**	**2.21%**			**$ 2,104.22**	**$ 77.46**	**3.82%**			**$ 2,179.06**	**$ 74.84**	**3.56%**
Retail Transmissioin Rate - Network Service Rate	per kW	$ 2.5690	180	$ 462.42	$ 2.6576	180	$ 478.37	$ 15.95	3.45%	$ 2.7525	180	$ 495.45	$ 17.08	3.57%	$ 2.7525	180	$ 495.45	$ -	0.00%	$ 2.7525	180	$ 495.45	$ -	0.00%	$ 2.7525	180	$ 495.45	$ -	0.00%	$ 2.7525	180	$ 495.45	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	per kW	$ 2.0515	180	$ 369.27	$ 2.3054	180	$ 414.97	$ 45.70	12.38%	$ 2.2259	180	$ 400.66	-$ 14.31	-3.45%	$ 2.2259	180	$ 400.66	$ -	0.00%	$ 2.2259	180	$ 400.66	$ -	0.00%	$ 2.2259	180	$ 400.66	$ -	0.00%	$ 2.2259	180	$ 400.66	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				**$ 2,467.68**			**$ 3,035.92**	**$ 568.24**	**23.03%**			**$ 2,647.00**	**-$ 388.92**	**-12.81%**			**$ 2,879.00**	**$ 232.00**	**8.76%**			**$ 2,922.87**	**$ 43.87**	**1.52%**			**$ 3,000.33**	**$ 77.46**	**2.65%**			**$ 3,075.17**	**$ 74.84**	**2.49%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0032	81,970	$ 262.31	$ 0.0032	81,970	$ 262.31	$ -	0.00%	$ 0.0032	81,331	$ 260.26	-$ 2.05	-0.78%	$ 0.0032	81,331	$ 260.26	$ -	0.00%	$ 0.0032	81,331	$ 260.26	$ -	0.00%	$ 0.0032	81,331	$ 260.26	$ -	0.00%	$ 0.0032	81,331	$ 260.26	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0003	81,970	$ 24.59	$ 0.0003	81,970	$ 24.59	$ -	0.00%	$ 0.0003	81,331	$ 24.40	-$ 0.19	-0.78%	$ 0.0003	81,331	$ 24.40	$ -	0.00%	$ 0.0003	81,331	$ 24.40	$ -	0.00%	$ 0.0003	81,331	$ 24.40	$ -	0.00%	$ 0.0003	81,331	$ 24.40	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	81,970	$ 32.79	$ 0.0004	81,970	$ 32.79	$ -	0.00%	$ 0.0004	81,331	$ 32.53	-$ 0.26	-0.78%	$ 0.0004	81,331	$ 32.53	$ -	0.00%	$ 0.0004	81,331	$ 32.53	$ -	0.00%	$ 0.0004	81,331	$ 32.53	$ -	0.00%	$ 0.0004	81,331	$ 32.53	$ -	0.00%
Standard Supply Service Charge	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	50,560	$ 3,286.40	$ 0.0650	50,560	$ 3,286.40	$ -	0.00%	$ 0.0650	50,560	$ 3,286.40	$ -	0.00%	$ 0.0650	50,560	$ 3,286.40	$ -	0.00%	$ 0.0650	50,560	$ 3,286.40	$ -	0.00%	$ 0.0650	50,560	$ 3,286.40	$ -	0.00%	$ 0.0650	50,560	$ 3,286.40	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	14,220	$ 1,336.68	$ 0.0940	14,220	$ 1,336.68	$ -	0.00%	$ 0.0940	14,220	$ 1,336.68	$ -	0.00%	$ 0.0940	14,220	$ 1,336.68	$ -	0.00%	$ 0.0940	14,220	$ 1,336.68	$ -	0.00%	$ 0.0940	14,220	$ 1,336.68	$ -	0.00%	$ 0.0940	14,220	$ 1,336.68	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	14,220	$ 1,877.04	$ 0.1320	14,220	$ 1,877.04	$ -	0.00%	$ 0.1320	14,220	$ 1,877.04	$ -	0.00%	$ 0.1320	14,220	$ 1,877.04	$ -	0.00%	$ 0.1320	14,220	$ 1,877.04	$ -	0.00%	$ 0.1320	14,220	$ 1,877.04	$ -	0.00%	$ 0.1320	14,220	$ 1,877.04	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	750	$ 57.75	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	78,250	$ 6,964.25	$ 0.0890	78,250	$ 6,964.25	$ -	0.00%	$ 0.0890	78,250	$ 6,964.25	$ -	0.00%	$ 0.0890	78,250	$ 6,964.25	$ -	0.00%	$ 0.0890	78,250	$ 6,964.25	$ -	0.00%	$ 0.0890	78,250	$ 6,964.25	$ -	0.00%	$ 0.0890	78,250	$ 6,964.25	$ -	0.00%
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164	79,000	$ 9,195.60	$ 0.1164	79,000	$ 9,195.60	$ -	0.00%	$ 0.1164	79,000	$ 9,195.60	$ -	0.00%	$ 0.1164	79,000	$ 9,195.60	$ -	0.00%	$ 0.1164	79,000	$ 9,195.60	$ -	0.00%	$ 0.1164	79,000	$ 9,195.60	$ -	0.00%	$ 0.1164	79,000	$ 9,195.60	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price (before Taxes)				**$ 11,983.22**			**$ 12,551.46**	**$ 568.24**	**4.7%**			**$ 12,160.04**	**-$ 391.42**	**-3.1%**			**$ 12,392.04**	**$ 232.00**	**1.9%**			**$ 12,435.91**	**$ 43.87**	**0.4%**			**$ 12,513.37**	**$ 77.46**	**0.6%**			**$ 12,588.21**	**$ 74.84**	**0.6%**
8% Provincial Rebate		-8%			-8%					-8%			$ -		-8%			$ -		-8%			$ -		-8%			$ -		-8%			$ -	
HST		13%		$ 1,557.82	13%		$ 1,631.69	$ 73.87	4.7%	13%		$ 1,580.81	-$ 50.88	-3.1%	13%		$ 1,610.97	$ 30.16	1.9%	13%		$ 1,616.67	$ 5.70	0.4%	13%		$ 1,626.74	$ 10.07	0.6%	13%		$ 1,636.47	$ 9.73	0.6%
Total Bill on Average IESO Wholesale Market Price (after Tax and Rebate)				**$ 13,541.04**			**$ 14,183.15**	**$ 642.11**	**4.7%**			**$ 13,740.85**	-$ 442.30	-3.1%			**$ 14,003.01**	$ 262.16	1.9%			**$ 14,052.58**	$ 49.57	0.4%			**$ 14,140.11**	$ 87.53	0.6%			**$ 14,224.68**	$ 84.57	0.6%
Total Bill on RPP (before Taxes)				**$ 9,809.62**			**$ 10,377.86**	**$ 568.24**	**5.8%**			**$ 9,986.44**	**-$ 391.42**	**-3.8%**			**$ 10,218.44**	**$ 232.00**	**2.3%**			**$ 10,262.31**	**$ 43.87**	**0.4%**			**$ 10,339.77**	**$ 77.46**	**0.8%**			**$ 10,414.61**	**$ 74.84**	**0.7%**
8% Provincial Rebate		-8%			-8%					-8%			$ -		-8%			$ -		-8%			$ -		-8%			$ -		-8%			$ -	
HST		13%		$ 1,275.25	13%		$ 1,349.12	$ 73.87	5.8%	13%		$ 1,298.24	-$ 50.88	-3.8%	13%		$ 1,328.40	$ 30.16	2.3%	13%		$ 1,334.10	$ 5.70	0.4%	13%		$ 1,344.17	$ 10.07	0.8%	13%		$ 1,353.90	$ 9.73	0.7%
Total Bill on RPP (after Tax and Rebate)				**$ 11,084.87**			**$ 11,726.98**	**$ 642.11**	**5.8%**			**$ 11,284.68**	-$ 442.30	-3.8%			**$ 11,546.84**	$ 262.16	2.3%			**$ 11,596.41**	$ 49.57	0.4%			**$ 11,683.94**	$ 87.53	0.8%			**$ 11,768.51**	$ 84.57	0.7%
Loss Factor (%)		3.76%			3.76%					2.95%					2.95%					2.95%					2.95%					2.95%				

Appendix 2-W
Bill Impacts

Customer Class: GENERAL SERVICE 1,000 TO 4,999 kW SERVICE

TOU / non-TOU: non-TOU — **SPOT Class A Non-WMP**

Consumption: 1,800 kW | 2,000 kVA | 900,000 kWh

○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		2018 Current Board-Approved			2019 Current Board-Approved			Impact		2020 Proposed			Impact		2021 Proposed			Impact		2022 Proposed			Impact		2023 Proposed			Impact		2024 Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change
Service Charge	per 30 days	$ 946.52	1	$ 946.52	$ 983.72	1	$ 983.72	$ 37.20	3.93%	$ 944.07	1	$ 944.07	-$ 39.65	-4.03%	$ 974.85	1	$ 974.85	$ 30.78	3.26%	$ 998.83	1	$ 998.83	$ 23.98	2.46%	$ 1,041.18	1	$ 1,041.18	$ 42.35	4.24%	$ 1,082.10	1	$ 1,082.10	$ 40.92	3.93%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 202	per kVA									$ 0.0130	2,000	$ 26.00	$ -	0.00%	$ 0.0130	2,000	$ 26.00	$ -	0.00%	$ 0.0130	2,000	$ 26.00	$ -	0.00%	$ 0.0130	2,000	$ 26.00	$ -	0.00%	$ 0.0130	2,000	$ 26.00	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per kVA									$ 0.0776	2,000	$ 155.20	$ -	0.00%	$ 0.0776	2,000	$ 155.20	$ -	0.00%	$ 0.0776	2,000	$ 155.20	$ -	0.00%	$ 0.0776	2,000	$ 155.20	$ -	0.00%	$ 0.0776	2,000	$ 155.20	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until Dec. 3	per kVA									-$ 0.1186	2,000	-$ 237.20	$ -	0.00%	-$ 0.1186	2,000	-$ 237.20	$ -	0.00%	-$ 0.1186	2,000	-$ 237.20	$ -	0.00%	-$ 0.1186	2,000	-$ 237.20	$ -	0.00%	-$ 0.1186	2,000	-$ 237.20	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per kVA									-$ 0.0190	2,000	-$ 38.00	-$ 38.00		-$ 0.0190	2,000	-$ 38.00	$ -	0.00%	-$ 0.0190	2,000	-$ 38.00	$ -	0.00%	-$ 0.0190	2,000	-$ 38.00	$ -	0.00%	-$ 0.0190	2,000	-$ 38.00	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per kVA									-$ 0.0004	2,000	-$ 0.80	-$ 0.80		-$ 0.0004	2,000	-$ 0.80	$ -	0.00%	-$ 0.0004	2,000	-$ 0.80	$ -	0.00%	-$ 0.0004	2,000	-$ 0.80	$ -	0.00%	-$ 0.0004	2,000	-$ 0.80	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per kVA									-$ 0.0025	2,000	-$ 5.00	-$ 5.00		-$ 0.0025	2,000	-$ 5.00	$ -	0.00%	-$ 0.0025	2,000	-$ 5.00	$ -	0.00%	-$ 0.0025	2,000	-$ 5.00	$ -	0.00%	-$ 0.0025	2,000	-$ 5.00	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31,	per kVA									-$ 0.1258	2,000	-$ 251.60	-$ 251.60		-$ 0.1258	2,000	-$ 251.60	$ -	0.00%	-$ 0.1258	2,000	-$ 251.60	$ -	0.00%	-$ 0.1258	2,000	-$ 251.60	$ -	0.00%	-$ 0.1258	2,000	-$ 251.60	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per kVA									-$ 0.0051	2,000	-$ 10.20	-$ 10.20		-$ 0.0051	2,000	-$ 10.20	$ -	0.00%	-$ 0.0051	2,000	-$ 10.20	$ -	0.00%	-$ 0.0051	2,000	-$ 10.20	$ -	0.00%	-$ 0.0051	2,000	-$ 10.20	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per kVA									-$ 0.0557	2,000	-$ 111.40	-$ 111.40		-$ 0.0557	2,000	-$ 111.40	$ -	0.00%	-$ 0.0557	2,000	-$ 111.40	$ -	0.00%	-$ 0.0557	2,000	-$ 111.40	$ -	0.00%	-$ 0.0557	2,000	-$ 111.40	$ -	0.00%
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	per kVA									-$ 0.0305	2,000	-$ 61.00	-$ 61.00		-$ 0.0305	2,000	-$ 61.00	$ -	0.00%	-$ 0.0305	2,000	-$ 61.00	$ -	0.00%	-$ 0.0305	2,000	-$ 61.00	$ -	0.00%	-$ 0.0305	2,000	-$ 61.00	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 18.89	1	$ 18.89	$ 18.89	1	$ 18.89	$ -	0.00%		1	$ -	-$ 18.89			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 5.48	1	$ 5.48	$ 5.48	1	$ 5.48	$ -	0.00%		1	$ -	-$ 5.48			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	per kVA	$ 6.1355	2,000	$ 12,271.00	$ 6.3766	2,000	$ 12,753.20	$ 482.20	3.93%	$ 6.6390	2,000	$ 13,278.00	$ 524.80	4.12%	$ 6.8554	2,000	$ 13,710.80	$ 432.80	3.26%	$ 7.02400	2,000	$ 14,048.00	$ 337.20	2.46%	$ 7.32180	2,000	$ 14,643.60	$ 595.60	4.24%	$ 7.6095	2,000	$ 15,219.00	$ 575.40	3.93%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per kVA	-$ 0.0653	2,000	-$ 130.60		2,000	$ -	$ 130.60			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per kVA	-$ 0.2017	2,000	-$ 403.40		2,000	$ -	$ 403.40			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per kVA	$ 0.0056	2,000	$ 11.20	$ 0.0056	2,000	$ 11.20	$ -	0.00%		2,000	$ -	-$ 11.20			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per kVA	$ 0.0038	2,000	$ 7.60	$ 0.0038	2,000	$ 7.60	$ -	0.00%		2,000	$ -	-$ 7.60			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per kVA	$ 0.0627	2,000	$ 125.40	$ 0.0627	2,000	$ 125.40	$ -	0.00%		2,000	$ -	-$ 125.40			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per kVA	$ 0.1226	2,000	$ 245.20	$ 0.1226	2,000	$ 245.20	$ -	0.00%		2,000	$ -	-$ 245.20			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per kVA	$ 0.0356	2,000	$ 71.20	$ 0.0356	2,000	$ 71.20	$ -	0.00%		2,000	$ -	-$ 71.20			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effe	per kVA	$ 0.1051	2,000	$ 210.20	$ 0.1251	2,000	$ 250.20	$ 40.00	19.03%		2,000	$ -	-$ 250.20			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Sub-Total A (excluding pass through)				**$ 13,378.69**			**$ 14,472.09**	**$ 1,093.40**	**8.17%**			**$ 13,688.07**	**-$ 784.02**	**-5.42%**			**$ 14,151.65**	**$ 463.58**	**3.39%**			**$ 14,512.83**	**$ 361.18**	**2.55%**			**$ 15,150.78**	**$ 637.95**	**4.40%**			**$ 15,767.10**	**$ 616.32**	**4.07%**
Line Losses on Cost of Power	per kWh	$ 0.1164	33,840	$ 3,938.98	$ 0.1164	33,840	$ 3,938.98	$ -	0.00%	$ 0.1164	26,550	$ 3,090.42	-$ 848.56	-21.54%	$ 0.1164	26,550	$ 3,090.42	$ -	0.00%	$ 0.1164	26,550	$ 3,090.42	$ -	0.00%	$ 0.1164	26,550	$ 3,090.42	$ -	0.00%	$ 0.1164	26,550	$ 3,090.42	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	per kVA	-$ 0.8339	2,000	-$ 1,667.80	-$ 0.2186	2,000	-$ 437.20	$ 1,230.60	-73.79%	$ 0.50370	2,000	$ 1,007.40	-$ 1,444.60	-330.42%			$ -	-$ 1,007.40				$ -					$ -					$ -			
Rate Rider for Disposition of Deferral/Variance Accounts for Non-Wholesale Market Participants	per kVA	-$ 0.5704	2,000	-$ 1,140.80		2,000	$ -	$ 1,140.80		$ 0.18640	2,000	$ 372.80	-$ 372.80				$ -	$ 372.80				$ -					$ -					$ -			
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	per kVA	$ 0.0295		$ -	$ 0.0114		$ -	$ -		-$ 0.01180		$ -	$ -					$ -																
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	per kWh	-$ 0.00112		$ -	$ 0.00068		$ -	$ -		-$ 0.00290		$ -	$ -					$ -																
Sub-Total B - Distribution (includes Sub-Total A)				**$ 14,509.07**			**$ 17,973.87**	**$ 3,464.80**	**23.88%**			**$ 17,413.09**	**-$ 560.78**	**-3.12%**			**$ 17,242.07**	**-$ 171.02**	**-0.98%**			**$ 17,603.25**	**$ 361.18**	**2.09%**			**$ 18,241.20**	**$ 637.95**	**3.62%**			**$ 18,857.52**	**$ 616.32**	**3.38%**
Retail Transmission Rate - Network Service Rate	per kW	$ 2.4821	1,800	$ 4,467.78	$ 2.5677	1,800	$ 4,621.86	$ 154.08	3.45%	$ 2.6594	1,800	$ 4,786.92	$ 165.06	3.57%	$ 2.6594	1,800	$ 4,786.92	$ -	0.00%	$ 2.6594	1,800	$ 4,786.92	$ -	0.00%	$ 2.6594	1,800	$ 4,786.92	$ -	0.00%	$ 2.6594	1,800	$ 4,786.92	$ -	0.00%
Retail Transmission Rate - Line and Transformation Connection Service Rate	per kW	$ 2.0494	1,800	$ 3,688.92	$ 2.30300	1,800	$ 4,145.40	$ 456.48	12.37%	$ 2.2236	1,800	$ 4,002.48	-$ 142.92	-3.45%	$ 2.2236	1,800	$ 4,002.48	$ -	0.00%	$ 2.2236	1,800	$ 4,002.48	$ -	0.00%	$ 2.2236	1,800	$ 4,002.48	$ -	0.00%	$ 2.2236	1,800	$ 4,002.48	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				**$ 22,665.77**			**$ 26,741.13**	**$ 4,075.36**	**17.98%**			**$ 26,202.49**	**-$ 538.64**	**-2.01%**			**$ 26,031.47**	**-$ 171.02**	**-0.65%**			**$ 26,392.65**	**$ 361.18**	**1.39%**			**$ 27,030.60**	**$ 637.95**	**2.42%**			**$ 27,646.92**	**$ 616.32**	**2.28%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0032	933,840	$ 2,988.29	$ 0.0032	933,840	$ 2,988.29	$ -	0.00%	$ 0.0032	926,550	$ 2,964.96	-$ 23.33	-0.78%	$ 0.0032	926,550	$ 2,964.96	$ -	0.00%	$ 0.0032	926,550	$ 2,964.96	$ -	0.00%	$ 0.0032	926,550	$ 2,964.96	$ -	0.00%	$ 0.0032	926,550	$ 2,964.96	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0003	933,840	$ 280.15	$ 0.0003	933,840	$ 280.15	$ -	0.00%	$ 0.0003	926,550	$ 277.97	-$ 2.19	-0.78%	$ 0.0003	926,550	$ 277.97	$ -	0.00%	$ 0.0003	926,550	$ 277.97	$ -	0.00%	$ 0.0003	926,550	$ 277.97	$ -	0.00%	$ 0.0003	926,550	$ 277.97	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004		$ -	$ 0.0004		$ -	$ -		$ 0.0004		$ -	$ -		$ 0.0004		$ -	$ -		$ 0.0004		$ -	$ -		$ 0.0004		$ -	$ -		$ 0.0004		$ -	$ -	
Standard Supply Service Charge	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	576,000	$ 37,440.00	$ 0.0650	576,000	$ 37,440.00	$ -	0.00%	$ 0.0650	576,000	$ 37,440.00	$ -	0.00%	$ 0.0650	576,000	$ 37,440.00	$ -	0.00%	$ 0.0650	576,000	$ 37,440.00	$ -	0.00%	$ 0.0650	576,000	$ 37,440.00	$ -	0.00%	$ 0.0650	576,000	$ 37,440.00	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	162,000	$ 15,228.00	$ 0.0940	162,000	$ 15,228.00	$ -	0.00%	$ 0.0940	162,000	$ 15,228.00	$ -	0.00%	$ 0.0940	162,000	$ 15,228.00	$ -	0.00%	$ 0.0940	162,000	$ 15,228.00	$ -	0.00%	$ 0.0940	162,000	$ 15,228.00	$ -	0.00%	$ 0.0940	162,000	$ 15,228.00	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	162,000	$ 21,384.00	$ 0.1320	162,000	$ 21,384.00	$ -	0.00%	$ 0.1320	162,000	$ 21,384.00	$ -	0.00%	$ 0.1320	162,000	$ 21,384.00	$ -	0.00%	$ 0.1320	162,000	$ 21,384.00	$ -	0.00%	$ 0.1320	162,000	$ 21,384.00	$ -	0.00%	$ 0.1320	162,000	$ 21,384.00	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	750	$ 57.75	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	899,250	$ 80,033.25	$ 0.0890	899,250	$ 80,033.25	$ -	0.00%	$ 0.0890	899,250	$ 80,033.25	$ -	0.00%	$ 0.0890	899,250	$ 80,033.25	$ -	0.00%	$ 0.0890	899,250	$ 80,033.25	$ -	0.00%	$ 0.0890	899,250	$ 80,033.25	$ -	0.00%	$ 0.0890	899,250	$ 80,033.25	$ -	0.00%
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164	900,000	$ 104,760.00	$ 0.1164	900,000	$ 104,760.00	$ -	0.00%	$ 0.1164	900,000	$ 104,760.00	$ -	0.00%	$ 0.1164	900,000	$ 104,760.00	$ -	0.00%	$ 0.1164	900,000	$ 104,760.00	$ -	0.00%	$ 0.1164	900,000	$ 104,760.00	$ -	0.00%	$ 0.1164	900,000	$ 104,760.00	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price (before Taxes)				**$ 130,694.46**			**$ 134,769.82**	**$ 4,075.36**	**3.1%**			**$ 134,205.67**	**-$ 564.15**	**-0.4%**			**$ 134,034.65**	**-$ 171.02**	**-0.1%**			**$ 134,395.83**	**$ 361.18**	**0.3%**			**$ 135,033.78**	**$ 637.95**	**0.5%**			**$ 135,650.10**	**$ 616.32**	**0.5%**
8% Provincial Rebate		-8%			-8%					-8%			$ -		-8%			$ -		-8%			$ -		-8%			$ -		-8%			$ -	
HST		13%		$ 16,990.28	13%		$ 17,520.08	$ 529.80	3.1%	13%		$ 17,446.74	-$ 73.34	-0.4%	13%		$ 17,424.50	-$ 22.23	-0.1%	13%		$ 17,471.46	$ 46.95	0.3%	13%		$ 17,554.39	$ 82.93	0.5%	13%		$ 17,634.51	$ 80.12	0.5%
Total Bill on Average IESO Wholesale Market Price (after Tax and Rebate)				**$ 147,684.74**			**$ 152,289.89**	**$ 4,605.16**	**3.1%**			**$ 151,652.40**	-$ 637.49	-0.4%			**$ 151,459.15**	-$ 193.25	-0.1%			**$ 151,867.28**	$ 408.13	0.3%			**$ 152,588.17**	$ 720.88	0.5%			**$ 153,284.61**	$ 696.44	0.5%
Total Bill on RPP (before Taxes)				**$ 106,025.46**			**$ 110,100.82**	**$ 4,075.36**	**3.8%**			**$ 109,536.67**	**-$ 564.15**	**-0.5%**			**$ 109,365.65**	**-$ 171.02**	**-0.2%**			**$ 109,726.83**	**$ 361.18**	**0.3%**			**$ 110,364.78**	**$ 637.95**	**0.6%**			**$ 110,981.10**	**$ 616.32**	**0.6%**
8% Provincial Rebate		-8%			-8%					-8%			$ -		-8%			$ -		-8%			$ -		-8%			$ -		-8%			$ -	
HST		13%		$ 13,783.31	13%		$ 14,313.11	$ 529.80	3.8%	13%		$ 14,239.77	-$ 73.34	-0.5%	13%		$ 14,217.53	-$ 22.23	-0.2%	13%		$ 14,264.49	$ 46.95	0.3%	13%		$ 14,347.42	$ 82.93	0.6%	13%		$ 14,427.54	$ 80.12	0.6%
Total Bill on RPP (after Tax and Rebate)				**$ 119,808.77**			**$ 124,413.92**	**$ 4,605.16**	**3.8%**			**$ 123,776.43**	-$ 637.49	-0.5%			**$ 123,583.18**	-$ 193.25	-0.2%			**$ 123,991.31**	$ 408.13	0.3%			**$ 124,712.20**	$ 720.88	0.6%			**$ 125,408.64**	$ 696.44	0.6%

Loss Factor (%)		3.76%			3.76%					2.95%					2.95%					2.95%					2.95%					2.95%				

Appendix 2-W
Bill Impacts

Customer Class: GENERAL SERVICE 1,000 TO 4,999 kW SERVICE

TOU / non-TOU: non-TOU | SPOT B

Consumption: 1,800 kW | 2,000 kVA | 900,000 kWh

● May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		2018 Current Board-Approved			2019 Current Board-Approved			Impact		2020 Proposed			Impact		2021 Proposed			Impact		2022 Proposed			Impact		2023 Proposed			Impact		2024 Proposed			Impact	
Charge Unit		Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change
Service Charge	per 30 days	$ 946.52	1	$ 946.52	$ 983.72	1	$ 983.72	$ 37.20	3.93%	$ 944.07	1	$ 944.07	-$ 39.65	-4.03%	$ 974.85	1	$ 974.85	$ 30.78	3.26%	$ 998.83	1	$ 998.83	$ 23.98	2.46%	$ 1,041.18	1	$ 1,041.18	$ 42.35	4.24%	$ 1,082.10	1	$ 1,082.10	$ 40.92	3.93%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per kVA									$ 0.0130	2,000	$ 26.00	$ 26.00		$ 0.0130	2,000	$ 26.00	$ -	0.00%	$ 0.0130	2,000	$ 26.00	$ -	0.00%	$ 0.0130	2,000	$ 26.00	$ -	0.00%	$ 0.0130	2,000	$ 26.00	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per kVA									$ 0.0776	2,000	$ 155.20	$ 155.20		$ 0.0776	2,000	$ 155.20	$ -	0.00%	$ 0.0776	2,000	$ 155.20	$ -	0.00%	$ 0.0776	2,000	$ 155.20	$ -	0.00%	$ 0.0776	2,000	$ 155.20	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per kVA									-$ 0.1186	2,000	-$ 237.20	-$ 237.20		-$ 0.1186	2,000	-$ 237.20	$ -	0.00%	-$ 0.1186	2,000	-$ 237.20	$ -	0.00%	-$ 0.1186	2,000	-$ 237.20	$ -	0.00%	-$ 0.1186	2,000	-$ 237.20	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per kVA									-$ 0.0190	2,000	-$ 38.00	-$ 38.00		-$ 0.0190	2,000	-$ 38.00	$ -	0.00%	-$ 0.0190	2,000	-$ 38.00	$ -	0.00%	-$ 0.0190	2,000	-$ 38.00	$ -	0.00%	-$ 0.0190	2,000	-$ 38.00	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per kVA									-$ 0.0004	2,000	-$ 0.80	-$ 0.80		-$ 0.0004	2,000	-$ 0.80	$ -	0.00%	-$ 0.0004	2,000	-$ 0.80	$ -	0.00%	-$ 0.0004	2,000	-$ 0.80	$ -	0.00%	-$ 0.0004	2,000	-$ 0.80	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per kVA									-$ 0.0025	2,000	-$ 5.00	-$ 5.00		-$ 0.0025	2,000	-$ 5.00	$ -	0.00%	-$ 0.0025	2,000	-$ 5.00	$ -	0.00%	-$ 0.0025	2,000	-$ 5.00	$ -	0.00%	-$ 0.0025	2,000	-$ 5.00	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per kVA									-$ 0.1258	2,000	-$ 251.60	-$ 251.60		-$ 0.1258	2,000	-$ 251.60	$ -	0.00%	-$ 0.1258	2,000	-$ 251.60	$ -	0.00%	-$ 0.1258	2,000	-$ 251.60	$ -	0.00%	-$ 0.1258	2,000	-$ 251.60	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per kVA									-$ 0.0051	2,000	-$ 10.20	-$ 10.20		-$ 0.0051	2,000	-$ 10.20	$ -	0.00%	-$ 0.0051	2,000	-$ 10.20	$ -	0.00%	-$ 0.0051	2,000	-$ 10.20	$ -	0.00%	-$ 0.0051	2,000	-$ 10.20	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per kVA									-$ 0.0557	2,000	-$ 111.40	-$ 111.40		-$ 0.0557	2,000	-$ 111.40	$ -	0.00%	-$ 0.0557	2,000	-$ 111.40	$ -	0.00%	-$ 0.0557	2,000	-$ 111.40	$ -	0.00%	-$ 0.0557	2,000	-$ 111.40	$ -	0.00%
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	per kVA									-$ 0.0305	2,000	-$ 61.00	-$ 61.00		-$ 0.0305	2,000	-$ 61.00	$ -	0.00%	-$ 0.0305	2,000	-$ 61.00	$ -	0.00%	-$ 0.0305	2,000	-$ 61.00	$ -	0.00%	-$ 0.0305	2,000	-$ 61.00	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 18.89	1	$ 18.89	$ 18.89	1	$ 18.89	$ -	0.00%		1	$ -	-$ 18.89			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 5.48	1	$ 5.48	$ 5.48	1	$ 5.48	$ -	0.00%		1	$ -	-$ 5.48			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	per kVA	$ 6.1355	2,000	$ 12,271.00	$ 6.37660	2,000	$ 12,753.20	$ 482.20	3.93%	$ 6.6390	2,000	$ 13,278.00	$ 524.80	4.12%	$ 6.8554	2,000	$ 13,710.80	$ 432.80	3.26%	$ 7.02400	2,000	$ 14,048.00	$ 337.20	2.46%	$ 7.32180	2,000	$ 14,643.60	$ 595.60	4.24%	$ 7.6095	2,000	$ 15,219.00	$ 575.40	3.93%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per kVA	-$ 0.0653	2,000	-$ 130.60		2,000	$ -	$ 130.60			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per kVA	-$ 0.2017	2,000	-$ 403.40		2,000	$ -	$ 403.40			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per kVA	$ 0.0056	2,000	$ 11.20	$ 0.0056	2,000	$ 11.20	$ -	0.00%		2,000	$ -	-$ 11.20			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per kVA	$ 0.0038	2,000	$ 7.60	$ 0.0038	2,000	$ 7.60	$ -	0.00%		2,000	$ -	-$ 7.60			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per kVA	$ 0.0627	2,000	$ 125.40	$ 0.0627	2,000	$ 125.40	$ -	0.00%		2,000	$ -	-$ 125.40			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per kVA	$ 0.1226	2,000	$ 245.20	$ 0.1226	2,000	$ 245.20	$ -	0.00%		2,000	$ -	-$ 245.20			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per kVA	$ 0.0356	2,000	$ 71.20	$ 0.0356	2,000	$ 71.20	$ -	0.00%		2,000	$ -	-$ 71.20			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kVA	$ 0.1051	2,000	$ 210.20	$ 0.1251	2,000	$ 250.20	$ 40.00	19.03%		2,000	$ -	-$ 250.20			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Sub-Total A (excluding pass through)				**$ 13,378.69**			**$ 14,472.09**	**$ 1,093.40**	**8.17%**			**$ 13,688.07**	**-$ 784.02**	**-5.42%**			**$ 14,151.65**	**$ 463.58**	**3.39%**			**$ 14,512.83**	**$ 361.18**	**2.55%**			**$ 15,150.78**	**$ 637.95**	**4.40%**			**$ 15,767.10**	**$ 616.32**	**4.07%**
Line Losses on Cost of Power	per kWh	$ 0.1164	33,840	$ 3,938.98	$ 0.1164	33,840	$ 3,938.98	$ -	0.00%	$ 0.1164	26,550	$ 3,090.42	-$ 848.56	-21.54%	$ 0.1164	26,550	$ 3,090.42	$ -	0.00%	$ 0.1164	26,550	$ 3,090.42	$ -	0.00%	$ 0.1164	26,550	$ 3,090.42	$ -	0.00%	$ 0.1164	26,550	$ 3,090.42	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	per kVA	-$ 0.8339	2,000	-$ 1,667.80	-$ 0.2186	2,000	-$ 437.20	$ 1,230.60	-73.79%	$ 0.50370	2,000	$ 1,007.40	$ 1,444.60	-330.42%			$ -	-$ 1,007.40				$ -	$ -				$ -	$ -				$ -	$ -		
Rate Rider for Disposition of Deferral/Variance Accounts for Non-Wholesale Market Participants	per kVA	-$ 0.5704	2,000	-$ 1,140.80		2,000	$ -	$ 1,140.80		-$ 0.18640	2,000	-$ 372.80	-$ 372.80				$ -	$ 372.80				$ -	$ -				$ -	$ -				$ -	$ -		
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	per kVA	$ 0.0295	2,000	$ 59.00	$ 0.0114	2,000	$ 22.80	-$ 36.20	-61.36%	-$ 0.01180	2,000	-$ 23.60	-$ 46.40	-203.51%				$ 23.60																	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	per kWh	-$ 0.00112	900,000	-$ 1,008.00	$ 0.00068	900,000	$ 612.00	$ 1,620.00	-160.71%	-$ 0.00290	900,000	-$ 2,610.00	-$ 3,222.00	-526.47%				$ 2,610.00																	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 13,560.07**			**$ 18,608.67**	**$ 5,048.60**	**37.23%**			**$ 14,779.49**	**-$ 3,829.18**	**-20.58%**			**$ 17,242.07**	**$ 2,462.58**	**16.66%**			**$ 17,603.25**	**$ 361.18**	**2.09%**			**$ 18,241.20**	**$ 637.95**	**3.62%**			**$ 18,857.52**	**$ 616.32**	**3.38%**
Retail Transmission Rate - Network Service Rate	per kW	$ 2.4821	1,800	$ 4,467.78	$ 2.5677	1,800	$ 4,621.86	$ 154.08	3.45%	$ 2.6594	1,800	$ 4,786.92	$ 165.06	3.57%	$ 2.6594	1,800	$ 4,786.92	$ -	0.00%	$ 2.6594	1,800	$ 4,786.92	$ -	0.00%	$ 2.6594	1,800	$ 4,786.92	$ -	0.00%	$ 2.6594	1,800	$ 4,786.92	$ -	0.00%
Retail Transmission Rate - Line and Transformation Connection Service Rate	per kW	$ 2.0494	1,800	$ 3,688.92	$ 2.3030	1,800	$ 4,145.40	$ 456.48	12.37%	$ 2.2236	1,800	$ 4,002.48	-$ 142.92	-3.45%	$ 2.2236	1,800	$ 4,002.48	$ -	0.00%	$ 2.2236	1,800	$ 4,002.48	$ -	0.00%	$ 2.2236	1,800	$ 4,002.48	$ -	0.00%	$ 2.2236	1,800	$ 4,002.48	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				**$ 21,716.77**			**$ 27,375.93**	**$ 5,659.16**	**26.06%**			**$ 23,568.89**	**-$ 3,807.04**	**-13.91%**			**$ 26,031.47**	**$ 2,462.58**	**10.45%**			**$ 26,392.65**	**$ 361.18**	**1.39%**			**$ 27,030.60**	**$ 637.95**	**2.42%**			**$ 27,646.92**	**$ 616.32**	**2.28%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0032	933,840	$ 2,988.29	$ 0.0032	933,840	$ 2,988.29	$ -	0.00%	$ 0.0032	926,550	$ 2,964.96	-$ 23.33	-0.78%	$ 0.0032	926,550	$ 2,964.96	$ -	0.00%	$ 0.0032	926,550	$ 2,964.96	$ -	0.00%	$ 0.0032	926,550	$ 2,964.96	$ -	0.00%	$ 0.0032	926,550	$ 2,964.96	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0003	933,840	$ 280.15	$ 0.0003	933,840	$ 280.15	$ -	0.00%	$ 0.0003	926,550	$ 277.97	-$ 2.19	-0.78%	$ 0.0003	926,550	$ 277.97	$ -	0.00%	$ 0.0003	926,550	$ 277.97	$ -	0.00%	$ 0.0003	926,550	$ 277.97	$ -	0.00%	$ 0.0003	926,550	$ 277.97	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	933,840	$ 373.54	$ 0.0004	933,840	$ 373.54	$ -	0.00%	$ 0.0004	926,550	$ 370.62	-$ 2.92	-0.78%	$ 0.0004	926,550	$ 370.62	$ -	0.00%	$ 0.0004	926,550	$ 370.62	$ -	0.00%	$ 0.0004	926,550	$ 370.62	$ -	0.00%	$ 0.0004	926,550	$ 370.62	$ -	0.00%
Standard Supply Service Charge	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	576,000	$ 37,440.00	$ 0.0650	576,000	$ 37,440.00	$ -	0.00%	$ 0.0650	576,000	$ 37,440.00	$ -	0.00%	$ 0.0650	576,000	$ 37,440.00	$ -	0.00%	$ 0.0650	576,000	$ 37,440.00	$ -	0.00%	$ 0.0650	576,000	$ 37,440.00	$ -	0.00%	$ 0.0650	576,000	$ 37,440.00	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	162,000	$ 15,228.00	$ 0.0940	162,000	$ 15,228.00	$ -	0.00%	$ 0.0940	162,000	$ 15,228.00	$ -	0.00%	$ 0.0940	162,000	$ 15,228.00	$ -	0.00%	$ 0.0940	162,000	$ 15,228.00	$ -	0.00%	$ 0.0940	162,000	$ 15,228.00	$ -	0.00%	$ 0.0940	162,000	$ 15,228.00	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	162,000	$ 21,384.00	$ 0.1320	162,000	$ 21,384.00	$ -	0.00%	$ 0.1320	162,000	$ 21,384.00	$ -	0.00%	$ 0.1320	162,000	$ 21,384.00	$ -	0.00%	$ 0.1320	162,000	$ 21,384.00	$ -	0.00%	$ 0.1320	162,000	$ 21,384.00	$ -	0.00%	$ 0.1320	162,000	$ 21,384.00	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	750	$ 57.75	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	899,250	$ 80,033.25	$ 0.0890	899,250	$ 80,033.25	$ -	0.00%	$ 0.0890	899,250	$ 80,033.25	$ -	0.00%	$ 0.0890	899,250	$ 80,033.25	$ -	0.00%	$ 0.0890	899,250	$ 80,033.25	$ -	0.00%	$ 0.0890	899,250	$ 80,033.25	$ -	0.00%	$ 0.0890	899,250	$ 80,033.25	$ -	0.00%
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164	-	$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164	900,000	$ 104,760.00	$ 0.1164	900,000	$ 104,760.00	$ -	0.00%	$ 0.1164	900,000	$ 104,760.00	$ -	0.00%	$ 0.1164	900,000	$ 104,760.00	$ -	0.00%	$ 0.1164	900,000	$ 104,760.00	$ -	0.00%	$ 0.1164	900,000	$ 104,760.00	$ -	0.00%	$ 0.1164	900,000	$ 104,760.00	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price (before Taxes)				**$ 130,118.99**			**$ 135,778.15**	**$ 5,659.16**	**4.3%**			**$ 131,942.69**	**-$ 3,835.47**	**-2.8%**			**$ 134,405.27**	**$ 2,462.58**	**1.9%**			**$ 134,766.45**	**$ 361.18**	**0.3%**			**$ 135,404.40**	**$ 637.95**	**0.5%**			**$ 136,020.72**	**$ 616.32**	**0.5%**
8% Provincial Rebate		-8%			-8%					-8%			$ -		-8%			$ -		-8%			$ -		-8%			$ -		-8%			$ -	
HST		13%		$ 16,915.47	13%		$ 17,651.16	$ 735.69	4.3%	13%		$ 17,152.55	-$ 498.61	-2.8%	13%		$ 17,472.68	$ 320.14	1.9%	13%		$ 17,519.64	$ 46.95	0.3%	13%		$ 17,602.57	$ 82.93	0.5%	13%		$ 17,682.69	$ 80.12	0.5%
Total Bill on Average IESO Wholesale Market Price (after Tax and Rebate)				**$ 147,034.46**			**$ 153,429.31**	**$ 6,394.85**	**4.3%**			**$ 149,095.23**	**-$ 4,334.08**	**-2.8%**			**$ 151,877.95**	**$ 2,782.72**	**1.9%**			**$ 152,286.08**	**$ 408.13**	**0.3%**			**$ 153,006.97**	**$ 720.88**	**0.5%**			**$ 153,703.41**	**$ 696.44**	**0.5%**
Total Bill on RPP (before Taxes)				**$ 105,449.99**			**$ 111,109.15**	**$ 5,659.16**	**5.4%**			**$ 107,273.69**	**-$ 3,835.47**	**-3.5%**			**$ 109,736.27**	**$ 2,462.58**	**2.3%**			**$ 110,097.45**	**$ 361.18**	**0.3%**			**$ 110,735.40**	**$ 637.95**	**0.6%**			**$ 111,351.72**	**$ 616.32**	**0.6%**
8% Provincial Rebate		-8%			-8%					-8%			$ -		-8%			$ -		-8%			$ -		-8%			$ -		-8%			$ -	
HST		13%		$ 13,708.50	13%		$ 14,444.19	$ 735.69	5.4%	13%		$ 13,945.58	-$ 498.61	-3.5%	13%		$ 14,265.71	$ 320.14	2.3%	13%		$ 14,312.67	$ 46.95	0.3%	13%		$ 14,395.60	$ 82.93	0.6%	13%		$ 14,475.72	$ 80.12	0.6%
Total Bill on RPP (after Tax and Rebate)				**$ 119,158.49**			**$ 125,553.34**	**$ 6,394.85**	**5.4%**			**$ 121,219.26**	**-$ 4,334.08**	**-3.5%**			**$ 124,001.98**	**$ 2,782.72**	**2.3%**			**$ 124,410.11**	**$ 408.13**	**0.3%**			**$ 125,131.00**	**$ 720.88**	**0.6%**			**$ 125,827.44**	**$ 696.44**	**0.6%**
Loss Factor (%)		3.76%			3.76%					2.95%					2.95%					2.95%					2.95%					2.95%				

Appendix 2-W
Bill Impacts

Customer Class: LARGE USE SERVICE

TOU / non-TOU: non-TOU — SPOT A Non-WMP

8,900 kW
9,700 kVA ● May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)
Consumption 4,100,000 kWh

Charge Unit	2018 Current Board-Approved Rate ($)	Volume	Charge ($)	2019 Current Board-Approved Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change	2020 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change	2021 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change	2022 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change	2023 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change	2024 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change
Service Charge	per 30 days	$ 4,178.03	1	$ 4,178.03	$ 4,342.23	1	$ 4,342.23	$ 164.20	3.93%	$4,137.37	1	$ 4,137.37	-$ 204.86	-4.72%	$4,272.25	1	$ 4,272.25	$ 134.88	3.26%	$ 4,377.35	1	$ 4,377.35	$ 105.10	2.46%	$ 4,562.95	1	$ 4,562.95	$ 185.60	4.24%	$ 4,742.27	1	$ 4,742.27	$ 179.32	3.93%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31,	per kVA									$ 0.0154	9,700	$ 149.38	$ 149.38		$ 0.0154	9,700	$ 149.38	$ -	0.00%	$ 0.0154	9,700	$ 149.38	$ -	0.00%	$ 0.0154	9,700	$ 149.38	$ -	0.00%	$ 0.0154	9,700	$ 149.38	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per kVA									$ 0.0916	9,700	$ 888.52	$ 888.52		$ 0.0916	9,700	$ 888.52	$ -	0.00%	$ 0.0916	9,700	$ 888.52	$ -	0.00%	$ 0.0916	9,700	$ 888.52	$ -	0.00%	$ 0.0916	9,700	$ 888.52	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effffective until Dec. 31, 2024	per kVA									-$ 0.1400	9,700	-$ 1,358.00	-$ 1,358.00		-$ 0.1400	9,700	-$ 1,358.00	$ -	0.00%	-$ 0.1400	9,700	-$ 1,358.00	$ -	0.00%	-$ 0.1400	9,700	-$ 1,358.00	$ -	0.00%	-$ 0.1400	9,700	-$ 1,358.00	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per kVA									-$ 0.0224	9,700	-$ 217.28	-$ 217.28		-$ 0.0224	9,700	-$ 217.28	$ -	0.00%	-$ 0.0224	9,700	-$ 217.28	$ -	0.00%	-$ 0.0224	9,700	-$ 217.28	$ -	0.00%	-$ 0.0224	9,700	-$ 217.28	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per kVA									-$ 0.0004	9,700	-$ 3.88	-$ 3.88		-$ 0.0004	9,700	-$ 3.88	$ -	0.00%	-$ 0.0004	9,700	-$ 3.88	$ -	0.00%	-$ 0.0004	9,700	-$ 3.88	$ -	0.00%	-$ 0.0004	9,700	-$ 3.88	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per kVA									-$ 0.0030	9,700	-$ 29.10	-$ 29.10		-$ 0.0030	9,700	-$ 29.10	$ -	0.00%	-$ 0.0030	9,700	-$ 29.10	$ -	0.00%	-$ 0.0030	9,700	-$ 29.10	$ -	0.00%	-$ 0.0030	9,700	-$ 29.10	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per kVA									-$ 0.1484	9,700	-$ 1,439.48	-$ 1,439.48		-$ 0.1484	9,700	-$ 1,439.48	$ -	0.00%	-$ 0.1484	9,700	-$ 1,439.48	$ -	0.00%	-$ 0.1484	9,700	-$ 1,439.48	$ -	0.00%	-$ 0.1484	9,700	-$ 1,439.48	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per kVA									-$ 0.0060	9,700	-$ 58.20	-$ 58.20		-$ 0.0060	9,700	-$ 58.20	$ -	0.00%	-$ 0.0060	9,700	-$ 58.20	$ -	0.00%	-$ 0.0060	9,700	-$ 58.20	$ -	0.00%	-$ 0.0060	9,700	-$ 58.20	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per kVA									-$ 0.0657	9,700	-$ 637.29	-$ 637.29		-$ 0.0657	9,700	-$ 637.29	$ -	0.00%	-$ 0.0657	9,700	-$ 637.29	$ -	0.00%	-$ 0.0657	9,700	-$ 637.29	$ -	0.00%	-$ 0.0657	9,700	-$ 637.29	$ -	0.00%
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	per kVA									-$ 0.0360	9,700	-$ 349.20	-$ 349.20		-$ 0.0360	9,700	-$ 349.20	$ -	0.00%	-$ 0.0360	9,700	-$ 349.20	$ -	0.00%	-$ 0.0360	9,700	-$ 349.20	$ -	0.00%	-$ 0.0360	9,700	-$ 349.20	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 85.84	1	$ 85.84	$ 85.84	1	$ 85.84	$ -	0.00%		1	$ -	-$ 85.84			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 25.18	1	$ 25.18	$ 25.18	1	$ 25.18	$ -	0.00%		1	$ -	-$ 25.18			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	per kVA	$ 6.5820	9,700	$ 63,845.40	$ 6.8407	9,700	$ 66,354.79	$ 2,509.39	3.93%	$ 7.1267	9,700	$ 69,128.99	$ 2,774.20	4.18%	$ 7.3590	9,700	$ 71,382.30	$ 2,253.31	3.26%	$ 7.5400	9,700	$ 73,138.00	$ 1,755.70	2.46%	$ 7.8597	9,700	$ 76,239.09	$ 3,101.09	4.24%	$ 8.1686	9,700	$ 79,235.42	$ 2,996.33	3.93%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per kVA	$ 0.0675	9,700	$ 654.75		9,700	$ -	$ 654.75			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per kVA	-$ 0.2084	9,700	-$ 2,021.48		9,700	$ -	$ 2,021.48			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per kVA	$ 0.0044	9,700	$ 42.68	$ 0.0044	9,700	$ 42.68	$ -	0.00%		9,700	$ -	-$ 42.68			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per kVA	$ 0.0039	9,700	$ 37.83	$ 0.0039	9,700	$ 37.83	$ -	0.00%		9,700	$ -	-$ 37.83			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per kVA	$ 0.0648	9,700	$ 628.56	$ 0.0648	9,700	$ 628.56	$ -	0.00%		9,700	$ -	-$ 628.56			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per kVA	$ 0.1382	9,700	$ 1,340.54	$ 0.1382	9,700	$ 1,340.54	$ -	0.00%		9,700	$ -	-$ 1,340.54			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per kVA	$ 0.0406	9,700	$ 393.82	$ 0.0406	9,700	$ 393.82	$ -	0.00%		9,700	$ -	-$ 393.82			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kVA	$ 0.2763	9,700	$ 2,680.11	$ 0.2282	9,700	$ 2,213.54	-$ 466.57	-17.41%		9,700	$ -	-$ 2,213.54			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -	
Sub-Total A (excluding pass through)				**$ 70,581.76**			**$ 75,465.01**	**$ 4,883.25**	**6.92%**			**$ 70,211.83**	**-$ 5,253.18**	**-6.96%**			**$ 72,600.02**	**$ 2,388.19**	**3.40%**			**$ 74,460.82**	**$ 1,860.80**	**2.56%**			**$ 77,747.51**	**$ 3,286.69**	**4.41%**			**$ 80,923.16**	**$ 3,175.65**	**4.08%**
Line Losses on Cost of Power	per kWh	$ 0.1164	76,670	$ 8,924.39	$ 0.1164	76,670	$ 8,924.39	$ -	0.00%	$ 0.1164	70,520	$ 8,208.53	-$ 715.86	-8.02%	$ 0.1164	70,520	$ 8,208.53	$ -	0.00%	$ 0.1164	70,520	$ 8,208.53	$ -	0.00%	$ 0.1164	70,520	$ 8,208.53	$ -	0.00%	$ 0.1164	70,520	$ 8,208.53	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	per kVA	-$ 0.8782	9,700	-$ 8,518.54	$ 0.3397	9,700	$ 3,295.09	$ 11,813.63	-138.68%	$ 0.53680	9,700	$ 5,206.96	$ 1,911.87	58.02%		9,700	$ -	-$ 5,206.96			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -	
Rate Rider for Disposition of Deferral/Variance Accounts for Non-Wholesale Market Participants	per kVA	-$ 0.5945	9,700	-$ 5,766.65	-$ 0.5628	9,700	-$ 5,459.16	$ 307.49	-5.33%	-$ 0.19440	9,700	-$ 1,885.68	$ 3,573.48	-65.46%		9,700	$ -	$ 1,885.68			9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	per kVA	$ 0.0032		$ -	$ 0.0095		$ -	$ -		-$ 0.00840			$ -					$ -					$ -					$ -					$ -		
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	per kVA	-$ 0.00112		$ -	$ 0.00068		$ -	$ -		-$ 0.00290			$ -					$ -					$ -					$ -					$ -		
Sub-Total B - Distribution (includes Sub-Total A)				**$ 65,220.96**			**$ 82,225.33**	**$ 17,004.37**	**26.07%**			**$ 81,741.64**	**-$ 483.69**	**-0.59%**			**$ 80,808.55**	**-$ 933.09**	**-1.14%**			**$ 82,669.35**	**$ 1,860.80**	**2.30%**			**$ 85,956.04**	**$ 3,286.69**	**3.98%**			**$ 89,131.69**	**$ 3,175.65**	**3.69%**
Retail Transmissioin Rate - Network Service Rate	per kW	$ 2.8295	8,900	$ 25,182.55	$ 2.9271	8,900	$ 26,051.19	$ 868.64	3.45%	$ 3.0316	8,900	$ 26,981.24	$ 930.05	3.57%	$ 3.0316	8,900	$ 26,981.24	$ -	0.00%	$ 3.0316	8,900	$ 26,981.24	$ -	0.00%	$ 3.0316	8,900	$ 26,981.24	$ -	0.00%	$ 3.0316	8,900	$ 26,981.24	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	per kW	$ 2.2769	8,900	$ 20,264.41	$ 2.5587	8,900	$ 22,772.43	$ 2,508.02	12.38%	$ 2.4705	8,900	$ 21,987.45	-$ 784.98	-3.45%	$ 2.4705	8,900	$ 21,987.45	$ -	0.00%	$ 2.4705	8,900	$ 21,987.45	$ -	0.00%	$ 2.4705	8,900	$ 21,987.45	$ -	0.00%	$ 2.4705	8,900	$ 21,987.45	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				**$ 110,667.92**			**$ 131,048.95**	**$ 20,381.03**	**18.42%**			**$ 130,710.33**	**-$ 338.62**	**-0.26%**			**$ 129,777.24**	**-$ 933.09**	**-0.71%**			**$ 131,638.04**	**$ 1,860.80**	**1.43%**			**$ 134,924.73**	**$ 3,286.69**	**2.50%**			**$ 138,100.38**	**$ 3,175.65**	**2.35%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0032	4,176,670	$ 13,365.34	$ 0.0032	4,176,670	$ 13,365.34	$ -	0.00%	$ 0.0032	4,170,520	$ 13,345.66	-$ 19.68	-0.15%	$ 0.0032	4,170,520	$ 13,345.66	$ -	0.00%	$ 0.0032	4,170,520	$ 13,345.66	$ -	0.00%	$ 0.0032	4,170,520	$ 13,345.66	$ -	0.00%	$ 0.0032	4,170,520	$ 13,345.66	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0003	4,176,670	$ 1,253.00	$ 0.0003	4,176,670	$ 1,253.00	$ -	0.00%	$ 0.0003	4,170,520	$ 1,251.16	-$ 1.84	-0.15%	$ 0.0003	4,170,520	$ 1,251.16	$ -	0.00%	$ 0.0003	4,170,520	$ 1,251.16	$ -	0.00%	$ 0.0003	4,170,520	$ 1,251.16	$ -	0.00%	$ 0.0003	4,170,520	$ 1,251.16	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004		$ -	$ 0.0004		$ -					$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Standard Supply Service Charge	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	2,624,000	$ 170,560.00	$ 0.0650	2,624,000	$ 170,560.00	$ -	0.00%	$ 0.0650	2,624,000	$ 170,560.00	$ -	0.00%	$ 0.0650	2,624,000	$ 170,560.00	$ -	0.00%	$ 0.0650	2,624,000	$ 170,560.00	$ -	0.00%	$ 0.0650	2,624,000	$ 170,560.00	$ -	0.00%	$ 0.0650	2,624,000	$ 170,560.00	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	738,000	$ 69,372.00	$ 0.0940	738,000	$ 69,372.00	$ -	0.00%	$ 0.0940	738,000	$ 69,372.00	$ -	0.00%	$ 0.0940	738,000	$ 69,372.00	$ -	0.00%	$ 0.0940	738,000	$ 69,372.00	$ -	0.00%	$ 0.0940	738,000	$ 69,372.00	$ -	0.00%	$ 0.0940	738,000	$ 69,372.00	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	738,000	$ 97,416.00	$ 0.1320	738,000	$ 97,416.00	$ -	0.00%	$ 0.1320	738,000	$ 97,416.00	$ -	0.00%	$ 0.1320	738,000	$ 97,416.00	$ -	0.00%	$ 0.1320	738,000	$ 97,416.00	$ -	0.00%	$ 0.1320	738,000	$ 97,416.00	$ -	0.00%	$ 0.1320	738,000	$ 97,416.00	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	750	$ 57.75	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	4,099,250	$ 364,833.25	$ 0.0890	4,099,250	$ 364,833.25	$ -	0.00%	$ 0.0890	4,099,250	$ 364,833.25	$ -	0.00%	$ 0.0890	4,099,250	$ 364,833.25	$ -	0.00%	$ 0.0890	4,099,250	$ 364,833.25	$ -	0.00%	$ 0.0890	4,099,250	$ 364,833.25	$ -	0.00%	$ 0.0890	4,099,250	$ 364,833.25	$ -	0.00%
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164	4,100,000	$ 477,240.00	$ 0.1164	4,100,000	$ 477,240.00	$ -	0.00%	$ 0.1164	4,100,000	$ 477,240.00	$ -	0.00%	$ 0.1164	4,100,000	$ 477,240.00	$ -	0.00%	$ 0.1164	4,100,000	$ 477,240.00	$ -	0.00%	$ 0.1164	4,100,000	$ 477,240.00	$ -	0.00%	$ 0.1164	4,100,000	$ 477,240.00	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price (before Taxes)				**$ 602,526.51**			**$ 622,907.54**	**$ 20,381.03**	**3.4%**			**$ 622,547.40**	**-$ 360.14**	**-0.1%**			**$ 621,614.31**	**-$ 933.09**	**-0.1%**			**$ 623,475.11**	**$ 1,860.80**	**0.3%**			**$ 626,761.80**	**$ 3,286.69**	**0.5%**			**$ 629,937.45**	**$ 3,175.65**	**0.5%**
8% Provincial Rebate		-8%			-8%		$ -			-8%		$ -			-8%		$ -			-8%		$ -			-8%		$ -			-8%		$ -		
HST		13%		$ 78,328.45	13%		$ 80,977.98	$ 2,649.53	3.4%	13%		$ 80,931.16	-$ 46.82	-0.1%	13%		$ 80,809.86	-$ 121.30	-0.1%	13%		$ 81,051.76	$ 241.90	0.3%	13%		$ 81,479.03	$ 427.27	0.5%	13%		$ 81,891.87	$ 412.83	0.5%
Total Bill on Average IESO Wholesale Market Price (after Tax and Rebate)				**$ 680,854.96**			**$ 703,885.52**	**$ 23,030.56**	**3.4%**			**$ 703,478.56**	**-$ 406.96**	**-0.1%**			**$ 702,424.17**	**-$ 1,054.39**	**-0.1%**			**$ 704,526.87**	**$ 2,102.70**	**0.3%**			**$ 708,240.83**	**$ 3,713.96**	**0.5%**			**$ 711,829.32**	**$ 3,588.48**	**0.5%**
Total Bill on RPP (before Taxes)				**$ 490,177.51**			**$ 510,558.54**	**$ 20,381.03**	**4.2%**			**$ 510,198.40**	**-$ 360.14**	**-0.1%**			**$ 509,265.31**	**-$ 933.09**	**-0.2%**			**$ 511,126.11**	**$ 1,860.80**	**0.4%**			**$ 514,412.80**	**$ 3,286.69**	**0.6%**			**$ 517,588.45**	**$ 3,175.65**	**0.6%**
8% Provincial Rebate		-8%			-8%		$ -			-8%		$ -			-8%		$ -			-8%		$ -			-8%		$ -			-8%		$ -		
HST		13%		$ 63,723.08	13%		$ 66,372.61	$ 2,649.53	4.2%	13%		$ 66,325.79	-$ 46.82	-0.1%	13%		$ 66,204.49	-$ 121.30	-0.2%	13%		$ 66,446.39	$ 241.90	0.4%	13%		$ 66,873.66	$ 427.27	0.6%	13%		$ 67,286.50	$ 412.83	0.6%
Total Bill on RPP (after Tax and Rebate)				**$ 553,900.59**			**$ 576,931.15**	**$ 23,030.56**	**4.2%**			**$ 576,524.19**	**-$ 406.96**	**-0.1%**			**$ 575,469.80**	**-$ 1,054.39**	**-0.2%**			**$ 577,572.50**	**$ 2,102.70**	**0.4%**			**$ 581,286.46**	**$ 3,713.96**	**0.6%**			**$ 584,874.95**	**$ 3,588.48**	**0.6%**
Loss Factor (%)		1.87%			1.87%					1.72%					1.72%					1.72%					1.72%					1.72%				

Appendix 2-W
Bill Impacts

Customer Class: STREET LIGHTING SERVICE

TOU / non-TOU: non-TOU | **16,000** Devices
SPOT CLASS B | **2,700** kW
2,700 kVA ● May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)
Consumption **955,000** kWh

Charge Unit		2018 Current Board-Approved			2019 Current Board-Approved			Impact		2020 Proposed			Impact		2021 Proposed			Impact		2022 Proposed			Impact		2023 Proposed			Impact		2024 Proposed			Impact	
		Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change
Service Charge (per device)	per device per 30 days	$ 1.55	16,000	$ 24,800.00	$ 1.61	16,000	$ 25,760.00	$ 960.00	3.87%	$ 1.66	16,000	$ 26,560.00	$ 800.00	3.11%	$ 1.71	16,000	$ 27,360.00	$ 800.00	3.01%	$ 1.75	16,000	$ 28,000.00	$ 640.00	2.34%	$ 1.82	16,000	$ 29,120.00	$ 1,120.00	4.00%	$ 1.89	16,000	$ 30,240.00	$ 1,120.00	3.85%
Distribution Volumetric Rate	per kVA	$ 34.4231	2,700	$ 92,942.37	$ 35.7759	2,700	$ 96,594.93	$ 3,652.56	3.93%	$ 36.9560	2,700	$ 99,781.20	$ 3,186.27	3.30%	$ 38.1608	2,700	$ 103,034.16	$ 3,252.96	3.26%	$ 39.0996	2,700	$ 105,568.92	$ 2,534.76	2.46%	$ 40.7574	2,700	$ 110,044.98	$ 4,476.06	4.24%	$ 42.3592	2,700	$ 114,369.84	$ 4,324.86	3.93%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per kVA									$ 0.0968	2,700	$ 261.36	$ 261.36		$ 0.0968	2,700	$ 261.36	$ -	0.00%	$ 0.0968	2,700	$ 261.36	$ -	0.00%	$ 0.0968	2,700	$ 261.36	$ -	0.00%	$ 0.0968	2,700	$ 261.36	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per kVA									$ 0.5764	2,700	$ 1,556.28	$ 1,556.28		$ 0.5764	2,700	$ 1,556.28	$ -	0.00%	$ 0.5764	2,700	$ 1,556.28	$ -	0.00%	$ 0.5764	2,700	$ 1,556.28	$ -	0.00%	$ 0.5764	2,700	$ 1,556.28	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per kVA									-$ 0.8812	2,700	-$ 2,379.24	-$ 2,379.24		-$ 0.8812	2,700	-$ 2,379.24	$ -	0.00%	-$ 0.8812	2,700	-$ 2,379.24	$ -	0.00%	-$ 0.8812	2,700	-$ 2,379.24	$ -	0.00%	-$ 0.8812	2,700	-$ 2,379.24	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per kVA									-$ 0.1412	2,700	-$ 381.24	-$ 381.24		-$ 0.1412	2,700	-$ 381.24	$ -	0.00%	-$ 0.1412	2,700	-$ 381.24	$ -	0.00%	-$ 0.1412	2,700	-$ 381.24	$ -	0.00%	-$ 0.1412	2,700	-$ 381.24	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per kVA									-$ 0.0088	2,700	-$ 23.76	-$ 23.76		-$ 0.0088	2,700	-$ 23.76	$ -	0.00%	-$ 0.0088	2,700	-$ 23.76	$ -	0.00%	-$ 0.0088	2,700	-$ 23.76	$ -	0.00%	-$ 0.0088	2,700	-$ 23.76	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per kVA									-$ 0.0187	2,700	-$ 50.49	-$ 50.49		-$ 0.0187	2,700	-$ 50.49	$ -	0.00%	-$ 0.0187	2,700	-$ 50.49	$ -	0.00%	-$ 0.0187	2,700	-$ 50.49	$ -	0.00%	-$ 0.0187	2,700	-$ 50.49	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per kVA									-$ 0.9343	2,700	-$ 2,522.61	-$ 2,522.61		-$ 0.9343	2,700	-$ 2,522.61	$ -	0.00%	-$ 0.9343	2,700	-$ 2,522.61	$ -	0.00%	-$ 0.9343	2,700	-$ 2,522.61	$ -	0.00%	-$ 0.9343	2,700	-$ 2,522.61	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per kVA									-$ 0.0380	2,700	-$ 102.60	-$ 102.60		-$ 0.0380	2,700	-$ 102.60	$ -	0.00%	-$ 0.0380	2,700	-$ 102.60	$ -	0.00%	-$ 0.0380	2,700	-$ 102.60	$ -	0.00%	-$ 0.0380	2,700	-$ 102.60	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per kVA									-$ 0.4134	2,700	-$ 1,116.18	-$ 1,116.18		-$ 0.4134	2,700	-$ 1,116.18	$ -	0.00%	-$ 0.4134	2,700	-$ 1,116.18	$ -	0.00%	-$ 0.4134	2,700	-$ 1,116.18	$ -	0.00%	-$ 0.4134	2,700	-$ 1,116.18	$ -	0.00%
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	per kVA									-$ 0.2264	2,700	-$ 611.28	-$ 611.28		-$ 0.2264	2,700	-$ 611.28	$ -	0.00%	-$ 0.2264	2,700	-$ 611.28	$ -	0.00%	-$ 0.2264	2,700	-$ 611.28	$ -	0.00%	-$ 0.2264	2,700	-$ 611.28	$ -	0.00%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per kVA	-$ 0.5347	2,700	-$ 1,443.69		2,700	$ -	$ 1,443.69			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per kVA	-$ 1.6506	2,700	-$ 4,456.62		2,700	$ -	$ 4,456.62			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per kVA	$ 0.0741	2,700	$ 200.07	$ 0.0741	2,700	$ 200.07	$ -	0.00%		2,700	$ -	-$ 200.07			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per kVA	$ 0.0312	2,700	$ 84.24	$ 0.0312	2,700	$ 84.24	$ -	0.00%		2,700	$ -	-$ 84.24			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per kVA	$ 0.5133	2,700	$ 1,385.91	$ 0.5133	2,700	$ 1,385.91	$ -	0.00%		2,700	$ -	-$ 1,385.91			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per kVA		2,700	$ -		2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per kVA	$ 0.0478	2,700	$ 129.06	$ 0.0478	2,700	$ 129.06	$ -	0.00%		2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kVA		2,700	$ -		2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -	
Sub-Total A (excluding pass through)				**$ 113,641.34**			**$ 124,154.21**	**$ 10,512.87**	**9.25%**			**$ 120,971.44**	**-$ 3,182.77**	**-2.56%**			**$ 125,024.40**	**$ 4,052.96**	**3.35%**			**$ 128,199.16**	**$ 3,174.76**	**2.54%**			**$ 133,795.22**	**$ 5,596.06**	**4.37%**			**$ 139,240.08**	**$ 5,444.86**	**4.07%**
Line Losses on Cost of Power	per kWh	$ 0.1164	35,908	$ 4,179.69	$ 0.1164	35,908	$ 4,179.69	$ -	0.00%	$ 0.1164	28,173	$ 3,279.28	-$ 900.41	-21.54%	$ 0.1164	28,173	$ 3,279.28	$ -	0.00%	$ 0.1164	28,173	$ 3,279.28	$ -	0.00%	$ 0.1164	28,173	$ 3,279.28	$ -	0.00%	$ 0.1164	28,173	$ 3,279.28	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	per kVA	-$ 1.0860	2,700	-$ 2,932.20	-$ 0.1687	2,700	-$ 455.49	$ 2,476.71	-84.47%	$ 0.25620	2,700	$ 691.74	$ 1,147.23	-251.87%		2,700	$ -	$ 691.74			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -		
Rate Rider for Disposition of Deferral/Variance Accounts for Non-Wholesale Market Participants	per kVA		2,700	$ -		2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	per kVA	$ 0.0236	2,700	$ 63.72	$ 0.0092	2,700	$ 24.84	-$ 38.88	-61.02%	-$ 0.01130	2,700	-$ 30.51	-$ 55.35	-222.83%		2,700		$ 30.51			2,700					2,700					2,700				
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	per kWh	-$ 0.00112	955,000	-$ 1,069.60	$ 0.00068	955,000	$ 649.40	$ 1,719.00	-160.71%	-$ 0.00290	955,000	-$ 2,769.50	-$ 3,418.90	-526.47%		955,000		$ 2,769.50			955,000					955,000					955,000				
Sub-Total B - Distribution (includes Sub-Total A)				**$ 113,882.95**			**$ 128,552.65**	**$ 14,669.70**	**12.88%**			**$ 122,142.45**	**-$ 6,410.20**	**-4.99%**			**$ 128,303.68**	**$ 6,161.23**	**5.04%**			**$ 131,478.44**	**$ 3,174.76**	**2.47%**			**$ 137,074.50**	**$ 5,596.06**	**4.26%**			**$ 142,519.36**	**$ 5,444.86**	**3.97%**
Retail Transmissioin Rate - Network Service Rate	per kW	$ 2.2849	2,700	$ 6,169.23	$ 2.3638	2,700	$ 6,382.26	$ 213.03	3.45%	$ 2.4481	2,700	$ 6,609.87	$ 227.61	3.57%	$ 2.4481	2,700	$ 6,609.87	$ -	0.00%	$ 2.4481	2,700	$ 6,609.87	$ -	0.00%	$ 2.4481	2,700	$ 6,609.87	$ -	0.00%	$ 2.4481	2,700	$ 6,609.87	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	per kW	$ 2.4461	2,700	$ 6,604.47	$ 2.7488	2,700	$ 7,421.76	$ 817.29	12.37%	$ 2.6541	2,700	$ 7,166.07	-$ 255.69	-3.45%	$ 2.6541	2,700	$ 7,166.07	$ -	0.00%	$ 2.6541	2,700	$ 7,166.07	$ -	0.00%	$ 2.6541	2,700	$ 7,166.07	$ -	0.00%	$ 2.6541	2,700	$ 7,166.07	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				**$ 126,656.65**			**$ 142,356.67**	**$ 15,700.02**	**12.40%**			**$ 135,918.39**	**-$ 6,438.28**	**-4.52%**			**$ 142,079.62**	**$ 6,161.23**	**4.53%**			**$ 145,254.38**	**$ 3,174.76**	**2.23%**			**$ 150,850.44**	**$ 5,596.06**	**3.85%**			**$ 156,295.30**	**$ 5,444.86**	**3.61%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0032	990,908	$ 3,170.91	$ 0.0032	990,908	$ 3,170.91	$ -	0.00%	$ 0.0032	983,173	$ 3,146.15	-$ 24.75	-0.78%	$ 0.0032	983,173	$ 3,146.15	$ -	0.00%	$ 0.0032	983,173	$ 3,146.15	$ -	0.00%	$ 0.0032	983,173	$ 3,146.15	$ -	0.00%	$ 0.0032	983,173	$ 3,146.15	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0003	990,908	$ 297.27	$ 0.0003	990,908	$ 297.27	$ -	0.00%	$ 0.0003	983,173	$ 294.95	-$ 2.32	-0.78%	$ 0.0003	983,173	$ 294.95	$ -	0.00%	$ 0.0003	983,173	$ 294.95	$ -	0.00%	$ 0.0003	983,173	$ 294.95	$ -	0.00%	$ 0.0003	983,173	$ 294.95	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	990,908	$ 396.36	$ 0.0004	990,908	$ 396.36	$ -	0.00%	$ 0.0004	983,173	$ 393.27	-$ 3.09	-0.78%	$ 0.0004	983,173	$ 393.27	$ -	0.00%	$ 0.0004	983,173	$ 393.27	$ -	0.00%	$ 0.0004	983,173	$ 393.27	$ -	0.00%	$ 0.0004	983,173	$ 393.27	$ -	0.00%
Standard Supply Service Charge	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	611,200	$ 39,728.00	$ 0.0650	611,200	$ 39,728.00	$ -	0.00%	$ 0.0650	611,200	$ 39,728.00	$ -	0.00%	$ 0.0650	611,200	$ 39,728.00	$ -	0.00%	$ 0.0650	611,200	$ 39,728.00	$ -	0.00%	$ 0.0650	611,200	$ 39,728.00	$ -	0.00%	$ 0.0650	611,200	$ 39,728.00	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	171,900	$ 16,158.60	$ 0.0940	171,900	$ 16,158.60	$ -	0.00%	$ 0.0940	171,900	$ 16,158.60	$ -	0.00%	$ 0.0940	171,900	$ 16,158.60	$ -	0.00%	$ 0.0940	171,900	$ 16,158.60	$ -	0.00%	$ 0.0940	171,900	$ 16,158.60	$ -	0.00%	$ 0.0940	171,900	$ 16,158.60	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	171,900	$ 22,690.80	$ 0.1320	171,900	$ 22,690.80	$ -	0.00%	$ 0.1320	171,900	$ 22,690.80	$ -	0.00%	$ 0.1320	171,900	$ 22,690.80	$ -	0.00%	$ 0.1320	171,900	$ 22,690.80	$ -	0.00%	$ 0.1320	171,900	$ 22,690.80	$ -	0.00%	$ 0.1320	171,900	$ 22,690.80	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	750	$ 57.75	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	954,250	$ 84,928.25	$ 0.0890	954,250	$ 84,928.25	$ -	0.00%	$ 0.0890	954,250	$ 84,928.25	$ -	0.00%	$ 0.0890	954,250	$ 84,928.25	$ -	0.00%	$ 0.0890	954,250	$ 84,928.25	$ -	0.00%	$ 0.0890	954,250	$ 84,928.25	$ -	0.00%	$ 0.0890	954,250	$ 84,928.25	$ -	0.00%
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164	955,000	$ 111,162.00	$ 0.1164	955,000	$ 111,162.00	$ -	0.00%	$ 0.1164	955,000	$ 111,162.00	$ -	0.00%	$ 0.1164	955,000	$ 111,162.00	$ -	0.00%	$ 0.1164	955,000	$ 111,162.00	$ -	0.00%	$ 0.1164	955,000	$ 111,162.00	$ -	0.00%	$ 0.1164	955,000	$ 111,162.00	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price (before Taxes)				**$ 241,683.44**			**$ 257,383.46**	**$ 15,700.02**	**6.5%**			**$ 250,915.01**	**-$ 6,468.45**	**-2.5%**			**$ 257,076.24**	**$ 6,161.23**	**2.5%**			**$ 260,251.00**	**$ 3,174.76**	**1.2%**			**$ 265,847.06**	**$ 5,596.06**	**2.2%**			**$ 271,291.92**	**$ 5,444.86**	**2.0%**
8% Provincial Rebate		-8%			-8%					-8%			$ -		-8%					-8%			$ -		-8%					-8%			$ -	
HST		13%		$ 31,418.85	13%		$ 33,459.85	$ 2,041.00	6.5%	13%		$ 32,618.95	-$ 840.90	-2.5%	13%		$ 33,419.91	$ 800.96	2.5%	13%		$ 33,832.63	$ 412.72	1.2%	13%		$ 34,560.12	$ 727.49	2.2%	13%		$ 35,267.95	$ 707.83	2.0%
Total Bill on Average IESO Wholesale Market Price (after Tax and Rebate)				**$ 273,102.29**			**$ 290,843.31**	**$ 17,741.02**	**6.5%**			**$ 283,533.96**	**-$ 7,309.35**	-2.5%			**$ 290,496.15**	**$ 6,962.19**	2.5%			**$ 294,083.63**	**$ 3,587.48**	1.2%			**$ 300,407.18**	**$ 6,323.55**	2.2%			**$ 306,559.87**	**$ 6,152.69**	2.0%
Total Bill on RPP (before Taxes)				**$ 215,507.44**			**$ 231,207.46**	**$ 15,700.02**	**7.3%**			**$ 224,739.01**	**-$ 6,468.45**	**-2.8%**			**$ 230,900.24**	**$ 6,161.23**	**2.7%**			**$ 234,075.00**	**$ 3,174.76**	**1.4%**			**$ 239,671.06**	**$ 5,596.06**	**2.4%**			**$ 245,115.92**	**$ 5,444.86**	**2.3%**
8% Provincial Rebate		-8%			-8%					-8%			$ -		-8%					-8%			$ -		-8%					-8%			$ -	
HST		13%		$ 28,015.97	13%		$ 30,056.97	$ 2,041.00	7.3%	13%		$ 29,216.07	-$ 840.90	-2.8%	13%		$ 30,017.03	$ 800.96	2.7%	13%		$ 30,429.75	$ 412.72	1.4%	13%		$ 31,157.24	$ 727.49	2.4%	13%		$ 31,865.07	$ 707.83	2.3%
Total Bill on RPP (after Tax and Rebate)				**$ 243,523.41**			**$ 261,264.43**	**$ 17,741.02**	**7.3%**			**$ 253,955.08**	**-$ 7,309.35**	-2.8%			**$ 260,917.27**	**$ 6,962.19**	2.7%			**$ 264,504.75**	**$ 3,587.48**	1.4%			**$ 270,828.30**	**$ 6,323.55**	2.4%			**$ 276,980.99**	**$ 6,152.69**	2.3%
Loss Factor (%)		3.76%			3.76%					2.95%					2.95%					2.95%					2.95%					2.95%				

Appendix 2-W
Bill Impacts

Customer Class: UNMETERED SCATTERED LOAD SERVICE

TOU / non-TOU: non-TOU | RPP

Consumption 1 Connection | 285 kWh ● May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

Charge Unit		2018 Current Board-Approved Rate ($)	Volume	Charge ($)	2019 Current Board-Approved Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change	2020 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change	2021 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change	2022 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change	2023 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change	2024 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change
Service Charge	per 30 days	$ 6.87	1	$ 6.87	$ 7.14	1	$ 7.14	$ 0.27	3.93%	$ 6.43	1	$ 6.43	-$ 0.71	-9.94%	$ 6.64	1	$ 6.64	$ 0.21	3.27%	$ 6.80	1	$ 6.80	$ 0.16	2.41%	$ 7.09	1	$ 7.09	$ 0.29	4.26%	$ 7.37	1	$ 7.37	$ 0.28	3.95%
Connection Charge (per connection)	per connection per 30 days	$ 0.71	1	$ 0.71	$ 0.74	1	$ 0.74	$ 0.03	4.23%	$ 0.67	1	$ 0.67	-$ 0.07	-9.46%	$ 0.69	1	$ 0.69	$ 0.02	2.99%	$ 0.71	1	$ 0.71	$ 0.02	2.90%	$ 0.74	1	$ 0.74	$ 0.03	4.23%	$ 0.77	1	$ 0.77	$ 0.03	4.05%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per kWh									$ 0.00020	285	$ 0.06	$ 0.06		$ 0.00020	285	$ 0.06	$ -	0.00%	$ 0.00020	285	$ 0.06	$ -	0.00%	$ 0.00020	285	$ 0.06	$ -	0.00%	$ 0.00020	285	$ 0.06	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per kWh									$ 0.00121	285	$ 0.34	$ 0.34		$ 0.00121	285	$ 0.34	$ -	0.00%	$ 0.00121	285	$ 0.34	$ -	0.00%	$ 0.00121	285	$ 0.34	$ -	0.00%	$ 0.00121	285	$ 0.34	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effffective until Dec. 31, 2024	per kWh									-$ 0.00185	285	-$ 0.53	-$ 0.53		-$ 0.00185	285	-$ 0.53	$ -	0.00%	-$ 0.00185	285	-$ 0.53	$ -	0.00%	-$ 0.00185	285	-$ 0.53	$ -	0.00%	-$ 0.00185	285	-$ 0.53	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per kWh									-$ 0.00030	285	-$ 0.09	-$ 0.09		-$ 0.00030	285	-$ 0.09	$ -	0.00%	-$ 0.00030	285	-$ 0.09	$ -	0.00%	-$ 0.00030	285	-$ 0.09	$ -	0.00%	-$ 0.00030	285	-$ 0.09	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per kWh									-$ 0.00002	285	-$ 0.01	-$ 0.01		-$ 0.00002	285	-$ 0.01	$ -	0.00%	-$ 0.00002	285	-$ 0.01	$ -	0.00%	-$ 0.00002	285	-$ 0.01	$ -	0.00%	-$ 0.00002	285	-$ 0.01	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per kWh									-$ 0.00004	285	-$ 0.01	-$ 0.01		-$ 0.00004	285	-$ 0.01	$ -	0.00%	-$ 0.00004	285	-$ 0.01	$ -	0.00%	-$ 0.00004	285	-$ 0.01	$ -	0.00%	-$ 0.00004	285	-$ 0.01	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per kWh									-$ 0.00196	285	-$ 0.56	-$ 0.56		-$ 0.00196	285	-$ 0.56	$ -	0.00%	-$ 0.00196	285	-$ 0.56	$ -	0.00%	-$ 0.00196	285	-$ 0.56	$ -	0.00%	-$ 0.00196	285	-$ 0.56	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per kWh									-$ 0.00008	285	-$ 0.02	-$ 0.02		-$ 0.00008	285	-$ 0.02	$ -	0.00%	-$ 0.00008	285	-$ 0.02	$ -	0.00%	-$ 0.00008	285	-$ 0.02	$ -	0.00%	-$ 0.00008	285	-$ 0.02	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per kWh									-$ 0.00087	285	-$ 0.25	-$ 0.25		-$ 0.00087	285	-$ 0.25	$ -	0.00%	-$ 0.00087	285	-$ 0.25	$ -	0.00%	-$ 0.00087	285	-$ 0.25	$ -	0.00%	-$ 0.00087	285	-$ 0.25	$ -	0.00%
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	per kWh									-$ 0.00047	285	-$ 0.13	-$ 0.13		-$ 0.00047	285	-$ 0.13	$ -	0.00%	-$ 0.00047	285	-$ 0.13	$ -	0.00%	-$ 0.00047	285	-$ 0.13	$ -	0.00%	-$ 0.00047	285	-$ 0.13	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue (per connection) - effective until Dec. 31, 2019	per connection per 30 days	$ 0.02	1	$ 0.02	$ 0.02	1	$ 0.02	$ -	0.00%		1	$ -	-$ 0.02			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue (per connection) - effective until Dec. 31, 2019	per connection per 30 days	$ 0.01	1	$ 0.01	$ 0.01	1	$ 0.01	$ -	0.00%		1	$ -	-$ 0.01			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.16	1	$ 0.16	$ 0.16	1	$ 0.16	$ -	0.00%		1	$ -	-$ 0.16			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.05	1	$ 0.05	$ 0.05	1	$ 0.05	$ -	0.00%		1	$ -	-$ 0.05			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.08632	285	$ 24.60	$ 0.08971	285	$ 25.57	$ 0.97	3.93%	$ 0.08073	285	$ 23.01	-$ 2.56	-10.01%	$ 0.08336	285	$ 23.76	$ 0.75	3.26%	$ 0.08541	285	$ 24.34	$ 0.58	2.46%	$ 0.08903	285	$ 25.37	$ 1.03	4.24%	$ 0.09253	285	$ 26.37	$ 1.00	3.93%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per kWh	$ 0.00203	285	$ 0.58	$ 0.00203	285	$ 0.58	$ -	0.00%		285	$ -	-$ 0.58			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per kWh	$ 0.00062	285	$ 0.18	$ 0.00062	285	$ 0.18	$ -	0.00%		285	$ -	-$ 0.18			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -	
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per kWh	-$ 0.00096	285	-$ 0.27		285	$ -	$ 0.27			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per kWh	-$ 0.00296	285	-$ 0.84		285	$ -	$ 0.84			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per kWh	$ 0.00029	285	$ 0.08	$ 0.00029	285	$ 0.08	$ -	0.00%		285	$ -	-$ 0.08			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per kWh	$ 0.00006	285	$ 0.02	$ 0.00006	285	$ 0.02	$ -	0.00%		285	$ -	-$ 0.02			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per kWh	$ 0.00092	285	$ 0.26	$ 0.00092	285	$ 0.26	$ -	0.00%		285	$ -	-$ 0.26			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kWh		285	$ -		285	$ -	$ -			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -	
Sub-Total A (excluding pass through)				**$ 32.42**			**$ 34.80**	**$ 2.38**	**7.35%**			**$ 28.92**	**-$ 5.89**	**-16.92%**			**$ 29.90**	**$ 0.98**	**3.39%**			**$ 30.66**	**$ 0.76**	**2.56%**			**$ 32.01**	**$ 1.35**	**4.41%**			**$ 33.32**	**$ 1.31**	**4.08%**
Line Losses on Cost of Power	per kWh	$ 0.0770	11	$ 0.83	$ 0.0770	11	$ 0.83	$ -	0.00%	$ 0.0770	8	$ 0.65	-$ 0.18	-21.54%	$ 0.0770	8	$ 0.65	$ -	0.00%	$ 0.0770	8	$ 0.65	$ -	0.00%	$ 0.0770	8	$ 0.65	$ -	0.00%	$ 0.0770	8	$ 0.65	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	per kWh	-$ 0.00316	285	-$ 0.90	-$ 0.00049	285	-$ 0.14	$ 0.76	-84.49%	$ 0.00073	285	$ 0.21	$ 0.35	-248.98%		285	$ -	-$ 0.21			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	per kWh	$ 0.00007	285	$ 0.02	$ 0.00003	285	$ 0.01	-$ 0.01	-57.14%	-$ 0.00003	285	-$ 0.01	-$ 0.02	-200.00%		285	$ -	$ 0.01			285	$ -	$ -			285	$ -	$ -			285	$ -	$ -	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	per kWh	-$ 0.00112		$ -	$ 0.00068		$ -	$ -		-$ 0.00290		$ -																					
Sub-Total B - Distribution (includes Sub-Total A)				**$ 32.37**			**$ 35.50**	**$ 3.13**	**9.68%**			**$ 29.76**	**-$ 5.73**	**-16.16%**			**$ 30.54**	**$ 0.78**	**2.62%**			**$ 31.31**	**$ 0.76**	**2.50%**			**$ 32.66**	**$ 1.35**	**4.32%**			**$ 33.97**	**$ 1.31**	**4.00%**
RTSR - Network	per kWh	$ 0.00460	296	$ 1.36	$ 0.00482	296	$ 1.43	$ 0.07	4.78%	$ 0.00500	293	$ 1.47	$ 0.04	2.92%	$ 0.00500	293	$ 1.47	$ -	0.00%	$ 0.00500	293	$ 1.47	$ -	0.00%	$ 0.00500	293	$ 1.47	$ -	0.00%	$ 0.00500	293	$ 1.47	$ -	0.00%
RTSR - Line and Transformation Connection	per kWh	$ 0.00390	296	$ 1.15	$ 0.00444	296	$ 1.31	$ 0.16	13.85%	$ 0.00429	293	$ 1.26	-$ 0.05	-4.13%	$ 0.00429	293	$ 1.26	$ -	0.00%	$ 0.00429	293	$ 1.26	$ -	0.00%	$ 0.00429	293	$ 1.26	$ -	0.00%	$ 0.00429	293	$ 1.26	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				**$ 34.88**			**$ 38.24**	**$ 3.36**	**9.63%**			**$ 32.49**	**-$ 5.75**	**-15.03%**			**$ 33.27**	**$ 0.78**	**2.40%**			**$ 34.03**	**$ 0.76**	**2.30%**			**$ 35.39**	**$ 1.35**	**3.97%**			**$ 36.69**	**$ 1.31**	**3.70%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0032	296	$ 0.95	$ 0.0032	296	$ 0.95	$ -	0.00%	$ 0.0032	293	$ 0.94	-$ 0.01	-0.78%	$ 0.0032	293	$ 0.94	$ -	0.00%	$ 0.0032	293	$ 0.94	$ -	0.00%	$ 0.0032	293	$ 0.94	$ -	0.00%	$ 0.0032	293	$ 0.94	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0003	296	$ 0.09	$ 0.0003	296	$ 0.09	$ -	0.00%	$ 0.0003	293	$ 0.09	-$ 0.00	-0.78%	$ 0.0003	293	$ 0.09	$ -	0.00%	$ 0.0003	293	$ 0.09	$ -	0.00%	$ 0.0003	293	$ 0.09	$ -	0.00%	$ 0.0003	293	$ 0.09	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	296	$ 0.12	$ 0.0004	296	$ 0.12	$ -	0.00%	$ 0.0004	293	$ 0.12	-$ 0.00	-0.78%	$ 0.0004	293	$ 0.12	$ -	0.00%	$ 0.0004	293	$ 0.12	$ -	0.00%	$ 0.0004	293	$ 0.12	$ -	0.00%	$ 0.0004	293	$ 0.12	$ -	0.00%
Standard Supply Service Charge	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	185	$ 12.04	$ 0.0650	185	$ 12.04	$ -	0.00%	$ 0.0650	185	$ 12.04	$ -	0.00%	$ 0.0650	185	$ 12.04	$ -	0.00%	$ 0.0650	185	$ 12.04	$ -	0.00%	$ 0.0650	185	$ 12.04	$ -	0.00%	$ 0.0650	185	$ 12.04	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	48	$ 4.55	$ 0.0940	48	$ 4.55	$ -	0.00%	$ 0.0940	48	$ 4.55	$ -	0.00%	$ 0.0940	48	$ 4.55	$ -	0.00%	$ 0.0940	48	$ 4.55	$ -	0.00%	$ 0.0940	48	$ 4.55	$ -	0.00%	$ 0.0940	48	$ 4.55	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	51	$ 6.77	$ 0.1320	51	$ 6.77	$ -	0.00%	$ 0.1320	51	$ 6.77	$ -	0.00%	$ 0.1320	51	$ 6.77	$ -	0.00%	$ 0.1320	51	$ 6.77	$ -	0.00%	$ 0.1320	51	$ 6.77	$ -	0.00%	$ 0.1320	51	$ 6.77	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	285	$ 21.95	$ 0.0770	285	$ 21.95	$ -	0.00%	$ 0.0770	285	$ 21.95	$ -	0.00%	$ 0.0770	285	$ 21.95	$ -	0.00%	$ 0.0770	285	$ 21.95	$ -	0.00%	$ 0.0770	285	$ 21.95	$ -	0.00%	$ 0.0770	285	$ 21.95	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	-	$ -	$ 0.0890	-	$ -	$ -		$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -	
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164		$ -	$ 0.1164	-	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Total Bill on RPP (before Taxes)				**$ 58.23**			**$ 61.59**	**$ 3.36**	**5.8%**			**$ 55.83**	**-$ 5.76**	**-9.3%**			**$ 56.61**	**$ 0.78**	**1.4%**			**$ 57.37**	**$ 0.76**	**1.4%**			**$ 58.72**	**$ 1.35**	**2.4%**			**$ 60.03**	**$ 1.31**	**2.2%**
8% Provincial Rebate		-8%		-$ 4.66	-8%		-$ 4.93	-$ 0.27	5.8%	-8%		-$ 4.47	$ 0.46	-9.3%	-8%		-$ 4.53	-$ 0.06	1.4%	-8%		-$ 4.59	-$ 0.06	1.4%	-8%		-$ 4.70	-$ 0.11	2.4%	-8%		-$ 4.80	-$ 0.10	2.2%
HST		13%		$ 7.57	13%		$ 8.01	$ 0.44	5.8%	13%		$ 7.26	-$ 0.75	-9.3%	13%		$ 7.36	$ 0.10	1.4%	13%		$ 7.46	$ 0.10	1.4%	13%		$ 7.63	$ 0.18	2.4%	13%		$ 7.80	$ 0.17	2.2%
Total Bill on RPP (after Tax and Rebate)				**$ 61.14**			**$ 64.66**	**$ 3.53**	**5.8%**			**$ 58.62**	-$ 6.04	-9.3%			**$ 59.44**	$ 0.82	1.4%			**$ 60.24**	$ 0.80	1.4%			**$ 61.66**	$ 1.42	2.4%			**$ 63.03**	$ 1.37	2.2%
Loss Factor (%)		3.76%			3.76%					2.95%					2.95%					2.95%					2.95%					2.95%				

DEFERRAL AND VARIANCE ACCOUNTS VARIANCE ANALYSIS

1. SUMMARY OF DVA BALANCES

Exhibit 9, Tab 1 includes detailed information about Toronto Hydro's Deferral and Variance Accounts (DVA). This schedule provides an updated summary of the Group 1 and Group 2 DVA balances, including the 2018 actuals and updated 2019 forecasts. The information is supported by the following appendices: DVA Continuity Schedule (Appendix A); GA Analysis Workform (Appendix B); Account 1595 Workform (Appendix C); Group 1 DVA Rate Rider Model (Appendix D); Group 2 DVA Rate Rider Model (Appendix E) and Energy Sales and Cost of Power (Appendix F). This schedule also includes an updated 2018 Earnings Sharing Mechanism calculation (Table 18).

Table 1: Summary of DVA Balances – Group 1 Accounts ($ Millions)

	Principal Balance as of Dec 31, 2018	Carrying Charge Balance as of Dec 31, 2018	2017 Balances approved for clearance (including CC)	Projected Interest for 2019	2018 Balances requesting for clearance
LV Variance Account	0.7	0.0	0.4	0.0	0.3
RSVA – Wholesale Market Service Charges	(29.4)	(0.6)	(25.8)	(0.1)	(4.3)
Variance WMS – Sub-account CBR Class B	0.0	0.0	0.6	0.0	(0.6)
RSVA – Retail Transmission Network Charge	17.0	0.3	8.3	0.2	9.2
RSVA – Retail Transmission Connection Charge	25.7	0.3	8.5	0.4	17.9
RSVA – Power	(8.8)	(0.2)	(3.4)	(0.1)	(5.6)
RSVA – Global Adjustment	(17.3)	0.5	6.9	(0.5)	(24.3)
Total Retail Settlement Variance Account ("RSVA")	**(12.1)**	**0.3**	**(4.5)**	**(0.1)**	**(7.4)**
Smart Meter Entity Charges	(0.8)	(0.0)	(0.1)	(0.0)	(0.7)
Total Group 1 Balances	**(12.9)**	**0.3**	**(4.6)**	**(0.2)**	**(8.2)**

Note: Rounding differences may exist.

Table 2: Summary of DVA Balances – Group 2 Accounts ($ Millions)

	Principal Balance as of Dec 31, 2018	Carrying Charge Balance as of Dec 31, 2018	Balances as of Dec 31, 2018	2017 Balances approved for clearance (incl. CC)	2019 Forecast Principal Activity	2019 Forecast Carrying Charges	Balances for clearance as at Dec 31, 2019
Stranded Meter Costs	3.3	0.3	**3.6**	-	(4.7)	(0.3)	**(1.4)**
IFRS-USGAAP Transitional PP&E[1] Amounts	5.7	-	**5.7**	-	(7.3)	-	**(1.6)**
LRAM Variance Account ("LRAMVA")	27.9	0.5	**28.4**	(12.3)	-	-	**-**
Impact for USGAAP Deferral	48.1	-	**48.1**	-	-	-	**48.1**
Capital Related Revenue Requirement Variance Account ("CRRRVA")	(52.8)	(0.9)	**(53.7)**	-	(22.8)	(1.4)	**(77.9)**
Externally Driven Capital Variance Account ("EDCVA")	(2.3)	(0.0)	**(2.3)**	-	(0.8)	(0.1)	**(3.2)**
.Derecognition	(21.0)	(0.8)	**(21.8)**	-	(12.1)	(0.6)	**(34.5)**
Wireless Attachments	(0.5)	(0.0)	**(0.5)**	-	(0.1)	(0.0)	**(0.6)**
Monthly Billing	7.4	0.2	**7.5**	-	4.1	0.2	**11.8**
Operating Centers Consolidation Program ("OCCP")	(52.8)	(0.5)	**(53.3)**	-	(19.1)	(1.1)	**(73.5)**
Other Post-Employment Benefits ("OPEB") Cash vs Accrual	5.5	-	**5.5**	-	2.6	-	**8.1**
Renewable Generation Connection Funding Adder Deferral Account – Provincial Rate Protection Payment Variances	(4.3)	-	**(4.3)**	-	(2.0)	-	**(6.3)**
Total	**(35.8)**	**(1.2)**	**(37.1)**	**(12.3)**	**(62.2)**	**(3.3)**	**(131.0)**

Note: Rounding differences may exist.

[1] International Financial Reporting Standards ("IFRS"); United States Generally Accepted Accounting Principles ("USGAAP"); Property, plant and equipment ("PP&E").

2. CARRYING CHARGES

Carrying charges have been applied to specific accounts using the OEB's Prescribed Interest Rates. For the periods up to 2019 Q2, the rates are as determined by the OEB. For the periods 2019 Q3 through Q4, the 2019 Q2 rate has been applied as a forecast. Toronto Hydro proposes to update these rates for the actual approved rates at the time of clearance of these accounts.

Table 3: Interest on Carrying Charges

OEB Interest Rates Applied Calculation of Carrying Charges			
Quarter	Annual %	Quarter	Annual %
Q1 2014	1.47%	Q1 2017	1.10%
Q2 2014	1.47%	Q2 2017	1.10%
Q3 2014	1.47%	Q3 2017	1.10%
Q4 2014	1.47%	Q4 2017	1.50%
Q1 2015	1.47%	Q1 2018	1.50%
Q2 2015	1.10%	Q2 2018	1.89%
Q3 2015	1.10%	Q3 2018	1.89%
Q4 2015	1.10%	Q4 2018	2.17%
Q1 2016	1.10%	Q1 2019	2.45%
Q2 2016	1.10%	Q2 2019	2.18%
Q3 2016	1.10%	Q3 2019	2.18%
Q4 2016	1.10%	Q4 2019	2.18%

3. DISPOSITION OF ACCOUNTS

The balances of the accounts have been updated for 2018 actuals as reflected in the audited financial statements for the year ending December 31, 2018. The sections that follow explain the material changes to the account balances based on the 2018 financials.

3.1 Account 1555 – Stranded Meters

There were no material changes to this account in 2018.

3.2 Account 1575 – IFRS USGAAP Transitional PP&E Amounts

There were no material changes to this account in 2018.

3.3 Account 1508 – Other Regulatory Assets, Subaccount – Impact for USGAAP Deferral Account

Toronto Hydro's actuary performed a full actuarial valuation of the OPEB plans for the year-ending December 31, 2018 (Exhibit U, Tab 4A, Schedule 3, Appendix C). The change in the balance of this account reflects the recognition of a $37.2 million actuarial gain on the OPEB obligation. The actuarial gain arose from updates to the actuarial assumptions (e.g. membership data, claim costs, and discount rate) and plan experience.

3.4 Account 1508 – Other Regulatory Assets, Subaccount – CRRRVA

The balance for clearance in this account has been updated from $57.6 million to $75.6 million credit (refund) to customers. The difference is related to lower than forecasted in-service additions in 2018 associated with distribution assets, the timing of the Copeland TS project, the ERP project, and Hydro One Networks Incorporated ("Hydro One") capital contributions.

Table 4: CRRRVA Balance ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge Updated	Updated Total	Original Total
Proposed Capital-Related RR, 2015-2019 CIR (1B-T2-S3-P10, Table 3)	437.8	465.0	517.3	567.2	607.3	2,594.6	2,594.6
RR impact from 10% reduction in capital spending	(7.3)	(8.7)	(10.7)	(17.7)	(24.1)	(68.6)	(68.6)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge Updated	Updated Total	Original Total
Capital-Related RR (Rate Order, Feb. 29, 2016 - Table 2)	430.5	456.3	506.6	549.5	583.2	2,526.0	2,526.0
RR impact from the application of stretch factor to capital funding[2]	-	(2.6)	(5.4)	(8.4)	(11.7)	(28.1)	(28.1)
Capital-Related RR in Approved 2015-2019 Rates	430.5	453.7	501.2	541.0	571.5	2,497.9	2,497.9
Sub-account 1508 - Externally Driven Capital Variance Account	(0.2)	(0.5)	(0.7)	(0.9)	(0.8)	(3.1)	(2.2)
Sub-account 1508 - Derecognition Variance Account	(12.9)	1.3	(3.9)	(5.5)	(12.1)	(33.1)	(40.8)
Other Adjustments[3]	(1.2)	0.6	(1.4)	(0.7)	3.5	0.8	(6.1)
Capital-Related RR in Approved Rates eligible for CRRRVA	416.2	455.1	495.3	533.9	562.1	2,462.5	2,448.8
Actual Historic & Forecast Bridge Capital-Related RR	413.6	449.3	481.0	503.9	539.3	2,387.1	2,391.2
Sub-account 1508 – CRRRVA	**(2.7)**	**(5.8)**	**(14.3)**	**(30.0)**	**(22.8)**	**(75.6)**	**(57.6)**
CRRRVA – carrying charges	(0.0)	(0.1)	(0.2)	(0.6)	(1.4)	(2.3)	(1.8)
Total	**(2.7)**	**(5.9)**	**(14.5)**	**(30.6)**	**(24.2)**	**(77.9)**	**(59.4)**

Note: Rounding differences may exist.

[2] Decision on Draft Rate Order, February 25, 2016, p. 3; Draft Rate Order, February 29, 2016, p. 5.
[3] These adjustments are primarily to account for variances in opening 2015 rate base and disposals. As is the case for Externally Driven Capital and Derecognition, these capital-related variances are outside the OEB-approved scope of the CRRRVA.

3.5 Account 1508 – Other Regulatory Assets, Subaccount – Externally Driven Capital Variance Account

The balance for clearance in this account has been updated from $2.2 million to $3.1 million credit (refund) to customers. The difference is driven by lower in-service additions amount in 2018. The tables below set out the actual/forecast versus approved expenditures and revenue requirement for 2015-2019.

Table 5: Externally Driven Capital Expenditures (2015-2019) ($ Millions)

Year	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge Updated	Total Updated	Original Total
Total Project Cost	3.8	9.0	12.5	24.2	21.2	70.7	72.0
Customer Contributions	1.6	6.4	9.9	18.3	12.9	49.1	48.7
Toronto Hydro Cost	2.2	2.6	2.6	5.9	8.3	21.6	23.2
Approved Capital Spend	4.0	4.0	4.0	4.0	4.0	20.0	20.0
Variance	(1.8)	(1.4)	(1.4)	1.9	4.3	1.6	3.2

Note: Rounding differences may exist.

Table 6: Externally Driven Capital Revenue Requirement (2015-2019) ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge Updated	Total Updated	Original Total
Approved Externally Driven Capital ISA	4.0	4.0	4.0	4.0	4.0	20.0	20.0
Actual and Bridge Externally Driven Capital ISA	0.2	0.1	2.4	0.1	10.1	12.9	18.2
Variance	(3.8)	(3.9)	(1.6)	(3.9)	6.1	(7.1)	(1.8)
Revenue requirement impact	(0.2)	(0.5)	(0.7)	(0.9)	(0.8)	(3.1)	(2.2)
Externally Driven Capital Variance Account	(0.2)	(0.5)	(0.7)	(0.9)	(0.8)	(3.1)	(2.2)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge Updated	Total Updated	Original Total
Externally Driven Capital Variance Account – carrying charges	-	-	-	(0.0)	(0.1)	(0.1)	(0.1)
Total	**(0.2)**	**(0.5)**	**(0.7)**	**(0.9)**	**(0.9)**	**(3.2)**	**(2.3)**

Note: Rounding differences may exist.

Revenue Requirement Calculation	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge Updated	Total Updated	Original Total
Rate Base	(1.9)	(5.6)	(8.1)	(10.6)	(9.2)		
Return on equity	(0.1)	(0.2)	(0.3)	(0.4)	(0.3)	(1.3)	(1.0)
Interest	-	(0.1)	(0.2)	(0.3)	(0.2)	(0.8)	(0.6)
Depreciation	(0.1)	(0.2)	(0.2)	(0.3)	(0.3)	(1.1)	(0.7)
PILs	-	-	-	-	-	-	0.1
Revenue Requirement	(0.2)	(0.5)	(0.7)	(0.9)	(0.8)	(3.1)	(2.2)

Note: Rounding differences may exist.

3.6 Account 1508 – Other Regulatory Assets, Subaccount – Derecognition

The balance for clearance in this account has been updated from $42.1 million to $34.5 million credit (refund) to customers. The difference is driven by higher derecognition in 2018 for distribution assets and for software as a result of implementing the new ERP system. Toronto Hydro updated the 2019 forecast based on a four year average of derecognition expense as opposed to using a three year average.

Table 7: Derecognition ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge Updated	Total Updated	Original Total
Losses on derecognition included in approved rates	33.9	26.6	28.0	29.4	32.6	150.5	150.5

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge Updated	Total Updated	Original Total
Actual and forecast losses on derecognition	24.1	27.0	24.5	24.5	22.4	122.5	116.5
Variance	(9.8)	0.4	(3.5)	(4.9)	(10.2)	(28.0)	(34.0)
PILs	(3.4)	0.2	(1.2)	(1.7)	(3.6)	(9.8)	(11.9)
Capital revenue requirement	0.4	0.7	0.7	1.1	1.7	4.7	5.1
Derecognition variance account	(12.8)	1.3	(4.0)	(5.5)	(12.1)	(33.1)	(40.8)
Derecognition variance account – carrying charges	(0.1)	(0.1)	(0.2)	(0.4)	(0.6)	(1.4)	(1.3)
Total	**(12.9)**	**1.2**	**(4.2)**	**(5.9)**	**(12.7)**	**(34.5)**	**(42.1)**

Note: Rounding differences may exist.

Capital revenue requirement calculation	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge Updated	Total Updated	Original Total
Rate Base	4.9	9.6	11.1	15.2	22.8		
Return on equity	0.2	0.4	0.4	0.6	0.8	2.4	2.6
Interest expense	0.1	0.2	0.2	0.4	0.6	1.4	1.6
PILs	0.1	0.1	0.1	0.2	0.3	0.8	0.9
Capital revenue requirement	0.4	0.7	0.7	1.1	1.7	4.7	5.1

Note: Rounding differences may exist.

3.7 Account 1508 – Other Regulatory Assets, Subaccount – Wireless Attachments

There were no material changes to this account in 2018.

3.8 Account 1508 – Other Regulatory Assets, Subaccount – Monthly Billing

There were no material changes to this account in 2018.

3.9 Account 1508 – Other Regulatory Assets, Subaccount – OCCP

The balance for clearance in this account has been updated from $71.2 million to $73.5 million credit (refund) to customers. The change is a result of updated carrying charges and updated total 2018 disposition amounts.

Table 12: OCCP ($ Millions)

	Original OCCP Variance Account			Total Update
	5800 Yonge	28 Underwriters	Total	
Net gain, net of tax	98.6	6.0	104.6	104.6
Tax Savings after gross-up	35.5	2.1	37.6	37.6
Actual net gain before carrying charges	**134.1**	**8.1**	**142.2**	**142.2**
Carrying Charges			1.5	1.7
Total net gain for clearance			**143.7**	**143.9**
Forecasted total disposition up to 2018	(60.4)	(12.1)	(72.5)	(70.4)
OCCP balance for clearing			**71.2**	**73.5**

3.10 Account 1508 – Other Regulatory Assets, Subaccount – OPEB Cash vs Accrual

The balance in this account has been updated from $8.9 million to $8.1 million. The change in is the result of the updated 2018 cash payments (to reflect actual payments incurred) and updated 2019 forecasted payments based on the most recent actuarial valuation (Exhibit U, Tab 4A, Schedule 3, Appendix C), in addition to an immaterial update to the forecasted OPEB costs.

Table 13: Cash versus Accrual Variance ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge Updated	Total Updated	Original Total
Forecasted OPEB costs (OM&A programs)	10.2	10.4	10.6	10.6	10.6	52.4	53.1
Estimated Capital Depreciation Collected for OPEB	2.2	2.4	2.6	2.8	3.0	13.0	13.0
Amount collected through rates (A)	12.4	12.8	13.2	13.4	13.6	65.4	66.1
Less: Cash payments (B)	9.1	10.8	10.9	10.9	8.9	50.6	50.0
Difference (C) = (A) – (B)	3.3	2.0	2.3	2.5	4.7	14.8	16.1
OpEx/Capex split (D)	56.2%	57.4%	55.0%	55.1%	55.2%		
Cash versus accrual variance (C) x (D)	1.8	1.1	1.3	1.3	2.6	8.1	8.9

Note: Rounding differences may exist.

3.11 Account 1533 – Renewable Generation Connection Funding Adder Deferral Account, Sub-account Provincial Rate Protection Payment Variances

The balance in this account has been updated from $5.1 million to $6.5 million. The change is due to lower than expected in-service additions in 2018.

Table 14: Provincially Funded Renewable Eligible Investment Variance Account ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge Updated	Total Updated	Original Total
Approved Revenue Requirement	0.3	0.9	1.5	2.1	2.6	7.4	7.4
Actual/Forecast Revenue Requirement	-	-	0.1	0.1	0.6	0.8	2.2
Variance Account Balance	(0.3)	(0.9)	(1.4)	(2.0)	(2.0)	(6.6)	(5.2)

Note: Rounding differences may exist.

3.12 New Deferral Account Requested: Excess Expansion Deposits

The balance in this account has been updated from $5.5 million to $8.0 million as a result of excess expansion deposits realized in 2018.

Table 15: Excess Expansion Deposits ($ Millions)

	Principal Balance as at Dec 31	Carrying Charge Balance	Total Balances as at Dec 31
2016	4.0	0.1	4.1
2017	5.1	0.2	5.3
2018 Updated	7.5	0.4	7.9
2019 Updated	7.5	0.5	8.0
2019 Original	5.1	0.4	5.5

4. TORONTO HYDRO SEEKS CLEARANCE OF GROUP 1 ACCOUNTS

Toronto Hydro requests disposition of the Group 1 DVA account balances, including RSVAs and SME charges. The GA Workform at Appendix B and the Account 1595 Workform at Appendix C support the request.

5. SUMMARY OF PROPOSED DVA DISPOSITIONS

Table 16: Summary of Proposed Dispositions for Group 1 Accounts ($ Millions)

	Principal Balance as of Dec 31, 2018	Carrying Charge Balance as of Dec 31, 2018	2017 Balances approved for clearance (including CC)	Projected Interest for 2019	2018 Balances requesting for clearance
Group 1 Accounts					
LV Variance Account	0.7	0.0	0.4	0.0	0.3
RSVA – Wholesale Market Service Charges	(29.4)	(0.6)	(25.8)	(0.1)	(4.3)
Variance WMS – Sub-account CBR Class B	0.0	0.0	0.6	0.0	(0.6)

	Principal Balance as of Dec 31, 2018	Carrying Charge Balance as of Dec 31, 2018	2017 Balances approved for clearance (including CC)	Projected Interest for 2019	2018 Balances requesting for clearance
RSVA – Retail Transmission Network Charge	17.0	0.3	8.3	0.2	9.2
RSVA – Retail Transmission Connection Charge	25.7	0.3	8.5	0.4	17.9
RSVA – Power	(8.8)	(0.2)	(3.4)	(0.1)	(5.6)
RSVA – Global Adjustment	(17.3)	0.5	6.9	(0.5)	(24.3)
Total Retail Settlement Variance Account ("RSVA")	**(12.1)**	**0.3**	**(4.5)**	**(0.1)**	**(7.4)**
Smart Meter Entity Charges	(0.8)	(0.0)	(0.1)	(0.0)	(0.7)
Total Group 1 Balances	**(12.9)**	**0.3**	**(4.6)**	**(0.2)**	**(8.2)**

Table 17: Summary of Proposed Dispositions for Group 2 Accounts ($ Millions)

	Original			Updated		
	Principal Balance	Carrying Charges up to Dec 31, 2019	Balances for clearance as at Dec 31, 2019	Principal Balance	Carrying Charges up to Dec 31, 2019	Balances for clearance as at Dec 31, 2019
Stranded Meter Costs	(1.4)	—	(1.4)	(1.4)	—	(1.4)
IFRS-USGAAP Transitional PP&E Amounts	(1.6)	—	(1.6)	(1.6)	—	(1.6)
Impact for USGAAP Deferral	85.3	—	85.3	48.1	—	48.1
CRRRVA	(57.6)	(1.8)	(59.4)	(75.6)	(2.3)	(77.9)
Externally Driven Capital	(2.2)	(0.1)	(2.3)	(3.1)	(0.1)	(3.2)
Derecognition	(40.8)	(1.3)	(42.1)	(33.1)	(1.4)	(34.5)
Wireless Attachments	(0.6)	(0.0)	(0.6)	(0.6)	(0.0)	(0.6)
Monthly Billing	11.5	0.3	11.8	11.5	0.4	11.8
OCCP	(69.7)	(1.5)	(71.2)	(71.8)	(1.7)	(73.5)
OPEB Cash vs Accrual	8.9	—	8.9	8.1	—	8.1
Excess Expansion Deposits	(5.1)	(0.4)	(5.5)	(7.5)	(0.5)	(8.0)
Total Balance	**(73.3)**	**(4.8)**	**(78.1)**	**(127.0)**	**(5.6)**	**(132.6)**

6. RATE RIDERS

Appendices D and E explain how the rate riders were calculated for each of the proposed clearances. The balances have been allocated to the rate classes in accordance with the OEB's EDDVAR Report (EB-2008-0046). Toronto Hydro applied the structure and logic of the DVA Workform but modified the calculations of rate riders found in the DVA Workform as necessary to take into account the utility's specific requests.

7. 2018 EARNINGS SHARING MECHANISM ("ESM") CALCULATION

Toronto Hydro's 2018 ESM calculation is shown in the Table 18 below. The utility did not surpass the ESM threshold in 2018.

Table 18: 2015-2018 ESM Calculations[4] ($ Millions)

		2015	2016	2017	2018
OM&A [a]	*A*	244.0	246.6	250.6	262.9
Revenue Offsets [a]	*B*	- 39.9	- 50.2	- 51.7	-52.8
Unadjusted non-capital revenue requirement ("Non-CRRR")	*C=A+B*	**204.1**	**196.4**	**198.9**	**210.2**
RRR Adjustments [b]					
Depreciation expense related to non-regulated assets (renewable energy investment)	*D*	-	-	- 0.0	-0.1
Non-recoverable expenses – donations and meals	*E*	- 0.4	- 0.4	- 0.6	-0.8
Subtotal	*F=C+D+E*	**203.7**	**196.1**	**198.2**	**209.2**
Adjustments for items not included in rates					
Amortization of 2014 balance in DVA account 1575 – IFRS USGAAP Transitional PP&E Amounts [c]	*G*	-	5.2	6.6	6.7
Amortization of capital contributions (deferred revenue) [d]	*H*	2.2	3.8	4.7	5.3
Actual non-CRRR items for ESM purposes	*I=F+G+H*	**206.0**	**205.1**	**209.5**	**221.2**
Less: non-CRRR embedded in rates [e,f]	*J*	**202.7**	**205.7**	**208.3**	**209.6**
Non-CRRR difference	*K=I-J*	3.3	- 0.6	1.2	11.6
Deemed equity portion of actual rate base [g]	*L*	1,285.2	1,420.1	1,540.4	1649.5
Non-CRRR difference	*M=K/L*	0.26%	- 0.04%	0.08%	0.70%
ESM threshold	*N*	1.00%	1.00%	1.00%	1.00%
ESM test result	*M compared to N*	Within threshold	Within threshold	Within threshold	Within threshold

Rounding variances may exist.

[a] Source: RRR 2.1.7 - trial balance.

[b] Source: RRR 2.1.5.6 - Appendices 1 and 2.

[c] Source: RRR 2.1.7 - trial balance account 4310, reported as revenue offsets.

[d] Source: RRR 2.1.7 - trial balance account 4245, reported as revenue offsets.

[e] EB-2014-0116, Decision and Order (29th Dec, 2015), page 49

f 2015 non-CRRR is from EB-2014-0116, Draft Rate Order Update (29th Feb, 2016), Table 2, Page 6. To determine 2016 and 2017 amount, I (2.1% and 1.9%) and X (0.6% and 0.6%) was applied to the previous year amount.

[g] Source: RRR 2.1.5.6 - ROE Summary.

[4] Source: Toronto Hydro's annual RRR submissions.

Ontario Energy Board

2019 Deferral/Variance Account Workform

version 1.0

Utility Name	Toronto Hydro-Electric System Limited
Service Territory	
Assigned EB Number	
Name of Contact and Title	
Phone Number	
Email Address	

General Notes

Notes

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

White cells contain fixed values, automatically generated values or formulae.

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Ontario Energy Board

2019 Deferral/Variance Account Workform

Instructions

Tab	Tab Details	Step	Instructions
2 - Continuity Schedule	This tab is the continuity schedule that shows all the accounts and the accumulation of the balances a utility has.	1	Complete the DVA continuity schedule. For all accounts, except for Account 1595, start inputting data from the year in which the GL balance was last disposed. For example, if in the 2018 rate application, DVA balances as at December 31, 2016 were approved for disposition, start the continuity schedule from 2016 by entering the closing 2015 balances in the Adjustments column under 2015. For all Account 1595 sub-accounts, complete the DVA continuity schedule for each Account 1595 vintage year that has a GL balance as at December 31, 2017 regardless of whether the account is being requested for disposition in the current application. For each Account 1595 sub-account, start inputting data from the year the sub-account started to accumulate a balance (i.e. the vintage year). For example, Account 1595 (2015) would have information starting in 2015, when the relevant balances approved for disposition were first transferred into Account 1595 (2015). The DVA continuity schedule currently starts from 2012, if a utility has an Account 1595 with a vintage year prior to 2012, then a separate schedule should be provided starting from the vintage year.
		2a	If you had any Class A customers at any point during the period that the Account 1589 GA balance accumulated (e.g. last disposition was for 2015 balances in the 2017 rate application, current balance requested for disposition accumulated from 2016 to 2017), check off the checkbox in cell BS13. If the checkbox is not checked off, then proceed to tabs 3 to 7 and complete the tabs accordingly. If the checkbox is checked off, tab 6 relating to Class A customer consumption will be generated, see step 7 to 10 below for further details. If the checkbox in step 2a is checked off, another checkbox will pop up to the right of the previous checkbox. If you had any Class A customers at any point during the period that the Account 1580, sub-account CBR Class B balance accumulated (e.g. 2016, 2017 or 2016 & 2017), check off the checkbox. If the checkbox is not checked off, then the balance in the Account 1580, sub-account CBR Class B will be allocated and disposed with Account 1580 WMS, as a part of the general DVA rate rider. If the checkbox is checked off, then tab 6.2 will be generated. This tab will calculate the billing determinants applicable to Account 1580 sub-account CBR Class B, using information inputted in tab 6. See step 12 below for further details. The CBR Class B balance will be allocated in tab 6.2a and the rate rider will be calculated in tab 7.
		2b	Enter the number of utility-specific 1508 sub-accounts that are approved for the utility in the textbox in cell B71. The DVA continuity schedule will generate the number of utility-specific 1508 sub-accounts starting in row 51. Input the name and the balances of the sub-account(s) starting in row 51. If a utility does not have utility-specific 1508 sub-accounts, the generic 1508 sub-account Other will still be listed in the DVA continuity schedule. Check off the "check to dispose of account" checkbox in column BT for sub-accounts requested for disposition.
3. Appendix A	This tab shows the year end balance variances between the continuity schedule	3	Provide an explanation for the variances identified.
4 - Billing Determinant	This tab shows the billing determinants that will be used to allocate account balances and calculate rate riders.	4	Complete the billing determinants table. Note that columns O and P are generated when a utility indicates they have Class A customers in tab 2a. Information in these columns are populated based on data from tab 6
5 - Allocating Def-Var Balances	This tab allocates the DVA balance (except for CBR Class B if Class A customers exist).	5	Review the allocated balances to ensure the allocation is appropriate. Note that the allocations for Account 1589, Account 1580, sub-account CBR Class B will be determined after tabs 6 to 6.2a have been completed.

Ontario Energy Board

2019 Deferral/Variance Account Workform

Instructions

Tab	Tab Details	Step	Instructions
6 - Class A Data Consumption	This is a new tab that is to be completed if there were any Class A customers at any point during the period the GA balance CBR Class B balance accumulated. The tab also considers Class A/B transition customers. The data on this tab is used for the purposes of determining the GA rate rider, CBR Class B rate rider (if applicable), as well as customer specific GA and CBR Class B charges for transition customers (if applicable).	6	This tab is generated when the utility checks in tab 2a. that they have Class A customers during the period that the GA balance accumulated. Under #1, enter the year for which the Account 1589 GA balance was last disposed.
		7	Under #2a, indicate whether you had any customers that transitioned between Class A and B during the period the Account 1589 GA balance accumulated. If no, proceed to #3b in step 9. If yes, #2b and tab 6.1a. will be generated. Proceed to #2b. Under #2b, indicate whether you had any customers that transitioned between Class A and B during the period the Account 1580, sub-account CBR Class B balance accumulated. If no, proceed to #3a in step 8. If yes, tab 6.2a. will be generated. Proceed to #3a in step 8.
		8	Under #3a, enter the number of transition customers during the period the Account 1589 GA balance accumulated. A table will be generated based on the number of customers. Complete the table accordingly for each transition customer identified (i.e. kWh/kW for half year periods, and the customer class during the half year). This data will automatically be used in the GA balance and CBR Class B balance allocation to transition customers in tabs 6.1a. and 6.2a., respectively. Each transition customer identified in tab 6, table 3a will be assigned a customer number and the number will correspond to the same transition customers populated in tabs 6.1a. and 6.2a. The data in tab 6 will also be used in the calculation of billing determinants in the allocation of GA and CBR Class B balances to the rate classes, as applicable.
		9	Under #3b, enter the number of customers who were Class A customers during the entire period since the year the Account 1589 GA balance accumulated (i.e. did not transition between Class A and B during the period). A table will be generated based on the number of customers. Complete the table accordingly for each Class A customer identified. This data will be used in the calculation of billing determinants in the allocation of GA and CBR Class B balances to the rate classes, as applicable.
6.1a. - GA Allocation	This tab has been revised. It allocates the GA balance to each transition customer for the period in which these customers were Class B customers and contributed to the GA balance (i.e. former Class B customers who contributed to the GA balance but are now Class A customers and former Class A customers who are now Class B customers contributing to the GA balance).	10	This tab is generated when the utility indicates that they have transition customers in tab 6, #2a during the period when the GA balance accumulated. In row 20, enter the total Class B consumption which equals to Non-RPP consumption less WMP consumption and consumption for Class A customers (who were Class A for partial and full year). The rest of the information in this tab will be auto-populated and will calculate the customer specific allocation of the GA balance to transition customers in the bottom table. All transition customers who are allocated a specific GA amount are not to be charged the general Non-RPP Class B GA rate rider as calculated in tab 7.
6.2 - CBR	This is a new tab that calculates the CBR Class B rate rider if there were Class A customers at any point during the period that the CBR Class B balance accumulated.	11	This tab is generated when the utility checks in tab 2a. that they have Class A customers during the period that Account 1580, sub-account CBR Class B balance accumulated. The rest of the information in the tab is auto-populated and will be used in the calculation of the CBR Class B rate rider calculated in tab 6.
6.2a - CBR_B Allocation	This is a new tab that allocates the CBR Class B balance to each transition customer for the period in which these customers were Class B customers and contributed to the CBR Class B balance (i.e. former Class B customers who contributed to the balance but are now Class A customers and former Class A customers who are now Class B contributing to the balance).	12	This tab is generated when the utility indicates that they have transition customers in tab 6, #2b during the period where the CBR Class B balance accumulated. In B16 select the year when the balance in CBR Class B was last disposed. In row 20, enter the total Class B consumption which equals to total consumption less WMP consumption and consumption for Class A customers (who were Class A for eiher partial or full year). The rest of the information in this tab will be auto-populated and will calculate the customer specific allocation of the CBR Class B balance to transition customers in the bottom table. Note that the transition customers for GA may be different than the transition customers for CBR Class B as this would depend on the period in which the GA and CBR Class B balances accumulated. Any transition customer who is allocated a specific CBR Class B amount is not to be charged the general CBR Class B rate rider.
7 - Calculation of Def-Var RR	This tab calculates all the applicable DVA rate riders.	13	Enter the proposed rate rider recovery period if different than the default 12 month period. For each rate class of each rate rider, select whether the rate rider is to be calculated on a kWh, kW or number of customers basis. The rest of the information in the tab is auto-populated and the rate riders are calculated accordingly .

Ontario Energy Board

Deferral/Variance Account Workform

This continuity schedule must be completed for each account and sub-account that the utility has approved for use as at Dec. 31, 2017, regardless of whether disposition is being requested for the account. For all accounts, except for Account 1595, start inputting data from the year in which the GL balance was last disposed. For example, if in the 2017 rate application, DVA balances as at December 31, 2015 were approved for disposition, start the continuity schedule from 2015 by entering the approved closing 2014 balance in the Adjustment column under 2014. For each Account 1595 sub-account, start inputting data from the year the sub-account started to accumulate a balance (i.e. the vintage year). For example, Account 1595 (2014), data should be inputted starting in 2014 when the relevant balances approved for disposition was first transferred into Account 1595 (2014). The DVA continuity schedule currently starts from 2012, if a utility has an Account 1595 with a vintage year prior to 2012, then a separate schedule should be provided starting from the vintage year. For any new accounts that have never been disposed, start inputting data from the year the account was approved to be used.

		2012										2013									
Account Descriptions	**Account Number**	**Opening Principal Amounts as of Jan-1-12**	**Transactions(1) Debit / (Credit) during 2012**	**OEB-Approved Disposition during 2012**	**Principal Adjustments during 2012**	**Closing Principal Balance as of Dec-31-12**	**Opening Interest Amounts as of Jan-1-12**	**Interest Jan-1 to Dec-31-12**	**OEB-Approved Disposition during 2012**	**Interest Adjustments(1) during 2012**	**Closing Interest Amounts as of Dec-31-12**	**Opening Principal Amounts as of Jan-1-13**	**Transactions(1) Debit / (Credit) during 2013**	**OEB-Approved Disposition during 2013**	**Principal Adjustments(2) during 2013**	**Closing Principal Balance as of Dec-31-13**	**Opening Interest Amounts as of Jan-1-13**	**Interest Jan-1 to Dec-31-13**	**OEB-Approved Disposition during 2013**	**Interest Adjustments(2) during 2013**	**Closing Interest Amounts as of Dec-31-13**
Group 1 Accounts																					
LV Variance Account	1550					$0					$0	$0				$0	$0				$0
Smart Metering Entity Charge Variance Account	1551															$0	$0				$0
RSVA - Wholesale Market Service Charge[9]	1580					$0					$0	$0				$0	$0				$0
Variance WMS – Sub-account CBR Class A[9]	1580																				
Variance WMS – Sub-account CBR Class B[9]	1580																				
RSVA - Retail Transmission Network Charge	1584					$0					$0	$0				$0	$0				$0
RSVA - Retail Transmission Connection Charge	1586					$0					$0	$0				$0	$0				$0
RSVA - Power (excluding Global Adjustment)[12]	1588					$0					$0	$0				$0	$0				$0
RSVA - Global Adjustment [12]	1589					$0					$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595					$0					$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595					$0					$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2011)	1596					$0					$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595					$0					$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595					$0					$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595					$0					$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595					$0					$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595					$0					$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595					$0					$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595																				
Not to be disposed of until a year after rate rider has expired and that balance has been audited																					
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
RSVA - Global Adjustment 12	**1589**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

For all OEB-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related OEB

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This continuity schedule must be completed for each account and Account 1595, start inputting data from the year in which the GL ba 2015 by entering the approved closing 2014 balance in the Adjustn example, Account 1595 (2014), data should be inputted starting in has an Account 1595 with a vintage year prior to 2012, then a sepa approved to be used.

		2014									2015								
Account Descriptions	**Account Number**	**Opening Principal Amounts as of Jan-1-14**	**Transactions(1) Debit / (Credit) during 2014**	**OEB-Approved Disposition during 2014**	**Principal Adjustments(2) during 2014**	**Closing Principal Balance as of Dec-31-14**	**Opening Interest Amounts as of Jan-1-14**	**Interest Jan-1 to Dec-31-14**	**OEB-Approved Disposition during 2014**	**Interest Adjustments(2) during 2014**	**Closing Interest Amounts as of Dec-31-14**	**Opening Principal Amounts as of Jan-1-15**	**Transactions(1) Debit / (Credit) during 2015**	**OEB-Approved Disposition during 2015**	**Principal Adjustments(2) during 2015**	**Closing Principal Balance as of Dec-31-15**	**Opening Interest Amounts as of Jan-1-15**	**Interest Jan-1 to Dec-31-15**	**OEB-Approved Disposition during 2015**	**Interest Adjustments(2) during 2015**	**Closing Interest Amounts as of Dec-31-15**
Group 1 Accounts																					
LV Variance Account	1550	$0	$1,680,006			$1,680,006	$0	$48,585			$48,585	$1,680,006	$447,453			$2,127,459	$48,585	$22,355			$70,940
Smart Metering Entity Charge Variance Account	1551	$0	$230,907			$230,907	$0	$10,096			$10,096	$230,907	-$103,295			$127,611	$10,096	$2,861			$12,957
RSVA - Wholesale Market Service Charge[9]	1580	$0	-$104,177,755			-$104,177,755	$0	-$4,243,265			-$4,243,265	-$104,177,755	-$53,058,389			-$157,236,144	-$4,243,265	-$1,397,797			-$5,641,062
Variance WMS – Sub-account CBR Class A[9]	1580												$554,306			$554,306	$0	$1,757			$1,757
Variance WMS – Sub-account CBR Class B[9]	1580												$5,967,910			$5,967,910	$0	$19,743			$19,743
RSVA - Retail Transmission Network Charge	1584	$0	$60,297,064			$60,297,064	$0	$1,969,184			$1,969,184	$60,297,064	$6,453,241			$66,750,305	$1,969,184	$753,147			$2,722,331
RSVA - Retail Transmission Connection Charge	1586	$0	$28,085,714			$28,085,714	$0	$981,663			$981,663	$28,085,714	$7,451,237			$35,536,950	$981,663	$375,400			$1,357,063
RSVA - Power (excluding Global Adjustment)[12]	1588	$0	-$18,770,687			-$18,770,687	$0	$0			$0	-$18,770,687	-$3,662,931			-$22,433,618	$0	-$261,729			-$261,729
RSVA - Global Adjustment [12]	1589	$0	$85,657,811			$85,657,811	$0	$2,633,307			$2,633,307	$85,657,811	$8,710,805			$94,368,616	$2,633,307	$1,177,873			$3,811,180
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	$0	-$363,600			-$363,600	$0	-$318,137			-$318,137	-$363,600	$0			-$363,600	-$318,137	-$48,826			-$366,963
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	$0	-$2,483,823			-$2,483,823	$0	$1,563,823			$1,563,823	-$2,483,823	$0			-$2,483,823	$1,563,823	$17,095			$1,580,918
Disposition and Recovery/Refund of Regulatory Balances (2011)	1596	$0	$109,729			$109,729	$0	-$261,355			-$261,355	$109,729	$0			$109,729	-$261,355	$1,308			-$260,047
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	$0	$0			$0	$0	$0			$0	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	$0	$95,890			$95,890	$0	-$55,626			-$55,626	$95,890				$95,890	-$55,626	$1,139			-$54,487
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	$0	$0			$0	$0	$0			$0	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	$0	$0			$0	$0	$0			$0	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0	$0			$0	$0	$0			$0	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$0				$0	$0				$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595																				
Not to be disposed of until a year after rate rider has expired and that balanc																					
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$50,361,255	$0	$0	$50,361,255	$0	$2,328,275	$0	$0	$2,328,275	$50,361,255	-$27,239,665	$0	$0	$23,121,590	$2,328,275	$664,326	$0	$0	$2,992,600
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	-$35,296,556	$0	$0	-$35,296,556	$0	-$305,032	$0	$0	-$305,032	-$35,296,556	-$35,950,470	$0	$0	-$71,247,026	-$305,032	-$513,547	$0	$0	-$818,579
RSVA - Global Adjustment 12	**1589**	$0	$85,657,811	$0	$0	$85,657,811	$0	$2,633,307	$0	$0	$2,633,307	$85,657,811	$8,710,805	$0	$0	$94,368,616	$2,633,307	$1,177,873	$0	$0	$3,811,180

For all OEB-Approved dispositions, please ensure that the disposition an balances are to have a positive figure and credit balance are to have a ne

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		2016										2017									
Account Descriptions	**Account Number**	**Opening Principal Amounts as of Jan-1-16**	**Transactions(1) Debit / (Credit) during 2016**	**OEB-Approved Disposition during 2016**	**Principal Adjustments(2) during 2016**	**Closing Principal Balance as of Dec-31-16**	**Opening Interest Amounts as of Jan-1-16**	**Interest Jan-1 to Dec-31-16**	**OEB-Approved Disposition during 2016**	**Interest Adjustments(2) during 2016**	**Closing Interest Amounts as of Dec-31-16**	**Opening Principal Amounts as of Jan-1-17**	**Transactions(1) Debit / (Credit) during 2017**	**OEB-Approved Disposition during 2017**	**Principal Adjustments(2) during 2017**	**Closing Principal Balance as of Dec-31-17**	**Opening Interest Amounts as of Jan-1-17**	**Interest Jan-1 to Dec-31-17**	**OEB-Approved Disposition during 2017**	**Interest Adjustments(2) during 2017**	**Closing Interest Amounts as of Dec-31-17**
Group 1 Accounts																					
LV Variance Account	1550	$2,127,459	$312,025	$1,192,584		$1,246,899	$70,940	$15,001	$64,774		$21,166	$1,246,899	$394,328	$934,874		$706,353	$21,166	$6,808	$19,906		$8,068
Smart Metering Entity Charge Variance Account	1551	$127,611	-$379,776	$435,919		-$688,084	$12,957	$14,090	$16,147		$10,900	-$688,084	-$113,182	-$308,308		-$492,958	$10,900	-$15,080	-$7,181		$3,001
RSVA - Wholesale Market Service Charge[9]	1580	-$157,236,144	-$26,035,861			-$183,272,005	-$5,641,062	-$1,776,861			-$7,417,923	-$183,272,005	-$25,199,715	-$157,236,144		-$51,235,576	-$7,417,923	-$555,630	-$7,370,570		-$602,984
Variance WMS – Sub-account CBR Class A[9]	1580	$554,306		$554,306		$0	$1,757		$1,757		$0	$0				$0	$0				$0
Variance WMS – Sub-account CBR Class B[9]	1580	$5,967,910	$1,535,334			$7,503,244	$19,743	$14,282	$19,743		$14,282	$7,503,244	$524,231	$5,967,910		$2,059,564	$14,282	$20,888	$85,385		-$50,215
RSVA - Retail Transmission Network Charge	1584	$66,750,305	-$16,414,401			$50,335,904	$2,722,331	$664,278			$3,386,608	$50,335,904	$8,096,178	$66,750,305		-$8,318,223	$3,386,608	-$83,173	$3,456,545		-$153,109
RSVA - Retail Transmission Connection Charge	1586	$35,536,950	-$29,949,890			$5,587,061	$1,357,063	$271,369			$1,628,432	$5,587,061	$8,333,125	$35,536,950		-$21,616,765	$1,628,432	-$278,307	$1,747,948		-$397,823
RSVA - Power (excluding Global Adjustment)[12]	1588	-$22,433,618	-$4,099,996		-$804,747	-$27,338,361	-$261,729	-$265,904			-$527,633	-$27,338,361	-$3,337,116	-$22,433,618		-$8,241,858	-$527,633	-$93,593	-$508,477		-$112,749
RSVA - Global Adjustment [12]	1589	$94,368,616	-$14,088,418		$804,747	$81,084,945	$3,811,180	$1,131,533			$4,942,712	$81,084,945	$56,920,194	$94,368,616	-$50,366,169	-$6,729,646	$4,942,712	$274,057	$4,812,604	-$127,586	$276,580
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	-$363,600		-$363,600		$0	-$366,963	-$26,599	-$393,562		-$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	-$2,483,823		-$2,483,823		-$0	$1,580,918	-$66,708	$1,514,210		-$0	-$0				-$0	-$0				-$0
Disposition and Recovery/Refund of Regulatory Balances (2011)	1596	$109,729		$109,729		-$0	-$260,047	-$12,853	-$272,900		$0	-$0				-$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	$0				$0	$0				$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	$95,890				$95,890	-$54,487	$966			-$53,521	$95,890		$95,890		-$0	-$53,521		-$53,433		-$88
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	$0				$0	$0				$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	$0				$0	$0				$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0	$8,704,230	-$45,304,160		$54,008,390	$0	-$28,061	-$131,074		$103,013	$54,008,390	-$13,829,257			$40,179,133	$103,013	-$18,718		-$993,537	-$909,242
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$0				$0	$0				$0	$0	$2,791,740			$2,791,740	$0	$142,065			$142,065
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595																				
Not to be disposed of until a year after rate rider has expired and that balanc																					
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$23,121,590	-$80,416,753	-$45,859,045	$0	-$11,436,118	$2,992,600	-$65,468	$819,096	$0	$2,108,037	-$11,436,118	$34,580,526	$23,676,474	-$50,366,169	-$50,898,236	$2,108,037	-$600,683	$2,182,727	-$1,121,123	-$1,796,497
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$71,247,026	-$66,328,336	-$45,859,045	-$804,747	-$92,521,064	-$818,579	-$1,197,000	$819,096	$0	-$2,834,676	-$92,521,064	-$22,339,668	-$70,692,141	$0	-$44,168,591	-$2,834,676	-$874,740	-$2,629,877	-$993,537	-$2,073,076
RSVA - Global Adjustment 12	**1589**	$94,368,616	-$14,088,418	$0	$804,747	$81,084,945	$3,811,180	$1,131,533	$0	$0	$4,942,712	$81,084,945	$56,920,194	$94,368,616	-$50,366,169	-$6,729,646	$4,942,712	$274,057	$4,812,604	-$127,586	$276,580

For all OEB-Approved dispositions, please ensure that the disposition an balances are to have a positive figure and credit balance are to have a ne

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2015 by entering the approved closing 2014 balance in the Adjustr
example, Account 1595 (2014), data should be inputted starting in
has an Account 1595 with a vintage year prior to 2012, then a sepa
approved to be used.

		2018										2019			
Account Descriptions	**Account Number**	**Opening Principal Amounts as of Jan-1-18**	**Transactions(1) Debit / (Credit) during 2018**	**OEB-Approved Disposition during 2018**	**Principal Adjustments(2) during 2018**	**Closing Principal Balance as of Dec-31-18**	**Opening Interest Amounts as of Jan-1-18**	**Interest Jan-1 to Dec-31-18**	**OEB-Approved Disposition during 2018**	**Interest Adjustments(2) during 2018**	**Closing Interest Amounts as of Dec-31-18**	**Principal Disposition during 2019 - instructed by OEB**	**Interest Disposition during 2019 - instructed by OEB**	**Closing Principal Balances as of Dec 31-18 Adjusted for Dispositions during 2019**	**Closing Interest Balances as of Dec 31-18 Adjusted for Dispositions during 2019**
Group 1 Accounts															
LV Variance Account	1550	$706,353	$320,000	$312,025	$0	$714,328	$8,068	$10,579	$5,861	$0	$12,787	$394,328	$9,276	$320,000	$3,511
Smart Metering Entity Charge Variance Account	1551	-$492,958	-$727,042	-$379,776	$0	-$840,224	$3,001	-$1,169	$13,241	$0	-$11,409	-$113,182	-$19,076	-$727,042	$7,667
RSVA - Wholesale Market Service Charge[9]	1580	-$51,235,576	-$4,206,092	-$26,035,862	$0	-$29,405,806	-$602,984	-$497,277	-$498,414	$0	-$601,847	-$25,199,715	-$556,274	-$4,206,092	-$45,573
Variance WMS – Sub-account CBR Class A[9]	1580	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Variance WMS – Sub-account CBR Class B[9]	1580	$2,059,564	-$570,685	$1,535,334	$0	-$46,455	-$50,215	$6,908	-$52,680	$0	$9,373	$524,231	$11,862	-$570,686	-$2,489
RSVA - Retail Transmission Network Charge	1584	-$8,318,223	$8,947,315	-$16,414,402	$0	$17,043,495	-$153,109	$200,783	-$205,715	$0	$253,388	$8,096,178	$197,730	$8,947,316	$55,658
RSVA - Retail Transmission Connection Charge	1586	-$21,616,765	$17,363,768	-$29,949,890	$0	$25,696,892	-$397,823	$277,670	-$446,320	$0	$326,167	$8,333,125	$197,868	$17,363,768	$128,299
RSVA - Power (excluding Global Adjustment)[12]	1588	-$8,241,858	-$5,431,100	-$4,904,742	$0	-$8,768,216	-$112,749	-$152,662	-$98,572	$0	-$166,840	-$3,337,116	-$73,995	-$5,431,100	-$92,845
RSVA - Global Adjustment [12]	1589	-$6,729,646	-$23,898,524	-$13,283,671	$0	-$17,344,499	$276,580	$274,390	$57,211	$0	$493,759	$6,554,025	$341,438	-$23,898,523	$152,321
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	$0	$0	$0	$0	$0	-$0	$0	$0	$0	-$0	$0	$0	$0	-$0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	-$0	$0	$0	$0	-$0	-$0	$0	$0	$0	-$0	$0	$0	-$0	-$0
Disposition and Recovery/Refund of Regulatory Balances (2011)	1596	-$0	$0	$0	$0	-$0	$0	$0	$0	$0	$0	$0	$0	-$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	-$0	$0	$0	$0	-$0	-$88	$0	$0	$0	-$88	$0	$0	-$0	-$88
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$40,179,133	-$14,888,043	$0	$0	$25,291,090	-$909,242	-$91,080	$0	$0	-$1,000,322	$0	$0	$25,291,090	-$1,000,322
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$2,791,740	-$2,695,385	$0	$0	$96,355	$142,065	-$35,114	$0	$0	$106,951	$0	$0	$96,355	$106,951
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595	$0	-$6,348,433	$0	$0	-$6,348,433	$0	-$711,779	$0	$0	-$711,779	$0	$0	-$6,348,433	-$711,779
Not to be disposed of until a year after rate rider has expired and that balanc															
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$50,898,236	-$32,134,222	-$89,120,985	$0	$6,088,526	-$1,796,497	-$718,751	-$1,225,388	$0	-$1,289,859	-$4,748,127	$108,829	$10,836,653	-$1,398,688
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$44,168,591	-$8,235,698	-$75,837,313	$0	$23,433,025	-$2,073,076	-$993,140	-$1,282,599	$0	-$1,783,618	-$11,302,151	-$232,609	$34,735,176	-$1,551,009
RSVA - Global Adjustment 12	**1589**	-$6,729,646	-$23,898,524	-$13,283,671	$0	-$17,344,499	$276,580	$274,390	$57,211	$0	$493,759	$6,554,025	$341,438	-$23,898,523	$152,321

For all OEB-Approved dispositions, please ensure that the disposition ar
balances are to have a positive figure and credit balance are to have a n

Ontario Energy Board

eferral/Variance Account

This continuity schedule must be completed for each account and Account 1595, start inputting data from the year in which the GL ba 2015 by entering the approved closing 2014 balance in the Adjustn example, Account 1595 (2014), data should be inputted starting in has an Account 1595 with a vintage year prior to 2012, then a sepa approved to be used.

If you had any Class A customers at any point during the period that the Account 1589 GA balance accumulated (i.e. from the year the balance was last disposed to 2017), check off the checkbox ☐

If you had Class A customer(s) during this period, Tab 6 will be generated and applicants must complete the information pertaining to Class A customers.

		Projected Interest on Dec-31-18 Balances				2.1.7 RRR	
Account Descriptions	**Account Number**	**Projected Interest from Jan 1, 2019 to December 31, 2019 on Dec 31 -18 balance adjusted for disposition during 2019 (6)**	**Projected Interest from January 1, 2020 to April 30, 2020 on Dec 31 -17 balance adjusted for disposition during 2019 (6)**	**Total Interest**	**Total Claim**	**As of Dec 31-18**	**Variance RRR vs. 2018 Balance (Principal + Interest)**
Group 1 Accounts							
LV Variance Account	1550	$7,192	$0	$10,703	$330,703.40	$727,114	-$1
Smart Metering Entity Charge Variance Account	1551	-$18,884	$0	-$11,217	-$738,258.55	-$851,633	-$0
RSVA - Wholesale Market Service Charge[9]	1580	-$94,532	$0	-$140,105	-$4,346,196.35	-$30,093,038	-$85,385
Variance WMS – Sub-account CBR Class A[9]	1580	$0	$0	$0	$0.00	$0	$0
Variance WMS – Sub-account CBR Class B[9]	1580	-$12,826	$0	-$15,316	-$586,001.52	$48,303	$85,385
RSVA - Retail Transmission Network Charge	1584	$201,091	$0	$256,749	$9,204,065.53	$17,296,882	-$0
RSVA - Retail Transmission Connection Charge	1586	$390,251	$0	$518,550	$17,882,317.91	$26,023,060	-$0
RSVA - Power (excluding Global Adjustment)[12]	1588	-$122,064	$0	-$214,909	-$5,646,008.99	-$8,935,056	$0
RSVA - Global Adjustment [12]	1589	-$537,119	$0	-$384,799	-$24,283,321.89	-$16,850,741	-$1
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	$0	$0	-$0	$0.00	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	$0	$0	-$0	$0.00	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2011)	1596	$0	$0			$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	$0	$0	$0	☐heck to Dispose of Account $0.00	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	$0	$0	-$88	☐heck to Dispose of Account $0.00	$0	$88
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	$0	$0	$0	☐heck to Dispose of Account $0.00	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	$0	$0	$0	☐heck to Dispose of Account $0.00	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0	$0	-$1,000,322	☐heck to Dispose of Account $0.00	$24,290,768	$0
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$0	$0	$106,951	☐**heck to Dispose of Account** $0.00	$203,308	$1
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595	$0	$0	-$711,779	☐heck to Dispose of Account $0.00	-$7,060,210	$2
Not to be disposed of until a year after rate rider has expired and that balance							
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$186,892	$0	-$1,585,580	-$8,182,700	$4,798,757	$89
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$350,227	$0	-$1,200,781	$16,100,621.45	$21,649,498	$90
RSVA - Global Adjustment 12	**1589**	-$537,119	$0	-$384,799	-$24,283,321.89	-$16,850,741	-$1
					☐**heck to Dispose of Account**		

For all OEB-Approved dispositions, please ensure that the disposition an balances are to have a positive figure and credit balance are to have a n

Account Descriptions	Account Number	2012 Opening Principal Amounts as of Jan-1-12	2012 Transactions(1) Debit / (Credit) during 2012	2012 OEB-Approved Disposition during 2012	2012 Principal Adjustments(2) during 2012	2012 Closing Principal Balance as of Dec-31-12	2012 Opening Interest Amounts as of Jan-1-12	2012 Interest Jan-1 to Dec-31-12	2012 OEB-Approved Disposition during 2012	2012 Interest Adjustments(1) during 2012	2012 Closing Interest Amounts as of Dec-31-12	2013 Opening Principal Amounts as of Jan-1-13	2013 Transactions(1) Debit / (Credit) during 2013	2013 OEB-Approved Disposition during 2013	2013 Principal Adjustments(2) during 2013	2013 Closing Principal Balance as of Dec-31-13	2013 Opening Interest Amounts as of Jan-1-13	2013 Interest Jan-1 to Dec-31-13	2013 OEB-Approved Disposition during 2013	2013 Interest Adjustments(2) during 2013	2013 Closing Interest Amounts as of Dec-31-13
Group 2 Accounts																					
Other Regulatory Assets - Sub-Account - Deferred IF	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incrementa	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508		$61,499,000			$61,499,000					$0	$61,499,000	-$22,718,000			$38,781,000	$0				$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - EIP	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Derecognition	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Monthly Billing	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - OCCP	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508					$0					$0	$0				$0	$0				$0
Retail Cost Variance Account - Retail	1518					$0					$0	$0				$0	$0				$0
Misc. Deferred Debits	1525					$0					$0	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548					$0					$0	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567					$0					$0	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572					$0					$0	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574					$0					$0	$0				$0	$0				$0
RSVA - One-time	1582					$0					$0	$0				$0	$0				$0
Other Deferred Credits	2425					$0					$0	$0				$0	$0				$0
Group 2 Sub-Total			$61,499,000	$0	$0	$61,499,000	$0	$0	$0	$0	$0	$61,499,000	-$22,718,000	$0	$0	$38,781,000	$0	$0	$0	$0	$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592				-$2,314,616	-$2,314,616				-$83,852	-$83,852	-$2,314,616				-$2,314,616	-$83,852	-$34,020			-$117,872
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592				-$1,100,000	-$1,100,000				-$34,148	-$34,148	-$1,100,000				-$1,100,000	-$34,148	-$16,169			-$50,317
LRAM Variance Account[11]	**1568**					$0					$0	$0				$0	$0				$0
Total including Account 1568		$0	$61,499,000	$0	-$3,414,616	$58,084,384	$0	$0	$0	-$118,000	-$118,000	$58,084,384	-$22,718,000	$0	$0	$35,366,384	-$118,000	-$50,189	$0	$0	-$168,189
Renewable Generation Connection Capital Deferral A	1531					$0					$0	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral A	1532					$0					$0	$0				$0	$0				$0
Renewable Generation Connection Funding Adder D	1533					$0					$0	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534					$0					$0	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535					$0					$0	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536					$0					$0	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance -	1555				$59,226,643	$59,226,643					$0	$59,226,643	-$59,226,643			$0	$0				$0
Smart Meter Capital and Recovery Offset Variance -	1555				-$27,078,565	-$27,078,565				$350,269	$350,269	-$27,078,565	$27,078,565			$0	$350,269	-$350,269			$0
Smart Meter Capital and Recovery Offset Variance -	1555				$0	$0					$0	$0	$16,876,471		-$1,085,160	$15,791,311	$0				$0
Smart Meter OM&A Variance[4]	1556				$22,925,549	$22,925,549					$0	$22,925,549	-$22,925,549			$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[10]	1557																				
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575					$0						$0			$30,506,428	$30,506,428					
Accounting Changes Under CGAAP Balance + Return Component[5]	1576											$0				$0					

		2014										2015									
Account Descriptions	**Account Number**	**Opening Principal Amounts as of Jan-1-14**	**Transactions(1) Debit / (Credit) during 2014**	**OEB-Approved Disposition during 2014**	**Principal Adjustments(2) during 2014**	**Closing Principal Balance as of Dec-31-14**	**Opening Interest Amounts as of Jan-1-14**	**Interest Jan-1 to Dec-31-14**	**OEB-Approved Disposition during 2014**	**Interest Adjustments(2) during 2014**	**Closing Interest Amounts as of Dec-31-14**	**Opening Principal Amounts as of Jan-1-15**	**Transactions(1) Debit / (Credit) during 2015**	**OEB-Approved Disposition during 2015**	**Principal Adjustments(2) during 2015**	**Closing Principal Balance as of Dec-31-15**	**Opening Interest Amounts as of Jan-1-15**	**Interest Jan-1 to Dec-31-15**	**OEB-Approved Disposition during 2015**	**Interest Adjustments(2) during 2015**	**Closing Interest Amounts as of Dec-31-15**
Group 2 Accounts																					
Other Regulatory Assets - Sub-Account - Deferred IF	1508	$0				$0	$0				$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incrementa	1508	$0				$0	$0				$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	$0				$0	$0				$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508	$38,781,000	$48,551,000			$87,332,000	$0				$0	$87,332,000	-$6,142,424			$81,189,576	$0				$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	$0				$0	$0				$0	$0	-$2,679,349			-$2,679,349	$0	-$13,714			-$13,714
Other Regulatory Assets - Sub-Account - EIP	1508	$0	$0			$0	$0				$0	$0	-$155,757			-$155,757	$0	$0			$0
Other Regulatory Assets - Sub-Account - Derecognition	1508	$0	$0			$0	$0				$0	$0	-$12,913,378			-$12,913,378	$0	-$41,430			-$41,430
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	$0	-$112,142			-$112,142	$0	-$738			-$738	-$112,142	-$100,000			-$212,142	-$738	-$1,780			-$2,518
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$0				$0	$0				$0	$0	$339,784			$339,784	$0	$0			$0
Other Regulatory Assets - Sub-Account - OCCP	1508	$0				$0	$0				$0	$0	-$5,844,028			-$5,844,028	$0	-$66,137			-$66,137
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$0				$0	$0				$0	$0	$1,840,000			$1,840,000	$0	$0			$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0	$0				$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0	$0				$0	$0				$0
Group 2 Sub-Total		$38,781,000	$48,438,858	$0	$0	$87,219,858	$0	-$738	$0	$0	-$738	$87,219,858	-$25,655,152	$0	$0	$61,564,705	-$738	-$123,061	$0	$0	-$123,799
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$2,314,616				-$2,314,616	-$117,872	-$34,020			-$151,892	-$2,314,616				-$2,314,616	-$151,892	-$27,603			-$179,495
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$1,100,000				-$1,100,000	-$50,317	-$16,170			-$66,487	-$1,100,000				-$1,100,000	-$66,487	-$13,114			-$79,601
LRAM Variance Account[11]	**1568**	$0				$0	$0				$0	$0	$9,112,988			$9,112,988	$0	$216,135			$216,135
Total including Account 1568		$35,366,384	$48,438,858	$0	$0	$83,805,241	-$168,189	-$50,928	$0	$0	-$219,117	$83,805,241	-$16,542,164	$0	$0	$67,263,077	-$219,117	$52,357	$0	$0	-$166,760
Renewable Generation Connection Capital Deferral A	1531	$0				$0	$0				$0	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral A	1532	$0				$0	$0				$0	$0				$0	$0				$0
Renewable Generation Connection Funding Adder D	1533	$0				$0	$0				$0	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance -	1555	$0				$0	$0				$0	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance -	1555	$0				$0	$0				$0	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance -	1555	$15,791,311			-$1,387,244	$14,404,067	$0				$0	$14,404,067				$14,404,067	$0				$0
Smart Meter OM&A Variance[4]	1556	$0				$0	$0				$0	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[10]	1557											$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575	$30,506,428				$30,506,428						$30,506,428			-$1,558,360	$28,948,068					
Accounting Changes Under CGAAP Balance + Return Component[5]	1576	$0				$0						$0				$0					

Account Descriptions	Account Number	2016 Opening Principal Amounts as of Jan-1-16	2016 Transactions(1) Debit / (Credit) during 2016	2016 OEB-Approved Disposition during 2016	2016 Principal Adjustments(2) during 2016	2016 Closing Principal Balance as of Dec-31-16	2016 Opening Interest Amounts as of Jan-1-16	2016 Interest Jan-1 to Dec-31-16	2016 OEB-Approved Disposition during 2016	2016 Interest Adjustments(2) during 2016	2016 Closing Interest Amounts as of Dec-31-16	2017 Opening Principal Amounts as of Jan-1-17	2017 Transactions(1) Debit / (Credit) during 2017	2017 OEB-Approved Disposition during 2017	2017 Principal Adjustments(2) during 2017	2017 Closing Principal Balance as of Dec-31-17	2017 Opening Interest Amounts as of Jan-1-17	2017 Interest Jan-1 to Dec-31-17	2017 OEB-Approved Disposition during 2017	2017 Interest Adjustments(2) during 2017	2017 Closing Interest Amounts as of Dec-31-17
Group 2 Accounts																					
Other Regulatory Assets - Sub-Account - Deferred IF	1508	$0				$0	$0				$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incrementa	1508	$0				$0	$0				$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	$0				$0	$0				$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508	$81,189,576	-$21,022,000			$60,167,576	$0				$0	$60,167,576	$25,093,000			$85,260,576	$0				$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	-$2,679,349	-$5,791,209			-$8,470,558	-$13,714	-$54,531			-$68,245	-$8,470,558	-$14,277,069			-$22,747,626	-$68,245	-$208,682			-$276,927
Other Regulatory Assets - Sub-Account - EIP	1508	-$155,757	-$472,141			-$627,897	$0	-$1,154			-$1,154	-$627,897	-$698,387			-$1,326,285	-$1,154	-$3,252			-$4,406
Other Regulatory Assets - Sub-Account - Derecognition	1508	-$12,913,378	$1,290,093			-$11,623,285	-$41,430	-$169,801			-$211,231	-$11,623,285	-$3,870,968			-$15,494,253	-$211,231	-$192,636			-$403,867
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	-$212,142	-$100,016			-$312,158	-$2,518	-$2,815			-$5,333	-$312,158	-$100,000			-$412,158	-$5,333	-$4,396			-$9,729
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$339,784	$1,653,589			$1,993,373	$0	$7,871			$7,871	$1,993,373	$2,024,793			$4,018,166	$7,871	$37,270			$45,142
Other Regulatory Assets - Sub-Account - OCCP	1508	-$5,844,028	$14,486,588			$8,642,560	-$66,137	-$11,273			-$77,409	$8,642,560	$18,394,134			$27,036,693	-$77,409	$212,645			$135,235
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$1,840,000	$1,131,000			$2,971,000	$0	$0			$0	$2,971,000	$1,300,000			$4,271,000	$0	$0			$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0	$0				$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0	$0				$0	$0				$0
Group 2 Sub-Total		$61,564,705	-$8,824,096	$0	$0	$52,740,609	-$123,799	-$231,702	$0	$0	-$355,502	$52,740,609	$27,865,503	$0	$0	$80,606,113	-$355,502	-$159,051	$0	$0	-$514,552
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$2,314,616		-$2,314,616		$0	-$179,495	-$4,244	-$183,739		$0	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$1,100,000		-$1,100,000		$0	-$79,601	-$2,017	-$81,619		$2	$0				$0	$2				$2
LRAM Variance Account[11]	**1568**	$9,112,988	$4,319,627	$3,452,615	$1,278,369	$11,258,369	$216,135	$109,612	$131,074		$194,673	$11,258,369	$9,612,739	$4,810,834		$16,060,274	$194,673	$156,370	$139,236		$211,807
Total including Account 1568		$67,263,077	-$4,504,470	$37,999	$1,278,369	$63,998,978	-$166,760	-$128,351	-$134,285	$0	-$160,827	$63,998,978	$37,478,243	$4,810,834	$0	$96,666,387	-$160,827	-$2,680	$139,236	$0	-$302,743
Renewable Generation Connection Capital Deferral A	1531	$0				$0	$0				$0	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral A	1532	$0				$0	$0				$0	$0				$0	$0				$0
Renewable Generation Connection Funding Adder D	1533	$0	-$1,026,599			-$1,026,599	$0				$0	-$1,026,599	-$1,400,410			-$2,427,009	$0				$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance -	1555	$0				$0	$0				$0	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance -	1555	$0				$0	$0				$0	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance -	1555	$14,404,067	-$3,102,224			$11,301,843	$0	$110,022			$110,022	$11,301,843	-$3,985,516			$7,316,327	$110,022	$109,435			$219,457
Smart Meter OM&A Variance[4]	1556	$0				$0	$0				$0	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[10]	1557	$0				$0	$0				$0	$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575	$28,948,068	-$9,933,709			$19,014,359						$19,014,359	-$6,583,043			$12,431,316					
Accounting Changes Under CGAAP Balance + Return Component[5]	1576	$0				$0						$0				$0					

		2018										Forecast 2019				2019			
Account Descriptions	**Account Number**	**Opening Principal Amounts as of Jan-1-18**	**Transactions(1) Debit / (Credit) during 2018**	**OEB-Approved Disposition during 2018**	**Principal Adjustments(2) during 2018**	**Closing Principal Balance as of Dec-31-18**	**Opening Interest Amounts as of Jan-1-18**	**Interest Jan-1 to Dec-31-18**	**OEB-Approved Disposition during 2018**	**Interest Adjustments(2) during 2018**	**Closing Interest Amounts as of Dec-31-18**	**Forecast Principal Amount - 2019**	**Forecast Interest Amount - 2019**	**Closing Principal Balance - Including Forecast 2019**	**Closing Interest Balance - Including Forecast 2019**	**Principal Disposition during 2019 - instructed by OEB**	**Interest Disposition during 2019 - instructed by OEB**	**Closing Principal Balances as of Dec 31-18 Adjusted for Dispositions during 2019**	**Closing Interest Balances as of Dec 31-18 Adjusted for Dispositions during 2019**
Group 2 Accounts																			
Other Regulatory Assets - Sub-Account - Deferred IF	1508	$0				$0	$0				$0			$0	$0			$0	$0
Other Regulatory Assets - Sub-Account - Incrementa	1508	$0				$0	$0				$0			$0	$0			$0	$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	$0				$0	$0				$0			$0	$0			$0	$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508	$85,260,576	-$37,157,000			$48,103,576	$0				$0			$48,103,576	$0			$48,103,576	$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	-$22,747,626	-$30,124,132			-$52,871,758	-$276,927	-$630,950			-$907,877	-$22,772,218	-$228,813	-$75,643,977	-$1,136,691			-$75,643,977	-$1,136,691
Other Regulatory Assets - Sub-Account - EIP	1508	-$1,326,285	-$918,437			-$2,244,722	-$4,406	-$30,653			-$35,059	-$833,163	-$6,811	-$3,077,885	-$41,870			-$3,077,885	-$41,870
Other Regulatory Assets - Sub-Account - Derecognition	1508	-$15,494,253	-$5,487,866			-$20,982,120	-$403,867	-$383,862			-$787,730	-$12,135,667	-$121,938	-$33,117,786	-$909,668			-$33,117,786	-$909,668
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	-$412,158	-$100,000			-$512,158	-$9,729	-$8,376			-$18,105	-$100,000	-$11,412	-$612,158	-$29,517			-$612,158	-$29,517
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$4,018,166	$3,332,692			$7,350,858	$45,142	$105,434			$150,576	$4,143,047	$41,629	$11,493,905	$192,205			$11,493,905	$192,205
Other Regulatory Assets - Sub-Account - OCCP	1508	$27,036,693	-$79,824,824			-$52,788,130	$135,235	-$634,606			-$499,371	-$19,060,013	$0	-$71,848,144	-$499,371			-$71,848,144	-$499,371
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$4,271,000	$1,182,000			$5,453,000	$0	$0			$0	$2,627,000	$0	$8,080,000	$0			$8,080,000	$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0			$0	$0			$0	$0
Misc. Deferred Debits	1525	$0				$0	$0				$0			$0	$0			$0	$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0			$0	$0			$0	$0
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0			$0	$0			$0	$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0			$0	$0			$0	$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0			$0	$0			$0	$0
RSVA - One-time	1582	$0				$0	$0				$0			$0	$0			$0	$0
Other Deferred Credits	2425	$0				$0	$0				$0			$0	$0			$0	$0
Group 2 Sub-Total		$80,606,113	-$149,097,567	$0	$0	-$68,491,454	-$514,552	-$1,583,015	$0	$0	-$2,097,567	-$48,131,014	-$327,346	-$116,622,468	-$2,424,913	$0	$0	-$116,622,468	-$2,424,913
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0				$0	$0				$0			$0	$0			$0	$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0				$0	$2				$2			$0	$2			$0	$2
LRAM Variance Account[11]	**1568**	$16,060,274	$18,290,141	$6,447,545		$27,902,870	$211,807	$410,304	$121,812		$500,299			$27,902,870	$500,299	$12,048,215	$295,181	$15,854,655	$205,118
Total including Account 1568		$96,666,387	-$130,807,426	$6,447,545	$0	-$40,588,584	-$302,743	-$1,172,710	$121,812	$0	-$1,597,265	-$48,131,014	-$327,346	-$88,719,599	-$1,924,611	$12,048,215	$295,181	-$100,767,814	-$2,219,792
Renewable Generation Connection Capital Deferral A	1531	$0				$0	$0				$0			$0	$0			$0	$0
Renewable Generation Connection OM&A Deferral A	1532	$0				$0	$0				$0			$0	$0			$0	$0
Renewable Generation Connection Funding Adder D	1533	-$2,427,009	-$1,873,867			-$4,300,876	$0				$0	-$2,236,158.79		-$6,537,035	$0			-$6,537,035	$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0			$0	$0			$0	$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0			$0	$0			$0	$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0			$0	$0			$0	$0
Smart Meter Capital and Recovery Offset Variance -	1555	$0				$0	$0				$0			$0	$0			$0	$0
Smart Meter Capital and Recovery Offset Variance -	1555	$0				$0	$0				$0			$0	$0			$0	$0
Smart Meter Capital and Recovery Offset Variance -	1555	$7,316,327	-$4,029,308			$3,287,019	$219,457	$98,856			$318,313	-$4,674,263	-$318,313	-$1,387,244	$0			-$1,387,244	$0
Smart Meter OM&A Variance[4]	1556	$0				$0	$0				$0			$0	$0			$0	$0
Meter Cost Deferral Account (MIST Meters)[10]	1557	$0				$0	$0				$0			$0	$0			$0	$0
														$0	$0				
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575	$12,431,316	- 6,740,859.89			$5,690,456	$0				$0	-$7,248,817		-$1,558,360	$0			-$1,558,360	$0
Accounting Changes Under CGAAP Balance + Return Component[5]	1576	$0				$0	$0				$0			$0	$0			$0	$0

		Projected Interest on Dec-31-18 Balances					2.1.7 RRR	
Account Descriptions	**Account Number**	**Projected Interest from Jan 1, 2019 to December 31, 2019 on Dec 31 -18 balance adjusted for disposition during 2019 (6)**	**Projected Interest from January 1, 2020 to April 30, 2020 on Dec 31 -17 balance adjusted for disposition during 2019 (6)**	**Total Interest**	**Total Claim**		**As of Dec 31-18**	**Variance RRR vs. 2018 Balance (Principal + Interest)**
Group 2 Accounts								
Other Regulatory Assets - Sub-Account - Deferred IF	1508			$0		$0.00		$0
Other Regulatory Assets - Sub-Account - Incrementa	1508			$0		$0.00		$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508			$0		$0.00		$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508			$0	☑ Check to Dispose of Account	$48,103,576.00	$48,103,576	-$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	-$1,188,293		-$2,324,983	☑ Check to Dispose of Account	-$77,968,960.17	-$53,779,636	-$0
Other Regulatory Assets - Sub-Account - EIP	1508	-$50,450		-$92,320	☑ Check to Dispose of Account	-$3,170,205.06	-$2,279,781	-$0
Other Regulatory Assets - Sub-Account - Derecognition	1508	-$471,573		-$1,381,241	☑ Check to Dispose of Account	-$34,499,027.38	-$21,769,849	-$0
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	$850		-$28,667	☑ Check to Dispose of Account	-$640,825.32	-$530,264	-$0
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$165,211		$357,415	☑ Check to Dispose of Account	$11,851,320.65	$7,501,434	$1
Other Regulatory Assets - Sub-Account - OCCP	1508	-$1,186,413		-$1,685,784	☐ Check to Dispose of Account	-$73,533,927.94	-$53,287,501	$0
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$0	$0	$0	☑ Check to Dispose of Account	$8,080,000.00	$5,453,000	$0
Retail Cost Variance Account - Retail	1518			$0	☐ Check to Dispose of Account	$0.00		$0
Misc. Deferred Debits	1525			$0	☐ Check to Dispose of Account	$0.00		$0
Retail Cost Variance Account - STR	1548			$0		$0.00		$0
Board-Approved CDM Variance Account	1567			$0		$0.00		$0
Extra-Ordinary Event Costs	1572			$0		$0.00		$0
Deferred Rate Impact Amounts	1574			$0		$0.00		$0
RSVA - One-time	1582			$0		$0.00		$0
Other Deferred Credits	2425			$0	☐ Check to Dispose of Account	$0.00		$0
Group 2 Sub-Total		-$2,730,668	$0	-$5,155,581		-$121,778,049.22	-$70,589,021	$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592			$0		$0.00		-$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592			$2		$2.17		-$2
LRAM Variance Account[11]	**1568**			$205,118		$0.00	$28,403,169	-$0
Total including Account 1568		-$2,730,668	$0	-$4,950,460		-$121,778,047	-$42,185,852	-$2
Renewable Generation Connection Capital Deferral A	1531			$0		$0.00		$0
Renewable Generation Connection OM&A Deferral A	1532			$0		$0.00		$0
Renewable Generation Connection Funding Adder D	1533			$0		-$6,537,035.00	-$4,300,876	$0
Smart Grid Capital Deferral Account	1534			$0		$0.00		$0
Smart Grid OM&A Deferral Account	1535			$0		$0.00		$0
Smart Grid Funding Adder Deferral Account	1536			$0		$0.00		$0
Smart Meter Capital and Recovery Offset Variance -	1555			$0		$0.00		$0
Smart Meter Capital and Recovery Offset Variance -	1555			$0		$0.00		$0
Smart Meter Capital and Recovery Offset Variance -	1555			$0	☑ Check to Dispose of Account	-$1,387,243.88	$3,605,333	$0
Smart Meter OM&A Variance[4]	1556			$0		$0.00		$0
Meter Cost Deferral Account (MIST Meters)[10]	1557			$0		$0.00		$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575			$0	☐ Check to Dispose of Account	-$1,558,360.02	5,690,456.49	$0
Accounting Changes Under CGAAP Balance + Return Component[5]	1576			$0	☐ Check to Dispose of Account	$0.00		$0

Ontario Energy Board

2019 Deferral/Variance Account Workform

Accounts that produced a variance on the continuity schedule are listed below.
Please provide a detailed explanation for each variance below.

	Account Descriptions	Account Number	Variance RRR vs. 2017 Balance (Principal + Interest)	Explanation
3	RSVA - Wholesale Market Service Charge9	1580	$ (85,384.86)	The 2017 approved disposition for CBR class B interest of $85,385 was recorded as part of RSVA - WMS Charge (primary account) for the RRR 2.1.7 Trial Balance. For the purposes of this continuity, the interest component has been reported in the Sub-account CBR class B line. The amount corresponds to the interest approved in EB-2016-0254. See offsetting amount below in the Sub-account CBR Class B.
3.2	Variance WMS – Sub-account CBR Class B9	1580	$ 85,385.39	See above.

Ontario Energy Board

GA Analysis Workform

Version 1.0

Account 1589 Global Adjustment (GA) Analysis Workform

Input cells
Drop down cells

Utility Name TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

Note 1 **Year(s) Requested for Disposition** **2018**

Note 7 **Summary of GA (if multiple years requested for disposition)**

Year	Annual Net Change in Expected GA Balance from GA Analysis (cell K51)	Net Change in Principal Balance in the GL (cell C62)	Reconciling Items (sum of cells C63 to C75)	Adjusted Net Change in Principal Balance in the GL (cell C76)	Unresolved Difference	$ Consumption at Actual Rate Paid (cell J51)	Unresolved Difference as % of Expected GA Payments to IESO
2014	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
2015	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
2016	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
2017	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
2018	-$ 17,118,545	-$ 23,898,524	$ 11,149,436	-$ 12,749,088	$ 4,369,457	$ 833,670,695	0.5%
Cumulative Balance	**-$ 17,118,545**	**-$ 23,898,524**	**$ 11,149,436**	**-$ 12,749,088**	**$ 4,369,457**	**$ 833,670,695**	**N/A**

Ontario Energy Board

GA Analysis Workform

Note 2 **Consumption Data Excluding for Loss Factor (Data to agree with RRR as applicable)**

Year		2018		
Total Metered excluding WMP	C = A+B	24,466,430,392	kWh	100%
RPP	A	10,416,743,189	kWh	42.6%
Non RPP	B = D+E	14,049,687,203	kWh	57.4%
Non-RPP Class A	D	5,208,597,011	kWh	21.3%
Non-RPP Class B*	E	8,841,090,192	kWh	36.1%

*Non-RPP Class B consumption reported in this table is not expected to directly agree with the Non-RPP Class B Including Loss Adjusted Billed Consumption in the GA Analysis of Expected Balance table below. The difference should be equal to the loss factor.

Note 3 **GA Billing Rate**

GA is billed on the 1st Estimate

Please confirm that the GA Rate used for unbilled revenue is the same as the one used for billed revenue in any paticular month ☐

Note 4 **Analysis of Expected GA Amount**

Year	2018								
Calendar Month	Non-RPP Class B Including Loss Factor Billed Consumption (kWh)	Deduct Previous Month Unbilled Loss Adjusted Consumption (kWh)	Add Current Month Unbilled Loss Adjusted Consumption (kWh)	Non-RPP Class B Including Loss Adjusted Consumption, Adjusted for Unbilled (kWh)	GA Rate Billed ($/kWh)	$ Consumption at GA Rate Billed	GA Actual Rate Paid ($/kWh)	$ Consumption at Actual Rate Paid	Expected GA Variance ($)
	F	G	H	I = F-G+H	J	K = I*J	L	M = I*L	=M-K
January	849,734,205	850,744,627	842,429,225	841,418,803	0.08777	$ 73,851,328	0.06736	$ 56,677,971	-$ 17,173,358
February	799,751,814	842,429,225	705,359,910	662,682,499	0.07333	$ 48,594,508	0.08167	$ 54,121,280	$ 5,526,772
March	739,653,450	705,359,910	756,475,470	790,769,009	0.07877	$ 62,288,875	0.09481	$ 74,972,810	$ 12,683,935
April	767,838,600	756,475,470	761,171,140	772,534,270	0.09810	$ 75,785,612	0.09959	$ 76,936,688	$ 1,151,076
May	727,410,928	761,171,140	738,400,175	704,639,964	0.09392	$ 66,179,785	0.10793	$ 76,051,791	$ 9,872,006
June	782,233,924	738,400,175	735,320,321	779,154,070	0.13336	$ 103,907,987	0.11896	$ 92,688,168	-$ 11,219,819
July	781,663,293	735,320,321	861,017,528	907,360,500	0.08502	$ 77,143,790	0.07737	$ 70,202,482	-$ 6,941,308
August	822,933,360	861,017,528	868,275,307	830,191,139	0.07790	$ 64,671,890	0.07490	$ 62,181,316	-$ 2,490,573
September	802,911,438	868,275,307	785,460,234	720,096,365	0.08424	$ 60,660,918	0.08584	$ 61,813,072	$ 1,152,154
October	782,253,575	785,460,234	674,331,062	671,124,404	0.08921	$ 59,871,008	0.12059	$ 80,930,892	$ 21,059,884
November	682,530,587	674,331,062	699,869,426	708,068,951	0.12235	$ 86,632,236	0.09855	$ 69,780,195	-$ 16,852,041
December	692,616,487	699,869,426	781,348,434	774,095,495	0.09198	$ 71,201,304	0.07404	$ 57,314,030	-$ 13,887,273
Net Change in Expected GA Balance in the Year (i.e. Transactions in the Year)	**9,231,531,663**	**9,278,854,426**	**9,209,458,233**	**9,162,135,470**		**$ 850,789,240**		**$ 833,670,695**	**-$ 17,118,545**

Calculated Loss Factor **1.0363**

Note 5 **Reconciling Items**

	Item	Amount	Explanation
	Net Change in Principal Balance in the GL (i.e. Transactions in the Year)	(23,898,524)	
1a	True-up of GA Charges based on Actual Non-RPP Volumes - prior year	-	Not applicable as Toronto Hydro ("TH") records the true-up RPP settlement amounts with the IESO on a quarterly basis. The RPP amounts for 2018 are based on the actual IESO invoices received.
1b	True-up of GA Charges based on Actual Non-RPP Volumes - current year	-	Not applicable as Toronto Hydro ("TH") records the true-up RPP settlement amounts with the IESO on a quarterly basis. The RPP amounts for 2018 are based on the actual IESO invoices received.
2a	Remove prior year end unbilled to actual revenue differences	(1,595,003)	
2b	Add current year end unbilled to actual revenue differences	3,079,023	
3a	Remove difference between prior year accrual/forecast to actual from long term load transfers	-	Not applicable.
3b	Add difference between current year accrual/forecast to actual from long term load transfers	-	Not applicable.
4	Remove GA balances pertaining to Class A customers	3,542,616	Due to timing differences between Class A GA charges from the IESO and billings to Class A customers, $3.5M was included in the 2017 RSVA account pertaining to Class A Customers, which reversed in 2018. There is no Class A GA RSVA pertaining to 2018 activity.
5	Significant prior period billing adjustments recorded in current year	-	Not applicable.
6	Differences in GA IESO posted rate and rate charged on IESO invoice	-	Not applicable.
7	Differences in actual system losses and billed TLFs	6,122,800	
8	Others as justified by distributor		
9			
Note 6	**Adjusted Net Change in Principal Balance in the GL**	(12,749,088)	
	Net Change in Expected GA Balance in the Year Per Analysis	(17,118,545)	
	Unresolved Difference	4,369,457	
	Unresolved Difference as % of Expected GA Payments to IESO	0.52%	

Ontario Energy Board

1595 Analysis Workform

Version 1.0

Account 1595 Analysis Workform

Input cells
Drop down cells

Utility Name	TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	**Utility name must be selected**

1595 Rate Years Requested for Disposition

- ☐ **2012**
- ☐ **2013**
- ☐ **2014**
- ☐ **2015**
- ☑ **2016**

Ontario Energy Board

1595 Analysis Workform

Step 1

Components of the 1595 Account Balances:		Principal Balance Approved for Disposition	Carrying Charges Balance Approved for Disposition	Total Balances Approved for Disposition	Rate Rider Amounts Collected/Returned	Residual Balances Pertaining to Principal and Carrying Charges Approved for Disposition	Carrying Charges Recorded on Net Principal Account Balances	Total Residual Balances	Collections/Returns Variance (%)
Total Group 1 and Group 2 Balances excluding Account 1589 - Global Adjustment		-$65,881,308	-$2,489,641	-$68,370,949	-$70,894,315	$2,523,366	-$234,170	**$2,289,197**	**-3.7%**
Account 1589 - Global Adjustment		$94,368,616	$4,812,604	$99,181,220	$102,688,259	-$3,507,039	$426,282	**-$3,080,757**	**-3.5%**
Total Group 1 and Group 2 Balances		$28,487,308	$2,322,963	$30,810,271	$31,793,944	-$983,673	$192,113	**-$791,560**	**-3.2%**

*Unresolved differences of +/- 10% require further analysis and explanation. Amounts originally approved for disposition based on forecasted consumption or number of customers must be compared to actual figures.

Additional Notes and Comments

This is for 1595 2017 balances, tab name cannot be changed (not an option to be selected on Information Sheet). Balances approved per Decision and Rate Order EB-2016-0254 including LRAM.

Billing Determinants

In the green shaded cells, enter the data related to the **proposed** load forecast. Do not enter data for the MicroFit class.
Used 2020 Load Forecast

			A		B		C		D=A-C		E			F =B-C-E (deduct E if applicable)
Rate Class (Enter Rate Classes in cells below as they appear on your current tariff of rates and charges)	**Units**	**# of Customers**	**Total Metered kWh**	**Total Metered kVA**	**Metered kWh for Non-RPP Customers [5] (excluding WMP)**	**Metered kVA for Non-RPP Customers[5] (excluding WMP)**	**Metered kWh for Wholesale Market Participants (WMP)**	**Metered kVA for Wholesale Market Participants (WMP)**	**Total Metered kWh less WMP consumption *(if applicable)***	**Total Metered kVA less WMP consumption (if applicable)**	**Total Metered 2018 kWh for Class A Customers that were Class A for the entire period the GA balance accumulated**	**Total Metered 2018 kWh for Customers that Transitioned Between Class A and B during the period the GA balance accumulated**		**Non-RPP Metered Consumption for Current Class B Customers (Non-RPP Consumption excluding WMP, Class A and Transition Customers' Consumption**
RESIDENTIAL SERVICE CLASSIFICATION	kWh	615,118	4,531,218,421	-	120,867,876		-	-	4,531,218,421	-	-	-	**4,531,218,421**	120,867,876
COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CL	kWh	85,852	297,763,685	-	1,256,022		-	-	297,763,685	-	-	-	**297,763,685**	1,256,022
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICAT	kWh	71,599	2,299,006,608	-	340,748,367		-	-	2,299,006,608	-	-	-	**2,299,006,608**	340,748,367
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kVA	10,417	9,659,470,299	24,899,004	6,675,659,664	17,765,688	51,161,050	107,338	9,608,309,249	24,791,665	172,242,450	171,190,992	**9,264,875,806**	6,332,226,222
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICAT	kVA	430	4,595,446,119	10,406,674	4,411,896,455	10,021,029	430,714	14,192	4,595,015,405	10,392,482	2,849,579,357	801,154,480	**944,281,567**	761,162,617
LARGE USE SERVICE CLASSIFICATION	kVA	38	2,164,924,150	4,600,360	1,908,284,149	4,126,573	275,445,723	503,078	1,889,478,427	4,097,281	1,678,111,033	29,403,915	**181,963,479**	200,769,201
STANDBY POWER SERVICE CLASSIFICATION	kVA		-	-			-	-	-	-	-	-	**-**	-
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	825	40,588,612	-	118,578		-	-	40,588,612	-	-	-	**40,588,612**	118,578
STREET LIGHTING SERVICE CLASSIFICATION	kVA	1	116,219,746	326,300	116,219,746	326,300	-	-	116,219,746	326,300	-	-	**116,219,746**	116,219,746
Total		**784,280**	**23,704,637,639**	**40,232,337**	**13,575,050,857**	**32,239,590**	**327,037,487**	**624,609**	**23,377,600,153**	**39,607,728**	**4,699,932,841**	**1,001,749,388**	**17,675,917,924**	**7,873,368,628**

[1] Account 1595 sub-accounts are to be allocated to rate classes in proportion to the recovery share as established when rate riders were implemented.

[2] The proportion of customers for the Residential and GS<50 Classes will be used to allocate Account 1551.

[3] Input the allocation as determined in the LRAMVA model. The associated rate riders will be calculated in the EDDVAR model.

[5] If a distributor uses the actual GA price to bill non-RPP Class B customers for an entire rate class, it must exclude these customers from the allocation of the GA balance and the calculation of the resulting rate riders. These rate classes are not

Allocation of Balances

		Amounts from Sheet 2	Allocator	RESIDENTIAL SERVICE CLASSIFICATION	COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICATION	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION	LARGE USE SERVICE CLASSIFICATION	STANDBY POWER SERVICE CLASSIFICATION	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	STREET LIGHTING SERVICE CLASSIFICATION
LV Variance Account	1550	330,703	kWh	63,215	4,154	32,073	134,759	64,111	30,203	0	566	1,621
Smart Metering Entity Charge Variance Account	1551	(738,259)	# of Customers	(587,800)	(82,039)	(68,419)	0	0	0	0	0	0
RSVA - Wholesale Market Service Charge	1580	(4,346,196)	kWh	(842,412)	(55,358)	(427,415)	(1,786,308)	(854,272)	(351,278)	0	(7,546)	(21,607)
RSVA - Retail Transmission Network Charge	1584	9,204,066	kWh	1,759,387	115,616	892,661	3,750,591	1,784,325	840,599	0	15,760	45,126
RSVA - Retail Transmission Connection Charge	1586	17,882,318	kWh	3,418,263	224,627	1,734,326	7,286,917	3,466,715	1,633,177	0	30,619	87,674
RSVA - Power (excluding Global Adjustment)	1588	(5,646,009)	kWh	(1,094,351)	(71,914)	(555,241)	(2,320,538)	(1,109,759)	(456,335)	0	(9,803)	(28,069)
RSVA - Global Adjustment	1589	(22,861,166)	Non-RPP kWh	(350,953)	(3,647)	(989,399)	(18,386,294)	(2,210,117)	(582,955)	0	(344)	(337,456)
Total of Group 1 Accounts (excluding 1589)		**16,686,623**		**2,716,302**	**135,086**	**1,607,985**	**7,065,421**	**3,351,120**	**1,696,366**	**0**	**29,597**	**84,746**
Variance WMS - Sub-account CBR Class B (separate rate rider if no Class A Customers)	**1580**	**(570,202)**	**kWh**	**(146,171)**	**(9,605)**	**(74,163)**	**(298,873)**	**(30,461)**	**(5,870)**	**0**	**(1,309)**	**(3,749)**
Total of Group 1 Accounts (1550, 1551, 1584, 1586 and 1595)		**26,678,828**		**4,653,065**	**262,358**	**2,590,641**	**11,172,267**	**5,315,152**	**2,503,979**	**0**	**46,945**	**134,421**
Total of Account 1580 and 1588 (not allocated to WMPs)		**(9,992,205)**		**(1,936,763)**	**(127,272)**	**(982,656)**	**(4,106,846)**	**(1,964,031)**	**(807,613)**	**0**	**(17,349)**	**(49,675)**
Balance of Account 1589 Allocated to Non-WMPs		**(22,861,166)**		**(350,953)**	**(3,647)**	**(989,399)**	**(18,386,294)**	**(2,210,117)**	**(582,955)**	**0**	**(344)**	**(337,456)**

Class A Consumption Data

1	**Please enter the Year the Account 1589 GA Balance was Last Disposed.**	2017	**(e.g. If in the 2018 EDR process, you received approval to dispose the GA variance account balance as at December 31, 2016, enter 2016.)**
2a	**Did you have any customers who transitioned between Class A and Class B (transition customers) during the period the Account 1589 GA balance accumulated (i.e. from year after the balance was last disposed to 2017)?**	Yes	**(e.g. If you received approval to dispose the GA account balance as at December 31, 2016, the period the GA accumulated would be 2017.)**
2b	**Did you have any customers who transitioned between Class A and Class B (transition customers) during the period the Account 1580, sub-account CBR Class B balance accumulated (i.e. from year after the balance was last disposed to 2017).**	Yes	**(e.g. If the CBR Class B balance was last disposed as at December 31, 2016, the period the CBR Class B variance accumulated would be 2017.)**
3a	**Enter the number of transition customers you had during the period the Account 1589 GA balance accumulated.**	127	

Transition Customers - Non-loss Adjusted Billing Determinants by Customer

			2018	
Customer	**Rate Class**		**January to June**	**July to December**
Customer 1	GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICAT	kWh	15,237,254	10,750,334
		kVA	37,162	31,849
		Class A/B	A	B
Customer 2	GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICAT	kWh	70,146,308	75,057,096
		kVA	198,802	199,630
		Class A/B	B	A
Customer 3	GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIF	kWh	68,119,407	65,561,674
		kVA	199,249	193,805
		Class A/B	A	B
Customer 4	GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIF	kWh	329,125,988	338,347,412
		kVA	698,099	733,007
		Class A/B	B	A
Customer 5	LARGE USE SERVICE CLASSIFICATION	kWh	14,205,212	15,198,704
		kVA	41,746	41,028
		Class A/B	B	A

3b	**Enter the number of customers who were Class A during the entire period since the Account 1589 GA balance accumulated (i.e. did not transition between Class A and B).**	278	

Class A Customers - Billing Determinants by Customer

Customer	**Rate Class**		**2018**
Customer A1	GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICAT	kWh	172,242,450
		kVA	419,165
Customer A2	GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIF	kWh	2,849,579,357
		kVA	6,029,167
Customer A3	LARGE USE SERVICE CLASSIFICATION	kWh	1,678,111,033
		kVA	3,329,196

GA Allocation

This tab allocates the GA balance to transition customers (i.e Class A customers who were former Class B customers and Class B customers who were former Class A customers) who contributed to the current GA balance. The tables below calculates specific amounts for each transition customer. The general GA rate rider to non-RPP customers is not to be charged to the transition customers that are allocated amounts in the table below. Consistent with with prior decisions, distributors are generally expected to settle the amount through 12 equal adjustments to bills.

Year of the Account 1589 GA Balance Last Disposed	**2017**

Allocation of total Non-RPP Consumption (kWh) between Current Class B and Class A/B Transition Customers

		Total	**2018**
Total Class B Consumption for Years During Balance Accumulation (Non-RPP Consumption LESS WMP Consumption and Consumption for Class A customers who were Class A for partial and full year)	A	8,363,158,143	8,363,158,143
All Class B Consumption (i.e. full year or partial year) for Transition Customers	B	489,789,515	489,789,515
Transition Customers' Portion of Total Consumption	C=B/A	**5.86%**	**7,873,368,628**

Allocation of Total GA Balance $

Total GA Balance	D	-$	24,283,322
Transition Customers Portion of GA Balance	E=C*D	-$	1,422,156
GA Balance to be disposed to Current Class B Customers through Rate Rider	F=D-E	-$	22,861,166

Allocation of GA Balances to Class A/B Transition Customers

# of Class A/B Transition Customers		127				
Customer		**Total Metered Consumption (kWh) for Transition Customers During the Period They Were Class B Customers**	**Metered Consumption (kWh) for Transition Customers During the Period They Were Class B Customers in 2017**	**% of kWh**	**Customer Specific GA Allocation During the Period They Were a Class B customer**	**Monthly Equal Payments**
Customer 1		10,750,334	10,750,334	2.19%	-$ 31,215	-$ 2,601
Customer 2		70,146,308	70,146,308	14.32%	-$ 203,677	-$ 16,973
Customer 3		65,561,674	65,561,674	13.39%	-$ 190,365	-$ 15,864
Customer 4		329,125,988	329,125,988	67.20%	-$ 955,652	-$ 79,638
Customer 5		14,205,212	14,205,212	2.90%	-$ 41,246	-$ 3,437
TOTAL		**489,789,515**	**489,789,515**	**100.00%**	**-$ 1,422,156**	**-$ 118,513**

CBR B Allocation

This tab allocates the CBR Class B balance to transition customers (i.e Class A customers who were former Class B customers and Class B customers who were former Class A customers) who contributed to the current CBR Class B balance. The tables below calculate specific amounts for each transition customer. The general CBR Class B rate rider is not to be charged to the transition customers that are allocated amounts in the table below. Consistent with with prior decisions, distributors are generally expected to settle the amount through 12 equal adjustments to bills.

Please enter the Year the Account 1580 CBR Class B was Last Disposed. **2017**

(Note: Account 1580, Sub-account CBR Class B was established starting in 2015)

Allocation of total Consumption (kWh) between Class B and Class A/B Transition Customers

		Total	2017
Total Class B Consumption for Years During Balance Accumulation (Total Consumption Less WMP Consumption and Consumption for Class A who were Class A for the full year)	A	18,165,707,440	18,165,707,440
All Class B Consumption (i.e. full year or partial year) for Transition Customers	B	489,789,515	489,789,515
Transition Customers' Portion of Total Consumption	C=B/A	2.70%	17,675,917,924

-

Allocation of Total CBR Class B Balance $

Total CBR Class B Balance	D	-$ 586,002
Transition Customers Portion of CBR Class B Balance	E=D*C	-$ 15,800
CBR Class B Balance to be disposed to Current Class B Customers through Rate Rider	F=D-E	-$ 570,202

Allocation of CBR Class B Balances to Transition Customers

# of Class A/B Transition Customers		127				
Customer		**Total Metered Class B Consumption (kWh) for Transition Customers During the Period They were Class B Customers**	**Metered Class B Consumption (kWh) for Transition Customers During the Period They were Class B Customers in 2018**	**% of kWh**	**Customer Specific CBR Class B Allocation During the Period They Were a Class B Customer**	**Monthly Equal Payments**
Customer 1		10,750,334	10,750,334	2.19%	-$ 347	-$ 29
Customer 2		70,146,308	70,146,308	14.32%	-$ 2,263	-$ 189
Customer 3		65,561,674	65,561,674	13.39%	-$ 2,115	-$ 176
Customer 4		329,125,988	329,125,988	67.20%	-$ 10,617	-$ 885
Customer 5		14,205,212	14,205,212	2.90%	-$ 458	-$ 38
Total		**489,789,515**	**489,789,515**	100.00%	**-$ 15,800**	**-$ 1,317**

CBR B

The purpose of this tab is to calculate the billing determinants for CBR rate riders for all current Class B customers who did not transition between Class A and B in the period since the Account 1580, sub-account CBR Class B balance accumulated.

The Year the Account 1580 CBR Class B was Last Disposed. 2017 **(Note: Account 1580, Sub-account CBR Class B was established starting in 2015)**

		Total Metered 2018 Consumption Minus WMP		Total Metered 2018 Consumption for Class A customers that were Class A for the entire period CBR Class B balance accumulated		Total Metered 2018 Consumption for Customers that Transitioned Between Class A and B during the period CBR Class B balance accumulated		Metered Consumption for Current Class B Customers (Total Consumption LESS WMP, Class A and Transition Customers' Consumption)		% of total kWh
		kWh	kVA	kWh	kVA	kWh	kVA	kWh	kVA	
RESIDENTIAL SERVICE CLASSIFICATION		4,531,218,421	-	0	0	0	0	4,531,218,421	-	26%
COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICAT		297,763,685	-	0	0	0	0	297,763,685	-	2%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION		2,299,006,608	-	0	0	0	0	2,299,006,608	-	13%
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION		9,608,309,249	24,791,665	172,242,450	419,165	171,190,992	467,443	9,264,875,806	23,905,058	52%
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION		4,595,015,405	10,392,482	2,849,579,357	6,029,167	801,154,480	1,824,160	944,281,567	2,539,155	5%
LARGE USE SERVICE CLASSIFICATION		1,889,478,427	4,097,281	1,678,111,033	3,329,196	29,403,915	82,773	181,963,479	685,312	1%
STANDBY POWER SERVICE CLASSIFICATION		-	-	0	0	0	0	-	-	0%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION		40,588,612	-	0	0	0	0	40,588,612	-	0%
STREET LIGHTING SERVICE CLASSIFICATION		116,219,746	326,300	0	0	0	0	116,219,746	326,300	1%
	Total	23,377,600,153	39,607,728	4,699,932,841	9,777,527	1,001,749,388	2,374,376	17,675,917,924	27,455,825	100%

Rate Rider Calculations

Please indicate the Rate Rider Recovery Period (in years) | 1

Rate Rider Calculation for Group 1 Deferral / Variance Accounts Balances (excluding Global Adj.)

1550, 1551, 1584, 1586, 1595, 1580 and 1588 per instructions

Rate Class (Enter Rate Classes in cells below)	Units	kVA / kWh / # of Customers	Allocated Group 1 Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts	ROUNDED Rate Rider for Deferral/Variance Accounts	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	4,531,218,421	$ 2,716,302	**0.00060**	0.00060	$/kWh
COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICATIO	kWh	297,763,685	$ 135,086	**0.00045**	0.00045	$/kWh
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	2,299,006,608	$ 1,607,985	**0.00070**	0.00070	$/kWh
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kVA	24,899,004	$ 11,172,267	**0.44256**	0.44260	$/kVA
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION	kVA	10,406,674	$ 5,315,152	**0.50375**	0.50370	$/kVA
LARGE USE SERVICE CLASSIFICATION	kVA	4,600,360	$ 2,503,979	**0.53684**	0.53680	$/kVA
STANDBY POWER SERVICE CLASSIFICATION	kVA	-	$ -	**-**	-	$/kVA
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	40,588,612	$ 29,597	**0.00073**	0.00073	$/kWh
STREET LIGHTING SERVICE CLASSIFICATION	kVA	326,300	$ 84,746	**0.25616**	0.25620	$/kVA
Total			**$ 23,565,113**			

Rate Rider Calculation for Group 1 Deferral / Variance Accounts Balances (excluding Global Adj.) - NON-WMP

1580 and 1588

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Group 1 Balance - Non-WMP	Rate Rider for Deferral/Variance Accounts for Non-WMP	ROUNDED Rate Rider for Deferral/Variance Accounts for Non-WMP	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	4,531,218,421	$ -	**-**	-	$/kWh
COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICATIO	kWh	297,763,685	$ -	**-**	-	$/kWh
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	2,299,006,608	$ -	**-**	-	$/kWh
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kVA	24,791,665	-$ 4,106,846	- **0.16339**	- 0.16340	$/kVA
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION	kVA	10,392,482	-$ 1,964,031	- **0.18640**	- 0.18640	$/kVA
LARGE USE SERVICE CLASSIFICATION	kVA	4,097,281	-$ 807,613	- **0.19441**	- 0.19440	$/kVA
STANDBY POWER SERVICE CLASSIFICATION	kVA	-	$ -	**-**	-	$/kVA
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	40,588,612	$ -	**-**	-	$/kWh
STREET LIGHTING SERVICE CLASSIFICATION	kVA	326,300	$ -	**-**	-	$/kVA
Total			**-$ 6,878,490**			

Only for rate classes with WMP customers are the Deferral/Variance Account Rate Riders for Non-WMP calculated separately in the table above. For all rate classes without WMP customers, balances in Accounts 1580 and 1588 are included in Deferral/Variance Account Rate Riders calculated in the first table above and disposed through a combined Deferral/Variance Account and Rate Rider.

Rate Rider Calculation for Account 1580, sub-account CBR Class B

1580, Sub-account CBR Class B

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Sub-account 1580 CBR Class B Balance	Rate Rider for Sub-account 1580 CBR Class B	ROUNDED Rate Rider for Sub-account 1580 CBR Class B	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	4,531,218,421	-$ 146,171	- **0.00003**	- 0.00003	$/kWh
COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICATIO	kWh	297,763,685	-$ 9,605	- **0.00003**	- 0.00003	$/kWh
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	2,299,006,608	-$ 74,163	- **0.00003**	- 0.00003	$/kWh
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kVA	23,905,058	-$ 298,873	- **0.01233**	- 0.01230	$/kVA
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION	kVA	2,539,155	-$ 30,461	- **0.01183**	- 0.01180	$/kVA
LARGE USE SERVICE CLASSIFICATION	kVA	685,312	-$ 5,870	- **0.00845**	- 0.00840	$/kVA
STANDBY POWER SERVICE CLASSIFICATION	kVA	-	$ -	**-**	-	$/kVA
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	40,588,612	-$ 1,309	- **0.00003**	- 0.00003	$/kWh
STREET LIGHTING SERVICE CLASSIFICATION	kVA	326,300	-$ 3,749	- **0.01133**	- 0.01130	$/kVA
Total			**-$ 570,202**			

Rate rider calculated separately only if Class A customers exist during the period the balance accumulated

Rate Rider Calculation for RSVA - Power - Global Adjustment

Balance of Account 1589 Allocated to Non-WMPs

Rate Class (Enter Rate Classes in cells below)	Units	kWh	Allocated Global Adjustment Balance	Rate Rider for RSVA - Power - Global Adjustment	ROUNDED Rate Rider for RSVA - Power - Global Adjustment	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	120,867,876	-$ 350,953	- **0.00290**	- 0.00290	$/kWh
COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICATIO	kWh	1,256,022	-$ 3,647	- **0.00290**	- 0.00290	$/kWh
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	340,748,367	-$ 989,399	- **0.00290**	- 0.00290	$/kWh
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kWh	6,332,226,222	-$ 18,386,294	- **0.00290**	- 0.00290	$/kWh
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION	kWh	761,162,617	-$ 2,210,117	- **0.00290**	- 0.00290	$/kWh
LARGE USE SERVICE CLASSIFICATION	kWh	200,769,201	-$ 582,955	- **0.00290**	- 0.00290	$/kWh
STANDBY POWER SERVICE CLASSIFICATION	kWh	-	$ -	**-**	-	$/kWh
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	118,578	-$ 344	- **0.00290**	- 0.00290	$/kWh
STREET LIGHTING SERVICE CLASSIFICATION	kWh	116,219,746	-$ 337,456	- **0.00290**	- 0.00290	$/kWh
Total			**-$ 22,861,166**			

Group 2 Rate Riders Development

	% to split by Class	Total	Residential	CS Muti-Units Residential	GS < 50 kW	GS - 50 to 999 kW	GS > 1,000 to 4,999 kW	Large User =>5,000 kW	Street Lighting	USL (Connections)	USL (Customer)
	Allocators										
	2016 kWh	100.0%	20.0%	0.9%	9.6%	40.6%	19.4%	8.8%	0.5%	0.2%	0.0%
	2017 Distribution Revenue	100.0%	39.7%	3.7%	14.2%	27.0%	8.5%	4.4%	2.0%	0.5%	0.0%
	2020 Revenue Offsets	100.0%	49.2%	4.0%	20.4%	18.3%	3.5%	1.5%	2.3%	0.8%	0.0%
	2009/10 Reg Assets Allocation	100.0%	18.2%	0.7%	8.2%	42.4%	19.6%	10.2%	0.5%	0.2%	0.0%
	2013 Non-RPP kWh	100.0%	2.1%	0.0%	2.4%	48.3%	31.0%	15.4%	0.8%	0.0%	0.0%
	LRAMVA	100.0%	7.2%	0.3%	29.8%	48.2%	7.3%	7.3%	0.0%	0.0%	0.0%
	2013 SM Entity Rider Recovery	100.0%	85.2%	5.2%	9.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Stranded Meters	100.0%	51.4%	0.0%	31.8%	16.8%	0.0%	0.0%	0.0%	0.0%	0.0%
	2020 kWh forecast	100.0%	19.4%	1.3%	9.8%	41.1%	19.7%	8.1%	0.5%	0.2%	0.0%
	Monthly Billing Conversion	100.0%	89.6%	0.0%	10.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Distribution Revenue GS>50 kW	100.0%	0.0%	0.0%	0.0%	63.6%	20.0%	10.5%	4.7%	1.2%	0.0%
	AR Credits	100.0%	83.5%	0.0%	15.0%	1.5%	0.0%	0.0%	0.0%	0.0%	0.0%
	Other Allocators 5	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Other Allocators 6	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Other Allocators 7	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Other Allocators 8	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Other Allocators 9	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

	RA Balance by Class	Allocators (Drop Down)	Total	Residential	CS Muti-Units Residential	GS < 50 kW	GS - 50 to 999 kW	GS > 1,000 to 4,999 kW	Large User =>5,000 kW	Street Lighting	USL (Connections)	USL (Customer)
1	Stranded Meters	Stranded Meters	- 1,387,244	- 713,195	-	- 441,086	- 232,962	-	-	-	-	-
2	Wireless pole attachments Rev	2020 Revenue Offsets	- 640,825	- 315,551	- 25,503	- 130,871	- 117,301	- 22,483	- 9,513	- 14,612	- 4,992	-
3	Impact for USGAAP (Actuarial loss on OPEB)	2017 Distribution Revenue	48,103,576	19,087,915	1,783,829	6,806,795	12,996,819	4,093,974	2,135,323	953,529	245,391	-
4	IFRS-CGAAP PP&E	2017 Distribution Revenue	- 1,558,360	- 618,371	- 57,789	- 220,512	- 421,044	- 132,628	- 69,176	- 30,890	- 7,950	-
5	CRRRVA	2017 Distribution Revenue	- 77,968,960	- 30,938,757	- 2,891,330	- 11,032,834	- 21,065,970	- 6,635,741	- 3,461,051	- 1,545,533	- 397,744	-
6	Monthly Billing	Monthly Billing Conversion	11,851,321	10,624,432	-	1,226,889	-	-	-	-	-	-
8	External Driven Capital	2017 Distribution Revenue	- 3,170,205	- 1,257,965	- 117,561	- 448,593	- 856,539	- 269,808	- 140,726	- 62,841	- 16,172	-
9	OPEB cash vs accrual	2017 Distribution Revenue	8,080,000	3,206,214	299,631	1,143,343	2,183,087	687,668	358,672	160,165	41,219	-
10	Derecognition	2017 Distribution Revenue	- 34,499,027	- 13,689,512	- 1,279,331	- 4,881,712	- 9,321,087	- 2,936,125	- 1,531,416	- 683,854	- 175,990	-
11	Deferred Gain on disposals	2017 Distribution Revenue	- 11,780,824	- 4,674,733	- 436,869	- 1,667,021	- 3,182,991	- 1,002,636	- 522,952	- 233,524	- 60,098	-
12	Operations Consolidation Plan Sharing Variance	2017 Distribution Revenue	- 73,533,928	- 29,178,898	- 2,726,866	- 10,405,264	- 19,867,695	- 6,258,287	- 3,264,180	- 1,457,620	- 375,119	-
13	Excess Expansion Deposits	Distribution Revenue GS>50 kW	- 8,021,484	-	-	-	- 5,104,215	- 1,607,818	- 838,601	- 374,478	- 96,372	-
14	AR Credits	AR Credits	- 3,407,868	- 2,844,480	-	- 510,430	- 52,044	- 415	-	-	- 499	-
	Total		- 147,933,830	- 51,312,902	- 5,451,788	- 20,561,296	- 45,041,941	- 14,084,299	- 7,343,619	- 3,289,659	- 848,326	

Note: This table lists all forecasted regulatory account balances proposed for clearance by THESL over the 2020-2024 period ($147.9M). The summary of amounts proposed for disposition in Tables 16 and 17, Exhibit X_T9_S01 excludes disposition of amounts described in Exhibit 8, Tab 1, Schedule 1, section 4.7. The continuity schedule (Exhibit X-T9-S01 App A) lists only the regulatory accounts previously approved by the OEB for tracking.

	Load / Customers / Devices / Connections Forecast		Total	Residential	CS Muti-Units Residential	GS < 50 kW	GS - 50 to 999 kW	GS > 1,000 to 4,999 kW	Large User =>5,000 kW	Street Lighting	USL (Connections)	USL (Customer)
	2020 Forecast Dist Billing Determinants (Jan - Dec)											
	kVA		40,232,337	NA	NA	NA	24,899,004	10,406,674	4,600,360	326,300	NA	-
	kWh		23,377,600,153	4,531,218,421	297,763,685	2,299,006,608	9,608,309,249	4,595,015,405	1,889,478,427	116,219,746	40,588,612	-
	Number of Customers		784,280	615,118	85,852	71,599	10,417	430	38	1	-	825
	Devices/Connections		177,454	NA	NA	NA	NA	NA	NA	165,274	12,180	-

	Rate Riders	RR Pass-through or not	Proposed Recovery Period (years)	Amount	Allocators	Rate Rider Start Year	Rate Rider End Year	Billing Unit	Residential	CS Muti-Units Residential	GS < 50 kW	GS - 50 to 999 kW	GS > 1,000 to 4,999 kW	Large User =>5,000 kW	Street Lighting	USL (Connections)	USL (Customer)
	Volumetric Rate Riders																
1	Stranded Meters	Not Pass-through	5.00	- 1,387,244	Stranded Meters	2020	2024	Customers [1]	- 0.02	-	- 0.10	- 0.37	-	-	-	-	-
2	Wireless pole attachments Rev	Not Pass-through	5.00	- 640,825	2020 Revenue Offsets	2020	2024	Cust.+ Usage [1]	- 0.01	-	- 0.00001	- 0.00090	- 0.00040	- 0.00040	- 0.00880	- 0.00002	-
3	Impact for USGAAP (Actuarial loss on OPEB)	Not Pass-through	5.00	48,103,576	2017 Distribution Reven	2020	2024	Cust.+ Usage [1]	0.51	0.34	0.00059	0.10300	0.07760	0.09160	0.57640	0.00121	-
4	IFRS-CGAAP PP&E	Not Pass-through	5.00	- 1,558,360	2017 Distribution Reven	2020	2024	Cust.+ Usage [1]	- 0.02	- 0.01	- 0.00002	- 0.00330	- 0.00250	- 0.00300	- 0.01870	- 0.00004	-
5	CRRRVA	Not Pass-through	5.00	- 77,968,960	2017 Distribution Reven	2020	2024	Cust.+ Usage [1]	- 0.83	- 0.55	- 0.00096	- 0.16690	- 0.12580	- 0.14840	- 0.93430	- 0.00196	-
6	Monthly Billing	Not Pass-through	5.00	11,851,321	Monthly Billing Convers	2020	2024	Cust.+ Usage [1]	0.28	-	0.00011	-	-	-	-	-	-
8	External Driven Capital	Not Pass-through	5.00	- 3,170,205	2017 Distribution Reven	2020	2024	Cust.+ Usage [1]	- 0.03	- 0.02	- 0.00004	- 0.00680	- 0.00510	- 0.00600	- 0.03800	- 0.00008	-
9	OPEB cash vs accrual	Not Pass-through	5.00	8,080,000	2017 Distribution Reven	2020	2024	Cust.+ Usage [1]	0.09	0.06	0.00010	0.01730	0.01300	0.01540	0.09680	0.00020	-
10	Derecognition	Not Pass-through	5.00	- 34,499,027	2017 Distribution Reven	2020	2024	Cust.+ Usage [1]	- 0.37	- 0.24	- 0.00042	- 0.07380	- 0.05570	- 0.06570	- 0.41340	- 0.00087	-
11	Deferred Gain on disposals	Not Pass-through	5.00	- 11,780,824	2017 Distribution Reven	2020	2024	Cust.+ Usage [1]	- 0.12	- 0.08	- 0.00015	- 0.02520	- 0.01900	- 0.02240	- 0.14120	- 0.00030	-
12	Operations Consolidation Plan Sharing Variance	Not Pass-through	5.00	- 73,533,928	2017 Distribution Reven	2020	2024	Cust.+ Usage [1]	- 0.78	- 0.52	- 0.00091	- 0.15740	- 0.11860	- 0.14000	- 0.88120	- 0.00185	-
13	Excess Expansion Deposits	Not Pass-through	5.00	- 8,021,484	Distribution Revenue GS	2020	2024	Cust.+ Usage [1]	-	-	-	- 0.04040	- 0.03050	- 0.03600	- 0.22640	- 0.00047	-
14	AR Credits	Not Pass-through	5.00	- 3,407,868	AR Credits	2020	2024	Cust.+ Usage [1]	- 0.08	-	- 0.00004	- 0.00040	-	-	-	-	-

[1] "Customers" means Residential, GS < 50 kW and GS 50 to 999 kW rates recovery are based on $/cust/30 days
[1] "Cust.+Usage" means Residential and CSMUR rates recovery are based on $/cust/30 days and all other Rate classes recovery are based on $/kWh or $/kVA or $/Device or $/Connection

December 31, 2018 - Reconciliation of Sale of Electricity and Cost of Power Expense
Filing Requirement 2.9 - Deferral and Variance Accounts

The sale of electricity and cost of power expense have been reconciled to the Audited Financial Statements and the net profit is zero as shown in the tables below.

The IESO Global Adjustment charge is pro-rated into the RPP and Non-RPP portions.

Table 1: Sale of Electricity and Cost of Power Expense

SALE OF ELECTRICITY		
USofA		**Dec 31 2018 RRR ($,000's)**
4006	Residential Energy Sales	-461,396
4010	Commercial Energy Sales	-1,481,102
4020	Energy Sales to Large Users	-171,949
4025	Street Lighting Energy Sales	-7,015
4035	General Energy Sales	-231,515
4050	Revenue Adjustment	-1,609
4062	Billed WMS	-93,145
4066	Billed NW	-156,050
4068	Billed CN	-126,607
4075	Billed - LV	0
4076	Billed Smart Metering Entity Charge	-5,620
	Total Sale of Electricity Revenue	**-2,736,007**
	Board filing 2.1.13 Sale of Electricity	**-2,736,007**
COST OF POWER EXPENSE		
USofA		**Dec 31 2018 RRR ($,000's)**
4705	Power Purchased	1,225,222
4707	Charges - Global Adjustment	1,129,362
4708	Charges-WMS	93,145
4714	Charges-NW	156,050
4716	Charges-CN	126,607
4750	Charges - LV	0
4751	Charges Smart Metering Entity Chg	5,620
	Total Cost of Power Expense	**2,736,007**
	Board filing 2.1.13 Cost of Power Expense	**2,736,007**

December 31, 2018 - Sale of Electricity and Cost of Power Expense
THESL Audited Financial Statements (AFS) Mapped to USofA Accounts
Filing Requirement 2.9 - Deferral and Variance Accounts

The sale of electricity and cost of power expense have been reconciled to the Audited Financial Statements and the net profit is zero as shown in the tables below.
reconciled to the RRR filed Sale of electricity and Cost of power expense OEB accounts.

Table 2: USofA Balances Mapped and Reconciled to the AFS - Sale of Electricity and Cost of Power Expense - Year ended December 31, 2018

	THESL Consolidated Audited 2018	Less: Net Movement adjustment	Adjusted THESL Consolidated Audited 2017	Dec 31 2018 RRR	Difference	Notes
	($,000s) (1)	($,000s) (2)	($,000s) (3)=(1)-(2)	($,000s) (4)	($,000s) (5)=(3)-(4)	
Sale of electricity	-2,704,128	-84,473	-2,619,655	**-2,736,007**	116,352	**1**
Cost of power expense	2,646,286	26,631	2,619,655	**2,736,007**	-116,352	**2**

Note 1: "Sale of electricity" difference of $116,352: Adjusted AFS balance of ($2,704,128) versus RRR balance of ($2,736,007), as follows:	**($,000s)**
a. For RRR reporting, the Global Adjustment (GA) modifier is presented gross in Energy sales as it should keep THESL financially whole/neutral for THESL's billing to customers who qualified for the GA credit. For AFS, the GA modifier is netted with Energy purchases per the new IFRS 15, which requires Energy sales to be recorded at the price customer pays.	110,732
b. Smart Metering Entity charge: As per AFS GAAP, THESL books the Smart Metering entity revenue and charge on a net basis, while for RRR it is booked on a gross basis, in the prescribed regulatory accounts 4076 "Billed Smart Metering Entity Charge" and 4751 "Charges Smart Metering Entity Charge":	5,620
	116,352

Note 2: "Cost of power expense" difference of ($116,352): Adjusted AFS balance of $2,646,286 versus RRR balance of $2,736,007, as follows:	**($,000s)**
a. For RRR reporting, the Global Adjustment (GA) modifier is presented gross in Energy sales as it should keep THESL financially whole/neutral for THESL's billing to customers who qualified for the GA credit. For AFS, the GA modifier is netted with Energy purchases per the new IFRS 15, which requires Energy sales to be recorded at the price customer pays.	-110,732
b. Smart Metering Entity charge: As per AFS GAAP, THESL books the Smart Metering entity revenue and charge on a net basis, while for RRR it is booked on a gross basis, in the prescribed regulatory accounts 4076 "Billed Smart Metering Entity Charge" and 4751 "Charges Smart Metering Entity Charge"	-5,620
	-116,352